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Decision 92-12-021 December 3, 1992

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's own motion to implement the Biennial Resource Plan Update following the California Energy Commission's Seventh Electricity Report.	I.89-07-004 (Filed July 6, 1989)
Order Instituting Investigation on the Commission's own motion to develop a policy on nondiscriminatory access to electricity transmission services for nonutility power producers.	I.90-09-050 (Filed September 25, 1990)

(See Decisions 90-03-060, 91-06-022, 91-10-039, and 92-04-045 for appearances.)

OPINION ON PROPOSED MODIFICATIONS TO THE
FINAL STANDARD OFFER 4 POWER PURCHASE AGREEMENT

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OPINION ON PROPOSED MODIFICATIONS TO THE FINAL STANDARD OFFER 4 POWER PURCHASE AGREEMENT

1. Introduction and Summary

In today's decision, we approve a proposed settlement on modifications to the Final Standard Offer 4 (FSO4) power purchase agreement.[1] We also approve an additional curtailment option and give further direction on how producers now holding Standard Offer 1 (SO1) contracts may compete in the FSO4 auction. These modifications implement the Commission's policy directions in Decision (D.) 91-06-022 (slip opinion).

The FSO4 settlement we are approving is the outcome of an agreement reached by a broad coalition of utility, qualifying facility (QF), and ratepayer representatives. The settlement will apply to the uniform FSO4 offered by Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (Edison). The additional FSO4 curtailment option will not apply uniformly at this time. This option was proposed via a stipulation between PG&E and representatives of various gas-fired cogenerators, for inclusion in PG&E's FSO4 agreement. We do not require SDG&E and Edison to include the identical option, but we are urging those two utilities to negotiate a functionally similar option tailored to the needs of their systems.

Today's decision also addresses certain additional issues that appear critical to resolve at this time. (See D.92-04-045, slip op., p.96.) These issues are (1) how much flexibility the

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1 In this and other decisions on standard offers, we use the terms "contract" and "power purchase agreement" (or sometimes just "agreement") interchangeably.

FSO4 QF should have to make additional sales, on a firm or as-available basis, either to the purchasing utility (under FSO4 and/or another contract) or to other entities, and (2) under what conditions (if any) a purchasing utility should have the flexibility to prematurely terminate its FSO4 contract with a nondefaulting QF.

We see QF and utility flexibility as important attributes of the fully competitive generation market toward which we are progressing. Thus, we give direction for negotiations that should result in additional flexibility for both buyers and sellers under FSO4 agreements.

Today's decision, in conjunction with D.92-09-078 (in Investigation (I.) 90-09-050), where we adopted an interim transmission access program, clears the way for an electric utility request for bids to provide generating capacity. The solicitation is planned for later this year.

Before the solicitation, the utilities will file conformed FSO4 power purchase agreements and revised auction protocols. These filings will incorporate (1) modifications approved herein, (2) revisions to coordinate the results of this proceeding with our transmission access investigation, and (3) negotiated provisions as described above. The schedule for these filings will be established by ruling of the Assigned Commissioner or Administrative Law Judges (ALJs).

2. Background

Competition in electric generation, to varying degrees, has long been a reality. This Commission's aim, through the standard offer program, is to harness this competition to serve the best interests of ratepayers.[2]

FSO4 is a key part of the portfolio of standard offers. It is designed specifically to allow nonutility sources to supply generation that the utility would otherwise have to get through major capital-intensive projects. Such projects in the recent past have proven very risky, with delays and cost-overruns that resulted in major rate increases. FSO4 shifts the development risk for such projects onto the entrepreneur, who (1) gets paid only for production (increased costs due to construction problems, etc., cannot be passed on to ratepayers), and (2) must perform at a total cost equal to or less than the utility project that the entrepreneur defers or avoids altogether. FSO4 is also unique among our standard offers in that it is allocated by means of an auction.[3]

This is the first FSO4 auction. The generating capacity for which bids will be solicited is consistent with the California Energy Commission's (CEC) current "integrated assessment of need" for these three utilities.

This need assessment comes from the 1990 Electricity Report (ER-90). Although we had intended that auctions generally follow the CEC's adoption of an Electricity Report within a

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2 Previous decisions have detailed the development of FSO4 and of the standard offers generally. We will not repeat that history here. We refer the reader to D.85-07-022, 18 CPUC2d 333, for discussion of long-run avoided cost methodology; D.86-07-004, 21 CPUC2d 340, for specification of key FSO4 terms and conditions; and D.91-06-022 and D.92-04-045 (both slip opinions) for recent modifications and identification of capacity for bidding in this auction.

3 Standard offers in the past have been made available either without a capacity limit or have been allocated on a first-come, first-served basis.

year,[4] this auction has been delayed while we made certain refinements to FSO4. These include, among other things, explicit consideration of transmission costs in choosing the lowest total-cost winners; creation of transmission-only service to enhance competition from bidders outside the purchasing utility's territory; separately-bid energy and capacity prices; expanded curtailment authority for the purchasing utility; and consideration of costs attributed to polluting air emissions.

These refinements, which we ordered in this proceeding (the Biennial Resource Plan Update, or just "Update") and in I.90-09-050, have required corresponding modifications to the FSO4 power purchase agreement and auction protocols. We are now ready to consider the parties' proposals for such modifications.

3. FSO4 Modifications Pursuant to D.91-06-022

3.1 The Settlement

Pursuant to our settlement procedures,[5] certain "settling parties" have proposed a comprehensive revision to the FSO4 power purchase agreement, to implement our policies set forth in D.91-06-022. The settling parties include PG&E, SDG&E, the Commission's Division of Ratepayer Advocates (DRA), Independent Energy Producers Association and Geothermal Resources Association (jointly, IEP/GRA), Coalition for Energy Efficiency and Renewable Technologies (CEERT), and British Columbia Power Exchange Corporation (Powerex).

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4 See D.88-09-026, 29 CPUC2d 263, 293.

5 Rule 51 et seq. of our Rules of Practice and Procedure.

With one exception, every party that has taken a position on most FSO4 issues has joined in the settlement. The exception is Edison.[6]

The settling parties have submitted a "Settlement Agreement" and joint testimony, together with a proposed uniform FSO4 power purchase agreement, as modified pursuant to their agreement. The new FSO4 implements Commission policy directions on many matters, such as project fees and project milestones, residual air emission adders/subtracters and emission monitoring, economic curtailment, project viability and security for levelized payments, shortage cost and energy-related capital cost payments, liquidated damages, eligibility of foreign entities for FSO4 contracts, and bid evaluation methodology.

The settling parties emphasize that their agreement is offered for Commission approval only in its entirety. Like any settlement, this one is the product of compromise. Of necessity, each of the settling parties has accepted an outcome on some issues that would not be that party's position if each issue were litigated piecemeal. Thus, the settling parties ask for an opportunity to renegotiate, should the Commission reject any part of the agreement; and if they fail to achieve a mutually acceptable new agreement embodying the Commission's changes, they ask for the opportunity to file testimony on and litigate all issues de

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6 Edison is not the only party to object to the settlement, but the other objecting parties are all concerned with limited provisions of the settlement or (in one case) with a provision of the existing FSO4 contract that the settlement carries over without change. Edison proposes a comprehensive rewrite of the FSO4 contract, going well beyond the provisions addressed in the settlement.

novo.[7] We note the settling parties' request follows standard settlement practice here, consistent with Rule 51.7.

The settling parties' "Implementing Contract Language" (Exhibit K-2) is a modification, in underline and strikeout format, of the existing uniform FSO4. It is undoubtedly a long and complex contract, but we note that some of the most cumbersome provisions (e.g. those governing curtailment) are substantially simplified in the Settlement Agreement.

The bulk of the changes the settling parties have negotiated are changes clearly needed to implement D.91-06-022. As described in the joint testimony, these necessary changes include:

- A methodology to implement the adopted bid evaluation system, which chooses winners on a common first-year cents per kilowatt-hour basis;
- A payment structure that gives the utility substantial economic curtailment rights while keeping the QF financially indifferent to such decisions;
- An air emissions adder/subtracter payment structure that does not create perverse incentives for either the QF or the purchasing utility, and that allows the QF to know the size of the payments it will receive under FSO4 at the time of bid submission;

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7 The Motion for Approval of Settlement Agreement, at page 5, reads in pertinent part: "If the Commission determines that changes...are necessary to the package of issues resolved by the Settlement Agreement, the parties are obligated under the Settlement Agreement to attempt to renegotiate the settlement package to accommodate the Commission's concerns within 30 days of such recommended change...and resubmit the renegotiated package for Commission approval. If the parties are unable to reach such a mutually acceptable resolution, the Settlement Agreement shall be null and void by its terms. In such event, the parties would expect to have the opportunity to file testimony on each issue resolved by the Settlement Agreement as if [it] had never been entered into."

- o Contract terms that allow owners of foreign facilities meeting the ownership, operating, and efficiency requirements set forth in federal law to be eligible to enter into FSO4 contracts; and

- o Provision for security in the event the QF chooses fully levelized shortage cost payments.

The settling parties have also negotiated other "enhancements" to FSO4. D.91-06-022 does not expressly call for those enhancements, but we find they are clearly and integrally related to the policies we adopted there, so we agree with the settling parties that they should be considered necessary parts of the settlement package.

For example, we extended the maximum length of FSO4 contracts (D.91-06-022, slip op., pp. 42-45), so the settling parties have augmented the milestone procedure and added post-operation requirements that will provide the purchasing utility with initial and ongoing measures of project viability, which are appropriate for longer-term contracts. We also adopted a system of separate energy and capacity bids to shield ratepayers from fuel price risk, improve system dispatch, increase utility curtailment rights, and enable all types of QFs to bid a payment structure appropriate to their own mix of fixed and variable costs. (Id., pp. 47-57.) The settling parties accordingly developed new provisions to enable QFs to specify periodic variations in their heat rate and their price escalation rate so that their energy bid price better reflects changes to their expected true running costs over time. These changes appropriately complement our energy bidding policies.

The settling parties' joint testimony also expressly acknowledges and endorses the Commission's policy regarding QF/utility negotiations in the standard offer context:

> "FSO4 is a single contract which is designed to be broad enough to contractually handle a wide range of circumstances. As has been the case

> with all standard offers, however, if a particular QF proposes modifications to tailor the contract to suit its needs, the utility is obligated to entertain such a proposal and to engage in good faith negotiations with the QF." (Exhibit K-1, p. 3.)

This policy is very pertinent to Section 9 of today's decision.

From our review of the settling parties' implementing contract language and the motion and joint testimony supporting the settlement, we have concluded that the settlement successfully embodies our policy directions from D.91-06-022. The settling parties have retained the structure and, wherever appropriate, the terms of the existing FS04 power purchase agreement, modifying it only where such modifications were necessary or useful in furthering our stated policies. We agree with this approach to modification. We and the parties have travelled a long road in developing FS04. Further changes should be incremental, not a return to where we started drafting in 1985, or even earlier.

There is no single "right" implementation of D.91-06-022; however, the implementation presented in the settlement is plausible, coherent, and responsive. In many cases, the settling parties have succeeded beyond our expectations, for example, in providing the purchasing utility with the ability to invoke economic curtailment for an <u>unlimited</u> number of hours each year.[8] Judged strictly from the perspective of what we envisioned in D.91-06-022, the settling parties have succeeded brilliantly. We turn next to a negotiated addition to the settlement, then to an

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8 Economic curtailment does not require the FS04 QF to physically curtail its output, but if it does not do so, it must accept an "alternate" energy price (i.e., the utility's cost for generation from other sources, such as economy energy, during the curtailment). Under the existing FS04, economic curtailment is limited to 1500 hours per calendar year.

implementation issue resulting from D.92-04-045, and finally to objections to the settlement.

3.2 Additional Curtailment Option

We enthusiastically approve an additional FS04 curtailment option (available only to firm capacity QFs) stipulated to by PG&E and the Gas Cogeneration Working Group (GCWG). The stipulation, reached after the hearings ended but before the record closed, is a variation on a curtailment alternative that GCWG presented in its testimony.

Under the stipulated option, as compared to the curtailment provision in the settlement, the utility accepts a limit on the number of hours per year that it can curtail the QF, and in return the QF grants substantial price and operational concessions during curtailment. Specifically, each year after the on-line date of the deferrable resource, the utility can invoke curtailment for the greater of either 2,500 hours or 120% of the expected hours of curtailment (determined from the marginal cost duration curve used in bid evaluation). However, the QF must physically curtail its output for the equivalent of 1,250 hours at full contract capacity,[9] and the QF must accept the utility's alternate energy cost for all QF energy delivered during a curtailment period. (Under the settlement, the QF is subject to economic curtailment in all hours of the year but need not actually reduce its energy deliveries during such curtailment and would receive its energy bid price for such deliveries for up to 30% of the contract capacity.)

9 The QF would have to provide additional hours of physical curtailment for any period when it failed to fully curtail its contract output pursuant to this provision. For example, if the QF physically curtails to 50% of contract capacity, it must do so for twice as many hours as a QF that ceases energy deliveries altogether when the utility invokes this curtailment provision.

The stipulated option is notable in that it would be the first time a QF, under a standard offer provision, accepted the obligation to physically curtail under routine system operating conditions (as distinguished from extreme circumstances like negative avoided costs).[10] An equally notable provision is the utility's ability to adjust the QF's curtailment obligation at several points during the contract period.

Specifically, in the 15th and 20th year after the on-line date of the deferrable resource, the utility has the option to require, with 12 months' notice, that the QF revert to the unlimited economic curtailment provisions currently proposed in the Settlement Agreement. Furthermore, in the 16th year, if the utility has elected to keep the QF on the stipulated option, the minimum number of curtailment hours increases to the greater of either 3,000 hours or 120% of the expected hours of curtailment determined from the marginal cost duration curve used in bid evaluation. In addition, the utility will be entitled to up to 1,500 hours of physical curtailment in any operating year. The utility retains the option to require the QF to revert to unlimited economic curtailment, with 12 months' notice, in year 20.

We like the flexibility that this "second look" provision gives the utility. The limits on curtailment provide the QF additional certainty in the early years of the contract, which helps the developer finance its project. Lower financing costs, according to GCWG, will translate to more competitive bids, thus benefiting the ratepayer. At the same time, PG&E believes it

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10 Utilities can require physical curtailment, under current standard offers, when acceptance of QF power would <u>increase</u> the running costs of utility resources, which is a theoretical possibility if a utility otherwise had to turn off baseload plants. This "negative avoided cost" provision has never been invoked. Some QFs have accepted broader dispatchability obligations under negotiated (nonstandard) contract provisions.

retains ample curtailment rights under the stipulated option.[11] In the later years of the contract, when there is less certainty about how many curtailment hours the utility will need, the utility has substantial ability to increase its curtailment rights, up to unlimited economic curtailment, to respond to then-current conditions on its system.

Parties commenting on the proposed stipulation sound various cautionary notes. IEP/GRA endorse the stipulation, based on their understanding that it is an additional option, and not a replacement for the unlimited economic curtailment in the settlement agreement.[12] SDG&E and Edison do not oppose the stipulation, as applied to PG&E's FSO4, but believe that the stipulated option is not appropriate for their systems. We limit our approval of the stipulation as SDG&E and Edison request; however, as we will discuss later, SDG&E and Edison should explore the possibility of alternative curtailment options tailored to their respective systems.

Only DRA opposes the stipulation. DRA believes that physical curtailment is unlikely to provide any greater benefits than economic curtailment, and that the QF's price concessions under the stipulation do not sufficiently compensate the utility for its acceptance of an annual cap on curtailment hours.

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11 PG&E calculates that under its current marginal cost duration curve, it expects to curtail a geothermal QF or efficient gas cogenerator less than 600 hours per year.

12 IEP/GRA's understanding is correct. Our approval of the stipulation for application to PG&E's FSO4 means that QFs providing firm capacity can choose at contract signing between unlimited economic curtailment (pursuant to the settlement) and a combination of economic and physical curtailment subject to a cap (pursuant to the stipulation). QFs providing as-available capacity do not have the latter alternative.

PG&E and GCWG convincingly rebut DRA's objections. As noted by PG&E, DRA has largely overlooked the substantial benefits to ratepayers in the utility's ability, under the stipulated option, to save the entire difference between the QF's energy bid price and the utility's alternate cost every time the QF is curtailed but continues to run.

PG&E concedes that it cannot now quantify the value of physical curtailment in comparison to economic curtailment but argues that it will have greater flexibility in system operation and greater certainty regarding QFs' response to curtailment orders. We think the stipulated option has merit even without a precise quantification of the value of physical curtailment. The utilities have long sought greater ability to physically curtail QFs. The stipulated option will enable us to observe the practical impact of physical curtailment, and to gauge whether such curtailment should be continued, expanded, or limited in future solicitations.

We also find plausible GCWG's assertion that many developers will be able to submit lower bids because the cap on overall curtailment hours will improve project financeability. This anticipated benefit, again, is not quantified, but it is consistent with much expert testimony both in this phase and throughout the development of FS04. The point is, we can now test this hypothesis, under the stipulated option, at little or no risk to ratepayers.

Perhaps the most gratifying aspect of the PG&E/GCWG stipulation is that it constitutes one kind of "additional performance feature" we have been urging QFs and utilities to develop since we approved this concept over six years ago. (See

D.86-07-004, 21 CPUC2d 340, 376.)[13] The standard offer, as an off-the-shelf, one-size-fits-all contract, treats electricity as a pure commodity. The "additional performance feature" is one means by which the purchasing utility may seek, and the QF offer, valuable load-following or system stability features, beyond the minimum requirements of the standard offer, that enable the utility to more finely tune QF deliveries to the particular needs of the purchasing utility's system.

The need for a given additional performance feature, by its nature, will differ from one utility to the next.[14] Thus, we are not surprised that SDG&E and Edison consider the stipulated option, which can be viewed as a physical curtailment feature, not well suited to their respective systems. We are disappointed, however, that they have not successfully negotiated what they consider a suitable feature of this type.

Both Edison and SDG&E have previously said they consider physical curtailability a valuable attribute. SDG&E, moreover, has

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13 In that decision, we referred to "additional performance features" as "adders" for the sake of brevity. Since then, "adder" has been used in a different sense, i.e., a payment to a QF reflecting the value of its contribution to air quality. Because "adder" in this sense is now a part of the FSO4 contract, we will henceforth use "adder" only in the environmental context, and will use "additional performance feature" to refer to extra operational benefits (e.g., physical curtailment) that a QF may provide, but is not required to provide, under a standard offer contract.

14 In fact, the need for some features, such as voltage support, may vary geographically within the same utility's system. Thus, we directed utilities to develop specifications for different kinds of features. Such specifications might include technical matters, geographical limitations, MW limits on features' availability, QF size qualifications, and anything else legitimately related to the feature's feasibility or value. (See D.86-07-004, 21 CPUC2d 340, 376.)

made much over the fact that its system is "transmission-dependent." Presumably, the ability to physically curtail a resource would be advantageous in a situation where transmission capacity is a serious constraint.

SDG&E comments, in explaining its objections to the PG&E/GCWG stipulation, that PG&E is soliciting less capacity, both in absolute terms and as a percentage of peak demand, than is SDG&E in the coming request for bids.[15] We find this comment unilluminating. We think a utility with a relatively large solicitation should be more aggressive in negotiating additional performance features, not less so.

In conclusion, the concept underlying the PG&E/GCWG stipulation appears to have merit for the SDG&E and Edison systems as well. We encourage all three utilities to explore additional performance features with QFs both in connection with this auction and for possible availability to QFs that are already operational.

3.3 Impact of D.92-04-045

While hearings on the proposed settlement were in progress, the Commission issued D.92-04-045 in the resource plan phase of this proceeding. That decision slightly modified the air quality policies that the parties were working to implement.

In D.91-06-022, we had preferred a uniform valuation method for air quality impacts. The method used values based on the purchasing utility's marginal cost of emission control. In D.92-04-045, we determined that an "alternative planning scenario," in which the values assigned to residual air emissions depend on the site where the emissions occur, is more appropriate for

15 We note that the same comment holds true for the Edison solicitation relative to PG&E's.

California's resource planning and acquisition process.[16] (Id., slip op., p. 100.) Accordingly, the settlement (specifically, the mechanism for air quality adders/subtracters) must be modified to reflect our shift from uniform to nonuniform emissions valuation.

DRA and PG&E present different formulas on how to do this. PG&E would attribute emission values for both the identified deferrable resource (IDR) and the QF based on the QF's generation site; DRA would value the IDR's emissions according to the IDR's site and the QF's emissions according to the QF's site.

DRA is right. It has correctly implemented our shift to nonuniform valuation, while PG&E has produced another version of uniform valuation (albeit different from the approach we used in D.91-06-022). The value (cost) imputed to the IDR's emissions can be greater or less than that imputed to the QF's, based <u>both</u> on the comparative volumes of such emissions and on the respective sites where they would occur. DRA's formula captures both of these valuation aspects.[17]

4. Opposition to the Settlement

Our long-run standard offer, in most respects, was and is the product of negotiation between utilities, interested parties,

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16 The critical factor affecting the emission value of a particular pollutant is whether the generation site is in an "attainment" area, i.e., a location that complies with air quality standards for that pollutant. Values imputed to emissions in an attainment area are much lower than those imputed to emissions of the same pollutant in a nonattainment area. Carbon emissions are an exception to this rule. These emissions continue to be valued uniformly, since the concern they raise (climate change) is a global risk.

17 Because the settlement is (of necessity) silent on the emissions valuation change effected by D.92-04-045, our adoption of DRA's proposed implementation of that change does not constitute a rejection of the settlement. Rather, we are resolving a late-arising issue outside of the settlement.

and Commission staff. The negotiations have been long and difficult, but they have led, at least until this year, to interim and final SO4 contracts that most of the participants have agreed to support in most respects.

This year, the participants reached an agreement in principle that Edison did not join. They proceeded to draft implementing language without Edison, although Edison offered to participate. Since Edison did not subscribe to the principles that the settling parties were trying to implement, we cannot fault these parties for excluding Edison from the drafting process, although such exclusion may have contributed to the number of issues Edison has with the settlement.

That number is staggering. Edison appears to differ with the settlement on 20 or more issues.[18] Many of the FSO4 provisions Edison proposes to change are, in fact, not features of the settlement but rather provisions in the existing FSO4 power purchase agreement previously negotiated and supported by Edison. We find that Edison has not shown good cause to modify provisions left unchanged by the settlement. We also find in each instance that the settlement is as good as or better than alternative provisions proposed by Edison and other parties.

4.1 Issues Raised by Edison

This will be the fourth edition of FSO4. The first edition was a wholesale rewrite of interim SO4 and was approved by the Commission in D.88-03-079, 27 CPUC 2d 559. The utilities incorporated minor revisions to FSO4 in subsequent editions filed on May 12, 1989, and July 16, 1990. Edison joined the settlement embodying the first edition of FSO4 and duly filed each subsequent revision.

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18 In contrast, the number of issues raised by all other parties is four (two by GCWG, one each by CEERT and a group of wind QFs).

Now, Edison wants to reinstate numerous provisions of interim SO4. Edison fails to convince that these long-deleted provisions are necessary, and we see nothing in our recent decisions that even remotely suggests these provisions should be reconsidered.

4.1.1 Air Quality Adder/Subtracter Mechanism

Probably the most significant debate between Edison and the settling parties concerns the mechanism by which the purchasing utility pays air quality adders (or subtracters). These are an adjustment to fixed payments to the QF under the Settlement Agreement. Edison, in contrast, would adjust variable payments to the QF to reflect the latter's air quality impacts.

Edison argues that it is following the Commission's directions, as set forth in D.91-06-022. The settling parties disagree. They also believe that, under Edison's approach, the utility dispatcher would make perverse curtailment decisions because the dispatcher would see a QF's air quality benefits as an extra cost.[19] Edison responds that this problem could be eliminated by having the utility make its dispatch decisions for FSO4 QFs based solely on those QFs' respective energy bids, disregarding air quality adders/subtracters.

We prefer the settling parties' solution to this problem. It is true that in D.91-06-022, we envisioned air quality adders/subtracters as a component of variable payments; but it is also true that in D.91-06-022, we envisioned only an increase in the number of curtailment hours, when in fact under the Settlement

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19 The dispatcher would also see a QF with air quality subtracters as providing extra savings, resulting in inverse environmental dispatch (i.e., the more polluting resources being preferred).

agreement QFs go beyond a mere increase and agree to be curtailable in all hours of the year.[20] This is part of an overall satisfactory quid pro quo.

Moreover, the treatment of adders/subtracters under the Settlement Agreement furthers other policies articulated in D.91-06-022. Optimal system dispatch, an important goal we have acknowledged often, requires that both the seller and the purchaser of energy get accurate price signals regarding the running costs of each resource. The settling parties' approach accomplishes this, while Edison's approach would give mixed signals to the QF and the utility dispatcher. We also wanted to devise a pricing scheme in D.91-06-022 in which the QF's fixed (capital) costs generally would be covered through fixed payments. Again, the settling parties' approach is superior to Edison's in this regard.

4.1.2 Foreign Generating Facilities

Special provisions pertaining to foreign generating facilities are necessary because the Federal Energy Regulatory Commission (FERC) does not certify or otherwise regulate foreign generating facilities for compliance with FERC regulations governing QFs. In D.91-06-022 (slip op., p.76), we determined that foreign entities should be allowed to bid, provided they (1) comply with all requirements (other than FERC certification) for QF status initially, and (2) maintain such compliance throughout the term of the contract, as would be required of a U.S.-based QF. According to the settling parties, the implementing contract language (Exhibit K-2) includes provisions, applicable only to foreign entities, that address compliance with QF requirements and provide the purchasing utility with legal remedies equivalent to the remedies it has regarding domestic QFs.

20 Even the PG&E/GCWG alternative curtailment option provides the utility with about twice as many curtailment hours as it has under the prior version of FS04.

Edison differs with the settling parties on several provisions regarding foreign generating facilities. Edison wishes to add to the FS04 contract five conditions that would apply only to these facilities. Powerex, representing various Canadian interests, counters that the General Agreement on Trade and Tariffs and the Free Trade Agreement between the U.S. and Canada prevent Edison from insisting on its conditions, because they unreasonably discriminate against facilities on a national basis.

Because we conclude that none of Edison's proposed conditions offers utilities a useful or necessary protection, we do not reach the question of whether Edison's conditions would violate any trade agreements. We will deal with each of the conditions in order.

<u>4.1.2.1 Indemnity Clause</u>

Section 12.4 of Exhibit K-2 requires foreign generating facilities to compensate utilities if FERC or a court finds that payments under the agreement are both regulated by FERC and unlawful. Edison would require compensation if either circumstance (regulation by FERC or unlawfulness) exists.

Section 12, of which § 12.4 forms a part, deals with the status of generating facilities under FERC regulations. It provides for rights of utilities and QFs with regard to FERC licensing. It does not create general remedies, which are found in § 27 of Exhibit K-2. Section 12.4 specifically adds to a utility's rights under § 12.1, which provides that a generating facility shall warrant that it meets FERC's standards for a QF.

With this in mind, the purpose of § 12.4 becomes clear. It offers a remedy if FERC decides at some later date to regulate imports of electric power in a manner that conflicts with our own approach, which is to treat the foreign generator as far as possible like any domestic QF, provided the generator meets all requirements for QF status other than FERC certification. Section

12.4 does not offer a general remedy in the event of any change in regulation, except with respect to this particular problem.

Section 12.4 is well-crafted to address any situation where FERC acquires or assumes jurisdiction over a purchase from a foreign generator under FSO4. If FERC decides to regulate these payments to a foreign generator and ratifies them, rather than finding them illegal, FERC's decision harms neither the buyer nor the seller. Thus, the purchasing utility incurs no harm, and should have no entitlement to indemnity, where this circumstance (the purchase is regulated by FERC but not unlawful) occurs. Only where both conditions occur (i.e., payments under the contract are found to be both subject to FERC jurisdiction and unlawful) does the purchasing utility need the recourse provided by § 12.4.

In sum, we find that the settling parties' use of the conjunctive "and" is logical, while Edison's disjunctive "or" would distort § 12.4 and complicate the contract to no good purpose.

4.1.2.2 Consent to Jurisdiction

Edison's proposal would give state and federal courts in Los Angeles nonexclusive jurisdiction over any litigation concerning FSO4 contracts. This means that either party could bring suit where it wanted to, but neither party could challenge the jurisdiction of a Los Angeles court if the other party sued there. Edison also proposes language preventing a party from challenging venue in a Los Angeles court.

The settling parties included no express choice-of-jurisdiction clause. However, § 32.1 of Exhibit K-2 provides that the FSO4 contract shall be governed by the laws of California, as if the agreement had been executed and were to be performed entirely within California. This section gives a California court adequate grounds to take jurisdiction. We do not see that Edison's proposal adds anything of value.

Insofar as Edison's proposal would restrict a foreign generating facility from challenging venue in a Los Angeles court, the proposal adds a new protection for utilities. However, the protection seems redundant. A seller under FS04 that tries to challenge venue in a Los Angeles-area court would need to make a very strong showing why venue should be somewhere else. We expect that removal would only occur for the best of reasons. Edison's proposal would attempt to prevent even the most reasonable of forum changes. We do not believe Edison or any other utility requires this level of protection at a potential litigant's expense, especially when Edison does not ask this of domestic QFs.

<u>4.1.2.3 Agent for Service of Process</u>

Edison proposes that the foreign generating facility irrevocably appoint an agent who will accept service of process in California. The settling parties have no provision for appointing an agent for service.

Under California law, a generating facility does "intrastate business" and must therefore appoint an agent for service of process. Corporations Code § 191 defines the transaction of intrastate business as "entering into repeated and successive transactions of...business in this state, other than interstate or foreign commerce."[21] The sale of electricity to a California buyer involves a continuous transaction within the state, extant every moment the seller supplies electricity and repeated every time the buyer pays for it.

California courts have found that out-of-state businesses conduct "intrastate business" when they merely ship goods into the state, even without a contract executed in California. <u>Thomas v. J.C Penney Co., Inc</u>., 186 Cal. App. 2d 223 (1960); <u>Harry Gill Co. v. Superior Court</u>, 238 Cal. App. 2d 666 (1965). Here, the seller has more than a passing contact with California--it will have

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21 All codes cited in the text of this section are California codes.

signed a contract in California for the sale of electricity into California, and it will expect a California utility to pay.

The settlement also precludes an out-of-state entity from using a "safe harbor" provision normally available under California law to avoid the appointment requirement. Under Corporations Code § 191, no out-of-state corporation, whether foreign or domestic, may be considered to be doing intrastate business solely because it solicits or procures orders where such orders require acceptance outside of California. The settlement draws the seller out of this safe harbor, however, by making acceptance take place in California; the law allows a court to find that it does intrastate business based on this fact alone.

When an out-of-state corporation does intrastate business in California, the provisions of Corporations Code §§ 2100-2117 automatically apply to it. These provisions tell the out-of-state corporation to name an agent for service of process. If the agent can no longer accept process, the company must consent to service on the Secretary of State. The corporation, not the agent, agrees irrevocably to accept process.

We find that these provisions adequately protect utilities who may need to litigate against foreign generating facilities.

<u>4.1.2.4 Enforceability of Judgments</u>

Edison wishes to add to § 32.2 of Exhibit K-2 a provision that all final judgments against the generating facility "shall be conclusive and may be enforced in any court or tribunal in any other jurisdiction." Section 32.2 states that parties may void the contract if the generating facility's jurisdiction fails to enforce California judgments.

Code of Civil Procedure § 1908 says that all judgments are conclusive. "Conclusive" means that the same parties may not litigate the issue again, although they may appeal the decision. As noted above, § 32.1 of Exhibit K-2 designates California law as governing FS04 contracts, so it appears to us that judgments would be "conclusive" within the meaning of the Code of Civil Procedure. We find that Edison's proposed provision adds nothing but a chance for confusion.

4.1.2.5 Legal Opinion on Enforceability of Judgments

The settlement requires a foreign generating facility to provide the purchasing utility an opinion by independent counsel stating that the courts in the facility's domicile will enforce California judgments. Edison proposes a change that would enable the utility to veto the foreign generator's choice of legal counsel for this purpose.

This provision gives the utility a vanishingly small amount of additional protection. It guards against the possibility that an attorney might give the wrong answer, through incompetence or malice or collusion with the foreign generator, and thereby fool the utility into a false sense of security. Edison makes no showing on the likelihood of harm from this cause, and the issue in fact seems highly speculative.

What does seem clear is that Edison's proposal regarding a foreign generator's choice of legal counsel would give the purchasing utility a means by which it can increase the seller's transactions cost and hold up any agreement to buy electricity from across national borders. We find this chance too high, and the legal protection afforded by the proposal too low, to justify including it in the FS04 contract.

4.1.3 Miscellaneous Edison Proposals

In addition to the matters discussed above, Edison suggests various modifications to the settlement and to provisions of the FS04 contract that are continued without change under the settlement. Edison has not established any basis for rejecting the settlement or reopening all of FS04 to accommodate its suggestions.

We made major changes to FS04 in D.91-06-022, but we also envisioned building on the existing FS04 structure, not starting all over. To do otherwise would likely delay the implementation of those changes and undermine the process of cooperation and compromise among the parties that we have tried to encourage.

Moreover, Edison's criticisms are often nothing more than alternative approaches, and in some cases entirely miss the mark. For example, Edison criticizes the settlement for failing to expressly require a $5/kW bidding fee.[22] But at the time of the bid, there can be no contractual obligation because the contract is only signed months later, after the winners are announced. The bidding fee is actually a requirement of the auction protocol, which we will require to be filed when it and the draft solicitation packages have been modified to conform with decisions in this proceeding and in our transmission access investigation.

Edison has made many other suggestions that we will not detail here. However, the bulk of the suggestions (e.g., curtailment in Period 1, limiting the types of acceptable security, an alternative approach to liquidated damages) were the subject of give-and-take in negotiation by the settling parties. We are not persuaded that Edison's alternatives are superior to the terms set forth in the FS04 contract by the settling parties.

Edison also notes some areas where the FS04 contract will have to be conformed to reflect developments in I.90-09-050 (our transmission pricing and access proceeding, now consolidated with this proceeding for the duration of the auction.) We have now addressed transmission access issues in D.92-09-078, and to the extent specific implementation issues have not been resolved, they

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22 The settlement does not ignore the bidding fee requirement, which is accounted for together with other pre-operational amounts paid by winning QFs pursuant to the contract's milestone procedure. That procedure tracks QF development for the whole period from contract signing through the date of "reliable operation."

will be addressed in further workshops conforming the FSO4 contract and auction protocol to D.92-09-078.

One of Edison's suggestions warrants further comment. Edison suggests a specific dispute resolution process, similar to a meet-and-confer requirement, before contracting parties pursue other legal remedies. We believe it is premature to put a specific dispute resolution process in the FSO4 contract. However, we do not rule out adopting such a process if parties are able in the final workshops to develop one that is mutually agreeable.

4.2 Issues Raised by Other Parties

4.2.1 Valuation of Emissions Reductions

GCWG believes that the implementing contract language for FSO4 should "clarify" the Commission's method for calculating residual air emissions. As outlined in D.91-06-022, "residual" air emissions from a plant are those occurring after Best Available Control Technology (BACT) has been applied.[23] We also directed that "offsets" acquired by a QF be netted against its residual emissions to the extent such offsets are acquired (1) to comply with requirements of the air quality district with jurisdiction over the QF's power plant, or (2) to avoid a subtracter where its emissions exceed those of the IDR. (*Id.*, slip op., p. 38.)[24]

GCWG argues that a QF may directly or indirectly cause other or additional emission reductions, and that these should also be netted against its residual emissions. We disagree, and hold instead that the quantification of a QF's offsets must conform to

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23 BACT is typically required for a new emission source under federal and state air quality law.

24 "Offsets" are more properly referred to as "emission reduction credits" but offset is the more widely used term and we will retain it in this discussion.

the accounting rules of the air quality district(s) that would enforce the offsets.[25]

4.2.1.1 Parties' Positions

GCWG argues that any adjustment (plus or minus) to payments to a QF intended to reflect that QF's impact on air quality should be calculated based on the "actual" reductions in emissions that the QF causes. In other words, GCWG would have us ignore any discount that the local air district might apply to "actual" reductions. For example, if the QF shuts down an existing boiler whose emissions rate exceeds current standards, GCWG wants the QF to be credited with eliminating all emissions from that boiler, even though the air district might count only those emissions that would have remained after the boiler had been retrofitted with appropriate emission controls.

GCWG asserts that offsets are calculated differently from one air district to another, and that this could create an inequitable situation for QFs when bidding against resources in another air district. GCWG also argues that air districts apply "discounts" to offsets in different ways, and that these decisions are "based purely on local priorities and have nothing to do with the provision of electrical energy." (Exhibit K-17, p. 17.)

Also, GCWG would add hydrogen sulfide to the list of air pollutants evaluated for resource planning and acquisition purposes. Thus, for example, if a proposed geothermal plant would result in a new violation of the hydrogen sulfide standard, and the applicant controls an existing geothermal facility as part of its

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25 More than one air quality district may be involved because the QF may acquire offsets in different air basins, depending on the location of the IDR against which the QF bids. For example, a QF may have to acquire offsets in the air basin in which its power plant is located, and may choose to acquire offsets (to avoid a subtracter) in a different air basin where the IDR would be located.

permitting, GCWG would credit the applicant with the "actual" reduction in hydrogen sulfide emissions associated with the controls.

No other party supports GCWG's proposal, and most actively oppose it. DRA believes that these issues were litigated and resolved in the resource plan phase of this proceeding and are no longer subject to litigation. DRA points out that the Commission has adopted a limited use of offsets, and believes that the GCWG recommendations are much broader than what the Commission has adopted. DRA is concerned that adopting the GCWG proposal would produce an inequitable situation between utility resources and potential QF bidders.

DRA notes the following statement of policy from D.91-06-022 (slip op., p. 38), which is also quoted in the Settlement Agreement: "We will only consider those offsets acquired by a QF (1) to comply with requirements of the air management district with jurisdiction over the QF's power plant, or (2) to avoid a subtracter relative to the IDR." DRA invites us to further explain these policies (possibly including them in the FSO4 contract itself) as follows:

"1) Offsets must be demonstrably 'real, quantifiable, permanent, and enforceable,' as defined by the appropriate Air District.

"2) Offset ratios greater than 1.0 should be applied as required by the applicable Air District.

"3) QFs which shutdown existing <u>non-utility</u> equipment may be able to receive emission offset credits and thus reduce their offset requirements, but not to a greater extent than the equipment would have received if operating with the best available control technology (BACT).

"4) Until the cost of offsets for pollutants other than NOx [oxides of nitrogen] are incorporated into the determination of IDRs in the utilities' resource plans, only

> those offset requirements associated with NOx emissions from QFs should be incorporated into the calculation of emissions adders and subtracters." (DRA, concurrent opening brief (June 10, 1992), p. 13, emphasis in original.)

DRA also opposes GCWG's proposal regarding valuation of hydrogen sulfide emissions. DRA believes any expansion of the list of criteria pollutants valued for resource planning and acquisition should be put over to the next ER/Update cycle.

CEERT believes that the methodology proposed by GCWG is contrary to federal, state, and local law, and that it unnecessarily exposes electric ratepayers to environmental clean-up costs associated with other industries. CEERT further argues that the Commission's intent in this proceeding, as documented in D.91-06-022 and D.92-04-045, is to calculate residual emissions for utility and QF plants in a consistent manner, and that the GCWG proposal would expand and alter the Commission's previous decisions.

PG&E and SDG&E agree with DRA and CEERT that the GCWG proposal is contrary to Commission decisions. PG&E also argues that this proposal could create a windfall for industries that manage to keep old, dirty boilers in service, rather than retrofit the boilers or take them out of service in order to comply with air quality regulations.

4.2.1.2 Discussion

While we appreciate the fact that "actual" emission reductions can be greater than the reductions for which a plant is given credit, we agree with CEERT and others that the GCWG proposal could easily result in ratepayers paying for emissions clean-up of cogenerators' steam hosts. We reaffirm our existing emissions accounting policies.

In D.91-06-022, we stated our policies for coordinating competitive generation procurement with agencies responsible for enforcing environmental laws. In general, this Commission coordinates with the efforts of air quality agencies and does not itself formulate air quality policy or attainment strategies. However, utilities regulated by the Commission must determine how to meet environmental requirements efficiently, and the Commission must conduct its regulatory supervision of utilities so as to complement other agencies' efforts to carry out their environmental mandates. Thus, we have adopted an offset policy designed to dovetail with policies of the local air districts in emission reduction requirements and accounting.

Adopting the GCWG proposal would entail creating our own accounting system for emission impacts. This is clearly contrary to our stated policy of working with the districts. We remind parties here of our statement at the time the policy was adopted: "The districts are responsible for developing programs to meet our air quality goals, and the districts are best situated to determine values for the costs and benefits of those programs." (D.91-06-022, slip op., p. 29.) It follows from this policy that any bidder in the Update should be credited for an emission reduction (whether acquired as part of permitting its plant or to avoid a subtracter) only as accounted for by the relevant air district.

The settling parties' implementing contract language provides that the adder (or subtracter) payment to a QF is calculated from the QF's residual emissions rates, relative to the corresponding rates of the IDR. These rates are stated by the QF at the time the QF receives the relevant permit. (See Exhibit K-2, §§ 1.2 and 2.1, and Appendix A.) As discussed below, NOx emission rates are adjusted to reflect acquisition of offsets. This is consistent with D.91-06-022 and is approved.[26]

We also reject GCWG's proposal to impute a value to hydrogen sulfide emissions. Geothermal resources, unlike other electrical generation technologies, have some amount of such emissions, because hydrogen sulfide is often associated with geothermal fluids. However, current technology captures most of this gas, converting it to elemental sulfur, so that geothermal resources are not regarded as having significant air pollution problems. The Energy Commission has not adopted a value for this pollutant; neither has the Bonneville Power Administration or the Nevada Public Service Commission. We conclude that no useful purpose would be served by adopting a value for hydrogen sulfide at this time.

In opposition to the GCWG proposals we have just rejected, DRA urges four additional sentences to explain offset policy in the FS04 contract. (See Section 4.2.1.1 above.) The first three of these sentences are consistent with our views on the role of local air districts, but the sentences do not seem to us to belong in the contract.[27] The fourth sentence, which would

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26 CEERT brings up one point regarding implementation, viz., a cogenerator must apportion its emissions and offsets between steam and electricity production. CEERT notes that a cogenerator, as part of its QF certification process at the Federal Energy Regulatory Commission, must make such an apportionment of total energy consumed. We agree with CEERT that this point does not require a change to the FS04 contract but can be handled in the current workshops reviewing the utilities' draft requests for bids and auction protocols.

27 For example, we do not see what is gained by reciting in the FS04 contract that offsets must be demonstrably real, quantifiable, permanent, and enforceable, as defined by the appropriate air district. The point of our frequent reference to local air

(Footnote continues on next page)

exclude consideration of any offsets other than NOx offsets from the calculation of the air quality adder/subtracter, is a correct application of our policies established in D.91-06-022. We therefore approve this limitation on the use of offsets other than those for NOx.

4.2.2 Additional Gas Price Indexes

The Settlement Agreement specifies a method for calculating energy payments. Under the agreement, Period 1 energy payments (i.e., energy payments prior to the on-line date of the deferrable resource) are based on short-run avoided operating costs. Period 2 payments are based on the seller's energy bid price. If the QF is gas-fired, the energy payment equals the QF's heat rate (as specified in its bid) times the utility's full average cost of gas, adjusted monthly. The Settlement Agreement allows the developer to specify heat rate degradation (i.e., decline in efficiency as the facility ages) in its bid, but such degradation cannot exceed 1,000 Btu/kWh over the life of the contract, and may not be adjusted more than once every 5 years.[28]

GCWG takes issue with the Period 2 energy payment scheme for gas-fired QFs. GCWG proposes to index each component of gas costs that the cogenerator faces. Alternatively, GCWG proposes

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(Footnote continued from previous page)

districts is that it is they, not the Commission, who set offset standards and determine the validity of offsets. Reciting offset criteria in the FSO4 contract can obscure enforcement responsibility and become inconsistent with air quality law and regulations as these develop over time.

28 If the QF uses a non-fossil fuel generation technology, the energy payment will escalate based on a measure of general price increases, i.e., the GNP deflator.

indexing Period 2 energy payments for three components: the commodity costs and inter- and intrastate transportation charges.

We reject GCWG's proposals, and order the parties to base Period 2 payments for gas-fired QFs on the utility's full average cost of gas, as described in the Settlement Agreement. We understand GCWG's concern about uncertainty in the gas market and the greater assurance gas-fired QFs can gain by linking variable payments to all or the principle cost components that a gas buyer faces in the market. However, in contrast to the PG&E/GCWG curtailment option (see Section 3.2 above), GCWG's indexing proposal addresses this problem by shifting risk to ratepayers.

Changes in the gas market are occurring with such rapidity that specifying in advance a set of fully disaggregated indexes is a formidable task. For the time being, we prefer using the utility's full average cost of gas, which is also to be the basis for bid evaluation.

4.2.3 Modified Consent-to-Assignment Provision

We reject a proposal by CEERT to modify the consent-to-assignment provision that has long been included in our standard offer contracts.[29] CEERT's suggested modification would limit a utility's recourse against financing parties. A financing party's liability under the contract would exist only for the period when the financing party controls the generating facility. Also, the utility's claims against the financing party would be limited to the facility. CEERT says it needs this change in the FSO4 contract because of changes in the liquidated damages provision resulting from D.91-06-022.

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29 The existing provision prevents either party to the contract from voluntarily assigning its rights or delegating its duties under the contract unless the other party consents. Such consent cannot be withheld unreasonably. CEERT's proposed modification is in addition to, and not a replacement for, the existing provision.

CEERT supports the liquidated damages provision, despite its claimed harshness to renewable energy sources. But in combination with an assignment clause that would make any controlling entity liable for the life of the contract, the provision will lead banks to refuse to finance renewable projects, according to CEERT.[30] Therefore, CEERT says, we should change the assignment clause.

To accept CEERT's proposed assignment clause, we would need to be convinced, first, that the current FS04 contract would hurt renewable energy sources' chances to compete fairly, and second, that the modification would remedy the harm through an appropriate means. CEERT does not prevail on either point.

We are not convinced that the interaction of the assignment and the liquidated damages clauses will create a competitive harm to renewable energy companies. The record shows that the relative magnitude of liquidated damages faced by a wind QF and a gas-fired cogenerator depends on the timing of the default and the assumptions regarding future costs. In some scenarios, the cogenerator would face similar or even higher liquidated damages. CEERT's witness testified that a lender is generally sensitive to the worst-case scenario for any particular borrower, so we do not perceive any systematic bias against renewables in the existing assignment provision.

Perhaps the liquidated damages provision interacts with the prospect of continuing liability to create a problem for lenders. We are not convinced, however, that their only solution is to stop financing any or all generation projects. Financial

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30 The existing assignment clause does not expressly state such a liability rule. Our understanding is that in practice, however, utilities will consent to assignment only if previous controlling entities face liability for any default during the life of the contract.

institutions can seek indemnity clauses from the parties they sell to, effectively limiting their liability after selling the project.

Moreover, the record indicates that financial institutions will look at a contract like FS04 in light of all of its provisions, not just those pertaining to assignment and liquidated damages. If the contract as a whole, or some other part of the contract, is problematic, we fail to see that the proposed modification would remove the difficulty by itself, especially since the existing assignment provision reflects California law and the industry standard.[31]

Finally, we believe that adopting CEERT's proposed assignment clause would be ill-advised. Changes affecting the liquidated damages provision, not the assignment clause, prompted CEERT to raise this issue. It proposes to solve its problem by altering a provision that all parties to standard offer contracts have lived with for several years. The assignment provision gives utilities appropriate protection. Utilities will have more parties to seek damages from in the event of a default, and those parties who do control the generating facilities will have more incentive both to avoid default and to find financially strong parties to whom to assign their contracts. We decline to remove these safeguards.

4.2.4 Levelization for As-available QFs

Zond Corporation and American Wind Energy Association (Zond/AWEA) propose a modification to certain payment provisions in the proposed Settlement Agreement, specifically, the ramped

31 We note the consent-to-assignment clause, in substantially its current form, exists in all of our previous standard offers, including Interim Standard Offer 4.

shortage cost payments (using a GNP Implicit Price Deflator) to as-available QFs. They ask that we authorize levelized shortage cost payments to as-available QFs. We reject this proposal.

4.2.4.1 Background: Positions of the Parties

As we noted in D.91-06-022, "Capital-intensive QFs prefer that contracts permit some degree of 'front-loading,' meaning that the value of payments under the contract declines over time. The concern...is with financing. QFs face higher debt service in the early years of their operations and would like a corresponding revenue stream." (Id., slip op., pp. 45-46.)

In the past, we have allowed some front loading of QF payments. The most common form is levelization of shortage costs. A levelized payment is constant in nominal dollars and thus is declining in "real" dollars. Both Standard Offer 2 and Interim Standard Offer 4 allow QFs selling firm capacity to get levelized shortage cost payments. These standard offer contracts also have security provisions for return of overpayments if the QF ceases operation before the end of the contract.

Zond/AWEA urge the Commission, for FSO4, to adopt two different as-available capacity payment options. One option would allow as-available QFs to receive levelized shortage cost payments (like firm QFs), the other option would retain ramped payments but would use a 5% escalation rate (instead of the GNP Implicit Price Deflator).

Regarding the levelized payment option, Zond/AWEA contend that limiting levelization to firm QFs would make as-available QF projects harder to finance and would be inconsistent with D.91-06-022, especially Conclusion of Law 21 ("Levelization will be available to all QFs, irrespective of their technology....").

Zond/AWEA acknowledge that under all prior standard offers, as-available QFs were not eligible to receive levelized shortage cost payments. However, Zond/AWEA claim that as-available QFs previously were distinguished from firm QFs; unlike the latter, as-available QFs had no performance or security requirements to ensure delivery of some predetermined level of capacity. The FS04 Settlement Agreement is different because, according to Zond/AWEA, it requires the as-available QF to meet many of the project viability, security, and performance obligations applicable to firm QFs.

Regarding the 5% ramped payment option, Zond/AWEA argue that the utility IDR cost-effectiveness evaluations were done using an assumed 5% escalation rate; therefore, if as-available QFs are not provided the same escalation stream, the contract will not be IDR-based for the as-available QFs.

No other party supports Zond/AWEA's proposal, and SDG&E strongly opposes it. SDG&E insists that as-available QFs do not have performance requirements or guarantees comparable to firm QFs under the proposed Settlement Agreement. In SDG&E's view, the settlement provides substantial and unprecedented opportunities for as-available QFs.

For example, under previous standard offers, as-available QFs had no opportunity to receive a fixed payment. The settlement, however, would allow such QFs to recover fixed costs through a payment corresponding to the IDR's energy-related capital cost, which is paid on a fixed, dollars per kilowatt basis. The QF itself designates the "as-available capacity factor" on which this payment is based. This self-designation enables the as-available QF to tailor its bid to its expectations of the actual operating capability of its plant.

4.2.4.2 Discussion

The proposed Settlement Agreement treats as-available QFs fairly and appropriately. We adopt neither of the payment options proposed by Zond/AWEA.

We agree with the arguments of those parties who maintain that this settlement improves the ability of as-available QFs to compete and to operate under FS04. We also believe that the limitation on eligibility for levelized payments does not discriminate against any technology. Some generation technologies are better adapted than others to providing firm capacity. Such capacity has greater value to the purchaser, however, and the eligibility requirement is an appropriate incentive to suppliers to find ways to provide such capacity.[32]

We also reject Zond/AWEA's proposal to modify the ramping of shortage cost payments for as-available QFs. The ramping methodology, which is retained from the existing FSO4, protects all parties to the power purchase transaction from errors in forecasting the escalation rate.

Signers of the proposed Settlement Agreement include both firm and as-available QFs representing a variety of technologies. U.S. Windpower was one of the parties sponsoring a witness in support of the Settlement. Although many QFs would no doubt prefer other or additional provisions, the broad-based QF support for the Settlement suggests that it reasonably meets the interests and needs of the QF community, including as-available QFs.

We have now treated all issues arising under the Settlement Agreement. We turn in the following sections to FSO4 issues not resolved by the settling parties.

5. Bidding by SO1 QFs

In D.91-06-022, we held that a QF operating under an existing SO1 contract would be eligible to bid in the FSO4 auction on the condition that such a QF commit to provide "new" capacity, for example, by expanding its existing as-available capacity or by

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32 We note that solar developers are able to provide firm capacity through supplemental natural gas firing. Other kinds of intermittent energy sources may meet firm commitments through use of storage (e.g., hydro).

converting such capacity to firm capacity.[33] Chevron, which has several existing SO1 contracts, differs with the utilities over how to implement this holding.

The primary issue is, what constitutes "new" capacity? D.91-06-022 dealt with the easy cases where the SO1 QF physically expanded its as-available capacity or converted all of its capacity to firm (thereby accepting onerous performance requirements, including availability during the purchasing utility's periods of peak demand). All parties agree that the QF in these cases would provide "new" capacity. The tough case, but one that Chevron appears to anticipate, is where the SO1 QF does not physically modify its plant and offers to convert to firm operation only a portion of its existing capacity. Is there some minimum conversion in order to satisfy the "new capacity" criterion?

Chevron, supported by DRA, argues that any commitment of one megawatt (MW) or more to firm operation should satisfy the "new capacity" criterion. Chevron reasons that any such conversion would increase the purchasing utility's rights (compared to what it had under SO1), and that ratepayers will benefit because a liberal eligibility rule for SO1 bidders would likely stimulate competition and result in lower prices in the FSO4 auction.

The utilities disagree. They note SO1 QFs already have a strong incentive to deliver as much energy as possible during

33 Standard Offer 1 is a contract for as-available (sometimes called "as-delivered") energy and capacity. All but the smallest QFs are eligible to sign SO1 contracts. Few restrictions or performance requirements apply to SO1 QFs, and there is no minimum term--the QF can terminate its SO1 upon notice to the purchasing utility. The quid pro quo for this flexibility is that SO1 QFs must accept highly variable payments that fluctuate with the purchasing utility's short-run marginal costs. When utility reserves are ample, as they have been for some time, these marginal costs can be very low.

periods of peak demand.[34] They argue that "new capacity" would be provided only where the S01 QF commits to firm operation more megawatts than it already provides on an as-available basis during peak periods. SDG&E would calculate the peak capacity already provided (the S01 QF's "dependable" capacity) by analyzing data from the QF's most recent three years of operation. PG&E would perform this calculation by applying the appropriate conversion factor developed for different technologies by the CEC in its Electricity Report analyses of as-available suppliers. Edison has indicated that either SDG&E's or PG&E's approach is acceptable.

Chevron and the utilities also differ regarding the appropriate treatment of that portion of the S01 QF's nameplate capacity that is <u>not</u> bid into the FS04 auction. Chevron believes that the purchasing utility should pay for deliveries from this residual capacity under S01 terms and conditions. The utilities argue that (1) the successful S01 QF bidder must terminate its S01 contract before executing the FS04 contract, and (2) the purchasing utility should have <u>no</u> obligation to pay for deliveries from any FS04 QF in excess of its contract capacity.

We accept Chevron's approach, with some modification. The utilities' calculation of "new capacity", coupled with their position regarding as-available deliveries in excess of firm commitment, leads to clearly unreasonable results.

<u>5.1 Resource Accounting Under Utility Proposals</u>

Suppose a cogenerator, with a 100 MW nameplate capacity and S01 contract in that amount, successfully bids 40 MW firm capacity into the FS04 auction of the utility which is the purchaser under the cogenerator's existing as-available

34 The incentive is created by time differentiation of energy and capacity payments under S01. Energy payments are highest during peak demand, and virtually all the value of as-available capacity is allocated to peak periods.

contract.[35] Under the utilities' proposals, the new FS04 contract (40 MW firm) would wholly supersede the existing S01 contract (100 MW as-available). But obviously, the physical reality--an operational power plant with 100 MW nameplate capacity--has not changed. What happens to the "residual" 60 MW as-available capacity (100 MW nameplate minus the 40 MW firm FS04 contract)?

The utilities would treat the residual 60 MW as if it disappeared. PG&E, for example, would use the CEC's nameplate-to-effective capacity conversion factor, which for an as-available cogenerator is 30%,[36] to calculate the cogenerator's net "new capacity" to the utility as follows:

> Firm Capacity (or Effective Capacity) - (S01 Nameplate Capacity x Capacity Conversion Factor) = New Capacity

In our hypothetical, PG&E would say the cogenerator's system contribution (new capacity) is 10 MW.[37] This new capacity would count toward the MW limit in the purchasing utility's FS04 auction, and would also be the MW to which the air quality adder/subtractor would apply. No resource value is assigned to the residual capacity.

We fail to see any justification for this treatment of

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35 For purposes of this hypothetical, assume (1) the cogenerator is making no physical changes to its power plant, and (2) no portion of the plant's electrical production goes to the cogenerator's own uses ("self-generators").

36 The CEC has developed different capacity conversion factors that it applies to the various as-available technologies in the different utility service areas when it assesses resource supply and future need. (These same factors are also used in the FS04 contract.) As we noted earlier, SDG&E would perform a functionally similar calculation, using recorded performance data from the S01 QF's most recent three years of operation.

37 40 MW [FS04 firm] - (100 MW x 30%) = 10 MW.

the residual 60 MW. The change of contract does not alter the fact that the plant's instantaneous capacity is 100 MW.[38]

Compounding the utilities' serious resource accounting error is their insistence that they have no obligation to receive or to pay for deliveries from residual generating capacity. At a time when economic and environmental concerns dictate efficient utilization of our generation and transmission assets, the utilities' proposals would exaggerate resource need and lead to underutilization of existing power plants.

The utilities' proposals would also erect a significant barrier to SO1 QFs' participation in the FSO4 auction, since winning that contract would limit--perhaps eliminate--such QFs' ability to market their residual capacity.[39] The barrier would at least drive up the SO1 QF's bid, and may keep many SO1 QFs out of the auction altogether.

Such a barrier would not be in ratepayers' interest. These QFs are low-risk. In contrast to new projects, they are already sited, permitted,[40] constructed, interconnected, and operational. For these reasons, and also for many of the same reasons that utility repowers are outstandingly cost-effective IDRs, these QFs may be able to substantially increase their energy

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38 Conceivably, the new obligation to provide firm capacity might mean that the residual capacity might operate at somewhat less than the conversion factor generally assumed for that technology, but still there is no basis for changing the conversion factor to zero, which is the effect of the utilities' treatment of residual capacity.

39 The record suggests that residual capacity is apt to constitute the bulk of the SO1 QF's nameplate capacity, so the market risk to the QF may be significant.

40 Additional permitting of various kinds may be necessary, however, if the SO1 QF expands its plant or alters its operations.

deliveries for modest additional investment. We therefore expect S01 QFs to be highly competitive bidders.

We are in an on-going effort to expand participation in the FS04 auction. Our goals are to lower total costs, preserve reliability, and lessen environmental impacts of electric service. Both utilities and QFs have announced their support of this effort and these goals. The inappropriate and unrealistic contract terms the utilities would apply to S01 QFs, one of the most attractive classes of potential bidders, would undermine this effort and must be rejected.

5.2 Resource Accounting Under Chevron's Proposals

Chevron believes that the winning S01 bidder in our hypothetical would hold two contracts, FS04 for its 40 MW firm capacity bid and S01 for its 60 MW as-available residual capacity. The latter capacity would also count for purposes of determining this QF's system contribution. Specifically, this QF would contribute 28 MW of "new" capacity.[41] This amount would count toward the auction MW limit and would be the amount to which the air quality adder/subtracter would apply.

5.3 Adopted Regimen for S01 Bidding

We adopt a simpler approach to resource accounting than Chevron or the utilities propose, although support for the approach we are adopting is evident in some of the comments on the ALJs' Proposed Decision. The "new capacity" provided by the winning S01 bidder is equal to the capacity it firms up (in our hypothetical, 40 MW). This new capacity is used for all FS04 purposes: the size of the contract the winning bidder receives; the amount counted

41 40 MW [FS04 firm] + (60 MW nonfirm x 30%) - 30 MW [effective capacity under former S01] = 28 MW.

toward the auction MW limit; and the amount to which the air quality adder/subtracter would apply.[42]

The simplicity of this approach is strong support for it, especially considering the parties continue to differ on how or whether to implement the ALJs' recommended treatment of "self-generation" in calculating new capacity. But we also think the approach is practical and accurate.

For example, SDG&E notes that many successful SO1 bidders will be selling under FSO4 contracts to remote utilities (e.g., a QF in PG&E's or Edison's service area that wins in SDG&E's auction). Virtually all SO1 power is currently sold to the interconnecting utility, not a remote utility. For the latter, <u>all</u> of the SO1 bidder's capacity truly is "new." We agree with SDG&E that most FSO4 capacity acquired in this auction from SO1 bidders is likely to be wheeled to remote utilities.

Another important point is that SO1 QFs can terminate their SO1 contracts almost at will (they need only give minimum notice to the purchasing utility). Currently, there is a reasonable expectation that these QFs will continue, since they have few other buyers for their power beyond the interconnecting utility. But with the advent of transmission service, SO1 QFs can look to other markets. Thus, there is a sound basis for according full resource value to capacity such a QF firms up through FSO4, even where the purchasing utility is the same utility under FSO4 and SO1.

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42 If the winning SO1 bidder will provide as-available energy and capacity under the FSO4 contract, then the amount counted toward the auction MW limit and to which the adder/subtracter would apply would be the effective capacity (i.e., contract capacity times the capacity conversion factor appropriate to the utility in whose service area the QF is actually located).

We differ from the Proposed Decision in our treatment of residual capacity. The most practical solution is that the utility presently interconnecting with the SO1 bidder will continue to have the obligation to purchase the output from the bidder's residual capacity under SO1. This is reasonable since the interconnecting utility is already buying the bidder's <u>total</u> output under SO1.[43]

However, we agree with the ALJs that residual capacity should be better knit into the resource mix of the utility purchasing that capacity. We do not impose the economic curtailment scheme (which was worked out for FSO4) on output from residual capacity. Instead, we require that the QF either (1) not increase output from such capacity for the duration of any period of economic curtailment invoked by the purchasing utility, or (2) accept the purchasing utility's alternate energy cost for any such increased output.

We also believe Chevron is too lax regarding the minimum amount of new capacity that a bidder should be required to offer. Under our hypothetical, the SO1 bidder could satisfy Chevron's eligibility requirement by firming one MW out of its 100 MW nameplate capacity. A QF that contributes a trivial amount of new capacity does little to heighten competition. We require, instead, that the SO1 QF bidding firm capacity into the auction meet an eligibility threshold. The threshold is firm capacity equal to half of the SO1 QF's effective capacity, as measured by the appropriate nameplate-to-effective capacity conversion factor. Thus, again using our hypothetical, the 100 MW cogenerator would

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43 The FSO4 utility, if different from the interconnecting utility, may purchase the residual energy and capacity, provided that the SO1 bidder and the interconnecting utility agree to the purchase. We expect, however, that the expense of arranging and paying for the requisite wheeling would generally render such a purchase uneconomic.

have to bid at least 15 MW firm capacity. In no event may a QF, whether bidding firm or as-available capacity, offer less than one MW of effective capacity, and any such tendered bid shall be disqualified.

5.4 Other S01 Bidding Issues

There are other problems that are more or less peculiar to the S01 bidder's situation. The solutions, for the most part, follow logically from our determinations in the preceding section.

The S01 bidder should make the transition to FS04 at the start of Period 2 (the projected on-line date of the IDR). The bidder retains its S01 contract for all of its capacity during Period 1, and it retains that contract for residual capacity (with a minor pricing change discussed in Section 5.3 above) in Period 2. This ability to operate under S01 during Period 1 is limited to the bidder already on-line under S01 contract when it submits its FS04 bid.

The milestone procedure for tracking QF development is formulated primarily to deal with new projects, not operational plants like S01 QFs.[44] Chevron and the utilities disagree on the procedure's applicability, Chevron arguing that many of the

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44 S01 QFs are by no means the only already on-line QFs that we anticipate bidding in the FS04 auction. For example, gas-fired cogenerators, like gas-fired utility plants, may be able to repower cost-effectively, enabling these cogenerators to improve their efficiency and increase their capacity. Even though the <u>original</u> capacity of such cogenerators may be firmly committed under existing contracts, they should be able to bid the <u>incremental</u> capacity. For reasons we discuss later, a sale under multiple contracts may require some nonstandard modifications, but we strongly encourage the utilities to respond quickly and affirmatively to requests for such modifications. Firm capacity QFs that can expand their capacity are likely to be strong bidders, and unnecessary barriers to their participation in this auction should be removed. (Cf. Section 5.1, text accompanying footnote 39 above.)

milesones are onerous and inappropriate in relation to S01 QFs, the utilities arguing that S01 QFs may in fact change their plants or operations for FS04 and that such changes should be tracked under the milestones. Both arguments have merit. Certain milestones should apply even to operational QFs in certain circumstances, but there should be a clear and simple mechanism for an operational QF to get a release from any milestone that is inapplicable. Chevron, the respondent utilities, and other interested parties should develop such a mechanism and present it for our consideration when we take a final look at the milestone procedure in connection with the transmission access program for the coming auction.

6. Increasing Flexibility for Sellers and Purchasers

We now discuss certain key refinements to FS04. These refinements are essential if we are to progress from the present high degree of regulatory involvement to an independently functioning, fully competitive market for electricity.

When we began creating the portfolio of standard offers, the investor-owned electric utilities largely supplied their own generation needs. Utilities also dominated the wholesale market and showed little enthusiasm for opening that market to nonutility competitors.

Against this background, it is understandable that the first legislative and regulatory initiatives to open that market usually obliged the utilities, in almost unqualified terms, to interconnect and purchase QFs' generation. The chief objective at that time was to assure the QF, not of a marketplace, but of a single buyer (the interconnecting utility). This buyer was not allowed to reject QF power except in extreme circumstances, and the possibility that a QF might want or need to sell power under multiple contracts to a single utility, or obtain transmission access to multiple purchasers, seemed too remote to justify immediate attention.

By the time we issued D.92-04-045, the situation had changed. Much QF capacity had come on-line under our standard offers, but more importantly, our development of FSO4 showed that QFs could and should be knit into utility operations and resource plans in much the same ways as traditional, utility-owned resources.

For example, FSO4 brings transmission considerations into QF procurement, enabling sales from remote and off-system QFs under competitive circumstances. FSO4 also gives the purchasing utility curtailment rights that it may exercise even under routine operating conditions. Recent developments also indicate QFs will shortly have substantially increased access to bulk power markets, either through individual agreements, regional transmission arrangements, or FERC order.

We therefore ordered the FSO4 contract modification hearings to include consideration of whether and how the FSO4 QF might make additional sales beyond its FSO4 commitments, and also whether and how the purchasing utility might terminate or reduce its FSO4 obligation before the end of the contract term.[45] The two issues are closely related and must be dealt with affirmatively if both the purchaser and seller under FSO4 are to be able to respond fully and appropriately to market conditions at the beginning of the contract and over time.

Underlying the arguments over the various proposals summarized in Sections 7 and 8 below is a simple proposition: in a fully competitive market, purchasers have many ways to buy and are also free <u>not</u> to buy, while sellers are not limited to any one buyer or any one form of sale. The flexibility purchasers and sellers seek is complementary, and this Commission must find ways to satisfy both parties to the transaction.

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45 See D.92-04-045, slip op., p. 96.

7. Additional Sales by FSO4 QFs

An ALJ ruling, subsequently affirmed by the Commission in D.92-04-045, invited testimony on what flexibility the FSO4 QF should have regarding multiple sales from the same project. We asked the parties to address three issues: (1) should utilities be required to purchase power from QFs in excess of their firm commitments; (2) should QFs be permitted to sell power to multiple entities; and (3) should QFs be permitted to submit bids to defer more than one IDR of the same utility?

Every party agrees that the utilities should be allowed to purchase "surplus power," i.e., as-available energy and capacity above a QF's firm commitment.[46] However, the parties disagree on whether utilities are obligated to purchase the surplus power, and on the price at which the power should be purchased.

The parties also agree that sales to multiple entities should be allowed. However, the parties disagree on the timing and implementation of this proposal.

Concerning bids to defer multiple IDRs, there is less agreement. SDG&E, PG&E, and DRA support the concept, but believe implementation would require complex modifications to the contract and therefore should not be considered for the current auction. IEP/GRA and GCWG suggest that IDR aggregation could take place in the current auction subject to certain restrictions. Edison disagrees with the concept.

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46 A QF may have surplus power for various reasons. For example, a generator's rated capacity is based on certain assumptions, including ambient temperature, etc. In favorable weather, a generator may exceed its rated capacity. Moreover, a firm QF may design its plant to slightly exceed the contract capacity as an assurance of reliability, to better accommodate the steam host, or for other reasons.

7.1 PG&E

PG&E supports allowing the utilities to negotiate the purchase of surplus power, but believes QFs should not be automatically entitled to additional energy and capacity payments for surplus power. PG&E suggests a QF with extra capacity due to expansion should either bid the expansion in a subsequent auction or approach the utility to negotiate an amendment to its FS04 contract.

PG&E thinks the appropriate price for surplus power is the market price, or what the utility would pay for its next best alternative. PG&E is opposed to setting S01 prices as the price floor. This would thwart the Commission's objective to broadening competition in short- and long-run markets, according to PG&E witness Schleimer, who asserts that ratepayers would risk overpayment to the QF for its as-available energy when S01 is above the market price, and would not receive any commensurate benefits when S01 is below the market price.

PG&E disagrees with the QFs' assertion that utilities will not negotiate market prices in good faith. It is PG&E's opinion that such negotiations will be quite straightforward and involve minor amendments to FS04, but that neither state nor federal policies require utilities to purchase surplus power at S01 prices. PG&E also believes that payment of S01 prices for excess capacity under FS04 would undermine the price signal objectives of the curtailment provisions of FS04.

PG&E believes this auction should be limited to sales by a QF to a single utility. According to PG&E, the Commission must resolve several issues, including implementing contract language, operating agreements, and some basic transmission agreements, prior to allowing QFs to bid to multiple entities.

If the Commission allows sales to more than one utility, PG&E suggests the following FS04 changes. First, PG&E believes that it is exclusively entitled to the energy and capacity which is produced by the facility under the FS04 contract. Second, a QF should not be allowed to sign contractual commitments which "over book" the facility's capacity. Third, PG&E should, in no circumstance, be obligated to accept or pay for any energy and capacity which is allocated to other uses by the QF under FS04. Fourth, PG&E should not be obligated to purchase any deliveries at the QF's full energy bid price, including the 30% minimum in the proposed FS04 contract.

Finally, PG&E agrees with the concept of allowing QFs to submit bids to defer multiple IDRs, but feels that there is insufficient time to give this matter the attention it requires for this auction. PG&E suggests that IDR aggregation rules be carefully considered for use in future auctions.

7.2 SDG&E

SDG&E says a negotiated price would better reflect the relevant market price than the SO1 price. SDG&E believes that if QFs are to be encouraged to bid their true energy cost, consistent with the assumptions underlying the second price auction, then payment based on the QFs true energy cost, not SO1 prices, is appropriate for any power purchases above a QF's firm commitment.

If the Commission requires utilities to purchase excess capacity, SDG&E believes that the following contract terms are appropriate: (1) no capacity payments would be made for deliveries over firm (since the fixed costs will be included in the firm bid price); (2) the utility would purchase energy above firm deliveries at the lower of the energy bid price or SDG&E's decremental costs; (3) energy deliveries above firm would be physically curtailable; and (4) deliveries above firm would not be used in determining whether a QF qualifies for any capacity bonus payments.

SDG&E supports permitting QFs to engage in sales to multiple entities, but points out that such transactions are complex and cannot be devised on a standardized basis. SDG&E and Edison also point out that, if the Commission includes a requirement that utilities may not unreasonably withhold consent to such sales, the Commission must give further guidance on what constitutes reasonable utility conduct in this situation.

SDG&E also supports permitting QFs to bid against multiple IDRs of the same utility. SDG&E would accomplish this by retaining the adopted timing of the IDR but requiring the QF to either phase its bid or accept Period 1 payments for the period from the time of initial plant operation until each deferred IDR was scheduled to come on-line.

7.3 Edison

Edison thinks the QF should be allowed to sell surplus power at market prices, since the utilities can purchase power from other producers at market prices. A utility should not be obligated to purchase surplus power, however.

Also, Edison proposes that the purchasing utility under the FSO4 contract should have the right of first refusal for all surplus power that the QF wishes to sell on the wholesale market. Edison believes a right of first refusal protects the utility's contractual right to the QF's entire firm obligation.

Edison notes that new transmission arrangements may be necessary to accommodate sales of surplus power. Edison would make transmission access available on the same conditions as it would to a non-FSO4 generator offering energy and capacity equal to the surplus power.

Edison would agree to a QF selling capacity and energy from a single generating facility to more than one utility under the following conditions: (1) Edison's rights and interests as a purchaser from the QF are adequately protected; (2) Edison is not exposed to greater risk of liability to other parties; (3) the QF is not able to shift deliveries of capacity and energy between the utilities purchasing its output to maximize its own profits, to the detriment of ratepayers; (4) such an arrangement is operationally and administratively feasible; and (5) any contract entered into by

Edison involving sales by a QF to more than one utility purchaser is made expressly contingent upon prior approval by the Commission.

Edison believes a QF that holds two or more firm FS04 contracts with different utilities should negotiate and execute, with all the purchasing utilities, a single addendum to the contracts. A QF with an existing FS04 contract would have to get the consent of the purchasing utility before entering into an additional contract, but the original utility may not withhold its consent unreasonably.

Edison believes that aggregation of IDRs of dissimilar technologies is inappropriate. Also, Edison believes that an aggregate IDR bid cannot be properly evaluated where the IDRs span several years. The value of the QF's power were it to come on line too early or too late would be difficult to reflect in the bid and in payments to the QF. Edison supports the aggregation of IDRs only if they have similar technologies, the same emission rates, and scheduled on-line dates in the same year or in consecutive years.

7.4 DRA

DRA believes that sales of surplus power should be permitted and that they should be at SO1 prices. This policy would increase competition and lower rates by allowing existing QFs to bid more effectively, and by giving potential QFs an increased financial incentive to construct their plants to efficient size.

DRA disagrees with the utilities' arguments that SO1 pricing will result in a windfall for QFs. DRA believes that utilities should be indifferent to paying SO1 rates for surplus power since SO1 prices represent the short-run avoided costs of the utility. In contrast, the increased uncertainty associated with market prices will lead to a higher bid price for long-term capacity and energy, ultimately resulting in higher prices for long-term resources.

DRA would allow sales to multiple entities if timely changes to contract language and bid protocol can be accomplished. Otherwise, the upcoming bid cycle should limit QFs to sales to one utility from each plant. Also, QFs should be allowed to submit one bid per IDR. QFs bidding for multiple IDRs of the same utility would have to pay bid fees for each contract. Finally, aggregation of IDRs should be allowed if their benchmark prices are less than 1 cent per kWh apart, they have similar operating characteristics, and they have on-line dates within two years of each other.

7.5 IEP/GRA

IEP/GRA recommend that QFs be entitled to SO1 payments for surplus power. IEP/GRA also support DRA's recommendations that the Commission permit QFs to sell power to multiple entities and to aggregate IDRs for bid purposes.

IEP/GRA argue the Commission has acknowledged the appropriateness of short-run avoided cost pricing for deliveries in excess of those associated with FSO4 obligations. They quote D.91-06-022, slip opinion, page 56, where we said, "The QF...should be paid according to its energy bid (for hours when the IDR was planned to run) or the purchasing utility's short-run avoided operating costs (for hours when the IDR was planned not to run)."

IEP/GRA also argue that, since the sellers are QFs, federal law requires the utilities to purchase any available energy and capacity at short-run avoided cost. If the Commission intends to redefine short-run avoided cost, that exercise should be undertaken in the methodology phase of this proceeding.

If the Commission approves their proposal, IEP/GRA suggest the following four conditions to ensure that sales of surplus power are consistent with the economic curtailment provisions in FSO4.

First, during non-curtailment hours all deliveries up to the firm capacity will be purchased under the firm capacity contract, with deliveries in excess of firm capacity purchased under the separate as-available contract.

Second, during a curtailment hour, as-available deliveries should be limited to the level of such deliveries being made at the time of curtailment notification. This prevents the perverse effect of increased as-available deliveries during curtailment periods.

Third, during a curtailment hour, a QF which does not reduce deliveries should be paid its bid energy price up to 30% of firm capacity (per the settlement), the curtailment price for the balance of deliveries up to firm capacity, and (subject to the limitation of condition 2, above) short-run avoided cost under a separate as-available contract for any deliveries above firm capacity.

Fourth, during a curtailment hour, a QF which does reduce deliveries should be paid its bid energy price up to 30% of firm capacity (or to the level of operation it advised the utility it would maintain, whichever is less), the curtailment price for deliveries above 30% and up to the level of operation it advised the utility it would maintain, and short-run avoided cost under the separate as-available contract for any additional deliveries.

7.6 Powerex

Powerex believes that California ratepayers will best be served if a QF selling power to a utility under FSO4 retains its ability to sell power from the same facility to another entity or entities, including another utility. Specifically, the QF should remain free to sell power to another entity when its deliveries are curtailed, and to make parallel sales of firm or as-available power when its capacity exceeds the capacity sought or contracted for by a utility purchasing under FSO4.

There are at least two advantages to allowing a project to sell power to any purchaser when it is economically curtailed. First, a seller may increase its revenues without any corresponding increase in cost to the ratepayer. Second, allowing sales to other entities during curtailment enables the seller to track seasonal diversity in the load patterns of purchasing utilities. For example, local utilities in British Columbia are winter-peaking, whereas California utilities are summer-peaking. This seasonal diversity means that power from a facility located in British Columbia may be most valuable to a utility there when a California utility would want to curtail the power.

Developers of independent projects are concerned that they may be unduly constrained by FS04 if it is read to require them to sell all of their output to the same purchaser. Retaining the ability to sell to other entities during curtailment gives projects a broader base of potential revenue. This, in turn, could also enhance their ability to obtain financing on favorable terms, allowing them to submit lower bids.

Similarly, project developers in British Columbia wish to confirm their ability to make parallel sales of firm power to a utility under FS04 and to other purchasers. Absent the ability to make parallel sales, a project may have to sacrifice a cost-effective design in order to mirror the IDR, resulting in a higher bid price.

Two types of multiple sales can be made within the framework of the standard offer mechanism: sales of power during curtailment to an entity other than the utility implementing the curtailment; and parallel sales of QF output to two or more utilities. The current FS04 permits both types of sales, according to Powerex. No one opposes the concept of sales to multiple entities, and Powerex believes that FS04 both allows multiple sales and provides adequate protection to the purchasing utility or utilities.

7.7 Other Parties

GCWG, CSC, and Chevron all recommend that the Commission allow FS04 QFs to sell surplus power to the utilities pursuant to

SO1. GCWG, CSC, and Chevron also recommend that the Commission permit sales to multiple entities.

GCWG believes such provisions would encourage bidding by larger projects, which will provide greater economies of scale and lower energy costs to ratepayers. By allowing cogenerators to "unbundle" power from their facilities into firm and as-available sales, the Commission effectively would lower the cost of firm deliveries by all QFs selling power under FSO4, which should directly lower ratepayer costs.

GCWG points out that the Commission, in Interim Standard Offer 4, permitted QFs to make as-available sales in excess of committed firm capacity. GCWG believes that FSO4 currently permits sales to multiple entities under one of the operating conditions. Based on this section of FSO4, the QF is only obligated to deliver power to the utility after the QF has satisfied "any other use" it may have for its output.[47]

CSC argues that the additional as-available power should enhance the overall reliability of the system while providing a source of low-cost energy. On the other hand, if the sale of surplus power becomes a negotiated item, uncertainty for the QF will increase, resulting in higher bid prices, and ultimately higher rates, for long-term capacity and energy.

Chevron believes the market price approach, if adopted, could deprive California of the economic and societal benefits

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47 In both the current FSO4 and the revised version offered by the settling parties, the QF must choose between two "operating options." The "Buy/Sell" option commits the QF to sell <u>all</u> of its output (less station use) to the purchasing utility under FSO4. The other option is designated "surplus sale." Under the latter option, the QF sells its "<u>Generating Facility</u> output, less <u>Station Use</u> and any other use by Seller [i.e., the QF], to [the purchasing utility under the FSO4 contract]." (Exh. K-2, § 7.1(b), emphasis in original.)

attributable to SO1 QF participation in the FSO4 auction. The increased risk may cause existing SO1 QFs to stay out of the auction and result in higher bids from QFs who do participate.

8. Termination Provisions

The three utilities have each proposed to include in the FSO4 contract some form of termination clause that could be invoked after the QF had become operational. Also, Edison has proposed a termination right that would apply to pre-operational FSO4 QFs.

The proposals fall under three general categories, distinguished by events triggering termination (or modification) of the contract. The events are: (1) a specific decision or finding by a regulatory agency ("regulatory out"); (2) prolonged economic curtailment of the QF by the purchasing utility; and (3) changes in the wholesale power market, as revealed by specified indicators ("market out"). The utilities' proposals all use the triggering event concept but differ in their definition of the content and timing of such events.

It should be stressed that these proposals are not designed to deal with any problems of QF default. The FSO4 contract already contains various rights and remedies for the purchasing utility if the QF does not perform its obligations. The proposals we discuss here all concern limited circumstances under which a utility could avoid its own FSO4 obligations even where the QF in question was fully in compliance with the terms of the contract.

We also note the PG&E and Edison proposals would vest the right to terminate solely in the purchasing utility; the QF would have no corresponding right to terminate or otherwise limit its obligations under the contract. SDG&E would give the FSO4 QF the option to terminate, but only as an alternative to accepting administratively determined payment reductions.

8.1 Parties Proposing Termination Provisions

8.1.1 PG&E

To protect ratepayers and shareholders from changing market conditions and regulatory policies, PG&E believes a termination clause is necessary in FSO4. PG&E says FSO4 is like a take-or-pay contract in that the economic curtailment provisions protect utilities from variable costs but not from fixed costs under the contract.

PG&E would give utilities certain contract termination rights that could be exercised on occurrence of any of three proposed termination conditions, but no sooner than the tenth anniversary of the date the QF demonstrates "Reliable Operation."[48] If the purchasing utility chooses to exercise its right under any of these conditions, it is first obligated to entertain an alternative pricing proposal from the QF. The QF's alternative should reflect then-current pricing, market, or regulatory conditions. However, the QF must in any event pay back to the utility certain payments made to the QF prior to the utility's exercise of its termination right.[49]

48 "Reliable Operation" is a defined term under the existing FSO4 contract. The definition is carried over without change under the Settlement Agreement. "Reliable Operation" is the last event in the Project Development Milestones, and it must occur no later than the IDR's scheduled date of firm operation. One impact of PG&E's reference to Reliable Operation is that the FSO4 QF might have less than 10 years of fixed price payments before its contract could be terminated under PG&E's proposal. Thus, there is even less assurance to the QF under PG&E's proposal than might initially appear.

49 The payback provision concerns shortage cost payments to FSO4 QFs that chose the levelized shortage cost payment option. If the purchasing utility exercises its right to terminate such a QF, that QF must refund any difference between ramped and levelized shortage cost payments, based on the difference in net present value at the time of termination.

The first condition occurs when the purchasing utility has economically curtailed the FSO4 QF for all hours over at least nine consecutive months. This trigger, according to PG&E, is analogous in function to Public Utilities (PU) Code §455.5(a),[50] which puts the utility at risk for certain ratemaking disallowances when a utility power plant is out of service for nine or more consecutive months. PG&E argues that allowing termination of any FSO4 QF economically curtailed for nine consecutive months amounts to "comparable treatment" of QF and utility power plants. (Exhibit K-33, p. 15.)

The second condition occurs "when the Commission or any other regulatory agency disallows the full and timely recovery of any payments made by PG&E to an FSO4 QF...." (Id., p. 16.)

The third condition is variously referred to as a "loss-of-market trigger" (PG&E) or a "market out" (DRA). In PG&E's version, "If and when the current year sales are less than the market benchmark, PG&E shall have the right to terminate the contract." PG&E's proposed market benchmark is defined as "PG&E's total energy sales to its industrial and commercial customers in kilowatthours in the year of contract execution." (Id.)

PG&E notes the Commission, while acknowledging the potential of long-term contracts to lower the costs of new electric supplies, has also expressed concern about the risks of such contracts. PG&E cites D.86-07-004, in which the Commission limited Period 2 (the fixed price period of the FSO4 contract) to 15 years, in part due to the uncertainty of long-term forecasting. (See 21 CPUC2d 340, 375.)

The Commission subsequently extended the fixed price period to enable more effective competition by a broader range of QFs. (D.91-06-022, slip op., pp. 42-45.) At this time, PG&E

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50 PU Code §455.5 is reproduced in full in Appendix B.

argues that a termination provision is needed to balance the additional risk associated with the longer contract term. PG&E believes FSO4 should protect ratepayers from long-term planning risk in the same way traditional regulatory oversight protects ratepayers from planning risk associated with utility-built projects.

8.1.2 Edison

Edison is the only party to propose a termination provision that could be exercised by the utility before some minimum period of operation. In theory, Edison could exercise its right under this provision to delay or terminate the FSO4 project the day after the contract is signed. The triggering event is a vague "market out" defined as any change in "Edison's resource requirements or projected needs for electric energy or generating capacity [such that] some or all of the [IDR's] capacity or energy....would not be required during some or all of the term" of the contract. (Exhibit K-16, App. A, Pt. C, $ C.1(a).)

This preoperational termination right can be exercised only prior to the QF's "substantial commitment date," i.e., before the time the QF developer has incurred major financial obligations in connection with its project.[51] (Id., $ C.1(b).) Also, the utility exercising this right would have to reimburse the developer its "net unavoidable costs" of delaying the project (id., $ C.2(a)) or its costs resulting from termination, less any amounts recoverable through efforts to mitigate, salvage value, etc., or costs incurred in bidding. (Id., $ C.3(b).) Edison believes such a right to delay or terminate at a pre-operational stage is

51 The developer would have to provide Edison a tentative project schedule and 30 days advance written confirmation of the "substantial commitment date."

necessary in order to give the purchasing utility the same degree of flexibility it would have if it were developing its own project.

Edison's other termination proposal is similar to PG&E's. However, Edison would not include prolonged curtailment as a triggering event and would not allow exercise of a regulatory out until at least 15 years after the FS04 QF's initial date of operation. Edison argues that the guarantee of 15 years of operation under FS04 would mitigate the impact that existence of the utility's termination right might have on the QF's ability to finance its project or on the prices the QF would bid.

8.1.3 SDG&E

SDG&E proposes only a regulatory out that could be exercised after year 15 of Period 2, which is the fixed payment period in the FS04 contract. SDG&E thus offers a longer period of guaranteed operation under IDR-based prices than PG&E or Edison.[52]

Under SDG&E's proposal, if this Commission or any other regulatory agency determines that any portion of the payments to a QF is unreasonable, such payments would be reduced accordingly. The QF would have the option of either accepting the reduced payment or terminating the FS04.

SDG&E argues that its proposal does not chill development of competing resources because the provision cannot act to terminate or reduce payments until after year 15 of Period 2, the price adjustment would be made by a third party regulatory body, and the option to terminate can be exercised by the QF and not by the utility.

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52 Edison's 15-year guarantee runs from the QF's initial date of operation, which could be earlier than the projected on-line date of the IDR. A QF in that circumstance could face termination under Edison's proposal well before the end of 15 years in Period 2. Likewise, PG&E's 10-year guarantee could involve less than 10 years under IDR-based prices.

8.2 Parties Opposing Termination Proposals

DRA, IEP/GRA, GCWG, Powerex, CEERT, and the Cogenerators of Southern California (CSC) all strongly oppose the inclusion of any termination provisions in FS04. The parties urge the Commission to reject the utilities' proposals for the same reasons that the Commission has rejected utility efforts to include such provisions in previous standard offers.

These parties generally argue that any such provision would upset the balance reached in the Settlement Agreement, significantly reallocating the risk incurred by the contracting parties and requiring complete renegotiation of the agreement. IEP/GRA are particularly emphatic on the latter point.

These parties note the Commission has consistently rejected termination provisions in standard offer contracts. IEP/GRA quote extensively from D.82-01-103, 8 CPUC2d 20, 85-86 (rejecting proposed "renegotiation" provisions); D.82-12-120, 10 CPUC2d 553, 617 (rejecting retroactive price adjustments); and D.83-09-054, 12 CPUC2d 604, 628-29, and D.83-10-093, 13 CPUC2d 84, 124-25 (rejecting regulatory out). In the latter decision, we found no need for such a provision, since its sole purpose would be to assure cost recovery by utilities and such assurance was already provided by the Commission's many earlier findings that purchasing utility costs properly incurred under standard offer contracts are deemed reasonable.

CEERT notes these decisions also recognize such provisions would create so much uncertainty as to stifle development of QF projects. The parties argue that lenders may be unwilling to finance projects under FS04 contracts with such provisions, or at least that financing costs would be considerably higher. The theoretically greater flexibility for the purchasing utility might come at a cost that would include diminished competition, higher bid prices, and de facto exclusion of capital intensive technologies.

IEP/GRA believe termination provisions are unnecessary in FSO4 because the utility has the ability to curtail QFs in order to take advantage of less expensive energy sources. The QF, in order to continue receiving fixed cost payments during curtailment, is required to ensure that its plant will be physically capable of providing power to the utility for the entire contract term.

CSC expresses concern that the proposed termination triggers would provide the purchasing utility a means of "gaming" the FSO4 contract. The utility is able to manage or control, directly or indirectly, many circumstances that cause a triggering event to occur, circumstances which the QF has no comparable means to influence.

Finally, DRA disagrees that there is any correspondence between PG&E's curtailment trigger and PU Code § 455.5, on which the trigger is supposed to be based. DRA believes ratepayers are already protected against nonperformance by QFs, since QFs are paid only for periods during which they are capable of performing. This is already a stricter standard than what the statutory provision imposes on utilities.

Although DRA opposes all of the current proposals for termination provisions at this time, it recommends consideration of a market out clause for future solicitations to mitigate planning risks. DRA proposes a test in which bidders would be required to submit two bids, one bid assuming no termination clause, the other bid tailored to reflect the financial impact of the termination clause. This would provide the Commission some quantification of the cost of such clauses, against which to weigh their expected value.

9. Conclusions on the Need for Flexibility

We have embarked on the long road to a fully competitive generation marketplace, not for the journey's sake, but because of our belief--by now, virtually a universal belief--that electric consumers are best served by a wholesale market in which there are many buyers, many sellers, and many types of transactions.

We can classify these transactions into two fundamental types: short-run and long-run. Short-run transactions involve energy and capacity from existing resources, while long-run transactions involve energy and capacity from new resources. Generally, a long-run transaction requires commitment of capital (high fixed costs), a commitment that is justified when the variable costs of increasing production from existing resources become excessive.[53] Exclusive reliance on either type would be inefficient (either existing resources would be run past obsolescence or new resources would be added prematurely).

For these reasons, a long-run standard offer (FSO4) is a necessary complement to our other standard offers, all of which are short-run. We have worked hard on FSO4, even during a period when adequate capacity was available to California, because we cannot prudently assume that adequate capacity will exist indefinitely, and because our procurement program must have the flexibility to respond to long-run need through long-run commitments.

Furthermore, we expect that at any given time, an electric utility will satisfy its resource needs, in part, from a mix of long-run and short-run purchases from a variety of sellers. Such diversity would play a large role in ensuring that the utility's costs of energy are reasonable and continue to be reasonable as conditions change.

FSO4 thus can provide flexibility in some important cost-saving respects. But because it is also a long-run commitment between buyer and seller, it reduces flexibility in certain other

53 Our concept of "cost" in this context is broad and includes not only fuel and capital expenditures but also cost of pollution control and clean-up and cost of declining reliability as reserve margins narrow.

respects. The task we face here is to preserve as much flexibility as possible without so diluting the quality of the commitment as to lose the desired long-run benefits.

Both buyers and sellers have a stake in maximizing their flexibility under FSO4. We think this is a classic situation where mutually beneficial tradeoffs can be worked out through negotiation. We therefore give policy direction on this last but very important area of negotiation before publication of the utilities' requests for bids (RFBs) soon after the end of this year.

9.1 Maximizing Sales Opportunities

Our goal generally is to promote beneficial exchanges in the wholesale generation market as a key part of achieving our regulatory objectives for electric service.[54] It follows from this general goal that a seller under FSO4 should be able, after satisfying its obligations under that contract, to market any additional output from its power plant.

The additional output could be sold on an as-available basis to the utility holding the FSO4 contract or to another purchaser; or if the seller is able to meet firm commitments (consistent with its FSO4 obligations) regarding the additional output, that output could be the subject of a firm capacity contract. In particular, the seller should be able to bid that additional output in a later auction, either of the utility holding the original FSO4 contract or another utility. Finally, a seller

54 These objectives are essentially that electric service be reliable, reasonably priced, and environmentally sensitive. See, e.g., PU Code §§ 451, 701.1.

whose capacity exceeds that of a single IDR should be able to bid simultaneously on another IDR of the same utility.[55]

Ratepayers should gain substantial benefits, in the form of enhanced competition, from this liberal marketing provision. Sellers should gain substantial benefits because they will be able to market all their output and to optimize their plant design considering, among other things, the total market available to them. Purchasing utilities should gain substantial benefits because a more robust market means more deals at lower prices.

The limiting factors on this policy are appropriate assurance to the utility holding the FSO4 contract (or the original FSO4 contract), and appropriate transmission arrangements for the additional transactions. These factors have different weight, depending on the type of additional transaction, so we will now discuss these transactions by type.

9.1.1 Sales of Surplus and Curtailed Power

In the situation where a seller has occasional surplus power beyond its FSO4 commitment, or where the seller during curtailment has an opportunity to sell to a purchaser other than the curtailing utility, the QF should be able to sell all surplus power to the purchasing utility at the QF's energy bid price and the purchasing utility's short-run capacity cost. The surplus power would be entirely subject to economic curtailment, however.

The QF should also be able to sell on the wholesale market any power that is curtailed by the FSO4 utility, subject to

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55 In the solicitation projected for later this year, we will not allow a single seller to bid its power plant simultaneously against IDRs of <u>different</u> utilities. Such a bid could create significant transmission complexities and make bid evaluation unduly difficult, further compromising our goal of transparency in the evaluation process. We do not rule out this kind of simultaneous bid in future solicitations, but the idea is not ripe for implementation at this time.

meeting its obligations to the FS04 utility at the end of the curtailment period. Finally, the QF should be able to make "parallel sales" of surplus power into the wholesale market, subject to the FS04 utility's consent, which shall not be withheld unreasonably.[56]

The sales we are discussing in this section are short-term. QFs do not presently have good access to short-term transmission service.[57] Nevertheless, many sellers under FS04 may be able to reach wholesale markets, for example, sellers outside the FS04 utility's system. Powerex has made a convincing showing that Canadian bidders could receive substantial revenues from sales to third parties during curtailment periods. These revenues could make the difference for off-system QFs in bidding effectively for FS04 contracts, and California ratepayers stand to gain from the enhanced competition.

We strongly encourage the utilities to develop transmission service to support short-term transactions of on-system FS04 QFs. Until such service is reasonably available, the FS04 utility should be required to buy surplus power under the terms we have stated.

Implementation of the "consent" provision must take into consideration the short-term nature of these transactions. An exchange of letters before each such sale would obviously be impractical. What we have in mind instead is that the FS04 utility would state a set of conditions and indicate its advance consent to

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56 For these purposes, "wholesale market" should include any third party to whom the QF may lawfully sell its energy and capacity. Also, we note that QFs selecting Operating Option I (committing all output, less station use, to the FS04 utility) are thereby prohibited from making sales to any other entity.

57 I.90-09-050 is concerned primarily with access to and pricing of long-term transmission service.

any parallel sale in conformity with those conditions, all of which should be limited to protecting the FS04 utility's rights under the contract. The conditions must apply uniformly.

To the extent a parallel sale does not conform to the stated conditions, other arrangements may be necessary. We expect the FS04 utility to make every effort to accommodate parallel sales, so long as they are consistent with the seller meeting its obligations under the FS04 contract.

9.1.2 Multiple Long-term Sales

Many nonutility projects, especially cogenerators, are quite large. Other projects are developed in stages, and still others have optimal design that cannot be downsized without a substantial loss of efficiency. For all these reasons, many developers will want to make firm sales to more than one buyer. We should accommodate such multiple sales, subject as always to the seller's satisfaction of its FS04 commitments.

Most of the parties agree that the FS04 contract does not clearly handle the situation where, during a partial forced outage, the seller would have to allocate its output, e.g., between more than one firm FS04 contract.[58] No consensus was reached, although QF parties and PG&E generally propose that each purchaser receive a pro rata share of the contract capacity and energy. This proposal is reasonable, especially considering that some allocation would be necessary under Operating Option II even if the seller's "other uses" did not include sales to a third party.

SDG&E hypothesizes various situations in which the FS04 utility would be exposed to risks or uncertainties peculiar to transactions with a seller dealing with several buyers. SDG&E, of

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58 However, where a QF has a long-term firm capacity contract and another long-term contract for as-available capacity, the firm commitment should prevail over the as-available commitment in this situation.

course, already obtains the bulk of its energy from sellers serving more than one buyer, so presumably those risks are manageable.

We recognize that the FS04 utility has a legitimate concern in assuring the quality of commitment from sellers serving SDG&E's long-term resource needs. However, FS04 contains a panoply of rights and remedies for the purchasing utility, and we fail to see that these somehow become inadequate when more than one buyer is involved.

Nevertheless, as IEP/GRA and Edison agree, there are conceivable situations in which a specific addendum to the FS04 contract must be created to establish the rights among several buyers from a single facility. Accepting this possibility does not contradict the proposition that the bulk of such transactions will <u>not</u> require such addenda. We agree with IEP/GRA's assessment:

> "What is important in this proceeding is that the Commission clearly affirm or establish the right of QFs to enter into such arrangements, without necessarily attempting to solve for every contigency as may arise. In general, the array of standard offers will prove sufficient to effect such arrangements. Where an alternative arrangement is pursued, or the case-specific facts indicate otherwise, some customized negotiation may be required. Such negotiation should not, however, be a threshold requirement to the right in the first instance to make such sales, or the exercise of the utility's monopsony power will always succeed in limiting them....
>
> "As noted by Edison, and IEP/GRA agree, there no doubt are many instances in which such sales can occur under straight standard contracts. IEP/GRA seek only to have the Commission clearly affirm or establish the right to do so. In the event that circumstances indicate, it is obvious that the QF and utilities will have to negotiate a custom arrangement, and we agree that no attempt should be made to anticipate and 'standardize' for each such eventuality. The QF should not be held hostage to negotiations, however, where the standard

> contracts will do fine." (IEP/GRA reply brief (June 19, 1992), pp. 7, 12.)

We will require that long-term sales to third parties (including to nonutilities where allowed by applicable law) be subject to the prior consent of the FS04 utility, but, as with parallel short-term sales, the FS04 utility may not withhold its consent unreasonably. To that end, consistent with IEP/GRA's recommendation, we envision a contractual "check list" giving the FS04 bidder advance assurance regarding any special conditions it will be subject to in making multiple long-term sales. We expect the FS04 utility to cooperate with FS04 sellers in devising appropriate amendments for the rare cases that the check list does not fit.

9.1.3 Aggregating IDRs

We think the flexibility we have just provided for multiple sales should obviate the need for IDR aggregation. Suppose a QF successfully bids against two IDRs of the same utility, the first IDR has a projected on-line date in 1996, and the second IDR has a projected on-line date in 1998. The QF would have to come on-line in 1996 and would receive Period 2 payments for the capacity committed to the earlier IDR. If the QF brings additional capacity on-line in 1996, it would receive Period 1 payments to the extent that capacity is committed to the later IDR. If that QF has additional capacity not committed to either IDR, it should be able to market that capacity as outlined in the two preceding sections.

One of the reasons IDR aggregation has been a significant concern is that SDG&E has a large IDR (Encina) scheduled early in the deferral window (because SDG&E has reliability-based need) and divided over two years (135 MW in 1995, 138 MW in 1996) in order to mitigate lumpiness. (See D.92-04-045, slip op., pp. 63-64.) We share the evident concern of the parties that this scheduling of the Encina repower may hinder effective competition because of the short-lead time and the artificially divided capacity. The question of whether a specific date should be targeted in the year of scheduled operation has also been raised. (See D.91-10-049, slip op., pp. 7-8.)

We are willing to allow the parties to discuss whether to simply schedule the whole Encina 1 IDR for 1997, as suggested by SDG&E. (See D.92-11-061, slip. op., p. 6.) This may defuse some of the issues taking up time in the workshops, and we note SDG&E has conditionally proposed this change in a recent filing.

9.2 Termination Provisions

We have previously refused to put early termination provisions in standard offer contracts. Our refusal was based on the gross disparity in market power between buyers and sellers when competition was introduced to the wholesale generation market, and on sellers' limited access to transmission-only service. These factors have changed significantly. We have not arrived at a fully competitive market, but we have come far enough, in part because of the marketing assurances we have just provided in Section 9.1 to sellers, to justify our requiring sellers to grant commensurate flexibility to buyers.

We have problems with all of the utilities' termination proposals. All of them place great reliance on predefined triggering events, and they ignore various mechanisms (an example of which is contained in the PG&E/GCWG stipulation approved in Section 3.2 above) that could reduce risks to buyers without unduly increasing risks for sellers. However, we think the "market out" concept has promise, as we further discuss in Section 9.2.2 below.

We call now for negotiation of at least two contract termination/modification options that sellers would have to choose between. We think some options are required because sellers finance their projects in different ways and will vary in their need for assured payment streams in the early years of their contracts. The basic options we have in mind would ensure that sellers could operate for a substantial time at IDR-based prices (referred to as "Period 2" in the FS04 contract) but would enable buyers to cut back or eliminate their purchase obligation if for any reason the Period 2 prices become uneconomic. The seller would indicate its choice among these options no later than the date of contract signing. Exercise by the buyer of either of these options should be made contigent on the availability to the seller of open access transmission service from the interconnecting utility, regardless of whether that utility is also the buyer under FS04.

The <u>first option</u> we propose would allow the purchaser, at several points during Period 2, to reduce its purchase obligation by, say, 10% of the original contract capacity. The purchaser would have to give substantial advance notice (a year or more) of its intent to exercise this right. The right could not be exercised before at least the 10th anniversary of the start of Period 2 for that particular FS04 QF, and could be exercised periodically, perhaps every two years thereafter.[59]

The QF could market the released capacity in various ways. For example, it could sell the released capacity under a standard offer then available, or it could negotiate a nonstandard contract, or it could bid the capacity into an auction of the same or a different utility. The QF could also sell the released capacity to the original purchasing utility. Such capacity would then qualify as capacity exceeding the FS04 QF's contract commitment and would be purchased under those terms (energy paid for at the QF's bid price, all of the energy subject to economic

59 For example, the purchase obligation could be reduced to 90% of original contract capacity after the 10th anniversary, to 80% after the 12th anniversary, and so on. Failure to give timely notice would constitute a waiver of the right for that anniversary, but the purchaser could still reduce its obligation by 10% at the next opportunity.

curtailment, and capacity paid for at the purchasing utility's short-run marginal cost). The QF would continue to receive its entire air quality adder so long as it sold all output from the released capacity to the original purchasing utility. The adder would otherwise be proportionally reduced.

The utility that reduced its purchase obligation would have to provide transmission-only service to the seller so that it could market the released capacity.[60] The utility would have no entitlement to the released capacity (e.g., right of first refusal), but could purchase the capacity in any of the ways just mentioned.

The <u>second option</u> would allow the purchaser to terminate its purchase obligation. This is a much more severe provision, so the seller should have more advance notice and a longer period of guaranteed operation under the FS04 contract. We would expect this termination right to be exercised no sooner than the 17th anniversary of the start of Period 2 for the subject FS04 QF, with not less than three years' notice. We also believe that in contrast with the first option, the QF should not face possible exercise of this option every two years; on the other hand, the purchasing utility should not be limited to a single opportunity to terminate. We leave this to negotiation.

The QF whose contract is terminated would be entitled to transmission-only service from the purchasing utility where

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60 The terms and conditions of such service cannot be prescribed or predicted at this time. We are confident, however, that regional and federal programs for transmission access will have evolved such that, several years from now, when a purchaser would first be able to exercise this option, utility and nonutility sellers will be able to get both firm and interruptible transmission service at reasonable and nondiscriminatory rates. We pledge to work vigorously with all of the parties to this end, which is critical not only to this auction but to all-source bidding in future auctions.

necessary to market the QF's power. The QF would have the same marketing opportunities as it does for released capacity, except that, since the FS04 contract is terminated, it can now sell all or any portion of its output to the original purchasing utility at short-run avoided energy and capacity costs, i.e., it is no longer bound by its energy bid. The QF would also continue to receive its entire air quality adder as long as it sells the output from the terminated FS04 capacity to the original purchasing utility.

Utilities exercising their rights to reduce or terminate FS04 purchase obligations should not be entitled to repayment of any levelized capacity payments to the QF before the effective date of the reduction or termination. After that date, the levelized payments are proportionally reduced (first option) or end altogether (second option). Requiring repayment by a nondefaulting QF would be unfair and would nullify most of the beneficial effects of allowing this modest amount of front-loading in the first place.

The proposals we outline above are neither rigid nor definitive. We expect much fine-tuning, and perhaps development of additional options, in the give-and-take of negotiation over the next six weeks.

9.2.1 No Preoperational Termination

We see no substantial benefit to allowing a utility to terminate a contract during the (probably brief) period between contract signing and commencement of significant work to actually develop the project. Many parties criticize this proposal of Edison's as simply another effort by Edison to relitigate the question of resource need in this Update cycle.

Even if Edison's proposal had broader support, we would not adopt it. Short-term forecasts fluctuate considerably, but long-term forecasts are much less volatile. Stated differently, the economic outlook for next year may indeed vary from month-to-month, but 30-year forecasts depend on patterns that work themselves out much more gradually. The way to deal with long-term risk is not to tear up newly signed contracts, but to revisit the forecast at stated intervals and devise hedging strategies, as we do in the ER/Update cycle.

PG&E has suggested that we explore the possibility of giving the purchasing utility some flexibility after contract signing to adjust the start date for the FS04 project. This suggestion would address at least some of the concerns underlying Edison's proposal, while providing a less drastic remedy. We are willing to consider a generic proposal for start-date flexibility in the next Update cycle. We note that we presently consider, on case-by-case basis, proposals to adjust QF on-line dates and have approved several such adjustments.

9.2.2 Triggering Events

The ALJs criticised all of the utilities' proposed triggers. We agree that the "regulatory out" is contrary to Commission policy on standard offer contracts and should not be considered further. The "market out" concept is more promising, but not in the versions presented. PG&E's termination provisions for prolonged economic curtailment and loss of commercial/industrial sales are both variations on market out, but we share QFs' concern that these versions are sensitive to factors that are (or should be) influenced by utility management. For example, decline of a utility's commercial/industrial sales (in kWh) may result from many things, like succesful conservation programs, besides uneconomic wholesale purchases.

The fault here may lie not with the concept but with the indicators PG&E has chosen. Perhaps a better defined index or indices can better reflect the relevant market. If so, it may be possible that a market out would enable developers and their lenders to make a reasonable forecast of project risk for financing purposes, while ratepayers would still be protected as we intend.

We encourage the parties to work on a suitable market out trigger. Such a trigger, while not a welcome development for QFs, seems more acceptable to that community than an option to terminate or reduce purchases contingent only on the giving of adequate notice and the sound discretion of utility management.

We have considered but reject QF proposals that if utilities can terminate these contracts, sellers have reciprocal rights to terminate. A reciprocal right does not address the uncertainty which QFs regard as the critical problem in giving a termination right to utilities.

Specifically, QFs have urged that termination provisions severely compromise project financeability, and that lenders always look at the "worst case" in making financing decisions. A reciprocal right to terminate, however, does not alleviate the worst case, which would be that the QF can no longer cover its costs at then-current market prices of power. A reciprocal right would work only to cut off precisely those contracts that work well for ratepayers (i.e., where then-current market prices are higher than the contract price).

Whether or not a triggering event is prerequisite, the purchasing utility's exercise of its option to reduce or terminate its purchase obligation should result from a management decision based on all the relevant information reasonably available to management at the time of the decision. This is basically no different from other decisions utility management is called on to make in the course of business.

10. Comments on Proposed Decision

Pursuant to PU Code $ 311 and our Rules of Practice and Procedure, the assigned ALJs published their Proposed Decision (PD) for comments and replies to comments.[61] We have modified the PD in several respects as a result. We have also made certain corrections and clarifications on our own initiative. We note the most significant changes below.

<u>Termination Provisions</u>. We reject some parties' requests that we either retract our termination/modification proposals altogether or shorten to 20 years the amortization period for IDRs. These requests do not respond to our concerns regarding risks to ratepayers, and may even exacerbate such risks. However, we temper the PD's critique of termination "triggers." We think a well-defined market-out provision may improve the ability of potential bidders to calculate their risks, while continuing to protect ratepayers against the principal risk of long-term power purchase agreements.

<u>Bidding by SO1 QFs</u>. We simplify the PD's approach to resource accounting for SO1 QFs bidding successfully into FSO4 auctions. We also determine that the PD's treatment of residual power from such bidders is not practical, given the constraints of the interim transmission access program. We order the obligation to purchase residual power to remain with the utility presently interconnecting with the SO1 bidder.

<u>Offset Costs</u>. We accept DRA's recommendation that only offset requirements associated with NOx emissions from QFs be

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61 Chevron, IEP/GRA and GCWG, AES Corporation, DRA, PG&E, SDG&E, and Edison filed opening and reply comments. CSC and CEERT filed opening comments only; a group of municipal utilities and the City of Vernon each filed reply comments only.

Air Products and Chemicals, Inc., filed opening comments together with a request to intervene in this proceeding. We find that Air Products' participation will not delay or broaden the scope of this proceeding and accordingly grant the request.

incorporated into the calculation of emissions adders and subtracters.[62]

Bidding Against Multiple IDRs. We clarify the PD to indicate that the regimen for bidding against multiple IDRs of the same utility is still to be specified. A workshop should be held to further consider the proposals in Attachment 6 of D.92-04-045.

We also clarify the restriction against bidding on multiple IDRs of different utilities. The restriction applies to a single QF project. A developer with many projects may participate in auctions of more than one utility, but the developer may not bid the same project against IDRs of different utilities. This restriction is not for all time; it simply is a reflection that our transmission access program is just beginning and is not yet well-adapted to handling every conceivable permutation of bidding.

Carbon. We accept DRA's recommended clarification that carbon emissions are not limited to carbon dioxide (CO_2). This is consistent with ER-90 and D.91-06-022. The FS04 contract (Exhibit K-2) should be corrected, as necessary.

Transmission Priorities. We decline Edison's invitation to specify priorities for each type of power sale discussed in today's decision. It is certainly premature, and could unnecessarily raise jurisdictional questions for us to get into this subject matter at this time.

Heat Rate Verification. We reject Edison's proposal that the bidder submit verification of its heat rate bid. The bidder takes the risk that its heat rate times its actual fuel cost will

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62 The PD misunderstood DRA's recommendation to limit adder/subtracter payments to NOx emissions, excluding the other four pollutants considered in the resource plan phase. In fact, DRA's recommendation is consistent with the Settlement Agreement, under which adder/subtracter payments are applicable to all five pollutants (NOx, particulate matter, sulfur dioxide, reactive organic gases, and carbon).

cover its variable expenses, and the ratepayer will not have to pay the QF more money if the QF experiences a shortfall.

11. The Last Lap

We are asking the parties for a final major effort, coming at the end of more than a year of intense work in the resource plan phase of the Update and in the transmission access proceeding. That we should be asking this is a reflection of the brilliant success of that work. Refinements that once seemed distant hopes for our procurement process are now ripe for consideration, and our duty to ratepayers requires us to undertake these refinements now.

Transmission access is the key to this marketplace. We will measure utilities' willingness to compete, not by their rhetoric, but by the scope and quality of access services they provide. While there may always be some arrangements that must be specially tailored, many conditions of service can be stated in advance, and barriers must be eliminated wherever possible, so that access services are available when and as needed, with minimal transactions cost.

Nonutility generators, for their part, must recognize that the proportion of long-term purchases in utility portfolios will necessarily depend in important part on the risks associated with such purchases. The lessons of take-or-pay commitments made in the natural gas market are too recent and too painful to be ignored. In this Update, we carefully limited the level of resource need that could be filled through long-term contracts in the FSO4 auction. Before we would consider increasing that level, the FSO4 contract must have appropriate "second look" provisions for the purchasing utility.

We acknowledge that flexibility has a price. Utilities and their ratepayers will see somewhat higher bids (but capped at the IDR benchmark) as the result of the risk sellers will bear that their contracts will be modified, or even terminated early.

We cannot continue merely to debate this risk/reward tradeoff in theory, however. If the utilities' competitors are given suitable assurances of market access, they should in turn be willing to take their chances in that market after a reasonable period of IDR-based prices.

Inevitably, the result of this last round of negotiations for this Update will not be the last word on either transmission access or termination provisions. Our consideration of a final access program (in Phase 2 of I.90-09-050) and of all-source bidding will build and hopefully improve on what we accomplish here. But the work needs to start now.

The core of the work will be head-to-head negotiation among the parties. The assigned ALJs, in consultation with the assigned Commissioner and the Commission Advisory and Compliance Division, shall take appropriate action to allow for productive negotiation and to enable the parties to present what we strongly urge to be their joint recommendations for our consideration. We do not anticipate further hearings but will consider adoption of the recommendations by motion of the parties. We expect to take final action on these recommendations at our first meeting in February 1993. This schedule reflects some slippage from our goal of publishing the RFBs by the end of 1992, but the slippage is realistically necessary in order to tie up loose ends and ensure coordination with our transmission access program.

Findings of Fact

1. We see QF and utility flexibility as important attributes of the fully competitive generation market toward which we are progressing.

2. FSO4 is designed specifically to allow nonutility sources to supply generation that the utility would otherwise have to get through major capital-intensive projects. Such projects in the recent past have proven very risky, with delays and cost-overruns that resulted in major rate increases. FSO4 shifts the development risk for such projects onto the entrepreneur, who (1) gets paid only for production (increased costs due to construction problems, etc., cannot be passed on to ratepayers), and (2) must perform at a total cost equal to or less than the utility project that the entrepreneur defers or avoids altogether.

3. The new FSO4 implements Commission policy directions on many matters, such as project fees and project milestones, residual air emission adders/subtracters and emission monitoring, economic curtailment, project viability and security for levelized payments, shortage cost and energy-related capital cost payments, liquidated damages, eligibility of foreign entities for FSO4 contracts, and bid evaluation methodology.

4. The settling parties have also negotiated other "enhancements" to FSO4 that are clearly and integrally related to the policies we adopted, so we agree with the settling parties that they should be considered necessary parts of the settlement package.

5. Under the stipulated option, as compared to the curtailment provision in the settlement, the utility accepts a limit on the number of hours per year that it can curtail the QF, and in return the QF grants substantial price and operational concessions during curtailment.

6. The stipulated option is notable in that it would be the first time a QF, under a standard offer provision, accepted the

obligation to physically curtail under routine system operating conditions. An equally notable provision is the utility's ability to adjust the QF's curtailment obligation at several points during the contract period.

7. The utilities have long sought greater ability to physically curtail QFs. The stipulated option will enable us to observe the practical impact of physical curtailment, and to gauge whether such curtailment should be continued, expanded, or limited in future solicitations.

8. The PG&E/GCWG stipulation constitutes one kind of "additional performance feature" we have been urging QFs and utilities to develop since we approved this concept over six years ago.

9. The need for a given additional performance feature, by its nature, will differ from one utility to the next.

10. The ability to physically curtail a resource might be advantageous in a situation where transmission capacity is a serious constraint.

11. Edison wants to reinstate numerous provisions of interim SO4. Edison fails to convince that these long-deleted provisions are necessary, and we see nothing in our recent decisions that suggests these provisions should be reconsidered.

12. Air quality adders (or subtracters) are an adjustment to fixed payments to the QF under the Settlement Agreement. It is true that in D.91-06-022, we envisioned air quality adders/subtracters as a component of variable payments; but it is also true that in D.91-06-022, we envisioned only an increase in the number of curtailment hours, when in fact under the Settlement Agreement QFs go beyond a mere increase and agree to be curtailable in all hours of the year. This is part of an overall satisfactory quid pro quo. Moreover, the treatment of adders/subtracters under the Settlement Agreement furthers other policies articulated in D.91-06-022.

13. Edison's proposal on choice of legal counsel would give the purchasing utility a means by which it can increase the seller's transactions cost and hold up any agreement to buy electricity from across national borders. We find this chance too high, and the legal protection afforded by the proposal too low, to justify including it in the FSO4 contract.

14. Edison has not established any basis for rejecting the settlement or reopening all of FSO4 to accommodate its suggestions.

15. The bidding fee is actually a requirement of the auction protocol.

16. We have now addressed transmission access issues in D.92-09-078, and to the extent specific implementation issues have not been resolved, they will be addressed in further workshops conforming the FSO4 contract and auction protocol to D.92-09-078.

17. It is premature to put a specific dispute resolution process in the FSO4 contract. However, we do not rule out adopting such a process if parties are able in the final workshops to develop one that is mutually agreeable.

18. Utilities regulated by the Commission must determine how to meet environmental requirements efficiently, and the Commission must conduct its regulatory supervision of utilities so as to complement other agencies' efforts to carry out their environmental mandates. Thus, we have adopted an offset policy designed to dovetail with policies of the local air districts in emission reduction requirements and accounting.

19. No useful purpose would be served by adopting a value for hydrogen sulfide emissions at this time.

20. GCWG wants to give greater assurance to gas-fired QFs by linking variable payments to all or the principal cost components that a gas buyer faces in the market. However, GCWG's indexing proposal addresses this problem by shifting risk to ratepayers. Specifying in advance a set of fully disaggregated indexes is a formidable task. For the time being, we prefer using the utility's

full average cost of gas, which is also to be the basis for bid evaluation.

21. We are not convinced that the interaction of the assignment and the liquidated damages clauses will create a competitive harm to renewable energy companies. The relative magnitude of liquidated damages faced by a wind QF and a gas-fired cogenerator depends on the timing of the default and the assumptions regarding future costs.

22. Financial institutions can seek indemnity clauses from the parties they sell to, effectively limiting their liability after selling the project.

23. The assignment provision gives utilities appropriate protection.

24. Under all prior standard offers, as-available QFs were not eligible to receive levelized shortage cost payments.

25. The limitation on eligibility for levelized payments does not discriminate against any technology. Some generation technologies are better adapted than others to providing firm capacity. Such capacity has greater value to the purchaser, however, and the eligibility requirement is an appropriate incentive to suppliers to find ways to provide such capacity.

26. The ramping of shortage cost payments, which is retained from the existing FS04, protects all parties to the power purchase transaction from errors in forecasting the escalation rate.

27. For S01 bidders, the utilities' calculation of "new capacity", coupled with their position regarding as-available deliveries in excess of firm commitment, leads to clearly unreasonable results.

28. The utilities' insistence that they have no obligation to receive or to pay for deliveries from residual generating capacity of successful S01 bidders would exaggerate resource need and lead to underutilization of existing power plants.

29. The utilities' proposals would also erect a significant barrier to SO1 QFs' participation in the FSO4 auction. Such a barrier would not be in ratepayers' interest.

30. The "new capacity" provided by the winning SO1 bidder is equal to the capacity it firms up. This new capacity is used for all FSO4 purposes: the size of the contract the winning bidder receives; the amount counted toward the auction MW limit; and the amount to which the air quality adder/subtracter would apply.

31. Virtually all SO1 power is currently sold to the interconnecting utility, not a remote utility. For the latter, <u>all</u> of the SO1 bidder's capacity truly is "new." Most FSO4 capacity acquired in this auction from SO1 bidders is likely to be wheeled to remote utilities.

32. In our treatment of residual capacity, the utility presently interconnecting with the SO1 bidder will continue to have the obligation to purchase the output from the bidder's residual capacity under SO1. This is reasonable since the interconnecting utility is already buying the bidder's <u>total</u> output under SO1.

33. We do not impose the economic curtailment scheme (which was worked out for FSO4) on output from residual capacity. Instead, we require that the QF either (1) not increase output from such capacity for the duration of any period of economic curtailment invoked by the purchasing utility, or (2) accept the purchasing utility's alternate energy cost for any such increased output.

34. The SO1 QF bidding firm capacity into the auction must meet an eligibility threshold. The threshold is firm capacity equal to half of the SO1 QF's effective capacity, as measured by the appropriate nameplate-to-effective capacity conversion factor. In no event may a QF, whether bidding firm or as-available capacity, offer less than one MW of new capacity, and any such tendered bid shall be disqualified.

35. The S01 bidder should make the transition to FS04 at the start of Period 2 (the projected on-line date of the IDR). The bidder retains its S01 contract for all of its capacity during Period 1, and it retains that contract for residual capacity (with a minor pricing change) in Period 2. This ability to operate under S01 during Period 1 is limited to the bidder already on-line under S01 contract when it submits its FS04 bid.

36. Gas-fired cogenerators, like gas-fired utility plants, may be able to repower cost-effectively, enabling these cogenerators to improve their efficiency and increase their capacity. Even though the <u>original</u> capacity of such cogenerators may be firmly committed under existing contracts, they should be able to bid the <u>incremental</u> capacity. A sale under multiple contracts may require some nonstandard modifications, but we strongly encourage the utilities to respond quickly and affirmatively to requests for such modifications.

37. Certain milestones should apply even to operational QFs in certain circumstances, but there should be a clear and simple mechanism for an operational QF to get a release from any milestone that is inapplicable. Chevron, the respondent utilities, and other interested parties should develop such a mechanism and present it for our consideration when we take a final look at the milestone procedure in connection with the transmission access program for the coming auction.

38. In a fully competitive market, purchasers have many ways to buy and are also free <u>not</u> to buy, while sellers are not limited to any one buyer or any one form of sale. The flexibility purchasers and sellers seek is complementary.

39. The termination proposals are <u>not</u> designed to deal with any problems of QF default. The FS04 contract already contains various rights and remedies for the purchasing utility if the QF does not perform its obligations. The proposals concern limited circumstances under which a utility could avoid its own FS04

obligations even where the QF in question was fully in compliance with the terms of the contract.

40. Consumers are best served by a wholesale generation market in which there are many buyers, many sellers, and many types of transactions. We can classify these transactions into two fundamental types: short-run and long-run. Short-run transactions involve energy and capacity from existing resources, while long-run transactions involve energy and capacity from new resources. Generally, a long-run transaction requires commitment of capital (high fixed costs), a commitment that is justified when the variable costs of increasing production from existing resources become excessive. Exclusive reliance on either type would be inefficient (either existing resources would be run past obsolescence or new resources would be added prematurely).

41. A long-run standard offer (FS04) is a necessary complement to our other standard offers, all of which are short-run.

42. Both buyers and sellers have a stake in maximizing their flexibility under FS04. This is a classic situation where mutually beneficial tradeoffs can be worked out through negotiation.

43. A seller under FS04 should be able, after satisfying its obligations under that contract, to market any additional output from its power plant. The additional output could be sold on an as-available basis to the utility holding the FS04 contract or to another purchaser; or if the seller is able to meet firm commitments (consistent with its FS04 obligations) regarding the additional output, that output could be the subject of a firm capacity contract.

44. A seller whose capacity exceeds that of a single IDR should be able to bid simultaneously on another IDR of the same utility.

45. The limiting factors on this liberal marketing policy are appropriate assurance to the utility holding the FS04 contract (or

the original FSO4 contract), and appropriate transmission arrangements for the additional transactions.

46. In the situation where a seller has occasional surplus power beyond its FSO4 commitment, or where the seller during curtailment has an opportunity to sell to a purchaser other than the curtailing utility, the QF should be able to sell all surplus power to the purchasing utility at the QF's energy bid price and the purchasing utility's short-run capacity cost. The surplus power would be entirely subject to economic curtailment. The QF should also be able to sell on the wholesale market any power that is curtailed by the FSO4 utility, subject to meeting its obligations to the FSO4 utility at the end of the curtailment period. Finally, the QF should be able to make "parallel sales" of surplus power into the wholesale market, subject to the FSO4 utility's consent, which shall not be withheld unreasonably. For these purposes, "wholesale market" should include any third party to whom the QF may lawfully sell its energy and capacity. QFs selecting Operating Option I (committing all output, less station use, to the FSO4 utility) are thereby prohibited from making sales to any other entity.

47. QFs do not presently have good access to short-term transmission service. Nevertheless, many sellers under FSO4 may be able to reach wholesale markets, for example, sellers outside the FSO4 utility's system. These revenues could make the difference for off-system QFs in bidding effectively for FSO4 contracts, and California ratepayers stand to gain from the enhanced competition.

48. Implementation of the "consent" provision must take into consideration the short-term nature of these transactions. An exchange of letters before each such sale would obviously be impractical. Instead, the FSO4 utility would state a set of conditions and indicate its advance consent to any parallel sale in conformity with those conditions, all of which should be limited to protecting the FSO4 utility's rights under the contract. The

conditions must apply uniformly. To the extent a parallel sale does not conform to the stated conditions, other arrangements may be necessary. We expect the FS04 utility to make every effort to accommodate parallel sales, so long as they are consistent with the seller meeting its obligations under the FS04 contract.

49. Many nonutility projects, especially cogenerators, are quite large. Other projects are developed in stages, and still others have optimal design that cannot be downsized without a substantial loss of efficiency. For all these reasons, many developers will want to make firm sales to more than one buyer.

50. Long-term sales to third parties (including to nonutilities where allowed by applicable law) should be subject to the prior consent of the FS04 utility, but, as with parallel short-term sales, the FS04 utility may not withhold its consent unreasonably.

51. The flexibility we have provided for multiple sales should obviate the need for IDR aggregation.

52. One of the reasons IDR aggregation has been a significant concern is that SDG&E has a large IDR (Encina) scheduled early in the deferral window (because SDG&E has reliability-based need) and divided over two years. The parties may discuss whether to simply schedule the whole Encina 1 IDR for 1997.

53. We have previously refused to put early termination provisions in standard offer contracts.

54. We have not arrived at a fully competitive market, but we have come far enough, in part because of the marketing assurances we have just provided to sellers, to justify our requiring sellers to grant commensurate flexibility to buyers.

55. The utilities' termination proposals place great reliance on predefined triggering events. However, a "market out" trigger that uses well-defined market indices may both address our underlying concern to protect ratepayers and help QFs gauge their

risk of termination better than termination provisions without any prescribed trigger.

56. We call for negotiation of at least two contract termination/modification options because sellers finance their projects in different ways and will vary in their need for assured payment streams in the early years of their contracts. The basic options we have in mind would ensure that sellers could operate for a substantial time at IDR-based prices but would enable buyers to cut back or eliminate their purchase obligation if for any reason the Period 2 prices become uneconomic. The seller would indicate its choice among these options no later than the date of contract signing. Exercise by the buyer of either of these options should be made contigent on the availability to the seller of open access transmission service from the interconnecting utility, regardless of whether that utility is also the buyer under FS04.

57. We see no substantial benefit to allowing a utility to terminate a contract during the (probably brief) period between contract signing and commencement of significant work to actually develop the project. The way to deal with long-term risk is not to tear up newly signed contracts, but to revisit the forecast at stated intervals and devise hedging strategies, as we do in the ER/Update cycle.

58. Transmission access is the key to the wholesale generation marketplace. We will measure utilities' willingness to compete, not by their rhetoric, but by the scope and quality of access services they provide. While there may always be some arrangements that must be specially tailored, many conditions of service can be stated in advance, and barriers must be eliminated wherever possible, so that access services are available when and as needed, with minimal transactions cost.

59. Nonutility generators must recognize that the proportion of long-term purchases in utility portfolios will necessarily

depend in important part on the risks associated with such purchases.

Conclusions of Law

1. The FS04 settlement we are approving will apply to the uniform FS04 offered by PG&E, SDG&E, and Edison. The additional FS04 curtailment option will not apply uniformly at this time. We do not require SDG&E and Edison to include the identical option, but we are urging those two utilities to negotiate a functionally similar option tailored to the needs of their systems.

2. Before the solicitation, the utilities should file conformed FS04 power purchase agreements and revised auction protocols. The schedule for these filings will be established by ruling of the Assigned Commissioner or ALJs.

3. The settlement successfully embodies our policy directions from D.91-06-022.

4. Further changes to FS04 should be incremental, not a return to where we started drafting in 1985, or even earlier.

5. We approve an additional FS04 curtailment option (available only to firm capacity QFs) stipulated to by PG&E and GCWG.

6. The settlement (specifically, the mechanism for air quality adders/subtracters) must be modified to reflect our shift from uniform to nonuniform emissions valuation. DRA has correctly implemented our shift to nonuniform valuation. The value (cost) imputed to the IDR's emissions can be greater or less than that imputed to the QF's, based both on the comparative volumes of such emissions and on the respective sites where they would occur. DRA's formula captures both of these valuation aspects.

7. Because the settlement is (of necessity) silent on the emissions valuation change effected by D.92-04-045, our adoption of DRA's propose implementation of that change does not constitute a rejection of the settlement.

8. FERC does not certify or otherwise regulate foreign generating facilities for compliance with FERC regulations governing QFs.

9. Edison differs with the settling parties on several provisions regarding foreign generating facilities. Because none of Edison's proposed conditions offers utilities a useful or necessary protection, we do not reach the question of whether Edison's conditions would violate any trade agreements.

10. Section 12.4 of the Settlement Agreement is well-crafted to address any situation where FERC acquires or assumes jurisdiction over a purchase from a foreign generator under FS04. If FERC decides to regulate these payments to a foreign generator and ratifies them, rather than finding them illegal, FERC's decision harms neither the buyer nor the seller. Thus, the purchasing utility incurs no harm, and should have no entitlement to indemnity, where this circumstance (the purchase is regulated by FERC but not unlawful) occurs.

11. The Settlement Agreement provides that the FS04 contract shall be governed by the laws of California, as if the agreement had been executed and were to be performed entirely within California. This section gives a California court adequate grounds to take jurisdiction.

12. Under California law, a generating facility does "intrastate business" and must therefore appoint an agent for service of process. California courts have found that out-of-state businesses conduct "intrastate business" when they merely ship goods into the state, even without a contract executed in California.

13. The Settlement Agreement precludes an out-of-state entity from using a "safe harbor" provision normally available under California law to avoid the appointment requirement.

14. California law says that all judgments are conclusive. "Conclusive" means that the same parties may not litigate the issue

again, although they may appeal the decision. The Settlement Agreement designates California law as governing FS04 contracts, so judgments would be "conclusive" within the meaning of the California Code of Civil Procedure.

15. "Residual" air emissions from a plant are those occurring after BACT has been applied.

16. NOx "offsets" acquired by a QF should be netted against its residual emissions rate to the extent such offsets are acquired (1) to comply with requirements of the air quality district with jurisdiction over the QF's power plant, or (2) to avoid a subtracter where its emissions rate exceeds that of the IDR. Offsets acquired in connection with polluting emissions other than NOx are not incorporated in the adder/subtracter calculation.

17. Quantification of a QF's offsets must conform to the accounting rules of the air quality district(s) that would enforce the offsets.

18. We reject the GCWG proposal regarding "actual" emission reductions because that proposal could easily result in ratepayers paying for emissions clean-up of cogenerators' steam hosts.

19. Any bidder in the Update should be credited for an emission reduction (whether acquired as part of permitting its plant or to avoid a subtracter) only as accounted for by the relevant air district.

20. DRA proposes that the adder (or subtracter) payment to a QF is calculated from the QF's residual emissions, net of any NOx offsets. This is consistent with D.91-06-022 and is approved.

21. The FS04 contract does not clearly handle the situation where, during a partial forced outage, the seller would have to allocate its output, e.g., between more than one firm FS04 contract. No consensus was reached, although QF parties and PG&E generally propose that each purchaser receive a pro rata share of the contract capacity and energy. This proposal is reasonable.

22. Utilities exercising their rights to reduce or terminate FSO4 purchase obligations should not be entitled to repayment of any levelized capacity payments to the QF before the effective date of the reduction or termination.

23. The purchasing utility's exercise of its option to reduce or terminate its purchase obligation should result from a management decision based on all the relevant information reasonably available to management at the time of the decision. This is basically no different from other decisions utility management is called on to make in the course of business.

24. We will conduct reasonableness review of the utilities' contract administration. They will have to demonstrate that each decision regarding the exercise of any of the contract termination/modification options is in the best long-term interests of ratepayers, when analyzed using then-current resource planning assumptions consistently applied to the whole utility resource plan.

25. In order to enable the utilities to publish their final RFBs in timely fashion, this order shall be effective immediately.

O R D E R

IT IS ORDERED that:

1. The Motion for Approval of Settlement Agreement, jointly filed by Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), the Commission's Division of Ratepayer Advocates (DRA), Independent Power Producers Association, Geothermal Resources Association, Coalition for Energy Efficiency and Renewable Technologies (CEERT), and British Columbia Power Exchange Corporation, is granted. DRA's proposal, described in Section 3.3 of the foregoing opinion, for implementing the change in air quality policies directed in Decision 92-04-045, is approved.

2. The additional curtailment option stipulated to by PG&E and Gas Cogeneration Working Group (GCWG) is approved. SDG&E and Southern California Edison Company (Edison) are directed to meet with GCWG to develop possible additional curtailment options adapted to SDG&E's and Edison's respective systems.

3. Edison's, GCWG's, CEERT's, Zond Corporation's, and American Wind Energy Association's objections and/or alternatives to the Settlement Agreement are rejected.

4. The request of Air Products and Chemicals, Inc., to intervene in this proceeding is granted.

5. The Assigned Commissioner or Administrative Law Judges shall set a schedule for filing of (1) revised Requests for Bids (RFBs), (2) revised auction protocols, and (3) revised uniform Final Standard Offer 4 Power Purchase Agreements by the respondent utilities herein. These filings shall conform to the determinations in the foregoing opinion regarding Final Standard Offer 4, and also to our determinations regarding transmission access and costs in Investigation 90-09-050, which has previously been consolidated with the Biennial Resource Plan Update for the completion of this bidding cycle. Such filings shall be subject to final review by the parties, and after any further required modification to ensure conformity with all applicable Commission decisions, the RFBs shall be published as the formal commencement of the solicitation period for this bidding cycle.

6. The Assigned Commissioner or Administrative Law Judges shall expeditiously confer with the parties and take any and all appropriate steps to promote the successful completion of all tasks remaining before commencement of the solicitation period. The Commission urges implementation of this and prior orders, and

negotiation as appropriate, be completed in time for final Commission approval in February 1993.

This order is effective today.

Dated December 3, 1992, at San Francisco, California.

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

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

NEAL J. SHULMAN, Executive Director

Table of Acronyms and Abbreviations

ALJ	-	Administrative Law Judge
BACT	-	Best Available Control Technology
CEC	-	California Energy Commission
CEERT	-	Coalition for Energy Efficiency and Renewable Technologies
D.	-	Decision
DRA	-	Division of Ratepayer Advocates
Edison	-	Southern California Edison Company
ER-90	-	1990 Electricity Report
FERC	-	Federal Energy Regulatory Commission
FSO4	-	Final Standard Offer 4
GCWG	-	Gas Cogeneration Working Group
I.	-	Investigation
IDR	-	Identified Deferrable Resource
IEP/GRA	-	Independent Energy Producers Association and Geothermal Resources Association
kW	-	Kilowatt
kWh	-	Kilowatt-hour
MW	-	Megawatt
NOx	-	Oxides of Nitrogen
PG&E	-	Pacific Gas and Electric Company
POWEREX	-	British Columbia Power Exchange Corp.
PD	-	Proposed Decision
PU Code	-	Public Utilities Code
QF	-	qualifying facility
RFB	-	Request for Bids
SDG&E	-	San Diego Gas & Electric Company
Settling Parties	-	PG&E, SDG&E, DRA, IEP/GRA, CEERT, and Powerex

APPENDIX A
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SO1	-	Standard Offer 1
SO2	-	Standard Offer 2
SO4	-	Standard Offer 4
Zond/AWEA	-	Zond Corporation and American Wind Energy Association

(END OF APPENDIX A)

APPENDIX B

Public Utilities Code Section 455.5

455.5. (a) In establishing rates for any electrical, gas, heat, or water corporation the commission may eliminate consideration of the value of any portion of any electric, gas, heat, or water generation or production facility which, after having been placed in service, remains out of service for nine or more consecutive months, and may disallow any expenses related to that facility. Upon eliminating consideration of any portion of a facility or disallowing any expenses related thereto under this section, the commission shall reduce the rates of the corporation accordingly and shall, for accounting purposes, record the value of that portion of the facility in a deferred debit account and shall treat this amount similar to the treatment of the allowance for funds used during construction. When that portion of the facility is returned to useful service, as provided in subdivision (c), the corporation may apply to the commission for the inclusion of its value and expenses related to its operation for purposes of the establishment of the corporation's rates.

(b) Every electrical, gas, heat, and water corporation shall periodically, as required by the commission, report to the commission on the status of any portion of any electric, gas, heat, or water generation or production facility which is out of service and shall immediately notify the commission when any portion of the facility has been out of service for nine consecutive months.

(c) Within 45 days of receiving the notification specified in subdivision (b), the commission shall institute an investigation to determine whether to reduce the rates of the corporation to reflect the portion of the electric, gas, heat, or water generation or production facility which is out of service. For purposes of this subdivision, out-of-service periods shall not include planned outages of predetermined duration scheduled in advance.

The commission's order shall require that rates associated with that facility are subject to refund from the date the order instituting the investigation was issued. The commission shall consolidate the hearing on the investigation with the next general rate proceeding instituted for the corporation.

(d) Upon being informed by the corporation that any portion of its electric, gas, heat, or water generation or production facility which was eliminated from consideration by the commission in establishing rates for being out of service for nine or more consecutive months pursuant to subdivision (a) or (b), has been restored to service and has achieved at least 100 continuous hours of operation, the commission may again consider that portion of the facility for purposes of establishing rates, and may adjust the corporation's rates accordingly without a hearing, except that a hearing is required on whether to include, for purposes of establishing rates, any additional plant value added.

(e) Nothing in this section prohibits the commission from reviewing the effects of any electric, gas, heat, or water generation or production facility which has been out of service for less than nine consecutive months or planned outages of predetermined duration scheduled in advance.

(f) For purposes of this section, an electric, gas, heat, or water generation or production facility includes only such a facility that the commission determines to be a major facility of the corporation, and does not include any facility determined by the commission to constitute a plant held for future use.

(END OF APPENDIX B)