ALJ/SK/jt

ORIGINAL

Decision 87 11 024 NOV 13 1987

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Second application of Pacific Gas and Electric Company for approval of certain standards 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

SECOND INTERIM OPINION - COMPLIANCE PHASE:
AVOIDABLE MEGAWATTS, REINSTATEMENT OF STANDARD OFFER 2

INDEX

SECOND INTERIM OPINION - COMPLIANCE PHASE: AVOIDABLE MEGAWATTS, REINSTATEMENT OF STANDARD OFFER 2

Following Decision (D.) 87-05-060, our first interim compliance phase opinion, in which we dealt with certain pricing and bidding issues, we held further hearings in this proceeding in June and July. These hearings concerned resource planning and contract drafting for final Standard Offer 4 and possible reinstatement of Standard Offer 2. Today's decision addresses only the most pressing of these issues. We find (1) that there are presently no avoidable resources for purposes of final Standard Offer 4, and (2) that Standard Offer 2 should be reinstated for San Diego Gas & Electric Company (SDG&E).

I. Avoidable Resources

Final Standard Offer 4 uses a simplified generation resource plan methodology. (See D.85-07-022.) We presently implement this methodology through review of utility resource plans based on assumptions from the then-current Electricity Report (ER) of the California Energy Commission (CEC) and such alternative planning scenarios as the utility may wish to present in order to test the effect of uncertainties in the forecast. Our review determines whether, for each utility applicant, there are any "avoidable" generation resources (including construction by the utility and power purchases from others). If we find such resources, we would direct that utility to make a final Standard Offer 4 available for bidding by Qualifying Facilities (QFs). The number of megawatts in the offer, and the base price that QFs must meet or beat, derive from the avoidable resource(s) that the utility would add in the absence of the QFs.[1]

The CEC adopted its current ER ("ER-6") in December 1986. The utility compliance filings followed in March 1987. Pacific Gas and Electric Company (PG&E) filed only a CEC-based scenario with its resource plan, although it also included a "sensitivity" case using capacity value calculated from the full annualized cost of a combustion turbine. SDG&E and Southern California Edison Company (Edison) included CEC-based and alternative scenarios with their respective resource plans.

For none of the utilities does the CEC-based scenario disclose a cost-effective baseload or intermediate resource over the next eight years, which is the "window" within which resources must appear in order to be avoidable (or perhaps deferrable) by QFs. The CEC says, and we agree, that this is sufficient basis for not making final Standard Offer 4 available to QFs at this time.

A detailed critique of the utility resource plans and of the parties' comments on those plans must await our final decision in this phase. What follows is a brief expansion of the rationale for our finding of no avoidable resources, considering the chief factors that might go against that finding.

A. <u>PG&E and Edison</u>

The reasonableness of our finding for these two utilities is virtually unchallenged, but many of the planning <u>assumptions</u> used by the utilities are strongly disputed. Indeed, the strength of the disputes seems to demonstrate that our finding is valid

1 D.86-07-004 and D.87-05-060 give much more detail on how final Standard Offer 4 works. Also, the final decision in this compliance phase will address various problems that have cropped up in this, our first run-through of the resource plan review created by D.86-07-004. The text of today's decision is devoted to the two key substantive issues; hence, our terseness in summarizing the procedural aspects.

under widely varying treatments of the supply and demand planning issues.[2]

PG&E presented only a CEC-based planning scenario. This is consistent with PG&E's position in Phase II of this proceeding. In Exhibit 219, PG&E witness Hindley said flatly, "The CEC load forecast should be used." He added that PG&E had stated, in its Test Year 1987 General Rate Case (Application 85-12-050), that "the Company's own decisions on future plant additions will be based on the CEC load forecast." PG&E's concurrent brief in the compliance phase supports the use of ER-6 adopted assumptions in this phase. As previously noted, no avoidable resources appear in PG&E's CEC-based scenario.

Edison presented a CEC-based scenario and a preferred scenario, based on Edison's Fall 1986 Resource Plan. The scenarios use different load growth and fuel price forecasts, and also differ in other respects, but are consistent in the conclusion that no avoidable resources appear within the eight-year "window."

We postpone a more complete discussion of these plans to our final decision in the compliance phase. For present purposes, we focus on just three aspects: Edison's supply assumptions; the significance attaching to these utilities' expressions of interest in the major proposed hydroelectric project in British Columbia known as Peace River Site C; and PG&E's reliance on ER-6 assumptions for purposes of this proceeding while to date ignoring those assumptions in other proceedings.

2 We do not ignore the importance of specific direction on the future treatment of self-generation, conservation/load management, and municipal load (among other issues) in resource plans. However, the consensus that developed during the hearings on the utilities' current circumstances justifies this interim order and enables the parties to focus their efforts on ER-7, which is already well under way.

1. Edison's Supply Assumptions

Many parties express concerns over the supply aspects of the Edison scenarios. These concerns include whether Edison's assertion of "committed" status for certain resources is proper; whether Edison shows resources brought on-line before need and without establishing their cost-effectiveness; and whether Edison overstates the capital and operating costs of potential coal-fired and combined cycle projects. The parties generally feel, however, that while these concerns are likely to have a significant impact in the next resource plan proceeding, they do not presently affect our finding of no avoidable resource for Edison at this time.

The sole qualification to the previous generalization is in the testimony of the Independent Energy Producers Association (IEP). IEP asserts that Edison inflates its estimate of coal plant construction costs by basing such costs on construction at an in-state location, such as Ivanpah. Using coal plant costs based on data submitted in this proceeding by PG&E and data used by regulatory commissions in several other Western states, IEP concludes that an $1,800/kilowatt coal plant would be cost-effective in 1994 under Edison's CEC-based scenario. IEP acknowledges that Edison does not show a "need" for capacity in that year based solely on reliability considerations. However, according to IEP, a coal plant should still be added, if one were to rely strictly on ER-6, because of the projection of high fuel prices and the relatively low number of minimum load hours forecast by the CEC in that year.[3]

Interestingly, IEP does not recommend that Edison make a final Standard Offer 4 solicitation based on an avoidable coal plant. IEP considers that fuel prices are a major uncertainty at this time. IEP notes that, while it disagrees with various items in Edison's own scenario, under that scenario even an $1,800/kilowatt coal plant is not cost-effective until 1997, in large part because of the lower fuel prices projected by Edison. Thus, IEP ultimately agrees with our finding of no avoidable plant, although it does so only after consideration of alternatives to the CEC-based scenario.

2. Peace River Site C

British Columbia Hydro is engaged in various planning activities regarding this site. These activities have included consultation with possible wholesale purchasers of power from the site. All three utility applicants in this proceeding are among

3 IEP seems here to be critiquing CEC's testimony as much as Edison's. IEP's point is that "need" is a larger question than merely whether a utility seems to be short of capacity. IEP says, and CEC witness Bakker seems to agree, that under certain conditions, a resource can be found cost-effective based on increased operating efficiency, regardless of the need for capacity. Probably everyone agrees that a cost-effective resource that is otherwise consistent with prudent resource planning is "needed" and should be added as soon as it becomes cost-effective. Where the CEC and the QF representatives in this proceeding may differ is in what is "otherwise consistent with prudent resource planning"--e.g., with environmental goals, fuel diversity, and system flexibility. The CPUC's consistent position in this proceeding has been and continues to be that all of these are elements of electric supply planning. They need to be assessed and, because there will always be tradeoffs, they need to be quantified so far as possible if we are to achieve a rational planning process.

the possible purchasers consulted extensively in connection with the Site C feasibility studies.

IEP and a group of other QF developers (Santa Fe Geothermal, Inc., Union Oil Company of California, and Freeport-McMoRan Resource Partners, whom we shall refer to collectively as SFG/U/F) are concerned about the treatment in utility resource plans of potential power purchases generally, and the future of Site C in particular. As we would expect, the utilities gather information more or less continuously about who's adding generation and when, without necessarily committing to participate either as investor or customer. The problem that IEP and SFG/U/F foresee is that utilities would treat potential purchases as too speculative to serve as the basis for an offer to QFs in the current resource plan proceeding, then enter into binding purchase contracts before the next biennial update. The QFs fear that such regulatory "leapfrog" could cut out QF competition with non-QF sellers, since purchases from the latter would always be "committed" resources before QFs could bid against them.

Several aspects of Site C cause IEP and SFG/U/F to suspect that California utilities are preparing to make binding purchase commitments after this proceeding. For example, project documents seem to call for commitment to the project by 1988. Also, there seems to be a link between Site C and the California-Oregon Transmission (COT) Project, for which all three utility applicants have stated their intention to pursue certificates of public convenience and necessity (CPCN) from this Commission. IEP notes that Site C was referenced as part of the justification for the COT Project in the initial CPCN filings of both Edison and

PG&E.[4] The QFs argue that if Site C justifies the new transmission line, and the line is required to take Site C power, then the line is part of the cost of Site C and the projects should be considered together.[5]

IEP and SFG/U/F therefore propose that the Commission order the utility applicants to study the cost-effectiveness of Site C (considering the likely costs of power purchases from the project) together with the COT Project. If the study shows such a resource to be cost-effective, the Commission should allow QFs to bid against it; otherwise, the Commission should find the resource not to be cost-effective and direct the utilities not to pursue it.

All the utilities deny the allegations made by these QFs, although there is also a general recognition that our resource plan proceeding, as currently envisioned, does not mesh well with the ongoing project study and negotiation processes of the utilities. We certainly would not bar the utilities from participating in studies, which we believe play an essential role in resource planning. It also does not seem to be practical to wait for the eleventh hour in a negotiation before testing the QF market.

Both SDG&E and the CEC have made interesting suggestions in their concurrent briefs regarding the treatment of potential purchases. (See SDG&E brief, pp. 22-25, and CEC brief, pp. 27-31.) We return to this subject later in today's decision. (See Sections

---

4 The Commission dismissed without prejudice the initial filings for CPCN for the COT Project. The grounds for the dismissals were informational deficiencies in the filings. See D.87-05-066 as to the SDG&E application, D.87-05-067 as to the PG&E application, and D.87-05-068 as to the Edison application. Of course, a dismissal without prejudice does not go to the merits of an application.

5 The Bonneville Power Administration shares the QFs' view that Site C and the COT Project are linked. Edison witness Schoonyan denies any such linkage and says that the reference to Site C in Edison's CPCN application was for illustrative purposes only.

I.B.4.d,e below.) However, we will not take the step requested by IEP and SFG/U/F at this time. Our understanding of the CPCN process is that, when the utilities have filed complete applications, we will look at all the benefits claimed for the COT Project, including the line's cost-effectiveness when all potential purchases (from both existing and prospective generating facilities) are considered. We think this process, though not ideal from the standpoint of promoting competition in electricity generation, is adequate to protect the interests of California ratepayers, and we expect that QFs will actively participate in the process.

3. PG&E's Selective Reliance on ER-6

One aspect of PG&E's testimony in the resource plan hearings makes credible the QFs' allegations about regulatory "leapfrog." This aspect is PG&E's treatment of planning scenarios here, as compared to the scenarios in its justification of the COT Project in Application 87-04-010 (its initial CPCN filing). While PG&E relied exclusively on a CEC-based scenario here, it included no such scenario in the CPCN proceeding and instead presented two scenarios relying on much higher demand forecasts (labeled "medium case" and "low case"). According to IEP, the "medium case" demand forecast that PG&E submitted for the CPCN is 2900 megawatts higher than the CEC-based scenario in 1991 and shows a need for capacity in Northern California in 1992 (well within our planning "window"). Even PG&E's "low case" demand forecast in the CPCN proceeding is 1000 to 1700 megawatts above the CEC-based scenario relied on here.

We noted earlier that PG&E's testimony in Phase II of this proceeding was to the effect that QFs should have to live by the results of the CEC demand forecast since that forecast would apply to PG&E's own projects. Despite this representation, PG&E gives every indication of trying to create a QF "ghetto," with QF opportunities restricted by one set of assumptions, and other far more liberal assumptions applied to PG&E's own projects. This is not acceptable. Under the letter and the spirit of the resource planning process that we created in D.86-07-004, all resource options should be compared on a common basis. Only in this way can we properly assess the benefits and detriments pertaining to each type of resource option.

We cannot blink at these signs of PG&E's continued readiness and willingness to take advantage of its monopsony position vis-a-vis QFs. PG&E has itself to blame if we find it necessary to maintain the regulatory supervision and encouragement of QF development against which PG&E chafes.

B. SDG&E

All analyses confirm that SDG&E, unlike PG&E and Edison, needs significant additional capacity within our eight-year "window." Different scenarios yield different results as to the type, timing, and amount of this needed capacity.

1. CEC's Position

CEC witnesses McGowan and Bakker conclude on the basis of ER-6 that SDG&E first shows a need for capacity in 1993. The capacity deficit in that year is nominal (-12 megawatts) but grows to -79 megawatts in 1994 and -127 megawatts in 1995, which is the last year in the deferral window.

These CEC witnesses do not allocate this need by resource type (baseload, peaking, intermediate); however, CEC witness Jaske does provide such a breakdown. He says that, ideally, SDG&E would have about 300 megawatts more peaking capacity but about 430 megawatts less baseload and intermediate capacity in 1990, which is the earliest adopted year in the ER-6 forecasts. By 1997, two years beyond the deferral window, SDG&E still has a surplus of baseload capacity but has a substantially greater need for both peaking and intermediate resources.[6] In short, the CEC believes that SDG&E has ample energy resources within the deferral window (see also Appendix B of ER-6) and that SDG&E's need during that period is likely to be only for peaking capacity. Since peaking capacity is not counted as an avoidable resource (see D.86-07-004), and considering a number of uncertainties discussed in the McGowan/Bakker testimony, the CEC concludes that SDG&E has no megawatts available at this time for purposes of final Standard Offer 4.

The CEC witnesses believe that SDG&E has failed to create a resource plan conforming to the demand forecast and supply planning assumptions adopted in ER-6, and that the higher demand forecast underlying SDG&E's preferred alternative to its resource plan based on ER-6 is an unjustified attempt to relitigate ER-6 issues. We will return to this critique in our discussion, but we will first describe the three resource plans in SDG&E's compliance filing and other parties' reactions.

2. <u>SDG&E's Position</u>

SDG&E provides three resource plans. The first is designed to respond to our requirement that the utility base one planning scenario on assumptions derived from ER-6. SDG&E deviates from ER-6 in a few respects, which it acknowledges and explains. The second plan uses the same assumptions as the first, except that SDG&E includes a projection of QF development after 1990, while

6 There are some numerical inconsistencies between Exhibit 408 (McGowan/Bakker) and Exhibit 403 (Jaske). These result from corrections to ER-6 described on the record by CEC counsel and do not appear to materially affect the witnesses' conclusions.

ER-6 projects QF development only through 1990.[7] The third plan, which SDG&E prefers, updates certain basic assumptions, such as the demand and fuel price forecasts, using SDG&E's own current estimates.

All three resource plans show significant capacity needs that SDG&E proposes to make available for deferral by QFs. SDG&E says that the refurbishment of its Silver Gate plant for use as a peaker in 1989 (one unit) and 1991 (the second unit) is cost-effective in all scenarios. New purchases and added gas turbines also appear cost-effective within the deferral window in all scenarios, although the timing varies.

SDG&E proposes to follow its "50/50" procurement strategy that we previously described in D.87-05-060, mimeo., pp. 41-45. Applying this strategy to the current situation, SDG&E would plan now to fill all of its near-term needs (i.e., those arising over the next two years) and half of its long-term needs (i.e., those arising after 1989 but within the deferral window). This results in about 280 megawatts being made available to QFs under the first (CEC-based) plan, 230 megawatts under the second plan (lower because additional short-run QFs are anticipated after 1990), and 380 megawatts under the third plan (higher because higher demand growth is assumed).

Despite these needed megawatts, SDG&E concedes that it has been unable to identify corresponding avoidable resources, as

7 SDG&E says that the forecast of QFs likely to become available after 1990 is taken from the original contractor's report used by the CEC to develop its QF forecast through 1990. CEC witness Jaske explains that no QF development after 1990 is projected by ER-6 because of uncertainty as to the amount of such development. The CEC's analysis of this issue is set forth at pages 3-10 through 3-13 of ER-6. As noted by Jaske, the CEC's approach in this regard may underestimate QF development after 1990 and thus overestimate the need for additional capacity.

that term is used for purposes of final Standard Offer 4. Peakers, such as new gas turbines and the refurbished Silver Gate units, are not avoidable pursuant to D.86-07-004. Power purchases are potentially avoidable by QFs; however, according to SDG&E witness Mitchell, the utility believes that its current negotiations for system purchases from other utilities are not sufficiently mature to permit it to derive appropriate prices against which QFs could bid.

Thus, SDG&E proposes that it be authorized to make available long-run standard offer contracts that differ from those envisioned in D.86-07-004. They would instead resemble payment option 3 of interim Standard Offer 4. For deferral of Silver Gate, SDG&E would use the plant's fixed operating costs as the basis for capacity payments (which SDG&E says are less than half the capital costs of a new combustion turbine), and would "lock in" a forecast of Incremental Energy Rates (IERs) for the 15-year duration of Period 2 as the basis for energy payments. For deferral of up to half the projected power purchases, SDG&E seems to urge the same approach, only substituting gas turbines for Silver Gate as the basis for capacity payments.

3. <u>Other Parties' Positions</u>

Public Staff is uneasy regarding some of the assumptions from ER-6, and in fact urges our adoption of alternative forecasts for fuel price escalation and purchases of economy energy. However, Public Staff does not believe its proposed alternative assumptions would result in a different finding as to deferrable resources.[8] Its position is that neither Silver Gate nor the prospective power purchases should be considered deferrable for purposes of this proceeding.

QF commenters also generally agree that Silver Gate, because its refurbishment is solely to meet peaking needs, should be considered nondeferrable if such refurbishment is cost-effective. IEP criticizes ER-6 assumptions but recognizes that, under D.86-07-004, the CEC-based scenario would be given great weight. Under IEP's interpretation of that scenario, SDG&E would have 100 megawatts of deferrable capacity additions in 1994. IEP's prepared direct testimony thus tentatively recommends that, "If prices and terms can be determined for such a 1994 resource, this is the only resource that should be made available for SDG&E...." (Exhibit 432, p. 13.)

SFG/U/F, in its rebuttal testimony, tested the cost-effectiveness of adding potential baseload and intermediate plants to the SDG&E system. Specifically, SFG/U/F simulated the addition of a coal plant and of a combined cycle plant in separate scenarios, and compared these to (1) running the existing system harder and (2) adding combustion turbines. SFG/U/F found that, even though it used certain inputs that (as compared to ER-6 assumptions) would tend to support the cost-effectiveness of baseload and intermediate resources, neither the coal nor the combined cycle plant were cost-effective within the eight-year deferral window. SFG/U/F concluded that there is no deferrable

---

8 Public Staff seems concerned that it maintain consistent positions in the various proceedings before this Commission on such issues as fuel price, economy energy purchases, forecasts of self-generation, and other matters regularly litigated here. We think this concern is commendable and may help to define the kind of alternative planning scenarios that should be considered when dealing with the issue of uncertainty. We will have more to say on the issue of consistency in our final compliance phase decision.

resource for SDG&E. IEP, in its concurrent brief, endorses this conclusion.

4. Discussion

a. The Debate Over Planning Assumptions. We do not try in today's decision to deal with all the issues that have arisen in creating resource plans consistent with the current ER, and in testing for uncertainty. However, because SDG&E's CEC-based scenario indicates a larger and earlier need for additional capacity than that found by the CEC itself, we must understand the sources of the differences in order to make appropriate findings on avoidable megawatts. There seem to be three important sources.[9] The first two of these seem to have little impact on SDG&E's long-term need assessment at this time; the third source (treatment of some categories of conservation and load management programs) has immediate significance.

First, the CEC and the CPUC currently have different ways to determine a utility's need for reserve capacity. The CEC adopts reserve margins using a reliability model called MAREL and a reserve target based on one-day-in-10-years Loss of Load Expectation (LOLE). (See Exhibits 462, 463.) The CPUC uses a

9 The CEC notes another source: SDG&E's treatment of out-of-state firm power purchase contracts. However, except for 1987, when SDG&E and the CEC have different ways of reflecting the expiration of an existing contract, the difference between SDG&E and ER-6 is very small (8-14 megawatts). CEC witnesses McGowan and Bakker say that the ER-6 numbers are net of transmission and distribution losses while SDG&E's numbers include these losses. We agree with the CEC that the capacity value to the purchasing utility of an out-of-state firm purchase should be net of such losses; moreover, the utilities, in the absence of direction to the contrary, should generally observe the CEC's conventions in preparing their CEC-based resource plans. Although the proper treatment of out-of-state firm power purchases is potentially very important, we conclude that the difference between SDG&E and the CEC does not materially affect the amount of capacity needed by SDG&E over the next eight years.

reserve target expressed as Expected Unserved Energy (EUE) and derived by analysis of the utility system in one historical reference year with certain adjustments. The utility's relative need for capacity is then determined by comparing the EUE calculated for the forecast period to the EUE target. (See D.86-11-071, mimeo., pp. 6-10.) However, the commissions' respective reliability methods yield very similar target reserve margins (generally well within 1% of each other, i.e., ±20 megawatts or less) for SDG&E. Neither the CEC nor SDG&E contends that this difference materially affects capacity needs during the deferral window.[10]

Second, there is a large difference between SDG&E and the CEC in their figures for existing oil/gas-fired capacity available for the years through 1990. However, this difference appears to result from different ways of representing the units placed in cold standby and their expected return to service. CEC witnesses McGowan and Bakker note, for example, that ER-6 lists Silver Gate as "contingency reserve," while SDG&E's resource plan shows the two

---

10 Our EUE target and the associated Energy Reliability Index serve primarily to adjust capacity payments to QFs based on the purchasing utility's current need for capacity. However, we also intended that this method of capacity valuation be applied in our certification and other proceedings to establish the value of proposed resource additions. Although our EUE target and the target reserve margin used by the CEC do not differ materially for present purposes, this may not always be the case. Furthermore, both this Commission and the CEC have observed that a value-of-service approach to capacity valuation has certain advantages when compared to both EUE and LOLE. Finally, there is a need to describe and calibrate the various reliability models that have been used in proceedings before the two commissions. The desirability of a coordinated approach to the whole subject of reliability measurement and capacity valuation is clear. In our final decision in the compliance phase, we will propose a series of workshops with the CEC to deal with this subject and other issues of joint concern in the resource planning process.

Silver Gate units as "planned additions" in 1989 and 1991.[11] It would be desirable to have a clearer understanding of the usages observed by SDG&E and the CEC, but there does not seem to be a substantive supply disagreement underlying the numerical differences.

Third, SDG&E and the CEC differ in reflecting the impact of demand-side management (i.e., conservation and load management). The CEC wants utilities to include in their supply plans all energy savings that the CEC attributes to a category of programs labelled "conditional RETO;" SDG&E includes no savings from this category even for its CEC-based scenario. This difference is significant. It reaches some 240 megawatts in 1995, which is the last year of the deferral window. CEC witnesses McGowan and Bakker show that, starting in 1992, virtually the whole difference between SDG&E and ER-6 in the estimated capacity requirements for SDG&E's service area is accounted for by the disparate treatment of conditional RETO.

Conditional RETO designates those conservation and load management programs that depend on future regulatory action. Such action typically consists of CEC adoption of new regulations in the case of efficiency standards or CPUC approval of funding levels in the case of utility programs. Many parties in this proceeding, not just SDG&E, believe that the resource plans should contain much less than the total capacity savings attributed to conditional RETO in ER-6.

---

11 These witnesses note that the Encina 1 and South Bay 3 units are also not counted in SDG&E's resource plan in 1987 and 1988 but are added without apparent cost in 1989. These units and the Silver Gate units add up to a nominal difference of 528 megawatts between ER-6 and the oil/gas-fired capacity shown in SDG&E's CEC-based scenario.

CEC witness Jaske concedes that the cost-effectiveness tests applied to conditional RETO programs differ from those applied to generation resources in this proceeding and from those contained in the joint CEC/CPUC Standard Practice Manual.[12] In some cases, according to Jaske, conditional RETO programs need not be cost-effective but might be pursued on other policy bases.

SDG&E and QF representatives say that, under current circumstances, pursuit of non-cost-effective conditional RETO programs amounts to uneconomic bypass, a result which the CPUC in other contexts has tried to avoid. Public Staff would substantially discount ER-6 conditional RETO in the resource plans by <u>including</u> the potential savings attributed to CEC efficiency standards but <u>reducing</u> the potential savings from utility load management programs and totally <u>excluding</u> the potential savings from utility conservation programs.

SDG&E states its case forcefully: "Conditional RETO should be shown to be cost effective [and] evaluated on an equivalent basis with other opportunities to ensure that the least cost alternative is chosen. This has not been done." (SDG&E concurrent brief, p. 12, citations omitted.) SDG&E also says that CEC has failed to demonstrate that conditional RETO programs meet other policy objectives to justify giving preferred status to such programs: "The CEC contends that final decisions on conditional RETO depend on analysis of the comparative merits of the conditional RETO with other resource options. At the same time,

---

12 The full title of this manual is Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs. This manual was published in 1983. A joint effort of the CEC and CPUC staffs is now under way to revise the manual. Utilities and other parties are participating in this effort, which should result in cost-effectiveness tests that take into account the dynamics of system operation and that permit more direct comparison of supply- and demand-side resource options.

the CEC is seeking to prevent these comparisons by including into the resource plan all conditional RETO. For example, Witness Jaske acknowledges that QF power could be sufficiently inexpensive that it would be preferred. Yet, he would deny QFs, or any other resource option, the opportunity to compete to demonstrate that they merit greater preference." (Id., p. 13, citations omitted.) SDG&E notes that additional uncertainties, such as future funding, technological potential, and market penetration, affect conditional RETO, so that a presumption that all the potential savings from these programs will materialize is quite risky.

The CEC response is that programs are not designated as conditional RETO until they have undergone an analysis by the CEC that at least approximates the criteria for nondeferrability that we set forth in D.86-07-004. Basically, the CEC determines an amount of program savings for each utility according to the utility's disaggregated resource need (baseload, intermediate, peaking) and then adjusts the amount either up or down by applying three other criteria (the long-run costs of the program, customer equity and satisfaction, and the program's importance in preserving the utility's demand-side infrastructure). Each program is tested for cost effectiveness by comparing its levelized costs against the costs of comparable new generation. (See Exhibit 403, pp. 16-19.)

b. Conclusions on Planning Assumptions. The key planning assumption in dispute for SDG&E is conditional RETO.

We now make clear what was at least implicit in D.86-07-004, that conservation and load management resources are not deferrable by QFs.[13] However, the fact that a given resource could not be replaced in a resource plan by QFs does not tell us whether that resource belongs in the resource plan at all. The answer to that question depends on the resource's satisfying several criteria. From the ratepayer's perspective, the most important of these criteria is cost effectiveness, although other criteria may affect the ranking of resource options or, in limited cases, justify inclusion of a non-cost-effective resource. But in most instances, the resources in a utility's resource plan, whether or not they are deferrable by QFs, must be cost-effective. This generalization applies to both demand-side management and peaking plants or purchases.

All parties recognize that current procedures result in different cost-effectiveness tests for generation resources on the one hand and conservation and load management programs on the other. This is a problem, but the CEC and the CPUC are already working on the solution: revising the Standard Practice Manual. The goal is to ensure that the benefits of all resource options, to the extent they are quantifiable, are quantified on a common basis, and to the extent that qualitative judgments must be made, that the qualities are identified in advance. We strongly support this effort and welcome input from the parties.

However, we do not think it worthwhile for either us or the CEC to try to rethink ER-6 results for conditional RETO in light of the outcome of the Standard Practice Manual workshops. One advantage of the two-year resource plan update cycle is that

13 In theory, generation resources could substitute for demand resources, as well as vice versa, once appropriate account is taken of the advantages and disadvantages of each type of resource. However, both the methodology and pricing structure that we have developed for final Standard Offer 4 are clearly conceived in terms of a generation resource.

the next look is not too far away. We prefer to devote our staff resources to refinements that, we hope, will affect ER-7 and later ERs.

SDG&E's other concern regarding conditional RETO is that ER-6 assumptions may not reflect current thinking at either commission on the level and timing of conservation and load management effort appropriate to the present electricity supply situation. As to the CEC's efficiency standards, we think the CEC is uniquely qualified to project these impacts. As to utility programs that require our funding authorization, CEC witness Jaske notes that it is unclear whether recent retrenchment in these programs is only a short-term phenomenon or represents a change in long-term policy. We recognize that our general rate case decisions involve a mix of short-term and long-term policy making. It is incumbent upon us to make clear the thrust of our decisions to the CEC so that the ERs accurately reflect our current outlook as it affects the forecasts.

In D.86-07-004, we said that one of the challenges in integrating QF development into the resource planning process is for California regulators to coordinate their pricing and forecasting efforts to achieve timely and consistent results. (Id., pp. 63-64.) One aspect of this challenge is for the CPUC to communicate to the CEC how we think the products of ratemaking and other CPUC regulatory activity should affect ER forecasts. Our funding decisions on utility conservation and load management programs are clearly relevant. We will discuss other examples in our final compliance phase decision.

To summarize, we see merit in some of SDG&E's criticisms of the way that conditional RETO is handled in ER-6. At the same time, SDG&E's solution--to exclude conditional RETO from the resource plan altogether--seems clearly less realistic than the ER-6 approach, however flawed. We agree with the CEC that the ER-6 numbers should be used for purposes of this resource plan proceeding, and that the problems we have discussed above should be addressed through joint staff efforts at the two commissions.

c. The Debate Over Avoidable Resources. SDG&E's resource plan filings raise two issues regarding avoidable resources: using the fixed costs of new or refurbished peaking plants to structure final Standard Offer 4 contracts; and the general approach for allowing QFs to compete against purchases from non-QF sources.

As to the first issue, we clearly say in D.86-07-004, page 82, that our main reason for considering peakers nondeferrable by QFs is that such plants typically have no energy-related capital costs.[14] We also note (id.) that utility concerns regarding system operability are strongest in the case of peakers; however, our experience with the numerous curtailment and dispatchability agreements successfully negotiated between QFs and each of the utility applicants since we issued D.86-07-004 confirms our belief that the absence of energy-related capital costs, and not the complexity of devising appropriate contractual operating terms, dictates our decision not to authorize a peaker-based long-run standard offer.

A review of the relationship between short-run and long-run standard offers clarifies the role of energy-related capital costs. The reason that we felt it necessary to develop a long-run standard offer in the first place is the failure of the short-run offers to capture energy-related capital costs: payments to short-run QFs go up in parallel with the purchasing utility's avoided costs, but at some point the utility would add a new plant in order to reduce marginal running costs. That new plant would not be a

14 A utility adds a power plant for reliability benefits and/or to improve its operating efficiency. The term "energy-related capital costs" designates that portion of a power plant's fixed costs that a utility incurs because of anticipated benefits to its operating efficiency.

peaker because a plant that saves running costs would generally be dispatched as much as possible, or at least in an intermediate mode. Two conclusions follow from this: first, that a long-run QF should be paid based on the fixed and operating costs of the new plant that the utility would otherwise add to its system; and second, that short-run QF pricing will be equal to or less than the utility's long-run marginal cost whenever the utility would not add a baseload or intermediate resource.

For these reasons, a peaker-based long-run standard offer seems to us virtually a contradiction in terms. We do appreciate SDG&E's effort, using a fixed forecast of IERs, to make available a long-run offer even in the absence of an avoidable resource. Unfortunately, that effort would lead us back to the approach of interim Standard Offer 4, namely, to a projection of short-run marginal costs. We have now rejected that approach in favor of the true long-run avoided cost methodology set forth in D.85-07-022 and implemented in D.86-07-004. We remain firmly committed to this methodology.

Turning to the second issue, SDG&E's proposal for allowing QFs to compete against non-QFs sellers (specifically, to fill that portion of SDG&E's capacity need not satisfied by the refurbishment of Silver Gate) puts a new light on the problem of out-of-state purchases in this resource planning process.

SDG&E explains that under its preferred scenario (the third resource plan) it contemplates the addition of several resources through new purchase contracts from existing resources. Because it views the price that might result from such contracts as purely speculative, SDG&E proposes that QFs "simply compete against the same standard that purchases would be measured against: the cost effectiveness standard, which is conceptually the highest price that [SDG&E] could agree to purchase a resource...." (SDG&E concurrent brief, p. 22.)[15]

The predicament for the California utility, according to SDG&E, is that direct competition between different sellers of power is not possible under the current process (although such competition could occur when multi-attribute bidding becomes viable); it is also not practical to interrupt the negotiation process by allowing a contract to be negotiated contingent on QFs being given the chance to beat the negotiated price, leaving the non-QF seller with nothing. SDG&E believes that negotiation under such circumstances would not be true competition and would be unacceptable to potential non-QF sellers. Thus, some yardstick other than fully negotiated terms is needed if QFs are to avoid such purchases. The yardstick could be "the price of similar transactions which are cost effective" or simply cost effectiveness calculated (we assume) using whichever resource planning scenario is approved in the update proceeding. (See *id.*, p. 24.)

The CEC is also concerned about the treatment of power purchase opportunities, and its concurrent brief outlines a mechanism that might allow QFs to bid against such opportunities that arise between update proceedings. The CEC notes, based on testimony in this proceeding by PG&E witness Hindley and Edison witness Schoonyan, that purchase opportunities are usually studied for such a long time that few of them can be considered "fleeting."

---

15 By "cost effectiveness" in this context, SDG&E appears to refer to the cost structure of its lowest capital cost capacity addition, i.e., a gas turbine. As we noted earlier in the text, we have severe methodological problems with this proposal because we are not convinced that it correctly prices long-run resources. At this point, however, we are focusing on another aspect of the problem: how to get the periodic procurement of long-run QFs to dovetail with more-or-less ongoing negotiations between California utilities and non-QF sellers from out-of-state.

In fact, the feasibility, preconstruction, and licensing work that go into major power plant construction projects typically last three to five years. Thus, according to the CEC,

> "[I]t might be feasible to meet the QFs' concerns by permitting the utilities to file in update proceedings not only a resource plan based on the latest Electricity Report, but also data on a 'blind' or generic basis about purchase opportunities that are under study and that have reached the point where preliminary cost estimates are available. For example, the utility might state that it was considering a project in the Northwest to be available nine years hence that would provide 'X' megawatts of capacity at a price of 'Y'. Specifications of the technology or generational characteristics being considered might also be included in order to insure, among other things, that sufficient operational flexibility would be retained. Even if no avoidable resource were found in the update proceeding, QFs would be invited to bid to meet this generic need. If the utility did not make such generic or 'blind' disclosures in its update filing about resources under study, it would be precluded from later seeking a certificate of public convenience and necessity (or any other type of regulatory approval) that was inconsistent with its resource plan." (CEC concurrent brief, p. 30.)

The CEC believes this mechanism may be useful during the period before an integrated CEC/CPUC process is in place, since the mechanism would increase QF bidding opportunities with minimal impact on utilities' negotiations. The CEC also recognizes that the mechanism may have pitfalls and therefore recommends that a workshop be held to discuss the proposal's implications before it is finally adopted. We note that the proposal is similar in method to the cost-effectiveness testing performed by SFG/U/F for potential baseload and intermediate plant additions to the SDG&E

system, using generic coal and combined cycle cost data. (See Section I.B.3 above.)

Generalizing from the QFs' approach regarding Site C in this proceeding suggests an alternative to the mechanism proposed by the CEC. Basically, the utility would be required to identify those potential purchases during the resource plan proceeding that have a reasonable likelihood of maturing to a "fleeting opportunity" in the interval before the next update. The utility would then have to demonstrate the cost-effectiveness of each such opportunity, and make available for QF bidding any purchases that pass the test, or forego committing to the purchase before the next update. SDG&E objects to this approach, noting that it involves speculation as to purchase terms, and that even though the presumed price might not be cost-effective, further negotiations might produce better prices, or additional benefits at the same price, sufficient to justify committing to the purchase before the next update.

d. Conclusions on Avoidable Resources. We are satisfied that, applying the criteria established in D.86-07-004, no avoidable resources appear at this time for SDG&E, despite the existence of capacity needs in its service area over the next eight years. No cost-effective resource option has been identified for SDG&E that is suitable for final Standard Offer 4, as we explained earlier in our discussion of energy-related capital costs.

Our finding of no avoidable resources for SDG&E (and for PG&E and Edison) can and should have certain consequences for these utilities during the period before the next update. Obviously, they will not have any final Standard Offer 4 contracts to make available. Moreover, if one of these utilities seeks authority to develop a new resource in an application filed before the next update, we expect the filing to include the applicant's CEC-based scenario and its preferred scenario (if any) from this proceeding. The applicant can also use additional scenarios with more recent assumptions to justify the requested authority, because we realize that the world continues to change between updates no matter how desirable it might be to hold the resource plans constant during that period. Nevertheless, at a minimum, the applicant must explain and justify deviations from the planning assumptions on which it chose to rely in the most recent resource plan proceeding.

Public Staff and other parties have urged that more far-reaching consequences attach to the results of each resource plan proceeding. One suggestion is that we adopt a long-run marginal cost for each utility, to be applied in any CPCN proceeding filed by the respective utility before the next update. There are also proposals to restrict, and/or establish reasonableness criteria for, utilities' power purchase commitments between updates. Generally, the proposals are intended to ensure even-handed treatment of QFs, provide guidance to utilities, and simplify reasonableness reviews.

These suggestions are attractive but premature. First, there are still a fair number of technical wrinkles (e.g., closer coordination between the ER and CPUC processes) still to work out. Second, far-reaching regulatory proposals often have unintended linkages or create perverse incentives; thus, we would want to think through carefully the full implications of these suggestions before applying the result of the resource plan proceeding rigidly or automatically in other matters. In the meantime, we are requiring the utilities at least to carry the burden of persuasion whenever they ask us to deviate from our findings in the most recent resource plan proceeding. We think this is fair and allows for further refinement of our resource planning process.

We find that SDG&E does have significant need for additional capacity over the next eight years. We stress that although SDG&E will not have final Standard Offer 4 contracts available to meet that need at this time, SDG&E management is not otherwise inhibited by today's decision from pursuing the resource strategy it deems to be in the best interests of the utility and its ratepayers. In fact, SDG&E could choose to pursue nonstandard contracts with QFs using terms similar to what it has proposed in this proceeding. Such nonstandard contracts would be subject to reasonableness review as in the case of purchases from non-QF sellers.

We also note that SDG&E's preferred scenario shows greater need than is indicated by either ER-6 or SDG&E's CEC-based scenario. The CEC bases its ER-6 conclusions in part on the availability of Silver Gate as "contingency reserve;" this suggests that SDG&E's proposed refurbishment of Silver Gate to meet its near-term need is basically consistent with ER-6. SDG&E management may feel that it has to make other resource decisions before the next update. We cannot prejudge such decisions; their prudence necessarily depends on the circumstances (including, e.g., the negotiated price and other terms of a power purchase) that exist when SDG&E's commitment is made. We will continue to review such decisions in appropriate proceedings, such as reasonableness reviews and CPCN applications.

Accepting the possibility that SDG&E may commit to purchase power from a non-QF seller before the next update does not mean that we have rejected QF competition in this proceeding. However, based on the analysis done by SFG/U/F, it appears that a cost-effective power purchase by SDG&E is unlikely to include a significant fixed price component analogous to the energy-related capital costs of a baseload or intermediate plant. Thus, the resource options that seem suitable for SDG&E at this time do <u>not</u> appear avoidable by QFs under Standard Offer 4.

Nevertheless, we share the concerns voiced by many parties that our resource planning process needs improvement if it is to achieve the goal of allowing QFs to compete on a fair basis with non-QF sellers to California utilities. The CEC, SDG&E, IEP, and SFG/U/F have all developed some interesting ideas that should be discussed in workshops before the next update proceeding. The joint CEC/CPUC workshops on coordination matters provide a logical venue, and our final decision in the compliance phase will have suggestions on the timing of these workshops. It may help to frame the later discussions by offering observations now on how we see the resource plan proceeding evolving.

e. Where We Are Heading. To maximize benefits from QFs, and to permit real competition between QFs and non-QF sellers, we think the resource plan proceeding must deal not only with avoiding new power plant construction (a relatively simple case) but also with filling the utility's disaggregated resource need, which is basically what a power purchase should do.[16]

The avoidable plant is a useful concept, but it has at least two major limitations. As the utilities point out, there is no guarantee that the QFs avoiding the plant will provide equivalent benefits. At the same time, the avoidable plant may understate the value of QFs. For example, one of the virtues of QFs is that they enable utilities to add capacity in small increments. If we always establish the size of a final Standard Offer 4 QF cohort on the basis of a plant that the utility would build itself, then we put some of the "lumpiness" problem, which QFs could have mitigated, back into the resource plan.

Perhaps the resource plan proceeding would benefit by inviting each utility to indicate what it regards as the optimal QF

---

16 We have previously urged the utilities to disaggregate their system needs by operating mode and performance features (see D.86-07-004, pp. 56-61), although we there saw this direction as leading away from the standard offer structure and toward more negotiated contracts. The past year has seen a very positive response by the utilities, with rapidly increasing sophistication in developing special performance features (e.g., downward dispatchability) for power purchase agreements with QFs. We now feel optimistic that sufficient flexibility can be built into final Standard Offer 4 to respond to disaggregated system needs.

contribution to its resource needs during the eight-year deferral window. Conceivably, a utility might want to add small increments (e.g., 20 megawatts) of baseload or intermediate generation in each year. Such a pattern would probably be hard to achieve through new construction or power purchases from non-QF sellers but feasible through final Standard Offer 4. The fixed costs of the capacity could be derived from generic cost data for baseload (probably coal-fired) and intermediate (probably combined cycle) plants, similar to the cost-effectiveness testing performed by SFG/U/F in Exhibit 432. The utility could prepare a list of desirable performance features, price them out separately, and treat them as adders or subtractors, depending on what the specific QF can provide as compared to the avoided generation resource. SDG&E is probably the farthest along of the utilities in the disaggregated valuation of performance features. Line loss calculation and interconnection costs can also be made QF-specific and the price adjusted by reference to the corresponding characteristics of the avoided capacity addition.[17]

Disaggregated resource need may entail more speculative price estimation than the avoidable plant, although this is by no means clearly so. We think that, in any case, the resource plan proceeding contains important safeguards: utilities would not be able to fill the need, either through QF purchases or their own

---

17 Some assumptions would have to be made on the approximate location of the avoided plant or purchase. The transmission-related benefits and costs of specific QFs, as in the case of performance features, may be higher or lower than those of the avoided resource. The line loss question has been addressed in workshops in 1983, and PG&E has made recent proposals regarding the estimation of transmission system reinforcement costs associated with QF development. These issues should be taken up in an appropriate forum, possibly by reopening our investigation of transmission system operations (I.84-04-077) following the final decision in the compliance phase herein.

efforts, if they propose unreasonably low prices; while the cost-effectiveness standard effectively caps the price for which QFs could argue.

II. Reinstatement of Standard Offer 2

Standard Offer 2 is limited to QFs that commit to provide firm capacity. The offer has energy payments based on the purchasing utility's short-run marginal operating costs, and capacity payments based on the full annualized fixed costs of a combustion turbine. The capacity payments are levelized over the term of the contract, which can be as much as 30 years.

Concerns with the capacity payment feature have led to our suspension of this offer's availability in D.86-03-069.[18] Specifically, we want to ensure that our updating procedure and method for valuing capacity reflect the purchasing utility's relative need for additional capacity.

We have determined that Standard Offer 2 should be reinstated as soon as possible for SDG&E, with a cumulative limit on new contracts before the next update proceeding of 100 megawatts. We are staying such reinstatement pending (1) our approval (anticipated shortly) of SDG&E's reliability target, and (2) receipt of comments on queue management and certain proposals made by SDG&E in its concurrent brief. We are not reinstating Standard Offer 2 for PG&E or for Edison before the next update.

A. Improved Capacity Valuation and Updating Procedure

Formerly, there was no limit on the amount of new QF capacity eligible for Standard Offer 2 contracts. The Commission simply established new capacity price schedules in each utility's general rate case, after which all new Standard Offer 2 QFs could receive the prices shown, regardless of whether such QFs represented 10 megawatts of new capacity or 1000 megawatts.

Under the capacity conditions existing when Standard Offer 2 was conceived and implemented, this approach to updating and capacity valuation was adequate. Reserve margins were low, major utility power plant construction was cancelled or delayed, and the general rate case cycle was two years. These conditions have changed. Nuclear and other units have entered service, the QF response to the standard offers has added significant capacity, and utility reserve margins appear ample. Thus, Standard Offer 2 capacity prices must not only be revised periodically, they must

18 The suspension was continued indefinitely in D.86-05-024.

also be revised for each block of additional capacity in order to give an accurate price signal.[19]

Also, the resource plan update proceeding that we have instituted on a two-year cycle for final Standard Offer 4 provides a better forum than the general rate case (which is now on a three-year cycle) to establish the long-term capacity price schedules needed for Standard Offer 2.

Finally, the next compliance phase decision will address the EUE targets that each utility has developed at our direction. These targets serve, among other purposes, to quantify capacity value on a utility system during a forecast period for successive blocks of additional capacity.

There is little controversy regarding the desirability of these changes in principle. The chief issue is whether block pricing should be coupled with an overall megawatt limit. QF representatives argue that, with block pricing, there is no need to also establish an overall megawatt limit for new Standard Offer 2 contracts between updates. Their theory is that additional capacity always has some value to the utility, so that as long as the capacity price reflects relative need, new QFs that seek to sign Standard Offer 2 contracts at that price should be permitted to do so. We believe, however, that prudence dictates limiting reliance on a given set of planning assumptions. At this time, for example, there is much uncertainty as to how many QFs already under

19 In other words, the capacity price (before levelization) during periods when the utility is projected to have capacity in excess of its reliability target should be some fraction of the full annualized fixed costs of a combustion turbine.

Block pricing is superior to a single overall megawatt limit because the value of successive capacity additions declines exponentially. Thus, individual pricing of a sequence of small blocks gives greater accuracy, and a truer economic signal to QFs, than a single capacity price averaged for the total megawatts made available between updates.

contract will ultimately come on-line. If the "success" rate is higher or lower than anticipated, the value of additional capacity will be higher or lower than the adopted Standard Offer 2 price schedules. By setting an overall megawatt limit between updates,, we minimize exposure to forecast error for all concerned.

The question that the CEC, Public Staff, and the utilities have raised is whether Standard Offer 2, even with the above modifications, should be reinstated at this time.

B. The CEC's Position

The CEC first took a position on the reinstatement issue in its concurrent brief. The CEC concluded in ER-6 that PG&E and Edison do not need capacity within the deferral window, while SDG&E needs capacity but only for peaking resources. According to the CEC, "The specific type of long-run contracts - SO 4 or SO 2 - is irrelevant to this capacity need conclusion. Thus, no new standard offer contracts of #2 or #4 variety should be allowed at this time. In future update offers, capacity and energy balances which result in identified avoidable resources should be treated as a "cap" for all new standard offers #4, #2, and nonstandard QF contracts. In this way, the physical need for resource additions will constrain the aggregate of new QF contract supplies." (CEC concurrent brief, p. 5.)[20]

20 Edison previously made a similar argument in this proceeding to the effect that Standard Offer 2 should not be available in the absence of an "identified deferrable resource." We have rejected Edison's position. See D.86-07-004, p. 71; D.86-11-071, p. 4. In the latter decision, we noted that "if a utility's resource plan shows no 'identified deferrable resource,' our new capacity valuation method would reflect the utility's capacity-rich condition in the Standard Offer 2 capacity price; and if there were an 'identified deferrable resource,' new Standard Offer 4 QFs would be assumed to defer it. The presence or absence of deferrable resources certainly affects prices under Standard Offer 2 but has no logical relation to its availability." (Id.)

For reasons that we discuss later, we reach the same conclusion as the CEC regarding the reinstatement of Standard Offer 2 for PG&E and Edison. We also believe that there is no fundamental difference of opinion between the two commissions regarding SDG&E.

We certainly agree with the principle that new resource additions should be economically and operationally suited to the needs of the utility. This is the chief reason that both commissions have been pressing for the disaggregated assessment and pricing of performance features such as dispatchability and curtailment. Standard Offer 2 is very well-suited to SDG&E's current needs. QFs contracting under this offer are committed to meet peak loads. They are upwardly dispatchable; their prices are time-differentiated; they must meet availability requirements keyed to the incidence of the purchasing utility's peak; they can achieve bonus payments for exceeding these availability requirements, and face derating if they fail to meet them.

Moreover, Standard Offer 2 is a short-run offer, using capacity and energy payment methods that track the purchasing utility's short-run marginal costs. As such, Standard Offer 2 does not avoid new resources but rather backs down existing resources. This is appropriate (indeed, it is the least-cost strategy) whenever a utility would not incur energy-related capital costs. Such is the case with SDG&E. (See generally our discussion of the relationship between short-run and long-run standard offers in Section I.B.4.c above.)

We have always shared the CEC's concern that QFs not back down other resources in a way that works to the ratepayers' detriment. Our use of IERs to calculate energy payments to QFs ensures that such payments are adjusted for periods when oil/gas-fired generation is not on the margin. Standard Offer 2 already has several curtailment provisions, most notably for periods when continued QF energy deliveries would result in negative avoided costs. Moreover, we are inviting comment on SDG&E's proposal that the 1500-hour curtailment provision developed for final Standard Offer 4 also be incorporated in Standard Offer 2. Such a provision should further help the efficient integration of QF output into the purchasing utility's system.

We stress that we do not discount the system operability objective in concluding that Standard Offer 2 should be reinstated for SDG&E. The utilities are already required to file various periodic reports on QFs' system impacts, including quarterly reports of any invocation of either hydro spill pricing or negative avoided cost curtailment. We are open to suggestions on further reporting requirements that could document and give early warning of system constraints related to QF energy deliveries. This could be a topic for the workshops on planning and coordination issues to follow the end of the compliance phase of this proceeding. We expect, however, that the development and use of contractual performance conditions, such as SDG&E's proposed curtailment adder for Standard Offer 2, can forestall potential constraints from materializing.

C. Proposals to Change Other Features of Standard Offer 2

1. Public Staff's Position

Public Staff favors reinstatement of Standard Offer 2, with one qualification: Public Staff would not levelize capacity payments to Standard Offer 2 QFs when the purchasing utility's Energy Reliability Index (ERI) is less than 0.5. (A utility that exactly meets its reliability target would have an ERI of 1.0.) As Public Staff envisions this proposal, a Standard Offer 2 QF that comes on-line during such a capacity surplus would receive fixed but not levelized capacity payments until the ERI hits 0.5; beginning in that year, the QF would receive levelized capacity payments for the duration of the contract.

PG&E and Edison feel that Public Staff's proposal has merit but only partially mitigates their concerns. Their primary position is that Standard Offer 2 should not be reinstated for them until there is greater certainty regarding the success rate for QFs already under contract but not yet on-line.[21]

QF representatives support reinstatement of Standard Offer 2. SFG/U/F would reinstate the offer for SDG&E and for PG&E, which shows a near-term capacity need under certain dry-year assumptions (see Exhibit 454), but not for Edison. IEP would reinstate Standard Offer 2 for all three utilities and prefers a megawatt cap to the Public Staff proposal. However, IEP believes that the proposal "is preferable to retaining the suspension of SO 2 for some of the limited number of firm QFs which may decide to proceed with project development or expansion. Some of these projects may be relatively difficult to delay but would be lost entirely (for periods when alleged oversupply is no longer present) if only SO 1 is available (e.g., building cogeneration in when a boiler must be replaced)." (IEP concurrent brief, pp. 53-54.) Northwest Power Company (NPC) would also reinstate for all three utilities. NPC says, "Without a wide range of choices, individual circumstances regarding technology, resources and financing could

21 PG&E and Edison also argue for additional restrictions on Standard Offer 2. The chief of these, supported also by SDG&E, is use of a second price auction to allocate available Standard Offer 2 capacity. We think these proposals are at least premature: we have carefully limited the reinstatement issues to updating frequency, caps on availability, and capacity valuation. We have not invited a rethinking of Standard Offer 2 methodology, nor have PG&E and Edison demonstrated a need to do so. In particular, PG&E's point that, in some circumstances, Standard Offer 2 may be more attractive to QFs than final Standard Offer 4, does not trouble us at all. Each standard offer serves particular purposes; the relative attractiveness may vary at different times and from one QF to another. In any event, these additional proposals are not properly before us; if the utilities wish to renew them, they should request such consideration in the biennial update proceeding.

limit otherwise economic development of QF resources." (NPC concurrent brief, p. 6.)

We have decided very reluctantly not to reinstate Standard Offer 2 for PG&E or Edison. Standard Offer 2 is the most important of the short-run offers, and its continued suspension for any of the utilities is a serious loss. We have already discussed some of the offer's advantages (see Section II.B above); IEP and NPC have correctly noted others. Other considerations temporarily outweigh these advantages, at least for PG&E and Edison.

First, the levelization feature of Standard Offer 2 is troublesome when the value of additional capacity is low. Block pricing and capacity values adjusted by the ERI accurately convey the marginal value of capacity, but this fine-tuned economic signal is blurred by levelization. We think that levelization is fully justified when the purchasing utility is not too far above or below its reliability target.[22] Under current circumstances, where PG&E and Edison appear to exceed their reliability targets substantially during the deferral window, and where this Commission is grappling with the problem of uneconomic bypass, the signing of even a limited number of levelized contracts with QFs is unattractive for those utilities.

Second, both PG&E and Edison have many QFs, representing thousands of megawatts, under contract but not yet on-line. Many of these QFs are products of the interim Standard Offer 4 "gold rush," and their dropout rate is still speculative. To reinstate

22 Levelized capacity payments result in a moderately front-loaded payment stream for Standard Offer 2 QFs; all other standard offers use ramped payments. This feature of Standard Offer 2 makes it well-suited to capital-intensive QFs (such as waste-to-energy projects) and perhaps also to QFs with research, development, and demonstration aspects. Even with levelization, Standard Offer 2 has much less front-loading than the electric utility revenue requirement stream for a corresponding capital investment.

Standard Offer 2 for these utilities now, with the present degree of uncertainty, may result in a very inaccurate price signal because the dropout rate could well be much higher or much lower than current estimates. We believe that the better course is to wait for the next update, when better information will be available.

Third, capacity valuation on the PG&E system continues to be problematic.[23] Exhibit 454 illustrates this. At the direction of the assigned ALJ, PG&E calculated ERIs for 1988 using the capacity value adjustment method, based on Loss of Load Probability (LOLP), that the Commission approved in PG&E's test year 1984 general rate case and used in D.86-11-071 to determine capacity payments on PG&E's system. Pursuant to that direction, PG&E combined assumptions from its current Energy Cost Adjustment Clause proceeding with dry and average hydro year data. The results show that under average hydro conditions, PG&E's ERI would be 0.22--in other words, the system would have capacity much in excess of the reliability target. Under dry conditions, the ERI would be 1.11--in other words, the system would be capacity-short! What this suggests to us is that a reliability target based on LOLP or EUE, which change exponentially in relation to changes in load or capacity, may simply be too sensitive for a system that, like

23 We will address in a later compliance phase decision the respective utilities' implementation of our orders on EUE targets and the ERI. For present purposes, it is sufficient to note that disputes regarding Edison's and SDG&E's implementation relate to input assumptions rather than methodology, while PG&E raises both types of issue.

PG&E's but unlike Edison's or SDG&E's, depends heavily on an as-available (hydro) resource.[24]

Perhaps our chief motivation in suspending Standard Offer 2 was to avoid adverse impacts while we were developing a capacity value adjustment method in which we had full confidence. The likelihood that we will need one more iteration before arriving at such a method for PG&E argues strongly for continuing the suspension as to that utility, especially since Public Staff's mitigation proposal does not work if the underlying ERI is flawed.[25]

We conclude that Standard Offer 2 should remain suspended for PG&E and Edison. We will reconsider the suspension during the resource plan update for ER-7.

2. SDG&E's Position

Standard Offer 2 should be reinstated for SDG&E. We plan shortly to authorize SDG&E to make available two blocks of contracts, with 50 megawatts cumulative capacity in each block. The capacity payment to a QF that straddles the two blocks should be computed according to the proportion of the QF's megawatts within each block. Where a QF straddles the megawatt limit of the second block, SDG&E shall use the same buffer allotment rule that we approved for final Standard Offer 4. (See D.87-05-060, p. 11.)

---

24 Edison has some hydro resources on its system but not nearly to the same degree of dependence as PG&E. SDG&E essentially has no hydro resources.

The CEC's LOLE reliability target belongs to the same "family" of probabilistic reliability measures as LOLP and EUE, so it may well exhibit similar sensitivity to input assumptions.

25 That the capacity valuation dilemma persists for PG&E is not due to any lack of cooperation by PG&E in this respect. Following Phase II, where we clearly directed that all three utilities develop an EUE-based reliability target and ERI, PG&E produced a responsive and thoughtful implementation proposal.

The characteristics of Standard Offer 2 are well-suited to a utility, such as SDG&E, that needs peaking capacity. Also, the arguments for continued suspension hardly apply to SDG&E. The EUE-based reliability target seems to yield reasonable results that closely parallel the results derived from the CEC's MAREL model and LOLE target. There is uncertainty regarding the QF dropout rate for SDG&E, as for the other utilities, but SDG&E has relatively fewer QFs under contract.

SDG&E itself favors reinstatement but proposes in its concurrent brief that certain "contractual safeguards" that the parties have jointly recommended for final Standard Offer 4 also be incorporated in reinstated Standard Offer 2, and possibly also in Standard Offer 1. The most important of these safeguards appear to be increased curtailment rights and refinements to the QF Milestone Procedure. These proposals appear attractive, but parties have not yet had an opportunity to consider them in the context of Standard Offers 1 and 2. We will therefore provide such opportunity for comment. We emphasize that we consider SDG&E's proposals for prospective application only; existing QF contracts are not affected. Also, our primary business at this time is to reinstate Standard Offer 2; if Standard Offer 1 involves significant considerations unique to that offer, we will defer possible modification of that offer to the update proceeding.

Certain other tasks must be finished before actual reinstatement. Our decision on SDG&E's proposed EUE target, ERIs, and capacity price schedules will follow today's decision shortly. We note that there is some disagreement as to the resources assumed "in" for purposes of the schedules. Accordingly, some revision to the proposed schedules may be necessary.

Thought should also be given to queue management. Access to the contract blocks is first-come/first-served. The financial consequences in establishing priority are considerable. Thus, the utility needs to specify, clearly and in advance of contract availability, what actions the QF needs to take in order to establish its priority. We will require SDG&E to file a proposal for queue management, and will allow comment by the other parties. We believe that SDG&E's proposal should follow generally our principle in the second price auction regarding required contents of bid packages. (See D.87-05-060, pp. 9-10.) Basically, there should be relatively few requirements in order to establish priority, but those few should be objective and rigidly enforced, with no "grace period" (i.e., no opportunity to fix an incomplete submittal so as to relate back to the date of initial tender: priority is established as of the date that a complete submittal is in the utility's hands).

III. Remaining Matters During the Compliance Phase

Comments of other parties on SDG&E's proposals for Standard Offers 1 and 2 shall be filed no later than November 18, 1987. SDG&E shall file its proposal for queue management in connection with block pricing no later than November 18, 1987, and other parties may also file comments on this issue at that time.

A third interim opinion will follow today's decision shortly. The third interim opinion will deal with the remaining pricing issues (capacity valuation, variable energy pricing) and miscellaneous contract provisions for final Standard Offer 4 (essentially, the jointly sponsored provisions in Exhibit 446 and the alternates supported by PG&E and IEP).

The final compliance phase opinion will complete the implementation of final Standard Offer 4 and reinstatement of Standard Offer 2 for SDG&E. It will contain the full discussion of planning assumptions, CEC/CPUC coordination, updating procedure, and adders that we have deferred from today's decision. The final opinion should be issued late in the year.

Many parties have suggested workshops on many topics, and we agree that workshops could be helpful. At the moment, the most timely topic, because of its usefulness for ER-7, would be the creation of a joint terminology for use in the ERs and resource plan updates. We suggest that the staffs of the respective commissions produce a joint draft and schedule a workshop to receive input from interested parties. The staffs should also consult on the scheduling and priorities for workshops on other topics, although many of these should probably be reserved until after our final compliance phase opinion.

IV. Response to Comments on ALJ's Proposed Decision

Pursuant to Public Utilities Code Section 311 and to our Rules of Practice and Procedure, the Proposed Decision of ALJ Kotz was issued before today's decision. Six parties (the CEC, Public Staff, PG&E, Edison, SFG/U/F, and IEP) filed comments on the proposed decision, and we have made a few modifications in light of those comments. The modifications are nonsubstantive (either strictly procedural or clarifications of the proposed decision), and they are found in Section I.B.4.e., Conclusion of Law 4, and Ordering Paragraphs 2 and 3 of today's decision.

Several parties suggested workshops on various implementation issues that they have identified in connection with the resource plan update procedure. We agree that workshops should be held and will address this matter specifically in our final compliance phase decision.

The comments of IEP are effectively a motion to set aside submission and to take additional testimony (on SDG&E's resource plan). IEP says that after the close of hearings, SDG&E tendered a Notice of Intention (NOI) relating to SDG&E's test year 1989 general rate case, and that this document shows (1) that a baseload purchase of 75 megawatts in 1989 would be cost-effective, and

(2) that 200 megawatts of combined cycle generation passed the iterative cost-effectiveness test in 1995, which is the last year of the "deferral window" in this proceeding. IEP notes that these resources are potentially avoidable for purposes of final Standard Offer 4, and that SDG&E's conclusions in its NOI differ significantly from those reached in its testimony in this proceeding. For these reasons, IEP says the record herein should be reopened.

We reluctantly deny IEP's motion. Ideally, the utility itself would seek reopening when a change in planning assumptions (here, IEP suggests, lower assumed heat rates for the combined cycle resource) yields additional avoidable megawatts. This seems fair and appropriate, since we have already authorized utilities to modify their needs assessment downwards after close of the record (to reflect a newly concluded power purchase, see D.87-05-060, p. 46). But the first time through a new procedure is never carried out ideally. Moreover, we already have a full slate of post-compliance phase QF-related matters to contend with, as well as ER-7. At the next biennial update, which will mark the first full cycle of CEC forecasting coordinated with QF procurement, we expect the utilities to have fully integrated the cost-effectiveness showing for this proceeding in their own resource planning process.

Findings of Fact

1. The CEC adopted its current ER (ER-6) in December 1986.

2. None of the CEC-based planning scenarios filed by the utilities, and none of the alternative scenarios, discloses a cost-effective baseload or intermediate resource over the next eight years.

3. Utility participation in studies of potential power plant projects is useful in developing the utility's resource plans.

4. In a CPCN proceeding for a transmission project, all benefits claimed for the project are considered, including the

project's cost-effectiveness when all potential purchases are taken into account.

5. One of the chief goals of the resource planning process is to fairly compare the benefits and detriments pertaining to each type of resource option.

6. SDG&E, but not PG&E or Edison, needs significant additional capacity over the next eight years.

7. SDG&E's need appears to be predominantly for peaking capacity, which is not deferrable by QFs.

8. The refurbishment of Silver Gate by SDG&E appears consistent with ER-6.

9. SDG&E's proposal to make a long-run offer to QFs at this time would use a projection of short-run marginal costs rather than the long-run marginal cost methodology previously approved for final Standard Offer 4.

10. The primary source of the differences in long-term need assessment between SDG&E and the CEC is their respective treatment of conditional RETO.

11. The CEC and CPUC staffs are jointly revising the Standard Practice Manual. The revisions are intended in part to permit more direct comparison of supply-side and demand-side resource options than is possible with the current manual. Some revisions are planned to be ready in time for use with ER-7.

12. Under the current methodology for final Standard Offer 4, conservation and load management resources are not deferrable by QFs.

13. Under the current methodology for final Standard Offer 4, nondeferrable resources that are cost-effective may be included in a utility's resource plan. Non-cost-effective resources are not deferrable by QFs and are not includable in resource plans unless their inclusion is supported by express regulatory policies.

14. The CEC is uniquely qualified to judge the impacts of its building and appliance efficiency standards.

15. Utility conservation and load management programs require funding authorization from the CPUC. The CPUC should make clear its short-term and long-term policies embodied in its authorization decisions so that the CEC can take appropriate account of those policies in the ER.

16. The absence of energy-related capital costs, and not the complexity of devising appropriate contractual operating terms, is the primary basis for not authorizing a peaker-based long-run standard offer.

17. Short-run QF pricing will be equal to or less than the utility's long-run marginal cost whenever the utility would not add a baseload or intermediate resource.

18. It is desirable for purposes of least-cost planning that QFs be allowed to compete against non-QF sellers of electricity to California. However, such competition must be made to dovetail with the negotiation process so that neither QF nor non-QF sellers gain unfair advantages.

19. To maximize benefits from QFs, and to permit real competition between QFs and non-QF sellers, the resource plan proceeding must deal not only with avoiding new power plant construction but also with filling the utility system's disaggregated resource need, which is basically what a power purchase should do.

20. Sufficient flexibility can be built into final Standard Offer 4 to respond to disaggregated system needs.

21. The use of IERs to calculate energy payments to QFs ensures that such payments consider periods when oil/gas-fired generation is not on the margin.

22. Standard Offer 2 is well-suited to SDG&E's current needs. Standard Offer 2 does not avoid new resources but rather backs down existing resources. This is the least-cost strategy whenever a utility would not incur energy-related capital costs.

23. Block pricing and an overall megawatt limit, together with clear and objective queue management rules for establishing priority, are adequate safeguards to justify reinstatement of Standard Offer 2 for SDG&E.

24. The resource plan update proceeding instituted on a two-year cycle for final Standard Offer 4 provides a better forum than the general rate case to establish the capacity price schedules needed for Standard Offer 2.

25. The levelization feature of Standard Offer 2 capacity payments obscures the marginal price signal conveyed by the ERI and block pricing. This is a concern when utilities appear to have capacity substantially in excess of their reliability targets (as is the case with PG&E and Edison) and uneconomic bypass may be occurring.

26. The continued uncertainty regarding the QF dropout rate and capacity valuation on the PG&E system also justify continuing the suspension of Standard Offer 2 for PG&E.

<u>Conclusions of Law</u>

1. Final Standard Offer 4, unlike interim Standard Offer 4, is based on avoidable resources and not on a projection of short-run marginal costs.

2. No final Standard Offer 4 contracts should be made available to QFs at this time.

3. Pursuant to the biennial update procedure for final Standard Offer 4, the question of avoidable resources should next be reviewed in connection with ER-7.

4. If PG&E, SDG&E, or Edison seeks authority to develop a new resource (including any proposals for demand-side management program funding) in an application filed before the next resource plan update, the filing should include the applicant's CEC-based scenario and its preferred scenario (if any) from this proceeding. The applicant can also use additional scenarios with more recent assumptions to support the requested authority; however, the applicant must explain and justify deviations from the planning assumptions on which it chose to rely in the most recent resource plan proceeding.

5. Standard Offer 2 should be reinstated for SDG&E but not for PG&E or Edison.

6. The reinstatement of Standard Offer 2 for SDG&E should be accompanied by a cumulative limit on new contracts signed before the next resource plan update of 100 megawatts. These contracts should be allocated in two successive, separately-priced blocks, with 50 megawatts cumulative capacity in each block. The capacity payment to a QF that straddles the two blocks should be computed according to the proportion of the QF's megawatts within each block. Where a QF straddles the megawatt limit of the second block, SDG&E should use the same buffer allotment rule approved in conjunction with the final Standard Offer 4 auction.

7. The reinstatement of Standard Offer 2 for SDG&E should be stayed pending (1) approval of SDG&E's reliability target, and (2) review of comments on queue management and SDG&E's proposals for use of certain contract provisions also under consideration for final Standard Offer 4. SDG&E's proposals regarding Standard Offers 1 and 2 are considered for prospective application only; existing QF contracts are not affected.

8. Although SDG&E will not have any final Standard Offer 4 contracts available to meet its capacity needs at this time, SDG&E management is not otherwise inhibited by today's decision from pursuing the resource strategy it deems to be in the best interests of the utility and its ratepayers.

9. This order should be made effective today in order to expedite resolution of issues in the implementation of final Standard Offer 4 and the reinstatement of Standard Offer 2.

SECOND INTERIM ORDER - COMPLIANCE PHASE

IT IS ORDERED that:

1. Approval of the final Standard Offer 4 compliance filings of Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (Edison) is deferred to the final decision in the compliance phase.

2. No final Standard Offer 4 contracts shall be made available by PG&E, SDG&E, or Edison before further order of the Commission. The motion of Independent Energy Producers Association to reopen the record for further testimony on avoidable resources is denied.

3. If PG&E, SDG&E, or Edison seeks authority to develop a new resource (including any proposals for demand-side management program funding) in an application filed before the next resource plan update, the filing shall include the applicant's CEC-based scenario and its preferred scenario (if any) from this proceeding. The applicant can also use additional scenarios with more recent assumptions to support the requested authority; however, the applicant shall explain and justify deviations from the planning assumptions on which it chose to rely in the most recent update proceeding.

4. The suspension of Standard Offer 2 for PG&E and Edison is continued pending further order of the Commission.

5. Standard Offer 2 shall be reinstated for SDG&E, subject to conditions and upon consideration of further comments, as described in conclusions of law 6 and 7.

6. SDG&E shall file its proposal for queue management in connection with block pricing no later than November 18, 1987. Other parties may also file comments on this issue at that time.

7. Comments of other parties on SDG&E's proposals for Standard Offers 1 and 2 shall be filed no later than November 18, 1987.

This order is effective today.

Dated NOV 1 3 1987, at San Francisco, California.

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

Commissioner Donald Vial, being necessarily absent, did not participate.

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

Victor Weisser, Executive Director

APPENDIX A
Page 1

Table of Acronyms and Abbreviations

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

ALJ	Administrative Law Judge (p. 1)
CEC	California Energy Commission (I)
Conditional RETO	See RETO (I.B.4.a)
COT Project	California-Oregon Transmission Project (I.A.2)
CPCN	Certificate of Public Convenience and Necessity (I.A.2)
CPUC or Commission	California Public Utilities Commission (I.A.1)
D.	Decision (p. 1)
Edison	Southern California Edison Company (I)
ER	Electricity Report (I)
ER-6	The Sixth Electricity Report (I), the CEC's most recent adopted ER
ER-7	The Seventh Electricity Report (I.A), now in preparation
ERI	Energy Reliability Index (II.C.1)
EUE	Expected Unserved Energy (I.B.4.a)
I.	Order Instituting Investigation (I.B.4.e)
IEP	Independent Energy Producers Association (I.A.1)
IER	Incremental Energy Rate (I.B.2)

APPENDIX A
Page 2

LOLE	Loss of Load Expectation (I.B.4.a)
LOLP	Loss of Load Probability (II.C.1)
MAREL	Multi-Area Generation System Reliability Model (I.B.4.a)
NOI	Notice of Intention to file an application, e.g., for a general rate case (IV)
NPC	Northwest Power Company (II.C.1)
PG&E	Pacific Gas and Electric Company (I)
Public Staff	Public Staff Division of the CPUC (I.B.3)
QF	Qualifying Facility (I)
RETO	Reasonably Expected to Occur (I.B.4.a); "Conditional RETO" is used by the CEC to designate conservation and load management programs deemed desirable but awaiting additional regulatory approval.
SDG&E	San Diego Gas & Electric Company (p. 1)
SFG/U/F	Santa Fe Geothermal, Inc., Union Oil Company of California, and Freeport-McMoran Resource Partners (I.A.2)

(END OF APPENDIX A)

INDEX

Following Decision (D.) 87-05-060, our first interim compliance phase opinion, in which we dealt with certain pricing and bidding issues, we held further hearings in this proceeding in June and July. These hearings concerned resource planning and contract drafting for final Standard Offer 4 and possible reinstatement of Standard Offer 2. Today's decision addresses only the most pressing of these issues. We find (1) that there are presently no avoidable resources for purposes of final Standard Offer 4, and (2) that Standard Offer 2 should be reinstated for San Diego Gas & Electric Company (SDG&E).

I. Avoidable Resources

Final Standard Offer 4 uses a simplified generation resource plan methodology. (See D.85-07-022.) We presently implement this methodology through review of utility resource plans based on assumptions from the then-current Electricity Report (ER) of the California Energy Commission (CEC) and such alternative planning scenarios as the utility may wish to present in order to test the effect of uncertainties in the forecast. Our review determines whether, for each utility applicant, there are any "avoidable" generation resources (including construction by the utility and power purchases from others). If we find such resources, we would direct that utility to make a final Standard Offer 4 available for bidding by Qualifying Facilities (QFs). The number of megawatts in the offer, and the base price that QFs must contribution to its resource needs during the eight-year deferral window. Conceivably, a utility might want to add small increments (e.g., 20 megawatts) of baseload or intermediate generation in each year. Such a pattern would probably be hard to achieve through new construction or power purchases from non-QF sellers but feasible through final Standard Offer 4. The fixed costs of the capacity could be derived from generic cost data for baseload (probably coal-fired) and intermediate (probably combined cycle) plants, similar to the cost-effectiveness testing performed by SFG/U/F in Exhibit 432. The utility could prepare a list of desirable performance features, price them out separately, and treat them as adders or subtractors, depending on what the specific QF can provide as compared to the avoided generation resource. SDG&E is probably the farthest along of the utilities in the disaggregated valuation of performance features. Line loss calculation and interconnection costs can also be made QF-specific and the price adjusted by reference to the corresponding characteristics of the avoided capacity addition.[17]

Disaggregated resource need may entail more speculative price estimation than the avoidable plant, although this is by no means clearly so. We think that, in any case, the resource plan proceeding contains important safeguards: utilities would not be able to fill the need, either through QF purchases or their own

17 Some assumptions would have to be made on the approximate location of the avoided plant or purchase. The transmission-related benefits and costs of specific QFs, as in the case of performance features, may be higher or lower than those of the avoided resource. The line loss question has been addressed in workshops in 1983, and PG&E has made recent proposals to enable QFs to calculate their interconnection costs. These issues should be taken up in our investigation of transmission system operations (I.84-04-077) following the final decision in the compliance phase herein.

efforts, if they propose unreasonably low prices; while the cost-effectiveness standard effectively caps the price for which QFs could argue.

A final point on avoidable resources concerns associated transmission costs and constraints. There is general agreement that resource planning must consider physical constraints of the existing transmission system affecting its ability to handle energy from a planned resource addition, and we have already addressed the question of what transmission reinforcements resulting from the avoidable resource are includable in avoided cost. (D.87-05-060, pp. 29-31.) The Bonneville Power Administration's Intertie Access Policy is another type of constraint that affects the access of California utilities to energy sellers in the Pacific Northwest. The CEC and the CPUC have both criticized the anti-competitive impacts of this policy. For purposes of final Standard Offer 4 we think the policy should be ignored. In other words, it should be assumed that California utilities have access, up to the limits of existing transmission capacity and upon payment of any appropriate wheeling charges, to surplus energy and capacity in the Pacific Northwest. To recognize the policy in this proceeding would give full scope to its anti-competitive impact, effectively limiting California's resource options as to both QF and Pacific Northwest purchases.

II. Reinstatement of Standard Offer 2

Standard Offer 2 is limited to QFs that commit to provide firm capacity. The offer has energy payments based on the purchasing utility's short-run marginal operating costs, and capacity payments based on the full annualized fixed costs of a combustion turbine. The capacity payments are levelized over the term of the contract, which can be as much as 30 years.

Many parties have suggested workshops on many topics, and we agree that workshops could be helpful. At the moment, the most timely topic, because of its usefulness for ER-7, would be the creation of a joint terminology for use in the ERs and resource plan updates. We suggest that the staffs of the respective commissions produce a joint draft and schedule a workshop to receive input from interested parties. The staffs should also consult on the scheduling and priorities for workshops on other topics, although many of these should probably be reserved until after our final compliance phase opinion.

Findings of Fact

1. The CEC adopted its current ER (ER-6) in December 1986.

2. None of the CEC-based planning scenarios filed by the utilities, and none of the alternative scenarios, discloses a cost-effective baseload or intermediate resource over the next eight years.

3. Utility participation in studies of potential power plant projects is useful in developing the utility's resource plans.

4. In a CPCN proceeding for a transmission project, all benefits claimed for the project are considered, including the project's cost-effectiveness when all potential purchases are taken into account.

5. One of the chief goals of the resource planning process is to fairly compare the benefits and detriments pertaining to each type of resource option.

6. SDG&E, but not PG&E or Edison, needs significant additional capacity over the next eight years.

7. SDG&E's need appears to be predominantly for peaking capacity, which is not deferrable by QFs.

8. The refurbishment of Silver Gate by SDG&E appears consistent with ER-6.

9. SDG&E's proposal to make a long-run offer to QFs at this time would use a projection of short-run marginal costs rather than

the long-run marginal cost methodology previously approved for final Standard Offer 4.

10. The primary source of the differences in long-term need assessment between SDG&E and the CEC is their respective treatment of conditional RETO.

11. The CEC and CPUC staffs are jointly revising the Standard Practice Manual. The revisions are intended in part to permit more direct comparison of supply-side and demand-side resource options than is possible with the current manual. Some revisions are planned to be ready in time for use with ER-7.

12. Under the current methodology for final Standard Offer 4, conservation and load management resources are not deferrable by QFs.

13. Under the current methodology for final Standard Offer 4, nondeferrable resources that are cost-effective may be included in a utility's resource plan. Non-cost-effective resources are not deferrable by QFs and are not includable in resource plans unless their inclusion is supported by express regulatory policies.

14. The CEC is uniquely qualified to judge the impacts of its building and appliance efficiency standards.

15. Utility conservation and load management programs require funding authorization from the CPUC. The CPUC should make clear its short-term and long-term policies embodied in its authorization decisions so that the CEC can take appropriate account of those policies in the ER.

16. The absence of energy-related capital costs, and not the complexity of devising appropriate contractual operating terms, is the primary basis for not authorizing a peaker-based long-run standard offer.

17. Short-run QF pricing will be equal to or less than the utility's long-run marginal cost whenever the utility would not add a baseload or intermediate resource.

18. It is desirable for purposes of least-cost planning that QFs be allowed to compete against non-QF sellers of electricity to California. However, such competition must be made to dovetail with the negotiation process so that neither QF nor non-QF sellers gain unfair advantages.

19. To maximize benefits from QFs, and to permit real competition between QFs and non-QF sellers, the resource plan proceeding must deal not only with avoiding new power plant construction but also with filling the utility system's disaggregated resource need, which is basically what a power purchase should do.

20. Sufficient flexibility can be built into final Standard Offer 4 to respond to disaggregated system needs.

21. Resource planning must consider physical constraints of the existing transmission system affecting the system's ability to handle energy from a planned resource addition. However, the Bonneville Power Administration's Intertie Access Policy is not a physical constraint. For purposes of final Standard Offer 4, it should be assumed that California utilities have access, up to the limits of existing transmission capacity and upon payment of any appropriate wheeling charges, to surplus energy and capacity in the Pacific Northwest.

22. The use of IERs to calculate energy payments to QFs ensures that such payments consider periods when oil/gas-fired generation is not on the margin.

23. Standard Offer 2 is well-suited to SDG&E's current needs. Standard Offer 2 does not avoid new resources but rather backs down existing resources. This is the least-cost strategy whenever a utility would not incur energy-related capital costs.

24. Block pricing and an overall megawatt limit, together with clear and objective queue management rules for establishing priority, are adequate safeguards to justify reinstatement of Standard Offer 2 for SDG&E.

25. The resource plan update proceeding instituted on a two-year cycle for final Standard Offer 4 provides a better forum than the general rate case to establish the capacity price schedules needed for Standard Offer 2.

26. The levelization feature of Standard Offer 2 capacity payments obscures the marginal price signal conveyed by the ERI and block pricing. This is a concern when utilities appear to have capacity substantially in excess of their reliability targets (as is the case with PG&E and Edison) and uneconomic bypass may be occurring.

27. The continued uncertainty regarding the QF dropout rate and capacity valuation on the PG&E system also justify continuing the suspension of Standard Offer 2 for PG&E.

<u>Conclusions of Law</u>

1. Final Standard Offer 4, unlike interim Standard Offer 4, is based on avoidable resources and not on a projection of short-run marginal costs.

2. No final Standard Offer 4 contracts should be made available to QFs at this time.

3. Pursuant to the biennial update procedure for final Standard Offer 4, the question of avoidable resources should next be reviewed in connection with ER-7.

4. If PG&E, SDG&E, or Edison seeks authority to develop a new resource in an application filed before the next resource plan update, the filing should include the applicant's CEC-based scenario and its preferred scenario (if any) from this proceeding. The applicant can also use additional scenarios with more recent assumptions to support the requested authority; however, the applicant must explain and justify deviations from the planning assumptions on which it chose to rely in the most recent resource plan proceeding.

5. Standard Offer 2 should be reinstated for SDG&E but not for PG&E or Edison.

15. Utility conservation and load management programs require funding authorization from the CPUC. The CPUC should make clear its short-term and long-term policies embodied in its authorization decisions so that the CEC can take appropriate account of those policies in the ER.

16. The absence of energy-related capital costs, and not the complexity of devising appropriate contractual operating terms, is the primary basis for not authorizing a peaker-based long-run standard offer.

17. Short-run QF pricing will be equal to or less than the utility's long-run marginal cost whenever the utility would not add a baseload or intermediate resource.

18. It is desirable for purposes of least-cost planning that QFs be allowed to compete against non-QF sellers of electricity to California. However, such competition must be made to dovetail with the negotiation process so that neither QF nor non-QF sellers gain unfair advantages.

19. To maximize benefits from QFs, and to permit real competition between QFs and non-QF sellers, the resource plan proceeding must deal not only with avoiding new power plant construction but also with filling the utility system's disaggregated resource need, which is basically what a power purchase should do.

20. Sufficient flexibility can be built into final Standard Offer 4 to respond to disaggregated system needs.

21. Resource planning must consider physical constraints of the existing transmission system affecting the system's ability to handle energy from a planned resource addition. However, the Bonneville Power Administration's Intertie Access Policy is not a physical constraint. For purposes of final Standard Offer 4, it should be assumed that California utilities have access, up to the limits of existing transmission capacity and upon payment of any

6. The reinstatement of Standard Offer 2 for SDG&E should be accompanied by a cumulative limit on new contracts signed before the next resource plan update of 100 megawatts. These contracts should be allocated in two successive, separately-priced blocks, with 50 megawatts cumulative capacity in each block. The capacity payment to a QF that straddles the two blocks should be computed according to the proportion of the QF's megawatts within each block. Where a QF straddles the megawatt limit of the second block, SDG&E should use the same buffer allotment rule approved in conjunction with the final Standard Offer 4 auction.

7. The reinstatement of Standard Offer 2 for SDG&E should be stayed pending (1) approval of SDG&E's reliability target, and (2) review of comments on queue management and SDG&E's proposals for use of certain contract provisions also under consideration for final Standard Offer 4. SDG&E's proposals regarding Standard Offers 1 and 2 are considered for prospective application only; existing QF contracts are not affected.

8. Although SDG&E will not have any final Standard Offer 4 contracts available to meet its capacity needs at this time, SDG&E management is not otherwise inhibited by today's decision from pursuing the resource strategy it deems to be in the best interests of the utility and its ratepayers.

9. This order should be made effective today in order to expedite resolution of issues in the implementation of final Standard Offer 4 and the reinstatement of Standard Offer 2.

appropriate wheeling charges, to surplus energy and capacity in the Pacific Northwest.

22. The use of IERs to calculate energy payments to QFs ensures that such payments consider periods when oil/gas-fired generation is not on the margin.

23. Standard Offer 2 is well-suited to SDG&E's current needs. Standard Offer 2 does not avoid new resources but rather backs down existing resources. This is the least-cost strategy whenever a utility would not incur energy-related capital costs.

24. Block pricing and an overall megawatt limit, together with clear and objective queue management rules for establishing priority, are adequate safeguards to justify reinstatement of Standard Offer 2 for SDG&E.

25. The resource plan update proceeding instituted on a two-year cycle for final Standard Offer 4 provides a better forum than the general rate case to establish the capacity price schedules needed for Standard Offer 2.

26. The levelization feature of Standard Offer 2 capacity payments obscures the marginal price signal conveyed by the ERI and block pricing. This is a concern when utilities appear to have capacity substantially in excess of their reliability targets (as is the case with PG&E and Edison) and uneconomic bypass may be occurring.

27. The continued uncertainty regarding the QF dropout rate and capacity valuation on the PG&E system also justify continuing the suspension of Standard Offer 2 for PG&E.

Conclusions of Law

1. Final Standard Offer 4, unlike interim Standard Offer 4, is based on avoidable resources and not on a projection of short-run marginal costs.

2. No final Standard Offer 4 contracts should be made available to QFs at this time.

SECOND INTERIM ORDER - COMPLIANCE PHASE

IT IS ORDERED that:

1. Approval of the final Standard Offer 4 compliance filings of Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (Edison) is deferred to the final decision in the compliance phase.

2. No final Standard Offer 4 contracts shall be made available by PG&E, SDG&E, or Edison before further order of the Commission.

3. If PG&E, SDG&E, or Edison seeks authority to develop a new resource in an application filed before the next resource plan update, the filing shall include the applicant's CEC-based scenario and its preferred scenario (if any) from this proceeding. The applicant can also use additional scenarios with more recent assumptions to support the requested authority; however, the applicant shall explain and justify deviations from the planning assumptions on which it chose to rely in the most recent update proceeding.

4. The suspension of Standard Offer 2 for PG&E and Edison is continued pending further order of the Commission.

5. Standard Offer 2 shall be reinstated for SDG&E, subject to conditions and upon consideration of further comments, as described in conclusions of law 6 and 7.

6. SDG&E shall file its proposal for queue management in connection with block pricing no later than November 18, 1987. Other parties may also file comments on this issue at that time.

7. Comments of other parties on SDG&E's proposals for Standard Offers 1 and 2 shall be filed no later than November 18, 1987.

This order is effective today.

Dated ____________________, at San Francisco, California.

APPENDIX A
Page 2

LOLE	Loss of Load Expectation (I.B.4.a)
LOLP	Loss of Load Probability (II.C.1)
MAREL	Multi-Area Generation System Reliability Model (I.B.4.a)
NPC	Northwest Power Company (II.C.1)
PG&E	Pacific Gas and Electric Company (I)
Public Staff	Public Staff Division of the CPUC (I.B.3)
QF	Qualifying Facility (I)
RETO	Reasonably Expected to Occur (I.B.4.a); "Conditional RETO" is used by the CEC to designate conservation and load management programs deemed desirable but awaiting additional regulatory approval.
SDG&E	San Diego Gas & Electric Company (p. 1)
SFG/U/F	Santa Fe Geothermal, Inc., Union Oil Company of California, and Freeport-McMoran Resource Partners (I.A.2)

(END OF APPENDIX A)