STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

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

January 12, 2004

Agenda ID 3136
Alternate to Agenda ID #3134
Ratesetting

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

RE: NOTICE OF AVAILABILITY OF REVISED ALTERNATE PROPOSED DECISION COMMISSIONER LYNCH

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 alternate proposed decision. This alternate proposed decision was originally issued by Commissioner Lynch on December 4, 2003, part of which was subject to a vote on December 18, 2003. The subject matter of the portion considered on December 18, 2003, for a vote resulted in the adoption of Decision (D.) 03-12-062. The remaining portion of this alternate proposed decision reflects changes based on comments and eliminates the already adopted matters in D.03-12-062. This revised alternate proposed decision is now being made available for additional public comment. 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 alternate proposed decision of Commission Lynch. 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 alternate proposed 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 alternate proposed 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 77.6 opening comments shall not exceed 15 pages and no reply comments will be accepted. Comments are due by noon on Tuesday, January 20, 2004. Given that this decision has been revised and is being made available for a second round of public comments, comments on the revisions are particularly welcome.

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 and Commissioner Lynch's Advisor Aaron Johnson at ajo@cpuc.ca.gov. Service by U.S. mail is optional, except that hard copies should be served separately on ALJ Walwyn and Aaron Johnson, 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, Chief
Administrative Law Judge

ANG:epg

Decision REVISED ALTERNATE PROPOSED DECISION OF COMMISSIONER LYNCH (Mailed 01/12/2004)

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 provides policy guidance and adopts components of a 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 ensure reliability, 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 refine the process for making the longer-term investments necessary to provide reliable service to all California customers over the coming decade. At this point, with critical resource issues unresolved by this Commission, including the feasibility of different entities ensuring resource adequacy, uniform forecasts of load growth (including issues surrounding future customer base), and Renewable Portfolio Standard (RPS) benchmarks for competitive solicitation, it is premature to provide the utilities with procurement authority for the next five years and to enact a long-term regulatory framework in its entirety. Given the operation of recently enacted legislation providing pre-approval of purchasing plans, AB 57 (Wright, 2002), providing the utilities with procurement approval extending throughout the next five years without resolving the concomitant statutory issues and policies in AB 117 (Migden, 2002) and SB 1078 (Sher, 2002), this Commission would be handing the utilities a pre-approved blank check for five years worth of procurement authority.

We authorized the utilities procurement activities for 2004 in D03-12-062 and now we provide the utilities with additional guidance on the structure of their long-term plans. This decision resolves many of the policy issues raised in and by the first iteration of those plans filed in mid 2003, moves some of those issues to other, more appropriate fora, and orders the utilities to file revised long-term plans after a series of workshops in the first quarter of 2004, with final approval of those long-term plans coming before the end of 2004.

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 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 adopt a gradual phase-in of a planning reserve requirement over the next four years. Our approach is consistent with 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. Having provided for direct utility ownership of new plant, we make permanent our ban on affiliate transactions, with exceptions for existing plant, 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 resource plan, 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 public proceeding that allows all interested parties an opportunity to participate effectively and rejects decision-making based on non-public and/or redacted materials. 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 adopt the recommendation of the three utilities, ORA, CEC, and TURN to have the utilities resubmit their long-term procurement plans in 2004, following the Commission's adoption of specific resource adequacy criteria to be

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[1] SCE's Mountainview application was before us as separate matters and was not addressed in this proceeding. The same applies to SDG&E's RFP, which will be addressed in a subsequent decision.

addressed in upcoming workshops in the first quarter of 2004. We firmly discourage the utilities from making ad hoc long-term resource decisions until a long-term framework can be adopted in 2004. The current limited needs of the utilities, the widespread availability of WECC capacity, and corresponding temporary respite for the development of new generation resources allow us to proceed cautiously in the coming year as we establish the long-term framework.

It is essential that California does not over-commit to existing fossil resources because this could raise rates for consumers and preclude the utilities from adhering to the loading order preference in the Energy Action Plan. In the coming year, we expect to receive additional clarity that will help shape outstanding issues, including transmission integration into the long-term plans, Renewable Portfolio Standards (RPS) solicitation guidelines, energy efficiency program administration and possibly customer base issues (affected by both the community choice aggregation and the uncertain future of direct access). Resolution of these issues will give the utilities more certainty in their planning process, allow for a more accurate assessment and evaluation of the utilities long-term plans and allow the Commission to ensure that its broad policy goals about resource loading order are firmly implemented through those plans. We will expect the utilities to provide a variety of scenarios and load forecasts in those plans to ensure that the Commission has the necessary flexibility to accommodate developments in the areas listed above.

Finally, we discuss the issues that should be addressed in the new Procurement OIR we expect to open in the first quarter of 2004. These issues are: (1) review and adoption of revised 2004 long-term procurement plans for the three utilities; (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 or resolved[2] through the workshop process; and (5) consideration of procurement incentive mechanisms for each utility. We will open this new procurement OIR in the first 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.[3]

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

[2] Ultimately, resolution would need to occur through a decision adopting any agreements in the workshop.

[3] 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.

through August 18, 2003. Opening briefs were filed on September 15, 2003 and reply briefs were filed on September 22, 2003.[4]

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 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).[5]

Implementation of Senate Bill (SB) 1078 and SB 1038 legislation on the Renewable Portfolio Standard (RPS) has occurred through a separate workshop

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[4] The Commission resolved, in a separate application, A.03-07-032, SCE's July 21, 2003 Application for Approval of a Purchase Power Agreement with the Mountainview Power Company, LLC, in D.03-12-059. 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).

[5] Two additional entities, Ratepayers for Affordable Green Energy and Constellation NewEnergy, Inc, filed motions to intervene for the purpose of submitting comments on the proposed decisions in this matter. While we formally accepted those comments in D.03-12-062, we wish to clarify that the motions of both entities to become parties to this proceeding are granted.

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. These proceedings are ongoing and the establishment of RPS benchmarks as directed by SB 1078 are a critical precursor to the approval of long-term procurement plans.

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. In addition, the Community Choice Aggregation OIR, R.03-10-003, recently initiated to implement AB 117, could have a significant impact on future load.

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

Finally, in December of 2004, the Commission approved the utilities 2004 short-term procurement plans, with slight modification, in D.03-12-062. The Commission chose at that time to act only on a portion of the issues in the scope of the original proposed decision put out for public comment and addresses the remainder of the issues in this order today.

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. The Commission was 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;[6] (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 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

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[6] 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 non-utility electric generation.

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.

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 (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 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[7] or unexpected plant outages. "Resource adequacy" seeks to address these same issues. Therefore, in developing our policies to guide resource procurement, the Commission is providing a framework to ensure resource adequacy, by laying a foundation for the required infrastructure investment and instruments to ensure that capacity is available when and where needed.

In this decision, the Commission (1) directs that in order to provide reliable service utilities have an obligation to acquire sufficient reserves for their customers, with other LSEs reserve obligations the subject of the upcoming workshops; (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 2008, through a gradual phase-in period complete with interim benchmarks; (4) establishes a requirement (to become effective in 2005) that utilities forward contract 90% of their summer peak 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 (with an allowance that if the utility has sufficient reserves under contract to ensure resource adequacy but can tap the spot markets in real time at a cost below its call options on contracts, the utility can go beyond this general threshold).[8]

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[7] Traditionally, this has involved use of a "1-in-10" year hot weather scenario.

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

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 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 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 provides further guidance on a series of workshops on additional topics including how to include a variety of forecasts to account for different possible scenarios surrounding customer base issues, confidentiality matters, further exploration of how other load serving entities can meet potential resource adequacy requirements and development of protocols for requests for proposals (RFPs) for purchasing non-utility resources. This decision also addresses other 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.

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 between resource procurement and resource adequacy it is desirable that California policy-makers exercise the necessary decision-making authority. 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 themselves of

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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).

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 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 proposal

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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.

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 California 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 are 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 efficiency, renewable energy and demand response/dynamic pricing. The development, timing, and

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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

calculation of a reserve level can have a significant effect in promoting 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 spot markets to meet a portion of reserve requirements. While no party advocates extensive reliance on spot markets, most parties believe that it may be both reasonable and prudent to allow for some portion of resource needs to be met through spot markets, 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

[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

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) to which utilities located outside of California are not subjected.

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.

In their individual comments, many of the parties supporting the Joint Recommendation 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 energy efficiency, which 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

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

(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. However, we note that the ISO forecast does not include the recently approved 1,054 MW Mountainview facility (D.03-12-059), the increased funding for energy efficiency as part of the short-term procurement decision (D.03-12-062) expected to yield 950 MW over five years, the existing interruptibles program of 1,100 MW, or SDG&E's recently proposed 500 MW Palomar facility, which will shortly be considered for approval by this Commission (all from CAISO Five-Year Assessment (2004-2008)). All of these factors combine to make the ISO's more pessimistic prognosis than the CEC's for California resource adequacy appear unwarranted for now.

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).

A planning reserve represents capacity to ensure that generation is available when required. This capacity or "call" option covers a generation resource's fixed costs. Essentially, this means that a generation resource receives a payment to reserve a specific quantity of power in the event that it is required. This capacity, or "call option", is not the same as energy, which is a commitment to actually provide the power. However, if that capacity is called upon in the day-ahead or real-time markets, the generator can be asked to "burn fuel" and is

[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."

then an energy resource. It should be noted as well that many long-term contracts contain provisions for both capacity and energy.

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. All parties agree as well that significantly more work needs to be done on defining and implementing what this means and how best 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% planning 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 capacity procurement requirement (i.e., peak load plus reserves). The ISO notes that a three-year phase-in would help alleviate concerns over the exercise of market power in the forward market.

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."
>
> * * *
>
> "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.[18]

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 that the utilities should engage in long-term resource procurement, we must also be

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[18] PG&E Opening Brief, p. 34

cognizant that, given their current financial resources, some prioritization of need may be appropriate.[19]

With regard to a phase-in period, the utilities should meet this 15% requirement by no later than the end of 2008, with interim benchmarks established. These are minimum standards. If cost-effective, the utilities may choose to meet this level sooner than 2008. In setting these targets we do not believe that we are setting a reserve level that will be difficult for the utilities to achieve.

WPTF observed that each of the utilities' original filings proposed target reserve levels in the 15-17% range to be achieved by the 2005-2006 timeframe.[20]

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

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[19] 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)

[20] 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.

7% minimum. SDG&E's testimony, for example, shows that it possesses sufficient capacity, either owned or under contract, to easily meet the 7% operating reserve requirement, implying that SDG&E's actual planning reserve levels are 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.[21]

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 fora to

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[21] 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.

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 if not most all months of the year (particularly off-peak or shoulder months) that the utilities are already forward contracted at the 90% level and in some months are net sellers into the market (i.e., greater than 100% coverage). Even for the peak 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.[22]

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

[22] We anticipate resolving the issue of which resources should "count" toward the reserve requirement, including DWR contracts, in the upcoming workshop and through a subsequent Commission decision.

[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

Footnote continued on next page

contracting can also provide price stability, a revenue stream for investment in new resources and maintenance of existing infrastructure, as well as increased grid reliability. However, a close match of need and contracts is critical to prevent creating excess and stranded costs.

Also important, as PG&E and SCE note, imposing a mandatory percentage of forward contracting is inconsistent with the risk assessment models the utilities are supposed to develop and use to minimize 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 (based on market and supply/demand conditions) presumably between the year-ahead and hour-ahead markets. It is therefore unclear what, if

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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.

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 for peak summer months (May to September). The next question we need to decide is whether this 90% level should be a target or a requirement. 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 strategies for acquiring its necessary 2004 reserves by November 2003, which has already passed. Therefore, it is appropriate to defer implementation of this requirement to the beginning of 2005.

The ISO is the only party that proposes that utilities' forward contract for 100% of their needs a 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, many parties, including the ISO, are concerned 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] This is but one example of the additional evidentiary development needed for this Commission to set an appropriate forward contracting target. Thus, until that work is completed, given that the utilities have very little need for additional resources in 2004, this percentage should remain a target. We expect this subject to be part of the upcoming workshops.

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

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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).

Western energy market. This ensures that any reliance on these purchases for meeting energy needs will be available.

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 throughout 2004. However, there are significant outstanding issues, including how to count resources, that must be addressed before the utilities can meet these needs for direct access customers. In particular, the issue of how ESPs can meet this obligation and avoid a proposed non-bypassable surcharge needs to be resolved. As such, this issue should be addressed in the workshop forum and will be the subject of a separate Commission decision after the issue is more thoroughly vetted in the workshop process.

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

[27] Joint Recommendation, Sec. I 9

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 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 states 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-

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[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.)

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 the appropriate entity to address reserve issues. (TURN, California ISO, SCE).

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 more simple administratively, allow each LSE to decide how to best meet Commission

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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).

[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.

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) 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]

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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)).

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 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

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

[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.

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 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 will 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. The level of direct access load fell from 15% to 2%, ESPs failed to honor their contractual obligations, and the utilities (and later DWR) were obligated to assume the procurement of energy for many customers within the utility service territories. 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]

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

[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*

Footnote continued on next page

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 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

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services for all customers", thereby envisioning that the Commission already has the authority to impose resource adequacy obligations upon ESPs.

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 a contingency. SDG&E also stated that having utilities acquire reserves for all of the customers in their service territory was legally supportable under the Commission's obligation to ensure that utilities provide reliable service.[39] This issue should be part of the future workshops as the utilities' raised concerns in their comments that having them buy, for example, 15% reserves guaranteed the reserve portion of meeting demand but did not account for the 100% of anticipated load.[40]

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

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

[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] This is akin to buying a spare tire for a car when one has no idea whether the car has any of its four regular tires.

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.[41] 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 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 later adopt other approaches to address the reserve issue.

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[41] 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.

Both PG&E and SCE raise several valid implementation issues that must be addressed if we were to adopt TURN's proposal. These issues should be resolved, with additional evidentiary development to guide implementation, so that the Commission has a robust, fact-based record before it before acting. This will not delay implementation as the ISO, too, would have to create the same kind of evidentiary record and develop and resolve the following implantation issues prior to acting as well. This record and evidence could be used in either venue, once developed.

First, to avoid cross-subsidization issues, there would need 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 would 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 exploring 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 would 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 an entity other than the utility. The utilities would 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 would need to develop criteria so ESPs can prove that they have acquired adequate reserves and this exploratory process should be part of the upcoming workshops on outstanding resource adequacy issues. We envision that this could 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. However, we must also consider that the ability to "opt-out" on an annual basis will make it difficult for utilities to do long-term planning and must be considered as part of the workshops on this topic.

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, if the utilities acquire reserves for ESPs and aggregators the utilities could 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 could 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.[42]

In their long-term procurement plans, the utilities should address a scenario with the acquisition of sufficient reserves for all customers within their service territory, subject to further direction from the Commission after the completion of the resource adequacy workshop process. Potential 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 in order to create a resource adequacy framework and this process will be substantially enhanced by a series of workshops.

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."[43]

[42] 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.

[43] Joint Recommendation, Section I.8

The ISO also supported the need for workshops.[44]

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."[45]

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

In setting the original scope of the workshops, 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: resource adequacy, appropriate reserve levels and phase-in period.

We now address the specific areas that the workshops are to address, all of which will contribute to the utilities' revised long-term procurement plans. The workshop topics will include forecasts of load,

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[44] 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)

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

accounting for resources, issues surrounding non-utility load serving entities, other reserve and resource adequacy questions, deliverability of resources, and confidentiality issues, as necessary.

The workshops are expected to provide a forum for parties to understand better, and for the utilities to explain better, how their load forecasts are performed. Workshop participants should consider 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]

The utilities will be supplying a range of forecasts of load in their revised 2004 long-term plans in order to account for potential changes in community choice aggregation and direct access, among other customer base issues. A variety of forecasts should allow the Commission to incorporate any changes in the expected customer base that occur over the course of 2004. The workshops

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

should assist in crafting those scenarios. It will also be necessary to identify the treatment of direct access load and who should be responsible for forecasting it.

To the extent possible, the workshops 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 and compare resource adequacy both between utilities, and for all other load serving entities. The workshops should ensure that Commission policy preferences are fairly and accurately accounted for concerning the type of resources that count toward the resource adequacy goal and that methods for verifying resource adequacy are developed.

Additionally, the workshops should address the possible implementation of an obligation for the utilities to procure reserves for all load within their service territory by means of a non-bypassable surcharge, as described herein. This final issue would include the details of an opt-out procedure for non-utility LSE's that choose to meet their own reserve requirements and appropriate verification. These aspects of the workshop will assist in guiding the Commission in its future decision about the feasibility of different approaches to ensuring resource adequacy for non-utility LSEs.

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. This includes utility retained generation (URG), qualifying facilities (QFs), long-term DWR contracts, and so-called soft resources, such as energy efficiency, demand response and intermittent renewables, which are discussed further below. Part of counting resources also include deliverability and we expect this issue to be incorporated into the discussion of how to count resources.

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 DWR's long-term 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 workshops, 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. This will also provide an opportunity to explore further the ISO's proposal to require 100% of utility capacity to be contracted for one month ahead, which we decline to adopt in this order.

The workshops should address how the preferred 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 resources (i.e., energy efficiency, demand response, and renewables) 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.

[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]

Counting these resources towards any resource adequacy framework or definition of need is consistent with previous Commission decisions. Not counting these type of resources in the traditional resource adequacy frameworks could result in California having to pay twice for capacity and thus limits the cost-effectiveness of these programs. Collectively, for example, the three utilities are planning to achieve over 1,000 MW of peak load reduction from energy efficiency programs. D.02-10-062 requires that "utilities

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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.)

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

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."

To the extent necessary after this decision and the filings it requires on the topic of confidentiality, we may hold an additional workshop to consider this issue.

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

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

These workshops will be scheduled and held as soon as possible after this decision, at the discretion of the assigned ALJ and Assigned Commissioner, with a workshop report due back to the Commission one month after the workshop. We expect the workshops to be complete by the end of February.

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 and direction. 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. Another aspect of deliverability is the question of resource location and we expect that the utilities will incorporate the benefits and costs of specific geographical resource decisions into their next round of long-term plans.

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) Energy Efficiency and Demand Response programs; (2) renewables; (3) transmission; and (4) other fossil fuels, i.e., coal or oil, which carry emissions costs risks.

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.

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

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

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. 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, SDG&E has made proposals to purchase and own new generation resources. Additionally, on July 21, 2003, SCE filed an application for approval of the Mountain View project, a power plant of 1,000 MW capacity that would be owned by a wholly-owned subsidiary of SCE. That project was evaluated in Application (A.) 03-07-032 and is the subject of D.03-12-059. 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 5,000 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 non-utility 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 (RFPs) 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. Alternatively, if the utilities do, there should 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 on competitive market theory and the behavior of market generators to meet its reliability needs. 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. 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 may capture the lowest prices and maximize choice. 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 presumption that utilities may favor their own capacity at the expense of third-party generators may be 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.

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. 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.

4. 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.

PG&E, in particular, raises concerns in its comments about its ability to buy firm system sales with their accompanying strong financial protection as well as its ability to do hydroelectric exchanges and purchases with the Pacific Northwest. One possible solution for the latter problem is to grant an exemption for hydroelectric purchases. While the Commission does not want to foreclose seasonal exchanges that benefit the ratepayers or PG&E's ability to tap cheap hydroelectric resources in the Pacific Northwest, we are opposed to signing of any additional non-unit contingent contracts that do not specify delivery point (e.g., the DWR contract with Sempra). Such a type of contract are not beneficial to providing California with reliable electricity and make more difficult the jobs of the utility dispatching the contract and the ISO. While we would not expect a utility to sign such a contract in the future, even under the most dire of circumstances, we will not allow such contracts prospectively.

It is clear from this beginning discussion that considerable additional work and evidentiary record development is needed for the Commission to establish workable and reasonable parameters for portfolio mixes most beneficial for the next five years. The next phase of this procurement effort should address these issues prior to the Commission's approval of a long-term or five year procurement plan for any utility. This issue will also be included in the upcoming workshops.

5. 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

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

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 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 pre-approval 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 continuing the process of 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 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] However, we will grandfather already existing

[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.

contractual relationships with affiliates (e.g., QF contracts) for the life of the existing plant in order to ensure that existing resources with such relationships can continue to serve California. 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 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

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[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 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.

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.

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 non-affiliates 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]

[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.*)

> "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 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

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[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.*)

[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).

> 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 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.
3. Grandfathering of already existing contractual relationships with affiliates (e.g., QF contracts) for the life of the plant.

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. All of these arguments and issues raised confirm the need for additional work to be done and issues to be resolved before this Commission approves long-term procurement strategies, much less give year plans for specific procurement.

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 all three major credit rating agencies and PG&E anticipates exiting bankruptcy with an investment grade credit rating. 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.

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 had an investment grade credit rating at the time of hearings. 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

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

Rating agencies use qualitative or subjective approaches to assessing debt equivalency. The methodology and risk factor applied vary according to the particular credit rating agency. SCE acknowledges this in its LTPP, Vol. II, on page 62, 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

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

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

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 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. It is noteworthy that SCE has subsequently returned to creditworthiness.

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 all three major rating agencies recently upgraded SCE's credit rating to investment grade.

c) Commission Procurement Policy and Treatment of Debt Equivalency

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 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."

One concern we have is that the rating process is not transparent. In implementing a debt equivalency policy, the Commission would look for an industry standard as a benchmark on which we can base our policy. 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 or Fitch's methodology, so there is scant basis on which the Commission can analyze and/or compare the methodologies of the major rating agencies. This makes it difficult to assess the costs and benefits of adjustments to the cost capital factors the utilities face (e.g., debt-equity ratios or return on equity). There is no indication that consensus

[61] ORA OB, p. 9.

among the major rating agencies is forthcoming or imminent. As previously mentioned, a final rating is influenced by purely subjective factors that cannot be quantified, like politics or perceived regulatory climate.

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. 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]

An additional factor to consider with credit ratings it that they are affected by 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

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

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

> 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]

We believe that SCE has raised a reasonable issue that needs further consideration in a more appropriate forum. The Commission has previously examined debt equivalency in its Cost of Capital proceedings and this is the proper forum. (See D.92-11-049 and D.93-12-022.) The utilities should present the issue of debt equivalence in their upcoming cost of capital filings.[65] The Commission will consider these issues therein and develop a more robust evidentiary record on this subject before reaching a conclusion.

V. Long-Term Planning Assumptions

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.

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

[65] In particular, the utilities should be certain to explain in those filings why this issue appears only now when the utilities have a long history of entering into PPAs.

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, a conclusion with which we agree and which shapes this decision.

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.[66]

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

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

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 are strongly discouraged, except in unique circumstances. Here we 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."

We strongly discourage the utilities from engaging in any ad hoc long-term planning without the adoption of the long-term framework within which it must work. AB 57 allows the utilities to avoid after-the-fact reasonableness reviews only if working within a Commission-authorized procurement plan and long-term commitments cannot be afforded this deference if they are not made within approved long-term plans. The current electricity market in the WECC allows California the opportunity to refine the utilities long-term plans before adopting them and we should take advantage of this opportunity rather than rush headlong into additional resource commitments. 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 provide the utilities with additional guidance for 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 95th percentile (that is, the one-in-twenty years case) of expected need levels. We also expect the utilities to continue to consider a core / non-core scenario in their forecasts. The utilities should also supply a range of forecasts of load in their revised 2004 long-term plans in order to account for potential changes in community choice aggregation and direct access

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.

In addition, resource location to either serve load or to reduce transmission congestion, real or anticipated, should factor significantly in the long-term plans. Optimal resource location has the ability to ameliorate much of the concerns about possible transmission infirmities in California and such planning has the potential to eliminate costly transmission upgrades.

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. The 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. The utilities themselves are the ones responsible and accountable for meeting the loads and energy requirements of the customers in their service areas. Therefore, 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. In their revised long-term plans, all three utilities should match SDG&E's initial effort as providing a range of diverse supply options, as described above.

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 review. 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 receive a Certificate of Public convenience and Necessity (CPCN). 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 CPCN.

In their next iteration of long-term plans, the utilities should be sure to include deliverability requirements and resource location issues, as discussed earlier in this decision. The utilities should also include proposed specific rules for acquiring long-term resource additions. And finally the utilities should include specific proposals to resolve any financial or viability issues discussed elsewhere in this decision.

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. We plan to finish this well before the end of the year to avoid the end of the year crunch that has occurred in this proceeding in the last two years. To achieve this undertaking, we will schedule an April 2004 PHC as an early status check. In preparation for the PHC, the utilities should file by the end of March 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 by mid April 2004. The exact dates will be determined in a subsequent ruling from the assigned ALJ. The revised 2004 long-term plans and the results of the workshops described herein will be reviewed in a new procurement-related Order Instituting Rulemaking, which we will open in the first quarter of 2004.

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) Summary of Energy Efficiency Action in D.03-12-062

In general, we find that the utilities have taken a credible first step in their short-term plans, which we approved in D.03-12-062, in beginning to capture the energy efficiency potential available in their service territories. In those plans, we authorized utility energy efficiency activities, including the following: establishment of utility funding levels for energy efficiency activities for a two-year interim period, 2004-2005, to coordinate with the two-year interim planning horizon for efficiency programs in R.01-8-028; program evaluation and selection criteria, submission timelines and proposal submission directives; a cost-recovery accounting mechanism and customer non-bypassable surcharge to fund procurement related energy efficiency programs; and a decision to shift deliberations on a potential performance incentives for procurement efficiency activities to R.01-08-028

Though we authorized short-term funding and addressed several other issues in D.03-12-062, we are nonetheless mindful of the tremendous potential for efficiency savings that the utilities have left untouched in their proposed plans and we look to the utilities to significantly enhance their energy efficiency procurement activities in future updates to long- and short-term plans. For the present, utilities will need to "ramp-up" their efforts to prepare for even more vigorous procurement related energy efficiency activities in the years ahead.

Furthermore, we note that each utility has used a somewhat different methodological approach to analyzing and integrating the energy efficiency component of their procurement efforts into their long-term plans. While we do not intend in this decision to proscribe a set format for each utilities' analysis of the potential for energy efficiency in their service territories and the relationship of that potential to meeting their overall resource needs, we do urge the three utilities to come together to decide on a common approach to integrating energy efficiency procurement activities into their overall procurement forecasts and resource acquisition strategies. Such an approach will ensure future consistency in Commission evaluation of procurement related energy efficiency efforts.

b) 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 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.[67] PG&E proposes a specific incentive structure for energy efficiency programs only, urging the Commission to adopt its proposal. NRDC supports utility incentive mechanisms urging the Commission to adopt these in this procurement proceeding as a part of a universal procurement 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."

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

(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.

c) 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, 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 balanced by consistency in timeframes and procurement plans approved in this decision pursuant to AB 57. In R.01-08-028, the Commission adopted a two-year interim cycle for energy efficiency programs funded through the PGC mechanism. In this proceeding, we followed this model and ordered 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[68] 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 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

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

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.

d) 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 CO_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

In D.03-12-062 we summarized the policy framework from R.02-06-001 and the Energy Action Plan supporting demand response programs in

California, provided an overview of the respondent utilities' demand response proposals from their long-term procurement plans, approved the proposals filed by PG&E and SDG&E, and rejected SCE's request for additional funding of a new Air Conditioning Cycling Program.

We note that on November 24, 2003, the Assigned Commissioner in R.02-06-001 issued a Ruling which, among other things, requires the utilities to submit plans on March 31, 2004, describing 2004 efforts for meeting the 5% system peak reduction goal in 2007. As part of the March 31 filing, the utilities will include an assessment of whether the programs authorized in D.03-06-032 need to be modified in order to achieve the 2007 goal, preliminarily identify new programs that may be needed, and propose changes to the demand reduction goals based on initial deployment of authorized programs. We expect any proposed program changes to be part of the utilities' revised long-term plans but evaluation of those changes will be considered in R.02-06-001 or any successor.

3. Renewables

D.03-12-062 addressed renewables issues in the utilities' 2004 plans, deferring long-term planning issues to this decision and the forthcoming Renewables Portfolio Standard (RPS) rulemaking. The prior decision reaffirmed the guidelines to be used for any interim procurement activity prior to full RPS solicitation, and declined to adopt interim reasonableness benchmarks. That decision also reaffirmed a finding in D.03-06-071 that renewables contracts should have terms no less than 10 years to foster a long-term market for renewables.

In D.03-12-062, we determined 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. The forthcoming RPS rulemaking will require the utilities to file renewable procurement plans pursuant to Pub. Util. Code § 399.14(a)(3). In those plans, we will require full assessments of renewables needs to meet the utilities' energy and capacity needs and RPS requirements. As we turn our attention now to the long-term plans, we require those plans to contain more detailed estimates of each respective utility's renewable resource profiles, as discussed below.

The long-term procurement plans currently under consideration do not constitute a filing of the required renewable procurement plans, nor does their approval "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. We reaffirm that interim solicitations will follow guidelines already established by the Commission.

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"[69] in the RPS program, is "ineligible to participate,"[70] and goes so far as to say it "will not participate in the RPS program until it is creditworthy."[71],[72] 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[73]. 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). A non-creditworthy utility may also be directed by the Commission to prepare a renewable procurement plan, as this is not considered "procurement" under Pub. Util. Code § 399.14(g).

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

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

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

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

[73] 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 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:

> "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.

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, contracts signed under the transitional procurement period, and anticipated long-term peaking and baseload needs, 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,[74] 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 shall be modified accordingly.

The IOUs should also update their long-term plans to include interim procurement activity from 2003 and any resulting changes to the quantity of renewable energy delivered in subsequent years. 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

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[74] 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.

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.

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 early this year. 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 separately filed conceptual transmission plans to this effect, and the Commission has submitted 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 CPCN for Devers-Palo Verde 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.[75] 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 2004 long-term 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.[76] In addition, we require that the utilities incorporate an analysis of resource location in their analysis of future transmission needs to

[75] Transcript 3864-5, Volume 31.

[76] 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.

ensure that resource placement creates an opportunity to ameliorate costly transmission upgrades.

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.[77] 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:

[77] Exhibit 49, pages 5-6.

> First, determined the level of cost-effective energy efficiency available to SDG&E;
>
> 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."[78]

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."[79]

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[78] Page 22.

[79] Page 23.

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.

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.[80] 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.[81] SCE is in

[80] Page 9.

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

the midst of a proceeding before us, A.02-05-046, on the future disposition of the Mohave power plant, which is the largest single coal-fired source for any of the utilities. In order to ensure that a variety of fuel diversity options exist in SCE's revised long-term plan, we expect SCE's revised long-term plan to contain scenarios both including and excluding the Mohave power plant.

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. Qualifying Facilities

In D.03-12-062, we continued the interim treatment of D.02-08-071 for QFs with contracts expiring in 2004, directed the utilities not to enter into any new QF contracts until a decision is reached on the utilities' revised long-term procurement plans, ordered that a new OIR be opened to examine and propose appropriate modification to SRAC methodology, and denied PG&E's QF curtailment proposal.

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."[82]

Although this determination was made eight years ago, the challenge of correctly implementing PURPA for a developed QF industry, which

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

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 myriad 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

	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 preferably to 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.)

CAC/EPUC Positions

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.[83] 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).[84]

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[83] 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.

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

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).
>
> "(b) Commission action. The Commission will grant such a waiver only if an applicant under paragraph (a) of this section demonstrates that

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(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.

> 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.[85] 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 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

[85] 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.

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. <u>Here, the Texas Commission has offered no such specific showing, relying instead on broad competitive assertions</u>."

> *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 <u>is essentially a complete waiver</u> of the PURPA purchase obligation <u>for all Texas utilities</u>. <u>On this record</u>, we cannot grant such a waiver." *Cogen Lyondell*, Inc., et al., 95 FERC 61,243 (2001), page 4 (<u>emphasis added</u>).

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 <u>all</u> 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 a qualifying facility should only be required to be paid for "energy or capacity the utility can use to meet its system load." (Emphasis added.)

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[86] 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 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

[86] 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.

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 <u>additional</u> capacity. Ideally, QF participation in such solicitations is the best way for the IOUs to match their need for <u>new</u> 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.

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. A process to begin that review was ordered in D.03-12-062.

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 continued to provide interim treatment in D.03-12-062, 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.

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.

C. 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 process. 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."[87]

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 with SDG&E[88] 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.

We will consider an incentive mechanism in the forthcoming Procurement OIR. 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

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

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

(2002-07-01), culminating in a final decision (D.03-001) in 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."[89] 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."[90]

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

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

[90] Page 29.

> capacity, along with clear assignment of responsibilities is the best way to manage this new set 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."[91]

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."[92]

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

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[91] Page 37.

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

> environmentally responsible and cost-effective options 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."[93]

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."[94]

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[93] Page 33.

[94] TURN Opening Brief, page 17.

CEC states that the peakers "could be a desirable resource addition"[95] under certain circumstances, but finds the CPA has not 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"[96] 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.

IEP provided comments indicating it opposes the CPA peaker initiative, favoring instead procurement through open, transparent, and competitive processes. Moreover, IEP recommends removing that portion of the PD directing the utilities to work cooperatively with the CPA so that the appearance of unwarranted preference may be avoided. We do not find unwarranted preference in directing the utilities to work cooperatively with the

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[95] CEC Opening Brief, page 20.

[96] WPTF Opening Brief, page 42.

CPA. TURN, by contrast, favors further investigation of the potential benefits of the CPA peakers, indicating that the peakers may be an economical choice. At the least, TURN argues, directing the utilities to negotiate with the CPA keeps this option open and gives the utilities an insurance policy. Not finding that there is a need for this capacity, we do not order the utilities to negotiate with the CPA over the peaker initiative.

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.

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.

Because direct access transactions have been suspended,[97] 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 operating, whereas "net" load excludes this on-site load and looks only at energy that is delivered to the grid.[98] 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.[99] 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

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

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

[99] *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.

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)[100] 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 apply to distributed generation.[101] 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. Procedural Process and Schedule for Future Filings

A. 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

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[100] ISO Opening Brief, p. 73.

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

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 resource plans as part of the utility's GRC showing. The CEC would like this schedule to revolve around the two year cycle for the CEC's Integrated Energy Policy Report.

We intend to review and adopt revised 2004 long-term procurement plans for the three utilities in our new Procurement OIR, opening in the first quarter of 2004. Following that, a three year cycle of utility-specific long-term planning is reasonable, and, therefore, we adopt this utility proposal. Although we believe the CEC's request is reasonable, we are concerned about a schedule that results in an effective 50% workload increase for the Commission and a time of fiscal and staffing constraint. 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.

B. 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 <u>prior year recorded data</u>. 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. Each utility should file its revised 2004 long-term procurement plan in the new Procurement OIR which we intend to open in the first quarter of 2004.

VII. Confidentiality Issues

At the February 18, 2003 Prehearing Conference, the Assigned Administrative Law Judge (ALJ) stated one of the objectives for the procurement proceeding's long-term planning process is to ensure that the public and interested parties can meaningfully participate in the proceeding and that the public can understand the basis for our decision. Towards that end, the ALJ outlined a procedural process by which the utilities would make a showing that their filed long-term plans do in fact provide for meaningful public participation. This process culminated with the issuance on April 4, 2003 of a Ruling from ALJs Allen and Walwyn that adopted guidelines governing the scope of information that shall be considered confidential in the utility's long-term plans filings. The April 4 Ruling also found that each utility had sufficiently demonstrated that its long-term procurement plan allows for meaningful public participation.

Since issuance of the April 4 Ruling, parties have continued to voice concern over the amount of information that is shielded from public review. We also recognize that the Legislature, particularly the Senate Energy, Utilities and Communications Committee, has taken a strong interest in this subject and has pressed this Commission to expand the amount of utility resource planning and procurement data that is made publicly available. In light of this ongoing concern and in effort to promote the widest possible dialogue on utility planning matters in California, we will again revisit our rules governing the treatment of confidential information in our new Procurement OIR. Our intent is to broaden the scope of information embedded in utility resource plans that can be made public.

We direct parties' attention to the 2003 Integrated Resource Plan of PacifiCorp (the PacifiCorp Plan), which was submitted to the regulatory commissions of the various western states in which it operates: Utah, Oregon, Wyoming, Washington, and Idaho (PacifiCorp also operates in California, but given its limited operations in the state, it is not subject to AB 57 requirements). The PacifiCorp plan provides considerable loads and resource information in its public plan. The extent of information made public in the PacifiCorp Plan appears to exceed the guidelines on confidentiality adopted in the April 4 Ruling and points to the need for parties and the PUC to re-examine the breadth of information that shall be made public in the next round of long-term procurement plan filings.

We hold out the PacifiCorp plan as a possible model of transparency in resource planning and invite parties to comment on the merit of looking to the PacifiCorp Plan as a standard suitable for use by PG&E, SCE, and SDG&E. As part of their comments, parties should specifically address the issue of whether and how California ratepayers could be harmed (e.g., higher procurement costs) as a result of making public the same extent of planning data as is made public in Utah, Oregon, Wyoming, Washington, and Idaho. Would California ratepayers be uniquely disadvantaged relative to ratepayers in other western states with regards to the consequence of expanding the breadth of publicly available planning information? Comments shall be due within 30 days of the effective date of this decision and will be incorporated and made part of the record in our new Procurement OIR once that rulemaking is formally instituted.

VIII. Next Steps

In this decision, we provide additional policy guidance and direction to the utilities for their revised long-term procurement plans and continue to develop the long-term regulatory framework under which each utility will conduct integrated resource planning. We also adopt a revised ERRA procedural process.

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 workshops scheduled and discussed in this decision that are needed for the utilities to file revised 2004 long-term plans.

We should open a new procurement rulemaking in the first quarter of 2004 that specifically addresses the additional procurement issues we identify here: (1) review and adoption of revised 2004 long-term procurement plans for the three utilities; (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) address and resolve resource adequacy issues that are the subject of the workshop process; and (5) consideration of procurement incentive mechanisms for each utility. We expect to open this new procurement OIR in the first quarter of 2004.

IX. Oral Argument and Comments on the Proposed Decision

The alternate proposed decision of Commissioner Lynch was mailed on December 4, 2003, for possible consideration at the Commission's December 18, 2003, agenda. Pursuant to Pub. Util. Code § 311(e) and Rule 77.6, 16 parties[102] filed comments on the alternate proposed decision by December 11, 2003, and

[102] The following parties filed opening comments on the alternate proposed decision: PG&E, SDG&E, SCE, ORA, TURN, ISO, City and County of San Francisco, Navaho Nation, AReM, WPTF, IEP, CAC/EPUC, CCC, the Center for Energy Efficiency and Renewable Technologies (CEERT), Duke Energy North America, and Vulcan Power Company. In addition, many of these same parties, as well as the CEC, CPA, City of San Diego, NRDC, Joint Parties, Sempra Energy Resources, Coalition of California Utility Employees, and the Local Government Commission, filed comments on the proposed decision and the alternate proposed decision of Commissioner Peevey, all of which were considered in formulating this decision. In addition, the Department of Water Resources submitted letter comments. Finally, two entities filed motions to intervene for the purpose of submitting comments; the motion to intervene of the Ratepayers for Affordable Green Energy and the motion to intervene of Constellation NewEnergy, Inc were granted for the purpose of considering the comments each filed and their motions to intervene are granted in this decision.

11 parties[103] filed reply comments by December 15, 2003. On December 18, 2003, the Commission adopted a portion of the subject matter of the original proposed decision in this proceeding, resulting in D.03-12-062. The remaining portion of this alternate proposed decision reflects changes based on comments and eliminates the already adopted matters in D.03-12-062. This revised alternate proposed decision is now being made available for additional public comment on January 12, 2004. Comments are due by noon on Tuesday January, 2004. No reply comments will be accepted.

Pursuant to Pub. Util. Code §1701.3(d), a final oral argument was held before a quorum of the Commission on December 2, 2003. Seventeen active parties presented argument. (48 RT 5927-6048.)

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. D.03-12-062 addressed the utilities' short-term procurement plans for 2004.

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[103] The following parties filed replies on the alternate proposed decision: PG&E, SDG&E, SCE, ORA, TURN, ISO, AReM, IEP, CAC/EPUC, CCC, and Ridgewood Olinda, LLC. The Navaho Nation also filed replies on the proposed decision and the alternate proposed decision of Commissioner Peevey, all of which were considered in formulating this decision.

4. Implementation of SB 1078 and SB 1038 legislation on the RPS has occurred through a separate workshop process.

5. The three service territories of the respondent utilities account for approximately 80% of California's electricity usage.

6. 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.

7. Additional workshops on a variety of issues are necessary, including development of additional forecast scenarios, accounting for resources, deliverability of resources, other reserve and resource adequacy questions, and confidentiality issues.

8. Given state accountability for resource adequacy, it is preferable that California, rather than federal regulators, shape the the necessary procurement policy framework.

9. A poorly designed resource adequacy framework could needlessly limit the Commission's flexibility to provide direction to the utilities' on procurement matters as well as eviscerate 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.

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

11. 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.

12. There is a broad range of resource applications and technologies that California can rely on to meet its reserve levels.

13. 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.

14. The development, timing, and calculation of a reserve level can have a significant effect in promoting development of these new resources.

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.

16. While no party advocates extensive reliance on spot markets, most parties believe that it may be both reasonable and prudent to allow for some portion of resource needs to be met through spot markets, a practice that some utilities responsibly engaged in under pre-AB1890 resource procurement.

17. Resource adequacy is affected by 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.

18. 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 and possibly 2008.

19. Ample resources in the West through at least 2007 allow the utilities to refine their long-term plans in 2004, albeit on an aggressive schedule, for adoption by the end of the year.

20. 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).

21. 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.

22. A four year phase-in period for a 15% reserve requirement is a prudent timeline for action that will ensure reliability for California while not upending capacity markets or creating potential stranded costs if community choice aggregation is widely adopted or direct access is reinstated.

23. It is reasonable to adopt a 90% level of forward contracting for each utility's peak summer needs one year in advance and it is appropriate to defer implementation of this requirement until 2005.

24. A 5% limit on spot purchases as a means of meeting resource adequacy needs provides a balance between flexibility and reliability and it is reasonable to continue to require the utilities to justify any higher level of reliance.

25. When the utility has met its resource adequacy requirements and there is sufficient capacity in the market and under contract to ensure reliability but can dispatch its resources in a least-cost manner by going beyond the 5% spot purchase limit for energy, this is reasonable and rational behavior.

26. The preferred approach is for California to address the resource adequacy at the state level.

27. Additional workshops are necessary in order to determine which entity should enforce resource adequacy provisions with ESPs and community aggregators.

28. 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%.

29. 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.

30. Deliverability and locating of resources need further study and consideration.

31. 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.

32. 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.

33. 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.

34. There is a need for the utilities to commit to new or refurbished generation capacity in the next few years but not immediately.

35. Since the long-term plans were filed, SCE and SDG&E have made proposals to purchase and own new generation resources.

36. 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.

37. 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.

38. Situations may arise where competitive bids do not produce adequate response.

39. The presumption that utilities may favor their own capacity at the expense of third-party generators in a competitive solicitation is not unreasonable.

40. Use of a least-cost dispatch standard is an important means for addressing the potential for utility bias in system operations.

41. A mix of contract lengths, sufficient to allow for new construction of power plants or transmission projects, is best.

42. 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.

43. The most direct and effective means to avoid any potential conflict of interest is to simply prohibit affiliate transactions.

44. Grandfathering already existing contractual relationships with affiliates for the life of the existing plant ensures that these resources continue to be available to serve California.

45. 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.

46. Today, the three utilities have all successfully resumed full procurement and the financial prognosis for PG&E and SCE is much improved.

47. 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.

48. Rating agencies use qualitative or subjective approaches for assessing debt equivalency. The methodology and risk factor applied varies according to the particular credit rating agency.

49. The credit rating process is not transparent.

50. In the Commission's procurement proceeding, we address issues of economic value by taking into consideration the relative costs of alternative procurement options.

51. The appropriate forum to address debt equivalency is in the Cost of Capital proceeding.

52. 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.

53. Long-term plans should include expected load and energy requirements, not only at their expected, or median, levels, but also at the 95th percentile (that is, the one-in-twenty years case) of expected need levels.

54. 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.

55. 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.

56. The utilities should supply a range of forecasts of load in their revised long-term plans due to the potential instability of the customer base due, in part, to the uncertain status of community choice aggregation and direct access.

57. 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.

58. 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.

59. 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.

60. Future long-term plans should explicitly address the benefits of specific locations for resources and actively integrate location of resources into the long-term planning process, as well as deliverability.

61. Non-unit contingent contracts should be the subject of further workshops to ensure that California can take advantage of seasonal power exchanges.

62. Non-unit contingent contracts, such as the Sempra contract, that do not specify a delivery point are not beneficial to providing reliable electricity to California.

63. SCE's revised long-term plan should contain scenarios both including and excluding the Mohave power plant to ensure that the future of this plant and A.02-05-046 is not prejudged.

64. 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.

65. We should refer future issues related to program duration and program cycles to R.01-08-028 for disposition in that rulemaking.

66. We should refer the issue of administration of energy efficiency programs authorized in this proceeding to R.01-08-028.

67. 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.

68. 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 and 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.

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.

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 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.

77. 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.

78. 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.

79. 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.

Conclusions of Law

1. The motions of Ratepayers for Affordable Green Energy and Constellation NewEnergy, Inc., to intervene in this proceeding should be granted.

2. 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.

3. AB 57 and SB 1976, codified in Pub. Util. Code § 454.5, provides a regulatory procurement framework for the Commission.

4. 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.

5. 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.

6. The utilities should meet this 15% requirement by no later than the end of 2008, with interim benchmarks established.

7. We should require the utilities to procure (under Commission jurisdiction) sufficient reserves to provide reliable service to all utility load located within their respective service territories.

8. Deferring to the ISO on resource adequacy (and thus to the FERC) is inconsistent with both the FERC's and the ISO's stated policies of defering to states, and thus California, on resource adequacy issues.

9. 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.

10. 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.

11. Under existing law, the utilities remain both the default provider, and provider of last resort for all load within their service territories.

12. A 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.

13. ESPs, as well as other LSEs, should be able to opt-out of any reserve charge if they can prove that they have acquired adequate reserves.

14. We should seek another round of comments, as part of this proceeding, as to how to assess and develop workable deliverability standards.

15. We do not have an adequate record upon which to adopt an energy efficiency incentive.

16. AB 57 takes a neutral position on whether the utilities should own additional generation capacity.

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 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.
>
> (3) Already existing contractual relationships with affiliates (e.g., QF contracts) are grandfathered for the life of the existing plant in order to ensure that existing resources with such relationships can continue to serve California.

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 the Commission is disinclined to approve additional long-term commitments until the long-term plans are complete and approved.

30. The utilities should file in March of 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 in mid April 2004.

31. We should direct utilities in their future demand forecasts to include expected energy savings from non-utility programs that operate in their service territories.

32. IOUs will file separate renewable procurement plans pursuant to Pub. Util. Code § 399.14(a)(3), and thus the long-term procurement plans currently under consideration do not constitute a filing of the required renewables plans.

33. 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.

34. 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."

35. 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.

36. The utilities shall also update their long-term plans to include interim procurement activity from 2003.

37. 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.

38. 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.

39. A minimum requirement for the revised 2004 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.

40. The PURPA purchase obligation is neither as broad or as absolute as the QF parties assert.

41. 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.

42. 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.

43. The PURPA purchase obligation originates out of a utility's need for power, either the need for energy or the need for capacity.

44. 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.

45. A utility must make a determination of need prior to offering a contract to a new QF.

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

47. 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.

48. Since direct access transactions have been suspended, there is currently no means for customers to serve their own loads with remotely sited generation.

49. 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.

50. 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.

51. Negotiated bilateral transactions should be separately reported in the utilities' quarterly compliance filings.

52. 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.

53. Commission approval of the utilities' Procurement Plans does not preclude the need for DWR to conduct after-the-fact reasonableness reviews.

54. 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.

55. The utilities should file their compliance reports by advice letter within 30 days of the end of the quarter.

56. Energy Division should, in consultation with each utility, 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.

57. We revise the ERRA filings dates as set forth in this decision.

INTERIM ORDER

IT IS ORDERED that:

1. The motions of Ratepayers for Affordable Green Energy and Constellation NewEnergy, Inc., to intervene in this proceeding are granted.

2. The Commission shall hold a series of workshops in the first quarter of 2004, as described herein.

3. The utilities shall file, by the end of March 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 in mid April 2004, with the exact dates to be determined in a subsequent ALJ ruling.

4. 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.

5. The utilities should supply a range of forecasts of load in their revised 2004 long-term plans in order to account for potential changes in community choice aggregation and direct access.

6. We revise the ERRA filings dates as set forth in this decision.

This order is effective today.

Dated ___________________________, at San Francisco, California.

CERTIFICATE OF SERVICE

I certify that I have by electronic mail, mailed to the parties of which an electronic mail address has been provided; this day served a true copy of the original attached Revised Alternate Proposed Decision of Commissioner Loretta Lynch on the Proposed Decision of ALJ Christine Walwyn on all parties of record for proceeding R.01-10-024 or their attorneys of record.

Dated January 12, 2004, at San Francisco, California.

/s/ EVELYN P. GONZALES
Evelyn P. Gonzales

N O T I C E

Parties should notify the Process Office, Public Utilities Commission, 505 Van Ness Avenue, Room 2000, San Francisco, CA 94102, of any change of address to insure that they continue to receive documents. You must indicate the proceeding number on the service list on which your name appears.

* *

The Commission's policy is to schedule hearings (meetings, workshops, etc.) in locations that are accessible to people with disabilities. To verify that a particular location is accessible, call: Calendar Clerk (415) 703-1203.

If specialized accommodations for the disabled are needed, e.g., sign language interpreters, those making the arrangements must call the Public Advisor at (415) 703-2074, TTY 1-866-836-7825 or (415) 703-5282 at least three working days in advance of the event.