STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION

505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

November 16, 2004

Agenda ID #4073
Ratesetting

TO: PARTIES OF RECORD IN RULEMAKING 04-04-003

RE: NOTICE OF AVAILABILITY OF PROPOSED DECISION ADOPTS WITH MODIFICATIONS, PG&E, SCE AND SDG&E LONG-TERM PROCUREMENT PLANS FOR 2004-2014

Consistent with Rule 2.3(b) of the Commission’s Rules of Practice and Procedure, I am issuing this Notice of Availability of the above-referenced proposed decision. The proposed decision was issued by Administrative Law Judge (ALJ) Brown on November 16, 2004. An Internet link to this document was 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 this document can be viewed and downloaded at the Commission’s Website (www.cpuc.ca.gov).

Any recipient of this Notice of Availability who is not receiving service by electronic mail in this proceeding may request a paper copy of this documents from the Commission's Central Files Office, at (415) 703-2045; e-mail cen@cpuc.ca.gov.

This is the proposed decision of ALJ Brown, previously designated as the principal hearing officer in this proceeding. It will not appear on the Commission’s agenda for at least 30 days after the date it is mailed. This matter was categorized as ratesetting and is subject to Pub. Util. Code § 1701.3(c). Pursuant to Resolution ALJ-180, a Ratesetting Deliberative Meeting (RDM) 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 RDM 10 days before hand. When an RDM is held, there is a related ex parte communications prohibition period.

When the Commission acts on the proposed decision, it may adopt all or part of it as written, amend or modify it, or set it 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 propose decision as provided in Article 19 of the Commission's "Rules of Practice and Procedure." These rules are accessible on the Commission's website at http://www.cpuc.ca.gov. Pursuant to Rule 77.3 opening comments shall not exceed 15 pages.

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

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

ANG:jva

Attachment

Decision **PROPOSED DECISION OF ALJ BROWN (Mailed 11/16/2004)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning.	Rulemaking 04-04-003 (Filed April 1, 2004)

OPINION ADOPTING PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY AND SAN DIEGO GAS & ELECTRIC COMPANY'S LONG TERM PROCUREMENT PLANS

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OPINION ADOPTING PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY AND SAN DIEGO GAS & ELECTRIC COMPANY'S LONG TERM PROCUREMENT PLANS

I. Summary

This decision adopts, with modifications, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company's (SDG&E) Long-Term Procurement Plans (LTPP) and provides direction to the utilities on the procurement of the resources identified in the LTPPs. Summaries of the LTPPs are attached as Attachment A.

In our direction to the Invest-Owned Utilities (IOUs) [PG&E, SCE and SDG&E] regarding the procurement of resources to meet identified needs, and in recognition of the substantial amount of procurement to be undertaken as a result of our resource adequacy decisions, we make a number of significant findings. First, following the "loading order" contained in the Joint Agency Energy Action Plan (EAP) is the highest priority, meaning that energy efficiency and demand-side resources should be employed first. When these opportunities are exhausted, renewable generation is to be procured to the fullest extent possible – whenever an IOU issues a Request for Offer/Proposal (RFO/RFP) for generation resources, it must be prepared to defend its selection of fossil generation over renewable generation offers. In other words, selection of renewable generation is the rebuttable presumption guiding IOU generation procurement.

In general, IOUs are directed to procure the maximum feasible amount of renewable energy in the general solicitations authorized by this decision, and will be allowed to credit this procurement towards their Renewables Portfolio Standards (RPS) targets in 2005 and beyond. This is in keeping with the

Legislature's clear intent, in creating the RPS program, that renewable procurement be integrated as closely as possible with general IOU procurement practices. To further this effort, we will be working over the course of the next LTPP cycle to fully imbed the RPS into long-term planning, placing renewable energy development where it belongs - central to the IOUs' resource planning efforts.

To further the state's clear goal of promoting environmentally responsible energy generation, we also adopt a policy that reflects and attempts to mitigate the impact of greenhouse gas (GHG) emissions in influencing global climate patterns. As described in this decision, the IOUs are to employ a "carbon adder" when evaluating fossil generation bids. This method, which will be refined in future proceedings, will serve to internalize the significant and under-recognized cost of GHG emissions, and will continue California's leadership in addressing this important problem.

II. Background

A. Background To R.04-04-003

There are numerous principal sources of guidance regarding what the California Public Utilities Commission (CPUC/Commission) should direct the three IOUs to do in this decision as a response to the LTPP each IOU filed on July 9, 2004: Assembly Bill (AB) 57,[1] EAP, [2]Decision (D.) 03-12-062, [3] D.04-01-

[1] Assembly Bill (AB) 57, (Stats.2002,Ch.850,Sec.3 Effective September 24, 2004). AB57 added Section 454.5 to the Pub. Util. Code.

[2] Energy Action Plan issued jointly on May 8, 2003, by the CPCU, the California Energy Commission (CEC) and the California Consumer Power and Conservation Financing Authority (CPA). A copy of the complete EAP is available for downloading on the Commission's website at www.cpuc.ca.gov.

050,[4] Order Initiating Rulemaking (OIR/R.) 04-04-003, and the Assigned Commissioner Ruling/Scoping Memo (ACR) issued by Commissioner Peevey on June 16, 2004, as amended June 29, 2004,[5] in R.04-04-003. These same guidance principals were to be used by the utilities in the drafting and design of their LTPPs.

Specifically, the ACR stated "[a]s indicated in the OIR [R.04-04-003], review and adoption of the utilities' long-term procurement plans is the centerpiece of this proceeding. . . . This exercise, including the adoption of upfront standards and criteria for rate recovery constitutes the last major step remaining for implementation of AB57. Completion of this review and approval of utility plans by the end of this year is of critical importance so that the utilities can make the investment decisions that are crucial to the reliable energy future of this state."[6]

In summary, that is the purpose of this decision: to give the three IOUs authorization to plan for and procure the resources necessary to provide reliable service to their customer loads for the planning period 2004 through 2014. In

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[3] D.03-12-062, issued in R.01-10-024, gave the IOUs procurement authority, often referred to as "AB57 authority" for 2004, including the authority to sign contracts for up to five-years duration for 2005 procurement needs.

[4] D.04-01-050 gave continued procurement authority to the IOUs through the first three quarters of 2005, with authority to sign contracts for up to one year's duration for 2005 procurement needs. D.04-01-050 closed Rulemaking (R.) 01-10-024, and established the parameters for R.04-04-003.

[5] The June 29, 2004, Administrative Law Judge (ALJ) Ruling augmented the June 16, 2004, ACR and directed the utilities to include in their LTPPs responses to specific questions regarding global climate change issues.

[6] ACR, June 4, 2004, p. 3.

addition, this decision also has to work in concert to coordinate and incorporate Commission and legislative efforts from other proceedings, in particular: Community Choice Aggregation (CCA),[7] Demand Response (DR),[8] Distributed Generation (DG),[9] Energy Efficiency (EE),[10] Avoided Cost and Long-term Policy for Expiring Qualifying Facility (QF) Contracts,[11] Renewables Portfolio Standard (RPS),[12] Transmission Assessment[13] and Transmission Planning.[14] In addition, on October 28, 2004, the Commission issued D.04-10-035, the Resource Adequacy (RA) decision in this docket.

The OIR instructed the utilities to incorporate the Commission's policy direction from these other proceedings into their LTPPs and to inform the Commission how the utilities intended to meet the established goals from the other proceedings through its procurement decisions between now and 2014. In addition to including these policy directives in their LTPPs, the utilities were directed to prioritize their resource procurements following the "loading order" of preferred resources established in the EAP. The EAP's "loading order"

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[7] R.03-10-003.

[8] R.02-06-001.

[9] R.04-03-017.

[10] R.01-08-028.

[11] R.04-04-025.

[12] R.04-04-026.

[13] R.04-01-026.

[14] R.00-01-001.

framework identifies certain demand-side resources as "preferred" because they work towards optimizing energy conservation and resource efficiency while reducing per capita demand, as well as certain preferred supply-side resources. The EAP loading order is: energy efficiency and demand response; renewables (including renewable DG); clean fossil-fueled DG; and finally clean fossil-fueled central-station generation. Sensible transmission investments should be made in concert with these other resource commitments.

Because the Commission recognizes that the utilities face many demand and resource uncertainties in planning for the next ten years, the ACR instructed the utilities to prepare three supply/demand scenarios: high-, medium-and low-incremental need. The medium-load plan is to be the preferred resource plan of each utility that meets the needs identified in its Alternative Base Case load-forecast scenario, or its CEC Integrated Energy Policy Report (IEPR) base case scenario. The high-load plan should be a reasonable guess at how great the burden of service could become under high future growth load and an optimistic view of economic growth, assuming modest customer migration for Community choice aggregation (CCA). The low-load should be based on reasonable assumptions about progress in conservation and pessimistic assumptions about the economy and generous assumptions about the development of core/non-core and CCA. The utilities were to use these scenarios to demonstrate how they planned to accommodate the many possible outcomes. Additionally, the utilities were instructed to employ a risk management approach vis-à-vis future commitments by incorporating long, mid and shorter term contract terms so as to remain flexible to refine resource portfolios as certainty increases.

PG&E, SCE and SDG&E filed their respective LTPPs on July 9, 2004. For the most part, each utility followed the direction provided in the OIR and the

ACR for their plans.[15] In particular, each utility prepared the three supply/demand scenarios, incorporated Commission orders and directives from the other related proceedings, planned for a mixed portfolio of resources, contract terms and ownership types and followed the EAP loading order. What is apparent, however, is that the more than twenty intervenors had differing expectations on what the LTPPs ought to include, their function and their relation to annual procurement plans, applications, advice letters and other planning activities—notably transmission planning. Many intervenors complained that the LTPPs did not meet *their* expectations and wanted the Commission to remedy the situation.

In addition, each utility chose differing assumptions regarding their medium case and the boundaries of high and low scenarios. This caused some difficulty in direct comparisons across the three utilities.

What further complicates review of the LTPPs is that fact that much of the detail of the plans is confidential, so some parties identified as "Market Participants"[16] (MP) did not have access to specific forecasts and projections and were only able to respond to the plans in general terms. While members of each

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[15] The June 4, 2004, ACR included an attachment, Attachment A, prepared by the Commission's Energy Division (ED) staff in consultation with staff of the CEC.

[16] The protective order signed by the utilities in the 2003 resource planning proceeding, R.01-10-024, defined market participants as follows: "1) an employee of a private, municipal, state or federal entity that engages in the purchase, sale or marketing of energy or capacity, or the bidding on or purchasing of power plants. Or consulting on such matters, or an employee of a trade association comprised of such entities that engage in one or more of such activities: 2) an attorney, paralegal, expert or employee of an expert retained by an MP for the purpose of advising, preparing for participating in Procurement Plan and Compliance Reviews regarding [IOU]."

utility's Procurement Review Group (PRG) did have access to the confidential files and other intervenors had access pursuant to confidentiality and non-disclosure rules, MPs who did not conform to the terms of the Amended Protective Order[17]did not have such access. The ever vexing and complicated issue of confidentiality and how it relates to ratepayer protection and public access to the Commission's decision making process is addressed further in this decision at Section F.

B. Procedural History

The OIR to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning was issued April 8, 2004, the initial Prehearing Conference (PHC) was held April 30, 2004, a second PHC was held August 25, 2004, and evidentiary hearings (EH) were held August 30 through September 24, 2004.

In preparation for the EH, the utilities filed their respective LTPPs on July 9, 2004. Intervenor testimony was received on August 6, 2004, from the Border Generation Group (BGG), Cogeneration Association of California (CAC), California Independent system Operator (CAISO), Calpine Corporation (Calpine), California Cogeneration Council (CCC), Center for Energy Efficiency and Renewable Technologies (CEERT), City of Chula Vista (Chula Vista), City of San Diego (CSD), California Manufacturers & Technology Association and the

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[17] On January 14, 2004, the assigned ALJ in R.01-10-024 issued a ruling adopting an Amended Protective Order that was substantially consistent with an order adopted by a Federal Energy Regulatory Commission (FERC) judge in FERC Docket Nos. EL02-60-003 and EL02-62-003, and allowed MPs access to Protected Materials following the FERC guidelines. This Amended Protective Order controlled confidentiality issues in this current proceeding.

California Large Energy Consumers Association (CMTA/CLECA), Constellation Power Source (Constellation), County of Los Angeles (LA), Duke Energy North America (DENA), California Department of Water Resources (DWR), Independent Energy Producers (IEP), Modesto Irrigation District (Modesto), Natural Resources Defense Council (NRDC), Office of Ratepayer Advocates (ORA), South San Joaquin Irrigation District (SSJID), Strategic Energy and Constellation New Energy (Strategic Energy), The Utility Reform Network (TURN),Utility Consumers Action Network (UCAN), Union of Concerned Scientists (UCS), West Coast Power (WCP) and the Western Power Trading Forum (WPTF).

On August 20, 2004, rebuttal testimony was received from PG&E, SCE, SDG&E, CAISO, Calpine, NRDC, ORA, Strategic Energy, TURN and UCS.

During the almost four weeks of evidentiary hearings there was extensive cross-examination of utility and intervenor witnesses and 128 documents were received in evidence. Post hearing briefs were received on October 18, 2004, from PG&E, SCE, SDG&E, BGG, CAC, CCC, Calpine, CAISO, CEERT, Chula Vista, CSD, CMTA/CLECA, Constellation, DENA, IEP, Modesto, NRDC, ORA, Sempra Energy Global Enterprises (SEGE), SSJID, Strategic Energy, TURN, UCAN, UCS, WCP and WPTF.

Reply briefs were received on November 1, 2004, from: PG&E, SCE, SDG&E, CAC, CCC, Calpine, CAISO, CEERT, Chula Vista, Constellation, DENA, IEP, Modesto, NRDC, ORA, SSJID, Silicon Valley Manufacturing Group (SVMG), Strategic Energy, TURN, UCS and WCP, and a letter was received from the California Department of Water Resources (DWR).

C. Motions

During the course of the proceeding numerous motions were filed. Motions regarding requests to strike or limit testimony and/or to exclude exhibits from the record were ruled on orally by the ALJ during the EH. There are a few motions that have yet to receive rulings and they will be addressed. Any motions not previously resolved or addressed in this decision are deemed denied.

UCAN and CEERT filed Notices of Intent to Claim Compensation (NOI) for their participation and contributions to the proceeding. Both of those motions will be ruled on in separate rulings independent of this decision.

On October 8, 2004, WCP filed a Motion for Official Notice, and followed that motion with a supplement on October 12, 2004. In sum, WCP asks the Commission to take official notice of the CEC Committee Draft Report in the IEPR: 2004 Update, dated September 2004 and posted on the CEC's web site. WEC attached a copy of the Committee Draft Report to its motion. In its supplemental filing, WEC advises the Commission that it is not asking the Commission to accept the factual statements in the Report, but rather seeks clarification that all parties may refer to the Report for policy conclusions of the IEPR Committee. At its November 4, 2004 Business Meeting, the CEC formally adopted the 2004 update.

No opposition was received to WEC's motion and official notice may be taken of the Committee Draft Report for the limited purpose set forth above.

D. Summary of Parties' Positions

While there were twenty-seven plus[18] active parties to this proceeding, most of the parties can be cataloged into one of the following categories: IOU; consumer/ratepayer advocate; environmental group; municipal/community choice proponent; co-generation facility; wholesale marketer and energy producer, the CAISO and "other." While each party brought a different perspective and advocacy position to this proceeding, there are common threads that connect many of these parties' points of view vis-à-vis the utilities' LTPPs and we summarize those positions below.

E. IOUs

To begin, each IOU had the responsibility for drafting a LTPP that met the criteria established in the OIR, the ACR/Scoping Memo and the EAP. For the most part, the IOUs did not "advocate" a position on their LTPPs, but rather presented them as compliance filings. Within each LTPP, however, there were a few specific positions that a utility took, primarily on the topics of planning and procuring for CCAs, recognition of debt equivalency, future contracting with qualifying facilities (QFs), length of contracting authority, appropriate policies regarding renewable generation procurement, use of aging power plants/reuse of brown sites and whether independent third-party observers were a necessary component of bid solicitations. To summarize the IOUs requests: they each seek approval of their LTPP and cost recovery assurance.

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[18] Not all parties participated to the same extent, for example, The County of Los Angeles and DWR served testimony, but did not file post-hearing briefs and SEGE did not serve testimony, but filed a post-hearing brief.

F. Consumer/Ratepayer Advocates

TURN, ORA and UCAN, while all consumer advocates, each focused on different categories in the LTPPs. UCAN, for example, only reviewed SDG&E's plan and criticized the plan for not following the EAP's loading order, not addressing Reliability Must Run (RMR) costs, congestion, transmission losses and load pocket needs, using a projected price for natural gas that was too low, failing to extend many short-term contracts that could provide potentially viable resources, especially in regards to EE, DR, DG and renewables—while criticizing the need for a new 500 kilovolt (kV) transmission line.

TURN's primary goal is to have the utilities procure adequate resources for all customers, with *all* customers paying, not just bundled load customers. In point of fact, TURN is concerned that the utilities have too many resources tied up in long-term contracts, and the Commission should enable them to enter into power contracts for terms up to five years. TURN is mindful that the IOUs, in their roles as LSEs, want to avoid over procuring in the face of "great uncertainty regarding the magnitude of their future bundled loads."[19] However, TURN is also concerned that if commitments are not made now by PG&E and SCE that new capacity will not be built to be on line by 2008, and the utilities will be left resorting to short-term contracts and the spot market to fill the net-short position—to the detriment of ratepayers. To avert this potential crisis, TURN urges the Commission to order PG&E and SCE, acting as "interim agents" of RA policy on behalf of all customers in the state, to each procure 500 MW of new capacity by contracting with non-IOU generators for periods of up to ten years,

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[19] TURN opening brief, p. 3.

with deliveries to start in 2008. The net costs of these resources should be recovered from all customers via a non-bypassable charge paid by all customers.

In summary, ORA argues that the following topics do not need to be resolved in *this* proceeding: approval of any transmission plans, especially SDG&E's proposed new transmission line, debt equivalence, a mechanism for comparing power purchase agreements (PPA) with utility-owned generation, use of independent third party evaluators in the bid solicitation process and stranded costs from customer departing load. Instead, ORA urges the Commission to adopt its aggregate analysis in the appendix to ORA's report, Exhibits 40 and 41 in drawing its conclusions on the IOU's planning scenarios, which ORA posits do not differ significantly from the IOU's conclusions for their procurement needs. In the future, ORA would like to see the Commission address the fact that there were inconsistencies in the use by the utilities of assumptions, especially regarding departing load, and if the utilities used the same forecast assumptions it would be easier to compare and contrast them.

G. Environmental Groups

NRDC, with its interest in minimizing the societal costs of reliable energy services, focused on the delivery of cost-effective EE programs, renewable energy resources and other suitable energy alternatives in reviewing and analyzing the IOU's LTPPs. NRDC found that the LTPPs lacked adequate information as to whether they would minimize economic and environmental impacts, failed to follow the EAP's loading order, did not compare different generation resource options, and did not adequately address carbon dioxide emissions. To remedy these deficiencies, NRDC urges the Commission to require the IOUs to account for the financial risk associated with carbon emissions; develop a strategy to reduce global warming pollution emissions, plan and procure renewable resources above and beyond the minimum established in the RPS and to implement policies on investing in EE and renewable resources.

CEERT shares similar goals with NRDC, such as improving air quality and reducing dependence on fossil fuels. CEERT's review of the IOU's LTPP found PG&E and SCE's to be deficient especially regarding their renewable procurement plans and asks that the Commission direct these two utilities to supplement or amend their plans to be consistent with that submitted by SDG&E. CEERT would like to see a more detailed analysis from PG&E and SCE as to how they intend to reach their RPS goals, more information as to the specific resource profiles they intend to procure, similar to the "portfolio stack" submitted by SDG&E, an incorporation of each utility's goals concerning the environment and a ten-year planning horizon so the renewable industry can plan. Even though many other parties criticized SDG&E's inclusion of a 500kV transmission as part of its LTPP, CEERT applauds the proposed line as a means to bring more renewables into the SDG&E service territory. Although PG&E and SCE justified the ambiguity in the renewable portion of their LTPP as to an actual renewable portfolio stack on the ground that the market would decide the portfolio stack, CEERT argues that PG&E and SCE have sufficient information from previous RPS request for offers/proposals (RFO/RFP) to make more detailed projections than they did.

UCS also did not find the IOU's LTPPs sufficient for demonstrating the utilities' commitment to climate change and related topics and asks the Commission to require supplemental filings that model potential cost impacts of carbon regulation and gas price risk, along with a more detailed analysis of renewable resource potential over the next ten years. In addition, if the Commission adopts a debt equivalency factor for long-term contracts, UCS requests that the factor for renewables be lower than for non-renewable, and that the IOUs incorporate the EE goals adopted in D.04-09-060. In particular, UCS urges the Commission to insist that the IOUs account for the cost of emissions associated with particular resource choices.

H. Potential CCA/Municipalization/Direct Access

Five intervenors could be described as parties representing potential "departing load" by way of CCA, municipalization, direct access (DA) or a core/non-core structure; Chula Vista, Modesto, SSJID, Strategic Energy and CMTA/CLECA.

These parties are all particularly concerned that the IOUs will over procure and then departing customers will be obligated to pay for their share of stranded costs so their departure will not over burden the bundled ratepayers remaining with the utilities. Chula Vista wants SDG&E to include CCA for the city as a likely case scenario, and only use short-term contracts to fill in for any net short in the near term. SSJID plans to provide service to its irrigation district customers in January 2007 and wants PG&E's LTPP to recognize this so PG&E does not procure energy for these customers. Modesto finds itself in a similar situation to SSJID and urges the Commission to instruct PG&E to make "wise" procurement decisions by using short-term power contracts to meets its 90% year ahead obligation, so there is no need for the non-bypassable surcharge. Modesto argues that changing weather conditions alone cause more fluctuation than Modesto's departing load, and so PG&E should not look to Modesto's customers for the collection of stranded costs.

CMTA/CLECA also want the IOUs to be mindful of over procuring in light of the uncertainty of departing load for DA or a core/non-core structure and want the utilities to minimize the risk of stranded costs by using a mix of contract lengths. From CMTA/CLECA's perspective, it is the IOUs responsibility to plan properly, so there should be no non-bypassable surcharge. CMTA/CLECA recognize that there might have to be limits on departing load, such as annual limits on net migration to or from the utility, but no surcharge. CMTA/CLECA also want more access to confidential IOU data [see discussion under "Confidentiality"], support an open and transparent RFO process and support the use of a third party evaluator for the RFO if an affiliate is involved in the bidding.

Strategic Energy is also concerned with the utilities over procuring and argues that the IOUs did not make reasonable assumptions in their LTPPs about departing load for CCA/DA/core/non-core and therefore if there are stranded costs, the utilities should be at risk. From Strategic Energy's vantage point, the IOUs failure to properly plan for departing load almost ensures that any migration of load will result in stranded costs. Strategic Energy urges the Commission to not institute any charge for departing customers as that removes risk from the utilities for over procurement, removes any incentive for the utilities to resell excess power, gives the benefit of increased reliability to bundled customers at the expense of departing load customers and frustrates competition by slowing down migration.

I. Co-Generation Facilities

CAC and CCC are concerned with the inclusion/exclusion of QF contracts in the IOUs LTPP. While CAC and CCC understand that the Commission is not determining the future fate of QFs in this proceeding, they still argue that the Commission must insist that the IOUs reserve a place in their LTPP for QFs as baseload resources and to sign up to five-year contracts with these resources. Both co-generation associations fear that the IOUs will be fully "resourced" without any QF contracts in excess of one year, without longer term contracts the QFs might not continue to exist, and because of their unique properties they cannot compete competitively in an RFO that is not seeking base load power. None of the utilities anticipated needing baseload resources in the near term. Instead, their projected need is for dispatchable peaking or shaping resources. Co-generation QFs run 24/7 to supply their hosts, and without a contract to sell that 24/7 power they would have to use steam boilers to meet their host's needs.

J. Energy Marketers and Independent Energy Producers

WCP, WPTF, IEP, DENA, Constellation, BGG and Calpine are all identified as MPs and as such did not have unfettered access to the IOU's confidential data supporting their LTPPs and referenced this information deficit in their briefs. For a further discussion of confidentiality see Section F in this Decision. Even without reviewing the background data for the LTPPs these parties were able to effectively cross-examine the IOU and intervenor witnesses and advance their position vis-à-vis the competitive energy market.

WCP, IEP, DENA and BGG all focused on the need for long-term contracts and an open and transparent solicitation process. BGG supports SDG&E's proposed new 500 kV transmission project because it would increase import capability and system reliability, decrease RMR costs and give access to out-of-area resources, including renewables. DENA, on the other hand, argues against SDG&E's 500 kV transmission project and wants the Commission to direct the utility to explore more in-area generation. Specifically, DENA could re-power its South Bay facility in the same time frame as the new transmission lines, if it can compete in a RFO for a three-five year contract.

WCP advances similar arguments to those of DENA: the Commission should recognize the value of aging power plants as providing needed RMR, peaking and intermediate power in the three-five year range, and most importantly, recognizing the value of using existing brown sites for new generation facilities - especially before approving a new 500 kV transmission line. All costs should be considered in comparing brown sites with green sites, especially those that are hard to quantify, such as location near the load pocket, and WCP even argues that brown sites should be given a recognized priority in the EAP. WCP argues that building on a brown site is cheaper than building a new combustion turbine (CT) or combined cycle (CC) facility, provides deliverability without long-distance transmission, and provides reduced costs to society as compared with the siting of a new location.

IEP favors a fair and equal field for competitive bidding and recommends that the Commission not adopt a debt equivalency factor for bid comparisons, allow short-term capacity procurement and utilize a third party evaluator to monitor an RFO when there are competing bids from PPAs and utility-owned projects.

Calpine, WPTF and Constellation all advocate for an open, fair and competitive RFO process with some protections to keep the playing field level for PPAs competing against utility owned projects. First and foremost, they argue vociferously against establishing recognition of debt equivalency as part of the bid evaluation. Under almost all scenarios where debt equivalency is a factor, all bids except the utility-owned option fail the least cost best fit (LCBF) criteria. Next, Calpine wants any IOU bid to be a binding commitment with the shareholders, not the ratepayers, at risk for overruns. Then, the Commission should allow long-term contracts, not just short-term as the CCA/DA intervenors request, because the marketers and IEPs need the financial security of long-term contracts to get the financing to refurbish old facilities and to build new resources. And, finally, no preference should be given to any bid outside of those preferences established by the EAP, Commission decisions or the legislature.

WPTF also proposes a tradable capacity market because then there would be no need for a non by-passable surcharge for departing load customers because then there would be no need for a non by-passable surcharge for departing load customers. WPTF recommends the use of an independent third party evaluator if a utility option is one of the bids, wants utility winning bids to be binding and non-recourse, with no cost overruns.

Constellation is in favor of a competitive wholesale market and proposes a "slice of load" concept or standard offer service (SOS) that would be a three to five year contract for wholesale services, bid through a competitive process, with Commission oversight, where the marketer would bid for a percentage of the utility's load and take the risk as the load varies from time to time. The risk of customer uncertainty would be borne by the marketer, not the IOU, so there would be no stranded costs. Constellation argues that this concept would provide ratepayer benefits from competitive prices, diversity of supply, elimination of stranded costs, alignment of customers and utility and application of market rules. The SOS would also include RPS and RA requirements.

K. The California ISO

CAISO finds the IOUs' filings insufficient for its purposes. The CAISO needs the location of a potential resource, the conceptual scenario for resource addition, and the identity of potential new resources and transmission needs. CAISO wants the IOUs to include a with/and/without scenario for new transmission in future LTPPs.

L. Other Intervenors

CSD and SEGE also intervenors in this proceeding but do not fit into the above categories. CSD focused exclusively on SDG&E's LTPP and argues against approval of the 500 kV transmission line until there has been time to weigh alternatives. The goal of CSD vis-à-vis SDG&E is to advocate for cost-effective reliability through a balance of customer-owned and utility-owned generation plus procured generation. CSD does not see enough flexibility in SDG&E's plan for departing load, sees too much out-of-area renewable power at the expense of local renewable DG, and is not in favor of allowing the utility to meet its RPS through renewable energy credits (REC) unless the RECs have been procured from DG with net-metered renewable generation.

SEGE argues for the Commission to rescind the ban on affiliate transactions since it prevents the utilities' from access to ready built facilities if owned by an affiliate. In addition, SEGE favors competitive solicitations, including for utility-owned generation, and affirms the public policy of prudent IOU procurement so as to reduce risk of stranded costs.

III. Analysis Of Long Term Procurement Plans

A. Do The LTPPS Integrate The Commission's Direction From Other Related Proceedings And Meet The Criteria Established In The ACR/Scoping Memo?

1. General Assessment

PG&E, SCE and SDG&E each used its resource plan to inform the procurement decision, rather than to select a deterministic set of resources or to identify specific procurement actions. The IOUs interpreted the directions for scenarios as preparing background for, and illustrations of, their procurement strategies. The resource scenarios demonstrate the impact of key uncertainties and how resource plans can be structured to deal with these risks. The utilities request procurement and cost-recovery rules, not a preferred resource list. The utilities vary, or are unclear, about adoption of a Residual Net Open level as a floor or ceiling for procurements.

After existing resources and policy preferred resources have been compared to load and necessary reserves, the result is the amount of energy and capacity which a Load Serving Entity must still acquire. This is called either "need" or the "net open" position, sometimes subdivided into "net short" and "net long." Actual forecasts of net open capacity and energy were contained in confidential filings, so discussion in the testimony and hearings is both limited and general.

2. Load Forecast

The load forecasts of all three utilities was largely unchallenged. Appendix A to the June 4, 2004, ACR directed the IOUs to prepare resource scenarios as follows:

> *The Medium-Load Plan Scenario.* The medium-load plan is to be the preferred resource plan of each utility that meets the needs identified in its Alternative Base Case load-forecast scenario or, if the utility does not choose to file an Alternative Base Case load-forecast scenario, its IEPR-CEC base case scenario. This Plan is to be a utility's best estimate of how it would prepare to meet the needs it believes ultimately will come to be. Though it is not necessary, or even possible, for utilities to specify in detail the placement of new generation facilities that may be needed up to ten years in advance, nor is it possible to indicate the specific paths of transmission additions or upgrades, it is appropriate that the utilities be more specific than they were in the Long-Term Plans submitted in 2003.

In addition, it would be appropriate to include alternative versions of this Plan reflecting different resource development options, reflecting differing expectations about the desirability of in-service-area generation, new transmission, and different fuel types.

> *High-Load Plan Scenario.* The High-Load Plan is not to be an extreme case that has little chance of coming to pass. Rather, it should be a reasonable guess at how great the burden of service could become under high, but not unreasonable assumptions about future load growth. The Plan should be based on the assumption of greater than expected economic growth, resulting in higher load growth, assumption of a modest core-noncore load loss beginning only in 2009, and a modest development of CCA, also beginning in 2009. The utilities should assume that current levels of DA will continue throughout the time horizon.
>
> *Low-Load Plan Scenario.* The Low-Load Plan similarly, is not to be an extreme example of conservation and changed priorities of Californians. Rather, it should be based on reasonable but pessimistic assumptions about the economy and on generous assumptions about the development of core-noncore impacts and CCA. Assume aggressive CCA development beginning in 2006, and an aggressive core-noncore scenario from the choices discussed above. Again, assume the continuation of DA service at current levels.

Although all three IOUs relied on different assumptions in modeling their medium case and in setting floors and ceilings for the high and low scenarios, for the most part the three LTPPs complied with the resource scenario request. The differing assumptions made cross-utility comparisons difficult, but each LTPP taken on its own provided a reasonable range of scenarios as boundaries of risk.

In reviewing the resource scenarios in the LTPPs, each intervenor brought a particular perspective to analysis of the plan that tended to color the evaluation. And to further complicate the resource scenario evaluation is the fact that it is sometimes difficult to integrate differing "load forecasts" with resource scenarios and to understand the interaction between the two concepts. For example, intervenors concerned with departing load are concerned that the IOUs are over resourced in general and that could lead to stranded costs if/when there is departing load. Other intervenors focused on whether the resource scenarios plan for sufficient RPS, EE, DR and DG.

PG&E asserts that it complied with the directions of the ACR, and that no party directly challenged PG&E's reference case (i.e. service area forecast) or its high, medium and low forecasts[20]. In its medium case, "PG&E assumed that three percent of its current customers with load under 500 kW will begin to migrate to community choice aggregation in 2006, and the rate of loss to this market will increase by one percent annually, reaching 10 percent in 2013[21]. PG&E also assumed implementation of a core/noncore market structure beginning in 2007 and that 50 percent of noncore customers with load above 500 kW who are not already direct access service customers will depart from PG&E service[22].

SCE contends that its forecasts are reasonable and that they comply with the ACR requirements. Since SCE's medium case, its preferred case, did not include any CCA or core/non-core, it was the focus of most discussion. SCE chose a forecast that was "consistent with Edison's current load forecast, without knowledge of what might come.[23]" This is also the forecast used in SCE's 2006 General Rate Case, adjusted for expanded energy efficiency. SCE's low load case assumes low economic growth and aggressive departing load.

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[20] PG&E opening brief, p. 7.

[21] Ex. 34, PG&E/Aslin, p. 4-7.

[22] Ex. 34, PG&E/Aslin, p. 4-7, PG&E Opening Brief, p. 7.

[23] SCE/Whatley Tr. Vol. 11, 1602:16 – 1603:14.

SDG&E asserts that its (area) load forecast was unchallenged in this proceeding. "The medium-load plan represents SDG&E's best estimate of the resources needed to reliably serve its customers, and it is based on a load forecast that does not show any loss of load to a core/noncore split or CCA implementation. Given the uncertainty surrounding the timing and magnitude of emerging rules for CCA, core/noncore, or reinstatement of direct access and the potential resulting outcomes, the medium-load plan is best suited to meet the expected need absent firm, enforceable commitments and other final details to assess departing load models." [24]

All three IOUs included current levels of direct access throughout the planning horizon and did not plan for the return of self-generation customers.

B. Position of Parties on Load Forecasts

ORA conducted a thorough review of the service area load forecasts, noting that the growth rates are similar to those in the CEC's 2003 IEPR, but adjusted to fit the higher actual growth in 2002 and 2003. ORA found the service area load forecasts reasonable[25]. ORA also examined the differing departing load scenarios and recommended that the IOUs use ORA's common set of departing load assumptions.

CMTA/CLECA found the IOU medium case differences in the treatment of departing load sufficiently troublesome to ask that the Commission direct parties to rerun their scenarios using a common set of assumptions. They also

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[24] SDG&E opening brief, p. 11.

[25] ORA Testimony, EX 41C, pp 1-16. "C" after an exhibit indicates that it is a "confidential" exhibit and only parties who are members of the PRG groups or who signed the protective order have access to the confidential version.

recommended that the Commission should have a low level of confidence in the medium case scenarios.[26]

Calpine recommended that a 1-in-10 peak weather planning standard be used for all demand forecasts, as is required for local reliability transmission studies. This would add about 6 percent to the demand forecasts.

CCA asked for and received assurance from all the IOUs that existing load served by large co-generation was assumed to be continued to be served by self-generation and had not been included in the demand forecasts.

Several parties, such as Modesto Irrigation District, South San Joaquin Irrigation District, and the City of Chula Vista, asked that the load in their jurisdictions be removed from IOU demand forecasts, because they intend to serve the load themselves.

C. Discussion of Load Forecasts

The "service area" or "reference" medium forecasts presented by the IOUs in their LTPPs indicate reasonable growth trends and levels. The utilities use similar growth factors and are generally consistent with the IEPR forecast trends, except the levels are higher because they are updated from a 2001 baseline to a 2003 baseline. This update reflects the unanticipated economic recovery in 2002 and 2003 that was not reflected in the IEPR forecast.

The most obvious disparity between the IOUs' forecasts was in the area of assumptions about departing load for DA, core/non-core and CCA. PG&E does include departing load projections in its baseline forecast, where SCE and SDG&E do not. Potentially, PG&E's baseline could be too low, whereas the other

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[26] CMTA/CLECA Opening Brief, p. 3.

IOUs' baselines could be too high. Parties representing potential departing load, and the energy marketers hoping to serve the departed load, questioned whether SCE and SDG&E's medium load scenario included sufficient assumptions about departing load.

The ACR required that the medium load forecast be the utility's preferred case and its best estimate of how it would prepare to meet the needs it believes ultimately will come to be. Since CCA has been set in statute and is the subject of an on-going CPUC implementation proceeding, it is reasonable that some CCA will start to occur in 2006. But, there was not sufficient evidence in this proceeding that CCA alone will have a material effect on IOU resource needs in the next few years.

The future of expanding direct access or creating a core/non-core market is more speculative. Direct access is currently suspended by legislation until the last DWR contract expires, currently scheduled for 2013. There is no record on which to base a choice on the probability that more retail competition will emerge.

As a consequence, we should take these demand uncertainty factors into account as one of the uncertainties affecting the level of acquisition and the need for flexibility in the resource plan. However, we are not going to adopt a fixed assumption regarding a most likely set of departing load. We acknowledge that the IOUs face considerable load variability risk, and will set policies accordingly.

We will not set a procurement cap based on the low cases, since this could seriously under-resource California's service areas during the planning period. Instead, we will rely on a portfolio approach and allow justification of specific contract types as the need arises. This will allow us to balance between obtaining adequate resources and not over-procuring in the case of departing load or crowding out of preferred resources towards the end of the planning period. We will monitor how the IOUs are doing on obtaining resources to meet their resource adequacy requirements on a forward looking basis.

We disagree with Calpine that all demand forecasting should switch to the 1-in-10 peak weather standard used for testing the robustness of local transmission systems. Existing resource planning uses average weather (1-in-2) and then adds a reserve margin which, in part, provides the cushion should hotter than average weather occur. This is the approach we adopted to implement our resource adequacy requirements.[27] Calpine's concern is already accounted for in existing practice.

In summary, although each IOU prepared its own LTPP using its own assumptions, each IOU asserts that its service area load forecasts are comparable to the IEPR, adjusted to more current data, and that their medium, preferred case is a reasonable basis for resource planning. We find all three LTPPs consistent with the 2003 IEPR, are reasonable for planning purposes and that the medium, preferred case should be followed for making planning and procurement decisions.

Adding another layer of complication to the review of the LTPPs is the fact that the utilities can only propose what characteristics would best fit Commission and direction and current circumstances, but only market-tested bids will actually produce a portfolio of specific resources. In this setting, planning is largely indicative, not deterministic. Some parties are concerned that the utilities will over subscribe to long-term contracts that will crowd out future

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[27] D.04-01-050 and D.04-10-035

opportunities. If the utilities have a mixed portfolio of different contract terms and lengths, this should be a manageable issue.

1. Resource Scenarios

Before reviewing load and resource assumptions, we need to set the stage by discussing the overall role of resource scenarios as a backdrop to the procurement plans. There are four principal sources of guidance regarding what this decision should direct the IOUs to do as a response to their long-term resource plans: the EAP; D.04-01-050;the April 4 R.04-04-003 OIR; and the June 16, 2004 ACR/scoping order as amended on June 29:

"The OIR is clear that the major focus is to review and adopt long-term *procurement* plans. However, the plans must be based on an integrated resource strategy that is consistent with Commission policy, reflects reasonable assumptions, and covers a rational range of scenarios."

D. Implementing the Energy Action Plan

The EAP contains explicit direction regarding the state's preferences for meeting identified resource needs and the IOUs are to prioritize their resource selections accordingly. As discussed earlier in the decision, the EAP "loading order" is as follows: energy efficiency and demand-side resources; renewable generation resources; efficient, clean fossil generation resources; upgrades and expansions to the transmission and distribution infrastructure; and customer- and utility-owned distributed generation. Sections of this decision describe the objectives and direction for aggressive procurement of renewable generation resources, contain guidance for procuring clean fossil resources and discuss transmission and DG, respectively. The direction is clear: IOUs should implement the EAP loading order when soliciting resources as a result of this decision.

1. Discussion on Compliance

Parties disagreed on whether the resource scenarios complied with the Commission's direction in the OIR and Scoping memo. Lingering behind these perceptions is the memory of the detailed resource assessments and specific direction which took place when utilities were monopoly resource suppliers. In a hybrid market, the utilities can propose which characteristics would best fit Commission direction and current circumstances, but only market-tested bids will actually produce a portfolio of specific resources. In this setting, planning is indicative, not deterministic.

E. Net Open Position

1. Position of IOUs on Net Open Positions

PG&E asserts that development of its Net Open position is reasonable. Based on the three scenarios PG&E developed, PG&E estimated the energy and capacity it will need to fill its net open position.

"For the first five years of PG&E's medium load scenario, PG&E's energy and capacity needs show little change because anticipated load growth and resource attrition are offset by projected load migration to the community choice aggregation and core/noncore markets. PG&E's energy and capacity needs begin to increase in the latter years of the 10-year planning horizon as the DWR contracts allocated to PG&E begin to expire."[28]

In PG&E's high-load scenario, PG&E's energy and capacity needs become increasingly greater throughout the planning horizon. In PG&E's low-load scenario, its net open position grows longer during the first five years of the plan,

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[28] (Ex. 34 and 35C, Tables 4-3 and 4-4.)

but becomes increasingly shorter during the latter half of the planning horizon. [29] PG&E's net open position is not affected by transmission additions, because PG&E did not propose any economically-driven transmission lines in its LTPP.

"SCE's current supply portfolio is dominated by long-term and baseload resource commitments. Such a portfolio results in SCE having excess supply that must be sold into the market.[30] There is a need for additional load-following and peaking resources.

Due primarily to the suite of grid reliability resources approved in D.04-06-011, SDG&E is essentially "fully resourced" through approximately 2009. Combined with efforts to achieve 20% of the energy mix by 2010 from renewable sources means SDG&E will primarily procure only renewable power until 2010. Nevertheless, SDG&E asks the Commission to take precise and specific action to address future needs identified in SDG&E's medium-load plan. Increased grid reliability needs, for example, appear in 2010 in the medium load plan due to load growth and limited in-basin generation. In addition, the presence of the DWR Sunrise contract in SDG&E's portfolio means that SDG&E does not have 'headroom' until after 2010 to obtain further local reliability contracts.[31]

F. Discussion on Net Open

In summary, all three IOUs have capacity needs throughout the planning horizon. Capacity needs expand considerably in 2011, due to the expiration of most of the DWR contracts. All three IOUs are long on energy, primarily in the

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[29] PG&E Exs. 34 and 35C, Tables 4-3 through 4-8, PG&E opening brief, pp. 16-17.

[30] SCE Opening Brief, Appendix A, p. A-7.

[31] SDG&E opening brief, pp. 16, 18.

off-peak and shoulder hours, through 2009 (PG&E) and 2010 (SCE and SDG&E) until the bulk of DWR contracts expire. Because resources are 'lumpy', adding preferred resources upon existing resources somewhat exacerbates this long position, requiring utilities to be energy sellers in many off-peak and shoulder hours.

The impact of these decisions is to reduce the amount of capacity needed in the 2010 medium case scenarios by 800 MW for PG&E and 1,500 MW for SCE, while increasing SDG&E's resources above the minimum reserve margin by 280 MWs.

This Commission favors openness in its decisions and in the information that market participants have in dealing with each other. Another section of this decision discusses specifically how we are responding to legislative direction on confidentiality matters. In this section we note that it is not the intent of the Commission to provide the means by which market power could be exercised against the LSEs and, hence, against electric service customers in California. Therefore, this decision does not present information about the current net open positions of the utilities. Nor do we provide the elements from which that information can be calculated. However, we will provide simplified tables based on projections of future resource balance information for the years 2007-2014 after those numbers have been refreshed from their initial filing back in July.

G. Implications of the Three Resource Scenarios

As set forth in the April 1, 2004 OIR, the purpose of the three resource scenarios was to "help the Commission understand how each utility intends to respond to a wide range of load scenarios. The focus is not on forecasts, but rather on the adoption of long-term plans that can accommodate many possible outcomes."[32]

The IOUs filed their LTPPs, with resource scenarios, on July 9, 2004, almost four months before the Commission issued its decision on Reserve Margin Requirements/Resource Adequacy (RMR/RA) in D.04-10-035 on October 28, 2004. At the time the LTPPs were prepared, the IOUs and many intervenors were concerned with the utilities overprocurring resources—especially in the short-term. However, pursuant to the direction given by the Governor Schwarzenegger and President Peevey, and adopted to by a majority of the Commission, the current focus is on maintaining and enhancing grid reliability through accelerated reserve margin targets. When this goal is integrated with the directive from D.04-07-028 issued by the Commission this summer ordering the utilities to concentrate on near-term reliability, it is evident that the IOUs must increase and retain supply for the near future. We will try to balance grid reliability with our other primary public duty of protecting ratepayers from excessive charges and also be mindful of potential departing loads and stranded costs.

Therefore, in capsulizing the IOUs resource scenarios, we note that the IOUs did not have the benefit of the RA decision when the scenarios were prepared in July 2004 and it may be necessary to direct the IOUs to revisit and update their LTPPs to comply with the new reserve margin targets.

As an appropriate segue, in its LTPP, PG&E states that it is most concerned about the resource risks associated with customer load uncertainty and the risk

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32 R.04-04-003, mimeo p. 4.

of stranded costs due to excess procurements. "IOUs devoutly wish to avoid being "over-resourced," but procurement strategies based on short-term procurement and dependence on external suppliers have even greater risk, as the energy crisis demonstrated. PG&E's plan is designed to recognize these tradeoffs. The full implementation of Assembly Bill (AB) 57, as called for in last April's letter from Governor Schwarzenegger to President Peevey; the assumptions and conditions suggested in PG&E's integrated resource plan, including a request for long-term procurement based on the low case scenario and the possibility of a nonbypassable charge if long-term procurement commitments are stranded; and the "hybrid market structure" already approved by the Commission, would all facilitate competition by ensuring that: (1) LSEs share the costs of long-term commitments; (2) bundled customers are indifferent to the departure of load to competitors; and (3) new resources are developed. [33]

PG&E urges the Commission to approve its resource assumptions, medium case load forecast scenario, and portfolio strategy, which implement the EAP loading order cost-effectively and fills PG&E's projected net open position with "preferred" resources and a mixture of short, medium, and long-term products. The utility argues that the Commission should ignore self-interested proposals from other parties that could force the utilities to procure resources that are unneeded or would not be cost-effective. "The Commission should find that PG&E may procure 1,200 MW of long term peaking resources by 2008 and an additional 1,000 MW of long term shaping resources by 2010. . ." [34] These

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[33] PG&E opening brief, p. 5.

[34] *Id.*, p. 2.

levels are based on net open needs identified in PG&E's low load scenario. PG&E also requests that the Commission re-authorize short- and mid-term contracts, in order to have a robust portfolio. Additionally, depending on resource need, PG&E may enter tolling contracts with existing resources and bilateral agreements with generators after they are no longer needed for reliability must run (RMR) support as well as with generators whose current contracts with DWR expire within the planning period.[35]

SCE states that under its scenarios:

- SCE's expanded demand-side portfolio is cost-effective in every scenario, but must be adapted based on SCE's bundled customer needs.
- SCE will meet the Energy Action Plan's accelerated renewables target in every scenario, and under the low load scenario SCE has no need for additional renewable generation until 2012,
- SCE has no need for baseload resources until at least the end of the decade and later, under the core/non-core scenario;
- SCE's current resource portfolio is overweight with long-term resources (greater than 5 year commitments) whether measured by capacity or energy. This situation is even more pronounced under core/non-core scenarios;
- SCE's current resource portfolio is overweight with baseload resources in the near-term and require s balancing with peaking resources,

[35] *Id.*, pp. 20-21.

- When compared to today's resource mix, SCE will require more peaking and intermediate resources and less baseload resources in the future.[36]

SCE seeks to minimize the financial risk of such [excess baseload] resources to bundled customers by committing only to short- and medium-term peaking and intermediate resources. The multiple scenarios SCE presented in its LTPP all indicated that SCE would follow this strategic path forward regardless of the changes to its load.[37]

Originally, SCE had requested authority only for short- and mid-term contracts of 5 years or less, but in its reply testimony it outlined a proposal for a 10-year contract if there could be off-ramps for specific purposes, such as greater than expected departing load. This option was added, in part, due to requests by parties that SCE enter some long-term contracts. SCE proposes to pursue this option in a future application to amend its procurement plan.[38]

SDG&E claims that its resource plan does not assume that the exact size, timing, and sequence of each specific future resource addition be etched in stone through approval of this plan. Instead, SDG&E argues that approval of its resource plan, tested under a variety of scenarios, provides a critical first step to subsequently bringing forward specific resources for Commission approval. Adoption by the Commission of SDG&E's long-term plan would therefore constitute the Commission's agreement that the portfolio of resource types

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[36] *Id.*, pp. 8-9.

[37] *Id.*, p. A-7.

[38] SCE/Cushnie Tr Vol. 10, 1539:23 – 1540:2

identified in this long-term plan represent desired outcomes for customers, and that SDG&E's moving forward to further study and permit the additions shown in the plan is consistent with Commission policy.[39]

SDG&E argues that the Commission should approve its medium-load plan because it is SDG&E's best estimate of how it can prudently and reasonably prepare to meet its customers' needs over the next ten years. SDG&E's medium-load plan fully reflects the Commission's preferred loading order that first takes into account cost-effective energy efficiency, demand response, and renewable sources of energy before consideration of supply side resources and transmission.

For SDG&E a key component of its long-term resource plan is it proposed 500kV transmission line and it is seeking Commission support on this concept as part of its LTPP approval. The utility does acknowledge that it will still have to file a CPCN application for the transmission line. The CPCN proceeding will, among other things, consider the trade-off between transmission and generation, which was an analysis that numerous parties specifically mentioned. SDG&E argues that this analysis need not have to be done at this stage, however, and it does not prevent the Commission from concluding now that new transmission is a key component of SDG&E's long-term resource plan that needs to be further analyzed. [40]

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[39] SDG&E opening brief, pp. 2-3.

[40] Id., pp. 45, 47.

H. Position of Parties on Implications of Resource Scenarios

To summarize, each party reviewed the IOUs resource scenarios under the microscope of their own perspective and ask for Commission action to promote that viewpoint. Those concerned with reliability and marketing power to the IOUs tended to argue in favor of more resources; those concerned with the environment, renewables, conservation and generally reducing demand for power wanted the IOUs to concentrate more on EE, DR, DG and renewables and less on fossil-fuel resources; proponents of brown sites advocated giving more priority to aging power plants; potential departing load parties worried the IOUs were over procuring, and consumer/ratepayer groups, while advocating reliability, question "at what cost?" Parties recommended a mix of contract terms from short-term ones to reduce the possibility of stranded costs, to long-term contracts to capture some certainty for prices in the future.

The IOUs complied sufficiently with Commission direction in preparing their resource scenarios so we will not require the preparation and resubmission of LTPPs at this time. What we glean from deficiencies in these LTPPs can be addressed by requesting updates as the Commission gives new direction or clarification in other resource/procurement proceedings and can direct us in giving guidance for the next LTPP proceeding.

In general, the three IOUs and the more than twenty-seven intervenors recognized that the resource scenarios represented "best guesstimates" and there is no way to predict the energy demand/supply situation with any certainty, especially in the face of changing load situations. A mix of resources, fuel types, contract terms and types, with some baseload, peaking, shaping and intermediate capacity, with a healthy margin of built-in flexibility and sufficient resource adequacy, is the best the IOUs can do at this point in time. It is also important the IOUs have room in their plans to procure resources as directed by the Commission in the areas of EE, DR, DG, renewables, and soon QFs. The IOUs need to balance expiring DWR contracts with required targets in EE, DR and renewables, so they are not fully resourced for the ten-year planning period with no head room for new resources.

Following is guidance on meeting the identified IOU needs in accordance with the EAP loading order and the carbon adder adopted in this decision. When executing procurement plans in response to the direction below, each IOU is to take the following steps:

- Procure the maximum amount of cost-effective energy efficiency and demand-side resources;
- For further resource needs, procure the maximum amount of renewable generation resources via all-source RFO, and be prepared to defend any selection of fossil over renewable resources; and
- Employ the GHG adder, described in this decision, when evaluating fossil generation bids.

Generation and demand-side commitments with start dates after 2010 may be deferred until the next procurement cycle. The winding-down of DWR contracts will materially affect the magnitude and nature of choices available, and we will be able to take advantage of two years of experience in implementing policy-preferred resources.

We find reasonable PG&E's strategy of adding 1,200 MW of reserve capacity and new peaking generation in 2008 and an additional 1,000 MW of new peaking and dispatchable generation in 2010 through RFOs is compatible with their medium resource needs, does not crowd out policy-preferred resources, and is a reasonable level of commitment given load uncertainty. Those commitments may need to be increased or expedited for PG&E to meet its 2006 resource adequacy obligations.

Depending on the nature of the bids obtained, PG&E is authorized to justify to the Commission why higher levels might be desirable. Nothing in this decision precludes PG&E from offering local reliability contracts, should they become necessary, pursuant to D.04-10-035.

We find SCE's LTPP resource plan is reasonable, subject to the compliance requirements covering its demand forecast, demand response, energy efficiency, QFs, and other factors set forth in this Decision and other Commission decisions in those designated proceedings. SCE has demonstrated that its primary residual resource need through 2011 is for peaking, dispatchable and shaping resources. SCE has considerable need for peaking and shaping resources, which should be obtained through a short, medium- and long-term acquisitions.

SCE's strategy of relying primarily on short- and mid-term contracts during this planning period is reasonable, but it may be prudent to add some long-term resources. SCE is authorized to present such a case to the Commission as an implementation of its LTPP by way of an application following an RFP.

SDG&E's resource scenarios were the most complete and useful in understanding the impact of differing loads, risk strategies, and the complex process of compiling a portfolio that meets reliability, adequacy, policy preferences and cost moderation goals. We find SDG&E's resource plan reasonable, subject to the modifications required for the compliance filing. SDG&E is essentially fully resourced through 2009, other than needed investments in renewable resources to meet RPS targets. Because SDG&E is fully resourced, SDG&E's resource plan is vulnerable to departing load and the utility is still obligated to meet its renewables, energy efficiency and DR goals. Since

SDG&E's estimated reserve margins, which exceed 17% in some years during the planning period are the result of prior Commission decisions. There should be no finding of unreasonableness if they exceed 17%.

One critical element of SDG&E's LTPP that we are not approving is their request for a 500kV transmission line. As we discuss elsewhere, we do acknowledge the lengthy process that is needed to plan, license and construct transmission, and thus encourage SDG&E to continue its planning efforts and move forward with evaluating these transmission alternatives for meeting a local resource deficiency by 2010.

For this round of procurement filings, we find that the IOU filings are EAP-compliant if they included the EAP targets established in the RPS, DR and EE proceedings; included, at a minimum, the DG forecasts in the 2003 IEPR, and added transmission and clean central-station generation to meet remaining energy and capacity needs.

We will direct a compliance filing of annual energy and capacity resource accounting tables, consistent with directions on baseline load forecasts, EE, QFs and DR as explained elsewhere in this decision, but we will not require refiling of whole resource plans. We do expect the IOUs to make incremental improvements in their next round of analysis to be filed with the Energy Commission in 2005. Procurement resulting from the plans should comport with the direction, above, regarding obtaining the maximum feasible amount of renewable generation.

We concur with the CA ISO that the transmission elements of the plans were insufficient to meet our goals and accept their recommendations that future plans should include conceptual scenarios that illustrate the impact of potential generator location. We also concur that when an IOU proposes a major transmission line, it should include a companion scenario without the line. To the extent an IOU believes that the range of need identified in the 2005 IEPR is sufficient to justify a transmission project then it may be identified as a specific proposal to satisfy need in the 2006 procurement proceeding filings.

I. Natural Gas Price Forecasts

1. Regulatory Background

The May 2003 EAP, D.04-01-050, R.04-04-003 and the June 4, 2004, ACR all informed the IOUs on the subject of natural gas price forecast issues. R.04-04-003 reiterated the EAP's message that the IOUs were to "[f]irst seek to optimize all strategies to increase conservation and energy efficiency in order to *minimize increases* in electricity and *natural gas demand.*" [41]

This was building on the direction from D.04-01-050, and further emphasized in the ACR that "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. 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 prices of fuel and costs of purchased power at least up to the 95th percentile of the expected distribution."[42](p.98)

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[41] R. 04-04-003, p. 6, emphasis added.

[42] D. 04-01-050, p. 98.

Building on that, the ACR stated "[i]n addition to providing estimates of the resulting increase in cost of meeting load under these assumptions, the utilities should provide gas prices and market prices that correspond to the 95th percentile. The utilities should submit a simple comparison of these price series to the base case assumptions. For gas prices, these should include monthly average prices."[43] (p. 16)

J. Utilities And Party Positions

PG&E developed gas price forecast using gas commodity prices based on the April 19, 2004, closing price of forward contracts traded on the NYMEX plus location basis obtained from broker quotes for gas delivered at AECO, Topock, Malin and PG&E Citygate for the period through February 2009, which marks the end of NYMEX availability. For March 2009 and beyond, PG&E extrapolates gas prices using monthly energy prices and maintaining the same monthly relationship as exhibited in the prior 12 months to March 2009. As required by the June 4 ACR, PG&E states it estimated its 95th percentile portfolio risk using thousands of natural gas and electricity price scenarios in a Monte Carlo simulation.[44]

PG&E includes Table 5-4 in its rebuttal testimony, Exhibit 36, at pp. 7-8, that presents gas prices resulting from their representation of volatility. Widths of the probabilities are substantial and grow as the delivery period is further into the future. Monte Carlo analysis was not driven by a set of fundamental variables; natural gas prices were simulated directly.

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[43] ACR, p. 16.

[44] PG&E direct, Ex. 34, pp. 4-10.

PG&E argues that its forecast shows substantial volatility, measured using standard deviation of probability distribution of prices, widths are substantial and grow in future exhibiting substantial deviation.[45]

SCE's gas forecast relied on a gas price forecast prepared by Global Insight (GI), an international consulting firm and noted expert in gas forecasting, for all the major pricing points in the WECC and provided SCE with first and second standard deviation gas price forecasts. GI developed its gas price forecast using global and local factors which impact gas prices in the WECC. Global impacts include the price of oil and importation of LNG into the U.S. Local impacts include LNG facilities and supply basin and pipeline development in the western U.S. Standard deviation forecast developed using fluctuating variables such as U.S. economic growth, LNG imports, California economic growth and weather. SCE provided an analysis between GI's forecast and CEC's. CEC's forecast is higher than GI's and assumed to be due to the impact of future LNG supplies. [46] SCE acknowledges that forward gas markets have risen since April 2004, however the magnitude of the gas price forecast is not a major factor for SCE in determining what proportion of resource additions are gas or non-gas fired.

SDG&E developed a gas price forecast of $4.70 based on San Juan basin prices said to be the dominant supply resource at the California border. The forecast was designed following a five step process using the Gross Domestic Price inflation index, basin differentials and adding various costs for transportation from the basin to the border. SDG&E provides comparisons with

[45] PG&E opening brief, p. 16.

[46] Edison, Ex. 73, pp. 93-4.

other gas price forecasts and SDG&E asserts that its forecast is in line with other gas forecasts. Variations among the other forecasts are due to assumptions about LNG and outlook about other supply conditions.

The average cash price of gas at Henry Hub is $5.92. The $1.22 difference between SDG&E's forecast and Henry Hub is statistically insignificant since it is within one standard deviation of historical monthly prices. SDG&E argues that it is inappropriate to use NYMEX futures as a forecasting tool, since it is a one day sample of the market.

Monthly prices at San Juan basin are not "adjusted", but calculated from historic month-to-annual ratios. In response to criticisms of its gas forecast, SDG&E contends that it is erroneous to state that many charges are added to San Juan Basin prices. It is reasonable to expect LNG supplies to continue to grow and moderate prices in out years. Gas price forecast applies to base case scenario and does not reflect "year-to-year" volatility.

UCS asserts that none of the utilities/ provided enough information (e.g., description of inputs or relationship to end results) in filings or confidential work-papers to allow UCS and other intervenors to determine exactly what their assumptions were in conducting computer simulations of expected future gas prices.

In general, UCS alleges that the IOUs gas price forecasts were deficient as follows: PG&E did not discuss how it would manage gas price risk associated with gas-fired resources apart from its DWR and QF contracts or whether PG&E designed its portfolio options in order to minimize gas price risk; SCE did not say what its preferred portfolio was and included no discussion on how it would manage gas price risk or provided any alternative portfolios designed to minimize that risk; and SDG&E, intentionally or unintentionally, minimized its gas price risk through 2010 by choosing a portfolio that would not require it to procure conventional resources before then and then failed to indicate whether gas price risk will be a consideration in procuring power post 2010.

UCS recommends that the Commission mandate that utilities account for gas price risk when determining how they plan to buy power; provide details of all variables and ranges used in simulations; and results of simulations should be used to create a portfolio least susceptible to future expected gas price risks. In addition, the Commission should require the IOUs to supplement their forecasts using different price scenarios and clearly detail the variables and range of values assigned to each variables used in simulations and use results to create portfolios that mitigate future gas price risk.

UCAN only addressed SDG&E's gas forecast and urges the Commission to reject it since it reflects prices significantly lower than current NYMEX prices. UCAN is concerned that low gas price projections may skew long-term resource plans and, if intended to be used as a baseline, then it may have the effect of triggering new procurement decisions and impacting hedging strategies. UCAN recommends that SDG&E use most up-to-date information available and that it update its natural gas price forecast at least monthly using NYMEX data and or broker quotes.

Given current gas spot and futures prices, Strategic Energy claims that all utilities forecasts appear too low. Strategic Energy asserts that unrealistic low gas price forecast would depress the wholesale power price forecast and may affect least-cost procurement and skew results of comparing bids between utility-build and third party procurement.

This group of intervenors is concerned that each IOU utilized a different method to develop its gas forecast making an across-utility comparison difficult.

Forecasts are flat showing little price volatility and they want the Commission to direct the IOUs to develop forecasts with more volatility.

WPTF finds the gas price forecasts too low and fears that they could be used by the utilities to skew results to favor its own or an affiliate's offer. The Commission should require a utility to commit to a gas price forecast if the utility offers a long-term resource based on a specific gas price forecast. WPTF also recommends the use of third party independent review of competitive solicitations.

Parties have recommended that the utilities have used separate approaches toward developing their gas price forecasts, that their forecasts appear low or that they do not exhibit much volatility. Such concerns were the basis for the gas price forecast guidelines we adopted in D.04-01-050 and the June 4, 2004 ACR and, in particular, that the LTPPs should reflect a range of expected prices. These requirements adequately address the concerns raised by the parties and ensure that the LTPPs are responsive to the uncertainties of predicting long-term gas prices. To ensure that gas price forecasts submitted in future LTPPs remain robust, we will require that the utilities provide updated gas price forecasts using the same criteria set forth in D.04-01-050 and the June 4, 2004 ACR when subsequent long term procurement plans are filed with the Commission.

K. How the Utilities' Long-Term Plans Reflect Policies, Goals, And Outcomes From Other Umbrella Proceedings and Comport with the Energy Action Plan

1. Umbrella Proceedings

This OIR was designed to be an "umbrella" proceeding to coordinate and incorporate Commission efforts in the CCA, DR, DG, EE, Avoided Cost and Long-term Policy for Expiring QF Contracts, RPS, Transmission Assessment and

Transmission Planning proceedings, as well as to address Resource Adequacy (RA) requirements. The June 4, 2004 ACR identified LTPP and RA as the "critical path" issues that need to be addressed in this proceeding.

2. Resource Adequacy

The Commission's decision in RA, D.04-10-035, issued October 28, 2004, among other things, established that all Load Serving Entities (LSE), including the IOUs, must have reserve margins of 15-17% by June 1, 2006. As part of meeting this reserve margin requirement, each LSE must have 90% of its next summer's requirement [May through September] fully resourced by September 30 of the year before. The decision also established a 100% forward commitment obligation for a month-ahead horizon for the five summer months, so each LSE must acquire the incremental remaining 10% of forward commitments needed to satisfy resource adequacy requirements. The IOUs are to plan to meet all RA requirements as set forth in D.04-10-035 as they go forward with their LTPPs.

IV. Community Choice Aggregation (CCA)

On October 29, 2004, the proposed decision (PD) in R.03-10-003 mailed in anticipation of a Commission vote on December 2, 2004, implemented certain provision of AB 117[47] which permits local governments the opportunity to aggregate energy procurement on behalf of the consumers in their communities and establishing certain protocols for CCA. As of the date of the mailing of the PD in this proceeding we cannot anticipate with absolute certainty what protocols the Commission will adopt, or when, but we can refer to the PD for guidance in adopting this decision. Once the Commission issues a decision in

[47] AB 117 (Chapter 838, September 24, 2002), which added Pub. Util. Code Sections 218.3, 331.1, 366.2, 381.1 and 394.25.

R.03-10-003, the IOUs are to incorporate the directives from that decision as they make future planning and procurement decisions.

What is known in this proceeding is that much of the debate over the LTPPs raised by potential CCAs, municipalities or irrigation districts, specifically Chula Vista, Modesto and SSJID, centered on how the IOUs could/should plan prospectively and judiciously for upcoming CCAs, or other departing loads, so that there would not be excess energy if, or when, the CCAs became fully functional and able to serve customers previously served by one of the IOUs. What the potential CCAs, and others, want to limit is the amount of cost responsibility (CRS) that departing CCA customers would be required to pay for utility liabilities incurred on their behalf that are still extant when the CCA customers leave utility service. Section 366.2(h) of AB 117 dictates that the Commission shall authorize CCA only if the Commission imposes a cost recovery mechanism in accordance with the bill. The overriding policy behind the CRS is to make remaining bundled ratepayers, those still served by the utility, neutral to stranded costs left by the departing customers.

Based on the PD in R.03-10-003, it can be anticipated that the Commission's decision will implement a program whereby cities and counties can procure energy on behalf of their communities, but also protects those bundled ratepayers who do not have the option of transferring to a CCA from the possible cost impacts resulting from the departing customers. It is expected that that decision will adopt a methodology for estimating the CRS that will allow bundled customers to be indifferent to the CCA program, including a methodology for CCA customers to pay their share of the costs of DWR bonds and contracts, utility procurement contracts and other items. The PD anticipates that there will be a Phase 2 of R.03-10-003 that will address issues unresolved in

Phase 1, including such topics as customer protections and switching protocols, billing and metering issues and reentry and switching fees.

Some parties offered guidance to the Commission on identifying trigger points whereby an IOU can proceed with confidence to stop procuring for potential departing load. TURN suggested that the delineation point should be when the CCA provides a binding statement of intent. Some suggested that the key point would be when a CCA files its implementation plan with the Commission; others suggested a more conservative approach of waiting until the Commission approves the CCA's plan. Obviously all parties, including the Commission, only want one LSE procuring for the same customer base at any one time. We will not determine a precise trigger point when an IOU can stop procuring in this decision.

Instead, we encourage cities and counties that are seriously considering CCA to approach their IOU and proactively seek strategies in which the two parties can share procurement risk going forward. Such strategies could include agreements between the IOU and CCA to allocate certain contracts to the CCA once it is formed, or the CCA could execute a binding notice of intent with a commitment to a target date, at which the CCA is responsible for energy procurement. The agreement should incorporate some element of penalty if the CCA does not make the target date. We support parties working together to seek the most efficient transaction between the IOU and CCA.

Our expectation in future procurement plans is that the IOUs shall incorporate reasonable anticipated CCA departing load. The assumption of the Commission is that the IOUs should acknowledge potential CCA departing load and identify which city and/or county has expressed intent to pursue aggregation, including MW estimates of this departing load, in future procurement plans.

A. Potential Stranded Costs Due To Customer Load Uncertainty

A major issue in this proceeding is the extent to which the utilities will be compensated for investments or purchases that they must make in order to meet their obligations to provide reliable service to their customers. The implementation of CCA, departing municipal load, and the potential for lifting, in some form or another, the current ban on allowing new direct access all create a great degree of uncertainty as to the amount of load the existing utilities will be responsible for serving in the future. Given the potential for a significant portion of the utilities' load to take service from a different provider, the utilities are concerned that they could end up over-procuring resources and incurring the stranded costs associated with these resources.

One solution to this problem, discussed elsewhere in this decision, is the adoption of load forecasts that seek to address, to the extent possible, the uncertainties over the future load that the utilities will be responsible for. Another solution is for the utilities to be entitled to recover any stranded costs occurring as a result of their efforts to meet their load obligations.

The IOUs support the concept of stranded cost recovery for their investments and believe it is a critical factor that needs to be resolved in order for them to plan their future procurement strategies. Consumer groups (TURN, ORA) worry that absent such a safeguard, the utilities' remaining customers would wind up responsible for these costs, violating the ratepayer indifference standard that the Commission has previously adopted. NRDC raises the concern that the "preferred" resources identified in the EAP require longer-term commitments. Limiting procurement choices solely to short-term options, many parties state, will result in a non-optimal resource portfolio and higher costs to all consumers.

Needless to say, the parties opposing the imposition of exit fees are either those most likely to depart the existing system (CMTA/CLECA, Modesto, SSJID) or ESPs that would serve this departing load. Modesto and Strategic/Energy, however, recognize that some stranded cost recovery might be allowed but only due to "unforeseen circumstances."

The above parties, generally advocate that the primary means to minimize or eliminate stranded costs is for the utilities to develop flexible portfolios with significant shorter-term purchases that could be rapidly reduced as load fluctuates.

WPTF also opposes stranded cost recovery, believing the utility should recover the costs of any excess capacity through a capacity market. Constellation makes a similar argument, proposing a "slice of load" approach wherein the utility would sell off a share of its resource commitments to other suppliers and that any new contracts entered into by a utility contain assignability provisions.

In general we agree that the utilities should be allowed to recover their ***net*** stranded costs from all customers, including the use of an exit fee. Such an approach best meets the Commission's goals of providing "the need for reasonable certainty of rate recovery" (as required under AB57 and noted in the June 4th ACR) as well as best ensuring that California meets its energy needs.

Requiring departing customers to assume a fair share of their costs is also consistent with the Commission's policy of holding captive ratepayers harmless as required by state law.

As many parties noted, in its last procurement decision (D.04-01-050) the Commission stated that a flexible utility portfolio, consisting of a mix of short-, mid- and long-term resources would be the best mechanism to protect against utility over-procurement. However, since the issuance of this decision, the Commission has now made the utilities responsible for ensuring local reliability, accelerated the resource adequacy requirement from 2008 to 2006, and adopted RPS target goals resulting in the solicitation of new renewable energy sources by the utilities. These initiatives, combined with the existing overhang of utility retained generation and long-term DWR contracts significantly limit the flexibility that the utilities have to quickly adjust their resource portfolios. All of these resource additions benefit all existing customers by improving reliability and promoting renewable energy development.

There is also a potential mismatch between the types of resources that the utilities need to procure (primarily peaking and load following) and the resources that departing customers require (primarily base load with a lesser amount of peaking/load following capability). Thus it may not be possible for the utility to develop a resource portfolio that accurately matches the load profile of expected departing load.

Providing for stranded cost recovery provides a greater incentive for the utilities to enter into five year or longer contracts for existing capacity that many parties (IEP, Duke, Calpine, SCE, PG&E, ISO) are advocating as the optimal approach to ensure the availability of these resources.

Even WPTF, which does not support exit fees, is advocating for the utilities to enter into these longer-term contracts.

There is also the concern that the utilities may need to enter into new contracts (and/or construct) new capacity to ensure that California has sufficient resources toward the latter years of this decade. In order for these resources to be on-line when needed, it may be necessary to begin construction of these projects in the very near term. Almost all parties, including WPTF, agree that new construction would require a minimum ten-year contractual commitment. In the near-term, it appears that the utilities are the only entities capable of facilitating the financing of these projects through long-term contracts.[48]

New renewable projects, necessary for the achievement of the EAP and legislative goals, also require long-term commitments in the range of 10 to 20 years.

For the above reasons, it appears that the utilities may need to make longer-term commitments for capacity and energy that may become stranded at some point during the life of these projects.

The utilities should be allowed to recover the net costs of these commitments. This does not mean that the utility should recover the total cost of these commitments, only the uneconomic portion. Similar to the treatment of DWR energy commitments, the utilities should take appropriate steps to minimize the costs by selling excess energy and capacity needs into the marketplace. These other revenue sources (market sales, sales into the ISO's energy/ancillary services market, and potential sales into renewable energy credit or capacity markets should they develop) should be credited against the utilities' costs. It is too speculative at this time, as WPTF suggests that the utilities' sole recourse should be a capacity market which has yet to be

48 See, for example, the comments of Calpine, the ISO, TURN and PG&E.

developed. Additionally, as Edison and others note[49], there is no guarantee that revenues from a capacity market would equal the utilities' costs.

Allowing the utilities to recover stranded costs from all customers who benefited is consistent with recent Commission policy with regards to new resource additions. In both the SDG&E Reliability RFP (D.04-06-011) and in Edison's Mountainview decision (D.03-12-059) the Commission required that all existing customers of the utility were responsible for any potential stranded costs for a period of ten-years. Even requiring a ten-year commitment for new resources may still increase costs for captive ratepayers due to the need for the project developer to see accelerated cost recovery for their investments rather than amortizing these assets over a longer time period.

This decision therefore adopts the same 10-year standard for new fossil-fueled resources acquired by the utilities. We are also proposing a 10-year standard for new renewable resources, but seek comment if this time-period is sufficiently long enough that it will not deter the development of these resources. For all other shorter contracts, the utilities should be allowed recovery over the life of the contract.

As part of the issue of stranded cost recovery, SCE proposes that we change the direct access switching rules adopted by the Commission. NRDC requests that departing customers provide 10-years notice. Both of these proposals are premature at this time. They are better discussed if and when the Commission addresses the issue of allowing new direct access to occur, which,

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[49] TURN, NRDC.

under present legislation, cannot be before expiration of the last DWR contracts in 2013.

V. Demand Response (DR)

Demand response programs can be used to help achieve both system efficiency and reliability goals. There are two general types of demand response programs that the IOUs use to reduce demand when energy prices are high or when supplies are tight: ‘price-responsive’ programs (in which customers choose how much load reduction they can provide based on either the electricity price or a per-kW or kWh load reduction incentive), and emergency-triggered programs (in which customers agree to reduce their load to some contractually-determined level in exchange for an incentive, usually a commodity discount). Both types of programs motivate customers to reduce their loads in exchange for some type of benefit – such as reduced energy rates, bill credits or exemptions from rotating outages. For purposes of clarification, the term ‘demand response program’ should be interpreted in this decision to mean ‘price-responsive’ programs for which the Commission has established specific MW targets to be incorporated into the IOU’s LT procurement plans.

Price-responsive programs have been the subject of R.02-06-001. D.03-06-032 adopted price-responsive programs, set target goals and directed the utilities on how to integrate demand response goals into their procurement plans. As of July 2004, the IOUs have a combined total of **519** MWs[50] enrolled in

[50] 290MW for PG&E, 205 MW for SCE and 24 MW for SDG&E, derived from utility demand response/interruptible monthly reports.

the authorized programs.[51] D.03-06-032 also adopted demand response goals for years 2003 – 2007. The 2005 goal is 3% of 'annual system peak demand', increasing to 4% in 2006 and 5% in 2007. The adopted goals apply only to 'price-responsive' demand response programs. MW savings generated by interruptible programs do not count toward the demand response goals articulated in the Energy Action Plan. Enrollment in interruptible programs is capped at 2,500 MW.

D.03-06-032 also directed the IOUs to include the adopted demand response MW goals in their procurement plans, along with documentation of the amount of MWs to be achieved by July of each year, the programs and/or tariffs they will rely on to achieve the MW targets and a contingency plan for covering capacity needs should they fall short of meeting the MW goals.

On October 15, 2004, the IOUs submitted demand response program proposals for the purpose of meeting their 2005 goals. These proposals include modifications to existing demand response programs as well as new programs. If their proposals are approved by the Commission, the IOUs anticipate enrollment of the following amounts of demand response MWs by July 2005:

PG&E:	**508** MWs[52]
SCE:	**442** MWs[53]

[51] The IOUs currently have a combined total of 1,500 MWs of potential interruptible MWs from programs authorized by previous Commission decisions.

[52] R.02-06-001 Proposal of Pacific Gas and Electric Company (U 39-E) Concerning Working Group 2 Programs and Related Issues, Public Version, October 15, 2004, Appendix C, p. 2.

[53] R.02-06-001 Southern California Edison Company's (U338-E) Demand Response Program Proposals for 2005-2008, October 15, 2005, p. 64.

SDG&E: **75** MWs[54]

PG&E complies with D.03-06-032 in that its LT procurement plan contains demand response MW goals that are derived by applying the appropriate percentages to its forecasted system peak demand for future years (PG&E assumes the 5% is applicable to the years after 2007) for the low, medium and high scenarios. In terms of specific MWs, PG&E assumes **450** MWs of price-responsive demand response for year **2005** (medium load scenario). PG&E acknowledges that it does not know if achieving this MW goal or future years goals are feasible, implying that its demand response component is not an accurate forecast of the future, but rather an attempt to be in regulatory compliance with D.03-06-032.

In contrast to PG&E, SCE's LT procurement plan does not assume the adopted 3% of annual system peak demand response will occur but provides a modest forecast of 358 demand response MWs for future years. SCE's forecast reflects what it believes is realistically achievable for the programs. This constitutes less than 2% of SCE's annual system peak demand in 2005.

Like SCE, SDG&E's LT procurement plan acknowledges that it will be short of achieving the Commission's demand response MW goals. Specifically, SDG&E estimates 27 MWs of demand response MWs by 2007. SDG&E's plan reflects what it believes is realistically achievable for these programs.

All three IOUs question the achievability and cost-effectiveness of the demand response MW goals, noting that there may be more cost-effective alternatives to meet their loads. The IOUs also note that it is currently unknown

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54 R.02-06-001 Filing of San Diego Gas & Electric Company…, October 15, 2004, p. 8.

as to how many MWs demand response programs can actually produce, and that current methods of measuring their effect may need to be revised. In addition, all three IOUs, in particular PG&E, advocate an annual review of the demand response goals and adjustments to the goals based on the performance of the demand response programs and their cost-effectiveness relative to other procurement options.

Since D.03-06-032 established the parameters of the demand response program, the only issue in this proceeding is whether the IOUs are implementing the adopted goals in their LTPPs and how they treat the load savings. ORA observes that PG&E categorizes demand response as a supply resource, while SCE and SDG&E consider it a 'load modifier'. SDG&E rebuts ORA's observation, noting that it categorized demand response as a supply resource.

In this proceeding, the utilities provide an estimate of the number of MWs that constitute 3% of their annual system peak demand. The following are the MW targets for the year 2005:

PG&E:	450 MW
SCE:	628 MW
SDG&E:	125 MW

It is clear that the utilities have used inconsistent definitions of annual system peak in arriving at their MW targets for price-responsive demand. For each utility, the "annual system peak' should be the annual system peak for their respective service territories, inclusive of all customers taking service within those boundaries. We direct the utilities to verify in their compliance filing, detailed below, that the numbers reported above are consistent with this definition, or provide updated targets that reflect this definition.

It is too early to judge whether or not the current demand response goals are achievable or not. Rather than adjust them now or institute an annual review/adjustment process as suggested by the IOUs, the Commission will retain the current 3% of annual system peak goal and further encourage the IOUs to continue with their best efforts in reaching them. Cost-effectiveness of demand response programs is also important to the Commission, and future demand response proposals will be evaluated for their cost-effectiveness in the demand response rulemaking (R.02-06-001) or its successor.

The Commission recognizes that by keeping demand response MW goals at their current levels there may not be, at some point, any program that is cost-effective relative to alternative supply resources. As stated above, we believe it is premature to make that judgment today. Because demand response programs are currently voluntary, the challenge of designing cost-effective programs while in pursuit of greater amounts of demand response MWs each year may very well prove to be an impossible task. If and when that point becomes evident, the Commission will need to either reduce its demand response MW goals or begin consideration of mandatory demand response programs and tariffs.

SCE's and SDG&E's LT plans provide demand response MWs that they believe are realistically achievable, as opposed to incorporating the Commission's demand response MW goals into their plans. PG&E's 2005 program plans would meet the MW goal for 2005, but it is not clear that the 3% figure PG&E calculated is based on its "annual system peak" as defined herein. In fact, the LTPPs for SCE and SDG&E reflect an even lower amount of MWs than the utilities expect to enroll in programs by July 2005. This decision's approval of the IOUs' LT plans is not an affirmation that the utilities are no longer required to pursue the more aggressive demand response goals, rather they are expected to continue to explore and find ways to meet those goals until otherwise directed. As part of their compliance efforts, within 30 days of this decision, each utility shall propose additional programs in R.02-06-001 that will allow them to enroll sufficient customer load to reach the adopted 2005 goals for price-responsive demand response programs described above. The Commission will consider whether or not to approve specific proposed programs in R.02-06-001.

VI. Distributed Generation (DG)

In D. 04-01-050, the Commission provided direction for the inclusion of DG in this long-term procurement proceeding as follows:

> "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."[55]

On March 16, 2004, the Commission opened a new distributed generation rulemaking, R. 04-03-017. Among the high-priority tasks of the rulemaking is the development of a cost-benefit analysis methodology applicable to distributed generation technologies. Parties filed opening testimony on October 4, 2004. Reply testimony is expected in early 2005 and evidentiary hearings are scheduled for March 2005.

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[55] D.04-01-050, p.122.

To date, the Commission's efforts in the area of DG have focused on promoting customer-side DG installations in utility service territories. These efforts are directed in four areas:

i. Financial Incentives – rebates are offered to customers installing DG through the Self-Generation Program & CEC's Emerging Renewables Technology program

ii. Interconnection Rules -- streamlining interconnection regulations and processes through the Rule 21 Working Group.

iii. Special Tariffs and Exemptions -- such as the standby charge exemptions for certain DG in accordance with PU Code Sections 353.1 and 353.2 and the Departing Load Cost Responsibility Surcharge exemptions from D. 03-04-030.

iv. Net Metering – the PUC expanded net metering eligibility to include biogas digester and fuel cell projects along with the currently-eligible solar and wind projects.

In addition to promoting customer-side DG, the Commission is also pursuing grid-side initiatives. In accordance with D.03-02-068, the three IOUs are required to evaluate DG as an alternative to distribution system upgrades, subject to a prescribed set of conditions enumerated in the decision. As of the effective date of this decision, none of the utilities have yet issued RFOs identifying projects where DG might serve as an appropriate alternative.

With respect to the utilities' long-term resource plans, each IOU prepared a DG forecast that is based on a forecast of DG operating on the customer-side of the meter. These estimates are then deducted from the load forecast. This treatment is consistent with the load forecasting approach recommended in the Workshop Report on Resource Adequacy Issues, dated June 15, 2004 and later adopted in D.04-10-035. The workshop report stated that "Parties agreed that customer-side distributed generation should be deducted from LSE load forecasts."[56] This resource counting protocol recognizes that customer-side DG reduces the utility's actual load to be served and the associated reserve margin attributed to that self-served load.

In its long-term plan testimony, SCE states that "it is planning on issuing a [RFP], soliciting location-specific demand-side DG to defer distribution upgrades in 2004."[57] SCE indicates in it Opening Brief that this effort has been pushed back to 2005.[58] [59] Interverners did not offer testimony on any DG specific issues raised in the utility resource plans.

We find that the utilities' treatment of DG as a component of the load forecast is appropriate. The utilities shall continue to adhere to the directives for reflecting DG estimates in load forecasting consistent with D.01-04-050 and D.04-10-035. We also encourage SCE to move forward with its planned DG RFO, the results of which will be monitored by the Commission for guidance in both the DG rulemaking and this docket. Lastly, we note that the DG rulemaking's progress towards developing a cost-benefit analysis methodology for DG will

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[56] Workshop Report on Resource Adequacy Issues, Prepared by ALJ Cooke, June 15, 2004, p.15.

[57] Exhibit XX, SCE testimony, p. 85.

[58] Edison's opening brief, pp. 29-30.

[59] We note current SGIP program eligibility rules prohibit utility customers "who have entered into contracts for DG services (e.g., DG installed as a distribution upgrade or replacement deferral) and who are receiving payment for those services; (this does not include power purchase agreements, which are allowed) from participating in the SGIP program." [D.01-03-073, Attachment 1, p.25]

inform future policy guidance we provide to the utilities regarding DG as a procurement resource.

VII. Energy Efficiency (EE)

The utilities reflected the Commission's preferred loading order by including energy efficiency savings targets in their LTPPs as the priority procurement resource. Since the IOUs filed their LTPPs on July 9, 2004, the Commission issued D. 04-09-060 on September 23, 2004. D. 04-09-060 translated into a numeric goal the mandate from the EAP to reduce energy use per capita. For the electric IOUs the adopted savings goals reflect the expectation that energy efficiency efforts in their combined service territories should be able to capture on the order of 70% of the economic potential and 90% of the maximum achievable potential for electric energy savings over the 10-year period covered by the LTPPs. The annual and cumulative goals for energy savings through 2013 are presented in tables to D. 04-09-060.[60]In its post-hearing brief, SCE states that its targets are already higher than the Commission goals established in D. 04-09-060, but PG&E's targets in its 10-year plan are lower than those in the said decision. SDG&E, on the other hand, continued to use its energy efficiency forecast from its 2003 LTP with the expectation that it will need to update its forecast and resource plans to reflect the goals adopted D. 04-09-060.[61]

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[60] Tables 1A to 1E of D.04-09-060 shows the total electricity and natural gas program savings goals for each IOU service territory and for all IOUs. Attachment 9 to the said decision shows the corresponding funding levels (PGC + procurement funds) implied by the adopted energy savings goals.

[61] NRDC's Opening Brief presents a comparison of the utilities' LTPP's proposed electricity savings targets versus those adopted in D.04-09-060.

PG&E, SCE and SDG&E should meet or exceed the Commission's EE goals over the next ten years and specifically over the next EE funding cycle (2006-2008) and to revise and update their plans to be in alignment with these goals. PG&E, SCE and SDG&E are to incorporate the goals from the EE decision in their LTPPs, and as these energy savings goals are updated and amended by subsequent decisions, the IOUs are to incorporate the most recently adopted energy savings goals into their plans. As directed in D. 04-09-060:

> The energy savings goals adopted in this proceeding shall be reflected in the IOUs' resource acquisition and procurement plans so that ratepayers do not procure redundant supply-side resources over the short- or long-term. **To this end, our upcoming decisions in R. 04-04-003 concerning the long-term procurement plans and 2005/2006 ongoing procurement authorizations of PG&E, SCE and SDG&E shall be made in full recognition of the aggressive energy savings goals we adopt today.** For the procurement plans that will be filed in 2006 and during subsequent procurement plan cycles, or for any updating to the long-term procurement plans required by the Commission before then, PG&E, SDG&E and SCE shall incorporate the most recently-adopted energy savings goals into those filings. " (D. 04-09-060, Ordering Paragraph 6, emphasis added)

SCE proposed to add a 1% reliability factor to downgrade program savings from non-utility energy efficiency programs operating in its territory. SCE asserted that this reliability factor would address the uncertainty in the timing and magnitude of savings from non-utility programs until rigorous evaluation, measurement and verification (EM&V) of these programs becomes available.[62] We reject SCE's proposal and reiterate our prior directive in D. 04-

[62] SCE Opening Brief, p.36.

01-050 for the utilities to count expected energy savings from non-utility programs that operate in their service territories. As we stated in D. 04-01-050:

> 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. (D.04-01-050, p. 107)

The utilities noted in their LTPPs that several issues are critical to the achievement of their energy savings targets and success of energy efficiency programs. These include EE program administrative structure, program funding cycle and duration, EM&V framework and protocols, performance incentives, fund shifting authority, and avoided costs used in cost effectiveness calculations for EE, demand response, and other applications. The Commission has deferred consideration of most of these issues to the energy efficiency rulemaking (R. 01-08-028) and not in this proceeding, as discussed in D. 04-01-050. The Commission has also instituted Rulemaking 04-04-025 to address avoided cost issues pertinent to energy efficiency programs and other resource applications. We will continue to coordinate these various proceedings to the extent that our decisions in those proceedings impact the utilities' LTPPs.

VIII. Qualifying Facilities: Long-Term Policy For Expiring QF Contracts

On September 30, 2004, ALJ Wetzell issued a ruling "initiating the Commission's consideration of a long-term policy for expiring QF contracts" (p.1). The ruling called for proposals for such a policy [to] be filed on November 10, 2004, which "may also address policy for new QFs" *Id.* Comments in response to those proposals are due November 24, 2004. The ruling further stated that "the final schedule for adopting a long-term policy for expiring QF contracts [in R.04-04-003] will be determined after review of the comments and a determination of whether evidentiary hearings are required" (p.4). The ruling "anticipated establishing a schedule providing for a Commission decision in the first quarter of 2005 if hearings are not required. If hearings are required, … a Commission decision [is anticipated] in the second quarter of 2005.

Although we anticipate adopting a long-term policy for expiring QF contracts in this rulemaking, R.04-04-003, by mid-2005, we may be able to benefit from the work being done on avoided cost issues in R.04-04-025, *Order Instituting Rulemaking to Promote Consistency in Methodology and Input Assumptions in Commission Applications of Short-run and Long-run Avoided Costs, Including Pricing for Qualifying Facilities*. Parties are, however, aware that R.04-04-025 will be litigated during 2005. A prehearing conference in R.04-04-025 was held on November 9, 2004. To the extent that the development of a long-term policy for expiring QF contracts in R.04-04-003 becomes contingent upon any anticipated policy outcomes in R.04-04-025, unacceptable delays in the establishment of such a policy could result. Specifically, QFs whose contracts expire after December 31, 2005 are not eligible for the one-year or five-year contract extension options set forth in D.03-12-062 and D.04-01-050, respectively. Currently, the only recourse for QFs, whose contracts expire in 2006 and beyond, is (1) to participate in any upcoming power solicitations, or (2) negotiate bilateral contracts with utilities. Neither of these two options is entirely certain. Though we expect QFs to continue to participate actively in these opportunities, thus, without contract extensions or a new long-term policy, QF contracts that lapse in 2006 could cause QF power to go off-line at that time. However, our plan to address these issues by mid-2005 will avert these concerns.

IX. Renewable Portfolio Standards (RPS)

The RPS Program requires each IOU to increase "its total procurement of eligible renewable resources by at least an additional 1% of retail sales per year so that 20% of its retail sales are procured from eligible renewable energy resources no later than December 31, 2017."[63] The EAP and the current RPS implementation proceeding, R.04-04-026, have announced a policy of accelerating the target date to 2010.

As stated above, following the "loading order" contained in the Joint Agency Energy Action Plan is the first priority for IOU resource procurement, meaning that energy efficiency and demand-side resources should be employed first. When these opportunities are exhausted, renewable generation is to be procured to the fullest extent possible – whenever an IOU issues an RFO for generation resources, it must be prepared to defend its selection of fossil generation over renewable generation offers. In other words, selection of renewable generation is the rebuttable presumption guiding IOU generation procurement.

In general, IOUs are directed to procure the maximum feasible amount of renewable energy in the general solicitations authorized by this decision, and will be allowed to credit this procurement towards their Renewables Portfolio Standards (RPS) targets in 2005 and beyond. If an IOU succeeds in procuring sufficient renewable resources to meet its 2005 RPS Annual Procurement Target (APT) via an all-source RFO, it will not be required to undertake an RPS-specific solicitation next year. This is in keeping with the Legislature's clear intent, in

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[63] Pub. Util. Code Section 399.15(b)(1).

creating the RPS program, that renewable procurement be integrated as closely as possible with general IOU procurement practices. To further this effort, we will be working over the course of the next LTPP cycle to fully imbed the RPS into long-term planning, placing renewable energy development where it belongs - central to the IOUs' resource planning efforts.

To further the state's clear goal of promoting environmentally responsible energy generation, we also adopt a policy that reflects and attempts to mitigate the impact of greenhouse gas (GHG) emissions in influencing global climate patterns. As described in this decision, the IOUs are to employ a "carbon adder" when evaluating fossil generation bids. This method, which will be refined in future proceedings, will serve to internalize the significant and under-recognized cost of GHG emissions, and will continue California's leadership in addressing this important problem.

This will have the effect of improving the economic viability of renewable energy resources in all-source IOU RFOs. In time, as this method is refined to include all appropriate environmental externalities – and, crucially, to *value them accurately* – it may be possible to recast the RPS program as more central to IOU procurement than a set-aside for particular types of resources.

X. IOU Positions on Renewable Energy in the LTPPs

PG&E projects that under the load assumptions of its medium load scenario, if the utility increases its renewables procurement by 1% annually and obtains the assumed wind repowering, it will achieve its 20% RPS target in 2010.[64] On June 30, 2004, the ED approved PG&E's Renewable Energy

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[64] PG&E opening brief, p. 37, citing Ex. 34, PG&E/LaFlash, pp. 5-12.

Procurement Plan, and in accordance with that approval PG&E issued an RFO on July 15, 2004, for renewable resources. PG&E's 2004 annual procurement target is 9,474 GWh per year. To meet the 20% renewable energy target by 2010, PG&E anticipates incremental energy deliveries from newly-contracted resources at an average rate of approximately 700 to 800 GWh per year. PG&E does not identify a preferred resource stack because the utility does not want to thwart market innovations that may occur over the course of the plan and believes the market is the best determiner of what resource is bid.

SCE's long-term plan includes a scenario for achieving the 20% target by 2017 and an accelerated target for achieving the 20% target by 2010. Under both scenarios SCE expects to achieve the 20% target by 2007. SCE's long-term plan does not foreclose procurement that would result in SCE's exceeding the 20% RPS target. SCE states that it will consider renewable resources as part of its all-source solicitation and evaluate the bid without regard to whether the 20% target will be exceeded. SCE does not express any preference for a technology type, but instead intends to procure the least-cost, best-fit (LCBF) renewable resources. SCE fears expressing a preference for technology types would create a bias for future renewable solicitations and could elevate a "preference" as a consideration over LCBF. [65]

SDG&E's LTPP includes an aggressive renewables resource plan that is designed to meet an overall renewables resource goal of 20% by 2010. SDG&E's aim is to attain a diversified portfolio resulting in a renewable resource mix consisting of Bio-Gas, Bio-Mass, Wind, Geothermal, Solar and Small Hydro

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[65] SCE opening brief, p. 39.

technologies. SDG&E developed this portfolio stack and technology mixes based upon information obtained from its 2002 renewable RFO process, discussions with potential developers, bilateral negotiations, information from the CEC and the utility's "best estimates" of the types and amounts of resources likely to be available in the future.[66] In order to achieve the target by 2010 with an ideal mix of technologies, SDG&E plans on procuring an additional 2,496 GWh through bilateral contracts and RPS RFP solicitations, including exploring the possibility of utility ownership.

While SDG&E is aggressively working towards achieving the 20% target by 2010, it realistically knows that a number of factors, including the availability of renewable resources, in and out of area, transmission access to sources in other areas, availability of funding, utility ownership, pricing issues, and the ability to procure and trade Renewable Energy Credits (REC)[67] may affect its ability to met its goal. SDG&E issued its first RPS RFO on July 1, 2004, and does not yet know the final results of that solicitation.

Many intervenors expressed agreement with the approach SDG&E took in identifying a renewable resource stack, estimating costs and benefits of each and identifying potential barriers to access. PG&E and SCE did not include the same level of specificity in their discussion of future RPS procurement and many parties urged the Commission to direct these utilities to supplement their LTPPs.

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[66] SDG&E opening brief, p. 53.

[67] TRECs allow the positive environmental attributes associated with renewable energy generation to be sold independently of the underlying electricity. In concept, an entity obligated under the RPS – or some other environmentally-derived procurement restriction – could purchase a TREC instead of electricity to satisfy its obligations.

PG&E and SCE retorted that they want to be open for what ever mix of resources presents itself in a RPS RFO and do not want to prejudge what bids will be the LCBF.

A. Parties' Positions

The City of San Diego focused on SDG&E's LTPP and especially on the utility's RPS goals to ensure that they comport with the direction the city is headed. Specifically, CSD is concerned that the utility will replace renewable DG with imported renewables, especially if the requested 500kV transmission line is approved. Instead, CSD would like SDG&E to balance its RPS goals with net-metered generation. While CSD supports the concept of tradable renewable energy certificates (TRECs), it argues that the utility should not be able to take DG RECs in an effort to achieve its RPS target. Instead SDG&E should pay for the RECs.[68]

UCS was one of the intervenors that wants PG&E and SCE to supplement their filings and provide more detailed annual analysis of renewable resource potential over the next 10 years. Specifically, the renewable resource analysis should include (1) assumptions for renewables procurement for the next 10 yrs., (2) development of a resource "stack," identifying the preferred potential resources, estimated costs and benefits of each, and potential barriers to access, and (3) identification of transmission upgrades that the utility believes will be needed in order to access sufficient renewable energy to meet its RPS goals.[69]

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[68] CSD opening brief, pp. 4, 10, 11.

[69] UCS opening brief, p. 8.

UCS also urges the Commission to direct the utilities to file their 2005 RPS procurement plans and on a going-forward basis, to include renewable resources in any and all future resource solicitations, regardless of whether the IOUs have already met their RPS targets. If the Commission adopts debt equivalency (DE) then LT renewable contracts should have a lower DE (5%) than non-renewable contracts. And finally, UCS wants the transmission constraints on renewable resources that SDG&E discusses addressed in the January 2005 supplement.[70]

Strategic Energy proposes that the Commission not require SDG&E to achieve the 20% RPS target by 2010, unless a REC trading system is established. Strategic is concerned that if SDG&E enters into long-term renewable contracts, and there is no REC trading, there will be stranded costs if load migration occurs.[71]

NRDC seeks clarification that the RPS targets establish a floor, not a cap. The IOUs should not curtail their procurement of renewables once the target is met, but should consider investments in all cost-effective renewable resources beyond 20%. Also, transmission planning should involve an integrated comparison of alternative resources.[72]

CEERT agrees with UCS that PG&E's and SCE's renewable procurement plans are inadequate and require immediate revisions. PG&E and SCE should supplement or amend their LT plans, no later than January 15, 2005, to include a comprehensive and credible renewable procurement plan consistent with that

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[70] UCS opening brief, pp. 4, 8, 17, 18, 19 and 24.

[71] Strategic opening brief, p. 11.

[72] NRDC opening brief, pp. 57-58.

submitted by SDG&E. CEERT also adopts the same recommendations made by UCS for the renewable resource analysis. Also, CEERT wants SCE to report on the status of its 2003 interim procurement negotiations.[73]

We agree that the renewable procurement sections in SCE's and PG&E's LTPPs are inadequate and need revision. However, the revisions, with a detailed analysis, will be developed in the IOUs' 2005 RPS procurement plans, which will be filed in R.04-04-026, following the guidance to be developed in that docket. All IOUs will provide detailed annual analysis of renewable resource potential over next 10 years in their 2006 LTPPs. All IOUs will need to include transmission planning for renewable resources in their 2006 LTPPs. Transmission issues will be further addressed in I.00-11-001, in coordination with the RPS docket.

We also find that RPS targets are a floor – not a ceiling. EAP loading order places renewables above conventional generation. "…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."[74]

With regards to using unbundled RECs for RPS compliance, this is a complex issue and the record here is insufficient. To make a determination on this policy in this proceeding at this stage is premature. R.04-04-026 will consider this issue as appropriate.

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[73] CEERT opening brief, pp. 15 and 26.

[74] D.04-01-050 pg.53.

XI. Transmission Assessment Process

The purpose of R. 04-01-026, issued January 24, 2004, is to streamline the transmission planning process for the IOUs by eliminating the duplicative transmission need assessments that currently exist at the CAISO and the Commission. A component of this streamlining remaining from the original more narrow scope of this rulemaking, which was to amend the Commission's General Order 131-D, is the Commission's proposed deference to CAISO need determinations in its grid planning processes.

The CAISO asserts that the issue is whether the LTPPs were adequate to allow the Commission to accomplish the objectives outlined by the Commission in R.04-01-026. In this context the CAISO observes that the utilities' LTPPs are insufficient, and that additional information must be obtained from the IOUs in future submissions, in order to allow the Commission and CAISO to accurately assess transmission requirements. The CAISO recommends that the utilities should include conceptual scenarios for planned resource additions and assessments of associated transmission requirements. The CAISO adds that integrating the CAISO Transmission Expansion Planning Process (TEP) with the LTPP process is a key element of this proceeding.

The Commission agrees that the LTPPs did not include sufficient information to enable the CAISO to accurately assess transmission requirements. We agree that integrating the CAISO grid planning processes with the Commission's LTPP process is a worthwhile goal. In that regard we observe that on October 15, 2004, the Assigned Commissioner in R.04-01-026 issued a ruling stating "To achieve a comprehensive resource planning framework, the Commission must streamline the transmission planning process and integrate that with the biennial procurement process."

Thus, we note that it is the Commission's intention to more fully explore this issue in R.04-01-026.

XII. Transmission Planning under I.00.11.001

Investigation I.00.11.001 was issued by the Commission in November 2000 to implement Assembly Bill 970 regarding the identification of electric transmission and distribution constraints, actions to resolve those constraints, and related matters affecting the reliability of electric supply. Eight transmission issues have been addressed in eight separate phases of this investigation. Phase 1 identified 30 initial projects designated by the utilities to relieve constraints; Phase 3 evaluated a proposal by SDG&E for a second 230kV Mission-Miguel transmission line based on economic need and Phase 4 ruled on the application by PG&E for a CPCN for the Path 15 upgrade. Three phases of the proceeding are still active:

XIII. Phase 5, Generic Economic Methodology for the Evaluation of Transmission Projects

It is generally accepted that transmission projects are undertaken for two reasons: reliability and economics. Reliability standards are issued by the North American Electric Reliability Council (NERC), the Western Electricity Coordinating Council (WECC) and the California Independent System Operator (CAISO). These standards are implemented by the utilities with little or no controversy (keep the lights on).

On the other hand, the evaluation of the need for transmission projects not required for reliability, but which could yield economic benefits, and to whom the benefits would apply (a set of ratepayers, consumers as a whole, electricity producers, or a combination of the foregoing) is extremely complex and methods are still being developed. The essential problem is that the benefits depend on future conditions which cannot be accurately predicted: the cost of fuel, interest rates, construction costs, the quantity of hydropower available and the behavior of merchant producers in optimizing their return. The CAISO has been working on a generic methodology for more than three years; the latest effort is called Transmission Economic Assessment Methodology (TEAM), which calculates the benefits of transmission and generation on an integrated basis. However, the Commission staff and others have found deficiencies in the methodology.

The development of a generic methodology for evaluating the economic feasibility of transmission infrastructure is still a work in progress. When it is successfully concluded, the Commission may defer the determination of need for transmission upgrades to the CAISO, see Section A.2.7, above. The application of this methodology is a key element in the LTPP because it is a means of integrated resource planning.

XIV. Phase 6, Transmission needs in the Tehachapi Wind Resource Area

The Energy Commission (CEC) has identified 4000MW of potential wind generation in the Tehachapi area in Kern County and an additional 500MW south of Tehachapi in Los Angeles County. The purpose of Phase 6 is to define and then construct the transmission infrastructure necessary to transmit this power to load centers. In Decision 04-06-010 the Commission staff, to be assisted by the CAISO as needed, was assigned the task of coordinating a nine-month study "to develop a comprehensive development plan for the phased expansion of transmission capabilities in the Tehachapi area." Each phase will trigger an application by SCE for a CPCN for construction of facilities defined in that phase. Because the lead time for transmission is longer than for generation, the challenge for the planners is to provide incremental transmission such that new generation has access to load as it comes on line, without building transmission that will not be used. A report on the study's findings will be filed by SCE on 3/9/05.

In addition, SCE is required to file by 12/9/04 an application for a CPCN for the construction of the first phase of the Tehachapi transmission. On 9/1/04 SCE filed a report stating that by 12/9/04 it would file a complete CPCN application for a transmission line to accommodate wind generation in the Los Angeles County area and "…as much of the CPCN application information as it has completed…" for the first phase of the Tehachapi transmission.

PG&E says that it will "examine a number of economically-driven projects…in accordance with Decision 04-06-010" [Tehachapi]. SCE describes the development of transmission for Tehachapi in its Renewable Conceptual Transmission Plan, dated August, 2003. This plan is being currently reviewed and revised in this phase of the proceeding.

The intention of this phase of the proceeding is to define and bring about the timely construction of the transmission infrastructure required to connect the Tehachapi and Los Angeles County wind power to load centers.

XV. Phase 8, Transmission Costs for Renewable Portfolio Standard Bid

Bids from developers of renewable resources are to be evaluated on the basis of LCBF. A factor in the cost to the utility of the connection to the network of a generation facility is the cost of the transmission upgrades required by the connection. Formulating the methodology for estimating this cost and dividing it among potentially multiple bidders is the subject of this phase. In Decision 04-06-013 a methodology was prescribed for the assignment of transmission costs to the first round of bids beginning on 7/1/04. The commission staff is working with the CEC to refine the methodology, which will be the subject of future decisions.

This phase of the proceeding will define an element in the procurement of renewable resources.

XVI. Integrated Generation and Transmission System Planning, Timing, Planning, Flexibility

PG&E suggests that an iterative process between resource planning and transmission planning is needed, so both can be planned in an orderly manner. However, it is PG&E's position that until the locations, timing and characteristics of the new resources can be identified and incorporated into the resource mix, it is not possible to definitively identify the transmission needed to accommodate them. PG&E adds that it is not desirable to plan transmission based on speculation that certain resources may develop. PG&E argues that to do so would waste ratepayer money and distract attention from developing transmission projects whose need is more immediate.

SCE believes that transmission and deliverability issues should be considered during the individual RFP solicitations in the economic evaluation of the individual bids.

SDG&E believes that its LTPP emphasizes the need for a diverse portfolio of supply- and demand-side options, as well as transmission, in order to balance lowest cost with reduced volatility and risk.

CEERT alleges that only SDG&E presented a credible renewable procurement plan integrating both resource and transmission planning. UCS found that each of the utilities' LTPs should be supplemented to add specific and detailed information on transmission upgrades. UCS further adds that the CAISO's grid planning process is a complement to, but not a substitute for, the

Commission's oversight of the utilities' procurement responsibilities. NRDC states that the CAISO's transmission economic assessment methodology (the TEAM being examined in Phase 5 of our Transmission Investigation described in A.2.8 above) should complement more robust utility LTPs, but should not substitute for the integrated analysis necessary in the LTPs.

TURN found that the issue of integration of generation and transmission planning in long-term procurement planning was not explored in any real depth in this proceeding but notes that the Commission is exploring this issue in R.04-01-026 and Phase 5 of I.00-11-001. UCAN found the integrated analysis to be lacking. ORA urges the Commission to insist that the IOUs include consideration of generation alternatives in the "need" determination for proposed transmission lines.

NRDC believes that the IOUs should be directed to thoroughly compare "non-wires" alternatives to transmission projects in an integrated fashion and include more detailed information in future LTPPs about alternatives to the proposed transmission projects that were considered.

The Commission agrees that the issue of integration of generation and transmission planning was not fully explored in this proceeding. The Commission also agrees that the utilities' LTPPs did not fully integrate generation and transmission planning. However, as discussed earlier, we note that the Commission intends to explore this issue more fully in R.04-01-026.

XVII. Transmission Upgrades and Expansion

The present procedure for transmission expansion and upgrades is for the individual utilities (IOUs) to prepare annually a grid expansion plan, which looks five and ten years into the future. The plans forecast growth in load, the connection of new generation, the retirement of plants whose service lives have come to an end, new transmission facilities and interconnections with adjacent and out-of-state networks. The plans are the product of several iterations of work by engineers followed by stakeholder meetings at which preliminary results are presented and commented upon by the stakeholders. This is an open process in which the Commission staff participates. The plans are then finalized for the year and submitted to the California Independent System Operator (CAISO) for review. The CAISO approves, modifies or rejects individual projects. Projects costing up to $20 million are approved by CAISO staff, projects whose cost is greater than that amount require approval of the CAISO board of governors. The CAISO also participates directly in the planning of transmission between utilities and, in particular, transmission interconnections with other states.

In their direct testimony in this proceeding, the IOUs present sketchy information on their transmission plans. PG&E, in its LTPP, makes reference to its annual grid expansion plan, but does not list any specific transmission projects. However, both SDG&E and SCE identify major transmission projects in their LTPPs.

SDG&E's LTPP includes an explanation of the megawatt amount of local resource deficiency that could be met by additional transmission and proposes two 500kV lines, to come on line around 2010. Most notably, SDG&E requests that the Commission approve the 500 kV transmission expansion component of its LTPP.

SCE's LTPP includes transmission projects to access the Tehachapi wind area and transmission upgrades to access generation markets in Southern Nevada and Arizona (i.e., Devers-Palo Verde No. 2).

As discussed earlier, the utilities' LTPPs should more fully integrate generation and transmission planning. It would be helpful to the Commission's review of the LTPPs if they included scenarios of potential resource portfolios to fully meet future resource needs, and identified the transmission expected to be needed to make the potential resource portfolios feasible. It is not acceptable for IOUs to take a position of only responding to interconnection requests.

We do not endorse or in any way approve the transmission projects proposed in the utilities' LTPP. Specifically with regard to SDG&E's request, we do acknowledge the lengthy process that's needed to plan, license and construct transmission, so we encourage SDG&E to continue its planning efforts and move forward with evaluating these transmission alternatives for meeting a local resource deficiency by 2010.

Phase 2 of the RA portion of this proceeding will provide a determination on local capacity requirement and deliverability for resource adequacy in the early summer of 2005. Those requirements will inform and govern the utility transmission and procurement requirements going forward. Therefore, it is premature to address specific requirements in this proceeding or make a judgment as to the sufficiency of the instant filings. However, it is important to provide clarity on how the local capacity and deliverability requirements will come into play in future planning decisions. We expect that the ISO will work closely with the Commission to establish the local capacity procurement requirements based on deliverability of resources into load pockets and transmission constrained areas of the grid. We expect that once established, the ISO will work to update the criteria as changes, such as new transmission or generation, occur.

Once the local procurement and deliverability criteria are established we expect the criteria to be incorporated into and guide the long-term plans going forward. For example, if the a determination is made that "x"% of the supply to meet San Francisco load must come from within the local area given the transmission transfer capability into that area, the long-term plan should incorporate that criteria. In this example, the long-term plans should specify how the utility will meet the "x"% in-city supply criteria, including through approved demand side options, or the transmission upgrades the utility intends to build to increase the transfer capability and decrease the local procurement requirement. We recognize the importance of the ISO in helping us to establish the criteria and so that the Commission can apply them to the utilities' planning practices. The ISO core expertise in the area of transmission planning and grid operations is critical to inform the Commission's procurement decisions. This approach will assure that the long-term resource procurement meets the ISO short-term grid requirements. It will also assure that the resources the utilities procure pursuant to their resource adequacy requirements meet the ISO operational needs.

XVIII. Implementing the EAP Loading Order

The Energy Action Plan prioritizes resources in a "loading order" of policy preferences that emphasizes energy conservation, resource efficiency and reducing per capita demand on the demand side of the equation, and favors renewables over fossil-fueled resources on the supply side. The order of resource priorities is: energy efficiency and demand response, renewables (including renewable DG), clean fossil-fired distributed generation, and clean central-station generation. Sensible transmission investments should be made in concert with these other resource commitments.

Sections of this decision describe the objectives and direction for aggressive procurement of renewable generation resources, contain guidance for procuring clean fossil resources and discuss transmission and DG, respectively.

The direction is clear: IOUs should implement the EAP loading order when soliciting resources as a result of this decision.

All three IOUs' LTPPs present resource procurement scenarios that indicate that they intend to follow the EAP loading order as they go forward with procurement solicitations, evaluations and determinations. In particular they all say they will follow all Commission orders and directives from the companion umbrella proceedings in meeting target goals for EE, DR, renewables and DG, and will consider the targets as floors, not ceilings, in terms of evaluating options. The IOUs followed the EAP loading order for each load and resource scenario."

XIX. Energy Efficiency

A. Cost Recovery for IOUs to Meet EE Savings Goals

While each of the utilities' LTPPs reflected energy efficiency as the top priority resource, they differed in their requests for funding approval to procure this resource. As NRDC noted in its reply brief, "PG&E specifically requests that the Commission approve funding for its 2006-2008 procurement of energy efficiency…In contrast, SCE's brief did not address how it intends to request funding approval for the efficiency procurement. And SDG&E requests that the Commission authorize it to file an advice letter to adjust EPEEBA to match the budgets approved in [D.] 04-09-060."[75] NRDC urged the Commission to approve each utility's proposed investments to procure energy efficiency programs for 2006 through 2008, noting that the Commission cannot do so in the energy efficiency rulemaking (R.01-08-028) because it is not a ratesetting proceeding.

[75] NRDC Reply Brief, p. 9.

PG&E shares similar views, further noting that the EE rulemaking authorizes only expenditures of PGC funds and is not the appropriate forum for augmenting EE expenditures by the utilities. SDG&E also noted that D. 04-09-060 approved much larger budgets to achieve the adopted energy savings targets but did not explicitly discuss where the incremental budget will come from. SDG&E assumed that the incremental budget could be authorized in this proceeding, just as D.03-12-062 approved the utilities' 2004-2005 procurement EE funding.

In addition, both PG&E and NRDC proposed that the Commission approve additional energy efficiency funding if savings targets are expected to be met and funds for 2006-2008 are depleted before the end of the three-year period. NRDC supports this proposal based on its analysis showing that more cost-effective energy savings remain in the outer years of the utilities' LTPPs.[76]

We disagree with NRDC and others that this proceeding is the appropriate forum for authorizing increases in procurement rates to fund incremental energy efficiency investments over and above the PGC funding levels. Since approving the utilities' procurement budget for energy efficiency in 2004-2005, we have consolidated consideration of both the administration and funding of energy efficiency in our energy efficiency rulemaking in proceeding. R. 01-08-028, consistent with our decision in D.04-01-050 that:

> "As the Commission will authorize a uniform of energy efficiency, we believe it is necessary that the Commission have in place a unified administrative structure to oversee of all energy efficiency programs regardless of the source of funding in the years ahead.

[76] NRDC Opening Brief, p. 56.

For this reason, we are referring the issue of administration of energy efficiency programs authorized in this proceeding.

Accordingly, we directed in D.04-09-060 that the program administrators we ultimately select for energy efficiency (which may or may not be the utilities) would submit proposed energy efficiency program plans and funding levels to meet the Commission-adopted savings goals every three years, beginning with a PY 2006-PY 2008 program implementation by Assigned Commissioner or ALJ ruling in R.01-08-028.[77] Authorizing the utilities to request incremental funding via procurement rates for PY 2006-2008 in the manner that NRDC, PG&E and SDG&E propose, would prejudge the issues being addressed in R01-08-028 and result in a bifurcated administrative structure – which we expressly rejected in D.04-01-050. Therefore, we leave to the energy efficiency rulemaking all issues related to the funding levels for energy efficiency, and how the cost associated with programs will be recovered in rates.

B. Energy Efficiency Data in Future LTPPs

NRDC proposed that the Commission establish a list of required data on the energy efficiency programs that the utilities should provide at a minimum in their LTPPs. UCS concurred with NRDC's suggestion. This list include:

- Total proposed investments in energy efficiency every year over the next decade, broken out into the PGC and procurement component (in real and nominal dollars);
- New annual and cumulative energy savings as a result of the programs every year over the next decade, broken out into the PGC and procurement components (in GWh);
- New annual and cumulative peak savings every year over the next decade, broken out into the PGC and procurement

[77] See D.04-09-060, Ordering Paragraphs, 1,4 and 5.

components (both coincident-peak and non-coincident-peak, in MW);

- The total resource cost (TRC) test net benefits of the proposed investments;
- The average levelized cost of the energy efficiency resources;
- Comparison of cumulative energy and peak savings to the Commission's targets;
- The projected percent of demand growth reduced by the programs; and
- The per capita electricity consumption for the service territory over the next decade after factoring in the energy savings from the programs.

We agree that providing information about the energy efficiency programs in a consistent format in the utilities' future LTPP filings will facilitate the Commission and parties' analysis of the proposals. NRDC's list provides a good starting point; hence, we will direct the utilities to provide the said information to the extent possible.

C. Distributed Generation

The EAP prioritizes DG in the loading order along with renewable resources and enumerates the following policy objectives:

i. Promote clean, small generation resources located at load centers;

ii. Determine whether and how to hold distributed generation customers responsible for costs associated with Department of Water Resources power purchases;

iii. Determine system benefits of distributed generation and related costs;

iv. Develop standards so that renewable distributed generation may participate in the Renewable Portfolio Standard program;

v. Standardize definitions of eligible distributed generation technologies across agencies to better leverage programs and activities that encourage distributed generation;

vi. 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 effecting distributed generation; and

vii. 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.[78]

[78] State of California Energy Action Plan, May 8 2003, pp 4 & 8.

The IOUs state that they are meeting the EAP policy goals for DG by reflecting customer-side DG in their load forecasts, by participating in the Rule 21 Interconnection Work Group, and by having Commission-approved methodologies in place for evaluating DG as a distribution alternative in system planning. Interveners did not file testimony specifically relating to DG and the EAP.

The state is currently meeting the goals of the EAP through two ratepayer-funded incentive programs: (1) the PUC's Self Generation Incentive Program; and (2) the CEC's Emerging Renewable Technology program. We also expect that the Governor's solar systems initiative when implemented, will contribute towards achievement of EAP goals by virtue of its focus on promoting and funding DG installations.

We find that the initiatives cited by the utilities in their LT plans (i.e., DG forecasting, the Rule 21 Work Group, including DG in distribution system planning) are consistent with EAP goals for DG. Furthermore, as we noted in Section A.2.3, we expect that the cost-effective work underway in R.04-03-017 will guide future guidance we provide the utilities for incorporating DG in resource planning.

D. Procurement contracting authority: AB 57, upfront standards, cost recovery and ratemaking

1. Contracting Authority

The initial procurement proceeding, R. 01-10-024, was the vehicle used by the Commission to put the IOUs back in the procurement business following the end of the deregulation experiment. Beginning in February 2002 and continuing up to the inception of this current procurement docket, the Commission issued the following decisions to direct the IOUs on filling their net open positions:[79]

- D.02-08-071 authorized the utilities to procure for low-case forecast scenario RNS needs between the effective date of the decision and January 1, 2003 (multi-year contracts were allowed).
- D.02-10-062 authorized contract terms for up to five years for transactions entered into under the modified short-term procurement plans addressing 2003 procurement activities. [80]
- D.02-12-074 authorized the utilities to hedge 2004 first quarter residual net short positions with transactions entered into in 2003.[81]
- D.03-12-062 authorized the utilities to enter into contracts with terms up to five years to meet 2004 needs with delivery beginning in 2004.
- D.04-01-050 extended the procurement authority to the first three quarters of 2005, limiting the purchase authority to short-term contracts (contracts of one year or less duration).[82]

E. Parties' Positions

Immediately following the issuances of the December 2003 and January 2004 Commission procurement decisions, PG&E requested an extension to its

[79] After existing resources and policy preferred resources have been compared to load and necessary reserves, the result is the amount of energy and capacity that an LSE must still acquire. This is called either "need" or the "net open" position, sometimes subdivided into "net short," the amount the LSE needs to acquire, or "net long," the surplus the LSE has to sell.

[80] D. 02-10-062, p. 47.

[81] D. 02-12-074, Ordering Paragraph 5.

[82] D. 04-01-059, p. 91.

procurement plan to enter into pre-approved transactions with terms up to five years during the term of its procurement plan, with changes suggested by PG&E in its petitions for modifications of D.03-12-062 and D.04-01-050 and for automatic renewal of procurement plans. Now, faced with the new reserve requirements of 15-17% by June 1, 2006, from the recently issued RA decision, D. 04-10-035, PG&E's net open position has increased over the next five years and increased its market risk exposure. The ability to enter into multi-year agreements is necessary to implement PG&E's midterm resource strategy and provide PG&E with the ability to acquire a resource portfolio with a mixture of contract terms to deal with load uncertainty over the next three to five years.[83]

CAISO, SCE, TURN supports and ORA does not oppose PG&E's request.

In its opening testimony, SCE proposed to have the AB 57 procurement plan be approved on a rolling five-year term. AB 57 does not say procurement transactions should be limited to five years or less duration, so there is no prescription against this modification, and PG&E supports it. In addition, SCE proposes to provide an updated capacity and energy position for seven years forward, based on its medium case scenario, beginning with a compliance advice letter submitted within 30 days of approval of its long term plan.[84]

SDG&E states that short-term procurement plans should continue to be affirmed by the Commission as the upfront standards and criteria for short-term procurement pursuant to AB 57. [85]

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83 PG&E opening brief, p. 46.

84 SCE opening brief, p. 67.

85 SDG&E opening brief, p. 74.

TURN supports additional authority to enter into contracts of up to five years' duration regardless of the initial delivery date. However, TURN recommends that contracts with duration of three years or longer to be submitted to the Commission for pre-approval.

Duke urged the Commission to direct the utilities to undertake interim capacity procurement to meet the needs during the next three to five years; NRDC wants the Commission to require that the expected carbon emission costs should be used in procurement bid evaluation process; and Strategic argues the IOUs should be making shorter-term commitments, e.g. five year or less.

It is reasonable to extend the IOUs' procurement on a rolling 10-year basis, given that the long-term procurement plans cover a ten-year period and they will be updated and reviewed every two years. We will diligently oversee how the utilities are using this authority. Therefore we authorize the utilities to enter into short-term, mid-term, and long-term contracts, with contract delivery start date through 2014, provided that the IOUs submit the necessary compliance filings. We adopt TURN's proposal that contracts with duration three years or longer be submitted to the Commission for preapproval.

NRDC's recommendation is addressed in Section C.3 below.

F. Cost Recovery

1. Parties' Positions

PG&E proposes a ratemaking mechanism for cost recovery that includes the following features: upfront assurance of cost recovery; no opportunity for after-the-fact reasonableness review of project costs if the terms of the upfront approval are met; and a mechanism to allow cost recovery to begin as soon as the facility is operational. In addition, PG&E argues that the Commission's preapproval process should constitute upfront approval of the acquisition costs.

That is, if the costs are determined to be reasonable in the preapproval process, and PG&E meets the preapproved upfront conditions, no after-the-fact reasonableness review should be necessary.

SCE states that its proposed revision to its Existing AB57 Procurement Plan[86] is a component of it's long-term procurement plan. SCE further clarifies that it does not have a separate AB57 long-term procurement plan and AB57 short-term procurement plan. Instead, SCE has one AB57 procurement plan which is a component of SCE's LTPP showing in this proceeding (SCE LTPP, July 9, 2004, Vol.2, p.1). SCE states that the objective for each IOU's AB57 procurement plan is to set the limits (i.e., the upfront achievable standards and criteria called for in AB57), within which the IOU's transaction activity would be deemed reasonable. All transactions and actions that fall within the boundaries of an AB57 procurement plan are compliant with the approved procurement plan and accordingly are assured cost recovery. Statute requires that a procurement plan contain upfront achievable standards and criteria (*Id.*, p.1-2).

SDG&E wants the Commission to provide reasonable assurance of timely and complete recovery of the costs of approved, newly acquired turnkey utility-owned generation assets. SDG&E suggest that the existing ERRA provides reasonable assurance that the cost of future procurement contracts acquired will be fully recovered through ERRA mechanism, but the utility is not certain that ERRA provide assurance for cost recovery for new turnkey generation assets.

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[86] The "Existing AB57 PP is the same as the "2004 Short-Term Procurement Plan – Confidential Version," dated May 15, 2003, as modified by the Commission in D.03-12-062 and submitted by SCE in Compliance Advice Letter 1770-E-A, dated February 23, 2004. These plans are also referred to at times in SCE's LTPP as the "Implementation Plan."

For utility-owned turnkey generation projects, SDG&E proposes a regulatory framework for recovery of costs that includes the following:[87]

> Initial Phase: The Commission should adopt the initial annual revenue requirement of a proposed turnkey project at the time of the approval filing. The initial revenue requirement would be recovered through the first full calendar year of the operation.
>
> Second Phase: The authorized revenue requirement would be annually updated to incorporate attrition adjustments.
>
> Third Phase: The updated revenue requirement will be reset in future COS filings for recovery during the term of the applicable COS.

TURN recommends that contracts with duration of three years or longer to be submitted to the Commission for pre-approval.

G. Cost recovery for Turnkey Projects:

In D. 04-06-011 we approved two turnkey generation projects for SDG&E: Ramco and Palomar. SDG&E, however, is concerned that the Commission did not establish a specific revenue requirements for these projects, nor has the Commission specified the framework under which the turnkey costs will be recovered. In the interim, SDG&E believes that ERRA mechanisms as established in Commission D.02-10-062, provide SDG&E with reasonable assurance that costs for future procurement contracts will be recovered. SDG&E requests that the Commission provide equivalent assurance for cost recovery of turnkey projects as it had for other procurement resources.

In the LTPP proceeding SDG&E proposes a three-phase cost recovery framework for turnkey project cost recovery that starts with the filing for

[87] SDG&E opening brief, pp. 81-86.

Commission approval of the project. In that filing, SDG&E will identify the rate-base and O&M-related revenue requirements associated with the project for the first full calendar year of operation of the generation plant. SDG&E proposed to record costs associate with the turnkey plants to its Non-Fuel Generation Balancing Account (NGBA) and Energy Resource Recovery Account (EERA) for recovery through SDG&E commodity rates. Under SDG&E's proposal, the Commission will adopt the annual revenue requirement of the applicable turnkey plant simultaneously with approval of the project. Prior to the operation of the turnkey generation unit, SDG&E will file an advice letter to incorporate any adjustments to the adopted revenue requirement.

The second phase of the framework covers the period from the end of the initial phase until the implementation of SDG&E's next Cost of Service (COS) decision to allow for annual attrition adjustments to the authorized revenue requirement.

The third phase, SDG&E's revenue will be trued up to reflect the costs of these projects.

PG&E requests that the Commission provide timely cost recovery of utility owned generation when the facility starts serving utility customers, whether PG&E operates the plant itself or when it contracts with a third party to operate it. Under PG&E's proposal, PG&E would include the initial capital cost of the acquisition in its request for approval of the contract.

UCAN opposes SDG&E's proposal for cost recovery and argues that the Commission sets revenue requirements in the General Rate Case (GRC) and should not allocate separate revenue requirements for each asset owned by the utility in a non-GRC proceeding.

1. Discussion:

We find SDG&E's mechanism reasonable and adopt it for all three IOUs. In the next few years, IOUs could add extensive new generation to their resource portfolios in order to meet their future resource needs. We believe a rate making mechanism needs to be in place to ensure proper and timely cost recovery for these facilities. Two issues need to be decided; the timing and the scope of the cost recovery. First, we determine the appropriate timing of the rate recovery. Both SDG&E and PG&E propose to start cost recovery when the new facility starts operation to serve utility customers. We agree and adopt this proposal.

Second, we adopt SDG&E's proposal for cost recovery. SDG&E proposes to establish rate-base and O&M-related revenue requirements associated with the generation plant and to use its Non-Fuel Generation Balancing Account (NGBA) and Energy Resource Recovery Account (EERA) to record costs associate with the turnkey plants and for recovery through SDG&E commodity rates. PG&E, however, proposes differently. In addition to the costs listed above, PG&E proposes that in some cases, it may be necessary to request recovery for "financial burden associated with acquisition of utility-owned generation."[88] In PG&E's opinion, these costs may include planning and administrative costs of preparing for the construction or acquisition of the generation facilities, financing costs as incurred, and costs if the project is ultimately abandoned. We believe that some of these costs or risks will be considered in our review and evaluation of IOU contracts for turnkey projects and some will be considered as part of establishing the revenue requirement for

[88] PG&E's prepared Testimony, Page 2-38.

these facilities. For example, we expect contracts for turn key projects address provisions and penalties for project abandonment. As such these types of costs should not receive special recovery treatment. We reject PG&E's proposal in this respect.

H. ERRA Trigger Mechanism

1. Background

The ERRA trigger mechanism requires the Commission to adjust procurement rates if the ERRA balancing account becomes undercollected by more than 5% of the previous year's non-DWR generation revenues. The trigger mechanism is set to expire on January 1, 2006.

AB 57 added the following to the Public Utilities Code 454.5 (d)(3):

> Ensure timely recovery of prospective procurement costs incurred pursuant to an approved procurement plan. The commission shall establish rates based on forecasts of procurement costs adopted by the commission, actual procurement costs incurred, or combination thereof, as determined by the commission. The commission shall establish power procurement balancing accounts to track the differences between recorded revenues and costs incurred pursuant to an approved procurement plan. The commission shall review the power procurement balancing accounts, not less than semiannually, and shall adjust rates or order refunds, as necessary, to promptly amortize a balancing account, according to a schedule determined by the commission. Until January 1, 2006, the commission shall ensure that any overcollection or undercollection in the power procurement balancing account does not exceed 5 percent of the electrical corporation's actual recorded generation revenues for the prior calendar year excluding revenues collected for the Department of Water Resources. The commission shall determine the schedule for amortizing the overcollection or undercollection in the balancing account to ensure that the 5 percent threshold is not exceeded. **After January 1, 2006, this adjustment shall**

> **occur when deemed appropriate by the commission consistent with the objectives of this section.** (emphasis added)

PG&E requests that the trigger mechanism remain in effect for the term of the LT contracts to be approved. DENA strongly supports PG&E's request on the grounds that the extension of the trigger mechanism will provide certainty needed to maintain or improve PG&E's credit rating and will benefit PG&E customers, by ensuring that any decreases in procurement costs are passed on to the customers.[89] IEP joins in support with DENA.

We find that the ERRA trigger provides the IOUs assurance that procurement costs will be recovered in a timely fashion, and we keep the trigger in effect during the term of the long-term contracts, or ten-years, whichever is longer.

2. ERRA Disallowance Cap

In D.02-12-074, the Commission adopted a disallowance cap applicable to utility administration and dispatch of allocated DWR contracts. The cap amount is equal to two times the utility's costs of procurement function.(?)[90] In D.03-06-067 the Commission ruled the following: SCE's request to expand the disallowance cap established in D.02-12-074 to include all procurement activities violates the legislative mandate of Assembly Bill 57, as codified in Pub. Util. Code § 454.5, as well as Sections 451 and 702.[91]

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[89] DENA opening brief, p. 13.

[90] D. 02-12-074, Ordering Paragraph 25.

[91] *Id.*, Conclusion of Law 1.

Current disallowance cap is applicable to utility administration and dispatch of allocated DWR contracts. PG&E Requests that disallowance cap apply to all utility dispatch, including URG, PPAs, and allocated DWR contracts on the ground that this would provide certainty in estimating the potential financial risk utilities face.

On July 8, 2004, the Commission issued D.04-07-028 requires utilities to consider local reliability effects in their dispatch decisions. Potentially, this could impact the least-cost dispatch process July 8 Reliability decision complicates the least-cost dispatch process that is an up-front standard that is included in procurement plans. PG&E argues that given the current concern in the investment community over the utilities financial health, if the Commission clarifies that the cap applies to all utility least-cost dispatch activities undertaken pursuant to the long-term plans approved by the Commission will provide needed regulatory assurance.

DWR does not oppose the development of a separate disallowance cap, but does oppose extending the disallowance cap to all IOU procurement activities, especially direct liabilities to DWR.

Consistent with our determination in D. 03-06-067, as discussed above, that an extension of the disallowance cap violates legislative intent and the statutes, we reject PG&E’s request.

3. Upfront Standards for Utility Procurement Products and Transactions

XX. Background

In previous decisions, The Commission authorized the following products and transaction processes:

	Authorized by D.02-10-062 and/or D.03-12-062
Transactions	(authorized by D.02-10-062) Ancillary Services Capacity (demand side) Capacity (purchase or sale) Electricity Transmission Products Financial call (or put) option Financial swap Forward Energy (demand side) Forward Energy (purchase or sale) Forward Spot (Day-Ahead & Hour-ahead) purchase, sale, or exchange Gas Purchases (monthly, multi-month, annual block) Gas Storage Gas Transportation Transaction Insurance (Counterparty credit insurance, cross commodity hedges) On-site energy or capacity (self-generation on customer side of the meter) Peak for off-peak exchange Physical call (or put) option Real-time (purchase or sale) Seasonal exchange Tolling Agreement

	Authorized by D.02-10-062 and/or D.03-12-062
Additional Transactions	*(authorized by D.03-12-062)* Counterparty Sleeves Emissions Credits futures or forwards Forecast Insurance FTR Locational Swaps Gas Purchases (daily) Non-FTR Locational Swaps Structured Transactions Weather triggered options
Transactional Processes	*(authorized by D.02-10-062)* Competitive Solicitations (Requests for Offers) Direct bilateral contracting with counterparties for short-term products (i.e., less than 90 days) Inter-Utility Exchanges ISO markets: Imbalance Energy, Hour Ahead, and Day Ahead (when operational) Transparent exchanges, such as Bloomberg and Intercontinental Exchange Utility ownership of generation (interim rules set in D.04-01-50)
Additional Transactional Processes	*(authorized by D.03-12-062)* Open Access Same-Time Information Systems (OASIS) Negotiated bilateral contracting allowed for Short-term transactions of less than 90 days duration and with delivery beginning less than 90 days forward. Longer-term non-standard products provided that the IOU include a product justification in quarterly compliance filings Standard products in cases where there are 5 or fewer counterparties (for gas storage and pipeline capacity, only Transparent exchanges to include voice and on-line brokers

In its Petition to Modify (PTM) D.03-12-062, filed February 20, 2004, PG&E asks the Commission to clarify that for purposes of upfront standards for procurement transactions, "short term" means up to and including 3 calendar months, or one quarter, not "90 days". PG&E also wants a clarification that the IOUs can conduct competitive solicitations in an auction format. PG&E argues that the use of online auction techniques for competitive procurement falls within the guidelines presented in D.03-12-062 and D.04-01-050.

In response to PG&E's PTM, ORA agreed with the short-term definition, but opposed electronic auction authority since the proposal lacks details.

On February 19, 2004, SCE filed a Petition for Modification (PFM) of D.03-12-062 (the 2004 Short Term Procurement Plan Decision). SCE's PFM presented argument on twelve separate issues in the D.03-12-062 that, SCE contends, affect its ability to procure power and make it difficult for SCE to comply with portions of the decision as it is written. SCE's list of twelve requested modifications are set forth in its LTPP, Vol.2, p.13-16, which we will not reiterate here. SCE, like PG&E, raised the 90-day vs. one quarter issue.

We grant PG&E's PTM and clarify that D.03-12-062 authorized IOUs to conduct procurement using negotiated bilateral agreements for transactions of up to three calendar months, or one quarter, forward; and that utilities will consult with their PRGs for transactions with delivery periods of greater than three calendar months, or one quarter. We further clarify that D.03-12-062 authorized IOUs to conduct procurement using an electronic auction format for execution of competitive solicitations, among other transactional methods. The authorized products are good for short-, medium-, and long-term procurement.

We grant ten of SCE's twelve requested modifications with the exception of modifications seven and nine, as shown here:

> 1. "Modify language that would require an "unqualified certification" as a basis for authorizing SCE's proprietary risk model. The language of the decision must be modified

because a certification of this level would be extremely difficult to obtain."

2. "Eliminate the requirement that SCE demonstrate that identified over-the-counter (OTC) brokers provide prices equivalent to those of exchanges. Allowing transactions from brokers only when the same transaction can be made with an exchange at an equivalent price is impractical."

With regard to an "unqualified certification" of SCE's proprietary risk model, we are not asking that the model be proven infallible. We are simply seeking an independent review of the internal validity of the model, that all the features of the model work as advertised, that the model is mathematically sound, and that the assumptions utilized by the model are reasonable.

With regard to the requirement that SCE demonstrate that identified over-the-counter (OTC) brokers provide prices equivalent to those of exchanges, this is a reasonable upfront standard, consistent with AB57. The use of transparent exchanges is one reasonable check on the competitiveness of a portion of SCE's procurement activity. We direct SCE to consult with its PRG regarding the specific implementation options that are available.

A. SCE'S AB 57 Plan

SCE states that its proposed revision to its Existing AB57 Procurement Plan[92] is a component of it's long-term procurement plan. SCE further clarifies that it does not have a separate AB57 long-term procurement plan and AB57

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[92] The "Existing AB57 PP is the same as the "2004 Short-Term Procurement Plan – Confidential Version," dated May 15, 2003, as modified by the Commission in D.03-12-062 and submitted by SCE in Compliance Advice Letter 1770-E-A, dated February 23, 2004. These plans are also referred to at times in SCE's LTPP as the "Implementation Plan."

short-term procurement plan. Instead, SCE has one AB57 procurement plan which is a component of SCE's LTPP showing in this proceeding (SCE LTPP, July 9, 2004, Vol.2, p.1). SCE states that the objective for each IOU's AB57 procurement plan is to set the limits (i.e., the upfront achievable standards and criteria called for in AB57), within which the IOU's transaction activity would be deemed reasonable. All transactions and actions that fall within the boundaries of an AB57 procurement plan are compliant with the approved procurement plan and accordingly are assured cost recovery. Statute requires that a procurement plan contain upfront achievable standards and criteria (*Id.*, p.1-2).

On February 19, 2004, SCE filed a Petition for Modification (PFM) of D.03-12-062 (the 2004 Short Term Procurement Plan Decision). SCE's PFM presented argument on twelve separate issues in the D.03-12-062 that, SCE contends, affect it's ability to procure power and make it difficult for SCE to comply with portions of the decision as it is written. SCE's list of twelve requested modifications are set forth in its LTPP, Vol.2, p.13-16, which we will not reiterate here. SCE, like PG&E, raised the 90-day vs. one quarter issue.

We grant ten of SCE's twelve requested modifications with the exception of modifications seven and nine, as shown here:

> 3. "Modify language that would require an "unqualified certification" as a basis for authorizing SCE's proprietary risk model. The language of the decision must be modified because a certification of this level would be extremely difficult to obtain."
>
> 4. "Eliminate the requirement that SCE demonstrate that identified over-the-counter (OTC) brokers provide prices equivalent to those of exchanges. Allowing transactions from brokers only when the same transaction can be made with an exchange at an equivalent price is impractical."

With regard to an "unqualified certification" of SCE's proprietary risk model, we are not asking that the model be proven infallible. We are simply seeking an independent review of the internal validity of the model,that all the features of the model work as advertised, that the model is mathematically sound, and that the assumptions utilized by the model are reasonable.

With regard to the requirement that SCE demonstrate that identified over-the-counter (OTC) brokers provide prices equivalent to those of exchanges, this is a reasonable upfront standard, consistent with AB57. The use of transparent exchanges is one reasonable check on the competitiveness of a portion of SCE's procurement activity. We direct SCE to consult with its PRG regarding the specific implementation options that are available.

B. Policy Issues Related To Long-Term Plans

The 2000-2001 energy crisis can undoubtedly be considered the antithesis of an open, transparent, and competitive bidding process. Fortunately, the California utilities are moving forward in a new hybrid market structure developed in large part by this Commission. Since the crisis, the Commission has authorized, and the utilities have conducted, a number of all-source and renewable power solicitations which have successfully procured thousands of megawatts of power under short- and long-term contracts to serve California customers. However, not all parties agree on how the solicitations should be conducted. Although all parties tend to agree that the solicitations should take place by way of an open, transparent and competitive bidding process, not all parties agree on the specific definitions, details and logistics of such a competitive process. We want the IOUs to have a mixed portfolio of demand

and supply side resources, and a combination of renewables and fossil- fuel sources, as well as different ownership types.

We have determined that it is time to allow greater head-to-head competition and hereby lift the affiliate ban on long-term power products. Accordingly, we adopt certain guidelines and safeguards, including an independent third party evaluator requirement. We will allow the consideration of debt equivalence in the bid evaluation process as specified herein, and we will also require the use of a carbon adder as a bid evaluation component. With these policies we continue to shape and define the hybrid power market in California so as to advance the positive benefits of competition.

C. Proposals Regarding Open And Transparent Competitive Bidding Process

1. Parties Positions

Calpine states that a lack of head-to-head competition and PG&E's 50/50 proposal are not features of an open, transparent, and competitive bidding process and will not ensure procurement of LCBF resources. In particular, Calpine is concerned that since IOU-owned resources generate earnings for the utility, there is an inherent incentive for IOUs to favor IOU-owned resources over third party PPAs, a fact that was recognized in Decision 04-01-050.[93] Calpine further adds that there is a "fundamental difference in the allocation of risk and the certainty of bid prices between IOU-owned projects and PPAs allows IOUs to unfairly advantage IOU-owned projects vis-à-vis PPAs in the bid evaluation process."[94] Since an IOU can shift the risk of cost overruns and other

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[93] D.04-01-050, mimeo at 61

[94] Calpine opening brief, p. 12.

problems related to the development, construction and operation of a project to ratepayers means that the IOUs' bid strategies are not constrained by normal bid considerations, such as being responsible for the economic consequences of submitting a low bid that is ultimately selected in the solicitation process. Calpine asserts that the only solution to this inequity is to require the IOU to 'commit' to the cost and operating performance estimates it uses in its bid evaluation of the IOU-owned project.

CMTA/CLECA share similar concerns about utility-owned generation contending that (1) "utility-owned generation constructed without the benefit of a competitive solicitation has been too costly" [and that] the Commission has long experience with cost overruns associated with utility-owned generation, citing Diablo Canyon, SONGs, and Helms Pumped Storage [in particular;]" and (2) that "a competitive bidding process also obviate[s] the need for after the fact reasonableness reviews." Lastly, CMTA/CLECA observe that SCE refuses to sign "contracts for terms longer than three years until the debt equivalence issue is resolved," yet the SCE recently received approval for "a 30-year power purchase agreement with its affiliate-to-be … the Mountainview project"[95]

In addition, CMTA/CLECA claim that the participation of an IOU affiliate can greatly detract from an open, transparent, and competitive bidding process. As a solution, CMTA/CLECA recommend the use of a independent third party evaluator, as set forth in The FERC's competitive solicitation guidelines[96] which

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[95] *Id.*, pp. 11, 12.

[96] FERC *Opinion and Order Affirming Initial Decision In Part, Denying Requests for Rehearing and Announcing New Guidelines for Evaluating Section 203 Affiliate Transactions, Opinion No. 473, Ameren Energy Generating Co., et al.* 108 FERC ¶ 61,081 (2004).

provide specific guidance on transparency, power product definition, evaluation, and oversight.

PG&E and Edison both object to parties having more access to confidential information, which is what some parties believe "open and transparent" means.

With regard to competition, SCE is opposed to head-to-head competition between PPAs and utility-owned generation . SCE contends that "there are important differences between utility-built and independent generation, which are extremely difficult to quantify and evaluate in the same process. The primary differences include the value of operational control, operational and financial risk, special local area needs, flexibility in case of changed circumstances, and the terminal and refinancing value associated with utility plant."[97]

SDG&E is understandably amenable to an open, transparent, and competitive bidding process that includes direct as it recently concluded an all-source grid reliability RFP that netted six new resources that included demand and supply side sources and different ownership schemes. The utility argues that "[g]iven the wide range of possible offers, however, the Commission should not attempt to predetermine specific methodologies for all future solicitations in this regard. Instead, the Commission should reinforce the objective that a utility seeking approval of a new resource should provide a robust comparison of options that maintains a level playing field for all bidders. The PRG can also play an important role here in advising the utility on its competitive solicitation

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[97] SCE opening brief, pp.88, 90.

activities, which is yet another reason that the PRG process should be extended."[98]

Sempra supports all-source solicitations and states that "the Commission should require that proposed utility-owned generation projects be competitively bid against other market solutions."[99]

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[98] SDG&E opening brief, pp. 96-97.

[99] Sempra opening brief, pp. 3-4.

WPTF recommends that long-term procurement efforts by the utilities must include the following mandatory competitive bidding requirements:

- Evaluation of bids should include all incremental costs delivered to load;
- Any procurement process in which the utilities can submit their own bids must be unbiased;
- RFPs should be mandatory for utility procurement;
- Barriers to transmission development that supports markets and fuel diversity should be removed; and
- Winning bids should be binding and non-recourse.[100]

Strategic Energy supports open and transparent competitive bidding for any new medium- and long-term resource needs. Strategic urges the Commission to reject PG&E's [50/50] proposal . There is simply no guarantee that set-asides would result in least-cost procurement for bundled customers. Generally, lower costs result from the consideration of the greatest number of procurement options.[101]

2. Discussion and Determinations

Our most recent experience with procurement solicitations was the SDG&E Grid Reliability RFP process that involved head-to-head competition among both supply-side and demand-side resources (megawatts and negawatts), peaking and baseload resources, an affiliate resource, renewable generators, a merchant PPA, and utility turn-key power plants. This was our first experience

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[100] WPTF opening brief, pp 11-13.

[101] *See* Ex. 70 (Fulmer), p. 20, line 20, to p. 21, line 5.

with such diversified head-to-head competition among competing resource types, yet it was a successful undertaking.

In Governor Schwarzenegger's October 8, 2004 energy plan letter published in the San Diego Union-Tribune,[102] the Governor spoke about SDG&E's RFP and said:

> "…it is the ability of utilities to engage in long-term contracts that attracts investors and gets power plants built. In [June 2004], the PUC approved [the SDG&E Grid Reliability RFP results in D.04-06-011,] a plan designed to meet San Diego's energy needs through this decade. The plan includes building two large power plants that will generate 1,085 megawatts of power. (One megawatt powers roughly 1,000 homes). Two more facilities planned for San Diego, one of which is a renewable biomass facility, will bring an additional 85 megawatts." (Governor Schwarzenegger, Energy Plan Letter, October 8, 2004)

D. Requirements for an All-Source Solicitations

- All-source open solicitations need to be transparent and competitive, and in addition, need to be open to all resources (conventional/renewable - turnkeys, buyouts, and PPAs).
- Following the "loading order" contained in the Joint Agency Energy Action Plan is the first priority for IOU resource procurement, meaning that energy efficiency and demand-side resources should be employed first. When these opportunities are exhausted, renewable generation is to be procured to the fullest extent possible – whenever an IOU issues an RFO for generation resources, it must be prepared to defend its selection of fossil gener.

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102 As referenced by IEP in its Opening Brief, October 18, 2004, p.2, footnote 2.

- IOUs are directed to procure the maximum feasible amount of renewable energy in the general solicitations authorized by this decision, and will be allowed to credit this procurement towards their Renewables Portfolio Standards (RPS) targets in 2005 and beyond. If an IOU succeeds in procuring sufficient renewable resources to meet its 2005 RPS Annual Procurement Target (APT) via an all-source RFO, it will not be required to undertake an RPS-specific solicitation next year.
- The IOUs will employ the Least-Cost Best-Fit methodology when evaluating PPAs and utility-owned bids in an all-source open RFO, taking into account the qualitative and quantitative[103] attributes associated with each bid.
- Green House Gas (GHG) adders are to be used for fossil bids in all-source open RFOs.
- Debt equivalency will be considered when evaluating individual PPA bids, regardless of whether the bids are from a fossil, renewable, or an existing QF resource. IOUs are not to consider resource-specific debt equivalency risk factors in their cost of capital proceedings but should instead use the methodology outlined in this decision.
- IOUs will not be allowed to recover costs in excess of their final bid price for utility-owned resources.
- The IOUs will be required to use a 3rd party evaluator in resource solicitations where there are affiliates, IOU-built, or IOU-turnkey bidders.

[103] Qualitative and quantitative attributes such as performance risk, credit risk, price diversity (10 vs. 20 yr. price terms), and operational flexibility etc.

E. Affiliate Transactions

D.04-01-050 continued the ban on affiliate transactions, however, our position on this issue warrants re-examination at this time.

> "We do not have the same level of oversight and authority over affiliate transactions that we do over direct utility operations. We recognize that cross-subsidies and anti-competitive conduct has occurred in the past in affiliate procurement transactions and that it could occur in the future under the market structure we adopt here"[1]

As noted earlier in this decision, SEGE argues for the Commission to rescind the ban on affiliate transactions since it prevents utility access to ready built facilities owned by an affiliate. As we have already found in the Mountainview proceeding, A. 03-07-032, D. 03-12-059, and in the SDG&E RFP proceeding, A. 03-10-007, D. 04-06-011, affiliates can present attractive procurement options.

Calpine, DENA, IEP, and WPTF do not oppose affiliate participation in resource solicitations, provided that certain safeguards are in place like a requirement for third party evaluators. In D.04-01-050, ORA recommended that the affiliate ban not extend to long-term transactions:

> "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

[1] D. 04-01-050, Conclusion of Law 19.

> current affiliate rules. ORA testifies this process should have enough built-in protections to prevent potential self-dealing and other abuses." (D.04-01-050, p.69-70)

Given our desire to consider all competitive options, instead of continuing the ban, and carving out exceptions for unique resources from time to time, we now find that it is in the best interest of the ratepayers and consumers to allow for a full vetting of all available resources in a RFP. We will institute appropriate safeguards for the solicitations for long-term transactions, in part through continuation of utility PRGs and through the use of independent third-party evaluators. Such safeguards can protect consumers from any anti-competitive conduct between utilities and their affiliates. **Therefore, by this decision we lift the ban on long-term affiliate transactions for transactions entered into through an open and transparent solicitation process. However, we maintain the ban on short-term transactions** 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**.**

We also reaffirm that the utilities, and in particular their respective risk management committees, maintain complete procurement planning independence from their affiliates. In D.04-01-050, we found that such procurement planning independence was severely lacking for SDG&E:

> "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." (D.04-01-050, p.72)
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> * * *
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> "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. We may review this finding after completion of the SDG&E/SoCalGas/SEU audit, as discussed below." (D.04-01-050, p.73-74)

F. Procedures, Rules And Protocols, Including Independent Third-Party Evaluators

The use of Independent Third-Party Evaluators or 'IEs' in resource solicitations has not been previously required by the Commission. Parties disagree on the role, scope, and need for an IE. Some parties contend that the role of an IE is currently being fulfilled through the PRG. The IOUs are opposed to the delegation of any final decision-making authority to an IE.

As noted by WPTF, FERC has recently set forth Guidelines for Reviewing Future Section 203 Affiliate Transactions, which include guidelines for IEs in 108 FERC 61,081 (July 29, 2004). FERC explained that to the extent to which a utility demonstrates that its RFP process follows the stated guidelines, its application processing time (including litigation) will likely be reduced, thus increasing the possibility of more timely Commission approval through an adequate showing under the *Edgar* standard.[104] In short, guidelines will allow FERC to more easily identify transactions that are consistent with the public interest, and, therefore, expedite their approval.[105]

The FERC guidelines provide for substantial IE involvement in resource solicitations at the "design, administration, and evaluation stages of the

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[104] FERC Edgar Standard: "We note that there are three ways to demonstrate lack of affiliate abuse under the *Edgar* standard: (1) evidence of direct head-to-head competition between the affiliate and competing unaffiliated suppliers in a formal solicitation or informal negotiation process; (2) evidence of the prices which non-affiliated buyers were willing to pay for similar services from the affiliate; and (3) and benchmark evidence that shows the prices, terms and conditions of sales made by non-affiliated sellers. Because the market for generating assets is not nearly as liquid as the market for PPAs, a competitive solicitation through a formal RFP in future section 203 cases is likely to be the most effective way to show that an affiliate transaction is not marred by affiliate abuse. In the context of an acquisition of affiliated generation, a competitive solicitation is the most direct and reliable way to ensure no affiliate preference." 108 FERC 61,081 (July 29, 2004), paragraph 67.

[105] This is similar to our use of the Appendix A "screens" adopted in the Merger Policy Statement to quickly identify transactions that are unlikely to harm competition. Largely due to these screens, this Commission has succeeded in reducing the amount of time necessary to analyze and approve section 203 applications.

competitive solicitation process." FERC has set forth "minimum standards for assuring independence and the scope of the third party's role." These IE guidelines are shown here:

> "A minimum criterion for independence is that the third party has no financial interest in any of the potential bidders, including the affiliate, or in the outcome of the process.[106] Preferably, the independence criterion would be the same as that of an ISO or RTO.[107] In this context, "independence" means that the third party's decision-making process is independent of the affiliate and all bidders.[108] Without such independence, the third party could be biased towards the affiliate in order to enhance its financial position. Obviously, a similar concern could arise regarding an actual or potential financial interest link between the third party and any potential bidder. Independence can also be satisfied if the state commission has approved the selection of a third party on the basis of established independence criteria. In addition, the third party should not own or operate facilities that participate in the market affected by the RFP.
>
> "The independent third party should be able to make a determination that RFP process is transparent and fair, and

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106 *See, e.g.,* Technical Conference Comments of Maine Public Utilities Commission Chairman Welch, Conference on Solicitation Processes for Electric Utilities, Docket No. PL04-6-000, (June 10, 2004) (PL04-6 Conference) at Tr. 78.

107 *See, e.g.*, Technical Conference Comments of John Hilke, Federal Trade Commission, PL04-6 Conference at Tr. 4.

108 Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (2000), FERC Stats. & Regs., Regulations Preambles July 1996 – December 2000¶ 31,089 at 31,061 (1999), *order on reh'g,* Order No. 2000-A, 65 Fed. Reg. 12, 088 (2000), FERC Stats. & Regs., Regulations Preambles July 1996 – December 2000 ¶ 31,092 (2000), *affirmed sub nom*. Public Utility District No. 1 of Snohomish County, Washington, *et al.* v FERC, 272 F. 3d 607 (D.C. Cir. 2001).

that the RFP issuer's decision is not influenced by any affiliate relationships. For example, if the RFP issuer wishes to use a collaborative RFP design process, the independent third party should be the clearinghouse for comments by potential bidders on a draft RFP and should evaluate those comments as possible revisions to the RFP. The independent third party's role as the sole link for transmitting information between potential bidders and the RFP issuer would also help to ensure that the RFP design will not favor any particular bidder, particularly an affiliate. The independent third party should continue to be a conduit of information between utility and bidders in determining which of the original bid responses are qualified bids or may be included in a short list.

"At the evaluation stage of the RFP process, the third party should be able to credibly assess all bids based on both price and nonprice factors. It should be able to consider both generation asset bids and power purchase agreements. Also, it should be able to independently verify transmission characteristics that may limit the suitability of certain alternatives. The third party should have access to the same information that the RFP issuer uses in its evaluation and should be able to independently verify its correctness. The third party should also be able to evaluate nonprice traits of various alternatives." (108 FERC 61,081, p.27-29)

The Commission's only recent experience with an IE was in the SDG&E Grid Reliability RFP process. SDG&E retained "an independent third party, Dr. Boothe, to observe the bid evaluation and selection process to ensure that Palomar[109] was not given special treatment" (D.04-06-011, p.48). Dr. Boothe's primary purpose was to ensure that "all competitors were

109 "SDG&E is proposing to purchase [Palomar] from SER [Sempra] a 500 MW (base load)/ 555 MW (peaking load) combined cycle natural gas-fired generation plant to be built by SER, and then turned over to SDG&E as a utility owned generation asset. This project is located in the utility's service territory on a 20-acre site in Escondido, and is expected to go on line in June 2006." (D.04-06-011, p.47)

treated fairly" (*Id.*, p.52). Neither the Commission, nor the IE found that any unfair advantage was conferred to the affiliate bidder. The Commission did not formally evaluate the role of the IE in this RFP process.

Relative to the SDG&E Grid Reliability RFP process, Calpine recommends that an IE play a more significant and active role in any resource solicitation involving an IOU affiliate, IOU-built or IOU-turnkey bids. Calpine envisions that "an IE would be responsible for both independently evaluating the fairness of the IOUs' evaluation process *and* conducting its own evaluation of which resources are the least cost/best fit for ratepayers." Calpine contends that this is "something the current PRGs do not do." In instances where the IE disagrees with an IOU's resource decisions, the IE would provide the Commission with an independent recommendation as to the least cost/best fit resources from the solicitation" (Calpine Reply Brief, p.18).

In the present case, "the IOUs believe that the Commission should not require the participation of an IE in resource solicitations that may involve an IOU-owned project (whether IOU-built or turnkey) or where an IOU affiliate participates in the process. Specifically, the IOUs believe the current procurement review groups ("PRG") provide sufficient independent review of IOU procurement decisions and that there is no reason to change the current structure" (Calpine Reply Brief, p.18).

According to WPTF, "a structure must be established that puts procurement via contract on an equal footing with utility-build options [and the PRG] process does not rise to the level of an independent evaluator" (Opening Brief, p.17-18). WPTF further contends that a "level playing field … will result in the least-cost option for ratepayers [which] can be addressed by the Commission adopting clear criteria for evaluation of bids and mandating the use of a third party independent evaluator when a utility-build project or a utility affiliate is a participant in the RFP" (*Id.*, p.18).

No party recommends the use of an IE in all resource solicitations. Certain non-IOU parties (Calpine, IEP, and WPTF) only recommend the use of an IE in resource solicitations involving an IOU affiliate, IOU-built, or IOU-turnkey, while the remaining non-IOU parties do not offer specific positions on this issue. In contrast, the IOUs state that the Commission should not require the use of IEs in any resource solicitations, and that IEs cannot, and should not, be delegated any authority to make binding decisions on behalf of the utilities.

SDG&E, for example, supports the IE process in concept (Opening Brief, p.102) but contends that the PRG already performs this function. However, SDG&E observes that there might be situations in which a third party IE would serve a "useful purpose" (Id, p.104), but that the "utility should be left to exercise its discretion to incorporate such a feature as needed into its bid evaluation process." SCE noted that an IE procurement feature was not adopted in D.04-01-050 (p.64). PG&E also opposes an IE requirement, citing the same language in D.04-01-050. In that decision, we stated that the PRG served as one safeguard in the PPA vs. utility-owned procurement process. However, we did not preclude the adoption of additional safeguards, as necessary: "Based on our continuing review of the RFP process, we will adopt additional safeguards if we find it is necessary" (*Id.*, p.64). We acknowledge the detailed IE guidelines set forth by FERC in its recent July 2004 and generally endorse them. At this time, we will outline an interim approach, which we may refine at a later date based on our further experience in this area. We determine here that we will not allow the IEs to make binding decisions on behalf of the utilities. We will require the use of an IE in resource solicitations where there are affiliates, IOU-built, or IOU-turnkey bidders. However, we will not require that the IEs administer the entire

RFO process. The IOU shall consult with its IE and PRG on the design, administration, and evaluation aspects of the RFO to ensure that the overall scope is not unnecessarily broad or otherwise too narrow. IEs should be available to testify as an expert witness in any associated Commission proceeding regarding upfront review of potential solicitation transactions.

IEs should come equipped with technical expertise germane to evaluating resource solicitation power products. IEs should not be general observers hoping to be educated on the job. In the case of an affiliate/IOU-turn key power plant, IEs should be able to quickly scrutinize, examine, and essentially break down bids to determine whether the various cost components are reasonable as presented. IEs should be skilled in analyzing an range of power market derivatives (e.g., futures, contracts, options, swaps). IEs should be familiar with the various standard contracts and industry practices. IEs should have experience analyzing the relative merits of various types of PPAs. IEs should be able to evaluate PPAs, turn-keys, and IOU-builds on a side-by-side basis. An IE should make periodic presentations regarding their findings to the IOU and to the PRG.

The IOUs may contract directly with IEs, in consultation with their respective PRGs. The IOUs shall allow periodic oversight by the Commission's Energy Division. Alternatively, Energy Division can contract with IEs directly, but we will not require this given that this may result in unacceptable delays in the procurement process. IEs shall coordinate to a reasonable degree with assigned Energy Division management and staff as a check on the process.

With regard to consultants that assume the role of an IE, they shall abide by clear conflict of interest standards. We note that FERC has provided guidance on this issue. We would like to require that consultants abide by the appropriate

Fair Political Practices Commission guidelines, in order to avoid the types of conflict of interest problems encountered by consultants working on behalf of the State of California and DWR during the 2000-2001 energy crisis. We must ensure the integrity of the third party evaluator process to provide firm assurances to the power market. We are open to comment from parties on specific conflict of interest standards.

G. Parties' Positions

PG&E proposes to conduct 2 parallel solicitations, one to obtain LT PPAs and another to obtain "turnkey" utility generation. For this round of solicitations PG&E will not accept bids from utility affiliates or subsidiaries. PG&E opines that by conducting separate solicitations for PPAs and utility-owned generation, the impact of debt equivalence becomes irrelevant to the choice between 3rd party and IOU-owned generation, except as between competing PPAs[110].

SCE agrees with the concept of a hybrid market structure provided through both a competitive market and utility-owned generators as established in D.04-01-050, but also argues that the same decision rejects the concept of evaluating IOU-owned and PPA resources in the same RFO. Utility-owned projects, with significantly different benefits, should not be compared against contracts in an RFP. An RFO is appropriate for non-utility owned generation resources and a CPCN application is the established procedure for comparison of utility-owned projects with alternatives.[111]

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[110] PG&E opening briefs, pp. 60,61,64,65

[111] SCE opening brief, pp. 89, 90, 91, 92, 96.

SDG&E is of the opinion that it is neither necessary nor desirable to adopt a mechanism for comparing PPAs to utility ownership. While there are techniques for structuring an evaluation process that puts these differing options on a common basis, it is a very complex process. It is preferable to conduct this analysis on an RFP-specific basis to ensure that each project's unique circumstances and attributes are captured. The Commission should not attempt to predetermine specific bid evaluation methodologies for future solicitations

While TURN supports the Commissions preference for a hybrid wholesale electric market consisting of PPAs and IOU owned resources, the Commission should not focus on comparing the value of PPAs to IOU-owned projects. The Commission should adopt the principle that the IOUs will acquire the resources that provide the lowest net cost to ratepayers, regardless of ownership form[112]. ORA's concerns center around balancing Commission and legislature policy for favoring certain resources and a hybrid market against the costs of different proposals when making comparisons of competing choices.

Calpine, as a potential bidder of non-utility owned PPA projects favors a transparent competitive solicitation to ensure that IOU-owned resources are not chosen by the utility over 3rd party PPA. Calpine is concerned that because IOU-owned resources generate earnings for the utility, there is an inherent incentive for IOUs to favor IOU-owned resources over 3rd party PPAs. In addition, because traditional cost-of-service ratemaking allows IOUs to pass the cost overruns associated with an IOU-owned resource onto the ratepayers, IOUs can favor

[112] TURN opening brief, pp. 12

IOU-owned resources in the bid evaluation process by submitting low bid prices with the expectation that they will be able to recover cost over runs.

Lastly, Calpine argues that the fundamental difference in the allocation of risk and the certainty of bid prices between IOU-owned projects and PPAs allows IOUs to unfairly advantage IOU-owned projects vis-à-vis PPAs in the bid evaluation. To correct the unlevel playing field, Calpine proposes that the IOUs should not be allowed to recover costs in excess of its final bid price. [113]

While the Commissions has stated a preference for a hybrid wholesale electric market consisting of PPAs and IOU owned resources[114], this should not undermine the Commission's goal of having the IOUs acquire supply-side resources based on LCBF principles, regardless of ownership form. We agree with Calpine that PPAs and utility-owned resources need to participate in the same all-source open solicitations to ensure LCBF, not in separate PPA and utility-owned specific solicitations as proposed by PG&E.

We are not persuaded by SCE's argument that D.04-01-050 precludes the IOUs from doing an all-source open RFO because a bid evaluation methodology doesn't exist. The IOUs will employ the LCBF methodology when evaluating PPAs and utility-owned bids in an all-source open RFO, taking into account the qualitative and quantitative[115] attributes associated with each bid. The IOUs will also need to add GHG adders, as discussed in this decision, to all fossil bids. In

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[113] Calpine opening brief, pp. 10-12.

[114] See Hybrid Market section (#?)

[115] Qualitative and quantitative attributes such as performance risk, credit risk, price diversity (10 vs. 20 yr. price terms), and operational flexibility etc.

addition, when seeking Commission approval for the proposed contracts the IOUs will need to demonstrate that they employed LCBF principles. It is expected that the Commission will revisit the LCBF methodology, integrating "lessons learned" from future all-source open RFOs.

Regarding capping cost overruns associated with utility-owned resources, we agree with Calpine that, "Putting shareholders – not ratepayers – at risk for cost overruns will put IOU-owned projects and PPAs on equal footing (at least with respect to the allocation of risk), impose some measure of market discipline on IOUs when formulating their bids, and better ensure that the resource solicitation process is fair and competitive[116]." Consequently, IOUs will not be allowed to recover costs in excess of its final bid price for utility-owned resources.

1. Debt Equivalency (DE)

Debt equivalence, the term used by credit rating agencies, specifically Standard & Poor (S&P) and to a lesser extent Moody's, to describe the fixed financial obligations resulting from long-term purchased power agreements, allegedly has significant effects on utilities' credit quality and costs of borrowing. As Edison's financial witness testified, "in determining a utility's credit rating, rating agencies pay particular attention to the company's cash flow, including its sources and uses of funds. Of particular concern are obligations that place a call on available cash, reducing a company's ability to make ongoing interest payments or to repay principal."[117] The credit agencies are concerned that PPA

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[116] Calpine opening brief, pp. 12

[117] SCE/Simpson Ex. 73, 21:2-5.

payments are fixed cash commitments that, in times of financial stress, may negatively affect bondholders.

SDG&E, SCE, and PG&E recommend that DE be adopted in procurement to ensure the resource acquisition process going forward takes into account the impact of DE on the rate of return. As SDG&E argues "[I]t is essentially undisputed that the credit analysts treat the utilities' long-term non-debt obligations, such as PPAs, as if they are in fact debt when they assess a utility's debt capacity."[118] PG&E proposes that the impact of DE on the utilities' financial condition should be addressed in the Cost of Capital (COC) proceeding, but that in this proceeding the Commission should establish that the DE impacts of new long-term commitments may be considered in the contract selection and approval process. This will allow for full disclosure of the financial effects of contracts on the utilities and promote equal consideration of competing procurement choices.[119] All 3 IOUs reject the idea of resource specific DE - all resources should have the same DE risk factor.

As forceful as the utilities were in their support for DE, many intervenors were just as strong in their opposition. The record from the four weeks of EH is replete with testimony and cross-examination on the subject of debt equivalency. In fact, except for the subject of QFs, no other subject received as much hearing time as DE.

UCS, for example, argued against using DE when evaluating renewable PPAs, and if the Commission does decide to adopt DE then they should use a

[118] SDG&E opening brief, p. 89.

[119] PG&E opening brief, p. 51.

lower the risk factor for renewable PPAs. UCS fears that if DE is used for renewable PPAs that the beneficial hedging attributes of renewables will not be properly evaluated, and the utilities may not reach their RPS targets. CCC and CAC do not want DE applied to existing QF contracts because of the beneficial properties associated with existing QFs. IEP, Calpine and WPTF all argue against considering DE in procuremnent since it is a subjective factor, one that could change over time based on an improving regulatory climate, and there is no guarantee that by considering it the credit ratings of the utilities will improve.

Lastly, while ORA urges that DE be only considered in the COC proceeding, TURN supports the use of DE in procurement - assuming it is adopted in the COC. Others just asked that the issue be resolved one way or the other now so it does not stand in the way of reliability and resource adequacy.

Consistent with our discussion and findings concerning in this decision, DE should be considered when evaluating individual PPAs bids. We will adopt a modified version of SDG&E's proposal for a methodology. Because the S&P methodology is the most well-developed, we will base our methodology on theirs. However, we agree with SDG&E and believe that the S&P risk factors are too high to be reasonable and fair to all PPAs. We find it reasonable to make some acknowledgement that DE is a factor in utility creditworthiness, but not to the degree shown in the S&P methodology. We believe the regulatory climate (a significant factor in S&P's qualitative 30% factor methodology) is improving in California. We also do not want to create an unfair burden on or a disadvantage for independent power sources over utility-owned, especially in the case of renewable resources. Weighing all of these factors, we will require the utilities to employ a methodology of using one-third of S&P's 30% risk factor, which results in a 10% risk factor being applied to all PPAs.

This methodology should be used by the utilities and/or the independent evaluator when evaluating bids in an all-source RFO. Then in the IOUs' cost of capital proceedings, the IOUs will still need to demonstrate that DE has a material impact on their credit rating, and therefore borrowing costs, on a case-by-case basis. As we gain more experience with DE evaluation in the cost of capital proceedings, we may adjust the DE methodology to be used for bid evaluation in procurement going forward to future solicitations.

2. Debt Equivalence Mechanism and use in Bid Evaluation

SDG&E's DE proposal is to adopt DE to ensure the resource acquisition process going forward takes into account the impact of DE on the rate of return. To do this, SDG&E recommends that we establish a mechanism using the S&P DE methodology but only use 65% of S&P's 30% risk factor, and apply it equally to all resources.

PG&E and SCE also want DE considered as a factor in evaluating long-term contracts, recommending that the S&P methodology be applied to individual PPA bids. PG&E goes further by proposing separate solicitations for PPAs and turn/key/utility-owned bids so that the PPAs will not be at a disadvantage, as they might in an all-source RFO.

Consistent with our discussion and findings concerning DE in this decision, DE should be considered when evaluating individual PPAs bids. In their cost of capital proceedings, the IOUs will need to demonstrate that DE has a material impact on their credit rating, and therefore their borrowing costs on a case-by-case basis.

3. Climate Change in LTPP

Consistent with established Commission policy, the positions of several parties, and the present actions of one IOU (PG&E), we adopt a range of values for a "greenhouse gas (GHG) adder" to be used in the evaluation of fossil generation bids. This range is taken from information in the present record. Each IOU will select a value within the adopted range and be prepared to respond to party comment on the value, before employing the adder in analyzing RFO responses.

The GHG value will be added to the fossil prices bid in future procurement, and will be used to develop a more accurate price comparison between fossil, renewable and demand-side bids. In the event that the fossil bid is ultimately selected, the adder *will not* be paid to that generator; it is an analytic tool only.

In addition to the GHG adder, the IOUs are directed to employ, when finalized and approved by the Commission, the externality values under development in the Avoided Cost Rulemaking (R.04-04-025). It is anticipated that these values will be adopted in approximately March 2005, and will include a fixed value for GHG (not simply a range) as well as values for other, non-GHG pollutants. These values should be appropriately added to any fossil bids the IOUs receive in response to an RFO. It is anticipated that the Commission will adopt these values in a decision in R.04-04-025 before the IOUs undertake any procurement as a result of this decision. Therefore, all procurement undertaken subsequent to this decision should employ the GHG adder adopted in this decision, until replaced with a decision in R.04-04-025, when analyzing bids.

Finally, Commission staff is directed to prepare a report analyzing the potential structure and merits of an IOU portfolio-wide "carbon cap" as an efficient means of minimizing utility contributions to climate change. This report should be prepared for Commission consideration in 2005.

H. Background

At the time of the issuance of this decision it is still not known if carbon regulation, in the form of emissions limits, will be instituted in the timeframe of the LTPPs. However, California, and in particular this Commission, along with the CEC and CPA, have given clear signals that they want to be the pacesetters in this arena and take positive steps in seeing action on this front. Beginning in May 2003 with the issuance of the EAP, the state and this Commission committed to making inroads to preserving the environment with the following:

> "The state needs to guide development of the energy system in the public's best long-term interest, to anticipate potential problems, and to make timely decisions to resolve problems. Specifically, the agencies commit to:
>
> 1. Make continuing progress in meeting the state's environmental goals and standards, including minimizing the energy sector's impact on climate change."

Following on the heels of the EAP, the Commission noted in D.04-01-050 that we were:

> "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….In this decision, we refer the question of potential financial risks associated with carbon dioxide emissions to R.01-10-028, to be considered in the context of updates to the avoided costs 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.”[120]

R.04-04-025 is the successor rulemaking to R.01-08-028 for purposes of addressing environmental issues in the context of generation investments.

The Commission then issued this proceeding, R.04-04-003, with Appendix “B” that set forth the “SkyTrust” type Cap-and-Trade Incentive Framework as follows:

> “In terms of specific pollutants, of significant concern to regulators and the public today is the environmental damage caused by carbon dioxide (CO_2) emissions—an inescapable byproduct of fossil fuel burning and by far the major contributor to greenhouse gases. Unlike other significant pollutants from power production, CO_2 is currently an unpriced externality in the energy market…. CO_2 is not consistently regulated at either the Federal or State levels and is not embedded in energy prices…. California needs a framework for procurement incentives that recognizes the importance of reducing California’s dependence on fossil fuels—for a variety of environmental, security, and price volatility reasons.”[121]

On June 29, 2004, ALJ Wetzell issued a ruling in this proceeding, R.04-04-003, presenting questions for the IOUs to answer and address in their LTPPs regarding climate:

> “San Diego Gas & Electric Company, Southern California Edison Company, and Pacific Gas and Electric Company shall address the following questions pertaining to climate change in their long-term plan filings:

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120 D.04-01-059, p. 108.

121 R.04-04-003, Appendix B, p. 5.

1. Describe the utility's position regarding the extent of the threat posed by climate change, and the contribution of electricity generation to that threat.
2. Describe any internal planning or measurement activities currently being undertaken to evaluate and address the threat of climate change, both generally and as a result of utility operations, including URG and power purchased under contract.
3. Describe, to the fullest extent possible, the utility's emissions profile with respect to the six criteria greenhouse gases: carbon dioxide (CO2); methane (CH4); nitrous oxide (N2O); hydrofluorocarbons (HFCs); perfluorocarbons (PFCs); and sulfur hexafluoride (SF6). Include both URG and power purchased under contract.
4. Describe any steps the utility has taken to minimize the release of these gases as a result of utility operations, and how your Procurement Plan advances this effort.
5. Describe the utility's position regarding the optimal policy response to the threat of climate change, and how your Procurement Plan is aligned with this policy response."
   i. In their LTPPs the IOUs offered a range of responses to these questions, from more concerned with climate (PG&E) to less so (SCE). None provide the profile requested, as they are all moving through the Climate Action Registry's inventory and auditing process now.

In its post-hearing brief PG&E indicated that it plans to value carbon risk with "reputable" price data[122] – and proposes using $8/ton, consistent with the data in the now final E3 Report on Avoided Cost.[123]

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[122] RT 9/7/04, p. 906: 17-20, Pulling.

[123] Methodology and Forecast of Long-Term Avoided Cost(s) for the Evaluation of California Energy Efficiency Programs, E3 Research Report Submitted to the CPUC Energy Division, October 25, 2004. http://www.ethree.com.

SCE stated that it planned to incorporate CEC and EPA in future climate strategizing.[124]

> NRDC proposes that the Commission direct the IOUs to financially impute a $/ton CO2 value into the analysis of all fossil bids; require the IOUs to include in their next LTPPs the emissions profiles compiled by CA Climate Action Registry; and that the IOUs must "develop and implement a comprehensive GHG reduction plan" via their next LTPPs. We find these suggestions consistent with the EAP and other Commission statements. UCS urges the Commission to require the IOUs to model carbon costs in future LTP plan preparation; to consider these costs, but not price them, in present resource solicitations; and to utilize PG&E's experience from this proceeding in educating parties and the IOUs for future LTPPs. TURN advocates the adoption of a carbon adder taken from the analysis in AC Rulemaking, R.04-04-025; the development of a policy to have bidders submit prices that include and exclude carbon regulation risk and a requirement that market sentiment on carbon prices be divulged.

I. Range of values for the GHG Adder

Utilizing data from the record in this proceeding (not doing this now), following is a range of values for the GHG adder:

a.	Final E3 Avoided Cost Report	-	**$5/ton C02 today** **$12.50 by 2008** **$17.50 by 2013**
b.	PG&E internal RFO review	-	**$8**
c.	PacifiCorp 2003 IRP	-	**$8**
d.	NRDC opening brief	-	**$12 beginning 2008**
e.	Idaho Power Co IRP	-	**$12.30 beginning 2008**
f.	EIA analysis of proposed legislation[125]	-	**$15-$25 in 2010**

[124] SCE/Hertel, Ex. 56, p. 78.

[125] PacifiCorp, IPC and EIA estimates sited in NRDC Opening Brief, 10/18/04, p.16-17

$14-$36 in 2020

Consistent with established Commission policy, the positions of several parties, including PG&E, we adopt a range of values for a "greenhouse gas (GHG) adder," of $ 8 to $25 per ton, to be used in the evaluation of fossil generation bids. This range is taken from information in the present record. Each IOU will select a value within the adopted range and be prepared to respond to party comment on the value, before employing the adder in analyzing RFO responses.

The GHG value will be added to the fossil prices bid in future RFOs, and will be used to develop a more accurate price comparison between fossil, renewable and demand-side bids. In the event that the fossil bid is ultimately selected, the adder *will not* be paid to that generator; it is an analytic tool only.

In addition to the GHG adder, the IOUs are directed to employ, when finalized and approved by the Commission, the externality values under development in the Avoided Cost Rulemaking (R.04-04-025). It is anticipated that these values will be adopted in approximately March 2005, and will include a fixed value for GHG (not simply a range) as well as values for other, non-GHG pollutants. Other GHGs, in addition to carbon, will also be included. These values should be added to any fossil bids the IOUs receive in response to an RFO. It is anticipated that the Commission will adopt these values in a decision in R.04-04-025 before the IOUs undertake any procurement as a result of this decision. Therefore, all procurement authorized subsequent to this decision should employ the GHG adder adopted in this decision, until replaced with a decision in R.04-04-025, when analyzing bids.

Finally, Commission staff is directed to prepare a report analyzing the potential structure and merits of an IOU portfolio-wide "carbon cap" as an efficient means of minimizing utility contributions to climate change. This report should be prepared for Commission consideration by XX, 2005.

J. DWR contract allocation and reallocation (Sunrise)

The June 4, 2004, ACR/Scoping Memo provided the IOUs with conventions for DWR contract allocation and reallocation to be used in their modeling. The ACR asked the utilities to assume that the new DWR contracts, Kings River and CCS, be allocated to PG&E as proposed by DWR, and Sunrise allocation remain as is with SDG&E.

PG&E presented no DWR issue in this proceeding. SDG&E, although its position is that the DWR Sunrise contract should be reallocated to PG&E, conformed with the directions from the ACR and included Sunrise in its resource portfolio. SCE had no issue concerning DWR contracts for this proceeding.

There is another proceeding, A.00-11-035, that is addressing the subject of cost allocation of DWR contracts. Therefore, except for including DWR contracts in the utilities' resource portfolios, there is no DWR contract issue.

Therefore the arguments presented by SDG&E that keeping Sunrise in its plan reduces its option to address local reliability issues because Sunrise is outside the territory, provides no benefit to local reliability and leaves the utility with no "headroom" to add a local resource till the contract expires in 2010, and ORA's proposal that SCE contract with SDG&E for dispatch rights for specific units under the DWR-Williams contract, will be addressed either in the next phase of RA, or in the DWR contract proceeding.

DWR requests that this decision clearly state that nothing in this decision makes changes to prior Commission decisions, particularly D.02-12-074, the IOU-DWR Servicing Agreements, or makes any changes in ratemaking treatment of the DWR contracts. We think DWR's request is reasonable and we adopt it until further Commission action on the subject.

1. Repowering:

WCP refers collectively to the limited liability companies that own and operate approximately 2,300 MW in Southern California. The facilities, Encina power plant, combustion turbines in the San Diego area, the El Segundo power plant and the Long Beach power plant are extant power plants that are often referred to as "aging" power plants. WCP urges the Commission to recognize the crucial role of these aging power plants in the electric system and recommend the Commission recognize and respond to the threat of aging power plants retiring before they can be replaced with new capacity. WCP suggests the following:

> Short term: Continue to use RMR contracts
>
> Mid term: The Commission must ensure that the IOUs enter into multi-year local reliability contracts with power plants in key locations. This would include contracts with three to five year terms, directing the IOUs to revise their resource plans to show how congestion and local reliability are considered in their procurement decisions. SDG&E should be required to conduct a comparison between the overall cost of its proposed new 500 kV line and the costs of new generation resources located at the site of existing generation in its service area, and to apply RA principles to load pockets.
>
> Long term: The Commission should recognize the benefits of siting new generation at the existing sites of aging power plants and adopt a policy to promote construction of new generation units at brownfield sites rather than green field sites.

WPC also urges the Commission to establish a capacity market.

SCE disagrees with WCP's position that brownfield sites should receive priority over other options. SCE points that WCP's position is self-serving and that majority of parties, including ORA agree with SCE. SCE argues that the benefits of brownfield sites such as proximity of existing sites to the load center, access to transmission lines and natural gas infrastructure, possession of permits required for operation, possession of rights to water and others are already accounted in SCE' selection of best fit/least cost resources. SCE notes that these advantages benefit the developer by substantially reducing the cost of the project and increasing the competitiveness of the brownfield over the greenfield sites. In SCE's opinion these plants should not be favored over new generation if they cannot compete cost-effectively with new generation.

Instead, SCE suggests that these aging power plants enter into RMR contracts, which limit the market power of such plants, sell into the spot market, or enter into short term contracts. SCE also notes the risk of entering into contracts with sub-investment grade companies such as Dynegy or NRG (WCP's owner). SCE argues that the least cost/best fit as the overarching principle of procurement for providing the best value to its customers.

Dynegy advocates continued availability of existing capacity pending implementation of RA, CAIS market design and the creation of a supporting capacity market structure.

K. Long-Term Planning in the Next Procurement Cycle

D.04-01-050 determined that in future cycles of the procurement process, we would link our timing to that of the CEC’s Integrated Energy Policy Report. Since that proceeding operates on a biennial calendar, by stature, that means that the next long-term procurement proceeding will be in 2006. D.04-01-050 also linked the substance of the analyses we direct IOUs to file with the results of the

CEC's IEPR information and analyses. In the past two years, the CEC and this Commission are collaborating to a much greater degree than ever before, and as evidence the CEC is not a party to this proceeding and its staff is assisting our own in review of IOU LTPPs and in developing resource adequacy procedures.

On September 16, 2004, President Peevey issued an Assigned Commissioner Ruling addressing further integration between the CEC's IEPR and our next procurement proceeding. That ACR suggested a specific type of coordination between the 2005 IEPR and the 2006 procurement proceeding. In essence, the CEC's IEPR would review IOU load forecasts, conduct a resource assessment and identify the range of need for new resource additions addressing significant uncertainties for each IOU. Our 2006 procurement proceeding would not relitigate those results, except in those cases where there is new information that was not available to be considered in the CEC's proceeding, and our 2006 procurement proceeding would address IOU resource procurement proposals and strategies in light of the range of need identified in the 2005 IEPR. We will also consider how CEC statewide policy recommendations may be translated into IOU-specific directives, given the circumstances of each IOU. A more specific enumeration of proposed relationships between this Commission, the CEC, and the CAISO is attached as Appendix B.

We endorse the coordination agreement and the direction to IOUs stated in the September 16, 2004 ACR. We direct IOUs to participate in the CEC IEPR proceeding as the one forum in which long-term load forecasts, resource assessments, and need determinations will be considered. We believe Appendix A constitutes a good foundation for coordinated proceedings and the minimization of duplication between various planning proceedings. We direct staff to work with the CEC and CAISO to effectuate this agreement in a complete and practical manner.

Commission provide equivalent assurance for cost recovery of turnkey projects as it had for other procurement resources.

In the LTPP proceeding SDG&E proposes a three-phase cost recovery framework for turnkey project cost recovery that starts with the filing for Commission approval of the project. In that filing, SDG&E will identify the rate-base and O&M-related revenue requirements associated with the project for the first full calendar year of operation of the generation plant. SDG&E proposed to record costs associate with the turnkey plants to its Non-Fuel Generation Balancing Account (NGBA) and Energy Resource Recovery Account (EERA) for recovery through SDG&E commodity rates. Under SDG&E's proposal, the Commission will adopt the annual revenue requirement of the applicable turnkey plant simultaneously with approval of the project. Prior to the operation of the turnkey generation unit, SDG&E will file an advice letter to incorporate any adjustments to the adopted revenue requirement.

The second phase of the framework covers the period from the end of the initial phase until the implementation of SDG&E's next Cost of Service (COS) decision to allow for annual attrition adjustments to the authorized revenue requirement.

The third phase, SDG&E's revenue will be trued up to reflect the costs of these projects.

PG&E requests that the Commission provide timely cost recovery of utility owned generation when the facility starts serving utility customers, whether PG&E operates the plant itself or when it contracts with a third party to operate it. Under PG&E's proposal, PG&E would include the initial capital cost of the acquisition in its request for approval of the contract.

UCAN opposes SDG&E's proposal for cost recovery and argues that the Commission sets revenue requirements in the General Rate Case (GRC) and should not allocate separate revenue requirements for each asset owned by the utility in a non-GRC proceeding.

We find SDG&E's mechanism reasonable and adopt it for all three IOUs. In the next few years, IOUs could add extensive new generation to their resource portfolios in order to meet their future resource needs. We believe a rate making mechanism needs to be in place to ensure proper and timely cost recovery for these facilities. Two issues need to be decided; the timing and the scope of the cost recovery. First, we determine the appropriate timing of the rate recovery. Both SDG&E and PG&E propose to start cost recovery when the new facility starts operation to serve utility customers. We agree and adopt this proposal.

Second, we adopt SDG&E's proposal for cost recovery. SDG&E proposes to establish rate-base and O&M-related revenue requirements associated with the generation plant and to use its Non-Fuel Generation Balancing Account

(NGBA) and Energy Resource Recovery Account (EERA) to record costs associate with the turnkey plants and for recovery through SDG&E commodity rates. PG&E, however, proposes differently. In addition to the costs listed above, PG&E proposes that in some cases, it may be necessary to request recovery for "financial burden associated with acquisition of utility-owned generation."[126] In PG&E's opinion, these costs may include planning and administrative costs of preparing for the construction or acquisition of the generation facilities, financing costs as incurred, and costs if the project is ultimately abandoned. We believe that some of these costs or risks will be considered in our review and evaluation of IOU contracts for turnkey projects and some will be considered as part of establishing the revenue requirement for these facilities. For example, we expect contracts for turn key projects address provisions and penalties for project abandonment. As such these types of costs should not receive special recovery treatment. We reject PG&E's proposal in this respect.

L. Other Procurement Issues

1. Resource Adequacy Issues Not Addressed in the Resource Adequacy Decision

As briefly discussed in Section A.2, the RA decision, D.04-10-035, accelerated the target date to June 1, 2006, for the IOUs to acquire their reserve margins of 15-17% as established in D.04-01-050. Comments on the PD in the RA decision were circulating concurrently with the post-hearing briefs in the LTPP portion of this proceeding. Numerous parties raised the same issues in the post-hearing briefs as well as in their comments to the RA PD. In particular, parties

[126] PG&E's prepared Testimony, Page 2-38.

weighed in on the creation of a multi-year forward commitment obligation. This topic is clearly specific to the RA decision since it is related to the design features of that program and it is appropriate to visit it in Phase II of RA.

Another area of possible policy conflict between RA and procurement is the treatment of resource acquisitions over 17%. D.04-01-050 established the reserve margin requirement of 15-17%, and D.04-10-035 accelerates the due date, but does not change the 15-17%. Some parties interpret the RA range to mean that 15% is desirable and up to 17% can be acceptable temporarily due to lumpiness issues. Others view 16%, the average of 15-17%, as being the target. Still others argue that only acquisitions over 17% should raise any issue of penalties or disapproval. Since the RA phase is designed to handle the reserve margin issues we will not rewrite D.04-01-050 in this decision. If parties want further clarification on the interpretation of the 15-17% requirement they should bring it up in Phase II of the RA portion of this docket. This LTPP decision is not intended to change or modify any aspect of D.04-10-035. Any clarifications, alterations or augmentations to D.04-10-035 will be deferred to Phase II of the RA aspect and not addressed here.

2. Local Reliability as Part of the Procurement Process

D.04-07-028, issued in July 2004, established temporary local reliability requirements. Parties presented a full spectrum of viewpoints on this topic in their post-hearing briefs from deferring procurement until requirements are actually established, to wanting the IOUs to procure now. While we expect RA Phase II to resolve local reliability issues, in the interim we extend the requirements of D.04-07-028. In particular, the policy requirements of D.04-07-028 and any implementation procedures should be handled by IOUs filing

Advice Letters until local reliability is resolved in RA Phase II, or by other action of this Commission.

SDG&E is a unique case among the three IOUs in that within service area resource additions almost certainly will provide local reliability benefits, unlike SCE or PG&E. We therefore direct SDG&E to pursue the EAP loading order priorities when it makes resource additions.

3. Bottom-up Planning

Prior to the restructuring of the electric utility industry in California, the utilities were actively involved in integrated resource planning. With the passage of AB1890 and the restructuring of the industry, the utilities moved away from active involvement in resource planning and became merchants of power on behalf of their customers. Since the California energy crisis, the pendulum has begun to move back in the other direction again. The utilities are more actively involved in developing as well as contracting for the resources required to serve their customers. Naturally, this has led to renewed interest in making sure that the choices reflect the best trade-offs among the uses of society's limited resources.

In the January Policy Decision (D.04-01-050) we stated that by relying on a bottom-up approach to system planning, "[t]he Commission and utilities would be able to ensure that state policies are implemented in a manner designed to contain cost while achieving other goals. Such a process is not merely consistent with the state's broader policy goals – it will help sustain them."[127] That decision discussed integrated resource planning to provide a comprehensive context for

[127] D.04-01-050, p. 97.

all of a utility's resource decisions. The Assigned Commissioner's Ruling and Scoping Memo in the current proceeding requested that the topic of bottom-up planning be included in the utilities' long-term plans.[128] All three utilities included discussions of bottom-up planning in their long-term plans as requested.

PG&E notes that it has followed the Commission's direction regarding planning, including following the Loading Order, which was developed since the last long-term plans were filed. PG&E states in its LT procurement plan that it has integrated the results of the CAISO-sponsored annual Assessment Studies and Electric Transmission Expansion Plan process into its integrated resource planning. The LT plan describes the processes underlying its adoption. PG&E will compare the most promising identified generation or demand response alternatives with the Commission-approved plan, and it will examine the planning level costs of all transmission, generation, and demand response alternatives. PG&E asserts that its account services representatives have historically looked at the individual needs of customers, practicing local planning at the lowest level, and will do so even more in the future as the Company acquires an increased portfolio of energy efficiency, demand response, and distributed generation resources.

SCE's LT procurement plan described the annual planning process it uses to identify projects necessary to serve new load added to the Company's transmission and distribution system. Edison begins with development of 10-year peak-load forecasts for each substation in the SCE distribution system. They

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[128] OIR 04-03-003, Assigned Commissioner's Ruling and Scoping Memo, June 4, 2004, p. 7.

are developed using a bottom-up approach which takes advantage of the Company's regional engineers' knowledge of the local areas. Those substation-level forecasts are then compared to, and reconciled with, system demand forecasts developed using a top-down approach. Identification of system requirements requires technical studies performed as part of the load-growth planning process, which determines whether expected growth can be accommodated through the existing distribution system, or what kinds of projects are required to bring the system back to within specified loading limits. Development and evaluation of alternatives identifies alternatives for correcting any projected system deficiency. Finally, selection, approval and budgeting results in identification of the best combination of system performance, reliability, operational flexibility, and cost to select a preferred plan from among the alternatives.

SDG&E states that because its entire service territory constitutes a single load pocket, the solutions offered for the service territory in total are identical to those envisioned by the Commission in its discussion of bottom-up planning. SDG&E has been an active participant in numerous regional planning and energy policy forums, as well as discussions with customers and other stakeholders, and has used any gained insights in its planning process. This approach includes, but is not limited to, working with the City of San Diego to assist in meeting the goal of installing 50 MW of renewable resources by 2013 and finding ways to promote further development of, and explore possible future sites for, solar facilities in the San Diego region.

The three utilities have presented information on the processes they undertake to develop bottom-up forecasts of their needs and of the plans to deal with those needs. We are satisfied that the utilities are seriously following our direction and taking into account the needs of local areas within their service areas in developing their plans.

4. Long-Term Planning in the Next Procurement Cycle

D.04-01-050 determined that in future cycles of the procurement process, we would link our timing to that of the CEC's Integrated Energy Policy Report. Since that proceeding operates on a biennial calendar, by stature, that means that the next long-term procurement proceeding will be in 2006. D.04-01-050 also linked the substance of the analyses we direct IOUs to file with the results of the CEC's IEPR information and analyses. In the past two years, the CEC and this Commission are collaborating to a much greater degree than ever before, and as evidence the CEC is not a party to this proceeding and its staff is assisting our own in review of IOU LTPPs and in developing resource adequacy procedures.

On September 16, 2004, President Peevey issued an Assigned Commissioner Ruling addressing further integration between the CEC's IEPR and our next procurement proceeding. That ACR suggested a specific type of coordination between the 2005 IEPR and the 2006 procurement proceeding. In essence, the CEC's IEPR would review IOU load forecasts, conduct a resource assessment and identify the range of need for new resource additions addressing significant uncertainties for each IOU. Our 2006 procurement proceeding would not relitigate those results, except in those cases where there is new information that was not available to be considered in the CEC's proceeding, and our 2006 procurement proceeding would address IOU resource procurement proposals and strategies in light of the range of need identified in the 2005 IEPR. We will also consider how CEC statewide policy recommendations may be translated into IOU-specific directives, given the circumstances of each IOU. A more specific enumeration of proposed relationships between this Commission, the CEC, and the CAISO is attached as Appendix B.

We endorse the coordination agreement and the direction to IOUs stated in the September 16, 2004 ACR. We direct IOUs to participate in the CEC IEPR proceeding as the one forum in which long-term load forecasts, resource assessments, and need determinations will be considered. We believe Appendix A constitutes a good foundation for coordinated proceedings and the minimization of duplication between various planning proceedings. We direct staff to work with the CEC and CAISO to effectuate this agreement in a complete and practical manner.

Commission provide equivalent assurance for cost recovery of turnkey projects as it had for other procurement resources.

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The third phase, SDG&E's revenue will be trued up to reflect the costs of these projects.

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Second, we adopt SDG&E's proposal for cost recovery. SDG&E proposes to establish rate-base and O&M-related revenue requirements associated with the generation plant and to use its Non-Fuel Generation Balancing Account (NGBA) and Energy Resource Recovery Account (EERA) to record costs associate with the turnkey plants and for recovery through SDG&E commodity rates. PG&E, however, proposes differently. In addition to the costs listed above, PG&E proposes that in some cases, it may be necessary to request recovery for "financial burden associated with acquisition of utility-owned generation."[129] In PG&E's opinion, these costs may include planning and administrative costs of preparing for the construction or acquisition of the generation facilities, financing costs as incurred, and costs if the project is ultimately abandoned. We believe that some of these costs or risks will be considered in our review and evaluation of IOU contracts for turnkey projects and some will be considered as part of establishing the revenue requirement for these facilities. For example, we expect contracts for turn key projects address provisions and penalties for project abandonment. As such these types of costs should not receive special recovery treatment. We reject PG&E's proposal in this respect.

5. Utility filings demonstrating compliance

In prior Commission decisions issued in R.01-01-024, we established the following filing requirements:

Filing	**Decision**	**Function**
Monthly ERRA Report	D.02-12-074 (OP 19)	Shows the activity in the ERRA balancing account with copies of original source documents supporting each entry over $100.00 recorded in the account.
Monthly Portfolio Risk Report	D.03-12-062 (OP 2 and 4)	Informs the Energy Division on the risk exposure of the IOU's

[129] PG&E's prepared Testimony, Page 2-38.

Filing	**Decision**	**Function**
		procurement portfolio.
Quarterly Transaction Report	D.02-10-062 (OP 8)	Tracks procurement transactions and shows that they comply with the approved procurement plan.
Semiannual ERRA Application	D.02-10-062 D.02-12-074 D.04-01-050	Sets electric energy procurement forecast rate. Enacts trigger, if met. Reviews contract administration and least-cost dispatch.
Short-Term Procurement Plan (STPP)	D.02-12-074 D.03-12-062	Addresses the procurement products, processes, risk management strategy and tools
Gas Supply Plan (GSP)	D.03-04-029 (OP 6)	
Long-Term Procurement Plan	D.04-01-050	

PG&E requests that the Commission streamline the review of procurement costs through quarterly transaction reports and ERRA proceedings. PG&E states that "by expediting the process for verifying that utility transactions are consistent with adopted procurement plans, the Commission can confirm the transactions are in compliance and eliminate any second-guessing during ERRA compliance reviews. The Commission should require that the reviews be completed on time and the scope should be limited to review of the transaction identified by the independent auditor."

PG&E proposes the following: (1) Issue an omnibus resolution approving all unprotected, unresolved, quarterly procurement transaction advice letters as submitted, and (2) focus on truing up forecasted expenses to actuals in the ERRA compliance review proceeding and review the tractions identified in the quarterly transaction review process that are noncompliant with the procurement plan.

SDG&E recommends that the semiannual Gas Supply Plans be consolidated into the ERRA/STPP process, "as gas is an integral part of least-cost dispatch and short-term procurement planning and consolidation would eliminate redundancy, thus easing the resource constraints for both the Commission and SDG&E." (McClenehan Opening Testimony, p.12) Furthermore, SDG&E proposes that advice letter updates to the forecasts contained in the plan be filed in conjunction with each utility's ERRA forecast and that authorization would be for a rolling five years. SDG&E also recommends that gas supply plans be consolidated into the ERRA/short term procurement plan process.

SCE suggests that the AB 57 plans need not be updated on an annual basis, and not in the ERRA proceeding. Instead, AB57 can be updated as needed, e.g. if there were changes in the LTPP that required it.

DWR opposes SDG&E's recommendation that the Commission consolidate the review and approval of gas supply plans into the ERRA proceedings, stating that the recommendation is not consistent with the contractual obligations of SDG&E under its current Operating Agreement with DWR. (Memo, p.3)

ORA recommends annual reviews of procurement plans in ERRA proceedings.

We continue the Monthly ERRA Report and Monthly Portfolio Risk Report. In regards to the Quarterly Transaction Report, the IOUs are ordered to file a joint proposal to reformat the report in a way that will provide the Commission concise and coherent information, thereby streamlining the review process. The objective of the report is to show that the transactions entered into are in compliance with the upfront standards identified by the Commission. These reports will be reviewed by the ED staff. If there are no protests and the staff concludes that the transaction entered into in that quarter comply with the utility's procurement plan, then by the Commission's Expressed Delegation of Authority, the ED Director can approve the reports. However, if there are substantive protests and the staff takes issue with certain transactions, the staff will issue a draft resolution for the Commission's approval.

We find that no change is necessary at this time for the Semiannual ERRA Application. As for the Short-Term Procurement Plan, the 2006 Long-Term Procurement Plans will contain the features of the Short-Term Plans that are not covered by the proposed 2004 LTPPs. That is, ultimately, we will eliminate the STPPs and the IOUs will act in accordance with a single Commission-approved plan. Until then, the existing STPPs will be in effect. Updates or modifications to the plans in between the biennial review will be filed with an advice letter. Any updates to the existing STPPs should be filed with an Advice Letter 30 days after the issuance of this decision.

In regards to the Gas Supply Plans and the biennial LTPPs, we find no change is necessary at this time.

M. Collateral Requirements

As part of its regular operation in a hybrid energy market, SCE periodically contracts with numerous counterparties for various electric and natural gas products. Counterparties require SCE to post collateral in the form of "cash or letters of credit if their exposure to SCE exceeds a predetermined negotiated limit (the Unsecured Credit Limit). According to SCE's long-term plan:

> "The requirement to provide collateral stems from a contracting counterparty's concerns that SCE will be unable to meet its obligations under the contract. These counterparties may be either physical buyers of SCE's excess energy or sellers of energy, capacity, or natural gas to SCE. SCE may also enter into financial transactions which act to hedge ratepayers' exposure to future market price movements.[130] In each case, the transaction counterparties will attempt to minimize their risk by requiring SCE to post cash or letters of credit if their exposure to SCE exceeds a predetermined negotiated limit (the Unsecured Credit Limit)." (SCE Long-Term Plan, Vol.1, July 9, 2004, p.28)

SCE states that its currently "authorized procurement plan includes sufficient collateral capacity for the near term. However, SCE's ability to stay within the current Commission authorized collateral limit will depend heavily upon the length of new contracts signed to meet resource needs" (*Id.*, p.31). SCE has stated its intent "to file an update to its STPP procurement plan within 30 days of the Commission's long-term procurement decision to conform it to Commission policies. If an increase to SCE's collateral capacity is required to carry out the revised plan, SCE will provide updated collateral estimates as part of this filing" (Opening Brief, p.131). No party has taken issue with SCE on this issue. Accordingly, we accept SCE's stated approach.

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[130] While not all financial hedges will result in collateral requirements, transactions such as financial futures or swaps will result in mark-to-market exposures similar to physical contracts.

We also note here that SCE can, and does, require counterparties to make similar collateral postings aimed at ensuring contract performance under changing market conditions. Calpine asks the "Commission [to] be sensitive to the fact that credit requirements can be used to either (i) squelch competition through onerous credit requirements; or (ii) to impose on ratepayers the costs associated with a zero risk tolerance" (Calpine Direct Testimony, p.18-19). Calpine warns that if "overcollateralized, project sponsors will be placed at a competitive disadvantage … [and that these] excessive credit requirements will be passed on to ratepayers through higher prices" (*Id.*, p.19). We are not aware of any specific claims of over-collateralization or associated recommendations.

1. New Accounting Rules

SCE has informed the Commission of two relatively new accounting rules promulgated by the Financial Accounting Standards Board (FASB) "that, like the debt equivalence issue, may affect electric utilities' costs of contracting for power" (SCE Long-Term Plan, Vol.1, July 9, 2004, p.47-50). One rule would require "utilities to include certain long-term contracts as liabilities on their balance sheets by deeming them capital leases,"[131] and the other rule (FASB interpretation) "could impose additional balance sheet impacts on utilities signing long-term contracts"[132] (*Id.*, p.47).

According to SCE, "a capital lease requires a utility to book the plant as an asset (similar to the accounting treatment for a utility-owned plant), and to

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[131] EITF Issue 01-08, "Determining Whether an Arrangement Contains a Lease," May 15, 2003, effective for new or revised power contracts entered into after June 30, 2003.

[132] FASB Interpretation No. 46 (revised December 2003) "Consolidation of Variable Interest Entities—an interpretation of ARB No. 51."

record the present value of the expected lease payments as long-term debt on its balance sheet." (*Id.*, p.49). The second rule may require SCE "to consolidate [certain counterparties in its balance sheet] for financial reporting purposes" (*Id.*, p.50). SCE has not requested any specific relief related to these new accounting rules.

We observe here that consideration of such accounting rules may have been more appropriate in the Cost of Capital proceeding. Since SCE contends that these new accounting rules are somewhat similar in effect to debt equivalence, SCE may seek further guidance from the Commission when appropriate in the same manner as set forth in the Cost of Capital proceeding.

XXI. Confidentiality

Consistent with the Commission's direction in D, 04-01-050, it is our intention that many more categories of planning information will be open and will be considered so in our review of the IOU's LTPPs. We have yet to determine if any information that routinely was considered confidential under former protocols might be deemed public when this decision is issued in final. We are still trying to balance the competing interests of the need of some confidentiality of IOU data to protect ratepayers, against the public interest in disclosure and the desire of intervenors to have better access to IOU confidential data to more fully participate in Commission proceedings. While we favor "open decision-making" we need to be pragmatic about mitigating any adverse ratepayer consequences.

Since this OIR issued, the Legislature passed, and the Governor signed, Senate Bill (SB) 1488[133] that directs the Commission to "initiate a proceeding to examine its current confidentiality rules under Pub. Util. Code Sections 454.5 and 583 and the California Public Records Act[134] to ensure that the Commission's practices under these laws provide for meaningful public participation and open decision making."

Currently under AB57, that added Section 454.5 to the Pub. Util. Code, the Commission is to have in place procedures that ensure the confidentiality of any market sensitive information submitted by an IOU as part of its proposed procurement plan, while ORA and other consumer groups that are not market participants (NMPP) access to the information under confidentiality provisions. This provision of AB57 was an attempt to balance the compelling ratepayer interest in ensuring that certain legitimately confidential information is kept out of the hands of those who can use it to manipulate wholesale energy markets, with promoting a sufficiently transparent decision-making process to allow for scrutiny and review by the legislature and the public.

Working from AB57 and the additions to the Pub. Util. Code, when the Commission initiated R.01-10-024 on October 25, 2001, to establish policies and cost recovery mechanisms for generation procurement and renewable resource development, the assigned ALJ issued a ruling establishing a Revised Protective Order on May 1, 2002. That protective order remained in place throughout 2002.

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133 SBl488, (stats.2004,Ch.690, Effective September 22, 2004).

134 Chapter 3.5(commencing with Section 6250) of Division 7 of Title 1 of the Government Code.

In early 2003, the ALJ reopened the issue in response to concerns that certain market participants and other entities did not have adequate access to information under the existing protective order. A revised ALJ ruling issued on April 4, 2003 [joint Walwyn/Allen ALJ ruling] allowing the CAISO, and other NMPP access to the same confidential information the consumer groups had with the direction that they must treat protected materials as confidential vis-à-vis third parties.

Following a request from SDG&E to amend the April 4, 2003, ALJ ruling to protect information submitted by parties to a RFP, the ALJ issued a ruling on December 1, 2003, amending the previous protective order allowing certain bid information to remain confidential, but also soliciting comments on a further modification to the protective order to incorporate a provision allowing outside attorneys and/or consultants to a MP who do not perform competitive duties for or on behalf of their client, and who execute a Non-Disclosure Certificate, to have access to materials relevant to the SDG&E RFP. Parties were directed to draft a Protective Order that paralleled language from an Amended Protective Order adopted by a FERC judge.[135] On January 14, 2004, following the receipt of comments on the FERC model, the ALJ issued a ruling adopting an Amended Protective Order that was substantially consistent with the FERC orders and that allowed the MPs access to Protected Materials following the FERC guidelines. As referenced earlier in this decision, this Amended Protective Order controlled confidentiality issues in this current procurement proceeding.

[135] FERC Docket Nos. EL02-60-003 and EL02-62-003. See footnote 16.

In preparation for review of the IOUs' LTPPs in this proceeding, in D.04-01-050 the Commission expressed its desire to move towards more open and transparent decision making and asked the parties to submit comments on how to allow more access to utility data, but not at the expense of the ratepayer/consumer. Comments were received on March 1, 2004, and in summary, PG&E, SCE and SDG&E argued against increased disclosure, ORA/TURN favored more public disclosure and offered some guidelines, and the MPs were the most forceful in arguing for an open, transparent and competitive process. By that time SB1488 was already in committee, so instead of issuing a new iteration of the January 14, 2004, Amended Protective Order we followed the guidelines implemented therein for this procurement proceeding.

We recognize our SB 1488 obligations and forthwith we will initiate a Rulemaking to fulfill our obligations under SB1488. For purposes of this decision and our review of the IOUs LTPPs, we believe intervenors, including MPs, had sufficient access to the IOUs' background data and assumptions, if they chose to follow the guidelines of the January 14, 2004 Amended Protective Order to allow for a robust EH and development of the record to satisfy us that there was a full vetting of the important issues.

We also note that more intervenors, in particular the environmental groups, had access to the IOUs confidential data since they signed on to the Amended Protective Order. So in addition to the consumer groups, other NMPP also had the benefit of reviewing all the utility data. None of the MPs chose to sign on to the Amended Protective Order. As a point of interest, the utilities and the MPs may have reached a point of equilibrium in that if the MPs had more access to utility information, the utilities may have demanded equal access to MP information.

A. Standard Offer Service

Constellation Power Source (CPS) proposes a slice of load utility procurement mechanism to provide "standard offer service" (SOS). It is a wholesale power procurement approach whereby a jurisdictional public utility secures all or a portion of the generation supply to meet its retail load through a multi-year wholesale service contract or contracts with a third-party provider or providers. CPS envisions that SOS would be procured through a competitive bid process approved by the Commission in advance and conducted with Commission oversight. Winning bidders would enter wholesale service supply contracts with the utility. The utility, in turn, would provide the ultimate retail service to its customers in fulfillment of its obligation to serve. CPS explains that this service can be contrasted with the traditional procurement approach. In traditional service, utilities secure quantities of capacity or energy to serve loads subject to subsequent prudence reviews by regulators, while the SOS procurement approach uses a competitive solicitation process to secure generation service related to some percentage, or "slice" of the utility's load, which will vary in quantity from time to time.

According to CPS, there are advantages to the utilities from SOS. It can transfer risks associated with load migration away from the utility to the wholesale supplier, removing the potential for new stranded costs or the need to impose new nonbypassable charges. It transfers some price risk and performance risk to the SOS provider. It promotes a diversity of suppliers and market entrance points, creating a portfolio of supply arrangements.

CPS states that some form of the SOS approach is currently used in Maryland, New Jersey, Maine, Massachusetts, Connecticut, and New Hampshire. And since the close of the record in this case, the District of

Columbia has adopted a SOS procurement mechanism modeled after Maryland's approach.

Standard Offer Service, while an interesting idea for certain types of market conditions and direct-access service systems, is not appropriate for California, at least at this time and under current conditions. At the present time, direct access is under suspension, and there is no competition to be promoted for slices of customer load. The eastern precedents, therefore, are not relevant to the California retail electric service system. Moreover, it is not clear that the proposal, which is very complex, would result in lower costs to consumers or that it would contribute to a more competitive wholesale supply system. Therefore, we reject the CPS slice-of-load proposal at this time.

Findings of Fact

1. The purpose of this decision is to give the three IOUs authorization to plan for and procure the resources necessary to provide reliable service to their customer loads for the planning period 2004 through 2014.

2. This decision must work in concert to coordinate and incorporate Commission and legislative efforts from other proceedings, in particular: Community Choice Aggregation (CCA), Demand Response (DR), Distributed Generation (DG), Energy Efficiency (EE), Avoided Cost and Long-term Policy for Expiring Qualifying Facility (QF) Contracts, Renewables Portfolio Standard (RPS), Transmission Assessment and Transmission Planning. This decision must also incorporate the Commission's direction, articulated in D.04-10-035, the Resource Adequacy (RA) decision in this docket.

3. Since the EAP was adopted, we have directed the utilities to prioritize their resource procurements following the loading order of preferred resources established in the EAP. The EAP's loading order framework identifies certain

demand-side resources as preferred because they work towards optimizing energy conservation and resource efficiency while reducing per capita demand, as well as certain preferred supply-side resources. The EAP loading order is: energy efficiency (EE), demand response (DR), renewables, distributed generation (DG) and other resource additions—with an emphasis on "clean" fossil-fueled generation.

4. After existing resources and policy preferred resources have been compared to load and necessary reserves, the result is the amount of energy and capacity which a Load Serving Entity must still acquire. This is called either "need" or the "net open" position, sometimes subdivided into "net short" and "net long." Actual forecasts of net open capacity and energy were contained in confidential filings, so discussion in the testimony and hearings is both limited and general.

5. The Assigned Commissioner appropriately directed the IOUs to file LTPPs based on 3 scenarios:

a) The medium-load plan is the preferred resource plan of each utility that meets the needs identified in its Alternative Base Case load-forecast scenario or, if the utility does not choose to file an Alternative Base Case load-forecast scenario, its IEPR-CEC base case scenario;

b) The high-load plan is a reasonable guess at how great the burden of service could become under high, but not unreasonable assumptions about future load growth, and should be based on the assumption of greater than expected economic growth, resulting in higher load growth, assumption of a modest core-noncore load loss and a modest development of CCA beginning in 2009, and assuming that current levels of DA will continue throughout the time horizon; and

6. The Low-Load Plan is based on reasonable but pessimistic assumptions about the economy and assumes aggressive CCA development beginning in 2006, and an aggressive core-noncore scenario, as well as the continuation of DA service at current levels. The purpose of the three resource scenarios is to assist the Commission in understanding how each utility intends to respond to a wide range of load scenarios; the focus is not on forecasts, but on the adoption of long-term plans that can accommodate many outcomes.

7. Although all three IOUs relied on different assumptions in modeling their medium case and in setting floors and ceilings for the high and low scenarios, for the most part the three LTPPs complied with the resource scenario request. The differing assumptions made cross-utility comparisons difficult, but each LTPP taken on its own provided a reasonable range of scenarios as boundaries of risk.

8. The "service area" or "reference" medium forecasts presented by the IOUs in their LTPPs indicate reasonable growth trends and levels. The utilities use

similar growth factors and are generally consistent with the IEPR forecast trends, except the levels are higher because they are updated from a 2001 baseline to a 2003 baseline. This update reflects the unanticipated economy recovery in 2002 and 2003 that was not reflected in the IEPR forecast.

9. Since CCA has been set in statute and is the subject of an on-going CPUC implementation proceeding, it is reasonable to assume that some CCA will start to occur in 2006. There was not sufficient evidence in this proceeding to prove that CCA alone will have a material effect on IOU resource needs in the next few years.

10. A major issue in this proceeding is the extent to which the utilities will be compensated for investments or purchases that they must make in order to meet their obligations to provide reliable service to their customers. The implementation of CCA, departing municipal load, and the potential for lifting, in some form or another, the current ban on allowing new direct access, all create uncertainty as to the amount of load the existing utilities will be responsible for serving in the future.

11. Existing resource planning uses average weather (1-in-2) and then adds a reserve margin which, in part, provides the cushion should hotter than average weather occur. This is the approach we adopted to implement our resource adequacy requirements and should also be applied here.

12. We provide guidance on resource planning based on the EAP and current circumstances, but only market-tested bids will actually produce a portfolio of specific resources. In this setting, planning is largely indicative, not deterministic.

13. Approving a mixed portfolio of different contract terms and lengths will help to ensure that the utilities will not over-subscribe to long-term contracts that will crowd out future opportunities.

14. All three IOUs have capacity needs throughout the planning horizon. Capacity needs expand considerably in 2011, due to the expiration of most of the DWR contracts. All three IOUs are long on energy, primarily in the off-peak and shoulder hours, through 2009 (PG&E) and 2010 (SCE and SDG&E) until the bulk of DWR contracts expire. Because resources are 'lumpy', adding preferred resources upon existing resources somewhat exacerbates this long position, requiring utilities to be energy sellers in many off-peak and shoulder hours.

15. The impact of these decisions is to reduce the amount of capacity needed in the 2010 medium case scenarios by 800 MW for PG&E and 1,500 MW for SCE, while increasing SDG&E's resources above the minimum reserve margin by 280 MWs. (Note from Ang – are we really saying this?? See p. 31 w/ ?)

16. We must balance grid reliability with our other primary public duty of protecting ratepayers from excessive charges and also be mindful of potential departing loads and stranded costs.

17. The IOUs complied sufficiently with Commission direction in preparing their resource scenarios so we will not require the preparation and resubmission of LTPPs at this time. Any deficiencies in the LTPPs can be addressed by requesting updates as the Commission gives new direction or clarification in other resource/procurement proceedings and can direct us in giving guidance for the next LTPP proceeding.

18. Because there is no way to predict the energy demand/supply situation with any certainty, especially in the face of changing load situations, the IOUs should include a mix of resources, fuel types, contract terms and types, with

some baseload, peaking, shaping and intermediate capacity, with a healthy margin of built-in flexibility and sufficient resource adequacy in their procurement portfolios.

19. The IOUs must have sufficient flexibility in their plans to procure resources as directed by the Commission in the areas of EE, DR, DG, renewables, and soon QFs. The IOUs must balance expiring DWR contracts with meeting required targets in EE, DR and renewable generation.

20. Generation and demand-side commitments with start dates after 2010 may be deferred until the next procurement cycle. The winding-down of DWR contracts will materially affect the magnitude and nature of choices available, and we will be able to take advantage of two years experience in implementing policy-preferred resources.

21. We find that PG&E's LTPP plan is reasonable and we approve PG&E's strategy of adding 1,200 MW of reserve capacity and new peaking generation in 2008 and an additional 1,000 MW of new peaking and dispatchable generation in 2010 through RFOs because it is compatible with PG&E's medium resource needs, does not crowd out policy-preferred resources, and is a reasonable level of commitment given load uncertainty. Those commitments may need to be increased or expedited for PG&E to meet its 2006 resource adequacy obligations. (Doesn't this conflict w/ p. 31 and FOF 18) Depending on the nature of the bids obtained, PG&E is authorized to justify to the Commission why higher levels might be desirable. Nothing in this decision precludes PG&E from offering local reliability contracts, should they become necessary, pursuant to D.04-10-035.

22. We find that SCE's LTPP resource plan is reasonable, subject to the compliance requirements covering its demand forecast, demand response, energy efficiency, QFs, and other factors set forth in this decision and other

Commission decisions in those designated proceedings. SCE has demonstrated that its primary residual resource need through 2011 is for peaking, dispatchable and shaping resources. SCE has considerable need for peaking and shaping resources, which should be obtained through a short, medium- and long-term acquisitions. SCE's strategy of relying primarily on short- and mid-term contracts during this planning period is reasonable, but it may be prudent to add some long-term resources. SCE is authorized to present such a case to the Commission as an implementation of its LTPP by way of an application following a RFP.

23. SDG&E's resource scenarios were the most complete and useful in understanding the impact of differing loads, risk strategies, and the complex process of compiling a portfolio that meets reliability, adequacy, policy preferences and cost moderation goals.

24. We find that SDG&E's resource plan is reasonable, subject to the modifications required for the compliance filing described herein. SDG&E is essentially fully resourced through 2009, other than needed investments in renewable resources to meet RPS targets.

25. We find that the IOU filings comply with the direction provided in the EAP because they included the EAP targets established in the RPS, DR and EE proceedings; included, at a minimum, the DG forecasts in the 2003 IEPR, and added transmission and clean central-station generation to meet remaining energy and capacity needs.

26. We concur with the CA ISO that the transmission elements of the plans were insufficient to meet our goals and accept their recommendations that future plans should include conceptual scenarios that illustrate the impact of potential generator location.

27. When an IOU proposes a major transmission line, it should include a companion scenario without the line. Pursuant to the September 16, 2004 ACR issued in this proceeding, these resource scenarios will be examined in the Energy Commission's 2005 IEPR. To the extent an IOU believes that the range of need identified in the 2005 IEPR is sufficient to justify a transmission project then it may be identified as a specific proposal to satisfy need in the 2006 procurement proceeding filings. (MEB and Stephen should take a look at this)

28. To address the concerns that the IOUs gas price forecasts were too low, that forecasts can become obsolete over time, and that underlying assumptions for the forecasts can change, the utilities should update their forecasts as new market information becomes available or assumptions used for forecasts in LTPP change.

29. Potential community choice aggregators raised policy issues centered on how the IOUs should plan prospectively and judiciously for upcoming CCAs, or other departing loads, so that there would not be excess energy if, or when, the CCAs became fully functional and able to serve customers previously served by one of the IOUs.

30. The threshold policy issue underlying cost responsibility surcharges is to ensure that remaining bundled ratepayers remain indifferent to stranded costs left by the departing customers.

31. We will not determine a precise trigger point when an IOU can stop procuring for a CCA in this decision. Instead, we encourage cities and counties that are seriously considering CCA to approach their IOU and proactively consider strategies in which the two parties can share procurement risk going forward. Such strategies could include agreements between the IOU and CCA to allocate certain contracts to the CCA once it is formed, or the CCA could execute

a binding notice of intent with a commitment to a target date, at which the CCA is responsible for energy procurement. The agreement should incorporate some element of penalty if the CCA does not make the target date. We support parties working together to seek the most efficient transaction between the IOU and CCA.

32. Given the potential for a significant portion of the utilities' load to take service from a different provider, the utilities are concerned that they could end up over-procuring resources and incurring the stranded costs associated with these resources.

33. In D.04-01-050, we stated that a flexible utility portfolio, consisting of a mix of short-, mid- and long-term resources would be the best mechanism to protect against utility over-procurement. Since the issuance of that decision, we have made the utilities responsible for ensuring local reliability, accelerated the resource adequacy requirement from 2008 to 2006, and adopted RPS target goals resulting in the solicitation of new renewable energy sources by the utilities. These initiatives, combined with the existing overhang of utility retained generation and long-term DWR contracts significantly limit the flexibility that the utilities have to quickly adjust their resource portfolios. All of these resource additions benefit all existing customers by improving reliability and promoting renewable energy development.

34. We recognize a potential mismatch between the types of resources that the utilities need to procure (primarily peaking and load following) and the resources that departing customers require (primarily base load with a lesser amount of peaking/load following capability). Thus it may not be possible for the utility to develop a resource portfolio that accurately matches the load profile of expected departing load.

35. In general we agree that the utilities should be allowed to recover their net stranded costs from all customers, which may require the application of additional cost responsibility surcharges or other non-bypassable surcharges.

36. Providing for stranded cost recovery provides a greater incentive for the utilities to enter into longer (3 to 5 year) contracts for existing capacity that many parties advocate as the optimal approach to ensure the availability of these resources.

37. The utilities may need to enter into new contracts or construct new capacity to ensure that California has sufficient resources toward the latter years of this decade. In order for these resources to be on-line when needed, it may be necessary to begin construction of these projects in the very near term, since the record demonstrates that new construction would require a minimum ten-year contractual commitment. In the near-term, it appears that the utilities are the only entities capable of financing these projects.

38. New renewable projects, necessary for the achievement of the EAP and legislative goals, also require long-term commitments in the range of 10 to 20 years.

39. The utilities should be allowed to recover the net uneconomic costs of these commitments. Similar to the treatment of DWR energy commitments, the utilities should take appropriate steps to minimize the costs by selling excess energy and capacity needs into the marketplace. These other revenue sources include market sales, sales into the ISO's energy/ancillary services market, and potential sales into renewable energy credit, as well as capacity markets should they develop. All revenue sources should be credited against the utilities costs.

40. Capacity markets may mitigate stranded costs, but it is too speculative at this time, to approve capacity markets to offset stranded costs. In addition, there

is no guarantee that revenues from a capacity market would equal the utilities' costs.

41. Demand response programs can be used to help achieve both system efficiency and reliability goals. There are two general types of demand response programs that the IOUs use to reduce demand when energy prices are high or when supplies are tight: 'price-responsive' programs (in which customers choose how much load reduction they can provide based on either the electricity price or a per-kW or kWh load reduction incentive), and emergency-triggered programs (in which customers agree to reduce their load to some contractually-determined level in exchange for an incentive, usually a commodity discount).

42. Both types of demand response programs should be designed to motivate customers to reduce their loads in exchange for some type of benefit, such as reduced energy rates, bill credits or exemptions from rotating outages. As used in this decision, the term 'demand response program' means 'price-responsive' programs for which the Commission has established specific MW targets to be incorporated into the IOU's LT procurement plans.

43. D.03-06-032 adopted price-responsive programs, set target goals and directed the utilities on how to integrate demand response goals into their procurement plans. As of July 2004, the IOUs have a combined total of 519 MWs enrolled in the authorized programs. D.03-06-032 also adopted demand response goals for years 2003 – 2007. The 2005 goal is 3% of 'annual system peak demand', increasing to 4% in 2006 and 5% in 2007. The adopted goals apply only to 'price-responsive' demand response programs. MW savings generated by interruptible programs do not count toward the demand response goals articulated in the Energy Action Plan. Enrollment in interruptible programs is capped at 2,500 MW.

44. It is clear that the utilities have used inconsistent definitions of annual system peak in arriving at their MW targets for price-responsive demand. For each utility, the "annual system peak' should be the annual system peak for their respective service territories, inclusive of all customers taking service within those boundaries

45. It is too early to judge whether or not the current demand response goals are achievable. Rather than adjust them now or institute an annual review/adjustment process as suggested by the IOUs, the Commission will retain the current 3% of annual system peak goal and further encourage the IOUs to continue with their best efforts in reaching them. Cost-effectiveness of demand response programs is also important to the Commission, and future demand response proposals will be evaluated for their cost-effectiveness in the demand response rulemaking (R.02-06-001) or its successor.

46. The Commission's efforts in the area of DG have focused on promoting customer-side DG installations in utility service territories. These efforts are directed in four areas: Financial Incentives – rebates are offered to customers installing DG through the Self-Generation Program & CEC's Emerging Renewables Technology program; Interconnection Rules -- streamlining interconnection regulations and processes through the Rule 21 Working Group; Special Tariffs and Exemptions -- such as the standby charge exemptions for certain DG in accordance with PU Code Sections 353.1 and 353.2 and the Departing Load Cost Responsibility Surcharge exemptions from D. 03-04-030; and Net Metering – the PUC expanded net metering eligibility to include biogas digester and fuel cell projects along with the currently-eligible solar and wind projects.

47. In addition to promoting customer-side DG, the Commission is also pursuing grid-side initiatives. In accordance with D.03-02-068, the three IOUs are required to evaluate DG as an alternative to distribution system upgrades, subject to a prescribed set of conditions enumerated in the decision. As of the effective date of this decision, none of the utilities have yet issued RFOs identifying projects where DG might serve as an appropriate alternative.

48. The DG rulemaking's progress towards developing a cost-benefit analysis methodology for DG will inform future policy guidance we provide to the utilities regarding DG as a procurement resource.

49. The utilities appropriately reflected the Commission's preferred loading order by including energy efficiency savings targets in their LTPPs as the priority procurement resource. Since the IOUs filed their LTPPs on July 9, 2004, the Commission issued D. 04-09-060 on September 23, 2004. D. 04-09-060 translated into a numeric goal the mandate from the EAP to reduce energy use per capita. For the electric IOUs the adopted savings goals reflect the expectation that energy efficiency efforts in their combined service territories should be able to capture on the order of 70% of the economic potential and 90% of the maximum achievable potential for electric energy savings over the 10-year period covered by the LTPPs.

50. As discussed in this decision, any incremental investments in energy efficiency over and above the PGC funding needed to achieve the Commission adopted energy savings targets will be considered in R.01-08-028 and related ratesetting dockets for energy efficiency funding that we may initiate.

51. SCE proposed to add a 1% reliability factor to downgrade program savings from non-utility energy efficiency programs operating in its territory. SCE asserted that this reliability factor would address the uncertainty in the

timing and magnitude of savings from non-utility programs until rigorous evaluation, measurement and verification (EM&V) of these programs becomes available.[136] We reject SCE's proposal and reiterate our prior directive in D.04-01-050 for the utilities to count expected energy savings from non-utility programs that operate in their service territories.

52. Energy efficiency issues such as the program administrative structure, program funding cycle and duration, funding levels and program portfolios, EM&V framework and protocols, performance incentives, fund shifting authority, and avoided costs used in cost effectiveness calculations will be considered in the energy efficiency rulemaking (R. 01-08-028) and not in this proceeding. The Commission has also instituted Rulemaking 04-04-025 to address avoided cost issues pertinent to energy efficiency programs and other resource applications. We will continue to coordinate these various proceedings to the extent that our decisions in those proceedings impact the utilities' LTPPs.

53. QFs whose contracts expire after December 31, 2005 are not eligible for the one-year or five-year contract extension options set forth in D.03-12-062 and D.04-01-050, respectively. Currently, the only recourse for QFs, whose contracts expire in 2006 and beyond, is (1) to participate in any upcoming power solicitations, or (2) negotiate bilateral contracts with utilities. Neither of these two options is entirely certain. We recognize that without contract extensions or a new long-term policy, QF contracts that lapse in 2006 could cause QF power to go off-line at that time; however, our plan to address these issues by mid-2005 will avert these concerns.

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[136] SCE Opening Brief, p.36.

54. In general, IOUs must procure the maximum feasible amount of renewable energy in the general solicitations authorized by this decision, and will be allowed to credit this procurement towards their Renewables Portfolio Standards (RPS) targets in 2005 and beyond. If an IOU succeeds in procuring sufficient renewable resources to meet its 2005 RPS Annual Procurement Target (APT) via an all-source RFO, it will not be required to undertake an RPS-specific solicitation next year.

55. We agree that the renewable procurement sections in SCE's and PG&E's LTPPs are inadequate and need revision. However, the revisions, with a detailed analysis, will be developed in the IOUs' 2005 RPS procurement plans, which will be filed in R.04-04-026, following the guidance to be developed in that docket. The IOUs must provide detailed annual analysis of renewable resource potential over next 10 years in their 2006 LTPPs and must include transmission planning for renewable resources in their 2006 LTPPs. Transmission issues will be further addressed in I.00-11-001, in coordination with the RPS docket.

56. We find that RPS targets are a floor – not a ceiling. The EAP loading order places renewables above conventional generation.

57. Using unbundled RECs for RPS compliance is complex and the record here is insufficient; therefore, it is premature to make a determination on this policy at this time. We will consider this issue in R.04-04-026 as appropriate.

58. We recognize that the IOUs' LTPPs did not fully, or adequately, integrate generation and transmission system planning. On October 15, 2004, the Assigned Commissioner in R.04-01-026, the Transmission Assessment OIR, issued a ruling stating "To achieve a comprehensive resource planning framework, the Commission must streamline the transmission planning process and integrate that with the biennial procurement process." It is the

Commission's intention to more fully explore this issue of integrating generation and transmission planning in R.04-01-026.

59. The purpose of R.04-01-026, issued January 24, 2004, is to streamline the transmission planning process for the IOUs by eliminating the duplicative transmission need assessments that currently exist at the CAISO and the Commission. A component of this streamlining is the Commission's proposed deference to need determinations made in the CAISO's grid planning processes.

60. I.00.11.001 was undertaken for the implementation of Assembly Bill 970 regarding the identification of electric transmission and distribution constraints, actions to resolve those constraints, and related matters affecting the reliability of electric supply.

61. The present procedure for transmission expansion and upgrades is for the individual utilities (IOUs) to prepare annually a grid expansion plan, which looks five and ten years into the future. The plans forecast growth in load, the connection of new generation, the retirement of plants whose service lives have come to an end, new transmission facilities and .interconnections with adjacent and out-of-state networks. The plans are the product of several iterations of work by engineers followed by stakeholder meetings at which preliminary results are presented and commented upon by the stakeholders. This is an open process in which the Commission staff participates. The plans are then finalized for the year and submitted to the CAISO for review. The CAISO approves, modifies or rejects individual projects. Projects costing up to $20 million are approved by CAISO staff and projects whose cost is greater than that amount require approval of the CAISO board of governors. The CAISO also participates directly in the planning of transmission between utilities and, in particular, transmission interconnections with other states.

62. LTPPs should more fully integrate generation and transmission planning. It would be helpful to the Commission's review of the LTPPs if they included scenarios of potential resource portfolios to fully meet future resource needs, and identified the transmission expected to be needed to make the potential resource portfolios feasible. It is not acceptable for IOUs to take position of only responding to interconnection requests, as SCE proposes.

63. Phase 2 of the RA portion of this proceeding is scheduled to adopt procedures that will allow identification of "year-ahead" local capacity requirement and overall deliverability for resource adequacy in the early summer of 2005. Those analytic procedures that identify local capacity requirements will inform and govern the utility transmission and procurement requirements going forward.

64. It is premature to address specific requirements regarding local capacity and deliverability in this proceeding or make a judgment as to the sufficiency of the instant filings. However, it is important to provide clarity on how the local capacity and deliverability requirements will come into play in future planning decisions.

65. We expect that the ISO will work closely with the Commission to establish the analytic procedures that identify local capacity procurement requirements based on deliverability of resources into load pockets and transmission constrained areas of the grid. We expect that once established, the ISO will work to update the criterion as changes, such as new transmission or generation, occur that alter these local needs as deliverability constraints evolve.

66. PG&E's net open position has increased over the next five years and increased its market risk exposure. The ability to enter into multi-year agreements is necessary to implement PG&E's midterm resource strategy and

provide PG&E with the ability to acquire a resource portfolio with a mixture of contract terms to deal with load uncertainty over the next three to five years.

67. In the next few years, IOUs could add extensive new generation to their resource portfolios in order to meet their future resource needs. We believe a rate making mechanism needs to be in place to ensure proper and timely cost recovery for these facilities.

68. Cost recovery should begin when the new facility starts operation to serve utility customers.

69. We adopt SDG&E's proposal for cost recovery framework for turnkey projects. Each utility should establish rate-base and O&M-related revenue requirements associated with the generation plant and should use its Non-Fuel Generation Balancing Account (NGBA) and Energy Resource Recovery Account (EERA) to record costs associate with the turnkey plants and for recovery through each utility's commodity rates.

70. Planning and administrative costs of preparing for the construction or acquisition of the generation facilities, financing costs as incurred, and costs if the project is ultimately abandoned will be considered in our review and evaluation of IOU contracts for turnkey projects and may be considered as part of establishing the revenue requirement for these facilities. Therefore, these types of costs should not receive special recovery treatment and PG&E's proposed approach should be rejected.

71. The current ERRA trigger mechanism requires the Commission to adjust procurement rates if the ERRA balancing account becomes undercollected by more than 5% of the previous year's non-DWR generation revenues. This trigger mechanism is set to expire on January 1, 2006.

72. We find that the ERRA trigger provides the IOUs assurance that procurement costs will be recovered in a timely fashion, and we keep the trigger in effect during the term of the long-term contracts, or ten-years, whichever is longer.

73. In D.02-12-074, the Commission adopted a disallowance cap applicable to utility administration and dispatch of allocated DWR contracts. The cap amount is equal to two times the utility's costs of procurement function. In D.03-06-067 the Commission ruled that SCE's request to expand the disallowance cap established in D.02-12-074 to include all procurement activities violates the legislative mandate of Assembly Bill 57, as codified in Pub. Util. Code § 454.5, as well as Sections 451 and 702.

74. PG&E requests that the disallowance cap apply to all utility dispatch, including URG, PPAs, and allocated DWR contracts on the ground that this would provide certainty in estimating the potential financial risk utilities face. Consistent with our determination in D. 03-06-067, as discussed above, that an extension of the disallowance cap violates legislative intent and the statutes, we reject PG&E's request. In its Petition to Modify (PTM) D.03-12-062, filed February 20, 2004, PG&E asks the Commission to clarify that for purposes of upfront standards for procurement transactions, "short term" means up to and including 3 calendar months, or one quarter, not "90 days". PG&E also wants a clarification that the IOUs can conduct competitive solicitations in an auction format. PG&E argues that the use of online auction techniques for competitive procurement falls within the guidelines presented in D.03-12-062 and D.04-01-050.

75. We grant PG&E's PTM and clarify that D.03-12-062 authorized IOUs to conduct procurement using negotiated bilateral agreements for transactions of

up to three calendar months, or one quarter, forward; and that utilities will consult with their PRGs for transactions with delivery periods of greater than three calendar months, or one quarter. We further clarify that D.03-12-062 authorized IOUs to conduct procurement using an electronic auction format for execution of competitive solicitations, among other transactional methods. The authorized products are good for short-, medium-, and long-term procurement. On February 19, 2004, SCE filed a Petition for Modification (PFM) of D.03-12-062 (the 2004 Short Term Procurement Plan Decision). SCE's PFM presented argument on twelve separate issues in the D.03-12-062 that, SCE contends, affect its ability to procure power and make it difficult for SCE to comply with portions of the decision as it is written. SCE's list of twelve requested modifications are set forth in its LTPP, Vol.2, p.13-16, which we will not reiterate here. SCE, like PG&E, raised the 90-day vs. one quarter issue.

76. We grant ten of SCE's twelve requested modifications with the exception of modifications seven and nine, as shown here. Thus, we deny the PTM regarding modification of language that would require an "unqualified certification" as a basis for authorizing SCE's proprietary risk model. we deny the request to eliminate the requirement that SCE demonstrate that identified over-the-counter (OTC) brokers provide prices equivalent to those of exchanges.

77. Consistent with established Commission policy, the positions of several parties, and the present actions of one IOU (PG&E), we adopt a range of values for a "greenhouse gas (GHG) adder" to be used in the evaluation of fossil generation bids. This range is taken from information in the present record. Each IOU will select a value within the adopted range and be prepared to respond to party comment on the value, before employing the adder in analyzing RFO responses.

78. The GHG value will be added to the fossil prices bid in future procurement, and will be used to develop a more accurate price comparison between fossil, renewable and demand-side bids. In the event that the fossil bid is ultimately selected, the adder will not be paid to that generator; it is an analytic tool only.

79. Consistent with established Commission policy, the positions of several parties, including PG&E, we adopt a range of values for a "greenhouse gas (GHG) adder," of $ 8 to $25 per ton, to be used in the evaluation of fossil generation bids. This range is taken from information in the present record. Each IOU will select a value within the adopted range and be prepared to respond to party comment on the value, before employing the adder in analyzing RFO responses.

80. The California utilities are moving forward in a new hybrid market structure developed in large part by this Commission. Since the crisis, the Commission has authorized, and the utilities have conducted, a number of all-source and renewable power solicitations which have successfully procured thousands of megawatts of power under short- and long-term contract to serve California customers.

81. Our most recent experience with procurement solicitations was the SDG&E Grid Reliability RFP process that involved head-to-head competition among both supply-side and demand-side resources (megawatts and negawatts), peaking and baseload resources, an affiliate resource, renewable generators, a merchant PPA, and utility turn-key power plants. This was our first experience with such diversified head-to-head competition among competing resource types, yet it was a successful undertaking.

82. We have determined that it is time to allow greater head-to-head competition and hereby lift the affiliate ban on long-term power products. Accordingly, we adopt certain guidelines and safeguards, including an independent third party evaluator requirement. We will allow the consideration of debt equivalence in the bid evaluation process as specified herein, and we will also require the use of a carbon adder as a bid evaluation component. With these policies we continue to shape and define the hybrid power market in California so as to advance the positive benefits of competition.

83. While the Commission has stated a preference for a hybrid wholesale electric market consisting of PPAs and IOU owned resources, this should not undermine the Commission's goal of having the IOUs acquire supply-side resources based on LCBF principles, regardless of ownership form.

84. We are not persuaded by SCE's argument that D.04-01-050 precludes the IOUs from doing an all-source open RFO because a bid evaluation methodology doesn't exist. The IOUs will employ the LCBF methodology when evaluating PPAs and utility-owned bids in an all-source open RFO, taking into account the qualitative and quantitative137 attributes associated with each bid. The IOUs will also need to add GHG adders, as discussed in Section C.3(?), to all fossil bids. (Mention 3rd party evaluators?) In addition, when seeking Commission approval for the proposed contracts the IOUs will need to demonstrate that they employed LCBF principles. It is expected that the Commission will revisit the LCBF methodology, integrating "lessons learned" from future all-source open RFOs.

[137] Qualitative and quantitative attributes such as performance risk, credit risk, price diversity (10 vs. 20 yr. price terms), and operational flexibility etc.

85. FERC has recently set forth Guidelines for Reviewing Future Section 203 Affiliate Transactions, which include guidelines for IEs in 108 FERC 61,081 (July 29, 2004). FERC explained that to the extent to which a utility demonstrates that its RFP process follows the stated guidelines, its application processing time (including litigation) will likely be reduced, thus increasing the possibility of more timely Commission approval through an adequate showing under the Edgar standard.

86. The FERC guidelines provide for substantial IE involvement in resource solicitations at the "design, administration, and evaluation stages of the competitive solicitation process." FERC has set forth "minimum standards for assuring independence and the scope of the third party's role."

87. We acknowledge the detailed IE guidelines set forth by FERC in its recent July 2004 and generally endorse them. At this time, we will outline an interim approach, which we may refine at a later date based on our further experience in this area. We determine here that we will not allow the IEs to make binding decisions on behalf of the utilities. We will require the use of an IE in resource solicitations where there are affiliates, IOU-built, or IOU-turnkey bidders. However, we will not require that the IEs administer the entire RFO process. The IOU shall consult with its IE and PRG on the design, administration, and evaluation aspects of the RFO to ensure that the overall scope is not unnecessarily broad or otherwise too narrow. IEs should be available to testify as an expert witness in any associated Commission proceeding regarding upfront review of potential solicitation transactions.

88. IEs should come equipped with technical expertise germane to evaluating resource solicitation power products. IEs should not be general observers hoping to be educated on the job. In the case of an affiliate/IOU-turn key power

plant, IEs should be able to quickly scrutinize, examine, and essentially break down bids to determine whether the various cost components are reasonable as presented. IEs should be skilled in analyzing an range of power market derivatives (e.g., futures, contracts, options, swaps). IEs should be familiar with the various standard contracts and industry practices. IEs should have experience analyzing the relative merits of various types of PPAs. IEs should be able to evaluate PPAs, turn-keys, and IOU-builds on a side-by-side basis. An IE should make periodic presentations regarding their findings to the IOU and to the PRG.

89. Cost overruns associated with utility-owned resources should be borne by shareholders because this approach will level the playing field for IOU-owned projects and PPAs, with respect to risk allocation

90. The IOUs have shown that rating agencies emply various methodologies to assign debt equivalence on their balance sheets for power purchase agreements.

91. Standard & Poor's (S&P) has the most robust methodology for calculating debt equivalence, but their 30% risk factor is based on subjective criteria that should be adjusted downward.

92. The arguments presented by SDG&E that keeping Sunrise in its plan reduces its option to address local reliability issues and ORA's proposal that SCE contract with SDG&E for dispatch rights for specific units under the DWR-Williams contract, will be addressed either in the next phase of RA, or in the DWR contract proceeding.

93. In the short- to mid-term, RMR and contracts should suffice to keep the aging plants in operation. These plants could bid into RFOs and because of their

advantage over new plants, such as proximity to load centers and infrastructure they should be competitive in their bids.

94. To the extent feasible, old plants should be retrofitted, and refurbished. It is generally good policy to consider using brownfields first instead of using greenfields, because of existing infrastructure, being close to load centers, and other benefits.

95. While we expect RA Phase II to resolve local reliability, in the interim we extend the requirements of D.04-07-028. In particular, the policy requirements of D.04-07-028 and any implementation procedures should be handled by IOUs filing Advice Letters until local reliability is resolved in RA Phase II, or by other action of this Commission.

96. SDG&E is a unique case among the three IOUs in that within service area resource additions almost certainly will provide local reliability benefits, unlike SCE or PG&E. We therefore direct SDG&E to pursue the EAP loading order priorities when it makes resource additions.

97. The three utilities have presented information on the processes they undertake to develop bottom-up forecasts of their needs and of the plans to deal with those needs. We are satisfied that the utilities are complying with our orders and taking into account the needs of local areas within their service areas in developing their plans.

98. We endorse the coordination agreement and the direction to IOUs stated in the September 16, 2004 ACR. We direct IOUs to participate in the CEC IEPR proceeding as the one forum in which long-term load forecasts, resource assessments, and need determinations will be considered. We believe Appendix A constitutes a good foundation for coordinated proceedings and the minimization of duplication between various planning proceedings. We direct

staff to work with the CEC and CAISO to effectuate this agreement in a complete and practical manner.

99. We find that no change is necessary at this time for the Semiannual ERRA Application. As for the Short-Term Procurement Plan, the 2006 Long-Term Procurement Plans will contain the features of the Short-Term Plans that are not covered by the proposed 2004 LTPPs. That is, ultimately, we will eliminate the STPPs and the IOUs will act in accordance with a single Commission-approved plan. Until then, the existing STPPs will be in effect. Updates or modifications to the plans in between the biennial review will be filed with an advice letter. Any updates to the existing STPPs should be filed with an Advice Letter 30 days after the issuance of this decision.

100. No change is necessary at this time to the gas supply plans and biennial LTTPs.

101. If an increase to SCE's collateral capacity is required to carry out the LTTP approved by the Commission, SCE will provide updated collateral estimates. No party has taken issue with SCE on this issue. Accordingly, we accept SCE's stated approach.

102. We also note here that SCE can, and does, require counterparties to make similar collateral postings aimed at ensuring contract performance under changing market conditions. We are not aware of any specific claims of over-collateralization or associated recommendations.

103. SCE has informed the Commission of two relatively new accounting rules promulgated by the Financial Accounting Standards Board (FASB) "that, like the debt equivalence issue, may affect electric utilities' costs of contracting for power. While SCE has not requested any specific relief related to these new accounting

rules, SCE may seek further guidance from the Commission when appropriate in the same manner as set forth in the Cost of Capital proceeding.

104. Consistent with the Commission's direction in D, 04-01-050, it is our intention that many more categories of planning information will be open to the public and will be considered so in our review of the IOU's LTPPs. We have yet to determine if any information that routinely was considered confidential under former protocols might be deemed public when this decision is issued in final.

105. We must balance the competing interests of the need of some confidentiality of IOU data to protect ratepayers, against the public interest in disclosure and the desire of intervenors to have better access to IOU confidential data to more fully participate in Commission proceedings. While we move closer to "open decision-making" we need to be pragmatic about mitigating any adverse ratepayer consequences.

106. Currently under AB57, that added Section 454.5 to the Pub. Util. Code, the Commission is to have in place procedures that ensure the confidentiality of any market sensitive information submitted by an IOU as part of its proposed procurement plan, while ORA and other consumer groups that are not market participants (NMPP) access to the information under confidentiality provisions. This provision of AB57 was an attempt to balance the compelling ratepayer interest in ensuring that certain legitimately confidential information is kept out of the hands of those who can use it to manipulate wholesale energy markets, with promoting a sufficiently transparent decision-making process to allow for scrutiny and review by the legislature and the public.

107. Following a request from SDG&E to amend the April 4, 2003, ALJ ruling to protect information submitted by parties to a RFP, the ALJ issued a ruling on December 1, 2003, amending the previous protective order allowing certain bid

information to remain confidential, but also soliciting comments on a further modification to the protective order to incorporate a provision allowing outside attorneys and/or consultants to a MP who do not perform competitive duties for or on behalf of their client, and who execute a Non-Disclosure Certificate, to have access to materials relevant to the SDG&E RFP. Parties were directed to draft a Protective Order that paralleled language from an Amended Protective Order adopted by a FERC judge.138 On January 14, 2004, following the receipt of comments on the FERC model, the ALJ issued a ruling adopting an Amended Protective Order that was substantially consistent with the FERC orders and that allowed the MPs access to Protected Materials following the FERC guidelines. As referenced earlier in this decision [p. XX], this Amended Protective Order controlled confidentiality issues in this current procurement proceeding.

108. In preparation for review of the IOUs' LTPPs in this proceeding, in D.04-01-050 the Commission expressed its desire to move towards more open and transparent decision making and asked the parties to submit comments on how to allow more access to utility data, but not at the expense of the ratepayer/consumer. Comments were received on March 1, 2004. By that time SB1488 was already in committee, so instead of issuing a new iteration of the January 14, 2004, Amended Protective Order we followed the guidelines implemented therein for this procurement proceeding.

109. We also note that more intervenors, in particular the environmental groups, had access to the IOUs confidential data since they signed on to the Amended Protective Order. So in addition to the consumer groups, other NMPP

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[138] FERC Docket Nos. EL02-60-003 and EL02-62-003. See footnote 16.

also had the benefit of reviewing all the utility data. None of the MPs chose to sign on to the Amended Protective Order. The utilities and the MPs may have reached a point of equilibrium in that if the MPs had more access to utility information, the utilities may have demanded equal access to MP information.

110. Standard Offer Service, a wholesale power procurement approach proposed by CPS, whereby a jurisdictional public utility secures all or a portion of the generation supply to meet its retail load through a multi-year wholesale service contract or contracts with a third-party provider may be an interesting idea for certain types of market conditions and direct-access service systems, but is not appropriate for California, at least at this time and under current conditions.

Conclusions of Law

1. We must incorporate the demand uncertainty factors into our consideration of the LTPPs and consider this uncertainty in determining the level of acquisition and the need for flexibility in the resource plans. Based on this uncertainty, we will not adopt a fixed assumption regarding the level of departing load. We acknowledge that the IOUs face considerable load variability risk, and will set policies accordingly.

2. We will not set a procurement cap based on the low cases, since this could seriously under-resource California's service areas during the planning period. Instead, we will rely on a portfolio approach and allow justification of specific contract types as the need arises. This will allow us to balance between obtaining adequate resources and not over-procuring in the case of departing load or crowding out of preferred resources towards the end of the planning period. We will monitor the IOUs' efforts to obtain resources to meet their resource adequacy requirements on a forward looking basis.

3. We find all three LTPPs consistent with the 2003 IEPR, are reasonable for planning purposes and that the medium, preferred case should be followed for making planning and procurement decisions.

4. The EAP contains explicit direction regarding the state's preferences for meeting identified resource needs and the IOUs are to prioritize their resource selections accordingly.

5. It is reasonable to require a compliance filing of annual energy and capacity resource accounting tables, consistent with directions on baseline load forecasts, EE, QFs and DR. We do expect the IOUs to make incremental improvements in their next round of analysis to be filed with the CEC in 2005.

6. It is not our intent to provide the means by which market power could be exercised against the LSEs and, hence, against electric service customers in California. Therefore, this decision does not present information about the current net open positions of the utilities, nor do we provide the elements from which that information can be calculated. It is reasonable to provide simplified tables based on projections of future resource balance information for the years 2007-2014 after those numbers have been refreshed from their initial filing in July 2004.

7. Pursuant to the direction adopted in D.04-10-035, the current focus is on maintaining and enhancing grid reliability through accelerated reserve margin targets. When this goal is integrated with the directive from D.04-07-028 issued by the Commission this summer ordering the utilities to concentrate on near-term reliability, it is evident that the IOUs must increase and retain supply for the near future.

8. Since SDG&E's estimated reserve margins, which exceed 17% in some years during the planning period are the result of prior Commission decisions, there should be no finding of unreasonableness if they exceed 17%.

9. While we do not approve SDG&E's 500kV transmission line here, we do acknowledge the lengthy process that's needed to plan, license and construct transmission, and thus encourage SDG&E to continue its planning efforts and move forward with evaluating these transmission alternatives for meeting a local resource deficiency by 2010.

10. The utilities should track their gas price forecasts with actual gas market price information and other publicly available gas price forecasts and must record any divergence. It is reasonable to direct the utilities to re-run procurement scenarios included in LTPPs with the updated gas price forecasts and to require the utilities to maintain copies of this analysis for staff review.

11. While we recognize that the potential CCAs want to limit the amount of cost responsibility surcharge applied to departing CCA customers for utility liabilities incurred on their behalf when the CCA customers leave utility service, Pub. Util. Code Section 366.2(h) requires that the Commission authorize community choice aggregation only if the Commission imposes a cost recovery mechanism in accordance with the law.

12. We anticipate that our decision regarding CCA will implement a program whereby cities and counties can procure energy on behalf of their communities, and will also protect those bundled ratepayers who do not have the option of transferring to a CCA from the possible cost impacts resulting from the departing customers. We expect that our CCA decision will adopt a methodology for estimating the CRS that will allow bundled customers to be indifferent to the CCA program, including a methodology for CCA customers to

pay their share of the costs of DWR bonds and contracts, utility procurement contracts and other items.

13. Ensuring that utilities be allowed to recover their net stranded costs from all customers meets the Commission's goals of providing "the need for reasonable certainty of rate recovery" (as required under AB57 and noted in the June 4th ACR) as well as best ensuring that California meets its energy needs.

14. Requiring departing customers to assume a fair share of their costs is also consistent with the Commission's policy of holding captive ratepayers harmless as required by state law.

15. Based on the analysis of resource needs, it appears that the utilities may need to make longer-term commitments for capacity and energy that may become stranded at some point during the life of these projects

16. Allowing the utilities to recover stranded costs from all customers who benefited is consistent with recent Commission policy with regards to new resource additions. In both the SDG&E Reliability RFP (D.04-06-011) and in Edison's Mountainview decision (D.03-12-059) the Commission required that all existing customers of the utility were responsible for any potential stranded costs for a period of ten-years. Even requiring a ten-year commitment for new resources may still increase costs for captive ratepayers due to the need for the project developer to see accelerated cost recovery for their investments rather than amortizing these assets over a longer time period.

17. The Commission recognizes that by keeping demand response MW goals at their current levels there may not be any program that is cost-effective relative to alternative supply resources. As stated above, we believe it is premature to make that judgment today. Because demand response programs are currently voluntary, the challenge of designing cost-effective programs while in pursuit of

greater amounts of demand response MWs each year may very well prove to be an impossible task. If and when that point becomes evident, the Commission will need to either reduce its demand response MW goals or begin consideration of mandatory demand response programs and tariffs.

18. We find that the utilities' treatment of DG as a component of the load forecast is appropriate.

19. Consistent with D.04-09-060, PG&E, SCE and SDG&E should meet or exceed the Commission's EE goals over the next ten years and specifically over the next EE funding cycle (2006-2008) and revise and update their plans to be in alignment with these goals. PG&E, SCE and SDG&E are to incorporate the goals from the EE decision in their LTPPs, and as these energy savings goals are updated and amended by subsequent decisions, the IOUs are to incorporate the most recently adopted energy savings goals into their plans.

20. It is reasonable to require the utilities to provide information about the energy efficiency programs in a consistent format in the utilities' future LTPP filings will facilitate the Commission and parties' analysis of the proposals.

21. Allowing an IOU to meet its RPS Annual Procurement Target via an all-source RFO, rather than RPS-specific solicitation is consistent with the Legislature's clear intent that renewable procurement be integrated as closely as possible with general IOU procurement practices. To further this effort, we will be working over the course of the next LTPP cycle to fully imbed the RPS into long-term planning, placing renewable energy development where it belongs - central to the IOUs' resource planning efforts.

22. To further California's goal of promoting environmentally responsible energy generation, it is reasonable to adopt a policy that reflects and attempts to mitigate the impact of greenhouse gas (GHG) emissions in influencing global

climate patterns and to direct the IOUs to employ a “carbon adder” when evaluating fossil generation bids. This method, which will be refined in future proceedings, will serve to internalize the significant and under-recognized cost of GHG emissions, and will continue California’s leadership in addressing this important problem.

23. The coordination agreement between the CEC’s IEPR and the CAISO’s annual grid planning process, and outlined in the attachment to the September 16, 2004 ACR also emphasizes the need for coordination between transmission planning and resource planning.

24. While CAISO’s grid planning process is a complement to the Commission’s oversight of the IOU’s procurement responsibilities, it is not a substitute for the Commission’s role.

25. Once the local procurement and deliverability criteria are established we expect that the criteria may also be useful in guiding the long-term plans going forward. We recognize the importance of the ISO in helping us to establish the criteria and so that the Commission can apply them to the utilities’ planning practices. The ISO core expertise in the area of transmission planning and grid operations is critical to inform the Commission’s procurement decisions. This approach will assure that the long-term resource procurement meets the ISO short-term grid requirements. It will also assure that the resources the utilities procure pursuant to their resource adequacy requirements meet the ISO operational needs.

26. Since the RA phase is designed to handle the reserve margin issues we will not rewrite D.04-01-050 in this decision. If parties want further clarification on the interpretation of the 15-17% requirement they should bring it up in Phase II of the RA portion of this docket. This LTPP decision is not intended to change or

modify any aspect of D.04-10-035. Any clarifications, alterations or augmentations to D.04-10-035 will be deferred to Phase II of the RA aspect and not addressed here.

27. Pursuant to DWR's request, nothing in this decision makes changes to prior Commission decisions, particularly D.02-12-074, the IOU-DWR Servicing Agreements, or makes any changes in ratemaking treatment of the DWR contracts.

28. D.04-01-050 continued the ban on affiliate transactions, however, our position on this issue warrants re-examination at this time.

29. Given our desire to consider all competitive options, instead of continuing the ban, and carving out exceptions for unique resources from time to time, we now find that it is in the best interest of the ratepayers and consumers to allow for a full vetting of all available resources in a RFP. We will institute appropriate safeguards for the solicitations for long-term transactions, in part through continuation of utility PRGs and through the use of independent third-party evaluators. Such safeguards can protect consumers from any anti-competitive conduct between utilities and their affiliates.

30. We should adopt a methodology for debt equivalence for IOUs to empoly when evaluating competitive bids from independent providers and utilities in an all-source solicitation.

31. We should adjust the S&P methodology for debt equivalence downward to a 10% risk factor to account for the fact that the California regulatory climate is improving, and we do not wish to disadvantage PPAs unduly over utility-owned generation, particularly when it comes to renewable generation.

32. It is reasonable to direct the IOUs to consider the use of brownfields and take full advantage of brownfield sites before they consider building new

generation on greenfield sites. If IOUs decide not to use brownfield, they must make a showing as to why they prefer greenfield sites.

33. It is reasonable to extend the IOUs' procurement on a rolling 10-year basis, given that the long-term procurement plans cover a ten-year period and they will be updated and reviewed every two years.

34. It is reasonable to require certification of SCE's proprietary risk model and to require an independent third-party verification of the internal validity of the model, aimed at ensuring that all the features of the model work as advertised, that the model is mathematically sound, and that the assumptions utilized by the model are reasonable.

35. With regard to the requirement that SCE demonstrate that identified over-the-counter (OTC) brokers provide prices equivalent to those of exchanges, this is a reasonable upfront standard, consistent with AB57. The use of transparent exchanges is one reasonable check on the competitiveness of a portion of SCE's procurement activity. We direct SCE to consult with its PRG regarding the specific implementation options that are available.

36. D.04-01-050 determined that in future cycles of the procurement process, we would link our timing to that of the CEC's Integrated Energy Policy Report. Since that proceeding operates on a biennial calendar, by statute, that means that the next long-term procurement proceeding will be in 2006. D.04-01-050 also linked the substance of the analyses we direct IOUs to file with the results of the CEC's IEPR information and analyses. In the past two years, the CEC and this Commission are collaborating to a much greater degree than ever before, and as evidence the CEC is not a party to this proceeding and its staff is assisting our our own in review of IOU LTPPs and in developing resource adequacy procedures.

37. Since this OIR issued, the Legislature passed, and the Governor signed, Senate Bill (SB) 1488 that directs the Commission to "initiate a proceeding to examine its current confidentiality rules under Pub. Util. Code Sections 454.5 and 583 and the California Public Records Act to ensure that the Commission's practices under these laws provide for meaningful public participation and open decision making."

38. We will soon initiate a proceeding too fulfill our obligations under SB1488. For purposes of this decision and our review of the IOUs LTPPs, we believe intervenors, including MPs, had sufficient access to the IOUs' background data and assumptions, if they chose to follow the guidelines of the January 14, 2004 Amended Protective Order to allow for a robust development of the record to satisfy us that there was a full vetting of the important issues.

O R D E R

IT IS ORDERED that:

1. The Long-Term Procurement Plans filed on July 9, 2004 by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E)are approved as modified in this decision.

2. When executing procurement plans in response to this decision, PG&E, SCE, and SDG&E shall:

   a. Procure the maximum amount of cost-effective energy efficiency and demand-side resources;
   b. For further resource needs, procure the maximum amount of renewable generation resources via all-source RFO, and be prepared to defend any selection of fossil over renewable resources; and
   c. Employ the GHG adder, described herein, when evaluating fossil generation bids.

3. We find that PG&E's LTPP plan is reasonable and we approve PG&E's strategy of adding 1,200 MW of reserve capacity and new peaking generation in 2008 and an additional 1,000 MW of new peaking and dispatchable generation in 2010 through RFOs because it is compatible with PG&E's medium resource needs, does not crowd out policy-preferred resources, and is a reasonable level of commitment given load uncertainty. Those commitments may need to be increased or expedited for PG&E to meet its 2006 resources adequacy obligations. (Doesn't this conflict w/ p. 31 and FOF 18) Depending on the nature of the bids obtained, PG&E is authorized to justify to the Commission why higher levels might be desirable. Nothing in this decision precludes PG&E from offering local reliability contracts, should they become necessary, pursuant to D.04-10-035.

4. We find that SCE's LTPP resource plan is reasonable, subject to the compliance requirements covering its demand forecast, demand response, energy efficiency, QFs, and other factors set forth in this decision and other Commission decisions in those designated proceedings. SCE has demonstrated that its primary residual resource need through 2011 is for peaking, dispatchable and shaping resources. SCE has considerable need for peaking and shaping resources, which should be obtained through short, medium- and long-term acquisitions. SCE's strategy of relying primarily on short- and mid-term contracts during this planning period is reasonable, but it may be prudent to add some long-term resources. SCE is authorized to present such a case to the Commission as an implementation of its LTPP by way of an application following a RFP.

5. We find that SDG&E's resource plan reasonable, subject to the modifications required for the compliance filing described herein. SDG&E is essentially fully resourced through 2009, other than needed investments in renewable resources to meet RPS targets.

6. Utilities shall file an advice letter with a new gas price forecast in the event they determine, based upon the analysis described in this decision, that the gas price forecast submitted in their LTPP is no longer valid and has a significant impact on the scenarios presented in their LTPP and procurement decisions. The updated gas price forecast advice letter shall include updated scenarios presented in their LTPPs and shall provide the rationale for the update and include a discussion on all the assumptions underlying the forecast and explain why the gas price forecast is reasonable in light of the availability of alternatives. If necessary, the advice letter may be filed under the confidentiality conditions discussed in the decision. Include in COLA: By this decision, we provide notice that failure to file the required gas price forecast updates may result in forfeiture of any utility profits gained by use of an invalid gas forecast.

7. The Commission's decision in RA, D.04-10-035, issued October 28, 2004, among other things, established that all Load Serving Entities (LSE), including the IOUs, must have reserve margins of 15-17% by June 1, 2006. As part of meeting this reserve margin requirement, each LSE must have 90% of its next summer's requirement [May through September] fully resourced by September 30 of the year before. The decision also established a 100% forward commitment obligation for a month-ahead horizon for the five summer months, so each LSE must acquire the incremental remaining 10% of forward commitments needed to satisfy resource adequacy requirements. The IOUs are to plan to meet all RA requirements as set forth in D.04-10-035 as they go forward with their LTPPs.

8. In future procurement plans, the IOUs shall incorporate reasonable anticipated CCA departing load. The assumption of the Commission is that the IOUs shall acknowledge potential CCA departing load and identify which city and/or county has expressed intent to pursue aggregation, including MW estimates of this departing load, in future procurement plans.

9. We adopt the same 10-year standard for new fossil-fueled resources acquired by the utilities. We are also proposing a 10-year standard for new renewable resources, but seek comment if this time-period is sufficiently long enough that it will not deter the development of these resources. For all other contracts, the utilities should be allowed recovery over the life of the contract.

10. As part of their compliance efforts, within 30 days of this decision, each utility shall propose additional programs in R.02-06-001 that will allow them to enroll sufficient customer load to reach the adopted 2005 goals for price-responsive demand response programs described above. The Commission will consider whether or not to approve specific proposed programs in R.02-06-001.

11. The utilities shall continue to adhere to the directives for reflecting DG estimates in load forecasting consistent with D.01-04-050 and D.04-10-035. We also encourage SCE to move forward with its planned DG RFO, the results of which will be monitored by the Commission for guidance in both the DG rulemaking and this docket.

12. Consistent with D.04-09-060, PG&E, SCE and SDG&E shall meet or exceed the Commission's EE goals over the next ten years and specifically over the next EE funding cycle (2006-2008) and to revise and update their plans to be in alignment with these goals. PG&E, SCE and SDG&E are to incorporate the goals from the EE decision in their LTPPs, and as these energy savings goals are

updated and amended by subsequent decisions, the IOUs are to incorporate the most recently adopted energy savings goals into their plans.

13. At a minimum, the utilities must provide the following data on their energy efficiency programs in the 2006 LTTPs:

a. Total Commission-authorized investments in energy efficiency every year over the next decade, broken out into the PGC and procurement component (in real and nominal dollars). If Commission authorizaton is pending for some or all years of the period, the utilities shall provide proposed investment levels that are designed to meet the Commission's adopted energy savings goals.

b. New annual and cumulative energy savings as a result of the programs every year over the next decade, broken out into the PGC and procurement components (in GWh);

c. New annual and cumulative peak savings every year over the next decade, broken out into the PGC and procurement components (both coincident-peak and non-coincident-peak, in MW);

d. The TRC net benefits of the proposed investments;

e. The average levelized cost of the energy efficiency resources;

f. Comparison of cumulative energy and peak savings to the Commission's adopted goals;

g. The projected percent of demand growth reduced by the programs; and The per capita electricity consumption for the service territory over the next decade after factoring in the energy savings from the programs.

14. We authorize the utilities to enter into short-term, mid-term, and long-term contracts, with contract delivery start date through 2014, provided that the IOUs submit the necessary compliance filings. We adopt TURN's proposal that contracts with duration three years or longer be submitted to the Commission for preapproval.

15. We grant PG&E's Petition To Modify D.03-12-062, and clarify that D.03-12-062 authorized IOUs to conduct procurement using negotiated bilateral agreements for transactions of up to three calendar months, or one quarter, forward; and that utilities will consult with their PRGs for transactions with delivery periods of greater than three calendar months, or one quarter. We further clarify that D.03-12-062 authorized IOUs to conduct procurement using an electronic auction format for execution of competitive solicitations, among other transactional methods. The authorized products are good for short-, medium-, and long-term procurement.

16. We grant ten of SCE's twelve requested modifications, as requested in its Petition to Modify, with the exception of modifications seven and nine, as discussed in this decision.

17. In addition to the GHG adder, the IOUs are directed to employ, when finalized and approved by the Commission, the externality values under development in the Avoided Cost Rulemaking (R.04-04-025). It is anticipated that these values will be adopted in approximately March 2005, and will include a fixed value for GHG (not simply a range) as well as values for other, non-GHG pollutants. These values should be appropriately added to any fossil bids the IOUs receive in response to an RFO. It is anticipated that the Commission will adopt these values in a decision in R.04-04-025 before the IOUs undertake any procurement as a result of this decision. Therefore, all procurement undertaken subsequent to this decision should employ the GHG adder adopted in this decision, until replaced with a decision in R.04-04-025, when analyzing bids.

18. As discussed in this decision, the Assigned Commissioner or the assigned ALJ may direct Commission staff to perform additional studies or analyses on "carbon caps" in coordination with our consideration of a procurement incentive framework modeled after the cap-and-trade principles of the Sky Trust in a subsequent phase of this proceeding.

19. The IOUs shall employ the Standard and Poor's methodology for debt equivalence, except they shall use only a 10% risk factor instead of S&P's 30% risk factor, when evaluating bids in an all-source solicitation.

20. The IOUs shall justify the debt equivalence factors for PPAs on a case by case basis in their cost of capital proceedings.

21. The utilities shall rfresh the tables provided in July in consultation with the Energy Division and the California Energy Commission staff.

22. We continue the Monthly ERRA Report and Monthly Portfolio Risk Report. The objective of the report is to show that the transactions entered into are in compliance with the upfront standards identified by the Commission. In regards to the Quarterly Transaction Report, the IOUs are ordered to file a joint proposal to reformat the report in a way that will provide the Commission concise and coherent information, thereby streamlining the review process. The objective of the report is to show that the transactions entered into are in compliance with the upfront standards identified by the Commission. These reports will be reviewed by the Energy Division staff. If there are no protests and the staff concludes that the transactions entered into in that quarter comply with the utility's procurement plan, then by the Commission's Expressed Delegation of Authority, the Energy Division Director can approve the reports. However, if there are substantive protests and the staff takes issue with certain

transactions, the staff will issue a draft resolution for the Commission's approval.

We adopt the following requirements for an All-Source Solicitations:

a. All-source open solicitations need to be transparent and competitive, and in addition, need to be open to all resources

b. (conventional/renewable - turnkeys, buyouts, and PPAs). See Section C.5.;

c. Following the "loading order" contained in the Joint Agency Energy Action Plan is the first priority for IOU resource procurement, meaning that energy efficiency and demand-side resources should be employed first. When these opportunities are exhausted, renewable generation is to be procured to the fullest extent possible – whenever an IOU issues an RFO for generation resources, it must be prepared to defend its selection of fossil generation over renewable generation offers. See Section A.2.6;

d. IOUs are directed to procure the maximum feasible amount of renewable energy in the general solicitations authorized by this decision, and will be allowed to credit this procurement towards their Renewables Portfolio Standards (RPS) targets in 2005 and beyond. If an IOU succeeds in procuring sufficient renewable resources to meet its 2005 RPS Annual Procurement Target (APT) via an all-source RFO, it will not be required to undertake an RPS-specific solicitation next year. See Section A.2.6.;

e. The IOUs will employ the Least-Cost Best-Fit methodology when evaluating PPAs and utility-owned bids in an all-source open RFO, taking into account the qualitative and quantitative attributes associated with each bid. See Section C.5.;

f. Green House Gas (GHG) adders are to be used for fossil bids in all-source open RFOs. See Section C.3.;

g. Debt equivalency will be considered when evaluating individual PPA bids, regardless of whether the bids are from a fossil, renewable, or an existing QF resource. IOUs are not to consider resource-specific debt equivalency risk factors. See Section C.6.;

h. When seeking Commission approval for PPA contracts, the IOUs will need to demonstrate, on a case-by-case basis, that the imputed debt equivalency was material. The IOUs will also need to provide the methodology used to calculate the debt equivalency adder applied to each PPA bid. See Section C.7.;

i. IOUs will not be allowed to recover costs in excess of its final bid price for utility-owned resources. See Section C.5.;

j. Mandate the use of 3rd party evaluators in resource solicitations where there are affiliates, IOU-built, or IOU-turnkey bidders.

23. By this decision we lift the ban on long-term affiliate transactions for transactions entered into through an open and transparent solicitation process. However, we maintain the ban on short-term transactions 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**.** The utilities, and in particular their respective risk management committees, must maintain complete procurement planning independence from their affiliates.

24. The IOUs may contract directly with IEs, in consultation with their respective PRGs. The IOUs shall allow periodic oversight by the Commission's Energy Division. Alternatively, Energy Division can contract with IEs directly, but we will not require this given that this may result in unacceptable delays in the procurement process. IEs shall coordinate to a reasonable degree with assigned Energy Division management and staff as a check on the process.

25. With regard to consultants that assume the role of an IE, they shall abide by clear conflict of interest standards. We note that FERC has provided guidance on this issue. We would like to require that consultants abide by the appropriate Fair Political Practices Commission guidelines, in order to avoid the types of conflict of interest problems encountered by consultants working on behalf of the State of California and DWR during the 2000-2001 energy crisis. We must ensure the integrity of the third party evaluator process to provide firm assurances to the power market. We are open to comment from parties on specific conflict of interest standards.

This order is effective today.

Dated ___________________________, at San Francisco, California.

Brown Attachment A

Brown Attachment B Adopting PG&E, SCE and SDG&E LTPP

Brown Attachment C