STATE OF CALIFORNIA GRAY DAVIS, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

August 6, 2002 8/22/2002
Agenda ID #952

TO: PARTIES OF RECORD IN RULEMAKING 01-10-024

Enclosed are the proposed decision of Administrative Law Judge (ALJ) Walwyn and the proposed alternate decision of Commissioner Lynch. They will be on the Commission's agenda at the meeting on August 22, 2002. The Commission may act then, or it may postpone action until later.

When the Commission acts on the proposed decisions, it may adopt all or part of them as written, amend or modify them, or set them aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

In setting the briefing schedule on July 2, 2002, the ALJ asked parties to address if they would stipulate to shortening the time for review of the proposed decision pursuant to Section 311(g)(2). Several parties stated their support for this in their briefs; no party opposed the request. Parties will have another opportunity to address this issue in their oral argument before the Commission on August 8, 2002. We will consider the silence of a party on the issue to imply consent. If no objections are raised to the Commission shortening time for public review of the proposed decision at the oral argument, comments will be due on August 19, 2002, and the decisions will be placed on the August 22, 2002 Commission agenda.

/s/ CAROL BROWN
Carol Brown, Interim Chief
Administrative Law Judge

CAB:sid

Enclosures

Decision **PROPOSED DECISION OF ALJ WALWYN** **(Mailed 8/6/2002)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development.	Rulemaking 01-10-024 (Filed October 25, 2001)

(See Appendix A for a list of appearances.)

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INTERIM OPINION

I. Summary

The question before the Commission in this interim decision is the extent to which, if at all, the respondent utilities should be permitted to immediately contract for a portion of their residual net short (RNS) in partnership with the California Department of Water Resources (DWR).[1]

In this decision, we authorize the respondent utilities to enter contracts in participation with DWR between the effective date of this decision and January 1, 2003. Because the RNS forecasts of each utility show a need for energy in 2003 in only a small number of peak hours, together with the uncertainty attached to these forecasts due to the pending status of DWR contract allocation and renegotiation, we are conservative in the amount and type of transitional authority we grant.[2]

We adopt a procedural process to review and approve these contracts. This process provides the utilities with an opportunity for an expedited decision that resolves reasonableness issues, while ensuring effective Commission oversight.

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[1] The residual net short is the amount of energy needed to serve a utilities' customers net of existing resources, including those supplied by DWR.

[2] This is not the decision in which full and detailed procurement plans will be authorized, nor is it the forum in which the requirements of Assembly Bill (AB) 57 – which is not yet law, although it has been unanimously approved by the state legislature – will be met. The task before us now is deliberately measured, as it must be if we are to meet the mounting demands of the calendar.

We also address the procurement of renewables in this transition period, assuring that our grant of contracting authority here does not harm our ability to include renewables in a final procurement plan.

Finally, we address the request of gas-fired cogeneration companies for qualifying facilities (QFs) to be given preference in the solicitation process for legal and policy reasons.

II. Procedural Background

On October 29, 2001, the Commission issued an Order Instituting Rulemaking (OIR), designated as Rulemaking (R.) 01-10-024, to

> (1) establish ratemaking mechanisms to enable California's three major investor-owned electric utilities, Southern California Edison Company (Edison), San Diego Gas & Electric Company (SDG&E), and Pacific Gas and Electric Company (PG&E) to resume purchasing electric energy, capacity, ancillary services and related hedging instruments to fulfill their obligation to serve and meet the needs of their customers, and
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> (2) consider proposals on how the Commission should comply with Public Utilities Code Section 701.3 (Section 701.3) which requires that renewable resources be included in the mix of new generation facilities serving the state.

A preliminary scoping memo contained in the OIR set a schedule for respondent utilities to file procurement proposals and for interested parties to comment on the proposals, and scheduled a prehearing conference for January 8, 2002. SDG&E and PG&E filed their proposals on November 21, 2001 and Edison late-filed its proposal on November 27, 2001. Interested parties requested and were granted a one-week extension until December 21, 2001 to file comments. In their comments, many parties urged the Commission to develop a fully integrated resource planning process but to only decide quickly those issues that need to be in place for the utilities to resume full procurement responsibilities no later than January 1, 2003, as anticipated by Assembly Bill ABX1 1 (Keely).

The procedural schedule and scope for the initial proceeding was adopted in the April 2, 2002 Assigned Commissioner Ruling Establishing Category and Providing Scoping Memo (April 2 Scoping Memo). The ruling explicitly emphasizes interim procurement methods for the immediate issue of restoring the utilities' obligation to serve and meet the needs of their customers no later than January 1, 2003. The ruling requested briefs on transition issues that needed to be resolved and set a schedule for the respondent utilities to file procurement plans for 2003 with accompanying testimony. The April 2nd Scoping Memo schedule anticipates a proposed decision in September, with a final Commission decision in October 2002. The only consideration of procurement practices post-2003 was for procurement of renewable resources to address our mandate under California Public Utilities Code Section 701.3 (Section 701.3).

The respondent utilities served their testimony on May 1, 2002. As part of this testimony, Edison proposed the Commission adopt a process by which it could immediately begin contracting for up to a five-year term for capacity and related products in conjunction with the DWR. On May 6, 2002, Edison filed a motion requesting that this proposal be approved on an expedited basis outside of the hearing process. By ruling on May 15, 2002, the scope of this initial phase was expanded to consider Edison's May 6th proposal in the hearing process.

Evidentiary hearings were held from June 10 through July 3, 2002. A bifurcated briefing schedule was set, with briefs on transitional procurement issues, to include Edison's May 6th Motion and how the Commission should address renewable energy procurement and QFs under any authority granted, due first on July 12, 2002. These issues are the subject of this interim opinion.[3]

III. Edison's May 6th Motion

A. Request

Edison's "Motion for an Interim Decision Granting Approval of Process for Early Procurement of Capacity" (Edison May 6th Motion) requests that the Commission issue an interim decision prior to June 15, 2002, that authorizes Edison to enter into multi-year capacity contracts using the credit of the DWR until Edison regains its investment grade rating. Edison claims that this approach would help bridge the gap to the procurement that it would conduct under a Commission approved procurement plan that is currently before the Commission for review. Edison contends that such authorization would allow it to begin procuring power prior to the Commission completing its review of the procurement plan and prior to Edison regaining an investment grade capacity rating.

Under this requested authority, Edison anticipates procuring capacity products that are dispatchable, together with related fuel and electric

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[3] Parties who participated actively in the proceeding are the respondent utilities, Aglet Consumer Alliance (Aglet), Alliance for Retail Energy Markets and the Western Power Trading Forum (ArM/WPTF), California Biomass Energy Alliance (CBEA), California Cogeneration Council (CCC), California Consumer Power and Conservation Financing Authority (California Power Authority), California Energy Commission (CEC), California Wind Energy Association (CalWEA), Center for Energy Efficiency and Renewable Technologies (CEERT), Cogeneration Association of California (CAC), Consumers Union (CU), Independent Energy Producers Association/Western Power Trading Forum (IEP/WPTF), Office of Ratepayer Advocates (ORA), Ridgewood Olinda, LLC (Ridgewood), Sempra Energy Resources (SER), The Utility Reform Network (TURN), and Union of Concerned Scientists (UCS).

transmission where appropriate, to meet its anticipated need, defined as its RNS, in super-peak periods. Edison asserts that entering capacity contracts for up to five years in duration would be beneficial for Edison's customers because it would allow Edison to be less dependent on the volatile spot market for power purchases.

Edison states that each contract would be submitted to the Commission by advice letter for approval within 30 days of its execution. Edison's proposal would require the Commission 's Energy Division to approve the contract within 30 days, unless it provides specific reasons why the contract is not in the best interest of Edison's ratepayers.

On May 15, 2002, the assigned Commissioner and Administrative Law Judge (ALJ) issued a ruling (May 15th Ruling) finding that the authority sought by Edison should not be considered outside of the full factual and evidentiary record being developed in this proceeding. The ruling provided a short extension to the procedural schedule to accommodate consideration of the motion in an expedited manner and required Edison, and any other utility interested in similar authority, to serve the additional testimony necessary for us to consider this request. Prior to Edison's motion, the scope of the procurement plans before us were limited to consideration of 2003 needs. As stated in the May 15th Ruling, the critical part of the evidentiary record needed to evaluate Edison's proposal was a reliable forecast of its residual net short requirements for 2003 through 2008. Edison and the other respondent utilities had previously stated that they could not provide this forecast until there was resolution of issues related to the allocation of DWR contract power and ongoing coordination of DWR and utility supply activities; therefore, the ruling set forth a process for parties to meet and confer in order to develop a proposal to resolve these issues.

The utilities were not able to timely resolve the DWR allocation issues identified as critical in the May 15th Ruling. Instead, in its May 24, 2002 supplemental testimony, Edison stated that the uncertainty regarding the effects of DWR contract allocation on its forecasted peak day shortages should be addressed by limiting the amount of megawatts (MWs) authorized under the motion.

On May 31, 2002, DWR wrote the Commission and parties a memo outlining its position on Edison's motion. This memo, received into evidence as Exhibit 131, states that DWR requires the following conditions for the proposed authorization to be consistent with its authority under AB1X:

1. DWR retains title to all power purchased by DWR.

2. DWR's costs for interim payment under the contracts are recovered through DWR's revenue requirement and are directly reimbursed by Edison's customers in the same manner as other net short purchases by DWR at present.

3. DWR and Edison would be signatories to any contract, providing for DWR to be removed from the contract upon Edison becoming creditworthy and assuming full responsibility for payment for energy under the contract(s) thereafter.

In addition, DWR states that the Commission should be aware if there are any contracts for energy payments which vary with the market price of fuel (presumably natural gas) or other market indices, such contracts could contribute to added volatility in DWR's payment obligations, thereby affecting the reserve fund balances and associated bond issue size. DWR further states that, to ensure the stability of rates, it is critical that the Commission adopt a contract allocation and resource dispatch policy as a part of its ruling on Edison's motion.

In its July 12, 2002 brief, Edison renews its request, with some modifications, under the Joint Principles for Interim Procurement dated July 12, 2002 (Joint Principles) it signed with CU, PG&E, and TURN. The Joint Principles proposes establishment of a Procurement Review Group whose members, subject to an appropriate non-disclosure agreement, would review and assess the details of Edison's overall interim procurement strategy and specific proposed procurement contracts and proposed procurement processes prior to Edison submitting filings to the Commission. Commission staff would be ex officio members of the group. Both renewable and non-renewable suppliers would be eligible to supply the capacity needs of Edison, with no accelerated or special consideration given to renewables or, more broadly, to QFs. The procedural process set forth in the Joint Principles requires the Commission to issue a resolution within 30 days of an advice letter filing. The Joint Principles state that this authorization should be granted no later than the end of July 2002.

Interested parties to the proceeding generally support a more limited transitional authority than that requested by the respondent utilities. Ridgewood and Aglet recommend the request be denied. Ridgewood claims that granting Edison's motion would prevent companies from developing new renewable resources in the state and cause many existing renewable facilities to shut down. Aglet states that the Commission should deny Edison's motion because the risks of unanticipated long-term consequences of hasty contract approval outweigh the benefits of current market opportunities. In the alternative, Aglet states that the Commission should impose restrictions of the type recommended by CEC. Examples of such limitations are a cap on on-peak capacity procured under Edison's motion, and dispatchability requirements. The recommendations of other parties on the amount and type of products will be discussed in a following section.

B. Applicability to PG&E and SDG&E

PG&E and SDG&E request similar authority to that requested by Edison, and also request that any interim procurement authority the Commission provides to one utility be extended simultaneously to all three utilities, to ensure fair and equitable opportunities for all California utilities to acquire reliable and reasonably-priced capacity for all their customers.[4]

SDG&E currently has an investment grade credit rating, and, therefore, a question exists as to whether the credit support of DWR should be provided, and if so, when SDG&E should assume financial and legal responsibility for the contracts from DWR. Edison and PG&E propose SDG&E assume this responsibility at the same time that either Edison or PG&E achieves an investment grade credit rating, whichever is earlier. SDG&E differs, requesting that it not assume full responsibility for the DWR contracts until both Edison and PG&E have achieved an investment grade credit rating.

SDG&E states that although it is creditworthy, its procurement needs are a small part of the market and it represents that the market does not distinguish between a creditworthy SDG&E and a non-creditworthy SDG&E because of the spillover effects stemming from PG&E and Edison. However, we note that SDG&E is distinguishable, for example SDG&E may fully participate in the CAISO market. Also, other creditworthy utilities operating in California

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[4] PG&E requests it also be granted authority for gas hedging under this motion, similar to the authority that Edison already has. PG&E also requests a different percentage of its RNS be authorized. These two issues will be addressed in Section D below.

such as PacifiCorp are able to procure for their customers, despite the financial situation of Edison and PG&E.

We are not persuaded that there is a need for DWR to "backstop" purchases for SDG&E. The purpose of DWR's involvement is to use the state's credit to assist the utilities, if necessary, and the state should not continue this relationship beyond its intended purpose. Therefore, we propose that SDG&E execute any contracts resulting from the authority granted today without DWR involvement. However, we will afford SDG&E other aspects of Edison's proposal, such as an expedited review process.

C. Should DWR Contract Allocation Be Completed First?

The May 15th Ruling stated that the DWR contract allocation should be completed in order for the Commission to have an accurate forecast of each utility's RNS and set forth an expedited procedural schedule to accomplish this. In their supplemental testimony, the utilities stated that they could not complete this task in the time allowed and proposed that the Commission use a percentage of a conservative estimate of the RNS to compensate for the range of uncertainty. At the end of hearing, the ALJ asked parties to brief this issue.

The utilities continue to argue that transitional procurement can be authorized prior to allocating the DWR contracts by using a percentage of a conservative RNS estimate. ORA, CEC, and several renewable parties are more cautious, their concern being that the utilities may foreclose the opportunities to purchase renewable power by signing long-term non-renewable capacity contracts prior to January 1, 2003. These parties recommend that the amount of power authorized under the requested transitional authority be less than requested by the utilities, and that less of the authorized amount be available for long-term contracts.

We share the concern that the utilities not over-procure in the transition period, especially for five-year contracts that could have the effect of shutting out new renewable generation or demand reduction options. We will consider Edison's May 6th motion here, but only in a manner that will not foreclose renewable generation in the final procurement plan. The specifics of this will be discussed in the following section.

When the decision on DWR contract allocation is final, both at the Commission and in any reviewing courts, the utilities may petition the Commission to increase the level of transitional authority if a need exists, and sufficient time remains in 2002 to exercise this authority.

D. What Types of Products Should Be Authorized and in What Amounts?

1. Parties' Positions

Most active parties in the proceeding were not permitted to review the underlying data submitted by the utilities because they did not meet the strict standard of "non-market participant" set forth in our May 1, 2002 Protective Order. And as market participants themselves, the respondent utilities did not have access to each others' confidential material. With many parties unable to review the evidence, we need to be very cautious in assuring that the underlying forecasts of RNS and the assumptions they are based on, have been vigorously examined, tested, and verified. We give particular weight to the testimony of ORA, CEC, Aglet, and TURN because they are parties with full access to the evidence and possess the technical expertise to understand and assess it.

We are particularly mindful of the needs of parties representing renewable resources because they do not have access to the confidential evidence. The renewable resources parties express strong concerns that the authority we authorize here does not foreclose, or in any way harm, the utilites' ability to meet their potential obligation under AB 57 to increase the amount of eligible renewables presently in their portfolio by 1% annually, beginning in 2003.

The specific amount each respondent utility is requesting is a confidential number, based on a percentage of a conservative forecast of its RNS energy needs in 2003 through 2007.[5]

The utilities assert that if multi-year dispatchable capacity or forward energy hedges can be purchased in these amounts at favorable prices, they will be far superior to reliance on short-term transactions in protecting electricity customers from the risks of volatile power prices. Edison states that it would be inappropriate for the Commission to specify precisely the types of contracts which it and DWR can jointly enter because the utilities will have less than six months to negotiate and gain all approvals of complex contracts before DWR's authority to contract expires.

Edison proposes that each contract be "either a capacity contract, an energy contract, an energy exchange contract, or a financial transaction that provides a hedge similar to that provided by any of the above types of contracts." (Ex. 119, Appendix A.) PG&E and SDG&E request they be granted

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[5] The confidential number for Edison is found in Exhibit 5C, page 11-6, for PG&E in Exhibit 48C, Table S-2, and for SDG&E in Exhibit 64C, page 5.

the same terms and conditions as those approved for Edison. In addition, PG&E requests it be granted explicit approval to enter gas hedge contracts, an authority that Edison now has under the terms of its settlement agreement with the Commission.

2. Discussion

a) Establishing a Procurement Limit

On May 24, 2002, PG&E, Edison, and SDG&E filed supplemental testimony providing capacity limits to be used under an interim procurement framework. Edison and SDG&E's testimony explicitly states that the capacity limits are based on low-case RNS scenarios (e.g., assuming low load, high direct access, and high allocation of DWR contracts) to produce conservatively low estimated procurement limits. The purpose in proposing a conservatively low limit for interim procurement is to establish a limit such that even though DWR contracts have yet to be allocated, the utilities will not over commit their RNS once contract allocation is resolved. PG&E's supplemental testimony does not explicitly acknowledge that its proposed procurement limit is based on a modeling scenario aimed at producing a conservatively low estimated capacity limit for purposes of interim procurement.

Numerous parties raise concerns with respect to the amount of the procurement limits proposed by the utilities. CEC comments that Edison's proposed interim procurement limit is too high and would obviate the need for procurement under Phase 2 of this proceeding as the level of capacity contracting requested would essentially cover all of Edison's RNS. CEC urges us to authorize the utilities to procure for a more limited quantity of resources, between one-fourth and one-third of their respective on-peak RNS requirements. Aglet also supports more restrictive limits. ORA indicates that its examination of

Edison's residual net short requirement shows that if interim procurement is allowed, "only a relatively small number of on-peak hours in the reference case RNS and a limited number on peak hours for the high-case RNS for 2003 and 2004 are projected to have RNS greater [than] SCE's proposed limit."[6] ORA advises that we consider the actual number of hours that would remain uncovered as the Commission decides the merits of Edison's Motion. SDG&E also cautions that the amount of power to be procured on an interim basis should be conservative in order to allow additional procurement to be guided by the Commission's final decision adopting the utilities' final procurement plans.

CEC also points out that Edison's estimates of its RNS energy requirement are highly sensitive to how the DWR contracts are allocated among the three utilities as well as to the outcome of the state's contract renegotiations efforts. Given that final allocation remains undecided and that contracts are subject to ongoing renegotiation, utility RNS estimates are "uncertain and speculative."[7]

Energy Division is in possession of the utilities' confidential data supporting their respective requests for capacity limits. A basic assessment of the supporting data shows that if the utilities are authorized to procure up to their conservatively estimated capacity limit (capacity without ancillary service capability), the number of hours that Edison is still short is reduced from roughly 45% of the total number of hours in 2003 to about 13%. For SDG&E, the decrease is more modest, dropping from 38% of total hours in 2003 to about 28%. Unlike

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[6] ORA Brief. p. 4.

[7] CEC Brief, p. 4.

Edison and SDG&E, PG&E did not explicitly make a showing in its Supplemental Testimony that its requested capacity limit for interim procurement is based on a methodology aimed at producing a conservatively low estimate for interim procurement. (See Exhibit 48C.) Edison and SDG&E present an alternative capacity limit that includes self-provision of ancillary services. Energy Division's review of the proposed capacity limits with ancillary services capability shows that the number of hours left uncovered in 2003 (i.e., the remaining RNS) drops to about 7% of total hours for Edison and 11% for SDG&E.

For transitional procurement authority, we adopt a capacity limit for each utility that reflects a cautious approach. First, we adjust PG&E's proposed capacity limit to reflect a comparable methodology to Edison's and SDG&E's conservative low RNS forecast. We do this by removing from total load adjustments the amounts PG&E shows for ancillary services and planning reserves. With this revision, we authorize Edison, PG&E, and SDG&E to procure up to 65% of their forecasted on-peak hourly RNS requirement reflected in a low-case RNS scenario for products with a contract duration up to one year and without self-provision of ancillary services included.

We find that 65% of the on-peak hourly RNS requirement based on a low-case RNS forecast strikes a reasonable balance that allows the utilities to procure on a transitional basis, but also does not commit all RNS requirements. In addition, this approach allows for the final procurement plan to consider changes in the RNS requirements.

Our adopted 65% figure is intended to not foreclose opportunities for the utilities to procure additional power under the 2003 utility procurement plans pending with the Commission, but also to be of a sufficient amount to generate robust interest in the supplier community. The limit we authorize here is not higher than that requested by any respondent utility. Further, the limit we authorize for Edison is below the maximum MW authorization recommended by CEC in its July 12 brief at page 2. In their applications for pre-approval of products, the utilities shall demonstrate that this 65% limit is adhered to.

Edison's May 6th Motion also requests authority to procure contracts with terms up to five years. Edison asserts that multi-year procurement authority is needed because:

> "…the availability in the marketplace of capacity contracts for a one-year term is highly unlikely and, to the extent they are available at all, SCE believes they will not provide a reasonable cost to our customers. Capacity contracts are more complex than other contracts and may require the seller to make a significant investment in generation to provide the service."[8]

Edison adds that:

> "Mutli-year capacity contracts may also be used, if approved by the Commission, to firm up investment in new generation which can help meet customer demand that currently must rely on the uncertain spot market. The contracts may help to assure that capacity additions that are now being differed, or at risk of being differed, will actually be completed when needed."[9]

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[8] Exhibit 5C, p. I-9.

[9] *Id.* p. I-10.

In supplemental testimony filed by the utilities, each utility proposes a procurement limit that reflects a significantly increasing amount of power annually between 2004 and 2007.

Several parties object to Edison's request for multi-year contracting authority. ORA argues against multi-year procurement citing: (i) uncertainty associated with wholesale market redesign issues; (ii) the fact that the utilities' procurement plans are pending at the Commission; (iii) the Commission possesses limited time and resources to review such contracts; and (iv) multi-year contracts with suppliers that do not have generation installed to meet 2003 needs will not satisfy near-term capacity needs of the utilities. CEC recommends that multi-year capacity products be limited to "a safe quantity assured to be required."[10] CEC comments that the substantive benefit provided through multi-year contracts is the revenue assurance it provides to a new generator. Like ORA, CEC points out that it takes about two years for a new generating facility to come on-line following commitments; therefore ratepayers won't receive the "majority of the benefits"[11] of such a contract in the near-term.

SDG&E proposes what it calls a "50/50 rule" for multi-year contracting whereby half of the total amount of capacity that is authorized for procurement under interim procurement be contracted for a term of up to five years. The remaining half could be contracted for a term not to exceed one

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[10] CEC Brief, p. 5.

[11] *Id.*

year.[12] SDG&E witness Resley provided context for this proposal during evidentiary hearing:

> "…this [50/50 proposal] derives from our concern about making too many commitment too soon for too long. We've learned some things in the past few years, and we have learned that some hedging, some time between commitments, some ability to see how things evolve is better than putting all your bets on a single outcome at a single time."[13]

We find merit in authorizing multi-year procurement. The prospect of signing multi-year procurement contracts will help attract suppliers to utility solicitations and will help attract capital investment in new generating projects. However, we are not convinced that authoring procurement up to the levels requested by the utilities is appropriate at this time. Given the uncertainty that exists surrounding final allocation of DWR contracts and the uncertain net effects of DWR contract renegotiation on the aggregate size and shape of DWR's supply portfolio over the next five years, as well as the concerns voiced by ORA and SDGE, we find that it is reasonable to adopt SDG&E's recommended 50/50 proposal. This limit will ensure that a significant remainder of procurement requirements will be guided by future Commission decisions and re-examination of utility RNS positions and market conditions.

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[12] SDG&E Brief, p. 11.

[13] Tr. Vol. 10, June 21, 2002, pp. 1222-1223.

b) Product Types

Edison proposes to enter into contracts for "dispatchable capacity, and for related fuel and transmission, where appropriate, of up to five years in length."[14] Edison also seeks to secure natural gas hedging in support of the capacity contracts negotiated through interim procurement. PG&E states that it needs the same types of procurement products described by Edison, but also requests authorization to purchase natural gas hedges to hedge the fuel price of its fossil-fuel Utility Retained Generation (URG) assets and QFs contracts whose energy payments are indexed to natural gas prices. SDG&E indicates that in addition to dispatchable capacity, one of its "significant residual net short needs" is for energy products to replace San Onofre Nuclear Generation Station (SONGS) Unit 3 during its scheduled refueling in early 2003.[15,16] Edison's testimony lists energy products without making a specific showing of need for them.

With the exception of ORA, parties do not dispute the utilities' identified need for capacity products. ORA characterizes Edison's proposal as an "unspecified need for capacity contracts" and argues that Edison's proposal fails to adequately define what it means by capacity.[17] Additionally, ORA

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[14] Edison Brief, p. 10.

[15] SDG&E Brief, p. 12.

[16] SDG&E contemplates that it may opt not to exercise the procurement authority granted by this Decision. SDG&E states: "There should be an explicit recognition in the authorization for interim procurement that authorization creates no presumption that it is imprudent not to use this authority to its full extent." (P. 12.)

[17] Notwithstanding these reservations, ORA recomends that "the utilities be authorized to pursue an initial purchase of capacity." (ORA Brief, p. 5.)

recommends that the Commission should explicitly encourage energy for capacity transactions given that "the utilities generally appear to be long in energy supplies and short in electric capacity."[18] CEC points out that the utilities should be encouraged to foster the development and trade of energy products that satisfy RNS requirements during "super-peak" periods.

Given the flexibility that capacity products provide in meeting a range of variously shaped residual net short requirements during certain hours in a month, we agree with Edison's proposal that capacity contracts should be allowed under transitional procurement process. For purposes of addressing ORA's concern that Edison has failed to precisely define the term capacity product, we adopt a combination of ORA's proffered definition[19] as well as PG&E's definition:[20]

> A capacity contract is one in which the buyer has the right to take energy at a known price in exchange for a capacity or reservation charge. The energy charge could be fixed or indexed to gas prices. Under this type of contract, the buyer has the right, but not the obligation to schedule energy up to the maximum number of MWs provided for in the contract.

Gas tolling agreements will be allowed as a subset of capacity contracts. Recognizing the scheduled refueling of SG&E's SONGS Unit 3 in 2003 and in consideration of CEC's recommendation for promoting peaking energy

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[18] *Id.* p. 6.

[19] See ORA Brief, p. 8.

[20] See Exhibit 45, p. 3-22.

products, we are also authorizing the use of forward energy products under interim procurement process. Additionally, we find the it is reasonable for the utilities to arrange for the transportation of the physical commodity portion to be deliver pursuant to capacity and energy contracts. Related fuel products, natural gas supply, transportation, and storage are also authorized to the extent the utilities make a showing that such arrangements are in support of the specific electric capacity transactions brought forward pursuant to this decision.

Energy exchanges, such as the energy for capacity transaction recommended by ORA, peak for off-peak exchanges, and seasonal exchanges, are authorized for interim procurement. As noted by ORA, these types of transactions have proven to be cost effective in the past plus the Commission and the utilities have significant previous experience with these types of transactions.

We do not provide additional authority to the utilities for the use of financially-settled hedging instruments for interim procurement, including natural gas hedges. Such transactions are likely to add a level of complexity to the interim procurement review process that could potentially overwhelm staff resources. Under this interim procurement framework, we are only authorizing physical transactions. Financial transactions will be addressed further in a future decision adopting utility procurement plans. The requests of PG&E and Edison for additional authority to transact for natural gas hedging as part of this short-term interim procurement mechanism is, therefore, denied. We also deny PG&E's specific request to procure gas hedging to hedge the fuel cost risks associated with its URG and QFs contracts. We reject PG&E's request for two reasons. First, the request goes beyond the scope of this proceeding. PG&E's gas hedging proposal is focused on hedging fuel costs associated with existing generation resources whereas this proceeding addresses the utilities' going-forward RNS procurement needs for 2003.[21]

We find that granting transitional authority, under the terms and conditions adopted here, is beneficial for both the utilities and their customers. Edison and PG&E will benefit by being able to enter procurement contracts prior to regaining an investment grade credit rating and to demonstrate to the financial markets that they can successfully resume their full procurement responsibilities under the Commission's regulatory oversight. All three utilities will benefit by reducing the amount of purchases they will need to make beginning in 2003 and beyond. Finally, customers of the utilities will benefit from the utilities receiving and exercising this authority in a manner that promotes reliable service at just and reasonable rates. We next discuss the process that should be used by the utilities to make this showing of ratepayer benefits.

The utility/DWR agreement proposed by Edison should be modified to meet the concerns expressed by DWR in its May 31st memo. The revised agreement should be submitted to the Commission by each respondent utility by a compliance filing within five days.

E. Procedural Process

1. What is Being Requested?

In their July 12th briefs, CU, PG&E, Edison, and TURN advocate that the Commission adopt their proposed expedited advice letter process. This

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[21] See Section 2.4 of the Settlement Agreement entered into by the Commission and Edison settling matters at issue in *Southern California Edison Company, Plaintiff, vs. Loretta M. Lynch, et al.*, October 21, 2001.

process would have the Commission commit to approve or disapprove the contract and/or procurement process by Commission resolution within 30 days of filing. Approval would constitute a determination by the Commission that costs incurred by the utility under the contract itself and/or under contracts conforming to the procurement process are "reasonable" and "prudent" for purposes of recovery in retail rates under the Public Utilities Code for the full term of the contract or contracts. Utility administration of such contracts would remain subject to reasonableness review by the Commission under reasonableness criteria or incentive ratemaking, as appropriate. If the Commission rejects a proposed contract or procurement process, it would designate alternative procurement choices that would be recoverable by the utility for ratemaking purposes without further reasonableness review.

ORA is the only other party proposing an alternative procedural process. ORA discusses the complexity of the issues it expects to confront and, therefore, states that the Commission should authorize only one application for each utility, and there should be a minimum review period of 30 days before parties need to respond by filing a protest. It recommends the Commission process these contracts by advice letter and if there is a protest, the Commission would resolve the dispute by a resolution.

The advice letter procedure proposed by the parties to the Joint Principles has the Commission approving by resolution the utility's filing within 30 days. The only likely way this can happen is if the utility's filing takes effect without Commission action.[22] Under our current procedures, the Commission

[22] This is what happened with the utilities' bilateral contracts submitted under similar procedures adopted in D.00-08-023. The Commission never acted on any contracts.

Footnote continued on next page

cannot commit to issuing a resolution within 30 days, especially if there are protests and disapprovals as provided for under the Joint Principles proposal. It generally takes approximately 60 days to adopt an advice letter by resolution. For the Commission to meet the Joint Principles' timeline, it would mean having the resolution written by the protest date, receiving no protests, and having an upcoming Commission meeting date within the next 10 days. The advice letter process is shown at Appendix B, which sets out the timeline for the joint proposal next to our existing advice letter process.

Edison proceeded to enter contracts based on the Commission's lack of action and testified at hearing that it viewed this as a successful process.

2. What Has the Commission Previously Done?

At the hearing, the assigned ALJ asked parties to consider an expedited application process, one that would either use our current process in a quick manner or that would use a process similar to the Expedited Application Docket (EAD) process we previously used to review and approve gas and electric special contracts for large customers with bypass options. PG&E and Edison prepared Reference Items 4, 4A, 4B, and 4C showing the Commission decisions issued under the EAD procedure. As PG&E's attorney noted, applications processed under the electric EAD process were significantly quicker than those processed under the gas EAD process. A major difference is that the gas EAD process had the Commission make a finding of reasonableness in the decision whereas in the electric EAD process the reasonableness review was undertaken in later proceeding.[23] The EAD process for gas and electric contracts, and the resulting decisions, are set forth in Appendix C.

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[23] The Commission did make a reasonableness finding for Edison's a special electric rate agreement for the Carson Refinery of Union Oil Company of California in D.95-06-055. This application was not filed under the EAD procedures, did not follow Edison's proposed expedited schedule, and an evidentiary hearing was held. The Commission found that the contract had essentially the same terms as an earlier contract and this, in conjunction with the extensive record in the proceeding, was sufficient for a finding of reasonableness. Approval of the contract was conditioned on Edison's acceptance of shareholder responsibility for 25% of any revenue shortfall arising from discounts between the rate agreement and the otherwise applicable tariff rate as well as Edison's shareholders assuming the risk for any future costs of uneconomic assets that may be allocated to this agreement which are not assumed by Unocal. Administration of the contract was subject to frequent reasonableness reviews, and the contract could be terminated upon a Commission finding that it no longer was in the interest of ratepayers.

Our discussion here will focus on the electric EAD process as a means of understanding the policy implications of adopting expedited procedures. There are both similarities and differences between the contracts considered under this process and the utilities' relief requested here. Briefly, these are:

1. Purpose. The electric EAD process was designed to review contracts for individual utility customers rather than major procurement contracts to serve all utility customers. The specific dollar amounts under the EAD contracts are not discussed. The request before us here will involve individual contracts in the hundreds of millions of dollars. The contracts were for a similar length of time as those being considered here.

2. Guidelines/Standards. Specific guidelines for EAD contracts were adopted in D.88-03-008 in order to accelerate review under the EAD procedure. We adopted a standard for approval to ensure that all other customers would be indifferent to the granting of the contract. Recognizing that this was not a high standard, the Commission stated that EAD approval "merely indicates that the contract's prices are high enough so that other classes of ratepayers are not unreasonably harmed." (*Id.*) However, in the request before us now, a finding of ratepayer benefit rather than indifference must be made. Further, Edison states that the Commission should not adopt guidelines as the contracts proposed here are "nonconforming" contracts.

3. Risk Allocation. The electric EAD process used a forecast of revenues that placed the utilities at risk for revenue losses. The request before us is for the utilities to be held risk-free.

4. Reasonableness Review. The Commission did not undertake a reasonableness review under the EAD process, stating "the nature of the review that occurs in the Expedited Application Docket…is not one that results in a finding that the level of prices in the special contract is reasonable and prudent." (D.88-03-008, at p. 40.) Edison sought, and was denied, a finding of reasonableness under the EAD process in D.88-12-097. In the request before us here, the utilities' request a finding of reasonableness on an expedited basis is requested.[24]

In summary, the electric EAD process had a narrower scope, adopted guidelines for review, a lower standard for approval, and required the utilities to bear the risk of revenue losses and future reasonableness reviews. The Commission processed only five applications under the EAD procedure, all between 1988 and 1989. After this period, the Commission processed two applications, two advice letters, and four "Approval Letters" drawing on the EAD guidelines and standards. (See D.94-03-075, D.95-06-055, Resolution E-3370 dated March 9, 1994 and Resolution E-3423 dated October 18, 1995, and Approval Letters set forth in Reference Item 4C.) The electric EAD process was not used extensively and the Commission did not apply the process to other types of applications. As testified at hearing by Mr. Weil, the expedited nature of the process left the Commission staff with serious reservations.

3. What is Required Now?

We agree it is reasonable to implement a transitional approach to procurement, but we should modify Edison's proposal. We need to develop a

[24] Our gas EAD process did provide a reasonableness review but had other features similar to those described in 1-3 above for the electric EAD process.

process that is balanced: one that meets the needs of the utilities for timely decisions that reduce regulatory uncertainties while at the same time ensuring that the Commission has exercised its statutory responsibilities to protect consumers from unreasonable costs through effective oversight and regulation. We must set forth the minimum procedures needed to ensure our responsibilities are met. Then, it is the utilities who have in their control how expedited the review and approval process will be based on the transitional procurement strategy they employ, the early and collaborative role they give staff and interested parties in reviewing their analysis and recommendations, the contracts they chose to enter, the quality of the application package they submit, and their responsiveness to requests for additional information.

We are confident the utilities can do what is needed to make the requested transitional procurement period a successful bridge to resumption of their full procurement responsibilities. At hearing, all the respondent utilities, and in particular Edison, made a strong showing that they had highly competent individuals managing their procurement function and that they had sufficient qualified staff and a formal senior management review procedure in place.

In order to ensure an adequate review period, the utilities should use an application process for nonstandard contract review and approval, especially as we undertake to quickly examine and provide, for the first time, up-front reasonableness approval to electric procurement contracts that are represented to be quite complex multi-year transactions. The advice letter process should be used primarily for ministerial matters, where staff is following established Commission policy or clear directives that do not require the exercise of discretion. The advice letter process provides a quick and simplified review of the types of utility requests that are expected to be neither controversial, nor to raise important policy questions. The primary use of the advice letter process is to review a utility's request to change its tariffs in a manner previously authorized by stature or Commission order, to conform the tariffs to the requirements of a statute or Commission order, or to get Commission authorization to deviate from its tariffs.[25]

An application should be required in matters that require the exercise of discretion. In this instance, the respondent utilities are requesting to have large dollar, long-term contracts approved with a final decision on reasonableness. Edison testified that under its proposal its base case residual net short for 2003 is about $500 million. Assuming a request to cover one third of that with a five-year contract, the approval sought here would total $750 million. Thus, these are obviously matters that require an application process.

In designing an application process that is responsive to the utilities need to quickly know that the procurement transactions they enter will be fully recoverable in a timely manner, the key will be to ensure that each utility has sufficient qualified staff who together with the active oversight and

[25] In 1987, the Commission first tried to process special electric contracts by advice letter but found the process was not the appropriate forum for considering the type of issues raised and that a multiplicity of individual contract filings inhibited full participation by interested parties that lack the staff and resources to intervene in a series of advice letter filings. The Commission conditionally approved two advice letters and directed that future contracts be filed by formal application. (See Advice Letter 1130-E which was conditionally approved in Resolution E-3017, dated January 28, 1987 and Advice Letter 1131-E which was conditionally approved in Resolution E-3021, dated March 25, 1987.) A description of the limitations on advice letter authority is set forth in the February 14, 2001 Draft Decision of ALJ Kotz on Opinion Revising Proposed General Order 96-B and Adopting that General Order as Revised, Section 5.1 "Matters Appropriate to Advice Letters."

documentation of senior management, develop and implement an appropriate risk management strategy. This risk management strategy would provide a diversified portfolio mix of energy products that provides customers reliable service at just and reasonable rates.

The Commission, its staff, and interested non-market participants must be able to review an application that clearly and thoroughly documents the steps followed by each utility's procurement staff, the risk management package presented to its senior management, the specific approvals and conditions given by management, the competitive bidding process undertaken, and criteria used to evaluate the bids, and the method of ranking the winning bid(s). Any requests by staff or other interested parties for further information or explanation must be expeditiously handled. Furthermore, the Commission must be assured that no conflicts of interest exist by prohibiting transactions, personnel movements, and communications between the utility procurement function and holding company entities, since we will not be able to take the time necessary to conduct comprehensive after-the fact auditing to detect and address any affiliate abuses.[26]

[26] The assigned Commissioner ruled in the April 2 Scoping Memo that there should be no transactions with any affiliates of the respondent utilities, not just their own affiliates. Several parties objected to this broad prohibition in their testimony, stating that this would deprive California of a significant source of generation. Recognizing this, what is being discussed here is the narrower prohibition of a utility purchasing from its affiliates. See Exhibits 73 (SDG&E), revised 79 (Edison), and 80 (PG&E) for a matrix of each utility's Energy Cost Adjustment Clause (ECAC) reasonableness proceedings disallowances. The exhibits show that while each utility experienced very small disallowance adjustments as a percentage of their fuel and purchased power costs, the number and dollars of these transactions involving affiliate transactions was substantial.

The expedited schedule of the electric EAD process was not designed to address reasonableness reviews. In order to ensure fairness to ratepayers and the utilities, we will adopt two of CU's principles: structural regulation and process regulation. As Mr. Ahern of CU states, the essential elements of the process must be wide publication of the product needed, arms-length solicitation and negotiation, and objective selection of the best supplier by skilled utility staff with no conflicts of interest. In addition, to avoid the appearance of conflict, we will prohibit utility staff from being involved in the procurement function if they have worked for a market participant eligible to bid for a contract within the last two years. As the utilities did not deem it appropriate to propose benchmarks for the products they intend to purchase under their requested transitional procurement authority, we should require products to be purchased using a competitive process.

Under the competitive process, we direct the respondent utilities to provide wide dissemination of the request to members of the generation community, to include renewable resource suppliers. The specifications for capacity and energy contracts should not be fuel or technology specific. We term this an "all-source solicitation."

Because the utilities have not provided us with the specific terms, conditions, selection criteria, and process of any requests for proposals (RFP) they intend to undertake, this process will also be subject to Commission review. For the first time in their July 12th filing, Edison and PG&E ask that we provide pre-approval of proposed procurement processes that would allow the utilities to be free from any further reasonableness review for any contracts entered into under the procurement process proposed. The utilities may file an application for pre-approval of a procurement process but unless it is very detailed and specific, the Commission reserves the right in its decision to require that the contracts that result from that procurement process also be subject to the application process we adopt here.

The process we adopt here is as follows:

1. Application. Edison, PG&E, or SDG&E file an application that conforms to the quantities, products, terms and conditions we discuss earlier for transitional procurement. The application should demonstrate it meets our standard for approval by a showing that entering into the contract(s) should result in favorable and stable rates for ratepayers relative to alternative options. An application may contain all winning contracts from a single RFP solicitation. SDG&E cannot use DWR's credit to undertake transitional procurement.

2. Master Data Request. We find the master data request proposal by ORA to be beneficial and will adopt it. The application must contain all information required under our adopted master data request. The specifics of this are attached to this decision as Appendix D. Each application should include documentation of the steps followed for each transaction, such as including at a minimum the risk management package presented to senior utility management, the specific approvals and conditions given by management, and the rationale and procedures of the selection process undertaken. The respondent utilities must also respond to all data requests within five working days, either by producing the requested material or by filing an objection under our Law and Motion procedures.

3. Procurement Review Group (PRG). Use of the PRG recommended in the Joint Principles. This group would meet prior to the application being filed and should be convened early on to assess any proposed RFP process before it is implemented. The PRG would meet again to assess the resulting bids, the winning procurement contracts, and reasonableness criteria with each respondent utility. The group would be open to parties designated under our Protective Order to review confidential information and would include

representatives of the Commission's Energy Division and ORA as ex officio members.

4. Protests. A 30-day protest period with replies due in five days.

5. Workshop. A workshop will be held approximately 40 days after the application is filed. After the workshop, the assigned ALJ, in consultation with the assigned Commissioner, shall issue a ruling designating whether there are issues of substantial controversy or importance to require the scheduling of hearings. The ruling shall also state whether the ALJ intends to prepare a draft decision which meets the criteria set forth in Public Utilities Code Section 311(g)(2) of being an uncontested matter in which the decision grants the relief requested, a criteria that allows the 30 day public review period to be reduced or waived.

6. Current Filings. The requirement that each respondent utility shall have only one application pending at a time. However, if the assigned ALJ issues a ruling stating that the ALJ intends to prepare a draft decision that meets the criteria of 311(g)(2) and that will not be issued for public review and comment, then another application may be filed.

7. Denial. If the Commission rejects a proposed contract or procurement process, it should not designate any alternative procurement choices that would be recoverable by the IOU for ratemaking purposes without further reasonableness review.

8. Reasonableness Review. In its decision on an application, the Commission shall apply the same

> reasonableness standards it used in the ECAC proceedings and prudency of contract administration shall be at issue over the life of the contract.[27] Similar to the gas EAD process, which provided an expedited procedure for reasonableness review of gas contracts, approval of the contracts shall be dispositive of all prudence questions which might arise at a later date regarding the contracts, absent a showing of: (a) misrepresentation or omission of material facts of which the utility is aware in connection with the utility's request for contract approval; and (b) imprudence in the utility's performance under the negotiated contract.

The procedural process set forth above is shown in Appendix E. It provides the utilities an opportunity for an expedited review and approval process while ensuring that the Commission, its staff, and all interested parties have the time and resources to fully analyze and consider each application and, where appropriate, hold an evidentiary hearing. Our reasoning here is based on the years of experience the Commission has had in doing reasonableness reviews and reviewing complex contracts. As ORA states in discussing the minimum length for a protest period:

> "ORA requires a minimum of 30 days. Review of contract restructuring of QF contracts, where the Commission and ORA has significant expertise in both contract form and evaluation, requires significantly more than 15 days. The Commission and ORA will be reviewing contracts which according to Edison are likely to require substantial time just for the utility to negotiate, contracts that do not offer

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[27] These standards include, for example, whether it was a decision a reasonable utility manager would have made knowing what he (she) should have known at the time the decision was made.

> standard industry terms, [and] contracts that involve evaluation which is based on risk management principles, ..." (July 12 brief, page 7.)

We do not commit to complete our process within a set timeframe because we must take the time necessary to make a finding that the contract is reasonable and will result in just and reasonable rates for ratepayers. As previously discussed, the pace at which we can proceed is largely within the utilities' control as it is governed by the contents of the application filed. In addition, we will not adopt a default mechanism that allows for contracts to be considered approved if the Commission fails to take action. This approach would provide a perverse incentive for the utilities not to provide all the necessary information in a timely manner. ORA testified at hearing that utility responses to some of its data requests were either not given in a timely manner or were simply still not answered.

ORA testifies that each utility should be authorized only one contract under the transitional authority and that to allow more filings would create a regulatory burden that would preclude genuine regulatory oversight. We find that allowing only one application in the review process at a time sufficiently addresses this critical issue. The Commission is committed to giving these applications a high priority and to proceeding as expeditiously as possible given its staff resources and other responsibilities.

If the utilities provide the Commission a complete and clearly laid-out application that is uncontested and meets our standard for approval, the Commission could place a decision on a Commission agenda within 60 days. The findings made in the first decisions will provide guidance that should facilitate future filings. Moreover, the utilities can include multiple contracts in the same application to further expedite the process.

The utilities have requested that the Commission pre-approve each contract. The utilities testified at some length that they were unwilling to accept any procurement risk. The record shows, however, that a cost premium may attach to a pre-approval process because the utilities may need to pay a fee to keep an offer open or pay a premium to "refresh" the offers after the Commission grants approval. If the utilities seek pre-approval, they should carefully monitor and report any cost premium paid for this. We are reluctant to allow a pre-approval process and will revisit this issue in the 2003 procurement planning proceeding. To minimize any cost premium, any contracts under which a utility is seeking pre-approval must be filed by application within 30 days of signing a selection.[28]

A consistent theme heard from the utilities over the years is that the Commission should not micromanage their activities, and the utilities may charge that we do so through our adopted review process. However, previous Commission decisions regarding procurement proposed a portfolio approach to procurement which gave broad discretion to the utilities. (See D.00-12-065 in R.94-04-031 and I.94-04-032.) Under this approach, the utilities would achieve an overall procurement portfolio at a Commission-approved price per megawatt, which means that the utilities would have the discretion to sign contracts above

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[28] A utility is not constrained by this timeframe and our requirement that only one application can be pending. It may sign additional contracts under the authority granted here and wait to submit them to the Commission for approval and a reasonableness finding provided there is not a request for pre-approval.

and below that price, provided the overall portfolio costs were at the Commission-approved price. If the utilities' portfolio exceeded the adopted price per megawatt, the utility would still have the discretion to file an application demonstrating the reasonableness of its proposal. Notwithstanding the broad discretion afforded them, the utilities opposed this proposal as too risky.

In the hearings, Edison demonstrated that it employs a large number of very well-paid staff for its resource procurement activities, and that it takes these employees months to assess and negotiate the resource contracts. Nonetheless, the utilities believe the Commission, with far fewer resources than the utilities, should effectively rubber stamp approval of these transactions without meaningful review, which is what would undoubtedly happen with a 30 days review process. We would be remiss to our duty of safeguarding the public interest to adopt such a proposal. Rather, the proposal we adopt today will expeditiously give the utilities the requested certainty regarding the reasonableness of their procurement decisions while exercising our duty to meaningfully review the contracts.

Without effective oversight, adoption of Edison's request would transfer the risks of procurement from the utilities that negotiate the transactions to their customers. These customers, unlike the utilities, have no ability to control procurement risk. The utilities acknowledge the shifting of risk but state that this is appropriate due to their weakened financial condition. They also state that the transitional authority requested can reduce overall procurement risk by lessening the reliance on volatile spot markets to meet customers' needs in 2003.

The procedural process laid out above is an ambitious one for the Commission. Our past experience with trying to review and approve large contracts in an expedited manner has not been entirely successful. However, we find there are policy reasons for adopting Edison's motion for transitional procurement authority, with modifications, and believe the process we adopt here, which adjusts for changes in the scope and standards of our former electric EAD process, is a workable process.

IV. Should the Commission Reinstitute Standard Offer 1 Contracts and Adopt a Right of First Refusal for Qualifying Facilities?

CCC calls upon the Commission to once again require utilities to make Standard Offer 1 contracts (SO1) available to QFs with a design capacity greater than 100 kilowatts (kW). CCC additionally asserts that QFs are entitled to a "right of first refusal" (ROFR) with respect to all energy and/or capacity contracts that investor-owned utilities (IOUs) might enter into with non-QF suppliers.

A. The Statutory and Regulatory Framework Governing PURPA

1. Federal Law

The Public Utility Regulatory Policy Act of 1978 (PURPA), as codified in the United States Codes (USC) at 16 U.S.C. § 824a-3, requires the Federal Energy Regulatory Commission (FERC) to prescribe and periodically revise rules that "require electric utilities to offer to . . . (2) purchase electric energy from [QFs]."[29] Rates paid by utilities for purchases of electric energy may not exceed "the incremental cost to the electric utility of alternative electric energy."[30] PURPA defines incremental cost with respect to electric energy purchased from a QF as "the cost to the electric utility of the electric energy which, but for the purchases from such [QF] such utility would generate or purchase from another source."[31]

The FERC has complied with its PURPA obligation to "prescribe rules" by promulgating in the Code of Federal Regulations (CFR) 18 CFR § 292 et seq. The rules set forth therein provide in pertinent part that: "each electric utility shall purchase, in accordance with [18 CFR] § 292.304, any energy and capacity which is made available from a [QF]. . . "[32] §292.304, entitled "rates for purchases," establishes a pricing regime for purchases by IOUs from QFs. Consistent with 18 U.S.C. § 824a-3, § 292.304(a)(1) requires first that "rates for purchases shall: (i) [b]e just and reasonable to the electric consumer of the electric utility and in the public interest. . ."[33] While rates may not exceed avoided costs,[34] rates will satisfy the "just and reasonable" and non-

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[29] 16 U.S.C. § 824a-3(a)

[30] 16 U.S.C. § 824a-3(b)

[31] 16 U.S.C. § 824a-3(d). PURPA also requires that the cost to the utility be "just and reasonable" to electric consumers while not discriminating against QFs. (*Id*. § 824a-3(b)(1) and (2).)

[32] 18 CFR § 292.303(a).

[33] 18 CFR § 292.304(a)(1).

[34] 18 CFR § 392.304(a)(2).

discrimination requirements of § 292.304(a) "if the rate equals the avoided costs determined after consideration of the factors set forth in paragraph (e) of this section."[35] Paragraph (e) provides a laundry list of factors to be taken into account in determining avoided costs, "to the extent practicable." These are elaborated upon below.

The FERC's rules require that standard rates for purchases be put into effect only "for purchases from qualifying facilities with a design capacity of 100 kilowatts or less."[36] Whether to implement standard rates for qualifying facilities "with a design capacity of more than 100 kilowatts" is discretionary.[37]

Purchases from "as-available" QFs are subject to special pricing rules. QFs may provide energy as it is available, "in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery."[38] QFs providing electric energy or capacity under a contract are to be paid either avoided costs at the time of delivery, or avoided costs calculated at the time the QF entered the contract, whichever the QF chooses at the time it enters the contract.[39]

2. State Law

PURPA also imposed an obligation on this Commission. "[E]ach State regulatory authority shall . . . implement [the FERC QF rules] for each

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[35] 18 CFR § 392.304(b)(2).

[36] 18 CFR § 392.304(c).

[37] 18 CFR § 392.304(c)(2).

[38] 18 CFR § 392.304(d)(1)

[39] 18 CFR § 392.304(d)(2).

electric utility for which it has ratemaking authority."[40] It falls to this Commission to implement the pricing provisions just elaborated. This Commission has a lengthy history of setting QF prices, which we need not elaborate here. For present purposes, it is sufficient to pick up the story with the Commission's D.96-10-036, which significantly revamped our handling of QF pricing, and which is central to any analysis of CCC's proposals. We will touch on the particulars of D.96-10-036 as it applies to CCC's proposals in more detail below, but will briefly summarize the decision here. In D.96-10-036, the Commission undertook to bring its QF implementation practices into the restructured world. Of particular significance to the issues in this docket, the Commission terminated as of January 1, 1998 any requirement that utilities enter SO1 or SO3 contracts with QFs. "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."[41]

The Commission further provided that "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."[42] The Commission explicitly migrated QFs towards full and equal participation in markets alongside other sources of generation, stating:

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[40] 18 U.S.C. § 824a-3(f)(1).

[41] D.96-10-036, Ordering Paragraph 7.0

[42] An exception to this rule was carved out for "small publicly owned biomass" facilities. (D.96-10-036, Ordering Paragraph 8.)

> 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, Edison, 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. 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." They will clear the power exchange if they bid low enough relative to all other sources to clear the market.[43]

For "grandfathered" QFs, i.e., those with contracts entered prior to December 20, 1995, pricing would continue to be based on the contract terms, which almost universally set price at "short run avoided cost." (SRAC.) With respect to SRAC, the legislature took a hand when it enacted Public Utilities Code Section 390 as part of AB 1890. Generally speaking, Public Utilities Code Section 390 sets out components (most significantly, gas costs) to use in setting SRAC, pending a shift to the use of PX prices to establish SRAC. The Commission implemented R.99-11-022 to work out the particulars of SRAC pricing under Public Utilities Code Section 390. Events overtook this rulemaking, and the demise of the PX in January 2001 ended any chance of a universal migration of QFs to PX-based SRAC pricing. At present, SRAC is set

[43] D.96-10-036 (citations and footnotes omitted).

using a formula based on gas prices.[44] Each utility has detailed QF pricing information (current and historical) on its respective website.[45]

B. Analysis of the CCC Proposals

1. The Proposal to Require IOUs to Offer SO1 Contracts to QFs With a Design Capacity of More Than 100 Kilowatts

In D.96-10-036, the Commission decided that IOUs need no longer make SO contracts available to QFs with a design capacity of more than 100 kW after January 1, 1998.[46] Whether to require that IOUs' offer QFs SO contracts is entirely within the Commission's discretion.[47] Indeed, even whether to set standard *rates* is discretionary with the Commission for facilities with a design capacity of more than 100 kW.[48]

Much has changed since this Commission issued D.96-10-036. But if circumstances have changed since the issuance of D.96-10-036, they have changed even more greatly since this Commission originally promulgated the

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44 See D.01-03-067, as modified by D.02-02-028.

45 http://www.pge.com/002_biz_svc/002e1_info_center.shtml

http://www.sce.com/sc3/005_regul_info/005i_qualifying_facilities/QFDataDoc.htm

http://www2.sdge.com/srac/

46 D.96-10-036, Ordering Paragraph 7.

47 See D.96-10-036: "It is useful to recall that the Commission's decision to have standard offers at all was one entirely within its discretion under PURPA."

48 See D.96-10-036; 18 CFR 292.304(c)(2).

SO1 contract. As we explained in D.96-10-036, the SO contracts were introduced 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.[49]

We are not persuaded on the record before us, in the context of this motion for *interim* relief, to overturn D.96-10-036 and re-institute the utility obligation to enter SO contracts. In implementing PURPA today, we are no longer jump-starting a nascent industry, as we were in 1982. Every aspect of the SO1 contract deserves scrutiny, beyond what has occurred in the context of CCC's proposal here. CCC dismisses the contentions of SDG&E witness Farrelly that the SO1 contract is out of date,[50] but we think the question of how well SO contracts conform to today's energy industry bears further examination. SCE witness Bergmann's assertion that the SO4 contract could form a basis for new contracts may well prove correct,[51] but this claim does not lend credence to the argument that the Commission should simply reinstitute a 20-year old contract without a detailed re-examination of that contract's terms.

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[49] D.96-10-036.

[50] See CCC brief, p.10-11.

[51] See CCC brief, p. 10 for CCC's discussion of Mr. Bergmann's testimony.

CCC's proposal has not received the unanimous support of the QF industry, and that in fact it is only co-generators (and not the broader community of QF generators, including renewables) pressing for the return of the SO1 contract. Not one of the renewable resource parties that filed a brief concerning SCE's motion[52] endorses CCC's proposal to reinstitute the requirement that utilities make available SO1 contracts.[53]

We note a host of problems with the arguments underpinning CCC's proposal. CCC asserts that prices under SRAC have been within "1% of the average spot market energy price," save for during the 2000-2001 crisis, when SRAC prices were below market prices.[54] However, the Beach testimony upon which CCC relies for its assertion regarding comparability does not make an apples-to-apples comparison between energy prices in markets (which *include* capacity payments in the energy price) and SRAC prices (which *do not include* capacity payments in the energy price). QFs receiving SRAC payments also received separate, additional, capacity payments, a fact not reflected in Mr. Beach's testimony. In addition, SRAC prices would be available at any time, even off-peak when well in excess of prevailing market prices. CCC's contention

[52] CEERT, CalWind, and Union of Concerned Scientists

[53] See Opening Brief of the California Wind Energy Association Regarding Interim Procurement Issues, at p.12: ". . . the utilities should be free to purchase renewables from QFs or non-QFs."

[54] CCC Brief, pp. 4-5. We take exception to any implication in CCC's arguments on this point that QFs were in some way *voluntarily* offering below-market prices. This Commission was involved in litigation at the FERC and at various courts with QFs and QF associations as these QFs and QF associations struggled mightily to take advantage of the exorbitant market prices that prevailed during the 2000-2001 energy crisis.

that excess power taken under QF contracts could be sold "in the market [at] a price that is comparable to the SRAC price paid to the QFs"[55] strikes us as wishful thinking. We are all too cognizant of the difficulties DWR is having disposing of excess power under its long-term power purchase agreements. Were it as simple as CCC would have us believe to economically dispose of excess power, CCC would not be making its proposal.

[55] CCC Brief, p. 5.

On a related note, PG&E complains that entering into additional SO1 contracts will complicate, or at the least fail to simplify, PG&E's procurement responsibility.[56] PG&E also observes that the proposal is "without limitation as to transitional procurement versus long-term." We observe that the longest duration agreement proposed by SCE would be for five years. SO1 contracts originally had a term "not to exceed 30 years," later shortened to six years, with the possibility of one year extensions thereafter.[57]

We deny here, in the narrow confines of SCE's motion for interim procurement authority, CCC's proposal to once again require utilities to enter SO1 contracts with QFs. Such issues are best addressed elsewhere on a less-expedited time frame and in the context of a fuller reexamination of our QF policies. In the meantime, CCC members remain free to pursue non-standard contract opportunities, as elaborated upon below.

2. The Proposal to Provide QFs With an ROFR

At the outset we must confess to some uncertainty regarding whether CCC proposes an ROFR for *any* QF, or just for QFs with energy not already encumbered by any SO contracts with IOUs. The proposal does not appear to distinguish between QF capacity or energy that is encumbered or unencumbered by SO contracts. A QF with capacity or energy encumbered by

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[56] ". . . far from being a normal procurement situation, the utilities are confronted with only a narrow and complicated peak supply gap left to them as a result of long-term contracts negotiated and executed by DWR. No system of unlimited standard offers can fit the unique supply situation represented by residual net short procurement in general and the requested transitional procurement program in particular." (PG&E Brief at 21.)

[57] D.96-10-036.

an SO contract is already required to make capacity and energy available under the terms SO contract, and so would not seem to have anything to offer other than energy not subject to the SO contract. Accordingly, we interpret CCC's proposal as limiting the ROFR to QFs with capacity or energy unencumbered by any SO contract with an IOU to the extent of the unencumbered energy.[58]

We reject the fundamental premise of CCC's claim to an ROFR – that the interim procurement process establishes avoided cost for purposes of implementing PURPA. The FERC's regulations[59] identify numerous factors that "shall, to the extent practicable, be taken into account" in determining avoided costs. These factors include data on utility generation construction costs,[60] the operating characteristics of a particular QF, including dispatchability, reliability, and usefulness during emergency, value of products from other QFs, and the relative ease with which QF capacity can be added to the grid,[61] reductions in

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[58] We are familiar with claims by some QFs that they have capacity in excess of that covered by the SO contract but are not prepared to express an opinion on how much, if any, energy or capacity falls within this category on the record before us now, and, in view of our ultimate disposition of the proposal, see no need to address such claims. Capacity subject to SO contracts shall continue to be prices according to the Commission's SRAC pricing guidelines and Public Utilities Code Section 390.

[59] 18 CFR § 292.304 (e).

[60] *Id.* at subsection (1), which we summarized as follows in D.96-10-03: 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.

[61] *Id.* at subsection (2).

fossil fuel use,[62] and reductions in line losses. In addition, we are constrained by Public Utilities Code Section 390 to calculate avoided costs "paid to nonutility power generators . . . based upon the commission's prescribed 'short run avoided cost energy methodology' . . . as set forth in [Public Utilities Code Section 390] subdivisions (b) and (c)." Subdivision (b) ties short run avoided cost energy payments to a gas index price, while Subdivision (c) ties short run avoided costs to "the clearing price paid by the independent Power Exchange," subject to the occurrence of certain conditions precedent.[63] What SRAC should be under Public Utilities Code Section 390 was the subject of a lengthy proceeding in R.99-11-022. CCC was deeply enmeshed in R.99-11-022, having sought rehearing of numerous commission decisions in that proceeding.[64] This Commission never determined that the PX was functioning properly, and it is now defunct. Accordingly, this Commission has never endorsed a shift to market prices for determining avoided costs.

Neither PURPA itself nor the FERC regulations implementing PURPA expressly grant an ROFR to QFs. CCC would have us find one implicit in the regulatory framework elaborated above. Presumably if PURPA contained an implicit grant we would find numerous occasions on which QFs were pushed

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[62] *Id.* at subsection (3).

[63] The conditions precedent are: (1) issuance by us of "an order determining that the Independent Power Exchange is functioning properly . . ." and either of (2) utility fossil fuel plants recover their going forward costs solely through the PX and the ISO, or (3) utilities divest 90% of gas-fired generation operated to meet load in 1994 and 1995. (Public Utilities Code Section 390(c).)

[64] See, e.g., D.02-05-012, denying CCC application for rehearing of D.01-10-069.

to the "head of the line" ahead of other procurement options, but we find no particular examples outside of the Biennial Resource Plan Update (BRPU) process, about which more later.[65] As PG&E points out in its brief, QFs were not pushed to the "head of the line" in the PX auction. Nor, we note, are QFs pushed to the head of the line in auctions in the ISO markets for energy or Ancillary Services.

PG&E brings up the FERC's order rejecting the BRPU process.[66] PG&E apparently reads that order as mandating a single, single-price auction, presumably in reliance on the statement that: "[t]he [FERC] reasoned that sections 210(b) and 210(d) of PURPA require that any determination of avoided cost must take into account all potential sources of capacity, and that the California program improperly limited itself to only certain sellers (QFs)."[67]

The principal faults allegedly suffered by the BRPU process were:

> [a]s explained in the February 23 order and as explained further below, [that] the ultimate method of determining price for California QF power was in the auction process following administrative determination of the IDR[68] benchmarks. The auction process did not include all sources of power and, as Edison and San Diego continue to explain in their answers to the requests for

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[65] We are cognizant that at least some IOUs generation was deferred or not built at all as it was displaced by QFs.

[66] *Southern California Edison Company*, 71 FERC 61,269 (1995), PG&E Brief at 22.

[67] *Id.* at 62,076 (footnote omitted).

[68] "Identified Deferrable Resources," basically the generation projects that a utility could avoid building by entering into contracts with other generation suppliers.

> reconsideration, did not allow for the selection of the lowest cost bidders."[69]
>
> Moreover:
>
> The benchmark considered only the purchasing utility's cost of generating energy but did not take into account fully what it would cost to purchase such energy from another source, as required by PURPA's definition of avoided (incremental) cost. While the benchmark process may have taken all technological sources into account, it did not consider all types of sellers (QFs, IPPs, IOUs, etc.).[70]

What CCC is proposing here is not the "QF only" auction that the FERC rejected in connection with this Commission's BRPU proceeding. Significantly, in contrast to the BRPU process' "QF only" auction, the proposal here would take account of "all generation resources"[71] by moving QFs to the "head of the line" at the *conclusion* rather than *outset* of the procurement process. This simple but significant distinction makes the *Southern California* decision inapplicable by ensuring that all resources' bids are taken into account in the ultimate method of determining a price for QFs.

There is, however, another aspect of the *Southern California* decision that merits further discussion. In *Southern California*, the FERC noted that:

> [t]he California utilities have claimed, *with considerable validity*, that in order to demonstrate that a non-QF

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[69] *Id.*

[70] *Id.* at 62,078.

[71] *Id.* at 62,075.

> purchase option was indeed available, it would be necessary to negotiate with potential non-QF sellers as to price and terms, and that non-QF suppliers would not, in reality, negotiate seriously if the resulting "sale" would simply result in a benchmark price to be used as a target for QF bidders.[72]

The argument made by the IOUs in *Southern California*, and endorsed by the FERC (as noted with italics) resurfaces here. As CCC notes in its brief, "Edison and SDG&E also objected that potential non-QF bidders might be reluctant to bid for a product if they knew another party had a ROFR."[73] CCC makes light of this objection, dismissing it as speculative,[74] and asserting that the threat of exercise of an ROFR will drive prices down.[75] We are not so sanguine. PG&E argues that:

> Few things would be as disruptive of an orderly and efficient RFO process as the "right of first refusal" contended for by CCC. California Wind Energy Association, which includes QFs among its members, points out that: 'Non-QFs might hesitate to bid if they believed their bids, if initially successful, would become mere targets for matching by non-selected QFs with a right of first refusal. Also, if non-QFs hesitate to bid, the competition will be less vigorous and the prices less favorable to consumers.'[76]

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[72] *Id.* at 62,078 (emphasis added).

[73] CCC brief at 13.

[74] *Id.*

[75] *Id.* at 14.

[76] PG&E brief at 23 (citation omitted).

This leads to a related concern – the fundability of suppliers. A wind generator is not necessarily substitutable for a combustion turbine. A steam host is not necessarily substitutable for a base-load plant. We are concerned about the possibility of mismatching contracts with providers if QFs generically are allowed to step into agreements negotiated with other parties. We will address these concerns in more detail in our decision resolving the balance of this case.

QFs will, like all market participants, have a chance to sell to IOUs through the interim procurement process. If a QF makes a "winning" bid (i.e., a bid conforming to the technical requirements of the RFP that is at or below the highest accepted bid) to an IOU, the IOU must accept the bid. If a QF has mis-gauged its bid, PURPA does not entitle the QF to another bite at the apple. CCC seeks to anticipate arguments that its proposal invites QF gaming of the auction process by clarifying that its proposal is for QFs to *either* bid, or exercise an ROFR, *but not both* in connection with a given procurement process. While this either/or approach might reduce gaming opportunities available to QFs were the ROFR adopted, it does not address the fact that members of a single class of bidders are free, at their discretion, to swoop down and snag for themselves the entirety or portions of the most attractive contracts at the last minute. This would seem to be just as likely to "lead to chaos in these solicitations"[77] as allowing a winning bidder to engage in a second round of bidding against a QF exercising its ROFR.

[77] CCC, Beach, Tr., p. 1908, l. 27 – p. 1909, l. 15

Anticipating the foregoing line of reasoning, CCC contends that "the Commission should appreciate that simply allowing QFs to participate in a first price auction, or other procurement forum in which prospective sellers receive their bid price if selected, would not satisfy PURPA's avoided cost requirements."[78] In rebuttal, ORA states that "ORA agrees with SCE's position that '[t]he Commission has dealt with that issue by suspending standard offers, and instead suggesting that the market is the alternative means by which you satisfy the mandatory purchase obligation" (Bergmann, Edison, Tr. p. 442).'"

We agree with Edison and ORA that the market *might* be an alternative means by which the Commission can satisfy PURPA's dictates. In D.96-10-036 we expressed our expectation that eventually all QFs would be paid and scheduled through the PX, which was expected to set prices and select sellers through a single price auction. Allowing QFs to participate in a first price auction – albeit an auction run by the IOUs rather than by the now-defunct PX – can satisfy PURPA's must-take and avoided cost pricing requirements. We never, however, approved a switch over to PX pricing for establishing avoided costs, and we are unready to conclude today that we have reached a point where a market provides a proper benchmark for establishing avoided costs. We will continue to rely on our administrative processes to set avoided cost prices for purchases pursuant to PURPA.

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[78] CCC Brief at 20.

V. Procurement of Renewables During the Transitional Period

There is a real concern, expressed by parties, that an interim contracting authorization might result in the foreclosure of all opportunities for the procurement of renewable resources this year, in 2003, and perhaps beyond. Such a result would clearly countermand the will of the legislature and the mandate of this Commission, as expressed in Public Utilities Code Section 701.3, and, tentatively, in AB 57. Accordingly, we have directed parties to respond to the May 6th Edison motion with specific recommendations as to how renewable generation should be treated in this initial decision.

We will not allow the satisfaction of an otherwise legitimate need – the early and economic acquisition of energy and capacity to fill a portion of each utility's residual net short – to further hamper the development of renewable generation in California. While this decision does not enact the utility procurement plans for 2003, neither should it frustrate the development of renewable resources, a central feature of the Plans as contemplated in both AB 57 and the Scoping Memo Ruling for this proceeding.

We are, therefore, guided in the immediate instance by the specific language of Public Utilities Code Section 701.3, which reads in relevant part:

> "The Commission shall direct that a specific portion of future generating capacity *needed for California* be reserved or set aside for renewable resources." (Emphasis added.)

In this decision, we focus on a specific portion of the unmet needs of the utilities, and in this context seek to encourage renewable generation to the fullest extent possible. We are aware that the size of the residual net short for each utility is influenced by contract allocation discussions, and that ongoing renegotiations of DWR contracts may result in the need for electrical products that are different from the peaking and dispatchable products the utilities currently seek to procure.

In any event, the emphasis in this instance is on presently identified need, and allowing renewable resources the opportunity to meet that need, even as we prepare for the considerably more substantial opportunity for renewable development in the next phase of this proceeding. Consequently, in this decision, we seek both to meet immediate resource needs and to anticipate new needs arising from ongoing contract discussions, and establish a process whereby these new needs can be met with renewable resources that are not placed under contract to help meet the present residual net short. We agree with parties that this interim procurement should not hamper the ability of the utilities to meet a potential mandatory increase in their renewable procurement in 2003. But we are also aware that the procurement needs of the utilities in this interim phase are particular, and that a blanket order to procure renewable generation irrespective of the nature of these needs will not do the job. This is the balance we attempt to strike now.

A. Authorized Interim Steps

In sum, we take three steps here that will allow renewable generators to compete for this authorized procurement, for procurement to meet unanticipated needs arising from ongoing negotiations with fossil generators under contract with DWR, and to allow this Commission to begin collecting the necessary information in furtherance of an optimal decision on the final Procurement Plans.

1. All-Source Solicitation With Preference for Renewables

We direct the utilities, in the all-source solicitation they conduct, to evaluate bids that are otherwise equal in terms of cost and electrical product offered so as to favor renewable generators. Bids from renewable generators that provide the required product, but at a cost above fossil generation, should be forwarded with the application for transitional procurement to the Commission for analysis.

The bid price of each renewable generator must clearly express the value of any Public Goods Charge (PGC) awards received, so that the cost equality of fossil and renewable bids can be accurately compared without this subsidy.[79] The utilities must be specific as to the products they seek to procure, so that renewable generators may seek to meet those needs in creative ways. Renewable generators that operate in tandem with fossil facilities to provide the needed products shall be eligible for this preference, provided that the net emissions of pollutants do not exceed those of the fossil bid that is superseded.[80] It is therefore essential that such combined renewable and fossil bidders document their emission profile in providing the desired product; such documentation will be scrutinized by the Commission in reviewing these bids, and will be subject to annual confirmation in the form of a compliance filing.[81]

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[79] All else equal, a renewable facility that *does not* receive a PGC award should be given priority. Thus, if two renewable bids are eligible to supersede a fossil bid, the facility that does not receive a PGC award should win.

[80] These pollutants, discussed in the testimony of the Union of Concerned Scientists, include nitrogen oxide (NOx), carbon monoxide (CO) and dioxide (CO2), particulate matter (PM), and sulphur dioxide (SO2).

[81] This process is ordered for this interim procurement only; future procurement from these "hybrid" renewable and fossil technologies may be subject to a different set of criteria.

We recognize that it will in many instances be difficult for renewable generators to provide the product the utilities seek in this interim procurement, and reiterate our requirement that utilities be as explicit as possible in describing their needs. We expect utilities to take into consideration in their resource selection the mandates of Section 701.3 and AB 57 with an eye to including renewables in their resource mix. To the extent that there are no renewables included in their transitional procurement, we will require the utilities to provide justification for their reliance solely on fossil resources.

While this authorization may not result in much, if any, new renewable generation under contract, neither will it reduce the amount of load that could be met by renewable generators under a mandatory renewables procurement framework. Thus, the concern expressed broadly by parties that this interim procurement not forestall the Renewable Portfolio Standard process is satisfied in this instance.

2. Determining the Least Cost/Best Fit

We further direct the utilities to collect in this all-source solicitation a range of information from renewable generators that presently operate without a contract or can be built and come online quickly, as discussed in hearings and in party briefs. Utilities should collect from all responding facilities, and potential facilities, the following information: renewable technology type, location, type of products available, bid price, production profile for 2001-2002, cost elements (fuel, O&M, debt/equity service, PGC), and, for facilities not presently on line, any potential interconnection or transmission issues that may impair their ability to begin generating in a timely manner. In the context of describing their cost elements, each renewable generator should provide an account of the capital pay-down schedule for their facility as it impacts their offer price. This will allow the Commission to understand the impact high capital costs have on renewable facilities, and the way in which these costs affect over time the price of electricity from renewable resources.

The purpose of the collection of information of renewables in the transition period is twofold. First, it will allow the Commission to better understand the present market for renewable generation in California, to inform the process of price benchmarking should it be pursued in later phases of this proceeding. Second, it will position the utilities and the Commission to meet any unexpected resource shortfalls, resulting from DWR contract allocation, renegotiation or other factors, with renewable generation that can be made available quickly. Parties have argued that there presently exists a substantial base of renewable generation, as much as twice what would be needed to meet a 1% mandatory increase for 2003, and suggest that this robust potential market would therefore yield competitive prices for power from renewable sources.[82] This process will allow the Commission to assess more fully the likelihood of such an outcome. The utilities are directed to submit these responses, along with an analysis of the products and prices offered, to the Commission for review,[83] and respondents should consider their submissions to be binding offers to produce power.

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[82] For instance, the Opening Brief of the California Wind Energy Association at p.10.

[83] In evaluating these bids, the utilities should: consider each cost element and comment on its reasonableness; discuss the fit of each facility's product offering with the utility's need for generation; and discuss any operational issues raised by the location, production profile and technology type of each bid.

We stress that the process of interim procurement to cover the RNS will not be delayed by this informational solicitation. We seek only to begin this process now in order to allow for a fully informed procurement decision in the next phase, and to further the widely shared goal of ensuring the "least cost/best fit" procurement of electricity from renewable sources.[84]

3. Securing the Existing Base of Renewable Generation

These first two steps provide an opportunity for renewable generators to compete in the residual net short solicitation, and allow the Commission to get an early start on the process of including renewable energy in the full Procurement Plans. Finally, we seek to stabilize the base of existing renewable generation presently operating under short-term contracts.

First, we take notice of the recent success of both Edison and SDG&E (A.02-01-018 and A.02-03-010, respectively) in negotiating voluntary contract extensions and amendments with renewable generators, to continue or increase production of electricity at prices beneficial to ratepayers. By this decision we direct the utilities to further pursue such extensions and amendments. Increased production from existing contracts will count towards future requirements under

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[84] Respondents to this informational solicitation should indicate if they have also submitted a bid in the interim residual net short solicitation, and how the acceptance of such a bid would alter or otherwise impact their response to the informational solicitation.

a Renewable Portfolio Standard for 2003, and the contracts will be given expedited reasonableness review via the Application process.[85]

Second, we take note of the Brief filed by the California Biomass Energy Alliance of July 12th, in which CBEA describes its success in negotiating extension of expiring 90-day contracts between its members and DWR through the end of this year. We are aware, although no party provided exact information, that a number of renewable facilities may similarly face the expiration of such 90-day contracts with DWR. DWR has evidently exercised its authority to extend these contracts, and perhaps others, through the end of this year. While we do not encourage further such extensions, it appears that a concern expressed early on in this proceeding - that many renewable facilities were in danger of imminent shutdown - has been relieved by DWR's actions.[86]

Third, we note that existing facilities with or without contracts are free to sell excess energy into the ISO spot markets. As we lay the groundwork for the Procurement Plan solicitations in the coming months, we encourage existing facilities to take advantage of this potential market for their output.

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[85] San Diego's Application was approved by this Commission in three and half months; we would endeavor to rule on other such Applications within a similar timeframe, particularly if such Applications meet with no protest.

[86] In this context, we deny the June 12 motion of Ridgewood Olinda LLC seeking an automatic extension of its DWR contract. We cannot make a finding on this record that it is in the public interest to order the respondent utilities to enter contracts under the terms and conditions proposed by Ridgewood. DWR has apparently undertaken an independent analysis of the merit of such an extension, and chosen not to offer one.

B. The Role of Public Goods Charge Funds in Renewable Procurement

As noted above, we anticipate that a number of the respondents to the solicitations hereby ordered will be recipients of PGC funds awarded by the CEC. These are funds that have been paid by utility customers over the past four years, with the intent that they cover the "above market costs" of renewable power in a competitive market. With the dissolution of the Power Exchange this competitive market benchmark is no longer available to us.

Nonetheless we are preliminarily directed by AB 57 to ensure that "above market costs" of renewable power are covered by the PGC, and as a policy principle we seek to render any such subsidies as transparent as possible, without stymieing entirely the process of new renewable procurement. The explicit information on PGC funding we seek to collect will allow us to evaluate the importance of this subsidy in California's renewable industry, and will aid us in developing, should the record compel us to do so, benchmark prices for renewable technologies.

The question of establishing appropriate market prices, above which subsidies from the PGC will be required, is a task for the next phase of this proceeding. The success of such an effort in the next phase, however, is largely dependent on legislative authorization of the CEC's financial plan for the future of the Renewable Energy Program. These funds represent the primary means of support for renewable generation; without them, the requirement in AB 57 that above-market costs of renewable generation be covered via the PGC represents an unfunded mandate. We anticipate that the legislature will have finalized the financial reauthorization of the PGC program when we turn to the full Procurement Plans in the next phase.

C. Bridging the Gap to AB 57 and the Full Procurement Plans

In closing, we reiterate that while AB 57 is not yet law, we are attempting to align our policy directives in a manner compatible with the bill's provisions, even as we stress that this Decision does not authorize the full Procurement Plans for the utilities. We take these steps regarding renewable resources to shore up the existing stock of generation to the fullest extent possible in the context of a targeted procurement, and to begin gathering information that will allow us to maximize the effectiveness of decisions authorizing the full Procurement Plan. Much of the work and opportunity lies ahead.

VI. Shortening the Public Review Period of the Proposed Decision

In setting the briefing schedule on July 2, 2002, the ALJ asked parties to address if they would stipulate to shortening the time for review of the proposed decision pursuant to Section 311(g)(2). Several parties stated their support for this in their briefs; no party opposed the request. Parties will have another opportunity to address this issue in their oral argument before the Commission on August 8, 2002. We will consider the silence of a party on the issue to imply consent. If no objections are raised to the Commission shortening time for public review of the proposed decision at the oral argument, comments will be due on August 19, 2002 and the decision will be placed on the August 22, 2002 Commission agenda.

Findings of Fact

1. PG&E, SDG&E, and Edison are the respondent utilities in this proceeding.
2. On May 6, 2002, Edison filed a "Motion for an Interim Decision Granting Approval of Process for Early Procurement of Capacity." Edison's motion

requests authority to enter into multi-year capacity contracts for a term of up to five years using the credit of the DWR until Edison regains its investment grade rating.

3. On May 15, 2002, the assigned Commissioner and ALJ issued a ruling finding that the authority sought by Edison should be considered in the hearings scheduled to commence shortly, and modified the hearing schedule to accommodate this.

4. At the hearings, held from June 10 through July 3, 2002, PG&E and SDG&E requested that they be granted the same transitional period authority as Edison is granted. In addition, PG&E requests it be granted authority to enter gas hedge contracts of the type currently authorized Edison under its Settlement Agreement with the Commission.

5. Interested parties to the proceeding generally support a more limited transitional authority that that requested by the respondent utilities; Ridgewood and Aglet recommend the request be denied.

6. SDG&E currently has an investment grade credit rating, and, therefore, a question exists as to whether the credit support of DWR should be provided, and if so, when SDG&E should assume financial and legal responsibility for the contracts from DWR. We find that SDG&E is creditworthy, its procurement needs are a small part of the market, and it can fully participate in the CAISO market. SDG&E may execute any contracts resulting from the authority granted today without DWR involvement. SDG&E may use the expedited review process

7. We will consider Edison's May 6th motion in a manner that will not harm renewable generation in the final procurement plan.

8. We will be conservative in any authority we grant until a decision on allocation of the existing DWR contracts is final, both at the Commission and in any reviewing courts.

9. We should adjust PG&E's proposed capacity limit to reflect a comparable methodology to Edison's and PG&E's conservative low RNS forecasts.

10. We find merit in authorizing multi-year procurement. The prospect of signing multi-year procurement contracts will help attract suppliers to utility solicitations and will help attract capital investment in new generating projects.

11. It is reasonable to grant Edison, PG&E and SDG&E authority to procure up to 65% of its on-peak hourly RNS requirement reflected in a low-case RNS scenario for products with a contract duration up to one year and without self-provision of ancillary services included.

12. Given the uncertainty that exists surrounding final allocation of DWR contracts and the uncertain net effects of DWR contract renegotiation on the aggregate size and shape of DWR's supply portfolio over the next five years, we find it reasonable to adopt SDG&E's recommended 50/50 proposal. Therefore, we should authorize Edison, PG&E, and SDG&E authority to procure up to 50% of their authorized amount with contracts of up to a five year duration. This limit will ensure that a significant remainder of procurement requirements will be guided by future Commission decisions.

13. For purposes of addressing ORA's concern that Edison has failed to precisely define the term 'capacity product', we adopt the following definition: A capacity contract is one in which the buyer has the right to take energy at a known price in exchange for a capacity or reservation charge. The energy charge could be fixed or indexed to gas prices. Under this type of contract, the buyer

has the right, but not the obligation to schedule energy up to the maximum number of MWs provided for in the contract.

14. It is reasonable to grant Edison and PG&E authority to purchase:

    (a) capacity contracts, as defined in this decision;

    (b) forward energy products;

    (c) transportation of the physical commodity portion to be delivered pursuant to authorized capacity and energy contracts;

    (d) related fuel products, natural gas supply, transportation, and storage for specific authorized capacity or energy contracts;

    (e) energy exchanges, such as energy for capacity transactions, peak for off-peak exchanges, and seasonal exchanges.

15. It is not reasonable to grant the respondent utilities authority to use financially-settled hedging instruments because of the complexity in reviewing these transactions in an expedited manner.

16. We should deny PG&E's request for additional authority to procure gas hedging to hedge the fuel cost risks associated with its retained generation and qualifying facilities contracts because it goes beyond the scope of authority being considered under Edison's motion.

17. We find that granting transitional authority, under the terms and conditions adopted here, is beneficial for both the utilities and their customers. Edison and PG&E will benefit by being able to enter procurement contracts prior to regaining an investment grade credit rating and to demonstrate to the financial markets that they can successfully resume their full procurement responsibilities under the Commission's regulatory oversight. Customers of the

utilities will benefit from the utilities receiving and exercising this authority in a manner that promotes reliable service at just and reasonable rates.

18. The Edison/DWR agreement proposed in Edison's May 6th Motion should be modified to meet the concerns expressed by DWR in its May 31st memo.

19. Edison, PG&E, and SDG&E have in their control how expedited the review and approval process will be based on the transitional procurement strategy they employ, the early and collaborative role they give staff and non-market participant parties in reviewing their analysis and recommendations, the contracts they chose to enter, the quality of the application package they submit, and their responsiveness to requests for additional information.

20. All products purchased under this authority should be purchased using a competitive process.

21. We cannot make a finding on this record that it is in the public interest to order the respondent utilities to enter contracts under the terms and conditions proposed by Ridgewood in its motion; therefore, we will deny this motion.

22. Renewable generators that operate in tandem with fossil facilities to provide needed products will be eligible for the same preference, provided that the net emissions of pollutants, as defined in this decision, do not exceed those of the fossil bid that is superseded.

23. In the all-source solicitation process, the respondent utilities, should collect the following information from bidders that are renewable generators renewable technology type, location, type of products available, bid price, production profile for 2001-2002, cost elements (fuel, O&M, debt/equity service, PGC funds), and, for facilities not presently on line, any potential interconnection or transmission issues that may impair their ability to begin generating in a timely

manner. The renewable generators participating in the bidding should consider their submissions to be binding offers to produce power.

24. Within 30 days of an all-source solicitation process, the respondent utilities should submit the responses from renewable generators to the Commission, together with an analysis of the products and prices offered.

25. The respondent utilities should pursue contract extensions and amendments with renewable generators at prices less than or equal to the utility's short-run avoided cost, as defined by existing formula approved by this Commission.

26. At this time, we should not re-institute the utility obligation to enter SO1 contracts for qualifying facilities, as defined under the Public Utility Regulatory Policy Act of 1978, because such issues must be considered in the context of a full re-examination of our QF policies.

27. It would not be good public policy to grant a right of first refusal to QFs.

28. We expect utilities to take into consideration in their resource selection the mandates of Section 701.3 and AB 57 with an eye to including renewables in their resource mix.

29. The collection of information of renewables in the transition period will allow the Commission to better understand the present market for renewable generation in California, to inform the process of price benchmarking should it be pursued in later phases of this proceeding

30. This information will also position the utilities and the Commission to meet any unexpected resource shortfalls, resulting from DWR contract allocation, renegotiation or other factors, with renewable generation that can be made available quickly.

31. Existing facilities, with or without contracts, are free to sell excess energy into the ISO spot markets. As we lay the groundwork for the Procurement Plan solicitations in the coming months, we encourage existing facilities to take advantage of this potential market for their output.

Conclusions of Law

1. We need to develop a process that is balanced: one that meets the needs of the utilities for timely decisions that reduce regulatory uncertainties while at the same time ensuring that the Commission has exercised its statutory responsibilities to protect consumers from unreasonable costs through effective oversight and regulation.

2. The utilities should use a competitive process that provides wide dissemination of the request to members of the generation community, to include renewable resource suppliers. The specifications for a capacity or energy contract should not be fuel or technology specific.

3. We are not obligated to reinstitute SO1 contracts for QFs.

4. We are not obligated to provide a first right of refusal to qualifying facilities for solicitations conducted under the transitional authority granted here.

5. In order to ensure an adequate review period, the utilities should use an application process for nonstandard contract review and approval, especially as we undertake to quickly examine and provide, up-front reasonableness approval to electric procurement contracts that are represented to be quite complex multi-year transactions.

6. In the all-source solicitations they conduct, in the respondent utilities should favor renewable generators, as defined in this decision, in the evaluation of bids otherwise equal in terms of cost and electrical product offered.

7. This order should be effective today in order to allow the utilities to expeditiously begin the all-source solicitation process, described herein.

INTERIM ORDER

IT IS ORDERED that:

1. The May 6th, 2002 motion of Southern California Edison is granted, with the modifications set forth in this decision.

2. The respondent utilities shall file by compliance letter the terms under which they will enter contracts in participation with the California Department of Water Resources (DWR), revised to address the concerns stated by DWR in its May 31, 2002 memo, within five days of the effective date of this order.

3. We adopt the following process to approve contracts for transitional procurement:

    a. Application. Edison, PG&E, or SDG&E file an application that conforms to the quantities, products, terms and conditions we discuss earlier for transitional procurement. The application should demonstrate it meets our standard for approval by a showing that entering into the contract(s) should result in favorable and stable rates for ratepayers relative to alternative options. An application may contain all winning contracts from a single RFP solicitation. SDG&E cannot use DWR's credit to undertake transitional procurement. Bids from renewable generators that provide the required product, but at a cost above fossil generation, shall be forwarded to the Commission with each utility's application.

    b. Master Data Request. We find the master data request proposal by ORA to be beneficial and will adopt it. The application must contain all information required under our adopted master data request. The specifics of this are attached to this decision as Appendix D. Each application should include documentation of the steps followed for each transaction, such as including at a minimum the risk management package presented to senior utility management, the specific approvals and conditions given by management, and the rationale and procedures of the selection process undertaken. The respondent utilities must also respond to all data requests within five working days, either by producing the requested material or by filing an objection under our Law and Motion procedures.

c. Procurement Review Group (PRG). Use of the PRG recommended in the Joint Principles. This group would meet prior to the application being filed and should be convened early on to assess any proposed RFP process before it is implemented. The PRG would meet again to assess the resulting bids, the winning procurement contracts, and reasonableness criteria with each respondent utility. The group would be open to parties designated under our Protective Order to review confidential information and would include representatives of the Commission's Energy Division and ORA as ex officio members.

d. Protests. A 30-day protest period with replies due in five days.

e. Workshop. A workshop will be held approximately 40 days after the application is filed. After the workshop, the assigned ALJ, in consultation with the assigned Commissioner, shall issue a ruling designating whether there are issues of substantial controversy or importance to require the scheduling of hearings. The ruling shall also state whether the ALJ intends to prepare a draft decision which meets the criteria set forth in Public Utilities Code Section 311(g)(2) of being an uncontested matter in which the decision grants the relief requested, a criteria that allows the 30 day public review period to be reduced or waived.

f. Current Filings. The requirement that each respondent utility shall have only one application pending at a time. However, if the assigned ALJ issues a ruling stating that the ALJ intends to prepare a draft decision that meets the criteria of 311(g)(2) and that will not be issued for public review and comment, then another application may be filed.

g. Denial. If the Commission rejects a proposed contract or procurement process, it should not designate any alternative procurement choices that would be recoverable by the IOU for ratemaking purposes without further reasonableness review.

h. Reasonableness Review. In its decision on an application, the Commission shall apply the same reasonableness standards it used in the ECAC proceedings and prudency of contract administration shall be at issue over the life of the contract. Similar to the gas EAD process, which provided an expedited procedure for reasonableness review of gas contracts, approval of the contracts shall be dispositive of all prudence questions which might arise at a later date regarding the contracts, absent a showing of:
(a) misrepresentation or omission of material facts of which the utility is aware in connection with the utility's request for contract approval; and (b) imprudence in the utility's performance under the negotiated contract.

4. Any contract under which a respondent utility is seeking pre-approval must be filed by application within 30 days of signing or selection. The utilities shall carefully monitor and report any cost premiums paid for pre-approval.

5. Within 30 days of an all-source solicitation process, the respondent utilities shall submit the responses from renewable generators to the Commission, together with an analysis of the products and prices offered.

6. The June 12, 2002 motion of Ridgewood Olinda, LLC is denied.

This order is effective today.

Dated ____________________________, at San Francisco, California.

APPENDIX A

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APPENDIX B

	Joint Principle Proposed Review Process		PUC's Advice Letter Approval Process	
Day	Days to Complete Task	Tasks	Days to Complete Task	Tasks
Days in advance of Application Filing Date	15	Review Group to assess proposed contracts and provide written comments to IOU before IOU submits contract(s) to PUC.	No limit	IOU internally plans, designs, and prepares AL to be filed with PUC
0	0	Advice Letter Filed by IOU including proposed contract(s), procurement processes, and Review Group recommendations	0	Advice Letter filed by IOU for purpose allowed under GO-96A or as specifically ordered by the PUC
7	7	Protests due within seven days of AL filing.		
10	3	Replies to protests due within three days of protest.		
20			20	Protests due within 20 days of AL filing
27			5 Bus Days	Replies to protests due within 5 business days of protest

APPENDIX B

30	30	PUC rules on Advice Letter. Approval constitutes a determination that cost incurred under contracts and/or contracts conforming to procurement process are reasonable and prudent. If PUC rejects proposed contract or procurement process, it would designate alternatives that would not be subject to further reasonableness review. Approval would constitute determination that cost incurred under the contracts itself and/or under contracts conforming to procurement process are reasonable and prudent.· IOU administration of contracts would remain subject to reasonableness review by the CPUC under reasonableness criteria or incentive ratemaking, as appropriate.	30	Section 455 of PU Code authorizes the PUC to "enter upon a hearing concerning the propriety of the rate...." for those ALs not resulting in a rate increase. The PUC may suspend the AL pursuant to Section 455 and the guidelines set forth in D.02-02-049 pending the dispostion of a Resolution to be prepared on the AL. Suspensions can last up to 10 months, i.e., for an initial period of 120 days, plus an additional six month period if the AL is not resolved. ALs not resulting in a rate increase become effective 30 days after filing if not suspended or otherwise disposed of by the CPUC or its staff. If it is determined that the AL will lead to a rate increase, Section VI of GO-96-A calls for the rate increase to be filed by formal application and for the PUC to make a finding (i.e., adopt a Decision) on whether the increase is justified. Requests for rate increases may be filed by AL under circumstances where the rate increase is minor in nature. Requests for approval of rate increases, or other tariffs that may result in rate increases, are not subject to Section 455, and thus may under Section 454 not go into effect on a default basis in the absence of a CPUC order.
31-59			Less than 30 days	PU Code Section 311(g) generally requires the PUC to circulate draft decisions for public review and comment at least 30 days before voting on the decision. Pursuant to 311(g)(2), the required public review period for Resolutions or Decisions (called for in 311(g)) can be reduced or waived under four conditions: (1) due to unforeseen emergency situation; (2) upon stipulation of all parties in a proceeding; (3) for uncontested matter in which the decision grants the relief requested; or (4) for an order seeking injunctive relief. Rule 81 of the Rules of Practice and Procedure defines unforeseen emergency circumstances. The Rule states that a rate increase is not an unforeseen emergency situation.

APPENDIX B

60+			30+	If the AL requires a Resolution or PUC Decision, and if the section 311(g)(2) conditions for reducing or waiving public review period either do not apply or are not exercised, under Section 311(g) the Resolution/Decision must be served on parties and subject to at least 30 days review and comment prior to PUC vote. 60 days is generally the quickest turnaround the PUC can provide on Resolutions (assuming the PUC has a public meeting scheduled close to the end of the review period). Often times, Resolutions will take longer than 60-days due to staff's need to conduct thorough analysis or because PUC public meeting dates do not match up with the end of the 30-day review period.

(END OF APPENDIX B)

APPENDIX C

	Procurement Contract Review Process	
Day	Days to Complete Task	Tasks
Days in advance of Application Filing Date	No Limit	Utility internally develops risk management plans for transitional procurement. Utility also meets with Procurement Review Group (PRG) recommended in the Joint Principles. This group would meet prior to the application being filed and should be convened early on to assess any proposed RFP process before it is implemented. The PRG would meet again to assess the resulting bids, the winning procurement contracts, and reasonableness criteria with each respondent utility. The group would be open to parties designated under our Protective Order to review confidential information and would include representatives of the Commission's Energy Division and ORA as ex officio members.
0	0	Edison, PG&E, or SDG&E file a complete application that conforms to the quantities, products, terms and conditions we discuss earlier for transitional procurement. The application should demonstrate it meets our standard for approval by a showing that entering into the contract(s) should result in favorable and stable rates for ratepayers relative to alternative options. An application may contain all winning contracts from a single RFP solicitation. The application shall include information responsive to the adopted master data request.
30	30	Protests due within 30 days of Application filing.
35	5	Replies to protests due within five business days of protest. (See rules of pp
40	1	A workshop will be held approximately 40 days after the application is filed.
41+	As required	After the workshop, the assigned administrative law judge (ALJ), in consultation with the assigned Commissioner, shall issue a ruling designating whether there are issues of substantial controversy or importance to require the scheduling of hearings. The ruling shall also state whether the ALJ intends to prepare a draft decision which meets the criteria set forth in Public Utilities Code Section 311(g)(2) of being an uncontested matter in which the decision grants the relief requested, a criteria that allows the 30 day public review period to be reduced or waived.
41-59	Less than 20	If the ruling states that the ALJ intends to prepare a draft decision which meets the requirements of Section 311(g)(2), the decision when drafted will be placed on the next Commission agenda.

60+	30+	If the ruling states that the application does not meet the criteria of Section 311(g)(2), a draft decision will be served on parties and subject to at least 30 days public review and comment prior to a PUC vote. If the ruling states that there are issues of substantial controversy or importance to require the scheduling of hearings, such hearings will be held and a proposed decision served on parties and subject to at least 30 days review and comment prior to a PUC vote.
Note: Approval of the contracts will also contain a decision on reasonableness, with prudency of contract administration being at issue over the life of the contract. During the transitional period, if the Commission rejects a proposed contract, it will not designate any alternative procurement choices.		

(END OF APPENDIX C)

APPENDIX D

ADOPTED MASTER DATA REQUEST

- Identification of the ultimate decision maker(s) up to the Board level, approving the contract.
- The briefing package provided to the ultimate decision maker.
- A summary of any issues and questions raised by the decision maker.
- The process used to obtain capacity contract offers.
- The quantitative process used to rank offers.
- Relative cost-effectiveness of the offer.
- The contract.
- The break-even spot price equivalent to the contract.
- A copy of the software used by the utility to analyze the contract.
- An electronic copy of any data or forecasts used by the utility to analyze the contract.

(END OF APPENDIX D)