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Decision 92-09-078 September 16, 1992

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

Order Instituting Investigation on the Commission's own motion to develop a policy of nondiscriminatory access to electricity transmission services for non-utility power producers.	I.90-09-050 (Filed September 25, 1990)

PHASE ONE OPINION:
INTERIM TRANSMISSION PROGRAM

(See Decision (D.) 91-10-048 for appearances.
See Appendix A for Additional Appearances.)

INDEX

INDEX

INDEX

PHASE ONE OPINION: INTERIM TRANSMISSION PROGRAM

1. Summary

In today's decision, we resolve key transmission policy issues which form the underpinnings for an interim transmission access program. Following the successful completion of the verification process on the utilities' transmission cost tables, the interim program adopted today should be ready for use with the Final Standard Offer 4 auction that we are planning in the near future in Investigation (I.) 89-07-004, the Biennial Resource Plan Update (Update).

We appreciate the parties' willingness to compromise their positions in order to develop this interim transmission access program. By definition, our interim program is limited in scope, and only applies to the upcoming auction. The program we adopt today involves pragmatic compromises, and also stops short of approving specific methodologies for all aspects of the interim program. However, with the safeguards we adopt today, we believe that considering transmission in the upcoming auction will greatly assist us in selecting winning bidders with the lowest total costs.

Although numerous issues are resolved by this interim transmission program for the upcoming auction, four key issues warrant summary:

1. We adopt pro rata cost allocation with a carrying cost adder applied for two years in evaluating bids by qualifying facilities (QFs) that require transmission upgrades for integration when such upgrades cause an oversized transmission expansion.

2. In evaluating bids requiring the wheeling services of another participating investor-owned utility (IOU), the full allocation of transmission upgrade costs, less system benefits, will be assessed to the bidder.

3. The purchasing utility will arrange and pay for the wheeling services necessary to interconnect a winning bidder.

4. In order to ensure that the purchasing utility can capture the economic benefit of opportunities to buy low-cost power over the short-term, an opportunity cost imputation will be applied to evaluate certain QF bids, if parties reach consensus in the verification workshops. Absent consensus, participating IOUs will use the amount of short-term transactions in the 1990 Electricity Report (ER-90) in determining available transmission capacity.

To date, this investigation has encompassed an extensive discovery phase and comment period, as well as evidentiary hearings. Progress in this investigation can now be gained through experience. Since our interim program is limited in application to the upcoming auction, it provides us with an excellent opportunity to monitor our policies in order to produce further improvements for a permanent transmission access program.

We recognize that our permanent transmission access program must accommodate broader participation among sellers and buyers of electric and transmission services in order to achieve low-cost energy services through a workably competitive market. We are encouraged by the progress made to form a voluntary transmission association, and the recent announcement of the goal to form the Western Association for Transmission Systems Coordination by the end of 1992. Having by this decision adopted an interim transmission program, we wish to lose no time in refocusing our efforts toward the permanent program to be developed in Phase Two. On the assumption that bid solicitations will have occurred before the end of the year, we instruct the assigned Administrative Law Judges to hold a prehearing conference in December 1992 to discuss the scope and timing of Phase Two.

2. Background

2.1 The Role of the Transmission Access Investigation

This Commission's key objective in regulating electric utilities is to ensure that California's electrical consumers get reliable service at reasonable cost, consistent with the State's environmental policies. We initiated this transmission access investigation to assist us in achieving this objective. This investigation concerns the terms and conditions whereby nonutility suppliers of generation may obtain transmission access and deliver their output to the wholesale marketplace.

This investigation complements our efforts in the Update to reduce the cost of energy services by enhancing competition among existing and potential suppliers of electricity to serve California's needs. The Update establishes biddable capacity for each of California's three largest IOUs[1] consistent with the economic and operational need tests of the California Energy Commission's (CEC) biennial Electricity Report (ER). The Update also establishes long-run avoided costs against which suppliers bid.

An investigation focusing on transmission access and cost allocation is critical to enhancing competition among suppliers.

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1 The IOUs are Pacific Gas & Electric Compny (PG&E), Southern California Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E).

An efficient market in electric supply depends not only on effective competition in generation, but also on efficient use of transmission facilities, so that suppliers of generation can transmit their product to wholesale purchasers of electricity in California.

> "Utilities still control their transmission systems, and QFs have only such access to the wholesale market as the interconnecting utility is willing to provide. If a QF does not own its transmission system, and cannot arrange for a utility to transmit its energy, it cannot get its energy to the marketplace. Thus, the transmission sector remains a natural monopoly and a 'bottleneck' to achieving full competition in the electric generation market." (Decision (D.) 92-04-045, slip at 39.)

This proceeding has many goals, which we have recognized might be accomplished in a single leap, but which also might have to be accomplished in a series of steps.[2] First, we want to promote competition in electric generation by facilitating participation in the wholesale market by as many sellers from as many areas as possible. This includes promoting beneficial exchanges among sellers within California, and between California and out-of-state producers. In order for these exchanges to occur, these sellers must have reasonable access to the transmission system, both (1) for "integration" (a producer of electricity sells power to a purchasing utility in whose area it is located), and (2) for "wheeling" (a producer of electricity transmits its output

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2 See D.91-10-048, slip opinion (slip) at 13.

through an interconnecting utility's area to the purchasing utility's system).[3]

Second, we also wish to better integrate transmission and generation resource planning. For environmental and economic reasons, we want to maximize our use of the existing transmission system. Moreover, if we reasonably add necessary transmission capacity in a timely fashion, we can achieve better access to low-cost power. This can result in ratepayer savings by avoiding or deferring the need for new power plant construction, and by helping to conserve resources which would otherwise be exploited to fill the generation need. This makes sense, especially since the generation costs of electricity are usually much higher than the transmission costs.

Third, allowing for improved access to transmission will also promote resource diversity and encourage a "portfolio" strategy[4] by diversifying California's generation resource mix. Improved transmission access allows sellers with diverse technologies and fuel types, which are for the most part smaller and more geographically dispersed than utility plants, to better compete in markets which may have been foreclosed to them because of lack of transmission access.

Finally, we need to improve our allocation of transmission costs, so that the resources with the lowest total

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3 In our October 1991 interim opinion in this investigation (D.91-10-048) we defined "power integration" as "transmission service performed by a utility for a seller of electricity, where the utility itself is the purchaser and the transmission service occurs inside the utility's service area from a point of interconnection to the utility's load center." We defined "wheeling" as "transmission-only service, where one or more third-party entities must give access to their transmission lines in order for the seller of electricity to deliver its power to the purchasing utility." (D.91-10-048, slip at 14.) We use these same definitions in today's opinion.

4 See D.92-04-045, slip at 47-49.

costs win in the bid selection process. Therefore, our Update bidding process needs to be refined so that transmission costs are taken into account in bid selection. This means that, for all capacity subject to bidding, both the benchmark price of the identified deferrable resource (IDR)[5] and bids by QFs[6] should take into account transmission costs in order to facilitate a direct comparison of each resource's total costs. In D.92-04-045, slip at 40, issued in our Update proceeding, we described the process we envisioned:

> "[S]pecific information regarding an IDR's transmission costs should be reflected in the benchmark price. [Also,] a QF needs to know in advance, from data published by the utility,

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5 Final Standard Offer 4, which is the contract allocated through the auction, derives from a utility's long-run marginal costs. These are determined from that utility's resource plan, which includes all cost-effective potential generation additions (e.g. new plant construction, refurbishments, power purchases, etc). In the Resource Plan phase of the Update, we designate "deferrable" generation resources, against whose costs and benefits QFs will bid. Deferrable generation resources are the cost-effective baseload or intermediate resource additions which the Commission designates as subject to bidding by QFs. These additions are called identified deferrable resources (IDRs). The utilities announce the availability of long-run standard offer contracts based on the capacity and fixed and variable costs (the benchmark price) of the IDRs. (See Attachment 4 of D.92-04-045 for a fuller description of how Final Standard Offer 4 works.)

6 QFs are the subset of nonutility generators (NUGs) which satisfies various efficiency and technical criteria established under the Public Utility Regulatory Policies Act (PURPA). The Commission's current solicitation process for nonutility power does not allow participation by independent power producers (IPPs) other than QFs, and no IPPs currently exist in California. Since this interim decision focuses on incorporating transmission considerations into the upcoming Final Standard Offer 4 auction in the Update proceeding, we limit our discussion in this interim opinion to QFs, as opposed to the broad class of NUGs. We note, however, that a petition to modify the auction process, by expanding eligibility to bid, is pending in the Update.

> what its transmission costs will be in order for the QF to properly determine its bid. The utility would then use these same published transmission costs in order to evaluate the bids and determine the winners. This process will further our goal of developing an environmentally sensitive least-cost resource plan which accounts for all the costs of power (as delivered to the utility load center) of the competing resource option."

These improved cost allocation principles should help minimize total costs, and ensure that our transmission system is not overbuilt, by providing incentives for QFs to locate near existing available transmission capacity, rather than a more remote location.

2.2 Arriving at a Permanent Transmission Access Program

2.2.1 Our Long-range Goals

In D.91-10-048, we described in broad terms our long-range aspirations. We envisioned that participants in our transmission program would have timely access to information, compiled and published by transmission owners.[7] This transmission data would include, for example, line losses, transmission capacity considered to be available, and costs of transmission upgrades at various points on a utility's system. Bidders would use this information in calculating competitive bids, and in choosing the auction where they might be competitive. Utilities would use this same information to evaluate bids which require wheeling and/or integration.

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7 We stated that such data could be compiled and published as part of the ER/Update resource planning cycle, where utilities already file information on their transmission systems.

We envisioned this exchange of information to be reciprocal. For example, municipal utilities[8] participating in the transmission access program should, among other things, share information on the same basis as participating IOUs and be prepared to provide wheeling service, where requested, on comparable terms and conditions as those offered by participating IOUs.

We also explained that transaction costs would be minimized in the transmission access program, largely because wheeling service would be available to the extent possible as a tariffed service on a nondiscriminatory basis. Increased access to information would also help reduce transaction costs. We reasoned that these two features should allow service arrangements to be made in a minimal amount of time and thus provide more certainty in the auction process. Finally, we reasoned that the information exchange and easier transmission access should result in a greater degree of regional transmission coordination without additional regulatory proceedings or modifying regulatory agencies' existing jurisdiction.

2.2.2 Taking the First Step -- Incorporating Transmission Considerations into the Final Standard Offer 4 Auction

We have concluded that a permanent transmission access and cost allocation program such as we outline above must be pursued in a series of steps. There are several factors that influence us.

8 We use the term "municipal utilities" loosely to include municipal utilities, special districts, rural electric cooperatives, and other transmission-owning entities that are not investor-owned. Although we do not have jurisidiction over municipal utilities, these utilities are active participants in our investigation. In D.91-10-048, we noted that the problem of how to provide for reciprocal commitments is one of the major issues to be addressed in the proceeding.

First, the IOUs will be holding a Final Standard Offer 4 auction in the near future. There is no time before the auction takes place to work out a detailed transmission program except among the three California IOUs which will hold auctions -- PG&E, Edison, & SDG&E. (These utilities will also be referred to as "participating IOUs," since they are the IOUs participating in our interim transmission program.)

Developing a permanent transmission program is complex, and requires more time to put into place than is available before the upcoming Update auction. For example, we envision that the permanent program would include municipal utilities and other IOUs as providers of transmission service. The permanent program should also accommodate "all-source bidding" -- that is, other suppliers of generation, such as IPPs and other utilities, would be allowed to bid in the auction. Implementing this permanent program raises sufficiently complex issues that it is appropriate to have an initial phase of this proceeding offering a more limited service.

Second, implementing transmission considerations into the bidding process is a new effort for all concerned. Since the upcoming auction involves a relatively small solicitation, this forum provides the Commission with an excellent opportunity to monitor the interim transmission program in order to produce future improvements for the permanent program. Also, limiting the scope of the first phase gives the parties an opportunity to reach compromise, or narrow the issues, and develop more pragmatic solutions to transmission issues than if broader, more permanent policies were being adopted.

Therefore, we will conduct this proceeding in two phases. The issues in Phase One, which are addressed in this decision, focus on an interim approach to transmission access and cost allocation issues to be ready for use in the auction the Commission is planning in the near future for the Update. The policies we adopt today are also limited in scope. (See Section 3 below.) The second phase will focus on the broader transmission access and cost allocation issues.[9]

Limiting the first phase of this proceeding to an interim program provides a workable means by which transmission factors may be considered in the Update auction. This phased approach also allows for the continuation of negotiation efforts for a voluntary transmission association called the Western Association for Transmission Systems Coordination (WATSCO). However, because of the important role transmission access and cost allocation issues play in our efforts to ensure reliable, environmentally sensitive, least-cost electric generation resources, the second phase of this investigation should commence promptly. (See Section 12.2.1, below.)

Because of Phase One's limited scope, some of the testimony presented at the policy hearings and some of the principles which we adopt today do not fully conform with the goals we articulated in D.91-10-048. For example, we stated that we preferred a program where all parties would have access to pre-bid information on wheeling costs, and would use this same information to determine how much to bid, as well as how to evaluate the bids. This conforms with a "transparent" auction methodology, where criteria for determining the auction winners are disclosed in advance of the auction to participants. However, the parties in this proceeding have generally agreed that, for wheeling requests, the wheeling utility may develop some wheeling cost estimates after the bidders have submitted bids and the purchasing utility has conducted an initial screening of the bids to create a "short

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9 Before addressing transmission policy issues in evidentiary hearings, we called for the parties to participate in a negotiating conference, in order to achieve consensus on certain issues, or at a minimum, narrow the range of positions on certain issues. The negotiating conference met from December 16 through 20, 1991, and from January 13 through 23, 1992. The parties to the negotiating conference generally agreed to phasing the proceeding.

list." We adopt this short list approach as a necessary temporary departure from our still highly desirable long-term goal of conducting an auction where the criteria for winning are fully transparent to all parties. (See Section 6.1 below.) Also, we indicated that we anticipated a permanent transmission program which is regional, with all significant wheeling utilities involved. Although municipal utilities participated in this phase of the proceeding, the transmission proposals to date focus on the three participating IOUs which will hold upcoming Final Standard Offer 4 auctions.

Phase One did narrow the issues and produce some consensus among the parties. For instance, the parties for the most part agreed that:

- The winners of the Update auction would receive access to transmission, subject to certain ratepayer and shareholder protections.

- Each of the three participating IOUs has agreed to wheel QF power acquired by either of the other two IOUs in the upcoming solicitation.

- Transmission costs (i.e., certain costs of line losses and upgrades) should be considered in bid evaluation.

- IOUs should be required to identify, in advance of the solicitation, transmission upgrade and line loss information for bidders to use in bid evaluation for integration.

- Special studies are needed if a bidder believes it will exceed the megawatt limits in the draft transmission cost tables.

- A "short list" evaluation of transmission costs is appropriate to use in this auction for wheeling purposes.

Notwithstanding this consensus, key contested policy issues remain for our determination. These issues are addressed in Sections 5 through 10 below.

2.3 Procedural Background

2.3.1 Policy Hearings

This investigation commenced in September 1990 with Order Institution Investigation (OII) 90-09-050. Many parties responded to our invitation for comments. The Assigned Commissioner also requested filings from IOUs regarding their transmission function and practices, including information on the following: planning criteria; computer models; projects and expenditures during the past decade; and involvement in wheeling transactions. The parties also conducted informational workshops in the summer and early fall of 1991.[10]

After reviewing the extensive record, we issued an interim opinion, D.91-10-048, where we provided policy direction for further proceedings. In the interim opinion, we called for the parties to modify their initial comments in light of the goals and policies articulated.[11] We also called for a negotiating conference discussed more fully in Section 2.2.2 above.

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10 Several workshops focused on the transmission systems of the three participating IOUs, as well as PacifiCorp and Sierra Pacific Power Company (SPPC), which have small service areas in California. The municipal utilities also conducted a workshop regarding their proposed voluntary transmission association, WATSCO.

11 The following parties filed written comments in response to the interim opinion: The Bonneville Power Administration (BPA), the CEC, the City of Vernon (Vernon), California Department of Water Resources (DWR), Destec Energy, Inc. (Destec), this Commission's Division of Ratepayer Advocates (DRA), Independent Energy Producers Association and Geothermal Resources Association (IEP/GRA), the Northern California Power Agency, Power Agency of California, and City of Anaheim (collectively referred to as NCPA), PG&E, the City of Pasadena, SDG&E, Edison, California Department of General Services (DGS), Texaco Cogeneration and Power Company (Texaco), and Transmission Agency of Northern California (TANC).

After the conclusion of the negotiating conference, the Assigned Administrative Law Judges (ALJs) issued a ruling setting forth issues to be addressed in policy hearings. The ruling specified that the policy hearings would be limited to issues which needed resolution to promote timely adoption by the Commission of an interim approach to transmission access and cost allocation to be ready for use in the upcoming Final Standard Offer 4 auction.

ALJ Econome held policy hearings from April 2 through April 10, 1992. After the conclusion of the hearings, the parties filed concurrent briefs on May 1, 1992, after which the issues addressed in the policy hearings were submitted for decision.[12]

The parties' policy recommendations at the April hearings generally fell into several groups. As a result of dialogue which began during the negotiating conference, parties from a wide spectrum of interests -- PG&E, DRA, IEP/GRA, and Destec -- sponsored joint testimony at the hearings. DGS and Texaco also supported the joint testimony and filed post-hearing briefs, although neither presented witnesses in support of the joint testimony. (These parties supporting the joint testimony are hereafter referred to as the "joining parties.") This joint testimony, which the parties termed a "Joint Proposal," addressed the joining parties' compromise view of how integration and wheeling issues should be resolved for use in the upcoming auction. Although we do not adopt the joining parties' testimony in its

12 The following parties were active in the April policy hearings by presenting witnesses, conducting cross-examination, or filing post-hearing briefs: PG&E, SDG&E, Edison, DRA, CEC, British Columbia Power Exchange Corporation (Powerex), IEP/GRA, Destec, DGS, NCPA, Vernon, and Texaco. SDG&E filed its brief together with a motion to file its brief one day out of time. Given there is no prejudice to any party, SDG&E's motion is granted.

entirety, we adopt significant portions and commend the parties involved for attempting to reach consensus on difficult issues of first impression.

Edison, SDG&E, the CEC, NCPA and Vernon each also presented thoughtful testimony at the hearings. Edison, SDG&E, and the CEC each presented a comprehensive set of policy recommendations for this Commission's adoption. The NCPA's testimony did not present a specific recommendation for Commission adoption in this phase, but generally requested that our decision today be consistent with the principles embodied in a draft set of by-laws for a voluntary transmission association known as WATSCO. Vernon's testimony also did not present a specific recommendation, but focused on select policy issues. [13]

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13 A February 28, 1992 ruling by the assigned ALJs addressed the issue that Vernon wished to advance at hearings, namely, whether the interim transmission program would affect its rights to transmission service from IOUs. The ruling stated that in D.91-10-048, slip at 27-28, the Commission contemplated that existing agreements to provide transmission service to other IOUs or municipalities would remain in force pursuant to the terms of those agreements. The ruling further stated that Vernon's issue therefore had no relevance to the April policy hearings. The ALJs also expressed concern over whether the Commission is the proper forum to address transmission access rights under existing agreements, but decided these jurisdictional questions were unnecessary to reach.

Vernon subsequently served proposed testimony for the April policy hearings. This proposed testimony reiterated Vernon's concern that the Commission "may authorize or direct Edison to do something that might diminish Edison's ability to wheel for Vernon or to hand Edison a ready excuse for failing to wheel for Vernon." (Vernon Response to Edison's Motion to Strike Portions of Vernon's Testimony at 3.) Edison moved to strike portions of Vernon's testimony, chiefly on relevancy grounds.

(Footnote continues on next page)

In the following sections we address the specific transmission policy issues necessary to resolve for the upcoming Final Standard Offer 4 auction. We concentrate on the chief points of contention, and do not try to summarize every nuance in individual positions.

We gratefully acknowledge the parties' time and effort in attempting to achieve a workable program to incorporate transmission considerations for use in this auction. The parties' recommendations provide an excellent basis for our determinations in this Phase One decision. However, completion of the verification process for the transmission cost tables (see Sections 2.3.2 and 9 below) is also necessary in order to incorporate transmission considerations into the upcoming auction. While we anticipate that participants in the verification process will achieve consensus on and finalize the draft transmission cost tables in a timely fashion, we are also committed to a Final Standard Offer 4 auction taking place in the near future.

2.3.2 Draft Transmission Cost Tables

In workshops which began in late March of this year and which are ongoing, the parties are conducting a verification process on the participating IOUs' draft transmission cost tables,

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(Footnote continued from previous page)

After full briefing and oral argument, ALJ Econome granted Edison's motion in part, on the alternative grounds that, inter alia, such testimony was beyond the scope of the proceeding, was not ripe, and that Vernon has remedies in other forums if it believes its existing rights are being violated. (RT 41-45; 475-476.) The ALJ also declined to refer this issue to the Commission under Rule 65 of our Rules of Practice and Procedure at the time of the April hearings. (Id.) We affirm the ALJ's ruling in all respects.

which were published on March 27, 1992. (See Section 9 for a more detailed description of the verification process.) These tables provide a bidder in the Final Standard Offer 4 auction with pre-bid information regarding the impact of new generation on the three IOUs' transmission systems to be used for bid evaluation. For example, this information includes, for various locations on a utility's system, (1) the amount of available capacity; (2) values for the costs of transmission upgrades; and (3) change in energy and capacity losses as a result of the new generation.

Each participating IOU has used its own analytical tools to develop its draft transmission cost tables. For example, PG&E has developed transmission upgrade cost estimates using what it calls the LOCATION model. The LOCATION model develops proxy cost estimates for upgrades. Edison's Long-Term Transmission Plan (LTTP) and SDG&E's cost tables include cost estimates using planning studies for a limited number of transmission busses.[14] These models appear similar in terms of precision of estimates.

3. Scope of Policies Adopted Today

The policies adopted in today's decision are limited in scope and should serve to govern transmission access and cost allocation in the next Final Standard Offer 4 auction. Since each participating IOU's auction addresses a small part of total cost-effective resource additions, we can conduct our interim transmission program without great risk. We will also monitor the interim transmission program in order to produce future improvements. (See Section 12.2.2 below.)

In this phase, the parties have compromised some of their earlier recommendations for a permanent program, and have approached these hearings from a pragmatic standpoint in light of what seems workable for an interim program and the size of the

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14 A bus is a single transmission line. Typically, high voltage lines consist of multiple busses, often three.

upcoming auction. For these reasons, and since we do not adopt a permanent program today, our resolution of these issues today should not prejudice the ultimate determination of these and other issues for the permanent program.

4. Striking the Proper Balance

In arriving at an interim transmission policy, it is necessary to strike a proper balance among the following factors. Because the upcoming Final Standard Offer 4 auction involves a relatively small solicitation, the balance we strike among the factors listed below may differ from that of a permanent program.

4.1 Risk Allocation

The interim policies we adopt today, like any policy dictating who bears what costs, involve risk allocation. Specifically, we must balance the risks inherent in these policies among the QFs, shareholders, and ratepayers.[15]

There are several risks associated with a competitive resource acquisition which includes a transmission component. First, the estimated upgrade costs may be more or less than actual upgrade costs. Second, the transmission policy may underestimate or overestimate future uses of lumpy transmission capacity.[16] Underestimating future uses may result in overallocating transmission costs to certain bidders, and the lowest cost resources not being selected. Overestimating future uses may result in the utility overbuilding its transmission system at ratepayer expense. Third, an upgrade and associated QF contract

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15 This type of balancing is a traditional function of public utility regulation.

16 Lumpy capacity is excess transmission capacity created when, for economic or technical reasons, an upgrade must be sized larger than the capacity of a QF whose addition requires the upgrade. (See Section 5.4 for a discussion of assigning the costs of lumpy transmission upgrades for bid evaluation in integration situations.)

may not be implemented if certain necessary approvals (i.e., a Certificate of Public Convenience and Necessity (CPCN)) are not obtained.

We believe that adding a transmission component to the upcoming auction will benefit ratepayers by providing that the resources with the lowest total cost are selected. However, we also recognize that ratepayers, as well as QFs and shareholders, may have to assume new risks in order to achieve these benefits. In risk allocation, we consider, among other factors, who is benefiting from the policies adopted and who is in the best position to bear the risk. Furthermore, after determining the proper risk allocation, we adopt policies which will assist in mitigating the risk to the extent possible.

4.2 Uniformity

In D.91-10-048, we anticipated that our permanent transmission access and cost allocation program would have uniform application both to the three participating IOUs and to all those involved in providing transmission service to the wholesale electric market in California. In today's decision, we are not requiring such uniformity. At the same time, we recognize the importance of the application of uniform policies wherever possible.

There are several examples where uniformity has been compromised. For example, different analytical tools underlie each participating IOU's draft transmission cost tables. Yet, all tables publish pre-bid transmission information on which bidders requiring integration may rely.

SDG&E suggests that there is no compelling reason for uniformity in the transmission programs adopted for each utility, since each utility administers its own auction. According to this argument, it would be appropriate to enact a transmission program for wheeling where the purchasing utility arranges and pays for wheeling service in PG&E's and Edison's auction, but where the QF arranges and pays for the wheeling service in SDG&E's auction. We disagree.

The upcoming Final Standard Offer 4 auction will be the first time this type of auction takes place. Furthermore, the bidders will be bidding against multiple IDRs. The process will be unduly complicated if different transmission access and cost allocation policies are adopted for each participating IOU.

Furthermore, in order to create a level playing field statewide, it is important for a transmission access and cost allocation program to be uniform at least in policy if not in implementation. Therefore, the policies we adopt today should be uniformly applied to each participating IOU, even though each IOU may utilize different analytical tools for this auction in order to implement these policies.

4.3 Transparent Auction Rules

Our decisions have required a transparent approach to our Final Standard Offer 4 auction. For example, in our interim opinion in this proceeding, we stated that the IOUs and other utility participants in our transmission program should publish transmission cost information for various locations in their territories, so that a bidder can determine "before submitting its bid the transmission costs that would be associated with its facility and could calculate its bid accordingly." (D.91-10-048, slip at 24-25.)

In today's decision, we adopt policies which encourage the participating IOUs to supply bidders with objective, pre-bid transmission information, which is binding for bid evaluation purposes. While utilizing transparent auction rules is fully feasible for integration, it appears that there is insufficient time before the auction to develop such an approach for wheeling. The "short list" wheeling approach adopted below (see Section 6.1), in which some determination of wheeling costs for QFs on the "short list" of winners is made after the bids are submitted, is a necessary temporary departure from the transparent auction rules that remain our goal for the permanent program.

Several parties argue that transparency necessarily sacrifices accuracy. Edison and SDG&E, for example, argue that accuracy can only be achieved if bidders were to provide the utilities with pre-bid information regarding the size and location of their projects, so that the utility can provide the best estimate of transmission costs. We rejected this argument in D.91-10-048 and we continue to reject it.

Although the policies we adopt today deviate to some extent from our policy of transparency, we are still persuaded that transparency is a desirable goal. We ultimately expect that Final Standard Offer 4 will be open to "all-source" bidding -- that is, other suppliers of generation, such as IPPs and utilities, would be allowed to bid in the auction. We ultimately wish to ensure that the protocol used to determine auction winners is transparent and does not rely on post-bid adjustments which may lead parties to call into question the auction results.[17]

Even when a utility does know the location and size of the project requiring transmission, it is still difficult to accurately determine transmission costs before upgrades are actually built. For example, a utility's actual costs for a transmission upgrade may be higher or lower than those set forth in its application for a CPCN. As PG&E's witness Jenkins indicated, a

17 To the extent that utilities or their affiliates are to bid in their own auctions (as some utilities have proposed), any requirement that the utilities' competitors provide pre-bid information on development plans would provide utilities with a signficant competitive advantage.

utility does not know the final transmission costs for an upgrade until the books are closed. (RT 279.)

The short list approach which we adopt for wheeling provides that the participating IOUs make an estimate of wheeling costs after the bids are submitted. However, even though the utilities will then know the location of the bidders for which they are determining wheeling costs, the utilities do not wish to be bound even by the post-bid estimates, since the estimates may vary from actual transmission costs. (See Section 6.1 below.)

We are convinced that relying on transparent criteria is consistent with a reasonable (indeed, inevitable) level of planning risks. However, the interim transmission program we adopt today will allow us to monitor pre-bid transmission information provided in integration situations to determine if, in fact, such pre-bid information sacrifices accuracy, and to what degree. (See Section 12.2.2 for the details of the monitoring program.)

5. Integration

We adopt a different method for considering transmission costs in bid evaluation for integration than we do for wheeling. In this section, we discuss the integration situation.

5.1 The Transmission Cost Tables Are Used by Bidders to Formulate Their Bids and by Participating Utilities to Evaluate Bids

For all capacity subject to bidding, both the benchmark price of the IDR and bids by QFs will take transmission costs into account. This method facilitates a direct comparison of each resource's total costs.

For integration purposes, bidders will be able to study the data contained in the transmission cost tables before bid submission in order to ascertain their transmission costs. This information will enable bidders to determine if an upgrade is necessary, and for the most part, what portion of the upgrade costs and other transmission costs would be assigned to their bid at a given location. This pre-bid information will assist bidders in locating their projects to minimize transmission costs. QFs submitting bids to a participating IOU in whose service territory they are located will take transmission costs into account in developing their bid, but would not include transmission costs in their bid.

The information published in the transmission cost tables would be binding for bid evaluation purposes in integration. Once the bidding period is closed, a participating IOU would add transmission costs to QFs' bids before selecting the winners. (Before selecting winners, the utility would also ascertain wheeling costs for QFs requiring wheeling by means of the short list approach discussed more fully in Section 6.1 below.)

The transmission costs a participating IOU would add to the bid of a QF requiring integration would be consistent with those published in the transmission costs tables, and would include energy and capacity losses, as well as system upgrades. (See Sections 5.4 and 5.5 below.) The IDR should also reflect projected upgrade costs and energy and capacity losses.[18] The participating IOU would be responsible for the costs of transmission upgrades necessary to integrate the winning bidders from the first point of interconnection into the utility's system. However, QFs would be responsible for costs needed to connect their plants to the first point of interconnection with a participating IOU's system. (See Section 5.4.2 below.)

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18 To the extent the IDR does not reflect these transmission costs, the participating IOUs should promptly modify the benchmark price of the IDR to reflect these costs. The IOUs should attribute transmission costs to their IDRs in the same manner as they attribute transmission costs to the bidders in the auction. (I.e., for integration, SDG&E and Edison should use pro rata cost allocation plus a carrying cost adder, not full cost allocation.) However, under no circumstances will the IDR benchmark price change from that published in the request for bids.

All parties addressing this issue, except for the CEC, agree that pre-bid transmission information should be binding for bid evaluation purposes in our interim program, notwithstanding the fact that the actual transmission costs may be higher or lower than the published pre-bid transmission costs.[19] We agree and find this evaluation method consistent with our goal of transparent auction rules. (See Section 4.3 above.)

5.2 Exceeding the Megawatt Limit

In formulating their transmission cost tables, the participating IOUs have made a reasonable effort to anticipate QF development in providing transmission cost data. However, the issue arises as to how bids will be evaluated if a QF's project alone, or in potential combination with other projects, exceeds the megawatt limit of estimated upgrade costs at a given site. The parties all agree that QFs who believe they may be subject to this situation can request the participating IOU to perform a special study of transmission costs for a specified megawatt size at a specified location. The parties propose that QFs requesting a special study must do so within 30 days of the publication of the draft transmission cost tables.[20] However, PG&E emphasized that special studies should not be made to validate the numbers in the draft transmission cost tables.

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19 The CEC proposes a two-step bid evaluation for integration discussed more fully in Section 5.4 below. Under the CEC proposal, transmission costs of potentially winning bidders would be refined after bid submission and a hearing, before bids are chosen. We reject this proposal for the reasons set forth in Section 5.4 below.

20 Pursuant to a February 28, 1992, ALJ ruling, the three participating IOUs published their draft transmission cost tables on March 27, 1992. They also served a notice of availability of the draft transmission cost tables on the service lists of this investigation, and of the Update, and widely distributed the notice of availability in relevant trade journals and other publications. The draft transmission cost tables and notices of availability refer to the special study process.

The final transmission cost tables would contain results of the special study, and all potential bidders would have access to this information in developing their bids. The parties also agree that absent a special study, utilities would not consider individual bids which exceed the megawatt limits contained in the transmission cost tables.

Since all parties agree that the special study procedure is necessary in situations where a bidder's project alone, or in combination with other projects, exceeds the megawatt limitations at a given location, we will approve this procedure for use in this interim program to address this limited situation. We also agree with PG&E that a special study should not be made to validate the numbers in the transmission cost tables. However, in D.91-10-048, slip at 33, we stated that QFs need not provide utilities information about their project before the bidding, citing confidentiality concerns. We therefore will explore in Phase Two how the utilities can develop complete transmission cost tables without requiring QFs to request a special study or otherwise provide utilities with information regarding their project in advance of bidding.

The joining parties, as well as SDG&E, propose a $10,000 fee for conducting a special study, based on a utility's costs, and in order to ensure that those requesting a special study are bona fide bidders. Edison proposes an unspecified fee for its costs, and finds the $10,000 fee not to be unreasonable. The joining parties also propose that this fee is not directly refundable, but may be indirectly refundable if one QF paying for a special study is not selected as a winning bidder, and another QF which exceeds the megawatt limit at that same location (and which benefited from the study paid for by the losing QF) is selected as a winner. We adopt the joining parties' and SDG&E's fee and refund recommendations as set forth above.[21]

5.3 Competing Bidders at One Location

If multiple QFs submit bids at one location, which transmission costs should be assigned to which QFs? This assignment could significantly affect the award of contracts where existing transmission capacity could accommodate some but not all of the bidders at that location. We will assign the lowest transmission costs to the "lowest price bidder." We agree with the parties that this objective is consistent with our goal of selecting the lowest cost resources.

In their comments to the Proposed Decision, PG&E and DRA seek further clarification of the definition of the "lowest price bidder." PG&E explains that although the Proposed Decision adopted the joining parties' recommended definition, recent discussion at the verification workshops reveal that determining the "lowest price bidder" is a dynamic, iterative process which may involve considering a bidder's total costs, including transmission costs. The parties are directed to discuss the appropriate protocol for determining the "lowest price bidder" in the verification workshops.

Because this policy may result in a project being assigned upgrade costs higher than if it were the only bidder at one location, the joining parties propose that bidders should be

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21 The joining parties made additional proposals as follows. Challenges to a special study should only be brought through a complaint to the Commission and served on all parties in this investigation and the Update. Any QF challenges to the transmission cost tables should be brought in the same manner, but should be limited to the issues specifically raised by the complainant in writing in the verification workshops. We decline to adopt these proposals for the reasons set forth in Section 9 below.

allowed to submit multiple site bids to a maximum of three busses for a purchasing utility to consider if (a) multiple bidders locating at the preferred site for a particular bidder cause that bidder to exceed the megawatt limit at that site and lose, or (b) the bidder's upgrade costs or losses are increased as a result of multiple bidders locating at the preferred site for a particular bidder and such increase causes that bidder to lose. The joining parties further propose that if, considering all the alternatives, a bidder still exceeds the megawatt limit at a given bus, that bidder would not be considered further in that round of bidding. SDG&E agrees with allowing QFs to submit multiple bids, but proposes that bidders only be allowed to bid at one additional site. Edison opposes multiple bids because of the administrative complexity entailed.

We agree that QFs should be allowed to bid against an individual IDR at multiple sites, not to exceed three busses (this includes the original site and two additional sites), for a purchasing utility to consider in the two instances set forth above. We also agree that if, after the above steps, a bidder still exceeds the megawatt limit at a given bus, either individually or as a result of multiple bidders locating at that site, that bidder should not be considered further in that round of bidding. Allowing QFs to bid at multiple sites helps mitigate the risk of any inaccuracies which may arise from using the transparent approach. The record does not persuade us that the administrative complexities involved outweigh the fact that an otherwise cost-effective QF may be excluded from a utility's resource plan if we do not adopt this provision.[22]

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22 We also reject Edison's argument that bidders be constrained to connecting at the nearest substation.

5.4 Assigning the Costs of "Lumpy" Transmission Upgrades for Bid Evaluation

5.4.1 Background

In cases where there is insufficient transmission capacity to get winning bidders' power from the first point of interconnection with the utility's system to its load center, a transmission upgrade is necessary. For economic and technical reasons, an upgrade might have to be sized larger than the capacity of the QF(s) whose addition requires the upgrade. We term this mismatch a "lumpy" upgrade.

The parties differ on what portion of the lumpy upgrade's cost should be assigned to the bidder for bid evaluation purposes. Edison believes that a bidder should be assessed the full cost of the lumpy upgrade, less system benefits to the utilities' ratepayers. SDG&E believes that a bidder should be assessed the full cost of the lumpy upgrade. The joining parties believe that a bidder should be assessed only pro rata costs, i.e., those ascribed to that portion of transmission capacity which the bidder will use to transmit its power.

Although DRA is a joining party and supports pro rata cost allocation, it alternatively argues that we adopt a carrying cost adder for lumpy upgrades. Under this approach, the bidder would be assessed both its pro rata allocation and an adder reflecting a carrying cost of a lumpy upgrade's unused capacity for a specific period of time. DRA recommends that we determine this period to be two years, the length of time before the next Update bidding cycle. Although Edison advocates full cost allocation, it alternatively recommends DRA's carrying cost approach, except that the period of unused capacity be ten years instead of two.

Finally, the CEC recommends a variant on the "short list" approach recommended by the parties for wheeling. (See Section 6.1 below.) First, the utility would compile a list of potential winning bidders following receipt of bids. Then, the utility would refine the pre-bid transmission cost information for these potential winning bidders to determine the transmission upgrades necessary to integrate these bidders. Finally, the CEC recommends that a "quick," 30-day analysis, including one public hearing, be conducted to roughly estimate the development potential in the areas served by the identified upgrades. This analysis would focus on resources likely to be developed within the next two bidding cycles. The estimate of the total potential use of the upgrade would be expressed as a ratio, multiplied against the total cost of the upgrade, and allocated to the potential winning bidders for bid evaluation purposes.

5.4.2 Pro Rata Cost Allocation With a Carrying Cost Adder

We adopt pro rata cost allocation plus a carrying cost adder. We agree with DRA that this method more appropriately balances the risks to the ratepayers and more closely reflects the use of excess capacity than either pro rata or full cost allocation for this bidding cycle. We emphasize that this determination is limited to this bidding cycle for the reasons set forth below.

The parties to this proceeding are in general agreement that the ratepayers will bear the transmission costs of integrating the winning bidders.[23] However, the method by which transmission costs are allocated to bidders for bid evaluation purposes is significant, because we want to ensure that the bidders with the lowest total costs are selected as the winners.

If our choice were solely between pro rata and full cost allocation, we would choose pro rata cost allocation. First, under pro rata cost allocation, a bidder would be better able to know, before it submits its bid, what portion of the cost of a new

23 The QF, however, will bear its transmission costs to the first point of interconnection.

upgrade would be assigned to its bid.[24] This furthers our goal of encouraging a competitive market by placing bidders on a more level playing field with utilities in terms of access to transmission information. This is in contrast to full cost allocation, where there is more uncertainty as to what transmission costs will be assigned to bids.[25]

Second, any excess capacity resulting from pro rata cost allocation may increase competition in future solicitations by encouraging bidders to locate near that capacity. However, using full cost allocation may result in the upgrade never being built in the first instance because no one project can absorb attribution of the full upgrade costs and still win the auction. Furthermore, a

24 Even under pro rata cost allocation, bidders will not be able to know under all circumstances exactly what costs would be assigned to their bids. For example, if there are multiple bidders at a single bus, the bidder with the lowest total generation costs will be assigned the lowest transmission costs. However, bidders will not know before all bids are evaluated which bidder will have the lowest generation costs.

25 The greater uncertainty results since a single bidder who triggers an upgrade would be assigned the full upgrade cost, whereas if multiple bidders bid at an existing site, they would be assigned their pro rata share of the upgrade. However, a bidder would not know in advance of submitting its bid whether there would be multiple bidders to trigger the same upgrade, and if so, how many bidders.

It can be argued that the same uncertainty may result from the carrying cost methodology we adopt today. However, two factors mitigate this uncertainty. First, if a bidder triggers a lumpy upgrade, it will be assessed a carrying cost adder. Second, unlike full cost allocation, the bidder would know in advance what that carrying cost adder will be. There may be some uncertainty if the adder will be applied in the first instance (i.e., sufficient bidders may aggregate in the same area so that no lumpy upgrade results). This uncertainty, however, is outweighed by the mitigation of ratepayer risk resulting from assessing the bidder with an appropriate factor reflecting the possibility that excess capacity may not be used for some period of time.

utility might make use of that excess capacity in the future for its own purposes, e.g., for importing economy energy or reliability purposes. In such circumstances, charging the full amount of this capacity to the bidder results in disproportionate cost allocation.

Proponents of full cost allocation argue that this approach reduces risk to the ratepayers that excess capacity will not be used in the future.[26] Under pro rata cost allocation, ratepayers bear the risk that transmission capacity may be unused for a period of time. However, since a lumpy upgrade is likely to be fully utilized over time, full cost allocation overstates transmission costs to the bidders, and in turn, to the ratepayers.

Pro rata cost allocation does not adequately address the following situation. Assume two bidders bid projects of 250 megawatts (MW) each, and their energy and capacity charges are equal. Bidder A triggers a 250 MW upgrade, and its project fully uses the upgrade. Bidder B triggers a 500 MW lumpy upgrade although its project only uses 250 MW of the upgrade. If we adopt pro rata cost allocation, both bidders will tie in the auction. Ratepayers may be deprived of receiving the most cost-effective resource since straight pro rata cost allocation in this case does not reward the bidder (bidder A) who does not trigger the excess cost of a lumpy upgrade.

Pro rata cost allocation with a carrying cost adder addresses the concern raised in the above example. First, this approach attributes to each bidder its pro rata costs for a necessary transmission upgrade. Second, it adds to the score of bidders who trigger a lumpy upgrade an appropriate carrying cost

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26 Proponents of full cost allocation also argue that this approach more fully comports with the selection of IDRs, which are assigned the full cost of tranmission upgrades. However, IDRs are generally large projects which utilize a large portion, if not all, of the transmission upgrade because of their size.

adder, reflecting the risk that this capacity may not be fully used in the near future.

We agree with DRA that the carrying cost adder be computed with the following data: (1) the amount of excess capacity involved, (2) a carrying charge rate,[27] and (3) an estimate of the duration of the amount of unused capacity. Items (1) and (2) are objectively determined. Item (3) involves our assessment of the duration of excess capacity. DRA recommends that we adopt a figure of two years, the length of time until the next Update cycle. DRA supports its recommendation with the rationale that this excess capacity may exist until the next round of bidding, although it may be used sooner by a utility for other purposes.

We adopt a two-year duration. We believe that lumpiness is likely to be digested quickly, and indeed may not exist at all. These are upgrades which will occur many years in the future -- primarily to integrate projects whose on-line dates are from 1997 to 1999.

We also emphasize that transmission costs are usually smaller in proportion to generation costs. Thus, it may be preferable to have some excess transmission available for use, rather than to build another expensive power plant because there is insufficient transmission to get existing generation to the load centers. We will monitor our interim program to seek improvements for our permanent program. This monitoring includes comparing

27 The carrying charge rate should be equivalent to the levelization factor used to levelize costs over multiple years. To the extent it is necessary to make assumptions in determining the carrying charge rate, these assumptions should be consistent with those used in the Update. The parties should further discuss the technical implementation of the carrying cost adder in the verification workshops.

estimated with actual transmission costs, to determine if, and to what degree, lumpiness problems do in fact exist. (See Section 12.2.2 below.)[28]

Because PG&E's LOCATION model uses small incremental generation to develop transmission cost estimates and does not predict the actual size of the upgrades needed to accommodate specific bidders, it cannot predict lumpiness associated with a given bidder. The LOCATION model is thus incompatible with a carrying cost adder. We therefore direct that PG&E use pro rata allocation without the carrying cost adder. We view this as a necessary interim departure from our goal of uniformity among the utilities, because of the nature of the LOCATION model. In Phase Two, PG&E should explore possible modifications of LOCATION to make it compatible with a carrying cost adder approach.

We do not adopt the CEC's recommendations. Under the CEC's proposal, bidders would not know in advance, for integration, what transmission criteria would be applied to their bids. Although we adopt a short list evaluation process for wheeling for this auction only, we want our permanent program to provide bidders, to the extent possible, with transparent information from which to determine their bids. In order for this information to have any value, it must also be applied in bid evaluation. We therefore adopt a bid evaluation approach for integration which addresses these concerns, and still offers additional ratepayer protections.

We also question whether there is sufficient time to conduct the planning studies the CEC recommends. Many parties

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28 Because we reject full cost allocation, we also reject Edison's "quasi-integer programming solution" (RT 695), which uses a computer program internal to Edison to find the lowest combination of bid prices and facility additions, arguably to mitigate the full cost allocation approach.

disagree that these studies can be completed within 30 days, especially since the hearings could be contentious, with all bidders advocating that their site be designated as an area with development potential. We think the process recommended by the CEC could easily consume 90 to 120 days and would impose a significant additional transaction cost on a process that is already lengthy and costly.

5.5 Energy and Capacity Line Losses

5.5.1 Background

Should both energy and capacity line losses be included in bid evaluation? This issue is applicable to both integration discussed in Section 5 and wheeling discussed in Section 6. Line losses affect both energy and capacity from a given plant. Currently, line losses, like all transmission costs, are not included in bid evaluation.[29] All parties addressing the issue agree that energy and capacity losses should be taken into account in bid evaluation. Also, all parties addressing this issue accept the methods by which the three IOUs calculate capacity losses for purposes of bid evaluation in this interim program. However, they disagree on the method of calculation of energy losses.

5.5.2 Summary of the Various Loss Methodologies

PG&E uses its LOCATION computer program to calculate capacity losses. First, PG&E performs a base power flow simulation for the summer peak period. Second, the LOCATION program calculates incremental losses by increasing the power at a

29 In D.91-10-048, slip at 26, n.19, we stated that "[t]he current treatment of line losses for calculating payments to QFs is essentially to assume that losses in transmitting QF power equal the system average. Thus, for most QFs, no payment adjustment (plus or minus) is made based on their line loss impact. However, we have expressly authorized utilities to calculate line loss factors on a case-specific basis for 'remote' QFs. (See, e.g., D.89-02-017, 31 CPUC2d 13, 24-25.)"

substation by a small amount and calculating the change in loss for the system. PG&E states that its method slightly understates losses compared with a more traditional planning study method, where an actual project site is used for purposes of loss calculation. PG&E calculates energy loss factors by taking a weighted average of capacity losses for different seasons and time periods.

Edison calculates capacity losses by performing a base case power flow without IDRs and then increasing the loads at all the busses by 1% to 5%. Edison then calculates the loss factor for a generation bus by allowing that bus to meet the incremental load while keeping other busses at their outputs. Edison calculates the energy losses from the capacity losses based on an empirical relationship between peak load and average load.

SDG&E calculates capacity losses by comparing system losses at peak load in a base power flow simulation which includes IDRs, with a simulation including QFs. In the second simulation, the IDR output is reduced to account for the QF output. SDG&E has not finalized its energy loss calculation methodology, but is considering using a method similar to that used by Edison.

<u>5.5.3 The Parties' Positions on Energy Losses</u>

The joining parties recommend that all participating IOUs use the PG&E method for calculating energy losses. They further suggest that if an IOU is unable to develop energy losses based on the PG&E method, it should not be allowed to include energy losses in bid evaluation. Although IEP/GRA agree with the joining parties' recommendations, they emphasize that attempting to account for energy losses is difficult, because (1) energy losses vary over the life of the project and (2) there is uncertainty that power flowing from a particular generation source will go to the assumed load center over the life of the project. For these reasons, IEP/GRA believe that energy losses could be excluded from an interim program.

IEP/GRA state that their willingness to include energy losses as part of bid evaluation is premised on our approval of PG&E's methodology for all three participating IOUs. IEP/GRA believe the PG&E methodology is superior to that used by Edison because the PG&E methodology does not assume a unique "load center." Furthermore, IEP/GRA argue that the time-weighting component of PG&E's methodology somewhat addresses the concern that power flow will likely vary over the course of the project, insofar as the method is sensitive to seasonal variations in losses. However, even PG&E's approach does not address the fact that energy losses may change over time, e.g., with changes in load distribution.

Edison disagrees. It has applied PG&E's time-weighted approach to several busses on its system and states that the results are comparable to those obtained from Edison's energy loss methodology. Both PG&E and Edison state that energy losses can in fact have a more significant impact on QFs' bid score than costs of transmission upgrades. They also insist that QF energy losses may predictably differ from system average. PG&E and Edison therefore recommend that we do not ignore energy losses in bid evaluation.

5.5.4 Energy and Capacity Line Losses Should Be Included in Bid Evaluation

The record demonstrates that energy and capacity losses could constitute a significant portion of total transmission costs associated with a QF contract. Therefore, if we are to consider transmission costs in evaluating bids, we should consider losses as well as upgrade costs.

The parties do not dispute the methodology each IOU has proposed for calculating capacity losses. We will therefore allow each participating IOU to use its own capacity loss methodology for this interim program, provided this methodology is consistently applied to its IDRs.

The issue of the appropriate methodology for calculating energy losses is more problematical. Although the record indicates that energy losses may be significant in determining a project's total transmission costs, our record is inadequate to approve any methodology for determining these losses. None of the participating IOUs has submitted benchmarking of their loss calculations. We are therefore unable to approve a specific methodology or to make the determination that PG&E's methodology for calculating energy losses is superior to that advanced by Edison. SDG&E has not advanced a methodology for determining energy losses.

However, given the fact that energy losses could constitute a significant portion of total transmission costs associated with a QF contract, we believe it appropriate to consider energy losses in bid evaluation, notwithstanding the uncertainties surrounding their determination, subject to the following provisions. We will allow the participating IOUs to include energy losses in bid evaluation provided the parties agree at the verification workshops that the energy loss numbers the IOUs intend to use in their transmission cost tables are reasonable for use in the interim program, and provided that the methodology used to determine the numbers is applied to the IOUs' IDRs.[30]

In D.91-10-048, slip at 27, we recognized that certain QFs may have positive impacts on the transmission system. We explained that such impacts could include unloading of heavily loaded lines through reduction of loop flows and deferral of transmission upgrades through changes in power flows. We agreed in principle with PG&E's recommendation that QFs be given credit for

30 See Section 9 below, which states that further ALJ or Commission action may be necessary if the parties fail to reach agreement.

such impacts where applicable, and we will apply this principle in our interim program.

Because of the uncertainties surrounding energy loss calculations, we stress that our determination is strictly limited to the upcoming auction.[31] We believe that the issues of (1) whether to specifically account for energy losses as opposed to system-averaging them, and (2) whether the IOUs' methods for calculating energy losses are satisfactory or need to be refined, can only be determined after a careful review of input and modelling assumptions, such as the Commission performs for computer models used in ratemaking, pursuant to Public Utilities (PU) Code §§ 585, 1821-1824.[32] We also believe that since the utilities have used empirical evidence in the past to arrive at estimates of system losses, a method should exist for monitoring actual losses on the IOU's systems. We therefore direct the participating IOUs to initiate a monitoring program, after consultation with the parties, to record losses at interconnection points representing a diversity of locations and other relevant variables on their systems. This monitoring will be part of the overall monitoring described in Section 12.2.2.

We also recommend that the parties explore in Phase Two ways in which the IOUs can develop consistent and more accurate methods for calculating energy and capacity losses.

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31 We also emphasize that the foregoing principles regarding line losses are approved solely for bid evaluation in the upcoming Standard Offer 4 auction. Possible adjustment of line loss factors for QFs now operating under standard or nonstandard power purchase agreements is beyond the scope of this investigation.

32 See, for example, the procedures established to review production cost models in D.87-12-066, 26 CPUC2d 392, and utilized in subsequent Energy Cost Adjustment Clause proceedings.

5.6 Reservation for Short-term Transactions

5.6.1 Background

The parties split on how to account for the impact of this transmission access program on a utility's short-term transactions.[33] The parties present three basic choices on this issue, which issue affects both integration and wheeling.

Many parties recommend that a participating IOU be permitted to reserve a reasonable amount of transmission capacity specifically for economy energy or for short-term transactions in general. The CEC, the joining parties, SDG&E, and the NCPA all support a variation of this proposal.

The CEC recommends that we allow the participating IOUs to include the amount of short-term transactions adopted by the CEC in ER-90 in determining available transmission capacity. In this way, short-term transactions are implicitly taken into account in calculating existing capacity, line losses and the cost of upgrades in the utility's transmission cost tables. This proposal is consistent with the NCPA's recommendations.

The joining parties' proposal is similar. They recommend that participating IOUs be allowed to make a reservation for demonstrable economy energy purchases consistent with the assumptions adopted by the CEC in ER-90. The joining parties oppose the alternative that the participating IOUs assess an opportunity cost imputation against QFs in this solicitation.[34]

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33 "Short-term transactions" as used here refer to a broad category of transactions including economy energy, spot capacity purchases, and seasonal exchanges.

34 Such costs are generally incurred when a utility provides third-party firm transmission service and thereby foregoes the opportunity to reduce its own costs by means of a short-term transaction. For example, a wheeling utility may be precluded from taking advantage of an opportunity to purchase economy energy for its own system as a result of a wheeling arrangement with a purchasing utility.

SDG&E also recommends an economy energy reservation for wheeling. However, SDG&E recommends that the reservation be based on historical information, rather than the methodology currently used by the CEC for projecting economy energy availability. SDG&E argues against the use of the CEC's models since those models use average economy energy availability and therefore conclude that SDG&E will incur little or no rejection of economy purchases. In contrast, SDG&E states that relying on historical information would show that SDG&E cannot meet wheeling requests on the interties without foregoing economy energy transactions.

SDG&E supports assessing an opportunity cost imputation against the QFs for integration. It also recommends an economy energy reservation for the upcoming auction for wheeling as an alternative to assessing an opportunity cost imputation. SDG&E argues that although the Federal Energy Regulatory Commission (FERC) has recognized and approved of the policy of recovering opportunity costs, FERC has not yet implemented this type of pricing scheme, which will involve substantial record keeping by the utilities, as well as appropriate FERC verification. For these reasons, SDG&E believes that the use of opportunity cost pricing is not practical for this bidding cycle.

In contrast, Edison recommends using an opportunity cost imputation to value its intertie capacity for purposes of scoring QFs who want to integrate their resources into Edison's system. Edison did not present its methodology at the April hearings, but recommends that the methodology for computing the opportunity cost imputation be further developed at the verification workshops now underway, and in additional hearings.

The remaining alternative is not to include economy energy, either as a reservation in transmission planning assumptions or in bid evaluation as opportunity costs. Destec supports this alternative in the event we do not adopt the joining parties' joint testimony in its entirety. Destec asserts that, as a rule, a utility does not plan its transmission system for the importation of nonfirm energy but only for the delivery of power from firm resources to the utility's load center. Destec therefore recommends that firm resources acquired by a utility through the bidding process should be treated similarly to utility-owned firm resources. According to Destec, ratepayers would benefit from the development of long-term firm resources for meeting the utility's load. Furthermore, Destec states that its recommendation would not preclude imports of economy energy but would give firm resources first priority on the transmission system. Destec further assures us that since the generation capacity in the upcoming solicitation is relatively small, its method would still allow for ample short-term imports.

5.6.2 Discussion

The Proposed Decision required the participating IOUs to include the amount of short-term transactions adopted by the CEC in ER-90 in determining available transmission capacity. We modify the Proposed Decision as set forth below.

We wish to ensure that the purchasing utility can capture the economic benefit of opportunities to buy low-cost power over the short-term, consistent with its long-term purchase contract with the QF. The parties suggest two mechanisms to do so: a reservation for short-term capacity or an opportunity cost imputation to a QF's bid score.

We believe that the existing substantial economic curtailment provisions in the Final Standard Offer 4 contract may go a long way to ensure that the purchasing utility can capture the benefit of opportunities to buy low-cost power. Furthermore, we have not yet addressed new curtailment proposals recommended by the parties in the Update, which, if adopted, may also prove beneficial in this regard. However, even with contractual curtailment rights, it is possible that a QF could displace even lower-cost power. It is our understanding that an opportunity cost imputation in bid scoring should capture the value of this lost opportunity. Since an upgrade would allow the utility to obtain both the QF and the economy energy transaction, an opportunity cost imputation should not be greater than the cost of an upgrade.

We have carefully considered both the reservation and the opportunity cost imputation in light of a utility's contractual curtailment rights under Final Standard Offer 4. We believe that a similar analysis applies to implementing each option. For example, if an intertie line was fully loaded a small portion of the year, a utility would want to explore, among other things, how much of this load is attributed to short-term transactions, how much of this load is more expensive than the QF capacity acquired through the auction, and how the utility's substantial economic curtailment rights under the Final Standard Offer 4 contract can reduce the amount of any opportunity cost imputation.

Since the opportunity cost imputation may be more dynamic than a reservation, unless the reservation can be expressed in variable terms, we are persuaded by Edison's recommendation, in its comments to the Proposed Decision, that the parties be allowed to further discuss an opportunity cost imputation in the verification workshops. If parties in the verification workshops reach consensus on an opportunity cost imputation, and this consensus is reflected in the workshop report, then the opportunity cost imputation should be used in the upcoming auction.

We caution that the opportunity cost imputation would only apply to existing (intertie) transmission lines, not upgrades. Additionally, the use of an opportunity cost imputation would be in lieu of a short-term transaction reservation. (This avoids double counting.) Edison agrees with both of these conditions.

If the parties are unable to reach consensus on the implementation of an opportunity cost imputation in the verification workshop, then we direct the parties to follow the holding of the Proposed Decision for the upcoming auction. Specifically, in that instance, we require the participating IOUs to include the amount of short-term transactions adopted by the CEC in ER-90 in determining available transmission capacity.

We clarify the Proposed Decision's requirements. We recognize that ER-90 expresses the short-term transaction forecast in gigawatt hours. Therefore, a technical issue arises as to how to convert these values into transmission capacity for use in this auction. The parties should address this issue in the verification workshops in the event there is not consensus on an opportunity cost imputation.

Either option must be interpreted reasonably. For example, it seems wasteful to reserve 100% of an intertie when that intertie is used to full capacity only a small portion of the year. If the reservation is utilized, the parties should also hold in mind such things as capacity utilization pattern for the line and the utility's need to schedule the various resources dependent on that transmission capacity. The parties should also consider a utility's curtailment rights.

Finally, if the reservation is utilized, we direct the parties to use ER-90 assumptions. We affirm D.92-04-045 that except for ER-92 gas prices discussed in that decision, we will consistently use ER-90 assumptions for this bid solicitation.

6. Wheeling

As stated in Section 5 above, the methodology we adopt for wheeling differs from that adopted for integration. In this section, we discuss issues relevant for considering transmission costs in bid evaluation for wheeling.

6.1 The Short List Approach

We adopt a short list approach for considering wheeling costs in bid evaluation. All parties agree in concept with the short list approach.[35] In contrast to the method we adopt for integration, the transmission costs associated with wheeling, which are published in the transmission cost tables, are not binding for bid evaluation. Instead, the wheeling IOU will estimate these costs for potential winners (i.e., those on a short list) after bids are submitted. These short list costs will be binding on both the purchasing utility and the QF bidders for bid evaluation purposes. Although this method does not meet our long-range goal of transparency, we are persuaded to adopt the short list approach for our interim program for the reasons set forth below. The specific short list approach we adopt is that recommended by the joining parties, with minor modifications.

6.1.1 Wheeling Information Shared in Transmission Cost Tables

First, the participating IOUs would publish the best available pre-bid information regarding wheeling rates and loss factors in their transmission cost tables. This information would include current wheeling rates and line losses, but would not include costs for any necessary transmission upgrades. Although this information would not be binding for bid evaluation, QFs whose projects would require wheeling through any of the three participating IOUs' service territories would be able to review

35 Although SDG&E supports the concept of a short list approach, its proposal differs from that which we adopt. The primary distinction is that SDG&E proposes the QF, not the purchasing utility, should pay and arrange for wheeling. Therefore, under the SDG&E proposal, QFs will internalize the wheeling costs in their bid price and the purchasing utility will score all bids inside and outside its area by adding transmission costs for integration to the bid prices. Since we require the purchasing utility, and not the QF, to arrange and pay for wheeling service (see Section 6.2 below), we do not adopt SDG&E's proposal. We also do not adopt SDG&E's proposal that QFs can adjust their bids after the 90-day wheeling study is completed.

this information to obtain an economic signal of which site would best minimize transmission costs.

6.1.2 QFs Submit Bids

After PG&E, Edison, and SDG&E publish their bid solicitations, QFs will submit bids. In this interim program, the three participating IOUs have agreed to wheel the power of the auction winners. Therefore, bidders located in the participating IOUs' service territory will submit bids which do not contain upgrade or wheeling costs on a wheeling IOU's system. After the bidding period closes, the participating IOUs would determine a "short list" of potential winners requiring wheeling as set forth in Section 6.1.3 below.

Because of the limited scope of the interim program, the other California IOUs (i.e., PacifiCorp and SPPC), California municipal utilities, and out-of-state utilities are not publishing transmission cost tables and are not otherwise participating utilities in the interim program. Therefore, a bidder located outside the participating IOUs' service territory would internalize transmission costs for service outside the three IOUs' service territory into its bid.

The California municipalities, PacifiCorp, and SPPC have actively participated in and contributed to this proceeding to date. We invite their continued cooperation in Phase Two. We also anticipate that they will work cooperatively with the participating IOUs in supplying cost data regarding the short list and in facilitating prompt wheeling services for winning bidders through their service territories pursuant to appropriate terms and conditions.

The joining parties, as well as Edison, propose that QFs located outside the service territory of one of the participating IOUs would arrange for transmission service to the border of the participating IOUs' service territory. This proposal is acceptable with one modification. The FERC order in the merger of PacifiCorp with Utah Power & Light provides that PacifiCorp is to provide wheeling to public utilities, but is not required to provide firm transmission service to QFs. (See Section 6.2 below.) Therefore, we find that either the purchasing utility or the QF (or in appropriate cases, both) may arrange for transmission service to the border of the three IOUs' service territory.[36]

What type of proof must a QF located outside of one of the participating IOUs' service territory offer the purchasing utility of the QF's ability to deliver its energy to the border of one of the participating IOUs' service territory? In D.89-02-017, addressing Standard Offer 2 contracts for SDG&E, we were confronted with this issue. In that case, the QFs noted they were in a "Catch-22" situation, where SDG&E required, as a condition precedent to their signing a standard offer contract, proof of their ability to deliver their energy to the point of interconnection. At the same time, the wheeling utility was likely to condition the signing of a wheeling agreement on proof of an executed power purchase contract. In D.89-02-017, we allowed wheeling arrangements to be finalized within six months after the power purchase agreement was executed, provided this obligation became an additional milestone under the QF Milestone Procedure. We also apply this holding to this interim program for QFs located outside the participating IOUs' service territory.

6.1.3 Purchasing Utility Scores Bids and Submits Short List to Wheeling Utility

After conclusion of the solicitation period, the purchasing utility will tentatively score bids. The utility will determine the bid score of a QF which requires wheeling through the

36 However, these bidders would still internalize costs for transmission service outside the participating IOUs' service territory in their bids.

service territory of any of the participating IOUs, by adding to each bid the current wheeling rate and line losses on the wheeling utility's system (as published in the wheeling utility's cost tables), as well as the published transmission upgrade and line losses on the purchasing utility's system. The purchasing utility would not add to the bid any transmission costs through non-participating utilities' service territories, as those costs should be internalized by the QF.

The purchasing utility will then prepare a short list consisting of potential winning bidders from outside its service area whose bid scores are less than those of the potential winners in its own service area.[37] (The potential winning bidders from within its service territory are the bidders with the best bid scores, whose cumulative size matches the size of the IDRs.)

The purchasing utility then submits the short list to wheeling utilities. At the same time, the purchasing utility requests and pays for expedited studies from wheeling utilities to determine estimated upgrade costs and wheeling charges required to wheel power from the short list of bidders. These studies should be conducted as expeditiously as possible, not to exceed 90 days.

All parties agree that full cost allocation of upgrades, less system benefits, will be attributed to the QF in bid evaluation for wheeling. Although we have reservations regarding full cost allocation (see Section 5.4), we adopt the parties' recommendation here, as it will provide a useful comparison of the two methodologies before we institute a permanent program. The

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37 Edison recommends that it create a short list for all "potential or marginal" winners. We prefer the definition of the joining parties since it more specifically defines such winners.

wheeling utilities then submit these estimates to the purchasing utility.

6.1.4 Purchasing Utility Selects Winning Bidders and Finalizes Upgrade Costs with Wheeling Utility

The purchasing utility will add to the QF bids the transmission costs from wheeling, as provided by the participating IOUs, as well as those costs associated with integration. It then selects the winners from both in-area and out-of-area QFs.

Finally, the IOUs would determine through a detailed study exactly what upgrades are required to wheel the winning bidders. The results of this study would be reflected in the Interconnection Report discussed in Section 7 below. The IOUs would allocate upgrade costs, less demonstrable system benefits, to the purchasing utility. Once the cost-sharing agreement is finalized, the IOUs would file it with the FERC for approval, if necessary.

We agree with the joining parties that the wheeling upgrade cost estimates provided by the wheeling utility in the short list process are not binding with respect to final cost allocation between the utilities.[38] However, in the absence of changed circumstances, the Commission's approvals of the costs set forth in the Interconnection Report should have preclusive effect in subsequent proceedings. In their agreements with each other (see Section 6.4) the participating IOUs should also provide for the contingency of actual upgrade costs being higher or lower than those set forth in the Interconnection Report, consistent with, inter alia, PU Code § 1005.5.

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38 However, wheeling upgrade cost estimates determined by the short-list approach are binding for bid evaluation.

We do not determine how the participating IOUs should resolve at what point cost estimates become binding for the interim program, but will leave it for the IOUs to negotiate. However, we believe it is reasonable to provide incentives for a wheeling utility to prudently plan and construct an upgrade necessary for wheeling. Therefore, we will explore in Phase Two the merits of limiting a purchasing utility's obligation for upgrade costs to those approved by the Commission in the Interconnection Report.

6.1.5 The Short List Approach is an Interim Departure from Our Long-Range Goal of Transparency

The short list approach is an interim departure from our long-range goal of transparency. Destec supported the joining parties' short list approach, but cautioned that this process could result in uncertainties and delays in bid evaluation. For example, a wheeling utility's 90-day study for the purchasing utility may hinge upon upgrades resulting from the list of winners the wheeling utility is likely to select in its own auction. In such a situation, if the wheeling utility awaits the results of a 90-day study from the purchasing utility before providing the results of its own study to the purchasing utility, and vice versa, an infinite loop could occur where neither one of the utilities would be able to choose its list of winners. A participating IOU should not await the results of another IOU's 90-day study to perform a requested 90-day study, but should conduct its own study upon request, using the best available information consistent with its own planning assumptions, and expressly noting contingencies where appropriate.

Although Destec supported the joint testimony, it alternatively proposed that we adopt pro rata cost allocation for bid evaluation in wheeling similar to the approach we adopt for integration. Edison and PG&E believe that adopting pro rata cost allocation for wheeling would impose risks on the wheeling utility's ratepayers which should more appropriately be borne by the purchasing utility's ratepayers. They emphasize that the short list approach will avoid any subsidization of the purchasing utility's ratepayers by the wheeling utility's ratepayers.

We are not necessarily convinced by Edison and PG&E. However, since this transmission program is a new endeavor for all parties, we believe that there are benefits in adopting a different method for bid evaluation for wheeling as opposed to integration. By monitoring the results of each method, we can learn from and compare the relative benefits between the two approaches before we enact a permanent program.

However, we reaffirm D.91-10-048 that, for a permanent transmission access program, we envision that transparent information would be available to all bidders irrespective of whether they happen to be located within or outside of a purchasing utility's service territory. We do not believe that pre-bid information for wheeling between IOUs would be difficult to provide. PG&E, Edison, and SDG&E can only wheel power to each other on specific paths. These IOUs should be able to provide information regarding existing capacity, losses, and costs of upgrades for wheeling on those paths in their transmission cost tables, at least within a reasonable range.

For example, the wheeling utility could publish in its transmission cost tables a band around the point forecast of wheeling costs. In this example, a party paying for the wheeling costs would bear cost overruns up to the high end of the band, while the low end of the band would be a minimum price.

Furthermore, as we stated in D.91-10-048, a wheeling utility's ratepayers may be willing to incur the risks associated with inaccurate estimates of costs of upgrades required for another utility in return for the benefit of receiving wheeling service and associated upgrades on the other utility's system. Edison expressed concern with this thesis because Edison anticipates a disproportionate distribution of QFs who will require wheeling among the three IOUs for this bidding cycle. The record does not justify this concern, and we will not know the distribution of winners until we know the results of the auction. However, regardless of whether Edison's concern has validity in the short term, it is put to rest by the short list approach we adopt today. In the long term, we believe that all of the IOUs will have an equal chance of benefiting, and that the rewards and penalties of such risk sharing among the IOUs will be shared equally among the ratepayers of the three IOUs.

In D.91-10-048, slip at 20-21, we recognized that it may at some point be appropriate to allow transmission owners to make money on wheeling service.

> "For example, potential profits from wheeling service would give transmission owners incentives to plan their transmission systems with regional needs in mind, to explore ways to operate their systems to accommodate more wheeling and wheeling-type service, and to market the service creatively and aggressively."[39]

We also stated in that decision that we are taking a broad look at incentive regulation initiatives for electric utilities in I.90-08-006. However, it is important to note here that in order for a transmission market to operate efficiently, shareholder risks and benefits should be commensurate. Therefore, a wheeling

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39 D.91-10-048 also noted that it was premature to explore transmission service incentives when we were "still grappling with the basic problem of providing meaningful access to firm wheeling service at cost-based rates," recognizing that until that problem is solved, "'incentives' may result simply in the transmission owner being able to exercise market power." (Id.)

utility's shareholders should be willing to incur some level of risk associated with inaccurate upgrade estimates for wheeling if they are allowed to earn potential profits from offering wheeling service.

6.1.6 Attribution of Costs When Upgrades Are Used for Both Wheeling and Integration

DRA proposes that when upgrades are used for both wheeling and integration, the costs of excess capacity be allocated between the purchasing utility and the wheeling utility based on relative use of the upgrade. In the DRA example, a utility is wheeling the power from a 75 MW QF for another utility and integrating a 25 MW QF for its own use. A 200 MW upgrade is built, leaving 100 MW of unused capacity. DRA recommends that both the wheeling utility and the utility purchasing the wheeled power pay for the 100 MW of excess capacity. DRA recommends the wheeling utility should pay for 25% of the excess capacity because it is integrating the 25 MW QF, and the purchasing utility should pay for 75% of the excess. DRA argues that unless the wheeling utility bears some costs, the wheeled QF might be allocated an excessive amount of the cost of the upgrade and lose the bid of the purchasing utility. This would leave the wheeling utility worse off, according to DRA, because it would then have to bear the full costs of the line for integration purposes. PG&E disagrees with DRA's cost attribution.

We reject DRA's proposal. In this interim program, we have adopted policies allocating transmission costs for bid evaluation which attempt to reflect the costs utilities incur for interconnecting both integration and wheeling QFs. (See Sections 5 and 6 above.) Any other approach, including the DRA recommendation, is a significant departure from these policies. Further, DRA has not provided evidence that this problem is significant and therefore justifies such a departure from our adopted policies. We remind DRA and other parties that this is an interim program and, if experience demonstrates the significance of this problem, we are prepared to make adjustments.

6.2 Purchasing Utility Arranges and Pays for Wheeling Service

All parties addressing the issue of who should arrange and pay for wheeling service, with the exception of SDG&E, agree that the purchasing utility should have this responsibility.[40] SDG&E, however, argues that the QF should do so.

In D.91-10-048, we reasoned that the purchasing utility should arrange and pay for wheeling service. The parties have offered convincing testimony that we should reaffirm this policy. We are not persuaded to the contrary by SDG&E.

Placing this responsibility on the purchasing utility is the most workable and efficient method to negotiate wheeling arrangements. It is also consistent with the needs and obligations of the various parties affected by the wheeling transaction.

> "The seller primarily needs assurance that it can deliver its output into the transmission grid whenever it is entitled to make such delivery under its power purchase agreement. The question of when and how this output gets to the purchasing utility's load center, on the other hand, is the primary concern of the purchasing utility, whose resource needs are being met. The purchasing utility may not need firm wheeling service at all times; it may be able to work out exchanges with the wheeling utility that capture efficiencies for both. The seller may not know about such possibilities and is certainly not in a position to work out such arrangements." (D.91-10-048, slip at 15-16.)

40 NCPA did not directly address this issue. However, NCPA states that the WATSCO draft by-laws include a provision that the entity which requests wheeling service (whether a QF or IOU) pay the "actual costs" of transmission upgrades. (See draft of WATSCO by-laws, attachment to Exhibit 5 at page 15.) Vernon did not specifically address this issue.

Furthermore, we agree with PG&E that since all three participating IOUs will ultimately be "purchasing utilities" in wheeling transactions, placing this responsibility on the purchasing utility provides incentives for the IOUs to develop a common understanding of transmission cost allocation in the building of an upgrade. SDG&E argues, and we fully expect, that a purchasing utility will negotiate as vigorously as a QF would in determining the cost allocation of an upgrade to be used for wheeling. However, since each IOU will at some point be a purchasing utility and a wheeling utility, the IOUs should be in a similar bargaining position vis-a-vis each other.[41]

Our holding is consistent with the terms of the PacifiCorp transmission access program imposed by the FERC. In its approval of the PacifiCorp merger agreement, the FERC mandated that PacifiCorp provide firm wholesale wheeling to public utilities, but expressly stated that PacifiCorp was not required to provide such transmission service to QFs. The FERC stated that the utility

41 SDG&E requests that we take official notice of certain utility and QF 1991 lobbying expenses to the legislature reported to the Secreatary of State. SDG&E argues that these expenditures constitute evidence of the QF industry's superior bargaining position. This argument is irrelevant. SDG&E's alleged evidence of the amount of the QF industry's lobbying expenses is not relevant or probative on the issue of whether utility-to-utility or a host of QF to utility negotiations would best facilitate access to wheeling for winning bidders. Therefore, SDG&E's motion is denied.

purchasing the QF power may itself obtain access under the transmission conditions in order to reach the QF.[42]

SDG&E is primarily concerned with risk allocation, e.g., what party should bear the risk of the cost of an upgrade if it is higher than estimated or of a "stranded" upgrade if a QF project does not materialize for whatever reason.[43] SDG&E opposes having the risks placed on the purchasing utility's ratepayers or shareholders, and argues that a better allocation would place these risks on the QF.

We disagree. SDG&E's proposal places the risk directly on the ratepayers of the wheeling utility. Under SDG&E's premise, in the event a QF project does not materialize, the wheeling utility, not the QF, bears the ultimate responsibility for these costs. However, the upgrade is to be constructed for the ultimate benefit of the ratepayers of the purchasing utility. Therefore, we agree that to the extent these risks exist, it is more equitable that the purchasing utility's ratepayers bear them.

It is important to note that our interim program contains various ratepayer protections which help avoid unnecessary expenditures in order to minimize ratepayer risks. For example,

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42 Utah Power & Light Company, PacifiCorp and PC/UP&L Merging Corporation, Docket No. EC88-2-007, 57 FERC ¶ 61,363 at 62191, Order on Remand from Environmental Action et al., v. FERC, et al., 939 F.2d 1057 (D.C. Cir. 1991).

43 The difference in positions between SDG&E and the other parties is more about risk allocation than who ultimately pays for the wheeling costs. Under the alternative preferred by most of the parties, the purchasing utility pays for the wheeling service; ultimately, these costs are paid by the purchasing utility's ratepayers. However, under SDG&E's proposal, the QF will include its transmission costs in its bid, and ultimately, the ratepayers of the purchasing utility will pay the transmission costs the QF internalized, which costs would be reflected in higher standard offer costs.

milestones for QF development should enable IOUs to avoid spending construction dollars for an upgrade until a QF achieves a certain level of viability. Furthermore, if a CPCN is required, obtaining a CPCN would be a milestone to further project development. (See Section 7 below for a more detailed discussion.)

Finally, it makes more sense for the purchasing utility, as opposed to the wheeling utility, to bear such risks since it is in a better position to mitigate risk if a QF project fails to materialize. The auction results will tend to show where upgrades are likely to be needed in the future. This is especially important in the wheeling context, where transmission systems are not currently planned with regional needs in mind. Thus, if a QF project did not materialize, the purchasing utility would need to replace the generation which was to be supplied by the QF. The purchasing utility would then have the option of arranging for cost-effective replacement generation, possibly using the upgrade which was intended for the original QF. Moreover, in the event that another utility were to utilize the upgrade paid for by the purchasing utility, the policies we adopt in Section 6.3 provide that the purchasing utility should receive appropriate benefits commensurate with its payments for the upgrades.[44]

SDG&E cites several examples of specific situations where it, or other IOUs, have contracted with QFs to obtain generation and the QF has arranged and paid for transmission service. SDG&E argues that because QFs have undertaken this responsibility in

44 Edison has proposed that a purchasing utility should pay the wheeling utility for transmission service for the full term of the transmission contract if the QF goes out of business, even if no upgrades are involved and transmission is provided from the wheeling utility's existing facilities. We view this argument as an unreasonable liquidated damages provision.

certain contracts, QFs should be responsible for arranging and paying for wheeling in our interim transmission program.

SDG&E's argument is not persuasive. In fact, the history of the QF contracts cited by SDG&E supports our holding that the purchasing utility should arrange and pay for wheeling service. The fact that a QF has been able to arrange for wheeling in some instances does not speak to the issue of risk on the wheeling utility's system, nor does that fact indicate how many transactions have not been pursued because a QF was unable to arrange for wheeling in instances where an IOU could have.[45]

Turning to several of the examples which SDG&E cites, the Standard Offer 2 contracts with Luz San Diego Solar Partners, Ltd. and Bonneville Pacific Corporation involved lengthy negotiations. These off-system QFs were found to be entitled to Standard Offer 2 contracts at least six months before D.89-08-031, at which point we had to extend the time for these off-system QFs to execute their agreements, in part because of transmission considerations. (See D.89-08-031, slip.) We expect SDG&E's Final Standard Offer 4 auction will involve many more than two off-system QFs, and that many of these QFs will be competing for service over the same transmission paths. Utility-to-utility negotiations should be simpler and easier to bring to fruition than a host of negotiations between the wheeling utility and QF bidders.

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45 SDG&E further supports its proposals by citing D.92-04-045, slip at 41, where we recognized that SDG&E's system has special transmission considerations. While it is true that we recognized that SDG&E has a much smaller and less varied service area than that of the other two participating IOUs, we also limited the size of SDG&E's solicitation, in part, in recognition of this factor. Furthermore, SDG&E's special transmission considerations should influence SDG&E to keep control over its own wheeling arrangements rather than to impose this critical responsibility on the QF.

Several other examples to which SDG&E refers, where QFs in Edison's and PG&E's service territory have agreed to build transmission facilities, either involve heavily contested matters (e.g., D.90-09-059; 37 CPUC2d 413) or settlements which necessarily contain compromises by all parties on a variety of issues addressed by the settlement.[46] Moreover, in several of the settlements, lack of timely assured transmission access was an underlying factor in the initial dispute. See D.91-02-044 [renegotiation of the power purchase agreement was necessary, in part, because the QF had to delay its on-line date while it arranged for suitable transmission]; see also D.90-08-046 [settlement where Edison had refused to execute several types of standard offer contracts because QF had not demonstrated to Edison's satisfaction that QF could deliver power from its projects, located outside Edison's service territory, to Edison].

We also disagree with SDG&E and DRA that QFs should provide additional security for upgrade construction. Since upgrades generally take less time to build than a QF project, the QF milestones should be sufficient to ensure that a QF is viable before the upgrade is constructed. The parties should examine the milestone procedures to see whether they need to be modified or augmented.[47]

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46 These examples involving settlements are of questionable probative value on this issue in light of Rule 51.8 of our Rules of Practice and Procedure, which provides that, unless we expressly provide otherwise, our adoption of a settlement does not constitute precedent regarding any principle or issue in the proceeding or in any future proceeding.

47 In its comments to the Proposed Decision, SDG&E states that it intends to reexamine the issue of whether the QFs should provide additional security when the parties examine the milestone procedures. However, we decide today that QFs should not provide additional security for upgrade construction. The parties should examine the milestone procedures with respect to timing, etc.

Finally, we disagree with SDG&E that the policy we adopt unconstitutionally burdens interstate commerce, in that it somehow gives an advantage to in-state, as opposed to out-of-state QFs. The policy we adopt today does not make this distinction. Under our interim transmission program, the participating IOUs have agreed to wheel power for winning QFs in the upcoming Final Standard Offer 4 auction, regardless of the generation's origin.

6.3 Ownership of Transmission Upgrades

6.3.1 Background

The issue of upgrade ownership arises primarily in the wheeling context.[48] For wheeling, the purchasing utility should arrange and pay for the wheeling service necessary to wheel a winning QF's power to the border of its service area. Since any necessary upgrades for wheeling will occur on the wheeling utility's system, the issue arises as to who should own the upgrades.

As we stated in D.91-10-048, slip at 31, the concern for recovery of the investment in an upgrade underlies much of this debate, especially when a lumpy upgrade is necessary:

> "Just as ratepayers should not subsidize the cost of wheeling service, the purchaser of such service should not subsidize the transmission system of the wheeling utility. Such subsidization could occur, e.g., if a purchaser pays the whole cost of an upgrade that would have been required (albeit at a somewhat later date) to serve the wheeling utility's ratepayers, or if the upgrade is used by subsequent purchasers of wheeling service without pro rata reimbursement of the original

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48 For integration, the purchasing utility should pay for the transmission upgrade necessary to integrate the QF from the first point of interconnection into the utility's system, and will own the upgrade. The QF will pay for and own necessary transmission to the first point of interconnection with the purchasing utility's system.

> purchaser. Such subsidization could prevent economically attractive power sales and chill the further development of competition in the electric generation market that wheeling service should promote."

The parties split on the issue of who should own the upgrades. The joining parties agree that the wheeling utility would own and control all upgrades built on its system to accommodate the wheeling of QF power, but that joint ownership of the radial lines which are not a vital component of the wheeling IOU's integrated network would be considered at the discretion of the IOU.[49] Edison and SDG&E agree to commit to joint ownership of new intertie transmission lines subject to the IOU receiving adequate compensation and the completion of appropriate contractual arrangements. However, they are unwilling to consider joint ownership over any part of the network, existing substations, or existing intertie facilities.

NCPA, Vernon, and the CEC disagree. The NCPA states that the draft WATSCO by-laws provide a definitive solution to the cross-subsidy problem which may arise when a purchasing utility pays for but does not own the upgrade.' This solution is that WATSCO members who financially participate in upgrades to be used for wheeling can either accept an ownership interest commensurate with their financial participation or accept a perpetual right to use firm transmission service and pay rates established in accordance with WATSCO principles. (WATSCO draft by-laws, attachment to Exhibit 5).

For the interim transmission program we adopt today, the NCPA proposes we adopt an ownership policy which would allow the

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49 The network generally consists of a utility's load center and other principal parts of a utility's electric system. Radial lines generally are those transmission lines linking generation to the network.

wheeling utility the first option to own and pay for the upgrade. If the wheeling utility did not elect this option, the purchasing utility would pay for the upgrade, but would have the option to enter into various arrangements (i.e., owner/leaseback, joint ownership, special facilities financing) with the wheeling utility, as long as the arrangement minimized transaction costs and allowed the purchasing utility to get ownership-like rights to transmission facilities, commensurate with its financial contribution. These rights would include the use of upgrade facilities and equitable compensation for use of lumpy portions of the transmission facilities.

Vernon agrees with the NCPA, and argues that parties which pay for the transmission upgrades should own them. Vernon suggests that one method to permit the purchasing utility to obtain the benefit for which it pays is to assign ownership of the increased transmission capacity to the purchasing utility, while permitting the wheeling utility to own the actual hardware.

The CEC concurs in the concepts advanced by NCPA and Vernon. The CEC urges the Commission to ensure that the purchasing utility, through whatever means are appropriate in a particular case, receives benefits commensurate with its payment for any modification to a wheeling utility's transmission system.

6.3.2 The Purchasing Utility Should Receive Benefits Commensurate With Its Payment for Upgrades or Other Modifications to a Wheeling Utility's System

In Section 6.2, above, we adopted the policy that the purchasing utility should arrange and pay for wheeling service, in part, to ensure that the wheeling utility's ratepayers do not subsidize the cost of wheeling service which would benefit the purchasing utility's ratepayers. Conversely, we believe the purchaser of wheeling service should not subsidize the transmission system of the wheeling utility, which could occur if a purchaser pays for a lumpy upgrade which is later used by another purchaser or the wheeling utility without reimbursement to the purchasing utility.

We agree with the CEC, and adopt the principle that the purchasing utility should receive benefits commensurate with its payment for upgrades and other modifications to a wheeling utility's system. We also agree with NCPA that these rights should include the use of upgrade facilities as well as equitable compensation for the lumpy portion of the transmission line in the event it is subsequently used by the wheeling utility or another user. However, the record is insufficient for us to mandate the type of right which the purchasing utility should receive, e.g., an ownership right, leaseback right, rights of assignment. For example, another alternative not advanced by the parties here but raised in D.91-10-048, slip at 32, is to provide the wheeling utility with reimbursement as in the case of line extensions. Therefore, for the upcoming auctions, we allow parties to the wheeling arrangements to negotiate solutions consistent with the policy we adopt today.

However, the parties should not discount the feasibility of some type of ownership right in equitably allocating the costs and benefits of upgrades. We do not agree that sole ownership of the transmission system is necessary to ensure reliability. As we recognized in D.91-10-048, some transmission lines are jointly owned and joint ownership is compatible with reliable operations, as long as a specific party has charge within the control area.

Moreover, we do not limit our policy to newly constructed intertie facilities, but to all modifications of the transmission facilities. Regardless of the interconnected nature of the network, we believe a purchasing utility should obtain a benefit commensurate with its payments. In fact, the parties generally agreed that the purchasing utility should be able to use the facilities it pays for on the wheeling utility's system, including lumpiness, or be compensated in some fashion therefore. (See e.g., Kritikson, RT 754-757; Linsey, Exhibit 4 at 16.)

According to the NCPA, other issues besides equitable cost allocation are tied into the ownership issue and the problem of upgrade lumpiness. First, the NCPA argues that the cost of transmission upgrades could be substantially increased if the purchasing utility may have to pay the contribution-in-aid-of-construction tax of the wheeling utility, and this cost increase would serve as a disincentive for expanding California's transmission system.[50] Second, the NCPA argues that when the purchasing utility pays for but does not own the upgrades, neither utility earns a rate of return, since the purchasing utility does not earn a return on its contributions as it cannot ratebase its investment in facilities it does not own, and the wheeling utility cannot ratebase facilities which are contributed. If wheeling service must be provided at cost, and a return is not allowed on facilities allocated to such service, then the risks of wheeling may be disproportionate to potential gains. Finally, the NCPA argues that the above factors work against our goal of encouraging competition, because they create a disincentive for a utility to purchase power which has to be wheeled.

Unfortunately, only the NCPA thoroughly addressed these issues. Given the importance of these issues in facilitating competition in the marketplace, we will address the ownership issues in depth in Phase Two. Among other things, we want to explore various methods to better ensure that upgrade costs are properly allocated and to eliminate disincentives to the

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50 According to the NCPA, if the wheeling utility owns the upgrade, the purchasing utility may have to pay a CIAC tax that is equivalent to the federal income tax rate of the wheeling utility times the amount of the upgrade contributions of the purchasing utility.

construction of cost-effective transmission capacity. Finally, as part of our monitoring program, the IOUs should report to us what arrangements they make to provide a purchasing utility with benefits commensurate with its payment for upgrades or other modifications. This information will be useful in Phase Two where, for example, we may develop a menu of such options for the permanent transmission program.

6.4 Wheeling Arrangements Among the Three IOUs

The parties differ on the issue of whether to accomplish the wheeling of QF power by a tariff of general application, contracts negotiated on a case-by-case basis, or a standardized three-party IOU contract.

The joining parties propose that the three California IOUs should negotiate and file with FERC a three-party IOU transmission service agreeement.[51] PG&E envisions a single master contract signed by the three IOUs which would govern the rates, terms, and conditions of transmission service for the winning QFs in the Update solicitation. PG&E recommends that this contract be negotiated as soon as possible, and not later than the solicitation for the ER-92 based bidding cycle, which it expects in 1994.

Edison concedes that a master agreement may have merit in the long run, but asserts that negotiations cannot be accomplished

51 The joining parties propose that the contract would specify, among other things: (1) the FERC rate applicable for service; (2) a mandatory binding dispute resolution process; (3) cost allocation rules for upgrades and a process for determining and allocating system benefits associated with upgrades; (4) operational requirements; (5) cancellation; (6) QF milestones to be completed before the obligation to build upgrades kicks in; (7) a table of transactions to be amended each time a new service is provided; and (8) a provision that QFs receiving service under the contract are express third party beneficiaries which may enforce the contract. (See Joint Testimony, paragraph II.4 at page 7-8.)

in time for the upcoming solicitation. In its post-hearing brief, Edison also states that since Edison, PG&E, and SDG&E have each agreed to wheel QF power acquired in the upcoming bid solicitation to either of the other two participating IOUs, it is not necessary for us to adopt a policy favoring one form of agreement over another. SDG&E favors that the QF should be responsible for arranging transmission service, and that when necessary, individual wheeling contracts should be executed accordingly. No party recommends tariffed service for the interim program.

In D.91-10-048, slip at 28, we stated our preference for tariffed service, because the competitive generation market requires greater speed and certainty than would be possible where wheeling arrangements for many of the participants had to be worked out on an ad hoc basis. We stressed that when we evaluated the quality of the wheeling service provided, an important aspect of this evaluation would be to determine how easy it is for the customer to get that service. We also conditioned our decision on whether or when to adopt all-source bidding, in part, on the ease and assurance of transmission access resulting from this investigation.

Although we do not change our opinion on the suitability of tariffed service for our permanent program, we are persuaded that wheeling tariffs cannot be produced in time for this auction. Therefore, some type of contractual relationship to implement wheeling among the three IOUs may be necessary. However, we are also persuaded by Edison that we need not decide at this juncture the specific form by which the IOUs accomplish this. The participating IOUs have agreed to wheel QF power acquired in this auction to each other. We will leave it to the IOUs to accomplish that wheeling by the most appropriate method for this interim program.

In rejecting the proposal that wheeling be exclusively accomplished by means of a three-IOU contract, we are placing substantial reliance upon the utilities' representations (especially Edison's and SDG&E's) that alternate approaches are in fact feasible to implement in a timely fashion.[52] We therefore require the three IOUs to finalize wheeling agreement(s) with each other as soon as possible. What we are talking about is an initial agreement, or agreements, which are not project specific, and which should be made by the utilities well in advance. We recognize that additional project specific agreements will be made at the appropriate time. Within 90 days after the auction winners are announced, the participting IOUs are to make a joint filing in this investigation, served on all parties, which either appends the agreement(s) or indicates when the agreement(s) will be forthcoming and the impediments to their finalization.[53]

Because of this requirement, we reject DRA's proposal that we decide at this time that the IOUs should bear any liability of the contract negotiation and approval in the event a QF cannot deliver power to a purchasing utility because contract negotiations reach an impasse. Pursuant to the requirements set forth above, the IOUs should conclude their wheeling arrangements with each other before the QFs incur substantial project costs.

SDG&E proposes that a purchasing utility should be able to terminate a Final Standard Offer 4 contract which requires wheeling by a participating utility if the utilities are unable to obtain any necessary FERC approvals for the utility-to-utility

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52 In fact, Edison asserts that our transmission access concerns for the Final Standard Offer 4 auction have been resolved. (See Edison's Petition dated May 26,1992, to Modify D.92-04-045 and D.91-06-022 in the Update at 5; see also SDG&E's Reply to Edison's Petition at 2, dated June 10, 1992.) We reserve judgment on this assertion and on the various requests made in Edison's petition, which will be addressed in the Update.

53 We understand that such agreement(s) may subsequently have to be approved by the FERC.

wheeling agreements. We believe that if FERC approval of such agreements is necessary, and if both the purchasing and wheeling utilities, acting in good faith, with due diligence, fail to obtain FERC approval, the purchasing utility should first attempt in good faith to renegotiate the contract with the QF. If that option fails, either party should be allowed to terminate the Final Standard Offer 4 contract, and the QF should obtain reimbursement of its project fee. For these reasons, the utilities should seek any necessary FERC approvals at the earliest opportunity. We also fully expect the utilities and QFs to actively cooperate in attempting to obtain any necessary FERC approvals. (See also Section 7.3 below.)

7. Ratepayer and Shareholder Protections

Under the transparent approach we adopt today, the transmission costs applied to the bidders' score for bid evaluation are proxies (for PG&E) or preliminary engineering estimates (for SDG&E and Edison). However, once the winning bidders are announced, the utility will determine the most cost-effective method to interconnect and integrate winning bidders. These costs may be higher or lower than the costs used for bid evaluation. This is so for two reasons. First, the costs used for bid evaluation are estimates, and are intended to provide a fair method, without systematic bias, for evaluating the transmission costs of bidders. Second, once the package of winning bidders is known, there may be more cost-effective ways to integrate the package than the individual transmission routes assumed for bid evaluation purposes.

Under the short list approach we adopt for wheeling (see Section 6.1 above), wheeling utilities will perform a post-bid study of the estimated wheeling costs for potential winners in a purchasing utility's auction, so that a purchasing utility can evaluate the potential winners' wheeling costs before ultimately selecting the winners. However, the results of the wheeling utilities' study are not binding with respect to final cost allocation between utilities, and the actual wheeling costs may be higher or lower than estimated, for the reasons set forth above for integration. Furthermore, QFs requiring wheeling may have integration costs (i.e., transmission costs on the purchasing utility's system) as well as wheeling costs.

All parties addressing the issue generally agree that ratepayers, as opposed to shareholders, should be required to bear all prudently incurred costs of the most cost-effective transmission project necessary to interconnect and integrate winning bidders for integration.[54] Similarly, all parties except SDG&E agree with this policy in a wheeling context. SDG&E appears to disagree, to the extent that it argues that the QF, not the purchasing utility, should arrange and pay for the wheeling service. However, this position, which we reject, merely shifts

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54 No party disagreed with the joining parties' proposal regarding ratepayer and shareholder protections:

> "Transmission projects and costs associated with a winning bidder shall be deemed needed and reasonable in accordance with the following principles. Winning QF bidders selected through a transparent bidding system approved by the Commission shall be deemed reasonable and needed in all subsequent reasonableness reviews. Ratepayers shall be required to bear all of the costs of the most cost effective transmission project necessary to interconnect and integrate winning QF bidders. The Commission may review the reasonableness of the IOU's choice among possible transmission projects which would adequately integrate the winning QF. The Commission may review the reasonableness and the prudence of the costs incurred in developing a transmission project for a winning QF bidder, however, IOU shareholders will not be required to bear the prudently incurred costs associated with transmission upgrades that are required to accommodate winning bidders." (Exhibit 1 of Exhibit 1 at 5, paragraph I.8.)

the risk from the purchasing utility's ratepayers to the wheeling utility's ratepayers. (See Section 6.2 above.)

Even with the ratepayer protections we adopt below, we cannot mitigate all possible risk to the ratepayers if prudently incurred actual costs of the transmission upgrades are higher than estimated. However, since generation costs are usually much higher than transmission costs, we believe that our policies appropriately place the risk on the least expensive part of the equation. (See Section 5.4.2 above.)

Our Update process is intended to select auction winners with the lowest total cost. Because ratepayers stand to benefit from this selection, we find it reasonable that ratepayers also bear some risk of imprecise upgrade estimates. These ratepayer risks are also mitigated by requiring the utility to minimize actual upgrade costs by interconnecting the auction winners with the most cost-effective package of transmission winners. We discuss the parameters of the policies we adopt below.

7.1 Final Standard Offer 4 Contracts Should Be Treated the Same as All Standard Offer Contracts in Subsequent Reasonableness Reviews

Our decision today establishes that using the transparent approach in integration is a reasonable and prudent method for evaluating transmission costs for selecting winners in the upcoming Update auction, and that the short list approach is similarly appropriate in the wheeling context. A Final Standard Offer 4 contract should be treated the same as all other standard offer contracts in subsequent reasonableness reviews. For example, all payments made pursuant to a correctly administered power purchase agreement under any standard offer are reasonable. Moreover, utilities are required to fulfill their obligations under such contracts in a reasonable manner.

7.2 Utilities Should File An Interconnection Report

Any ratepayer risk which may be associated with these transmission policies can be mitigated, in part, by requiring the utility to minimize actual upgrade costs by interconnecting the auction winners with the most cost-effective package of transmission upgrades. Therefore, we agree with PG&E that the IOUs should be required to file with the Commission an Interconnection Report in this investigation describing the upgrades necessary to accommodate winning bidders.

Notice of availability of this report should be served at the time of filing on the parties to this investigation. This report should address the most cost-effective package of upgrades necessary, and should include both upgrades necessary to integrate generation into a utility's system and to wheel generation to another utility's system. The report should also compare the package of upgrades used for bid evaluation purposes to the preferred package, if different.

The utility should submit its Interconnection Report to the Commission as soon as possible and in no event later than 180 days after the auction winners are announced. The Commission may then make appropriate findings regarding the Interconnection Report. In the absence of changed circumstances, these findings should have preclusive effect in subsequent proceedings.[55] The Commission's review of the Interconnection Report is to ensure winners are interconnected by the most cost-effective package of upgrades. However, this Commission review does not affect the designation of bid winners, nor is any aspect of the Final Standard Offer 4 contract affected by the review.

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55 It is unnecessary for us to determine at this time if or how the provisions of PU Code $ 1005.5 affect this process.

In its comments to the Proposed Decision, DRA expressed its concern that any interim findings of need for a proposed specific upgrade may violate the California Environmental Quality Act (CEQA). It is an open question whether our approval of the Interconnection Report, which we intend to have a preclusive effect with respect to the cost-effectiveness of the proposed package of upgrades, would require CEQA compliance. Of course, there will be CEQA review in the context of individual transmission project CPCN proceedings, but the Interconnection Report could be seen as an early project "stage." (See e.g., State CEQA Guidelines, 14 Cal. Code of Regulations, § 15167 (Staged Environmental Impact Report).) We direct that this issue be addressed in Phase Two.

7.3 Failure to Obtain a CPCN

PG&E recommends that a utility should be able to terminate a Final Standard Offer 4 contract if it fails, under certain circumstances, to obtain a CPCN. Specifically, PG&E recommends that a utility could terminate a Final Standard Offer 4 contract if it acts without negligence or fault, and with due diligence in timely applying for and pursuing a CPCN for a transmission upgrade in order to integrate a winning bidder, and fails to obtain the CPCN. Edison and SDG&E generally support PG&E's recommendation.

IEP/GRA and Destec disagree. They argue that this type of "off ramp" provision will make QF financing difficult, if not impossible to obtain. Alternatively, they argue that if we adopt this proposal, we should also require utilities to apply for any necessary CPCNs as soon as possible, and that QFs should be reimbursed for all expenses they have incurred up to the point of the utility's failure to obtain a CPCN.

We recognize that winning the auction is not a guarantee that the QF will obtain all necessary permits. Similarly, it is not a guarantee that we will issue all necessary CPCNs. For example, the CPCN proceeding not only addresses need and cost-effectiveness issues regarding the upgrade,[56] but also environmental concerns.[57] If, in the CPCN proceeding, we determine that environmental concerns impose cost-prohibitive measures on an upgrade (such as re-routing a significant portion of the line) we may deny a CPCN.

If a CPCN for a necessary upgrade is denied, we believe that the participating IOU and the QF should first have the opportunity to renegotiate the contract in lieu of terminating the contract, as certain other options short of terminating the contract (e.g., relocating the transmission line or the QF project, renegotiations on payment provisions) may be mutually agreeable and in all parties' best interests.

We agree with IEP/GRA that a utility should apply for a CPCN at the earliest opportunity, before QFs incur substantial project costs, and before the QFs' contractual deadlines for obtaining permits and financing. We also agree with Edison that the actual construction of the upgrade should not begin until the IOU is assured of the QF's viability. We direct the parties to reexamine the milestone procedures to see whether milestones relating to integration and wheeling should be added or modified.

We envision that both the purchasing and wheeling utility would timely file for and pursue any necessary CPCN application(s), and would act in good faith with due diligence in so doing. If, in an integration situation, a purchasing utility does so, fails to obtain any necessary CPCN, and attempts in good faith to

56 See Section 7.2 above.

57 Need and cost-effectiveness of the winners are resolved by the auction process itself. The cost-effectiveness of the package of upgrades is resolved in the Interconnection Report.

renegotiate the contract with the QF but is unable to do so, we agree that the Final Standard Offer 4 contract can be terminated by either party. The same termination provisions should apply for wheeling, if the wheeling utility fails to obtain any necessary CPCN for an upgrade necessary to deliver power from a winning QF to another IOU, and the purchasing IOU attempts in good faith to renegotiate the contract but is unable to do so. In these events, we believe it is sufficient that a QF recover its project fee. We do not agree that a QF should be compensated for its expenses. The risk of not obtaining a CPCN is part of the risk of doing business for the QF.

It is important to note that the CPCN process we describe creates incentives for both the utility and the QF to engage in active communication with each other from the outset. Entering into a Final Standard Offer 4 contract is the beginning of a long relationship between the two parties. We envision communication between the parties and active participation by the QF, as well as the utility, in the CPCN proceeding.

7.4 Other Proposals

DRA, SDG&E, and Edison would allow utilities to renegotiate or terminate contracts with winning bidders if the actual costs of transmission result in an overall cost which exceeds that of the lowest losing bidder by some large amount (DRA says 10%). If the contract is terminated, DRA proposes that the utility return the QF's project fee and also pay for actual development costs incurred up to two percent of the capital cost of the bid price.

No other party supports these recommendations. IEP/GRA voiced the same financing concerns as they did on PG&E's "off ramp" proposal for failure to obtain a CPCN. IEP/GRA, together with Destec and the CEC, also argue that DRA's after-the-fact evaluation of bidders may leave a hole in a utility's resource plan several years after resources have been selected. A lowest losing bidder may then not be available to replace the winning bidders, thus causing the ratepayer to pay higher prices for substitute generation. Finally, parties argue that the DRA evaluation is faulty because it compares the actual costs of the winning bidder with the estimated pre-bid costs of the lowest losing bidder -- an "apples and oranges" comparison.

We reject the DRA proposal for these reasons, and also because it adds a layer of uncertainty on an already complex process. (This same reasoning also applies to the SDG&E and Edison proposals.) We believe that the method we adopt today strikes the proper balance among ratepayer and shareholder protections.

We also reject, for this round of bidding, Edison's proposal that if an upgrade is built to accommodate multiple winners and one winner does not achieve certain contract milestones, that the utility should be able to terminate the contract for the remaining QFs.[58] This proposal causes too much uncertainty in the auction process, and may result in higher ratepayer costs to replace these resources at a later date. Furthermore, the fact that more than one winner utilizes the same upgrade suggests that this upgrade is linked to an area with resource development potential. Thus, any excess transmission capacity which may result from one winner failing to achieve certain milestones will probably be used by the utility or other QFs quickly.

58 In its written testimony, Edison also proposed that ratepayers should absorb the risk if the utilities' transmission costs set forth in the CPCN proceeding differ from the actual costs. During cross-examination, Edison's witness Kritikson stated that Edison was not proposing to overturn the prudency review process. We agree that no changes of our prudency review process need be made for situations where the costs set forth in the CPCN proceeding differ from actual costs.

8. Renewable Bidders Should Not Be Given Preferential Access to the Lowest Cost Transmission

In D.92-04-045, slip at 22-23, issued in our Update proceeding, we stated that since our methodology does not yet quantify the value of fuel diversity, the provisions of newly enacted PU Code § 701.3 require us to "set aside" a portion of generating capacity for renewable resources in the upcoming bid solicitation. We then delineated a renewable set-aside for each utility.

As a "supplement" to the joining parties' testimony, DRA proposes that bidders for renewable set-asides have preferential access to the lowest cost transmission at a given substation up to the level of the renewable set-aside.[59] DRA states that its proposal would minimize total resource costs of QFs selected in an auction with set-asides. DRA states that if the lowest cost transmission were attributed to the lowest cost bidders, some QFs could displace the renewables competing for the set-aside at a particular interconnection point. DRA further states that since renewables are constrained to certain locations, renewables in such a situation could be assigned the cost of a significant transmission upgrade if they could not gain access to existing transmission capacity. In that case, DRA argues, renewable bidders would be attributed a higher transmission cost, with a resulting increase in the costs of the set-aside. DRA believes that the increase in the cost of the set-aside bidders would outweigh the reduction in cost of the other QFs, resulting in an overall

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59 Although DRA states that this proposal is a supplement to the joint testimony, DRA's proposal here contradicts the testimony which the joining parties (including DRA) advocate, namely, when multiple QFs bid at one substation, the lowest price bidder should be allocated the lowest transmission costs for bid evaluation.

resource plan which would cost the ratepayers more than it needs to.

All other parties addressing this issue oppose DRA's proposal. Destec and Texaco argue that granting renewables preferential treatment would preclude selection of the lower-cost non-renewable projects, thus leading to higher costs to ratepayers. PG&E states that DRA's proposal, depending on the assumptions regarding bidders, could result in the selection of a higher-cost portfolio of winners than if the lowest cost bidder at a given substation (excluding transmission costs) were allocated the lowest cost transmission at that substation. IEP/GRA's witness Branchcomb describes DRA's proposal as ill-conceived, as there is no evidence that a renewable set-aside would increase ratepayer costs. Edison opposes DRA's proposal as unsupported by analysis, and argues it would lead to increasing complexity in bid evaluation.

In Section 5.3 above, we adopt the policy advocated by all parties (including DRA) that when multiple QFs bid at one substation, the lowest price bidder should be allocated the lowest transmission costs. We agree that this policy should benefit the ratepayers by leading to the selection of the resources with the lowest total costs. DRA has not established that an exception to this policy -- granting renewables bidding for the set-aside the lowest cost transmission -- will decrease the total cost of resources acquired in the auction. In D.91-10-048, slip at 27, we stated that our decision to pursue renewable resources "must rest on a full recognition of their costs, along with their benefits." Since this interim transmission program will be a learning experience for all concerned, we believe that a policy of ascribing the lowest transmission costs to the lowest cost bidder will best enable us, at this time, to assess the total costs of competing resources.

Finally, in Section 5.2, we also adopt a policy of allowing bidders for a single IDR to submit multiple interconnection site bids, to a maximum of three busses. This policy of allowing all bidders (renewables and non-renewables alike) to submit multiple bids should increase the likelihood of bidders being attributed the lowest transmission costs at a given site, and the most cost-effective package of resources being selected.

9. The Verification Process

9.1 Background

In a February 28, 1992 ruling, the assigned ALJs directed the participating IOUs to publish their draft transmission cost tables on March 27, 1992. (See Section 2.3.2 above for a description of the draft transmission cost tables.) The February 28 ruling also directed the three IOUs to serve a notice of availability of the draft tables on the service lists (including information only lists) of this investigation and of the Update, and to widely distribute the notice of availability in relevant trade journals, etc. The three IOUs have done so.

The February ruling also directed the Commission Advisory and Compliance Division (CACD) to schedule verification workshops for the participating IOUs to answer questions regarding the derivation of the tables and the methodology underlying the transmission costs set forth in the tables. The ruling further instructed CACD to develop with the parties an understanding of the verification process and what it entails, and to conduct the verification process concurrently with the April policy hearings.

CACD has held verification workshops on April 8, April 22, May 18, June 26, and July 15, 1992. Further workshops are scheduled.

In the verification workshops so far, the parties have had an opportunity to examine the draft transmission cost tables and to question their derivation. They have also had an opportunity to determine if the tables appear reasonable for use in bid evaluation in the upcoming Update solicitation. We understand that the parties have come to tentative agreements in many areas.

A June 24, 1992 ALJ ruling directed that the report resulting from the verification workshops contain a list of specific agreements which the parties have reached regarding the reasonableness of the draft transmission cost tables. For example, all parties may agree, without endorsing a utility's transmission costing methodology per se, that the results set forth in the tables appear reasonable. In addition, the June 24 ruling also directed the participating IOUs to verify at the workshop that the transmission cost tables are derived from a set of inputs and algorithms or methodologies which are consistent with their own planning processes. Such verification would be duly reported in the workshop report. The ruling envisioned that if all parties to the verification process find the draft tables reasonable for use in the upcoming solicitation, and if the participating IOUs verify the derivation of the tables as described above, the tables could be used in the upcoming auction for bid evaluation purposes. The ruling also instructed the parties to set forth the areas of disagreement, if any.

9.2 Concluding the Verification Process

We generally affirm the ALJ rulings set forth above. Specifically, if the parties to the verification process find the draft tables reasonable for use in the upcoming bid solicitation, and if the participating IOUs verify that the tables are derived from a set of inputs and algorithms consistent with analysis of their own IDRs, the tables should be ready for use in the upcoming bid solicitation. We decline to adopt the portion of the ALJ ruling which requires consistency with an IOU's own planning process, since several of the utility's models differ somewhat from those used in their planning processes.

Furthermore, the participating IOUs have also provided QFs the opportunity to request a special study under certain circumstances. (See Section 5.2 above.) The IOU should disclose the results of the special studies in advance of the tables being finalized, and those results should be reviewed as part of the verification process. To the extent the QF on whose behalf the special study is conducted, or another party, has objections, we agree with the ALJ ruling that they should be set forth in the workshop report. The QF should be prepared to make a methodological representation that the costs are other than represented.

After consultation with the parties and an opportunity for comment, CACD's workshop report should be filed and served as soon as possible, and in any event no later than five weeks from the effective date of this decision.

We recognize that some issues raised in the verification workshop may overlap with issues decided in today's decision. Some issues also may involve technical discussions extending beyond the scope of the Phase One hearings and testimony. This is appropriate to the extent it assists the parties in examining the cost tables and their derivation. However, no issue decided in today's decision is open to renegotiation or relitigation in the verification process. For example, today's decision decides whether and to what extent to include energy and capacity line losses in bid evaluation. This issue is not open for reconsideration in the verification workshops. In contrast, an examination of the derivation of the IOUs' energy and capacity line loss factors is appropriate.

If the parties are able to reach agreement as set forth above on the draft transmission cost tables, we will not entertain complaints challenging the transmission cost tables. The QFs are provided the opportunity to question the derivation of the draft transmission cost tables in the workshops. If a party does not believe the contents of the draft transmission cost tables are reasonable, it should so state at the workshop. Indeed, part of the risk borne by the QFs under a transparent approach is the risk that another set of QFs might be winners once the actual transmission costs are known. We believe that this is an appropriate risk for QFs to bear, in light of the benefits of transparency in affording bidders the opportunity to account for transmission system impacts in site selection, and in generally knowing what transmission costs would be applied in evaluating their bids.

Edison and SDG&E have proposed that we certify the auction results once the winners are announced. We have rejected similar proposals before, and continue to reject them. The participating IOUs should generally have the same rights and responsibilities regarding the Final Standard Offer 4 auction as they do in any other competitive procurement they conduct.

In D.87-05-060, 24 CPUC2d 253, 261, we rejected a similar proposal made by Edison that we resolve complaints and approve the list of winning bidders resulting from the Final Standard Offer 4 auction within 30 days of the utility's filing of the auction results. We reasoned that we did not see "the need for or advantage of such Commission involvement in light of the openness of the process and the objective rules for determining winners and prices."

We take this opportunity to commend CACD and the parties to the verification workshops for working cooperatively to identify the issues associated with verifying the draft transmission cost tables, and to resolve those issues. We recognize that if the parties are unable to reach agreement in the verification process, further ALJ or Commission action may be necessary in order to finalize the cost tables.

As we make clear in today's decision, we desire to have some reflection of transmission costs and reasonable access to wheeling service as part of the upcoming solicitation. However, we also desire to have the solicitation take place in the near future. We view the parties' conduct in the verification process as an indication of their commitment to having in place a process which takes transmission considerations into account in time for the upcoming solicitation.

We also direct CACD to hold one or more workshops after the workshop report issues and before the draft tables are finalized, so that the tables can be conformed to today's decision, and so the parties can review the final tables before they are officially published to point out omissions, possible typographical errors, and the like.

10. A Winning QF's Transmission Costs Should Be Considered in Bid Evaluation But Not in Bid Payment

All parties who addressed the issue of whether transmission costs should be taken into account in bid evaluation or payment agree that transmission costs, including transmission upgrades and losses, should be considered in bid evaluation but that a winning QF's transmission costs should not be considered in bid payment. However, DRA pointed out that the inclusion of transmission costs in bid evaluation but not payment could produce "anomalous" results in certain situations.

An example might be where a bidder's transmission cost is high, but its generation cost is low, such that its total cost makes it the lowest losing bidder. If this occurred, payments based solely on the lowest losing bidder's generation cost could result in payments to a winning bidder which are lower than its generation costs.

The joining parties recommend the following method of paying winning QFs, and further state that under this method, DRA's anomaly would not occur.[60] Under this method, each bid would be ranked according to its total costs (including transmission and generation costs) and the winners, as well as the lowest losing bidder, would be determined when compared to the IDR. A winning bidder would be paid its generation costs (which include its bid energy cost, its bid shortage cost, and its bid energy-related capital cost), as well as the difference between the total bid evaluation price of the lowest losing bidder and the bid evaluation price of the winner. (RT 381-382.) Under this method, payments to winning bidders would not include the bidder's transmission costs, since the utility would pay for these costs.

Edison's witness Kritikson proposed to resolve the anomaly by paying all winning bidders their own generation costs. SDG&E's witness Gaebe stated that he generally found the joining parties' proposal a reasonable way to resolve the anomaly, and did not offer an alternative recommendation.[61]

We agree that a winning QF's transmission costs should be included in bid evaluation but not in payment in our interim transmission program. Subject to the policies set forth in today's decision, ratepayers generally would pay for the reasonable and prudently incurred costs of transmission upgrades to wheel or integrate winning bidders into the purchasing utility's system. Therefore, the costs of the upgrades should not also be included in the price the ratepayers pay the QFs for power delivered.

However, we believe that if QF payments are properly computed as described below, the DRA anomaly would not occur. QF

60 IEP/GRA witness Branchcomb illustrated this proposal in Exhibit 10.

61 SDG&E's witness Gaebe also stated that the anomaly would not occur under SDG&E's proposal where the QF arranges and pays for the transmission service. However, we reject this proposal. (See Section 6.2 above.)

payments should be based on a comparison of the <u>total</u> costs of the winning bidder and the IDR (or the lowest losing bidder if the bid is over-subscribed). Payments to the winning bidders should be based on the total costs of the IDR or the lowest losing bidder (whichever is less), minus the transmission costs of the winning QF. The following example illustrates the policies we adopt today.

Assume the IDR has an energy value of 2.0, a capacity value of 2.0, and a transmission value of 2.1, with a total value of 6.1.[62] The lowest losing bidder has an energy value of 3.0, a capacity value of 2.0, and a transmission value of 1.0, for a total value of 6.0. A winning bidder has an energy value of 2.0, a capacity value of 2.0, and a transmission value of 1.9, for a total value of 5.9.

If a QF's price is based on that of the lowest losing bidder, it would receive 6.0. However, a utility will pay for the transmission necessary to interconnect the QF with the utility's system. Therefore, the QF's transmission costs should be deducted from the total price of the lowest losing bidder. The winning QF would receive 4.1 (6.0-1.9 = 4.1).

	Energy	Capacity	Transmission	Total Cost
IDR	2.0	2.0	2.1	6.1
Lowest Losing Bidder	3.0	2.0	1.0	6.0
Winner	2.0	2.0	1.9	5.9

62 The numbers used in this example are not in any specific units, for simplicity's sake.

DRA's anomaly involved a situation where the lowest losing bidder's generation costs were very low. The joining parties' approach, which we adopt, also avoids anomalous results where the lowest losing bidder has relatively high generation costs but low transmission costs. The above example demonstrates that basing QF payments solely on the generation costs of the lowest losing bidder would not benefit the ratepayers. Under the above example, the QF's price, based solely on the generation costs of the lowest losing bidder, would be 5.0, instead of 4.1. The ratepayers would therefore pay too much.

The joining parties' approach also avoids anomalous results in the DRA situation where the lowest losing bidder's transmission costs are high, but its generation costs are lower than the winners' generation costs. Assume in the above example that the lowest losing bidder's energy value is 1.0, its capacity value is 2.0, and its transmission value is 3.0, for a total value of 6.0. In this example, payments to the winning QF based solely on the generation costs of the lowest losing bidder would be 3.0. However, since the winner's energy and capacity costs are 4.0, it is highly unlikely that a QF project receiving less than its own actual costs would be built. In this case, the ratepayers would lose the least-cost resource. However, if the winner is paid the total cost of the lowest losing bidder, less the winner's own transmission costs, it would receive 4.1. The DRA anomaly would not occur, and there is the greater likelihood that the project would be built. So long as the winning QF gets paid the total cost of the lowest losing bidder minus the winning QF's own transmission costs (which are borne by the utility interconnecting that QF's power), the QF will be appropriately priced and potential "anomalies" in including transmission costs in bid evaluation will be avoided.

We realize that bid protocols may need refinement as a result of our decision today, and instruct the parties to address these issues promptly through workshops. (See Section 11 below.)

11. Final Standard Offer 4 Contract Language and Bidding Protocol Modification Required by Today's Decision

A number of parties have noted that Final Standard Offer 4 contract language and bidding protocols will need modification to fully incorporate the transmission policies adopted by today's decision. The assigned ALJs, in coordination with the Presiding Officer of the negotiating conference described in Section 2.2.2 above and/or CACD, should promptly notice workshops to complete the process of conforming the contract and protocol to the changes made in today's decision and in the contract modification phase of the Update.

12. Next Steps

This is the first stage in a process that will evolve a robust and effective program for both integrating transmission into resource procurement decisions and provide reasonable access for nonutility power projects to utility transmission facilities. This latter objective is essential to our goal of promoting a competitive market in the wholesale electric generation market.

In reviewing the future work that should be undertaken, there are items that must be accomplished immediately in preparation for the upcoming Standard Offer 4 auction, and other items which we will address in Phase Two.

12.1 Immediate Steps

There are two procedures which the parties should conclude promptly so that transmission considerations can be a part of our upcoming Final Standard Offer 4 soliciation. First, the parties should successfully conclude the verification process regarding the IOUs' transmission cost tables. (See Section 9 above.) Second, modifications to Final Standard Offer 4 and bidding protocol necessitated by today's decision and in the contract modification phase of the Update should be made promptly. (See Section 11 above.)

12.2 Phase Two

12.2.1 A Permanent Transmission Access Program

Phase Two is to focus on broader transmission access issues, including wheeling to and from in-state municipal utilities and out-of-state utilities. At the negotiating conference which preceded the April policy hearings, the parties, including most municipal utility representatives, agreed to such phasing of the issues, in part, to allow interested parties more time to negotiate a voluntary transmission association. This two-phase approach appears to have been profitable, as a number of parties to this proceeding (including some of the IOUs) have recently announced their goal of forming WATSCO (a voluntary transmission association) by the end of 1992.

Phase One has focused on incorporating transmission considerations into the upcoming Final Standard Offer 4 auction. However, we have stated many times in the past that one of our key objectives in regulating electric utilities is to promote a competitive market in wholesale generation so that California's electrical consumers get reliable service at reasonable cost, consistent with the State's environmental policies. In D.91-10-048, slip at 36, we recognized that municipal utilities are integral to our long-range goal, since they serve a substantial part of California's population, and in many instances control substantial transmission and generation facilities. We also stated that the municipal utilities' extensive participation in the Western Systems Power Pool underscores the significant potential benefits of including them in a program to promote competition and economic efficiency in the electric generation market. Furthermore, our future auctions may include all-source bidding, and municipal utilities might be participants as either wheeling utilities or bidders requiring wheeling through one of the IOUs' service territory.

Although we lack jurisdiction over municipal utilities, we are pleased that the municipal utilities have been active participants to date, and anticipate that they will continue in Phase Two. The NCPA offered testimony at the April hearings, primarily on how the current draft by-laws of WATSCO would address certain Phase One issues. The NCPA offered its comments "with the intent of making a contribution to the success of the CPUC-sponsored bidding proceedings, now and in the future, and to further the CPUC's goal and the Municipal Utilities' goal of a competitive generation market in California." (Opening Brief of NCPA at 5.)

As we stated in D.91-10-048, slip at 36-37, the basis of the municipal utilities' participation in the permanent program must be reciprocal rights and obligations (e.g., municipal utilities must be prepared to provide wheeling service, where requested, on terms and conditions comparable to the wheeling service provided them by participating IOUs.) Furthermore, their participation must not jeopardize reliable, low-cost service to the IOUs' ratepayers. Finally, participating municipal utilities should share information on the same basis as the IOUs. We are encouraged by evidence that municipal utilities can work with these principles.

Because of the importance of these broader issues of transmission access to the ratepayers of California, we intend to commence Phase Two promptly. We instruct the ALJs to hold a prehearing conference at an appropriate time in December 1992, in order to discuss the scope and timing of these broader issues, on the assumption that bid solicitations will have occurred before that date.

12.2.2 Monitoring the Interim Program

We have stated our intention to develop an interim transmission access program so that we might account for transmission considerations in the upcoming Final Standard Offer 4 solicitation. Implementing transmission considerations in the upcoming auction is a new effort for all concerned. As stated in Section 2.2.2 above, enacting interim policies and phasing this proceeding serves several purposes.

In today's decision, we identified certain elements of the interim program which should be monitored. Also, in a February 20, 1992 ruling, the ALJs, in response to a DRA recommendation, ordered CACD to draft a report in consultation with the parties, describing the goals, means, and schedule for an evaluation of the results of an interim program.

The draft report should also describe the information that would be useful to gather from this bidding solicitation, including the specific monitoring called for by today's decision, and the process for collecting this information. CACD should then hold a workshop on the report. This workshop should be held promptly after the Final Standard Offer 4 solicitation issues. The outcome should be an agreement on how monitoring is to be done, and how and when the utilities are to report results to the Commission. CACD's final report on monitoring should be filed and served within 60 days after the workshop.

12.2.3 Developing a Common Methodology to Determine Transmission Costs for All Utilities

A number of parties have questioned what constrains the utilities from using a common methodology for developing transmission costs on the utilities' systems. More specifically, several of the joining parties advocate that Edison and SDG&E use PG&E's LOCATION model for determining transmission costs.

The policies we adopt today are to be uniformly applied by the participating IOUs. In the interest of having a transmission program available for use in the upcoming auction, today's decision allows each utility, for the most part, to use its own methodological tools for determining upgrade costs and line losses for use in bid evaluation. We agree, however, with the parties that question the utilities' justification for different methodologies. For example, no utility has satisfactorily addressed why Edison and SDG&E cannot use a variation of the LOCATION model for estimating transmission costs and line losses on their systems, aside from time constraints. Today's decision, to the extent that it requires consistency among the utilities' policies for this interim program, should pave the way for the utilities to develop a common model. Alternatively, if utilities are to continue to use different costing models, these models should be benchmarked against each and compared to actual data.

Because LOCATION most closely adheres to the Commission's adopted policies, we urge the parties to explore using LOCATION, or a variation thereof, for all utilities. We realize that LOCATION is new, has not yet been modified to incorporate a carrying cost adder, and may not prove to be an effective tool to be used in our permanent transmission program. This underscores the importance of the monitoring efforts we discuss in Section 12.2.2 above. However, the potential of LOCATION to provide valid transparent information is an attractive attribute.

The assigned ALJs, in coordination with CACD, should work with the utilities to develop a common model, whether it be LOCATION or some alternative. CACD should also prepare a report to the Commission within 90 days after the Commission approves the participating utilities' Interconnection Reports, in order to have some information on the success of the various models being used. Further, we instruct CACD to explore the ability of common models to be used in providing transparent information for wheeling transactions as well as integration requests.

13. Comments on the Proposed Decision

Pursuant to PU Code § 311 and our Rules of Practice and Procedure, the Proposed Decision of ALJs Econome and Kotz was published on July 22, 1992. Parties then had an opportunity to file comments and replies.[63] While we affirm the Proposed Decision in most respects, we have made several changes discussed below.[64]

We modify the Proposed Decision's requirement that utilities make a reservation for short-term transactions, such as economy energy, consistent with the short-term transactions projected by the CEC in ER-90. (See Section 5.6.)

We also make the following changes reflected in the specific sections cited: (1) The costs for a lumpy upgrade assigned in bid evaluation to integrating bidders in PG&E's auction is based on pro rata allocation, without a carrying cost adder (Section 5.4.2); (2) The time within which the IOUs are to finalize wheeling agreements is modified (Section 6.4); (3) The Interconnection Report and CPCN filings are no longer concurrent (Section 7.2); (4) The standard of IOU conduct in applying for a CPCN and any requisite FERC approvals is modified (Sections 6.4 and 7.3); (5) The resolution of the definition of the "lowest price

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63 We received comments from PG&E, SDG&E, Edison, CEC, DRA, IEP/GRA, Destec, Texaco, Vernon, SPPC and the Coalition for Energy Efficiency and Renewable Technologies (CEERT). All except the CEC, Texaco, SPPC, and CEERT filed reply comments. Vernon moved to file reply comments to Edison's reply. This motion is denied. In any event, the substance of Vernon's reply, which we have read, would not have affected the outcome of today's decision.

64 We have also made other changes to the Proposed Decision to improve the discussion, add references to the record, and correct typographical errors.

bidder" is left to workshops (Section 5.3); and Sections 5.5.4 and 9 are modified regarding the consistent application of the IOUs' various methodologies in resource planning and acquisition.

<u>Findings of Fact</u>

1. This investigation concerns the terms and conditions whereby nonutility suppliers of generation may obtain transmission access and deliver their output to the wholesale marketplace.

2. An investigation focusing on transmission access and cost allocation is critical to enhancing competition among suppliers.

3. Power integration involves transmission service performed by a utility for a seller of electricity, where the utility itself is the purchaser and the transmission service occurs inside the utility's service area from a point of interconnection to the utility's load center.

4. Wheeling involves transmission-only service, where one or more third-party entities must give access to their transmission lines in order for the seller of electricity to deliver its power to the purchasing utility.

5. A permanent transmission access and cost allocation program must be pursued in a series of steps. Implementing a permanent program raises sufficiently complex issues that it is appropriate to have an initial phase of this proceeding offering a more limited service.

6. Since the upcoming Final Standard Offer 4 auction involves a relatively small solicitation, limiting the application of the interim transmission program to the upcoming auction provides the Commission with an excellent opportunity to monitor the interim program in order to produce future improvements for the permanent program.

7. The parties are conducting a verification process in workshops on the participating IOUs' draft transmission cost tables, which were published on March 27, 1992. These tables provide a bidder in the Final Standard Offer 4 auction with pre-bid

information regarding the impact of new generation on the three IOUs' transmission systems to be used for bid evaluation. Each participating IOU has used its own analytical tools to develop its draft transmission cost tables.

8. The assigned ALJ granted Edison's motion to strike portions of Vernon's testimony in part, on the alternative grounds that, <u>inter alia</u>, such testimony was beyond the scope of the proceeding, was not ripe, and that Vernon has remedies in other forums if it believes its existing rights are being violated. The ALJ also declined to refer this issue to the Commission under Rule 65 of our Rules of Practice and Procedure at the time of the April hearings.

9. Adding a transmission component to the upcoming auction will benefit ratepayers by providing that the resources with the lowest total cost are selected. However, there are several risks associated with a competitive resource acquisition which includes a transmission component. Ratepayers, as well as QFs and shareholders, may have to assume new risks in order to achieve these benefits.

10. Since the upcoming Final Standard Offer 4 auction will be the first time this type of auction takes place, and the bidders will be bidding against multiple IDRs, the process will be unduly complicated if different transmission access and cost allocation policies are adopted for each participating utility.

11. Commission decisions have required a transparent approach to our Final Standard Offer 4 auction. This approach requires objective, pre-bid transmission information which is binding for bid evaluation purposes. While utilizing transparent auction rules is fully feasible for integration, it appears that there is insufficient time before the auction to develop such an approach for wheeling.

12. Relying on transparent criteria is consistent with a reasonable (indeed, inevitable) level of planning risks. However,

the interim transmission program we adopt today will allow us to monitor pre-bid transmission information provided in integration situations to determine if, in fact, such pre-bid information sacrifices accuracy, and to what degree.

13. If a QF believes that its project alone, or in potential combination with other projects, may exceed the megawatt limit of estimated upgrade costs listed in the draft transmission cost tables at a given site, a QF can request the utility to perform a special study of transmission costs at a specified megawatt size at a specified location, pursuant to Section 5.2 of this decision.

14. The assignment of transmission costs if multiple QFs submit bids at one location could significantly affect the award of contracts where existing transmission capacity could accommodate some but not all of the bidders at that location.

15. For economic and technical reasons, an upgrade might have to be sized larger than the capacity of the QF(s) whose addition requires the upgrade. This type of upgrade is called a "lumpy" upgrade.

16. Under pro rata cost allocation with a carrying cost adder, the bidder would be assessed both its pro rata allocation and an adder reflecting a carrying cost of a lumpy upgrade's unused capacity for a specific period of time.

17. Under pro rata cost allocation, a bidder would be better able to know, before it submits its bid, what portion of the cost of a new upgrade would be assigned to its bid. Under full cost allocation, there is more uncertainty what transmission costs will be assigned to bids.

18. Any excess capacity resulting from pro rata cost allocation may increase competition in future solicitations by encouraging bidders to locate near that capacity. However, using full cost allocation may result in the upgrade never being built in the first instance because no one project can absorb attribution of the full upgrade costs and still win the auction. Furthermore, a

utility might make use of that excess capacity in the future for its own purposes, e.g., for importing economy energy or reliability purposes.

19. Under pro rata cost allocation, ratepayers bear the risk that transmission capacity may be unused for a period of time. However, since a lumpy upgrade is likely to be fully utilized over time, full cost allocation overstates transmission costs to the bidders, and in turn, to the ratepayers.

20. Transmission costs are usually smaller in proportion to generation costs.

21. It may be preferable to have some excess transmission available for use, rather than to build another expensive power plant because there is insufficient transmission to get existing generation to the load centers.

22. Line losses affect both energy and capacity from a given plant.

23. Energy and capacity losses could constitute a significant portion of total transmission costs associated with a QF contract.

24. Short-term transactions have value to the transmission-owning utility.

25. The short list approach adopted for use in wheeling is an interim departure from our long-range goal of transparency.

26. Placing the responsibility of arranging and paying for wheeling service on the purchasing utility is the most workable and efficient method to negotiate wheeling arrangements, and is also consistent with the needs and obligations of the various parties affected by the wheeling transaction. Placing this responsibility on the purchasing utility also provides incentives for the participating IOUs to develop a common understanding of transmission cost allocation in the building of an upgrade. Since each IOU will at some point be a purchasing utility and a wheeling utility, the IOUs should be in a similar bargaining position vis-a-vis each other.

27. SDG&E's proposal that the QF arrange and pay for wheeling service places the risk directly on the ratepayers of the wheeling utility.

28. The Final Standard Offer 4 auction results will tend to show where upgrades are likely to be needed in the future.

29. The fact that a QF has been able to arrange for wheeling in some instances does not speak to the issue of risk on the wheeling utility's system, nor does that fact indicate how many transactions have not been pursued because a QF was unable to arrange for wheeling in instances where an IOU could have.

30. Although tariffed service is preferred for our permanent program, wheeling tariffs cannot be produced in time for this auction.

31. The three participating IOUs have agreed to wheel QF power acquired in this auction to each other.

32. Pre-bid information for wheeling between IOUs should not be difficult to provide. PG&E, Edison, and SDG&E can only wheel power to each other on specific paths. These IOUs should be able to provide information regarding existing capacity, losses, and costs of upgrades for wheeling on those paths in their transmission cost tables, at least within a reasonable range.

33. Using the transparent approach in bid evaluation for integration is a reasonable and prudent method for evaluating transmission costs for selecting winners in the upcoming Update auction. The short list approach is similarly appropriate in the wheeling context.

34. Winning the auction is not a guarantee that the QF will obtain all necessary permits. Similarly, it is not a guarantee that the Commission will issue all necessary CPCNs.

35. QFs are provided the opportunity to question the derivation of the draft transmission cost tables in the verification workshops.

36. In D.87-05-060, 24 CPUC2d 253, 261, we rejected a proposal made by Edison that we resolve complaints and approve the list of winning bidders resulting from the Final Standard Offer 4 auction within 30 days of the utility's filing of the auction results.

37. We desire to have some reflection of transmission costs and reasonable access to wheeling service as part of the upcoming solicitation. However, we also desire to have the Final Standard Offer 4 auction take place in the near future.

38. Phase Two of this investigation will focus on broader transmission access issues, including wheeling to and from in-state municipal utilities and out-of-state utilities.

39. No utility has satisfactorily addressed why Edison and SDG&E cannot use a variation of the LOCATION model for estimating transmission costs and line losses on their systems, aside from time constraints.

Conclusions of Law

1. The Commission should conduct this proceeding in two phases.

2. We affirm the ALJ's ruling striking portions of Vernon's testimony and denying Vernon's request to refer the matter to the Commission under Rule 65 of the Commission's Rules of Practice and Procedure.

3. The policies adopted in today's decision are limited in scope and should serve to govern transmission access and cost allocation in the upcoming Final Standard Offer 4 auction. The Commission's resolution of these issues today should not prejudice the ultimate determination of these and other issues for the permanent transmission access program.

4. The policies adopted today should be uniformly applied to each participating IOU, even though each IOU may utilize different analytical tools for this auction in order to implement these policies.

5. Although the policies adopted in the interim program deviate to some extent from the policy of transparency, transparency is a desirable goal. We ultimately expect that Final Standard Offer 4 will be open to "all-source" bidding -- that is, other suppliers of generation, such as IPPs and utilities, would be allowed to bid in the auction. We ultimately wish to ensure that the protocol used to determine auction winners is transparent, and does not rely on post-bid adjustments which may lead parties to call into question the auction results.

6. For all capacity subject to bidding, both the benchmark price of the IDR and bids by QFs should take transmission costs into account.

7. The information published in the transmission cost tables should be binding for bid evaluation purposes in integration. The participating IOUs should conduct bid evaluation in integration as set forth in Section 5 of this decision.

8. We approve the special study procedure set forth in Section 5.2 of this decision for use in this interim program. A special study should not be made to validate the numbers in the transmission cost tables.

9. The final transmission cost tables should contain results of any special study performed as set forth in Section 5.2 of this decision, and all potential bidders should have access to this information in developing their bids. Absent a special study, participating IOUs should not consider any single bid which exceeds the megawatt limits contained in the final transmission cost tables.

10. We approve a $10,000 fee for conducting a special study. This fee is not directly refundable, but may be indirectly refundable if one QF paying for a special study is not selected as a winning bidder, and another QF which exceeds the megawatt limit at that same location (and which benefited from the study paid for by the losing QF) is selected as a winner.

11. The lowest transmission costs should be assigned to the "lowest price bidder," irrespective of the bidder's generation technology. The parties should discuss the appropriate protocol for determining the "lowest price bidder" in the verification workshops.

12. Bidders should be allowed to submit multiple site bids against one IDR to a maximum of three busses for a purchasing utility to consider if (a) multiple bidders locating at the preferred site for a particular bidder cause that bidder to exceed the megawatt limit at that site and lose, or (b) the bidder's upgrade costs or losses are increased as a result of multiple bidders locating at the preferred site for a particular bidder and such increase causes that bidder to lose. If, after the above steps, a bidder still exceeds the megawatt limit at a given bus, either individually or as a result of multiple bidders locating at that site, that bidder should not be considered further in that round of bidding.

13. For Edison and SDG&E, we adopt pro rata cost allocation plus a carrying cost adder for assigning costs of lumpy transmission upgrades for bid evaluation in integration. Because the carrying cost adder is incompatible with LOCATION, we adopt pro rata cost allocation for PG&E.

14. If our choice were solely between pro rata and full cost allocation, we would choose pro rata cost allocation.

15. The carrying cost adder should be computed with the following data: (1) the amount of excess capacity involved, (2) a carrying charge rate, and (3) an estimate of the duration of the amount of unused capacity. The carrying charge rate should be equivalent to the levelization factor used to levelize costs over multiple years. To the extent it is necessary to make assumptions in determining the carrying charge rate, these assumptions should be the same as those used in the Update. We adopt a two-year duration for the adder.

16. Capacity losses should be considered in bid evaluation for both integration and wheeling. Each participating IOU should use its own capacity loss methodology for this interim program, provided this methodology is consistently applied to its IDRs.

17. Energy losses may be considered in bid evaluation for both integration and wheeling, provided the parties agree at the verification workshops that the energy loss numbers the IOUs intend to use in their transmission cost tables are reasonable for use in the interim program, and provided that the methodology used to determine the numbers is applied to the IOUs' IDRs.

18. The participating IOUs should initiate a monitoring program, after consultation with the parties, to record losses at interconnection points representing a diversity of locations and other relevant variables on their systems. This monitoring should be part of the overall monitoring described in this decision.

19. The parties should further discuss an opportunity cost imputation in the verification workshops. If parties in the verification workshops reach consensus on an opportunity cost imputation, and this consensus is reflected in the workshop report, then the opportunity cost imputation should be used in the upcoming auction. If the parties are unable to reach consensus, then the participating IOUs should include the amount of short-term transactions adopted by the CEC in ER-90 in determining available transmission capacity for both integration and wheeling. The parties should address the technical issue of how to convert the ER-90 values into transmission capacity for use in this auction at the verification workshops.

20. We adopt a "short list" approach for considering wheeling costs in bid evaluation as set forth in Section 6 of this decision. The participating IOUs should conduct bid evaluation in wheeling as set forth in Section 6 of this decision.

21. In D.89-02-017, addressing Standard Offer 2 contracts, we allowed wheeling arrangements to be finalized within six months

after the power purchase agreement was executed, provided this obligation became an additional milestone under the QF Milestone Procedure. We also apply this holding to this interim transmission program for QFs located outside the participating IOUs' service territory.

22. A participating IOU should not await the results of another IOU's 90-day study to perform a requested 90-day study under our "short list" approach, but should conduct its own study upon request, using the best available information consistent with its own planning assumptions, and expressly noting contingencies where appropriate.

23. We reject DRA's proposal that when upgrades are used for both wheeling and integration, the costs of excess capacity be allocated for bid evaluation purposes between the purchasing utility and the wheeling utility based on relative use of the upgrade.

24. For wheeling, the purchasing utility should arrange and pay for the wheeling service necessary to wheel a winning QF's power through participating IOUs' service territories to the border of its own service area.

25. Since upgrades generally take less time to build than a QF project, the QF milestones should be sufficient to ensure that a QF is viable before the upgrade is constructed. The parties should examine the milestone procedures to see whether they need to be modified or augmented.

26. The wheeling policies adopted in this decision do not burden interstate commerce. Under our interim transmission program, the participating IOUs will wheel power for winning QFs in the upcoming Final Standard Offer 4 auction, regardless of the generation's origin.

27. The purchasing utility should receive benefits commensurate with its payment for upgrades and other modifications to a wheeling utility's system. For the upcoming auctions, the

parties negotiating the wheeling arrangements should negotiate solutions consistent with the policy we adopt today.

28. As part of our monitoring program, the participating IOUs should report to the Commission what arrangements they make to provide a purchasing utility with benefits commensurate with its payments for upgrades and other modifications.

29. Some type of contractual relationship to implement wheeling among the participating IOUs may be necessary. However, we need not decide at this juncture the specific form by which the IOUs accomplish this. The participating IOUs should accomplish IOU-to-IOU wheeling by the most appropriate method for this interim program.

30. The participating IOUs should finalize wheeling agreement(s) with each other as soon as possible consistent with the provisions of Section 6.4 of today's decision.

31. If FERC approval of IOU-to-IOU wheeling agreements necessary to wheel a winning QF's generation is necessary, and if both the purchasing and wheeling utilities, acting in good faith, with due diligence, fail to obtain FERC approval, the purchasing utility should first attempt in good faith to renegotiate the Final Standard Offer 4 contract with the QF. If that option fails, either party to the Final Standard Offer 4 contract should be allowed to terminate the contract, and the QF should be reimbursed its project fee, but it is not entitled to other recovery from the purchasing IOU. For these reasons, the participating IOUs should seek any necessary FERC approvals at the earliest opportunity.

32. A Final Standard Offer 4 contract should be treated the same as all other standard offer contracts in subsequent reasonableness reviews.

33. Once the winning bidders in the Final Standard Offer 4 auction are announced, the participating IOUs should determine the most cost-effective method to interconnect and integrate winning

bidders. These costs may be higher or lower than the costs used for bid evaluation.

34. The participating IOUs should file an Interconnection Report in this investigation describing the upgrades necessary to accommodate winning bidders. Notice of availability of this report should be served at the time of filing on the parties to this investigation. The report should address the most cost-effective package of upgrades necessary, and should include both upgrades necessary to integrate generation into a utility's system and to wheel generation to another utility's system. The report should also compare the package of upgrades used for bid evaluation purposes to the preferred package, if different. The IOU should submit the Interconnection Report to the Commission as soon as possible, and in no event later than 180 days after the auction winners are announced.

35. In the absence of changed circumstances, the Commission's findings regarding the Interconnection Report should have preclusive effect in subsequent proceedings. The Commission's review of the Interconnection Report is to ensure winners are interconnected by the most cost-effective package of upgrades. This Commission's review of the Interconnection Report does not affect the designation of bid winners, nor is any aspect of the Final Standard Offer 4 contract affected by the review.

36. If a CPCN for a necessary upgrade is denied, the participating IOU and the QF should first have the opportunity to renegotiate the contract in lieu of terminating the contract.

37. A participating IOU should timely file for and pursue any necessary CPCN application, and should act in good faith with due diligence in so doing. If, in an integration situation, a purchasing utility does so, fails to obtain any necessary CPCN, and attempts in good faith to renegotiate the contract with the QF but is unable to do so, the Final Standard Offer 4 contract can be terminated by either party. The same termination provisions should

apply for wheeling, if the wheeling utility fails to obtain any necessary CPCN for an upgrade necessary to deliver power from a winning QF to another IOU, and the purchasing IOU attempts in good faith to renegotiate the contract with that QF but is unable to. In these events, the QF should recover its project fee, but is not entitled to other recovery from the participating IOU.

38. A participating IOU should apply for a CPCN at the earliest opportunity, before QFs incur substantial project costs, and before the QFs' contractual deadlines for obtaining permits and financing. The actual construction of the upgrade should not begin until the IOU is assured of the QF's viability. The parties should reexamine the milestone procedures to see whether milestones relating to integration and wheeling should be added or modified.

39. A policy of ascribing the lowest transmission costs to the lowest price bidder will best enable us, at this time, to assess the total costs of competing resources.

40. We affirm the ALJ rulings set forth in Section 9, except in one respect. We modify the ALJ's June 24, 1992 ruling so that if the parties to the verification process find the draft tables reasonable for use in the upcoming bid solicitation, and if the participating IOUs verify that the tables are derived from a set of inputs and algorithms consistent with analysis of their own IDRs, the final tables should be ready for use in the upcoming bid solicitation.

41. The participating IOU should disclose the results of the special studies in advance of the tables being finalized, and those results should be reviewed as part of the verification process. To the extent the QF on whose behalf the special study is conducted, or another party, has objections, they should be set forth in the workshop report on the draft tables. The QF should be prepared to make a methodological representation that the costs are other than represented.

42. After consultation with the parties and an opportunity for comment, CACD's workshop report on the draft transmission cost tables resulting from the verification process should be filed and served as soon as possible, and in any event no later than five weeks from the effective date of this decision. If a party does not believe the contents of the draft transmission cost tables are reasonable, it should so state at the workshop.

43. No issue decided in today's decision is open to renegotiation or relitigation in the verification process.

44. If, in the verification process, the parties are able to reach agreement on the draft transmission cost tables, we will not entertain complaints challenging the tables. If the parties are unable to reach agreement in the verification process, the assigned ALJs or the Commission should take any further action necessary in order to finalize the cost tables.

45. The Commission should not certify the auction results. The participating IOUs should have the same rights and responsibilties regarding the Final Standard Offer 4 auction as they do in any other competitive procurement they conduct.

46. CACD should hold one or more workshops regarding the transmission cost tables after the workshop report issues and before the draft tables are finalized, so that the tables can be conformed to today's decision, and so the parties can review the final tables before they are officially published to point out omissions, possible typographical errors, and the like.

47. A winning QF's transmission costs should be included in bid evaluation but not in payment in the interim transmission program. QF payments should be based on a comparison of the total costs of the winning bidder and the IDR (or the lowest losing bidder if the bid is over-subscribed). Payments to the winning bidders should be based on the total costs of the IDR or the lowest losing bidder (whichever is less), minus the transmission costs of the winning QF as imputed by the utility in bid evaluation.

48. Bid protocols may need refinement as a result of our decision today. The parties should address these issues promptly through workshops.

49. The assigned ALJs, in coordination with the Presiding Officer of the negotiating conference described in Section 2.2.2 above and/or CACD, should promptly notice workshops to complete the process of conforming the contract and protocol to the changes made in today's decision and in the contract modification phase of the Update.

50. The ALJs should hold a prehearing conference at an appropriate time in December, 1992, in order to discuss the scope and timing of Phase Two transmission issues, on the assumption that bid solicitations will have occured before that date.

51. CACD should draft a monitoring report in consultation with the parties, describing the goals, means, and schedule for an evaluation of the results of an interim program consistent with this decision.

52. In Phase Two, the assigned ALJs, in coordination with CACD, should work with the participating IOUs to develop a common model to determine transmission costs, whether it be LOCATION or some alternative. CACD should also prepare a report to the Commission within 90 days after the Commission approves the participating IOUs' Interconnection Reports, in order to have some information on the success of the various models being used. CACD should also explore the ability of common models to be used in providing information for wheeling transactions as well as integration requests.

53. Because we wish transmission considerations to be taken into account in the upcoming Final Standard Offer 4 auction, this order should issue immediately.

INTERIM ORDER

IT IS ORDERED that:

1. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall take transmission considerations into account in the upcoming Final Standard Offer 4 auction in conformance with the discussion, findings, and conclusions set forth in this decision. The assigned Administrative Law Judges shall schedule necessary proceedings in order to complete the verification process. The assigned Administrative Law Judges shall also coordinate activities in this Investigation with Investigation 89-07-004, including, but not limited to, modifications to the Final Standard Offer 4 contract, Qualifying Facility milestone procedures, and bidding protocol issues pursuant to Decision (D.) 91-06-022, D.92-04-045, and today's decision.

2. The assigned Administrative Law Judges shall notice prehearing conferences and/or workshops in conformance with the discussions, findings, and conclusions in this decision. The workshops shall be conducted by the Commission Advisory and Compliance Division (CACD) and/or the Presiding Officer from the negotiating conference, as appropriate.

3. CACD shall file and serve a workshop report on the verification workshops as soon as possible, and in any event no later than five weeks from the effective date of this decision.

4. CACD shall file and serve a monitoring and other reports in conformance with the discussion, findings, and conclusions in this decision.

5. San Diego Gas & Electric Company's petition to file its post-hearing brief one day out of time is granted. All other motions and requests still outstanding in this phase of this investigation are denied.

This order is effective today.

Dated September 16, 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
PB

APPENDIX A

Additional Appearances

Respondents: E. Gregory Barnes, Michael C. Tierney, Geoffrey P. Gaebe, Sr., Attorneys at Law, and Beth A. Bowman, for San Diego Gas & Electric Company and Frank A. McNulty and Tanya D. Scott, Attorneys at Law, for Southern California Edison Company.

Interested Parties: David C. Hjelmfelt and David B. Brearley, Attorneys at Law, for City of Vernon; Jerome Candelaria, Attorney at Law, for Wright & Talisman; Steven Kelly, for Transmission Agency of Northern California; Kashi Mattu, for the British Columbia Power Exchange Corporation (POWEREX); Henry Ramirez, for California Department of Water Resources; Jo Shaffer, Attorney at Law, for herself; Janet L. Prewitt, Attorney at Law, for Bonneville Power Administration; and Christopher Ellison, Attorney at Law, for Destec Energy, Inc. and California Department of General Services.

Commission Advisory and Compliance Division: William Meyer.

Division of Ratepayer Advocates: James E. Scarff, Attorney at Law, Steve Linsey, and John Scadding.

(END OF APPENDIX A)

APPENDIX B
Page 1

List of Abbreviations and Acronyms

ALJs	- Administrative Law Judges
BPA	- Bonneville Power Administration
CACD	- Commission Advisory and Compliance Division
CEC	- California Energy Commission
CEERT	- Coalition for Energy Efficiency and Renewable Technologies
CEQA	- California Environmental Quality Act
CPCN	- Certificate for Public Convenience and Necessity
Destec	- Destec Energy, Inc.
D.	- Decision
DGS	- California Department of General Services
DRA	- Division of Ratepayer Advocates
DWR	- California Department of Water Resources
Edison	- Southern California Edison Company
ER	- Electricity Report
FERC	- Federal Energy Regulatory Commission
I.	- Investigation
IDR	- Identified Deferrable Resource
IEP/GRA	- Independent Energy Producers Association and Geothermal Resources Association
IOU	- Investor-owned Utility
IPPs	- Independent Power Producers
LTTP	- Long-Term Transmission Plan

APPENDIX B
Page 2

MW	- Megawatt
NCPA	- the Northern California Power Agency, Power Agency of California, and City of Anaheim
NUG	- Nonutility Generator
OII	- Order Instituting Investigation
PG&E	- Pacific Gas and Electric Company
Powerex	- British Columbia Power Exchange Corporation
PURPA	- Public Utility Regulatory Policies Act
PU	- Public Utilities
QF	- Qualifying Facility
SDG&E	- San Diego Gas & Electric Company
SPPC	- Sierra Pacific Power Company
TANC	- Transmission Agency of Northern California
Texaco	- Texaco Cogeneration and Power Company
Update	- Biennial Resource Plan Update
Vernon	- City of Vernon
WATSCO	- Western Association for Transmission Systems Coordination

(END OF APPENDIX B)