STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

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

November 18, 2003

Agenda ID #3005
Ratesetting

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

RE: NOTICE OF AVAILABILITY OF PROPOSED DECISION AND ALTERNATE DECISION OF COMMISSIONER PEEVEY

Consistent with Rule 2.3(b) of the Commission's Rules of Practice and Procedure, I am issuing this Notice of Availability of the above-referenced proposed decision. The proposed decision was issued by Administrative Law Judge (ALJ) Walwyn and the alternate decision by Commissioner Peevey on November 18, 2003. An Internet link to these documents were sent via e-mail to all the parties on the service list who provided an e-mail address to the Commission. An electronic copy of these documents can be viewed and downloaded at the Commission's Website (www.cpuc.ca.gov). A hard copy of these documents can be obtained by contacting the Commission's Central Files Office [(415) 703-2045].

This is the proposed decision of ALJ Walwyn, previously designated as the principal hearing officer in this proceeding and the alternate decision of Commissioner Peevey, the Assigned Commissioner. They will not appear on the Commission's agenda for at least 30 days after the date it is mailed. This matter was categorized as ratesetting and is subject to Pub. Util. Code § 1701.3(c). Pursuant to Resolution ALJ-180, a Ratesetting Deliberative Meeting to consider this matter may be held upon the request of any Commissioner. If that occurs, the Commission will prepare and mail an agenda for the Ratesetting Deliberative Meeting 10 days before hand, and will advise the parties of this fact, and of the related ex parte communications prohibition period.

When the Commission acts on the proposed decision and alternate decision, 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.

Parties to the proceeding may file comments on the draft decision as provided in Article 19 of the Commission's "Rules of Practice and Procedure." These rules are accessible on the Commission's website at http://www.cpuc.ca.gov. Pursuant to Rule 77.3 opening comments shall not exceed 15 pages.

Consistent with the service procedures in this proceeding, parties should send comments in electronic form to those appearances and the state service list that provided an electronic mail address to the Commission, including ALJ Christine M. Walwyn at cmw@cpuc.ca.gov. Service by U.S. mail is optional, except that hard copies should be served separately on ALJ Walwyn, and for that purpose I suggest hand delivery, overnight mail or other expeditious methods of service. In addition, if there is no electronic address available, the electronic mail is returned to the sender, or the recipient informs the sender of an inability to open the document, the sender shall immediately arrange for alternate service (regular U.S. mail shall be the default, unless another means – such as overnight delivery is mutually agreed upon). The current service list for this proceeding is available on the Commission's Web page, www.cpuc.ca.gov.

/s/ ANGELA K. MINKIN
Angela K. Minkin, Chief
Administrative Law Judge

ANG:tcg

Attachment

Decision **PROPOSED DECISION OF ALJ WALWYN** (Mailed 11/18/2003)

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))

INTERIM OPINION

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INTERIM OPINION

I. Summary

This decision adopts the long-term regulatory framework under which California's three largest investor-owned utilities, Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE), will plan for and procure the energy resources and demand-side investments necessary to ensure their customers receive reliable service at low and stable prices. As part of this framework, we promote environmentally sensitive resource choices, set reserve margin standards to protect California's electricity grid, and provide cost-recovery mechanisms that promote the creditworthiness of each utility.

In our decisions last year, the Commission took the actions necessary for the three respondent utilities to resume full procurement on January 1, 2003. We allocated to the three utilities the contracts the California Department of Water Resources (DWR) entered into during the energy crisis when the utilities did not have the creditworthiness to continue to procure energy for their customers, approved short-term procurement plans and cost-recovery mechanisms under which the utilities would resume procurement, and gave the policy direction for long-term procurement plans to be filed in 2003.

Our focus now is on ensuring the respondent utilities make the longer term investments necessary to provide reliable service to all California customers over the coming decade. The California Independent System Operator (ISO) has deferred to the Commission to adopt and enforce adequate planning reserve requirements for the utilities and other electricity providers operating in their service territories. We do that here. We find that there is ample surplus of electric energy capacity available in the Western Electricity

Coordinating Council (WECC) region that California can draw upon today and for the next few years. Therefore, we affirm an operating reserve requirement for 2004 and a phase-in of a planning reserve requirement over the next three years. Our approach is consistent with, but more aggressive than, the timetable and process recommended jointly by the three utilities, the California Energy Commission (CEC), the Office of Ratepayer Advocates (ORA), and The Utility Reform Network (TURN).

We address here the market structure rules the utilities should follow in making long-term resource acquisitions. We endorse a hybrid market structure, with the utilities able to compete through a competitive Request for Proposals (RFP) process to acquire ownership of new generation facilities. Having provided for direct utility ownership of new plant, we make permanent our ban on affiliate transactions as a direct and effective means of preventing potential conflicts of interest at a level where we have less oversight and control. The holding companies and affiliates of each utility should plan for future generation investment to be made outside of their utility's service territory and sold to other load serving entities. [1]

In reviewing each utility's short-term and long-term resource plans, we look to the statutory requirements of Assembly Bill (AB) 57 and the goals of the Energy Action Plan, a joint product of the Commission, the CEC, and the California Power Authority (CPA). We also look to the utilities to pursue an integrated resource planning process that balances the need for additional generation, transmission, and demand-side investments and to do this in a

[1] SCE's Mountainview application and SDG&E's RFP are before us as separate matters and are not addressed here.

public proceeding that allows all interested parties an opportunity to participate effectively. We require each utility to adhere to upfront standards in conducting their procurement and to be accountable for operating in a manner that mitigates the risks of high prices, ensures reliable service and delivers measurable value to their customers.

We modify and adopt short-term procurement plans for the utilities to operate under in 2004 and 2005. We adopt the recommendation of the three utilities, ORA, CEC, and TURN to have the utilities resubmit their long-term procurement plans in mid-2004, following the Commission's adoption of specific resource adequacy criteria to be addressed in upcoming workshops. We also adopt CEC's "no regrets" standard for the review of any long-term commitments the utilities propose prior to our adoption of final long-term plans.

Finally, we discuss the issues that should be addressed in the new Procurement OIR we expect to open in the second quarter of 2004. These issues are: (1) the need to develop procurement incentive mechanisms for each utility; (2) the need to develop a long-term policy for expiring QF contracts; (3) review of the management audits of SDG&E's and PG&E's electric procurement transactions with their regulated affiliates; (4) handling resource adequacy issues not addressed in the workshop process; and (5) review and adoption of revised 2004 long-term procurement plans for the three utilities. We expect to open this new procurement OIR in the second quarter of 2004.

II. Procedural History

On October 29, 2001, the Commission opened this proceeding to establish the necessary operating procedures and ratemaking mechanisms for the utilities to resume full procurement responsibilities by January 1, 2003. In a series of decisions between August and December 2002, we allocated the existing DWR contracts to each utility, established requirements for the procurement of renewable resources, established cost recovery mechanisms, and adopted short-term procurement plans under which the utilities operate through March 31, 2004.[2]

This decision addresses the procurement planning issues set for further hearing last year in Section X.B. of Decision (D.) 02-10-062. These issues were further delineated at the prehearing conferences on February 18, 2003, March 7, 2003, and July 16, 2003. The evidentiary hearings were held from July 21, 2003 through August 18, 2003. Opening briefs were filed on September 15, 2003 and reply briefs were filed on September 22, 2003.[3]

Parties who participated actively in the review of the utilities' long-term plans and 2004 short-term plans are the respondent utilities, Alliance for Retail Energy Markets and the Western Power Trading Forum (ArM/WPTF), the California Cogeneration Council (CCC), California Consumer Power and

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[2] The key decisions for allocation of DWR contracts are: D.02-09-053, allocation of existing contracts to each utility; D.02-12-069, adoption of Operating Order between DWR and each utility; and D.03-04-029, adoption of Operating Agreements between DWR and PG&E and SDG&E. Interim procurement authority was authorized for the utilities in D.02-08-071; in D.02-10-062 we adopted the regulatory framework under which the utilities would resume full procurement; and in D.02-12-074 we approved the short-term procurement plans for each utility and set a framework for addressing renewable resources procurement.

[3] Before the Commission in a separate application, A.03-07-032, is SCE's July 21, 2003 Application for Approval of a Purchase Power Agreement with the Mountainview Power Company, LLC. On October 7, 2003, SDG&E filed a motion in this proceeding for approval to enter into new contracts resulting from its Grid Reliability Capacity Request for Proposals; a separate schedule to consider this motion was set at the October 31, 2003 prehearing conference (PHC).

Conservation Financing Authority (CPA), California Energy Commission (CEC), The California Independent System Operator (ISO), The Cogeneration Association of California and The Energy Producers and Users Coalition (CAC/EPUC), the City of Chula Vista, the City of San Diego, the Independent Energy Producers Association (IEP), The Joint Parties Interested in Distributed Generation/Distributed Energy Resources (Joint Parties), the Natural Resources Defense Council (NRDC), the Navajo Nation, the Office of Ratepayer Advocates (ORA), Save Southwest Riverside County (SSRC), and The Utility Reform Network (TURN).[4]

Implementation of Senate Bill (SB) 1078 and SB 1038 legislation on the Renewable Portfolio Standard (RPS) has occurred through a separate workshop process. D.03-06-071 addressed the RPS issues needing to be decided by June 30, 2003 and directed that a new docket be opened to continue with implementation requirements.

Other proceedings that address programs and policies for specific types of resources are: Rulemaking (R.) 01-08-028 for energy efficiency; R.02-06-001 for demand response; and R.99-10-025 and R.98-07-037 for distributed generation (DG). We anticipate shortly opening a rulemaking to streamline the transmission planning process for the utilities in a manner that upholds environmental standards, meets the Commission’s statutory obligations under Pub. Util. Code § 1001, and ensures consumer benefits. An OIR to establish policies, procedures, and incentive mechanisms regarding DG and Distributed Energy Resources will be forthcoming.

[4] The Navajo Nation’s August 18, 2003 motion to intervene should be granted.

The utilities' procurement plans bring together the policies developed in each of the above proceedings into an integrated resource planning framework.

III. Regulatory Goals and Interagency Collaboration

The three service territories of the respondent utilities account for approximately 80% of California's electricity usage, placing the procurement issues before us here at the forefront of the state's energy agenda:

> "California is a diverse and vibrant society. The fifth largest economy in the world, California's population is expected to exceed 40 million by 2010. California's economic prosperity and quality of life are increasingly reliant upon dependable, high quality, and reasonably priced energy. Following the biggest electricity and natural gas crisis in its history, the state is well aware of the need for stable energy markets, reliable electricity and natural gas supplies, and adequate transmission systems. Looking forward, it is imperative that California have reasonably priced and environmentally sensitive energy resources to support economic growth and attract the new investment that will provide jobs and prosperity throughout the state." (Energy Action Plan.)

The Commission's legislative mandate is to ensure that all utility customers receive reliable service at just and reasonable rates, as specifically stated in Pub. Util. Code § 451 (§ 451), with § 701 giving the Commission power to undertake all necessary actions to properly regulate and supervise California's investor-owned utilities. Our ability to fulfill this mandate was challenged in the energy crisis of 2000 and 2001, both by reliability alerts that included rolling blackouts and by extreme price volatility (i.e., price spikes) in the wholesale price of natural gas and electricity. The crisis led to substantial rate increases for utility customers, financial turmoil for the utilities, their investors, and their creditors, and for two years, from January 2001 through

December 2002, the state assumed the utilities' responsibilities for procuring power for customers.

From this crucible of experience, the Commission, the legislature, interested parties, and the public have closely examined market structure issues and questioned the means by which the utilities plan for and acquire energy resources, and the means by which the utilities obtain cost approval and cost recovery for their acquired energy resources. This proceeding is where the Commission has addressed these issues, within the regulatory framework provided by the 2002 legislature in AB 57, and been able to return the utilities to their full procurement responsibilities on January 1, 2003.

AB 57 and SB 1976, codified in Pub. Util. Code § 454.5, provides a regulatory procurement framework for the Commission that (1) requires each utility to prepare and file a procurement plan that meets specified requirements;[5] (2) provides the criteria by which the Commission should review and either adopt, modify, or reject each utility's plan; (3) eliminates the need for after-the-fact reasonableness reviews of utility actions in compliance with an approved plan; (4) ensures timely recovery of prospective procurement costs incurred pursuant to an approved plan; and (5) requires that an approved

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[5] These requirements include, among other things, the assessment of price risk associated with the procurement portfolio; a risk management policy, strategy, and practices, including specific measures of price stability; specification of the duration, timing, and range of quantities of each product to be procured; a competitive procurement process; upfront standards and criteria by which acceptability and eligibility for rate recovery will be known; a diversified portfolio to include both short-term and long-term electricity-related and demand reduction products; a renewable resources requirement; and a plan to achieve appropriate increases in diversity of ownership and diversity of fuel supply of nonutility electric generation.

plan enable the utility to fulfill its obligation to serve its customers at just and reasonable rates, with such just and reasonable rates to include an appropriate balancing of price stability and price level.

Last year, we adopted short-term procurement plans for each utility under the AB 57 regulatory framework, recognized the need for the utilities to procure reserves on behalf of their customers' needs, and directed each utility to undertake an integrated resource planning effort, based on a 20-year time horizon, to include procurement from a mixture of different sources with various environmental, cost, and risk characteristics. At the February 18, 2002 Prehearing Conference (PHC), as well as in the Energy Action Plan, we emphasized that in making plans to procure a mixture of resources, the utilities should take into account the Commission's longstanding procurement policy priorities – reliability, least cost, and environmental sensitivity; we also stated the Commission's policy preference that resource adequacy be met first through cost-effective energy efficiency programs, other cost-effective demand reduction programs, and cost-effective renewable resources.

This year, we carefully reviewed the detailed long-term plans each utility filed, and focused on key policy issues of resource adequacy and market structure. We have reached out in partnership to other agencies, recognizing that common goals exist and can best be met by coordinated action. The ISO is an active participant in this proceeding, and we will rely on their continued involvement in future proceedings. Their analysis and expertise in electricity grid operations and wholesale electricity markets is especially beneficial in setting reliability standards, monitoring and reporting of planning reserve levels, and transmission grid assessment. The CEC and CPA, partners with the Commission in the Energy Action Plan, also contribute their considerable resources and expertise to our record, and we join with them in pursuing our goal to:

> "Ensure that adequate, reliable, and reasonably-priced electric power and natural gas supplies, including prudent reserves, are achieved and provided through policies, strategies, and actions that are cost-effective and environmentally sound for California's consumers and taxpayers." (Energy Action Plan.)

IV. Threshold Policy Issues

The three threshold policy issues addressed in this decision are (1) adoption of a resource adequacy framework, to include specific reserve level requirements; (2) adoption of a market structure for longer term resource commitments by the utilities and a requirement to include long-term investment in their procurement planning; and (3) an analysis of whether each utility will be financially capable of making the longer term investments necessary to meet its obligation to serve its customers. In discussing these issues, we give specific direction for the utilities to follow in their procurement planning and operations.

A. Reserves and Resource Adequacy

1. Summary

Resource procurement traditionally involves the Commission developing appropriate frameworks so that the entities it regulates will provide reliable service at least cost. This involves, as was done in this proceeding, the determination of an appropriate forecast of demand and then ensuring that the utility either controls, or can reasonably be expected to acquire, the resources necessary to meet that demand, even under stressed conditions such as hot weather[6] or unexpected plant outages. "Resource adequacy" seeks to address these same issues. Therefore, in developing our policies to guide resource procurement, the Commission fundamentally ends up addressing and resolving the issue of resource adequacy.

In this decision, the Commission (1) directs that in order to provide reliable service utilities have an obligation to acquire sufficient reserves for all customer load located within their service territory (i.e. the combination of load from bundled service, direct access, and community aggregation); (2) makes permanent the 15% reserve level provisionally adopted by the Commission in D.02-12-074; (3) directs the utilities to meet this 15% reserve requirement by no later than the beginning of 2007, including the establishment of interim benchmarks; (4) establishes a requirement (to become effective in 2005) that utilities forward contract 90% of their needs a year in advance (subject to adjustment if implementation results in either significantly increased costs or fosters collusion and/or the exercise of market power in the Western energy markets); and (5) continues the 5% limitation on utilities' reliance on the spot market (i.e., Day-Ahead, Hour-Ahead, and Real-Time energy) to meet their energy needs.[7]

An Assigned Commissioner/ALJ Ruling issued in this proceeding on September 25, 2003, directed the convening of workshops to address the issue of standardizing, to the greatest extent possible, the load forecasts and methodologies used by the utilities to value and count resources. Today's

[6] Traditionally, this is based on a "1-in-10" year hot weather scenario.

[7] This creates in many respects, a de facto 95% month-ahead requirement.

decision also provides further guidance to these workshops on the issue of counting resources, particularly with regards to maximizing the use of the preferred resources (energy efficiency, renewables, demand response) identified in the Energy Action Plan to meet California's energy needs and, consistent with the ISO Board's adopted motion,[8] the long-term DWR contracts. Once consistent methodologies are developed, the Commission will work with the ISO and other interested parties to develop appropriate reporting requirements. In the interim, the ISO can continue to monitor the utilities' procurement activities through their on-going involvement (including access to confidential data) of the utilities' on-going procurement related filings. This decision also addresses other miscellaneous issues associated with resource adequacy including deliverability and day-ahead commitment. The Commission has already addressed, in a previous decisions in this proceeding (D.02-12-074 and D.03-06-067) the issue of penalty provisions associated with a utilities' failure to follow its established procurement standards. We also do not need to reaffirm our extensive and pre-existing authority to ensure compliance with our decisions.

2. California Should be Responsible for Determining its Energy Future

Resource procurement inherently involves numerous policy decisions that have major implications for the cost and portfolio structure of resources used to meet California's energy needs. Given the strong interaction

[8] ISO Board of Governors' Resolution approving the ISO's "Comprehensive Market Design" (adopted April 25, 2002) states that: "…any available capacity obligation give full credit to any contracts endorsed by CERS."

between resource procurement and resource adequacy it is desirable that California policy-makers have the the necessary decision-making authority. It is for this reason that the Commission believes that it should be responsible for addressing resource adequacy for the roughly 90% of the ISO load located within the utilities' service territory. As the ISO notes:

> "[It] is not aware of any other entity besides the CPUC and/or local regulatory authorities (e.g. municipal boards) that can currently impose planning reserve/resource adequacy requirements. Accordingly, the CA ISO considers that the CPUC should clearly define planning reserve/resource requirements for these loads in a manner that is equitable and assures consistent treatment and requirements."

With regard to municipal utilities, as the Commission, the ISO,[9] and CEC[10] have all recently noted, such utilities have traditionally provided reliable service including provision of adequate reserves and have availed

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[9] In the PROTEST AND COMMENTS ON ISO MARKET REDESIGN PROPOSAL SUBMITTED BY THE PUBLIC UTILTIES COMMISSION OF THE STATE OF CALIFORNIA ON BEHALF OF THE STATE OF CALIFORNA INTER-AGENCY WORKING GROUP submitted in Docket No. EL00-95-001 and ER02-1656-000 (May 30, 2002), the Commission stated (citing from an ISO report) that:

> Governmental entities have long planned their systems to ensure resource adequacy. In fact, during the advent of competition, while other entities were moving away from the concept of long-range resource planning, government entities were continuing to plan their systems to ensure that they had sufficient resources to satisfy their future load.

[10] In its recently adopted Integrated Energy Policy Report (adopted November 12, 2003).

themselves of other regulatory options to address resource adequacy.[11] Additionally, the CEC is engaged in collaborative processes with the municipal utilities to address this issue.

Because of the concern that a poorly designed resource adequacy framework could needlessly limit the Commission's flexibility as well as usurp the Commission's statutory responsibilities, the Commission has routinely advocated, in a variety of forums, that it should address resource adequacy and procurement issues. This position has now been acknowledged by both FERC and the ISO.

FERC, in its recently released "White Paper" on Standard Market Design (SMD) states that it would:

> "Allow an RTO/ISO to "implement a resource adequacy program only where a state (or states) asks it to do so, or where a state does not act."…"*States may decide to ensure resource adequacy through state imposed requirements on utilities serving load within the region*…"[12]

FERC, in its recent October 28th Order addressing the redesign of the California wholesale electric market reiterated this conclusion noting that it was "encouraged that the State has undertaken a procurement proceeding," (Order, para. 215) and would defer consideration of many elements of the ISO's

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[11] A significant portion of the municipal load within the ISO is served by municipal utilities which have chosen to become Metered Subsystems (MSS) under the ISO's tariffs (ISO Amendment 46, approved by FERC [100 FERC ¶ 61,234 (2002) (August 30 Order)].

[12] FERC White Paper on Wholesale Power Market Platform, p. 5 (Issued April 28, 2003 in Docket RM 01-12-000); *See* also Edison reply brief, p. 46, ftn. 174.

proposal until 60 days after the final rule issued by the CPUC within this proceeding. (para. 216.)[13]

Similarly, the ISO, has recognized that resource procurement is primarily a state function, adopting at its November 21, 2002 Board meeting a resolution to defer consideration of its resource adequacy proposal and directing ISO staff to actively participate in this proceeding.

3. Policy Issues

While virtually all parties in this proceeding agree that it is critical for the state to ensure adequate reserves and to address resource adequacy, there are a number of policy issues that must first be resolved.

First, there is a trade-off between reliability and least-cost service given the cost to acquire and retain reserves. As TURN's witness Woodruff noted, each incremental increase in reserves offers progressively smaller improvements in reliability[14] As SDG&E calculated, each additional 1% increase in reserve level adds $2.8 million to its costs. Adjusting for SDG&E's smaller size, costs for SCE and PG&E would be significantly higher.

Second, there is a broad range of resource applications and technologies that California can rely on to meet its reserve levels. The Energy Action Plan, as well as the guidance given for this proceeding, established a "loading order" for new resource additions emphasizing increased energy

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[13] FURTHER ORDER ON THE CALIFORNIA COMPREHENSIVE MARKET REDESIGN PROPOSAL (Issued October 28, 2003 in Dockets ER02-1656-003,ER02-1656-004, ER02-1656-015 and EL01-68-028)

[14] TURN, Exh. 81, p. 18-19

efficiency, demand response/dynamic pricing, and renewable energy. The development, timing, and calculation of a reserve level can have a significant effect in promoting (or deterring) development of these new resources. As FERC recently noted in its order on the ISO's proposed redesign of the California wholesale electric market:

> "[R]ushing to relieve inadequate regional supplies and reduce high regional spot prices may bias construction choices toward supply resources that can be constructed quickly, perhaps sacrificing long-term cost minimization, environmental concerns and fuel diversity goals." [15]

An appropriate balance should be achieved between meeting reserve requirements expeditiously while seeking to optimize the resource mix/portfolio. Paradoxically, rushing to implement a reserve requirement might further increase California's reliance on natural-gas fired resources, posing a different set of reliability concerns if there are supply constraints and price risks for the fuel input.

Third, there is the issue of reliance on the spot market to meet a portion of reserve requirements. While no party advocates extensive reliance on the spot market, most parties believe that it may be both reasonable and prudent to allow for some portion of resource needs to be met through the spot

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[15] FURTHER ORDER ON THE CALIFORNIA COMPREHENSIVE MARKET REDESIGN PROPOSAL (Issued October 28, 2003 in Dockets ER02-1656-003,ER02-1656-004, ER02-1656-015 and EL01-68-028), footnote 98 to para. 215

market, a practice that some utilities responsibly engaged in under pre-AB1890 resource procurement.

Fourth, there is the need to ensure that in establishing reserve requirements, we are not creating a potential for the collusion or exercise of market power in the forward markets for capacity. Unlike spot markets such as the ISO's existing hour-ahead (and soon to be established day-ahead market), there are significantly fewer safeguards and opportunities for regulatory review by FERC of forward market transactions. FERC's recent order denying rehearing of California's request to find that the DWR contracts were not "just and reasonable" as required by federal law emphasize the high burden of proof needed to challenge the reasonableness of forward market contracts

Fifth, there is the need to evaluate resource adequacy in the context of the broader regional energy markets and the market design rules that these markets will operate under. Both the ISO (in its MD-02 proposal) and FERC (in its SMD proposal) are in the process of redesigning these markets. Any actions taken by the Commission should work in conjunction with these efforts, not only in the area of scheduling/timing, but also as a complement to (i.e., not a substitute for) the maintenance of effective market mitigation rules. Additionally, the Western energy markets, outside of California, have neither functioning ISOs nor any resource adequacy or capacity market requirements. Therefore, in adopting resource adequacy requirements, we must ensure that we are not unilaterally imposing burdens upon California's utilities (and by extension California's economy) that utilities located outside of California are not subjected to.

4. Current and Forecasted Market Conditions

A key factor that needs to be considered in evaluating resource adequacy is the current state of the wholesale energy market in the West, and the degree to which California's utilities have obtained or can access these resources to meet their energy needs.

Many of the parties supporting the Joint Recommendation, in their individual comments, believe that adequate reserves should exist until around the year 2008. A late-filed exhibit, consolidating each utilities' resource needs and comparing it to available supplies, concluded that:

> "[T]here appears to be sufficient existing, and highly probable new generation, located outside of California or importable over existing transmission ties, to meet IOU reliability needs (including a 15% reserve requirement) over the time period 2004-2010."[16]

PG&E also believes that sufficient resources will be available to California to meet its requirements until around 2010. Equally important, almost all parties believe that there are ample amounts of resources available for California to meet its resource needs for 2004, thus providing the Commission a brief period to develop an optimal resource procurement strategy.

The CEC, based on its review of the California energy market, believes that new capacity needs are unlikely to occur until 2007, at the earliest. As the CEC also notes, its review, as well as those of the utilities, are based primarily on a review of existing and planned generating resources and do not consider non-generating resource additions, such as increased funding for

[16] Exh. 68 prepared by Mr. Lauckhart at the request of ALJ Walwyn

energy efficiency, that would defer even further into the future the need for new resources.

The CEC expresses the concern that focusing on reserve levels based only on generating resources may bias planning decisions to the detriment of demand-side resource options. According to the CEC, the successful implementation of additional energy efficiency and demand response programs can allow California to maintain sufficient reserves even farther into the future (beyond the 2007-2008 timeframe), even if there is little or no new generation being built.

The ISO and CPA by contrast, expect that capacity constraints could appear earlier than 2007, and that setting a reserve requirement will assist in ensuring that existing resources remain available for use. IEP and WPTF make somewhat similar points, arguing that ensuring the availability of existing resources should be considered in setting reserve levels.

Based on the assessments described above, we conclude that there are ample resources for California to meet demand for 2004 as well as adequate resources available for California to meet peak demand through 2007 although all of these forecasts, particularly in the "out" years, contain some element of uncertainty.

5. Appropriate Reserve Levels and Phase-in Period

The relative balance between California's energy need and the resources available to meet it is important in determining the procurement strategies of the utilities' in acquiring reserves.

As the Joint Recommendation notes, reliable operation of the electric system requires two types of reserves – operating reserves and planning reserves.

In order to ensure reliability, a grid operator must ensure that there are sufficient resources available to meet peak demand, plus an additional reserve to accommodate unexpected outages. The level of the reserve is determined by the Western Electricity Coordinating Council and is approximately 7% of peak demand.[17] This is the operating reserve.

"Planning reserves" involve a longer-term perspective of ensuring that in real-time there will be sufficient energy to meet peak demand plus needed operating reserves. Typically this requires that a utility have more than 7% reserves, since at any given time some percentage of plants may not be available due to such factors as maintenance, forced outage, fuel limitations, or in the case of hydroelectric power (insufficient water conditions).

The Joint Recommendation proposes definitions for "operating reserve margin" and "planning reserve margin" that are reasonable. The Joint Recommendation defines:

- <u>Planning Reserve Margin ("PRM")</u>: The reserve margin shall be an obligation over and above the capacity required to meet peak demand. PRM is computed as follows: PRM = ((Dependable Capacity / Peak Load) – 1) x 100%. In calculating PRM,

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[17] As the Joint Recommendations states, the level of operating reserve was last "…defined in the April 2003 WECC Minimum Operating Reliability Criteria ("MORC"). MORC includes "contingency reserves," which is capacity needed to cover the greater of the largest single generation or transmission contingency, or 5% of the load met by hydro generation plus 7% of the load met by thermal generation. "

"Dependable Capacity" shall not be reduced to reflect Reasonably Expected Resource Outages.[18]

- Operating Reserve Margin ("ORM"): ORM shall be used for purposes of reviewing resource adequacy over a shorter term, such as a year or less and shall be applicable to short term procurement plans. ORM is computed as follows: ORM = (((Dependable Capacity – Reasonably Expected Resource Outages)/Peak Load) – 1) x 100%.

While virtually all parties agree that it is appropriate to set a longer-term planning reserve level, parties disagree over both the level and whether a phase-in period should be used to achieve it.

The Joint Recommendation proposes a 15% planning reserve, phased in beginning 2005 through 2008 based on equal percentage increments (i.e., 2% per annum increase). For 2004, the utilities will meet the 7% Operating Reserve level required of the ISO.

The CPA, based upon its study (officially noticed as part of the record) recommends the adoption of a 17% reserve level. The ISO supports the 17% reserve level, and also supports a three-year phase in to achieve this level, provided that the utilities meet a 90% year-ahead and 100% month-ahead procurement requirement. The ISO notes that a three-year phase-in would help alleviate concerns over the exercise of market power in the forward market.

[18] The Joint Recommendation proposes that the terms "Dependable Capacity," "Peak Load" and "Reasonably Expected Resource Outage" should be defined as part of a permanent resource adequacy framework to be developed. (See Section I.8 of this Joint Recommendation.)

Finally, IEP supports the 17% reserve level, while WPTF states that the reserve level should be "at least 15%."

In D.02-12-074, the Commission provisionally adopted a 15% reserve level subject to further revision in this proceeding. Based on the record developed in this proceeding, we reaffirm and make permanent the 15 % reserve level, essentially adopting the target level proposed by the Joint Recommendation.

In approving a 15% planning reserve we note the strong concerns expressed by many parties as to the CPA's calculation of a 17% reserve level. These include concerns that the CPA's analysis contained overly pessimistic assumptions over the shape of the future market, and that no utility-specific analysis was done to determine an appropriate forced outage rate, a key determinant of setting an appropriate reserve level. As the CPA itself notes, its recommendation is not binding upon any load-serving entities.

A 15% reserve level should provide reliable service. As PG&E states:

> "Based upon the simulations performed by Henwood, a 15% reserve requirement produces a 2006 loss of load probability of 0.2 days in 10 years."
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>
> "TURN witness Woodruff concurs that a 15% planning reserve level would result in a "one day in fifty years" generation reliability criteria and that this level of reliability is reasonable.[19]

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[19] PG&E Opening Brief**,** p**. 34**

SCE and SDG&E reach similar conclusions.

A 15% reserve level also strikes an appropriate balance for ensuring reliable service by providing incentives to encourage the retention of existing resources, whereas setting reserves at a higher level could require the utilities to make short-term investment decisions inconsistent with the Energy Action Plan's preferred "loading order" of new resources. Although we are directing in this decision that the utilities should engage in long-term resource procurement, we must also be cognizant that, given their current financial resources, some prioritization of need may be appropriate.[20]

With regard to a phase-in period, the utilities should meet this 15% requirement by no later than the end of 2006, with interim benchmarks established. These are minimum standards. If cost-effective, the utilities may choose to meet this level sooner than 2006.

In setting these targets we do not believe that we are setting a reserve level that will be difficult for the utilities to achieve.

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[20] As TURN's witness Woodruff noted: "I believe a 'phase in' period is generally necessary to avoid driving up the IOUs' costs and to allow PG&E and SCE to regain their financial footing." (TURN, Ex. 81, p. 21)]Additionally, PG&E stated: "Upon emergence from bankruptcy, PG&E is expected to have $1 billion in short-term credit facilities, which will be needed to serve a number of uses. Only a small portion of this amount will be able to cover the credit and collateral requirements associated with electric procurement. Given this finite amount of credit capacity, every procurement decision will require a balancing of competing needs and every commitment that uses up credit capacity involves a trade-off of some other option." (PG&E Opening Brief, p. 31)

WPTF observed that each of the utilities' original filings proposed target reserve levels in the 15-17% range to be achieved by the 2005 time period.[21]

Additionally, although several parties were opposed to the Joint Recommendation's proposal that each utility only meet the ISO's proposed 7% operating reserve requirement for 2004, a closer look at the utilities' filings shows that their actual planning reserve margins for 2004 were significantly above the 7% minimum. SDG&E's testimony, for example, showed that it possessed sufficient capacity, either owned or under contract, to easily meet the 7% operating reserve requirement, implying that SDG&E's actual planning reserve levels were well above 7%. A review of SCE's filing shows that, in determining its resource needs, it had already included in its calculation estimates of expected plant availability (a major component of a planning reserve level) as well as excluding its interruptible load programs in calculating its reserve level. Thus, SCE's actual planning reserve margin would appear to be significantly higher (perhaps in the 12-13% range) for 2004. Only for PG&E does it appear that there might be some over-reliance on spot purchases, but again PG&E's original filing did not include its subsequent procurement efforts (approved by the Commission) to firm up a significant portion of its outstanding short position.[22]

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[21] The initial recommendations of the utilities were; SDG&E, 15% with a +/- 2% deadband; PG&E, 7% for 2004, increasing to a 15% in 2005; Edison, 17% in both its Preferred and Interim Plans.

[22] In D.03-08-066, the Commission approved PG&E's request to solicit offers to procure up to 50% of its non-baseload needs for 2004; and in Resolution E-3853 approved PG&E's request to procure additional renewable resources to meet its RPS targets.

6. Appropriate Balance Between Forward Contracting and Spot Purchases

The ISO was the only party to propose specific percentages that each utility should forward commit to, proposing that utilities forward contract 90% of their capacity needs (i.e., annual peak load plus the target reserve level) a year in advance and 100% of their monthly peak capacity need plus reserves a month in advance. SCE and PG&E specifically opposed this proposal. The Joint Recommendation proposes that the utilities can rely on "spot capacity" purchases for 2004, and that going-forward, some reliance upon "spot capacity" may be appropriate (the Joint Recommendation proposes further forums to determine the proper limits.)In addressing this issue we note that there is no analytical support behind the ISO's proposed benchmarks. As the ISO's own witness noted, the 90% figure was a number within a range and that other numbers, such as 85% might be equally appropriate.

In determining what an appropriate benchmark for forward contracting should be, we should begin our analysis of what the *de facto* percentage of forward contracting is based upon each utilities' existing portfolio of retained generation and assigned DWR contracts. Summarizing at a high level, to respect confidentiality concerns, it appears that for many months of the year (particularly off-peak or shoulder months) the utilities are already forward contracted at the 90% level and in some months may actually be net sellers into the market (i.e. greater than 100% coverage.) Even for the peak periods during the summer months, the degree of forward contracting appears to be in the 70-75% range, without taking into account subsequent activities undertaken by the utilities since the time of their filings.

The question therefore becomes what are the benefits of further forward contracting. As noted when the DWR contracts were originally signed, it was thought that being forward contracted at somewhere around the level of 70-80% was sufficient enough to minimize the incentives for generators to engage in physical or economic withholding.[23]

Equally important, as PG&E and SCE note, imposition of a mandatory percentage of forward contracting is inconsistent with the risk assessment models the utilities are supposed to develop and use to measure and report ratepayer risk exposure.[24] The purpose of these models is to measure utility portfolio price risk exposure vis-à-vis consumer risk tolerance. Thus, the application of these models should inherently result in utilities seeking to forward contract to a significant extent, to optimally minimize exposure to any high prices or reduced reliability of spot market purchases. Optimally designed, these risk assessment models would more precisely match and determine the optimal forward contracting strategy than setting an arbitrary percentage as the ISO proposes. Supporters of the Joint Recommendation raise a similar issue, namely that in advocating for the utilities to procure some portion of their capacity needs in the spot capacity markets they do not mean purchasing all of this need in the day-ahead/real-time markets, but instead that these purchases would occur in a continuum

[23] For example, in a market of 100 MW where 50 MW are subject to the spot market, a generator who withholds a MW of capacity can benefit from the increased price for the remaining 50 MW of demand in the spot market. If, however, due to forward contracting, only 10 MW are subject to spot prices, than a generator who withholds a MW of capacity only sees a higher price for 10 MW, not 50 MW. At some point, the foregone revenue from reduced sales by withholding capacity is greater than the increase in revenues that result from withholding this capacity.

[24] The actual use and evaluation of the utilities' models is discussed elsewhere.

(based on market and supply/demand conditions) presumably between the year-ahead and hour-ahead markets. It is therefore unclear what, if any distinction exists with regard to reliability, if a utility contracts for its needs only 9 to 10 months in advance instead of 12-months.

However, given that for many months there appears to be a relatively small difference between the current de facto level of forward contracting and the 90% level, we propose to adopt the 90% level. The question we need to decide is whether this 90% level should be a target or a requirement. To help promote reliability, we will make this a requirement for the utilities but will allow the utilities the flexibility to justify to the Commission, on a case-by-case basis, excursions below this level. Thus, the 90% level serves as a benchmark and further safeguard to operate in conjunction with each utilities' risk assessment models. Granting the utilities some flexibility provides protection against the exercise of market power in the forward capacity markets, a concern noted by many parties, including the ISO. It also allows the utilities to account for unusual market conditions. Because of the difference between the existing level of forward contracting (70-100%) and the proposed target, utility compliance with this level appears feasible. As PG&E, notes, however, establishing this requirement for 2004 would require that PG&E complete, and receive Commission approval for its procurement strategiesfor acquiring its necessary 2004 reserves by this month, November 2003. Therefore, it is appropriate to defer implementation of this requirement to 2005.

The ISO is the only party that proposes that utilities' forward contract for 100% of their needs month ahead, a position opposed by other parties. As the Joint Recommendation notes, it appears that utilities can rely upon uncommitted supplies for a portion of their energy needs while still ensuring reliable service. In large part, this depends upon the shape of the underlying market and expected availability. In order to ensure reliability, however, a concern of many parties, including the ISO, is that any reliance on the spot market be based on reasonable (and perhaps even conservative) estimates of the energy available in this market.[25] For example, we do not want all three utilities assuming they will be able to acquire the same surplus energy from the Pacific Northwest. Thus, reasonable estimates, taking into account expected loads/resources in the Western region, and the procurement strategies of energy purchasers in the West would be helpful to define a reasonable estimate of appropriate reliance on the short-term energy markets.[26]

In D.02-10-062 the Commission adopted a limitation on spot purchases to less than 5%. This limit was to provide a balance between flexibility and reliability. This is a reasonable limitation to continue in the utilities' current procurement practices. Additionally, we will allow utilities' to continue to rely on short-term and spot market purchases to meet their energy needs but only if they can verify that the energy is reasonably expected to be available taking into account adverse conditions and the procurement choices of other entities in the Western energy market. This ensures that any reliance on these purchases for meeting energy needs will be available.

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[25] For example, as WPTF states: "While some reliance on spot power is appropriate, WPTF submits that over-reliance is not in the ratepayers' best interests." (WPTF Opening Brief, p. 9)

[26] An issue for further analysis proposed by the Joint Recommenders, and one the CEC is examining as part of the Western Resources Assessment Team (WRAT).

7. Utility Obligation to Procure for all Load and Customers Within their Service Territory

Today's decision requires the utilities' to procure (under Commission jurisdiction) sufficient reserves to provide reliable service to all load located within their service territory. The utilities should be compensated for this service by a non-bypassable customer charge.

Virtually all parties that addressed the issue agree that ensuring adequate reserves for all load within the utilities' service territory is a critical and important issue. The Joint Recommendation, for example:

> "…[A]gree[s] that capacity and reserve requirements must apply to both IOU bundled customers and Direct Access and Community Aggregation customers, regardless of what entities are ultimately responsible for acquiring the capacity and reserves."[27]

There was disagreement among the parties, however, as to the appropriate entities that would be responsible for achieving and implementing this goal. Even the Joint Recommendation did not reach a consensus viewpoint on this issue.[28]

Several parties (WPTF, SDG&E) believe that either FERC or the California ISO should have this responsibility for all load-serving entities, including the utilities. PG&E appears to suggest that the ISO should perform

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[27] Joint Recommendation, Sec. I 9

[28] "This Joint Recommendation does not address nor take any position on whether and to what extent the IOU's should procure capacity and reserves for Direct Access customers. However, if IOUs are required to procure capacity and reserves for Direct Access customers, appropriate adjustments in capacity and reserves will be necessary and IOUs should be compensated in full for such procurement." (Joint Recommendation, I. 5.)

this duty only for the ESPs. Both of these approaches would conflict with the Commission's officially adopted position, filed in comments before FERC, that resource procurement is fundamentally an issue of state, not federal concern, and that imposition of a resource adequacy requirement would infringe upon the state's sovereignty. It is inconsistent with both FERC and the ISO's stated policies of giving deference to the State to address resource adequacy issues.

Adoption of either of these approaches would also preclude the Legislature from addressing this issue as well. To date, both of the major legislative proposals to change the existing market structure (AB428 and SB888) specify that the Commission should address resource adequacy issues.

TURN notes the jurisdictional confusion that would arise from having the ISO seek to enforce CPUC-adopted reserve requirements. This would put the ISO in the position of enforcing rules it did not create. Additionally, it is unclear how the ISO could enforce these rules without doing so under FERC-approved tariffs, thus transferring final decision-making authority over California's energy future away from California to Washington.[29]

The preferred approach is for California to address the resource adequacy at the state level. Several parties recognize that the state is theappropriate entity to address reserve issues. (TURN, California ISO, SCE).

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[29] As an example of the potential conflict between federal and state regulation, some of the parties advocating that resource adequacy should be addressed at the federal level are the same parties who have argued against allowing the "preferred resources" identified in the Energy Action Plan (such as energy efficiency) from being counted toward meeting any resource adequacy requirement, thus negating their value (**See** for example, WPTF Opening Brief, p. 9).

In determining how the Commission should address this issue, two approaches were proposed. They are:

- Each LSE in the utility service territory (utility, ESP, community choice aggregator) would be responsible for acquiring its own reserves needed to ensure reliable service; or,
- The utility would acquire reserves for all load within its service territory including that of ESPs and community choice aggregators.

Putting aside the issue of jurisdiction (whether California or federal) almost all parties expressing an opinion on this issue (except SDG&E[30]) believe that the preferred approach is to require each LSE to be individually responsible for acquiring its own reserves. This approach would be administratively simpler, allow each LSE to decide how to best meet Commission imposed requirements, and properly assign responsibility for providing reliable service.

The major impediment to implementing this approach is a perceived concern as to whether the Commission currently has the jurisdictional authority to impose resource adequacy requirements upon ESPs and community choice aggregators.

PG&E, SDG&E, SCE, and TURN all believe that the Commission has the requisite authority. ARM and WPTF do not.

SDG&E and SCE both note that the Commission could impose reserve requirements upon non-utility LSEs (such as Energy Service Providers)

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[30] SDG&E's proposal would create an ISO-capacity market where the ISO, not the Commission, would oversee the acquisition of capacity through formats such as auctions or RFPs.

under the requirements of Pub. Util. Code § 394. This code section allows the Commission to determine that ESPs demonstrate "technical and operational reliability" and "financial viability." Similar legislative requirements apply to community aggregators as well.[31] Requiring an ESP or community aggregator to acquire adequate reserves in order to ensure reliable service would appear to clearly fall within this legislative authority.

Requiring ESPs to acquire their own reserves is also consistent with the approach for addressing resource adequacy proposed in SB888.[32]

As Sempra states, "apart from the law and theory, the State as a matter of public policy may determine that system reliability requires that LSEs meet a resource adequacy test, inclusive of supply reserves."

ARM and WPTF dispute this contention, relying primarily upon Commission decisions D.98-03-072 and D.99-05-034[33] where the Commission initially defined an ESP's responsibilities under the requirements of PU Code 394. In both of these decisions, the Commission chose to narrowly define its jurisdiction, allowing an ESP to meet the requirements of PU Code 394

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[31] Under the requirements of AB117, community aggregators must demonstrate both "reliability" (PU Code 366.2(c) (4)(b) as well as "any other requirements established by state law or by the Commission concerning aggregated service" (PU Code 366.2 (c)(4)(D).

[32] The latest substantive version of SB888 (July 1, 2003):

> Requires electric service providers to comply with conditions, including resource adequacy standards, that the commission determines to be necessary and appropriate to ensure there is no adverse effect on the reliability or cost of electricity for core customers. (Proposed PU Code 365(h)).

[33] These decisions resulted in the adoption of Rule 22, also cited by ARM/WPTF.

primarily by proving it had the technical capabilities to interact with the utilities' billing and metering systems and the ISO's scheduling protocols. This latter function was verified through an ESP either becoming or contracting with an ISO Scheduling Coordinator (SC). ARM/WPTF also state that imposing a reserve requirement upon ESPs would conflict with the "terms and conditions" under which direct access customers take service that is not allowed under Pub. Util. Code 394. [34]

In reviewing ARM/WPTF's claims, we are unpersuaded that the Commission does not have the authority, if it chooses to exercise it, to impose broader reliability requirements (such as a resource adequacy requirement) upon ESPs. Although the Commission chose to narrowly limit the exercise of its jurisdiction in implementing PU Code 394, it is a well-settled legal principle that there is no legal or statutory prohibition against the Commission revisiting and revising its authority in a subsequent proceeding. As SCE states: "If the Commission can develop those standards, it can certainly modify those standards if there is a need to ensure reliability."[35] This is particularly true when the circumstances upon which the original decisions were based have changed. . At the time that both D.98-03-072 and D.99-05-034 were issued, the

[34] ARM/WPTF make a subsidiary claim that imposing a reserve requirement upon ESPs would require them to divulge their underlying supply contracts and that this would violate PU Code 399.14(b)(3)(B) which states that "nothing in this subdivision may require an electric service provider to disclose the terms of the contract to the Commission." However, this Code section (part of the Renewable Portfolio Standard) only applies "for purposes of this Article [16]"(i.e. how the Commission chooses to implement the RPS standard and does not limit or preclude any other jurisdiction the Commission may possess through other provisions of the PU Code.

[35] Edison Brief of Issues in Compliance with March 7, 2003 Order, p. 11

underlying assumption of the Commission was that reliability in the electric markets could be achieved by market mechanisms such as the Power Exchange and ISO.[36] Subsequent events have proven that this may not occur absent proper safeguards. During the tight energy supplies and market manipulation of the California energy crisis, for example, many ESPs were unable to provide reliable service to their customers with the level of direct access load falling from 15% to 2%, ESPs failing to honor their contractual obligations, and the utilities (and later DWR) obligated to assume the procurement of energy for many of their customers. As TURN notes, it is not clear if ESPs have the appropriate financial incentives to ensure reliable service under adverse conditions. Thus it would be appropriate if the Commission were to decide that additional safeguards should be imposed upon ESPs under the requirements of Pub. Util. Code § 394.[37]

Nor do we find that requiring ESPs to meet a reliability obligation (as allowed under Pub. Util. Code § 394) would conflict with the "terms and conditions" under which direct access customers receive service. In setting a requirement upon ESPs, the Commission is not affecting at all any of the contractual relationships between the ESP and the direct access customer. The ESP remains free to request whatever pricing and other terms it desires from the customer. One of the main purposes of a reliability requirement, by

[36] **See** for example PU Code Sections 330 and 350

[37] Although it has no legal impact or authority, AB428 would "*affirm* the electrical corporation's obligation to provide transmission, distribution, and *resource adequacy services for all customers*", thereby envisioning that the Commission already has the authority to impose resource adequacy obligations upon ESPs.

contrast, is to ensure that the failure of an ESP to procure sufficient reserves does not affect *all other* customers on the grid.

Although we find significant merit, and no legal preclusion, from requiring ESPs to procure adequate reserves for their customers, we share the concern of TURN that imposing such a requirement could delay the expeditious resolution of the issue of resource adequacy.

It was precisely in response to these concerns that TURN proposes that the utilities acquire sufficient reserves to meet the needs of all customers within their service territories. In addition to avoiding the litigation associated with imposing requirements directly upon ESPs, TURN argues that this approach is consistent with how the utilities have traditionally procured resources to meet the needs of their customers. In procuring reserves in order to provide reliable service, the utility traditionally had to factor in the potential that other market participants would either under-procure or lean on the system, thus requiring the utility to acquire additional reserves in order to ensure reliable service to its customers.[38]

Equally important, under existing law, the utilities remain both the default provider, and provider of last resort for all load within their service territory. Thus when the level of direct access load shrank from 15% to 2% during the energy crisis, it was the utilities that were obligated to acquire energy to meet the needs of these customers. Thus, it is prudent to have the utilities acquire reserves to plan for such contingency. SDG&E also stated that having utilities acquire reserves for all of the customers in their service territory

[38] Although in the pre-restructuring time of traditional vertically-integrated utilities it is not clear how often under-procurement occurred.

was legally supportable under the Commission's obligation to ensure that utilities provide reliable service.[39]

As TURN and ARM/WPTF both note, ESPs appear to generally rely on short- to mid-term contracts to meet their energy needs. In support of its proposal, TURN states that given the changing and fluid customer base that most ESPs utilize, ESPs may not have sufficient incentives to acquire necessary reserves.

Finally, TURN's proposal is consistent with the approach to addressing resource adequacy issues envisioned in AB428[40]. Under the proposed requirements of AB428:

> "…[T]he commission [in consultation with the CEC and ISO] shall establish resource adequacy requirements that ensure the availability of planning reserves sufficient to serve all customers of the corporation, including noncore and community choice aggregation customers. The resource adequacy requirements shall

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[39] SDG&E Pre-hearing Opening Brief in response to ALJ's March 7th Ruling. SDG&E references PU Code 451 as a "legal basis for the Commission to impose on utilities an obligation to acquire adequate capacity for direct access and other customers" and that: "…The Commission also has the authority to address unsafe, improper, inadequate, or insufficient utility rules, practices or service (see, e.g., Public Utilities Code Sections 701, 761, 762, and 768)."

[40] AB428, Sec. 1 (Legislative intent) as last amended (June 16, 2003) states that:

> it is the intent of the legislature to *affirm the electrical corporation's obligation to provide* transmission, distribution, and *resource adequacy services* for all customers.

> ensure cost recovery by the electrical corporation for acquired reserves through a nonbypassable component of the electrical corporation's transmission and distribution charges." (AB 428, proposed PU367.6(i).)

TURN's proposal also realizes that the utilities (and their customers) should not subsidize ESPs. It therefore proposes a non-bypassable surcharge, as well as allowing ESPs who have acquired sufficient reserves to "opt-out" of paying this surcharge.

We find merit in TURN's proposal as a mechanism that will allow the Commission to quickly address resource adequacy issues, maintain Commission jurisdiction, and retain flexibility for the Commission and Legislature to to later adopt other approaches to address the reserve issue.

In approving this approach we clearly see it as an approach to ensure reliability. Our hope is that all ESPs/community aggregators will voluntarily choose to provide their own necessary reserves. However, utility provision of these services is necessary to ensure reliable service.

Both PG&E and SCE raise several valid implementation issues that must be addressed to adopt TURN's proposal.

First, to avoid cross-subsidization issues, there needs to be a non-bypassable surcharge so that all customers within the utility service territory pay their fair share of the costs of acquiring needed reserves. Such a surcharge should be similar to the existing surcharges, already approved by the Commission such as SCE's Historic Procurement Charge (HPC) approved by D,02-07-032 and the Cost Responsibility Surcharge (CRS) approved by the Commission in D.03-07-030. In establishing this surcharge we only seek to impose the same burdens and responsibilities upon ESPs to provide reliable service that we are imposing upon the utilities.

Second, the utilities will need to calculate and determine the amount of reserves that they need to acquire. SDG&E already assumed in its filing that it would have to provide reserves for all load located within its service territory. In their short-term procurement filings the utilities already have determined the amount of load within their service territory that is served by other than the utility. The utilities should assume that they will have to acquire reserves for all of this load, unless the LSE chooses to "opt-out" and provide its own reserves.

The ability of ESPs and Community Aggregators to "opt-out" provides a means for those entities who already provide reliable service are not charged twice for reserves. The Commission will need to develop criteria so ESPs can prove that they have acquired adequate reserves. We envision that this would be a yearly process. The workshops that we are convening to address resource adequacy, discussed further below, will be helpful in developing a template for determining how to evaluate an ESPs/aggregators' reserves. This will provide an opportunity for groups such as ARM to prove their contention that ESPs do provide reliable service, including the provision of adequate reserves.

Third, the level of direct access and community aggregation is subject to change due to both market conditions and any actions taken by the Commission. Therefore, in acquiring reserves for ESPs and aggregators the utilities should focus on acquiring short-term capacity products designed to run concurrently with the process of when ESPs/aggregators have to declare whether they will self-provide reserves or rely on the utility.

Fourth, the utilities should bid the reserves that they have acquired for ESPs into the appropriate markets (such as the ISO's ancillary services market) as needed to maintain reliability. This approach ensures that sufficient reserves will be available in these markets when needed if LSEs under-procure and lean on the market to meet their needs. Revenues from these sales will also help offset the cost of acquiring the reserves. This also helps address the "dual scheduling coordinator" problem identified by the ISO.[41]

In their long-term procurement plans, the utilities should address the acquisition of sufficient reserves for all customers within their service territory. Implementation issues associated with this proposal will be further addressed in the new OIR that will replace this existing proceeding.

8. Issues to be Addressed in Workshops

This decision begins the process for the Commission to formalize its resource procurement processes to explain how it creates a resource adequacy framework.

The Joint Recommendation proposes that:

> "The Commission should immediately initiate a parallel process to develop a permanent resource adequacy framework…[and] to initiate a collaborative process to develop such a framework and submit a joint report to the Commission no later than January 15, 2004."[42]

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[41] Under ISO tariffs each LSE must designate a single Scheduling Coordinator who is responsible for acquiring resources sufficient to meet the LSEs demand. The ISO has expressed a concern that having the utilities acquire reserves for ESPs/aggregators would create the need for two Scheduling Coordinators for these LSEs, especially if the utility were bidding its reserves into the market specifically for a certain LSE.

[42] Joint Recommendation, Section I.8

The ISO also supported the need for workshops.[43]

On September 22, 2003 an Assigned Commissioner/ALJ Ruling "establishe[d] a workshop process to address the technical details of specific resource adequacy issues" with:

> "[T]he scope of the workshop…confined to the more technical aspects of this issue, namely the issues of how Load Serving Entities (LSEs) forecast demand, and how supply resources should be valued and considered in assessing an LSEs' resource adequacy."[44]

The Ruling envisioned use of a Commission-generated questionnaire, followed by a workshop, with the potential for additional workshops if needed.

In setting the scope of the workshop, the Assigned Commissioner/ALJ Ruling recognized that there were numerous "threshold issues" that the Commission first needed to determine before it could develop a permanent resource adequacy framework. Many of these issues are addressed in today's decision including; jurisdictional responsibility for resource adequacy, appropriate reserve levels and phase-in period, treatment of direct access/community aggregation load, penalty structure, etc.

The purpose of the workshop, as reflected in the Ruling, is not to "re-invent the wheel." In developing their procurement plans, the utilities have

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[43] As the Sept. 22nd Ruling noted: "The ISO, Edison, and the CEC support the need for workshops. These parties preferred the Joint Recommendation's broader scope of issues, accept the more limited scope of workshops proposed by the ALJ, but continue to press for [additional issues]…to be considered. (Ruling, p. 3)

[44] Assigned Commissioner/ALJ Ruling Establishing a Workshop Related to Resource Adequacy Issues, p. 1

explicitly engaged in resource adequacy by assessing the availability of resources to meet their expected demand. Additionally, many of the same parties involved in this proceeding have already participated in the CPA's Reserve Rulemaking (included as part of the record of this proceeding); the CEC's Integrated Energy Policy Report (IEPR) process; and the Resource Adequacy Working Group (RAWG) process run by the Inter-Agency Working Group[45] on behalf of the ISO. Although these efforts may not have resulted in parties reaching consensus, they have resulted in framing many of the questions that need to be addressed, and the options available for addressing them.

Second, to the extent possible, the workshop should develop a common approach, or "template" as WPTF calls it, for evaluating each LSE's resource adequacy. While complete consistency may not be feasible between all LSEs' at a minimum the workshop process should result in common approaches so that decision-makers and interested parties can evaluate resource adequacy both between utilities, and as a whole for all entities under Commission jurisdiction.

Finally, the workshop should ensure that Commission policy preferences are fairly and accurately accounted as to the type of resources that should count toward the resource adequacy goal.

We now address the specific areas that the workshop is to address.

First, the workshop will provide a forum for parties to better understand, and for the utilities to explain, how their load forecasts are

[45] This group was comprised of representatives of the Commission, CEC, Electricity Oversight Board, CPA, and DWR.

performed and opportunities to improve consistency between the utilities. However, as we discuss elsewhere, the utilities should retain the primary responsibility for developing their forecasts. As SCE states, although parties have complained about the lack of consistency of the forecasts, no party has substantively challenged the results of its forecast. As SDG&E states:

> "As a general matter, SDG&E previously explained that there is an unnecessary preoccupation with 'common' or 'perfect' assumptions to be used by the utility in its long-term resource planning. In SDG&E's view, while assumptions clearly need to be reasonable, the more critical piece is the testing of the assumptions to accommodate uncertainty). In the end, the utilities must plan using the best data for their unique circumstances, as they are accountable for the results."[46]

In the workshop it will be necessary to identify the treatment of Direct Access load and who should be responsible for forecasting it.

With regard to supply resources the primary focus of the workshop should be the "counting" of resources available to meet demand. How resources are counted in large part depends upon the type of resources that are considered.

The treatment of Utility-Retained Generation (URG) appears fairly straightforward, as almost all parties believe it should be based upon some variant of "dependable capacity" (although there is no consensus on how to calculate it.) A review of the utilities' filing tends to confirm that they have already accounted for, to a large extent, the availability of their URG resources

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[46] SDG&E Reply Brief, p. 15

in developing their procurement plan. How the utilities should value their retained generation should be one of the focuses of the workshop.

The treatment of existing and future contracts and how they should be valued in a resource adequacy framework should be another area of focus for the workshop. As previously mentioned, this includes; the recognition of the long-term DWR contracts; the criteria under which other contracts should be counted; and, as ARM suggests "the treatment of ESP firm energy contracts."[47]

Another issue for the workshop, and consistent with the Joint Recommendation is the criteria to be used for the reliance of the utilities upon the spot capacity and energy markets to meet a portion of their energy needs. As previously mentioned, we want to ensure that to the extent the utilities rely upon this capacity that we be reasonably sure that this capacity will be available even under adverse conditions.

Finally, the workshop should address how the preferred or "soft" energy resources that the Commission is planning to rely on to meet its energy needs can be fully valued under a resource adequacy framework. These "soft" resources (i.e. energy efficiency, renewables, demand response) can provide a significant and cost-effective means to reduce capacity needs yet they have proven exceedingly difficult to count towards resource adequacy requirements under the traditional resource adequacy frameworks such as the ISO-run capacity markets in the East.

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[47] Sept. 22nd Ruling, p. 3

The Joint Recommendation proposes to include these resources in each utilities' resource adequacy framework, proposing that each utilities' peak load requirements (for both planning and operating reserves) be:

> "reduced to reflect: 1) Energy Efficiency programs with authorized and funded program designs; 2) Additional Energy Efficiency Programs proposed by the IOUs in their resource plans (and approved by the Commission) based upon potential savings estimates; and 3) existing and future Interruptible or Non-Firm Load Programs."

And that:

> "Demand Response Programs consistent with the levels adopted by the Commission in D.03-06-032 should be included in the IOU load forecasts or resource plans."[48]

The Joint Recommendation goes on to propose that methodologies be developed to reflect the value that these programs have in reducing peak demand requirements.[49]

Not counting these type of "soft" resources in the traditional resource adequacy frameworks could result in California having to pay twice for capacity thus limiting the cost-effectiveness of these programs. Collectively, for example, the three utilities are planning to achieve over 1,200 MW of peak load reduction from energy efficiency programs.

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[48] Joint Recommendation I. 6 and I. 7.

[49] "The accounting for all Energy Efficiency programs to meet capacity and reserve requirements shall be subject to corrective feedback from measurement and evaluation of actual impacts compared to expected impacts…" (Joint Recommendation, I.6.)

Counting these resources towards any resource adequacy framework is also consistent with previous Commission decisions.

D.02-10-062 requires that "utilities include in their plans procurement of base-load and intermediate load reductions in the form of energy efficiency"[50] while D.03-06-032 in the Advanced Metering OIR requires the utilities to "include the MW targets for calendar year 2003-2007 in their procurement plans to be filed in R.01-10-024"[51]

The ability to count these resources (under reasonable and realistic parameters) should therefore be addressed in the workshop. In addressing this issue, parties should focus on how the results of other Commission proceedings can be coordinated with the procurement proceeding so that the Commission (and other parties) do not end up evaluating the same programs twice.

For example, the Commission, in R.01-08-028 is already examining the effectiveness of the utilities' energy efficiency expenditures.

Finally, as noted in the Assigned Commissioner/ALJ Ruling:

> "[I]t is premature to address reporting requirements at this time. It is difficult to determine reporting requirements when it is still unclear what exactly it is that is to be reported…Based on the policy guidance given by the Commission in its year-end decision, the results of the workshop and the success of parties in reaching agreement, the Commission will be in a better position to address the issue of how the information will be used. This subject may be appropriate for a follow-on workshop."

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[50] D.02-10-062, p. 27

[51] D.03-06-032, Ordering Paragraph 1c

To avoid reinventing the wheel on some subjects, a questionnaire will be mailed prior to the workshop and parties are requested to complete it and return it to James Hendry in the Division of Strategic Planning. This workshop is currently scheduled for December 10, with a workshop report due back to the Commission by January 15.

9. Deliverability

In general, the utilities in their filing sought to address the issue of ensuring that the generating resources upon which they plan to rely are deliverable to their systems. As SCE notes, the simulation models it uses take into account general transmission constraints in order to ensure that proposed resource additions can be delivered to the load. Such an approach is reasonable for longer-term planning purposes in identifying and evaluating various resource options to meet demand. As the utilities resource choices become more focused (e.g., selecting a specific plant or transmission path to access a resource), the utilities should provide greater specificity in their showings that such resources are deliverable to loads, including the effect of adverse conditions upon such delivery.

SDG&E, based in large part upon work done by the ISO, offers a more specific example of how resources should be evaluated for deliverability once they become more clearly identified, stating that:

> "In regard to deliverability of potential resource additions internal to the SDG&E LRA that are currently in SDG&E's or the ISO's interconnection queues, we have completed (or are in the process of completing) generation interconnection studies that have been (or will be) reviewed by the ISO pursuant to their established tariff procedures. Furthermore, prior to contractually committing to a capacity purchase from

> any project in our generation study queue that seeks to meet SDG&E reliability needs, we would complete further deliverability analysis for review by the ISO. For other generic resource additions internal to SDG&E's service area that are not presently in the interconnection queue, we have not identified any specific transmission deliverability upgrades in our opening testimony. However, SDG&E intends to develop a transmission plan of service for such resources that will satisfy deliverability requirements. These studies will also be submitted to the ISO for their review. . . .
>
> "Furthermore, . . . it is critical that deliverability of a resource located outside an LRA be determined for both normal and emergency conditions. This is necessary because remote resources that can be scheduled for delivery to an LRA under normal operating conditions may not be deliverable during certain transmission contingencies when they are needed to serve the LRA's reliability needs and vice-versa."

SDG&E a definition is a useful starting point to address deliverability requirements for larger resources. We remain concerned, however, that for smaller energy sources that are either located close to load centers (such as distributed generation) or that displace load (such as a broad scale energy efficiency or demand response programs), appropriate deliverability requirements can be developed that will not impose excessive or unreasonable regulatory burdens that deter their use and deployment.

The issue of deliverability is an issue that needs further study. Therefore, following the workshop process, we will seek another round of comments, as part of this proceeding, as to how to assess and develop workable deliverability standards.

B. Market Structure for Longer Term Resource Commitments

1. Determining the Need for Resource Commitments

At the March 7, 2003 PHC, clear direction was given to the utilities to consider all cost effective energy efficiency, demand response, and renewable resources prior to considering the addition of conventional supply or transmission resources in meeting future resource needs. In addition, utilities were directed to include provision for customer-owned, as well as utility-owned, distributed generation, and to propose a methodology for weighing the tradeoffs between transmission and generation investments. This prioritization of resource additions is consistent with our direction in D.02-10-062 and the loading order of resources stated in the Energy Action Plan.

Our record here supports further policy direction on resource selection. To the extent that new generation resources are required, the utilities should first consider the overall advantages of repowering at existing plants or of development of brown field sites located close to load rather than development of new green field sites remote from load and requiring substantial transmission and other upgrades to the system. We prefer that generation assets be sited in California and that they minimize the overall economic and environmental impact, including the costs of transmission and power losses.

Next, utilities should increase the degree of diversity of fuel types and sources for the generators serving California electric customers. To the extent it is cost-effective, utilities should be looking to new generation capacity that is not powered by natural gas, currently the prime mover for 42 percent of the electric energy consumed in this state.[52] Options for fuel diversity include: (1) other fossil fuels, i.e., coal or oil, which carry emissions costs risks; (2) Energy Efficiency and Demand Response programs; (3) renewables; and (4) transmission.

The hearing record shows a need for the utilities to commit to new or refurbished generation capacity in the next few years and also provides a fuller discussion in several areas on how that should be done. Therefore, we need to adopt specific rules for how the utilities should acquire long-term resource additions.

2. Today's Hybrid Market Structure

California's policy regarding utility ownership and control of power plants has undergone profound changes over the years. Prior to the 1980s, the utilities were entirely in control of their own supplies. With the passage of the Public Utilities Regulatory Policies Act (PURPA) in 1978, California, along with the other states, began to welcome cogeneration in the form of Qualifying Facilities (QFs). California began considering proposals to move to a competitive market structure in the 1990s. Under the restructuring process adopted by the legislature in AB 1890, the utilities divested most of their generating plants with the exception of nuclear, hydro, and some remaining fossil capacity. During our state's energy crisis of 2000-2001, new legislation forbade any further divestiture.

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[52] Department of Energy/EIA – 0348 (01) 2 State Electricity Profiles 2001, p. 19, published October 2003.

Today, at the wholesale level, California's IOUs are primarily relying on short-term energy and capacity products (i.e., less than one-year in term) to meet a substantial portion of their residual net short open positions. A utility's residual net short open position is the result of the utilities' retail load requirement less utility retained generation (URG) resources, existing utility contracts, QF power, and long-term DWR contracts operated under a least-cost dispatch framework. More recently, we are seeing shift towards procurement of longer term contracts (i.e., SCE's Mountainview application and SDG&E's Motion for approval to enter into new resource contracts). There are about 18,000 megawatts (MW) of divested generation in California as well as several newer merchant power plants operating in the WECC region. Jurisdiction over transmission rates and terms of service passed to federal jurisdiction under California's AB 1890 restructuring and is now administered by the California ISO under FERC.

The Commission regulates rates and service for utility retained generation plant and all distribution services, oversees utility procurement practices, oversees Public Goods Charge (PGC) funded energy efficiency and renewable resource programs, and establishes rules for direct access. At the retail level, about 13% of IOU aggregated load is direct access, meaning it is served by competitive energy providers; the ability of new customers to sign up for direct access is precluded by legislation. The utilities are the provider of last resort for all customers within their service territories.

3. Benefits of Utility Ownership v. Benefits of Third-party Contracts

The issue of whether the utilities should own additional generation capacity has been renewed with the resumption of utility procurement. AB 57 takes a neutral position on this issue. In D.02-10-062, we asked the utilities to put forward long-term resource procurement plans that included supply options, and stated that in these plans the utilities should consider both utility owned/retained and merchant generation sources.

In their long-term plan filings on April 15, 2003, no utility proposed owning a new generating plant and only PG&E provided a cost-recovery mechanism proposal for utility ownership of new plant. PG&E proposes the Commission adopt a traditional cost of service ratemaking methodology for utility constructed and owned generation. SCE and SDG&E propose that the utilities consider a mix of generation resources by fuel type and ownership and that the Commission consider the merits of specific projects and cost recovery mechanisms on an individual basis.

Since the long-term plans were filed, SCE and SDG&E have made proposals to purchase and own new generation resources. On July 21, 2003, SCE filed an application for approval of the Mountain View project, a power plant of 1,000 MW capacity that SCE would control through a wholly-owned subsidiary. That project is being evaluated in Application (A.) 03-07-032. On October 7, 2003, SDG&E filed a motion in the instant proceeding that would, if granted, result in ownership of the Palomar project, a 500 MW generation plant to be constructed for its eventual ownership and control. SDG&E's motion also includes a proposed purchase power agreement (PPA) for the output of the to-be-constructed 500 MW Otay Mesa project and several other smaller PPA contracts.

The CEC's reports show that approximately 5000 MWs of new generation have been permitted in California but not yet built. Many market generators that hold these permits are in severe financial distress and cannot continue construction without long-term supply contracts with the utilities or other load serving entities. There is an opportunity today to acquire additional generation cheaply and, therefore, we should not delay in setting out clear market structure rules.

SDG&E observes that there is increasing interest and discussion of the possibility of a future utility role in ownership of generation, as at least a partial alternative to reliance on purchased power contracts with suppliers and exclusively nonutility ownership of future generation. It states that consideration of this would require clear-cut rules that would support a long-term utility role in serving a stable customer base.

Benefits of utility ownership cited by SDG&E include the stability and permanence of a regulated utility, the ability of the Commission to directly regulate the price, terms and quality of the generation service provided by the utility, the availability of a proven high-quality workforce (both management and labor) to operate and maintain utility generation, and the increased likelihood that such generation would be located within the State of California.

TURN, IEP, and WPTF recommend that the utilities acquire power through an open competitive solicitation process based on formal request for proposals for PPAs with third-party market generators. These parties express concern about the potential for conflicts of interest by the utility, both in the design of the bid solicitation and the evaluation/selection process, and do not recommend that the utilities be able to compete in these solicitations, or if they do, that there be independent administration of the bid preparation and review process. IEP and WPTF also question whether there can be a level playing field if the utilities are allowed to later request cost recovery of any construction overruns under a cost of service ratebase approach.

TURN proposes that while the utility should not be allowed to compete in the competitive solicitation, it should be prepared to build the plant itself if market bids do not provide the lowest cost means. TURN recognizes that the competitive market does not always work as it "should" and the utilities should pursue a "self-help" alternative for meeting their needs as an insurance policy against potential future dysfunctions in long-term markets.

The primary advantage of third-party bids, TURN, IEP, and WPTF state, is that it provides a market standard for the true competitive cost of new generating capacity. This standard is useful primarily in getting the best deal for ratepayers. It is also valuable in providing a proper benchmark against the cost of alternatives to new capacity, such as demand reduction programs and transmission system efficiency enhancements. In addition, it provides a standard against which the costs of existing and future utility-owned generation could be measured.

Third-party developers assert they exist in a competitive environment that is different from the regulated environment of the utilities. They are subject to market discipline and shareholder control to a greater degree than regulated electric utilities. Their mistakes, cost overruns, and the financial consequences of development of resources that are ultimately not feasible or cost-effective are their own. Third-party power plant developers have no incentive to overcapitalize or to build excess capacity. IEP and WPTF state that utilities will have an incentive to overreach because there is a greater probability that their costs can be recovered.

Further, testimony in support of a competitive market indicates that in the case of a PPA contract with a third-party, there can be clear responsibilities and performance obligations and assignment of costs. The holder of a third-party power contract assumes a great deal of risk. Difficulties that arise during the construction of the plant and later, in its operation, can be resolved in a clear manner, and to the extent that ratepayers are to be charged for additional costs, there will be clarity in how they arose and the resolution of the conflict with the third-party generator. A further point made in testimony is that with the utility contracting with itself there is less clarity about where the risk is held, and costs may be shared or shifted onto the utility's customers.

Several parties assert that by eliminating the utility itself from the competition for new capacity, the number of competitors is reduced, and hence, the degree of competition is reduced. Additional competitors yield greater competition and, as a result, a better outcome for all. However, IEP added that the degree of competition is reduced not only by a reduction in the number of competitors but also by whether the utility itself is a competitor in the bid process. Competition for new generation capacity may be enhanced, not diminished with the utility removed from the competitive process. Allowing the utility to compete to serve itself may result in a bias toward self-dealing or an advantage for the utility's own offerings over those of third-party competitors.

In weighing the arguments on market structure, we find that California should not rely solely on competitive market theory and the behavior of market generators. While market redesign is underway by the ISO and FERC, it is not complete. California has a long history of reliable service being provided by utility-owned and operated generation plant and a recent painful history of rolling blackouts and high price spikes from reliance on third-party generators in a poorly designed competitive market. We agree with SDG&E that a portfolio mix of short-term transactions, new utility-owned plant, and long-term PPAs is optimal, combining the security of generation assets under the full regulatory oversight of the Commission with the flexibility of ten-year contracts, and the potential benefits of operating efficiencies and lower costs from a competitive market. We reference a ten-year PPA based on ORA's recommendation and SDG&E's pending RFP.

We find that designing rules for a hybrid market structure is a complex undertaking. First, a competitive solicitation should be used in order to capture the lowest prices and maximum choices. IEP raises the issue of a level playing field, with the utilities not being able to bid low and then later seek additional cost recovery. The record here shows that the utilities are not well suited to actually construct new plant as it has been twenty to thirty years since they built fossil-fuel plants. Therefore, we expect the solicitations to request turn-key plants and PPAs with later purchase options rather than initial utility construction. If situations arise where competitive bids do not produce adequate response, the utility may need to take on construction, but firm cost caps would need to be in place.

The presumption that utilities may favor their own capacity at the expense of third-party generators is well founded, with effects in both procurement of power from existing resources and in the procurement of new capacity. In their procurement from existing resources, utilities are monitored for their patterns of dispatch to assure that the operations are undertaken in a least-cost manner (i.e., Standard of Conduct No. 4). The presumption is that without that standard, utilities would favor their own resources at the expense of lower cost available alternatives. The historical relationship of the utilities with QF producers similarly leads to concern that given the choice utilities would rather rely on their own resources than on those that come from the market.

The utilities' unwelcoming reception of the California Power Authority's peaker generating units initiative presents a current example of the utilities' desire to avoid contracting with third parties for capacity. The difficulty in adding to California's generating capacity at all during the years of the Biennial Review Proceeding Update (BRPU) process provides a historical example. IEP asserts that the Mountain View procurement application is an example of SCE being unwilling to participate in a competitive process at all. Whether these operating and capital accumulation biases are real or they are only perceived, the Commission should address them.

Careful design and monitoring of a competitive solicitation process and use of a least-cost dispatch standard are important means of addressing the potential for bias. Another means is to adopt a procurement incentive mechanism, so that the interests of utility investors, management, and ratepayers are better aligned. The utilities have an opportunity to invest and earn a return from generation assets; a similar opportunity for profit should be provided for selecting and managing well all other procurement products. We address this in a later section of this decision.

The utilities also request that the Commission provide assurance that our cost-recovery mechanisms will be reliable and consistent over the long term and that we do not adopt policies that would lead to a less stable customer base wherein investments in generation and long-term power contracting would create significant stranded cost exposure. While some of these issues, such as pending legislation to establish a core-noncore market and to change direct access eligibility, are beyond our ability to address here, we are committed to returning the utilities to financial health and to not adopting any mechanisms that would lead to a deterioration of their creditworthiness.

At same time we provide an opportunity for the utilities to own new generation, we want to provide assurance to the third-party generators that we see a meaningful role for them in California's energy future. Third-party generating capacity, if contracted properly, holds a number of advantages for California ratepayers. Moreover, it is necessary to have a thriving independent generating sector for these advantages to be secured. We recognize the financial duress, manifested in significant debt and credit problems, that has beset the merchant generator community post energy crisis. Some firms have closed shop, others have scaled back their operations. We wish to support depth and liquidity in energy markets and, by not letting them compete, this will shrink the market. If third-party generators come to believe, as a result of Commission decisions or utility actions, that an unfavorable market for their services exists in California, then they may withdraw from our state and concentrate their limited resources elsewhere. We would soon face a shortage of serious independent generators able and willing to bid, construct, and operate productive generating capacity here. California would be left with utility development of new capacity as its only option.

4. Competitive Solicitations

Based on our discussion above, the utilities should rely on the formal RFP process to secure future long-term generating capacity resources. The RFP process, if properly designed, calls forth from the marketplace the widest set of choices for development. It is likely to produce the most competitive prices as well, with the possible exception of fleeting-opportunity possibilities.

WPTF argues for a specific structure for capacity procurement that puts procurement via contract on an equal footing with utility-build options. WPTF's proposal is that prior to its issuance, an RFP must be approved by the Commission or an independent third party to verify that it is not tilted in favor of the utility or its affiliate's bid. Second, bids should be evaluated by an independent third party, such as an accounting firm, consultant, or specially convened review panel. Finally, the third party will select a winning bid which, if it meets the criteria presented in the RFP, the utility must accept.

WPTF's proposal would result in a cumbersome process, and one that would be difficult for any utility to endorse, especially as it reserves final choice of contracting partner to a party other than the utility itself. But its need derives from the perception that without the involvement of independent parties in the development of the RFP, the evaluation of the bids, and the ultimate selection of the winning bidder, the utility would have an incentive to act in ways that would bias the process in favor of itself.

The Commission currently has in place safeguards to address WPTF's concerns. First, each utility has a Procurement Review Group (PRG) that consults with the utility in the design of the RFP and the evaluation of bids. ORA proposes an 11-step process for this that we address in a later section of this opinion. Next, the Commission will review all long-term commitments that result from an RFP through its formal process which allows notice to all parties and an opportunity for public review and comment. Based on our continuing review of the RFP process, we will adopt additional safeguards if we find it is necessary.

5. Length and Type of Contracts

As ORA's testimony discusses, over reliance on shorter-term energy markets can be dangerous, as in the energy crisis, and also does not ensure reasonable cost and rate stability due to potential resource shortages and increased prices with price spikes. While commitments beyond one to five years are needed, this does not mean that thirty-year commitments are necessary; ORA testifies that ten-year contracts could provide sufficient assurance for market generators to construct new power plants and five-year contracts could provide generator owners the financial guarantees to invest in emission control equipment and for refurbishing units with the latest technologies. We agree with ORA and SDG&E that a mix of contract lengths, sufficient to allow for new construction of power plants or transmission projects, is best. We also agree with SDG&E that in evaluating an optimum portfolio mix, consideration needs to be given to existing resources and their terms.

Parties discussed types of contracts that could provide the utility increased control and supply reliability. First, with respect to non-unit contingent contracts (i.e., contracts with unspecified resources) with existing resources, ORA proposes that's such contracts should be authorized only for less than one-year in term and executed no more than one-year forward. For contracts for existing resources where the utility would have dispatch rights to specified resources, ORA recommends contract language stating that only specific plants could provide the power, and perhaps ancillary services, with no allowance for substitution from the market. We adopt these contract guidelines. California sited plants, under the must-offer requirements of the ISO and the operation and maintenance standards of SBx2-39, provide additional protection against market power abuses. TURN discussed having contractual arrangements such as step-in-rights and take-over type rights to address longer term issues of supplier nonperformance.

In D.03-06-067 we eliminated Standards of Conduct 6 & 7. We will not reinstate Standards of Conduct 6 and 7, but instead rely on more specific contract terms, as discussed above. We will be able to make a better assessment of the potential for future market power abuses when the ISO and FERC complete their redesign of the wholesale energy market.

6. Affiliate Transactions

a) Existing Moratorium and Standard of Behavior 1

In last year's hearings, the Commission considered the issue of transactions with affiliates at considerable length. The assigned Commissioner ruled in the April 2, 2002 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. Parties that supported a prohibition on affiliate transactions supported only the narrower prohibition of a utility purchasing from its own affiliates. TURN, Aglet, and the Consumers Union submitted testimony and comments discussing the risks inherent in allowing utilities to buy power from their own affiliates within the current holding company structure.

During the hearings, the Commission requested each utility to prepare an exhibit showing electric procurement disallowances made by the Commission during the 17-year period from 1980 to 1996. These exhibits show that there were only a limited number of disallowance decisions in that period, and that the majority of these decisions and dollar adjustments involved affiliate transactions. Recognizing this, and that the current affiliate transaction rules adopted in 1997 were not designed for today's market structure, the Commission adopted a moratorium on PG&E, SCE and SD&E dealing with their own affiliates in procurement transactions, beginning January 1, 2003, to allow for a careful reexamination and appropriate modification of our affiliate rules.[53] (D.02-10-062, page 49.) We also adopted permanent minimum standards of behavior for the respondent utilities, Standard 1 being:

> "Each utility must conduct all procurement through a competitive process with only arms-length transactions. Transactions involving any self-dealing to the benefit of the utility or an affiliate, directly or indirectly, including transactions involving an unaffiliated third party, are prohibited."

In applications for rehearing on D.02-10-062 and D.02-12-074, PG&E and Sempra raise legal challenges to the moratorium on affiliate transactions and SDG&E and Sempra raise legal challenges to Standard of Behavior #1. In D.03-06-076, the Commission found that the ban on affiliate transactions was properly noticed, jurisdictional, constitutional, violated no federal laws, and the record supported the need for a moratorium on utility procurement from its own affiliates until adequate safeguards are fashioned. Further, the decision states that the issue of adequate safeguards against affiliate abuses in energy procurement is an extremely important issue that can

[53] The moratorium did not preclude "transactions through the ISO that can be demonstrated to include multiple and anonymous bidders". (See FF21.)

be addressed in the long-term procurement phase of this proceeding or in R.01-01-011.

D.03-06-076 also sustained Standard of Behavior 1 and provided the following clarification:

> "Standard 1 does not preclude the IOUs from entering into 'anonymous' transactions through approved interstate brokers and exchanges, provided that the solicitation/bidding process is structured so that the identity of the seller is not known to the buyer until agreement is reached, and vice-versa. Under these circumstances, the risk of affiliate transaction abuses is minimal. It is our understanding that most, if not all, of the brokers and exchanges being used by the IOUs already structure the bidding so that it is anonymous. Thus, this standard imposes little, if any, burden on interstate commerce."

b) This Year's Hearing Record

In this year's hearings, the moratorium on affiliate transactions was combined with the issue of utility ownership of new generation for the purpose of testimony and briefs. At hearing, the ALJ also asked witnesses whether there should be different rules for short-term and long-term transactions. Additional questions were asked by the ALJ regarding PG&E's and SDG&E's dealings with other departments within their company and with affiliates.

Of the three IOUs, PG&E and SCE focus their comments on utility ownership and do not directly address the moratorium on affiliate transactions, while SDG&E takes a position on both, the stronger position being that the moratorium on affiliate transactions is unnecessary because current rules are adequate to govern any transaction. Further, SDG&E states that transactions between SoCalGas and SDG&E are not, and should not be, subject to the affiliate transactions moratorium.

ORA states that the Commission should continue the ban on affiliate transactions for short-term procurement because the short-term market moves too fast and there is too great of a potential for abusive self-dealing, with little or no possibility for Commission oversight of these types of transactions. However, for long-term transactions, such as long-term PPAs or a turn-key agreement or take-over of a power plant, the Commission should evaluate these transactions under the current affiliate rules. ORA testifies this process should have enough built-in protections to prevent potential self-dealing and other abuses.

TURN states the Commission should extend the ban on affiliate transactions because there still exists the possibility of improper behavior by the IOUs. If the Commission does not extend the ban, then it should require preapproval of affiliate contracts of more than one year's duration and complete disclosure of all affiliate transactions for procurement from affiliated generators or marketers (i.e. no confidentiality would exist, and the utilities must make the contracts publicly available). TURN also states that the utility risk management committees must not contain non-utility corporate officers and the Commission should direct SDG&E to create a risk management committee that only looks at transactions from the utility, i.e. SDG&E's, perspective.

IEP and WPTF do not object to affiliate transactions, preferring them to direct utility participation in generation bidding. CAC/EPUC testifies that participation by utility affiliates will enhance competition and specifically requests that the Commission lift the ban we adopted in D.93-03-021 on SCE procuring new resources from its QF affiliates. CCC states the Commission should not allow utilities to circumvent the procurement process by entering into special affiliate deals, citing SCE's Mountainview application process.

c) Discussion

In this decision, we are setting the market structure and rules for long-term procurement. We are allowing the utilities to directly participate in owning new generation facilities but recognize that we will need to be vigilant in overseeing that no perceived bias occurs in selecting, or dispatching the resources, especially when the current cost recovery mechanisms favor the rate-based power plants. We include utility participation in order to have the assurance of more state control over resources and an effective check against competitive market manipulations and abuses.

We do not have the same level of oversight and authority over affiliate transactions that we do over direct utility operations. We recognize that cross-subsidies and anti-competitive conduct has occurred in the past in affiliate procurement transactions and that it could occur in the future under the market structure we adopt here. The most direct and effective means to avoid any potential conflict of interest is to simply prohibit the transactions.[54] The holding companies and affiliates of each utility should plan for future generation investment to be made outside of the utility's service territory and sold to other load serving entities.[55] Two exceptions we need to address here

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[54] SDG&E has a pending motion before us to consider a transaction with a Sempra affiliate, Palomar Energy. That matter has been separately set for hearing and is not addressed here. Likewise, SCE's Mountainview application is under separate consideration.

[55] CAC/EPUC states that its request to revisit the settlement agreement between SCE and ORA adopted in D.93-03-021 applies to the ability of four SCE QF affiliates with

Footnote continued on next page

are the gas storage and transportation transactions that SDG&E needs to conduct with SoCalGas and that PG&E may need to conduct with separate company departments and unregulated affiliates.

d) SDG&E and SoCalGas

SDG&E states that its dealings with its regulated affiliate, SoCalGas, should not be subject to any affiliate transaction rules because SoCalGas is the only provider of natural gas storage and intra-state transportation in Southern California outside SDG&E's service territory and therefore ratepayers receive benefits from these transactions and would be harmed by any restrictions placed on the transactions.

In response to the ALJ's request, SDG&E prepared Exhibits 110C and 132 to describe all procurement transactions that occur between SDG&E and SoCalGas and entered Exhibit 70 to show its risk management committee and the Sempra Energy corporate committees. Exhibit 132 shows that SDG&E purchases transportation and storage services from SoCalGas, for its own procurement as well as an agent for DWR, pursuant to Commission-approved tariffs and filed negotiated rates, as well as pursuant to the 25 "Remedial Measures" adopted as part of the merger between Pacific Enterprises and Enova Corporation (D.98-03-073, Attachment B). Exhibit 110C shows that SDG&E has recommended additional SoCalGas services to DWR.

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existing contracts for firm capacity totaling about 1100 MWs and which supply approximately 9,100,000 MWh of energy annually, to bid for new contracts. In last year's hearings, SCE entered revised Exhibit 79 which shows D.93-03-021 adopted a $250 million disallowance based on a finding that SCE's QF Affiliate transactions were unreasonable. A petition to modify D.93-03-021 would be the appropriate procedural vehicle for the Commission to fully examine this request.

Exhibit 70 shows (1) that 7 of the 9 members of SDG&E's Electric and Gas Procurement Committee are from Sempra Energy Utilities (SEU), the parent of SoCalGas and SDG&E; (2) Sempra's Energy Risk Management Oversight Committee, the analytical platform supporting enterprise-wide energy risk-management activities, contains members from both the regulated and unregulated affiliates; and (3) Sempra's Project Review Committee, which reviews and approves all transactions in excess of $10 million and commitments with important policy implications, has no members from SDG&E or SoCalGas and only one member from SEU on an 11 member committee.

In 1998, when the Commission approved the merger between Pacific Enterprises and Enova Corporation, California's electric market was under the competitive market structure of AB 1890. The remedial measures adopted then for transactions between SoCalGas and SDG&E should be reexamined in light of today's market structure. For instance, as a condition of approving the merger, the Commission required SDG&E to sell its gas-fired generation plants to nonaffiliates of the merged company, a market power mitigation measure sought by FERC and ORA. Today, the Commission is entertaining a proposal from SDG&E to own a Sempra gas-fired generation plant and has placed SDG&E as agent of DWR contracts with gas-fired generation plants.

In addition, as well as adopting the remedial measures in Attachment B referenced by SDG&E, the Commission in D.98-03-073 ordered the hiring of an independent auditor for a management audit of how the combined utilities operated. One of the concerns found by the auditors, and addressed by the Commission in D.02-09-048, was the sharing of SoCalGas risk management information with a Sempra Energy Trading vice president. The audit was conducted between June of l999 and July of 2000.

Even without the benefit of examples of any harm to SDG&E customers from including Sempra personnel, we find that including such people on a committee to evaluate procurement options for the ratepayers is troubling. Sempra officers have a foot on each side of the firewall, partly representing SDG&E's customers, and partly representing the affiliates. To protect the appearance as well as the fact of affiliate separation, we think there should not be affiliate or holding company personnel involved in utility procurement decisions of the utilities.

We are also troubled by SDG&E's procurement risk management committee being dominated by SEU officers. SDG&E has extremely competent management and it is this management whose duties should include assuring that procurement activities are undertaken in the most appropriate and economical manner.

Therefore, we direct that SD&E file a revised Exhibit 70 to reflect that the risk management committee(s) overseeing SDG&E's electric procurement operations and DWR-related gas procurement operations are comprised solely of SDG&E management. This filing should be by Advice Letter within 30 days.

In D.01-09-056, the Commission reviewed Sempra Energy's September 13, 2000 request to reorganize its regulated California utility businesses to further integrate the management and cultures of SoCalGas and SDG&E and found the proposed functions for shared resources to make business sense. SDG&E was not procuring electricity in the market at the time of this filing and decision. A review of whether negotiated transactions with

SoCalGas should be subject to special transaction rules and reporting should be undertaken, especially since SoCalGas' services are under an incentive mechanism while neither SDG&E's electric procurement operations nor its DWR related gas procurement are under an incentive mechanism.

The management audit discussed above should be narrowly focused on two issues: SEU's participation in the risk management committee structure for SDG&E procurement operations; and any rules or reporting needed for SDG&E's energy procurement transactions with SoCalGas. The Commission's Energy Division should draft the scope of work required, select an independent auditor, and oversee the analysis. At the conclusion of the analysis, an analysis report should be filed with the Commission and served on all parties to this proceeding. The auditor should remain available to explain the report's findings, and testify in evidentiary hearings at the Commission on the findings included in the report. These audit costs should be reimbursable. SDG&E should place the costs in a memorandum account.

In Resolution (Res.) E-3838, issued on July 10, 2003, the Commission authorized SDG&E's first Gas Supply Plan for its administration of DWR contracts. In that resolution, we apply the affiliate transaction rules to all procurement transactions between SDG&E and SoCalGas, and set an interim standard for transactions SDG&E enters on behalf of DWR with either itself or an affiliate for services which are paid on a negotiated basis. We should adopt this standard on an interim basis for all SDG&E's procurement transactions.

e) PG&E and Affiliates

In Res. E-3825, adopting a Gas Supply Plan (GSP) for PG&E's administration of the gas tolling arrangements of DWR electricity contracts, the Commission expressed concern that PG&E may engage in inappropriate self-dealing with its affiliate or operating divisions and proposed an interim method for addressing it. Specifically, the Commission stated:

> "An additional consideration is the extent that PG&E may engage in inappropriate self dealing with its affiliates or operating divisions. Such abuse is possible since PG&E owns and markets, through its Golden Gate Market Center operation, gas storage (in direct competition with Wild Goose Storage) and intrastate backbone transmission services. As a case in point, PG&E is proposing using parking and lending services with the Golden Gate Market Center under the Gas Supply Plan for managing imbalances. Additionally, PG&E Gas Transmission Northwest, a pipeline connecting western Canadian gas pipelines to the utility's backbone transmission system is controlled by a utility affiliate."
>
> "In D.02-10-062, we adopted standards of behavior that the utilities' must observe in connection with their procurement practices. For transactions with affiliates, Standard of Behavior No. 1 is applicable and specifies the following:[56] [57]
>
> "Each utility must conduct all procurement through a competitive process with only arms length transactions. Transactions involving any self-dealing

[56] D.02-10-062, placed a moratorium on SCE, PG&E and SDG&E dealing with their own affiliates in procurement transactions, beginning January 1, 2003, lasting for two years or until the rulemaking is completed, whichever date is first. (See p. 50, *mimeo.*)

[57] D.03-06-067, "Gas Procurement for the utilities' DWR is a hybrid: it should follow the same standards as gas procurement for the utilities' own contracts, yet it is reviewed under a separate Gas Supply Plan, with the review conducted annually in conjunction with DWR contract administration and least-cost dispatch." (See p. 10, *mimeo.*)

to the benefit of the utility or an affiliate, directly or indirectly, including an unaffiliated third party, are prohibited." (D.02-10-062, p. 51, *mimeo.*)

"To the extent that PG&E will consider using a utility affiliate to provide service for the DWR contracts, it must obtain a waiver from this prohibition through a petition to modify D.02-10-062.

"In cases where PG&E is considering use of its utility owned facilities and services, we are concerned about PG&E's ability to engage in earnest negotiations as an agent of DWR for services offered and provided by the utility.[58] In some cases there may be competitive alternatives available to PG&E and that the utility has discretion to use its own facilities or those of another provider (e.g., gas storage). A conflict of interest is inherent in such bargaining because the utility has opposing goals to increase utility profits yet protect the interests of DWR, the principal, and minimize costs. To remedy this conflict, we need a standard to gauge whether PG&E's negotiated prices for these services on behalf of DWR are the product of the competing interests of a buyer and seller in an arm's length transaction. An additional factor for consideration are PG&E's request for offers (RFO) and bids received from competitors to provide services. We expect PG&E to seek such bids in all cases where competitive services are available.

"For PG&E's initial Gas Supply Plan, we will adopt the following presumption of reasonableness standard. We will presume in such cases where an RFO is issued and offers are received that a reasonable price is paid if PG&E's charge to DWR for the use of the utility's

[58] In some instances PG&E's tariff allows the utility to negotiate prices with their customers for certain services (e.g., parking and lending).

> facilities or services is the same as or lower than the bid(s) received. In cases where there are no competitive alternatives for comparison, we will presume that a reasonable price is paid if PG&E's charge to DWR for the use of the utility's facilities or services is either: 1) the tariff recourse rate for the service; or 2) if the price is negotiated, no higher than the volume weighted average of the price the utility negotiated (except for DWR) for each similar service in the same month and for the same period the service is provided. PG&E will be required to show why any transaction entered into above the weighted average price level was appropriate and reasonable. Whether the utility's decision to use such services was prudent will be considered in our reasonableness review."
> (Res. E-3825, issued July 10, 2003, pages 18-20.)

The concerns raised in Res. E-3825 apply beyond the GSP to include future electricity procurement by PG&E for its own portfolio. We should establish rules for any dealings with PG&E Gas Transmission Northwest if PG&E needs to deal with this affiliate in order to access Canadian gas pipelines. In cases where PG&E is using its own facilities, we have the same concern with negotiated rates that we discuss earlier for SDG&E and also question whether the limited competitive market for storage services is an appropriate benchmark or whether a cost-based standard should be developed. For dealings with other departments, we should examine any potential for abuse due to different department's costs recovery mechanisms and incentive structures. Therefore, we direct a management audit focused on these procurement issues be undertaken, using the same procedure we specify above for the management audit of SDG&E again, these audit costs are reimbursable; PG&E should place the costs in a memorandum account.

In summary, we adopt here a permanent ban on affiliate transactions for procurement with the following exceptions:

1. "Anonymous" transactions through approved interstate brokers and exchanges, provided that the solicitation/bidding process is structured so that the identity of the seller is not known to the buyer until agreement is reached, and vice-versa.
2. Transactions for natural gas services between SDG&E and SoCalGas and between PG&E and affiliates and operating divisions that are found necessary and beneficial for ratepayer interests. These transactions should be subject to the rules adopted in Res. E-3838 and Res. E-3825 pending receipt and review of the management audits ordered here.

C. Financial Capabilities of the Utilities

Each utility's long-term plan shows a need for additional supply-side resources within the next five years, but PG&E's and SCE's recommended plans rely solely on short and medium term contracts to meet their needs, rather than proposing commitments to new or repowered power plants. Both utilities cite their inability to access the capital market at reasonable rates and the need for maximum flexibility due to the lack of clear resolution on the critical issues of direct access policy, community aggregation, and prospects for a core/non-core market structure, as the reasons they are unwilling to make longer term commitments. ORA testifies that PG&E's and SCE's recommended plans rely too much on market purchases and may not have adequate resources to meet their customers' need.

In D.02-10-062, we addressed the utilities' capability to meet their obligation to serve, and found that PG&E and SCE did not need to obtain an investment grade credit rating prior to resuming the procurement role. We addressed each of the arguments raised by PG&E and SCE regarding why they were not capable of resuming full procurement. We found that PG&E and SCE were capable of resuming full procurement and, under their continuing obligation to serve, should do so beginning on January 1, 2003.

Today, the three utilities have all successfully resumed full procurement and the financial prognosis for PG&E and SCE is much improved. SCE has received an investment grade credit rating from Fitch and PG&E anticipates exiting bankruptcy with an investment grade credit rating by the end of this year. We expect each utility to make the investments necessary to meet their obligation to serve their customers at just and reasonable rates.

The uncertainties surrounding direct access policy and the legislature's consideration of core/noncore market structure make procurement planning challenging, especially for long-term commitments. PG&E provided a core/noncore scenario to guide its planning and other utilities should consider this in the next plan filing. We agree with the utilities and other parties that care should be taken not to make commitments that could later result in stranded costs. For their next long-term plan filings, all three utilities should include an appropriate level of long-term commitment to additional power plants or plant-specific purchase power contracts.

The utilities are concerned with the financial and credit implications of any long-term power contracts they may enter into, particular as it affects their long-term prospects of becoming commercially viable. Of the three utilities, only SDG&E has investment grade credit rating. As such, it did not discuss debt equivalency, credit capacity and collateral issues as barriers to its long-term procurement plans. SCE cites the debt equivalency issue and lack of Commission policy on cost recovery issues as barriers to their entering into long-term contracts, while PG&E focuses more on credit capacity and collateral issues.

1. Debt Equivalency

Given the Commission's policy objective of encouraging the IOUs to enter into longer term PPAs, we now turn our attention to the issue of debt equivalency. Debt equivalency is a term used by credit analysts for treating long-term non-debt obligations -- such as PPAs, leases, or other contracts -- as if they were debt. Credit analysts adjust a utility's balance sheet and income statement entries by assigning a debt equivalence amount (in $), expressed as a "risk factor". The risk factor can account for 0% to 100% of a PPA's fixed payments, depending on the type of PPA structure. This dollar amount is used to calculate the financial measures used to assess a utility's credit quality.

The CPA testifies on the limitations of the debt equivalency issue within the context of our procurement proceeding. As a party active in municipal market financing, the California Power Authority states, "debt equivalency is not a cost…in this proceeding, it's a 'red herring,' since it represents an accounting entry." The methodology for determining debt equivalency is an accounting treatment, with little implication for cashflow. These observations are underscored by S&P, who state: "Cashflow analysis is the single most critical aspect of all credit rating decisions."[59] SCE acknowledges the limitations of the debt equivalency issue as well, saying:

> "…higher levels of equity do not necessarily provide ongoing cashflow by themselves. As an additional solution, SCE advocates higher returns on equity or other cash flow enhancements that directly affect

[59] S&P Rating Methodology: Corporate Ratings Criteria, p. 26.

financial metrics may be necessary to support credit ratings."[60]

Rating agencies use qualitative (i.e. subjective) approaches to assessing debt equivalency. The methodology and risk factor applied varies according to the particular credit rating agency. SCE acknowledges this, saying: "…the rating agencies do not use a uniform approach to determining debt equivalence, and S&P has indicated that its methodology is evolving (our emphasis) in response to changing conditions. Further, not all PPAs are alike. For example, S&P uses a higher risk factor for take-or-pay PPAs than for performance-based PPAs.

a) SCE's Concerns for Long-Term Power Contracts

SCE asks that the Commission take steps to improve and maintain the utility's creditworthiness and financial viability. SCE states that restoring its creditworthiness status is a prerequisite to implementing its long-term procurement plan. In support of its argument, it cites the 2001 Settlement Agreement in which the Commission recognized the importance of SCE regaining creditworthiness as soon as possible, so as to provide reliable electric service.

SCE states that as it takes on additional power contracts and other long-term commitments, its credit rating will decline, undermining its ability to maintain its investment-grade status. To counter this rating decline, SCE asserts that the Commission should add more equity to its capital

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[60] SCE LTPP, Vol II, p. 58.

structure, thereby recognizing debt equivalency costs in rates as well as in overall costs of procurement.

b) Implications for Market Structure

SCE testifies that the rating agencies are looking for the longer term solution to the market structure problem in California, and will only allow an investment grade rating once they are comfortable that a permanent framework is in place and that it works well in the long term.

ORA counters SCE's position, stating: "SCE's current credit rating reflects the state of the regional electricity industry coming out of the electricity crisis, and cannot be blamed on the Commission's cost recovery mechanisms or the debt equivalence impact of long-term contracts with any degree of certainty."[61] Credit ratings upgrades often occur due to improvements in general economic or industry conditions. We note that Fitch recently upgraded SCE's credit rating to investment grade.

c) Commission Procurement Policy and Treatment of Debt Equivalency

We find there are limits to the debt equivalency methodology. The debt equivalency issue is an accounting treatment applied to long-term financial commitments. It does not represent a market-driven process for valuing long-term contractual commitments. An assessment of price risk inherently involves market dynamics in valuing these commitments. In the Commission's procurement proceeding, we address issues of economic value, not accounting value, by taking into consideration the relative costs of

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[61] ORA OB, p. 9.

alternative procurement options. This is implicit in Pub. Util. Code § 454.5(1)(d), which directs the Commission to "assure that each electrical corporation optimizes the value of its overall supply portfolio." To introduce accounting processes into this proceeding might skew our assessment of the relative value of various procurement options.

The rating process is not transparent. SCE acknowledges that S&P is the only rating agency that publishes guidelines for the metrics it uses. There is little discussion of Moody's methodology, so there is no basis on which the Commission can analyze and/or compare the methodologies of the major rating agencies. There is no indication that consensus among the major rating agencies is forthcoming or imminent. In implementing a debt equivalency policy, the Commission would look for an industry standard as a benchmark on which we can base our policy.

Furthermore, while credit ratings may look the same, their computations are based on non-uniform qualitative factors, hence the potential for confusion. An "A" rating from S&P is based on a different analysis than the "A" rating from Moody's. Thus, the utilities' somewhat overstate the case for Commission policy as a means to garner a particular credit rating. Moody's says that the "same rating from different agencies only looks the same." Further, it adds that, "…ratings are opinions about risk, not formulas. Accurate, forward-looking credit analysis cannot be mechanized. As a borrower, you cannot assume that a rating from any agency will provide the same degree of access to the sources of investor capital."[62]

[62] Moody's Understanding Risk, p. 1.

The credit rating process is a dynamic process. The utilities have not taken into account the impact of general economic and industry conditions over rating changes. As ORA notes:

> "The utilities have failed to demonstrate any correlation between entering long-term contracts and credit ratings. In fact the health of the entire electricity market, more than micro-factors such as cost recovery mechanism and specific contract terms determines the utilities' credit ratings."[63]

> "SCE implicitly agrees, stating that "The business position….has to do with evaluating the environment in which a company operates in, so that would include the political and regulatory environment, the ability for a company to make business decisions and pursue them without obstacles." SCE adds that "The ability of the company to pursue their business in a manner that will mitigate the business risks that they encounter really defines the business risk number that S&P comes up with."[64]

Seeing no consensus regarding the methodology and application of debt equivalency, we believe that implementing a Commission policy at this time would be premature and over-reaching. The Commission has previously examined debt equivalency in its Cost of Capital proceedings. (See D.92-11-049 and D.93-12-022.) The utilities should make a showing for specific relief in their upcoming cost of capital filings.

2. Cost of Collateral

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[63] ORA OB 9/15, p. 5.

[64] SCE Witness Abbott, TR 8/4, p. 4755.

The long-term power contracts that utilities will enter into must be supported by collateral. PG&E and SCE state that their ability to secure reasonably priced financing for these contracts is hindered because of (1) SCE's non-investment-grade rating and (2) PG&E's bankruptcy status. Given their financial duress, , each argues that their financial status precludes them from committing to long-term contracts and limits the procurement options available to them.

SCE asks that the Commission take steps to improve and maintain its creditworthiness and financial viability by recognizing the costs associated with collateral requirements. It indicates that the ERRA proceeding is the appropriate forum for addressing the impact and treatment of collateral costs; the cost of capital proceeding is the first forum SCE should raise this issue.

PG& E states that its procurement-related credit capacity is presently capped by a dollar limit as per the terms of its Reorganization Plan. Given these limitations, it does not expect to be able to enter into long-term contracts while in bankruptcy.

With respect to the administration of the DWR long-term contracts, the Commission authorized the three IOUs to serve as limited agents for DWR for fuel management services. PG&E states in its 2004 procurement plan that:

> "DWR is currently arranging [for gas hedging for the DWR contracts] and would continue to do so under PG&E's proposed gas supply plan. However, to the extent that DWR fails to continue to hedge gas prices under its contracts, it is likely PG&E would not have sufficient credit capacity to enter into such hedges given the other demands for its limited credit capacity. PG&E, therefore, requests that the Commission relieve PG&E of any responsibility to hedge gas on behalf of DWR to the extent PG&E's collateral requirements associated with

> such hedges, in combination with other procurement-related collateral requirements would exceed PG&E's ability to provide such collateral."

The utilities suggest other approaches to dealing with limited credit capacity. PG&E states that the Commission can increase the utility's available credit capacity by increasing the authorized rate of return, by improving various cost recovery mechanisms to limit overall business risk, and by providing for stable decisionmaking. In our earlier discussion of debt equivalency, we referred issues affecting utilities' capital structure to the Cost of Capital proceeding. We reiterate that position here.

It is essential to balance the cost of collateral against the risk of counterparty default. PG&E and SCE currently have non-investment credit ratings, and with it, limited sources from which they can secure collateral financing. One possible solution is to rely more on transacting with similar non-investment grade counterparties, without collateral support. However, as a general rule of thumb, companies seek to limit their credit/counterparty exposure by primarily transacting with creditworthy counterparties and/or by requiring counterparties to post collateral. We note that should exposure exceed a predetermined limit or a counterparty fail to supply energy when required, ratepayers will suffer the consequences.

The Commission recognizes the dearth of financially stable and viable trading counterparties in the market, as well credit contraction in the industry, and the implications of these conditions on each utility's credit policy. Nonetheless, we must act on behalf of ratepayers to protect them from the adverse impact of counterparty non-performance, as it relates to cost exposure and/or lack of reliable supply. With respect to unsecured credit limits, when dealing with non-investment counterparties, the Commission insists that as a first option, utilities explore the use of credit mechanisms such as parent company or third party guarantees, letters of credit, surety bonds, etc. The credit assessment should rely on master agreements with special parent and or guarantor provisions for posting collateral and for assuring continuity of service. When dealing with investment-grade counterparties, we approve of the credit thresholds proposed by the utilities. Credit criteria for non-guaranteed government entities are approved, according to the guidelines proposed by each IOU.

V. Long-Term Planning Assumptions and Policy Guidance

A. Utilities' Current Filings

1. Parties Positions

On April 15, 2003, the respondent utilities filed long-term resource plans presenting their estimates of resource needs and how they plan to fill those needs over the years out to 2023. The plans provide basic information about the expected load growth in the utilities' service areas and the resources that will be required to meet that load. Each utility reminded the Commission of the policy issues it considers outstanding that make long-term resource planning difficult.

The utilities' plans are different from one another in style and substance, but on one point they all agree: It is difficult to make long-term plans in the absence of certainty, particularly certainty regarding future Commission policy on such issues as Direct Access. The utilities raised other issues that inhibit their ability to contract or to make long term commitments, including the lack of creditworthiness.

ORA conducted a comprehensive review of the utilities plans, including employing a consultant, Electric Power Group, to analyze and report on the resource plans. ORA states that the long-term plans represent the first significant effort in over a decade for the Commission to review the utilities' forecasts of demand and supply in a statewide planning context. It finds that the plans are voluminous, complex, and should be viewed as works-in-progress.

ORA testifies that the utilities present primarily broad generalities of their need assessments and generic options for meeting them; further, the utilities do not present specific objectives for meeting their long-term resource needs. A procurement planning proceeding, ORA asserts, should set concrete goals based on specific assumptions that can generally be relied on to evaluate the utilities anticipated procurement filing applications for resource needs and addition. ORA also notes that the utilities' fuel price forecasts were out of date, and that actual gas prices were higher than expected. Through its expert witnesses, ORA provides a number of specific criticisms of individual utility long-term plans.

TURN's position is that the utilities should submit updated long-term plans early next year and that the plans should be approved before they are implemented. TURN makes a number of comments about the utilities' long-term plans, including a statement that they are inadequate to serve as a basis for long-term resource adequacy planning. TURN argues that the utilities should be required to use standardized load forecasting methodologies, and, in the future the CEC should take charge of developing load forecasts for the state. TURN notes that the utilities' fuel and price forecasts were already outdated by the time of their submittal and recommends that the utilities should be ordered to consider specific high-price gas scenarios.

Similar to the utilities' stated position, TURN is concerned that there are certain planning variables the utilities and the Commission must face before they can plan for the future with full confidence. TURN notes a significant increase or decrease in DA customers or market distortions causing DA load to return to bundled service; the potential creation of core and non-core classes; and progress in Community Aggregation. Any one of these scenarios, TURN notes, may cause a utility's long-term plans to become sub-optimal for ratepayers.

The CEC's testimony focuses on strengthening the integration of transmission and generation planning, creating and adopting a resource adequacy framework, and placing the CEC's Integrated Energy Policy Report (IEPR) process at the center of the utilities' procurement planning. CEC states that pursuant to Public Resources Code 25302(f), the Commission is to use the CEC's IEPR "information and analyses" in its own proceedings, unless it has a "reasonable objection" to justify an alternative. CEC proposes that the IEPR information should be used as the base case for all resource planning assessments, demand forecasts and fuel analyses that project more than two years into the future, and for any identification of residual net short (RNS) positions motivating contractual and market purchase activities.[65]

WPTF proposes a common framework or standard template for utility procurement plans to facilitate plan comparison and to evaluate the

[65] Opening Brief, pp. 1-4.

assumptions across the utilities even if the details remain confidential. This framework, it asserts, would result in a clearer understanding of resource adequacy and system reliability. WPTF agrees with other parties that policy uncertainties, including the future of DA customers and load, contribute to the difficulty of utilities (and LSEs) in planning.

The utilities, ORA, TURN, and CEC also, as part of their Joint Recommendation, propose to revise the long-term procurement plans in 2004 and for the IOUs to submit their revised plans for approval by the Commission by the end of 2004. Parties to the Joint Recommendation agree that any specific long-term commitments made before this process is complete should satisfy the "no regrets" criteria proposed by the CEC or be a resource needed for local grid reliability.

2. Discussion

As stated in D.02-10-062, we intend that the long-term plans of the utilities be the primary vehicles for their decision-making, planning, and procurement. AB 1890's over-reliance on the short-term PX market is a failed system. To ensure reliable service at just and reasonable rates, the Commission must ensure that the IOUs develop and implement sound long- term procurement plans and longer term resource acquisitions. Long-term plans that provide solid information in appropriate detail, and that are reviewed and approved by this Commission, can provide the basis for confidence on the part of consumers, of utility managers, of investors, and of the financial community upon which the utilities depend for capital.

We agree with the utilities, ORA, TURN, and CEC that revised long term plans should be submitted and approved in 2004 and that any long-term commitments brought to the Commission in the interim should meet a "no regrets" criteria. We have addressed the resource adequacy framework these plans should reflect in an earlier section and here we will discuss other refinements needed and set a procedural schedule for 2004.

The CEC's testimony states:

> "…while the process focused on the long term continues, the CEC recommends that the Utility Distribution Companies (UDCs) be authorized to continue procurement using 2003 rules as modified by a decision pertaining to the 2004 short-term procurement plans filed in May.
>
> "In addition, to the extent that a 'no regrets' perspective can lead to selective long-term commitments, some long-term commitments may be acceptable. In this context a 'no regrets' perspective might mean allowing some resource additions that are highly cost-effective under any circumstance; requiring that specific resource additions be more flexible than would otherwise be required; contract terms that allow the UDC to void the agreement under various predefined triggering conditions; etc. What is unfortunate is that it will be very difficult to avoid ad hoc decisions that a particular proposed resource is 'good enough' when a thorough review of the options and the risks they mitigate or exacerbate will be impossible. Without the criteria of a framework, there is no basis for evaluating alternatives." (Exhibit 49, pp. 9-10.)

Any long-term commitments brought to the Commission prior to adoption of the revised 2004 long-term plans should be reviewed within the context of the April filed plans and should make the "no regrets" showing required above. We share the concerns of the utilities, ratepayer interest groups, and market generators and retailers that with current legislation pending on Direct Access and a Core/Noncore market structure, the utilities should be careful to avoid the possibility of making long-term commitments that could become "stranded costs."

The primary focus in this decision is to guide the utilities in what we expect from them in their revised long-term plans. The first issue is the planning horizon. Several parties discuss the ISO's transmission planning process, which has a ten-year horizon. TURN recommends a ten-year planning horizon here based on estimates to allow a four-year lead time to build a power plant in California and have it in-service, and then to provide the Commission and others adequate time to evaluate resource needs and the best means to meet them.

We agree with TURN that a ten-year procurement planning horizon is appropriate and should provide relatively long notice to all industry players of the state's anticipated needs and allow them to respond appropriately.

Next, we address the level of specificity the plans should contain. ORA's concern that the utilities were overly broad and general in their long-term plans and without specific information is well taken. Though it is not appropriate for utilities to specify in detail the placement of new generation facilities that they may not need to contract for until years pass, or the specific beginning and endpoints for new transmission facilities, it is appropriate that they be more specific than they were in the submitted plans.

The long-term plans should include expected load and energy requirements, not only at their expected, or median, levels, but also at the 95^{th} percentile (that is, the one-in-twenty years case) of expected need levels. The long-term procurement plans should include a mix of all of the resources and products authorized in this decision, with a policy priority given to specific resources, as discussed in the following section. As part of its long-term plan, the utilities should identify which procurement proposals will require environmental review, special permits, separate applications, or other regulatory procedures or proceedings.

We find that the utilities should include the CEC's IEPR "information and analyses" in their plans but should make their own assessment as to whether the IEPR information should be used as the base case for any resource planning assessments, demand forecast and fuel analyses that examine more than two years into the future. CEC's demand forecast should always be one of the scenarios presented, and if it is not the base case, the utilities should report in their long-term plans how and why the assumptions underlying their forecasts differ from those of the CEC forecasts. We also encourage the utilities to consider a core/non-core scenario. The utilities themselves are the ones responsible and accountable for meeting the loads and energy requirements of the customers in their service areas. Therefore, regulatory clarity and appropriate placement of responsibility requires that the utilities should have the responsibility of estimating their own future needs.

Long-term plans should reflect the most recent fuel-price forecasts available at the time of the plans' preparation and should include fuel-price variation as an element of the plans. ORA and TURN raise an important issue regarding the use of forecast prices in long-term plans. Fuel prices are notoriously volatile, especially on a short-term basis. They vary with changes in the economy, changes in hydro conditions, changes in drilling and pipeline conditions. They vary for other reasons that are sometimes understandable only in retrospect if at all. We are not convinced that the actual degree of potential variation in fuel costs was reflected in the cost scenarios presented in the long-term plans. Therefore, we caution the utilities to consider seriously the degree of volatility that should be expected in fuel prices when developing high percentile scenarios for procurement costs particularly. We direct that future long-term procurement plans should reflect fully the expected range of fuel prices at least up to the 95th percentile of the expected distribution.

The long-term plans should include not only the utilities' preferred portfolio choice for how to meet their needs, but also other portfolio alternatives/ variations to meet those needs. We found SDG&E's plan, supplemented by confidential work papers, to be the most helpful in this regard. SDG&E presented its preferred "balanced" plan along with three others reflecting differing expectations about the desirability of in-service-area generation, new transmission, and different fuel types. SCE presented two "what-if" scenarios based on increased gas reliance and reduced gas reliance in addition to its preferred resource plan. PG&E presented several levels of need, but did not propose different ways to meet the need. The utilities should present estimated ratepayer costs associated with each method of meeting their needs, and should include some metric of the variability of those costs. SDG&E presented potential costs at the mean and at several different percentile cut-offs in the total distribution, up to the 98th percentile. We find this to be very helpful and request that the utilities include at least the 90th and 95th percentile projections in their reports.

It should be understood that filing a long-term plan and having it approved by this Commission does not supplant the requirements for the individual authorizations and traditional procedures for actions that would normally require such procedures. For example, all long-term acquisitions of generating resources should be filed by application and, in the case of utility ownership of a new plant, the utility must apply for a Certificate of Public convenience and Necessity (CPC&N). Likewise, our approval of a plan that calls for the construction or upgrade of transmission capacity does not authorize the construction or upgrade itself. As discussed in a following section, while the Commission is moving to streamline its transmission review procedures, the utility must still apply for a CPC&N.

We plan to review the revised long-term procurement plans through a full evidentiary process that will conclude with a final Commission decision by end of 2004. To achieve this undertaking, we should schedule a May 7, 2004 PHC as an early status check. In preparation for the PHC, the utilities should file on April 23, 2004 a working outline of their long-term plans that includes the level of detail and specific scenarios addressed in this decision, the means by which they will incorporate the resource adequacy framework developed through workshops, and a showing that the material provided in the public filing will allow for meaningful participation by all parties; interested parties may file comments on the outlines on May 3, 2004. Following is a procedural schedule through early May 2004. The revised 2004 long-term plans will be billed and reviewed in a new OIR.

April 23, 2004	Utilities file long-term plan outlines
May 3, 2004	Interested parties file comments on the outlines
May 7, 2004	Prehearing Conference

B. Integrated Approach

We address here the policy each utility should follow in integrating specific types of resources into their procurement plans. Guiding our discussion is the "loading order" set forth in our Energy Action Plan:

> "The Action Plan envisions a 'loading order' of energy resources that will guide decisions made by the agencies jointly and singly. First, the agencies want to optimize all strategies for increasing conservation and energy efficiency to minimize increases in electricity and natural gas demand. Second, recognizing that new generation is both necessary and desirable, the agencies would like to see these needs met first by renewable energy resources and distributed generation. Third, because the preferred resources require both sufficient investment and adequate time to 'get to scale,' the agencies also will support additional clean, fossil fuel, central-station generation. Simultaneously, the agencies intend to improve the bulk electricity transmission grid and distribution facility infrastructure to support growing demand centers and the interconnection of new generation."

1. Energy Efficiency

a) Procurement Energy Efficiency Funding Levels for 2004-05

In D.02-10-062, we established policy priorities for resource acquisition for utility long- and short-term procurement plans. In that decision we identified energy efficiency as a priority resource and ordered utilities to include all cost-effective energy efficiency in their portfolio proposals.

> "Utilities should include in their plans procurement of baseload energy reductions in the form of energy efficiency. Utilities should consider investment in all cost-effective energy efficiency, regardless of the limitations of funding through the public goods charge (PGC) mechanism."

In D.02-10-062, we also ordered utilities to submit long-term procurement plans, with estimates of energy efficiency savings projections for the first year, five years, and twenty years. PG&E, SCE, and SDG&E filed their long-term plans with the Commission on April 15, 2003. Each plan included estimates of energy efficiency resources they propose to acquire for these time periods.

The following table shows utility projected procurement costs for energy efficiency programs for the years 2004 through 2008.

Utility	2004	2005	2006	2007	2008	Total
PG&E	25	50	50	75	100	300
SCE[66]	60	60	60	60	60	300
SDG&E	25	25	25	25	25	125
Total	110	135	135	160	185	725

(1) Parties' Positions

No parties opposed utility energy efficiency procurement proposals. In its long-term plan testimony, ORA analyzed the cost-effectiveness of the energy efficiency component of the three utilities' long-term procurement plans over the first five years of the plan, finding each utility's proposal cost-effective. CEC's long-term plan testimony supported the inclusion of energy efficiency program elements in the long-term plan that go beyond the limits of PGC funding levels and recommended acceptance of utility energy efficiency proposals in its opening brief (p. 13). The "Joint Parties" recommendation (CEC, ORA, TURN, SCE, SDG&E, PG&E) also supports the additional proposed

[66] SCE's energy efficiency costs from their "referred plan."

energy efficiency programs. NRDC in its long-and short-term plan testimony supports Commission authorization of utility energy efficiency procurement proposals and urges the Commission to allow utilities the flexibility to capture additional cost-effective efficiency resources that have been identified in potential studies. Finally, TURN urges the Commission to authorize only funding levels for energy efficiency resource acquisition in this proceeding, with specific program selection to be accomplished in R.01-08-028.

(2) Discussion

Utilities approach the energy efficiency component of their long-term plans in different fashions. Both SDG&E and SCE worked directly with a contractor, Kema-Xenergy, to determine the potential for energy efficiency in their service territories, focusing on the several options for capturing the energy efficiency resource available in their territories. PG&E developed its long-term proposal based on forecasts of its net-residual short needs, matching these to programs that deliver energy savings and peak demand reduction measures with load profiles that reduce demand and save energy at times of forecasted need. We agree with NRDC and the City of San Diego that these approaches result in utility plans that capture "some," but not "all" of the energy efficiency potential identified in the latest studies of the available potential of energy efficiency in the utility service territory.[67] Nonetheless, each utility will need time to ramp-up enhanced existing and new

[67] M. Rufo and F. Coito, California's Secret Energy Surplus: The Potential for Energy Efficiency, Xenergy Inc., for the Energy Foundation and the Hewlett Foundation, 2002 www.energyfoundation.org/energyseries.cfm

energy efficiency programs. For this reason, we are inclined to accept utility long-term energy efficiency plan proposals as proposed.

The utilities' long-term plans identify procurement funded energy efficiency program activities for the five-year period 2004-2008. In this decision we authorize utility procurement energy efficiency budgets for the two-year period 2004 and 2005. We limit these initial procurement energy efficiency activities to this two-year period to ensure consistency across the Commission's entire portfolio of energy efficiency programs, with a specific goal of ensuring consistency with efficiency program activities authorized in this proceeding and those authorized in the Commission's Energy Efficiency Rulemaking 01-08-028. Consistent with the July 3 ACR, we choose this two-year program horizon as an interim-step to allow the Commission to review and address key issues identified in the ACR. Included among these are: long-term administration of Commission authorized energy efficiency programs; duration and cycle of these programs; energy efficiency goals; performance incentives and related issues. In this decision, we therefore maintain the status quo in term of program administration and other identified issues. By taking this approach, we balance the advantages of a multi-year (2-year) planning and budgeting cycles with the reality of the time needed by the Commission adequately deliberate on and resolve these questions. We refer parties to our discussion below of energy efficiency program administration and other key issues identified in the July 3 Assigned Commissioner's Ruling.

In summary, we should authorize procurement energy efficiency budget levels for the utilities for 2004 and 2005 as follows: PG&E - $25 million for 2004 and $50 million for 2005; SCE - $60 million for 2004 and $60 million for 2005; SDG&E - $25 million for 2004 and $25 million for 2005.

b) Program Selection Criteria

At the July 16, PHC, we asked parties to comment on program evaluation and selection criteria for energy efficiency activities funded here. At that time, we suggested parties comment on whether these programs should be evaluated using four specific criteria: long-term energy savings, cost-effectiveness, peak savings, and equity among rate classes, or utilizing other criteria for selection of procurement energy efficiency programs, such as those subsequently adopted in D.03-08-067 in R.01-08-028.

(1) Parties' Positions

Parties commenting on program selection criteria proposed several different approaches. SDG&E supports use of three selection criteria for evaluation of procurement energy efficiency programs: long-term annual energy savings, cost-effectiveness, electric peak demand savings. In its testimony, NRDC notes that all programs must be "cost-effective," and recommends three criteria, including long-term annual energy savings, electric-peak demand savings, and the addition of "equity between customer classes." The ORA testimony focuses on the need to have a consistent Commission energy efficiency portfolio and recommends use of the same criteria for procurement programs as those used to evaluate PGC funded energy efficiency programs, including proposers' demonstrated success in implementing EE programs.

(2) Discussion

Utility long-term plan forecasts project expected energy savings and demand reductions from both procurement funded and PGC funded efficiency programs. As such, these programs, whether PGC or procurement funded, are part of a comprehensive portfolio of energy efficiency resource acquisition programs to be authorized by the Commission. Consistent with our desire to proffer a uniform energy efficiency portfolio, we agree with ORA's comments that the Commission should evaluate and select utility 2004 and 2005 procurement energy efficiency proposals using both the selection process and primary and secondary selection criteria adopted in D.03-08-067. These primary criteria include: cost-effectiveness, long-term savings, peak demand reductions, equity considerations, ability to overcome market barriers, innovation, and coordination with other programs.

c) Procurement EE Program Submissions, Evaluation and Selection

For 2004-2005 utilities submitted to the Commission a total of eighteen[68] procurement energy efficiency program proposals totaling $244,586,000 million over the two-year period 2004-2005. Total projected energy savings and demand reduction from these programs are: 1,675,845 MWh and 336.5 MW. PG&E proposed a single program effort for a cost of $75 million over the two-year period. Projected two-year energy savings for PG&E are 466,883 MWh with projected demand reductions of 124.4 MW. SCE proposes 8 statewide procurement energy efficiency programs and 2 local programs at a two-year energy cost of $120 million with a two-year energy savings goal of 956,994 MWh and a demand reduction goal of 168.2 MW over the period. SDG&E proposes 2 statewide and 5 local programs for a total cost

[68] This count includes only the PG&E single program proposal in the PGC Rulemaking, which is for all of the procurement related energy efficiency program activity it proposes to implement in 2004 and 2005. It does not include the count of specific program activity proposed by PG&E that include activities in five statewide residential and nonresidential programs

of $49,586 million over the two-year period. Projected energy savings over this period are 251,968 MWh and 43.9 MW in demand reductions.

The following table shows the projected incremental energy efficiency program costs, energy savings, and demand reductions from utility procurement programs in 2004 and 2005 as compared to estimated program costs, savings and demand reductions from proposed 2004-2005 PGC funded programs.[69]

(1) Projected Utility Energy Efficiency Procurement and PGC Funded Cost, Energy Savings &Demand Reductions for Procurement and PGC Funded Programs

2004-2005

	PGC Budget ($million)	Procurement Budget ($ million)	PGC Energy Savings (MWh)	Procurement Energy Saving (MWh)	PGC Demand Reductions (MW)	Procurement Demand Reductions (MW)
PG&E	257,932,300	75.0	1,069,568	466,883	196.9	124.4
SCE	182,692,272	120.0	483,636	956,994	107.9	168.2
SDG&E	76,746,020	49.6	259,015	251,968	48.5	43.9
Total	**517,370,592**	**244.6**	**1,069,568**	**1,675,845**	**353.3**	**336.5**

Parties having a further interest in reviewing specific utility energy efficiency procurement proposals may view these on the Commission's website at http://www.cpuc.ca.gov.

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[69] Based on 2004-05 utility PGC and Procurement Submissions (9/23/03)

To ensure consistent evaluation of the Commission's total energy efficiency portfolio being developed in both this proceeding and in R.01-08-028, the ALJ directed the utilities to submit in R.01-08-028 the 2004-2005 procurement energy efficiency proposals for evaluation at the time of Commission review and evaluation of Public Goods Charge (PGC) funded energy efficiency program proposals. The Commission reviewed these programs by using the process and criteria described above.

In this decision we authorize only the overall funding levels for procurement energy efficiency programs. We refer program specific review and approval, including required programmatic or budgetary modifications to utility procurement program proposals, to the Energy Efficiency Rulemaking 01-08-028 where the Commission will select a balanced portfolio of utility and non-utility energy efficiency programs for 2004 and 2005. This Commission expects to authorize its portfolio of energy efficiency programs in R.01-08-028 before the end of 2003.

d) Cost-Recovery Mechanism for Procurement EE Activities

(1) Parties' Positions

Each utility proposes somewhat different mechanisms for cost-recovery of procurement related energy efficiency activities. PG&E proposes the establishment of an Incremental Procurement Energy Efficiency Balancing Account (IPEEBA) to record the costs of authorized incremental energy efficiency programs as these costs are incurred.[70] PG&E would request

[70] PG&E, Chapter 3, p. 10.

recovery of these costs in subsequent ERRA proceedings. SCE proposes to record expenses for procurement authorized energy efficiency programs directly in its ERRA, and request approval of these during its October annual ERRA filing.[71] SCE testifies that such an approach is reasonable as such expenses directly benefit bundled service customers who take generation and procurement related services from SCE. SDG&E, in its testimony, proposes that incremental procurement energy efficiency costs be subject to recovery through a non-bypasssable charge to all customers and requests the Commission establish a balancing account for costs and revenues recorded in the balancing account.[72]

In its long- and short-term procurement plan testimony, NRDC supports utility cost-recovery for the actual costs incurred for procurement energy efficiency programs provided that these programs meet Commission rules for cost-effectiveness and rigorous evaluation, measurement and verification. The Joint Parties' recommendation also endorses utility cost-recovery for incremental procurement energy efficiency programs identified in their long- and short-term procurement plans.

(2) Discussion

In deciding which of the proposed cost-recovery mechanisms best serve the needs of providing utilities cost-recovery in an expeditious and fair manner, we are cognizant of the fact the SCE's proposal, if adopted, holds the potential for increasing recorded costs in the ERRA account

[71] SCE, V.2, C. Dominiski, pp. 87-88.

[72] Smith/SDG&E, Tr. 30/3650, 3667-68.

to a degree that could trigger the adjustment mechanisms within that account. Both PG&E and SDG&E propose the establishment of balancing accounts to record energy efficiency costs and revenues outside the ERRA. SDG&E also proposes that these costs be funded through a non-bypassable surcharge on all customers.

After reviewing the various proposals, we find that SDG&E's proposed approach to implement a non-bypassable surcharge on all customers to pay the costs of energy efficiency program funding authorized in this proceeding provides a simple to understand, fair, and expeditious mechanism for providing utilities cost-recovery for procurement related energy efficiency activities. Moreover, this approach provides symmetry to the current Commission approach for funding Public Goods Charge programs as enunciated in Public Utilities Code § 381. In authorizing a non-bypassable surcharge to pay the costs of procurement efficiency program, the Commission remains mindful of the need for continued coordination of procurement efforts related to cost-recovery with related issues that may arise in R.01-08028. We therefore order the respondent utilities to establish a one-way Procurement Energy Efficiency and Balancing Account (PEEBA) to track the costs and revenues associated with authorized programs in this proceeding. Costs associated with these accounts should be submitted simultaneously with utility monthly ERRA filings to the Energy Division for review on a monthly basis. Further, within twenty days of this decision, we order the utilities to file advice letters establishing the methodology and surcharge rate for incremental procurement energy efficiency programs for PY 2004 and 2005.

e) Performance Incentives for Procurement Efficiency Activities

(1) Parties' Positions

In D.02-10-062, we expressed our preference to adopt a uniform incentive mechanism to provide an opportunity for utilities to balance risk and reward in the long-term procurement process. We directed SDG&E to sponsor, in coordination with the other utilities, an all-party workshop to develop an incentive mechanism proposal for utility electric procurement, including the energy efficiency component. SDG&E held several workshops on the issue resulting in the identification of key principles for an incentive mechanism. No consensus was reached by the utilities on specific incentive proposals and no proposals have been filed for our review.

At the hearing, many parties testified on this issue. The CEC supports supports the Commission adoption of an "incentive mechanism that motivates utilities to pursue CPUC objectives at both the planning and operational stages of procurement." (Jaske, 6/23/03, p. 27.) SDG&E cites in its workshop status report statement that although no consensus for uniform incentives was reached, it will continue on to develop its own SDG&E proposals with several of the parties to the workshop process. SCE states that it has developed a DSM incentive mechanism that it is prepared to file in the new phase of this proceeding.[73] PG&E proposes a specific incentive structure for energy efficiency programs only, urging the Commission to adopt it proposal. NRDC supports utility incentive mechanisms urging the Commission to adopt these in this procurement proceeding as apart of a universal procurement

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[73] SCE-LTP-Rebuttal, p.100.

incentive program (LTP/STP testimony - p. 20), with a particular focus on rigorous measurement and verification of program impacts for energy efficiency activities. (ORA (LTP testimony, p. 59) and TURN (Opening Brief, p. 13) oppose utility incentives in the procurement proceeding and specifically urge the Commission to address incentives for energy efficiency in the energy efficiency Rulemaking 01-02-8-028. TURN further notes (Opening brief, p. 12) that "neither the issue of administration of energy efficiency programs, nor the issue of the appropriateness of any incentive payments, was adequately analyzed and debated in this proceeding."

(2) Discussion

Incentive mechanisms for both supply- and demand-side options present the complex problems of a potential to design a "one-scheme-fits-all," mechanism that may not be appropriate to all parties. We laud SDG&E's efforts to identify principles and mechanism for comprehensive incentive mechanisms that cover both generation and non-generation resources. Nonetheless, the difficulty in finding consensus on this issue across a broad array of technologies and resource options leads us towards a more manageable approach that defers certain resource incentive mechanism development to specific resource proceedings where these can be presented and debated by parties in a focused manner. Further, we concur with TURN's comments that we do not have an adequate record on this issue with which to decide the issue.

By today's decision we refer the issue of energy efficiency incentives to R.01-08-028 for disposition in that rulemaking. We take this approach due to the complexity of the topic, the need to develop a more comprehensive record on this issue, and the need for a focused effort that encompasses the entire energy efficiency portfolio authorized by this Commission.

As discussed in this decision, we are also addressing in R.01-08-028 the issue of what administrative structure should be in place for energy efficiency development in the future. Therefore, the incentive mechanisms for energy efficiency proposed by parties in this proceeding, along with others that we will consider in R.01-08-028, must be evaluated in the broader context of what role the utilities will play in program administration in the near and long-term. Moreover, as the Assigned Commissioner in R.01-08-028 observes:

> "Once the Commission articulates program goals for reducing energy consumption, it will need rigorous measurement and evaluation activities in order to assess our progress towards meeting those goals. In addition, if the Commission decides to award incentives for superior performance in meeting or exceeding energy efficiency goals, the Commission will need assurance that the reported performance is accurate. In both instances, rigorous evaluation is necessary." (Assigned Commissioner's Ruling Proposing Direction and Scope for Further Rulemaking, R.01-08-028, July 3, 2003, p. 10.)

We intend to evaluate and update existing measurement protocols for this purpose in R.01-08-028. Today's referral of the incentives issue to our energy efficiency rulemaking recognizes that any development of energy efficiency incentive mechanisms is also linked to the measurement issues being addressed in that forum.

Accordingly, in recognition of the interrelationship among the various issues currently being considered in R.01-08-028, and the issue of energy efficiency incentives, we request that a further prehearing conference be held as soon as practicable in R.01-08-028, the purpose of which would be to address the scope and schedule of the issues identified in the July 3 ACR in light of today's decision to also refer the consideration of energy efficiency incentives to that proceeding.

f) Procedural Issues Related to Efficiency Rulemaking 01-08-028

Energy efficiency activities initiated in this procurement proceeding need to be closely coordinated with efforts underway in the commission's energy efficiency rulemaking, R.01-08-028. This is the case not only for this decision round, but also for future Commission deliberation on efficiency policy in both R.01-08-024 and R.01-10-028. Below we address a series of current "crossover" procedural issues and provide guidance concerning the future disposition of these issues.

(1) Program Duration and Cycles

As we stated above, we seek consistency in the portfolio of energy efficiency programs authorized by the Commission. This consistency applies to the question of the duration and programs and future cycles of energy efficiency program efforts. In R.01-08-028, the Commission adopted a two-year interim cycle for energy efficiency programs funded through the PGC mechanism. In our proceeding, we have followed this model and order utilities to present procurement related incremental energy efficiency proposals to the Commission for the same two-year interim period. Many parties addressed the subject of multi-year planning horizons, with several favoring these (NRDC, SDG&E, SCE, PG&E, and several others opposed to planning horizons of more than a year or two (ORA and TURN). To ensure ongoing alignment of energy efficiency program activities in the procurement and energy efficiency Rulemakings, we refer future issues related to program duration and program cycles to R.01-08-028 for disposition in that Rulemaking.

(2) Program Specific Evaluation

The Commission will continue the model established in this Rulemaking to require that all proposed program specific procurement related energy efficiency activities be evaluated and modified as necessary in R.01-08-028 as part of the overall Commission portfolio of program activities. Hence, in this Rulemaking we will continue the practice of authorizing specific levels of funding for energy efficiency procurement activities, but refer review of specific program offerings in the future to the Energy Efficiency Rulemaking.

(3) Energy Efficiency Goals for the Commission's Portfolio of Programs

In our hearings we, took into our record testimony related to utility procurement program proposals related to the 1 percent per capita per year energy reduction goals identified in the July 3, 2003 Assigned Commissioner Ruling (R.01-08-028). Utilities provided information related to their procurement energy efficiency proposals and the per capita reduction goal. Since that time, CEC has issued a staff workpaper[74] on this issue, and the CPUC has scheduled workshops on the issue. Continued discussion and resolution of what energy efficiency goals, if any, should be established is a continuing subject of review in R.01-08-028. We therefore refer future issues

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[74] *Discussion of Proposed Energy Savings Goals For Energy Efficiency Programs in California*, Energy Efficiency and Demand Analysis Division, California Energy Commission, September 2003

related to the per capita or other types of overarching energy efficiency goals to the EE Rulemaking for disposition.

(4) Future Administration of Energy Efficiency Programs

SDG&E, SCE, and PG&E all urge the Commission in their long-term plan testimony to establish utilities as the lead organization for implementing energy efficiency programs funded through these Procurement proceedings. SCE, in particular, argue early-on in the proceeding that it could not guarantee the energy savings projections from its procurement "preferred plan" unless it was specifically charged with administering the plan, and therefore suggested that it might need to implement its "interim plan " with lower energy efficiency savings projections. SCE changes this position in its opening brief, requesting the Commission to adopt the energy efficiency and demand response budgets associated with their "preferred plan." Each of the utilities urge resolution of this issue as soon as possible in R.01-08-028.

Many parties comment on the issue of administration of energy efficiency programs. In its testimony, TURN took no explicit position on whether utilities should or should not administer energy efficiency programs but strongly urged the Commission to address this issue in the energy efficiency proceeding. ORA concurs with TURN, urging the Commission to "promptly" address this issue. NRDC urges the Commission as well to resolve the "unsettled issues" regarding the administration of energy efficiency programs. Utility long-term plans also support prompt resolution of this issue in R.01-08-028.

Both the initial Order Instituting Rulemaking and the July 3 ACR for R.01-08-028 identify administration of energy efficiency programs as one of the key issues to be addressed in that Rulemaking, with a goal of resolving this issue in 2004. As the Commission will authorize a uniform portfolio of energy efficiency, we believe it necessary that the Commission have in place a unified administrative structure to oversee all energy efficiency programs regardless of the source of funding in the years ahead. For this reason, we are referring the issue of administration of energy efficiency programs authorized in this proceeding to R.01-08-028.

g) Other Issues

(1) Utility and Non-Utility Filings for Procurement Related Energy Efficiency Programs

During the course of this proceeding we have given attention exclusively to utility energy efficiency proposals in response to Commission direction in D.02-10-062 to integrate energy efficiency in utility plans for procurement of baseload energy reductions. We noted in that decision that utilities should consider investment in all cost-effective energy efficiency. In response utilities have filed procurement proposals as described above. We are confident that utilities will make every effort to meet projected energy savings goals. Nonetheless, in this proceeding we wish to broaden the base of those parties able to assist utilities in meeting their demand reduction and energy savings goals through the offering of innovative energy efficiency program proposals. Hence, in future procurement decisions, we intend to open the process for application for procurement energy efficiency programs to non-utility parties as well as utilities.

(2) Valuing Potential Penalty Cost for CO_2 Emissions

In its long-term plan testimony, NRDC requests that the Commission require PG&E, SDG&E and SCE explicitly analyze financial risks associated with any future regulation of carbon dioxide emissions and incorporate protections for their customers by shifting any risk to customers to the sponsor of the resource creating the risk. NRDC suggests that such risk may occur should utilities build in the future or own coal-fired plants or be involved in other ways with plants presenting a potential financial risk to customers from the $C0_2$ emissions. In reviewing this question, we note that the Commission is presently working with a contractor in R.01-08-028 for the explicit purpose of reviewing and updating its avoided-cost methodology for analyzing the costs and benefits of various resource options. For the energy efficiency component of that methodology the Commission has in the past taken into account the environmental benefits associated with energy efficiency by incorporating environmental "adders" to the calculation of the Societal Total Resource Cost Test (TRC). The Commission and its contractor are working with an advisory group to that process that includes representatives from CEC, NRDC, utility and other parties. In this decision, we refer the question of potential financial risks associated with carbon dioxide emissions to R.01-08-028, to be considered in the context of the avoided cost methodology -- as part of the overall question of valuing the environmental benefits and risks associated with utility current or future investments in generation plants that pose future financial regulatory risk of this type to customers.

(3) Valuing Non-Utility Energy Savings in Procurement Forecasts

In the July 3, 2003 ACR (R.01-08-028), the Assigned Commissioner states,

> "I (also) see no distinction in the reliability of the resource between a utility-operated program and one delivered by a non-utility entity. Therefore, I propose to treat all energy efficiency programs as an integrated portfolio to be authorized in this proceeding."

TURN echoes this comment in its opening procurement brief when it suggests that "there is no reason why expected savings from energy efficiency programs conducted by other entities cannot be used as inputs to determine other resource needs, such as energy procurement on the spot market, which may be met by the utilities." We concur with this view. As more and more non-utility entities enter the energy efficiency program delivery field, more and more energy savings will be attributed to non-utility providers. Therefore, in this proceeding, in the next utility filing of their long- and short-term procurement plans, we order utilities in their demand forecasts for those filings to include expected energy savings from non-utility programs that operate in their service territories.

2. Demand Response

Demand response, like energy efficiency, is a demand-side resource for the utilities. While energy efficiency resources can often meet baseload procurement needs, demand response can fill on-peak requirements. In D.02-10-062, we directed the utilities to consider all cost-effective investment in demand response that meets their procurement needs. We also stated that the Commission, CEC, and CPA are cooperating in a joint rulemaking, R.02-06-001, to design strategies, tariffs, and programs for additional demand response resources and, in the course of that proceeding, expect to identify quantitative targets for utilities to procure in demand response resources. Further, we directed that the targets adopted in R.02-06-001 should be integrated into the utilities long-term plans.

Our EAP places a top priority on energy efficiency and demand response programs in its “loading order” of energy resources. Specifically, the plan states:

- Implement a voluntary dynamic pricing system to reduce peak demand by as much as 1,500 to 2,000 megawatts by 2007.
- Improve new and remodeled building efficiency by 5 percent.
- Improve air conditioner efficiency by 10 percent above federally mandated standards.
- Make every new state building a model of energy efficiency.
- Create customer incentives for aggressive energy demand reduction.
- Provide utilities with demand response and energy efficiency investment rewards comparable to the return on investment in new power and transmission projects.
- Increase local government conservation and energy efficiency programs.
- Incorporate, as appropriate per Public Resources Code section 25402, distributed generation or renewable technologies into energy efficiency standards for new building construction.
- Encourage companies that invest in energy conservation and resource efficiency to register with the state's Climate Change Registry.

In their filings, the utilities include various interruptible programs, the Commission’s traditional, reliability-based demand response programs, and newer, price-triggered demand response programs such as the Critical Peak

Pricing (CPP) tariff currently being implemented for larger customers, and tested for smaller customers in the Statewide Pricing Pilot (SPP).

In D.03-06-032, the Commission adopted demand response goals for each utility and directed that the IOUs include the MW targets for calendar years 2003 through 2007 in their procurement plans, specifically stating the filings in this proceeding should include: numeric targets coinciding with the findings in this decision; documentation of the amount of demand response (price-triggered) to be achieved by July 1 of each calendar year (with the exception of 2003, where the goals shall be met by the end of the calendar year); which programs and/or tariffs the IOU will rely upon to achieve the targets; and a contingency plan for covering capacity needs should the utility fall short of meeting the demand response goals.

The MW targets for each utility are set forth in Table 1 of D.03-06-032:

Table 1. Demand response goals

Year	**PG&E**	**SCE**	**SDG&E**
2003	150 MW	150 MW	30 MW
2004	400 MW	400 MW	80 MW
2005	3% of the annual system peak demand		
2006	4% of the annual system peak demand		
2007	5% of the annual system peak demand		

Funding for price-responsive demand response programs is also addressed in D.03-06-032. In Ordering paragraph 22, we state:

> "The total cost expenditures authorized as a result of this decision are capped at $33.0 million over the two calendar years, exclusive of revenue shortfalls and costs

> related to "other incentives" which are part of the DWR revenue requirement. Each IOU shall use the cost recovery mechanisms previously adopted in D.03-03-036 as applicable to all Phase 1 programs."

PG&E's long-term plan includes its existing demand reduction programs and three new price-responsive programs. No additional funding is requested here. PG&E provides a conservative forecast, testifying on the difficulty of estimating demand reduction levels from new DR programs given various uncertainties. ORA testifies it reviewed the request and supports PG&E's filing on this issue. We adopt PG&E's demand reduction proposal.

SDG&E's plan reflects an aggressive demand response forecast and encourages the Commission to consider an incentive mechanism for all demand-side programs. SDG&E does not request any funding authorization here. ORA expresses concern with counting untested demand reduction programs for purposes of resource adequacy. We address this resource counting issue in our earlier Resource Adequacy and Reserve Requirements section.

In its "preferred plan," SCE requests $40 million in pre-approved funding for seven years and approval of a "new and improved" Airconditioning (A/C) Cycling Program (ACCP). Further, SCE states program review should not be subject to after-the-fact reasonableness review. ORA testifies the expected peak load reduction from this program seems unrealistic and does not support the funding request. CEC recommends this program be referred to R.02-06-001 for in-depth examination.

We agree with CEC and ORA's recommendation that new ACCP programs need to be reviewed in R.02-06-001 or its successor demand response rulemaking. This allows for program specifics to be carefully examined and for the necessary evaluation and measurement standards to be adopted. The Commission can then directly authorize funding that proceeding. SCE's proposed program is an emergency-demand response program, and the future of these programs, in relation to price-response programs, is a policy issue for R.02-06-001 or its successor. We do not approve SCE's request for funding.

3. Renewables

In general, we find that the utilities did not provide a robust analysis of future renewables supply growth in the renewables sections of their respective 2004 and long-term plans. This can be largely attributed to the fact that at the time the utilities prepared their filings, RPS program development was in progress and the Commission had yet to issue and adopt D.03-06-071. We note that the IOUs will file separate renewable procurement plans pursuant to Pub. Util. Code § 399.14(a)(3), thus the 2004 and long-term procurement plans currently under consideration do not constitute a filing of the required renewables plans. Our approval of the 2004 procurement plans today does not "trigger" an RPS solicitation as detailed in D.03-06-071. That solicitation requires further development of RPS criteria, such as the Market Price Referent (MPR), additional least-cost and best-fit evaluation criteria, and standard contract terms and conditions. Interim solicitations will follow guidelines already established by the Commission, and are also addressed below.

a) RPS Requirements

Pub. Util. Code § 399.14(a)(2) requires the Commission to adopt, by rule, four key RPS elements:

1. a process for determining market prices;
2. a process that provides criteria for the rank ordering and selection of least-cost and best-fit

renewable resources to comply with the RPS on a total cost basis;

3. flexible rules for compliance;
4. standard terms and conditions to be used in contracting for eligible renewable resources, including performance requirements for renewable generators.

D.03-06-071 adopts rules for these RPS elements, and addresses other issues such as creditworthiness and renewable energy credits. The Assigned Commissioner's Ruling Specifying Criteria for Interim Renewable Energy Solicitations (ACR) dated August 13, 2003, provides criteria for any interim renewables solicitations conducted by a utility prior to a full RPS solicitation implementing the utility's renewable procurement plan. While we strongly discourage pre-RPS solicitations, any renewables solicitations that do occur prior to a full RPS solicitation will follow the criteria set forth in the ACR.

We now discuss elements of the RPS that pertain to the 2004 and long-term plans.

(1) Renewable Procurement Plan

One of the first actions of the forthcoming RPS OIR will direct the utilities to file renewable procurement plans pursuant to Pub. Util. Code § 399.14(a)(3). This section states:

> "Consistent with the goal of procuring the least-cost and best-fit eligible renewable energy resources, the renewable energy procurement plan submitted by an electrical corporation shall include, but is not limited to, all of the following:
>
> "(A) An assessment of annual or multiyear portfolio supplies and demand to determine the optimal mix of renewable generation resources with deliverability

> characteristics that may include peaking, dispatchable, baseload, firm, and as-available capacity.
>
> "(B) Provisions for employing available compliance flexibility mechanisms established by the commission.
>
> "(C) A bid solicitation setting forth the need for renewable generation of each deliverability characteristic, required online dates, and locational preferences, if any."

(2) Full RPS Solicitation

Once the renewable procurement plans are approved by the Commission, a solicitation conforming to all the adopted parameters and rules of the RPS will commence pursuant to Section 399.14(a)(3)(C). As noted above, those elements necessary for a full solicitation are still being developed and refined. We anticipate that the first solicitation will take place in Q2 2004, and discourage renewable energy solicitations prior to that time. The RPS phase of this proceeding and the new forthcoming RPS OIR are the appropriate venues for new or revised rules pertaining to the RPS solicitations.

(3) Market Price Referent and Interim Benchmarks

The ACR does not adopt an interim benchmark for determining the cost-effectiveness of renewables bids. Instead it allows the utilities to develop internal benchmarks for evaluation purposes, provided those benchmarks are provided to the PRG and submitted to the Commission as part of its Advice Letter filing requesting approval of contracts.

The purpose of the MPR is to establish a market price up to which utilities may purchase renewable energy. Costs above the MPR for selected contracts will be paid through Supplemental Energy Payments following CEC guidelines. Following Commission approval of the MPR methodology, the referent will be developed by Commission staff and made available to the utilities during the RPS solicitations after bidding has closed.

(4) Contract Lengths

Pub. Util. Code § 399.14(a)(4) requires utilities to "offer contracts of no less than 10 years in duration, unless the commission approves of a contract of shorter duration." D.03-06-071 found that shorter contract terms were not desirable:

> "We do not see any good reason to permit the utilities to offer contracts of less than 10 years in duration…" (Decision at p. 57.)

The Decision specifies that "utilities should seek bids for 10, 15, and 20-year products."

(5) Eligibility for Supplemental Energy Payments

No contracts entered into during the interim period prior to full RPS solicitations may be contingent upon receiving PGC funds for Supplemental Energy Payments (SEPs) pursuant to Pub. Util. Code § 399.15(a)(2). The ACR states:

> "Any renewable procurement in this interim period (regardless of whether it is conducted through an RFO or bilateral negotiation) must not anticipate the use of any Supplemental Energy Payments to be awarded by the CEC pursuant to Public Utilities Code Sec. 383.5(d)."

Bidders may, however, retain previous CEC awards, consistent with direction given in the ACR:

> "Projects that have previously won an award from an auction conducted by the CEC (public goods funds which were collected pursuant to SB 90)

> may bid or negotiate and still remain eligible to receive their award once the project begins producing electricity pursuant to a Power Purchase Agreement."

(6) Creditworthiness

We determined in D.03-06-071 that utilities are not required to procure renewable energy under the RPS until they are creditworthy. However, utilities that are not creditworthy still have an annual procurement target (APT), and may be directed to prepare a renewable procurement plan prior to RPS solicitation, as this is not considered "procurement" under Pub. Util. Code § 399.14(g). Additionally, SB 67 provides a condition by which non-creditworthy utilities may be directed to undertake renewables procurement, as discussed below.

(7) Standard Terms and Conditions

D.03-06-071 provided parties with guidance on further development of standard terms and conditions to be used in contracting for renewable energy. Specifically, Energy Division held two workshops to bring parties together and explore areas of agreement on which terms should be made standard and possible language for those terms. ALJ Allen issued a ruling on October 22 requesting briefs on which terms and conditions should be made standard. Briefs were submitted on November 12, with reply briefs due December 3. The Commission will issue an interim decision identifying which terms and conditions shall be adopted as standard. Subsequently, the parties will submit briefs with specific recommended language for each of those terms and conditions. Finally, the Commission will issue a decision adopting specific language for each standard term and condition. Any standard contract terms and conditions, upon adoption by the Commission, will be used in all subsequent solicitations for renewable products.

b) Short-Term Plan Issues

PG&E proposes that the Commission adopt an interim all-in benchmark of 5.37 cents per kWh, and subsequently review and update the benchmark. The Commission will develop the MPR to accomplish this goal. Additionally, the ACR provides guidance on use of interim benchmarks. Our attention is now focused on refining the methodology for the MPR, and as such we do not adopt an interim benchmarking process. We therefore decline to adopt PG&E's request for an interim all-in benchmark of 5.37 cents per kWh.

PG&E also proposes to conduct a renewables solicitation within 60 days of approval of its 2004 procurement plan. PG&E proposes to sign only one-year contracts, due to its credit status. In its testimony, ORA states that such short-term contracts will "increase the chances of a utility having greater difficulty in meeting its RPS in the future…"[75] Although the term lengths addressed in D.03-06-071 should apply to RPS solicitations, one goal of the RPS program is to foster a long-term market for renewable energy by providing contracts of 10 or more years. We do not find that PG&E's proposed short-term solicitation adheres to this principle. We address PG&E's credit status below, noting here that the Commission may determine that PG&E can undertake renewables procurement prior to creditworthiness subject to specific conditions. We deny PG&E's request for one-year renewables contracts, and focus attention instead on progress towards a full RPS solicitation in early 2004.

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[75] ORA testimony, p. 67

The IOUs recommend meeting their QF obligations under PURPA in various ways, including competitive solicitations (SCE proposal) and one-year SO1 contract extensions (PG&E proposal). SDG&E refers to holding an "auction" for QF contracts. While renewable bidders are welcome to participate in all-source solicitations outside the RPS bidding parameters, a unique MPR will not be developed for such solicitations. Therefore, bidders must not anticipate the use of SEPs, nor shall bids contain SEP contingencies. This is consistent with the August 13 ACR. Bidders may, however, retain previous CEC awards, as stated above. The utilities may receive and select cost-effective renewables bids under an all-source solicitation, and the bid evaluation process must not treat those bids unfairly when compared with non-renewable product offerings. Additionally, any contracts resulting from these solicitations will count toward an IOU's RPS targets, provided the facilities are deemed eligible renewable resources.

We reaffirm that all renewables contracts must be filed for approval by the Commission by Advice Letter filing as required by D.03-06-071 and the ACR. Approval of the 2004 plans does not constitute a waiver of this requirement.

c) Long-Term Plan Issues

While PG&E proposes to enter into renewables contracts prior to obtaining an investment-grade credit rating, it states in its 2004 and long-term plans that it is "not required to participate"[76] in the RPS program, is

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[76] PG&E 2004 plan, p. 4-4

"ineligible to participate,"[77] and goes so far as to say it "will not participate in the RPS program until it is creditworthy."[78],[79] D.03-06-071 found that while "utilities that are not creditworthy are not required to procure under the RPS program," such a utility will still have an APT for a given year. SB 67, signed into law after the IOUs filed their plans, provides an optional means of renewables procurement prior to creditworthiness[80]. Thus, PG&E will accrue an APT prior to creditworthiness, and can utilize the adopted flexible compliance mechanisms to meet its APT once it either becomes creditworthy or is able to procure renewables subject to Pub. Util. Code § 399.14(a)(1)(A)(ii). As noted above, a non-creditworthy utility can also be directed by the Commission to prepare a renewable procurement plan under the provisions of Pub. Util. Code § 399.14(g).

PG&E also states at page 1-21 of its long-term plan that its "participation in the RPS is conditioned on it having a demonstrable need for resources and having first attained an investment grade rating…" D.03-06-071 addresses this issue:

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[77] PG&E long-term plan, p. 6-19

[78] PG&E 2004 plan, p. 4-5

[79] See also PG&E 2004 plan, p. 1-17, PG&E long-term plan, 1-21

[80] Pub. Util. Code § 399.14(a)(1)(A)(ii), as added by SB 67, allows an electrical corporation to undertake renewables procurement to fulfill its RPS obligations once the Commission has determined "[t]he electrical corporation is able to procure eligible renewable energy resources on reasonable terms, those resources can be financed if necessary, and the procurement will not impair the restoration of an electrical corporation's creditworthiness. This provision shall not apply before April 1, 2004, for any electrical corporation that on June 30, 2003, is in federal court under Chapter 11 of the federal bankruptcy law."

> "PG&E's position that 'unmet long-term resource needs' means a specific utility's resource needs, as defined and identified by that utility, is inconsistent with the statewide focus and purpose of the legislation. 'Unmet long-term resource needs' must be considered on a statewide basis, not a utility-by-utility basis, and the Legislature has already essentially found that there are statewide unmet long-term resource needs." (Decision at p. 41.)

Thus, the conditions PG&E attaches to its RPS participation are invalid.

SCE does not explain why its resource model assumes $100 per MWh for "new generic renewables" (Vol. 2, p. 52). This price exceeds any Commission-established benchmark to date. SCE must provide an explanation of the derivation of this value and its use. Additionally, we have stated that the plans must be modified to provide additional detail of expected renewable product types.

We are concerned that SCE modeled renewables as a "generic" block of energy, irrespective of resource type, in its portfolio model. This simplified approach also appears to be inconsistent with Pub. Util. Code § 454.5(b)(2), which requires procurement plans to include "[a] definition of each electricity product, electricity-related product, and procurement related financial product, including support and justification for the product type and amount to be procured under the plan." The IOUs should project some amount or percentage allocation of baseload, peaking and intermittent resources, as each provides a different fit to a utility's resource needs. SDG&E estimates 20 percent wind and 80 percent baseload resources. PG&E estimates its five-year renewables needs will be primarily for peaking and reserve requirements (amounts not specified), with specific baseload needs in 2007 and 2008.

Given their existing base of renewables, and contracts signed under the transitional procurement period, the IOUs should be able to estimate renewable resource profiles with a greater degree of specificity. This amount of energy is substantial over the long-term planning horizon, and will undoubtedly affect the utilities' need for other procurement products in the future. The renewable procurement plans will require such an assessment,[81] and it is feasible and prudent to perform this analysis now, on a preliminary basis, in the long-term plans. The utilities should also provide a forecast of the percentage of retail sales met each year by renewables, indicating the projected year for achieving the 20 percent RPS target, and maintaining or increasing that percentage in future years. The long-term plans should be modified accordingly.

The IOUs should also update their 2004 and long-term plans to include interim procurement activity from 2003. The Commission approved PG&E contracts for biomass energy in Res. E-3853. While SCE and SDG&E have renewables solicitations in progress, they should summarize the proposed bids (with publicly filed information) and describe how those products fit into their procurement portfolios. SCE should provide an update on its current RFOs for general renewables and wood waste renewables products. SDG&E should provide an update on its grid reliability solicitation, filed with the Commission on October 7.

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[81] Pub. Util. Code § 399.14(a)(3)(A) requires the renewable procurement plan to include: "[a]n assessment of annual or multiyear portfolio supplies and demand to determine the optimal mix of renewable generation resources with deliverability characteristics that may include peaking, dispatchable, baseload, firm, and as-available capacity.

The Energy Action Plan calls for the acceleration of the 20 percent RPS goal to year 2010. In its testimony, NRDC urges the IOUs to provide details on how they intend to respond to the Energy Action Plans' accelerated RPS target. The accelerated target will necessitate changes in the IOUs' overall portfolios. Each IOU should modify its plan to include an accelerated RPS target renewables procurement scenario that evaluates any resulting changes to its overall energy procurement portfolio.

Meeting the goals of the RPS on the accelerated schedule of the Energy Action Plan will require a thoroughgoing review of the total resource portfolios of the IOUs, and careful consideration of which nonrenewable resources, in the long run, can or should be displaced or shut down to accommodate renewable development at this scale. This task will be the principal point of interconnection between this docket and the new RPS OIR to be opened in early 2004. While the near-term need for generation in California must remain central to the resource planning and procurement process, the decisions we make today must not work at cross-purposes with the long-term goals we have embraced for renewable energy development. Without an assertive planning role in this regard it is unclear how the renewable energy goals of the EAP can be met.

We acknowledge that development of renewables to achieve the goals of the RPS will necessitate transmission upgrades and possible construction. The IOUs have separately filed conceptual transmission plans to this effect, and the Commission is preparing a report to the Legislature on these issues. These issues will most likely affect long-term planning and will be addressed in I.00-11-001, the RPS phase of this proceeding, and any relevant successor rulemakings.

4. Distributed Generation

In D.02-10-062, we ordered the utilities to explicitly include provision for distributed generation and self-generation resources in their long-term procurement plans. We stated that:

> "Distributed generation and self-generation resources encompass a broad and diverse set of technologies to fit a variety of procurement needs. In addition to providing capacity and energy benefits, they can offer transmission and grid-support benefits that should be included in the utilities' procurement plans." (D.02-10-062, p. 27.)

The Energy Action plan adopted by the Commission, the CPA, and the CEC, provides additional support for distributed generation, placing it second in the loading order and enumerating a number of objectives for the state to achieve:

1. Promote clean, small generation resources located at load centers;
2. Determine whether and how to hold distributed generation customers responsible for costs associated with Department of Water Resources power purchases;
3. Determine system benefits of distributed generation and related costs;
4. Develop standards so that renewable distributed generation may participate in the Renewable Portfolio Standard program;
5. Standardize definitions of eligible distributed generation technologies across agencies to better leverage programs and activities that encourage distributed generation;
6. Collaborate with the Air Resources Board, Cal-EPA and representatives of local air quality districts to

achieve better integration of energy and air quality policies and regulations affecting distributed generation; and

7. Work together to further develop distributed generation policies, target research and development, track the market adoption of distributed generation technologies, identify cumulative energy system impacts and examine issues associated with new technologies and their use.

Based on its review of the utilities' long-term procurement plans, ORA testifies that:

> "It is difficult to compare, or, in some cases, even extrapolate, the self-generation projections by the different utilities…. Another problem arises when utilities lump self-generation with energy efficiency measures, since from the utilities' point of view, both are seen as load reductions. But from ORA's point of view, it is important to be able to separate these out."

In its direct testimony, the Joint Parties Interested in Distributed Generation/Distributed Energy Resources (Joint Parties) find that the utilities did not provide a sufficient level of detail in their respective procurement plans showing how they will incorporate distributed generation into their resource portfolios. The Joint Parties therefore conclude that the utilities did not comply with Commission directives on this issue. Additionally, the Joint Parties recommend that the Commission direct the utilities to undertake a study effort to analyze the cost-effectiveness of distributed energy resources and to assess the size of the potential distributed energy resources market in California. Lastly, the Joint Parties propose a set-aside for distributed energy resources while study work is being conducted.

> "The Joint Parties recommend that the Commission require that the utilities increase procurement from on-site DER projects 20 MW or less by a minimum of 1.5% per year (using 2003 as the baseline year), beginning in 2004, up to a minimum total of 7.5% in 2008. Only new contracts with the [IOUs] for output from the units 20 MW or under would count toward the Joint Parties' proposed DER procurement requirement." (Joint Parties Closing Brief, pp. 11-12.)

The Joint Parties also state:

> ". . . this percentage could be implemented as a placeholder for the first year, while the utilities perform studies of the potential DER market, similar to those that have been performed regarding the energy efficiency market, and develop for Commission approval specific goals and costs for the DER component of long-term procurement plan.
>
> "In any year the applicable requirement is not met, a utility should have to demonstrate why this is the case, and how it place to make up for the any DER procurement shortfall in the following years. In addition, the requirement could be subject to revision up or down on an annual basis, depending on resource adequacy and market conditions. The need for a formal DER procurement directive beyond 2008 would be evaluated during a procurement proceeding or a procurement update proceeding scheduled for completion prior to 2008." (Joint Parties' Direct Testimony, pp. 16-17.)

In lieu of setting a mandated set-aside, the Joint Parties propose an alternative approach whereby the Commission would establish a "procurement goal" for distributed energy resources. The goal would be quantified as set forth above and the utilities would be required to explain if they failed to meet the objective. If the Commission determines that the utilities are not making "reasonable efforts" to meet the goal, the Commission would then elevate the goal to a directive.

We find that beyond including forecasted levels of customer-side distributed generation, the utilities' procurement plans do not contain explicit proposals or strategies for promoting distributed generation within their respective service territories as a supply-side procurement resource. In the long-term procurement plans, the utilities' treat distributed generation as a demand-side program, netting out the effects of distributed generation as part of the load forecasting process. While not foreclosing the potential of using distribution generation as a supply-side option in the future, the utilities indicate that such efforts should await the results of cost/benefit studies.

We agree with ORA's findings that it is difficult to compare and extrapolate the distributed generation forecasts from the utilities long-term procurement plans. The utilities' next round of long-term procurement plans should include a more robust discussion of distributed generation to include: (1) a line item entry clearly identifying distributed generation separate and apart from other entries such as energy efficiency and departing load; (2) the energy (GWh) and demand (MW) reduction attributed to distributed generation; and (3) a description of the technologies the utility includes in its definition of distributed generation as well as a statement noting whether its forecast includes utility-side distributed generation, such as QFs. We recognize that distributed generation encompasses many types of applications and technologies and different parties embrace different definitions of this resource category. It's important that each utility clearly define the resources it includes in its forecast of distributed generation.

As described in D.03-02-068, the Commission plans to institute a new rulemaking on distributed generation that will, among other things, address the various cost/benefit and market issues mandated by AB 970, SBX1-28, and the Energy Action Plan. We will refer the Joint Parties' proposal to the future rulemaking. At this time, we will not predetermine the outcome of these issues in advance of the rulemaking, and therefore do not adopt the Joint Parties recommended approach for a set-aside.

5. Transmission

In D.02-10-062, we found that to the extent transmission can meet or offset procurement needs, utilities should explicitly include transmission in their resource plans. We also made clear in the EAP that it is critical for the state to ensure there is adequate transmission to support California's needs, stating:

> "Reliable and reasonably priced electricity and natural gas, as well as increasing electricity from renewable resources, are dependent on a well-maintained and sufficient transmission and distribution system. The state will reinvigorate its planning, permitting, and funding processes to assure that necessary improvements and expansions to the distribution system and the bulk electricity grid are made on a timely basis."

Each utility in its long-term plan included the transmission upgrades for reliability that had been reviewed and approved through the ISO's annual grid study. They also included a general assessment of whether additional transmission is needed to support power imports for future needs, based on production cost computer modeling. In its plan, SCE cites the need for additional transmission capability to the Southwest for economic reasons, to access surplus capacity and energy, and references its intention to file for a

Certificate of Public Convenience and Necessity (CPCN) for Devers PaloVerde 2 line.

ORA and the ISO testify that the utilities' plans are not sufficiently detailed to fully assess the deliverability of power that each utility, particularly PG&E, relies on to meet future needs. In particular, PG&E relies on "generic" resources within the western grid. In hearings, the ISO testified that it could work with the utilities to identify conceptual scenarios for these generic units, i.e. general geographic regions, add scenarios for distribution within the state, and then combine the three utilities to test whether or not these scenarios are compatible with the transmission system and transmission system plans.[82] In its brief, the ISO states this would be the minimum deliverability requirement needed. SCE supports a deliverability showing for resources imported into the ISO control area, but does not support going so far as to assess local deliverability.

We establish here a minimum requirement that the IOUs work with the ISO on defining conceptual scenarios for assessing resources imported into the ISO control area and deliverable to the individual IOU's load, so that after the June 2004 plans are filed, the ISO can timely run combined scenarios, serve testimony, and fully participate in our hearing process. We look to further refine a standard of deliverability through the comments we request in our earlier resource adequacy section.[83]

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[82] Transcript 3864-5, Volume 31.

[83] In assessing deliverability for specific PPAs the utilities propose entering, we should also look to see that the supplier pays for any network upgrades needed to ensure power deliverability under the contract.

In its testimony, the CEC states that the Commission's focus in D.02-10-062 was generation-focused and we must expand the record to include transmission and demand-side or customer-oriented alternatives. Further, the CEC states its IEPR process will establish the integrated planning process that we should use in this proceeding to determine the combination of demand-side or customer-oriented and infrastructure investments (including generation and transmission) that best meet California's short- and long-term needs.[84] While we welcome the CEC participation and expertise in our proceeding, we do not support requiring the utilities to adopt the forecasts and resource plans of the IEPR. We strongly believe that the utilities themselves must be responsible and accountable for providing their customers reliable service and just at reasonable rates; this is the utilities' statutory obligation.

In guiding the utilities' long term planning process, we focus on developing an integrated resource approach, one that recognizes the loading order of preferred resources in the EAP, and that optimizes generation and transmission resources.

SDG&E presents this approach in its plan. It places emphasis on the first 5 to 10 years of the plan, since these are the years for which policy and implementation decisions need to be made in the near term, and allows for a level of short-term and medium term resources that provide sufficient flexibility. SDG&E explained its planning approach as follows:

> First, determined the level of cost-effective energy efficiency available to SDG&E;

[84] Exhibit 49, pages 5-6.

> Second, demand response programs were added to meet a challenge of reducing peak demand 5% by 2007;
>
> Third, renewable resources were added to ensure 20% of the energy SDG&E provides to its customers will come from renewable sources by 2017 or sooner; and
>
> Fourth, developed and tested four distinctly different candidate resource portfolios that could fill any remaining supply gap.

While we conceptually agree with this model, more refinement is necessary in specifying the cost/benefit analysis that should be performed in each step and the level of specific project analysis to include. ORA finds that SDG&E's plan failed to incorporate all anticipated new generation, and its demand response programs were untested, thereby undermining the reliability of the planning assumptions. We agree with both of these points.

Save Southwest Riverside County (SSRC) testifies that the transmission component of SDG&E's preferred proposal is not supported by substantial evidence. Specifically, it cites SDG&E's inclusion of a "Near-term Interconnection Project" that would be constructed and available to serve load by the summer of 2008. SSRC cites to SDG&E's testimony on cross-examination that this is not the Valley-Rainbow line, and states that since licensing and construction of another major new transmission line would take five to six years, SDG&E's plan is risky, and perhaps infeasible. This is a valid criticism that SDG&E should address in its re-filed long-term plan.

The City of Chula Vista states that SDG&E's proposal shows that existing transmission systems will be fully utilized by 2005, and that additional transmission capacity must be added by 2008. The City is concerned that future transmission lines be given early and active coordination with affected local jurisdictions, to include specific notice and a public involvement process. The

City would like the Commission to consider: (1) requiring the removal of old, surplus, above-ground lines when new ones are added; (2) tying in local power sources and renewables in evaluating sites; (3) upgrading line capacity for growth; and (4) the consideration of growth in siting new or replacement lines. We give the City assurance that before a new transmission line could be authorized, a separate CPCN process would be required. Our CPCN process provides full public notice to all affected communities, a detailed environmental assessment under CEQA standards, and a specific finding of economic need.

SCE requests that the Commission (1) avoid duplicating the transmission project need assessments performed by the ISO with the assessment performed by the Commission under its General Order 131-D CPCN provisions; and (2) refrain from conducting transmission project need assessments in this proceeding unless the results of those assessments can and will be adopted in the project's separate General Order 131-D CPCN proceeding. The Commission intends to open shortly a new rulemaking to address this issue. Our commitment under the EAP is:

> "The Public Utilities Commission will issue an Order Instituting Rulemaking to propose changes to its Certificate of Public Convenience and Necessity process, required under Pub. Util. Code § 1001 et seq., in recognition of industry, marketplace, and legislative changes, like the creation of the CAISO and the directives of SB 1389. The Rulemaking will, among other things, propose to use the results of the Energy Commission's collaborative transmission assessment process to guide and fund IOU-sponsored transmission expansion or upgrade projects without having the PUC revisit questions of need for individual projects in certifying transmission improvements."

6. Fuel Diversity in Non-Renewables

The California Energy Commission (CEC) notes that there are concerns about California's increasing dependence on natural gas. The latest version of the *2003 Integrated Energy Policy Report* (IEPR), states:

> "With demand for natural gas increasing to meet the needs of a growing electricity generation market, concerns have emerged among state policy makers about California's increasing dependence on natural gas. These concerns have become even more pronounced with increased price volatility."[85]

CEC's recommendation is to mitigate the risk of relying heavily on natural gas by reducing demand for natural gas for power generation through greater reliance on renewable generation. The draft final report is less encouraging about substituting other non-renewable fuels for gas:

> "Using other fuels can also reduce the demand for natural gas facilities. For a host of legal, environmental, and cost reasons, nuclear, large hydroelectric, residual fuel oil, and coal facilities are unlikely candidates for offsetting natural gas-fired generation for California. On the other hand, the development of cost-effective renewable resources (wind, geothermal, biomass, and solar) have [sic] tremendous potential in California to meet part of our future demand."[86]

It is clear that the CEC does not see the use of alternative fuels, except for renewable sources, as a long-term source of diversity in generation sources in California.

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[85] Page 22.

[86] Page 23.

SDG&E proposed a Balanced Portfolio as part of its long-term plan. The plan posits increased transmission capability, additional on-system generation both prior to and after the transmission addition, and off-system resources including the fuel diversity represented by a coal-fueled resource. SDG&E's Robert Resley's testimony notes that its ability to add fuel diverse resources is constrained by the nature of its service territory, public policy, and possible limited availability of non-fossil resources.[87] SDG&E recognizes that the advantage of diversity, a significant reduction in potential price volatility by reduced dependence on gas prices, would be counterbalanced by additional emissions.

The long-term plans of the other utilities, PG&E and SCE, do not mention fuel diversity by name, and do not include non-gas power plants in their future plans.

California is an environmentally sensitive state both by its geography and by its politics and sensitivities. Conventional power plants are difficult to site here. Even those fired by the cleanest technologies and fuels – at this time, that means natural gas – are not generally welcomed here. The most recent data show that electric generation in California from coal, petroleum, and other gases besides natural gas accounts for only three-percent of total generation in the state, compared to about 56 percent for natural gas.[88] SCE is in the midst of a proceeding before us, A.02-05-046, on the future disposition of

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[87] Page 9.

[88] DOE/EIA State Electricity Profiles 2001, published October 2003, Energy Information Administration, US Department of Energy.

the Mohave power plant, which is the largest single coal-fired source for any of the utilities.

SDG&E is correct in arguing that a balanced portfolio that includes a coal-fired resource would require new transmission, for it is very unlikely that a coal-fired plant ever could be built within its service area.

Fuel diversity is not only a matter of choices of different fuels. The principal advantage we are looking for, reduced likelihood of shortages and price spikes, can be achieved through greater reliance on additional sources of fuel, including natural gas itself. It is possible that the addition of at least one Liquefied Natural Gas (LNG) port capable of serving gas to Californians, including California's electric power plants, can provide at least some of the benefit we are searching for in fuel diversity. Only in this case, it would not be diversity of the fuel types, but of the fuel sources.

7. QFs

Currently, there are about 600 QFs under contract to PG&E, SCE, and SDG&E. These QFs supply power used to serve about one-fourth of the combined retail load for the three utilities (see Table QF-3, Load Served by QFs below). QFs have been reliably providing power for over 20 years, under standard offer and fixed-priced contracts, and under some non-standard offer contracts, approved by this Commission. As we discussed in our Interim Opinion, QF power does provide many benefits to California:

> "As a general proposition, we find that QF power provides significant benefits to the state, in the form of more efficient industrial processes, as well as electric power. QFs have continued to provide power to the state during difficult circumstances during the past several years. A consequence of not making provisions for continuing QF contracts would be more QF power

> going off-line, creating additional net short that the utilities would need to procure during the interim period." (D.02-08-071, p. 31.)

The QF industry marked its beginning with the passage of the Public Utility Regulatory Policies Act (PURPA) of 1978 which required utilities to purchase QF power under certain terms and conditions. By 1995, FERC noted that the QF industry had matured considerably:

> "The QF industry is now a developed industry and the need for integration of policy objectives under PURPA and other federal electric regulatory policies is pronounced. This is particularly the case given the fact that the electric utility industry is in the midst of a transition to a competitive wholesale power market, and some States, including California, are considering direct access for retail customers."[89]

Although this determination was made eight years ago, the challenge of correctly implementing PURPA for a developed QF industry, which now co-exists with increasingly developed wholesale power markets, does present a considerable challenge. We must strike the proper balance between certain policy preferences and a myriad of legal requirements.

This industry is so mature, in fact, that QF power contracts are actually set to expire at a significant rate over the next five to seven years. By 2008, expired QF contract capacity is expected to exceed 1,000 MW and approach 1,800 MW by 2010. SCE is projected to lose the most QF capacity during this time period.

Table QF-1, Expiring QF Contract Capacity

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[89] *Southern California Edison and San Diego Gas & Electric, 70 FERC 61,215 (1995)*

	2005	2006	2007	2008	2009	2010
PG&E QFs	0%	1%	6%	8%	19%	23%
SCE QFs	1%	11%	11%	31%	38%	43%
SDG&E QFs	0%	0%	0%	0%	0%	0%
Combined QFs	1%	6%	8%	19%	28%	32%

a) Parties' Positions

Utility Recommendations

PG&E, SCE, and SDG&E have proposed to not automatically renew expired QF contracts, but differ in their willingness to do so. SDG&E is the most willing of the three and does assume that its QF power deliveries will remain relatively constant throughout the forecast period, and that expired QF contracts will be renewed under certain conditions. However, all three utilities agree that the Commission should reexamine SRAC pricing to ensure that utility avoided cost more accurately reflects the cost of their replacement power alternatives. SDG&E is amenable to renewing expired QF contracts through the use of Standard Offer 1 (SO1) contracts that would be renewed annually based on need. SDG&E is opposed to the use of QF-only auctions.

PG&E occupies the middle-ground on QF issues with its proposal to offer one-year SO1 contracts with modifications pertaining to: (1) the provision of 1,000 discretionary curtailment hours, both financial and physical curtailment, (Tr.5744, lines 2-9), although the detailed protocols on specific curtailment frequency, duration, and notice provisions were not specifically set forth; (2) providing for an option to terminate a contract once the seller enters into a winning RPS bid; (3) revisiting SRAC methodologies, and (4) the opportunity for QFs to participate in any upcoming power solicitations.

SCE stands alone at the other end of the spectrum with its solicitation-only proposal. SCE contends that its PURPA obligations will be fully satisfied simply by affording QFs the opportunity to participate in upcoming solicitations for renewable and/or non-renewable contracts. SCE puts forth that California and other states have considerable discretion in implementing PURPA's mandatory purchase requirement, and that the demise of the California Power Exchange ("PX") has not altered the basic proposition that PURPA may be properly implemented by providing QFs with the opportunity to participate in a competitive procurement process. SCE further notes that revival of mandated SO1 contracts would impose must-take obligations on the IOUs in all hours, including many hours when the true costs avoided by the QF purchases approach zero and may even be negative.

Several parties have weighed in on QF issues on some detail: CCC, CAC-EPUC, and ORA.

CCC Recommendations

CCC recommends that QFs should be allowed to preferably enter into 10-year SO1 contracts, or alternatively, short-term annual SO1 contracts; (2) bid to provide long-term procurement products to the IOUs (such as firm capacity products), while (3) retaining their right to sell energy at SRAC prices to the IOUs in other hours. CCC contends that its long-term procurement proposal (for cogenerators) would provide benefits to both ratepayers and QFs, including conservation, energy efficiency, additional supply, and market-based pricing under SRAC.

CCC also proposes a way to mitigate impacts of excess base load power through the expanded use of bid curtailment programs. IOUs could utilize such programs to economically back-down QF power. CCC states that these programs encourage QFs with operational flexibility to reduce their output during hours when the utility has too much must-take power. The purchasing utility provides each of its QFs with the opportunity to bid a price for megawatt-hours of production that each QF can curtail. The IOU can accept those bids that offer ratepayer benefits.

CCC also notes that SRAC TOU (time of use) factors could be revised to more accurately encourage QFs to deliver power when it is needed. CCC states that the vast majority of QF power is either under non-standard contract or is on 5-year, fixed price contracts at 5.37/kWh until mid-2006. Thus, modifications to SRAC pricing would have no appreciable effect until after mid-2006. (CCC Direct Testimony, 06-23-2003, p.5, line 20).

CCC observes that PURPA is still law, that it has not been repealed, and that the statute still requires "IOUs to purchase power from QFs at prices based on the IOUs' full avoided costs" (CCC Direct Testimony, 06-23-2003, p.10, line 26). CCC notes that D.02-08-071 required the IOUs to offer SO1 contracts during the interim procurement period (p.12, line 4). CCC contends that a long-term SO1 contract "will allow the IOU to meet its PURPA purchase mandate…" (p. 4, line 40.)

CCC states that QF capacity will decline sharply after 2005, as a result of the termination of the large cohort of QF contracts with 20-year terms for projects that began operations from 1985 to 1990." (CCC Direct Testimony, p. 7, lines 18-21). CCC contends that more capacity needed by 2008, even though CEC 'incorrectly' assumes constant QF power:

> "The CEC forecast appears to assume that present levels of QF generation are maintained. Even assuming QF resources are retained, the CEC forecast suggests that, on a statewide basis, another 2,000 to 5,000 MWs of peak capacity will be needed by 2008, simply in order to maintain reserve margins in the range of 15% to 20%." (CCC Direct Testimony, p. 8, line 8.)

CCC contends that QFs can supply additional power in 2004 and beyond:

> "Cogeneration projects that could supply additional power to the IOUs in 2004 are, for the most part, already built and have operated successfully for many years. Most are located in the state's load centers, improve the reliability of the state's electric grid, and avoid the need for the California Independent System Operator (ISO) to contract for reliability must-run (RMR) generation." (CCC Direct Testimony, p. 3, line 3.)

CCC notes that the IOUs can readily hedge their exposure to high SRAC prices through the use of financial hedge products. SCE hedged its QF price risk in 2002 and 2003 and has obtained authority to hedge in the first half of 2004. PG&E and SDG&E also have such hedging authority. (CCC Direct Testimony, p.10, line 34). CCC states that QFs avoided the construction of additional central station coal and nuclear power plants, such as the Diablo Canyon and SONGS plants that were built in the 1980s. CCC also notes that there are conservation and efficiency benefits associated with cogeneration -- the dual production of two useful forms of energy from a single fuel source. (Direct Testimony, p. 2, line 22.).

CCC also encourages the Commission to reject PG&E's proposal to incorporate 1,000 hours of annual curtailment into SO1 contracts. CCC contends that PG&E has not shown that the utility's avoided costs are negative in this many hours, nor has the utility provided details on how it would administer such curtailments. CCC states that this issue would be best considered during a comprehensive review of SRAC pricing issues. Finally, CCC notes that QFs are still ready, willing, and able to sell power to below investment-grade utilities.

> "Most, if not all, of the cogeneration projects that could provide additional power to the IOUs in 2004 are already built and have operated reliably for many years under standard offer QF contracts. The IOUs have many years of performance data for such projects. These are resources that are ready, willing, and able to supply power to California. QFs continue to be willing to sell to PG&E and Edison despite the fact that the credit of these IOUs remains below investment-grade." (CCC Direct Testimony, p. 27.)

<u>CAC/EPUC Positions</u>

On QF issues, CAC/EPUC contends that (1) the IOU power solicitation proposals do not solely satisfy utility PURPA purchase obligation requirements, and (2) changed circumstances do not preclude QF cost recovery, thus existing QF contracts must be upheld. CAC/EPUC cites *Cogen Lyondell, Inc., et al., 95 FERC 61,243 (2001)* in support of its first contention on PURPA purchase obligation requirements: "The opportunity to participate in a solicitation process is a far lesser right than that expressed in the FERC rules and may not be sufficient to encourage QF cogeneration as prescribed by Federal law" (CAC/EPUC Direct Testimony, 06-23-2003, p.5, line 6). With regard to existing QF contracts, CAC/EPUC notes that *New York State Electric & Gas Corp., 71 FERC 61,027 (1995)* upholds existing QF contracts even under changed circumstances. Both of these FERC orders are discussed in more detail below.

During cross-examination of PG&E's QF witness (Pappas), CAC/EPUC counsel noted that existing State of California policy, as set forth in Pub. Util. Code § 372(f), also encourages the continued development, installation, and interconnection of clean and efficient self-generation and cogeneration resources (Tr. 5694, lines.20-28), in addition to the federal PURPA statute. Pub. Util. Code § 372(f) is as follows:

> "372 (f) To encourage the continued development, installation, and interconnection of clean and efficient self-generation and cogeneration resources, to improve system reliability for consumers by retaining existing generation and encouraging new generation to connect to the electric grid, and to increase self-sufficiency of consumers of electricity through the deployment of self-generation and cogeneration, both of the following shall occur:
>
> > "(1) The commission and the Electricity Oversight Board shall determine if any policy or action undertaken by the Independent System Operator, directly or indirectly, unreasonably discourages the connection of existing self-generation or cogeneration or new self-generation or cogeneration to the grid.
> >
> > "(2) If the commission and the Electricity Oversight Board find that any policy or action of the Independent System Operator unreasonably discourages, the connection of existing self-generation or cogeneration or new self-generation or cogeneration to the grid, the commission and the Electricity Oversight Board shall undertake all necessary efforts to revise, mitigate, or eliminate that policy or action of the Independent System Operator."

<u>ORA Positions</u>

Although ORA does not appear to oppose PG&E's power solicitation and SO1 contract proposals, ORA does state that these seem to be "inconsistent with the Commission's intent for a limited revival of SO1 contracts" (ORA Direct, p.80). Regarding PG&E's 1,000-hour discretionary curtailment proposal, ORA's direct testimony at page 79 did not reflect a full understanding of PG&E's proposal, as evidenced during hearings (Tr.5883, through 5886). Under cross- examination by CCC, ORA did express concern over the possibility that "PG&E's exercise of the [1,000 hour] curtailment right [might have] the effect of shutting down [some] QF operations" (Tr.5886, ln.17-20). ORA is not opposed to PG&E's proposal to revamp SRAC pricing methodologies, but ORA notes that no specific details were provided.

ORA's position on SCE's position that, "its PURPA obligations will be fully satisfied by affording QFs the opportunity to participate in upcoming solicitations for renewable and/or non-renewable contracts," is ambiguous:

> "If, as SCE represents, additional SO1 contracts will not be a good fit to SCE's primary need, then so be it. SCE should not force itself to enter into this type of contract beyond those already required in existing Commission orders. SCE has indicated several planned new contracts during the plan period through 2012. But SCE should describe in more explicit terms the solicitation opportunities it plans to make available to QFs and all other bidders in both renewables and non-renewables." (ORA, Direct Testimony, p. 82.)

As a policy matter, ORA states that SCE should be more explicit in identifying specific opportunities for QFs to bid in future SCE solicitations.

b) Discussion

The spectrum of QF issues is defined on the one end by an absolute, mandatory PURPA purchase obligation regardless of utility need (as advanced by CCC), and on the other end by a solicitation-only opportunity for QFs to bid on yet-to-be-defined power products at future yet-to-be-specified dates. We are not only faced with a range of policy choices but also with complex legal requirements set forth in federal and state law.

(1) The PURPA Purchase Obligation Requirement

In our Interim Opinion in this rulemaking, D.02-08-071, we discussed the applicable federal and state mandates associated with PURPA, along with our interim approach on QF issues. In that decision, we stated that, "[a]lthough the requirements of PURPA give us considerable discretion and do not obligate us to continue SO1 contracts [until long-term procurement plans have been adopted], we nonetheless must comply with PURPA." With regard to QFs, the issue of the obligation to purchase QF power according to the requirements set forth under PURPA is at issue in this rulemaking. In 105 FERC 61,004 (Para. 20), FERC clearly summarized the PURPA purchase obligation requirement, along with some associated provisions:

> "[FERC] implemented the purchase obligation set forth in PURPA in Section **292.303** of its regulations, **18 C.F.R.** § **292.303**(a) (2003), which provides: Each electric utility shall purchase, in accordance with § 292.304, any energy and capacity which is made available from a qualifying facility . . . . Section 292.304, in turn, requires that rates for purchases shall: (1) be just and reasonable to the electric customer of the electric utility and in the public interest; and (2) not discriminate against qualifying cogeneration and small power

> production facilities. **18 C.F.R.** § 292.304(a)(1) (2003). The regulation further provides that nothing in the regulation requires any electric utility to pay more than the avoided costs for purchases. 18 C.F.R. § 292.304(a)(2) (2003)." (Emphasis added.)
>
> "'Avoided costs' is defined as 'the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.'" 18 C.F.R. § 292.101(b)(6) (2003)

The QF parties in this rulemaking have generally portrayed the PURPA purchase obligation requirement as rather absolute.[90] However, the PURPA purchase obligation is neither as broad or as absolute as the QF parties assert. The QF parties do acknowledge that the PURPA purchase obligation is subject to specific curtailment provisions in 18 C.F.R. Section 292.304(f).[91]

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[90] In fact, during hearings in response to a hypothetical example, the CCC witness (Beach) even went so far as to state that the PURPA purchase obligation would probably even require an electric utility (that is isolated from the transmission grid outside its service territory) to build a transmission line for the expressed purpose of exporting QF power to an outside market, as opposed to not contracting for unneeded power in the first place.

[91] 292.304 (f) Periods during which purchases not required.

> (1) Any electric utility which gives notice pursuant to paragraph (f)(2) of this section will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself.
>
> (2) Any electric utility seeking to invoke paragraph (f)(1) of this section must notify, in accordance with applicable State law or regulation, each affected

Footnote continued on next page

Additionally, the waiver provision in 18 C.F.R. 292.402 provides further flexibility to states in their implementation of the PURPA purchase obligation. Specifically, section 292.402 provides for a waiver of Subpart C of Part 292. Subpart C is titled as, and sets forth, "Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities Under Section 210 of the Public Utility Regulatory Policies Act of 1978." The waiver allowed for under section 292.402 applies to sections 292.301 through 292.308, excluding section 292.302, but including section 292.303, which is the particular section that sets forth the obligation of electric utilities to purchase QF power. Section 292.402 reads as follows:

> "(a) State regulatory authority and non-regulated electric utility waivers. Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or non-regulated electric utility may, after public notice in the area served by the electric utility, apply for waiver from the application of any of the requirements of subpart C (other than 292.302 thereof).

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qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the electric utility.

(3) Any electric utility which fails to comply with the provisions of paragraph (f)(2) of this section will be required to pay the same rate for such purchase of energy or capacity as would be required had the period described in paragraph (f)(1) of this section not occurred.

(4) A claim by an electric utility that such a period has occurred or will occur is subject to such verification by its State regulatory authority as the State regulatory authority determines necessary or appropriate, either before or after the occurrence.

> "(b) Commission action. The Commission will grant such a waiver only if an applicant under paragraph (a) of this section demonstrates that compliance with any of the requirements of subpart C is not necessary to encourage cogeneration and small power production and is not otherwise required under section 210 of PURPA."

It is clear from this language in FERC's regulations that states, through their utility regulatory commissions or individual utilities, have the authority to request FERC authorization to waive the applicability of the PURPA purchase obligation under certain conditions.[92] During the course of these proceedings, a number of QF parties have raised the issue of the scope of this waiver authorization, citing a FERC decision, *Cogen Lyondell, Inc., et al., 95 FERC 61,243 (2001)*, as a definitive refutation of PG&E's and SCE's power solicitation proposals, which the utilities claim will satisfy their PURPA purchase obligation requirements.

Although, the QF parties claim that PG&E's and SCE's power solicitation proposals are inconsistent with the requirements of PURPA and its implementing regulations, the QF parties' reliance on the *Cogen Lyondell* order for such a proposition is misplaced. At issue in the *Cogen Lyondell* case is the Texas PUC's request for a waiver, under 18 C.F.R. 292.402, of the PURPA purchase obligation set forth in 18 C.F.R. 292.303. In that order, FERC stated that "the Texas Commission's proposal amounts to an opportunity for QFs to

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[92] We note that the right to seek any such waiver rests with the state regulatory commission, and not with the utilities over which any such commission may have regulatory authority.

make sales, which is inferior to having an electric utility-purchaser with a mandatory purchase obligation under PURPA" (pages 6-7). Notwithstanding this determination, FERC noted that: (1) the purchase obligation could be waived in some circumstances; (2) FERC has, in fact, granted waiver of the purchase obligation in certain limited circumstances; and (3) in the *Cogen Lyondell* case, FERC stated that "the Texas Commission has offered no specific showing [for a waiver], relying instead on broad competitive assertions." The relevant language to this effect is stated in the *Cogen Lyondell* order, as follows:

> "The Commission recognized, when it promulgated its regulations implementing PURPA, that the purchase obligation could be waived in some situations. See Small Power Production and Cogeneration Facilities: Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, Order No. 69, FERC Stats. & Regs. Regulations Preambles 1977-1981 30,128 at 30,871, 30,894 (1980), order on reh'g, Order No. 69-A, FERC Stats. & Regs. Regulations Preambles 1977-1981 30,160 (1980), aff'd in part and vacated in part, American Electric Power Services Corporation v. FERC, 675 F.2d 1226 (D.C. Cir 1982), rev'd in part, American Paper Institute, Inc. v. American Electric Power Service Corporation, 461 U.S. 402 (1983)."

> "The Commission has in the past granted waiver in certain limited circumstances. See City of Ketchikan, Alaska, 94 FERC 61,293 (2001) (Ketchikan); Seminole Electric Cooperative, Inc., 39 FERC 61,354 (1987); Oglethorpe Power Corporation, 32 FERC 61,103 (1985), reh'g denied, 35 FERC 61,069 (1986), aff'd Greensboro Lumber Company, 825 F.2d 518 (D.C. Cir. 1987). In the recent Ketchikan order, for example, the Commission granted waiver of the purchase

> obligation based on a showing that QF capacity was not needed and would merely displace sales of capacity from other resources. Here, the Texas Commission has offered no such specific showing, relying instead on broad competitive assertions." *Cogen Lyondell*, Inc., et al., 95 FERC 61,243 (2001), footnote 3 (emphasis added).

With regard to the extreme breadth of the Texas Commission's request, FERC stated:

> "We will deny the Texas Commission's request for waiver. As an initial matter, what the Texas Commission requests is essentially a complete waiver of the PURPA purchase obligation for all Texas utilities. On this record, we cannot grant such a waiver." *Cogen Lyondell*, Inc., et al., 95 FERC 61,243 (2001), page 4 (emphasis added).

Thus, FERC's *Cogen Lyondell* order does not stand for the broad proposition that the QF parties in this proceeding have cited it for. Rather, this order addresses an extremely broad request for waiver that was supported by nothing more than generalized assertions, and is in no way dispositive of the complex and nuanced issues relating to the future procurement of QF power in California that are under review in this proceeding. In contrast to what FERC was addressing in the *Cogen Lyondell* order, the PG&E and SCE power solicitation proposals that were put forward in this proceeding are being reviewed in the context of a very detailed, factually intensive record addressing both short- and long-term policy issues and procurement plans for California's three largest investor-owned electric utilities.

The *Cogen Lyondell* order can be distinguished from the circumstances we are dealing with here in a number of other key respects. First the Texas PUC request in that case was for the removal of the PURPA purchase obligation for all of its QFs, both existing QFs and future QFs. In contrast, in this case, PG&E and SCE would continue to honor existing QF contracts. Second, the underpinnings of the Texas PUC request were very general competitive assertions, whereas in this case, PG&E and SCE have put forward very specific concerns about their QF contracts and PURPA purchase obligations. The two utilities have noted that as a result of DWR contract allocations, they have had excess power in a range of hours, a condition that may persist for some years. The two utilities also note that this excess power situation will be alleviated over the next few years as a significant number of QF contracts expire. However, the QF parties have expressed a definite interest either in entering into new contracts that could be renewable on an annual basis or on longer terms, given that there is still remaining useful life in many of these facilities.

As a counterpoint to the *Cogen Lyondell* case, both PG&E and SCE cite *City of Ketchikan, 94 FERC 61,293 (March 15, 2001)*. In that order, FERC granted a limited waiver of the PURPA purchase obligation because a proposed QF contract would, in fact, displace existing utility resources and result in additional unneeded power. PG&E describes the order in its September 22, 2003 reply brief:

> "In *Ketchikan*, a self-certified QF who had not yet constructed a new facility attempted to displace energy the City utility was already under contract to purchase by requiring it to purchase from its proposed QF. The City sought and was granted a waiver of any PURPA requirement to take power from the new QF. FERC approved the waiver because "there is no obligation under PURPA for a utility to pay for capacity that would displace existing capacity arrangements." (*Id.* at p. 62,061.)

> Because capacity from the new project was not needed, FERC held that its acquisition did not avoid "building or buying future capacity." (*Id.* at p. 62,062.) FERC also held "compliance with the utility purchase obligation, by means of a purchase that would displace power from the Four Dams Pool Initial Project, is not necessary to encourage cogeneration and small power production and is not otherwise required under section 210 of PURPA." (*Id.* at p. 62,061.) In support of its ruling, FERC also cited a long-standing Order No. 69, FERC Stats. & Rags. Preambles 1977-1981 ¶ 30,128 at p. 30,870, which provides that <u>a qualifying facility should only be required to be paid for "energy or capacity the utility can use to meet its system load</u>." (<u>Emphasis added.</u>)

The PURPA purchase obligation does not lawfully exist apart from the determination of the need for such power by the host utility. FERC's *Ketchikan* order, provides abundant support for this proposition, both in project-specific terms and much more broadly as a gloss on the basic requirements of PURPA:

> "…we find that compliance with the utility purchase obligation, by means of a purchase that would displace power from the Four Dam Pool Initial Project, is not necessary to encourage cogeneration and small power production and is not otherwise required under section 210 of PURPA. We make this finding because, as we have stated previously, there is no obligation under PURPA for a utility to pay for capacity that would displace its existing capacity arrangements. Moreover, there is no obligation under PURPA for a utility to enter contracts to make purchases which would result in rates which are not 'just and reasonable to electric consumers of the electric

> utility and in the public interest' or which exceed 'the incremental cost to the electric utility of alternative electric energy.'" 16 U.S.C. § 824a-3(b) (1994). (footnotes omitted, emphasis added) *City of Ketchikan, 94 FERC 61,293 (March 15, 2001), pages 15-16.*

Thus, as FERC itself has recognized, we must balance the PURPA mandate that utilities are to purchase energy and capacity from QFs with the overarching requirement that electric utilities may only charge just and reasonable rates for the power they supply to their customers. In this regard, we note that this Commission has suspended QF standard offer contracts at various times to prevent over-subscription[93] because additional power would have resulted in negative avoided cost and/or displaced existing cost-effective utility resources.

In light of the foregoing legal and policy considerations, it is now appropriate to consider our options with regard to several distinct groups of QFs: (1) Existing QFs with existing utility contracts, (2) Existing QFs with expired, or soon-to-be expired, utility contracts, and (3) New QFs with possible future utility contracts.

(2) Existing QFs With Existing Utility Contracts

None of the three utility proposals on QF issues would affect or impair existing QF contracts. This is, of course, in stark contrast to the *Cogen Lyondell* case wherein the Texas PUC sought a complete waiver of the

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[93] The SO2 contract was temporarily suspended in D.86-05-024. The SO4 contract was temporarily suspended in D.85-04-075, and permanently suspended in D.85-07-021, in anticipation of a final long-run contract.

PURPA purchase obligation for all its QFs, both existing and new. We will continue to uphold existing QF contracts.

(3) Existing QFs With Expired, or Soon-to-be Expired, Utility Contracts

On the issue of whether to renew existing QFs with expired, or soon-to-be expired, utility contracts, the three utility proposals, already discussed in some detail, do differ from one another.

Of the three proposals, SCE argues in the extreme that renewal of existing QF contracts is not necessary and that QFs can instead compete in any upcoming power solicitation proposals that maybe offered in the future. Under SCE's paradigm, determinations of need might be made from time-to-time as the utility issues RFOs for power under certain quantity, quality, and duration parameters; in addition, instead of plainly stating its need in the form of an exact quantity, the utility might be expected to simply specify acceptable bidding units of, for example, anywhere from one megawatt to 25 MW, or more in order to avoid revealing its exact net short position.

The SCE proposal appears to us to be inconsistent with a long-term, integrated resource planning process. SCE's “solicitation-only” opportunity for existing QFs to renew existing contracts that are expiring may technically comply with PURPA, but it does not fit well within the context of a long-term planning process of the type that is at the heart of this procurement proceeding. In this proceeding, we are reviewing proposed 20-year plans. By 2008, SCE will have a need for baseload power, which results, at least in part, from the expiration of QF contracts. Although the need for baseload power does diminish in the near-term, due in large part to the existence of the DWR contracts, we note that there is a need for power that materializes as existing QF contracts expire. Renewal of existing QF contracts should accordingly be encouraged, so long as they are priced within the range of comparable replacement power, to the extent that they can meet the IOUs' need for power.

The IOUs have proposed to comply, in whole or in part, with their PURPA purchase obligations by allowing QFs, including existing QFs with expiring contracts, the opportunity to participate in power solicitations. A competitive all-resource bidding process is an optimal means for an IOU to determine what resources can best meet its need for additional capacity. Ideally, QF participation in such solicitations is the best way for the IOUs to match their need for new capacity with the range of potentially available resources, including QFs. However, we do not believe that such participation should be mandatory for existing QFs seeking to renew their contracts.

In light of the continuing need for most of the power that QFs currently provide, we do not think that IOUs proposal is, in and of itself, sufficient. We accordingly encourage the IOUs to renegotiate contracts with existing QFs independently of their planned power solicitation processes. To the extent that a given IOU individually, or all three of the major electric IOUs collectively, seeks to propose a new or revised standard offer contract to be used in entering into such renewed contracts, we encourage them to do so and to apply to the Commission for approval of such new or revised contracts.

Although we are not requiring existing QFs seeking to renew their contracts to do so via the competitive solicitation process, it is foreseeable that there will be problems if a given existing QF seeking to renew its contract proposes to do so on terms that are inconsistent with the IOU’s then current and future needs for power. A given utility may have imminent needs for peak and intermediate (load-following) power, but no need for baseload power. In such cases, there would be no legal obligation under PURPA for a utility to enter into a renewed contract with a QF that offers only must-take baseload power 24 hours per day, seven days per week. To require the utility to enter into such a contract would not provide reasonable value either to the utility or to its ratepayers and would unduly subsidize the QF at the expense of ratepayers. A subsidy with no commensurate value is not a prudent expenditure of ratepayer funds. On the other hand, an existing QF with an expiring or expired contract proposing to provide power in a manner that does track the utility’s actual needs would, under PURPA, be entitled to an agreement to provide the energy and capacity needed by the utility.

By definition, the PURPA purchase obligation originates out of a utility's need for power, either the need for energy or the need for capacity. Without need, there is no avoided cost because without a need for power the utility would not have the obligation to either generate or purchase any incremental amount of energy or capacity to serve load. The key to resolving this problem is through a revision to the methodology used to determine the prices that existing QFs seeking to renew their QF contracts are actually paid for the power they provide. It is entirely possible that a revision to this methodology will result in a scenario under which a given existing QF, which must generate power 24 hours per day, 7 days per week will be required to pay the IOU to take that power during certain off-peak periods, when the IOU’s short-run avoided cost (SRAC) for that power is negative. Of course, an existing QF seeking to renew a QF contract could avoid such a result by agreeing in the renewed contract not to require the IOU to take (or pay for) power it does need when it does not need it. Accordingly, we encourage both the QF community and the IOUs to be creative and flexible in negotiating the terms of renewed contracts for existing QF facilities.

Given the importance of the need to match an IOU's actual power needs with the nature of the resource being offered by certain QFs, there is one important element of the IOUs' competitive bidding processes that is highly relevant to the terms of future renewed contracts for existing QFs, namely, the use of such bidding processes to establish the value of the capacity provided by QFs. The price for new capacity that results from a competitive all-source bidding process is the best way for an IOU to identify the basis for establishing the capacity payment that an existing QF seeking to renew a QF contract should receive. Accordingly, the results of the competitive all-source bidding processes that the IOUs have already undertaken, or will shortly undertake, will greatly assist in updating the value of the capacity component of the total short-run avoided cost (SRAC) that QFs are entitled to be paid pursuant to PURPA and state law. As will be discussed in more detail below, it is important that the current methodologies to establish SRAC be modified.

We understand that most of the existing QF contracts will not expire before the end of 2005, and we expect that our review of the SRAC methodology will be completed well in advance of that date. However, there will be some QF contracts that expire prior to the completion of that review. Since the resolution of the key questions relating to how QFs will be paid on a going-forward basis must await the completion of our review of the SRAC methodology, we should continue to provide interim treatment, as we did in Decision D.02-08-071, for QF contracts expiring prior to the completion of that SRAC review for which the QF and the utility do not reach agreement on the terms of a new long-term QF contract. Accordingly, the utilities shall continue to purchase power until December 31, 2005 from any QF pursuant to an SO1 contract under the following conditions:

- The QF must have been in operation and under contract to provide power with an IOU at any point between January 1, 1998 and the effective date of this decision; and
- The QF contract must be set to expire before January 1, 2006, or have already expired.

The pricing terms for any such contract should be consistent with existing Commission SRAC policy established in D.01-03-067, as modified by D.02-02-028; provided, however, to the extent that the Commission adopts a revised SRAC policy at any time prior to December 31, 2005, the pricing terms of the contract shall be modified to reflect said revised SRAC policy as of the effective date of the Commission decision adopting a revised SRAC policy.

Thus, as to existing QFs with expired, or soon-to-be expired, utility contracts, we conclude that the potential anomaly between the nature of the power offered by a QF and the actual system needs of an IOU can be resolved in any one of three ways: (i) voluntary QF participation in IOU competitive bidding processes; (ii) renegotiation by the QF and the IOU on a case-by-case basis of contract terms that explicitly take into account the IOU’s actual power needs and that do not require the IOU to take or pay for power that it does not need; and (iii) appropriate revisions by the Commission to the SRAC methodology that will assure that existing QFs entering into renewed contracts on standard terms only receive payment for power that the IOU actually needs and can use. Compliance with any one of these three alternatives should assure fairness both to the QF community and to the IOUs and their ratepayers.

(4) New QFs With Possible Future Utility Contracts

With regard to new QFs with possible future utility contracts, we believe that the PURPA purchase obligation is clearly subject to a determination that such QF power is, in fact, needed. As FERC stated in *Ketchikan*, "…we find that compliance with the utility purchase obligation, by means of a purchase that would displace power … is not necessary to encourage cogeneration and small power production and is not otherwise required under section 210 of PURPA. We make this finding because, as we have stated previously, there is no obligation under PURPA for a utility to pay for capacity that would displace its existing capacity arrangements."

We accordingly find that in connection with all systematic procurement activities starting in 2005, each of the utilities shall examine its need for additional QF power from new facilities. In a given procurement cycle, a utility may have imminent needs for peak and intermediate (load-following) power, but no need for baseload power. In such cases, there would be no obligation under PURPA for a utility to enter into a contract with a new QF that offers only must-take baseload power 24 hours per day, seven days per week. To require the utility to enter into such a contract would not provide reasonable value either to the utility or to its ratepayers and would unduly subsidize the QF at the expense of ratepayers. On the other hand, a new QF proposing to provide power in a manner that does track the utility's actual needs would, under PURPA, be entitled to an agreement to provide the energy and capacity actually needed by the utility.

Thus, as to new QFs, we conclude that a utility must make a determination of need prior to offering a contract to a new QF. Such determinations can be made as part of a utility's normal procurement cycle, but, so long as PURPA remains operative law, a new QF that offers to meet a utility's actual, demonstrated power needs at avoided costs prices would be entitled to a contract.

(5) PG&E's Proposed 1,000 Hours Curtailment Proposal

PG&E has proposed to offer SO1 contracts to QFs whose contracts have expired, provided the contract is mutually agreeable with possible annual renewal. As part of that contract proposal, PG&E included an updated curtailment provision, which would allow the utility, at its discretion, to physically and financially curtail such QF contracts up to 1,000 hours annually. PG&E contends that its proposal should be adopted for several reasons: (1) baseload power is not needed until after 2008, (2) allocated DWR contracts result in more energy than PG&E can use in many hours during the year, and (3) the 1,000 curtailment hours provision was previously approved by the Commission in connection with the Interim Standard Offer No. 4 Curtailment Option B. PG&E further contends that its 1,000-hour curtailment proposal is very reasonable and is perhaps overly generous, given that PG&E does not need additional generation during the next several years. (PG&E Post-Hearing Brief, September 15, 2003, pp. 85-87).

We are unpersuaded by PG&E's arguments on this issue. PG&E's 1,000-hour curtailment proposal is not the result of any detailed avoided cost calculations based upon an approved avoided cost methodology or concept. However, modifications to SRAC, which are discussed just below, should address PG&E's concerns, and will provide a more reasoned basis for the type of SRAC payment adjustments that PG&E's proposed contract provision seeks to effectuate.

(6) Revision of SRAC Prices

As mentioned already, all three utilities contend that revision of the current SRAC methodologies for determining QF energy and capacity payments is needed. For many years now, SRAC has been approximated through time-differentiated energy prices (set once a month) and time-differentiated capacity prices (set annually). However, there is substantial evidence on the record in this proceeding that indicates that the current SRAC energy pricing methodology has yielded prices in excess of spot market prices for significant periods of time.

The Commission has established SRAC methodologies used to calculate avoided cost energy and capacity payments for QF power. Per the requirements of Pub. Util. Code § 390, SRAC energy prices are tied to natural gas spot border prices, which have not necessarily reflected the more diverse utility portfolio that should be reflected in utility avoided cost. The result of the current SRAC pricing system has been that utilities have paid too much for QF power in certain time periods relative to market prices. More specifically, based on current SRAC time of use (TOU) factors, utilities have paid too much for QF power at certain times of day.

Because of this pricing problem, the Commission has also authorized utilities to purchase financial derivative products to hedge the QF price risk created, in part, by the approved SRAC methodology, which has been greatly affected by the volatility in the natural gas market over the past several years. In fact, the utilities have expended considerable sums of money hedging QF price risk resulting from this spot market-based (and in part Legislatively-mandated) avoided cost pricing formula. The amount of this hedging activity demonstrates that the current avoided cost pricing formula has not reflected utility avoided cost either as accurately as we had hoped or as precisely as we would like to see in the future.

Accordingly, in our view, there is a pressing need for a modified SRAC pricing system, which will accurately and fairly set utility avoided cost prices both under current and expected future market conditions and with an eye to the diversity of a given utility's actual resource portfolio.

Section 390 is now something of an artifact of the AB 1890 electric restructuring landscape, for the reason that Section 390 can never be fully implemented in accordance with the provisions set forth in Section 390(c) due to the demise of the Power Exchange (PX).

As the foregoing discussion demonstrates, the SRAC energy pricing formula is now out-of-date and inequitable. However, the capacity pricing component of the SRAC formula is also problematic, because the QFs receive capacity payments in addition to energy payments. With SRAC energy prices that are now frequently above market prices, the additional capacity payments that QFs receive merely compounds the inequity to the utilities and their ratepayers of the current SRAC pricing formula.

The Commission should carefully consider how to modify the SRAC methodology and whether to seek legislative changes to Section 390. We have a two-year window until most existing QF contracts begin to expire, and we should craft a remedy in the new OIR that better matches QF contracts with the actual needs and economic alternatives of the IOUs.

C. Risk Management

In the legislative intent section of AB 57, Section 1(d), the Legislature:

"Directs the Public Utilities Commission to assure that each electrical corporation optimizes the value of its overall

> supply portfolio, including Department of Water Resources contracts and procurement pursuant to Section 454.5 of the Public Utilities Code, for the benefit of its bundled service customers."

In implementing Pub. Util. Code § 454.5, the Commission is required to (1) assess the price risk associated with each utility's portfolio; (2) ensure the utility has moderated its price risk; and (3) ensure the adopted procurement plan provides for just and reasonable rates, with an appropriate balancing of price stability and price level. (Sections 454.5(b)(1), 454.5(d)(4), and 454.5(d)(5).)

The manner in which each utility identifies and manages price risk in and optimizes the value of its overall supply portfolio for the benefit of its bundled service customers is the risk management function. The Commission has four primary oversight responsibilities in risk management: (1) specify the level of consumer risk tolerance that the utilities should use in managing their procurement portfolios; (2) make sure each IOU has tools in place to measure ratepayer risk exposure; (3) review and adopt utility procurement plans; and (4) adopt and administer a procurement incentive mechanism for each utility. We address here consumer risk tolerance and incentive mechanisms.

1. Consumer Risk Tolerance (CRT)

In D.02-10-062, we defined consumer risk tolerance (CRT) as "the price that an average consumer would be willing to pay to reduce the risk of higher prices in the future (i.e., the cost-to-risk tradeoff), discuss its importance is setting the limits of potential price risk under which each utility should manage its procurement portfolio, direct the Energy Division to retain a consultant to gather additional information regarding appropriate CRT levels, and requested parties to propose an interim CRT.

In D.02-12-074, we adopted an interim CRT level and notification protocol based on modifications to proposals advanced by ORA and TURN. While PG&E and SDG&E filed CRT proposals in their modified 2003 plans, SCE did not. SCE's interpretation of the CRT protocol that was outlined in Confidential Appendix C to D.02-12-074 led it to later file a petition to modify D.02-12-074, which we addressed in D.03-06-076.[94]

At present, each utility implements the CRT slightly differently. PG&E is the only utility to publicly discuss the specifics:

> "PG&E currently manages the electric portfolio recognizing a consumer risk tolerance of one-cent per kWh, assumed to apply to a potential rate increase of one-cent per kWh over a one-year period. This translates to a risk tolerance level of about (confidential number). PG&E's approved 2003 Procurement Plan also established a notification limit to the Commission when portfolio exposure reached 125 percent of this risk tolerance." (Exhibit 26, p. 3-2.)

As a result of budget uncertainties, the consultant study authorized under Section 454.5(f) has been delayed. Energy Division plans to consult with each utility in the first quarter of 2004 and then prepare a draft scope of work for comment by all parties. A final consultant's report should be served on all parties for comment and the consultant be available as a witness if requested by the Commission.

For 2004, the utilities should continue to use the interim CRT.

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[94] In hearing testimony, witness Cini indicated that, as per D.03-06-067, SCE no longer sees the CRT as a barrier to forward procurement, and that its 2004 STPP should be modified to reflect this position.

2. Incentive Mechanism

In D.02-10-062, the Commission recognized the importance of developing an incentive mechanism and directed SDG&E, the only utility to support development of an procurement incentive mechanism, to lead a workshop proess. The Commission stated:

> "SDG&E shall sponsor, in coordination with the other utilities, an all-party workshop to develop an incentive mechanism proposal. If consensus is reached, the proposal should be filed in each utilities' long-term procurement plan. If consensus is not reached, SDG&E should file a workshop report containing areas of agreement and disagreement by February 15, 2003, for our further consideration." (Ordering Paragraph 7.)

SDG&E hosted a series of workshops on incentive regulation in February and March. All three of the respondent utilities sent representatives as did the California Farm Bureau Federation (CFBF), CAISO, Calpine, CEC, CUE, Duke Solar, Mirant, NRDC, ORA, Sempra, TURN/UCAN, and Vulcan Power. On April 15, 2003, SDG&E submitted a Workshop Status Report to the Commission, in which it cited the Joint Consensus Incentive Mechanism Principles, stating that they are the "result of robust debate among a wide range of stakeholders who participated in the workshop process."[95]

The Joint Consensus principles are helpful in understanding the difficulties in crafting an appropriated incentive mechanism. But it is another long step from principles to an actual incentive mechanism proposal. We understand that ORA is currently negotiating an incentive mechanism proposal

[95] SDG&E Workshop Status Report, April 15, 2003, p. 2.

with SDG&E[96] and has held preliminary discussions with SCE on this subject. To date, none of the IOUs has submitted a formal incentive mechanism proposal to the Commission.

The Commission considers an incentive mechanism an integral part of its long-term procurement strategy, and as such, shall direct the IOUs to move more ambitiously in crafting incentive mechanism proposals. We give specific direction in the new Procurement OIR we intend to open in the second quarter of 2004.

We direct each utility to submit by application a supply-side procurement incentive mechanism by March 1, 2004. Other parties also may propose supply-side procurement incentive mechanisms. We start with a supply-side mechanism here for simplicity. Proceedings dealing specifically with demand-side resources are better able to tailor appropriate demand-side incentive mechanisms and design the necessary measurement and evaluation requirements. An energy efficiency incentive mechanism should be addressed in R.01-08-028 and, when appropriate, a demand reduction incentive mechanism considered in R.02-06-001.

D. Other Proposals

1. CPA Peaker Initiative

CPA notes that the law charges it with insuring that electricity reliability is maintained by providing financing for power plants, efficiency, and renewable resources that meet this charge. The Agency carried out a rulemaking (2002-07-01), culminating in a final decision (D.03-001) in

[96] Hearing Testimony of Jan Reid, July 28, p. 4218.

January 17, 2003. In D.03-001, the CPA finds that "Each utility should demonstrate to its appropriate regulatory body, and to others as required, that the utility owns, controls or reliably can acquire capacity that is expected to be available to the utility to reliably serve its load."[97] Further, the CPA finds that dependable capacity should equal 117-percent of monthly peak load, resulting in a reserve ratio of 17-percent. The decision states:

> "The Power Authority expects that the reasoning and information stemming from this rulemaking will offer helpful guidance to the appropriate regulatory bodies when considering procurement policies and deciding whether or how much to differ from these recommendations based on their particular circumstances. The Power Authority also notes that this rulemaking was cited in the recent Procurement Decision in CPUC Proceeding R01-10-024; and provides this Final Decision as further input to that ongoing proceeding."[98]

In D.03-001, the CPA also finds that reserves are not adequate in California:

> "The Power Authority believes that up to this time, the evidence favoring the need for additional reserves is convincing. Documented withholding, exercise of market power, and rotating outages during the past two years provide stark evidence that the new paradigm brings a host of issues not envisioned under the previous scheme. Some level of additional dependable capacity, along with clear assignment of responsibilities is the best way to manage this new set

[97] CPA Decision D03-001, pages 5-6.

[98] Page 29.

> of problems. The Power Authority intends to visit this reserve target recommendation each year, as it reviews its Energy Resource Investment Plan. There will be ample opportunity at that annual review to adjust targets as needed to compensate for improvements in the market structure."[99]

CPA's Energy Resource Investment Plan – 2003-2004 was issued in final form on June 27, 2003. That document makes explicit conclusions about the need for more capacity in California, and it is that document that enunciates the proposal for new peaking capacity:

> "The CPA has initiated an effort to increase the Statewide electricity reserve margin to ensure reliability and reduce peak price volatility. The goal is to obtain up to 300 MW of new efficient peaking resources under CPA ownership, with the power output to be provided ***at cost*** for California's electricity consumers. The CPA invited proposals from generators that meet three primary criteria: lowest cost, proximity to reliability-need areas, and earliest on-line date."[100]

CPA also notes that its policy and strategic contributions include a commitment to:

> "[C]ollaborate with the CPUC, CEC, and investor-owned utilities during 2003 regarding the resource plans and specific procurement strategies by the IOUs. The CPA's focus will be on ensuring that environmentally responsible and cost-effective options

[99] Page 37.

[100] CPA Energy Resource Investment Plan – 2003-2004, page 27. Emphasis in the original.

> are considered for meeting renewable energy, localized reliability, and demand response resource needs. CPA may be able to offer ownership and/or financing solutions to achieve these needs."[101]

The testimony and brief of CPA emphasize that action is needed now to bring on new peaking capacity by the summer of 2005 to lessen the risk of another cycle of high and uncontrollable spot market prices and blackouts. The benefits to consumers of CPA's peaker initiative include (1) current conditions that are very favorable to plant construction; (2) the ability of CPA to help shore up investor confidence in California, (3) bolster in-state reserves; and (4) reduce RMR and other locational costs. CPA also asserts that there would be a benefit to the utilities having access to one-hundred-percent debt financing through the public power sector of the municipal bond market.

TURN supports the Peaker Initiative arguing that contracting for peaking capacity may be better than the utilities' current practice of purchasing 6-by-16 power contracts. Moreover, TURN favors CPA's low-cost financing options and favors the public investment aspect of the initiative, stating "All customers benefit from a more reliable system, but investment in such resources may not be profitable for the private sector because of the sporadic use of these units."[102]

CEC states that the peakers "could be a desirable resource addition"[103] under certain circumstances, but finds the CPA has not

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[101] Page 33.

[102] TURN Opening Brief, page 17.

[103] CEC Opening Brief, page 20.

demonstrated those circumstances as part of CEC's 2003 IEPR analyses. ORA finds that CPA has not made a particular showing in this record that peaker plants are necessary to support California's future electricity needs.

PG&E and SCE mounted a vigorous opposition to CPA's initiative. PG&E states that CPA's proposal for 300 MW of new peakers should be rejected because no need for them has been demonstrated, they are not cost-effective, and they do not meet the stated objective of enhancing local reliability. SCE argues that the CPA process that determined the need for the peakers was deficient, that the CPA would force the utilities to take the contracts without recourse for damages, and that the CPA itself would face no risk for construction costs for the plants.

WPTF argues that the Peaker Initiative "jumps the gun"[104] on the resource adequacy issue and pre-defines the solution. WPTF would rather the utilities put their future needs out to bid after resource adequacy is fully defined.

Based on the record here, we do not find that there is a need for 300 MW of additional peaker capacity to be operational by 2005, either in the service area of PG&E or in the service area of SCE. Therefore, we do not direct the utilities to facilitate the CPA Peaker Initiative by entering into good faith negotiations with CPA for PPAs tied to specific power plants at specific prices. However, we do direct the utilities to work cooperatively with CPA in areas where the utilities see a need to finance projects and the CPA can provide a favorable financing source.

[104] WPTF Opening Brief, page 42.

2. City of San Diego's Proposal

In its testimony, the City of San Diego requests that the Commission allow cities to serve their own load with renewable energy, where the renewable generators are owned by a city and located distant from the load being served. City of San Diego witness Monsen describes the proposal, stating:

> "Cities with developable sites for renewables should be able to serve their own loads (i.e., loads for city facilities) with renewable energy, even if loads are at locations that are remote from the renewable generation." (Testimony at p. 10.)

Witness Monsen further states:

> "[T]he net metering treatment chaptered through Assembly Bill 2228 for dairy farm operations, if extended to include multiple sites and multiple generators, could serve as a model for such a crediting system." (Testimony at p. 11.)

It appears the proposal would allow retail credit for renewable generation against a distant customer site, an accounting method similar in concept to the method used for on-site generation under existing net metering tariffs. However, those tariffs, including those implementing the pilot program under AB 2228, allow customers to net generation against consumption only at a single customer site. The current tariffs are not intended to permit such net accounting for multiple or remote sites.

We will neither modify net metering tariffs nor reinterpret the intent of the Legislature with respect to net metering law in this proceeding. Any changes to net metering tariffs should be considered in the distributed generation rulemaking, where those changes may be considered in the context of broader distributed generation policy, including ratesetting and cost allocation issues.

D.03-02-068 addressed retail sales by a generator to a customer on the same distribution circuit, and did not adopt a distribution-only tariff. The City of San Diego proposal alludes to the use of high voltage transmission lines, which are located "in close proximity to these parcels of land." (Testimony at p. 11) This suggests that the facilities would utilize transmission facilities in addition to the distribution facilities used to serve the load. The proposal also refers to a "means to transmit power from these remote locations to [the city's] loads," while remaining silent on the impacts (such as costs) associated with use of transmission and distribution facilities.

Since direct access transactions have been suspended,[105] new transactions of the type proposed by the City of San Diego between non-utility generators and consumers that utilize utility facilities are not allowed. Thus, there is currently no means for customers to serve their own loads with remotely sited generation. For the foregoing reasons, we do not adopt the City of San Diego's proposal.

3. CAC/EPUC's Request for Clarification of Net v. Gross Load Calculation

A major issue during the hearings was the appropriate calculation of reserve requirements for Qualifying Facilities and other on-site generation. The issue involved whether reserve requirements should be calculated on a "gross" or "net" basis. The distinction between "gross" and "net" load is that "gross" load includes the on-site load served by the generator while it is

[105] See D.02-03-055 and Water Code § 80110.

operating, whereas "net" load excludes this on-site load and looks only at energy that is delivered to the grid.[106] Prior to the end of the hearing on August 12, 2003, FERC issued a final order where the issue of gross versus net determination of operating reserves was litigated.[107] In its order, FERC "[A]ffirm[ed] the judge's finding that the long-standing practice in the CA ISO control area of scheduling, metering and procuring reserves on a net load basis should be permitted to continue, so long as a QF has contracted for standby service with a [Utility Distribution Company ("UDC")], *i.e.*, a contract that provides for the immediate replacement of energy in case of the QF's forced outage."

Based on FERC's decision, all parties (including the ISO which was one of the stronger advocates for use of the "gross" approach)[108] have agreed that the use of the "net" approach is appropriate for those resources that contract with the utility for stand-by service. We will therefore adopt this approach. In doing so, we note that adoption of this approach may have only minimal effects on the utilities' procurement needs. For example, in reviewing the utilities' filings, it appears that they already implicitly discount QF availability by using historical deliveries to the grid.

The Joint Parties Interested in Distributed Generation / Distributed Energy Resources (Joint Parties) argue that the same "net" treatment should

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[106] Tr. (Pettingill) at 4378-4381.

[107] *California Independent System Operator Corporation*, 104 FERC ¶ 61,196 (August 12, 2003) in docket Nos. ER98-997-000; ER98-997-002; ER98-1309; ER02-2297-001; and ER02-2298-001.

[108] ISO Opening Brief, p. 73.

apply to distributed generation.[109] Provisionally, we agree. However, since the Commission has stated its intention to soon open a new rulemaking into the issue of distributed generation, we will revisit this determination in that proceeding.

VI. Short-Term Plans

A. Overview

The objectives of each utility's procurement process should be (1) to ensure sufficient and reliable energy supply at low and stable rates and (2) to optimize the value of its overall supply portfolio for the benefit of its customers. We recognize that an incentive mechanism is needed to fully align the interests of the utilities and ratepayers and, as discussed in Section V.C.2, the development of such a mechanism within early 2004 is a high priority of the Commission.

Our review of each utility's short-term plan raises concerns in four areas, and we make modifications to ensure that:

- effective mechanisms for measuring and managing portfolio price risk are in place;
- each utility is given flexibility to sign multi-year contracts, but with certain limitations placed on this authority to preclude a utility from locking up all needs for the next five years while the Commission works to implement programs in renewables, energy efficiency, and demand reduction;
- upfront standards are proposed that mitigate the possibility of customers significantly overpaying for procurement products; and

[109] Joint Parties Opening Brief, p. 15.

- transparent markets and competitive procurement processes are used unless a strong showing is made that ratepayers benefit from bilaterally negotiated transactions.

In preparing their 2004 plans, the utilities focus on the planning and procurement process that takes place as they move from a twelve month or less position to the actual delivery of electricity to their customers. For this short-term look, the utility's focus is on measuring the price risk exposure of its open portfolio position and managing that position, within a specified consumer risk tolerance level, in a manner that ultimately leads to the procurement and dispatch of power in a least-cost manner. As PG&E's procurement guidelines state: transactions are based on defined customer needs; the utility should not arbitrage in energy markets.[110]

The planning and procurement process is conceptually identical in all timeframes; however, the input assumptions and the granularity of those assumptions become more focused and certain as the operating timeframe approaches real-time.

The table below seeks to illustrate the process that a utility employs to conducts procurement planning and transaction execution. This table was adapted from PG&E's 2004 ERRA testimony, pages 2-16 and 2-17.

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[110] August 1, 2003 ERRA filing, page 4-2.

Utility Resource Planning & Dispatch Process

Time Horizon	Input Assumptions	Output and Action
Annual (Conducted on a regular 12-month rolling basis)	Hydro, load, price scenarios (based on forward prices), resource availability.	Forecasted net open position estimate. Formulate strategies for managing open position (identify transaction types and amounts, price thresholds). Assess impact of open position on risk management policy. Make gas supply decisions and volume nominations. Implement procurement strategy and confer with PRG.
Quarterly/ Monthly/Intra-Month	Updates to load, price, and resource availability assumptions.	Forecasted net open position estimate. Formulate strategies for managing open position (identify transaction types and amounts, price thresholds). Schedule plant maintenance. Schedule DWR contracts. Make gas supply decisions and volume nominations. Implement procurement strategy and confer with PRG, if needed.
Weekly Planning	Updates to weekly hydro system operating plan, plant availability, and market prices.	Forecasted net open position estimate. Formulate strategies for managing net open position (identify transaction types and amounts, price thresholds). Schedule DWR contracts. Make gas supply decisions and volume nominations.
Daily Planning	Adjust load forecast, hydro conditions, plant availability, current market prices, transmission constraints, assess activities of ISO operations, pre-scheduling (hourly) of hydro.	Conduct least-cost analysis to determine unit dispatch and market transactions. Strategies for managing open position (identify transaction types and amounts, price thresholds) are conveyed to Day-Ahead traders and Real-Time operators. Re-schedule operations of retained hydro generation to reflect updated conditions. Schedule DWR contracts and other existing contracts. Counterparties are advised per contract terms. Day-Ahead transactions are executed. Market prices are monitored via brokers and electronic exchanges and procurement strategies are revised as needed.
Hour Ahead	Updates to load forecast, hydro conditions, plant availability, market prices. Actual loads are monitored. Retained generation is monitored. Assess activities of ISO	Manage open positions with Hour-Ahead transactions. Monitor market prices. Re-schedule operations of retained hydro generation to reflect updated conditions. Re-schedule DWR contracts to reflect current conditions. Respond to ISO Reliability Must Run calls and further revise schedules of retained generation and DWR contracts as needed.

	operations.	

B. Review of Risk Management and Reporting Proposals

Our discussion here will focus on (1) refinements to risk management and reporting the Commission directed be given further review in D.02-10-062 and D.02-12-074; and (2) changes the utilities request in their 2004 short term plans that are substantially different from the existing authority they have under their 2003 plans.

1. Consistent Measurement of Degree of Portfolio Risk

In the 2003 short-term plans adopted last year, each utility proposed its own tools and framework to measure portfolio risk, we agreed with ORA's position that the utilities should move in the direction of analyzing portfolio risk based on a probability distribution of risk drivers, but we did not want to be prescriptive at that time in requiring the use of the Value at Risk (VaR) or Cash-Flow-at-Risk (CFAR) models. We approved, with modifications, the scenario approaches of PG&E and SCE and approved SDG&E's methodological approach without modification. Lastly, we directed Energy Division to schedule a workshop in early 2003 to assist us in gathering additional information on the subject of portfolio risk measurement. Energy Division held the workshop in April 2003 and filed a report on the use of probability distribution models with the Commission on June 6, 2003.

In their 2004 STPPs, both PG&E and SDG&E propose to use TeVaR (To Expiration Value at Risk), a type of VaR model, to measure and report risk and to trigger review of their hedging plans with the PRG.[111] SCE states it can report using a TeVaR model, but it is in the process of developing a proprietary, in-house model that uses "statistical distribution of portfolio costs....which will show the probability of each particular portfolio cost outcome." At the time of evidentiary hearing, SCE testified that this new model was in a conceptual stage of development. SCE asks that the Commission make a finding here to approve the concept and all development costs. SCE indicates that it will share the results of its in-house model with Commission staff and the PRG before using the model. On cross-examination, SCE's witness testified that the utility would be willing to have the model validated by an independent source.

ORA objects to SCE's request, testifying that if the model is still conceptual at this late stage, it is untimely for approval or consideration in this proceeding. ORA also states that ratepayers should not have to pay for development of this model.

TURN testifies in support of the VaR models and requests the utilities specifically focus on the concept of "Ratepayer Cost at Risk" in using the models.

Section 454.5 (b) (1) states that an electrical corporation's proposed procurement plan shall include "an assessment of the price risk associated with the electrical corporation's portfolio." The Commission has a fiduciary duty to ratepayers to ensure that this price assessment is conducted in a consistent manner, with standards of transparency inherent in today's commercially available risk management models. Based on the Energy Division's filed

[111] TeVar is not proposed by either utility to make specific trade decisions, a policy that ORA endorses.

workshop report and based on the hearing record, the Commission has a better understanding of the nuances and complexities involved in measuring portfolio risk, as well as the features specific to each utility's energy portfolio.

We recommend that portfolio risk be reported using TeVaR. The VaR product is a staple of the financial industry. It was developed in the mid-1990's and is widely used by Wall Street as well as by non-financial blue-chip corporations. ORA testifies that all of the IOUs' holding companies indicate in their 2002 Annual Reports that they use a VaR model. The validity of VaR and other commercially available risk methodologies is that their commercial viability provides the Commission with a consistent and transparent benchmark through which IOU portfolio risk can be measured. As has been noted: "VaR has become a common language for communication about aggregate risk taking, both within an organization and outside (e.g., with analysts, regulators, rating agencies, and shareholders)."[112]

While we continue to believe that the Commission should not be overly proscriptive in directing utility risk management practices, we need to balance our preference for an "even-handed" treatment on procurement policy with an emphasis on transparency and consistency in risk management reporting. The Commission recognizes the importance of standardized risk reporting in order to measure ratepayer risk on an "apples-to-apples" basis and to ensure that utility procurement decisions will benefit all IOU ratepayers in an equitable and unbiased manner. By establishing a common benchmark, the Commission can assure itself that California's ratepayers, regardless of utility,

[112] RiskMetrics Group; Risk Management: A Practical Guide, p. 3.

are equally protected from adverse risk, and thereby can reap the benefits of reliable energy at low and stable rates.

While we adopt here the use of a consistent, transparent model for AB 57 compliance, SCE can continue to develop its own in-house model and bring it back for consideration here when it is fully developed and independently tested and verified. Cost recovery for this model would be sought through the General Rate Case (GRC) process, the same as all procurement administration expenses.

We now address the issue of the level of risk the utilities should report using TeVAR. The 95th percentile, as indicated by SDG&E, accounts for all of the cost possibilities except for the last 5 percent of the high-end tail of the distribution of possibilities. Both SDG&E and ORA recommend this level as the standardized reporting measure. SCE states that it can report risk using its proprietary model at any confidence level, but does not advocate a specific level. PG&E recommends reporting at both the 95th and the 99th percentile, with use of the 99th as the standard for managing its portfolio within the CRT.

We believe risk reporting should be a "roadmap," alerting the Commission of the relative risk in different time periods. At a 95th percentile, we would not be aware of a 1 in 20 possibility. As discussed in relation to the interim CRT, we have found that the tolerance of California ratepayers for high price volatility is low, and the utilities should measure the probability of extreme price spikes all the probabilities, and then apply the one cent/kWh CRT. The current risk reporting is at 95th percentile and under this standard, only twice has an IOU called a PRG meeting to discuss the situation (SDG&E on February 25, 2003 and PG&E on March 5, 2003). Based on this, we find a 99th percentile reporting will provide additional price volatility protection and should not be burdensome to the IOUs. We are also guided by TURN's testimony that our risk management standards should be a protection against highly unlikely events. While we do not adopt PG&E's additional stress scenario proposal as a requirement, there may be instances, e.g., the gas price run-up earlier this year, where this analysis is prudent and we encourage the utilities to perform any additional scenario analysis they believe is warranted and to discuss this information with their PRG. With respect to portfolio risk notification, we adopt ORA's proposal that:

1. If between quarterly updates, a utility's estimated risk is over 125% of the CRT, the utility will promptly meet and confer with its PRG and discuss specific hedging strategies and plan modifications so that the value of the utility's open position will stay within the CRT.
2. Within 10 days of the PRG meeting, the utility will file plan modifications in the form of an expedited application.
3. Until the application is approved, the utility may purchase from spot markets, enter into bilateral trades, broker-assisted trades, or execute trades through an exchange.

Therefore, we adopt risk reporting using a by-product of VaR (TeVaR), measured on a 12-month rolling basis, at a 99% confidence level. Risk reporting should cover a longer period if the utility entered longer term transactions within the quarter.

C. Limits on Length and Volume of Contracts Authorized

Based on our review and parties comments, we find PG&E's and SDG&E's volumetric limits and length of contracts reasonable.

In D.02-12-074, the Commission agreed with concerns expressed by ORA and TURN regarding the prospect that SCE could over-procure energy and capacity. The proposals before us there and our findings are:

> "Both ORA and TURN propose downward adjustments to Edison's position limits. ORA states that given the great degree of uncertainty regarding both the size of the 2003 RNS and the distribution of probable future electric market costs, and because customer risk aversion has not yet been measured, the Commission should be conservative and not authorize the utilities to sign excessive amounts of contracts for 2003. It also states that the Commission should keep in mind that, unlike during the energy crisis of 2000-2001, market prices only apply to about 5 to 10 percent of the market, not 100 percent. ORA recommends that the maximum RNS purchase limit be set to a specified percentage of the average hourly RNS for the reference or expected case. For Edison, ORA proposes a modified annual limit for capacity contracts, a modified monthly forward energy contract limit, as well as separate volume limits for gas contracts.
>
> "TURN states it is concerned that Edison's plan appears completely focused on ensuring that Edison is not caught short in a period of price volatility while failing to contemplate the possibility of over-procurement and its adverse financial consequences for bundled ratepayers. TURN states that based on its review of the forecasts provided by Edison, the risks associated with potential high market prices (or total dysfunction) appear to be manageable even without locking in any major additional capacity commitments.
>
> "As an additional measure to protect ratepayers, TURN proposes that Edison be authorized to procure only 50% of its proposed energy and capacity limits through transactions that do not require pre-approval by the Commission. To the extent that Edison believes that

> forward purchases of the remaining 50% will benefit ratepayers, it should be required to make a showing as part of a pre-approval process that does not presume reasonableness of the quantities or prices.
>
> "We share the concerns of ORA and TURN regarding the prospect that Edison could over-procure energy and capacity. While recognizing that Edison proposes maximum limits that it may not in fact utilize, it is not prudent at this time to pre-approve these ceilings based on a worst-case RNS scenario. We are particularly concerned that Edison could over-hedge its position for a five-year term. This would effectively preclude the Commission's ability to consider renewable procurement under the Renewable Portfolio Standard (RPS), and additional energy efficiency and demand reduction programs for the 2004-2007 period in the long-term planning process. It would also preclude the Commission's ability to ensure that Edison responds in an economically efficient manner to possible reductions in its 2004-2007 RNS from community aggregation and other factors.
>
> "Therefore, we adopt ORA's recommendation that Edison establish its monthly forward energy limit based on its Reference Case RNS-Reference Dispatch Scenario, with certain modifications that are specified in confidential Appendix B. We also adopt a modification of TURN's 50% recommendation to address five-year contract limits. We do not find sufficient justification in this record to adopt ORA's recommendations to further limit gas volumes."

In this proceeding, SCE again requests five year contracting authority, and, based on an escalating formula over 2004-8, it is for over 100% of its 2004 RNS needs. SCE proposes volume transaction limits based on its Reference Case scenario (rather than High Case scenario as it did last year), however, the 2004 Reference Case forecast for RNS filed here is 55% higher than the 2004 RNS High Case forecast included in SCE's 2003 plan. In addition:

- SCE's 2004 average off-peak annual position limit for forward energy purchases is about 7 times the limit indicated in its 2003 plan (with the 2003 plan using a High Case scenario while the 2004 plan uses a Reference Case scenario);
- SCE's 2004 average on-peak annual position limit for forward energy purchases is about 4 times the limit indicated in its 2003 plan, using the same scenarios described above.
- SCE's 2004 plan's position limit for capacity contracts is over twice the MWs of its 2003 plan's position limit; and
- SCE's 2004 plan's average monthly limit for natural gas hedging is about four times the average monthly limit in its 2003 plan. (Note: This monthly limit does not include QF gas hedging)

No party specifically testified on SCE's five-year request for authority. SCE's request is not in line with the authority requested by PG&E and SDG&E, and we are again concerned that granting this authority could effectively preclude our ability to consider renewable procurement under RPS, and additional energy efficiency and demand reduction programs for the 2005-2008 period in the long-term planning process, and that it could preclude SCE from effectively responding to the uncertainties it cites regarding its customer base. Therefore, we retain the existing modification of TURN's earlier 50% recommendation we adopted in D.02-12-074.

For the substantial changes in SCE's RNS forecast, we look to the testimony of Jan Reid of ORA. He states that RNS appears to be very difficult to model in the near term and that if pre-approval is given for a longer time and its essentially based on the RNS models, then you run the risk of significantly overpaying for what you thought were hedges at the time that you signed them.[113]

ORA does not specifically cite the RNS forecast variances we discuss here or the substantial changes in volume limits being requested. The only specific recommendation ORA provides, is to never allow a utility to hedge all its risk, and to limit all IOUs natural gas hedging for QF price risk to 73%.

We do not have a record here to find SCE's request for maximum volume limits based on its 2004 plan RNS and position limits for off-peak annual, on-peak annual, capacity contracts, forward energy sales, and average monthly limit for natural gas to be reasonable. We do find sufficient justification for SCE's proposals for gas storage capacity, to include associated injection and withdrawal rights, based on a certain term. We note that SCE's transmission and gas pipeline capacity requirements have yet to be determined, and direct that SCE make a filing when firm estimates become available.

We recognize that with pre-approved cost recovery and no incentive mechanism, there may be a perverse incentive for the utilities to pay too high a price to remove all risk. Therefore, we direct SCE use the 2004 RNS Reference Case forecast from its 2003 STPP and the transaction rates currently adopted.

We find ORA's proposal for a 73% limit on hedging for QF price risk to be reasonable and, therefore, adopt it.

D. Upfront Standards for Utility Procurement Products and Transactions (was Consideration of 2004/5 Policies/Programs)

[113] Transcript at 4221, July 28, 2003.

In D.02-10-062, Section VI, the Commission adopted a list of authorized products, specified authorized procurement transaction processes, and established upfront reasonableness guidelines for transactions. Parties propose various modifications in these areas.

1. Authorized Products

In D.02-12-062, we authorized the utilities to conduct procurement using a wide range of products and instructed the utilities to specify in their 2003 procurement plans the products they intend to use along with a definition of the product and the associated benefit/cost attributes. The specific procurement products that we authorized in D.02-12-062 are shown below. We continue to authorize the utilities to procure these products.

Table 1
Authorized Procurement Products

Transaction	**Description**	**Benefit /Cost**
Forward Spot (Day-Ahead & Hour-ahead (purchase, sale, or exchange)	Purchase pre-scheduled energy or load reductions at fixed price	Needed to balance short-term load/resource changes/ Vulnerable to price volatility
Real-time (purchase or sale)	Energy imbalance transactions or load reductions	Balances Short-term needs/ Vulnerable to price volatility
Forward Energy (purchase or sale)	Contracts entered into in advance of delivery time, includes block/forward products (e.g., fixed amounts of energy over a specified period of time (e.g., 7x24, 6x16, super-peak, and shaped products) Could be fixed price	Reduces price risk / Risk that prices will be below contracted rate
Forward Energy (demand side)	Baseload usage reduction through investments in permanent energy efficiency	Reduces price risk and cost overall
Capacity (purchase or sale)	Right to purchase energy in exchange for	Reduces spot price risk /

Table 1
Authorized Procurement Products

Transaction	Description	Benefit /Cost
	capacity payment. If exercised, buyer also pays incremental energy charge at specified rate	Reduced risk comes at cost of reservation and energy charges
Capacity (demand side)	Right to purchase load reductions for capacity payments	Provides dispatchable reliability
On-site energy or capacity	Energy or capacity products self-generated on the customer side of the meter	Provides locational reliability and lowers price risk through supply diversity
Tolling Agreement	Type of capacity product where buyer hedges fuel cost risk by providing the gas supply, transportation, and storage	Reduces peak price risk / Buyer pays reservation or capacity charges, and is open to gas price risk
Peak for off-peak exchange	Trades peak energy for off -peak energy (x peak MWh < y off-peak MWh)	Reduces peak price risks / Increases off-peak price risks
Seasonal exchange	Buyer receives peak energy in Summer and returns peak energy in Winter	Reduces summer price risk /Increases winter peak price risk
Physical call (or put) option	Deal to purchase energy in future at pre-set price (price may be pegged to an index). [Call is right to purchase, put is right to sell.]	Call reduces price risk, with option to not exercise right if prices lower. Put insulates from reduced value of excess energy / Fee associated with these rights
Financial call (or put) option	Caps energy price without losing the benefit of lower prices. Price of energy is capped at a fixed price; at times when an agreed upon index price falls below the fixed (strike) price, the buyer pays the lower index price	Reduces price risk / Reduced risk comes at price of option premium (fee)
Financial swap	Buyer gets or pays difference between floating price index and a fixed negotiated price	Locks in fixed price (reduces price risk) / Cost if negative difference between floating index and fixed price

Table 1 Authorized Procurement Products		
Transaction	**Description**	**Benefit /Cost**
Insurance (Counterparty credit insurance, cross commodity hedges)	Buyer can insure against various adverse events (such as extreme temperature, a generating unit failure, or counterparty default, among others), to reduce price risk	Insurance policies can reduce price risk, but increase energy costs by the amount of the insurance premium
Electricity Transmission Products	Arranged through CA ISO and with non-CAISO transmission owners. Also includes purchase of transmission rights or use of locational spreads.	Reduces price risk associated with varying transmission conditions.

Gas Transportation Transaction	Buyer contracts for transportation of gas to a determined delivery point, at a set price (could be fixed or variable) over a specified time-frame	Reduces price risk associated with gas transportation (and therefore, limits some electric generation price risk for gas-fired units)
Gas Storage	Buyer reserves gas storage capacity for a defined price	Hedges price risk associated with gas storage
Gas Purchases	Purchased on a monthly, multi-month, or annual block basis	Used to hedge fuel cost risk associated with capacity contracts
Ancillary Services	Replacement reserve, regulation up, regulation down, spinning-reserve, non-spinning reserve	Needed to assure system reliability

In its 2004 procurement plan, PG&E identifies a confidential subset of these authorized products that it is likely to use. SCE notes that in addition to the products listed in D.02-10-062, it seeks authority to transact for the following additional products.

Transaction	Description	Benefit/Cost
Structure Transactions	Combine one or more product types, varying expiration dates, tiered prices, etc.	Tailor hedges to match your exposure.
Emissions Credits futures or forwards	Provides right to purchase emissions credits at a fixed price	Hedge exposure to emissions limits resulting from contractual terms.
Weather triggered option	Any transaction otherwise authorized with payment/exercise rights based on weather.	Tailor hedges to match exposure correlated with weather conditions.
Forecast Insurance	Payment to SCE occurs in case of deviations of weather from forecast	Hedges costs resulting from inaccurate forecasts
Gas Purchases	Purchased on a daily basis	Used to hedge fuel cost risk associated with capacity contracts.

We find that these types of transactions are reasonable for SCE's 2004 procurment.

SDG&E's 2004 procurement plan states that last year's table of authorized procurement products includes substantially all of the physical products SDG&E intends to use in its short-term procurement activities. SDG&E explains in detail the types of transactions it wishes to engage in during 2004. In addition to the products that are included on the list from D.02-10-062, are the following:

Transaction	Description	Benefit / Cost
Non-FTR Locational Swaps	SDG&E will have available to it certain resources located outside of the SDG&E service territory that do not have FTR protection. SDG&E may choose not to import the power into SP15 but sell it at the delivery point, purchasing replacement power in SP15 or another location with less congestion risk.	There is some risk of congestion from distant resources without FTR protection. This strategy mitigates that risk. Such open positions would be measured and managed consistent with overall risk management practices.
FTR Locational Swaps	SDG&E owns some FTRs from ZP26 to SP15 via the CAISO2003 FTR auction. When some or all of the FTR capacity is not being used for Sunrise energy deliveries, SDG&E will enter into locational swaps to improve on the initial value of the FTR hedge.	This allows SDG&E to take advantage of the value of its FTRs and reduce overall costs.
Counterparty Sleeves	Two-sided trades where the same product is purchased from one counterparty and sold to another simultaneously.	This helps SDG&E reduce its credit exposure with overexposed parties. It may also reduce SDG&E's costs where it facilitates trades between parties that cannot trade with each other due to credit restrictions.

We find that these types of transactions, though not explicitly accounted for in the list of authorized procurement products included in D.02-10-062, are reasonable for SDG&E's 2004 procurement.

2. Transactional Processes

In D.02-10-062, the Commission authorized the utilities to procure products using the transaction processes listed below.

Transaction Process	Guidelines
Competitive Solicitations (Requests for Offers)	D.02-10-062 set forth guidelines governing the process by which the IOUs shall conduct RFOs. These guidelines are as follows: • Procurement plans shall specify the steps of the solicitation process to be used. The process shall be consistent with the competitive solicitations in use now under transitional procurement authority. • Competitive solicitations may be all-source or may be segmented to allow similar sources to compete with each other, but must cover all of the sources described in section V above. • Solicitations should be widely distributed (starting with bidders list used under transitional procurement authority). Required items shall include among other things: ➢ Description of product requirements ➢ Term ➢ Minimum and maximum bid quantities ➢ Scheduling and delivery attributes ➢ Credit requirements ➢ Pricing attributes • Each utility shall update its procurement plans to specify and describe the evaluation tools and methodology it will use to rank and select bids, such as: ➢ Minimum requirements for counter-party creditworthiness ➢ Minimum number of bids that must be received ➢ An evaluation of cost-to-risk tradeoff (consumer risk tolerance level) of the various bids
Transparent exchanges, such as Bloomberg and Intercontinental Exchange.	• Approved utility plans will identify and describe the various electronic energy trading exchanges that each utility proposes to use (e.g., Bloomberg, Trade Spark, Intercontinental Exchange). • The procurement plans shall demonstrate that the identified electronic trading exchanges the utility intends to use provide transparent prices.
ISO markets: Imbalance Energy, Hour Ahead, and Day Ahead (when operational)	• ISO spot market transactions are authorized to balance system and meet short-term needs. • Procurement plans shall describe procurement strategies for hedging the utility's overall portfolio risk with ISO spot purchases

	hedging the utility's overall portfolio risk with ISO spot purchases. • While we wish to provide utilities with timing flexibility in meeting their residual net short needs, it is not our intention to have the entire RNS met in the spot market. Though we do not set an explicit limit on spot market purchases, utilities should plan to minimize their spot market exposure and should justify their planned spot market purchases if they exceed 5% of monthly needs. •We authorize the use of a Day-Ahead Market should it become operational.
Inter-Utility Exchanges	In. D.02-10-062 the Commission provided the following guidance: • Unless we adopt specific guidelines for negotiated IUEs these deals would only occur through an RFO process, which is unlikely to be as successful in price or in meeting specific needs of both parties. By adopting the benchmark and other guidance discussed below we allow negotiated IUEs to be included for approval in the monthly advice letter filings. • The important elements to justify an IUE as reasonable would include: ➢ Cost-effective reductions to seasonal or specific RNS, ➢ Cost effective reductions to seasonal or specific Residual net-long positions. To justify as cost-effective an IUE to reduce RNS (acting as a buyer), the utility will have to demonstrate that at the time of executing the IUE agreement the expected costs for the repayment was less than the avoided incremental costs at the time of delivery. This determination would be based upon the incremental costs of the existing delivery time and repayment time portfolios available when the IUE is negotiated. For example, if the delivery's existing portfolio incremental transaction cost or the most recent RFO bids for the delivery period are more than $100 and if the repayment portfolio's incremental transaction cost was $100 or less then the IUE could be deemed reasonable when filed by advice letter. This total transaction cost would account for the differing values of capacity, energy, ancillary services, and volume of energy in the two sides of the transaction. To justify as cost effective an IUE to reduce residual net long positions (as a seller being repaid in capacity, energy, or ancillary services) the utility would have to demonstrate that the average portfolio value of the time of repayment is higher than the forecast of spot prices when firm energy would otherwise be dumped as surplus into the spot market. (D.02-10-062 ,)
Direct bilateral contracting with counterparties for short-term (i.e., less than 90 days) products	D.02-10-062 authorized such contracting subject to a "strong showing" that these transactions represent a reasonable approximation of what a transparent competitive market would produce. D.02-12-074 added that the strong showing can be met by a "comparison to Requests for Offers completed within a month of the transaction." In D.03-06-067, the Commission waived the "strong showing" standard for

	negotiated bilaterals for non-standard products procured 31 days or less in advance of delivery and with terms of one-calendar month or less. "Although we waive the strong showing standard for these transactions, the utilities should demonstrate that such transactions are reasonable based on available and relevant market data supporting the transaction. This may include, showing competing price offers, result of market surveys, broker and online quotes, and/or other source of price information such as published indices, historical price information for similar time blocks, and comparison to RFOs completed within one month of the transaction. Additionally, we stated that in instances when a utility knows that it will have a need for non-standard products on a forward and recurring basis, "we strongly encourage the utilities to transact for such products using an RFO process."
Utility Ownership	Utilities may propose to buy or construct generation

The utilities propose to conduct procurement using the same transactional processes listed above in their 2004 procurement plans. SCE's short-term plan also notes that it plans to use (i) Open Access Same-Time Information Systems (OASIS) to procure standard electric transmission products from transmission providers throughout the WECC region at FERC tariffed rates and (ii) voice and on-line brokers, as it did in its approved 2003 procurement plan. SDG&E and PG&E propose to use brokers as well. SDG&E's plan speaks to the use of over-the-counter brokers stating:

> "SDG&E includes over-the counter brokers. . .in the definition of exchanges because these firms offer a common mechanism of matching buyers and sellers at the current competitive market price, in concert with electronic exchanges… In addition, there is a high degree of overlap of products and prices offered since counter parties can use electronic exchanges and over-the-counter brokers interchangeably, thus increasing transparency and providing an opportunity for price comparisons." (SDG&E 2004 Short-Term Plan, p. 22.)

We recognize that there may be a pro-competitive effect from broadening our understanding of transparent exchanges to include reputable OTC brokers. We will hold the utilities to the same high standards for transactions consummated through OTC brokers as we do for exchange transactions. That is, the utilities shall demonstrate that the identified OTC brokers provide prices that are equivalent to those of exchanges.

With regards to bilateral contracting, PG&E proposes to expand the use of this transaction process to include products with delivery starting up to six months out. This differs from the authorization we provided in D.02-10-062 where we restricted direct bilateral contracting to short-term products only (i.e., less than 90 days). PG&E does not specify a term length restriction for the expanded bilateral contracting authority it seeks in its 2004 procurement plan.

In explaining the use of bilateral contracts in procurement, PG&E explains that such contracting occurs through private negotiation, through electronic exchanges, and through brokers. In support of expanding the authorized use of bilateral contracting, PG&E explains that bilateral contracting is preferred over competitive solicitations for a number of reasons, including: (1) use of competitive bid processes limits PG&E's price discovery; (2) the competitive bid process has potentially high transaction costs for both buyers and sellers and this can limit the number of parties participating in an RFO process; (3) RFOs may require bidders to hold prices open for an extended period of time while the process unfolds, thereby increasing prices; (4) competitive solicitations typically take several months to complete; (5) limiting transactions to only competitive solicitations can lead to market power because bidders will know the utility has limited alternatives to execute transactions; (6) utilities outside of California are the most likely counterparties for inter-utility exchanges; and (7) the financial duress besetting many counterparties in the WECC region may limit the role of marketers. Finally, PG&E states:

> "If all products greater than three months' duration, or to be delivered three months out, were transacted via a competitive bid process, PG&E would be frequently issuing RFO/RFP up to two months before actual delivery, a costly and impractical proposition. Hence, PG&E necessarily relies more frequently on bilateral contracting for products with delivery starting up to six months out." (2004 short-term plan, PG&E, p.4A-3, 4.)

SCE seeks to expand the use of bilateral contracting as well, specifically for negotiated bilaterals as opposed to brokers and exchanges. For negotiated bilaterals, SCE requests authority to transact for products up to five years in term. SCE conditions this expansion of bilateral authority in instances where "five counterparties or fewer can supply the service or enter into a particular transaction (this may occur, for instance, when purchasing natural gas storage or pipeline capacity). SCE also proposes that physical gas bilateral transactions be authorized for up to [five years] if the pricing for such a transaction is index linked." (SCE 2004 Short-term plan, p. 128.)

SDG&E likewise proposes to use negotiated bilaterals, particularly for non-standard products, but does not specify a term length restriction.

With the exception of ORA objecting to SCE incorporating a five-year horizon under its 2004 short-term plan, no party voiced opposition to these bilateral contracting proposals. We discuss this request for authority in relation to the cost-effectiveness testing for transactions and benchmarks proposed for each type of transaction, as discussed below.

3. Cost-Effectiveness Testing for Transactions & Benchmarks

ORA, PG&E and SCE each propose modifications to the transaction selection protocols adopted in the 2003 short-term procurement plans.

a) ORA's Proposal

In its June 23, 2003 direct testimony, ORA requests that the Commission approve a procurement process for use by PG&E, SCE, and SDG&E. The process, as proposed by ORA, is as follows:

1. Define scenarios or model inputs;
2. Weight scenarios or model inputs;
3. Establish other input assumptions;
4. Establish candidate products that would be effective given particular stress scenarios or other model results;
5. Solicit hedge products;
6. Share bids with PRG;
7. Evaluate candidate hedges and rank according to cost-benefit analysis;
8. Meet with the PRG and solicit comments from PRG members and attempt to reach a consensus;
9. Tentatively select hedges;
10. Update TeVaR to reflect the addition of the new candidate hedges; and
11. Select hedges.

The 11-step process outlined above is consistent with the procurement process proposed by PG&E in its 2004 procurement plan with the exception that ORA has inserted several steps for utility consultation with its PRG. We also note that ORA's 11-step procurement process generally reflects the procurement process that each utility employed in 2003 for competitive solicitations.

The issue of how often this process should be used by the utilities was raised by SCE during hearing when it pointed out that the utility typically enters into between 20,000 and 50,000 transactions a year. SCE implied that the process would be too cumbersome and unwieldy for all procurement transactions given the large volume of transactions the utility conducts per year. ORA clarified on cross-examination that it does not advocate use of its proposed process for spot-market transactions, one-week-ahead transactions, and prompt-month transactions (transactions executed one calendar month prior to the month of delivery).

b) PG&E's Proposal

PG&E proposes price benchmarks for the various procurement products it seeks to transact for under its 2004 short-term plan. For transactions of real-time energy and ancillary service from ISO markets, PG&E proposes that ISO settlement prices should serve as the benchmark given that ISO markets are the only markets for such products. For standard procurement products, PG&E essentially proposes to use "available and relevant market data, including price quotes from counterparties, brokers, and electronic exchanges, forward curves developed by PG&E and/or third parties, and published indices, supplemented by online price information from news services like Bloomberg and Reuters." {PG&E short-term plan, p. 4A-4} For non-standard spot market transactions in the day-ahead and hour-ahead markets, when there is no relevant market information, PG&E proposes to demonstrate that these transactions are reasonable based on the need for the products and to document how these non-standard products "were evaluated and adjusted in value compared to more visible price benchmarks." (p. 4A-4)

PG&E further states that in situations where no relevant market data exists to establish a benchmark, PG&E will seek the concurrence of its PRG to go forward with the transaction based on a benefit/cost test pre-agreed with the PRG.

ORA does not challenge PG&E's proposed benchmarks for real-time energy and ancillary services procured from ISO markets. With respect to other product benchmarks ORA recommends that the Commission reject these benchmarks finding that they are incomplete, oversimplified, and lacking definition. Additionally, as discussed in more detail in Section the previous section addressing ORA's proposed 11-step procurement process, ORA objects to PG&E's proposal to use a pre-approved benefit/cost transaction test.

We note that although PG&E did not advance specific benchmarks in its procurement testimony, in its PG&E's 2004 Energy Resource Recovery Account testimony, filed August 1, 2003, PG&E presents numerous specific benchmarks for electricity products. We summarize those benchmarks below by transaction term.

Term Transaction

Forward: Prompt-month or longer
Term: 21 days or longer.

Index: Calculated by averaging end of trading day forward prices for the appropriate product (on-peak or off-peak), location (COB, NP15, SP15), time frame (month or quarter), and transaction date of Brokers (Amerex, Natsource, ICE, Prebon and TFS).

Balance of Month Transaction

Forward: Current month or next month
Term: less than 21 days, ≥ 14 days

Index: Calculated by averaging the end of trading day forward prices for the appropriate product (on-peak or off-peak or flat), location (COB, NP15, SP15), month, and transaction date of Brokers.

<u>Day Ahead Transaction</u>

Forward: Transactions for the next one, two or three days (according to ISO scheduling protocols)
Term: One day

Index: Calculated by averaging the index for the appropriate product (on-peak or off-peak or flat), location (COB, NP15, SP15), month, and transaction date of Brokers.

<u>Hour Ahead Transaction</u>

Forward: HA Market, current month or next month forward
Term: less than 24 hours.

Index: Developed using Dow Jones Hour Ahead indices, which are currently the only publicly available HA indices. The HA indices for some hours at COB and SP15, and all hours at NP15 were estimated, as there is no published NP15 HA index and hourly price data for COB and SP15 are spotty. For **<u>COB</u>**: the COB HA index was used when available; when there was not a Dow Jones published index for COB for a given day, the hourly Dow Jones MidC index was used with an adder based on the DA COB/MidC spread. For **<u>NP15</u>**: when a COB hourly index was available it was used with an adder based on the NP15/COB DA spread (on-peak or off-peak hours as appropriate). If a COB index was not available, the SP15 hourly index was used when available with an adder based on NP15/SP15 spread (on-peak or off-peak hours as appropriate). If neither the COB nor the SP15 hourly index was available, the MidC hourly index was used with the

> DA on-peak or off-peak NP15/MidC spread. For **SP15**: the SP15 HA index was used when available, when there was not a Dow Jones published index for SP15 for a given day, the hourly Dow Jones Palo Verde (PV) index was used with an adder based on the DA SP15/PV spread. If neither the SP15 nor the PV index was available, the calculated NP15 hourly index was used with the DA on-peak or off-peak SP15/NP15 spread.

c) SCE's Proposal

In its 2003 adopted plan, SCE established a benchmark for all transactions that the Risk Hedged (RH) divided by the Cost of the Hedge (COH) must be greater than a confidentially specified value. In its 2004 filing, SCE does not propose to use this risk screening criteria. Instead, SCE states that no risk screening criteria should be applied to transactions extending X (confidential) years or less, and that for those extending more than X years, the prospective transaction must reduce portfolio risk. SCE's requirement from its 2003 procurement plan that transaction timing and volume policy mitigate price risk has been eliminated from its 2004 plan.

We find SCE's proposal to not apply a risk screening criteria to transactions of less than a certain length to be in contravention of AB 57, which requires utilities to optimize portfolio value, regardless of the maturity of the transaction. SCE should retain its existing standard for its 2004 plan.

d) SDG&E's

SDG&E's 2004 plan asserts that its proposed trading methods meet the criteria for reasonableness. Regarding its proposed use of bilateral contracts, the Company asserts:

Prior to executing such an [sic] structured transaction, SDG&E would (1) compare the economic and operational benefits to its associated premium over dispatching a CDWR contract and against purchasing a standard energy product valued against the forward prices covering the same period of delivery, and (2) demonstrate that the product benefits the overall portfolio by reducing net cost or customer VaR. This meets the criteria for bilateral contracts set forth in Section VI.E. of D.02-10-062 and these transactions should therefore be deemed reasonable.[114]

SDG&E also asserts in its 2004 plan that all transactions entered into through use of transparent exchanges and brokers should be deemed reasonable, as should its proposed use of spot markets, competitive solicitations, and purchases of reserves and other ancillary services, all of which will be completed in a manner meeting the criteria established in D.02-10-062.

4. Discussion

For the 2004 short-term plans, we authorize the utilities to conduct procurement using the following transactional methods:

1. Competitive Solicitations (RFOs/RFPs)
2. Electronic exchanges and voice and online-brokers
3. ISO Markets
4. Inter-utility Exchanges
5. Negotiated Bilateral Contracting as defined and limited below
6. Open Access Same-Time Information Systems (OASIS) sites

[114] SDG&E ST Plan, page 21

We adopt the 11-step procurement process proposed by ORA as the standard procurement process to be used by PG&E, SCE, and SDG&E. This process is to be used in that small minority of the total number of transactions where there is substantial value and risk. As discussed below, for the great multitude of transactions, the 11-step procurement process is not helpful and is too burdensome. The exceptions are discussed below.

Recognizing that this process is not appropriate for all procurement transacting, we provide exceptions to this process as discussed below. The 11-step process is best suited for procurement transactions that are developed and planned over a long period, such as transactions that are entered into on a multi-month forward basis, long-term PPAs, acquisition of generating resources, or other significant contracting efforts involving competitive solicitations (i.e., Requests for Offers). Such transactions are likely to involve more planning cost and they embody more risk. With respect to negotiated bilateral agreements, we do not authorize such contracting except as provided below.

For short-term transactions (i.e., less than 90 days in term) executed within a 90-day window prior to delivery, the IOUs are not required to employ the 11-step process. Given the speed by which transacting occurs during this short-term time period, we find that the 11-step process would be too unwieldy to apply, particularly given the enormous number of transaction that the IOUs typically transact for during this timeframe.

We grant authority for the use of negotiated bilateral in three limited circumstances only. First, for short-term transactions of less than 90 days duration and less than 90 days forward, the IOUs are authorized to continue to use negotiated bilaterals subject to the strong showing standard we adopted in D.02-10-062, as modified by D.03-06-067. Any such negotiated bilateral transactions shall be separately reported in the utilities quarterly compliance filings.

Second, utilities may use negotiated bilateral contracts to purchase longer term non-standard products by including a statement in quarterly compliance filings justify the need for a non-standard product in each case. The justification must state why a standard product that could have been purchased through a more open and transparent process was not in the best interest of ratepayers.

We are receptive to expanding the use of negotiated bilaterals for standard products in instances where there are five or fewer counterparties who can supply the product, as suggested by SCE. We limit this authority, however, only to the two categories of gas products cited by SCE: gas storage and pipeline capacity. In such instances, the utility needs to affirm that five or fewer counterparties in the relevant market offered the needed product. Any resulting contract shall be separately reported in the utilities' quarterly compliance filings

In D.02-10-062, we restricted the use of "direct bilateral contracting." Our purpose in limiting the use of such contracting was to (i) prevent a situation from arising where utilities would conduct substantial levels of procurement through private negotiated deal-making as opposed to through processes involving greater price transparency and competition while at the same time (ii) providing the utilities with transaction flexibility to procure near-term and short-term products (including non-standard products) necessary for system balancing and reliability purposes without burdening the utility with a competitive bid process. In limiting the use of negotiated bilaterals, we also sought to promote procurement transaction transparency given the restriction in Pub. Util. Code § 454.5(d)(2) on ex-post reasonableness reviews of a utility's procurement activities and given the Legislative intent of AB 57 for the Commission to approve procurement plans that employ the use of competitive procurement processes.

PG&E articulates a number of significant points regarding the use of negotiated bilaterals, but other than stating that such contracting would be conducted for products with delivery up to six months out, it does not propose any restrictions or parameters delineating how much of its procurement would be secured through negotiated deal-making. If we adopted PG&E's request, would a utility seek to conduct most or nearly all of its procurement up to six months out through a series of negotiated bilateral agreements? This remains our concern. Pending the development and adoption of a procurement incentive mechanism, we authorize the utilities to pursue negotiated bilaterals subject to the restrictions outline above. We stop short of adopting PG&E's proposal until a showing is substantiated that such bilateral contracting will not become the default transactional process for all products with delivery up to six months out.

Lastly, we note that PG&E did not identify the electronic energy trading exchanges and brokerages that is proposes to use under its 2004 short-term plan. In its re-filed, short-term plan, PG&E should include such a list.

E. Fuel and Power Forecasts

ORA and TURN both note that SCE and SDG&E gas price forecasts did not include near term gas prices, and this factor may affect the accuracy of the conclusions. ORA recommends that the utilities should use consistent fuel price forecasts in both short-term and long-term resource planning. ORA also recommends that near term gas prices should always be incorporated or used to supplement testimony in future procurement planning proceedings. TURN argues that the IOUs' fuel and price forecasts are already outdated, jeopardizing the value of the analyses contained in their resource plans. TURN adds that actual gas and electric market prices reported for June 2003 were approximately equal to the "90 percent high" levels of the IOU probability distributions for future Junes starting in 2007.

Discussion

While it is our expectation that the IOUs use the best available data in preparing analyses, it is an eternal truth that forecasts are quickly outdated. We cannot fault the utilities for relying on forecasts that did not anticipate this spring's run up in gas prices. And we note that since the spring, prices have declined. If anything, the facts that TURN and ORA present support a different conclusion: it may be that gas price forecasts upon which the utilities depend underestimate the degree of price volatility in gas markets. Perhaps the distribution of future gas prices is wider than anticipated by current forecasters. Though the forecasters may have the long-term trends right, the amount of price variability around those trends may be greater than has been thought up to now. For future filings, we expect the utilities to use their best effort to obtain up-to-date forecasts, and also to estimate appropriately the high and low cases surrounding those forecasts. Additionally, we note that as part of its 2004 procurement plan, PG&E proposes to update its plan on a quarterly basis to reflect changes to its open position and to relevant market prices. We find that it is appropriate for each of the utilities to review market conditions relative to fuel forecasts on a quarterly basis with its PRG and to file plan updates if the plan does not adequately capture current market conditions. Finally, we note that given the fact that seven months have elapsed since the utilities filed their short-term procurement plans on May 15, 2003, each IOU shall update its within 5 days from the effective date of this decision to reflect changes to fuel prices forecasts and open positions.

F. Role of PRG

In D.02-08-071, the Commission approved the joint request of SCE, PG&E, TURN and the Consumers Union to create utility-specific Procurement Review Groups (PRGs) comprised of eligible non-market participants. In D.02-10-062, the Commission approved the continuation of the PRGs for 2003. The concept of a Procurement Review Group (PRG) was first formally proposed as part of SCE's May 6, 2002 filing of its motion for Capacity Procurement. In this filing, SCE stated that the PRG is a "Commission-authorized entity whose members, subject to an appropriate non-disclosure agreement, would have the right to consult with and review"[115] the confidential details of IOU procurement activity. The PRG would assess procurement activity and upfront reasonableness criteria and offer assessments and recommendations to the IOU when contracts are submitted for Commission review. Following this filing, SCE drafted a memo entitled Joint Principles for Interim Procurement. The three IOUs, TURN and the Consumers Union (CU) are signatories to these Principles. A Procurement Contract Review Process was established, endorsed by the PUC, and incorporated as Appendix B to D.02-08-071.

Each IOU's 2004 procurement proposal is based on the assumption that the PRG process will continue into 2004, and that there will be regular IOU-PRG consultations on proposed procurement and hedging activities. ORA and TURN also support continuation of the PRG in 2004. As TURN states:

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[115] SCE Brief on Generation Procurement, May 6, 2002, p. 11.

> "The creation of the PRGs constitutes an innovative effort to involve utilities, consumers and state agencies in a forward-looking dialogue before formal filings are submitted for Commission approval. The impetus behind the formation of the PRGs - the switch to up-front approval standards under AB 57 - remains relevant for the foreseeable future."

As a key element of its long-term procurement policy, the Commission will be establishing an incentive mechanism and/or upfront standards and criteria to augment the PRG process. Should the PRG "sunset" this year, and without elements of our long-term policy in place, there would be no pre-defined forum in which utilities could inform the Commission and non-market participants of their day-to-day risk management concerns and objectives.

If the PRG were to "sunset" at the end of 2003, PG&E has stated that as a default, it would pursue an on-going, informal dialogue with ORA and other non-market parties regarding proposed procurement and hedging activity[116]. We note, however, that in the absence of a PRG process, this consultation would be strictly ad-hoc and at the discretion of the utilities.

SCE witness Kevin Cini testified during the hearing that, "…I actually think that the PRG process provides more visibility to the Commission and the parties that have access to SCE confidential information than if we had some other process in place."[117] Mr. Cini goes on to say, "Our procurement plan contemplates the PRG continuing to 2004. The PRG is an integral part of our procurement plan."…"we would still want to work with the consumer advocates in an informal way, where we would still share with them business issues that

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[116] Hearing Testimony, Witness Jeung, July 25, p. 4100.

[117] Hearing Testimony, Witness Cini, August 7, pp. 5222-24.

we have….and we would share with them the models that we're considering using to get their feedback on that…"

Though it only has consultative and informal advisory functions, the Commission finds the PRG to be an effective vehicle for IOU dialogue with Commission staff familiar with the nuances of their energy portfolios and the necessary policies/strategies needed to mitigate portfolio risks. The PRG has played a valuable role in identifying potential issues or concerns regarding IOU procurement. Perhaps the most significant achievement of the PRG process since its inception is the reduction of contested or litigated procurement transactions. As stated by TURN in its closing brief:

> "Many of TURN's suggestions have been incorporated into procurement activities without the need for time-consuming and combative litigation. As result, the amount of actual litigation associated with individual transactions and strategies has been limited to a few isolated disagreements . . . ." (p. 38.)

PRG members have sufficient access and dialogue with the utilities, that they can advise utilities of potentially contentious issues or procurement activities prior to the utility executing a trade. The value of this collaborative process is accurately portrayed by TURN in its closing brief:

> "Without a PRG structure, TURN and other non-market participants would be denied the opportunity to learn about ongoing activities and challenges in real-time and instead would be forced to review materials underlying the Advice Letter filings for the first time after the decisions had been made and submitted for approval." (p. 39.)

We find that it is beneficial to continue the PRG process. As provided for in D.02-10-062, each utility shall meet and confer with its PRG on a quarterly basis. Each PRG has the option of conducting meetings by teleconference. When

PRG meetings are conducted by teleconference, we urge each utility to provide electronic copies of meeting materials to PRG members in advance of the meeting, and to provide adequate time for review of such materials prior to the meeting. During the quarterly meetings, each utility shall review with its PRG the utility's open position, changes in market conditions from the previous quarter, including gas and electric prices, hedging strategies going forward, and the necessity of filing a plan update. PRG meetings may be held for often than quarterly under circumstances when portfolio risk exceeds the CRT as described in Section 5.C.1. of this decision.

Even with an incentive mechanism and upfront standards and criteria in place in place, the PRG can serve as a "streamlining" entity, interfacing with utilities and helping to facilitate utility filings at the Commission, thereby making the filing process more efficient. The PRG structure allows for **substantive** review of and input to time-sensitive procurement and risk management proposals, since PRG members (including Energy Division staff) have advance access to the large volume of data and market information inherent in procurement report filings.

The Commission is proposing a long-term risk management framework in which the role/process of the PRG would still be useful, though not as vital. The PRG would not be obsolete, but could continue to serve as an advisory/consultative group to the utilities. Further, PRG members now have knowledge and experience with the utilities' risk management and procurement practices, and most would likely participate in negotiating with the IOUs to develop the incentive mechanism, one of the main elements of our long-term risk management policy. The PRG could alert the Commission if there are concerns or if issues arise as a result of the utilities' procurement activity.

In response to a memo from DWR, we note that the PRG's role is an advisory one, and it does not preclude DWR's authority to conduct a reasonableness review. The Commission has recognized this authority, and now reiterates its recognition of Article 4.2 of the Rate Agreement, which stipulates DWR's authority to determine just and reasonable costs, as per its reasonableness review.

G. Modification and Approval of Short-Term Plans

In its short-term plan, SCE does not use the pro-rata cost allocation of DWR contracts that the Commission adopted in D.02-09-053 and confirmed in D.02-12-045 and D.02-12-069; it should amend its plan to comply with this requirement.

PG&E requests the Commission relieve it of its responsibilities to manage gas hedging for its allocated DWR contracts in the event it does not have sufficient credit capacity to enter into such hedges given the other demands for its limited credit capacity. We deny PG&E's request here. PG&E's responsibilities are set forth in its Operating Agreement with DWR and any changes to that agreement must be done through negotiations with DWR and/or a petition to modify D.03-04-029.

PG&E requests the Commission extend the disallowance cap we adopted in D.03-06-067 to the 2004 short-term plans. We should do this, and on the same terms as we adopted in D.03-06-067, and confirmed in D.03-06-076 and D.03-10-090. We do not entertain PG&E's request to extend the scope of the disallowance cap as we have previously addressed this issue in the above mentioned decisions.

Each utility should file by advice letter within 15 days a revised short-term plan that conforms to this decision. These plans shall conform to all Commission decisions unless specific findings are made here to change a previous Commission decision.

VII. Procedural Process and Schedule for Future Filings

A. Quarterly Compliance Filings

On September 10, 2003, PG&E and SDG&E filed a joint petition to modify D.02-10-062, specifically to extend the due date of the Quarterly Procurement Plan Compliance Reports from within 15 days of the end of the quarter to within 30 days of the end of the quarter. Both utilities state they need this additional time to prepare sufficiently detailed and comprehensive reports. Parties testified to the thousands of transactions that are included in the quarterly compliance filings. Therefore, we find PG&E's and SDG&E's joint petition reasonable and grant the relief sought, on a going forward basis, in this decision.

We also take this opportunity to address the procedural process under which we review these compliance filings. In D.02-12-074, in Section VI, we set a procedural process under which the Energy Division would review the quarterly compliance filings on an expedited basis, with a 30 day review period as a guideline, and then prepare a resolution with their findings and place it on the Commission's agenda. With the Commission's current staff resources, a full review of the filings cannot be done in these expedited timeframes. Rather, the Commission should look to streamlining its review by having the utilities provide an independent auditor's certification that all transactions were reviewed and verified to be in compliance with their adopted procurement plans. This procedure was discussed with SCE's witness Cini, who agreed that Energy Division, in consultation with the PRG, could select an outside auditor for this function.[118] Therefore, we find that the Energy Division should, in consultation with each utility and its PRG, select an outside auditor to review and verify the quarterly compliance filings, and the audit expenses should be paid by the utilities and recorded in a memorandum account. A resolution for the Commission's agenda should only be prepared if Energy Division or the outside auditor find transactions or procurement practices that are not in compliance with the adopted plans.

B. Long-term Procurement Plan Filings

SCE proposes that its long-term plan be reviewed on a three year cycle, in coordination with its general rate case. Specifically, SCE proposes that each utility would develop and submit a long-term integrated resource plan within 90 days of the final decision in its respective GRC, such plan to incorporate those issues resolved in the GRC. Further, SCE states that the Rate Case Plan (D.89-01-040, as modified) already contemplates submission of long-term resurce plans as part of the utility's GRC showing. No party objects to SCE's proposal.

We intend to review and adopt revised 2004 long-term procurement plans for the three utilities in our new Procurement OIR. Following that, a three year cycle of utility-specific long-term planning is reasonable, and, therefore, we adopt this proposal. In our decision on the revised 2004 plans, we should revisit the specific timing of each utility's next GRC filing and revise any long-term plan filing dates as necessary.

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[118] Transcript at 5225, Volume 42

C. ERRA Filings

ORA and SCE recommend that the Commission annually update the short-term procurement plans in each utility's ERRA filing. In addition, PG&E, SCE, and SDG&E have all indicated in their ERRA filings that efficiencies could be made in the procedural process we adopted in D.02-10-062, especially with forecasts established closer in time to the applicable year, a combining of the forecast, reasonableness review, and ERRA true-up in one application for each utility, and the possibility of the ERRA trigger amount being handled by Advice Letter rather than application.

2004 ERRA Schedule

IOU	2004 ERRA AL Trigger /1	2004 ERRA Forecast /2	2003 Reasonableness Review	ERRA Over/Under Collection True-up /3
PG&E	April 1,2004	August 2003	August 2003	N/A
SCE	April 1, 2004	October 2003	October 2003	N/A
SDG&E	April 1, 2004	December 2003	December 2003	N/A

Footnotes:
1/ AL Trigger is based on 12-months (calendar) of prior year recorded data. The IOU's will refile AL if Reasonableness Review Decision modifies recorded data. Note: By April 1, 2004 the IOUs will have closed their books for 2003 and filed their SEC reports.

2/ ERRA Forecast application will be combined with the Short Term Procurement Plan application in 2005

3/ ERRA over/under collection true-up is independent of when IOUs file ERRA Forecast or Reasonableness Review applications - IOUs will file whenever there is an over/under collection.

2005 ERRA Schedule				
IOU	2004 ERRA AL Trigger /1	2005 ERRA Forecast & Short Term Procurement Plan /2	2004 Reasonableness Review /3	ERRA Over/Under Collection True-up /4
PG&E	April 1,2005	June 1, 2004	February 2005	N/A
SCE	April 1, 2005	August 1, 2004	April 2005	N/A
SDG&E	April 1, 2005	October 1, 2004	June 2005	N/A

Footnotes:
1/ AL Trigger is based on 12-months (calendar) of prior year recorded data. The IOU's will refile AL if Reasonableness Review Decision modifies recorded data. Note: By April 1, 2005 the IOUs will have closed their books for 2004 and filed their SEC reports.

2/ ERRA Forecast application will be combined with the Short Term Procurement Plan application. Note: The dates have been changed so the IOUs file earlier in the year. This will allow IOU/PUC to have decisions out by the end of the year.

3/ 2004 Reasonableness Review period will incorporate 12 months of 2004 calendar year data.

4/ ERRA over/under collection true-up is independent of when IOUs file ERRA Forecast or Reasonableness Review applications - IOUs will file whenever there is an over/under collection.

For 2004, the utilities should only update the forecasts in their 2004 adopted short-term procurement plans, all other parts of their short-term procurement plans will be operational for 2005, unless modifications are ordered based on our review of revised 2004 long-term plans. Each utility should file its revised 2004 long-term procurement plan in the new Procurement OIR which we intend to open in the second quarter of 2004.

VIII. Next Steps

In this decision, we adopt the long-term regulatory framework under which each utility will conduct integrated resource planning, to include a resource adequacy requirement and market structure rules. We also adopt modified short-term procurement plans, a revised ERRA procedural process, and direct Energy Division to hire a consultant to perform a CRT study.

We expect to complete all outstanding matters in this rulemaking by the end of May 2004. The outstanding matters are (1) the October 7, 2003 motion of SDG&E for approval to enter into new contracts resulting from its Grid Reliability Capacity RFPs; and (2) the resource adequacy workshops scheduled in Section IV.A of this decision that are needed for the utilities to file revised 2004 long-term plans.

We should open a new procurement rulemaking in the second quarter of 2004 that specifically addresses the additional procurement issues we identify here: (1) the need to develop procurement incentive mechanisms for each utility; (2) the need to develop a long-term policy for expiring QF contracts; (3) review of the management audits of SDG&E's and PG&E's electric procurement transactions with their regulated affiliates; (4) handling resource adequacy issues not addressed in the workshop process; and (5) review and adoption of revised 2004 long-term procurement plans for the three utilities. We expect to open this new procurement OIR in the second quarter of 2004.

IX. Oral Argument and Comments on the Proposed Decision

The proposed decision was mailed on November 18, 2003 for consideration at the Commission's December 18, 2003 agenda. Under the provisions of Rules 77.2-77.5, parties may file comments on the proposed decision by December 8, 2003 and reply comments by December 15, 2003.

An oral argument before the Commissioners has been scheduled for December 2, 2003.

X. Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner and Christine M. Walwyn is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. PG&E, SDG&E, and SCE are the respondent utilities.

2. This decision addresses the procurement planning issues set for further hearing last year in Section X.B. of D.02-10-062 and further delineated at the PHCs on February 18, 2003, March 7, 2003, and July 16, 2003.

3. Implementation of SB 1078 and SB 1038 legislation on the RPS has occurred through a separate workshop process.

4. The three service territories of the respondent utilities account for approximately 80% of California's electricity usage.

5. An Assigned Commissioner/ALJ Ruling issued in this proceeding on September 25, 2003, directed the convening of workshops to address the issue of standardizing, to the greatest extent possible, the load forecasts and methodologies used by the utilities to value and count resources.

6. Given the strong interaction between resource procurement and resource adequacy it is desirable that California rather than federal regulators make the necessary decisions. It is for this reason that the Commission believes that it should be responsible for addressing resource adequacy for all customers within the utilities' service territory; these customers constitute roughly 90% of the ISO load.

7. A poorly designed resource adequacy framework could needlessly limit the Commission's flexibility as well as usurp the Commission's statutory responsibilities. Therefore, the Commission has routinely advocated, in a variety of forums, that it should address resource adequacy and procurement issues.

8. The ISO has recognized that resource procurement is primarily a state function, adopting at its November 21, 2002 Board meeting a resolution to defer consideration of its resource adequacy proposal and directing ISO staff to actively participate in this proceeding.

9. There is a trade-off between reliability and least-cost service given the cost to acquire and retain reserves. As SDG&E calculated, each additional 1% increase in reserve level adds $2.8 million to its costs. Adjusting for SDG&E's smaller size, costs for SCE and PG&E would be significantly higher.

10. There is a broad range of resource applications and technologies that California can rely on to meet its reserve levels.

11. The Energy Action Plan, as well as the guidance given for this proceeding, established a "loading order" for new resource additions emphasizing increased energy efficiency, demand response/dynamic pricing, and renewable energy.

12. The development, timing, and calculation of a reserve level can have a significant effect in promoting (or deterring) development of these new resources.

13. An appropriate balance should be achieved between meeting reserve requirements expeditiously while seeking to optimize the resource mix/portfolio. Paradoxically, rushing to implement a reserve requirement might further increase California's reliance on natural-gas fired resources, posing a different set of reliability concerns if there are supply constraints and price risks for the fuel input.

14. While no party advocates extensive reliance on the spot market, most parties believe that it may be both reasonable and prudent to allow for some portion of resource needs to be met through the spot market, a practice that some utilities responsibly engaged in under pre-AB1890 resource procurement.

15. A key factor that needs to be considered in evaluating resource adequacy is the current state of the wholesale energy market in the West, and the degree to which California's utilities have obtained or can access these resources to meet their energy needs.

16. We find that there are ample resources for California to meet demand for 2004 as well as adequate resources available for California to meet peak demand through 2007.

17. The Joint Recommendation proposes a 15% planning reserve, phased in beginning 2005 through 2008 based on equal percentage increments (i.e., 2% per annum increase).

18. A 15% reserve level strikes an appropriate balance for ensuring reliable service by providing incentives to encourage the retention of existing resources, whereas setting reserves at a higher level could require the utilities to make short-term investment decisions inconsistent with the Energy Action Plan's preferred "loading order" of new resources.

19. It is reasonable to adopt a 90% level of forward contracting for each utility at one year in advance. We should allow the utilities the flexibility to justify to the Commission, on a case-by-case basis, excursions below this level. It is appropriate to defer implementation of this requirement to 2005.

20. A 5% limit on spot purchase provide a balance between flexibility and reliability and it is reasonable to continue to require the utilities to justify any higher level.

21. The preferred approach is for California to address the resource adequacy at the state level.

22. As a result of the tight energy supplies and market manipulation of the California energy crisis, many ESPs were unable to provide reliable service to

their customers. ESPs failed to honor their contractual obligations to customers, and direct access loads plummeted from 15% to 2%.

23. California should receive full credit and value for the long-term contracts entered into by the DWR to help California meet its energy needs during the crisis.

24. The issue of deliverability is an issue that needs further study.

25. The utilities should prioritize resource additions consistent with our direction in D.02-10-062 and the loading order of resources stated in the Energy Action Plan.

26. We prefer that generation assets be sited in California and that they minimize the overall economic and environmental impact, including the costs of transmission and power losses.

27. To the extent it is cost-effective, utilities should be looking to new generation capacity that is not powered by natural gas, currently the prime mover for 42 percent of the electric energy consumed in this state.

28. There is a need for the utilities to commit to new or refurbished generation capacity in the next few years.

29. Since the long-term plans were filed, SCE and SDG&E have made proposals to purchase and own new generation resources.

30. There is an opportunity today to acquire additional generation cheaply and, therefore, we should not delay in setting out clear market structure rules.

31. California has a long history of reliable service being provided by utility-owned and operated generation plant and a recent painful history of rolling blackouts and high price spikes from reliance on third-party generators in a poorly designed competitive market.

32. Third-party generating capacity, if contracted properly, holds a number of advantages for California ratepayers.

33. We find that a portfolio mix of short-term transactions, new utility-owned plant, and long-term PPAs is optimal, combining the security of generation assets under the full regulatory oversight of the Commission with the flexibility of ten-year contracts, and the potential benefits of operating efficiencies and lower costs from a competitive market.

34. Utilities are not well suited to actually construct new plant as it has been twenty to thirty years since they built fossil-fuel plants.

35. Situations may arise where competitive bids do not produce adequate response and the utility then needs to take on construction.

36. The presumption that utilities may favor their own capacity at the expense of third-party generators is well founded.

37. Careful design and monitoring of a competitive solicitation process and use of a least-cost dispatch standard are important means for addressing the potential for bias.

38. The utilities should rely on the formal RFP process to secure future long-term generating capacity resources.

39. A mix of contract lengths, sufficient to allow for new construction of power plants or transmission projects, is best.

40. Exhibits from last year's hearings show that there were only a limited number of disallowance decisions from 1980-1996, and that the majority of these decisions and dollar adjustments involved affiliate transactions.

41. The most direct and effective means to avoid any potential conflict of interest is to simply prohibit affiliate transactions.

42. In D.02-10-062, we addressed the utilities' capability to meet their obligation to serve, and found that PG&E and SCE did not need to obtain an investment grade credit rating prior to resuming the procurement role.

43. Today, the three utilities have all successfully resumed full procurement and the financial prognosis for PG&E and SCE is much improved.

44. Debt equivalency is a term used by credit analysts for treating long-term non-debt obligations -- such as PPAs, leases, or other contracts -- as if they were debt. The risk factor assigned by a credit analyst can account for 0% to 100% of a PPA's fixed payments, depending on the type of PPA structure.

45. The methodology for determining debt equivalency is an accounting treatment, with little implication for cashflow.

46. Rating agencies use qualitative (i.e. subjective) approaches for assessing debt equivalency. The methodology and risk factor applied varies according to the particular credit rating agency.

47. In the Commission's procurement proceeding, we address issues of economic value, not accounting value, by taking into consideration the relative costs of alternative procurement options.

48. The rating process is not transparent.

49. The appropriate forum to address debt equivalency is in the Cost of Capital proceeding.

50. A ten-year procurement planning horizon is appropriate and should provide relatively long notice to all industry players of the state's anticipated needs and allow them to respond appropriately

51. Long-term plans should include expected load and energy requirements, not only at their expected, or median, levels, but also at the 95^{th} percentile (that is, the one-in-twenty years case) of expected need levels.

52. As part of its long-term plan, the utilities should identify which procurement proposals will require environmental review, special permits, separate applications, or other regulatory procedures or proceedings.

53. The utilities should include the CEC's IEPR "information and analyses" in their plans but should make their own assessment as to whether the IEPR information should be used as the base case for any resource planning assessments, demand forecast and fuel analyses that examine more than two years into the future. If CEC's IEPR is not the base case, the utilities should report in their long-term plans how and why the assumptions underlying their forecasts differ from those of the CEC forecasts.

54. Long-term plans should reflect the most recent fuel-price forecasts available at the time of the plans' preparation and should include fuel-price variation as an element of the plans.

55. Future long-term procurement plans should reflect fully the expected range of fuel prices at least up to the 95^{th} percentile of the expected distribution.

56. Long-term plans should include not only the utilities' preferred portfolio choice for how to meet their needs, but also other portfolio alternatives/ variations to meet those needs. The utilities should present estimated ratepayer costs associated with each method of meeting their needs, and should include some metric of the variability of those costs.

57. In this decision we authorize only the overall funding levels for procurement energy efficiency programs. We refer program specific review and approval, including required programmatic or budgetary modifications to utility procurement program proposals, to the Energy Efficiency Rulemaking 01-08-028 where the Commission will select a balanced portfolio of utility and non-utility energy efficiency programs for 2004 and 2005.

58. SDG&E's proposed non-bypassable charge approach for funding procurement energy efficiency provides a simple to understand, fair, and expeditious mechanism for providing utilities cost-recovery for procurement related energy efficiency activities.

59. In D.02-10-062, we expressed our preference to adopt a uniform incentive mechanism to provide an opportunity for utilities to balance risk and reward in the long-term procurement process.

60. We should refer the issue of energy efficiency incentives to R.01-08-028 for disposition in that rulemaking.

61. We should refer future issues related to program duration and program cycles to R.01-08-028 for disposition in that Rulemaking.

62. We should refer the issue of administration of energy efficiency programs authorized in this proceeding to R.01-08-028.

63. In future procurement proceedings, we intend to open the process for application for procurement energy efficiency programs to non-utility parties as well as utilities.

64. We should refer the question of potential financial risks associated with carbon dioxide emissions to R.01-08-028, to be considered in the context of the avoided cost methodology -- as part of the overall question of valuing the environmental benefits and risks associated with utility current or future investments in generation plants that pose future financial regulatory risk of this type to customers.

65. Demand response, like energy efficiency, is a demand-side resource for the utilities. While energy efficiency resources can often meet baseload procurement needs, demand response can fill on-peak requirements.

66. In D.02-10-062, we directed that the demand response targets adopted in R.02-06-001 should be integrated into the utilities long-term plans.

67. In D.03-06-032, the Commission adopted demand response goals for each utility and directed that the IOUs include the MW targets for calendar years 2003 through 2007 in their procurement plans, specifically stating the filings in this proceeding should include: numeric targets coinciding with the findings in this decision; documentation of the amount of demand response (price-triggered) to be achieved by July 1 of each calendar year (with the exception of 2003, where the goals shall be met by the end of the calendar year); which programs and/or tariffs the IOU will rely upon to achieve the targets; and a contingency plan for covering capacity needs should the utility fall short of meeting the demand response goals.

68. Funding for price-responsive demand response programs is also addressed in D.03-06-032.

69. One goal of the RPS program is to foster a long-term market for renewable energy by providing contracts of 10 or more years. We do not find that PG&E's proposed short-term solicitation adheres to this principle.

70. It is difficult to compare and extrapolate the distributed generation forecasts from the utilities long-term procurement plans.

71. In guiding the utilities' long term planning process, we focus on developing an integrated resource approach, one that recognizes our policy priority for demand-side resource additions, and that optimizes generation and transmission resources.

72. There are about 600 Qualifying Facilities (QFs) under contract to PG&E, SCE, and SDG&E. These QFs supply power used to serve about one-fourth of the combined retail load for the three utilities.

73. The QF industry marked its beginning with the passage of the Public Utility Regulatory Policies Act (PURPA) of 1978 which required utilities to purchase QF power under certain terms and conditions.

74. By 2008, expired QF contract capacity is expected to exceed 1,000 MW and approach 1,800 MW by 2010.

75. We encourage both the QF community and the IOUs to be creative and flexible in negotiating the terms of renewed contracts for existing QF facilities.

76. The price for new capacity that results from a competitive all-source bidding process is the best way for an IOU to identify the basis for establishing the capacity payment that an existing QF seeking to renew a QF contract should receive.

77. The SRAC energy pricing formula is now out-of-date and inequitable.

78. It is important that the current methodologies to establish SRAC be modified.

79. The manner in which each utility identifies and manages price risk, in a manner that optimizes the value of its overall supply portfolio for the benefit of its bundled service customers, is the risk management function.

80. We do not find that there is a need for 300 MW of additional peaker capacity to be operational by 2005, either in the service area of PG&E or in the service area of SCE.

81. We direct the utilities to work cooperatively with CPA in areas where the utilities see a need to finance projects and the CPA can provide a favorable financing source.

82. Based on FERC's August 12, 2003 decision, all parties agree that the use of the "net" approach is appropriate for those QF and other on-site generation resources that contract with the utility for stand-by service.

83. The utilities short-term focus in the planning and procurement process should be on measuring the price risk exposure of its open portfolio position and managing that position, within a specified consumer risk tolerance level, in a manner that ultimately leads to the procurement and dispatch of power in a least-cost manner.

84. Portfolio risk should be reported using TeVar.

85. The Commission recognizes the importance of standardized risk reporting. By establishing a common benchmark, the Commission can assure itself that California's ratepayers, regardless of utility, are equally protected from adverse risk, and thereby can reap the benefits of reliable energy at low and stable rates.

86. We find a 99th percentile reporting will provide additional price volatility protection and should not be burdensome to the IOUs.

87. We find PG&E's and SDG&E's volumetric limits and length of contracts are reasonable.

88. We find that it is beneficial to continue the PRG process.

Conclusions of Law

1. The Commission's legislative mandate is to ensure that all utility customers receive reliable service at just and reasonable rates, as specifically stated in Pub. Util. Code § 451 with § 701 giving the Commission power to undertake all necessary actions to properly regulate and supervise California's investor-owned utilities.

2. AB 57 and SB 1976, codified in Pub. Util. Code § 454.5, provides a regulatory procurement framework for the Commission.

3. In D.02-12-074, the Commission provisionally adopted a 15% reserve level subject to further revision in this proceeding. Based on the record developed in this proceeding, we should reaffirm and make permanent the 15 % reserve level.

4. A 15% reserve level also strikes an appropriate balance for ensuring reliable service by providing incentives to encourage the retention of existing resources, whereas setting reserves at a higher level could require the utilities to make short-term investment decisions inconsistent with the Energy Action Plan's preferred "loading order" of new resources.

5. The utilities should meet this 15% requirement by no later than the end of 2006, with interim benchmarks established. These are minimum standards. If cost-effective, the utilities may choose to meet this level sooner than 2006.

6. We should require the utilities to procure (under Commission jurisdiction) sufficient reserves to provide reliable service to all load located within their respective service territories. The utilities should be compensated for this service by a non-bypassable customer charge.

7. Deferring to the ISO is inconsistent with both FERC and the ISO's stated policies of giving deference to the State to address resource adequacy issues.

8. Although the Commission chose to narrowly limit the exercise of its jurisdiction in implementing Pub. Util. Code § 394, it would be appropriate if the Commission were to decide that additional safeguards should be imposed upon ESPs under the requirements of Pub. Util. Code § 394.

9. Requiring ESPs to meet a reliability obligation, as allowed under Pub. Util. Code § 394, would not conflict with the "terms and conditions" under which direct access customers receive service.

10. Under existing law, the utilities remain both the default provider, and provider of last resort for all load within their service territories.

11. The reserve surcharge would be consistent with other charges the Commission has recently adopted to ensure that all customers pay their share of ensuring the reliability of the electric system.

12. ESPs, as well as other LSEs, should be able to opt-out of this reserve charge if they can prove that they have acquired adequate reserves.

13. We should seek another round of comments, as part of this proceeding, as to how to assess and develop workable deliverability standards.

14. We do not have an adequate record on which to adopt an energy efficiency incentive.

15. AB 57 takes a neutral position on whether the utilities should own additional generation capacity.

16. We adopt these contract guidelines:

(a) For non-unit contingent contracts (i.e., contracts with unspecified resources) with existing resources, contracts should be authorized only for less than one-year in term and executed no more than one-year forward;

(b) For contracts for existing resources, the utility would have dispatch rights to specified resources. Contract language should state that only specific plants could provide the power, and perhaps ancillary services, with no allowance for substitution from the market; and

(c) There should be contractual arrangements such as step-in-rights and take-over type rights to address longer term issues of supplier nonperformance.

17. In D.03-06-076, the Commission found that the ban on affiliate transactions was properly noticed, jurisdictional, constitutional, violated no federal laws, and the record supported the need for a moratorium on utility procurement from its own affiliates until adequate safeguards are fashioned.

18. D.03-06-076 also sustained Standard of Behavior 1.

19. In allowing the utilities to directly participate in owning new generation facilities, we recognize that we will need to be vigilant in overseeing that no bias occurs in selecting, or dispatching the resources.

20. We do not have the same level of oversight and authority over affiliate transactions that we do over direct utility operations. We recognize that cross-subsidies and anti-competitive conduct has occurred in the past in affiliate procurement transactions and that it could occur in the future under the market structure we adopt here.

21. The holding companies and affiliates of each utility should plan for future generation investment to be made outside of the utility's service territory and sold to other load serving entities.

22. SD&E should file a revised Exhibit 70 to reflect that the risk management committee(s) overseeing SDG&E's electric procurement operations and DWR-related gas procurement operations are comprised solely of SDG&E management. This filing should be by Advice Letter within 30 days of the effective date of this decision.

23. A management audit to review whether negotiated transactions with SoCalGas should be subject to special transaction rules and reporting should be undertaken. The management audit should be narrowly focused on two issues: SEU's participation in the risk management committee structure for SDG&E procurement operations; and any rules or reporting needed for SDG&E's energy procurement transactions with SoCalGas. The Commission's Energy Division should draft the scope of work required, select an independent auditor, and oversee the analysis. At the conclusion of the analysis, an audit report should be filed with the Commission and served on all parties to this proceeding. The

auditor should remain available to explain the report's findings, and testify in evidentiary hearings at the Commission on the findings included in the report. SDG&E should place the audit costs in a memorandum account.

24. In Res. E-3838, we apply the affiliate transaction rules to all procurement transactions between SDG&E and SoCalGas, and set an interim standard for transactions SDG&E enters on behalf of DWR with either itself or an affiliate for services which are paid on a negotiated basis. We should adopt this standard on an interim basis for all SDG&E's procurement transactions.

25. We should direct a management audit of PG&E's transactions for electric procurement for its customers and gas procurement for DWR contracts with other departments and affiliates.

26. We adopt here a permanent ban on affiliate transactions for procurement with the following exceptions:

> (1) "Anonymous" transactions through approved interstate brokers and exchanges, provided that the solicitation/bidding process is structured so that the identity of the seller is not known to the buyer until agreement is reached, and vice-versa.
>
> (2) Transactions for natural gas services between SDG&E and SoCalGas and between PG&E and affiliates and operating divisions that are found necessary and beneficial for ratepayer interests. These transactions should be subject to the rules adopted in Res. E-3838 and Res. E-3825 pending receipt and review of the management audits ordered here.

27. Each utility should make the investments necessary to meet their obligation to serve their customers at just and reasonable rates. Care should be taken not to make commitments that could later result in stranded costs.

28. For their next long-term plan filings, all three utilities should include an appropriate level of long-term commitment to additional power plants or plant-specific purchase power contracts.

29. Revised long-term plans should be submitted and approved in 2004 and any long-term commitments brought to the Commission in the interim should meet a "no regrets" criteria.

30. The utilities should file on April 23, 2004 a working outline of their long-term plans that includes the level of detail and specific scenarios addressed in this decision, the means by which they will incorporate the resource adequacy framework developed through workshops, and a showing that the material provided in the public filing will allow for meaningful participation by all parties. Interested parties may file comments on the outlines on May 3, 2004.

31. Consistent with the July 3, 2003 Assigned Commissioner's Ruling in R.01-08-028, we authorize utility procurement energy efficiency budgets for the two-year period 2004 and 2005.

32. We should authorize procurement energy efficiency budget levels for the utilities for 2004 and 2005 as follows: PG&E - $25 million for 2004 and $50 million for 2005; SCE - $60 million for 2004 and $60 million for 2005; SDG&E - $25 million for 2004 and $25 million for 2005.

33. Consistent with our desire to proffer a uniform energy efficiency portfolio, the Commission should evaluate and select utility 2004 and 2005 procurement energy efficiency proposals using both the selection process and primary and secondary selection criteria adopted in D.03-08-067.

34. Respondent utilities should establish a one-way Procurement Energy Efficiency and Balancing Account (PEEBA) to track the costs and revenues associated with authorized programs in this proceeding. Costs associated with

these accounts should be submitted simultaneously with utility monthly ERRA filings to the Energy Division for review on a monthly basis.

35. We should direct utilities in their future demand forecasts to include expected energy savings from non-utility programs that operate in their service territories.

36. We should adopt PG&E's demand reduction proposal.

37. SCE's new ACCP programs and its funding request needs to be reviewed in R.02-06-001 or its successor demand response rulemaking.

38. IOUs will file separate renewable procurement plans pursuant to Pub. Util. Code § 399.14(a)(3), thus the 2004 and long-term procurement plans currently under consideration do not constitute a filing of the required renewables plans.

39. Our approval of the 2004 procurement plans today does not "trigger" an RPS solicitation as detailed in D.03-06-071.

40. We should decline to adopt PG&E's request for an interim all-in benchmark of 5.37 cents per kWh for renewables.

41. We should deny PG&E's request for one-year renewables contracts, and focus attention instead on progress towards a full RPS solicitation in early 2004.

42. All renewables contracts must be filed for approval by the Commission by Advice Letter filing as required by D.03-06-071 and the ACR.

43. PG&E's position that 'unmet long-term resource needs' means a specific utility's resource needs, as defined and identified by that utility, is inconsistent with the statewide focus and purpose of the RPS legislation.

44. SCE's modeling of renewables as a "generic" block of energy, irrespective of resource type is inconsistent with Pub. Util. Code § 454.5(b)(2), which requires procurement plans to include "[a] definition of each electricity product,

electricity-related product, and procurement related financial product, including support and justification for the product type and amount to be procured under the plan."

45. In the revised 2004 long-term plans, the utilities should also provide a forecast of the percentage of retail sales met each year by renewables, indicating the projected year for achieving the 20 percent RPS target, and maintaining or increasing that percentage in future years. Each IOU should also modify its plan to include an accelerated RPS target renewables procurement scenario that evaluates any resulting changes to its overall energy procurement portfolio.

46. The utilities shall also update their 2004 and long-term plans to include interim procurement activity from 2003.

47. The utilities' 2004 revised long-term procurement plans should include a more robust discussion of distributed generation to include: (1) a line item entry clearly identifying distributed generation separate and apart from other entries such as energy efficiency and departing load; (2) the energy (GWh) and demand (MW) reduction attributed to distributed generation; and (3) a description of the technologies the utility includes in its definition of distributed generation as well as a statement noting whether its forecast includes utility-side distributed generation, such as QFs.

48. We should not adopt the Joint Parties recommended approach for a set-aside because it could predetermine the outcome of a new rulemaking on distributed generation.

49. A minimum requirement for the 2004 revised long-term plans is that the IOUs work with the ISO on defining conceptual scenarios for resources imported into the ISO control area and deliverable to the individual IOU's load.

50. The PURPA purchase obligation is neither as broad or as absolute as the QF parties assert.

51. We should balance the PURPA mandate that utilities are to purchase energy and capacity from QFs with the overarching requirement that electric utilities may only charge just and reasonable rates for the power they supply to their customers.

52. Renewal of existing QF contracts should be encouraged, so long as they are priced within the range of comparable replacement power, to the extent that they can meet the IOUs' need for power.

53. The PURPA purchase obligation originates out of a utility's need for power, either the need for energy or the need for capacity.

54. Thus, as to existing QFs with expired, or soon-to-be expired, utility contracts, we conclude that the potential anomaly between the nature of the power offered by a QF and the actual system needs of an IOU can be resolved in any one of three ways: (i) voluntary QF participation in IOU competitive bidding processes; (ii) renegotiation by the QF and the IOU on a case-by-case basis of contract terms that explicitly take into account the IOU’s actual power needs and that do not require the IOU to take or pay for power that it does not need; and (iii) appropriate revisions by the Commission to the SRAC methodology that will assure that existing QFs entering into renewed contracts on standard terms only receive payment for power that the IOU actually needs and can use. Compliance with any one of these three alternatives should assure fairness both to the QF community and to the IOUs and their ratepayers.

55. A utility must make a determination of need prior to offering a contract to a new QF.

56. The Commission should carefully consider how to modify the SRAC methodology and whether to seek legislative changes to Section 390.

57. Under Section 454.5, the Commission is required to (1) assess the price risk associated with each utility's portfolio; (2) ensure the utility has moderated its price risk; and (3) ensure the adopted procurement plan provides for just and reasonable rates, with an appropriate balancing of price stability and price level.

58. For 2004, the utilities should continue to use the interim CRT.

59. Changes to net metering tariffs such as City of San Diego's should be considered in the distributed generation rulemaking, where those changes may be considered in the context of broader distributed generation policy, including ratesetting and cost allocation issues.

60. Since direct access transactions have been suspended, there is currently no means for customers to serve their own loads with remotely sited generation.

61. The use of the "net" approach is appropriate for those QF and other on-site generation resources that contract with the utility for stand-by service.

62. We should adopt the following portfolio risk notification:

> (1) If between quarterly updates, a utility's estimated risk is over 125% of the CRT, the utility will promptly meet and confer with its PRG and discuss specific hedging strategies and plan modifications so that the value of the utility's open position will stay within the CRT.
>
> (2) Within 10 days of the PRG meeting, the utility will file plan modifications in the form of an expedited application.
>
> (3) Until the application is approved, the utility may purchase from spot markets, enter into bilateral trades, broker-assisted trades, or execute trades through an exchange.

63. We should adopt risk reporting using a by-product of VaR (TeVaR), measured on a 12-month rolling basis, at a 99% confidence level.

64. We should retain the existing modification of TURN's earlier 50% recommendation we adopted in D.02-12-074 for SCE's five-year requested authority.

65. We should adopt 73% limit on hedging for QF price risk.

66. SCE's proposal to not apply a risk screening criteria to transactions of less than a certain length in contravenes the requirements of AB 57.

67. Negotiated bilateral transactions should be separately reported in the utilities' quarterly compliance filings.

68. Where there are five or fewer counterparties in the relevant market, we should authorize the use of negotiated bilaterals for standard products for two categories of gas products cited by SCE: gas storage and pipeline capacity.

69. Each utility should update its fuel and power forecasts within 15 days from the effective date of this decision.

70. Each utility should meet and confer with its PRG on a quarterly basis.

71. Commission approval of the utilities' Procurement Plans does not preclude the need for DWR to conduct after-the-fact reasonableness reviews.

72. SCE should amend its plan to comply with the pro-rata cost allocation method of DWR contracts that the Commission adopted in D.02-09-053.

73. We should extend the disallowance cap we adopted in D.03-06-067 to the 2004 short-term plans.

74. Each utility should file by advice letter within 15 days a revised short-term plan that conforms to this decision.

75. The utilities should file their compliance reports by advice letter within 30 days of the end of the quarter.

76. Energy Division should, in consultation with each utility and its PRG, select an outside auditor to review and verify the quarterly compliance filings, and the audit expenses should be paid by the utilities and recorded in a memorandum account. A resolution for the Commission's agenda should only be prepared if Energy Division or the outside auditor find transactions or procurement practices that are not in compliance with the adopted plans.

77. We revise the ERRA filings dates as set forth in Section VII C. of this decision.

78. For 2004, the utilities should only update the forecasts in their 2004 adopted short-term procurement plans, all other parts of their short-term procurement plans will be operational for 2005, unless modifications are ordered based on our review of revised 2004 long-term plans.

INTERIM ORDER

IT IS ORDERED that:

1. Respondent utilities shall establish a one-way Procurement Energy Efficiency and Balancing Account (PEEBA) to track the costs and revenues associated with authorized programs in this proceeding. Costs associated with these accounts shall be submitted simultaneously with utility monthly ERRA filings to the Energy Division for review on a monthly basis. Within 20 days of the effective date of this decision, utilities shall file advice letters establishing the methodology and surcharge rate for incremental procurement energy efficiency programs for PY 2004 and 2005.

2. The utilities shall file on April 23, 2004 a working outline of their long-term plans that includes the level of detail and specific scenarios addressed in this decision, the means by which they will incorporate the resource adequacy

framework developed through workshops, and a showing that the material provided in the public filing will allow for meaningful participation by all parties. Interested parties may file comments on the outlines on May 3, 2004.

3. In the revised 2004 long-term plans, the utilities shall also provide a forecast of the percentage of retail sales met each year by renewables, indicating the projected year for achieving the 20 percent RPS target, and maintaining or increasing that percentage in future years. Each IOU shall also modify its plan to include an accelerated RPS target renewables procurement scenario that evaluates any resulting changes to its overall energy procurement portfolio.

4. Each utility should file by advice letter within 15 days a revised short-term plan that conforms to this decision.

5. We revise the ERRA filings dates as set forth in Section VII C. of this decision.

This order is effective today.

Dated ____________________________, at San Francisco, California.