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Decision 92-10-049 October 21, 1992

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

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)

OPINION ON MOTIONS
TO COMPEL COMPLIANCE

1. Introduction and Summary

The Independent Energy Producers Association, Geothermal Resources Association, and Gas Cogenerators Working Group (IEP et al.) have jointly filed a motion to compel compliance, with certain Commission decisions, by the respondent utilities herein. The motion concerns the draft Requests for Bids (RFBs) of the electric utilities in preparation for an auction to supply new electric generation. The assigned Administrative Law Judges (ALJs) permitted responses and replies to responses. The responses of Coalition for Energy Efficiency and Renewable Technologies (CEERT) and Southern California Edison Company (Edison) raised additional compliance questions. The ALJs treated these questions as additional motions and permitted responses and replies. In today's decision, we resolve all issues raised by these three motions.

Concerning the five matters in the motion by IEP et al., we hold as follows. We affirm that the RFBs must set forth the values adopted in Decision (D.) 91-06-022 and D.92-04-045 for criteria pollutants and carbon emissions. We reaffirm the adopted value for carbon emissions, which was also the value used in the 1990 Electricity Report (ER-90) and was recently continued by order of the California Energy Commission's (CEC) ER-92 Committee. We affirm that the utilities' bid evaluation for the coming auction should use ER-90 assumptions except where we have expressly directed use of other assumptions, one example of which is our decision to rely on the gas price forecast (in "real" dollars) that the CEC has approved for ER-92. Finally, we give further guidance regarding the benchmark price for "repowers" (upgrades of existing resources) and the specification of on-line dates for identified deferrable resources (IDRs).

The other two motions each raise one issue. We deny CEERT's motion regarding the capacity factor to be assumed for Pacific Gas and Electric's (PG&E) wind IDR, based on our understanding of PG&E's commitments.

We deny Edison's motion to turn this Commission into a forum for all challenges to the conduct and results of the auction. However, we acknowledge the potential for disputes, given the high stakes and the novelty of the auction procedure. We also acknowledge the undesirable impact that would result from lengthy litigation over the auction, whether that litigation occurred at this Commission or in the courts. Accordingly, we outline a proposal for an independent binding arbitration procedure, intended to provide prompt, effective review and ensure finality of the auction results.

2. Background

D.92-04-045 ordered each of the respondent utilities to "...prepare a bid solicitation package [Request for Bids] in conformance with the discussion, findings, and conclusions set forth in this decision." (Id., slip op., Ordering Paragraph 1.) The decision (Ordering Paragraph 3) also ordered the assigned ALJs to convene workshops, noting that "[w]e believe it is prudent to develop some procedure by which the parties can preliminarily review the solicitation packages in order to prevent delay or confusion that could result from typographical errors, omissions, or other problems with the packages turning up after the utilities have published them." (Id., slip op., p. 94.)

Draft RFBs were published by the utilities on July 24, written comments were circulated August 5, and a three-day workshop was convened August 12-14, 1992, to discuss the draft RFBs. The agenda for this workshop was based on the comments on the draft RFBs.

The Commission Advisory and Compliance Division (CACD) published a report on September 10, summarizing the workshop discussions. The participants reviewed the report in draft before publication to make sure all issues were addressed and properly characterized. Although the draft RFBs themselves are not before us at this time, the ALJs authorized the parties to refer to CACD's Workshop Report in discussing the subject matter of these motions.

The ALJs also referred these motions to the full Commission for disposition. Typically, the Commission does not hear motions or interlocutory appeals; in this case, however, implementation and compliance matters must be resolved rapidly and definitively if we are to meet our goal of commencing the solicitation before year-end. We therefore affirm the ALJs' Rulings referring these motions to us.

In their ruling of September 18, the ALJs indicated they would be selective in accepting motions of this type. They stated that they accepted these motions "based on our understanding that, at least implicitly, an impasse has been reached on these issues at the workshops and definitive disposition is timely and necessary. However, we are increasingly concerned that such motions not be used when in fact no impasse has been reached."

The ALJs also noted that there have been recent decisions in the Biennial Resource Plan Update (Update) (I.89-07-004) and the related transmission investigation (I.90-09-050), and a further major decision on modifications to the Final Standard Offer 4 (FSO4) contract is pending. Some results of these decisions will have to be rolled into the draft RFBs and will occasion further workshops. Until such further workshops, the ALJs indicated they would not entertain any additional compliance motions.

We approve the approach the ALJs have taken. Compliance issues should be resolved expeditiously but not before we and the parties reach an understanding of what a particular issue involves. The time for us to take up an issue is after it has been discussed in workshops, and further discussion appears fruitless. The assigned ALJs, in consultation with CACD staff assigned to the workshops, should continue to use their discretion in determining when a compliance issue should be referred to the full Commission.

3. Values for Criteria Pollutants and Carbon Emissions

There is no serious dispute on this point, viz., that the RFBs list the Commission-approved values for "residual emissions" (specifically, four criteria pollutants and carbon). The bidder needs this information in comparing its own cost characteristics to those of the IDR, preparatory to bidding.

PG&E has already included such a list in its draft RFB. Edison and San Diego Gas & Electric Company (SDG&E) should amend their draft RFBs to show these values. All the utilities need to state the attainment status, by pollutant, of the air basin in which the respective IDRs are located, since (pursuant to D.92-04-045) the value imputed to a particular emission depends on the attainment status of the location where the emission occurs.

4. Carbon Emissions Associated with IDRs

IDRs relying on combustion technologies will have some amount of associated carbon emissions. Consistent with previous decisions in this proceeding, the FSO4 contract should include a value for carbon dioxide emissions and the amount of such emissions that would be associated with operation of the IDR. As discussed in the preceding sections, bidders need this information for bid preparation.

Edison has omitted this information for its Huntington Beach repower IDR. Edison also attempts to litigate, yet again, the value imputed to carbon emissions. We reject that attempt. Edison shall modify its draft RFB to indicate (1) our adopted value for carbon emissions, and (2) the relevant emissions rate for the Huntington Beach repower, as well as for the San Bernardino repower if Edison has filed updated costs for that repower pursuant to D.92-09-088.

5. ER-92 Gas Prices

In D.92-04-045, we directed the utilities to use, for bid evaluation purposes, the CEC's gas price forecast for its 1992 Electricity Report (ER-92). We did this on the CEC's recommendation (see D.92-04-045, slip op., p. 9 and Conclusion of Law 38), and with the understanding (based on the CEC's March 31, en banc statement at p. 7 and reiterated at the hearing itself) that the new gas price forecast was about 7% lower than the prior forecast.

The utilities' draft RFBs reveal that they not only used that forecast in real dollars (as it was represented in the CEC adoption order that we referred to in D.92-04-045) but also translated the forecast into nominal dollars using a new (lower) inflation assumption.[1] IEP et al. maintain that we made no change to the inflation assumption in D.92-04-045, and that the utilities should change assumptions from the previously reviewed resource plans only where we have expressly directed such changes.

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1 The new assumption is one that the ER-92 Committee directed be used for ER-92 analytical work. The effect of the new inflation assumption is to make the ER-92 gas price forecast appear much lower than was represented to us by the CEC at our en banc hearing.

The CEC supports IEP et al., noting the danger of a cascade of interrelated assumptions being changed, with the result of further delay and inconsistencies. We agree.

The utilities argue that the gas price forecast and inflation assumption cannot logicily be separated, and that failure to use the new inflation assumption would result in higher ratepayer costs. Neither point is well-taken.

Fuel prices are a major driver of price fluctuation in the general economy but there are many others. Fuel price increases in the 1970s spiked well above inflation, and fuel price forecasts in the early 1980s generally projected a continuation of that trend. Nor are fuel prices tracking inflation now: if that were so, there would have been deflation (rather than modest inflation) in the general economy over the past few years.

Regarding ratepayer costs, we again stress that in Final Standard Offer 4, unlike Interim Standard Offer 4, actual energy payments do not depend on a fixed fuel price forecast. Changing inflation assumptions could affect the mix of winning bidders, just as it could affect the choice of IDRs. The same could be said in regard to changing other assumptions. We cannot selectively change assumptions targeted by utilities without revisiting assumptions that other parties might like to revise.[2] Further time spent on assumptions is unlikely to improve either the process or the result.

To summarize, for bid evaluation, we direct the utilities to use the CEC's gas price forecast for ER-92, together with the (ER-90) inflation rate previously used in their testimony in the resource plan phase of the Update.

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2 And in both cases we confidently anticipate that the proponent of a revised assumption would maintain that its adoption would result in lower ratepayer costs.

6. IDR On-Line Date

The issue here is that our decisions specify an on-line year for each IDR but not a specific day within the year. Our lack of specificity is understandable. Neither cost-effectiveness analysis nor power plant construction is so finely-tuned a process as to enable us relistically to pick a particular day on which a plant should go on-line.

Nevertheless, Edison and SDG&E argue for a more refined on-line target than "any-time-in-the-specified-year," which is the target IEP et al. infer from our lack of greater specificity. The target the utilities advocate is the beginning of the season of peak demand (generally, June 1 of each year) on their respective systems. They note that much of any power plant's value in any 12-month period depends on its availability and production during peak. They argue that a qualifying facility (QF) becoming operational after the peak season begins would get payments disproportionate to its benefits.[3]

While conceding the utilities' argument has some merit, IEP et al. note another important consideration. Some of the IDRs, especially SDG&E's repowers, are due on-line fairly soon - as early as 1995. There is still much to do before the solicitation period begins, and the bid evaluation period will be longer than we originally planned because of the inclusion of transmission considerations. These factors alone could mean that winning

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3 More precisely, this is a first-year problem. A QF having a 30-year FS04 contract, and receiving IDR-based payments that begin on December 1, will be on-line for 30 peak seasons, just like a 30-year FS04 QF receiving IDR-based payments that begin on June 1. However, the latter QF provides greater near-term benefits and hence (all other things being equal) is more valuable to the purchasing utility. The underlying principle is that the utility would prefer its IDR (or QFs displacing the IDR) to go on-line no later than the start of the peak season in the first year that the IDR is cost-effective.

bidders might have less than two years to build their projects to meet a June 1, 1995 on-line target. Many QF projects can be built that quickly but many others cannot. If there is less competition on near-term IDRs due to this factor, higher prices could result and possibly more than outweigh the benefits of the June 1 target.

Both the utilities and IEP et al. make good points. They themselves recognize this. Discussion of possible solutions began in the workshop and has continued in the various responses and replies occasioned by the IEP motion.

We are confident that negotiation can result in a solution that maximizes value to ratepayers while reasonably protecting QFs and utilities. We encourage consideration of solutions already proposed, and possibly others. The FSO4 contract already has a 90-day "cure" period (together with penalties) if the QF misses the IDR's operational deadline. Possibly a longer cure period should be provided where the QF has, say, less than four years to come on-line, measured from the date of contract award to June 1 of the target year.

We anticipate further workshops at which this and other implementation issues can be hammered out. But the parties need not await a workshop. IEP et al., the utilities, and any other party interested in this issue may present a jointly recommended solution by motion in this proceeding. The motion should include the parties' recommended implementing language. Other parties may respond to the motion, as provided in Rule 42 of our Rules of Practice and Procedure.

7. Repower Benchmark Price

IEP et al. challenge the heat rate which Edison and SDG&E use in their RFBs for their repower IDRs.[4] Specifically, IEP et al. believe that the heat rate of the repower IDRs should be the full load heat rate of the entire repower project, not an imputed heat rate for the increment which is being put out to bid. IEP et al. agree with the way PG&E has calculated the benchmark price of its Hunters Point repower. PG&E has used the cost and performance characteristics of the entire 435 megawatt (MW) repower project to calculate the benchmark price of the IDR (including the heat rate), even though only 221 MW of that capacity is put out to bid in the upcoming auction. No party objects to PG&E's method of calculating the heat rate for PG&E's IDR.

On the other hand, Edison and SDG&E impute a heat rate for the incremental capacity only. We call this an "imputed" heat rate because it is a mathematical manipulation: it is quite a bit lower than the actual heat rate of the IDR at full load, or at any intermediate load. Essentially, these utilities argue that if the original capacity of the IDR had a heat rate of 10,000 Btu/kWh, and the repowered IDR has a full load heat rate of 8,000 Btu/kWh, then (assuming the plant exactly doubled in size) a heat rate of 6,000 Btu/kWh must be attributed to the incremental capacity.[5]

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4 The repower IDRs are currently Huntington Beach 3 and Encina 1 for Edison and SDG&E respectively. However, in D.92-09-088, we allowed Edison to request an alternative project for its repower IDR. Edison has submitted such a request, and we will respond in a separate opinion. Our directions in this section on determining the heat rate component of a repower IDR benchmark apply regardless of which repower serves as Edison's IDR.

5 Although SDG&E has basically derived the heat rate for its repower IDR as set forth above, it states that as a compromise, it is willing to explore PG&E's approach for determining the heat rate of its repower IDR for the RFBs.

DRA supports the position of IEP et al. DRA notes that although only the incremental capacity of these repowers is deferrable, in the event the repowers prevail in the auction and the utility pursues the repower, the entire repower would be built, not just an increment. Thus, use of an imputed heat rate guarantees that the energy cost component of the bid will be exceeded if the project is actually built, since the imputed heat rate does not represent the actual efficiency of the repower.

PG&E explained that it calculated the benchmark price of its Hunters Point IDR based on the design of the entire project, because "[t]here is no simple way for PG&E to determine which portion of the costs and increases in efficiency are attributable to existing (214 MW) and incremental (221 MW) segments of the project."[6]

The incremental capacity of a repower cannot in reality exist independently as a stand-alone resource. With this principle in mind, we determine that Edison and SDG&E should use PG&E's approach to calculate the heat rate associated with the benchmark price of their repower IDRs, i.e., Edison and SDG&E should use the full load heat rate of the entire repower to calculate the benchmark price for the incremental deferrable capacity associated with their repower IDRs.

The rationale articulated by PG&E is applicable to both Edison and SDG&E. For each utility, the total capacity of its repower IDR is greater than the amount the Commission has held should be subject to bidding. However, assuming the repower is built, the MW associated with the existing and incremental segments

6 PG&E also noted that when using the SDG&E approach on the Hunters Point IDR, the heat rate imputed to the incremental capacity is a number which represents over 100% efficiency - an "impossible" result.

of the project are indistinguishable, as are the particular costs associated with each MW. The deferrable resource is the entire IDR. Therefore, the appropriate heat rate is the full load heat rate for the entire repower IDR.

Edison should use a full load heat rate (8,029 Btu/kWh) for its Huntington Beach 3 IDR, consistent with this decision, as well as D.92-09-088. SDG&E should use the full load heat rate for its Encina 1 IDR (8,384 Btu/kWh). Consistent with today's decision, SDG&E should not use the heat rate associated with the fifth block of loading, which is the most efficient loading but is also less than full load (333 MW vs. 378 MW).

8. Assumed Capacity Factor for PG&E's Wind IDR

PG&E originally based its proposed wind IDR on a turnkey quote PG&E had solicited from U.S. Windpower before the resource plan phase of this proceeding. Later, PG&E substituted a smaller wind IDR with higher capital costs (per unit of nameplate capacity) than those quoted by U.S. Windpower. PG&E justified the substitution by asserting that the smaller wind IDR would operate at a higher capacity factor.[7]

PG&E did not investigate whether the U.S. Windpower design could achieve the same capacity factor as PG&E's substitute IDR under PG&E's assumed wind conditions. PG&E explained that it had a small site in mind with excellent wind conditions but insufficient acreage to accommodate the U.S. Windpower project. PG&E conceded that if both wind designs could achieve the same capacity factor under the same wind conditions, the U.S. Windpower project would be preferable. We agreed and ordered PG&E to use the turnkey quote as the basis of its IDR.

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7 Wind generation has low operating expense and no fuel cost, so a higher capacity factor translates into improved cost-effectiveness and, other things being equal, a more stringent bidding benchmark.

The debate over the draft RFB is solely over the assumed capacity factor. PG&E now asserts, based on wind data from two sites, that there is indeed enough prime acreage to support a 27% capacity factor assumption for the U.S. Windpower project.[8] CEERT reads D.92-04-045 to require PG&E to use the <u>lower</u> of 27% or the capacity factor at which the U.S. Windpower project would be preferred to the smaller substitute IDR running at the higher capacity factor.

CEERT's interpretation of D.92-04-045 is correct. However, PG&E's final argument in favor of the higher capacity factor assumption indicates that PG&E is willing to be accountable for that assumption:

> "PG&E has no incentive to understate the wind IDR benchmark price since the Commission has already ruled that the benchmark price will be a cost cap for PG&E. In D.92-04-045, the Commission stated (emphasis supplied) 'If the IDR is not substantially fully subscribed . . . PG&E may itself develop the renewable capacity <u>if it is willing to accept the benchmark price as a cost cap</u>' (mimeo. at 57).
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> "Under these circumstances, the Commission should allow PG&E to use a 27% capacity factor which will lower the benchmark price. Ratepayers are protected since in no event will they pay more than the benchmark price." (PG&E Reply to Responses to CEERT's Motion, p. 4.)

D.92-04-045 goes on to say, after the fragment quoted by PG&E, that if PG&E chooses <u>not</u> to develop the renewable capacity itself, it must pursue the IDR if U.S. Windpower is still willing to proceed under the terms and conditions of the turnkey quote.

As we read PG&E's statement in the context of D.92-04-045, PG&E is making essentially the same commitments that

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8 These data are set forth in an "offer of proof" included in PG&E's response to CEERT's motion.

Edison made regarding its Huntington Beach repower IDR. These commitments justify our approving a more stringent bidding benchmark, based on utility assurance that ratepayers will gain at least the level of benefits projected in the benchmark, should the IDR prevail in the auction. (See D.92-09-088, slip op., pp.13-15.)

Accordingly, PG&E shall assume a 27% capacity factor for its wind IDR. The transmission assumptions for the wind IDR shall be appropriate to the specified sites whose wind conditions were used by PG&E to justify the assumed capacity factor. PG&E shall build the wind IDR (or contract for its construction), accepting the benchmark price as a cost cap, if that IDR is not substantially fully subscribed in the auction; furthermore, pursuant to PG&E's commitments, a capacity factor of not less than 27% shall be imputed to the wind IDR in any future Energy Cost Adjustment Clause (ECAC) or similar proceeding.

9. Challenges to Auction Results

We have repeatedly rejected utility proposals that we "certify" or otherwise review and approve their findings on the winners and prices resulting from the auction. (See, e.g., D.87-05-060, 24 CPUC2d 253, 261; D.92-09-078, slip op., p. 80.) Edison's motion renews such a proposal, including a suggested procedure for the Commission to receive and resolve challenges within a timeline yet to be developed.

All of the utilities and DRA now believe that some systematic method for resolving challenges should be created. DRA cautions that, whatever the method, it must dispose of challenges quickly, so DRA declines to endorse Edison's proposal, at least until an appropriate schedule is worked out. IEP believes the Edison proposal should be rejected for the same reasons the Commission rejected earlier proposals of this kind.

We agree with Edison and others that the FS04 auction now involves considerable complexity, and also utility judgment in the bid evaluation of transmission impacts. These factors increase the likelihood that utility findings will be challenged. We also agree that such challenges should be resolved quickly, fairly, and definitively. All parties - utilities, winning bidders, losing bidders, and ultimately ratepayers - would suffer from protracted litigation and the resulting expense and uncertainty.

We doubt, however, whether any of the proposals to date would provide quick, fair, and definitive results. To the contrary, it is possible that administrative adjudication at the Commission would be a prelude to judicial appeals. Another possibility is that the party challenging the auction would try to remove the litigation to a court or, conceivably, another administrative agency. While the prospects of overturning or evading the Commission's process may be slight, delay and uncertainty would be likely.

Equally important, we hesitate to further involve this Commission in utility procurement practices, when one of the main goals of this program is to reach a point where the utilities routinely solicit bids for electric supply under general guidelines of prudence and good business sense, much as they now seek bids for goods and services they use in the course of their operations. The California Supreme Court has upheld this Commission's authority to require competitive procurement procedure by a utility, without suggesting the Commission thereby had to assume jurisdiction over contract disputes arising from such procedure. (See General Tel. Co. of Cal. v. Cal. Pub. Util. Comm'n, 34 Cal.3d 817, 195 Cal. Rptr. 695 (1983).)

The parties, however, have overlooked alternative means of dispute resolution that may provide the speed, fairness, and finality we agree is desirable for the auction. We ask the parties to consider the following proposal.

Each RFB would include a statement requiring the bidder to accept mandatory binding arbitration of any dispute it has regarding the contract awards, prices, or other determinations made by the utility conducting the auction in which it bids. The bidder must sign this statement; otherwise, its bid is disqualified without further consideration in the auction.

We expect that most challenges will come from losing bidders. Given the amount of innovation in this auction and the potential impact on other bidders, we would not allow the arbitrator to award a contract. If the losing bidder prevails in its challenge, its recovery would be limited to (1) its reasonable cost of bid preparation (as determined by the arbitrator), (2) its costs in the arbitration, including attorney's fees, (3) the fee which accompanied its bid, and (4) an appropriate interest award. If the utility prevails, the bidder would be liable for the utility's attorneys' fees, not to exceed the bidder's bidding fee.[9] No appeal would be allowed from the arbitrator's decision.

Requests for arbitration would have to be presented within a specified time, e.g., 30 days after announcement of the auction results. There would also be a specified timeline for preparing, hearing, briefing, and deciding the arbitration. The process should be completed within six months of the arbitration request.

Arbitration decisions against a utility would not in themselves cause either a rate impact or expense disallowance. Rather, we would review in an appropriate ratemaking proceeding whether negligence or other improper utility conduct was responsible for the error found by the arbitrator, and if so, what disallowance to make. If the utility error was not occasioned by negligence or other improper conduct, the arbitration award should be flowed through in rates.

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9 The bidding fee ($5 per kilowatt) is normally returned to a losing bidder.

We ask for input from the parties on the merits of this proposal generally, and on specific implementation problems. For example, should each arbitration be conducted by a panel of arbitrators or a single arbitrator, and how should the arbitrator(s) be chosen? What provision should be made for discovery? Should a generic timeline apply to all arbitration, or should the arbitrator have discretion to make certain adjustments? What relief should be available to a <u>winning</u> bidder that disputes some aspect of its award? How should the arbitration process be funded? From what period should interest be awarded and how should the interest rate be determined?[10]

We direct CACD to schedule written comments on this proposal, followed by a workshop. We are not absolutely wedded to the specific proposal described above, but our rejection herein of Commission adjudication of challenges to the auction results is emphatic. Parties should henceforth concentrate on other ideas for resolving such challenges quickly, fairly, and finally.

We urge the parties to develop a joint position on this proposal, or possibly another proposal designed with the same ends in mind. Appropriate handling of challenges to the auction results will permit us to undertake these procurement innovations with assurance of fairness and without undue risk to the parties or to ratepayers.

<u>Findings of Fact</u>

1. Compliance issues should be resolved expeditiously after the Commission and the parties reach an understanding of what a particular issue involves.

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10 This list of implementation problems is not intended to be all-inclusive. Parties should note and discuss any other issues necessary to address in setting up an arbitration or similar procedure.

2. In Final Standard Offer 4, unlike Interim Standard Offer 4, actual energy payments do not depend on a fixed fuel price forecast.

3. Changing inflation assumptions could affect the mix of winning bidders, just as it could affect the choice of IDRs.

4. Some of the IDRs are due on-line fairly soon - as early as 1995. Winning bidders might have less than two years to build their projects if June 1, 1995 is the on-line target.

5. The Commission anticipates further workshops in which the issue of more finely defining an appropriate IDR on-line date, as well as other implementation issues, can be addressed.

6. PG&E is making the commitment to build its wind IDR (or contract for its construction), accepting the benchmark price as a cost cap, if that IDR is not substantially fully subscribed in the auction.

7. The incremental capacity of a repower cannot in reality exist independently as a stand-alone resource.

8. The FSO4 auction now involves considerable complexity, and also utility judgment in the bid evaluation of transmission impacts. These factors increase the likelihood that utility findings will be challenged. Such challenges should be resolved quickly, fairly, and definitively. All parties - utilities, winning bidders, losing bidders, and ultimately ratepayers - would suffer from protracted litigation and the resulting expense and uncertainty.

Conclusions of Law

1. We affirm the ALJs' Rulings referring the motions to compel compliance which are the subject of this decision to the full Commission.

2. The assigned ALJs, in consultation with CACD staff assigned to the workshops, should continue to use their discretion in determining when a compliance issue should be referred to the full Commission.

3. Edison and SDG&E should amend their draft RFBs to list the Commission-approved values for "residual emissions" (specifically, four criteria pollutants and carbon). All the utilities should amend their draft RFBs to state the attainment status, by pollutant, of the air basin in which the respective IDRs are located, since (pursuant to D.92-04-045) the value imputed to a particular emission depends on the attainment status of the location where the emission occurs.

4. Edison should modify its draft RFB to indicate (1) our adopted value for carbon emissions, and (2) the relevant emissions rate for the Huntington Beach repower, as well as for the San Bernardino repower if Edison has filed updated costs for that repower pursuant to D.92-09-088.

5. For bid evaluation, we direct the utilities to use the CEC's gas price forecast for ER-92, together with the (ER-90) inflation rate previously used in their testimony in the resource plan phase of the Update.

6. The parties should address the issue of more finely defining an appropriate IDR on-line date, as well as other implementation issues in section 6 of the decision, in workshops. However, the parties need not await workshops to address these issues. The parties may present a jointly recommended solution by motion in this proceeding. The motion should include the parties' recommended implementing language. Other parties may respond to the motion, as provided in Rule 42 of our Rules of Practice and Procedure.

7. PG&E shall assume a 27% capacity factor for its wind IDR. The transmission cost assumptions for the wind IDR shall be appropriate to the specified sites whose wind conditions were used by PG&E to justify the assumed capacity factor. PG&E shall build the wind IDR (or contract for its construction), accepting the benchmark price as a cost cap, if that IDR is not substantially fully subscribed in the auction; furthermore, pursuant to PG&E's

commitments, a capacity factor of not less than 27% shall be imputed to the wind IDR in any future ECAC case or similar proceeding.

8. Edison and SDG&E should use the full load heat rate of the entire repower to calculate the benchmark price for the incremental deferrable capacity associated with their repower IDRs. For Edison's Huntington Beach 3 repower, this heat rate is 8,029 Btu/kWh. SDG&E should use the full load heat rate associated with the entire Encina 1 repower project, or 8,384 Btu/kWh.

9. CACD should schedule written comments on the dispute resolution proposal in section 9 of the decision, followed by a workshop.

10. Since we wish a Final Standard Offer 4 solicitation to take place this year, this order should take effect immediately.

O R D E R

IT IS ORDERED that:

1. The joint motion to compel compliance of the Independent Energy Producers Association, Geothermal Resources Association, and Gas Cogenerators Working Group, as well as the additional compliance questions raised by the Coalition for Energy Efficiency and Renewable Technologies and Southern California Edison Company, are granted in part and denied in part as described above.

2. Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company shall revise their Requests for Bids for the upcoming Final Standard Offer 4 solicitation in conformance with today's decision.

3. The assigned Administrative Law Judges and/or the Commission Advisory and Compliance Division shall notice workshops in conformance with the discussions, findings, and conclusions in this decision.

This order is effective today.

Dated October 21, 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

NEAL J. SHULMAN, Executive Director

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