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Decision 96-10-036 October 9, 1996

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of San Diego & Electric Company (U 902-E) for an Ex Parte Order Approving Modifications to Uniform Standard Offer No. 1 and Standard Offer No. 3.	Application 95-11-057 (Filed November 22, 1995)
Application of Southern California Edison Company (U-338-E) for an Ex Parte Order Approving Modifications to Uniform Standard Offer No. 1 and Standard Offer No. 3.	Application 96-01-008 (Filed January 3, 1996)
Application of Pacific Gas & Electric Company (U 39-E) for an Order Approving Modifications to Uniform Standard Offer No. 1.	Application 96-01-014 (Filed January 12, 1996)

(See Appendix B for appearances.)

PHASE 1 OPINION

1. Summary

This order grants the joint motion of San Diego Gas & Electric Company (SDG&E), Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), Independent Energy Producers Association (IEP), Division of Ratepayer Advocates (DRA), Cogeneration Association of California (CAC), Nordic Power of South Point I, L.P. (Nordic), and Otay Power Inc. (collectively, Joint Parties) for approval of a compromise proposal (Joint Recommendation) which proposes to resolve all Phase 1 issues in these consolidated applications.

The Joint Recommendation reduces the 30-year maximum term of Uniform Standard Offer 1 (USO1) and, in the case of SDG&E and Edison, Standard Offer 3 (SO3) (collectively, standard offers) pursuant to which the utilities purchase as _available power from qualifying facilities (QFs). New standard offer agreements are subject to a maximum term which ends on December 31, 2002, subject to possible extension by order of the Commission.

This order:

- o Concludes Phase 1 of this proceeding by adopting without condition, modification, or change the Joint Recommendation as reasonable in light of the record, consistent with the law, and in the public interest.

- o Phase 2 issues are considered and resolved by allowing 30 year terms for contracts that were formed before April 16, 1996 in light of other measures taken to align USO1's with the restructured market. Contract formation issues for a variety of circumstances are delineated.

- o Additional policy issues not identified by the parties and potentially affecting new USO1's capacity payments are identified for further comment, after which the Commission will determine whether an evidentiary hearing is appropriate.

- o Transitional issues for dispatch of USO1's after the power exchange is operating are resolved to protect fair competition and which require new USO1's to be subject to all source bidding.

- o New Charleston is given procedural guidance concerning its efforts to negotiate a replacement to the power purchase agreement previously terminated through a Commission approved buy-out.

2. Background

2.1 Applications

Currently, the standard offers allow QFs to unilaterally choose a contract term binding the utility for up to 30 years.[1] The utilities assert a need to restructure their long-term power purchase obligations for a more competitive marketplace, one brought about by Rulemaking 94-04-031/Investigation (I.) 94-04-032 (the electric industry restructuring proceeding), the Energy Policy Act of 1992 (EPAct), and the possible repeal of the Public Utility Regulatory Policies Act of 1978 (PURPA). They point out that the standard offers were developed a decade and a half ago to implement PURPA when the QF industry was still developing and a competitive marketplace for power purchases was not contemplated. SDG&E, for example, asserts that the standard offers do not provide for

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[1] The 30-year period runs from the date the project goes on line. QF projects have up to five years from the date of the contract to go on line. Accordingly, the standard offers can create purchase obligations continuing up to 35 years into the future.

changes in power purchasers, bidding or scheduling power to an independent system operator (ISO), curtailments due to transmission congestion related to economic dispatch decisions by the ISO, sales to non-utility purchasers, reallocation of transmission due to ISO operations, new definitions of system emergencies, or changes in the provider of transmission services as a result of changes in the purchasing utility's vertically integrated structure. Edison also asserts that a 30-year contract is inconsistent with normal business transactions in a competitive marketplace. SDG&E asserts that the standard offers could impede competition by restricting the availability of transmission for the next 30 years.

The utilities are concerned that if the standard offers are left unmodified, new QFs could execute standard offers and limit the ability of all power producers to compete in the restructured marketplace. In the words of SDG&E,

> The "not to exceed" 30-year term language is a remnant of the pre-EPAct and pre-Industry Restructuring regulatory environment. That environment has evolved and this Commission's Industry Restructuring proposals will drastically change the way in which power producers and consumers do business in California. Modifying the term of the Standard Offers in the manner SDG&E proposes...will allow new QF contracts the flexibility to adjust to the restructured marketplace without affecting the Commission's implementation of PURPA. Moreover, QFs and utilities may agree to execute non-standard contracts reflecting the change proposed herein or with terms longer than one year.
>
> Once restructuring commences, a utility's obligation to serve may cease to exist. Thus, to allow one class of generators, QFs, to continue to execute and impose 30-year power purchase obligations on the eve of Industry Restructuring provides these power producers a competitive advantage that is not merely unfair

> to other competitors; it is potentially harmful to customers who will lose the benefits of all-source competition, but bear the continuing burden of these long-term contracts. (Application (A.) 95-11-057, p. 5.)

SDG&E, Edison, and PG&E filed these applications to modify the standard offers by replacing their 30-year term with a maximum term of one year.[2] The proposals differ slightly but in general each provides for automatic renewal of the contracts on a year-to-year basis and for conversion to any standard offer that might be in effect at the end of each one-year term. Such revised standard offers, if any, would reflect the then-current transitional stage of industry restructuring. The contracts would be renewable until the Commission modifies or suspends the standard offers or the mandatory purchase obligation under PURPA is repealed. Also, the standard offers would retain the current provision that allows up to five years to commence operations. Once the project commences operations, the one-year term would be in effect.

Applicants believe that as industry restructuring commences (or if Congress repeals PURPA), the Commission should determine whether the standard offers are still necessary and either terminate them or replace them with agreements containing terms and conditions more appropriate for operating in the restructured marketplace. In the meantime, they maintain, there is an immediate need for the relief sought in the applications.

Applicants take the position that developments including proposed PURPA repeal legislation, the EPAct, and industry restructuring have placed QFs on notice that they too are subject to changes as the industry evolves. Accordingly, each applicant seeks to make the standard offer modifications effective as of the date its application was filed (November 22, 1995, January 3, 1996,

[2] As its SO3 already contains a one-year term, PG&E seeks to change only USO1.

and January 12, 1996 for SDG&E, Edison, and PG&E respectively).

The applications do not propose any changes to standard offers executed and received by the utility as of the date of the application. Also, they seek to change only the term of the standard offers. Thus, for example, they do not seek to address the current methodology for calculating Short-Run Avoided Cost (SRAC), which is the subject of proceedings in I.89-07-004. SDG&E and PG&E explicitly stated that their applications are not intended to initiate a proceeding to review and revise all the standard offer terms and conditions.

2.2 Protests and Responses

California Cogeneration Council, IEP, New Charleston Power 1 LP (New Charleston), California Energy Company, Inc., and Nordic each filed a protest to one or more of the applications. CAC, which did not file a protest, generally opposed the applications in its filed prehearing conference (PHC) statement. Otay Power did not file a protest but intervened on May 15, 1996 on the basis of two proposed USO1 agreements submitted to SDG&E on April 12, 1996. Among the points raised in opposition to the applications are the following:

1. The proposed modifications could have an anticompetitive impact on the development of the marketplace envisioned by the Commission in the electric industry restructuring process. Standard offers are essential to prevent market power imbalance during the transition to a competitive market. QFs are not viable without the certainty of longer term contracts.

2. The proposed modifications would allow the utilities to circumvent their obligations to purchase power from QFs as required under PURPA. Making the effective date of the standard offer revisions retroactive to the date of the applications violates due process and cannot be done unilaterally by

the utilities.

3. QFs and other generators will lack transmission access to current markets in the absence of the standard offers.

4. There was inadequate notice of the proposed changes and the proposals violate due process rights. At a minimum, the revised standard offers should apply only to new contracts, not preexisting contracts.

5. The proposed term limit is equivalent to a "regulatory out clause" and is therefore prohibited Decision (D.) 82-01-103 and D.83-10-093.

6. Standard offer purchases will be made at market prices through pending SRAC reform. Utilities and ratepayers should therefore be indifferent to whether the source is a QF or other generator.

Nordic raised concerns specific to ongoing negotiations with SDG&E. Nordic alleged that in 1994 it initiated negotiations with SDG&E for a standard offer contract, and that SDG&E negotiated in bad faith and delayed negotiations until it could file this application. Nordic further alleged that it had made investments and taken other actions in reliance on existing law, and that in fairness it should not be prejudiced in the event that the Commission grants SDG&E's application.

New Charleston, a QF located in El Centro and formerly a party to a long-term power sales contract with Edison, does not currently have a power purchase agreement with any utility. New Charleston alleges that it requires access to USO1 contracts to have access to the wholesale market. New Charleston further alleges that it terminated its contract with Edison based on its belief that it would have access to a USO1 contract. Specifically, New Charleston states that it relied on the "fact that both PURPA and the Federal Energy Regulatory Commission ('FERC') implementing regulations give QFs the perpetual right to sell their power production to utilities." (New Charleston protest to Edison's application, p. 1.)

The applicant utilities filed responses supporting each other's applications. DRA filed a response to PG&E's application, noting that its concerns and recommendations were applicable to SDG&E's and Edison's applications as well. In DRA's view, the utilities' concern that prices paid to QFs under the standard offers will continue to exceed market levels even after industry restructuring occurs, yet payments under agreements signed after January 1, 1996 will not be recovered in any Competitive Transition Charge (CTC) after 2005 (D.95-12-063, as modified by D.96-01-009 (Restructuring Decision), p. 143), can be directly addressed by assuring that QF prices truly reflect market levels. Nevertheless, DRA shares the utilities' concerns that short-run QF prices will exceed current and future market levels. DRA suggested an alternative for reducing the 30-year standard offer term to the earlier of the year 2005, the date on which Congress and the State of California repeal the utility obligation to purchase QF power under PURPA and California law[3], or the Commission converts SRAC to the Power Exchange clearing price and the direct access market is opened to QFs. DRA objected to the utilities' proposal to implement the proposed changes effective the dates of their respective applications.

2.3 Procedural History

An Administrative Law Judge's (ALJ) ruling issued on March 7, 1996 consolidated the applications and set a PHC for March 27, 1996. Parties were directed to file PHC statements identifying issues and the potential for narrowing and settlement

[3] Public Utilities Code { 2801 et seq.

of issues. The ruling also directed the parties to meet and confer, as part of the March 27 PHC, on identification of issues, use of settlement techniques, and other topics set forth in Rule 49(b) of the Rules of Practice and Procedure. The parties agreed thereafter to consider and discuss a proposal for reducing the term of the standard offer contracts. (Tr. PHC, p. 44.)

Following an extensive series of negotiations, during which period the parties periodically informed the ALJ that discussions were continuing, a second PHC was held on May 15, 1996. SDG&E advised the Commission on behalf of the negotiating parties that they had reached agreement in principal on a compromise proposal for reducing the 30-year term of the standard offers and that they would soon be ready to submit a joint recommendation incorporating the compromise principles. The ALJ established a schedule for submission of the Joint Recommendation and responses, and adopted the Joint Parties' proposal that the proceeding be phased so that the prospective availability of the standard offers addressed by the Joint Recommendation would be considered separately from other, project-specific issues raised by protestants. The second phase of these consolidated proceedings was established to provide a procedure for parties who had entered into negotiations for contracts under the standard offers, and had filed protests to one or more of these applications, to pursue their rights before the Commission if those negotiations were not acceptable to one or both parties. (Tr. PHC-2, pp. 52, 63.)

2.4 May 20 Motion

As an integral part of their compromise proposal, the Joint Parties agreed that April 16, 1996 should be the common effective date for the changed standard offer term rather than the filing dates of these applications as originally proposed by the respective utilities. On May 20, 1996, in accordance with the procedure established at the May 15 PHC, the Joint Parties filed a motion for an immediate interim order approving the revised contract term for QFs that entered into negotiations for or signed and tendered a standard offer after April 16, 1996.

In bringing the May 20 motion, the Joint Parties addressed the prospect of a "gold rush" of QFs seeking to sign up for standard offers. The Joint Parties did not agree on whether there is an imminent danger of a gold rush to lock in long-term standard offer contracts on the eve of industry restructuring, as the utilities contended. The nonutility Joint Parties did recognize that an unfettered, prospective right to enter into long-term contracts could have an adverse effect on the transition to a competitive market if numerous contracts were to be tendered.

We have not acted upon the May 20 motion. Since we are today considering the entire Joint Recommendation, which effectively encompasses the relief sought in the May 20 motion, that motion is moot.

2.5 Joint Recommendation

On May 31, 1996 the Joint Parties filed a motion for approval of the proposals set forth in their Joint Recommendation (attached to this decision as Appendix A). They regard the Joint Recommendation as a package reflecting a compromise among them, and agree that the resolved issues are interrelated and that no issue should be evaluated in isolation from the package. Through the Joint Recommendation, the Joint Parties agree to resolve all issues arising from these consolidated applications regarding the term of prospectively available standard offers, i.e., Phase 1 issues. The Joint Recommendation includes the following major elements:

1. Future USO1 agreements and, in SDG&E's and Edison's case, SO3 agreements will contain the following term in place of language in the "Terms and Termination" sections of the respective standard offers that provide for a term of up to 30 years. The Joint Parties acknowledge that non-material language changes may be required for Edison's and SDG&E's SO3s.

> "This Agreement shall become effective as of the date first written above and shall continue in full force and effect until January 1, 2003, at which time this Agreement shall terminate, unless extended by a Commission decision issued on or before December 31, 2002; <u>provided</u>, <u>however</u>, this Agreement shall not continue for a period greater than 10 years after January 1, 2003. This Agreement may be terminated sooner by Seller upon providing thirty (30) days prior written notice in accordance with Section ___."

2. Either party to an agreement executed under the revised standard offer term will be able to apply to the Commission for an extension of the contract term based on seven broad criteria that are set forth in the Joint Recommendation. If the Commission grants an extension, that extension will not exceed one year unless good cause is recognized by the Commission.

3. Utilities will be allowed to offer the reduced term as of April 16, 1996. This is without prejudice to the rights and obligations of QFs and utilities with respect to those QFs that entered into negotiations for or signed and tendered a standard offer on or before April 16, 1996.

4. The Joint Recommendation supports full recovery by the utilities of all costs associated with the utility's obligation to purchase QF power under standard offers entered into after December 20, 1995.

New Charleston filed a response in opposition to the

Joint Recommendation on June 10, 1996. No other party responded to the motion. SDG&E, Edison, and PG&E filed a Joint Reply in opposition to New Charleston's response on June 14, 1996.

3. Discussion

We start from the premise that this Commission's considerable experience with QFs proves quite conclusively that efforts to address the quantity of QF subscription to a standardized offer without addressing the associated contract price are misguided and damaging. This point is relevant because the continued availability of the USO1 is directly the cause of additional quantities of USO1 priced electricity.

As explained more fully below, in our early efforts to promote QF development, we made available standard offers that were not contingent upon the utility's voluntary offer: standard offers were effectuated through regulatory order of their availability, and the voluntary acceptance of that offer by a QF formed the agreement. This approach failed dramatically and we suspended, without hearings, standard offer 2 and interim standard offer 4 for that reason. The combination of standard offer prices and their ready availability led to more dramatic subscription than the Commission anticipated. Because a basic tenant of PURPA is the indifference of ratepayers of the purchase price, relative to utility self-generation <u>or other purchases</u> (18 Code of Federal Regulations (CFR) Section 292.101(b)(6)), the Commission has previously suspended the availability of standard offers. Unfortunately, by the time the Commission acted to suspend standard offer 2 and interim standard offer 4, many agreements the Commission chose to honor had been signed by QF developers, and those agreements are now a significant (but not the only) contributor to California's high rate problem and corresponding regional competitive disadvantage to California business. Existing QF agreements are expected to contribute billions of dollars to the competitive transition charge (CTC) that must be paid by ratepayers in order to move to a more competitive generation market.

Although there are other contributors to the CTC, the Commission cannot avoid its dual responsibility to protect ratepayers and implement PURPA. The Commission now has the added responsibility of ensuring the fairness of competition under new market structures expected to be available in 1998, and containing the CTC so that it can be collected and paid as soon as possible, removing the impediment it presents to new generation and utility competitors.

We note that many states have implemented PURPA without any standard offers at all, leaving QFs to negotiate agreements with utilities that at a minimum match the prices offered by competitive suppliers. Such states have, it is true, far fewer QFs and less diverse generation resources. But they also have lower rates and do not violate PURPA.

The lesson is not lost upon us that, when market circumstances affecting other purchases are significantly less advantageous than an available standard offer, available standard offers will be sought and signed up in greater quantity. For many years, the standard offer 1 has attracted little interest or controversy. Of the QFs still operating, San Diego Gas & Electric Company, for example, signed 37,028 kw of SO1 agreements when they first became available between 1982 and 1987. In the next five years (1988-1992) only 6,990 kw were signed. Since 1992, 14,775 kw have been signed, all of them in 1995 and 1996.[4] Although it matters little whether one characterizes this as a "gold-rush", it is reasonably anticipated that interest will only increase, particularly with new state created incentives to develop

[4] Admittedly, this data does not depict the number of kw actually signed, as it reflects only those SO1's operating. (SDG&E June 1996 Quarterly Customer Generation Status Report.) One of the inherent difficulties in setting QF policy is the problems associated with predicting what level of signed offers will actually develop, or, once developed, stay in operation.

particular types of generation congruent with QF status.

Many of these agreements attend circumstances in which self-generation for a cogeneration customer's steam host was more attractive than any discount the utility could provide to maintain the customer, and the customer chose to make the investment in a generation facility. This trend is likely to continue. As the technology for cogeneration has improved over the last decade, and the costs of building generation and buying gas have fallen, many customers have opted for economic bypass of utility generation. Although these developments occurred slowly over time, recent changes in the industry and law have brought the planning and economic benefits of such projects into sharper focus. However, for much of the last decade, market circumstances simply did not make these offers sufficiently attractive in price to draw significant interest.

Much has changed since 1992 when the Energy Policy Act was passed, as the wholesale market is now broadened in geographic scope, and is accessible to new entrants through open transmission access. The wholesale market will continue to change and become even more competitive in California, with implementation of a power exchange and an independent system operator. These dynamics have renewed attention and interest in standard offer 1, and it is entirely appropriate that utilities have filed applications to seek our re-examination of the offer. In any other ordinary commercial relationship, a buyer dissatisfied with the terms and conditions of an agreement would simply not make the offer to buy on those terms. Because the standard offers are available only by our order, not the voluntary action of utilities, changes to the availability of the offer must be sought and approved by the Commission.

By the same token, the situation is to be avoided which requires utilities to form agreements they otherwise would not, and on the other hand imposes upon their shareholders any above market costs associated with those agreements under clear definitions of

CTC eligibility. If the offer results in costs to the utility above otherwise available market prices, someone must bear that cost, a burden most directly proportional to the quantity of offers accepted. Availability of offers cannot be addressed without examining cost consequences.

3.1 Approval of the Joint Recommendation Without Change Or Modification

We start from the premise that the Joint Recommendation before us, although not an all party settlement, commands broad support from affected stakeholders. (Only New Charleston protested.) We therefore look to Commission Rule 51.1(e) to determine whether the Joint Recommendation is reasonable in light of the whole record, consistent with the law, and in the public interest. We conclude it is.

3.1.1 The Present Record Is Complete

New Charleston argues we are not prepared to make a decision. Thus, we first examine the adequacy of the record.

New Charleston's protests to the applications seeks rejection of the applications on legal grounds and for policy reasons. As Rule 44.2 states, "If the protest requests an evidentiary hearing, the protest must state the facts the protestant would present at an evidentiary hearing to support its request for whole or partial denial of the application." New Charleston made no such request in response to the utilities' applications.[5] "The filing of a protest does not insure that an evidentiary hearing will be held. The decision whether or not to hold an evidentiary hearing will be based on the content of the protest." (Rule 44.4.) The content of New Charleston's protest

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[5] New Charleston protests states, "The Commission has to: consider its past policies with respect to USO1 contracts issued in Commission decisions as far back as the early 1980s; account for the impact of Industry Restructuring on USO1 terms and pricing; know the outcome of any legislation pending before Congress; and evaluate the impact of any decision on the industry itself, before ruling on the Application." (Protest to SCE application, p.10.) None of these considerations of admittedly relevant matters are truly evidentiary in nature, and the speculative and implausible conclusions that might be drawn from impacts of changes that have not happened yet, and are not quantifiable before the fact, place us squarely in our policy-making role.

does not persuade us that any hearings are necessary.

New Charleston also protested the Joint Recommendation, and asked for more careful analysis, presuming the Commission could not consider "all the issues and ramifications", which we have in fact considered in making this decision.[6] No request for hearings is made, only a vague allusion to unspecified "due process issues." (Response to motion, p. 8.) As an initial point, because New Charleston did not have a right to an evidentiary hearing on the applications themselves, and we would not in the absence of the Joint Recommendation grant hearings on the basis of New Charleston's protest, it logically follows that no larger right exists with respect to the motion for approval of the Joint Recommendation. If the underlying issues do not require a hearing to resolve, then the Commission can, if it has sufficient information to evaluate a settlement, rule on a settlement without hearings as well. (That is, in fact, one of the objectives of a settlement: avoiding the burden of full litigation.)

We therefore conclude that there is no due process error involved in reaching a decision on either the Joint Recommendation or other issues not resolved by the Joint Recommendation on the existing record, which is complete. The Commission, given its many responsibilities and expertise with this industry, is aware of its policy, the legal requirements of PURPA, as interpreted by past Commissions, the changes in the industry, the status of all relevant proposed legislation, and, perhaps, even a few "ramifications" New Charleston has not outlined.

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[6] New Charleston named its June 10, 1996 filing an answer, but as it is "in opposition to" the joint motion requesting approval of the Joint Recommendation, it is in actuality a response to a motion under Rule 45 (a) and (f).

3.1.2 The Joint Recommendation Is Reasonable In Light Of The Record

The Joint Recommendation's most important point of agreement is the shortening of the USO1 to a six-year term. Although we may have found shorter terms reasonable, that is not what the parties have recommended we approve. After the power exchange is operating, the market price ratepayers will bear for generation will be an hourly clearing price. (CTC portions of the rate will contribute to the bill, but will decline over time.) It is readily apparent to us that six years is much closer to hourly than thirty years. Therefore, the Joint Recommendation is a dramatic improvement over continued availability of a 30-year term in aligning the agreement with the structure of the market after 1998, and the length of the local distribution company's purchase period.

All the parties to the Joint Recommendation approve this change, and these parties fairly reflect the affected interests. In part due to the involvement of DRA, the parties can be assumed to have negotiated at arm's length and without collusion. We therefore find the Joint Recommendation reasonable in light of the record.

New Charleston objects that this change to the USO1 is unwarranted, creates a regulatory gap, and leaves QFs that are attempting to form unmodified USO1's with an execution date before April 16, 1996 in limbo. As an initial matter, if every issue in every proceeding had to be included in a settlement for it to be reasonable, the Commission would see far fewer settlements. It promotes consensus building and alternative dispute resolution to allow parties to agree to the extent they can, and leave resolution to disagreements for Commission resolution, rather than litigate the entire proceeding on an "all or nothing" basis. Specifically, the Joint Recommendation states that:

Phase II will address project-specific issues related to

> or raised by protests filed in this proceeding by individual projects. Phase I and Phase II are parallel, non-consecutive phases, and Phase II issues may be considered by this Commission both during and after the resolution of Phase I. (JR, p. 8.)

Also,

> This Joint Recommendation is without prejudice to the rights and obligations of QFs and the utilities with respect to those QFs that entered into negotiations for or signed and tendered a Standard Offer on or before April 16, 1996. (JR, p. 7.)

Hence, New Charleston's objection is not with the substance in the Joint Recommendation, but with subject matter that is explicitly not in the Joint Recommendation.[7] It is therefore without merit. The Joint Recommendation, for the scope of USO1's affected (those signed after April 16, 1996), is reasonable. New Charleston does not provide any reason why six years is too short a term for the USO1's that would be affected by adoption of the Joint Recommendation.

Furthermore, although not necessary to our approval of the Joint Recommendation, our resolution of Phase II issues in this decision eliminates the regulatory gap perceived by New Charleston. This regulatory gap exists only if the Commission were to grant New Charleston's request to do nothing to change the status quo. Because the Joint Recommendation specifically allows for Commission resolution of Phase II issues "both during and after the resolution

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[7] In utilities' joint reply to New Charleston's response and objections to the Joint Recommendation, utilities similarly point out that New Charleston's objections are identified as Phase II issues not affected by the Joint Recommendation. We agree, and take a consistent position with respect to other issues not addressed by the Joint Recommendation.

of Phase I," our inclusion of Phase II issues in this decision does not change, modify, or condition the Joint Recommendation, and we therefore can approve it in it's entirety as requested. (JR, p. 9.)

3.1.3 The Joint Recommendation Is Consistent With The Law

Several aspects of the Joint Recommendation touch upon legal matters, and we begin with those that are more procedural and interpretive in nature.

First, the Joint Recommendation provides that the Commission "shall" consider the following factors in making any decisions to extend USO1 terms after 2002:

1. The rationale set forth in the request for extension.

2. The rationale set forth in any response to the request for extension.

3. A rationale not addressed by any party that the Commission determines, based on the law and status of the electric industry at the time of the request for extension, reasonably supports granting or denying the extension request.

4. Whether the Commission or FERC has determined that a competitive market for the generation and purchase of electricity exists.

5. Whether the terms of the Standard Offers are consistent with the then-current rules regulating electric transmission and sales.

6. Whether the purchasing utility has an obligation to purchase power from new or existing QFs under PURPA or then-applicable state or federal statute.

7. Whether, in the absence of a Standard Offer or QF status, there is the provision of an

> interconnection for power projects in accordance with Commission- or FERC-approved interconnection rules. (JR, p. 6.)

The Joint Recommendation also states that future extensions granted by the Commission "shall be based on any one or any combination of the factors listed above." (Id., see also p. 8 Section F.) To the extent this list of factors was interpreted to be exclusive, these provisions might violate the law in that it could constrain future Commission's ability to act upon the record created in a future proceeding and it would violate our settlement rules. (Rule 51.1(a) prohibits resolution of "substantive issues which may come before the Commission in other or future proceedings.") However, other provisions of the Joint Recommendation lead us to a differing interpretation. The Joint Recommendation limits any <u>party</u> from applying for extensions other than on the factors above. "Parties" is defined in the Joint Recommendation as the parties signing the Joint Recommendation (JR, p. 1), and thus does not serve to bind any other entity that, in the future, may come forward and seek extensions based on other factors. Naturally, both the Commission and utilities would need to respond substantively to those requests, even if some other factor were raised that did not squarely fall into those outlined above. The flexibility to do so can be found in the Joint Recommendation, despite it's use of the prescriptive word "shall," in Sections II(F) and III(A). Hence we interpret the Joint Recommendation as providing a non-exclusive list of factors, which renders it consistent with the law: future Commission may make decisions on the merits of the record created in future proceedings seeking extensions, or modify this decision as needed, and the Joint Recommendation does not violate Rule 51.1(a).

The second provision of the Joint Recommendation affecting the law concerns the provision on jurisdiction. The

Joint Recommendation provides the Commission has "exclusive" jurisdiction over "any issue related to the interpretation of this Joint Recommendation, the enforcement of the Joint Recommendation, or the rights of the Parties to the Joint Recommendation...." (JR, p. 10.) However, it also acknowledges the jurisdiction of courts with respect to "matters of interpretation regarding the Standard Offer contracts" or "PURPA implementation matters." Obviously, only one forum can be given "exclusive" jurisdiction. The first and exclusive jurisdiction category (matters of "interpretation regarding the Standard Offer contracts") overlaps with the second, non-exclusive jurisdiction category ("any issue related to" the interpretation or enforcement of the Joint Recommendation). Because the Joint Recommendation requests approval in its entirety, we are reluctant to conclude this provision is not consistent with the law because it is fatally vague, self-contradictory, or inartful. Instead, we again interpret this provision in a manner consistent with the existing law, which admittedly has jurisdictional overlaps. This interpretation is supported by the supporting parties' claim that the Joint Recommendation is consistent with the law.

It falls to this Commission exclusively and as a practical matter (since it is before us and no other decisionmaker) to decide whether to adopt the Joint Recommendation. Once modified USO1's are formed, the contracting parties can, as they do with other QF contracts, seek relief in court on issues of contract administration and interpretation giving rise to disputes other than those at issue in this proceeding and resolved by adoption of the Joint Recommendation. Additionally, USO1 policy issues are, like any other QF policy issues, within our exclusive jurisdiction to the extent consistent with PURPA. Should an entity choose to pursue action against the Commission in federal court for alleged failure to comply with PURPA, despite our broad discretion under the act to implement it, we are clearly without authority to prohibit the initiation of such action through approval of the Joint Recommendation, and would defend our policy on its merits. We reasonably assume this is what the parties supporting the Joint Recommendation intended, as it allows us to agree with their conclusion that the Joint Recommendation is consistent with the law.

New Charleston raises two legal objections to the Joint Recommendation: (1) that Section 210 of PURPA obligates utilities to buy power at full avoided costs, as prescribed by statute and interpreted by regulations (response to JR, pp. 5-6), and (2) prior Commission decision (D.89-02-065) obligates utilities to continue executing USO1 contracts (id., p.6).

3.1.3.1 Does PURPA Require A Mandatory Term Of Agreement?

We begin with Section 210 (16 U.S.C. Section 824a-3(h)), which obligates utilities to purchase electricity from QFs. The shortening of the USO1 term from thirty to six years does not remove that obligation. As New Charleston correctly points out, Section 210 requires such purchases at avoided cost, "as prescribed by statute and interpreted by regulations." Shortening the USO1 term does not affect the avoided cost provisions of the USO1, which, if they complied with PURPA under thirty year terms must be equally compliant with PURPA under shorter terms.

Taking a look at the statute, we find no mandated minimum term for PURPA required purchases. Looking to FERC regulations, we similarly find no mandated minimum term. New Charleston cites no statute, regulation, or case indicating PURPA requires a mandatory, minimum term.

New Charleston does refer to the definition of avoided cost (response, p. 6, n. 8), and one could conclude that New Charleston may be confusing the regulations affecting the calculation of avoided costs with the term of the agreement. FERC's regulations at 18 CRFR Section 292.302 require that the calculation of avoided costs take into consideration the electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years. However, this requirement applies to QFs selling firm, not as-available electricity. Even if we included longer run marginal costs in the calculation of as-available avoided costs, this would not require a 10 year or any other term standard offer.

FERC regulations merely provide that QFs other than as-available QFs have the option of avoided costs calculated at the time of delivery, or at the time the obligation is incurred, "pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term." (292.304(d), emphasis added.) Because the USO1 energy and capacity is delivered "as-available," unlike other long term standard offers (SO2, ISO4, FSO4), the avoided cost prices in the USO1 are short term avoided costs that need not have any "specified term" or provide for avoided costs calculated at the time the obligation is incurred. (Compare, 18 CFR 292.304(d)(1) and (d)(2).) The USO1 is by nature subject to changes in short-run avoided cost calculations. The Commission's view of what constitutes a short or long period for looking at as-available avoided costs relative to utilities' other purchase options logically reflects the wholesale market, where purchases have become increasingly short and contracts as long as six years are virtually unheard of.

It is useful to recall that the Commission's decision to have standard offers at all was one entirely within its discretion under PURPA, and one made after staff complained that non-standard negotiation would not develop the QF industry with the desired speed. PURPA does not require us to have standard offers at all,[8]

[8] FERC regulations (18 CFR Section 292.304(c)(1)) require: "There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less." (Emphasis added.) Standard rates (not contracts) are

much less mandate that a standard offer agreement may be formed without any action on the part of the utility. Both of these aspects of standard offers stem from Commission policy decisions implementing PURPA in the early 1980's. Obviously, other states that do not have standard offers do not violate PURPA, and the continued availability of standard offers is not a right to which PURPA entitles QFs. Both of these policy decisions were made in 1982 when the Commission had an overarching policy objective of encouraging QF development, no excess capacity forecasts, no stranded costs to consider, no rate cap, no broadly available transmission access to facilitate other competitive generation sources, and other wholesale purchase activities of utilities were, by today's standards, relatively shallow and uninformative.

3.1.3.2 Do Prior Commission Policies Limit Our Ability To Define The Date Of Suspension Or The Availability Of The USO1?

We turn to New Charleston's second legal argument, that the Commission cannot change the policy decision to make USO1 available without any action on the part of utilities (response, p. 6, citing D.89-02-065), and find it without merit.

As an initial matter, D.89-02-065 did not prohibit utilities from ever seeking any further change to the USO1, or from seeking to suspend it. It simply did not require any act by the utility for an offer to be effectively made, and therefore in the absence of any regulatory uncertainty affecting that offer a QF could sign the USO1 and form the agreement by accepting it.

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not required for larger QFs. Although the Commission chose to use the same as-available avoided cost for SO3's (100 kw or less) as for SO1's (D.82-01-103, p. 74), the federal requirement is not one of standard offers, but one that requires a standard rate for projects with a design capacity of 100 kilowatts or less. Note that even for these projects, no minimum term is mandated.

Even if D.89-02-065 did prohibit utilities from seeking a suspension, either while the Commission considered changes or more permanently, the Commission has authority under Public Utilities Code Section 1708 to modify prior decisions, provided proper notice is given. Applicants have requested we reconsider, and their applications were adequate notice that we were doing so. Any potential counterparty to a USO1 after the date of effective legal notice of the applications was on constructive notice that the Commission was considering a change in policy. Such changes in regulatory policy are hardly shocking: they occur with two week regularity as the Commission issues decisions that continue to mold, apply, and implement the changes affecting the electric industry. Although regulatory uncertainty is unpleasant to unregulated entities like QFs, it is a fact of life for both utilities, their shareholders, and their ratepayers. Although any experienced QF representative knows this to be true, the Commission's authority to change, modify, or add to past policies is not at the mercy of individual stakeholders' expertise or understanding of this fundamental.

New Charleston does not claim that the applications' appearance on the Commission's Daily Calendar is not effective legal notice, or that New Charleston in fact did not receive notice of the pendency of the applications. (New Charleston filed protest to SDG&E's application on January 12, 1996, and protest to SCE's application on February 2, 1996.) In addition to notice on the Commission's Daily Calendar, which is the means by which legal notice is effectuated for all filings, there was also broad notice by using the service list for I.89-07-004/I.90-09-050, the Biennial Resource Plan Update proceeding. (Tr. PHC p. 40; A.96-01-008, Certificate of Service; A.96-01-014, Certificate of Service by

Mail.) The March 7, 1996 ALJ ruling consolidating these applications and setting a PHC was served on the service list for I.89-07-004/I.90-09-050 as well as all known parties in this proceeding, i.e., those <u>like New Charleston</u> who had filed pleadings in one or more of these consolidated dockets.

Looking to the purpose of our objective in D.89-02-065, it is true that we sought to adopt a uniform SO1 that could be made available, as it had been "with little controversy since it was first approved." (D.89-02-065, 31 CPUC2d 115, 117, finding of fact 4.) The changes at issue in that decision were intended to improve the administrability of the offer and simplify planning for utilities and new QFs. (Id.) The "planning" referred to was specific in nature, and for:

> both the utility and for other potential QF projects. For example, a Standard Offer 1 QF that has essentially ceased operation or development may nevertheless contribute to a transmission bottleneck on the purchasing utility's system because of allocation of transmission capacity to that QF. This could result in existing transmission capacity standing idle, while new QFs might have to pay for additional capacity. (Id., p. 116.)

The solution was revisions to various provisions involving abandonment, project development milestones, and interconnection tariffs (Rule 21). The finding was not a reference to the planning of individual QFs that had not yet executed an agreement: it was to manage the transmission aspects of formed standard offers, and the problems that arose from the fact that while these QFs have "few fixed obligations to perform, the utility must stand ready to accept the QF's power." (Id.) The planning impact on <u>other</u> QFs with formed agreements that "might have to pay for additional [transmission] capacity" was the planning impact at issue. This interpretation follows from the fact that no QF would "pay" for transmission capacity (additional or otherwise) unless it had first signed an agreement for power deliveries and had an interconnection agreement. The interconnection tariff (Rule 21) referred governed the terms by which QFs enter into interconnection agreements and paid for interconnection. The project development milestones were the means by which QFs with signed agreements, meeting certain other requirements, established their priority to available transmission capacity relative to later signing QFs. At the time, there was no broad right of transmission access, and PURPA entitled QFs to be interconnected to utilities' transmission systems. Without agreeing to be a QF, and meet the qualifying standards of QFs, there was no right of interconnection or ability to secure a priority for transmission. [9] Therefore, D.89-02-065 in no way reflects a policy that sought to protect the planning activities of QFs that do <u>not</u> have a power purchase agreement, or unwisely relied upon their belief and interpretation of unassailably rigid Commission policy.

Because we must address the formation of various different categories of QFs to determine whether the Joint Recommendation is consistent with this regulatory law, it is important to review the prior decisions choosing a standard offer approach. The requirement that standard offer one be made available, without an active offer on the part of the utility, was one established as a matter of evolving Commission <u>policy</u> in the early 1980's.

In D.91109, a proceeding investigating PG&E's resource plans and alternatives, staff pressed for <u>guidelines</u> that the utility would be required to follow:

> An issue, at the outset, is whether the role of the Commission should be to direct that a

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[9] Transmission access has changed substantially since 1989, and it is now entirely possible to have transmission access without committing to QF status or having any agreement with the interconnecting utility concerning power purchases.

> pricing policy be applied or to announce price guidelines that may be followed by the utility in the exercise of managerial discretion. The latter is consistent with the tradition under which this Commission operates, i.e., allowing or disallowing utility expenditures, not directing management. Accordingly the Commission adopts that approach in this case. (D.91109 (1979) 3 CPUC2d 1, 13.)

The Commission rejected the notion that price be established only through negotiations, without any guidelines:

> While a negotiated price might provide some savings to the utility and the ratepayer in the short run, a second staff position (Exhibit 41) argues that it would encourage less than the economically optimal amount of cogeneration in the long run. It is argued that reliance on negotiations is untenable due to the monopsony position of the utility in the cogeneration market. Specifically, the utility is the sole buyer for cogenerated power and, therefore, exercises undue price control. This control is sufficient to keep economically justifiable cogeneration from being developed.
>
> This market condition of monopsony requires that specific Commission action be taken (just as it is required in the monopoly market) to more nearly approximate the price/quantity solution of a competitive market and, therefore, to further the public interest. To simulate a market solution, price guidelines need to be established so that the utility can make a public offering to buy cogenerated electricity, both firm and nonfirm, at published prices.
>
> ...Consideration of the cogenerator's costs, as in negotiations, only serves to place the cogenerator at a disadvantage in obtaining an acceptable price and to delay action on projects. The nominal amounts of cogeneration

> online, the the face of much larger potential, attests, in part, to the inadequacy of previous negotiation attempts. (Id., at 14.)[10]

The Commission shifted this position, no longer satisfied with mere guidelines, after beginning a broader rulemaking applicable to all utilities. OIR 2 began with a strong intent favoring guidelines: "In accordance with these rules, the Commission has concluded that a rulemaking to establish cogeneration and small power production pricing guidelines should be instituted." (OIR 2, p. 3.) It ordered a rulemaking for "establishing standards governing the prices, terms, and conditions of electric utility purchases" from QFs. (OIR 2, p. 4.)

As OIR continued, the Commission in D.82-10-103 found that generic policy questions "we resolve in this decision" were appropriately addressed without evidentiary hearings. (D.82-10-103, 8 CPUC2d 20, 29.) One of the issues resolved in that decision was whether the presence of standard rates were enough to promote QF development, or whether standard <u>offers</u> (including those for as-available capacity and energy) would in addition be required. (Id., at 119, Ordering Para. 2.) The Commission decided, after considering "the nature and extent" of mutual obligations associated with "standard <u>rates</u>", that "the result is the standard offer." (Id., at 39, emphasis added.)

> The above offers shall become effective two weeks after the date of filing, unless otherwise suspended by the Commission. (Id., at 199, Ordering Para. 3.)

This shift from prior policy, which espoused a philosophy of guidelines and managerial "discretion," was contributed to by many

[10] This quote is an interesting reflection on how much the industry has changed: cogeneration now has transmission access and can sell at wholesale to many buyers.

factors, not the least of which was ratemaking treatment and a desire for certainty with respect to the reasonableness of the utility's resulting revenue requirements. (Id., pp. 39-41.) Yet this history demonstrates that the decision to implement standard rates, which are only required for projects at or under 100 kw, through standard offers applicable to project over 100 kw, was entirely within this Commission's discretion, and decided as a matter of policy.

A brief review of the many QF policy decisions we have issued over the years is sufficient illustration of the nature of change in this Commission's QF policies. Although we ordered the availability of the standard offers "unless otherwise suspended," we have on several previous occasions done so. (D.84-10-098; D.84-12-027; D.85-01-040; D.85-02-069; D.85-04-075; D.86-03-169.) And we have done so without evidentiary hearings. Standard offers signed by QFs but not utilities before the date of one of the decisions suspending the offer were offers the Commission in D.85-04-075 chose to honor:

> In suspending [interim] Standard Offer 4 in D.85-04-075, the Commission honored its commitment to alter that offer on a prospective basis only. By that order, the Commission intended that the suspension would apply only to those qualifying facilities who had not signed an interim Standard Offer 4 agreement before April 17, the effective date of D.85-04-075. (D.85-06-163, 18 CPUC2d at 282, finding no. 6.)

In making this decision, the Commission had considered the amount of nameplate capacity at issue (17 CPUC2d at 551, finding no. 10), the likelihood that all QF offers would develop and the effect on utility reserve margins (id., finding nos. 11-16), the natural gas rates and their alignment with the suspended offer payment provisions (id., finding nos. 17-21), and the consequences for ratepayers of "paying too great a price" for QF electricity (id., finding no. 22). Hence all the then current circumstances affecting the quantity and price of QF power affected the

Commission's decision to honor contracts signed by QFs, but not utilities, prior to a chosen date. Had the factual circumstances varied, the Commission would have had it equally within its discretion to decide the opposite. Consequently, New Charleston is simply incorrect in its assertion that prior decisions require the utilities to continue executing USO1's after the date they applied for reconsideration and modification of those offers, or that the Commission is legally required to apply modifications on a prospective basis, long after reasonable commercial reliance upon the availability of the unmodified USO1 could be factually established.[11]

Furthermore, New Charleston's position is more similar to that of the non-standard agreements that had been negotiated to completion but were based upon suspended standard offers. In D.85-06-163, the Commission considered the status of non-standard agreements based upon suspended standard offers that QFs had signed but that, due to the suspension of the offer, utilities had not. The Commission for these agreements also chose to direct utilities to sign all of the suspended offers "which were properly completed and signed by a qualifying facility and personally delivered or deposited in the mail to the utility" before the date of the Commission's decision suspending the offer. (D.85-06-163, 18 CPUC2d 264, 284, Ordering Para. 1.) We discuss such non-standard situations further below.

Based on the above review of our policy concerning the availability and formation of standard offers, we can conclude that approval of the Joint Recommendation is consistent with the law, despite the fact that the date of this decision is well after April 16, 1996, the date the Joint Recommendation would begin the

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[11] Factual matters specific to New Charleston are discussed further below.

applicability of new shortened terms. Were we to agree with New Charleston (as we do not), that no retroactivity is legally permissible, we would have to reject or modify the Joint Recommendation to limit its scope to USO1's formed after today. Instead, we agree with the majority of active and expert parties in these dockets that the shorter term can be made applicable for "QFs that entered into negotiations for or signed and tendered a Standard Offer [One or Three] after April 16, 1996." (JR, p. 7.) We note, consistent with our analysis of past policy decisions, that this conclusion does not depend upon the existence of the Joint Recommendation. Were it otherwise, our policy and the regulatory law concerning formation of standard offers we authorize would be untenably contingent upon consensus. It is not.

3.1.4 Is The Settlement In The Public Interest?

We conclude that the Joint Recommendation is in the public interest. For periods after January 1, 1998, it shortens the USO1 to a time frame much closer to the relevant pricing period of hourly, rather than a thirty year time frame. Also, because we will move quickly to address avoided costs calculation issues and other preferences associated with the continuation of USO1, we will ensure that ratepayers, and competitors, do not pay too high a price for the continued availability of the USO1. The Joint Recommendation, by providing the Commission latitude to decide Phase II matters "during and after" resolution of Phase I (JR, p. 8), respects the flexibility needed to resolve the remaining issues in this proceeding concerning individual QF reliance. By addressing these remaining issues we are able to conclude that no public harm will occur by approving the Joint Recommendation, and that it is therefore sufficiently congruent with the public interest to approve.

By approving the Joint Recommendation we are not modifying our Restructuring Decisions concerning CTC. Payments to QFs entering into new standard offers after December 20, 1995 will continue to be deemed reasonable, but may not be included in CTC if they generate above-market costs and may not be included in rates if other legal restrictions on rate increases do not permit rate recovery in the year the payment is made.

3.2 Phase II Issues

3.2.1 Contract Formation: From Date Of Notice To April 16, 1996

First, successful formation of a USO1[12] has been achieved by any QF that: (1) fully executed (a) a USO1 (filling in at a minimum nameplate capacity, specific location, and name), or (b) a non-standard agreement based upon USO1 and negotiated with the utility to successful conclusion, as evidenced by documentation indicating the utility's assent and a meeting of the minds on the terms and conditions, and (2) personally delivered or deposited in the mail to the utility that agreement prior to the date the utility's application first appeared on our Daily Calendar.

As for QFs that did not complete the actions above in time, but had fully executed a USO1 and personally delivered or deposited it in the mail to the utility before April 16, 1996, we decline to shorten the term, as we clearly could. We exercise our discretion in honoring these commitments solely because the harm that would be caused to ratepayers and other competitors is, through other policy decisions addressed here, fully mitigated. Were this not the case, we would also shorten the term of these agreements as well because: (1) FERC regulations do not require "specified terms" for as-available rates, (2) it is not reasonable to rely on an offer that one has constructive or actual notice has been or is argued by the counter-party to be withdrawn. Because the preferences associated with these agreements are being eliminated by this decision, we need not shorten these agreements and conclude that these agreements have been formed.

As for QFs that are not described in the prior two

[12] SO3's are similarly situated.

paragraphs, but had begun negotiations based upon the USO1 prior to April 16, 1996, we similarly decline to shorten the term of those agreements, as we could, so long as the QF: (1) negotiated with the utility to successful conclusion, as evidenced by documentation indicating the utility's assent and a meeting of the minds on the terms and conditions, and (2) personally delivered or deposited in the mail to the utility that agreement prior to April 16, 1996. We similarly conclude, for the same reasons in the paragraph above, that these agreements have been successfully formed.

All QFs desiring to form USO1 agreements, or non-standard agreements based on USO1, that are not described in this section of the decision above, are subject to the shorter six-year term.

3.2.2 Eliminating Reliance Upon Preferences Relative To All Source Competition

As discussed above, this Commission's prior efforts to address QF standard offer subscription without connecting price and quantity shattered on a series of suspension decisions in which the ratepayer costs of standard offers available in unlimited quantities was too much. Estimates of competition transition costs arising from existing QF contracts validate the danger of refusing to learn from past mistakes.

We therefore reiterate that the policy and pricing affecting as-available USO1 agreements is subject to continued regulatory and legislative change. **We require that each utility provide any party seeking a copy of its USO1 with a copy of this decision, which will eliminate reliance on inaccurate verbal statements or written opinions with respect to the inherent changeability of USO1 prices or the manner in which such purchases will be accepted by the power exchange.** FERC regulations provide that as-available QF power is to be paid at avoided costs determined at the time of delivery, and that is an inherently unstable determination over the next six years, particularly once operations under a restructured electricity market begin, and will continue on into the foreseeable future.

We see no reason to "hide the ball" with respect to the currently expected low avoided costs likely after January 1, 1998, or suggest that we will do anything other than use market prices to the extent consistent with the law in setting avoided costs for energy and capacity.[13] The unbundling of ancillary services like spinning and non-spinning reserve will provide new market based measures of the value of capacity. During hours of minimum load[14], the power exchange will often have no bid from any generator dispatched by the power exchange, and the value of capacity may be zero. This results because local distribution companies will not be bidding must-take resources into the power exchange (D.95-12-063, p. 85), and such resources will be more than total system load during some times. DRA has estimated that this may occur, taking into account <u>only</u> existing QF contracts as "must take" resources, as much as one third of the hours in an annual period.

Even during hours that the system is not in a state of minimum load, the difference between the market clearing customer demand bid at the level of generation dispatched by the independent power exchange and the highest supplier bid dispatched, is expected by some to be frequently, if not always, zero. This result occurs from the flexibility of decremental demand bids, expressing interruptible customers willingness to be curtailed above a

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[13] Transitions to market prices are expected to be consistent with the law, including PU Code { 390.

[14] Minimum load occurs when resources defined by the CPUC as "must-take" resources have a combined output in excess of the total system load. The Commission has defined "must take" resources as "all grand fathered generation contracts, including QF's, and nuclear facilities." (D.95-12-063, p. 35.)

particular clearing price. A supplier bid that is higher than this clearing price will not clear the market, and the difference between the demand bid and last clearing supplier bid could be frequently if not always zero. This comports with the Commission's view of the power exchange's development. "Over time, as transition costs are eliminated and excess capacity diminishes, the clearing price for the electricity commodity will gradually reflect a value for capacity." (D.95-12-063, p. 54.)[15] We need not now resolve implementation of new pricing methodologies. We intend merely to emphasize that reliance upon particular prices cannot be

[15] Note that, were above-market avoided costs permitted to grow through the addition of new USO1's, and be added to the CTC, that unfair competition would result because the transition costs would never be eliminated. Savvy competitors would sign a USO1 if they could meet the qualifications for QFs, recoup their capacity costs through above-market avoided costs, leaving all other generators to recover their fixed costs from a direct access customer or a clearing price that only reflects energy. Over time, these distortions in the market would render local distribution companies a "deep pocket," harming those customers least likely to pursue other options: full service customers.

based upon past or outdated policies.

We will endeavor, to the extent consistent with the law, to encourage utilities to meet all the conditions necessary for us to find as-available short run avoided costs are no more than the hourly market price revealed by the power exchange as soon as possible. Therefore, QFs entering into USO1's do so with the knowledge that they cannot reasonably expect above-market prices for either their energy or capacity to persist for long, if at all. No preference for QF power justifies payment above levels arrived at by all source bidding, as such above-market prices would violate PURPA's standard of ratepayer indifference.

In the meantime (prior to 1998), a policy argument we have previously considered but not adopted is ripe for reconsideration. Utilities have previously suggested that energy provided by a QF on an as-available basis does not allow a utility to avoid any capacity costs. (D.82-01-103, supra, at p. 45.) We decided that issue as a matter of policy in 1982, a policy influenced by an overriding desire to encourage the "fullest possible efficient development" of QFs. (Id., at 40.) The basis of this position is that as-available capacity cannot be counted upon to meet reserve requirements or peak loads. This policy argument has some merit in today's changing circumstances, and is one we are entitled to make in examining short-run avoided cost calculation methodology and setting prices at the time of delivery.

It is a commonly understood fact in the industry that the Western markets have excess capacity in the near to mid term, which renders the value of more capacity very low.[16] Quarterly reports of all the IOU's purchasing activity over short terms indicates that capacity is rarely priced above zero. We therefore reconsider, on

[16] Recent outages experienced in the Western region have not been caused by any inadequacies in the amount of capacity available to meet reserve margins.

our own motion, our prior policy decision that the as-available value of capacity be higher than zero for USO1's (or SO3's) formed after the date these applications were effectively noticed and before January 1, 1998 (or when the restructured market is operating). We subject this change in policy to a comment and reply comment phase in this proceeding, as it is a policy intended only to apply to these new offers, prior to the date a restructured market is operating.[17]

Because the consequence of any above-market short-run avoided costs after the restructured market is operating and for QF contracts formed before December 20, 1995, is a rate impact that contributes to CTC, we wish to emphasize that neither our policy decision or the law requires that we expand the scope of generation resources eligible for CTC recovery to include obligations incurred after December 20th. CTC is a market entry barrier to new generators of all types, not just QFs, and it will never be completed if new sources of CTC are continually added. We anticipate that utilities will seek changes in the law to relieve their shareholders of the squeeze created by new QF contracts that are excluded from CTC but that may generate costs above market. Consistent with our discussion above, payments made to standard offer holders will be deemed reasonable, even if they are not eligible for CTC. They may be excluded from rates only if other legal restrictions on rate increases render recovery unavailable in the year the electricity was delivered and paid for.[18] Non-standard agreements entered into after December 20, 1995 are similarly not eligible for CTC recovery, and any portion of the payment that is

[17] USO1's and SO3's signed by QFs before the date of notice of these applications are not the "new" offers we refer to here and should be deemed formed before those notice dates.

[18] Rate increases are limited by new provisions of law enacted in Assembly Bill 1890.

above market-costs at the time of delivery will not be deemed reasonable or recovered in rates.[19]

Last but not least, and in fact the chief impetus behind new USO1 contracts, we must address the preference that could attach to new QF agreements relative to the rest of the market's competitors with respect to dispatch priority. To ignore this issue would be to permit the elimination of the direct access market, which we are determined to develop and defend. With the elimination of above-market costs for short-run avoided cost calculations, this perceived advantage would otherwise be the one that would inefficiently spur more new USO1 agreements than we would permit. Without this policy affecting USO1 (and SO3) dispatch after 1998 (or operation of the restructured market), we would instead simply suspend both offers effective from the notice date of the applications, and set a standard rate for QFs at or under 100 kw that reach a successfully negotiated non-standard agreement. This transitional policy is critical to our continued tolerance of any standard offers, for the reasons below.

The independent system operator (ISO) will have the obligation to maintain system reliability. This means the ISO will be balancing load and resources. As noted above, the existence of "must-take" resources will at times exceed load. Exacerbating this problem, by adding additional must-take resources, will further push direct access users off the grid.

The utilities have proposed an over-generation protocol for managing minimum load conditions in FERC Docket No. EC96-19-000, Application, Appendix E.[20] Those protocols were not

[19] This ratemaking treatment is consistent with our prior decisions affecting pending negotiations for QFs that have agreed to arbitrate disputes arising from relevant decisional law, subject to limitations in the arbitrators' award. (D.93-032-020, pp. 7-8; D.93-06-099, p.8.)

[20] SDG&E's alternative proposal for over-generation has been withdrawn.

objected to by the Commission, and are expected to develop with further detail (after some guidance from FERC is obtained) in what is now termed "stage 2" filings of additional application material. At this point in time, the conceptual design of these protocols agreed to by many diverse stakeholders provides that power exchange generation other than must-take and hydro spill is curtailed first, all non-power exchange generation is curtailed second, and reductions in must-take and hydro spill generation are curtailed last, according to an allocation method applicable to PG&E, SDG&E, and SCE. (Application, pp. E-2 to E-3.) The Application specifically states that "non
_PX generation" (curtailed second in order) "refers to generation supplying end-use customer loads being served over the Applicants' transmission or distribution facilities." (Id., E-3, n. 3.) These generators and loads are understood to include all direct access customers and suppliers. The Commission was well-aware of the minimum load problem associated with comparable and efficient grid use prior to issuing its Restructuring Decision. The Commission anticipated this very problem in defining regulatory must-take generation resources very deliberately as "grand fathered" QF contracts. Those contracts were signed as of December 20, 1995, and correspondingly were insulated from market pressures by a regulatory commitment to honor existing contracts and flow the above-market costs of those contracts through to all ratepayers in the CTC. We see no reason to change that definition now, as it will only expand the category of generation qualifying for curtailment <u>after</u> all direct access generators have been curtailed.

If a generator seeks to compete in the new market as a direct access provider, and other competing generators are able, through the continued availability of the USO1 for some or all of their capacity, to stay avoid curtailment, then the number of hours during which minimum load conditions exist will expand to fill the year. Generators' profitability is highly correlated to the magnitude of unplanned outages, as turning a plant on and off increases operations and maintenance costs of the QF and disturbs the steam host's operations. The advantage of obtaining must-take status is viewed as providing a "right to run" when others are subject to curtailment. This consequence is not the comparable, non-discriminatory access to and use of the transmission grid we require. The number of minimum load hours experienced today with separate control areas for PG&E, SCE, and SDG&E will dramatically swell if a preference relative to other generators in the market can be obtained through the USO1.

We therefore place QFs, with two limited exceptions, on notice that they cannot rely upon obtaining regulatory must-take status if the date of formation of their agreement with PG&E, SCE, or SDG&E is after December 20, 1995. No modification of our Restructuring Decision is involved: the plain meaning of "grand fathered" is consistent with this result.[21] New QFs will be, as soon as the restructured market begins operation, "subject to the same protocols and prices regarding transmission access and treatment of transmission congestion." (D.95-12-063, p. 34.) They will clear the power exchange if they bid low enough relative to all other sources to clear the market.[22]

Severable from the issues associated with changes to avoided cost pricing proposed or required by law, such QFs will have to bid directly into the power exchange, and clear the market

[21] A grand father clause is a "provision in a new law or regulation exempting those already in or a part of the existing system which is being regulated. An exception to a restriction that allows all those already doing something to continue doing it even if they would be stopped by the new restriction." Black's Law Dictionary (1979, 5th ed.).

[22] The first notable exception to this would be QFs that modify through non-standard negotiations their USO1, which is an agreement covering all the output of the facility, in order to deliver to a direct access customer. Direct access customers may be eligible to take renewable QF power prior to others. The second exception concerns projects that for policy reasons we exempt from our discussion of dispatch priority, beginning on page 38 and until 2002. Exempted projects are small, publicly owned, landfill biomass QFs. We do not expect such projects would exceed 40 MW in aggregate for the state, and we will address CTC recovery issues that may be associated with these projects in future CTC proceedings. These projects are distinguishable on the basis that they qualify for tax exemption benefits. These projects will also be eligible for today's SRAC capacity value at least until January 1, 1998.

at their bid price in order to run. They will have no right to be included in the local distribution company's (LDC's) submitted schedule as a must-take resource, although they may use the LDC as a schedule coordinator to submit bids to the power exchange (not on a must-take basis) if they choose. Local distribution companies, after the restructured market is operating, do not have an obligation to plan for load and build new rate based generation. Their role for customers not choosing other options is to deliver power procured by the power exchange, and they therefore purchase all their electricity for full service customers from the power exchange (id., p. 53). Our requirement that all persons requesting USO1's from utilities be provided with this order goes far beyond the notice legally effective in precluding new USO1 QFs from presuming they have must-take status or will not have to clear the power exchange through all source bidding in order to deliver as-available energy or capacity.

Because our elimination of any preferences associated with standard offers is so critical to the functioning of the restructured market, and in particular the availability of direct access, we will automatically suspend both USO1 and SO3 if challenges to this decision are made in any forum. In that event, QFs with projects 100 kw or less can negotiate a non-standard agreement based on standard rates available to grand fathered USO1 agreements entered into before the notice date of these applications.

3.2.3 Further Procedural Matters

The joint motion submitted by the parties for interim relief is moot and denied with prejudice as we did not reach a decision on that motion prior to our decision on the Joint Recommendation, as anticipated by the parties.

The assigned administrative law judge will issue a ruling setting the date for comments and reply comments on the Commission's proposed modification to its prior policy decision to assign shortage cost value to as-available avoided cost of capacity for new USO1's formed after the date utilities' applications first appeared on the Commission's Daily Calendar. We intend to further consider setting that avoided cost at zero until the restructured market is operating.

We are particularly interested in comments indicating above zero capacity prices: (1) from publicly accessible information about wholesale prices in the western region (WSCC extensive), (2) for purchases of non-firm power less than one year in duration. We caution parties from relying too heavily upon the rationale of past Commission decisions, as we have always reserved the right to modify methodology for determining as-available avoided costs of capacity, and no reliance claim to the contrary can be validly based on a comprehensive reading of Commission policy on this subject. We consider many of the (highly) theoretical underpinnings of decisions first made in the early 1980's entirely out of date with present purchase alternatives of utilities.

To the extent a party chooses to comment that incremental utility generation should be used to determine the avoided cost of capacity, we commend to them the task of addressing our related concerns: (1) identifying a current utility resource plan including new utility owned generation, and (2) addressing whether PURPA's requirement of ratepayer indifference can be met if the method advocated for the avoided cost of as-available capacity exceeds that available to utilities from purchases. We will consider, after we have received comments, whether evidentiary hearings are required.

No party should rely upon past decisions designating this issue for some other forum or proceeding: we intend to address it now, in this proceeding, and with the limited scope stated (contracts formed after the applications were filed and noticed), and for a limited time (prior to the operation of the restructured market).

With respect to New Charleston, the only protestant to the Joint Recommendation, we are unable to determine whether the policies we decide today resolve its formation difficulties. We suggest to New Charleston procedural guidance should it have continued problems concerning its asserted "right" to a USO1 or non-standard agreement based on a USO1. As non-standard negotiations are by their nature voluntary if they result in successful formation, New Charleston's recourse is to file a complaint for bad faith negotiations, based on the standards for QF negotiation we have previously articulated. (D.82-01-103, supra, 8 CPUC2d at pp. 84-85.) We caution New Charleston that, having filed a complaint, the Commission may on its own initiative combine that case with an investigation or order to show cause to determine whether the factual premises New Charleston submitted to us in securing Commission approval of a buy-out agreement were true, including any representations made during ex parte communications about whether the facility would or could be operated under an SO1. We have a rather vivid memory, based on the relatively recent approval of New Charleston's buy-out, of New Charleston's stated business plan were we to approve the buy-out.

Hopefully, the policies in this decision will provide sufficient direction, but we are mindful that issues of intent with respect to the buy-out agreement may be raised that render New Charleston dissimilar from other new facilities that may form a USO1. New Charleston may have contractually compromised that right, but this conclusion would depend upon an evidentiary record and support not available to us here.[23] We do know from

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[23] We note that in our review of buy-outs we have generally found the more common practice to be the inclusion in the buy-out agreement an explicit provision concerning whether the facility may in the future sell under PURPA, and that generally the agreement provides for future deliveries, if any, from a non-QF generator. We encourage parties negotiating buy-outs to be explicit on this subject.

A.95-04-026 that the ratepayer benefits of the buy-out were dependant upon forecasting of future plant performance, and therefore we suggest New Charleston be circumspect and deliberate before initiating proceedings seeking further relief.

Findings of Fact

1. Until 1998, it is reasonable to continue making the uniform standard offer one and standard offer three agreements available to QFs to sign provided that prices and advantages relative to the restructured market are eliminated.

2. Reducing the standard offer term will allow a more flexible approach in that parties to the standard offer contracts will be able to adjust the terms and conditions to the evolving market environment.

3. The applications were served on the service list for I.89-07-004/I.90-09-050, and the March 7, 1996 ALJ ruling consolidating these applications and setting a PHC was served on the service list for I.89-07-004/I.90
_09-050 as well as all known parties.

4. New Charleston had actual notice of the applications by at least January 12, 1996 (SDG&E) and February 2, 1996 (SCE).

5. All parties were provided with an opportunity to file responses to the Joint Recommendation.

6. The applications, protests and other responses and replies thereto, PHC statements, motions, and responses to the motions and replies thereto constitute a complete record.

7. The proposed factors for consideration of contract 46 extensions beyond 2002 broadly state the types of issues the Commission would need to consider to make a reasoned decision, and are not exclusive.

8. The parties sponsoring the Joint Recommendation merely intended their provision on jurisdiction to reflect the existing jurisdictional law concerning QFs.

9. The rights and obligations of QFs and the utilities with

respect to those QFs that entered into negotiations for or signed and tendered a standard offer on or before April 16, 1996 are not affected by the change in standard offer terms proposed by the Joint Recommendation.

10. New Charleston protests only subjects not included in the Joint Recommendation.

11. Small publicly owned landfill biomass QFs are eligible for certain tax benefits.

Conclusions of Law

1. The May 20, 1996 motion for interim relief should be dismissed with prejudice as moot.

2. Evidentiary hearings are not necessary for matters decided in this decision.

3. The appearance of utilities' applications on the Commission's Daily Calendar constitutes constructive notice that the Commission had been asked to reconsider the availability of standard offers.

4. PURPA does not require that we made standard offers available.

5. PURPA does not require a minimum or specific term for as-available QF purchases.

6. The Commission should reconsider the continued availability of the USO1 and SO3 after 1998.

7. The Commission should reconsider its policy of paying above zero for new as-available capacity prior to 1998.

8. The continuation of any standard offers at this time should depend upon their providing no preference relative to all other sources of generation after 1998 or the beginning of the restructured market.

9. The Commission has the discretion to decide whether formation of standard offers will be effective when making duly noticed decisions to suspend or modify those offers.

10. Reliance upon the availability of unmodified standard offers that are the subject of requests for change or suspension is not reasonable in light of the regulatory law and policy affecting formation of these agreements.

11. Because of policies established to eliminate curtailment priority for new QFs and move avoided costs for as-available agreements toward market prices, approval of the Joint Recommendation is in the public interest.

12. The Joint Recommendation is reasonable in light of the record and consistent with the law, and should be adopted effective today. Approval of the Joint Recommendation should not be construed as a modification of the Restructuring Decision policies regarding CTC recovery.

13. The May 31, 1996 Joint Motion for approval of the Joint Recommendation should be granted as provided in the following order.

14. Contract formation policies for QFs not within the scope of the Joint Recommendation are established in Section 3.2 of our Discussion. Small publicly owned landfill biomass QFs shall be exempt from the discussion of dispatch priority in that section until 2002, as well as any changes in short-run avoided cost of capacity prior to January 1, 1998.

15. The USO1 and SO3 should be suspended during the pendency of any challenges to this decision in any forum.

INTERIM ORDER

IT IS ORDERED that:

1. The May 20, 1996 "Joint Motion of San Diego Gas & Electric Company (U 902-E), Southern California Edison Company (U 338-E), Pacific Gas and Electric Company (U 39-E), The Independent Energy Producers, Division of Ratepayer Advocates, Nordic Power of South Point I, L.P., Otay Power Inc., and the Cogeneration Association of California for Immediate Order Authorizing Revised Contract Term in the Uniform Standard Offer No. 1 and Standard Offer No. 3, Pending Commission Consideration of Joint Recommendation" is dismissed as moot.

2. The May 31, 1996 "Joint Motion For Expedited Approval of the Joint Recommendation of San Diego Gas & Electric Company (U 902-E), Pacific Gas and Electric Company (U 39-E), Southern California Edison Company (U 338-E), Independent Energy Producers Association, Division of Ratepayer Advocates, Cogeneration Association of California, Nordic Power of South Point I, L.P., and Otay Power Inc." is granted in its entirety.

3. For QFs that first entered into negotiations for or signed and tendered a Standard Offer one or three after April 16, 1996, San Diego Gas & Electric Company (SDG&E), Pacific Gas and Electric Company (PG&E), and Southern California Edison Company (Edison) are authorized to replace the current language in the "Term and Termination" sections of their respective Uniform Standard Offer 1 the revised term language set forth in the Joint Recommendation attached as Appendix A, subject to the terms and conditions set forth therein. SDG&E and Edison are authorized to replace the current language in the "Term and Termination" sections of their respective Standard Offer 3 the revised term language set

forth in the Joint Recommendation attached as Appendix A, subject to the terms and conditions set forth therein. In making such changes, SDG&E, PG&E, and Edison are authorized to make changes that conform all language in the offer to the shortened term.

4. Any QF that (1) fully executed (a) a USO1 or SO3 (filling in at a minimum nameplate capacity, a specific location, and a name), or (b) a non-standard agreement based upon USO1 and negotiated with the utility to successful conclusion, as evidenced by documentation indicating the utility's assent and a meeting of the minds on the terms and conditions, and (2) personally delivered or deposited in the mail to the utility that agreement prior to the date the utility's application first appeared on our Daily Calendar, has successfully formed an agreement which is not the subject of proposed changes to short-run avoided capacity made in this decision.

5. Any QF that had fully executed a USO1 or SO3 and personally delivered or deposited it in the mail to the utility before April 16, 1996, has successfully formed an agreement which is not subject to our order shortening the term of USO1 and SO3.

6. QFs that had first begun negotiations based upon the USO1 prior to April 16, 1996 and (1) negotiated with the utility to successful conclusion, as evidenced by documentation indicating the utility's asset and a meeting of the minds on the terms and conditions, and (2) personally delivered or deposited in the mail to the utility that agreement prior to April 16, 1996, has successfully formed an agreement that is not subject to our order shortening the term of the USO1.

7. The UOS1 and SO3 will, without further order, be suspended on January 1, 1998, or upon initiation of any challenge to this decision in any forum. In the event of suspension, QFs with design capacity 100 kw or less may negotiate non-standard agreements based upon the standard rates applicable to grand fathered USO1's and tariff Rule 21.

8. With the exception of small, publicly owned landfill biomass projects, utilities shall not recover in rates any portion of payments to as-available QFs holding non-standard agreements entered into after December 20, 1995, that, at the time of delivery, are greater than market prices.

9. This proceeding remains open for an order of the assigned administrative law judge setting forth comment and reply comment dates for proposed changes to the methodology for as-available short-run avoided capacity payments at the time of delivery, prior to 1998, and for new QF agreements formed after the date of effective notice of utilities' applications.

This order is effective today.

Dated October 9, 1996, at San Francisco, California.

P. GREGORY CONLON
President
DANIEL Wm. FESSLER
HENRY M. DUQUE
Commissioners

I will file a concurring opinion.

/s/ P. GREGORY CONLON
President

I will file a written dissent.

/s/ JESSIE J. KNIGHT, JR.
Commissioner

I dissent.

/s/ JOSIAH L. NEEPER
Commissioner

APPENDIX B

List of Appearances

Applicants: Mike Tierney, Attorney at Law, for San Diego Gas & Electric Company; Gloria Ing, Attorney at Law, for Southern California Edison Company; and Randall Litteneker and Peter Ouborg, Attorneys at Law, for Pacific Gas and Electric Company.

Protestants: Ater, Wynne, Hewitt, Dodson & Skerritt, by Michael P. Alcantar and Kirk H. Gibson, Attorneys at Law, for Cogeneration Council of California; Goodin, MacBride, Squeri, Schlotz & Ritchie, by Diane Fellman, Attorney at Law, for Independent Energy Producers Association; Latham and Witkins, by Joel H. Mack, Attorney at Law, and Diana L. Strauss, for Nordic Power; Jan Smutny-Jones, for Independent Energy Producers Association, and FMY Associates, by Faramarz M. Yazdani, for New Charleston Power.

Interested Parties: Edson and Modisette, by Carolyn A. Baker, Attorney at Law, and Gary Darnsteadt, for Chevron Corporation; Morrison & Foerster, by Jerry R. Bloom, Marc Young, and Joseph M. Karp, Attorneys at Law, for California Cogeneration Council, and John R. Shiner, Attorney at Law, for California Energy Company; Jennifer Chamberlin, for Barakat and Chamberlin; Robert Finkelstein, Attorney at Law, for Toward Utility Rate Normalization; Norman Furuta, Attorney at Law, for the Department of Defense; Douglas K. Kerner, Attorney at Law, and Michael R. Starzer, for Berry Petroleum Company; Reed V. Schmidt, for Bartle Wells Associates; Morse, Richard, Weisenmiller & Associates, by Holly Senn, for Richard B. Meisenmiller, for Various Clients in Monitoring this Proceeding; Latham and Watkins by Diana L. Strauss, Attorney at Law, for Otay Power; Joseph G. Meyer, for Joseph Meyer Associates; Coudert Brothers by Ed Lozowicki, Attorney at Law, for himself; and James Scarff, Attorney at Law, and Brian Schumacher, for the Division of Ratepayer Advocates.

(END OF APPENDIX B)

I N D E X

Subject Page

Appendix A
Appendix B

See formal file for Appendix A.