Decision 07-12-052 December 20, 2007

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 06-02-013 (Filed February 16, 2006)

(See Appendix A for a list of appearances.)

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

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

1. Introduction

1.1. Summary

This decision reviews, critiques and adopts, with modifications, Pacific Gas and Electric Company's (PG&E), Southern California Edison Company's (SCE) and San Diego Gas & Electric Company's (SDG&E) Long-Term Procurement Plans (LTPP), for the 10-year period 2007 – 2016, and provides direction to the utilities on preparing their conformed 2006 LTPPs compliance filings. Summaries by the utilities of their LTPPs are attached as Appendix B. More than 30 intervenors provided valuable insight and dissection of these LTPPs and gave us guidance for our evaluation. Summaries of the intervenors' contributions are attached as Appendix C.

Our primary focus in reviewing the LTPPs was whether the utilities are procuring preferred resources as set forth in the Energy Action Plan (EAP), in the order of energy efficiency, demand response, renewables, distributed generation and clean fossil-fuel. In addition, California is the pioneer in the nation, and in some areas of the world, in emphasizing and implementing policies that promote the reduction of green house gases (GHG), especially in the production and delivery of electric resources by the utilities we regulate. Each LTPP was to prepare different candidate plans that indicated how the utility would meet its renewable portfolio standard targets, demand response as a percentage of resource adequacy requirements, energy efficiency savings from committed and

uncommitted programs,[1] and then show how each candidate plan minimized environmental impacts, at what cost to ratepayers, and at what reliability level.

Our analysis determined that all three LTPPs were deficient and spotty in regards to addressing filling their net short position with preferred resources from the EAP loading order and particularly inadequate in accounting for GHG emission reductions. The LTPPs show the utilities, for the most part, filling and projecting to fill their projected net short positions with conventional resources without providing a highly developed analysis to support this strategy. Going forward the utilities will be required to reflect in the design of their requests for

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[1] We recognize that the terms, "committed" and "uncommitted," have specific meanings as adopted by the California Energy Commission (CEC) in its demand forecast, however in this decision this Commission's use of the terms differs slightly and therefore warrants clarification. According to the CEC, "committed programs are defined as programs that have already been implemented or for which funding has been approved. (CED 2008 Revised, p. 25.)" In the CEC's use of the term, committed EE includes (but is not limited to) savings from the 2006-2008 EE program cycle, and is treated as a load forecast reduction embedded in the forecasting methodology. According to the CEC, "uncommitted effects are the incremental impacts of the level of future programs…impacts of new programs, and impacts from expansions of current programs (CED 2008 Revised, p. 25)." These incremental savings are treated as a resource for planning purposes.

In this decision, we define "committed EE" as only those savings attributed to the IOUs' 2006-2008 EE program cycle portfolios that meet or exceed Commission-adopted EE goals. We define "uncommitted" EE as the projected savings attributable to future EE program cycles (2009-2011 and beyond) that meet or exceed the Commission-adopted EE goals. Due to certain mechanics in the CEC's demand forecasting methodology, a situation arises where uncommitted EE (in this Commission's use of the term) is reflected in one of two places in the 2006 LTPPs: either (1) embedded as a reduction in the load forecast (to the extent that uncommitted EE *does* overlap with the CEC's concept of committed effects) or (2) forecasted as an available resource (to the extent that uncommitted EE does *not* overlap with the CEC's concept of committed effects."

offers (RFO) compliance with the preferred resource loading order and with GHG reductions goals and demonstrate how each application for fossil generation comports with these goals.

In summary, although the 2006 LTPP filings substantially complied with the directives in the scoping memo, we are requiring that the investor-owned utilities (IOUs) conform their 2006 LTPPs through a compliance filing in order to reflect the modifications we direct in this decision. In addition, we will require that subsequent LTPP filings for our regulated utilities not only conform to the energy and environmental policies in place, but aim for even higher levels of performance. We expect the utilities to show a commitment to not only meet the targets set by the Legislature and this Commission but to try on their own to integrate research and technology to strive to improve the environment, without compromising reliability or our obligation to ratepayers.

1.2. Energy Procurement and California Environmental Policy

There are numerous principal sources of guidance that apply to the California Public Utilities Commission's (Commission) review of the long-term procurement plans filed by each IOU on December 11, 2006: The February 16, 2006 Order Institution Rulemaking (OIR); the Scoping Memo; and the stated policy direction of the Governor and Legislature, to be implemented by the Commission, for California's energy policies going forward in the 21st Century.

California is a pacesetter in the nation in emphasizing and implementing policies that promote the reduction of GHG, especially in the production and delivery of electric resources by our regulated utilities. While many of the rules and regulations concerning GHG and the reduction of carbon emissions are still under consideration in open proceedings at the Commission, others are choate and imbedded in Commission policy. As discussed throughout this decision, the

primary principles that are of importance to the Commission are the procurement of the preferred resources set forth in the EAP in the following "loading order": energy efficiency, demand response, renewables (including self-generation), followed at the end of the loading order with efficient fossil-fuel resources.

The Scoping Memo directed the IOUs to include GHG forecasts as part of their 10-year resource plans and to specify which methodology and assumptions they used to make their GHG calculations. Attachment A provided further guidance to the IOUs by instructing them to provide "expected GHG emissions of candidate resource plans," and to "explicitly express the RPS [renewable portfolio standard] percentages that will be met by the candidate resource plans, the percentage of demand response as a percentage of RA requirements, and energy efficiency savings from committed and uncommitted programs."[2]

In addition to evaluating their plans for minimizing environmental impacts, the IOUs were to weigh the ratepayer costs and reliability impact of each proposed plan.

Each of the IOUs appears to assume fossil-fuel generation, for the most part, will be procured to fill their net short positions. The overarching problem in all three LTPPs is the absence of any scenario analysis regarding what types of resources the IOUs should use to fill their net short positions to best transition to the inevitably GHG-constrained world we are moving towards. While the specific Assembly Bill (AB) 32 implementation details are still under consideration in Rulemaking (R.) 06-04-009, it would be prudent for the IOUs to

[2] Scoping Memo, September 25, 2006, Attachment A, p. 20.

make reasonable assumptions and/or develop reasonable scenarios regarding different mixes of preferred resources and the operational characteristics of additional fossil generation that the IOUs will need to reduce their carbon emissions from electric generation resources back to, at a minimum, 1990 levels.

We share the concern raised by many intervenors that the IOUs are filling, and are projecting to fill, their respective net short positions with conventional resources to the effect of there being no room in an IOUs' portfolio for other resources, or the conventional resources will be obsolete and result in large stranded costs.

The perception, real or otherwise, is that, once state mandates for preferred resources are met, filling net short positions with fossil resources is somehow a foregone conclusion. Such a conclusion would be legitimate, if it were based on highly developed analysis. Even in a GHG-constrained world, fossil resources are likely to play a vital role, due to flexibility and reliability attributes; but the IOUs' plans do not demonstrate the analytical rigor to draw this conclusion.

Several parties have made strong arguments that, in general, the IOUs' approach to resource planning and analysis fails to provide information on both the cost and risk of resource plan alternatives in the face of long-term planning uncertainties, such as GHG regulations. Informed decision-making depends on robust analysis. While we recognize that electric resource planning is inherently uncertain, perhaps now more than ever before, we expect the IOUs to integrate the best, most recent planning methodologies and analytical techniques.

In subsequent iterations of the long-term procurement process, the IOUs will be expected in their resource planning to meet and exceed the high standards Californians expect as pacesetters on energy and environmental issues. We agree with parties that find areas that could be improved on

throughout the IOUs' planning process from planning assumptions and scenario development, to candidate portfolios and portfolio analysis, and ultimately, evaluation and final selection of a preferred portfolio. The IOUs need to focus on loading order goals and how any fossil generation will complement these goals when filling net short positions. We will reinforce this by:

1. Requiring IOUs to reflect in the design of their RFOs compliance with the preferred resource loading order and how the resources sought will advance the IOU's efforts to reduce GHG levels;

2. Requiring a demonstration of how each application for fossil generation filed based on the procurement authority granted in this proceeding fits into each IOU's GHG reduction strategy; and

3. Providing more explicit directions in the next LTPP OIR regarding steps the IOUs must take to plan for reducing carbon emissions, achieving the State's 33% renewables goal, and conform to the EAP II loading order through the application of resource planning methodologies and analytical techniques that consider cost and risk.

Our overall analysis of the three LTPPs in general, without reference to specific plans or sections of plans, is that while it is apparent that IOU staff labored to comply with the Scoping Memo, their efforts resulted in plans that do not fully reflect our goals in regards to preferred resources and a commitment to the EAP loading order. We will be more specific in subsequent proceedings with our expectations for the long-term plans.

We identified many of the same deficiencies in the 2004 LTPPs. Specifically, in Decision (D.) 04-12-048, Finding of Fact (FOF) #54, we stated, "We agree that the renewable procurement sections in SCE's and PG&E's LTPPs are

inadequate and need revision. The revisions, with a detailed analysis, will be developed in the IOU's 2005 RPS procurement plans . . . [T]he IOUs must provide detailed analysis of renewable resource potential over the next 10 years in their 2006 LTPPs …" We further amplified our commitment to preferred resources, and in particular to renewables, in FOF #55: "We find that RPS targets are a floor—not a ceiling. The EAP loading order places renewables above conventional generation."

In summary, the 2006 LTPP filings did not achieve the high standards we require the state's regulated utilities to meet in conforming California's energy procurement with our environmental policies. Since it is too late in this LTPP cycle to require that the IOUs resubmit their LTPPs, we are requiring that the IOUs file conformed 2006 LTPPs via a compliance filing no later than 90 days from the date of this decision. The conformed 2006 LTPPs shall incorporate all of our directives contained in the body of this decision as well as any updates filed through the Commission's Advice Letter process between the issuance of this decision and the due date of the compliance filing. For future LTPP filings, it is our intention that if any LTPPs, or sections therein, are not fully compliant with Commission directives, we will require the IOUs to resubmit the plans until they are in full compliance with the new OIR and Scoping Memo. Subsequent LTPPs, when approved, will constitute the complete AB 57 authority for the IOUs, and any procurement actions not contained within will not be eligible for AB 57 cost recovery.

1.3. Background

The Commission initiated LTPP proceedings to continue our efforts to ensure a reliable and cost-effective electricity supply in California. Each LTPP proceeding serves as the umbrella proceeding for the Commission to consider, in

an integrated fashion, all of the Commission's electric resource procurement policies and programs, including implementation of directives from other procurement-related proceedings. The LTPP proceedings operate on a two-year cycle, with IOUs responsible for submitting procurement plans that project their need over a 10-year horizon.

Prior to the first LTPP proceeding, we completed numerous rounds of shorter term procurement planning and preparation for the long-term proceedings in compliance with Pub. Util. Code § 454.5.[3] Specifically, this includes:

- the adoption of the IOUs' "2003 short-term procurement plans" (STPP) filed on May 1, 2002, for the 2003 year;[4]
- the adoption of the IOUs' revised "2003 STPPs" filed on November 15, 2002;[5]
- the approval of the "2004 STPPs" filed in April/May 2003, and deferral of other long-term planning issues to a separate decision;[6]
- the approval of a long-term policy framework and ordering that utilities file new long-term plans;[7] and
- the approval of the first set of IOU LTPPs submitted in July 2004 for 2005-2014.[8]

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[3] Herein, references to Code sections are to the State of California Public Utilities Code and references to Rules are to the California Public Utilities Rules of Practice and Procedure.

[4] D.02-10-064 ordered the IOUs to submit modified STPPs to reflect issues decided in D.02-10-064, incorporate the allocation of existing California Department of Water Resources (DWR) contracts (D.02-09-053), and cover procurement that would be undertaken by the IOUs in the 2003 year.

[5] D.02-12-074.

[6] D.03-12-062.

[7] D.04-01-050.

This decision not only approves the 2006 LTPPs, but also establishes a skeleton upon which future LTPP filings in the biennial cycle may build and grow. It identifies the key issues and areas of planning that the IOUs must address and improve upon in their next LTPP filings.

1.3.1. R.06-02-013

This OIR, R.06-02-013 initiated review of the IOUs LTPPs. It is the successor to R.04-04-003, in which we approved the first set of long-term plans, and R.01-10-024, which initially ordered the biennial cycle of procurement plan filings and review. In this current LTPP proceeding, we again consider in an integrated fashion all of the Commission's electric resource procurement policies and programs, including implementation of directives from other procurement proceedings relevant to this cycle. As set out in the Assigned Commissioner Ruling/Scoping Memo dated September 25, 2006 (Scoping Memo), this combined procurement plan was intended to replace all previous procurement plan authority and move forward into the future with one, combined procurement plan that includes information from prior iterations of short-term and long-term plans. After the approval of the 2006 LTPPs, utilities may no longer continue to conduct procurement indefinitely under the short-term plans originally submitted in April/May 2003.

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[8] D.04-12-048.

1.3.2. Related Agency Direction

1.3.2.1. D.04-12-048

D.04-12-048, issued by the Commission on December 16, 2004, adopted the three IOUs' LTPPs that were filed in July 2004. This was the first decision by the Commission implementing AB 57, the legislative directive that allowed the IOUs to resume the procurement of electricity for their customers, and D.04-12-048 instructed the IOUs to file procurement plans that included specified criteria set forth in the legislation. The goal of AB 57 was to allow the IOUs to reliably serve their customers' needs at just and reasonable rates, and also to set forth achievable standards and criteria for rate recovery. If the IOUs made procurement decisions consistent with their approved plans, there would be no need for after-the-fact reasonableness review by the Commission of the IOUs' procurement actions. The Commission chose a 10-year horizon for the planning period, and the first LTPPs covered the years 2005 through 2014.

D.04-12-048 established upfront standards and criteria for rate recovery and authorized the IOUs to make procurement decisions that incorporated the Commission's policy direction from other procurement proceedings. In particular, the IOUs were directed to prioritize their resource procurements following the "loading order" of preferred resources established in the EAP[9] discussed below. In addition, the IOUs were authorized to enter into short-term, mid-term and long-term contracts, and we promoted head-to-head competition

[9] EAP I was issued jointly on May 8, 2003, by the Commission, the CEC and the California Consumer Power and Conservation Financing Authority (CPA). EAP I was updated with the adoption of EAP II in October 2005.

in the bidding process and adopted guidelines and safeguards for the procurement practices.

1.3.2.2. Energy Action Plan II

EAP I was updated with the adoption of EAP II by the Commission in October 2005, and is a joint policy plan by the Commission and the CEC.[10] EAP II builds on EAP I and identifies the set of priorities for energy policy, many of which are directly relevant to this proceeding. The priorities, or "loading order" is as follows: energy efficiency (EE), demand response (DR), renewable power, distributed generation (DG), clean and efficient fossil-fired generation. EE and DR are considered the highest priority and should be employed first by a utility in making procurement decisions since they are demand-side resources. Once a utility captures the targeted EE and DR opportunities, the utility is to procure renewable generation to the fullest extent possible. The IOUs were directed in the OIR and Scoping Memo to follow the EAP II loading order and these priorities are considered in this review of procurement plans and policies.

1.3.2.3. Integrated Energy Policy Report

The CEC's Integrated Energy Policy Report (IEPR) for 2005 made numerous procurement-related recommendations to the Commission which were considered throughout this proceeding.[11] The IEPR's five policy recommendations are:

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[10] See http://www.cpuc.ca.gov/PUBLISHED/REPORT/50480.htm.

[11] CEC's IEPR 2005 is available at http://www.energy.ca.gov/2005publications/CEC-100-2005-007/CEC-100-2005-007-CMF.PDF.

1. Implementation of the loading order from EAP II: EE, DR, renewable power, DG, clean and efficient fossil-fired generation; addressing the need for long-term contracts; and encouraging combined heat and power (CHP) resources;

2. Development of portfolio and risk assessments to determine least-cost/best-fit resource selection;

3. Implementation of GHG performance standards as part of 2006 LTPP;

4. Requirement of more transparency in energy planning and procurement to facilitate implementation of state energy policy goals from EAP II; and

5. Establishment of rules for departing load customers that implement goals of increasing long-term contracts without risk to IOUs or their ratepayers.

Item (3) is being addressed in a separate GHG proceeding. Item (4) was addressed in the Commission's separate Confidentiality proceeding, R.05-06-040. In that docket, Commission issued D.06-06-066, which adopts rules and guidelines for the treatment of confidential procurement-related data and D.06-12-030 which establishes guidelines for non-disclosure agreements and protective orders.

1.3.3. Related Legislation

The Legislature provided guidance in the procurement plan process via enactment of AB 57[12] and AB 380.[13] Each piece of legislation requires the

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

Commission to take certain steps with respect to electricity procurement in the State.

AB 57 (Pub. Util. Code § 454.5), as referenced earlier, was enacted to authorize the IOUs to commence again the procurement of electric resources on behalf of their customers after the period of de-regulation had taken that responsibility away from the IOUs. In summary, Pub. Util. Code § 454.5 requires the Commission to review and approve IOU procurement plans, establish policies and cost-recovery mechanisms for energy procurement, ensure that the utilities maintain an adequate reserve requirement, implement a long-term resource planning process, and implement an RPS program. The Scoping Memo directed the IOUs to address each required element set forth in Section 454.5 in their respective LTPPs.

AB 380 (Pub. Util. Code § 380), requires the Commission to establish a resource adequacy (RA) program. The Commission initiated R.05-12-013 to refine the RA requirements for all load serving entities (LSEs), including IOUs. As R.05-12-013, and successor Rulemakings, revise and improve the RA program requirements, we will expect the IOUs to incorporate the updates into their LTPPs.[14]

1.4. Proceeding History

This rulemaking proceeded in two phases. In Phase I, we examined the need for additional policies to support new generation and long-term contracts

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[13] AB 380, (Stats. 2005, Ch. 357, Sec. 10. Effective September 24, 2006). AB 380 added Section 380 to the Pub. Util. Code.

[14] In the future, it may be necessary for the Commission to require all LSEs to submit LTPPs in order to comply with Pub. Util. Code § 380.

in California. We issued D.06-07-029, as modified by D.07-11-051, which adopted a cost-allocation mechanism that allows the advantages and costs of new generation to be shared by all benefiting customers in an IOU's service territory. D.06-07-029 designated the IOUs as the procuring agents to sign long-term power purchase agreements (PPAs) for new generation for their respective service territories. The capacity and energy are unbundled, and the rights to the capacity are to be allocated among all the LSEs in the IOU's service territory. Each LSE would share in the capacity according to the LSE's share of the 12-month service area coincident peak, and the LSE can apply the capacity towards its RA requirement. The LSE's customers receiving the capacity only pay for the net cost of the capacity, once the energy revenues are subtracted from the cost of the PPA. The energy revenues are to be determined by the results of periodic energy auctions for the PPA energy rights.

D.06-07-029 did not specify the implementation details of the energy auction, but instead instructed the IOUs to file proposals for the auction process in Phase II.[15] After extensive mediation efforts by the parties, a Joint Proposal for an energy auction was submitted to the Commission, and adopted by the Commission, with clarifications, on September 20, 2007, D.07-09-044. In summary, the Settlement Agreement establishes principles that ensure an independent, transparent and fair auction procedure in which multiple stakeholders and the Commission maintains active involvement, and which

[15] *D.06-07-029*, Ordering Paragraph (OP) 2, "Pursuant to the mechanism adopted herein and as refined in response to the IOUs' Implementation Proposals for an energy auction filed in Phase 2, each IOU is to conduct periodic auctions for the energy rights to all resources acquired pursuant to this mechanism…"

establishes products that facilitate an active market and allows for the development and auction of new products.

Phase II focuses on our obligations under Pub. Util. § 454.5 to oversee the IOUs' LTPPs from 2007-2016. Within Phase II are three tracks: Track 1 addressed the energy auction, and other issues deferred to this phase; Track 2 focuses on the LTPPs; and Track 3 addresses issues involving the nonbypassable charge (NBC) issue that was ordered in D.04-12-048 to keep IOU ratepayers indifferent to migrating load.

1.5. Scope of Phase II, Track 2

In this phase of the proceeding, we review the LTPPs filed by PG&E, SCE and SDG&E in accordance with the directives set forth in the Scoping Memo, including Attachment A. In particular, the Scoping Memo required two volumes in each utility's filing. Volume 1 must be a stand-alone plan covering procurement practices and the resource plan for the next 10 years based on existing Commission policies, and Volume 2 should include the IOU's comments on selected policies and procedures for implementing plans that the Commission has identified for review during the 2006 proceeding cycle. Whereas Volume 1 should incorporate existing Commission policies related to procurement without commenting upon those underlying policies, Volume 2 should review and potentially expand and amend those policies. Volume 1 must be based on existing procurement authority and Commission established procurement policy, and is not designed to be an advocacy piece. On the other hand, Volume 2 may present testimony on the issues identified by the Scoping Memo and gives the IOUs the opportunity to advocate for the continuation of existing practices, the adoption of new practices and policies, or modification of certain policies that the IOU has implemented and has suggestions for improvement.

1.6. Requirements of the 2006 IOU Plans

The specific requirements of the IOU Plans were outlined in detail in the Scoping Memo's Attachment A. However, to inform the IOUs as they drafted their respective LTPPs, the Scoping Memo also set out the Commission's key goals for the 2006 LTPP review process, as set forth below:

- IOUs will file one complete set of 2006 LTPPs that merges the contents of approved short-term and long-term plans, following the outline provided in Attachment A.

- IOUs will integrate EAP II goals and specific procurement targets from other proceedings into 2006 long-term procurement plans.

- IOU 2006 LTPPs will detail practices and procedures required for implementation of procurement.

- IOU 2006 LTPPs will include a 10-year resource plan, including a resource supply portfolio consistent with the EAP II, especially the EAP loading order.

- IOU 2006 LTPPs will identify need for new resources and describe how they will be procured, examining both bundled customer need and system need in the context of new generation resources.

- IOU 2006 LTPPs will include greenhouse gas forecasts for its 10-year resource plan and a discussion of compliance with the Commission's GHG policies.

- IOU 2006 LTPPs will include cost estimate forecasts for its 10-year resource plan.

- IOUs will review procurement policies related to procurement practices and risk management in Volume II, as listed above.

Attachment A to the Scoping Memo set forth the outline and organizational structure the IOUs were to follow in drafting their LTPPs to comply with their Volume 1 requirements. The issues for Volume 2 were set out in the Scoping Memo at § D(8), p. 25 and focused on procurement practices and risk management issues.

A summary of each IOU's 2006 LTPP is provided in Attachment B.

1.7. Intervenors

In addition to the three IOUs, the following intervening parties are participating in this proceeding:

ACRONYM	PARTY NAME
	Aglet
AReM	Alliance for Retail Energy Markets
	Areva
CAC/EPUC	Cogeneration Association of California / Energy Producers and Users Coalition
	Calpine
	Caithness Energy
CAISO	California Independent System Operator
CALWEA	California Wind Energy Association
CARE	Californians for Renewable Energy
CCC	California Cogeneration Council
CCSF	City and County of San Francisco
CDGC	Clean DG Coalition
CEC	California Energy Commission
CEERT	Center for Energy Efficiency and Renewable Technologies
CLECA	California Large Energy Consumers Association
CMA	Competitive Market Advocates
CMUA	California Municipal Utilities Association
	Constellation
CUE	Coalition of California Utility Employees
DACC	Direct Access Customer Coalition
DRA	Division of Ratepayer Advocates
GPI	Green Power Institute

IEP	Independent Energy Producers
	LS Power
	Mirant
MMID	Modesto/Merced Irrigation Districts
NRDC	Natural Resources Defense Council
NRG	NRG Energy
TURN	The Utility Reform Network
UCAN	Utility Consumers' Action Network
WEM	Women's Energy Matters
WPTF	Western Power Trading Forum

Appendix C provides a summary of the positions of each intervenor who filed a post-hearing brief.

2. Forecasts, Resources, and Need Determination

2.1. General Approach to Need Determination

The need determination made in this section for each IOU is based on a service area assessment because the IOUs are responsible to plan for new capacity additions within the IOUs' distribution service territories.[16] Load forecasts, resource and supply assumptions, and planning reserve margins are discussed by topic in the following subsections. Each subsection provides a general discussion followed by IOU-specific results. Tables PGE-1, SCE-1, and SDGE-1, located at the end of Section 2, use each IOU's preferred or recommended plan as a base that is then adjusted to reflect the conclusions drawn in the various load and resource subsections.

[16] D.06-07-029, at p. 26.

After all of the inputs are addressed, we develop a need determination for each IOU in the need determination subsection. Recent experience suggests that the time required to develop and carry out competitive long-term RFOs, then finance, permit and construct new generation resources – including a cushion to account for unanticipated delays – requires that these procurement decisions be made up to seven years in advance of when the resources are needed. Otherwise, we are forced to perform "just-in-time" procurement that threatens reliability, drives up the costs of delivering power, and typically does not result in additional preferred/renewable resources. Given this up to seven-year lag from authorization to in-service date and the one-year schedule slip in this decision, the need determinations made in this decision are based on the IOUs' summer 2015 residual net short.

Finally, Section 2 concludes with a discussion of, and proposed process for making refinements to, IOU identification of system versus bundled resources.

2.2. Load Forecasts

The last LTPP decision, D.04-12-048, directed the IOUs to prepare a Medium-Load Plan Scenario in future LTPPs using the CEC's IEPR base case load-forecast scenario or an Alternative Base Case load-forecast scenario, if the utility chose to file one. In R.04-04-003, the predecessor LTPP rulemaking that resulted in D.04-12-048, the assigned Commissioner issued a ruling on March 14, 2005 (hereinafter referred to as the "IEPR Ruling") directing all parties interested in the IOUs' load forecasts for 2006 to participate in the CEC's 2005 IEPR process since the Commission did not intend to re-examine specified issues resolved during the IEPR process.[17]

Since the IEPR load forecast was the subject of considerable testimony by numerous parties in this proceeding, we find it useful to summarize the procedural history of the 2005 IEPR load forecast. In June 2005, the CEC issued a draft staff energy and demand forecast.[18] The draft staff forecast was based on results from the CEC's end-use forecasting model and used data supplied by the IOUs and other sources. At a June 30, 2005 hearing, CEC staff and utility staff presented their respective forecasts and discussed possible reasons for discrepancies, including whether end-use or econometric forecasting techniques are better suited to long-term demand forecasts. In September 2005, the CEC

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[17] *Assigned Commissioner's Ruling Detailing How the California Energy Commission 2005 Integrated Energy Policy Report Process will be used in the California Public Utilities Commission's 2006 Procurement Proceedings and Addressing Related Procedural Details*, R.04-04-003, March 14, 2005.

[18] *California Energy Demand 2006-2016 Staff Energy Demand Forecast,* CEC-400-2005-034-SD, June 2005.

adopted a final staff forecast,[19] which, based on parties' comments, presented a revised baseline forecast and additional forecasts for high and low stress cases. Further, in its 2005 IEPR transmittal to the Commission, the CEC found that "end-use modeling methods are more appropriate for long-term planning purposes."[20] In June 2006, pursuant to D.05-10-042, the CEC issued staff's updated 2007 peak demand forecast,[21] describing several plausibility adjustments to the September 2005 revised forecast, including significant increases in the forecast for all IOUs.[22]

The IEPR, with revisions, established growth rates and weather multipliers that, when applied to the June 2006 revised forecast for each IOU, established base (medium or expected), high and low demand forecasts under 1-in-2 ("baseline"), 1-in-5, 1-in-10 and 1-in-20 temperature conditions over the 10-year planning period of this LTPP. To be clear, the range of projected demand in the CEC forecasts (base, high, and low) was due to different assumptions about non-weather related variables. Pursuant to D.05-10-042, and the Commission's determination that the CEC's demand forecast shall serve as the "state's official load forecast," the CEC defines 1-in-2 temperatures as the baseline weather

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[19] *California Energy Demand 2006-2016 Staff Energy Demand Forecast, Revised September 2005*, CEC-400-2005-034-SF-ED2, September 2005.

[20] *Transmittal of 2005 Energy Report Range of Need and Policy Recommendations to the California Public Utilities Commission*, CEC-100-2005-008-CMF, November 2005.

[21] *Staff Forecast of 2007 Peak Demand*, CEC-400-2006-008, June 2006.

[22] The CEC's June 2006 update raised PG&E's, SCE's and SDG&E's summer 2007 forecasts by 526 MW, 960 MW and 79 MW, respectively.

condition. Variations due to weather conditions were captured in the temperature scenarios, and not in the composition of forecasts themselves.

The IEPR Ruling stated that, "with very *narrow exceptions*," [23] the 2006 LTPP proceeding would not allow reexamination of the load forecast. The IEPR ruling went on to define these exceptions as "(i) material new information that could not reasonably have been considered by the CEC during the 2005 IEPR or (ii) materially changed circumstances."[24] The Scoping Memo for this proceeding required the IOUs to use the CEC's revised demand forecast for 2007-2016. Consistent with the IEPR Ruling, the Scoping Memo indicated that, if an IOU wanted to adjust the IEPR demand forecast in light of "new information," the IOU was to introduce and litigate that information in the proceeding.[25]

In order to provide some context to parties' comments and the discussion on load forecast, it is instructive to look back at the historical accuracy of the CEC's 10-year forecasts as a predictor of actual peak demand. Figure 1 illustrates this for the SCE planning area. SCE is selected as an example because it is the utility for which CEC has the most comparison points and because SCE's load forecast was the most heavily litigated in this proceeding. For the five forecasts of demand in the SCE planning area adopted by the CEC in its Electricity Reports from 1988 to 1996, the average annual absolute error over the

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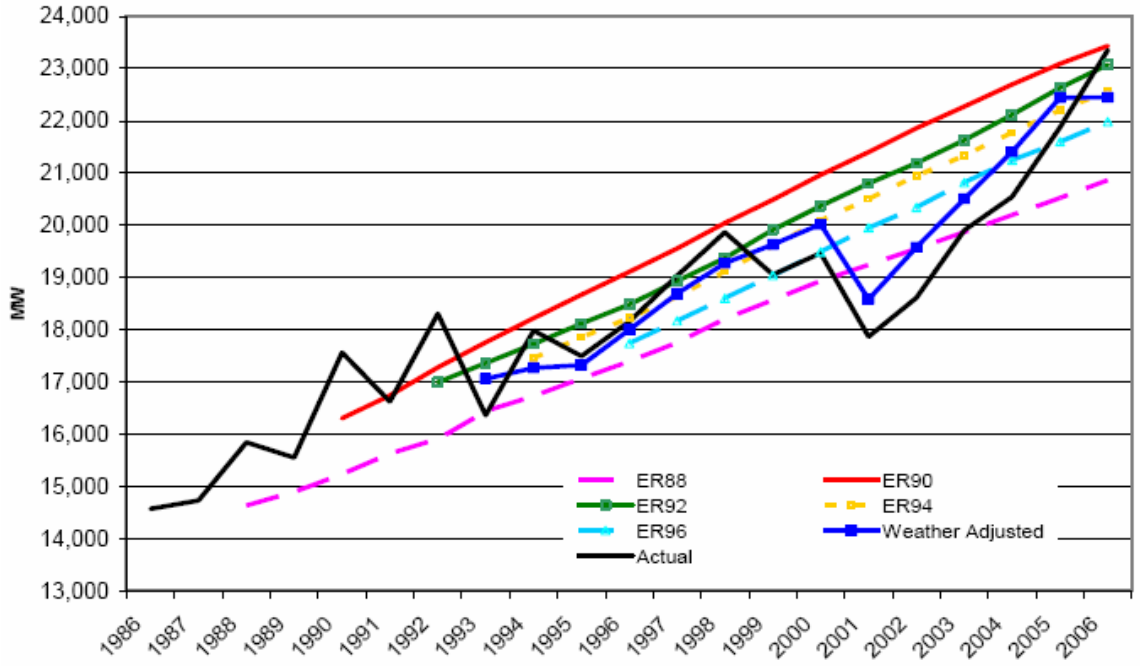
[23] March 14, 2005 ACR, at p. 4.

[24] *Id.*, at p. 10.

[25] September 9, 2005 ACR/Scoping Memo, Attachment A, at p. 13.

forecast horizon was 4%.[26] There also does not appear to be any consistent bias above or below actual peak demand in the collective CEC forecasts.

Figure 1. Forecasted versus Actual Peak Demand in the SCE Planning Area



Source: California Energy Commission

Another point of comparison is to look at the year-ahead peak demand forecast versus actual peak. For SP-26, the planning area on which SCE's system reliability tables are based, the 2007 actual peak load was 28,230 MW.[27] The CEC's June 2006 forecast update to the 2005 IEPR and the 2007 draft IEPR

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[26] *2007 Integrated Energy Policy Report*, CEC-100-2007-008-CTF, at p. 30, available at http://www.energy.ca.gov/2007publications/CEC-100-2007-008/CEC-100-2007-008-CTF.PDF

[27] Based on CAISO records, and factoring in a 1% peak coincidence adjustment for SDG&E.

forecast predicted 28,400 MW[28] and 28,100 MW[29] peaks, respectively, which were both within one percent of the actual SP-26 peak. In contrast, the SP-26 forecast in SCE's 2006 LTPP was 28,910 MW,[30] which over-predicted the actual peak by 2.5%.

2.2.1. Summaries of Parties' Positions on General Forecasting Issues

The CEC strongly argues in its argument that the IOUs are to use the IEPR load forecast. In particular, the CEC considers SCE's approach to the load forecast to be in conflict with the expressed directives of the Scoping Memo and the IEPR Ruling. The CEC points to various and repeated Commission decisions and rulings supporting its view that "…the IEPR load forecast stands unmodified as the sole authorized basis for long-term planning in this proceeding."[31] In particular, the CEC stresses that the burden of proof lies with the IOUs to substantiate whether and how new information introduced into this proceeding conforms with the aforementioned narrow exceptions defined in the IEPR Ruling.

Other parties echo or make no objection to the CEC's pointed assertion that litigation of the load forecast, with narrow exceptions, is out-of-scope in this

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[28] *Staff Forecast of 2007 Peak Demand*, CEC-400-2006-008, June 2006.

[29] *California Energy Demand 2008-2018 Staff Draft Forecast,* CEC-200-2007-015SD, July 2007.

[30] SCE's Need Determination Tables.

[31] *Post-Hearing Closing Brief of the California Energy Commission for Phase II of the LongTerm Procurement Plan Proceeding,* R.06-02-013, August 29, 2007, at 15.

proceeding. DRA found that the IOU's treatment of growth rates in the LTPP is consistent with the IEPR.[32]

WPTF and other parties ask that the Commission require the IOUs to use a single, independently established load forecast for all their procurement and RA requirements, instead of having the IOUs use two separate planning criteria. One uniform planning criteria for the IOUs would benefit investors, buyers and sellers to assess the market and make investment decisions; would allow the Commission to assess the cost-benefit tradeoffs between reliability and cost; would allow all LSEs to meet their RA obligations; and would facilitate Commission staff oversight of the IOUs procurement choices. WPTF further notes that "every single organized market uses a single load forecast…"[33]

CLECA observes that the Commission's policies to encourage energy efficiency exacerbate a steady erosion of load factor statewide, leading to faster growth in peak demand relative to energy demand.[34]

2.2.2. Discussion of General Load Forecast Issues

We discuss in the individual IOU subsections below the extent to which each IOU followed the Scoping Memo guidance in developing its load forecast. We clarify in this decision, and will reiterate in the OIR for the next LTPP proceeding, that the IOUs are to use the CEC's forecast in their LTPPs. The

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[32] Opening Brief of the Division of Ratepayer Advocates, August 1, 2007, at p. 9.

[33] *Opening Brief on Phase II Issues of the Western Power Trading Forum*, August 1, 2007, at p. 11.

[34] *Opening Brief of the California Large Energy Consumers Association*, August 1, 2007, at p. 6.

CEC's IEPR process is the proper forum to litigate and contest issues related to each IOU's demand forecast. If an IOU believes that the CEC's forecast is too "conservative" or that the CEC should use different forecasting models, data or other inputs, that IOU must bring those issues up and have them resolved in the IEPR proceeding.

The Scoping Memo recognized the importance, for long-term planning purposes, of analyzing a range of load forecasts. As such, the Commission directed the IOUs to identify a range of need stemming from the CEC's three demand forecasts (low, base, and high), as well as other planning uncertainties.[35] Although the Scoping Memo did not specify *which* forecast and temperature condition should apply in the IOUs' approved plans, previous Commission decisions provide some direction on this issue. In D.04-12-048, we concluded that, in approving the 2004 LTPPs, "…the *medium, preferred case* should be followed for making planning and procurement decisions."[36] The same decision found as fact the following statement:

> 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*.[37]

We find it prudent to review load forecast sensitivities, but for purposes of granting procurement authority, need determination should be based on the

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[35] September 9, 2005 ACR/Scoping Memo, Attachment A, at p. 13.

[36] D.04-12-048, Conclusion of Law (COL) #3. (*Emphasis added.*)

[37] D.04-12-048, FOF #11. (*Emphasis added.*)

CEC's base forecast under baseline (1-in-2) temperature conditions pursuant to D.04-12-048.

We generally agree with intervenors' comments regarding the value of uniform planning criteria, such as load forecast, capacity counting protocols, and planning reserve margin (PRM). The Commission has taken just such a position, in D.04-04-033 and in this decision, with regard to standardization of the load forecast in the RA and LTPP processes.

Parties in favor of uniform planning criteria identify numerous benefits, but one in particular resonates with the Commission: the ability of the Commission to oversee prudent procurement choices. Due to the inherent complexity of electric resource planning, on the one hand, and the need for meaningful public participation, on the other hand, we believe it is in the public interest to standardize the presentation of capacity resource counting tables and to require that future LTPPs conform to a format substantially similar to the Need Determination tables provided later in this section.

We concur with many of the concerns raised by the CEC and other parties. To address these concerns and conform to our own policy directives, we base the IOU need determination tables on the CEC's base case, 1 in 2 summer temperature demand forecast (the three need tables, PGE-1, SCE-1, and SDGE-1, all use the forecasts from CEC's 2007 IEPR issued on November 21, 2007).[38]

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[38] While we recognize that the 2007 IEPR forecast estimates were not vetted in this proceeding, many aspects of the IEPR forecasting process were. The IEPR process is a public one, involving many of the same participants that are parties to this proceeding, and the IEPR document is a public document. We find it prudent to update the forecast estimates used as inputs in this decision based on the most current public information available to us, particularly given the long time lag that has occurred since the LTPPs were developed. The *California Energy Demand Forecast, 2008-2018,* the underlying load

Footnote continued on next page

Specific issues associated with the load forecast treatment in each IOU's LTPP are addressed below.

2.2.3. PG&E's Load Forecast

PG&E developed four scenarios to represent the potential conditions that its candidate procurement plans will be exposed to over the next 10 years. Each scenario represents a collection of events which have a particular effect or stress condition, including changes to the load forecast.

Scenario 1 exposes PG&E's portfolio to "stranded cost" conditions and assumes a low demand for electricity, using the CEC's low demand forecast for PG&E's service area.

Scenarios 2 and 3 represent "current world" conditions and assume a high demand for electricity, using the CEC's high demand forecast. Higher market availability of preferred resources distinguishes Scenario 3 from Scenario 2. Scenario 4 is characterized by high market prices and very high demand conditions. In this "high growth/high price" scenario, PG&E assumed a growth rate 0.3% higher than the CEC's high-load case growth rate in order to reflect a growth rate similar to that exhibited during the 1995-2000 era of dot-com/telecom expansion. According to PG&E, the scenarios were designed to test candidate plans under low, moderate and high stress conditions. Notably absent from PG&E's load forecast scenarios, however, is the CEC's base forecast. PG&E based its scenarios on either the CEC's low forecast, its high forecast, or

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forecast which the 2007 IEPR assumes, had not been officially adopted by the CEC, as of the mailing of this Proposed Decision. We note that the incorporation of the draft 2007 IEPR demand forecast into our overall needs analysis may give certain parties concern, however, we believe that the draft forecast provides a better 'snapshot' of the current needs of the system.

some derivation thereof; but PG&E does not use the CEC's base forecast in any of its scenarios.

All four load forecast scenarios used by PG&E begin with the 2007 PG&E load forecast approved by the CEC in July 2006 for use in PG&E's 2007 RA compliance filing. In order to project load growth for the remainder of the forecast horizon (2008-2015), PG&E used the growth rates corresponding to CEC's 2005 IEPR low and high case projections.

Because PG&E has more recent information on EE and self-generation (including CSI) than was available when the 2005 IEPR was produced, the growth rates from the 2005 IEPR could not be used directly in PG&E's development of the load scenarios for the 2006 LTPP. Working with the CEC staff, PG&E first developed an adjustment to the published IEPR growth rates to net out EE and self-generation effects from the IEPR growth rates. Once this was accomplished, PG&E replaced the IEPR assumptions with respect to EE and self-generation with updated assumptions.

2.2.3.1. Summary of Parties' Positions on PG&E's Load Forecast

Parties made no comments regarding PG&E's load forecasting methodology for system peak. Numerous intervenors opined on whether PG&E's methodology accurately predicts potential CCA and DA departing load. PG&E responds that migration to or from PG&E to an alternative provider within PG&E's service area will not have an impact on the forecast since it is developed for the entire service area. In addition, PG&E claims that, since the CEC did not include large DA or CCA load changes in its 2005 IEPR, PG&E's scenarios are consistent with the CEC's forecast approach.

PG&E is aware of the concerns of many intervenors that if it does not properly predict possible DA and CCA expansion, it could "over-procure" and then departing load could be saddled with a NBC. PG&E responds to these arguments by repeating its position that its numbers are for the entire service area, and that includes DA and CCA, and even if there are significant load departures, PG&E can adjust its portfolio to address these changes.

2.2.3.2. Discussion of PG&E's Load Forecast

PG&E asserts that the methodology underlying its load projections is consistent with the requirements of the Scoping Memo.[39] We find otherwise. As stated in the general load forecast discussion, the Scoping Memo explicitly required the IOUs to use the CEC's revised demand forecast. Not one of PG&E's four scenario analyses used CEC's base forecast, as required by the Scoping Memo.[40]

As noted earlier in the general forecasting discussion, we establish PG&E's need determination using the CEC's base forecast. Table PGE-1 reflects this adjustment to PG&E's preferred plan demand forecast.

Regarding parties' concerns over PG&E's assessment of departing load, we concur with PG&E's response that its analysis of system need is not impacted by possible future load shifting due to DA and CCA, and that future DG and MDL is captured by historical trends used to develop the forecast.

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[39] *PG&E's 2006 Long-Term Procurement Plan, Vol. I* – Amendment, at p. IV-6.

[40] September 9, 2005, ACR/Scoping Memo, Attachment A, at p. 13.

2.2.4. SCE's Load Forecast

SCE evaluated each of its two candidate plans using two different load forecast scenarios, a CEC-based load forecast and its own recommended load forecast, which provides a higher peak demand growth rate than the CEC forecast.

SCE explains that its recommended forecast differs from the CEC's because the CEC uses an end-use forecasting model, while SCE uses an econometric model. SCE makes three main arguments supporting the validity of its forecast. First, SCE contends that its data is more consistent with the demographic and economic data in its distribution service territory that shows that peak demand is growing faster than energy.[41] SCE's preferred forecast has peak demand growing at 3.1% annually, compared to the CEC's 1.6% peak growth rate. In particular, SCE states that CEC's data is inconsistent with SCE's analysis showing that "[r]esidential customers are building larger homes in the hotter inland areas, resulting in greater air conditioning usage and faster growth in peak demand."[42] Second, SCE defends its forecast as being more accurate than the CEC's with regard to future projections of declining load factor based on an analysis of historical trending data. And third, SCE claims that its load forecast is more current than the CEC's, since SCE included data through the summer of 2006, whereas the CEC forecast was published in September 2005.

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[41] Southern California Edison Company's Opening Brief, August 1, 2007, p. 7, citing SCE/Canning, Ex. 37 at pp. 34-35.

[42] *Southern Californa Edison Company's Opening Brief*, p. 6, citing Canning testimony, Ex. 37 at pp. 34-35.

SCE acknowledges that the CEC updated its peak demand forecast beyond 2005, but SCE still believes its own forecast is more accurate.

2.2.4.1. Summary of Parties' Positions on SCE's Load Forecast

Not all intervenors agreed with SCE's methodology or with its projected load growth. In particular, the CEC objects to SCE's manipulation of the CEC's IEPR numbers and SCE's attempt to "re-litigate" issues contested and addressed by the CEC in its 2005 IEPR proceeding. SCE presents its own load forecast as its recommended case instead of utilizing the CEC's IEPR forecast, and the CEC believes this causes SCE to over-inflate its need. CEC observes that, in the years 2010 and 2016, SCE's forecasted system need is, respectively, 1,364 MW and 2,007 MW greater than the IEPR forecast. According to the CEC, "these are very large forecast differences and not minor adjustments."[43]

SCE states it is not seeking to "re-litigate" the CEC's IEPR forecast in this proceeding. Rather, SCE proposes to evaluate its plan under an alternative load forecast, based on "new information" introduced and litigated in the proceeding, as permitted by the Scoping Memo.[44] SCE contends that, in compliance with the Scoping Memo, it evaluate both of its candidate plans under the CEC forecast. But, SCE believes that the Commission should approve its plan under the alternative SCE forecast, because it allegedly introduced sufficient evidence of new information.

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[43] *Post-Hearing Opening Brief of the California Energy Commission*, July 31, 2007.

[44] *Southern California Edison Company's (U-338-EE) Reply Brief*, August 30, 2007, at p. 4.

Citing the IEPR Ruling, the CEC insists that SCE has not met its burden of proving "material new information" and states that the information SCE introduced into this proceeding is "neither 'new' nor 'material'."[45] The CEC maintains that SCE is attempting to rehash arguments that were presented and rejected in the 2005 IEPR proceeding. According to CEC, in the 2005 IEPR proceeding, it specifically addressed and denied, the assertion that SCE's forecast reflects higher peak demand growth and greater declines in load factor than the CEC's own forecast. Therefore, the Commission should not accept this as "new" information. In response to SCE's claim that its forecast uses more current data than the CEC forecast, CEC points out that their analysis, which uses data from over 44 years, could "at most only be negligibly impacted by the addition of a single recent data point."[46] Consequently, the Commission should not be convinced that this constitutes "material" information.

Finally, CEC and CMA underscore the testimony of SCE's own witness, Art Canning, whose stated opinion that econometric techniques are superior to end-use techniques for long-range load forecasting was offered as the sole, unsubstantiated source of new information in this proceeding.[47] The CEC asks that the Commission direct SCE to use the CEC's forecast as they should have for their 2006 LTPP.

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[45] *Post-Hearing Opening Brief of the California Energy Commission*, July 31, 2007, at p. iv.

[46] *Post-Hearing Closing Brief of the CEC for Phase II of the LTPP Proceeding*, August 29, 2007, at p. 14.

[47] *Post-Hearing Opening Brief of the California Energy Commission*, July 31, 2007, at pp. 17-19, and *Opening Brief of the Competitive Market Advocates*, August 1, 2007, at p. 6.

In addition to preparing its own forecast, SCE modified the CEC's forecast to account for uncommitted EE that in SCE's opinion should not be represented in the forecast. As a result, SCE's "CEC" forecast, for the years 2010 and 2016, is 489 MW and 1,408 MW lower than the CEC's unmodified forecast. According to CEC witness, Ms. Sylvia Bender, "SCE incorrectly subtracts all post-2008 DSM from the Energy Commission forecast, when some of these effects are already in the forecast…"[48] Bender went on to explain that since the CEC uses an end-use modeling technique, "a large portion of the impacts attributed by SCE to utility programs…are already occurring in the [CEC] models as naturally occurring efficiency, market effects, or as the effects of building and appliance standards."[49] SCE responds that to put the CEC forecast on the same comparative basis as the SCE forecast, uncommitted EE must be deducted from the forecast.[50]

2.2.4.2. Discussion of SCE's Load Forecast

Pursuant to the IEPR Ruling, the test we apply here is whether SCE introduced "materially new information" into this proceeding that could not have been provided in the 2005 IEPR process. We concur with CEC's and CMA's position that SCE failed to demonstrate that its LTPP forecast was based on new and material information that was not available in the IEPR proceeding. Therefore, its recommended use of an alternative load forecast is unjustified.

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[48] *Prepared Direct Testimony of Sylvia Bender on Behalf of the California Energy Commission Regarding the Issue of Load Forecast in the Long-Term Procurement Plan of Southern California Edison (SCE),* March 1, 2007, at p. 10.

[49] *Id.*, at p. 13.

[50] *Southern California Edison Company's 2006 Long-Term Procurement Plan Reply Testimony – Vol. I*, at p. 37.

SCE also had no basis for modifying CEC's forecast, as SCE appears to have done so to compare the CEC's end-use model results with SCE's econometric model. The IEPR proceeding already concluded that the end-use forecast would be the approved methodology for long-term forecasting; tinkering with the CEC forecast to fit SCE's econometric approach is unwarranted. Consequently, SCE's need determination should be based on neither SCE's forecast nor SCE's representation of the CEC's IEPR forecast; rather, need determination shall be based on the 2007 IEPR base forecast, and Table SCE-1 reflects this forecasting adjustment to the need determination in SCE's recommended plan.

Regarding parties' concerns over SCE's assessment of departing load, we concur with the position that system need is not impacted by possible future load shifting due to DA and CCA, and that future DG and MDL is captured by historical trends used to develop the forecast.

2.2.5. SDG&E's Load Forecast

SDG&E derived its energy and peak demand forecasts for its LTPP from the CEC's June 2006 updated service area demand forecast. In addition to this base case, SDG&E developed both a high and low forecast reflecting possible changes in its bundled customer need. From SDG&E's perspective, the CEC's baseline forecast is conservatively low, so the utility used as its low case a forecast it argues is more moderate than the CEC's base case and uses a high case forecast that is twice its low case.

SDG&E applied the implied growth rates from the 2006 IEPR base case forecasts to the CEC's updated 2007 system demand levels to project loads

through 2016.[51] In consultation with the CEC, SDG&E made an adjustment to the IEPR forecast, adding back self-served load and uncommitted EE for the years 2009-2016. For the SDG&E service area, the modified CEC forecast projects customer growth at 1.2%, with load growth at 1.5% over the next 10 years. According to the CEC, SDG&E's assumptions for self-served load and energy efficiency are equivalent to the IEPR forecast.

SDG&E's high and low forecast cases reflect potential changes in its customer demand from movement to/from DA and CCA. SDG&E assumes a 1-2% load growth from 2007-2010 for its high forecast, followed by a .25-.50% growth adder for the rest of the planning period. SDG&E's low need case is half of the high case and assumes load loss from direct access over a five-year period, and a load loss from movement to a CCA in the next three years.

2.2.5.1. Summary of Parties' Positions on SDG&E's Load Forecast

In its initial testimony, DRA objected to SDG&E's upward adjustment to the IEPR forecast, which DRA believed, resulted in netting out of EE from SDG&E's plan in the years 2009-2016.[52] Later, in its opening brief, DRA retracted its objection, after it consulted with SDG&E, reviewed actual growth data, and was persuaded that the adjustment was practical and consistent with the intent of the 2005 IEPR forecast.[53] In rebuttal testimony, SDG&E witness, Robert Anderson, illustrated that the unadjusted CEC forecast indicated a 0.4% peak

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[51] *San Diego Gas & Electric's Opening Brief*, August 1, 2007, p. 7.

[52] Division of Ratepayer Advocates, *Report on the Long-Term Procurement Plans of San Diego Gas & Electric Company, Vol. D*, March 2, 2007, at pp. 12-14.

[53] *Opening Brief of the Division of Ratepayer Advocates*, August 1, 2007, at p. 10.

demand growth rate for the years 2009-2016 – "an implausibly low forecast." [54] The adjusted forecast raises the growth rate to 1.5%, which is still low compared to the 3% growth rate observed during the historical period, 1990-2006. According to DRA, the CEC is in agreement with SDG&E's treatment of load growth. Energy Division confirmed with CEC that SDG&E made a legitimate adjustment to the load forecast.

2.2.5.2. Discussion of SDG&E's Load Forecast

As noted earlier in the general forecasting discussion, we establish SDG&E's need determination using the CEC's 2007 IEPR base forecast. Table SDGE-1 reflects this adjustment to SDG&E's preferred plan demand forecast.

Based on the record in this proceeding, SDG&E's handling of the load forecast appears consistent with the intent of the CEC's 2005 IEPR. We note, however, that any manipulation of the CEC's approved forecast can raise legitimate questions from concerned parties. To the greatest extent possible, such adjustments should be avoided in future LTPP proceedings, in order to maintain the integrity and credibility of load forecast calculations across all jurisdictional utilities. Pursuant to the IEPR Ruling, we encourage the CEC and the utilities to resolve such inconsistencies in the IEPR process, and not the LTPP proceeding.

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[54] *Rebuttal Testimony of Robert B. Anderson San Diego Gas & Electric Company*, April 9, 2007, at p. 2.

Regarding departing load, we note that system need is not impacted by possible future load shifting due to DA and CCA, and that future DG and MDL is captured by historical trends used to develop the forecast.

2.3. Resource Assumptions

2.3.1. Energy Efficiency

The CEC forecasting methodology distinguishes between committed EE (which consists of EE resulting from approved and funded three-year forward Commission programs and is incorporated into the load forecast) and uncommitted EE (which consists of projected EE savings beyond and/or outside of the projected savings from committed EE programs and is treated as a resource). An issue that complicates this distinction considerably is that the CEC embeds into its forecast beyond the three-year program cycle some EE savings from existing programs (especially from Building Codes and Standards) that the IOUs count as uncommitted EE resources.

2.3.1.1. Summary of Parties' Positions on General EE Issues

DRA's analysis of each IOU's treatment of EE relative to the CEC's demand forecast reveals inconsistencies in how the Commission's assigned EE goals were applied. DRA recommends that the CEC and the utilities should come to a clear understanding of what proportion of the Commission's EE goals are embedded in the forecast and apply that forecast consistently in the LTPPs.

TURN states that the Commission ordered the utilities to reflect their EE goals in their LTPPs "so that ratepayers do not procure redundant supply-side resources over the short- or long-term." TURN fully concurs with this goal.

2.3.1.2. Discussion on General EE Issues

Similar to our position on the load forecasting debate, the Commission does not intend to relitigate EE treatment in the CEC load forecast in this proceeding. We concur with DRA's recommendation that the CEC and the IOUs need to come to a consensus on what proportion of the Commission's EE goals are embedded in the CEC load forecast, and with TURN's position that the IOUs accurately reflect their EE goals in their LTPPs.

We also agree with CEC's recommendation that the portion of IOU's EE goals not included in the forecast (i.e., the uncommitted EE that does not overlap with EE-induced reductions embedded in the CEC forecast in the years beyond the Commission EE programs' three-year program cycle) should be treated as a resource in the LTPPs.

It is important to clarify the definition of "uncommitted" in the context of the LTPPs. The terms, "committed" and "uncommitted," have specific meanings in the CEC demand forecast, however, in this Decision our use of the terms differs slightly and therefore requires clarification. According to the CEC, "committed programs are defined as programs that have already been implemented or for which funding has been approved."[55] In the CEC's use of the term, committed EE includes (but is not limited to) savings from the 2006-2008 EE program cycle, and is treated as a load forecast reduction embedded in the forecasting methodology. According to the CEC, "uncommitted effects are the *incremental* impacts of the level of future programs…impacts of new programs,

[55] CEC. *California Energy Demand 2008-2018 Staff Revised Forecast*, CEC-200-2007-015-SF2, November 2007, at p. 25.

and impacts from expansions of current programs."[56] The CEC's methodology calculates EE savings by looking at the unique characteristics (e.g., useful life) of each EE measure (e.g., lighting). If future portfolios contain a different mix of measures or new measures, those incremental savings would not be reflected in the CEC's demand forecast. Therefore, in the CEC's forecast "committed" EE projects EE savings from IOU programs through 2016, based, in part, on an assessment of the savings from the specific measures contained in the IOUs' 2006-2008 EE and earlier program portfolios. These EE measures are treated as a load forecast reduction embedded in the forecasting methodology.

In this Decision, we define "committed EE" as only those savings attributed to the IOUs' 2006-2008 and earlier EE programs, that meet or exceed Commission-adopted EE goals. We define "uncommitted" EE as the projected savings attributable to future EE program cycles (2009-2011 and beyond) that meet or exceed the Commission-adopted EE goals.[57] Due to the mechanics in the CEC's demand forecasting methodology discussed above, uncommitted EE (in this Commission's use of the term) is reflected in one of two places in the 2006 LTPPs: either: (1) embedded as a reduction in the load forecast (to the extent that uncommitted EE *does* overlap with the CEC's concept of committed effects); or (2) forecasted as an available resource (to the extent that uncommitted EE does *not* overlap with the CEC's concept of committed effects. The question that we must address here is the degree of "overlap" between our post-2008 EE goals

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[56] *Id.* (*emphasis added*)

[57] Hereinafter, all references to "committed" or "uncommitted" EE savings refers to the Commission definition, unless otherwise noted.

and the amount of savings from EE programs that are embedded in the CEC's demand forecast. A 100% overlap in uncommitted EE savings means that 100% of our EE goals are embedded in the CEC demand forecast.

In the PD, we applied a 60% overlap factor developed by the CEC for PG&E to both PG&E and SCE's uncommitted EE goals,[58] and we applied a 100% overlap factor to SDG&E's goals. We applied a different factor to SDG&E because we recently ruled that we would revisit SDG&E's EE goals in recognition of the fact that SDG&E's goals as a percentage of economic EE potential are higher than PG&E's or SCE's goals. (D.07-10-032, p. 77.)

Based on parties' comments, review of the CEC's updated forecast and in consultation with CEC staff, we have reviewed the uncommitted EE overlap factor used in the PD. The 60% overlap factor developed for PG&E was based on quantifications from an earlier forecast period that reflected a different mix of EE measures (i.e., 2004-2005 and earlier EE program cycles) than those represented in current programs (i.e., 2006-2008 EE program cycle). Because the EE savings embedded in the CEC forecast are program specific, the previous forecast did not accurately reflect the overlap in uncommitted EE savings associated with the 2006-2008 programs.

For example, the current mix of programs heavily emphasizes commercial lighting, which is already represented in the CEC's model as recently passed standards are applied to buildings being replaced or retrofitted. But those same lighting standards were not in effect for much of the time period which the CEC

[58] We also increase the goals via a line loss multiplier which reflects the additional benefits of this demand-side resource relative to generation resources.

used to calculate the 60% overlap factor, and the program mix during that period placed less emphasis on lighting.

In its "California Energy Demand 2008-2018 Staff Revised Forecast (November 16, 2007), the CEC undertook additional analysis of this issue, developing quantifications explicitly for the 2006-2008 portfolios. Tables in Appendix A of the document provide quantifications of the direct program impacts (i.e., the portion of uncommitted EE goals not embedded in the forecast based on past and existing measures). Using the same methodology employed by the CEC to develop the 60% overlap, with the updated data included in the Staff Revised Forecast, results in overlap factors for PG&E and SCE of 85% and 95%, respectively.

However, two factors may significantly impact the CEC analysis. First, we are confident that measures adopted in the 2009-2011 and 2012-2014 EE program cycles will result in lower overlap factors. In D.07-10-032, we required the IOUs to focus on programs that produce measures with longer-term savings, increase savings from existing measures, and emphasize programs to achieve market transformation for EE measures in their 2009-2011 EE portfolios. All of these directives are likely to result in major changes in the IOUs' portfolio composition, and thus, impact the CEC's demand forecasts in the future. Second, it is unclear how the CEC has incorporated cumulative EE savings into its forecast. In D.07-10-032, we reiterated our definition of cumulative savings:

> . . . in any given year, the IOUs are responsible for implementing additional energy efficiency measures that deliver savings *in that year* equal to the Total Annual Electricity Savings goal established for that year. In addition, the utilities remain responsible for ensuring the total savings available in a given year are equal to the cumulative savings goal for that year. If measures implemented in an earlier year to achieve that earlier year's annual electricity

> savings goal are no longer in service (*e.g.*, reached their full expected useful life), then in order to achieve their Total Cumulative Savings goal the IOUs will have to undertake additional actions to maintain the target efficiency resource. (Page 77.)

It is important to recognize two additional issues associated with this uncommitted EE overlap estimate. First, neither this analysis nor any other demand estimate affects the IOUs' EE goals themselves. The overlap estimate is an accounting exercise that attributes, based on the CEC's model architecture, the portion of uncommitted EE goals embedded in the CEC's forecast and the portion that are not – the CEC model does not set or adjust our EE goals. The IOU EE goals are adopted in the EE proceeding, and the analysis of what the level of goals should be and whether or to what extent the goals are achieved is based on the measurement and verification programs also developed within the EE proceeding.

Second, there is a clear recognition among the IOUs, the CEC, this Commission, and a number of intervenors, that these issues must be better understood, and a robust methodology is needed to quantify the portion of future EE program measures that are embedded in the CEC forecast and the portion that should be treated as a resource. In the CEC's 2007 Integrated Energy Policy Report (IEPR), the CEC has committed to "[c]onduct[ing] a public process including the CPUC, utilities and other stakeholders to determine an effective method to better delineate the energy efficiency savings assumptions in the Energy Commission's staff forecasts."[59] It is anticipated that this issue will be

[59] Executive Summary to 2007 Integrated Energy Policy Report, Committee Final Report, December 5, 2007, at p. 8.

the subject of significant evaluation in both the CEC IEPR update for 2008 and in the 2008 Long Term Procurement Proceeding at this Commission.

Based on the CEC's analyses and our direction to the IOUs in D.07-10-032, there is evidence that suggests that the overlap factors may be in the range of 60% to 95%. Until a methodology is developed to more accurately estimate future EE savings in the CEC forecast, we will apply an 80% overlap factor to PG&E and SCE. This is a reasonable adjustment to properly balance between reliability concerns that could result from underestimating the overlap factor and over-procurement that could result from overestimating the overlap factor. Consistent with the CEC's assessment and the concerns identified in D.07-10-032 regarding SDG&E's EE goals, we will retain the 100% overlap factor used in the PD for SDG&E. We recognize that further adjustments to the IOUs procurement need may be warranted based on the outcome of the completed analysis.

2.3.1.3. PG&E's EE Treatment

2.3.1.3.1. Summary of Parties' Positions

The CEC notes that in its revised testimony, PG&E proposed that the Commission's EE targets be used in establishing the range of need for its 2006 LTPP. The CEC notes that PG&E predicates achievement of the efficiency goals on changes to Commission policies for post-2008 programs. The CEC recommends that until such time as the Commission formally revises the established targets for energy efficiency, the Commission should limit the procurement of non-designated capacity by PG&E to amounts consistent with the levels of uncommitted energy efficiency set forth in D.04-09-060.

DRA states that in its supplemental filing, PG&E lists several energy efficiency policy issues that it urges the Commission to act upon in order for it to be able to meet its energy savings goals. DRA recommends that PG&E refer any issues it believes need Commission attention, such as those in its LTPP February 2, 2007 supplemental filing, to the Energy Efficiency proceeding. In that venue all interested parties can participate on the record.

NRDC notes that PG&E's Supplemental Testimony (February 2, 2007) indicates that PG&E has updated the EE section of its procurement plan such that EE savings in all planning scenarios now meet the existing goals, extending through 2013, set forth by the Commission in D.04-09-060. NRDC believes this update is reasonable, as it would be premature to adopt in the utilities' LTPPs any energy savings goals other than those that are Commission-approved, until the Commission adopts any changes to its energy savings targets in the energy efficiency proceeding.

2.3.1.3.2. Discussion

Adopting the CEC forecast builds PG&E's committed EE goals and the embedded portion of PG&E's uncommitted EE goals into the need determination. In its preferred plan, PG&E applies a CEC-recommended 60% "overlap factor" to adjust the amount of uncommitted EE available as a resource (i.e., it treats approximately 40% of the total uncommitted EE projections as uncommitted EE resources).[60] In this decision, we apply an 80% overlap factor for the reasons described above. Line 16 of Table PGE-1 reflects these adjusted uncommitted EE resource values, including a 10% line loss adder. This approach is consistent with PG&E's intention to include all of its EE goals in its LTPP, and it reflects the recommendations of CEC, DRA, TURN, and NRDC.

2.3.1.4. SCE's EE Treatment

2.3.1.4.1. Summary of Parties' Positions

According to the CEC, SCE recommends the use of "…levels of energy efficiency that are reliably achievable based on the most credible, up-to-date information and analysis available." The *Transmittal Report* clearly states that "SCE's long-term planning and procurement should be based on the targets established at the CPUC that consider statutory directives." The *Transmittal Report* goes on to say that "While some of the concerns raised by SCE [in their 2004 LTTP] may be valid, these concerns should be addressed through monitoring and evaluating approved programs and through future energy

[60] We anticipate that this percentage of overlap will change as new EE programs are developed, and that this shift will be reflected in future LTPPs.

efficiency proceedings at the Commission that establish funding for programs for 2009 and later years and adjust energy efficiency targets as appropriate."

The CEC states that SCE's use of levels of uncommitted energy efficiency for 2009 – 2016 that are below those set as targets by the Commission in D.04-09-060 in their Best Estimate Plan result in capacity shortfalls ranging from 72 MW – 77 MW in 2009 (depending on whether the Energy Commission or SCE load forecast is used) to 667 MW – 705 MW in 2016.

The CEC recommends that the Commission should direct SCE to incorporate the efficiency goals from D.04-09-060 into any resource plan that they intend to pursue. Any proposed changes to these efficiency procurement targets should be addressed in the appropriate efficiency proceedings at the Commission, and at such time that new targets are established, the procurement limits for non-designated capacity should be adjusted accordingly. SCE should not be allowed to re-litigate efficiency targets based on the State's statutory directives in this procurement proceeding.

According to DRA, the Commission should not allow SCE to use its own EE potential study as the basis for altering goals established in Commission decision D.04-09-060. If SCE has concerns about its energy efficiency savings targets, it should appropriately address them within the parameters of the energy efficiency proceeding.

NRDC states that SCE's Best Estimate Plan includes EE savings based on its own forecast of "maximum reliably-achievable and cost-effective potential," which is significantly lower than the Commission's current energy saving targets. SCE states that its forecast of the "maximum reliably-achievable potential" is based on an SCE-specific version of a recent statewide potential study. However, NRDC notes that statewide potential study estimates that the

maximum achievable cost-effective energy and demand savings for the three California IOUs over the next decade is 23,974 GWh and 4,887 MW, respectively, which is slightly higher than the 10-year saving targets adopted by the Commission in D.04-09-060 for all three utilities (23,183 GWh and 4,885 MW). Since this most recent potential study does not appear to show any reductions in the cost-effective achievable potential since the last time the Commission adopted energy saving targets, it appears reasonable to NRDC for SCE to plan to continue to meet the Commission's targets.

NRDC also notes that SCE has used assumptions in developing its efficiency forecast that result in an underestimation of the cost-effective achievable savings. First, SCE states that it uses avoided costs that exclude the environmental adders, an assumption that effectively reduces the amount of cost-effective savings and is contrary to Commission policy. Second, SCE assumes a 10-year average life, which is shorter than the 12-year average life that the efficiency programs have demonstrated historically; this assumption also reduces the amount of cost-effective savings. Third, SCE estimates a "total resource cost" (TRC) cost-benefit ratio of 2.38 for the 2006-08 program cycle, but estimates a TRC ratio of less than 1.35 (a 43% reduction) for every year thereafter, without providing explanation. It is unreasonable to assume that the cost-benefit ratio will drop so dramatically following the current program cycle. And finally, even with these assumptions, SCE shows an average lifecycle cost of the efficiency programs for 2009-2016 of 3.3¢/kWh, which is significantly less than its forecast of the expected market marginal price of approximately 5¢/kWh (which, in turn, would be less than the full avoided cost), implying that more cost-effective savings would remain untapped.

NRDC concludes that SCE has not provided sufficient evidence that its Best Estimate Plan is superior to the Required Plan, or sufficient justification for not planning to achieve its EE goals. The Commission should require SCE to plan to achieve the current targets unless and until the Commission makes a different determination in R.06-04-010.

2.3.1.4.2. Discussion

We concur with NRDC's evaluation of EE potential and its conclusion that SCE has not provided sufficient justification for not planning to achieve its EE goals. Consequently, by adopting the CEC forecast we build SCE's committed EE goals and the embedded portion of its uncommitted EE goals into the need determination.

In addition, we find that SCE incorrectly embeds all of its EE goals into its load forecasts, and as a result of this approach we have no SCE-specific information on the level of overlap between CEC's forecast beyond the committed program years and SCE's uncommitted EE goals. In this decision, we apply an 80% overlap factor for the reasons described above. Consequently, Line 12 of Table SCE-1 reflects these adjusted uncommitted EE resource values (and an 8% line loss adder). This approach reflects the recommendations of CEC, DRA, TURN, and NRDC.

2.3.1.5. SDG&E's EE Treatment

2.3.1.5.1. Summary of Parties' Positions

The CEC states that for program years 2004 and 2005, SDG&E met and exceeded the goals established by the Commission for both energy savings and peak savings. SDG&E's 2006-2008 portfolio exceeds the Commission targets, but SDG&E's procurement filing "only reflects the Commission targets adopted in

D.04-09-060 because final measured and certified results may be less than the portfolio targets."

The CEC also notes that SDG&E indicates that the Commission's EE goals are very aggressive and may not be attainable from a technical standpoint or at cost-effective levels for the long term. The original goals decision knowingly set SDG&E's goals at 118% of the maximum achievable potential. The decision recognized the need for a fresh look at the underlying 2004-2005 baseline assumptions that created the disparity when the savings potential estimates are updated in the future.

The *Transmittal Report* acknowledges agreement that the post-2009 goals are "somewhat unrealistic and will be revisited and revised in the next Commission proceeding when new cost-effectiveness and performance information is available." SDG&E expects that "when the Commission updates its energy savings goals for the next program cycle 2009-2011, it will adopt more realistic goals that will be consistent with future energy efficiency study estimates for SDG&E's service territory."

UCAN notes that improvements to SDG&E's distribution system can result in significant energy efficiency savings not included in SDG&E's LTPP, based on the findings of an Energy Policy Initiatives Center (EPIC) study of "Smart Grid" technologies that UCAN and SDG&E jointly commissioned (the 193-page study was provided as an attachment). Despite the fact that SDG&E was a co-funder of the study, and despite the fact that it was completed by the fall of 2006, it is not mentioned nor is its recommendations incorporated into SDG&E's LTPP. Also excluded from the LTPP is the fact that SDG&E's distribution grid upgrade is likely to occur during the LTPP time frame. Pursuant to a settlement entered into in early 2007, the Commission is likely to

allow SDG&E to move forward with a full deployment of its Smart Grid upgrades that would be completed by
2011 - five years before the end of the LTPP.

UCAN states that one very tangible and real example of Smart Grid upgrades is the home area network (HAN) that is to be fully deployed throughout San Diego County by SDG&E by 2011. UCAN also states that SDG&E states "the Commission's goals in the area of energy efficiency…are very aggressive," but offers no support for this self-fulfilling assessment. UCAN disagrees, due to anticipated advances over the 10-year planning period in Light-emitting diode (LED) and distribution grid technologies.

2.3.1.5.2. Discussion

SDG&E adds its uncommitted EE goals to the CEC forecast, then subtracts them back out as a resource, which is essentially equivalent to embedding them fully into the forecast. While this approach is not consistent with the CEC's methodology, the CEC has acknowledged that based on its forecast for SDG&E and the aggressive goals adopted in the EE proceeding for SDG&E, this is an appropriate treatment of SDG&E's EE goals. Consequently, we adopted SDG&E's treatment of its load forecast and Table SDGE-1 does not include a separate line that treats uncommitted EE as a resource.

We also expect that if, per UCAN's suggestion, additional EE opportunities arise in excess of existing program levels as a result of SDG&E's Smart Grid upgrades, SDG&E will reflect these improvements in future EE goals in the EE proceeding (and those goals will in turn be incorporated into future LTPPs, either as embedded in the adopted CEC forecast or as an uncommitted EE resource).

2.3.2. Demand Response

DR gives customers the ability to reduce or adjust their electricity usage in a given time period or shift that usage to another time period in response to a price signal, a financial incentive, or an emergency signal.[61] The Commission distinguishes two forms of DR: reliability-triggered and price-responsive. Reliability-triggered programs are typically used on short notice, when grid conditions may warrant an immediate load reduction "in which customers agree to reduce their load to some contractually-determined level in exchange for an incentive, often a commodity price discount."[62] Customers participating in reliability-triggered programs agree to quickly curtail their energy use when asked in exchange for a reduction of rates or, possibly, an increase in rates should they be unwilling or unable to reduce their load when asked.

Price-responsive programs are those that respond when market prices reflect a financial benefit to customers to reduce energy consumption "in which customers choose how much load reduction they can provide based on either the electricity price or a kW or kWh load reduction incentive." [63] Customers participating in price-responsive programs have the ability to curtail their energy use when market prices indicate increased demand in the system.

Demand response is second in the EAP II loading order, after energy efficiency. In EAP II, state agencies are called to "Integrate demand response

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[61] D.03-06-032, Attachment A, California Demand Response, A Vision for the Future, p. 1.

[62] D.06-03-024, p. 5.

[63] D.06-03-024, p. 5.

into retail sellers' electricity resource procurement efforts so that these programs are considered equally with supply options."[64] In D.03-06-032, the Commission established DR goals for the IOUs at "5% of the annual system peak demand"[65] and the goal is met with "programs and tariffs that are triggered by price and not by emergency conditions."[66] The IOU LTPPs provide explanation of their DR programs of both types and how they fit into their DR goals and strategies.

2.3.2.1. Summaries of Parties' Positions on DR Issues

2.3.2.1.1. Parties' Positions on PG&E's DR Treatment

In compliance with the Scoping Memo, PG&E detailed both its price-responsive and reliability-triggered DR programs in its LTPP. PG&E advocates counting both types of DR programs to meet Commission goals. By counting just price-responsive programs, PG&E could achieve the targets in all scenarios under the Increased Reliability and Preferred Resources Plan. They would be considerably less successful meeting the Commission goals under the Basic Procurement Plan or the Increased Reliability Plan.[67]

Aglet believes that PG&E's DR assumptions are unrealistic.[68] Aglet testified that PG&E assumes existing programs will not change for 10 years and that its proposed enhancements will not increase from 2010-2016. The historical

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[64] Energy Action Plan II, Demand Response Key Action #7, p. 5.

[65] D.03-06-032, p. 9.

[66] D.03-06-032, footnote, p. 8.

[67] PG&E 2006 LTPP Vol. 1 amended, VI-7.

[68] Aglet Initial Testimony, pp. 1-10.

growth of demand response programs is not fully reflected in PG&E's demand response assumptions. Aglet recommends that for planning purposes a 10% annual growth rate in DR be assumed. Without additional information on what additional DR programs can be added or how existing programs can be improved, PG&E finds Aglet's recommendation without merit and not within the scope of the LTPP proceeding.[69]

DRA recommends that PG&E adjust its recommended plan to reflect the position that all Commission-approved programs are cost-effective as well as to use "Best Estimates" of MW reductions for all DR programs in the near-term and for reliability DR programs for 2009-2016. It should also ramp-up price-responsive DR to the full 5% goal during the first summer after the "full deployment" year of Advanced Metering Infrastructure (AMI) in 2011. DRA finds these assumptions are reasonable for planning purposes given the numerous initiatives underway to increase the availability of DR.[70]

DRA believes that until DR cost-effectiveness tests and measurement protocols are developed pursuant to R.07-01-041, PG&E is not in a position to determine which DR programs are cost effective. For the purposes of LTPP, DRA believes PG&E should assume all Commission-approved programs are cost-effective.

WPTF testified that PG&E's DR forecasts are inflated based on PG&E's LTPP plan noting unresolved issues in some DR programs. WPTF cautions the Commission not to endorse PG&E's DR projections without careful analysis and

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[69] PG&E Rebuttal Testimony, p. 4-3.

[70] DRA Initial Testimony, Vol. B, pp. 20-21.

review.[71] PG&E claims that its updated LTPP identifies all DR programs the Commission has either approved (AMI) or expressed interest in (AC recycling) and its DR projections are reasonable.[72]

[71] WPTF Initial Testimony, p. 2-7.

[72] PG&E Opening Brief, p. 12.

2.3.2.1.2. Parties Positions on SCE's DR Treatment

The SCE LTPP presents two plan scenarios that both meet Commission targets. Its Required Plan meets the goals through price responsive programs only. SCE cautions that though customers are enrolling in the price responsive programs many are not actually responding to events. In its Best Estimate plan, SCE meets the Commission targets by also using reliability driven DR that it considers most reliable and realistically achievable levels of DR. SCE asks the Commission to approve their Best Estimate Plan.

The CEC states that SCE implements the loading order as specified in the goals decision in the Required Plan, but not in its Best Estimate Plan.[73] SCE states that it "first included the maximum amount of cost effective energy efficiency, demand response and distributed generation that is expected to be developed in the future."[74] SCE further states that its candidate plans "include all regulatory-preferred resources first and then identify remaining capacity and energy need. The remaining need is met on a least-cost basis using peaking, intermediate, and base load resource types."[75] SCE contends that its Best Estimate Plan is "based on procurement goals that are both achievable and cost-effective."[76]

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[73] CEC Initial Testimony, (Bender) EE and DR in the LTPP of SCE, p. 12.

[74] SCE 2006 LTPP Vol. IB, p. 48.

[75] SCE 2006 LTPP Vol. IB, p. 49.

[76] SCE 2006 LTPP Vol. IB, p. 52.

The CEC states that SCE argues that the 5% DR goal would be exceeded "if all types of demand response resources were taken into account" and argues that the Commission policy of counting only "price-responsive" DR toward the goal "ignores the important role served by other types of demand response programs."[77] SCE asserts that despite their "aggressive outreach and education campaign" and the "success" they have achieved by enrolling 350 MW of price-responsive DR resources that only 50 MW of actual load reductions from these customers has actually been observed.[78]

The CEC states that SCE is not consistent with the Energy Commission's Transmittal Report because the level of DR reported in SCE's Best Estimate Plan "is the level that is reliably and realistically achievable for resource planning purposes." This is inconsistent with the *Transmittal Report,* which specifically provides that "SCE's long-term planning and procurement should be based on the targets established at the Commission that consider statutory directives."[79]

The CEC recommends that until a revision takes place and new goals are established, the Commission should direct SCE to incorporate the goals from D.03-06-032 and D.05-01-056 into any resource plan that they intend to pursue. Any proposed changes to these demand response targets should be addressed in the appropriate proceedings at the Commission. SCE should not be allowed to

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[77] CEC Initial Testimony, (Bender) EE and DR in the LTPP of SCE, p. 15.

[78] SCE 2006 LTPP Vol. IB, p. 71.

[79] CEC Initial Testimony, (Bender) EE and DR in the LTPP of SCE, p. 16.

re-litigate demand response targets based on the State's statutory directives in this procurement proceeding.[80]

DRA recommends that SCE adjust its recommended plan to reflect the position that all Commission-approved programs are cost-effective as well as to use "Best Estimates" of MW reductions for all DR programs in the near-term and for reliability DR programs for 2009-2016. It should also ramp-up price-responsive DR to the full 5% goal during the first summer after the "full deployment" year of AMI in 2013. DRA asserts that these assumptions are reasonable for planning purposes given the numerous initiatives underway to increase the availability of DR.[81]

DRA believes that The Best Estimate plan does not reflect the Commission's 5% goal for price-responsive programs even over the long term. The plan shows SCE reaching only 75% of the Commission's 5% goal in 2016. SCE's Required Plan, on the other hand, reflects the Commission's 5% goal for price-responsive programs throughout 2007-2016. DRA believes neither the Best Estimate plan nor the Required Plan include realistic DR reductions that can be achieved throughout 2007-2016.

2.3.2.1.3. Parties' Positions on SDG&E's DR Treatment

SDG&E's LTPP includes the approved 2007-2008 DR targets plus 2009-2016 targets of 5% of peak.[82]

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[80] CEC Initial Testimony, (Bender) EE and DR in the LTPP of SCE, pp. 16-17.

[81] DRA Initial Testimony, Vol. C, pp. 19-20.

[82] SDG&E 2006 LTPP Vol. 1, p. 186.

Aglet recommends that SDG&E's DR should use a 10% growth rate over the 10-year planning period, having over 900 MW of DR by 2016.[83] SDG&E claims that based on that recommendation, it would have to call on DR for up to 250 - 300 hours per year, which is beyond the dispatch limit envisioned in current DR programs.[84] SDG&E also claims that Aglet incorrectly states that SDG&E's DR results have grown from 75 MW in 2005 to 218 MW in 2007. SDG&E explains that Aglet's claim is based on targets from SDG&E's expected peak DR enrollment and not actual peak reduction.

The CEC states that SDG&E addresses the issue of demand response in its LTPP filing by using three different planning scenarios, all "derived from the Energy Commission's June 2006 updated demand forecast," for capacity resources in their LTPP: a "preferred resource" scenario, and "high" and "low" cases. Each is reported to use the "adopted targets for DR." The plan states that the DR goals are "very aggressive" and cautions that "SDG&E has not determined" whether the goals can be met cost-effectively. However, the report also notes that "holding room for these goals" in the long-term procurement plans "means that resource commitments today do not foreclose opportunities in these policy areas in the future" and suggests that the two-year planning review process "provides ample room for adjustment." Consistent with this perspective, SDG&E reports actual projected enrollment of DR resources in 2007

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[83] Aglet Initial Testimony, pp. 6-4, 6-5.

[84] SDG&E Rebuttal Testimony, (Anderson) p. 4.

and 2008 while including the DR targets for years 2009-2016 in all three scenarios of their capacity resource accounting tables.[85]

CEC recommends that the Commission direct SDG&E to provide additional testimony describing the process SDG&E used to forecast the DR goals for each scenario for 2009-2016 and to either account for the shortfalls or amend the capacity resource tables. CEC testified that SDG&E should also be directed to amend its LTPP to reflect any changes in DR impact measurement and DR goals that result from R.07-01-041.[86]

SDG&E clarifies that it uses the Commission definition of "system peak" for DR as that from bundled and direct access customers. SDG&E understands that CEC used what is often referred to as "area peak" which adds to system self-served load and uncommitted energy efficiency. SDG&E claims that it is the CEC that is using an "adjusted peak."[87]

DRA recommends that SDG&E adjust its recommended plan to reflect the position that all Commission-approved programs are cost-effective as well as to use "Best Estimates" of MW reductions for all DR programs in the near-term and for reliability DR programs for 2009-2016. It should also ramp-up price-responsive DR to the full 5% goal during the first summer after the "full deployment" year of AMI in 2011. These assumptions are reasonable for

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[85] CEC Initial Testimony, (Bender) EE and DR in the LTPP of SDG&E, p. 4.

[86] CEC Initial Testimony, (Bender) EE and DR in the LTPP of SDG&E, p. 11.

[87] SDG&E Rebuttal Testimony, (Anderson) p. 3.

planning purposes given the numerous initiatives underway to increase the availability of DR.[88]

DRA states that SDG&E presents a "Preferred Plan" with a "base" need scenario and also with a "high" need and a "low" need scenario. None of the three scenarios include a "Best Estimate" scenario that reflects realistic DR reductions that can be achieved in the mid-term based on the actual DR reductions achieved during summer 2006. SDG&E simply assumes that as early as 2009 it will procure and meet its 5% goal. DRA thinks this is unrealistic given that SDG&E does not expect to reach even 50% of its 5% goal in 2008 and it does not expect to fully deploy its AMI until 2011, at the earliest. DRA believes SDG&E could expand its price-responsive programs only gradually corresponding to its AMI deployment and reach the 5% goal by 2011.

While agreeable to DRA's recommendation to ramp up its 2009-2010 DR targets to get to 5% by 2011 while its AMI program is being installed, SDG&E clarifies that DR targets for 2008 and on will be set in R.07-01-041.

2.3.2.2. Discussion

In their attempts to meet Commission goals, the IOU LTPPs provide demand response forecasts and expectations based on enrollment and percentage of the enrollment that is expected to actually participate. Considering the present state of the IOU's DR portfolios and the limited IOU experience with the effects of AMI, we believe the IOUs projections are an acceptable estimate of firm DR reductions for the purposes of planning for new supply-side resources. We emphasize here that the IOUs should continue to aggressively increase their

[88] DRA Initial Testimony, Vol. D, p. 15.

DR portfolios to meet the 5% system peak demand goal until that goal is otherwise modified in R.07-01-041 or any subsequent DR proceeding.

The CEC, DRA, Aglet, and WPTF recommend changes to the projection, implementation, and counting of the IOU's DR resources. These issues are best addressed in R.07-01-041, and we will not adjust or revisit DR program goals or enrollment estimates in this proceeding.

2.3.3. Renewable Energy

The State of California has adopted aggressive policies focused on increasing the state's reliance on renewable resources for its energy needs. As stated in EAP II, adopted by the Commission and the CEC: "California can reduce its greenhouse gas emissions, moderate its increasing dependence on natural gas, and mitigate the associated risks of electricity price volatility by aggressively developing renewable energy resources to meet the Renewables Portfolio Standard (RPS) requirements." In addition, the development of renewable energy will likely be a key component in achieving GHG reduction goals as defined in AB 32. The standards and guidelines of the RPS program were outlined in detail in R.06-05-027, the *Rulemaking to Implement the California RPS Program*, and as such, many of the issues raised by IOUs and Intervenors alike are best addressed by that or subsequent RPS proceedings. However, several areas of the RPS proceeding have a direct overlap with this LTPP proceeding and will thus be analyzed in detail below. Furthermore, this decision attempts to provide clarification and guidance on uncertainties in the RPS program that were raised by both IOUs and Intervenors in the testimony.

In the Scoping Memo of this proceeding, IOUs were directed to provide detailed information on their individual renewable energy procurement strategies for the planning period, including information on existing and

planned renewable projects. Furthermore, IOUs were directed to discuss their compliance with RPS program targets and to discuss renewable integration costs, as necessary. Finally, IOUs were directed to show how they could get to a 33% renewables target by 2020, as discussed in EAP II. This final mandate is examined in the 33% Renewables Target section of this decision.

D.04-12-048, FOFs #53 and #54, provided the IOUs with direction for their renewable procurement strategies:

> 53. 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. If an IOU succeeds in procuring sufficient renewable resources to meet its RPS Annual Procurement Target (APT) via an all-source RFO, it will not be required to undertake an RPS-specific solicitation.
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> 54. …The IOUs must provide detailed annual analysis of renewable resource potential over the 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.

2.3.3.1. Summary of Parties' Positions on General Renewable Energy Issues

GPI states that all three IOUs expect to achieve 20% renewables by 2011 or 2012; however, GPI is concerned that the IOUs assume that 100% of their signed RPS contracts for projects under development will be fulfilled. GPI disagrees with this assumption and prefers the CEC's suggestion of a 70% contract fulfillment rate. For this reason, GPI feels that none of the three IOUs are on a trajectory to achieve the 20% goal by 2010. GPI disagrees with PG&E and SCE's arguments that California is experiencing a shortage of renewables, agreeing

instead with the CEC that California has a bountiful endowment of renewable resources. GPI notes that, to the extent that there are impediments to the development of new renewable generating facilities in California, it is not in the area of inadequate physical renewable resources or inadequate technologies to harness these resources. GPI feels that the real problem might be an unrealistic view of what "reasonably priced renewables" means.[89]

IEP states that the IOUs, particularly PG&E and SCE, assume unreasonably high percentages of recontracts with qualifying facilities and other renewable contracts due to expire during the planning period. IEP suggests that a re-contracting rate of zero would allow the IOUs to most accurately calculate their expected need and adequately solicit offers.[90]

UCAN recommends the development of energy parks, referred to as "site banking" to harvest the sun and other renewable energy sources.

2.3.3.2. Parties' Positions on PG&E's Renewable Energy Treatment

PG&E states that it strongly supports renewable resources and renewable energy's preference in the State Loading Order. PG&E intends to aggressively pursue renewable energy procurement throughout the planning horizon of the 2006 LTPP to meet and exceed the renewable targets set by SB 107 and Commission decisions.[91] PG&E also intends to develop new programs, including the Emerging Renewable Resource Program (ERRP) in order to further

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[89] GPI Initial Testimony.

[90] IEP Initial Testimony.

[91] PG&E Volume I at V-20.

facilitate the development of available renewable energy resources.[92] PG&E states that it filed its 2006 RPS compliance report on August 1, 2006, showing RPS-eligible deliveries of approximately 8,800 GWh in 2006.[93] PG&E plans to pursue RPS targets through annual RPS solicitations and bilateral agreements.

PG&E states that it solicited renewable ownership offers for the first time as part of its 2005 RPS plan; however, no ownership offers were competitive with the power purchase offers received. In 2006, PG&E expanded its 2006 RPS solicitation to include offers for sites on which the utility could develop eligible renewable ownership options, and PG&E planned to employ, for the evaluation of any such offers, the protocol used to evaluate offers for utility ownership.[94]

PG&E believes that the development of new renewable technologies and resource areas is essential to a healthy renewables market in the post-2010 time frame and is actively pursuing a number of emerging technologies. Furthermore, PG&E seeks to build upon its efforts with emerging technology by proposing the ERRP.[95] In order to support development of existing renewable resources, PG&E plans to expand transmission and engage in active market development and resource validation. PG&E's resource mix for planned renewable resources includes wind, geothermal, solar, biomass, emerging

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[92] *Id.*

[93] Actual 2006 deliveries for PG&E were 9,114 GWh.

[94] PG&E Volume I at V-24.

[95] The May 2, 2007 R.06-02-013 ruling determined that PG&E's ERRP proposal would be more appropriately submitted as a separate application. PG&E and SDG&E subsequently filed a joint application, A.07-07-015.

technologies, repowering, British Columbia renewables[96] and identification of other available renewable resources in California.[97]

PG&E forecasts that 50% of all renewable energy added between 2007 and 2016 will be from wind. However, as a "safety-valve" pending more knowledge of the operating effects and integration costs of intermittent renewables, PG&E established a planning and modeling limit that no more than 10% of the bundled energy load should be made up of incremental intermittent wind energy. That level was never achieved in the plan by 2016. PG&E states that CEC and NRDC have misunderstood the purpose and effect of this 10% limit. The theoretical limit did not include projects currently delivering, under contract but not delivering, or wind that has been firmed and shaped before delivery. Had these resources been included, the threshold limit would have been more than 13% of bundled energy load.[98]

GPI strongly disagrees with PG&E's statement that PG&E will be unable to reach the statutorily mandated 20% renewables by 2010 but will achieve 20% by 2011 or 2012. GPI states that, by its calculations, PG&E will achieve only 15.2% renewables in 2010, thus making it highly unlikely that PG&E will achieve 20% by 2012.

The CEC argues that PG&E's plan does not meet the 20% renewables goal by 2010; rather, PG&E anticipates achieving approximately 18% to 19%

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[96] Emerging technologies and British Columbia renewables are more long-term solutions that may help to meet a 33% renewables target rather than the 20% 2010 target.

[97] PG&E Volume 1 at IV-33.

[98] PG&E Reply Comments.

renewable deliveries in 2010 and 20% in 2011 or 2012, depending upon the scenario. The CEC claims that PG&E should be required to develop a conforming plan showing what steps they could take to meet the 20% by 2010 goal. The CEC recommends at least a 30% margin of safety to account for contract failure. The CEC states that PG&E should be directed to not limit intermittent renewables to 10% of its bundled sales.

DRA proposes that the Commission require PG&E in its "preferred plan" to separate, by resource, the costs of increased reliability from the costs of increased use of preferred resources. DRA notes that the combined costs do not indicate the incremental cost of using additional renewable resources.

NRDC posits that PG&E gives no rationale for the 10% cap on intermittent renewables that it proposes in its LTPP. NRDC states that studies of several electricity systems have shown that wind energy penetration levels of up to 20% can be readily accommodated at minimal cost. NRDC thus suggests that PG&E amend its plan.

2.3.3.3. Parties' Positions on SCE's Renewable Energy Treatment

SCE estimates that 16.5% of its 2006 retail load was served by eligible renewable resources. SCE's strategy for meeting the 20% RPS by 2010 includes using existing ERRs currently under contract, projects for which SCE executed contracts in its 2003 and 2005 solicitations and projects with which SCE will execute contracts in its 2006 RPS solicitation.[99,100] For planning purposes, SCE

[99] SCE Volume 1B at 76.

assumed that all contracts executed in the 2003 and 2005 solicitations will result in meter-spin commencing consistent with current projections of transmission capacity becoming available.[101] This assumption relies on the timely addition of transmission capacity to permit deliveries under contracts executed by SCE with ERRs in these three solicitations. SCE assumed a re-contracting rate of 90% through 2013 with existing resources currently under contract with SCE. In 2014 through the end of the planning period, SCE dropped that re-contracting rate to 60%.

SCE notes that GPI has offered no basis for its argument (discussed below) for discounting the likelihood that signed contracts will come online, and further notes that SCE plans for a variety of contingencies, including transmission considerations, contract delay, and unexercised options. SCE did assume that most of the executed projects will come online, but not at the maximum potential of the contract in cases in which project expansions are an option. SCE states that this issue has also been addressed in R.06-05-027, the *Rulemaking to Implement the California RPS Program*.

SCE contends that existing law requires the Commission to develop a market price referent (MPR). To the extent that the contract price of renewable generation exceeds the MPR, it is to be funded with Supplemental Energy Payments (SEPs), which are supported by the public goods charge (PGC). If the SEP funds are exhausted, the obligation to procure renewable energy priced

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[100] In addition, at the time of this writing, SCE has issued and closed a 2007 RPS solicitation.

[101] SCE Volume 1B at 77.

above the MPR is relieved. Thus, the overall cost of RPS contracting could act as a constraint on procurement.[102] Upon exhaustion of SEP funds, it is up to the Legislature to either increase the amount of SEP funding or abandon above-market RPS procurement activities.[103] The planning scenarios presented by SCE assume a sufficient level of SEP funding to cover the above-market costs of any renewable contracts entered into during the planning period; however, the truth of this assumption is not verifiable, as the actual future price of contracted RPS energy will determine how quickly the SEP fund is exhausted.[104]

GPI maintains that SCE had the largest initial base renewable portfolio of the three IOUs; however, due to load growth, SCE has seen a decrease in the percentage of its load served by renewables. GPI argues that SCE predicts assured achievement of the 20% standard by 2011 yet provides little detail as to how it will move beyond its current portfolio of operating renewable generators and PPAs with renewable projects under development. GPI notes that, like PG&E, SCE assumes a 100% success rate for all projects under development; using an assumed success rate of 70%, SCE would see its renewable percentage shrink steadily. GPI comments that SCE relies heavily on the success of the

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[102] SCE Volume 1B at 75.

[103] SCE initially made reference only to the PGC; however, SEP payments were the actual funding source, which were supported by the PGC. This change was made for clarification purposes.

[104] We note that SB 1036, effective January 1, 2008, abolishes the current SEP process and redistributes PCG money among the large utilities. SCE's discussion is, thus, rendered moot.

Tehachapi project, which puts the company at substantial risk of delay in achieving RPS compliance due to potential transmission project delays.

SCE contends that its LTPP meets the 20% renewables goal by 2010 in the two scenarios analyzed in its Required Plan and Best Estimate Plan, with one exception; however, the CEC states that both SCE's testimony and the CEC's 2006 IEPR cast doubt on whether physical deliveries will actually be sufficient by 2010. The CEC argues that the Commission should not approve SCE's Best Estimate Plan and that SCE should be required to amend its Required Plan to better reflect the cost-effectiveness of renewable resources.

NRDC claims that SCE assumes that the cost of renewable resources is 25% above the Commission's MPR. NRDC notes that, at the time of NRDC's filing, only two of the contracts signed under the RPS exceeded the MPR. While SCE offers several reasons for this increase in cost, NRDC claims that SCE does not consider countervailing factors, such as economies of scale, that tend to lower cost.

2.3.3.4. Parties' Positions on SDG&E's Renewable Energy Treatment

SDG&E's position is that it continues to move aggressively toward the 20% by 2010 requirement. To achieve this objective, SDG&E plans to issue competitive solicitations, pursue ownership opportunities, and, to the extent necessary, utilize flexible compliance mechanisms permitted under the RPS program.[105] SDG&E's resource assumptions presented in this LTPP assume that new transmission facilities will be built as required to allow SDG&E to access

[105] SDG&E Volume 1 at 189.

out-of-area renewables by 2010 and beyond.[106] SDG&E plans to meet the 20% renewables goal, in part, through RFOs issued in 2003, 2004, 2005, and 2006. In addition, SDG&E is considering ownership of certain renewables and will continue to do so. SDG&E estimates that it will need to procure incremental renewable energy in 2010 equal to approximately 3.6% of its portfolio needs; that is, SDG&E currently has 16.4% of renewable energy under contract for delivery in 2010. SDG&E may contract for energy in excess of this amount due to contract delivery uncertainties. SDG&E states that lack of transmission is a major impediment to achieving 20% by 2010 and higher percentages in future years.[107]

GPI finds that SDG&E has made impressive progress in procuring renewables, exceeding its annual RPS procurement target in every year of required program performance. Nevertheless, SDG&E is still a long way from achieving the 20% goal by 2010. GPI is encouraged by SDG&E's recognition of the need to over procure renewables in order to account for contract fulfillment risk. GPI notes that SDG&E, due to the inherent geographic limitations of its service territory, has a particularly strong need to develop new transmission capacity to bring renewable power into its territory from adjacent jurisdictions and/or be given the ability to use tradable RECs as a means of compliance with the RPS.

GPI, along with the CEC, raise objections to SDG&E's desire to roll renewable procurements into an all-source RFO process for renewable energy procurement beyond 20%.

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[106] SDG&E Volume 1 at 190.

[107] SDG&E Volume 1 at 192.

SDG&E contends that its LTPP meets the 20% renewables goal by 2010 in its preferred plan. As in the case of SCE, however, both SDG&E's testimony and the CEC's 2006 IEPR Update cast doubt on whether physical deliveries will be sufficient by 2010. The CEC also argues that SDG&E's LTPP does not include an adequate margin of safety to prepare for possible contract failure.

2.3.3.5. Discussion

The State of California has taken an aggressive position toward achieving energy independence and reduced GHG emissions. The development of renewable energy is an important component to achieving these goals and has further environmental, economic, and public health benefits enumerated in the Legislation establishing the RPS program. Achievement of California's ambitious renewable energy goals is thus of great importance to the Governor, the State of California, and the Commission.

In this proceeding, the three IOUs were directed to provide detailed information on their individual renewable energy procurement strategies for the planning period, including information on existing and planned renewables. Furthermore, IOUs were directed to discuss their compliance with RPS program targets – including such issues as procurement, resource mix, resource potential and rate impacts – and to discuss renewable integration costs, as necessary. The Commission finds the IOUs' LTPPs provide, with some exceptions, sufficient information to meet the minimum requirements mandated in the Scoping Memo. However, all LTPPs could have been strengthened by providing more detailed information that would more fully enable the Commission to understand how each IOU's long-term RPS strategy fits into and impacts a more integrated approach to procurement. Although not directly mandated in the Scoping Memo, the plans could have more completely addressed and analyzed the

possibility of contract failure and its impact on the IOUs' respective strategies. In addition, the plans would have been strengthened by providing renewables needs assessments that are informed by general and resource-specific uncertainties (general DA departure, increased competition for renewables from municipal utilities, CCAs, and neighboring states, project performance, technological change) and risks (contract failure, transmission project delays). We recognize that a more detailed filing of short-term renewable procurement plans occurs within the RPS proceeding; however, the LTPP proceeding is designed to capture the IOUs long-term renewable procurement plans. In recognition of the direction the State is taking in regards to overall IOU procurement, the IOUs did not make sufficient traditional resource need determinations based on "reasonable expectations" of renewable supply; that is to say, they did not incorporate the breadth of the EAP II goals in their projected fossil-based needs.

Recognizing the complexity associated with the development and implementation of a long-term renewables strategy, the Commission acknowledges that the IOUs' LTPPs provide useful information in several areas. SDG&E provides a complete breakdown of how much baseload and as-available energy it wants to obtain between 2006 and 2010. In addition, all three IOUs do a good job of forecasting supply from existing contracts and those undeveloped resource areas that have been studied.

The Commission recognizes that much of the uncertainty in the LTPPs comes from the need for guidance provided by established scenario analyses going forward. We further recognize that the market for renewable energy in California is extremely dynamic, and that developments in the past year – the record response to the 2007 RPS solicitations, for example – provide information

that could obviously not be captured in the 2006 plans but will be very valuable in subsequent long-term plans. Therefore, the Commission finds the treatment of RPS by all three IOUs to be acceptable for the purposes of this proceeding, with some notable exceptions discussed below. We also identify below those issues raised by Intervenors and the IOUs that are best handled in the RPS proceedings, R.06-02-012 and R.06-05-027, and/or their successor proceedings.

The methodology established in the Scoping Memo for long-term renewable resource planning was not as robust as we believe is necessary for effective resource planning decisions; therefore, we direct the IOUs to work with ED staff to refine this planning methodology. We anticipate methodology that employs an integrated portfolio approach. We expect that this methodology will explore renewable procurement within a broader post-2010 paradigm, given the lead time associated with the development of those renewable resources that are procured in 2008. Designing a robust methodology process lends itself to the development of a trajectory towards achieving the 33% renewables target as well as an integrated GHG-constrained portfolio that takes into account the various resource types that will be necessary to develop in order to comply with AB 32 goals. We agree with several of the parties, however, that the 33% by 2020 goal warrants further analysis; this issue is further addressed in the section of the decision addressing the IOUs' discussion of the 33% goal.

Several intervening parties raised concerns about the IOUs' lack of adequate margins of safety in procuring renewable resources to allow for contract failures and other uncertainties. The Commission recognizes the potential value in a margin of safety and addressed this issue within the RPS proceeding (R.06-05-027), through D.06-05-039. We here uphold the finding in that decision that each IOU is ultimately responsible for taking all necessary

actions to ensure that it meets its RPS targets, and that building another requirement into an already complex RPS program will add little value. The RPS proceeding gives the IOUs flexibility to procure renewables in a manner that best meets their overall procurement strategies; failure to meet their targets will result in fines as discussed in that proceeding. As D.06-05-039 states, "We expect an IOU, in any non-compliance defense, to show its plan included a reasonable margin of safety, or it took other reasonable actions, to satisfy its RPS targets."[108] Therefore, the Commission denies the requests of Intervenors to mandate here a margin of safety for the procurement of renewable energy sources, while noting that each IOU states that it is already over-contracting. Any failure to comply with the 20% renewable standard by 2010 will be addressed in the RPS proceeding.

Each of the IOUs mentions transmission constraints as a major barrier to achieving renewable energy procurement targets. The Commission recognizes the need for sufficient transmission for new renewable sources; for this reason, the Scoping Memo directed the IOUs to "discuss how to integrate long-range transmission planning into the long-term procurement process for all resource categories, especially renewables." We find that none of the IOUs fully addressed long-term transmission needs for the duration of the planning period beyond those projects that are already set to come on-line, and we anticipate greater discussion of this issue in the next LTPP proceeding. The Commission, in conjunction with the CEC, the CAISO, IOUs, municipal utilities, and other stakeholders, has recently launched the California Renewable Energy

[108] D.06-05-039 at 23.

Transmission Initiative (RETI),[109] a statewide initiative to help identify the transmission projects needed to accommodate our clean energy goals, support future energy policy, and facilitate transmission corridor designation and transmission and generation siting and permitting. Because RETI begins with a thorough assessment of the renewable resource potential in California and neighboring regions, the output from RETI will be a critical input for the renewable procurement sections of the IOUs' future LTPPs. The Commission thus encourages the IOUs and all other interested parties to participate fully in RETI as a means of addressing both transmission and procurement shortages in the renewable energy sector.

The IOUs mention a shortage of renewable sources as another barrier to achieving renewable portfolio targets. The Commission recognizes that, in the short term, transmission shortages present a challenge to procuring renewable energy. The Commission notes, however, that the IOUs have dozens of RPS contracts in the pipeline, that the response to the IOUs' RPS solicitations has increased dramatically, that much new transmission for renewables is already under consideration at the Commission, and that more needed transmission will be identified by RETI. This shortage may therefore be relieved in the longer term, provided other project development challenges can be overcome. Beyond lack of transmission capacity, oft-cited reasons for project delay include project permitting, site control, and interconnection delays associated with the CAISO queue process. The Commission is working with the relevant state and federal

[109] http://www.energy.ca.gov/reti/index.html

entities to address these hurdles to project development; all of these issues, however, are beyond the scope of this proceeding.

The Commission acknowledges several parties' comments about the MPR and the difficulty of properly assessing the value and costs of RPS procurement. The MPR methodology will be revisited in R.06-02-012 in 2008, and we direct parties to raise any issues and suggest improvement in that proceeding. We agree that assessing the cost of California's RPS is one of the biggest challenges facing the program. Given the rise in bid prices that we have observed from solicitation to solicitation, we find it advisable to include, in developing a work plan for 33% by 2020, a portfolio-wide assessment of the costs of such a plan. The Commission also recognizes that utility-owned generation from renewable energy sources can potentially put a downward pressure on increasing renewable prices, and therefore encourages the three IOUs to continue their examination of utility-owned renewable generation (UOG). The Commission generally discourages UOG unless UOG helps to meet a policy objective; however, given the rapid increase in bid prices among already existing renewables, the Commission finds this to be the case in renewable energy procurement. Also, the Commission acknowledges SDG&E's comment that RECs may be necessary to achieve RPS targets; however, this issue is being addressed in the RPS docket, R.06-02-012.

The Commission recognizes that the cap on intermittent generation capacity proposed by PG&E is an inherently complex issue involving both capacity requirements and system reliability. The Commission acknowledges that wind generation capacity and integration costs are currently under study at the CAISO and elsewhere – the Commission declines, therefore, to make a

determination on this issue within this proceeding. The Commission will address this issue in other proceedings as more information becomes available.

The Commission rejects PG&E's request to change the qualifying capacity to 3% of installed capacity for wind, noting that the Commission has, in D.05-10-042, Section 7.7 and D.07-06-029, Section 9.2, adopted qualifying capacity counting rules for wind based on unit-specific historical data. Changes to the RA qualifying capacity counting conventions are not within the scope of this proceeding.

In regards to SDG&E's request to roll RPS procurement beyond 20% into an all-source RFO, this issue is best considered in RPS proceedings that will carry RPS beyond the 20% goal. We note that the consistency of the timing and parameters of the RPS solicitations are helpful at this stage in the development of the market for renewable energy in California. Renewable developers are free now to bid into all-source RFOs if they so choose and in fact, we encourage them to do so; several have already done so. In the interim, we provide guidance on the inclusion of RPS procurement in all-source RFOs in Section 3.3.2.3.

Finally, the Commission acknowledges that UCAN's suggestion to create an Energy Parks program is an interesting idea worth consideration. It is best considered, however, within Phase I of RETI, as the Commission does not have the jurisdiction to order such a program. RETI includes a robust stakeholder process, and we encourage UCAN to participate fully.

2.3.4. Customer Generation DG

There are a number of definitions of DG. D.03-04-030 defines customer generation as a resource that wholly or in part serves its on-site load, or wholly or in part serves its on-site load and serves over-the fence load as permitted by statute. Customer generation DG is addressed in this section. DG that produces

significantly more power than it needs and exports (or is intended to export) the surplus to the grid is addressed in the following section on QFs and CHP.

2.3.4.1. Summary of Parties' Positions

With respect to customer generation DG, all three IOUs state that they are committed to implementing the state's preferred resource loading order, and particularly the California Solar Initiative (CSI).

In its LTPP, PG&E used historical growth rates to forecast future DG installations, which PG&E testified was consistent with the CEC's approach. Many intervenors challenged PG&E's numbers as being too conservative, but the utility responded that its DG numbers do not include DG designed to export power to the grid (addressed separately in the QF/CHP subsection).

SCE defines DG as '[g]eneration of 5 MW or less sited at or near the point of consumption and designed primarily to serve on-site load."[110] This includes solar development spurred on by CSI. SCE assumes that distributed/self generation will increase by an average of 25 MW per year from 2005 – 2016.

SDG&E used the CEC's forecast for DG and added the impacts of CSI as an incremental load reduction to that number. SDG&E's DG assumption numbers were also challenged as too low and potentially leading to "over-procurement of non-DG resources."[111] SDG&E stands by its CEC embedded DG forecast, but argues that if the DG numbers increase, it has time to adjust for these changes in its procurement plan.

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[110] SCE opening Brief, p. 10, citing Testimony of Horwatt, Ex. 21/22C, p. 17.

[111] SDG&E Opening Brief, p. 20, citing Wong/CCDG, Exhibit 59, p. 7.

CCC argues that the utilities take too narrow of a view of DG, and ignore larger CHP projects which can be a significant indigenous resource for new, clean, efficient generation sited in or near the state's load centers.

2.3.4.2. Discussion

We find that the IOUs followed the OIR and Scoping Memo directives and included forecasts for DG in their LTPPs. CSI goals were embedded in demand reduction forecasts pursuant to CEC forecasting methodology. The following section on QFs and CHP addresses issues pertinent to DG resources with excess power to sell to the grid.

2.3.5. QFs/CHP and Renewables

Qualifying facilities (QFs) are producers of energy and capacity as defined by the Public Utilities Regulatory Policy Act of 1978 (PURPA).[112] PURPA was passed to encourage resource competition and the development of cogeneration and renewable energy technologies by non-utility power producers, called QFs. PURPA encouraged such development by requiring the electric utilities to purchase electric power from the QFs, at a rate that may not exceed "the incremental cost to the electric utility of alternative electric energy."[113]

For over 20 years, QFs were functioning under various pricing systems and contracts, many of which have expired since 2000. Many parties raised concerns regarding whether the QFs were being paid too much or not paid

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[112] The United States Congress passed PURPA in 1978, as codified in the United States Codes (U.S.C.) at 16 U.S.C. Section 824a-3, and 18 Code of Federal Regulations (CFR) Sections 292.301 *et seq.*

[113] 16 U.S.C. Section 824a-3(b).

enough to stay in the energy business, and the corollary issue of where IOUs would get the alternative power if the QFs went out of business.

In 2004, the Commission opened two Rulemakings, R.04-04-003 and R.04-04-025 to address the QF issues. R.04-04-003 was the 2004 LTPP proceeding, and one important procurement topic was the development of a long-term policy for handling QFs with expiring contracts. R.04-04-025 was initiated to develop avoided costs in a consistent and coordinated manner across Commission proceedings. Both proceedings were joined for evidentiary hearings and briefings.

2.3.6. Summary of Parties' Positions

SCE assumes it will recontract with parties representing 90% of the energy from existing QFs in its service territory as their contracts expire and that the operating characteristics of the facilities will remain the same. PG&E made a similar assumption: it would recontract with 90% of their current QF providers. Both SCE and PG&E assumed that existing QFs in their service territories would continue to provide power to some LSE, whether it was an IOU or not, so it was reasonable for both SCE and PG&E to assume that level of QF capacity and power going forward. In its system reliability evaluation, SDG&E assumes that existing QF resources in its service territory will be available.

CCC argues that since CHP results in the efficient use of natural gas to meet the combined electrical and thermal needs of California industries and institutions, optimizing use of CHP should be a top priority for the state. CCC also believes that with supportive state policies more than 7,000 MW of CHP capacity could be developed. CCC also states that there needs to be more support for existing CHP projects to repower or expand.

CCDG claims that the IOUs underestimate the amount of CHP DG likely to be installed over the next decade, which may lead the IOUs to over procure other resources. CCDG is also concerned with the possibility that its customers, or IOU ratepayers, or a combination of both will end up paying the cost of excess power.

CAC/EPUC urges the Commission to take steps that would preserve existing and promote new CHP development. In particular, CAC/EPUC recommends that the Commission direct the IOUs to (1) recognize CHP as a loading order preference, (2) reserve a specific amount of space in their portfolios for CHP resources, and (3) have an option to interface with the CAISO for CHP resources.

2.3.7. Discussion

The Commission had not issued a decision in the QF proceedings at the time the IOUs filed their LTPPs in December 2006, and we find their treatment of QF resources for system reliability purposes to be reasonable given the information available to the IOUs at the time of their filing. We note that on September 20, 2007, the Commission issued D.07-09-040,[114] which adopts policies and pricing mechanisms for the IOUs' purchase of energy and capacity from the QFs. The Commission indicated that "we do not want to see erosion of the utilities' QF supplies, therefore we expect that as old QF contracts expire, new or renewed QF contracts will replace them."[115] The availability of new QFs is

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[114] Applications for Rehearing have been timely filed, but D.07-09-040 remains in full force and effect unless superseded by subsequent Commission decision.

[115] D.07-09-040 at p. 122.

predicted in the 2005 IEPR that states that "CHP has significant market potential, as high as 5,400 MW, despite high natural gas prices."[116] Thus, we require the IOUs to at least maintain their current QF capacity over the next decade. The IOUs current QF capacities are recorded as 2,166 MW for PG&E; 4,162 MW for SCE; and 270 MW for SDG&E[117] and shall be preserved through re-contracting with existing QFs and contracting with new QFs. These changes are consistent with the pricing and policy mechanisms for the IOUs' purchase of energy and capacity from QFs that the Commission adopted in D.07-09-040. We anticipate that any changes in QF development and/or re-contracting policy the IOUs experience and anticipate will be addressed in their subsequent LTPP filings.

2.4. Existing Plant Retirements

Predicting when aging plants will retire presents a significant challenge to capacity planning. Most of the state's fleet of aging plants are owned by unregulated entities, and the factors that inform an owner's decision to retire the plant are not within the knowledge or control of the IOUs or the Commission. Estimates of future retirements in an IOU's service territory are based on public announcements, general knowledge about the plants and their economics, and the IOU's predicted contracting plans. However, these plants can also contract with non-IOU LSEs, so this is not necessarily sufficient information to predict retirements. Ultimately, the IOUs can only guess when a plant in its service territory might retire.

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[116] 2005 IEPR at p. 76.

[117] D.07-09-040 at p. 123.

The CEC provides assumptions about aging power plants in its IEPR and *Transmittal Report* and in testimony provided in this proceeding. The CEC recommends the orderly retirement of approximately 50 aging plants totaling 14,000 MW of capacity in the three IOUs' service territories between 2008 and 2012. From the CEC's perspective, keeping aging power plants on "life-support" by giving them short-term contracts has the negative effect of deterring the construction of new, more efficient plants. In addition, while these old plants "limp" along, the LSEs do not have to replace that power with preferred resources, such as energy efficiency, demand response or renewable resources.

The other side of the retirement coin is that these units are generally retained for capacity rather than energy needs, and are often only called during peak periods (and consequently run only a very small percentage of the time). In this role, these aging units are much more cost-effective compared with developing new peaking resources (though the aging plants are not usually as operationally flexible).

2.4.1. Summary of Parties' Positions

PG&E adopts the CEC's aging plant analysis in its recommended Plan and assumes that approximately 4,400 MW of aging generation in its service territory will retire by 2012.

Of the 8,100 MW of aging generation CEC identifies for retirement by 2012 in SCE's service territory, SCE estimates in its recommended plan that 2,850 MW of existing capacity in SP 26 might retire during the 10-year planning horizon.

SCE based its retirement predictions on public statements and its knowledge of particular generators with which it has contracts.[118]

The CEC identifies two potential retirements in SDG&E's service territory: the South Bay Power Plant (South Bay) and Encina Power Plant, totaling approximately 1,600 MW. Both in its 2004 and its 2006 LTPP, SDG&E assumed that the South Bay Power Plant would retire at the end of 2009. This is consistent with the CAISO's grid planning assumption that the plant will be retired by 2010—but the CAISO assumption depends on other contingencies that will replace the electricity from the South Bay facility (the Otay Mesa Generating Plant coming on-line, some peaking-units being completed and the Sunrise Power Link transmission line being approved and built[119]). In addition, the Port of Chula Vista, the owner of the land on which the South Bay plant is built,[120] has publicly stated that it hopes to be able to retire the plant at the end of 2009.[121] However, none of these facts is a guarantee as to when the plant will actually close, and numerous parties criticized SDG&E for this assumption. SDG&E states that it makes no assumptions about the Encina plant retiring, but does not include any capacity purchases from Encina in its 2007 – 2016 resource estimates.

Not all parties agree with the CEC's recommended retirement deadline. Ratepayer groups argue that if the IOUs do not contract with these older units in order to encourage their retirement, direct access providers or out-of-state users

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[118] SCE Opening Brief, August 1, 2007, p. 11.

[119] CPUC Proceeding A.06-08-010.

[120] LS Power owns the actual South Bay Plant.

[121] Union-Tribune, 3/13/07.

will still have the option to purchase their relatively inexpensive capacity while utility ratepayers are left to pay for the new, more costly replacement plants.

TURN recommends against arbitrary retirement dates for the aging power plants, suggesting that market forces instead should dictate the pace of retirements. TURN is concerned that if an IOU is too aggressive in forecasting retirements, it may end up constructing new conventional units as a contingency for delays in the development of preferred resources. TURN sees aging plants serving to "bridge the gap" as an IOU brings preferred resources on-line.[122]

WPTF does not think a plant should be considered "retirement age" until its owner/operator declares an intention to retire the plant.[123] Some parties were much more specific – LS Power argues forcefully that SDG&E should not assume that South Bay will retire in 2009 since the CAISO has identified the plant as being needed for reliability unless several contingencies are met, such as the Otay Mesa generating plant and the Sunrise transmission project being built.

2.4.2. Discussion

We have no better information than the IOUs or other intervenors regarding the timing of plant retirements by private, unregulated owners. While we recognize that these aging plants will not continue to operate indefinitely, we suspect that the CEC's retirement timeline is unlikely.

We find merit in TURN's position that these units represent a natural contingency for a number of uncertainties that the IOUs, and in particular PG&E,

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[122] TURN Opening Brief, August 1, 2007, p. 2.

[123] SDG&E Opening Brief, August 1, 2007, p. 24, citing WPTF Testimony, Ackerman, Exhibit 119, p. 1-15.

have raised in identifying their need for additional generation. However, we also recognize the benefits of transitioning from the use of these aging units as relatively inflexible peaking resources (a number of them are over 40 years old, and many are former baseload resources) to new peaking and intermediate units with much greater flexibility that will better support the anticipated intermittent-heavy, GHG-constrained portfolios resulting from AB 32.

Encouraging the retirement or repowering of these older units also supports a variety of California's policy aims (e.g., reduction of once-through cooling units, Brownfield development per the goals set out in AB 1576, air quality goals, and reduction of GHGs). Consequently, our goal is to strike a balance between inducing retirements or repowerings through our procurement authorizations and containing the costs associated with replacing many of these facilities in a short period of time.

In light of these concerns, we have revised PG&E's unannounced retirement schedule, which was based on the CEC's fairly aggressive aging plant retirement goals, to reflect a more measured retirement pace of approximately 600 MW per year beginning in 2009 until all 4,400 MW are retired by 2015. This revision is reflected in Table PGE-1, but this does not result in any material change since procurement authority in this decision is provided through 2015.

Similarly, we have added to SCE's SP-26 retirement assumptions the laddered retirement of approximately 500 MW per year (this reduced value reflects the fact that SCE's announced or anticipated retirement estimate was significantly higher than PG&E's announced level) beginning in 2009 until 6,850 MW of the identified 8,100 MW are retired by 2016. This assumption results in a total 6,350 MW of retirements in SP-26 through 2015, and this revision is reflected in Table SCE-1.

We have not revised SDG&E's retirement assumptions.

The biennial nature of the LTPP process allows us to incorporate better information into the process relatively quickly after it is obtained. We will continue to evaluate the trends in actual retirements and repowerings relative to IOU assumptions and will revise our approach to these assumptions based on these trends in future LTPP cycles. In addition, if any protocol for developing retirement assumptions results from the recently announced PRM rulemaking, it will be incorporated into future LTPPs.

2.5. Planning Reserve Margin/Other Contingencies

D.04-01-050 required all LSEs within CA to procure sufficient capacity to meet an RA obligation equal to their 1 in 2 monthly peak load forecast plus a 15%-17% Planning Reserve Margin (PRM). D.06-06-064 adopted a local capacity requirement based on a 1 in 10 annual peak load forecast and uses CAISO recommended contingencies as the planning reserve.

Applying the PRM to the IOU's system reliability obligation is complicated. As explained in the general approach to need determination discussion at the beginning of Section 2, recent experience suggests that there is an up to seven-year lag from authorization to in-service date to avoid "just-in-time" procurement that threatens reliability, drives up the costs of delivering power, and typically does not result in additional preferred/renewable resources. This seven-year lead time in turn exacerbates uncertainties associated with the need determination (i.e., resources contracted to come online in the interim, retirement assumptions for aging resources, etc.,) and contributes to a concern among the IOUs and other parties regarding whether the 15%-17% PRM will be met if additional "contingency generation" is not procured.

The use of the PRM and other contingencies for system reliability is addressed below, followed by a discussion of the additional contingencies proposed in PG&E's LTPP to address these uncertainties.

2.5.1. PRM

PG&E's preferred plan recommends a 16% PRM for system reliability, but basing it on a one in ten weather forecast. SCE performs an "adverse conditions" analysis for system reliability, using a 1 in 2-year temperature demand forecast and a PRM of 5%. SDG&E makes no changes to the PRM for its service area reliability analysis.

2.5.1.1. Summary of Parties' Positions

Aglet recommends not changing PG&E's PRM, based on an analysis of a 2005 PG&E Value of Service Study conducted by Freeman Sullivan and Company. Aglet argues that the study "found that 71% of residential customers, 58% of small/medium business customers, 79% of agricultural customers, and 21% of big business customers considered at least one 1-to-4-hour outage per year to be acceptable." (Exhibit 52, p. 2-10.) Aglet performed a cost-benefit analysis of PG&E's PRM proposal and found that an increase in the PRM would not be cost-effective for PG&E's residential ratepayers. (Exhibit 52, p. 2-11.)

The CEC contends that the LTPP proceeding is not the appropriate forum in which to consider changes to the PRM. Specific to PG&E, the CEC notes that PG&E has not demonstrated that the probability of involuntary load curtailments is unacceptably high if the current PRM is maintained. In addition, the CEC states that PG&E does not present enough data to demonstrate that customers would benefit from a higher reserve margin. The CEC claims that the consequences of approving PG&E's higher reserve margin would be that PG&E would be authorized to acquire extra capacity resources that would be paid for

by all LSEs. According to the CEC, this is an undue burden for other LSEs, who would not have the option of determining how to best meet the reliability needs of their customers. The CEC claims that the decision to allow PG&E to procure to a higher reserve margin would effectively allow PG&E to determine the tradeoff between cost and reliability for the customers of all LSEs in its service area.

More specifically, the CEC argues that PG&E's assessment of the insufficiency of the 15% PRM based on a 1-in-2 peak weather demand forecast to meet one-in-ten peak demand conditions is flawed. The CEC further states that PG&E claims that Table Vol. 2, IVA-1 illustrates that "[t]he current planning reserves do not provide sufficient margin to cover load increases due to one-in-ten or hotter temperatures." The CEC finds that by including minimum operating reserves equal to 7% of the peak load, PG&E is effectively assessing the PRM needed to avoid a Stage 1 alert, not to avoid involuntary load shedding. Consequently, PG&E has merely illustrated that the current reserve margin would fail to prevent a Stage 1 alert under conditions more adverse than once in ten years.

The CEC also mentions that the inclusion of 429 MW to meet regulation needs assumes that, at the moment load is at its very highest, additional capacity is needed to handle upward fluctuations in demand. The definition of "peak demand" precludes this capacity from being necessary.[124]

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[124] In addition, regulation is considered by the WECC to be a component of the minimum operating requirement.

DRA contends that, "PG&E's justification for moving to a 16% PRM appears to be based upon a 'perfect storm' of extreme demand and supply conditions occurring at the same time, e.g., 1-in-10 temperature demand level and high forced outages." (Exh. 82, DRA's Vol. B, p. 15.)

WPTF advocates in both this and in the RA proceedings that a single planning criterion be used for all procurement – specifically, a single load forecast, counting protocol, and reserve margin.

2.5.1.2. Discussion

The Commission recognizes the need to develop a consistent and transparent standard for the three IOUs to use in determining their system reliability responsibilities. An approach that is standard across all Commission jurisdictional LSEs will (1) determine an appropriate level of procurement necessary to enable the CAISO to operate the system in compliance with minimum operating standards; (2) ensure that ratepayers all bear equal burdens of the costs associated with providing reliability; and (3) avoid, to the extent possible, the procurement of excess resources as a result of poor coordination among IOUs or between IOUs, ESPs, CCAs, and POUs. An approach that is transparent and consistent across the forward planning horizon will (1) consistently and transparently integrate all the planning processes within the Commission (transmission, generation, renewable development, demand response) for maximum efficacy and efficiency and; (2) provide all market participants with the information needed to make investment decisions in infrastructure without relying solely on ratepayer-backed contracts.

The design and implementation of a statewide capacity trading mechanism, including some form of forward capacity component, is being addressed in Phase II of the RA proceeding. This effort has highlighted the need

for a comprehensive, transparent PRM methodology for all jurisdictional LSEs, and an ACR issued in R.05-12-013 and R.06-02-013[125] signaling the Commission's intent to open a rulemaking to accomplish this objective. Collectively, these two forums will address the interplay between the bundled and system reliability planning reserves, including the system reliability backstop function that the IOUs are currently providing.

We plan to adopt for the LTPP program the system reliability backstop function and associated PRM methodology that results from these processes, and believe that this approach appropriately addresses the intervening parties' concerns. It would be premature at this time to adopt for a system reliability reserve margin methodology any of the variations proposed by the IOUs from the existing 15%-17% PRM currently used for bundled customer load. Consequently, the IOU need determination tables calculate need based on a 1 in 2 year weather demand forecast and a 15%-17% PRM.

2.5.2. PG&E's Proposed Additional Contingencies

In addition to the recommended change in the PRM, PG&E recommends the following contingencies be included in its need determination:

- 600 MW of contracted resource uncertainty – 10% of the approximately 6,000 MW of new resources currently in PG&E's pipeline (various future resource additions in PG&E's NP-26 need determination tables have been reduced below the contracted values to reflect this reduction);

[125] ACR, issued November 19, 2007 in R.05-12-013 and R.06-02-013.

- 500 MW in anticipated revisions to RA counting rules, especially for DR and wind resources (Line 2 in PG&E's NP-26 need determination tables reflects this anticipated decrease); and
- 500 MW of authority to procure, either (1) as additional backup for contracted resource uncertainty (if one of the large generation units procured in PG&E's last Long-Term RFO does not materialize) or (2) for RFO "optionality" if all the previous Long-Term RFO resources do materialize, but PG&E nonetheless identifies an offer that in its opinion is to good to pass up in its next Long -erm RFO.

2.5.2.1. Summary of Parties' Positions

Aglet recommends that the Commission reject PG&E's request to discount existing contracts based on questionable viability, noting that it is inconsistent with historic Commission practices. Aglet also urges that the Commission reject PG&E's request to procure an additional 500 MW of capacity, noting that it is unaware of any instance where the Commission has allowed a regulated utility to over-procure.

DRA criticizes PG&E's need estimate because of its request for an uncertainty contingency for its contracted resources.

TURN interprets PG&E's request for additional contingencies as a permanent adder to its PRM with a corresponding permanent addition in cost to ratepayers. TURN does recommend, however, that PG&E be allowed to procure a limited amount of new resources beyond those needed for the PRM, but only if these resources reduce the Net Present Value of ratepayer costs when compared with not procuring such new resources.[126]

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[126] *Ibid.*, p. 2.

2.5.2.2. Discussion

Each of the contingencies PG&E identifies in its LTPP is discussed in turn below:

RA Counting Contingency – The LTPP proceeding is not the appropriate forum to address this concern.[127] Parties should address any recommended changes to RA counting rules in the current RA proceeding, or any successor proceeding. Should the RA proceeding(s) result in changes in the qualifying capacities of resources, the LTPP proceeding shall incorporate those changes.

Contract Uncertainty Contingency – We agree with Aglet's position that discounting existing contracts based on questionable viability is inconsistent with historic Commission practices and we do not adopt such a contingency for PG&E in this decision.

Regarding the portion of this contract uncertainty contingency that is the result of viability concerns of contracts for renewable resources, we reaffirm the need for PG&E to reach, <u>at a minimum</u>, its mandated RPS goals. To the extent that PG&E has contract viability concerns with a portion of its renewable contracts, it needs to address this concern within its renewables procurement strategy (for instance, by adopting a viability adder), not turn to this proceeding and request to make up this shortfall with fossil fuel resources. We do not subscribe to the philosophy that IOUs should be able to replace renewable resources (or any preferred resource) with fossil generation, and we will not adopt a general procurement framework that will allow the IOUs to crowd out

[127] ALJ Brown's 05/02/07 ruling explicitly ruled RA Requirement issues outside the scope of this proceeding, noting that "This rulemaking will serve as an umbrella proceeding to handle procurement policy issues that do not warrant a separate rulemaking…" (Pages 6-7.)

preferred resources and/or systematically overprocure. This type of procurement would only lead to "stranded assets" to the detriment of customers of all LSEs.

Regarding the portion of this contingency that is the result of conventional generation contracts, we would expect the IOUs to handle this uncertainty in a similar manner that they did with the many viability challenges that plagued the vertically integrated utility era – delaying retirements (in this case, via contract extensions with aging facilities) until these uncertainties are addressed.

Alternate System Reliability PRM – We find merit in PG&E's request to use an alternate, more conservative planning approach for system reliability. However, as we noted in the PRM subsection, a separate rulemaking has been opened to develop a comprehensive PRM methodology that will address this issue, so we will not formally adopt an outcome in this decision that could undermine the analysis and conclusions we anticipate will come out of the PRM rulemaking. While we acknowledge that in the interim we must determine need for system reliability, PG&E has not supplied sufficient analysis to support its alternate system reliability PRM, and therefore we have an incomplete record to adopt the policy PG&E proposes in this proceeding.

500 MW RFO "Optionality" or Additional Contract Contingency – Two conditions would need to be met to authorize the concept of providing additional procurement authority to IOUs to obtain an additional, attractively-priced resource in an RFO:

- An anticipated need for the additional resource within a sufficiently short period after it comes on line to justify, economically, its "early" procurement.

- Certainty that market conditions provide a good benchmark for assessing a "good deal."

PG&E has provided no analysis with which we might make the assessment that additional resources will be needed within a sufficiently short period after it comes on line to justify its early procurement. In fact, based on PG&E's own need determination tables, which factor in PG&E's other requested contingencies, there is no additional unmet need through the 10-year planning cycle (e.g., preferred loading order resources and/or new resources currently under contract fully meet additional load growth in the 2013-2015 timeframe). In addition, as discussed earlier in this decision, there is currently considerable uncertainty associated with the types of resources the IOUs will need to procure to meet future GHG requirements. Absent any scenario analysis by PG&E, we are unable to evaluate whether the "extra resource" PG&E might decide to procure based on price attractiveness in an RFO would be optimal for a future, GHG-constrained portfolio.

There is also little certainty that market conditions provide a good benchmark for assessing a good deal. On the contrary, the current pricing environment for building new generation is an extremely tight one (national scarcity of skilled utility labor, high demand for power plant engineering and design services, scarcity of metals resulting in inflated turbine prices, etc.). A reasonably likely conclusion is that a "good deal" by today's standards may not look so good to the extent that these are near-term imbalances that normalize in a few years.

Without information that substantiates that these two conditions are met, we do not provide PG&E with this discretionary authority. More generally, we

find it unlikely that these conditions could be proven sufficiently to convince us it would be prudent to grant optional procurement authority.

To the extent that PG&E is requesting this 500 MW to replace one of the resources that PG&E secured in its last Long Term RFO (i.e., as a default contingency for a subset of the new generation currently under contract above and beyond the 10% default cushion described above, effectively raising the 600 MW contingency to 1,100 MW, or nearly 20% of the contracted "pipeline" resources), our position here is consistent with the discussion above – we would expect the IOUs to handle these uncertainties by delaying retirements (in this case, via contracts) until these uncertainties are addressed. However, we will address PG&E's position concerning these two contingency requests regarding the viability of its 6,000 MW of new resource contracts.

One point raised by PG&E in its litany of contingencies raises particular concern to the Commission, and bears additional discussion here. In its analysis of additional resource needs associated with an increase in the PRM to 16% based on a one in 10-year temperature demand, PG&E requests in this proceeding only 700 MW of the additional 1,100 MW need driven by this increase, indicating that it anticipates meeting the balance of this need (approximately 30%) with preferred resources.

First, since at least 800 MW of the remaining 1,600 MW of fossil fuel contingency generation PG&E is requesting replaces capacity from preferred resources (i.e., much if not all of the 500 MW of RA counting capacity reductions and over half of its 600 MW contract viability contingency), it is unclear why PG&E is not proposing to replace these resources in-kind, or at the very least why it would not apply this same 30% reduction for preferred loading order resources to all of its requested contingencies.

Of more fundamental concern, though, is the question of why PG&E believes that there would be additional preferred resources available to procure. The conventional generation procurement authority we grant in the LTPP proceeding is, essentially, a backstop authorization that results from additional identified net short after all preferred loading order resources are exhausted. PG&E's intent to procure a portion of its identified residual need with preferred loading order resources suggests to us that the IOU does not believe it has exhausted all preferred loading order resources available to it in its residual net short calculation for this planning period.

2.6. Need Determination

The Scoping Memo, and in particular Attachment A, advised the IOUs to make their need determinations based on the "net" of their demand and load assumptions and forecasts.[128] In addition, decisions D.04-12-048 and D.06-07-029 designate the IOUs as the entities responsible for providing new investment in system reliability resources on behalf of all customers within their respective service territories. Consequently, need analyses are required – one for system reliability across the IOU's service territories and one for the IOU's own bundled customers. As noted at the beginning of Section II, the need determination made in this section for each IOU is based on a service area assessment.

One of the most controversial subjects in the LTPP proceeding is each IOU's need determination. Generally, stakeholders want the IOUs to procure sufficient resources to ensure reliable service, without interruptions or black-outs. However, a number of intervenors have a financial stake in the amount

[128] Scoping Memo, Attachment A, p. 13.

and types of resources the IOUs propose and the Commission authorizes. Other intervenors, including DA providers, potential CCA providers, and current or potential self-generation customers, want to ensure that the IOUs do not over-procure resources, which could result in some form of an NBC. Intervenors representing green and renewable interests scrutinize how much of the identified need will be filled with preferred versus conventional resources. Ratepayer groups are mindful of the need for preferred resources and reliability, yet are also cognizant of the cost of these attributes to the ratepayers.

As noted in the previous PRM discussion, this controversy is compounded by the fact that given the time required to hold competitive RFOs and then finance, permit and construct new generation resources, these procurement decisions must be made approximately seven years in advance of when the resources are needed.

2.6.1. Summary of Parties' General Positions on Need Determination

CMA recommends that authority be provided to allow IOUs to meet their RA requirements only, noting that procurement beyond this level will interfere with the end-state of a competitive wholesale market. MMID requests that the Commission require IOUs to use prudent planning and not procure power or system reliability resources on behalf of departing load identified in the POU forecasts provided to the CEC.

DRA is concerned with the cost-risks associated with the Commission's pre-approval of the three IOUs' procurement activities for the 10-year planning horizon, especially in the areas of construction costs, GHG requirements and meeting renewable resource targets. Basically, DRA fears that the IOUs will

over-procure fossil fueled resources that will crowd out other preferred options and leave little to no room for compliance with any GHG policies.

TURN's primary interest in the IOUs' need assessment numbers is whether the IOUs procure more than necessary then burden ratepayers with stranded costs.[129] TURN agrees with the IOUs that any changes in CCA or DA load will not affect the physical resource need in an IOU's service territory, but TURN is still concerned with the impact load migrations will have on future bundled customer needs and costs.

2.6.2. Discussion on General Need Determination Issues

As discussed earlier in the PRM subsection, a separate rulemaking will be opened to develop a comprehensive PRM methodology that addresses, among other things, lead time needed to bring new system resources on line. Consequently, it would be premature to adopt any of the reserve margin methodologies or specific contingency approaches proposed by IOUs in their Plans at this time.

However, until a standard, consistent, and transparent system reliability reserve margin methodology has been developed we must make need determinations today that, in our assessment, will result in sufficient system resources to permit all jurisdictional LSEs to meet their PRM obligations in the seven-year new resource procurement timeframe.

To accommodate the seven-year procurement timeframe, and given the schedule slip in issuing this decision, we have identified need determinations for

[129] TURN Opening Brief, August 1, 2007, p. 1.

each IOU through 2015, rather than through 2012, as the IOUs do in their LTPPs, and IOUs are to structure their RFOs for authorized resources to coincide with the projected system need on a timeline that ensures system reliability.

A need determination is made for each IOU in the following three subsections based on: (1) the load, resource, and PRM assessments discussed previously in this section, (2) other relevant information IOUs and other parties have provided in the record in this proceeding, and (3) the principle that each of the three IOUs should provide approximately the same level of system reliability to its customers.

Also, in addition to the few instances in which the IOUs' bundled need determinations were addressed in this section, all revisions to system load and resources that apply to the bundled need analyses should be made in the compliance filing stipulated in this decision. With these adjustments, the IOUs' bundled need assessments are adopted, and the IOUs are authorized to procure existing resources (in addition to the authorized new generation) as needed to meet their bundled need.

Finally, as noted earlier in this section the need determination tables developed in this decision include retirement assumptions designed to promote procurement that will result in the retirement of some of the state's aging, inefficient generation facilities. We make abundantly clear that any procurement authority granted herein shall in no way be used by the IOUs to <u>instead</u> reduce or adversely impact procurement of EE, DR, renewables, or QF resources to the maximum extent feasible. ED and the PRG are directed to provide close oversight of IOU procurement activities to ensure that this unintended consequence does not materialize.

2.6.3. PG&E Need Determination

PG&E calculates its service area needs by subtracting all identified NP-26 resources from the NP-26 load forecast (including the reserve margin), then multiplying the resulting net short (or long) by 92% to remove the 8% of the control area that consists of municipal providers.

As previously noted in this section, PG&E also builds the following assumptions into its need determination:

- 700 MW of additional conventional generation associated with using a 1 in 10 weather forecast with a 16% PRM rather than a 1 in 2 weather forecast with a 15%-17% PRM (this approach results in an total need of 1,100 MW, but PG&E assumes that approximately 30% of the total need would be met with preferred resources);
- 4,400 MW of retirements (i.e., the aging plants the CEC has identified in PG&E's service area);
- 600 MW of contracted resource uncertainty – 10% of the approximately 6,000 MW of new resources currently in PG&E's pipeline (PG&E reduces various future resource additions in its NP-26 need determination tables to below the contracted values to reflect this reduction);
- 500 MW in anticipated revisions to RA counting rules, especially for DR and wind resources (Line 2 in PG&E's NP-26 need determination tables reflects this anticipated decrease); and
- 500 MW of authority to procure, either (1) as additional backup for contracted resource uncertainty (if one of the large generation units procured in PG&E's last Long-Term RFO does not materialize) <u>or</u> (2) for RFO "optionality" if all the previous Long-Term RFO resources do materialize, but PG&E nonetheless identifies an offer that is "to good to pass up" in its next Long-Term RFO.

Based on these adjustments, PG&E requests that the Commission approve its Recommended Plan and allow the utility to procure up to 2,300 MW in new

resources for its service area, although based on a straight calculation this number would appear to be 2,500 MW [i.e., 4,200 – (4,400+600+500+700+500)].[130]

2.6.3.1. Summary of Parties' Positions on PG&E's Need Determination

Most of parties' positions with PG&E's need determination are directed at its load, resource, or PRM/contingency assumptions or proposals, and are addressed in those subsections. Generally, though, DRA is concerned that the IOUs will over-procure fossil fueled resources that will crowd out other preferred options and leave little to no room for compliance with future GHG policies.

In addition, the CEC believes that PG&E overstates the export of energy and therefore commensurately overstates the amount of new capacity needed to meet its service territory's needs. Aglet believes PG&E's request represents substantial over-procurement, and recommends authorizing 662 MW of additional procurement.

2.6.3.2. Discussion on PG&E's Need Determination

Table PGE-1 provides a need determination for PG&E for the 10-year planning period using the assumptions and conclusions reached in this decision. Based on this analysis, PG&E's service area shows a need of 800 to 1,200 MW (to provide a PRM between 15% and 17%) by 2015.

We also note that if a previously authorized resource is determined unviable during the development process and the associated contract is

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[130] PG&E has indicated to ED staff that this discrepancy is due to the fact that these values are not strictly additive, but PG&E does not make clear in its Plan how they overlap.

terminated, the procurement authority for those megawatts remains. PG&E is encouraged to take any viability concerns it has with its contracted 2004 LTRFO resources into account in the design and timing of its RFO for resources authorized in this decision.

To support the types of needs we anticipate in a GHG-constrained portfolio and to replace the aging units on which some of this authorization is based, we require PG&E to procure dispatchable ramping resources that can be used to adjust for the morning and evening ramps created by the intermittent types of renewable resources. Preference should be given to procurement that will encourage the retirement of aging plants, particularly inefficient facilities with once-through cooling, by providing, at minimum, qualitative preference to bids involving repowering of these units or bids for new facilities at locations in or near the load pockets in which these units are located.[131]

Prior to its solicitation for these resources, we require that PG&E provide ED and the PRG with a description of the resources it is soliciting and how these resources support PG&E's transition to a GHG-constrained portfolio, an analysis we had asked the IOUs to include in their 2006 LTPPs (additional RFO process refinements are described in the Procurement Process Issues section of this decision).

[131] ED, the PRGs, and the IEs are to work with the IOUs in the RFO bid development process described in Section 3.3 to determine the manner in which this qualitative or additional quantitative preferences for resources will be incorporated into bid evaluation criteria on an RFO-specific basis.

2.6.4. SCE Need Determination

SCE's LTPP provides distinctions, in various locations, between CAISO control area SP-26, SCE's bundled customers, and SDG&E's system, which is also located within SP-26. As discussed in the PRM section, SCE performs an "adverse conditions" analysis for system reliability using a 1 in 2-year temperature demand forecast and a planning reserve margin of 5%. SCE then calculates its service area share of SP-26 system reliability responsibilities as 80% to account for SDG&E's system reliability responsibilities within SP-26. Based on its LTPP need analysis, SCE did not identify a need for additional new generation through 2012 beyond the 1,500 MW authorized in D.06-07-029 to serve system needs.

SCE's analysis assumed that the second Devers-Palo Verde transmission line (DPV2) would be completed in 2009 and that about 900 MW of new firm imports would be deliverable on that path. On May 30, 2007, the Arizona Corporation Commission (the Arizona Commission) rejected SCE's application to construct DPV2. SCE estimates that the Arizona Commission's rejection of the project will delay DPV2 by at least two years and may delay the project indefinitely.

Pursuant to ALJ Brown's June 29, 2007 ruling in this proceeding, on July 12, 2007, SCE distributed an update of its SP-26 regional need outlook to remove DPV2 as a resource addition. The updated SP-26 regional need outlook removes 900 MW from imports for 2010 through 2016. Based on this update, and extending the target COD date by one year (from 2012 to 2013) due to the delay in the LTPP proceeding timeline, SCE requests authority to procure an additional 1,380 MW of new system generation resources in SCE's distribution territory by

2013 (in addition to the 1,500 MW of new generation resources authorized under D.06-07-029).

2.6.4.1. Summary of Parties' Positions on SCE's Need Determination

The CEC argues that because SCE uses its own load forecast as its recommended case rather than the CEC's IEPR forecast, SCE's need is inflated. In the future, the CEC asks that the Commission direct SCE to use the CEC's forecast as they should have for their 2006 LTPP (and as discussed above in the load forecast subsection, we adopt that recommendation).

Aglet recommends that the Commission deny SCE's late-filed request for authority to fill the gap resulting from the delay or elimination of the DVP2 project, reasoning that the next LTPP proceeding will provide SCE with sufficient time to adjust for this change.

CMA contends that while SCE made a filing, it was insufficient to evaluate SCE's revised needs assessment, particularly since the Commission's approval of the DPV2 project was not premised on it satisfying a *reliability* or capacity need, but rather that it provided access to economy energy, particularly during the winter peaking months.

NRG believes that, given the unanimous vote of the Arizona Corporation Commission, the DPV2 project will be delayed significantly longer than two years. Consequently, NRG recommends that this decision include a finding that at least an additional 1,000 MW of in-basin, load pocket, gas-fired intermediate and peaking generation to support intermittent renewable resources within SCE's current Standard Track RFO.

TURN notes that SCE's request is supported if the Commission adopts SCE's load forecast, but if the CEC's forecast is adopted then this need goes

away. TURN recommends that if any new resource procurement is authorized for SCE, it should not exceed 1,000 MW given the uncertainties regarding the actual need for SP-26.

2.6.4.2. Discussion on SCE's Need Determination

Table SCE-1 provides SCE's service area need determination based on its recommended plan, with the revisions described in the previous load and resource discussions and the additional revisions described below.

First, SCE's system need determination did not back out POUs' contributions to system load or POU resources. Consequently, SCE's approach provides backstop reliability resources for POUs in SP-26 who (1) may not procure to the same reserve requirements used by SCE, (2) SCE cannot bill with the CAM charge associated with system resources, resulting in a cost shift to SCE's bundled customers and the other system LSEs, and (3) may have resource procurement plans or load curtailment behaviors that SCE is not aware of or does not factor into its analysis (e.g., DWR's pumping station load, which represents approximately 2% of SP-26 load, is curtailed during periods of forecasted peak load), which would result in SCE over-procuring system resources. Consequently, Table SCE-1 calculates SCE's proportion of system resources based on its regional (bundled plus DA) forecast divided by the system forecast.

Second, because there is insufficient information at this time to determine if or when the DPV2 project will be developed, SCE-1 reflects a 450 MW addition for DPV2 beginning in 2012. This "splitting of the difference" will either halve the amount of procurement SCE will need to perform in a tight timeframe if DPV2 is not developed or is substantially delayed, or it will halve the amount of resources SCE brings on line earlier than needed if the project is developed by

2012. This approach represents our best judgment regarding how to address the uncertainty associated with this significant potential resource addition to SCE's portfolio.

This approach reflects this Commission's optimism that this project, which we believe is mutually beneficial to both California and Arizona, will ultimately be constructed, but that the process involved in providing Arizona with sufficient information in support of this assessment will take some time. We encourage SCE to provide as complete an update as possible on the status of this resource in its next LTPP so the Commission can revise this admittedly "half-right and half-wrong" approach to counting this resource at that time.

We find that parties' positions on whether DPV2 was intended as a reliability or economy energy resource, and therefore whether any increase in the need determination is warranted in its absence, appear to miss the point. Regardless of the initial purpose for which the project was proposed, SCE has attempted to estimate the resulting capacity value that it would provide the system on peak. Consequently, it was used in SCE's need determination tables as a resource that decreased the determined need by that amount. If SCE has overestimated this resource's ability to deliver the estimated capacity on peak, or if deployment of the resource is delayed or does not come to pass then SCE's need determination would only increase, regardless of the original rationale for developing the resource.

We recognize the concerns parties have raised regarding SCE's introduction of the DPV2 issue into the proceeding on the final day of evidentiary hearings and not subjecting the information to a full discovery process. However, we need to balance our objective of having a full vetting of information by all interested parties on as many topics that impact this

proceeding as possible with our responsibility to make need determinations based on the most accurate information available to ensure system reliability. If this proceeding cannot demonstrate the flexibility to react to changes in the "facts on the ground," the IOUs are likely to provide much more conservative assumptions on the COD dates for future resources, and the accuracy of this process will be eroded, at the expense of the ratepayers.

When faced with this choice, our best judgment is to apply the methodology developed through the publicly noticed and fully vetted process, but to consider an update of the numbers that are inputs into that methodology depending on our informed opinion of their veracity. In this case, as noted above, any answer to the question of whether and how much of this resource SCE should have counted towards peak capacity would only increase the need determination. The only significant question of fact is when, if at all, this resource will become available.

Finally, Table SCE-1 also reflects 400 MW of additional generation in SDG&E's service territory authorized later in this decision (the remaining 130 MW of authorization were already included in SCE's resource estimates), since SDG&E's resources are included in SCE's system reliability evaluation.

As indicated in Table SCE-1, our need determination analysis indicates that SCE's service area shows a need of 1,200 – 1,700 MW (to provide a PRM between 15% and 17%) by 2015. We note that this need is in addition to the 305 MW of previously authorized resources remaining in SCE's Standard Track RFO.

To support the types of needs we anticipate in a GHG-constrained portfolio and to replace the aging units on which some of this authorization is based, we require SCE to procure dispatchable ramping resources that can be used to adjust for the morning and evening ramps created by the intermittent

types of renewable resources. Preference should be given to procurement that will encourage the retirement of aging plants, particularly inefficient facilities with once-through cooling, by providing, at minimum, qualitative preference to bids involving repowering of these units or bids for new facilities at locations in or near the load pockets in which these units are located.[132]

Prior to its solicitation for these resources, we require that SCE provide ED and the PRG with a description of the resources it is soliciting and how these resources support SCE's transition to a GHG-constrained portfolio, an analysis we had asked the IOUs to include in their 2006 LTPPs (additional RFO process refinements are described in the Procurement Process Issues section of this decision).

Finally, we note that there was confusion on the part of some intervenors regarding SCE's request for authority to procure to a 17% reserve margin plus 1,950 MW (850 MW to deal with the possible outage of a major generation unit, and 1,100 MW to protect against an error in the near-term peak load forecast). We clarify here that this was not a system reliability request for new generation, but was a request for an adjustment to SCE's self-imposed forward procurement limits for its bundled load under its ratable rate methodology (i.e., contractual need). This request and SCE's proposed ratable rate methodology in general are discussed in the Risk Management portion of Section III (Procurement Process Issues) of this decision.

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[132] ED, the PRGs, and the IEs are to work with the IOUs in the RFO bid development process described in Section 3.3 to determine the manner in which this qualitative or additional quantitative preferences for resources will be incorporated into bid evaluation criteria on an RFO-specific basis.

2.6.5. SDG&E Need Determination

SDG&E provides three need analyses in its LTPP: a bundled need analysis using the 1 in 2-year temperature demand forecast and a planning reserve margin of 15%; a system need analysis using the CAISO N-1/G-1 criteria; and a bundled local capacity requirement analysis also using the CAISO N-1/G-1 criteria.

SDG&E's analyses indicate that its need determination is constrained by local capacity requirements rather than system need, and that its bundled and system needs are substantially altered with the addition of the Sunrise Powerlink.

2.6.5.1. Summary of Parties' Positions on SDG&E's Need Determination

From the CEC's perspective, SDG&E's need numbers are deficient since SDG&E did not properly consider potential plant retirements or make the proper assumptions for procurement of renewable resources. Aglet recommends that SDG&E's maximum authority be reduced to 813 MW, which reflects no additional authorization for Sunrise Powerlink uncertainty.

DRA recommends the Commission approve SDG&E's "contractual procurement need…(but) only those physical resources SDG&E would need before 2012 under its Preferred Plan." (DRA Opening Brief, 8/1/07, p. 37.) DRA recommends that the Commission defer approval of the combined cycle plant SDG&E proposes to procure in 2012 until the next LTPP when more information will be available regarding the South Bay Power Plant.

2.6.5.2. Discussion on SDG&E's Need Determination

Table SDGE-1 provides SDG&E's service area need determination based on the 1 in 2 demand forecast with a 15%-17% PRM approach (we have included

in Table SDGE-1 the 480 MW El Dorado baseload power plant, approved in Commission decision D.07-11-046, which has a projected on-line date of October 2011 and 130 MW of peaking units with on-line dates in 2008, approved in Commission decision D.07-09-010[133]). As indicated by the table, SDG&E does not have any system need in the 2015 timeframe.

However, as previously noted, SDG&E's need determination is constrained by local capacity requirements. Without the Sunrise Powerlink project, and updating SDG&E's local capacity need assessment to reflect the CEC's 2007 demand forecast, SDG&E's local capacity requirements result in a need for approximately 530 MW of new local capacity by 2015. As noted above, though, subsequent to its 2006 LTPP filing SDG&E has procured 130 MW of local peaking units.[134] Backing these 130 MW of local resources out of SDG&E's need determination results in a remaining procurement need of 400 MW of local resources if the Sunrise Powerlink project is not developed (the El Dorado facility is not a local resource and is therefore not backed out of this local capacity-driven need).

Because there is insufficient information at this time to determine if or when the Sunrise Powerlink project will be available to meet local capacity

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[133] While it would not generally be appropriate for an IOU to seek or procure new resources for system reliability need prior to evaluation of the need determination and authorization of the procurement via an LTPP proceeding, the Commission recognized unique circumstances associated with these procurement requests and approved the El Dorado and peaker applications prior to this decision on SDG&E's 2006 LTPP.

[134] Per the discussion in the previous footnote, the Commission recognized unique circumstances associated with this procurement request—in this case an identified local capacity need in the 2008 timeframe—and approved SDG&E's application for these resources prior to this decision on SDG&E's 2006 LTPP.

needs, we authorize SDG&E to procure 530 MW of additional local capacity (which includes the 130 MW of local peakers already approved by the Commission for a residual of 400 MW remaining procurement authorization) if its application for the Sunrise Powerlink is denied. If the Sunrise project is developed, only the 130 MW of local peakers are (retroactively) authorized.

We also note that if a previously authorized resource is determined unviable during the development process and the associated contract is terminated, the procurement authority for those megawatts remains. In addition, we authorize SDG&E to procure the equivalent quantity of local capacity associated with any retirements of local area resources that occur beyond the amount of retirements it forecasts in its LTPP.

To support the types of needs we anticipate in a GHG-constrained portfolio, we require SDG&E to procure dispatchable ramping resources that can be used to adjust for the morning and evening ramps created by the intermittent types of renewable resources. Preference should be given to procurement that will encourage the retirement of aging plants, particularly inefficient facilities with once-through cooling, by providing, <u>at minimum</u>, qualitative preference to bids involving repowering of these units or bids for new facilities at locations in or near the load pockets in which these units are located.[135]

Prior to its solicitation for these resources, we require that SDG&E provide ED and the PRG with a description of the resources it is soliciting and how these

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[135] ED, the PRGs, and the IEs are to work with the IOUs in the RFO bid development process described in Section 3.3 to determine the manner in which this qualitative or additional quantitative preferences for resources will be incorporated into bid evaluation criteria on an RFO-specific basis.

resources support its transition to a GHG-constrained portfolio, an analysis we had asked the IOUs to include in their 2006 LTPPs (additional RFO process refinements are described in the Procurement Process Issues section of this decision).

2.6.6. Differentiation Between System and Bundled Need

The Scoping Memo prescribed the development of two need analyses for each IOU, one for the IOUs' bundled customers and one for system need. SDG&E is the only utility that provides an explicit comparison of the two need analyses in its LTPP.

SCE's LTPP includes a significant amount of discussion on system need and bundled need, but does not ultimately derive a residual net bundled customer need similar to the net system need analysis provided in Tables IV-7/IV-8 of its Plan. Also, SCE's system need analysis includes SDG&E's system information, since it is within SCE's CAISO control area, but provides little information on how it distinguishes the two utilities' systems, and no explanation of how SCE will coordinate its planning and procurement with SDG&E to ensure the two utilities do not develop duplicative system resources. PG&E's analysis distinguishes between CAISO control area NP-26 and PG&E service area need, but does not provide a separate bundled versus service area need analysis.

This issue is of particular concern because IOUs are permitted to make use of the CAM developed in D.06-07-029 for resources procured for system reliability, but the decision deferred to Phase II of the proceeding the development of CAM implementation details. So far, the utilities are not approaching this issue in a consistent manner in practice. For instance, SDG&E

has not sought CAM treatment for any resources procured since D.06-07-029, nor has it indicated any intention to do so. PG&E sought CAM treatment for one of the non-UOG resources procured in its most recent Long-Term RFO. SCE, on the other hand, has identified all of its newly developed, long-term generation contracts as system resources (except for UOG, which is ineligible for CAM treatment).

The absence of a standard methodology or consistent practices for identifying system versus bundled resource needs raises several concerns. First, as noted above, it is unclear how SCE and SDG&E will coordinate the identification of system need to ensure that they do not procure duplicate system resources.

Second, without a standard methodology for differentiating system and bundled need, there is no way to ensure whether an IOU election to utilize the CAM for a new resource is appropriate. AReM raised this concern (and specifically the need to link cost allocation with cost causation) in the context of SCE's shrinking bundled customer load factor that SCE attributes to increased inland residential development. AReM states that, "Using the principle of cost causation, the customers causing the particular need for the resource should pay for it. If bundled customers' load is exacerbating the peak or decreasing the load factor (as SCE suggested), then the bundled customers should pay for the resources necessary to meet that need. In determining whether to apply the adopted cost allocation mechanism in D.06-07-029 in this phase of the proceeding, the Commission should only do so when the costs creating the need can be attributed to *all* customers." (3/2/07 Testimony on Behalf of AReM, p. 8.)

Another problematic example is the scenario in which ESPs have procured their proportional share of long-term resources (an outcome that various policy

initiatives in this and other proceedings are attempting to facilitate), yet the IOU has not procured its appropriate share. Until a methodology is in place that accurately accounts for this, the IOU could inappropriately elect CAM treatment of new resources procured to meet this bundled need.

AReM points out in its brief that testimony from each of the IOUs clearly indicates that changes in IOU load factors resulting from bundled customer growth are currently driving much of the recent need for peaking resources:

> SCE's prepared testimony indicates that residential air conditioning load is the primary cause of the extreme "peakiness" of the bundled load shape, noting "the continuing trend of new meters [i.e., customers] being set in the hotter inland areas of the SCE service are where air conditioning is used to a much larger extent (causing higher growth in peak demand)…" SCE says that it expects that the increasing residential air conditioning load will cause peak load to increase at nearly twice the rate of energy demand for at least the next five years. (AReM Reply Brief, p. 9.)
>
> …as SDG&E's witness explained at the hearing, the peaker plants currently being developed by the utility will be needed to meet its bundled load. Accordingly, SDG&E is not requesting authorization to apply the CAM to these new resources. (AReM Reply Brief, p. 10.)
>
> For PG&E, the evidence that direct access customers are not contributing in any material way to the need for new capacity is found in the utility's own peak load forecasts and capacity tables. For example, according to PG&E's own figures, the highest peak DA load in 2011 will occur in April (936 MW), and the next highest peak in September (903 MW). The months of July and August, which have the highest "system" peaks, show the third and second lowest DA peak loads, respectively (797 MW and 785 MW). And the DA peak load for June (833 MW), which is the other peak summer month, falls in the middle range of the DA peak loads. Since the months of highest system peak demand do not correspond with the highest DA peak loads, the need for new system reliability resources

> in PG&E's service area cannot be attributed to DA customers. (AReM Reply Brief, pp. 10-11.)

Third, as AReM points out, without some clear methodology for identifying system need versus bundled need, there is no way to ensure that IOUs will not elect to utilize the CAM for less attractive new resource acquisitions, while keeping "good" deals for bundled customers only.

None of the IOUs provided explicit arguments in response to AReM's recommendation that implementation of the CAM be linked to resource need causation. PG&E and SCE instead argue that AReM is attempting to relitigate the D.06-07-026 decision. However, Ordering Paragraph (OP) #5 of D.06-07-029 indicates that, "It is reasonable to defer many of the implementation details of this cost-allocation mechanism (to Phase II of this proceeding) along with associated ratemaking issues." Clearly, developing a methodology to determine whether new resources are needed to address changes in bundled or unbundled load growth represents an implementation detail, so PG&E and SCE's argument is unfounded.

AReM did not propose the components of a methodology that would identify separate bundled versus system resource needs, nor did any of the IOUs or other intervening parties. In the next LTPP procurement cycle scoping document, the IOUs and other interested intervenors will be instructed to develop proposals for methodologies for identifying bundled- versus system-driven resource needs to:

- Capture respective growth trends of bundled and unbundled components of service area load (rather than the static "snapshot" of current bundled and unbundled contributions to system peak used to develop overall need).

- Identify how load growth trends and any resources ESPs are procuring to serve their own load can be included in this analysis, given the confidential nature of these data.

- If not addressed by the capacity market design in Phase II of the RA proceeding, develop mechanisms for ESP self-provisioning to opt out of the CAM and penalties for instances in which ESP self-provisioning plans do not materialize.

- Explore how re-opening of DA would affect the proposed methodology (i.e., can a sufficiently robust methodology be developed at this time, or will the methodology need to be revised if and when DA is reopened).

Based on the record in this docket, it is clear that the election of a resource for CAM treatment when the application is submitted (i.e., after an RFO) creates the potential for IOUs, in their dual role as bundled customer electricity providers and system-reliability providers, to "cherry-pick" resources for their bundled customers, to the detriment of DA customers. Until the system versus bundled methodology is developed, we anticipate that the development of a separate CAM review group (as described in the PRG subsection of Section 3) will prevent this outcome. We direct ED to monitor the veracity of this assumption and bring any claims of unfair treatment by IOUs of CAM and non-CAM elections of selected resources to the Commission's attention.

TABLE PGE-1
NP-26 Regional Need (MW)

Based on PG&E's LTPP Scenario - 4

	LOAD FORECASTS	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	1-in-2 System Summer Temperature Demand [1]	21,406	21,671	21,954	22,236	22,547	22,855	23,158	23,453	23,752	24,050
2	1-in-2 PG&E Service Area Summer Temperature Demand [2]	19,845	20,096	20,364	20,633	20,928	21,222	21,511	21,793	22,078	22,363
	RESOURCES										
	System Resources										
3	Existing Generation	24417	24417	24417	24417	24417	24417	24417	24417	24417	24417
4	Retirements (Announced)	0	0	(135)	(135)	(135)	(135)	(135)	(135)	(135)	(135)
5	Retirements (Laddered Reduction of Aging Units) [3]	0	0	(600)	(1200)	(1800)	(2400)	(3000)	(3600)	(4200)	(4200)
6	NP26 RPS Additions (Including Imports)	28	142	293	635	895	1181	1496	1609	1733	1870
7	PG&E Planned Additions	0	0	998	2251	2251	2251	2251	2251	2251	2251
8	Other Known/High Probability NP-26 Additions	0	0	180	180	180	180	180	180	180	180
9	Imports -- NW	2348	2348	2348	2348	2348	2348	2348	2348	2348	2348
10	Imports -- WAPA (Firm)	700	700	700	700	700	700	700	700	700	700
11	Adjustment RPS NW Imports	0	(12)	(23)	(42)	(62)	(85)	(110)	(128)	(149)	(172)
12	Exports -- to SP26	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)
13	Net Interchange	48	36	25	6	(14)	(37)	(62)	(80)	(101)	(124)
14	Total System Resources	24,493	24,596	25,178	26,154	25,793	25,457	25,147	24,642	24,145	24,259
15	Service Area Portion of System Resources [4]	22,707	22,808	23,354	24,268	23,941	23,638	23,359	22,897	22,443	22,557
	Service Area Specific Resources										
16	Uncommitted Energy Efficiency [5]			56	109	166	228	295	362	430	497
17	Price Sensitive Demand Response (DR)	342	394	554	695	750	765	774	783	792	801
18	Interruptible/DR Curtailable Programs	310	353	353	353	353	353	353	353	353	353
19	Contract viability re-adjustment (for PGE 2006 LTPP) [6]	100	200	300	400	500	600	600	600	600	600
20	Total Service Area Specific Resources	752	947	1263	1557	1769	1946	2022	2098	2174	2251
21	Total Service Area Resources	23,459	23,755	24,617	25,825	25,711	25,584	25,381	24,996	24,618	24,808
	PLANNING RESERVES										
22	Planning Reserve	3,614	3,659	4,253	5,192	4,783	4,362	3,870	3,203	2,540	2,445
23	Planning Reserve (%) [7]	18.2%	18.2%	20.9%	25.2%	22.9%	20.6%	18.0%	14.7%	11.5%	10.9%
24	Lower Bound of Planning Reserve Requirement (15%)	2,977	3,014	3,055	3,095	3,139	3,183	3,227	3,269	3,312	3,354
25	Upper Bound of Planning Reserve Requirement (17%)	3,374	3,416	3,462	3,508	3,558	3,608	3,657	3,705	3,753	3,802
26	**1 in 2 PG&E Service Area Surplus (Deficit) [8]**	**240**	**243**	**791**	**1,685**	**1,225**	**754**	**213**	**(66)**	**(772)**	**(909)**

[1] Based on CEC's 2007 IEPR 1-in-2 peak demand, which embeds self-served load, committed EE and approximately 80% of uncommitted EE. Note the average growth rate of the forecast peak including uncommitted EE (Line 2 - Line 16) is 1.06% per year.

[2] Service area calculation includes bundled and DA customers and excludes POUs.

[3] This line provides a laddered reduction of aging units as described in the Retirements section of the decision.

[4] This line provides the portion of system resources that are available to PG&E's service area (system resources * Line 2/Line 1).

[5] Uncommitted EE resources not captured in the CEC's demand forecast (approximately 20% total uncommited EE goals plus a 10% line loss factor).

[6] This line replaces deductions for a 10% contract viability derate embedded in PG&E's resource assumptions.

[7] Planning Reserve % = [(Service Area Resources/Service Area Demand)-1].

[8] Surplus represents amount above upper bound of PRM, deficit represent amount below lower bound. No deficit or surplus for values within PRM bounds.

TABLE SCE-1
SCE's Share of SP-26 Regional Need (MW)

Based on SCE's Recommended Plan

	LOAD FORECASTS	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	1-in-2 System Summer Temperature Demand [1]	28,144	28,604	29,079	29,557	30,029	30,498	30,949	31,398	31,844	32,281
2	1-in-2 SCE Service Area Summer Temperature Demand [2]	21,109	21,476	21,849	22,227	22,597	22,966	23,321	23,672	24,022	24,365
	RESOURCES										
	System Resources										
3	Existing Generation	21,910	21,910	21,910	21,910	21,910	21,910	21,910	21,910	21,910	21,910
4	Retirements (Announced or Anticipated)				(850)	(1550)	(2500)	(2850)	(2850)	(2850)	(2850)
5	Retirements (Laddered Reduction of Aging Units) [3]			(500)	(1000)	(1500)	(2000)	(2500)	(3000)	(3500)	(4000)
6	RPS Renewables @ 20% (est. effective capacity)		100	250	450	650	750	900	1000	1100	1200
7	Potential/Planned Additions [4]	436	613	1203	2148	3243	4193	4193	4193	4593	4593
8	Imports carrying own reserves	6100	6100	6100	6100	6100	6100	6100	6100	6100	6100
9	Imports not carrying own reserves	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000
10	Net Interchange	10,100	10,100	10,100	10100	10100	10100	10100	10100	10100	10,100
11	Total System Resources	32,446	32,723	32,963	32,758	32,853	32,453	31,753	31,353	31,353	30,953
12	Service Area Portion of System Resources [5]	24,336	24,569	24,767	24,634	24,722	24,438	23,927	23,638	23,652	23,363
	Service Area Specific Resources										
13	Uncommitted Energy Efficiency [6]			348	424	511	605	707	707	707	707
14	Price Sensitive Demand Response (DR)	88	113	174	309	457	595	708	799	868	908
15	Interruptible/DR Curtailable Programs	1,328	1,370	1,339	1,309	1,280	1,253	1,227	1,203	1,180	1,158
16	Total Service Area Specific Resources	1416	1483	1861	2042	2248	2453	2642	2709	2755	2773
17	Total Service Area Resources	25,752	26,052	26,629	26,677	26,970	26,891	26,569	26,347	26,407	26,136
	PLANNING RESERVES										
18	Planning Reserve	4,643	4,576	4,780	4,450	4,373	3,925	3,248	2,675	2,385	1,771
19	Planning Reserve (%) [7]	22.0%	21.3%	21.9%	20.0%	19.4%	17.1%	13.9%	11.3%	9.9%	7.3%
20	Lower Bound of Planning Reserve Requirement (15%)	3,166	3,221	3,277	3,334	3,390	3,445	3,498	3,551	3,603	3,655
21	Upper Bound of Planning Reserve Requirement (17%)	3,589	3,651	3,714	3,779	3,841	3,904	3,965	4,024	4,084	4,142
22	**SCE's Service Area Surplus (Deficit) [8]**	**1,054**	**925**	**1,065**	**671**	**532**	**21**	**(250)**	**(876)**	**(1,219)**	**(1,884)**

[1] Based on CEC's 2007 IEPR 1-in-2 peak demand, which embeds self-served load, committed EE and approximately 80% of uncommitted EE. Note the average growth rate of the forecast peak including uncommitted EE (Line 2 - Line 13) is 1.22% per year.

[2] Service area calculation includes bundled and DA customers and excludes POUs.

[3] This line provides a laddered reduction of aging units as described in the Retirements section of the decision.

[4] Includes DPV #2 as a 450 MW resource coming on-line in 2012 and the additional 400 MW of 2006 SDG&E authorization coming on line in 2015.

[5] This line provides the portion of system resources that are available to SCE's service area (system resources * Line 2/Line 1).

[6] Uncommitted EE resources not captured in the CEC's demand forecast (approximately 20% total uncommited EE goals plus an 8% line loss factor).

[7] Planning Reserve % = [(Service Area Resources/Service Area Demand)-1].

[8] Surplus represents amount above upper bound of PRM, deficit represent amount below lower bound. No deficit or surplus for values within PRM bounds.

TABLE SDGE-1
SDG&E Service Area Need (MW)

	LOAD FORECASTS	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	1-in-2 SDG&E Service Area Summer Temperature Demand [1]	4,506	4,568	4,641	4,712	4,784	4,856	4,925	4,994	5,063	5,131
	RESOURCES										
2	Existing Service Area Generation	2924	2924	2924	2924	2924	2924	2924	2924	2924	2847
3	Service Area Additions [2]		761	761	761	761	761	761	761	761	761
4	Transmission Import Limit [3]	2400	2337	2214	2057	2000	1926	1873	1780	1718	1658
5	Retirements	0	0	0	(702)	(702)	(702)	(702)	(702)	(702)	(702)
6	RPS Additions	100	163	286	443	500	574	627	720	782	842
7	Price Sensitive Demand Response	76	96	230	233	236	237	238	240	232	245
8	Interruptible/DR Curtailable Programs	123	139	139	139	139	139	139	139	139	139
9	Total Service Area Resources	5,623	6,420	6,554	5,855	5,858	5,859	5,860	5,862	5,854	5,790
	PLANNING RESERVES										
10	Planning Reserve	1,117	1,852	1,913	1,143	1,074	1,003	935	868	791	659
11	Planning Reserve (%) [4]	24.8%	40.5%	41.2%	24.3%	22.4%	20.7%	19.0%	17.4%	15.6%	12.8%
12	Lower Bound of Planning Reserve Requirement (15%)	676	685	696	707	718	728	739	749	759	770
13	Upper Bound of Planning Reserve Requirement (17%)	766	777	789	801	813	826	837	849	861	872
14	**1 in 2 SDG&E Service Area Surplus (Deficit) [5]**	**351**	**1,075**	**1,124**	**342**	**261**	**177**	**98**	**19**	**0**	**(111)**

[1] Based on CEC's 2007 IEPR 1-in-2 peak demand, which embeds self-served load, committed EE and approximately 100% of uncommitted EE.
[2] Adds the 2008 peakers to the 623 MW of new local cpacity included in SDG&E's service area base case estimate.
[3] Conservatively assumes that all RPS additions are imported.
[4] Planning Reserve % = [(Service Area Resources/Service Area Demand)-1].
[5] Surplus represents amount above upper bound of PRM, deficit represent amount below lower bound. No deficit or surplus for values within PRM bounds.

3. Procurement Process Issues

3.1. PRG

Procurement Review Groups (PRGs) were initially established in D.02-08-071 as an advisory group to review and assess the details of the IOUs' overall procurement strategy, RFOs, specific proposed procurement contracts and other procurement processes prior to submitting filings to the Commission as an interim mechanism for procurement review. PRG recommendations are advisory and non-binding, and no participants in the PRG process give up any rights associated with future litigation of issues addressed in PRG meetings.

The Commission has consistently acknowledged the value of PRGs by ordering their continued use, so they continue to advise IOUs on their procurement activities.[136] Current Commission orders require IOUs to meet with the PRG (1) quarterly to review their portfolio position and transactions and (2) as needed to review all transactions with terms greater than three months.

PRGs review procurement activities including, but not limited to:

- RFO development
- Bid evaluation and ranking
- Gas supply plans
- Hedging strategies
- Consumer Risk Tolerance (CRT) triggers
- Nuclear fuel plans
- Congestion Revenue Rights
- New technologies

[136] D.02-08-071, D.02-10-062, D.03-12-062 and D.04-12-048.

- Procurement portfolio position and transactions (on a quarterly basis, as noted)

With some exceptions, the same individuals and organizations make up the PRGs for each of the three IOUs (e.g., DRA, TURN, Aglet, UCS, ED, DWR). PRG members participate in separate meetings with each IOU and are tasked with staying abreast of the many issues noted in the above list for each IOU. As it is a considerable task to manage the significant amount of data and other information, PRG participants who are also intervenors in this proceeding have proposed a number of process improvements, which are discussed in this subsection.

In addition, PG&E requested a change to the PRG consultation threshold for transactions with a term greater than three calendar months, some parties have raised transparency concerns related to the PRG process and representatives of DA have requested that non-market participants including DA and CCA representatives be present at PRG meetings that address resources that will be subjected to the CAM. The issues are also addressed in the subsection.

3.1.1. Meeting Calendar

3.1.1.1. Parties' Positions

Besides the required quarterly PRG meetings, the IOUs frequently schedule meetings for the various reasons listed above. DRA has requested that each IOU develop a monthly calendar on a quarterly basis that identifies the planned meetings and procurement issues to be addressed.[137] SCE finds this request reasonable provided it leaves the IOUs flexibility to update the calendar as needed, including organizing a PRG meeting even if it is not on the

calendar.[138] PG&E stated they would willingly provide a calendar of planned meetings and solicitation activity.[139] The IOUs cite scenarios such as issuance of RFOs, bidder's conference, bid deadlines, and other procurement activities that by their nature are, at times, scheduled upon short notice.

3.1.1.2. Discussion

We concur with DRA's suggestion that a PRG calendar would be a useful process tool. Further, to address the issue of scheduling of conflicting PRG meetings, we direct the IOUs to individually set up and maintain a web-based PRG calendar that can be accessed and updated by the IOU. This will enable each IOU to efficiently schedule meetings with full knowledge of other IOU PRG meeting dates and times.

Scheduling PRG meetings requires planning and coordination with all PRG members; maintaining these PRG calendars will be part of that planning. The calendar will also include dates of expected solicitation milestones (RFO release dates, bid deadlines, etc.). To maintain the confidential nature of PRG data, though, calendar content shall be restricted to non-confidential information.[140]

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[137] DRA, Volume A at 28 (Khosrowjah).

[138] SCE Reply Testimony at 16.

[139] PG&E Reply Testimony at 3-9

[140] Non-confidential information is determined pursuant to the confidentiality matrix in D.06-06-066 and D.07-05-032.

3.1.2. Meeting Agenda and Materials

3.1.2.1. Parties' Positions

DRA recommends that for each PRG meeting, the IOUs develop an agenda to include the meeting date and time, and a list of issues covered in the meeting with a brief description of each issue. DRA also suggests a "standard" format for PRG meeting presentations that includes an introductory page explaining the purpose and background of the presentation, and a conclusion page describing next steps.[141]

DRA claims that there have been times in the past where PRG members received PRG materials only a few hours or one day before the meetings. "The materials are, by necessity, typically very technical requiring sufficient time to adequately review the material and provide useful feedback to the IOU."[142] DRA therefore requests that meeting materials be distributed five days in advance. Aglet testified that PRG members often received materials less than two days ahead of meeting times and recommended that meeting materials need to be distributed at least two days in advance.[143]

PG&E agrees that PRG participation is improved if parties have the opportunity to review written material in advance. PG&E agrees that providing meeting materials two days in advance is a reasonable goal, but notes that when 48 hours advance distribution is impossible, they attempt to provide PRG members sufficient opportunity to understand the written material and provide

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[141] DRA, Volume A at 29 (Khosrowjah).

[142] DRA, Volume A at 29 (Khosrowjah).

[143] Aglet at 1-7 (Reid).

their feedback.[144] SCE is concerned that strict meeting material deadlines would be difficult to meet in consideration of some procurement process that requires PRG consultation. RFO bid closing windows and bid acceptance are sometimes on a quick 24 to 48-hour interval that precludes providing PRG members accurate updates 48 hours before a meeting.[145]

3.1.2.2. Discussion

There is presently no formal agenda requirement for PRG meetings. PRG members often participate in several PRG meetings over a short period of time (sometimes three or more meetings with different IOUs in a one-week period). Also, in light of the PRG's responsibility to advise and review IOU procurement activities, preparation for PRG meetings is imperative. Meeting materials such as presentations, data sheets, or summaries must be reviewed and analyzed to develop informed opinions and lines of inquiry in advance of the corresponding PRG meeting. Providing an agenda and meeting materials with sufficient lead time will aid PRG members in effectively organizing and focusing their participation.

Consequently, we direct the IOUs to provide PRG members with meeting agendas <u>and materials</u> a minimum of 48 hours in advance of the PRG meeting, unless there are unusual, extenuating circumstances that the IOU communicates to PRG members in an email announcing a meeting or distributing meeting materials on a tighter timeframe.

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[144] PG&E Reply Testimony at 3-9.

[145] SCE Reply Testimony at 18.

3.1.3. Meeting Summary

3.1.3.1. Parties' Positions

Aglet requests that the IOUs provide PRG meeting minutes and a "to do list" when PRG members ask for additional information during a meeting.[146] While DRA understands preparing PRG minutes could be difficult, it recommends a minimal requirement that the IOUs prepare a list of the participants and issues discussed after each PRG meeting.[147] PG&E has no objection to minutes.[148] SCE testifies that memorializing PRG discussions and party positions in accurate minutes would jeopardize the free flow of opinions and ideas due to concerns that it could become evidence in a future legal argument.[149]

3.1.3.2. Discussion

We agree that providing a post-PRG meeting summary will further facilitate efficient and effective use of the PRG. We adopt DRA's recommendation the IOUs provide (confidential) meeting summaries to PRG members. Meeting summaries will include a list of attending PRG members, including the organizations represented, a summary of topics presented and discussed, and a list of information requested or offered to be supplied after the meeting, (and identify the requesting party). We do not require the IOUs to develop detailed PRG meeting minutes in this decision, and we also stress that

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[146] Aglet at 1-9 (Reid).

[147] DRA, Volume A at 29 (Khosrowjah).

[148] PG&E Reply Testimony at 3-10.

[149] SCE Reply Testimony at 19.

this information is in no way admissible in hearings as evidence or able to be cited in testimony.

3.1.4. Transparency

3.1.4.1. Parties' Positions

Parties that are not part of the PRG raised concerns that IOU procurement conducted in consultation with the PRG exists in a "black box" of secrecy since the nature, content, and results of PRG meetings are confidential. This issue was further explored in the May 2007 ED workshops, and most of the concern revolved around who was on the PRGs and what was accomplished in the process.

As a result, a PRG Transparency working group was formed consisting of CPUC staff, PRG members, non-PRG members and representatives of the IOUs. The working group met several times with the goal of making this "black box" less opaque. To make the PRG process less mysterious, working group participants agreed that the IOUs could provide the following information to the public:

1. The date and meeting time that a specific PRG meeting occurred and the duration of the meeting;

2. The individuals participating in the PRG meeting, and the organization that the individual represents (e.g., TURN, Aglet, etc.); and,

3. A list of items discussed during the meeting, including only public (i.e., non-confidential) information.

3.1.4.2. Discussion

We adopt the Transparency Working Group's information-sharing proposals, and recommend that the IOUs work together to incorporate this

information into the web-based calendar or another web-based forum, and provide this information to this and future LTPP proceeding service lists.

3.1.5. CAM Group

D.06-07-029 provides the IOUs with a mechanism to recover procurement costs for system reliability resources from all customers in the system, bundled and unbundled. This subsection addresses the fact raised by some intervenors that no DA- or CCA-specific representatives are currently participants in PRG meetings.

3.1.5.1. Parties' Positions

AReM contends that the goal of fairness to all customers would be served by including DA and CCA customer advocates on each IOU's PRG. AReM supports a proposal for expanding the PRG as a fair and responsible way to protect the interests of customers who are asked to bear the costs of system resource procurement.[150]

DACC points out that all three IOUs speak highly of their PRGs and the PRG process. DACC notes that until the adoption of D.06-07-029, the utilities have not procured new resources on behalf of direct access customers, and thus DA input was not needed. DACC argues that this has changed dramatically with the adoption of D.06-07-029, and that now DA customers should be explicitly represented on each of the PRGs.[151]

CCSF agrees with the DACC proposal that since DA customers will be paying for capacity procured by the IOU's, they should have a representative on

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[150] AReM at 27 (McClary).

[151] DACC at 6 (Hoegger).

each of the IOU PRGs. The CCSF argues that the same argument holds for customers of CCAs. Since CCA customers will also be paying for capacity procured by the IOUs, CCAs also should have customer representation on the IOU PRGs.[152]

SDG&E testified that if the Commission finds the need for additional PRG members from CCA and DA customers, it is essential that the following limits be placed on any benefiting customers' involvement: (1) if benefiting customers are allowed to participate in the PRG, it should only be for discussion of any supply procured on behalf of those customers (i.e., there is no need for unbundled customer representatives to be involved in any IOU procurement matters unrelated to the contracts subject to D.06-07-029), and (2) benefiting customer involvement should be allowed only to the extent that any attendee warrants that it will not bid, or assist others in bidding, in the resulting energy auction.[153]

SCE testified that D.06-07-029 fairly allocates procurement of new generation to all benefiting customers. SCE claims they do not engage in excessive procurement that would burden all system customers and that should they do so, the existing PRG members would object.[154]

3.1.5.2. PRG Participation Working Group

A PRG Participation Working Group consisting of representatives of DA and CCA customers and organizations, PRG members, and Commission staff met several times to determine if and how CCA and DA customers could be

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[152] CCSF at 3 (Casey).

[153] SDG&E Reply Testimony at 7-8 (McClenahan).

[154] SCE Reply Testimony Vol. 1 at 15.

explicitly represented in the PRG process. The working group determined that the existing PRG does not include participants that solely represent CCA and DA customers. The working group proposed the creation of a new advisory CAM Group supplemental to the PRG.[155] The new CAM Groups would include existing PRG members, CCA and DA customer representatives, and representatives of any other non-bundled customers established in future Commission policies. The working group's proposal to create the CAM Group is presented in Attachment D.

The proposal states that the CAM Group would be called upon when an IOU plans to procure new generation resources and recover the costs of the resources through the CAM, or when an IOU, at the time it decides to seek new generation, has not decided its cost recovery basis, bundled or non-bundled. When an IOU plans to procure and recover costs solely from bundled customers, the PRG would continue to be the IOU's advisory group. When an IOU plans to procure and recover costs using the CAM, or has yet to determine this at the time of initiating an RFO, an IOU would notify the ED and the CAM Group participants.

The CAM Group would operate as the PRG does except it will review activities and information isolated to procurement that will or may use the CAM, and the IOUs will not be required to meet quarterly with the CAM Group. The CAM Group would have the same privilege to request and receive additional

[155] Named for the Cost Allocation Method from D.06-07-029.

information of the IOUs, just as PRG members do for bundled procurement related processes.[156]

The CAM Group would be composed of existing PRG members, Commission staff, and a reasonable number of end use non-bundled customers or individuals hired to represent their interests.[157] CAM Group members would be subject to a Non-Disclosure Agreement ("NDA") developed specifically for the CAM Group.[158] CAM Group members who are not part of the existing PRG who are authorized for intervenor compensation would qualify for compensation for CAM Group participation pursuant to Commission rules governing such compensation, and PRG members who receive such compensation would be eligible for it for their CAM Group participation. IOUs may continue to use the existing PRG to conclude existing, on-going CAM procurement provided final contract selections are made within 60 days of this decision.

3.1.5.3. Discussion

We adopt the PRG Participation Working Group proposal, as presented in Attachment D, to create a CAM Group for procurement for which IOUs recover costs from bundled and unbundled customers using the D.06-07-029 CAM. In

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[156] Subject to applicable confidentiality provisions.

[157] No CAM Group member can be a wholesale market participant or represent a wholesale market participant. The details of the qualifications and participation of CAM Group Non-PRG members are explained in the CAM Group proposal in Attachment D.

[158] The form and content of the NDA will be resolved before activation of the CAM Group. The creation of the NDA cannot delay the effective period of the CAM Group.

order to ensure adequate representation of the various affected groups we will require that at a minimum the CAM Group should include one member representing CCAs, two members representing ESPs, and one member representing other non-bundled customers. Each IOU shall develop and convene a CAM Group when it becomes necessary according to the requirements of the adopted proposal.

3.1.6. Transaction Consultation Requirement

Ordering Paragraph 15 of D.04-12-048 required the IOUs to consult with PRGs for all transactions greater than three calendar months. PG&E requests that PRG consultation only be required for transactions with a term greater than six calendar months.

3.1.6.1. Parties' Positions

PG&E posits that with increased market volatility, there have been times when it has been necessary to act quickly in order to mitigate sudden and significant price changes in the forward markets. Even though consulting the PRG is a relatively efficient process, there are situations where delays of even a day or two could lead to unfavorable contracting terms (costs) due to rapidly developing situations, such as unfavorable nationwide weather conditions in the winter months (November-March) and catastrophic events like Hurricane Katrina.

Moreover, greater liquidity in the markets up to 12 months forward means that there are more opportunities for PG&E to hedge these risks, provided that the short-term procurement framework is streamlined. Therefore, by changing the consultation requirements to six months, PG&E believes it will have the flexibility to respond to market conditions, and will not overload the PRG with discussions of liquidly traded, standard transactions.

PG&E argues that no party has opposed its proposal to change the required PRG consultation from the current requirement for any transaction with a delivery term greater than three months' duration to a transaction delivery term greater than six months' duration.

3.1.6.2. Discussion

We deny PG&E's proposal to change the required PRG consultation from the current requirement for any transaction with a delivery term greater than three months duration to a transaction delivery term greater than six months duration. PG&E has not demonstrated that the procurement process has been detrimentally inhibited by the timeliness of the PRG process. Emergency PRG meetings have been successfully convened to address issues requiring quick action, and the appropriate process for requesting an emergency PRG meeting based on extenuating circumstances is described earlier in this subsection.

3.2. Independent Evaluator/IE Report Template

In D.04-12-048, the Commission authorized the IOUs to use an independent evaluator (IE) to monitor competitive solicitations that involved affiliate transactions, IOU-built or IOU-turnkey bidders. In D.06-07-029 and D.07-09-044, the Commission established the conditions for IE participation in the Energy Auctions. The Commission also requires that an IE be used in all RPS solicitations. Since 2004, each IOU has gained some experience with the use of the IE. While the policy surrounding the use of an IE is not within the scope of this proceeding, parties were asked to evaluate the implementation of the use of IEs. In particular, parties were asked to consider the following questions:

- Should all competitive solicitations require an IE?
- Should solicitations that do not have affiliate transactions, or involve a utility-owned or utility-turnkey bid require an IE?
- How can the Commission ensure the impartiality of the IE?

- What are the costs and benefits associated with the use of an IE, and how do these benefits directly affect procurement outcomes?

In D.04-12-148, the Commission stated that:

> "IEs should come equipped with technical expertise germane to evaluating resource solicitation power products… 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 ED. Alternatively, ED 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 ED and staff as a check on the process.[159]

3.2.1. Parties' Positions

All three IOUs generally agree that the use of IEs in RFOs provides a significant level of oversight, fairness and assurance to the overall solicitation process.[160] However, the IOUs disagree on the types of solicitations in which IEs should participate. PG&E believes that IE participation in solicitation processes where the potential for ownership interests exists is beneficial; however, the use of IEs should be optional when no ownership interest exists.[161] SCE does not feel that an IE should be required for solicitations where an affiliate is not

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[159] D.04-12-048.

[160] TURN Initial Comments.

[161] PG&E Volume II at II-17.

participating in the solicitation and there is no utility-owned or utility-turnkey project in the solicitation. SCE states that when no incentive exists for the IOU to deviate from "fair, consistent and reasonable practices,"[162] the implementation costs of retaining an IE may far exceed the benefits. SDG&E states that while it is not necessary to mandate the use of an IE in all RFOs, SDG&E has found the IE's participation to be of value.[163]

PG&E states that the IOU, ED and the PRG must balance the cost and expertise that a candidate IE brings to the solicitation process with any perceived conflicts that may exist including (1) a financial interest in the IOU and (2) any consulting work that the IE may have done recently for the IOU or any potential bidder. PG&E feels that such activity should not automatically disqualify an IE from consideration; rather the IE should be required to fully disclose any such conflicts.[164]

To ensure impartiality of the IE, SCE suggests that "Energy Division staff and/or legal counsel review the IE engagement scope and contract terms periodically, or when a new IE is being retained by SCE in order to ensure that mutually agreeable terms are added to the IE retention, such as direct lines of communication between the Energy Division and the IE or the PRG and the IE."[165] SCE goes on to state that during the selection process, the development of the scope of work, and the drafting of the contract terms with the IE, the Energy

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[162] SCE Volume II at 49.

[163] SDG&E Volume II at 10.

[164] PG&E Volume II at II-17.

[165] SCE Volume II at 49.

Division should be involved and have the right to final approval of such engagements.[166]

SDG&E suggests that the ED involvement in the PRG ensures a fair IE hiring process. Furthermore, SDG&E states that ED "staff have the ability to contact the IE at any point for an update and to review IE reports at the conclusion of an RFO."[167] SDG&E rejects the suggestion that the Commission hire and retain the IE stating that this process would delay and hamper procurement efforts and the Commission and the PRG already have full access to participate in the IE process at all stages, including selection.[168]

PG&E states that the costs associated with the use of an IE fall into three categories: (1) the direct cost of the IE services, (2) any incremental time needed to bring the IE on board and involve the IE in the RFO process and (3) any incremental work required of the bidder to assist the IE in the scope of work.[169] SCE states that the obvious cost of the IE is the consulting payments, which are borne by the IOU's bundled customers.[170] All three IOUs state that there are many intangible benefits to the use of an IE including increased confidence by market participants in utility procurement practices and that selected offers were the most economical and appropriate procurement choices.

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[166] SCE Reply Comments.

[167] SDG&E Volume II at 11.

[168] SDG&E Reply Comments.

[169] PG&E Volume II at II-18.

[170] SCE Volume II at 49.

WPTF disagrees with PG&E on the matter of IEs only being retained in solicitation processes greater than five years stating that the purpose of the IE is to ensure that utilities do not engage in preferential treatment of their affiliates or their own projects. IEP, NRG, DRA, TURN and WPTF voiced concerns over the actual independence of the IE suggesting that the best way to ensure a fair and impartial process was for the Commission to hire and supervise the IE. NRG states that an "IE cannot be truly "independent" under circumstances that could result in future limited engagements if the IE is critical of utility procurement practices or proposals or fails to select the utility- or affiliate-build option..."[171]

TURN agrees with the IOUs that the use of an IE significantly enhances competition within the solicitation process. DRA believes that letting the IOUs hire and manage the IE raises concerns regarding his or her independence. Although in the initial phase of the IE selection the IOUs consult PRG members and Energy Division staff, once the IE is hired most of his interactions are with the IOUs. Most procurement practices are already closed to public and market participants, so the true independence of the IE brings more confidence to this process. Therefore, to ensure the true impartiality of the IE, DRA recommends that the Energy Division hire and supervise the IE, in consultation with the IOUs and the PRG.[172]

DRA also recommends that the Commission require the following information regarding the use of IEs in the next LTPP proceeding:

- The name and information of the IE for each IOU

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[171] NRG Initial Comments.

[172] DRA Initial Comments.

- The type of procurement solicitation the IE was used for
- The amount of money involved in the procurement solicitation
- The cost of the IE for each solicitation for each IOU

3.2.2. Discussion

As discussed in D.04-12-048, the initial IE mandate was intended as an interim approach that was to be refined based upon further experience. Based on the record in this proceeding it is reasonable to find that the IE process, while deemed beneficial by most involved, requires further refinement in order to maximize benefit to all involved parties. The Commission recognizes the need to develop a fair and transparent process for IOUs to use in selecting the IE for each RFO process. We acknowledge that ensuring the independence of the IE is of the utmost importance and that the current hiring and selection process may not adequately ensure, or at least appear to ensure, such independence. Furthermore, we feel that it is important to develop multiple qualified candidates for the IE position that are familiar with California policies and practices and our high standards for procurement.

At this time, it is not practical to transfer the IE contracting authority to the Commission; however, we will continue to explore ways in which to do so in the future. In the interim, there are several steps that can be taken to ensure the independence of the IEs while also developing a robust pool of qualified candidates. D.04-12-048 states that the IOUs may contract directly with the IE's in consultation with their respective PRGs. To strengthen this approach, we direct each IOU, in conjunction with each respective PRG, to develop a pre-qualified pool of at least three, but preferably more, IEs to be used beginning

January 1, 2009.[173,174] Each IOU should develop and periodically add[175] to its IE pool as follows:

1. The IOU shall develop a list of prospective IEs via industry contacts, literature searches, PRG recommendations, and similar methods, solicit information from the prospective IEs and circulate the list of candidates and their "resumes" to the PRG and ED staff for feedback;[176]

2. The IOU should rely on the guidance regarding IE expertise and qualifications provided in D.04-12-048. However, these qualifications should represent the minimum necessary for an IE to be effective, and the IOU and the PRG should include any additional relevant information that it has gained through its experiences implementing the IE requirements;

3. The IOU and PRG shall interview a subset of prospective candidates that the IOU, its PRG, and ED staff deem most suitable for the role (IOUs should arrange for the PRG to conduct interviews with candidate IEs in isolation from the contracting IOU);

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[173] The IOUs will have until January 1, 2009 to work through the IE interviewing and selection process. In the mean time, the IOUs may continue to contract with existing IEs for all 2008 RFOs; however, we encourage the IOUs to explore the use of different IEs for successive 2008 RFOs. Any RFO issued on or after January 1, 2009 shall only use an IE that is a member of the approved IE pool. All changes to the IE process within this decision will go into effect prospectively beginning January 1, 2009.

[174] Based upon DRA's and the IOUs' comments on the PD, successive rotation through the IE pool will not be required; however, the IOU must seek approval from ED of the selected IE for each RFO. ED reserves the right to deny approval of the use of a particular IE.

[175] IOUs shall expand their IE pool as needed to maintain a minimum of three IEs and/or to add additional IEs as the IOU finds suitable candidates.

[176] Candidate names shall be kept confidential as part of the PRG process.

4. The PRG shall coordinate the development and submittal to the IOU its recommendations on each prospective candidate (including the general consensus and any opposition to the consensus). The IOU shall submit a written list of qualified IEs to ED to add to the IOU's pool. The list must contain the recommendations of the PRG that were submitted to the IOU. ED will evaluate the proposed IE's competencies based on the guidelines in D.04-12-048 as well as evaluating the IEs independence including any conflicts of interest.[177] ED shall give final approval for inclusion of an IE in the IE pool by letter to the submitting IOU;[178]

5. Beyond the development of the initial IE pool, additional IE's may be added to the pool by following the same procedures listed above;[179]

6. An IE may remain in the IE pool for two years, after which he/she must go through a reevaluation process based upon the inclusion criteria to assure continued compliance. The reevaluation process will involve additional reviews of the IE

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[177] Inclusion of an IE in the IE pool does not require the signing of a contract between the IOU and the IE.

[178] Once the IE pool is established, the IOU may select an IE only from that pool of candidates and only after notifying the PRG and ED of the selected candidate. The IOU shall submit the preferred IE name to the PRG and ED no less than 15 days before the IE begins work on the RFO contract. Based upon the recommendation of DRA in its comments on the PD, ED shall have final approval of the use of the selected IE for each RFO.

[179] If an IOU wishes to remove an IE from the pool, it must communicate this to its PRG and to ED.

candidate by the PRG, IOU and ED staff including additional interviews, if necessary;[180] and

7. The IOUs shall develop a pro forma contract to be used each time it contracts with an IE. If deviations from the pro forma are necessary, the modifications must be fully supported by ED staff when the IOU seeks final approval of the contract. This pro forma contract shall be submitted as part of the next LTPP filing and will be subject to Commission approval.[181]

The Commission adopts SCE's suggestion that during the selection process, the development of the scope of work, and the drafting of the terms of the contracts with the IE, ED should be involved and have the right to final approval of such engagements. Final approval of IE pro forma contracts shall be made at the discretion of the Commission as part of the upcoming LTPP proceeding. As noted above, the IOUs will submit a list of qualified candidates to ED (including the PRG's recommendations); however, ED will make final approval of an IE for inclusion in the IE pool.[182] The Commission further

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[180] Review of an IE does not preclude the IE from continuing to remain in the IE pool. Reevaluation gives all interested parties, including the IOU, its PRG and ED an opportunity to evaluate the suitability of the IE for continued participation in the pool.

[181] We encourage the three IOUs to work together in an attempt to find a pro forma contract that is acceptable to all three companies.

[182] Based upon the IOUs comments received on the PD, IEs will no longer be restricted from participating in two different IOUs' RFOs within the same six month period. Such a prohibition may lead individual IEs to contract solely with one IOU, thus, potentially reducing the overall independence of the evaluator.

recognizes that IE costs as part of the procurement process are recoverable through ERRA.[183]

The Commission further recognizes that transparency of the IE selection process is of critical importance and therefore adopts DRA's recommendation with modifications that the name and information of the IE for each IOU, the type of procurement solicitation the IE was used for and the amount of money involved in the procurement solicitation be reported to the IOUs PRG before and after the solicitation takes place. We acknowledge that this and other information is already available to the IOUs' PRGs.

The purpose of an IE in the RFO solicitations is to ensure a fair, competitive procurement process free of real or perceived conflicts of interest. Based on the record in this proceeding it is reasonable to find that an IE should continue to be contracted with and retained for all long-term solicitations that involve affiliate transactions or utility-owned or utility-turnkey bids. Further, given that IOUs may not know with certainty whether or not it or its affiliate will bid on a particular solicitation, the Commission requires that an IE be utilized for all competitive RFOs[184] that seek products of more than three months in duration.[185] For solicitations of less than five years, the IE report shall be filed with the QCR.

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[183] IOUs that seek ERRA recovery for IE expenses must submit notice of this change via advice letter to the Commission.

[184] Competitive RFOs include RFOs issued to satisfy service area need and supply-side resources not including EE and DR.

[185] This requirement creates uniformity between the product length for which the IOU must consult its PRG and the IE process.

An additional concern of market participants is that the IE remains independent and free of any and all conflict. The Commission agrees with market participants in this regard, but we realize that the IEs which are qualified to perform the functions required will most likely come from firms that have multiple clients. We are also cognizant of the fact that a consultant's client base is fluid. Given all of these factors, a potential conflict of interest may present itself over the life of the IE contract that was not present when entering into the IE contract or the IE pool- whether it is with the individual IE or the IE's firm. Therefore, we order the IOUs, in consultation with the PRG and ED, to develop comprehensive conflict of interest disclosure requirements for the IE. An IE may be disqualified from participating in an RFO process if there are particular egregious conflicts of interest that arise during the contract. The conflict of interest disclosure requirements shall be approved along with the pro forma contracts in the next LTPPs.

Currently, the IE submits a report to the Commission in support of applications for resources procured in competitive RFOs; however, the reports have been inconsistent and do not always contain the necessary information for the Commission to make an informed decision. We recognize that no formal template for IE reports has been offered; therefore inconsistencies are to be expected. In order to clarify the information required in IE reports, we direct ED to develop a template for IEs to use when developing their reports. The report template should, at a minimum, contain the following information and answer the following questions:[186]

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[186] ED may expand upon the questions and information to be addressed in the IE report template listed above based upon its findings during the template creation process.

1. Describe in detail the role of the IE throughout the solicitation.

2. Is the IOU's methodology for bid evaluation and selection designed fairly?

3. Was the least cost, best fit (LCBF) contract evaluation process fairly administered? (This should include a thorough analysis of the RFO results.)

4. Did the IOU do adequate outreach to bidders, and was the solicitation robust?

5. Were project-specific negotiations fair? [187]

6. Does the contract merit Commission approval?

We direct ED to develop the IE report template through a public process which will allow for public comments and workshops, if needed. ED shall submit the IE report template for public comment no longer than 30 days after adoption of this decision. After receiving comments and making necessary revisions, ED shall serve the final IE Report Template on the service list. Once adopted, these IE report templates shall be included as part of the next LTPP filings.

3.3. RFO Process

Development of a functional RFO process in the hybrid market is an evolutionary exercise in which we must balance a number of competing priorities, and we are continually striving to improve on the process based on industry experiences. Aside from UOG bids, which are addressed in the

[187] For contracts less than five years, IE reports shall be submitted with the QCR, as mentioned previously.

following policy section, there are two primary sources of tension in the existing RFO process: the transparency of the process and the restriction of certain products from an RFO (e.g., truly all source solicitations versus new generation only restrictions).

3.3.1. Summary of Parties' Positions

AReM states that the sharing of capacity costs via the CAM mechanism established in D.06-07-029 for resources acquired by the utilities reinforces the need to assure that the RFO process is conducted in a fair and transparent manner.

Calpine states that the current practice of excluding existing generation (uncommitted or otherwise somehow available) from new generation RFOs minimizes the benefits of competitive solicitations and sends the wrong message to the market.

Calpine recommends that IOU RFOs be approved by the Commission before the solicitation goes public. In support of its recommendation, Calpine states that if an RFO is found to be noncompliant late in the process the whole time-consuming process must be restarted or bids from a noncompliant process may have to be accepted because there will not be enough time to meet supply needs.

IEP does not believe that the current IOU RFO process is sufficiently transparent or fair to allow for truly competitive bidding. IEP recommends the following refinements and requirements to the RFO Process:

- No potential bidder should have preferential access to any information relative to any other bidder. This may entail enforcing codes of conduct between functional groups of the IOU.

- The long-term procurement processes should (1) provide for input by the potential supplier community to help the IOU identify RFO terms that will align IOU needs and market-based providers' offers, and (2) provide for reasonable schedules and adequate clarity and communication with the potential supplier community over terms of the RFO.

- The RFO and contract terms must be fair. For instance, the imposition of differential contract terms (e.g., collateral and credit terms) between IOU and non-IOU offers must reflect the actual differences in risks and circumstances.

- The evaluation criteria and process must be fair.

- Evaluation criteria should be transparent and consistent.

WPTF argues that, although all-source solicitations are strongly encouraged by D.04-12-048, the utilities have overwhelmingly favored RFOs for new generation. Utility customers benefit when the competition to supply their needs is as broad as possible. The eligibility of all resources, which includes existing generation, repowering projects, renewable resources, as well as new generation, to bid in any utility RFO should be confirmed and implemented by Commission order.

WPTF proposes that a utility should produce clear bid evaluation criteria well before accepting competitive bids. Ambiguous criteria and inadequate lead time for bid preparation blocks independent proposals and contributes to inefficient project valuation. WPTF believes that bid evaluation criteria, including the methodology for comparing UOG against power purchase agreements, should be determined by a public process and published in detail so that all bidders know how bids will be scored and how to design a competitive bid.

TURN disagrees with the IEP/WPTF position that the entire bid evaluation methodology in an RFO, including monetary and non-monetary values, computer programs and input assumptions, should be made publicly available to bidders. TURN states that this proposal is reminiscent of the Biennial Resource Plan Update, in which the Commission attempted to specify the entire bid evaluation protocol in great detail. TURN notes that the BRPU process failed, in part because bidders were able to game the evaluation protocols. TURN's position is that bidders should be given a reasonable amount of information regarding how their bids will be evaluated, and that as long as an IE is reviewing the process there should be no meaningful opportunity for a utility to skew these factors. TURN also notes that the models and input assumptions in utility RFOs are typically "locked down" prior to any bids coming in.

TURN endorses the IEP recommendation that the codes of conduct and bans on preferential access to information that apply between a utility and a generation affiliate should extend to the internal IOU functions involved in project development and bid preparation. Under these restrictions, the employees developing the utility-build bid would be barred from access to any information not made available to outside bidders.

TURN also contends that it is generally desirable to solicit bids from as many sources as possible. However, when an IOU is seeking specific types of products (e.g., "new" generation for reliability purposes, in order to assure an adequate future PRM in its service territory) it makes sense to tailor the RFO accordingly. TURN notes that this is entirely consistent with D.04-12-048 (p. 128), in which the Commission stated that: "the IOUs have the flexibility to tailor their RFOs to reflect their specific resource needs . . ."

PG&E argues that it discusses its RFOs with ED and the PRG and holds a bidder's conference prior to launch, and solicits feedback. PG&E believes that the current consultation process has worked well and should be continued.

SCE acknowledges that RFO draft document review and comment by market participants can be useful, when time allows for such review and comment. SCE claims that in its last several RFOs it has endeavored to accommodate this type of process and will continue to do so in the future. SCE continues that, unfortunately, sometimes it is either not possible or would unduly constrict the schedule for other RFO activities (such as for response development or negotiations, etc.). Therefore, SCE does not support the recommendation that such a process be required for every RFO.

SCE is concerned that while it believes that consultation with the PRG and Commission staff is helpful, formal Commission approval of RFO documents would add a considerable administrative burden to the process with no demonstrated benefit. Under its current plan, SCE provides draft versions of its RFO documents to its PRG prior to finalization of the documents. The PRG and the ED are then given an opportunity to provide input to SCE on all RFO elements, including requirements and pro forma contracts. SCE then carefully considers this input when finalizing the RFO documents.

SCE states that it explicitly outlines its valuation methodologies and valuation inputs in its competitive solicitations via the RFO public documents. SCE argues against a more complete disclosure of all data required for valuation and selection, as this would, for example, allow bidders to determine areas where they have market power and are able to extract a greater premium for their products. SCE believes that allowing bidders to have exact formulas and

software programs used by the utilities to evaluate bids would allow them to manipulate the process to drive prices higher.

SCE claims that it provides a very detailed explanation of the LCBF evaluation process in its LTPP and that there is also ample guidance provided to the bidders via the RFO Documents (*i.e.*, Transmittal Letters, Offer Sheets, and associated Appendices), bidders conference calls, and SCE's frequently asked questions (FAQs) pertaining to any particular RFO.

SCE argues that while it procures the vast majority of its capacity and energy needs through all-source RFOs, there are times when a specific need is identified and the only efficient manner to meet this need is through a targeted RFO. SCE's New Generation Resources and Renewable RFOs are examples of solicitations tailored to meet targeted needs identified by the Commission. SCE does not believe that a requirement that prohibits the IOUs from conducting targeted solicitations would be in the best interest of IOU customers or potential bidders.

SDG&E identifies the key benefit of competitive bid solicitations as the bringing together of the largest number possible of market participants to make offers to sell, thus promoting liquidity, competition and price discovery. SDG&E cautions that these benefits must be balanced with the fact that RFOs are very slow relative to the volatility of market prices, thus leaving the portfolio exposed until contracts are negotiated and signed. Further, SDG&E notes that RFOs are administratively costly due to the extensive contract negotiations required to cover deal-specific commercial, legal and credit terms. SDG&E regularly evaluates the needs of the portfolio to determine whether RFOs present advantages compared with the alternative of spot trades, exchange traded products, bilateral transactions or some combination.

SDG&E believes that RFOs are most beneficial for long-term (not short-term) procurement where the utility is acquiring highly structured, non-standard products and little or no transparent pricing exists. RFOs are also useful where products may be standardized, but no exchange exists on which to trade them. SDG&E also notes that when multiple projects are chosen in the RFO process, it creates a tremendous amount of workload at a single point in time, whereas bilateral contracting spreads this work over a longer period of time.

Finally, SDG&E proposes to conduct renewables procurement along with conventional resources in its all-source solicitations.

3.3.2. Discussion

3.3.2.1. RFO Flexibility

Regarding tailoring RFOs to, for example, address system reliability needs (and therefore limiting the solicitation to new or repowered generation) or RA requirements (system, zonal, or local), the Commission is in full agreement with the IOUs that ratepayers benefit from this level of flexibility, and that IPPs actually benefit from this practice as well in that they are properly discouraged from utilizing their resources to develop bids for products not needed by the IOU. That being said, we expect RFO product descriptions to be based on each utility's operational needs and not create false barriers to participation or otherwise limit the competitive process.

3.3.2.2. Transparency

Regarding transparency, the IPP community desires more information in the RFO process to ensure that (1) developers can put their "best foot forward" in their bids, and (2) the IOUs cannot put a thumb on the scale in the bid development and/or evaluation process in favor of UOG or affiliate bids. The

IOUs argue that their practices provide sufficient information for parties to design bids to their strengths, and that providing too much information could result in gaming opportunities and consistently higher bids.

The fundamental issue the Commission must address concerning RFO transparency is what types of transparency benefit ratepayers. Generally, we concur with TURN and the IOUs that too much information can result in undesirable outcomes. However, in some instances the RFO information provided by IOUs has been sufficiently short on details (e.g., instances in which an IOU had too much latitude to identify a bid as nonconforming based on the vagueness of the bid requirements).

One of the working groups created as a result of the workshops ED held in the spring was the Transparency Working Group. The Transparency Working Group was tasked with identifying, among other things, areas in which additional information could be provided to IPPs by the IOUs that would not harm the competitive process. However, the group did not actually focus on most of the transparency issues raised by IPPs in comments and workshops, so were unable to make any recommendations as a result of this process.

The Commission believes that the RFO process would benefit from additional rigor on the part of the PRGs, IEs, and ED in scoping, reviewing, and revising RFO bid documents to help identify data gaps, confirm the fairness of the components of the RFO that the IOU identifies as confidential, and ensure that both the letter and spirit of the RFO are consistent with the Commission policies set forth in this and past procurement decisions. To address these concerns, the IOUs will need to build consultation with PRGs and ED into the early stages of the RFO process.

Prior to drafting RFO bid documents, we will require all IOUs to hold a meeting with the IE, PRG, and ED to outline their plans (quantities and types of products they intend to solicit, category definitions if multiple bid categories are envisioned, any unique circumstances to be addressed in the RFO) and solicit feedback. Then, the draft RFO bid documents are to be developed under the oversight of an IE. The bid documents should include (for internal review by the PRG and ED staff) clear descriptions of the bid criteria (including the rationale for selecting and weighting the criteria) and the evaluation and selection process. The draft bid documents are to be vetted through the PRGs, and any differences are to be resolved with ED staff in advance of the public issuance of bid documents. In addition, the IOU is to provide the PRGs and ED staff a decision rationale with respect to each selected and rejected bid upon completion of an RFO.

Finally, no IOU is to initiate an RFO for new fossil resources that have not been formally authorized in an LTPP decision unless the IOU makes a strong showing in advance, by an approved Advice Letter, that unusual or extreme circumstances warrant such an action.

The Commission has also been unsatisfied with the amount of process details provided by the IOUs in their applications for Commission approval of winning bid projects. Substantial inadequacies in initial submittals have required ED staff to issue data requests to develop an adequate record. To remedy this concern, we direct ED to develop a template for IOUs to use when

developing their applications. The selected project application template should, at a minimum, cover the following topics:[188]

1. Detailed description of bid selection process,

2. Consistency with Commission decisions,

3. Consistency with the EAP loading order and the IOU's GHG reduction strategy,

4. Outside participation and feedback, and

5. Contingencies and milestones.

We direct ED to develop the selected project application template through a public process that allows for public comments and workshops, if needed. ED shall submit the project application template for public comment no longer than 30 days after adoption of this decision. After receiving comment and making necessary revisions, ED shall serve the final project application template on the service list. Once adopted, the template shall be utilized by the IOUs in future project applications.

3.3.2.3. Timing

One aspect of the RFO bid selection process that troubles this Commission is the protracted RFO process itself, from conducting an RFO, negotiating contracts, and ultimately filing applications with the Commission for approval. PG&E released its LTRFO on March 18, 2005, and filed the winning contracts for

[188] ED may expand upon the questions and information to be addressed in the project application template listed above based upon its findings during the template creation process.

Commission approval a full 13 months later on April 11, 2006 (seeking expedited approval). SCE was authorized to conduct a solicitation for up to 1,500 MWs on July 20, 2006, released its RFO on August 14, 2006, executed contracts on February 15, 2007, and filed for approval of the contracts on February 28, 2007. SCE also has a standard track from this solicitation that is due to close in the first quarter of 2008 – nearly 18 months after releasing the solicitation. This process is much too time intensive; much too protracted. The process, as the IOUs are currently implementing it, invariably places our IOUs behind the market – in a reactive, catch up position (and all-too-often trying to do so via expedited public review). This is not in the best interest of California's ratepayers.

Similarly, IOU All Source RFOs consistently extend from early in the summer into the fall, and often completed very close to the year-ahead RA filing dates, essentially freezing out other ESPs from the market.

We realize that this is a fairly new method of procuring resources but clearly improvements must be made – and quickly for that matter. Several steps to improve the procurement process have already been taken with the issuance of this decision today, but we are not convinced that more improvements are beyond reach, and we direct the IOUs to work with the PRGs and ED staff to develop ways in which efficiencies can be achieved in the RFO process.

3.3.2.4. SDG&E's Proposal to Combine its Renewables and All Source Solicitations

Conclusion of Law (COL) # 22 in D.04-12-048 states that "Allowing an IOU to meet its RPS annual procurement target via an all source RFO, as well as via an 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." We encourage SDG&E and all the IOUs to encourage

renewable resource bids in their RFOs, with the two following caveats intended to ensure that the renewable procurement processes developed in the RPS proceeding (MPR, etc.) are not circumvented via the all source RFOs:

- All resources within an RFO should be compared against one another on a consistent, LCBF basis using the GHG adder to increase the costs of fossil resources relative to renewables (i.e., the solicitations should not be designed with separate groupings for renewables and conventional generation), and
- Decisions regarding whether or not to continue conducting separate RPS solicitations should be addressed in the RPS proceeding.

3.4. Contract and Bid Evaluation

As the Scoping Memo specified, a key goal of this proceeding is to review the procurement process of the RFOs to consider whether any refinements are necessary to further the goal of open, transparent and competitive procurements. An open, transparent and competitive procurement process is the king-pin to a successful hybrid market, and that theme, in tangent with environmental issues, guide our decision on the 2006 LTPPs. Therefore, although we address specific procurement related issues in this section of the decision, our commitment to an improved procurement process promoting a hybrid market speaks throughout the decision.

3.4.1. Evaluation Criteria

The three IOUs report that LCBF is their guiding principal for contract/bid evaluation. As SDG&E states, "[I]t is not feasible, however, to adopt a pre-

determined, 'one size fits all' set of evaluation criteria . . ."[189] SDG&E includes the evaluation criteria it plans to use in each RFO.

SCE's Least Cost valuation takes into account credit, collateral, DE, GHG adders and transmission adders, as well as improvements in energy and ancillary service valuations, with the ability to value offers under different pricing scenarios to generate a net present value (NPV) for each contract. SCE achieves a Best Fit by determining by a mathematical equation how to maximize the NPV with capacity and energy needs, as well as with qualitative characteristics such as location, product type, procurement limits and other criteria.[190] While SCE believes that the RFO process should be as open as possible, it still urges the Commission to protect SCE's [and by extension the other IOUs] confidential and proprietary assumptions, models, formulas and computer programs used to select resources in an RFO from market participants to prevent the manipulation of bids. SCE also argues against the adoption of a particular model, such as Black's Model as requested by Aglet, for all IOUs to use for all transactions and to allow each IOU to develop and implement its own evaluation system.[191]

PG&E presented a detailed list of the evaluation criteria it uses in the RFO process during the May workshops, including GHG adders and DE. For long-term RFOs, PG&E delegates to the IE and his/her staff the task of

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[189] SDG&E Opening Brief, p. 51.

[190] SCE Opening Brief, p. 51.

[191] SCE's Opening Brief, pp. 53-55.

developing and implementing criteria to ensure that PG&E is selecting the best bids in the process.[192]

3.4.2. Discussion

The evaluation criteria used in competitive solicitations must be clear, transparent, and available to potential bidders early enough in the procurement process to permit potential bidders to tailor their projects to fit the utility's actual needs. Bid evaluation is currently one of the most opaque steps of the procurement process, and as a result not only do "losing" bidders not know why they lost, but "winning" bidders may similarly not know why they won.

A well-functioning competitive process requires that all bids – including the bids of utility-sponsored projects – are evaluated using criteria that are consistent with the goals of the RFO and in a manner that encourages competition among bidders to meet the objectives of the RFO. When the utility functions as both buyer and seller, it is particularly critical to ensure that the bid evaluation is fair and transparent. In the absence of a fair and transparent evaluation process, it is unlikely that ratepayers will benefit fully either from competition or from the utilities' participation in a hybrid market.

We have taken many steps in an attempt to make the procurement process more transparent and fair. We discuss below certain bid evaluation metrics that we urge the utilities, in conjunction with Independent Evaluators, Procurement Review Groups and Energy Division, to consider when developing the RFO bid documents and process. In addition, when filing an application for approval of a

[192] PG&E Opening Brief, p. 59.

resource selected through a competitive solicitation, a utility must justify why the bid evaluation criteria were appropriate.[193]

In general, we are concerned that the IOUs are not properly taking into account certain bid characteristics that in hindsight could be very costly. We realize that 'hindsight is 20/20,' but we are convinced that the IOUs need to be much more selective when it comes to the ultimate winner of an RFO. We agree with the IOUs that it may prove counterproductive to be too prescriptive in identifying specific RFO bid evaluation criteria. A 'one-size-fits-all' approach may not be achievable and, therefore, may not truly 'fit all.' However, we are concerned that the other extreme – allowing IOUs too much leeway in determining the criteria upon which a bid will be evaluated – is also problematic.

We understand that the LCBF framework cannot entirely be reduced to mathematical models and rules that completely eliminate the use of qualitative factors. However, the IOU must be able to fully justify why a particular project wins a solicitation, and we provide here some general guidance to the IOUs regarding the types of evaluation criteria that should be applied to bids in RFOs for the resources authorized in this decision.[194]

The bid criteria raised specifically by parties in testimony, including credit and collateral, debt equivalence, Fin(46), and transmission costs/savings, are discussed in further detail in the following subsections. Other obvious criteria

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[193] A detailed description of the RFO process, including a thorough explanation of the evaluation metrics should be submitted as part of the RFO Application Template directed elsewhere in this decision.

[194] IOUs should be continually improving and refining their bid criteria and bid evaluation processes based on lessons learned in past RFOs, including lessons learned from their RPS solicitations.

include capacity and energy benefits, resource diversity, portfolio fit, local reliability/resource adequacy, and congestion costs. Some criteria for which we believe the IOUs need to provide greater weight include disproportionate resource sitings in low income and minority communities, and environmental impacts/benefits (including Greenfield vs. Brownfield development).

Finally, one criterion that we believe requires far greater scrutiny by the IOUs is project viability. PG&E executed contracts for seven new resources as a result of its 2004 LTRFO – Starwood, Panoche, Eastshore, Humbolt Bay Replacement, Russell City, Colusa, and Bullard. These resources represent 2,250 MWs of new generation in PG&E's service area. However, at the time PG&E executed contracts for these resources, only one resource – Russell City – had obtained a permit to construct from the CEC. These contracts were approved by the Commission in D.06-11-048. In a notice submitted to the service list in this proceeding on November 13, 2007, PG&E represented that only two projects had obtained permitting – Starwood and Russell City[195] - and not a single project had begun construction.

In addition, on November 14, 2007, PG&E filed an application for expedited issuance of a certificate of public convenience and necessity for the Colusa power project. In the application, PG&E states that E&L Westcoast Holdings, LLC (the entity that won a PSA contract in the 2004 LTRFO) informed PG&E that it intended to terminate the existing PSA, and offered to sell and transfer the development assets associated with the proposed project to PG&E.

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[195] That notice however, also stated that the Russell City project's permit was on appeal and therefore also in doubt.

Due to the existing need in PG&E's service territory and the short time between the application and the proposed online date of the plant, PG&E proposes to construct the Project itself.

We note that PG&E is not the only IOU that has demonstrated difficulty getting approved procurement permitted, constructed, and operational. SCE is currently experiencing significant delays in bringing two resources from its fast track RFO to fruition. In SCE's fast track RFO it selected offers from Blythe Energy, LLC (Blythe) and CPV Ocotillo, LLC (CPV) which resulted in 490 MW and 455 MW, respectively, of incremental generation capacity. SCE filed an application for approval of these projects on Febraury 28, 2007. These projects have yet to be approved by the Commission due to significant project development uncertainties presented as a result of the ACCs rejection of the DPV2 project.

All this is occurring despite the fact that there are 6,000 – 8,000 MWs of permitted projects in the state of California. However, projects that have already obtained permits from the CEC are consistently not winning projects in the utility RFOs. We recognize that the primary driver of this result is cost, but we are concerned with the hidden viability costs associated with projects that experience extensive delays or do not come to fruition.

If procurement authority approved in the 2004 Long-Term Procurement Proceeding decision has yet to reach the construction phase – or to even be permitted in many instances – then the IOUs must be more proactive in determining project viability among the offers submitted into RFOs.

One way that the IOUs could reduce project development uncertainty is to recognize as a bid evaluation criterion a value for projects that have already gone through the CEC's permitting process (potentially including various sub-criteria

for project development efforts/developer progress to date, local permitting status, and project viability vs. cost[196]) and an incrementally higher viability value for "new" resources that already exist (i.e., repowers) or have begun construction. While this will not remove all development uncertainty associated with a particular project, it will remove significant uncertainty, quite likely speed up the process, and reduce hidden and indirect viability costs associated with delayed or aborted projects.

3.4.3. Credit and Collateral

Each IOUs' LTPP includes details of their respective credit and collateral (C&C) policies for different types of procurement for their portfolio needs. The Scoping Memo asked the IOUs to consider three questions that in summary asked whether it was possible, and practical to have standard C&C policies across all three IOUs and whether there was an alternative method, other than C&C, that could be utilized.

Like a number of other issues under consideration in this decision, C&C policies are a multi-faceted topic. To begin, C&C can apply to both parties to a PPA. Any benefit an IOU receives from having a counterparty post collateral may be offset by the fact that the IOU could be asked by the counterparty to post collateral. In addition, market conditions are volatile and even if one party is financially sound today, the counterparty may request the maintaining of collateral facilities as insurance should that sound position shift. Therefore, the C&C cost arises in the context of PPAs, and not with utility-owned assets and

[196] For example, the bid evaluation might take into consideration a bid that is more expensive but has a greater likelihood of resulting in a viable project.

should be recognized as part of the contract price. Each IOU has to determine an appropriate methodology to weigh that cost as an adder in evaluating that bid.

Intervenors with an interest in a competitive, robust market are concerned that the IOUs could use C&C adders to discriminate against certain bidders in a RFO. This concern is heightened if a UOG project is competing head-to-head with a merchant-owned project, and the fear is the C&C adder, especially when combined with a DE adder, could tip the scales making the UOG project look more economic. When an asset is utility owned, the utility neither receives nor posts collateral, nor needs to maintain collateral facilities. However, on the other hand, C&C is a real cost for an IOU as it evaluates the credit worthiness of a counterparty and determines to what extent that factor impacts the bid evaluation for that asset.

While this is a strong argument in favor of standardizing the C&C factor, we have to balance that concern against the fact that if a counterparty fails economically, the IOU will have to replace the power from the market, at a higher cost to customers. The IOU needs the flexibility to weigh the financial strength of a bidder in evaluating the whole bid package.

We agree with the IOUs that crafting, adopting and implementing standard C&C rules would be difficult to do. Each bidder in a RFO has its own unique credit situation, and an IOU's own credit rating is constantly changing, which impacts the resources a bidding counterparty needs to provide on its side of the equation. After reviewing the C&C requirements used by the IOUs, and

utilizing the audit results from an audit ordered by the Commission,[197] we determine that no changes are warranted, at this time, on the subject of C&C, beyond approving SCE's request to increase its collateral exposure limit from $1.4 billion to $2.0 billion resulting from increased physical and financial transactions. However, as stated in the following subsection on risk management, we anticipate taking a comprehensive look at IOU risk management practices in the 2008 LTPP proceeding. Part of risk management/mitigation is credit and collateral and methods of dealing with certain types of exposure – financial risk, physical concentration, counterparty concentration, netting etc. – and we need to gather more information on these important subjects.

3.4.1. Debt Equivalence

The issue of Debt Equivalence (DE)[198] was a hotly litigated topic in the 2004 LTPP, and D.04-12-048 recognized DE as a factor to be considered by an IOU in evaluating a PPA against other contract options. That decision found DE associated with an IOU carrying a PPA on its books to be a real economic cost that can impact a utility's credit rating and cost of borrowing. Because of these factors, D.04-12-048 found that DE is properly a cost to be recovered in an IOU's

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[197] See Vantage Consulting, Evaluation of Credit & Collateral Requirements for the Commission, February 22, 2007.

[198] In this context, "debt equivalence" (also called "imputed debt") is a tool used by credit rating agencies to assess potential financial risks associated with a utility's PPA obligations. In certain circumstances, a rating agency may treat some portion of PPA costs as payments on debt obligations rather than as operating costs (treating them as "debt equivalent"), and in turn make corresponding adjustments to the utility's credit metrics and financial ratios used as part of the rating agency's overall assessment of credit quality.

cost of capital proceeding andthat, an IOU could impute a DE of 20% to a PPA as a bid evaluation tool. However, the Commission also indicated in D.04-12-048 that the adopted approach was not fixed and immutable:

> DE is a subjective factor based on the credit rating agencies' perceived risk associated with PPAs. The credit rating agencies' views on such risk are not static and can change with respect to a particular PPA during the term of the PPA. In addition the imputed DE costs for existing PPAs will be reduced as the regulatory climate in California improves.[199]

The Commission went on to conclude that, "(a)s the rating agencies' views on DE change or as we gain more experience with DE evaluation in the [cost of capital] proceedings, we may adjust the DE methodology used in [the] future."[200] The current proceeding provides a timely opportunity to reexamine the use of DE in the evaluation of bids.

3.4.1.1. Parties' Positions

Both SCE and PG&E note the economic reality of DE as applicable to a PPA, and ask that the Commission carry forward the 20% from D.04-12-048.

Two intervenors, IEP and WPTF, asked that DE be eliminated as a bid evaluation criterion considered in RFOs since it could have a negative impact on a PPA bid, especially if compared to an IOU owned asset with no imputed DE factor. On the other hand, SDG&E asks that the DE be increased to incorporate an updated methodology from S&P. SDG&E included supporting data in its testimony to justify its request to increase the DE percentage and to get an

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[199] D.04-12-048, p. 144.

[200] D.04-12-048, p. 145.

adjustment to its cost of debt and cost of equity. In response to a Motion to Strike brought by DRA, the ALJ ruled that the LTPP proceeding was not the appropriate place to argue adjustments to SDG&E or any other IOUs' capital structure.

3.4.1.2. Discussion

DE has engendered considerable controversy in this proceeding. In D.04-12-048, we determined that DE is a real economic cost borne by an IOU when it enters into a PPA, and can have an impact on a utility's credit rating and ultimately increase its cost of borrowing, and that an IOU may impute a DE of 20% to a PPA bid in RFO bid evaluations. IEP and WPTF have contended in this proceeding that this determination was in error, and that the proper place to consider impacts of DE is in the IOU cost of capital proceedings and not on an individual, case-by-case basis in the bid evaluation stage of utility solicitations.

The Commission currently considers debt equivalence in two contexts. First, debt equivalence is one of several considerations that rating agencies factor into their assessment of a utility's overall risk profile. The Commission considers the rating agencies' credit ratings in the cost of capital proceeding and thus considers debt equivalence when it determines the IOUs' cost of capital. For example, in the current cost of capital applications [A.07-05-003 (SCE), A.07-05-007 (SDG&E), A.07-05-008 (PG&E)] the IOUs cite DE among a host of other factors that affect their credit risk, including loss of load due to direct access, community choice aggregation, and municipalization, high levels of capital spending and construction, high retail rates, and fuel price volatility, among others.

The second context is the use of DE in evaluating offers in competitive solicitations. In D.04-12-048, the Commission concurred with the utilities'

proposal to base the debt equivalence adder on S&P's approach, "because it is the most developed and transparent approach to calculating DE."[201] The Commission modified the S&P approach, however, because the 30% risk factor that S&P then applied was "too high to be reasonable and fair to all PPAs," and the Commission did not want "to create an unfair burden on or a disadvantage for independent power sources over utility-owned . . . ."[202] For those reasons, the Commission elected to discount S&P's risk factor by one-third from 30% to 20% for purposes of evaluating bids in competitive solicitations.

Based on the record of this proceeding, we agree that DE in and of itself is not a cost that the utilities directly incur by entering into a PPA. DE, which is also referred to as imputed debt, is a term rating agencies use to describe the potential financial risks a utility may incur when it enters into a long-term PPA. Under certain specific circumstances, a rating agency may treat some portion of the utility's obligation under the PPA as equivalent to debt, rather than an operating cost, and may adjust the utility's credit metrics and financial ratios to reflect increased levels of debt.

When the Commission considered this issue in the last procurement proceeding [R.04-04-003], it authorized the utilities to "take into account the impact of DE when evaluating individual bids . . ." and directed the utilities to use a 20% "risk factor" for all PPAs, based on a discount of the 30% risk factor

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[201] D.04-12-048, p. 144.

[202] D.04-12-048, pp. 144-145.

developed by Standard and Poor's (S&P) for the California utilities.[203] The Commission also acknowledged, however, "As the rating agencies' views on DE change or as we gain more experience with DE evaluation in the [cost of capital] proceedings, we may adjust the DE methodology used in [the] future."[204] Since the issuance of D.04-12-048, the Commission has gained more experience with debt equivalence.

The preceding discussion demonstrates that the Commission's approach to debt equivalence creates a disparity between the treatment of PPAs and utility-owned projects in the procurement process, in direct contradiction to the Commission's stated goal of promoting head-to-head competition between PPAs and utility-owned options. The evaluation of bids by PPAs in competitive solicitations includes a DE "bid adder" in an attempt to quantify potential risks presented by IPP projects, while the evaluation of utility-owned projects includes no similar upfront bid adder, even though utility-owned projects present incremental risks to ratepayers and utility shareholders. We believe that to further encourage fair, head-to-head competition between PPAs and utility-owned projects, as stated in D.04-12-048 and numerous times throughout this decision, the bid adder for PPAs should be eliminated. Based on an examination of all three of the rating agencies' treatment of DE, recent changes to these

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[203] D.04-12-048, pp. 144-145. In practice, the three utilities use the adopted 20% risk factor in a calculation to determine a "bid adder" for debt equivalence that is added to the cost of a PPA for purposes of bid evaluation. See Exh. 96, p. 12 (Meal/IEP).

[204] D.04-12-048, p. 145.

treatments, and the improved credit ratings of the California utilities, we find that no DE adder is warranted.[205]

We recognize that at some point, DE *may* reach a point where it can affect the utilities' credit ratings and cost of capital, and it is not disputed in this proceeding that the potential effect of DE on credit ratings, if any, is an appropriate topic for the utilities' cost of capital proceedings. Today's decision focuses on the evaluation of PPA bids received in utility request for offers and in no way presupposes any related cost recovery, or adjustments to capital structures in future cost of capital proceedings. We continue to direct the IOUs, especially SDG&E, to raise any individual concerns it has with the impact of a particular PPA on its debt to equity ratio in its Cost of Capital proceeding.

3.4.2. FIN46(R)

SDG&E is the only IOU requesting consideration for FIN 46(R)[206] impacts to be considered in the bid evaluation process. While SDG&E states that it considers "PPAs to be an attractive option that mitigates construction and cost

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[205] The record in this proceeding includes numerous submissions, analyses, and discussions regarding the issue of DE and the various approaches taken by the three major rating agencies (Moody's, Fitch and S&P) and while we do not repeat the record in this decision we assure parties that we have weighed the entire record in reaching our decision.

[206] FIN 46 (R), Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51, issued in 2003 by the Financial Accounting Standards Board (FASB). FIN 46(R) was issued to provide guidance on the identification of and financial reporting for, entities over which control is achieved through means other than voting rights. Such entities are called variable-interest entities (VIE). FIN 46(R) stipulates that a contract to purchase the entire output of a single plant entity at something other than a fixed price constitutes a "variable interest" in that entity. The "primary beneficiary" of a VIE's activities must consolidate the financial statements of the VIE when issuing the primary beneficiary's financial statements.

escalation risks associated with building and operating a new facility,"[207] it also asks the Commission for clear guidance on how to calculate the costs for both DE and FIN 46(R) when evaluating bids. We have given guidance on DE, and now address FIN 46(R).

From SDG&E's analysis of FIN 46(R), it is possible that certain long-term PPAs are within the scope of the FIN 46(R) financial reporting requirements that would require SDG&E, as the purchaser/beneficiary of a power contract, to consolidate the financial statements of the power plant owner/provider, with its own when filing annual and quarterly reports with the Securities and Exchange Commission (SEC). SDG&E posits that this could then negatively impact its balance sheet. Therefore, SDG&E would like a mechanism to assess the potential impact of a FIN 46(R) filing requirement when it is evaluating bids.

Our response to SDG&E's request for FIN 46(R) impact treatment is that it is reasonable for SDG&E, or any of the other IOUs, to argue in its respective Cost of Capital proceeding, that it needs to increase its equity to debt ratios in order to keep its capital structure in line with Commission directives. At this point in time, without prejudice to the issue being re-introduced in future LTPP filings, we do not find that there is sufficient information for us to know how a utility should weigh the FIN 46(R) impacts of a PPA when evaluating competing bids.

3.4.3. Transmission

SDG&E, PG&E, and SCE all stated that transmission is one of many factors taken into account as an evaluation criterion in the contract and bid evaluation

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[207] SDG&E Opening Brief, August 1, 2007, p. 53, citing Schneider Testimony, Exhibit 40, pp. 215-16.

process. The transmission analysis is complicated in the RFO process by FERC Order 2004, which restricts the flow of non-public information between the transmission department and the procurement departments at the IOUs.

There are also transparency issues associated with the transmission criterion, as evidenced by the fact that the Transparency Working Group addressed this subject at its September 13, 2007 meeting.[208] In general, the Working Group addressed transmission related costs/benefits as they relate to: (1) particular projects under consideration in a competitive solicitation; (2) costs/benefits that may not currently be captured in the analysis; and (3) the feasibility and means by which additional costs/benefits could be captured.

PG&E and SCE[209] made presentations on the means they utilize to estimate the network upgrade costs associated with a particular project. Although they each use different means to identify transmission related costs, there were no costs that were not captured. The more difficult analysis is how to evaluate the transmission benefits. For example, SCE and PG&E stated that they do not quantify the benefits associated with deferred or avoided transmission that can result from local generation. The Working Group stated in its Updated Report

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[208] The Transparency Working Group submitted a Status Report on August 30, 2007. On September 26, 2007, the Working Group submitted an Updated Status Report to summarize the results of two additional meetings. How transmission is considered in the RFO process was also raised in the AB 1576 Repowering Working Group, but parties agreed to move the topic to the Transparency Working Group since the issue applies more broadly to project bid evaluation rather than strictly to repowering projects.

[209] SDG&E's experts did not make presentations at the meeting, but did attend via teleconference and commented that SDGE generally treats transmission costs in the same manner as SCE and PG&E.

that a better understanding of the capacity and energy values associated with congestion are needed to more thoroughly evaluate RFO alternatives. Mirant also suggested that once locational marginal pricing (LMP) is implemented the value of local generation will be known through market prices. Without information on congestion and LMP, the parties could not reach a consensus and did not present a recommendation to the Commission.

In summary, the AB 1576 Repowering Working Group raised the transmission benefits issue in that Working Group as to how transmission costs/benefits are evaluated in the RFO process and because of interrelated issues it was also raised in the Transparency Working Group. Although participating parties have a better understanding of the challenges that are associated with assessing the transmission benefits of a particular project, they also comprehend that the problem cannot be resolved in the current market structure where locational prices are lacking. Since there are no recommendations presented for consideration, and in the absence of a fully developed record on the topic we do not make any findings or orders at this time on how transmission costs and benefits are to be evaluated for specific generation projects in the RFO process. However, as we note below, MRTU is currently scheduled to "go live" in spring 2008. As more details surrounding the implementation of MRTU become known we anticipate having more information available to make informed decisions regarding the potential impacts that this new market design may have upon IOU procurement activities. As such, we fully expect to continually examine MRTU as part of future LTPP proceedings.

3.5. Risk Management and Fuel Supply Plans

3.5.1. IOU Procurement Risk Management Approaches

Because other market participants could use information regarding the IOUs' risk management approaches to game their bidding strategies, the IOUs consider portions of this information to be confidential. PG&E redacts virtually all of its risk management testimony, while SCE and SDG&E provide much of the programmatic details of their methodologies and redact primarily the proposed values. Due to the confidential nature of this testimony, there was little intervenor testimony in response to it (Aglet was the only intervenor that provided significant analysis of risk-related issues).

The risk management strategy SDG&E describes in its plan is generally consistent with its current practices, and is adopted as presented. However, both PG&E and SCE propose significant changes to their gas and electricity product risk management approaches. While we agree in principle with a number of PG&E and SCE's proposed changes, more work is needed before we can adopt them.

We recommend that ED, in concert with the PRG, address the issues of concern with the respective IOUs in future PRG meetings with each IOU, and that the IOUs submit revised risk management proposals via Advice Letter. In the interim, we require the two IOUs to continue operating under their existing Commission-approved risk management plans.

3.5.2. Contract Duration Preapproval Limits

D.04-12-048 states that procurement contracts[210] with durations of less than five years do not require Commission preapproval. Current guidance ED has provided to IOUs states that the five-year duration clock begins:

- At the time the contracted resources begin delivery if delivery begins within one year of contract execution; or
- At the time of contract execution if delivery does not begin within one year of contract execution.

There were two purposes for this interpretation. First, it prevented 'contract stringing,' in which two successive contracts for the same resource, each under five years in length, could be entered into to avoid filing an application.

Second, it preserved Commission oversight and approval of procurement for the "out-years" of the 10-year LTPP planning horizon (i.e., years six through ten). ED believes that more active procurement oversight than after-the-fact quarterly compliance filings is necessary in those out years to ensure that IOU procurement practices do not result in (1) entering contracts to reduce price risk at levels that are not economically efficient (over-hedging); (2) buying excessive fossil resources that crowd out procurement of EAP loading order resources later in the procurement cycle or provide guaranteed future income streams to resources that the Commission deems incongruent with GHG goals or other policy objectives; and/or (3) buying resources that may not be needed for future load because of load forecast error or load migration to direct access or CCAs.

[210] All references to contracts in this discussion include any extension options provided for in the contract.

The IOUs are forecasting a significant shortage in contracted energy in the current LTPP cycle's out years (i.e., 2012-2016) due to the expiration of many of the DWR contracts. In light of this situation, the Commission has reviewed its current guidance to determine if there are other methods of achieving the goals which drove the development of this guidance that would provide IOUs with more flexibility in procuring for their net short positions. We adopt the following revisions:

- IOU may execute a contract of under five years without pre-approval for which deliveries end at any point within the 10-year LTPP procurement cycle, provided the procurement complies with a procurement limit methodology (which various parties refer to as a ratable rate, laddering, or layering methodology) developed by the IOU and approved by a Commission resolution or decision.
- Absent a Commission-approved procurement limit methodology, an IOU may execute a contract of under five years without pre-approval provided, per existing ED guidance, that the five-year duration clock begins:
  - At the time the contracted resources begin delivery if delivery begins within one year of contract execution; or
  - At the time of contract execution if delivery does not begin within one year of contract execution.
- In calculating contract duration, calendar days are used, not days of obligation, days of service under the contract, or days of need for the resource.

3.5.3. Gas Hedging "Best Practices"

The Scoping Memo solicited input regarding whether all the IOUs should conform to a common set of gas hedging best practices. All three IOUs objected to this idea, citing concerns about divulging confidential information (which would weaken their negotiating positions), the lack of uniformity of their

respective portfolios (hence one size does not fit all), and possible accusations of collusion.

The Scoping Memo also solicited input regarding whether all the IOUs were hedging the same relative percentages of their portfolios across the same time horizon, and if not, whether they should be. The answers from all three IOUs were no and no. The reasons cited are much the same as those addressing the question of best practices.

Aglet proposes that each IOU use the following mix as a hedging guideline – 75% swaps and 25% options. The IOUs uniformly opposed the recommendation, citing its lack of analytical support, its rigidity, and the disadvantage that such a constraint would place on the IOUs when they are negotiating these hedge products.

We will not require the IOUs to adhere to a common set of "best practices," establish identical forward positions over time according to a set formula, or achieve a particular mix of swaps and options. In addition, the IOUs and Aglet oppose the use of standardized models for calculating the To Expiration Value at Risk (TEVaR). We concur, noting the benefits of allowing the IOUs flexibility and the lack of benefit from forcing uniformity on this matter.

3.5.4. Modifications to TEVaR and CRT Methodology:

The Commission developed its procedures to monitor and manage rate level risk primarily in three decisions, D.02-10-062, D.02-12-074, and D.03-12-062. These procedures make use of two metrics, the Customer Risk Tolerance (CRT) and the To Expiration Value at Risk (TEVaR). The TEVaR represents an estimate, at a given confidence level, of the amount of electric rate increase that could occur due to changes in market conditions such as nuclear outage risk,

hydro-power availability risk, electricity spot market price volatility, credit risk, and gas price volatility (which represents the single greatest historical source of price volatility). For example, TEVaR 95% measures the maximum rate increase over the expected value with 95% confidence level (in other words, it is the 1-in-20 worst case scenario). Likewise, TEVaR 99% is the 1-in-100 worst case scenario.[211] CRT essentially is a cap on unforeseen electric rate increases looking 12 months into the future due to electric procurement activity. This was set by the Commission at one cent per kWh.[212]

Hedging, and particularly hedging future gas purchases, is the IOUs' primary method for reducing volatility risk, by either locking in or limiting the amount of variation of a future price. The "downside" of hedging is that it not only reduces the possibility of paying higher future prices than expected, it also restricts (directly or indirectly, depending on the extent to which options are used) the possibility of outcomes below expected future prices (which would result in lower than expected rates).

CRT and TEVaR can be expressed either as cents per kWh (that is, the average electric rate fluctuation), or dollars per year (the total portfolio cost fluctuation). The portfolio value is obtained by multiplying the rate value times

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[211] SCE helpfully expresses TEVaR 95% another way, as the difference between the potential electric portfolio cost at the 95% level (a "high cost" scenario) and the expected electric cost (the "medium cost" scenario).

[212] Originally, SCE and for SDG&E kept confidential the values for CRT (one cent per kWh) and PRG notification trigger (125% of CRT), while PG&E did not. We understand the importance of confidentiality in commercial negotiations that the utilities engage in to procure hedges, but we believe that publishing these metrics and guidelines will not unduly harm the utilities' negotiating positions, since by now these numbers have been

Footnote continued on next page

the amount of kWh sales over a 12-month period for that utility. The two values interact with each other in the following manner:

- At any point in time, each IOU can calculate its estimated electricity costs (absent any hedging practices) for the following 12 months, based on current expectations of forward gas and energy prices, forecasted energy consumption, and a host of other expected outcomes.
- For any expected 12-month electricity cost, there is a value greater than the expected cost that would result in an increase in rates of 1.25 cents/kWh more than the expected rates, which would trigger a PRG meeting and possible remedial action.
- The IOU can vary the expected input values across a range of possible outcomes (based on historical variations, for instance) and create a distribution of possible electricity costs for the 12-month period (and the corresponding likelihood that each will be the actual cost after the 12 months are over), creating a distribution curve of possible actual outcomes around the expected cost.
- With a 99% TEVaR, if 99% of the potential outcomes correspond to a 12-month electricity cost that is less than the value that would result in a 1.25 cent/kWh increase in expected electricity rates, then no additional hedging would be warranted. Otherwise, additional hedging would be required to narrow the potential range of outcomes until 99% of them are within the cost resulting in the 1.25 cent/kWh increase over expected rates.

The Commission requires the utilities to submit to Energy Division monthly reports on TEVaR 99% on a rolling 12-month basis.[213] These monthly reports also report the TEVaR 99% on a quarterly basis for months 13-24 looking

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published in several places, including Attachment A to the Scoping Memo in this proceeding.

[213] Some of the utilities report also TEVaR 95%.

forward, and on an annual basis for months 25-60. In the event that the 12-month TEVaR 99% value exceeds 125% of the CRT (i.e., if it exceeds 1.25 cents/kWh) then the utility calls a special meeting of its PRG to review the causes for the high volatility and decide whether new hedges are needed to bring TEVaR back within the allowed threshold.

In their descriptions of how they calculated TEVaR and made use of it, we find that PG&E's and SCE's descriptions conform to the Commission's directives to use a rolling 12-month TEVaR and compare that on a monthly basis to the CRT for purposes of determining whether to convene a meeting of the PRG and develop further hedges to bring the level of possible price volatility back inside the CRT threshold.

SDG&E, on the other hand, states that while it calculates TEVaR on a rolling 12-month basis, it instead uses a calendar year approach when it comes time to make hedging decisions (SDG&E Vol. 1, pp. 125-126). We order SDG&E to modify their methodology to comply with the rolling 12-month approach.

PG&E argues that no changes should be made to either the CRT or the TEVaR at this time. PG&E argues that this should wait until the Energy Division has conducted a thorough review of the experiences which the PRGs and the utilities have had with the existing methodology and has conducted the review of consumer risk preferences which was ordered previously by the Commission (D.02-10-062 directed Energy Division to retain a consultant to gather additional information about customer risk preferences, but this study has not yet been conducted). Thus PG&E argues against switching from TEVaR 99% to TEVaR 95% at this time.

SCE, on the other hand, argues for switching now from TEVaR 99% to TEVaR 95%, since the latter is a more robust and statistically valid number. SCE

also points out that the 99% confidence level is more cautious than even reliability parameters that the Commission has set for the utilities, and asks why this should be so. SCE also notes that when they were originally established, the CRT and TEVaR values were not supported by any empirical basis. SCE argues that CRT should be indexed to inflation.

SDG&E expresses its preference for TEVaR 95% over TEVaR 99%, since the former is inherently a more knowable, predictable number, while one-in-a-hundred year events are so unusual that predicting them is impossible, and numbers that purport to do so are meaningless. SDG&E also points out that the existing value for CRT was established in D.02-12-074, when the Commission was thinking about using TEVaR 95%. The switch to TEVaR 99% came only later in D.03-12-062, and so no change to CRT is needed.

Aglet argues for changing from TEVaR 99% to TEVaR 95%, arguing that a one-in-100 level of caution is more appropriate for a "mission critical" application, where error can lead to loss of life. Aglet argues that since CRT is inherently a judgment call, not based on academic literature or empirical analysis, it is not useful to litigate or argue what level it should be. Aglet believes it should stay at its current level for now.

DRA cautions against changing from TEVaR 99% to TEVaR 95%, noting that in order to maintain the same level of protection from risk the CRT threshold should commensurately be reduced. DRA argues that SCE's proposal to index CRT to inflation is counterproductive, noting that it is especially in volatile times, when inflation is high, that consumers will want extra price security and so will desire a smaller CRT.

We agree with parties who recommend the use of TEVaR 95% as a more robust metric for risk than TEVaR 99%, and we adopt it as the primary metric for

guiding hedging decisions. We will not at this time change the CRT level or the 125% threshold metric. We recognize that effectively we are loosening the risk guidelines (that is, allowing more potential for electric rate deviation). We anticipate that the effect of this change will be fairly modest, and that it will result in hedging strategies that are more robust and grounded in reality.

The Commission currently requires that the utilities report TEVaR looking forward up to five years. We believe this can be useful and so we maintain this requirement. SDG&E is skeptical of the value of TEVaR for periods beyond one year, given the amount of uncertainty that far in the future. We do not have sufficient evidence to evaluate this assertion, but we note that in any event using TEVaR for periods greater than one year is not the main metric used for guiding hedging decisions.

The parties also describe other risk metrics which they believe will be useful – such as forward-start TEVaR and one- and ten-day VaR. We welcome the use of these metrics in evaluating risk, but note that these are not the metrics guiding hedging decisions. The rolling 12-month TEVaR 95%, compared against 125% of CRT, will perform that function.

In addition, in the 2008 LTPP proceeding, or in another subsequent proceeding (see Fuel Supply Plans section), ED may convene a workshop to discuss possible modifications to risk management policies, including topics such as CRT levels, TEVaR, other risk metrics, the use of the Black Model, and a study of customer risk preferences.

3.5.5. Fuel Supply Plans

Each IOU has a gas fuel portfolio for its DWR gas-tolling contracts and a gas fuel portfolio for resources that it owns or contracts with directly via PPA and QF contracts. The Scoping Memo solicited input regarding whether

modifications were necessary to make hedging more consistent. All three IOUs indicate that their approaches for both portfolios are the same, although because of differences in the power plants those portfolios serve, the mix of hedging instruments may differ. Currently, the DWR supply and hedge plans are updated twice a year, while the non-DWR hedge plans are updated less frequently, when requested by the Commission.

SCE proposes to coordinate the scheduling of its ratable rate update for its own portfolio and its DWR portfolio. SCE requests that both portfolios be updated annually, at the time of the ERRA filings. No party has objected, and we agree that this approach would streamline administrative efforts, and so we will order SCE to update its ratable rate schedule for its own portfolio annually at the same time as the ERRA filings.

We also authorize the IOUs to update their gas supply and hedge plans for their DWR portfolios (for SCE, this includes its ratable rate schedule) annually, instead of twice a year. But because DWR has not participated in this proceeding or agreed to this change, we cannot enforce the change for the IOUs' DWR portfolios at this time. If and when DWR agrees to this change, the IOUs should notify the Commission by Advice Letter.

The nuclear and coal fuel plans proposed by the IOUs are adopted as presented. The gas supply procurement proposals of the IOUs in their 2006 LTPPs are not adopted because the Commission needs to address and review the proposals by the IOUs more thoroughly than we have in this current proceeding, and assess the proposals in conjunction with other rulemaking proceedings. For example, since the date the IOUs submitted their gas supply plans, the Commission initiated a rulemaking which will address the IOUs procurement of natural gas supplies from LNG regasification terminals, R.07-11-001. In addition,

the Commission will address other gas supply procurement issues involving the IOUs, including gas supply, firm interstate pipeline capacity, and storage in a subsequent proceeding.

In order for the IOUs to continue necessary gas supply procurement for their electric generation requirements, the Commission authorizes the IOUs to continue operation under their existing gas supply plans approved in the 2004 LTPP and 2005 Short-Term Procurement Plans until new gas supply plans are approved by the Commission. If an IOU needs to propose specific gas supply procurement contract(s) that are not authorized by their existing gas supply plans beforehand, an IOU can file an application with the Commission to receive such authorization.

3.6. Streamlining and Transparency of Compliance Filings

Attachment A to the Scoping Memo directed the IOU's to "…describe the process for the Commission's review of the implementation of the Procurement Plan."[214] The Scoping Memo also detailed the numerous filings that are currently required of the IOU's to demonstrate compliance with the Commission-approved AB 57 LTPP and stated that the IOUs should explain the procurement information reported to the Commission in the following reports:

- Monthly Reports
  - Portfolio Risk Reduction Report
  - Monthly ERRA Report
  - Standing Data Requests from Energy Division or other parties
- Quarterly Filings
  - Quarterly Compliance filings

[214] Attachment A, p. 21.

- Semi/Annual filings
    - ERRA filings
- Biennial filings
    - Biennial Long-Term Procurement Plan
- As Needed Filings
    - Non-Conforming transactions
    - Advice Letter updates to LTPP

The Scoping Memo also stated that "the IOU should describe the process for submitting updates to its approved LTPP. Comments should specifically address the feasibility of instituting a common numbering system (common to all three IOUs) in order to track revisions to the LTPP. This numbering system would be akin to that currently utilized to track tariff revisions." In addition, the Scoping Memo sought proposals from the IOUs regarding streamlining opportunities for filings in its Volume II testimony.

3.6.1. Parties' Positions on General Streamlining Issues

The IOUs each addressed the issues raised in the Scoping Memo in their own way and to varying degrees of completeness and adequacy. SCE, between its LTPP and its draft Rulebook, might have provided the Commission with the most complete listing of the various compliance filings currently required, while PG&E and SDG&E provided a much less detailed accounting. Essentially, each IOU files different versions of the above-referenced filings in order to demonstrate compliance with a Commission-approved AB57 procurement plan.

3.6.2. Discussion

We do not take specific issue with any of the IOUs' recitation of the information contained in each LTPP regarding the number, type and scope of the various required compliance filings. Therefore, we do not make a specific ruling related to that aspect of their procurement plans. We do, however, raise several

tangential issues related to periodic compliance reporting, as well as general compliance, and we address these below.

Outside of the IOUs' filed LTPPs and their initial briefs, virtually no other party provided input regarding how and to what extent the Commission could improve and/or streamline the reporting requirements. The apparent lack of attention paid to this topic by parties is particularly troubling to this Commission especially given that one of the main complaints from parties is that the LTPP proceeding presents parties with such a "mountain of information" that it is "near impossible to make sense of it all." And yet, when we specifically seek input on this matter – not once, but twice – intervenors fail to provide us with a record upon which we can make an effective, informed decision.[215]

As SDG&E correctly points out, many of the existing procurement rules were put together in a relatively short period of time as the Commission established a regulatory framework that allowed the utilities to resume procurement on January 1, 2003. Although the Commission has at various stages clarified rules, this proceeding creates an additional opportunity to learn from four years of practice and adopt changes that will maintain proper regulatory oversight while eliminating duplicative workload on the Commission, the utilities, and stakeholders.

The Scoping Memo issued in this proceeding stressed the importance of this procurement proceeding by specifically stating:

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[215] We note that "Commission Review and Implementation of Procurement Plan" is explicitly listed as a topic in the September 25 Scoping Memo as well as in a May 2, 2007 Administrative law Judge's Ruling, both issued in this proceeding – R.06-02-013.

> "A key objective of this proceeding is to review and approve updated 2006 Long-Term Procurement Plans that supersede all previously approved plans, as modified.
>
> Although some of the activities detailed in the approved STPPs have not changed, it is necessary for the Commission to have an updated, complete 2006 LTPP. The complete 2006 LTPPs will merge the contents of the two previous filings, include the AL amendments proposed by each utility over the past several years, and reflect the Commission's numerous decisions on procurement policies and transactions. It may appear that the Commission is asking for a large amount of information in Attachment A; however, since the "approved plans" are currently scattered in numerous plans, decisions, ALs—it is necessary for the plan components to be consolidated in one place.[216]

Therefore, the Commission's request to streamline and increase the transparency of the compliance process should be a high priority for all parties to this proceeding. While the lack of a more fully developed record limits our ability to make certain changes to the procurement process, we will rely on the record available, as well as the Commission's own experience and expertise, to make incremental changes with the expectation of undertaking a more comprehensive process review in the next LTPP.

An example of our disappointment is evidenced by the complete lack of attention paid to our explicit request for comment on "…the feasibility of instituting a common numbering system (common to all three IOUs) in order to track revisions to the LTPP. This numbering system would be akin to that currently utilized to track tariff revisions." No party addressed this request.

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[216] Scoping Memo pp. 15-16.

As such, we direct the IOUs to develop a common numbering system in order to track revisions to each Commission-approved LTPP. We repeat our guidance that this numbering system would be akin to the system currently utilized to track tariff revisions.[217] The FERC-approved CASIO tariff could also serve as a model. As we have stated several times in the Scoping Memo and throughout this decision: Part of the challenge of determining compliance with Commission procurement rules is simply determining which procurement plan is the "latest and greatest" for each IOU.

Having a tariff-like numbering system in place combined with a redline strikeout method of proposing updates to the LTPP should go a long way in reducing the amount of confusion surrounding these procurement plans and this proceeding in general. This updating process should be fairly straight forward for all parties given that this proceeding has combined all the previous procurement plans into one document (potentially with several volumes and attachments). We direct the utilities to work with ED staff to develop this tariff-like numbering system.

D.04-12-048 FOF 106 states that updates or modifications to an IOU's procurement plan between the biennial procurement plan filings should be filed with an advice letter. We have found that this process, as defined in our prior decision, is inadequate. Thus, we require all updates proposed between the biennial procurement plan filings (via the Advice letter process) to include redlined pages of the existing procurement plan as well as "cleaned up" replacement pages which include the tariff-like numbering system discussed

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[217] See GO 96-B, Section 8.4.2 Tariff Sheet Numbering.

above. This system should alleviate much of the confusion expressed by parties regarding an inability to determine what the "latest and greatest" currently in effect procurement plan actually is. We require the IOUs to implement this tariff-like numbering system when they make their compliance filing to submit the conformed 2006 long-term procurement plans discussed below. In addition, to address the lag time between this decision and the compliance filing, we require that all advice letters seeking modifications to the approved LTPP filed in the interim include redlined versions of the corresponding pages of the filed 2006 LTPPs.

3.6.3. Quarterly Compliance Reports

The Commission currently requires each IOU to submit a Quarterly Compliance Report (QCR) via the Commission's advice letter process within 30 days of the end of every calendar quarter, in order for Commission Staff to review the IOU's procurement transactions for compliance with the Commission-approved procurement plan and its up-front and achievable standards and criteria.

D.04-12-048 directed the IOUs to file a joint proposal to reformat the quarterly procurement transaction compliance report to provide the Commission concise and coherent information.

3.6.3.1. Parties' Positions on Streamlining QCRs

PG&E, SCE and SDG&E have worked collaboratively to draft a proposed streamlined quarterly procurement transaction compliance report and have discussed the proposal with Energy Division. Since filing testimony in the 2006 LTPP, the IOUs have held additional discussions with the Energy Division with the hope of reaching agreement on the format standardization proposal. Once an agreement is reached, PG&E recommends the Commission adopt the

reformatted report. PG&E states that, in order to make meaningful changes and improvements to this report, the Commission should direct the Energy Division to promptly review and approve or modify the IOUs' proposal on the format and contents of this report.

SCE states that, since early 2005, the IOUs have worked collaboratively to develop a standardized format for the QCRs and accompanying electric, natural gas and financial transaction workpapers, submitted in conjunction with each utility's AB 57 procurement plan. Earlier this year, preliminary standardization results were shared with the Energy Division and important feedback was received.

SCE believes that the Commission will find that the final proposed joint format for the QCRs strikes the optimal balance between many interests, including, but not limited to, streamlining of the QCR process to improve efficiency and facilitate a timely review and approval process, providing the public with greater access to information, and preserving the confidentiality of market sensitive data.

In the future, as it pertains to MDR and other aspects of the IOUs' QCR advice letter submittals, SCE suggests that the Commission may want to take into account any recommendations that the Energy Division's external auditors may make while submitting their audit review reports. SCE also observes that the amount of data that is currently required to be submitted is very voluminous, and that this in itself might be a root cause of Energy Division's inability to review the QCRs in a short time-frame. If so, the Commission might want to consider reducing the data submittal requirement to transaction details only, with the rest of the material to be made available upon request by the Energy Division. In addition, SCE believes that its Procurement Rulebook will provide a

convenient guide for the Energy Division in reviewing SCE's transactions for compliance with its procurement plan.

3.6.3.2. Discussion

The QCR and its workpapers include transaction details as well as a wide variety of supporting documents, including all the items listed in the Commission's Master Data Request,[218] for all transactions entered into the calendar quarter.

ED has not been able to review and approve the QCRs in a timely manner consistent with the 30-day schedule that the Commission earlier adopted for such review.[219] At the time the IOUs were required to submit their LTPPs, only the 2003 transactions have been reviewed and approved by the Energy Division. Earlier this year, ED retained an external auditor to review all of the 2004, 2005 and 2006 transactions.[220] This review by the external auditors is nearly complete with audit review reports on 2007 transactions expected in 2008. However, this represents a very long review and approval process. As an example, the transactions executed in Q1 2004 were not approved by ED for almost three years. Clearly, this is unacceptable.

Once the external auditors complete their final review and offer any recommendations, the Commission will revisit the transaction review and approval process, including the elements contained in the QCR Master Data

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[218] See D.02-10-062 COL 7, OP 8 and Appendix B for details.

[219] See p. 46, Paragraph 2, of D.02-12-074 for details.

[220] This external review process has been extended to include the 2007 Quarterly Compliance Reports.

Request (MDR).[221] However, we see no valid reason for waiting until the middle of 2008 to examine the QCRs. Part of the contract entered into with the external auditors requires them to make recommendations to the Energy Division when they submit the audit reports. Therefore, we direct the Energy Division, in conjunction with the external auditors and the IOUs, to continue the collaborative effort formed earlier this year and develop a reformatted QCR. We direct ED staff to submit a project timeline to the service list of this proceeding, within 30 days of issuance of this decision, which provides sufficient time for public comment. We delegate authority to Energy Division to authorize the implementation of the reformatted and streamlined QCRs as well as the authority to continue to make ministerial changes to the content and format of the report as needs arise.[222]

We also note that the QCRs represent thousands of transactions per IOU per quarter that must be reviewed and approved in order to assure compliance with the approved LTPPs. As such, we shall increase the timeframe for approving the QCRs from the current 30-day requirement to 60 days. This modification should be fairly non-controversial since, as noted above, none of the QCRs to date have been approved anywhere close to 30 days from the end of the quarter.

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[221] This review will not be limited to the QCRs. As stated above, when the Commission initiates the next LTPP proceeding, we fully intend to undertake a comprehensive review of the Commission's AB 57 long-term procurement compliance and review process.

[222] In addition, we note that several of the directives contained in this decision impact the QCRs and we expect the ED collaborative effort to incorporate the necessary changes.

3.6.3.3. Additional Resources

We take this opportunity to address the administrative and technical components of the compliance review process, and place resource needs in perspective. As a result, for the reasons explained below, we authorize the Executive Director to hire and manage one or more contractors to perform certain tasks, with cost recovery from ratepayers through the IOUs that are respondents to the Commission's long-term proceeding.

The Commission initiated long-term procurement plan proceedings to continue our efforts to ensure a reliable and cost-effective electricity supply in California. Each LTPP proceeding serves as the umbrella proceeding for the Commission to consider, in an integrated fashion, all of the Commission's electric resource procurement policies and programs, including implementation of directives from other procurement related proceedings. The LTPP proceedings operate on a two-year cycle, with IOUs responsible for submitting procurement plans that project their need over a 10-year horizon.

Beginning with the 2006 long-term planning proceeding, we intend that the approved LTPPs supersede all previous procurement plan authority as granted in R.04-04-003 and R.01-10-024. This decision not only approves the 2006 LTPPs, with modifications described in this decision and exclusive of new policy proposals or proposed policy modifications not addressed herein, but also establishes a skeleton upon which future LTPP filings in the biennial cycle may build and grow. It identifies the key issues and areas of planning that the IOUs must address and improve upon in their future LTPP filings. As such, this and subsequent LTPP proceedings represent significant undertakings that touch on many of the Commission's energy-related activities and policy goals. The staff of the Commission must coordinate and consider, in an integrated fashion, all of

the Commission's electric resource procurement policies and programs, including implementation of directives from other procurement proceedings relevant to this cycle. In addition, this proceeding is the forum in which we consider potential *future* policies that the federal government, state legislature, the CEC or the Commission may implement that will impact the procurement practices of California's utilities. This is an immense undertaking for the Commission and its staff.

The three IOUs expend roughly 11 billion dollars annually on electricity procurement, and this number is growing rapidly.[223] This is a huge expenditure of ratepayer dollars, and the policy and implementation detail requirements and refinements set forth in this and past LTPP decisions represent the Commission's best efforts to control these costs.

Needless to say, implementation and administration of this program is an immense task involving a plethora of technical details and Commission resources. We identify in this decision a number of tasks that will benefit from additional expertise that can supplement Commission resources. Therefore, we authorize the Executive Director to hire and manage a contractor (or contractors) to provide technical support to assist staff in the following areas:

- General program design, implementation and evaluation (including process improvements and compliance assurance);

[223] See Table 1 and related discussion on pp. 9 and 10 of the Scoping Memo.

- Design and evaluation, in coordination with the IOUs, of a more rigorous portfolio evaluation approach to long term resource planning, as encouraged by many parties to this proceeding; and

- Other tasks staff identifies to promote LTPP program goals and maintain a reliable, cost-effective, and environmentally sound electric supply in California.

To support these resources, SCE, PG&E and SDG&E are each authorized to establish an LTPP Technical Assistance Memorandum Account (LTAMA). The Commission will send approved invoices issued by contractors or invoices issued by the Commission for reimbursement of costs incurred by the Commission to PG&E, SCE and SDG&E for payment of these technical assistance costs on a pro rata basis (i.e., 33.3% to each IOU) unless the contractor(s) perform work related to only a specific utility. PG&E, SCE, and SDG&E are authorized to record these charges into the LTAMA, and each company may later apply for recovery in rates. We shall limit costs that may be charged to the LTAMA to a $400,000 annual cap.

3.6.4. SCE & PG&E Petition to Modify D.02-12-074 & D.04-12-048

On December 2, 2005, SCE and PG&E filed a petition to modify D.02-12-074, and D.04-12-048 to change the requirement that energy utilities must file a periodic report on their ERRA with the Commission from a monthly report to a quarterly report.[224] In their petition to modify, SCE and PG&E

[224] In discussions between SCE and the Commission's Utility Audit and Finance Compliance Branch ("UAFCB"), UAFCB indicated that the sheer volume of ERRA related data submitted to the Energy Division each month causes major storage problems for the staff. A typical monthly ERRA report, including supporting documentation, consists of a few pages of summary information and approximately

Footnote continued on next page

requested that the Commission modify D.02-12-074 and D.04-12-048 to allow each utility to submit one quarterly ERRA summary report with a monthly breakdown of costs to the Commission's Utility Audit Finance and Compliance Branch (CUAFCB), and to make all supporting documentation available to the Branch upon request, rather than submitting a 1,000-page ERRA report every month.

PG&E correctly notes in its brief that the Commission recently acted on the petition to modify by issuing D.07-04-020, agreeing to reduce the amount of supporting documentation but still requiring the utilities to file monthly rather than quarterly.[225] Therefore, this issue is now moot. However, PG&E's characterization of the Commission's ruling on this matter is inaccurate and we feel the need to clarify. D.07-04-020 denied the request to change the monthly ERRA filing to quarterly filings, but granted the request that the utilities only supply a breakdown of costs with their ERRA monthly filings and make all supporting documentation available to *Commission Staff and interested parties upon request*.

We further directed that "if Commission Staff or interested parties request supporting documentation, the utility must comply with the request within 10 business days. Furthermore, pursuant to Public Utilities Code Section 314.5, if Commission Staff deems it necessary to review any supporting documentation being maintained at the utilities' offices, upon request the utilities are to grant

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1,000 pages of supporting documentation. Thus, the Commission's UAFCB is burdened with approximately 24,000 pages per year of monthly ERRA report documentation from SCE and PG&E.

[225] D.07-04-020.

Footnote continued on next page

Commission Staff access to their offices."[226] Therefore, PG&E's characterization that the information only be available to the UACFB is incorrect.

3.6.1. Compliance with this Decision

Throughout the body of this decision we make several significant modifications to the proposed LTPPs of the IOUs. In order to reflect all of the guidance provided here – in one, comprehensive, going-forward long-term procurement plan – we shall require the IOUs to file conformed long-term procurement plans through a compliance filing. This conformed "2006 long-term procurement plan" would "…supersede all previously approved plans, as modified…The complete 2006 LTPPs will merge the contents of the two previous [LTPP] filings, include the AL amendments proposed by each utility over the past several years, and reflect the Commission's numerous decisions on procurement policies and transactions."

We direct the IOUs to file the conformed 2006 LTPPs, via a compliance filing no later than 90 days from the date of this decision.[227] The conformed 2006 LTPPs shall incorporate all of the directives contained in the body of this decision as well as any updates filed through the Commission's Advice Letter process between the issuance of this decision and the due date of the compliance filing. We direct the utilities to work with the Energy Division to develop a

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[226] *Id.*, p. 4.

[227] We direct each IOU to separately file a Tier 3 Advice Letter when it submits its Compliance Filing for approval.

format for the compliance filing. In addition, we recognize that the extensive changes necessary to the LTPPs base on this decision may be difficult to complete within 90 days and we hereby delegate to the Executive Director the authority to defer the filing for up to an additional 90 days.

In the interim, each IOU's 2006 LTPP is adopted with the modifications stipulated in this decision and summarized in the Ordering Paragraphs and the Compliance Table provided as Attachment E (and exclusive of any policy proposals embedded in the Plans that are not specifically addressed in this decision).

We recognize that this requirement, and the extensive nature of the LTPP filings in general, are process-focused and potentially burdensome to all parties involved. As more structured, transparent procurement policy and compliance guidelines such as those established in this decision are incorporated into the IOU procurement "culture," though, we are optimistic that they will lead to greater efficiencies and a simplification of this process than currently exist in this proceeding.

In comments on the Proposed Decision, SCE stated that the language contained in the PD does not adequately explain the specific changes that the utilities are required to make in their compliance filings. We shall provide more clarity as to the Commission's expectations of the compliance filing by providing limited examples drawn from the utilities LTPPs filed on December 11, 2006.[228]

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[228] We acknowledge that all three IOUs made subsequent updates to their filings after the initial December 1, 2006 filing date. However, relying on the initial filings for the purpose of providing the requested clarity for the compliance filing should not result in any concerns. These examples are to serve illustrative purposes only and are not intended to be all-inclusive or definitive.

The discussion contained in SCE's LTPP regarding the Energy Auction[229] is now incomplete and must be updated to include a discussion of the completion of phase I of this proceeding. For instance, the Commission issued D.07-09-044, *Opinion Adopting Joint Settlement Agreement, as Clarified, Regarding Principles for the Energy Auction Process and Products*, and the issuance of this decision should be reflected in SCE's LTPP.

In addition, SCE's LTPP references an outstanding petition for Modification of D.06-07-029.[230] This discussion is incomplete and must be updated, as part of the compliance filing, to include a discussion of the Commission's ruling on SCE's Petition. The Commission issued D.07-06-022, which denied SCE's request.

Further, SCE's LTPP discusses the Commission's policy on debt equivalence.[231] This decision modified the Commission's debt equivalence (in RFO bid evaluation) policy and, as such, the compliance filing should include an updated discussion on the topic of debt equivalence.

Similarly, in Volume II of its LTPP (Section VII. D. Changes in SCE's Collateral Requirements) SCE seeks Commission approval to increase its collateral capacity limit up $2.0 billion. SCE's request is granted in this decision, and as such, in its compliance filing, SCE should modify its LTPP top reflect this approval (Volume IA, Section 3B).

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[229] Volume 1A of SCE's LTPP (Section II. F. 5. Energy Auction (R.06-02-013)

[230] Volume 1A of SCE's LTPP filing (Section II. F. 6. Petition For Modification of D.06-07-029) p. 46.

[231] Volume 1A of SCE's LTPP (Section III. A. 7. b) Debt Equivalence) p. 68.

We also note that recently each IOU asked for modifications to their AB 57 procurement plans to obtain congestions revenue rights (including long-term CRRs).[232] This requested modification to the existing procurement authority was granted by the Commission in a series of Resolutions. The Resolutions were issued after December 11, 2007, and included in the Resolutions were various 'criteria for implementation,' and as such the IOUs must include the new procurement authority in their respective compliance filings.

As noted above, we direct the utilities to work with ED to further refine the scope and format of the compliance filing if necessary.

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[232] SCE filed AL 2142, SDG&E filed AL 1920 and PG&E filed AL 3095 to modify their AB 57 procurement plan to enable each IOU to procure Long-Term CRRs. The Commission approved the requests in Resolution 4117, Resolution 4124, and Resolution 4122, respectively.

SCE filed AL 2141, SDG&E filed AL 1926 and PG&E filed AL 3106 to modify their AB 57 procurement plan to enable each IOU to procure CRRs. The Commission approved the requests in Resolution 4134, Resolution 4136, and Resolution 4135, respectively.

4. Policy Issues

4.1. UOG[233]

Restructuring resulted in the divestiture of most of the IOUs' conventional (fossil fuel) generation. The IOUs retained ownership of their nuclear and hydroelectric assets, which represent approximately half of the three IOUs' current capacity requirements. In the past several years, a number of conventional generation plants have been acquired by the three IOUs as a result of the August 16, 2007 ACR, various unique opportunities, and RFO selections (i.e., PSAs, EPCs, and PPAs that convert to UOG at the end of the PPA term – there have been no utility-build offers in IOUs' solicitations to date).

Issues associated with this increase in conventional UOG are generally related to one of these four questions:

- Will UOG stifle the Commission's goal of transitioning to a viable competitive market structure, or should it continue to be permitted during the transition?
- Is it possible to fairly compare UOG and merchant developer bids in RFO bid evaluations?

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[233] For the purposes of this discussion, the term UOG includes, but is not limited to, utility-built, Engineer, Permit and Construct (EPC), and Purchase and Sale Agreement (PSA) acquired resources. When a specific acquisition path is under consideration, it is referenced (i.e., 'utility-build' rather than 'UOG'). In addition, the discussion of UOG in the IOU LTPPs and subsequent intervenor and IOU testimony generally focused on utility ownership of conventional generation resources. The Commission recognizes that there are additional factors associated with utility ownership of renewable and other loading order or non-conventional resources that have not been fully vetted in this proceeding. The appropriate treatment of UOG for accomplishing resource-specific policy goals will be identified within the appropriate proceedings, and the treatment of utility ownership of conventional generation in this LTPP decision does not prejudice those proceedings in any manner.

- If UOG continues to be permitted during this transition period, under what circumstances is it appropriate?
- Should the 50/50 savings sharing mechanism developed for UOG in D.04-12-048 be replaced?

Each of these questions is addressed in this section.

4.1.1. UOG and Competition

There are a wide variety of opinions among IOUs and intervenors regarding whether new UOG is appropriate for the three IOUs. The IOUs recommend the continued use of UOG as one of the procurement tools they can utilize to provide the best value to ratepayers. The ratepayer advocates generally concur with this position, suggesting that certain circumstances for or quantities of UOG will provide a good balance for developer built and owned generation. Developers are generally against UOG out of concern for either (1) the inability to fairly compare utility and developer RFO bids or (2) the incompatibility of ratepayer-backed UOG with the desired competitive market end state.

4.1.1.1. Summary of Parties' Positions

As noted above, the IOUs are all in favor of preserving new UOG as one of the procurement tools they can utilize to provide value to ratepayers.

Testimony from the developer community, which includes individual developers as well as advocacy groups like CMA and IEP, was mixed on whether or not UOG should be permitted to continue.

CMA takes the position that developers will not commit substantial capital to new merchant generation until it is clear that utilities will no longer be in the business of funding new generation through ratebase investments (or even long term PPAs) with regulatory guarantees. As CMA states in its initial testimony:

> Merchant investors are willing to bear the risk that their investment can be "devalued" through the actions of other market competitors. They are not, however, willing to take the risk that their investment could be "devalued" by the actions of a utility with preferential access to regulatory guarantees. Although the common refrain is "no one will build without long term contracts," the more accurate statement would be "no one will build a new plant without a long-term contract *while the state still has a policy of having utilities sign such contracts*." So long as the current hybrid model is perceived to be the permanent policy of the state, there is likely to be little or no true merchant entry. The use of long term contracts backed by regulatory guarantees creates a self-fulfilling prophecy where "no one will build without one."' [CMA, Schnitzer, p. 9.]

Thus, CMA argues that all ratepayer backed investment, including but not limited to UOG, will prevent the development of a competitive energy market made up of direct private investment in generation resources.

CAC/EPUC do not object to new UOG provided that the utility projects win a fair and unbiased solicitation.

IEP notes that a long-term procurement process that favors IOUs will discourage potential wholesale suppliers from identifying and developing opportunities to serve the California market and investing in the costly process of development and bid preparation; potential suppliers will be less willing to participate in a game where the deck has been stacked against them. IEP states that the preservation of the benefits of competition (through effective regulation and oversight) requires regulation that embodies the relevant principles of competitive procurement in rules to which the IOU is bound and provides oversight to ensure that the regulation is effective.

CARE appears to advocate for UOG until the risks associated with PPAs are better understood. CUE argues that the Commission should continue to encourage the IOUs to examine ownership options and that IOUs should enter

into them when appropriate. CUE suggests that there will always be a range of generation costs, risks, and benefits not just between utility-owned and contracted-for generation, but among different utility-owned generation options and among different contracted-for generation options. Thus, it is appropriate to both keep open the option for utility-owned generation and also keep flexibility about the rate treatment to be applied to different generation resources.

Aglet recommends that the IOU Plans be modified so that a target of 50% UOG is established for all new contracts with terms of 10 years or greater and that the target should apply to both renewable and non-renewable resources. TURN urges that UOG should be permitted, because "cost-based generation needs to be available to discipline the market, every bit as much as the market needs to be available to discipline the utilities" (TURN's Opening Brief, p. 28). TURN identifies conditions under which UOG should be permitted, and these conditions are discussed later in subsection 3.

4.1.1.2. Discussion

CMA's position that continued reliance on UOG (and ratepayer-backed PPAs) is incompatible with the development of a competitive market model that stimulates private investment is consistent with basic economic theory. The Commission is taking measured, cautious steps in the direction of this end-state, and a number of programs and security measures must be developed and tested before California relies on competitive markets to provide this critical resource to our state. D.06-07-029 stated that we were in a transitional period, and this remains the case. Anticipated rulings on forward RA requirements (and the market structures for acquiring these resources) in Phase 2 of the RA proceeding and the development of a transparent PRM methodology in the PRM rulemaking are key steps in this process. To a great extent, they represent the "horse" to this

proceeding's "cart," and we must be mindful that our actions do not put the cart in front of – and, more importantly, in the way of -- the horse.

We recognize the need for policy consistency with the forward RA structure and revised PRM methodology, but until they are developed and implemented this proceeding will continue to be relied upon to (among other things) ensure that sufficient resources are available to ensure system reliability throughout the state. We are prepared to curtail or prohibit new, fossil fuel UOG, and even ratepayer-backed PPAs, if we are convinced that other mechanisms are in place to perform this function. Until we are further down this path, though, we see no reason to dismiss out-of-hand any particular method for acquiring these resources.

We do not prohibit UOG in this decision; however, we weigh heavily in the remainder of this section the concerns related to UOG expressed by the IPP community as we consider whether and how UOG and IPP bids can be compared in a competitive solicitation and the appropriate role of UOG in IOU procurement. However, we do weigh heavily in favor of a competitive market first approach as we discuss further.

4.1.2. Comparing UOG and IPP Bids

D.04-12-048 stated that "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 attributes associated with each bid," and the qualitative and quantitative attributes were defined as "performance risk, credit risk, price diversity (10 vs. 20-year price terms), and operational flexibility etc." (D.04-12-048, FOF #86.) Finding of Fact #86 in D.04-12-048 also indicated that "It is expected that the Commission will revisit the LCBF methodology, integrating 'lessons learned' from future all-source open RFOs."

Attachment A of the September 25, 2006 Scoping Memo noted that, "(n)umerous parties have commented that the procurement practices of the IOUs to date have not promoted all-source solicitations and have not insured an even playing field for utility and non-utility electric resources to compete. See, for example, the Pre-workshop Proposal of the Independent Energy Producers Association, March 7, 2006, filed in R.06-02-013. D.04-12-048 called for open, transparent, competitive procurements. Many non-utility competitors urge the Commission to re-visit the procurement policies, and issue directives that will ensure more open competition."

There have been no utility-build bids proposed in any of the long-term RFOs since D.04-12-048 was adopted, although there has been an EPC (PG&E's Humboldt Project), a PSA (PG&E's Colusa Project), and a number of UOG acquisitions resulting from unique opportunities. The purpose of this subsection is to evaluate lessons learned from these experiences and incorporate them into the process.

4.1.2.1. Parties' Positions

There is general agreement among parties that comparing UOG to IPP bids presents many challenges. Parties who do feel that it is possible to compare UOG and IPP bids have provided precious little detail regarding how, specifically, to do so.

The IOUs take two very different positions on comparing UOG and IPP bids in the RFO process. PG&E and SDG&E both argue that UOG and IPP bids can be compared within a competitive RFO, though neither party provided any substantial description in their LTPPs regarding how the different risk and return regimes faced by the two entities would be reconciled to compare their bids fairly. SCE, on the other hand, does not believe that IOU and IPP bids can

be compared in a meaningful, quantitative manner. SCE instead takes the position that generally it will offer bids in instances in which the market does not provide the product it seeks. If circumstances arise in which SCE does perceive the need to propose a utility product for which it has received market bids, SCE will provide a separate treatment of the UOG version and articulate, qualitatively, its rationale for recommending its project over the market-derived product.

CAC/EPUC do not object to new UOG per se, but recommend that UOG projects only be approved after they have been subject to an appropriately structured competitive solicitation process which allows for fair and unbiased evaluation of third-party owned projects. To do otherwise "invites mischief by the utilities by providing loopholes in the process that may seriously denigrate the integrity of the procurement process."

CMA focuses its analysis on ratepayer-backed versus privately funded generation, not on issues associated with comparing UOG and merchant PPA bids. NRG recommends that utilities be required to submit firm bids and their shareholders be held liable for overruns.

NRG also finds that as long as the IOUs are in the RFO "driver's seat" to control the timing of the RFO and the bidding process, the perceived and real likelihood of distorted outcomes remains high. NRG finds it important to recognize that even the perception of bias can be sufficient to dampen participation from other potential non-utility investors and developers are less likely to get support from capital markets if there is a perception that merchant bids will be undermined by utility built or affiliate projects. NRG concludes that the Commission or another independent agency should manage the procurement process to eliminate the potential for conflicts of interest and ensure

impartiality, noting that a process of this sort has been adopted in Connecticut with considerable success.

NRG notes that, "Another benefit of state administered procurement is that there is greater likelihood of consistency among utility contract terms and conditions and credit and collateral (C&C) policies. The current contracts and C&C policies of the utilities have significant differences that are not justified in terms of the unique characteristics of each utility or service territory. These differences in contract terms add costs and raise the bar for non-utility entities to participate."

IEP makes a series of recommendations to promote fair solicitation processes. IEP argues that no potential participant in a competitive RFO, including a utility's project development group, should have preferential access to information. Therefore, IEP believes the Commission should prohibit communications of competitively sensitive information to the project development group from other utility departments.[234]

TURN takes the position that there can be no perfect, apples-to-apples comparison of UOG bids in their various forms and PPA bids. TURN recommends that we not let the perfect be the enemy of the good, though, and that head-to-head comparisons based on quantitative (NPV) and qualitative differences among the offers, especially with respect to the residual risks that will be borne by ratepayers. TURN notes that sometimes such factors will result in the selection of a project that is not strictly the least cost on a numeric basis,

[234] IEP Opening Brief, pp. 58-59.

because of the ratepayer risks or other factors that the particular project encompasses.

TURN provides an additional refinement to the process, based on the Colusa PSA and PPA bid comparison that resulted in the selection of the PSA in the most recent PG&E Long-Term RFO. When a UOG and non-UOG bid are relatively close in prices, there should be a preference for the non-UOG bid.

TURN also supports IEP's proposals to ban the utility from having preferential access to information when submitting a bid for a UOG in a competitive solicitation. TURN supports functionally separating the individuals performing the bid evaluation from the individuals preparing the bids.[235]

4.1.2.2. Discussion

The Commission has repeatedly stated its desire to develop a functional competitive energy market in California, and as noted earlier in this section, we are in the process of implementing a number of programs and safety mechanisms in support of this end state. In the interim, we are operating in an evolving "hybrid market," and the issue at hand represents one of the challenges posed by such a market.

In D.04-12-048, IOUs were instructed to compare UOG and IPP bids, but UOG bids were capped at initial offer costs, and a 50/50 savings sharing mechanism required that ratepayers and shareholders split any cost savings associated with the IOU delivering the project under budget. The IOUs and other parties have challenged the fairness of this requirement and requested that

[235] TURN Opening Brief, pp. 26-27.

the Commission revisit this requirement, and this issue is addressed in subsection 4.1.4.

The PD disallowed any form of UOG bidding into competitive solicitations until a functional, transparent methodology for comparing the bids on a level playing field has been established. This prohibition was supported in comments by the IPP community, CLECA, SCE, and several other parties. However, a number of parties reference in their comments recent RFOs in which robust mechanisms for comparing PSA and PPA bids were developed and implemented, and the processes were deemed fairly and successfully administered by the PRGs, IEs, and this Commission.

We are sufficiently convinced by these arguments – and particularly by the positions articulated by TURN and DRA – that, recognizing the additional safeguards adopted in this decision regarding IE, PRG and ED oversight of the RFO development process, we will relax for the moment the proposed restriction to exclude head-to-head competition between PPAs and PSAs (and in appropriate circumstances, EPCs). However, we reiterate that, as a precondition for conducting an RFO seeking utility ownership options, the IOU, in conjunction with its IE, PRG, and ED staff shall develop a strict code of conduct – to be signed by any and all IOU personnel involved in the RFO process – to prevent sharing of sensitive information between staff involved in developing utility bids and staff who create the bid evaluation criteria and select winning bids.[236]

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[236] This code of conduct would be very similar to the codes of conduct and bans on preferential access to information that apply between a utility and its generation affiliates. Therefore, the internal IOU functions involved in project development and

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We will not, however, permit IOUs to recoup from ratepayers any bid development costs associated with losing PSA or EPC bids, in the event that any such costs are incurred.

We have insufficient experience at this time regarding how the different qualitative and quantitative attributes associated with straight Utility build bids and IPP bids that are identified in D.04-12-048 (performance risk, credit risk, 10-year versus life-of-asset price terms and operational flexibility) will be reconciled in order to perform meaningful, apples-to-apples comparisons of Utility build and IPP bids, so we retain the prohibition on Utility build bids in competitive RFOs at this time. [237]

We encourage interested parties to introduce well-developed proposals in the 2008 LTPP proceeding that address the issues raised in D.04-12-048 and, at a minimum, the following additional concerns:

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bid preparation. Thus, if a utility were soliciting turnkey bids or EPC contracts as well as PPAs in a given solicitation, the individuals performing the bid evaluation would have to be functionally separated from the individuals preparing the bids (or the cost estimates) for projects that would ultimately be utility-owned (we note that some of the utilities already do this). Under this restriction, the employees developing the utility-owned project would be barred from access to any evaluation protocols, input assumptions, or bid information not made generally available to outside bidders. This approach would provide assurance that the utility could not use "inside information" to the advantage of its own project, without requiring the publication of every detail of the bid evaluation protocol.

[237] It should be noted that in this context Utility build bids do not include PPAs with affiliates.

- How IOU bid development costs, particularly for unsuccessful bids, would be addressed (e.g., are these costs "at-risk" or are they ratepayer-guaranteed?);

- To the extent that penalty and reward components are added to UOG bids to make them more consistent with IPP bids, whether and how limits would be placed on the participation of the IOU's ratebased resources on the proposed project (i.e., what would prevent an IOU from re-directing its ratebased staff and other resources well in excess of the amounts estimated in its winning bid); or

- What further measures (outside of, or in addition to, those highlighted in this decision)will be taken to prevent sharing of sensitive information between staff involved in developing utility bids and staff who create the bid evaluation criteria and select winning projects?

We agree with parties and find it important to recognize that even the perception of bias in an RFO can be sufficient to dampen participation from other potential non-utility investors and developers are less likely to get support from capital markets if there is a perception that merchant bids will be undermined by utility built or affiliate projects. In order to address this bias issue – whether perceived or real – we have established many "checks and balances" on the front end and back end of the RFO process.[238] Our goal with these additional safeguards is to eliminate any potential for impartiality at any stage of the RFO process – whether that RFO is seeking PPA only bids or merchant and utility owned bids.

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[238] For example, increased requirements on the IOU to consult with the IE, PRG and ED staff on the development and implementation of an RFO including the bid evaluation criteria.

4.1.3. Circumstances for UOG Outside the RFO Process

Among those parties who feel that the development of new UOG outside of the competitive RFO process is appropriate, there are a variety of opinions regarding under what circumstances (and how much) UOG is permissible or desirable.

We want to make it clear that we continue to believe in a "competitive market first" approach. As such we believe that all long-term procurement should occur via competitive procurements, rather than through preemptive actions by the IOU, except in truly extraordinary circumstances.

4.1.3.1. Parties' Positions

SCE identifies three specific instances in which it envisions developing UOG rather than procuring from the market: grid reliability projects (e.g., a local reliability resource in a load pocket to mitigate market power), fuel diversity (development of a nuclear or Integrated Gasification Combined Cycle (IGCC) resource that it does not expect the market to develop), or as a market backstop (in the event that some facet of the market is not working as anticipated). PG&E and SDG&E identify a broader role for new UOG as, essentially, one of the procurement tools they can utilize to provide the best value to ratepayers in competitive RFOs or outside of the RFO process.

IEP recommends that all long-term procurement should occur via competitive procurements, rather than through preemptive actions by the IOU, except in truly extraordinary circumstances. NRG recommends that the Commission adopt a "Competitive Market First" policy in which utilities are required to demonstrate that they have solicited market alternatives before being allowed to pursue utility-built or affiliate-built turnkey options.

TURN states that UOG should only be proposed if it meets one of the following criteria:

- The project was chosen in the course of a competitive solicitation.
- The utility had conducted a competitive solicitation within the previous 12 months and found no (or insufficient) bids to be acceptable from a ratepayer perspective.
- The project resulted from a unique opportunity.
- The project was required to fulfill a specific system or portfolio need that could not reasonably be expected to be met via a competitive solicitation.

4.1.3.2. Discussion

The Commission is committed to developing a functional competitive energy market in California, and under the current hybrid market we have a strong preference for competitive solicitations for generation. However, as noted by several parties, unique circumstances could arise that dictate a need for UOG outside of a competitive RFO. Both SCE and TURN offer reasonable proposals for unique circumstances in which UOG outside of a competitive RFO may be the most attractive option to ratepayers for resource development.

At this time, we divide the unique circumstances warranting some form of utility ownership into five categories.[239] Below, we list and describe each category. Because the Commission has a strong preference for competitive

[239] The categories listed here are not permanent. As our procurement experience grows and processes evolve the needs highlighted in these five categories may change.

solicitations, in all cases, if an IOU proposes a UOG outside of a competitive RFO, the IOU must make a showing that holding a competitive RFO is infeasible:

- Market Power Mitigation – the IOU must make a strong showing that as a result of some attribute of the desired resource, a private owner would have the ability to exert significant influence over the price of its development or of the price and quantity of its output (energy, capacity, or ancillary services);

- Preferred Resources[240] – while we continue to rely on markets to deliver efficiently priced products for ratepayers, we see no reason to limit our options and intend to continue to deploy all resources available to us, including utility development and ownership, to meet California's vital environmental policy objectives;

- Expansion of Existing Facilities – we can envision certain unique circumstances in which ratepayers would benefit from development on or expansion of an existing IOU asset that would not lend itself to the PPA project structure, but the IOU would need to make a strong showing that such development were clearly preferable to a resource that could be obtained via a competitive solicitation that would not necessarily result in utility ownership;

[240] As noted in Section 1.1, preferred resources in order of preference are energy efficiency, demand response, renewables, distributed generation and clean fossil-fuel. However, a utility may only develop a clean fossil-fuel UOG outside of the RFO process if it utilizes an advanced or emerging technology that the market is unlikely to develop.

- Unique Opportunity – an attractively priced resource resulting from a settlement or bankruptcy proceeding (we anticipate that these opportunities will diminish over time);[241] and
- Reliability - resources needed to meet specific, unique reliability issues (particularly under circumstances in which it becomes evident that reliability may be compromised if new resources are not developed, and the only means of developing new resources in sufficient time is via UOG.

We shall consider these unique circumstances for UOG approval outside of a competitive solicitation on a case-by-case basis via an IOU application. In instances in which an IOU submits an application for UOG that falls into one of the above categories, the IOU should request in its application to hold a competitive RFO for turnkey project development of the resource (a PSA). If a competitive solicitation for a PSA contract to build the UOF is not appropriate, in its application the IOU should explain why this is the case and propose either an EPC or straight utility build project approach, depending on the circumstances.

Finally, several RFOs have required or provided as an option the transfer of the fully depreciated resource underlying a PPA to the IOU. We believe that this practice distorts the market, and we prohibit IOUs from including this approach as an option in their competitive RFOs.

We again express our support for our "competitive market first" approach. By taking these steps we believe we are moving further along in our transition to a robust competitive generation market. We firmly believe that all long-term procurement should occur via competitive procurements, <u>except in truly</u>

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[241] We note that one method in which the IOU could demonstrate that the resource really is favorably priced is by subjecting the resource to a "market test" by conducting a competitive solicitation.

extraordinary circumstances. While we do not explicitly disallow utility ownership options in the generation market we continue to look unfavorably on this procurement option but realize that in extraordinary times this may be the optimal method for meeting the needs of California's ratepayers.

4.1.4. 50/50 Savings Sharing Mechanism

As previously noted, D.04-12-048 required IOUs to bid utility-build projects into competitive solicitations. For its successful bids, the IOU was not allowed to recover "…initial capital costs in excess of its final bid price for utility owned resources."[242] This policy has come to be known as the "cost cap" on UOG. The Decision also requires a "50/50 sharing of savings between ratepayers and utilities" for costs that come in under the capped bid.[243] Thus, under the present process, if actual construction costs come in below the cap, 50% of the savings are allocated to customers and 50% to utility shareholders. If actual construction costs come in above the cap, utility shareholders are responsible for all cost overruns.

The 50/50 savings sharing related to construction cost savings is an unresolved issue from D.04-12-048 following a decision granting rehearing on SCE's Application for Rehearing.[244] The 50/50 savings sharing issue was originally set on its own track in this proceeding, with a separate schedule for its discussion and possible resolution. The interested parties exchanged proposals

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[242] D.04-12-048 at p. 128.

[243] D.04-12-048 at p. 129.

[244] The issue on rehearing as stated in D.05-09-022 was "the 50/50 sharing provisions related to construction cost savings … "

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and had meetings and reported back to the proceeding that the issue should properly be part of the whole LTPP since it was inextricably intertwined with procurement.[245]

Although parties disagreed about many issues associated with this mechanism, including the appropriateness of a cost cap altogether, there was general agreement (among parties who believe that UOG is appropriate at all) that the "50/50 sharing mechanism" is not workable and should be eliminated. They argue that, on its surface the asymmetric risk sharing is unreasonable – that is, shareholders bear 100% of all risk of cost overruns but are only eligible for 50% of any potential benefits from completing a project under budget. Generally, parties who are open to UOG believe that neither utility ratepayers nor utility shareholders should bear asymmetric risk.

4.1.4.1. Summary of Parties' Positions

PG&E proposes that the Commission adopt a flexible approach to ratemaking for utility-owned generation. In particular, when a utility-owned project is chosen in a competitive solicitation and presented to the Commission for approval, the utility would propose an appropriate ratemaking approach. The Commission could then accept, reject or modify the utility's ratemaking proposal. PG&E's proposal is based, in part, on the utility-owned projects approved by the Commission to date, which have adopted a number of different ratemaking mechanisms.[246] PG&E argues that, by allowing utilities the flexibility

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[245] SCE reported to the ALJ on January 5, 2007, that the meet-and-confer discussions did not reach a resolution and the 50/50 share issue needed to be further explored as part of the LTPP proceeding.
[246] Ex. 7 at I-3 – I-6.

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to propose differing ratemaking mechanisms for utility-owned projects, the Commission will avoid a rigid approach and be able to determine the ratemaking for a specific facility that has the greatest customer benefit.

PG&E believes that traditional cost of service ratemaking is preferable in most situations. It provides for Commission oversight of the cost of owning and operating the facility, and provides the utility with the opportunity to recover any costs the Commission finds reasonable. Traditional cost of service ratemaking is intended to carefully balance the risks and rewards of new utility-owned generation between customers and utility shareholders, and is appropriate in a wide range of situations. In an application for approval of utility-owned generation, the utility could propose cost of service ratemaking for a specific facility where this kind of ratemaking would be beneficial for customers and the utility.

SCE argues that the Commission should replace the solicitation-cost-cap-50/50 sharing mechanism framework in D.04-12-048 with the comprehensive framework that SCE set forth in Volume 2 of its LTPP and in supplemental testimony.[247] Under the scenarios SCE presents it argues that the UOG projects should not be subject to a cost cap. In many instances, IOUs will be acquiring new projects to advance cutting-edge technology, or to maintain reliability of the system. In sum, SCE states that the Commission has provided some flexibility in

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[247] SCE proposes to consider new utility-owned generation under two broad cases. In the first case, SCE proposes to own generation if competitive market alternatives are not readily available. In the second case, based on an evaluation of competitive market alternatives and/or in consideration of portfolio diversity, SCE will own the generation if utility ownership offers greater value and/or benefits to its customers.

cost recovery mechanisms and should continue to recognize that certain modifications to the framework set forth in D.04-12-048 are necessary.

SDG&E recommends that the Commission adopt a framework where bid prices for both UOG and IPP generation are fixed upon submittal of the project to the Commission for approval. Additionally, SDG&E recommends that the Commission adopt a modest incentive mechanism to be used for treatment of cost savings and overruns.

Under the methodology outlined in D.04-12-048, a bid for utility-owned generation is frozen once entered into a solicitation. SDG&E states that there are numerous reasons why bid prices might legitimately change for both utility-owned and merchant-owned generation after bid prices have been submitted.[248] For example, changes in scope, schedule, and force majeure can cause price increases or decreases depending upon the circumstances at hand regardless of ownership. Additionally, risks that are equally present for both merchant-owned and utility-owned projects come in the form of credit, permitting, technology, regulatory, legislative, construction, and operational risks, among others. After bids are tendered, contractual language in PPAs is negotiated and agreed upon to balance these risks and allow for fair resolution.

SDG&E argues that under the current framework utility shareholders are exposed to higher risks from scope and schedule refinement. Holding merchant projects to their initial bid price eliminates this risk disparity, but creates the same problems for merchants as faced by utilities under the present mechanism.

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[248] These changes might occur during negotiation, after the contract is entered into, or after delivery of the product regardless of who owns the generation.

High contingencies and/or extensive exclusionary terms would abound. In the end, it is in the best interest of utility customers to allow a certain degree of price and scope flexibility prior to submittal of projects to the Commission for approval. Otherwise, both UOG and IPP generation bids would contain high contingencies to cover the greater risks.

Furthermore, SDG&E believes that holding the utility shareholders alone as responsible for these greater risks will essentially preclude utility ownership as a viable option and eliminate SDG&E's claimed cost-of-service benefits.[249] Instead, as a true measure of fairness, both utility and merchant-owned generation bids should follow the process whereby the utility submits final bids and contracts to the Commission for approval. Any changes to the price or material changes in terms between the initial bid and submittal to the Commission for approval should be fully investigated by the IE, the Parties to the proceeding and by Commission staff for both utility-owned and merchant-owned generation.

TURN claims that different UOG projects create different risks from a ratepayer standpoint. In some cases the initial capital cost (which was the focus of the cost cap and 50/50 sharing policy adopted in D.04-12-048) may be the most important risk to mitigate from a ratepayer standpoint. But in other cases heat rate and unit availability may be more important in the long run, or the future trend in O&M expenses and/or capital additions over time. All of these

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[249] And if the utility were to pursue ownership under this mechanism, there is a perverse incentive for the utility NOT to make cost saving modifications (during or after construction) that would clearly be in the customer's best interest yet require additional upfront capital not covered in the initial bid price (e.g., improvements that lower heat rate, lower auxiliary load, increase capacity, lower long-term O&M, etc.).

factors need to be considered in coming up with an appropriate set of ratemaking incentives and penalties for a particular utility-owned project.

TURN notes that ratemaking mechanisms to mitigate the cost and performance risks to ratepayers of a UOG project can take many forms in different situations. One example is the "cost cap" approach adopted in D.04-12-048, under which the utility is not allowed to recover initial capital costs above the forecast that was the basis for the selection of the project. This could also include a "cost sharing" formula such as that adopted in the settlement approving PG&E's acquisition of the Contra Costa Unit 8 (now known as "Gateway") project from Mirant. In other cases, such as the Edison Mountainview acquisition and SDG&E's purchase of the Palomar plant, the Commission has adopted heat rate and/or plant availability incentive mechanisms, under which the costs resulting from deviations above and below a benchmark level of performance are shared between the utility and its customers based on an established formula.

TURN contends that these mechanisms provide a tangible incentive for the utility to operate the plant efficiently, and protect ratepayers to some degree against the economic impacts of poor plant performance over time. By listing these various possibilities, TURN does not intend to preclude the adoption of creative new approaches that achieve the same basic objective of ratepayer risk mitigation in the case of utility-owned generation. Regardless of the approach taken, TURN emphasizes that what is most important is that the IOU be required to justify the requested rate treatment in any application proposing a UOG project.

4.1.4.2. UOG Ratemaking Proposals

Parties propose that the Commission adopt a more flexible approach to ratemaking for UOG, rather than trying to establish a single approach (such as a cost cap and 50/50 savings sharing) that would apply to all projects regardless of the specific circumstances. Given that UOG projects may be developed to satisfy a variety of concerns, such as local reliability constraints, specific CAISO operational needs, or for meeting various regulatory mandates (RPS, AB 32, etc.), some parties state that the Commission should establish equally flexible ratemaking.

The three broad categories of ratemaking alternatives that the Commission could consider for UOG are discussed below. Essentially all possible ratemaking approaches are represented by one or a combination of these categories.

4.1.4.2.1. Traditional Cost of Service

Cost of service ratemaking provides for Commission oversight of the cost of owning and operating the facility, and provides the utility with the opportunity to recover any costs the Commission finds reasonable. Traditional cost of service ratemaking is intended to balance the risks and rewards of new UOG between customers and utility shareholders, and has been used in a wide range of situations. In an application for approval of UOG, the utility could propose cost of service ratemaking for a specific facility where this kind of ratemaking would be beneficial for customers and the utility.

The concern with this approach is that there is an asymmetric incentive for the IOU. Any savings incurred in developing the project results in a decrease in capital expenditures for which the IOU does not receive a return on investment, while the IOU does receive a return on any cost overruns for which it receives Commission authorization.

4.1.4.2.2. Cost and/or Savings Sharing

Another alternative would be to adopt some schedule for sharing (between ratepayers and shareholders) of cost savings or overruns. This schedule could be as simple as the 50/50 sharing approach adopted for project cost savings in D.04-12-048 (applied to cost overruns, as well, if symmetric risk/reward were desired), to the structure employed in the Gateway settlement to address relatively minor capital cost overruns,[250] to SDG&E's proposed limited risk and reward incentive mechanism with symmetrical dead bands and shareholder rewards/penalties.[251]

4.1.4.2.3. Cost Cap

The final alternative would be a cost cap in which any cost overruns would be born strictly by the IOU shareholders. Similarly, any savings resulting from a below-bid final construction cost would be passed on to shareholders. This represents the risk/reward regime faced by IPPs who bid into RFOs.

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[250] The Gateway settlement adopted an initial capital cost estimate of $295 million. If the actual cost of Gateway is less than $305 million, the total amount goes into rate base without further review. If the amount is between $305 and $345 million, PG&E can recover the $305 million and 90% of the amount over $305. If the amount exceeds $345 million, PG&E can only recover any amount above $345 million subject to a finding of reasonableness by the Commission. If the actual cost is less than $295 million, customers will receive 100% of the savings.

[251] SDG&E proposes that for changes in price occurring after initial Commission approval of a UOG asset and prior to commercial operation, utility shareholders should be held without gain or loss for changes in price by 5% above or below the Commission-approved price. For the next 10% price increase or reduction, shareholders should be responsible for 10% of the additional costs or rewarded for 10% of the additional savings above the 5% threshold. The full savings below or full costs above the 15% threshold would be garnered or borne by customers. Costs above the 15% threshold would be subject to recovery through a regulatory review process.

4.1.4.3. Discussion

We agree with parties that flexibility in procurement is critical to obtain the best resources for customers. Commensurate flexibility in ratemaking associated with the new generation resources is also important, as we agree that providing for ratemaking flexibility will facilitate the development and construction of a broader range of generation facilities that should benefit all customers. We concur with parties that a "one-size-fits-all" ratemaking regime is not desirable and that the "50/50 cost cap" directed in D.04-12-048 should be eliminated.

We will consider cost-and savings-sharing ratemaking mechanisms such as those utilized by PG&E or proposed by SDG&E on a case-by-case basis, based on the unique circumstances associated with the procurement, and proposals for the requested treatment must be justified by these unique circumstances.

We agree with SDG&E that bids received in RFOs should be fixed upon submittal to the Commission for approval. For the reasons explained by SDG&E, though, we also agree that there are legitimate reasons why a bid price might need to be adjusted between the time it is originally submitted into a solicitation and the time it is finalized and brought to the Commission for approval. Limiting bids to the initial offer price, and subsequently ignoring any changes to the terms and conditions of the deal, will undoubtedly lead to increased costs for consumers due to the need for entities to anticipate contractual negotiation risk and therefore price that risk into the initial bid.[252]

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[252] We note that, generally speaking, resource attributes desired by the IOU or the presence or absence of these attributes needs to be factored into the bid comparison process; the Commission will have little tolerance for the appearance of a litany of "adders" on winning bids that may have been built into other bid prices.

4.2. Procurement Rulebook

As part of its LTPP filing SCE included a "Procurement Rulebook" as Volume III. SCE states that it developed the Procurement Rulebook in order to further its goal of remaining in full compliance with its Commission-approved AB 57 procurement plan and all Commission rules and guidance that relate thereto.

ED staff held a workshop on the need for and potential design of a Procurement Rulebook on May 23, 2007, and at that time parties agreed to establish a Rulebook Working Group (referenced in ALJ Brown's June 29, 2007 ruling) to assist ED staff with the design and development of a rulebook.

4.2.1. Summary of Parties' Positions

SCE believes the Rulebook to be a useful tool for several reasons. First, because SCE's Commission-approved LTPP consists of guidance and rules that is dispersed among various procurement plan filings, decisions, rulings, advice letters and advice letter approvals, SCE feared that an employee could inadvertently violate a rule of which he or she were unaware or which had been since modified. SCE argues that employees would benefit greatly from having all of the rules in one place and in an organized fashion.

Second, SCE believes that because the rules governing its procurement activities were scattered across various filings, it was possible that some of the rules could be in conflict with each other. Therefore, SCE contends that an organized Rulebook that compiled all of these rules in one place would help identify any conflicts and ensure that those conflicts could be resolved. Third, SCE argues that there could be ambiguities in the rules, and therefore, sought to compile its understanding of the rules so that it could identify any areas of ambiguity and seek clarification from the Commission. Finally, SCE urges that a

comprehensive Rulebook would assist the Commission in identifying areas where it wishes to add clarifications or make modifications in order to further its policy goals.

For all of the above reasons, SCE seeks approval of its Procurement Rulebook in this proceeding. In doing so, SCE asks that the Commission clarify any rules that it believes SCE has inaccurately construed and/or identify any rules that it believes have been left out, so SCE may definitively provide the Procurement Rulebook as a guide to its employees in an effort to achieve 100% compliance with its procurement plan. SCE states that once its Rulebook is approved, it will become the implementation portion of SCE's procurement plan and any of its power procurement activities that are compliant with the Procurement Rulebook should be deemed compliant with SCE's procurement plan.

Further, SCE posits that its Procurement Rulebook was designed to be a living document that can be updated in response to changing rules and requirements. SCE proposes that whenever it submits a request to modify its procurement plan or the rules governing its procurement activities, it will submit a redlined version of the affected Rulebook pages, and/or a proposed Rulebook insert incorporating those changes for review and approval along with its request. SCE further suggests that it submit a complete copy of its most current version of its Procurement Rulebook every two years in the LTPP proceeding for review and approval. This combination of procedures will ensure that the Rulebook will always be up-to-date and that any additional new rules and guidance provided by the Commission between procurement planning cycles will be submitted to the Commission for review and approval.

While SCE believes that the Procurement Rulebook has already proven to be very beneficial to SCE in striving towards it goal of 100% compliance with its procurement plan and all related Commission rules and guidance, it does not necessarily believe that each IOU should be required to adopt its own procurement rulebook. SCE recognizes that all three IOUs have developed their own methods of compliance, and does not know whether its method would be compatible with the other systems in place at the other utilities. Thus, SCE asks that its Procurement Rulebook be approved as an accurate compendium of its procurement plan in this proceeding, and will explore the issue of whether this format could also be adopted by the other utilities in the next procurement planning cycle in the Rulebook Working Group, in which SCE has taken a lead role. Should the Commission seek to impose a formal Rulebook requirement on all three IOUs, SCE strongly urges the Commission to issue a ruling on its Procurement Rulebook in this proceeding, rather than hold off on its decision until the next planning cycle.

PG&E agrees that a Procurement Rulebook would be useful for the utilities, the Commission and its Staff, as well as parties interested in utility procurement. The purpose of the rulebook, development, and review by the Commission are all issues which need to be discussed and addressed before development of a rulebook for PG&E can commence.

In comments, SDG&E states that it has no objection to the Rulebook being adopted or approved for SCE's use. However, SDG&E does not support a Rulebook requirement to govern its own procurement activities. Rather, the Commission-approved AB 57 procurement plan represents SDG&E's best interpretation of what the Commission decisions require. The Rulebook,

therefore, offers little apparent benefit for SDG&E, and the burden of developing and updating it would be considerable.

SDG&E also questions whether it is truly possible for each individual utility to condense years of Commission decisions and dicta into a satisfactory set of "rules" that the Commission could legitimately approve outside the context of specific factual situations. Many of the decisions in this area have evolved over the years, and they will continue to evolve, so it will be difficult for each utility to ensure that its interpretation of those decisions has conclusively established what all the rules in fact are. SDG&E notes that even if the rules could be established for a period of time, inevitably changes would occur.

SDG&E also argues that another major threshold issue is the extent to which the rules need to be the same for all three utilities. Given the interpretive aspect of developing a rulebook, it is nearly impossible to conceive that accord could be reached among all three utilities about important procurement activities and how the rules apply, particularly when each utility will have its own legitimate reasons for why the rule should be developed or interpreted in a certain way.

If it is intended as an internal reference tool, then SDG&E has somewhat more agreeability towards the concept of a Rulebook, but again finds it to be unnecessary when the Commission-approved plan reflects SDG&E best interpretation of Commission guidance and the plan establishes SDG&E's AB 57 upfront standards. According to SDG&E, the status of the rulebook also needs to be carefully considered: Does the rulebook supersede the Commission decisions from which it is derived? Is it binding on the utility with the same force and effect as its Commission-approved procurement plan or is it a reference tool that is not formally a part of the AB 57 plan? As a binding part of the Plan,

developing and maintaining a rulebook would unduly burden and complicate a procurement process that is already laden with regulatory filings and process.

SDG&E understands the basic desire for clarity in this challenging and complex area, but believes the best way to achieve that goal is to perfect the procurement plans themselves. As such, SDG&E strongly advises the Commission not to adopt or require a Procurement Rulebook requirement for SDG&E. If the Commission decides to require a rulebook for each utility, then the next LTPP proceeding is the appropriate forum for such an effort.

TURN believes that the procurement Rulebook created by SCE is a very useful tool for the Commission, the utilities, and the parties active in procurement matters. The development of modified versions for PG&E and SDG&E would be a worthwhile endeavor. However, TURN submits that the rulebook should remain a reference tool, and should not supersede or otherwise supplant the underlying Commission decisions and resolutions upon which the rulebook is based.

4.2.2. Discussion

The Scoping Memo directed the IOUs to reflect in their 2006 long-term procurement plans all of the procurement-related decisions made by the Commission to date in all other procurement-related dockets. Volume 3 of SCE's LTPP represents the most thorough attempt at fulfilling this directive. For the most part, it is a clear, comprehensive reflection of Commission-approved procurement policy. In its present form, however, SCE's Rulebook cannot be adopted by this Commission. Both ED and Commission legal staff have determined that prior to adoption, SCE's proposed rulebook would need to undergo a number of modifications to (1) correct substantive errors; (2) refine

language; and (3) be reformatted to apply to all IOUs. We discuss each category of modification in turn below.

ED and Commission legal staff conducted an initial comparison of the Rulebook with several Commission decisions, and several substantive errors were identified, including an oversimplification of the Commission's adoption of the GHG adder,[253] and a misrepresentation of whether to count reliability-must-run units toward resource adequacy requirements.[254] Staff did not have the resources to perform a more comprehensive comparison against all relevant Commission decisions, but the results of this initial comparison confirm that this exercise will be necessary prior to Commission adoption of the Rulebook as a tool that ensures compliance with all Commission rules and guidance.

ED's review also determined that SCE's Rulebook frequently deviates from the precise language selected by the Commission. Most deviations seem incidental and insubstantial. For example, whereas the Commission concluded, "In their month-ahead filings, LSEs should be required to incorporate adjustments to their year-ahead load forecasts to account for customer migration," SCE wrote, "LSEs must include load migration adjustments in their forecasts and in their monthly resource adequacy filings." For compliance purposes, such interpretations may get the message across to IOU employees,

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[253] SCE's Rule 3.A.1(b)(3) indicates the GHG adder is fixed at $8/ton, when in fact the annualized value, based on avoided cost, should rise to $10/ton beginning in 2007, according to D.05-04-024, COL 27, p. 29.

[254] According to SCE Rule 9.A.2, all RMR units should count toward Local and System RAR, but D.06-06-064, p. 47, states that Condition 1 RMR units should not count toward System RAR.

but they confound the Commission's plain meaning, and thus make a poor substitute for the original decision language.

Consequently, while we believe that the creation and adoption of a "Rulebook" (hereafter referred to as an "AB 57 Procurement Plan Implementation Manual," which more specifically identifies the purpose of the document) will be a useful tool for the Commission, our staff, the staff of the IOUs, and other market participants, we do not adopt SCE's Rulebook at this time. We do, however, direct ED staff to continue the work begun by SCE and work with the IOUs and other interested parties to create a Commission-endorsed "AB 57 Procurement Plan Implementation Manual" for each IOU.

The focus of this process should be to develop an AB 57 Procurement Plan Implementation Manual that contains the comprehensive set of procurement rules, including any IOU-specific requirements, (including an updating procedure) that can be accessed by all interested market participants to determine each IOU's compliance with its AB 57 Procurement Plan.

We envision that this process will answer many of the outstanding questions that have been raised by parties regarding this Implementation Manual, including what authority will the Manual have, how and by whom the Implementation Manual will be updated, etc., and will allow parties to evaluate and come to consensus on various implementation details proposed in the IOUs' 2006 LTPPs that are not ruled on in this decision. ED staff is directed to notice the service list with a proposed schedule for Implementation Manual development within 60 days of the date of this Decision.

4.3. Implementation of AB 1576 and Repowering

AB 1576,[255] codified as Section 454.6 of the Pub. Util. Code, gave the owners of aging power plants incentives to repower or replace the plants in lieu of retiring them by providing rate recovery for IOUs entering into contracts for electricity from replacement or repowered projects. Section 454.6 is silent as to implementation details for repowering projects, except to establish the criteria that a project must meet to be eligible for the rate treatment instituted by the legislation.

Mirant, LS Power, SCE, and TURN all submitted proposals in this proceeding for methodologies to implement AB 1576. Based on an ED workshop on repowering and retirements, interested parties formed a Working Group to synthesize one or more "consensus proposals" from the original individual proposals. While the Working Group made significant progress, it did not reach an agreement on all disputed issues. While several parties agreed to certain elements for implementing AB 1576, the agreement is still inchoate and not ripe for consideration by the Commission in this decision.

However, by reviewing the issues that were discussed and negotiated in the AB 1576 Working Group, we are aware of some of the parties' main concerns, which include: the extent to which AB 1576 projects should be afforded special consideration in the RFO process, and if so, how to weigh and evaluate that status; whether there should be a pre-certification process for eligible AB 1576 projects, and if so, what role would the ED play in the certification; how to facilitate the development of repowering and replacement projects meeting the

[255] AB 1576, (Stats. 2005, Ch. 374, Sec. 2. Effective January 1, 2006), codified in the Pub. Util. Code as Section 454.6.

statutory criteria; whether a utility must explain its decision to not select an AB 1576 project from a RFO; and whether potential transmission cost savings are captured in the existing RFO evaluation process.

Most important is the concern that all the benefits of AB 1576 projects are properly considered and evaluated in a RFO – including quantifiable economic benefits and non-quantifiable social and environmental benefits. Mirant urges the Commission to direct the utilities to select AB 1576 projects from their RFOs, unless there is a clear superior economic alternative. While we find Mirant's arguments cogent, because there is not sufficient consensus from the Working Group on the disputed issues, we will not make any new orders concerning the selection of AB 1576 projects from RFOs at this time. We do, however, repeat the direction we provided in D.04-12-048, at p. 145-6, that the IOUs are "…to consider the use of Brownfield sites first and take full advantage of their location before they consider building new generation on Greenfield sites. If IOUs decide not to use Brownfield, they must make a showing that justifies their decision."

To further clarify our directive from the 2004 LTPP decision, IOUs are to consider repowered or replacement options presented in a RFO (i.e., not strictly for UOG projects, as some IOU representatives indicated they had interpreted this directive in D.04-12-048) before they choose options developed on Greenfield sites, or make a showing that justifies their decision not to do so.

Interested parties are urged to continue meeting and negotiating on AB 1576 related issues, and further Commission action on the topic will be deferred for consideration in the 2008 LTPP proceeding.

4.4. Implementation of AB 32 and GHG Issues

On June 1, 2005, Governor Schwarzenegger signed Executive Order S-3-05 thereby establishing California's leadership in and commitment to reducing the

negative impacts of climate change. The Executive Order establishes GHG emission targets that call for a reduction of GHG emissions to 2000 levels by 2010; to 1990 levels by 2020; and to 80% below 1990 levels by 2050. The Executive Order also directs California Environmental Protection Agency to lead a multi-agency Climate Action Team to conduct an analysis of the impacts of climate change on California and to develop strategies to achieve the targets and mitigation and adaptation plans for the State. Since that time, these orders have been further refined through the passage of AB 32, which requires the California Air Resources Board (CARB) to promulgate regulations to reach the 2020 goal of reducing total GHG emissions to1990 levels.

As stated in EAP II:

> "Climate change is the most serious threat to our environmental future, and demands immediate action. Its symptoms are already evident in California… Increasing energy efficiency, demand response, and renewable resources to the maximum extent possible in California and the western region will further reduce our contribution to climate change."

The Commission has been strongly committed to pursuing a path toward reduced GHG emissions, and the IOUs received their first request to consider the implications of various GHG scenarios in their LTPPs in proceeding R.04-04-003. In their 2004 LTPPs, the IOUs offered a range of responses; however, none provided the profile requested, as they were all moving through the Climate Action Registry's inventory and auditing process.

Although a policy for the reduction of GHGs was not in place at the time of the 2004 LTPP decision (D.04-12-048), the Commission recognized the importance of beginning to plan for the possible effects of a GHG cap. As stated in that decision, "…it is appropriate for us to consider policies that would limit the exposure of IOU ratepayers to risks associated with this future regulation. California, and in particular this Commission, along with the CEC and CPA, has given clear signals of its intent to be the pacesetters in this arena and take positive steps in seeing action on this front."

D.04-12-048 further directed IOUs to employ a GHG adder when evaluating fossil and renewable bids received via an all-source RFO. Consistent with established Commission policy and the positions of several parties, we adopted a range of values to explicitly account for the financial risk associated with GHG emissions of $8 to $25 per ton of CO_2, to be used in the evaluation of fossil generation bids.

In the current proceeding, R.06-02-013, the Commission's Scoping Memo provided guidance to the IOUs on the Commission's expectations for inclusion of the impacts of GHG reduction in the 2006 LTPPs. The Commission indicated that the 2006 LTPPs should include the key planning decisions that the utilities would need to make in the next few years in order to ensure that the Commission's energy policy objectives would be maintained and pursued in the future, including reducing GHG emissions to 1990 levels by 2020. This involved including GHG forecasts as part of ten-year resource plans, indicating the methodology and assumptions used in making GHG calculations and ensuring that the LTPP comports with the direction given in AB 32 and SB 1368.

A further modification by the ALJ said that the briefings were to include "planning uncertainty associated with the rules for implementation of AB 32." Also, the Commission is committed to moving procurement decisions further out into the future to "avoid just-in-time procurement activity" and increasing "attention to greenhouse gas forecasts and carbon constraints in the LTPPs."

4.4.1. Parties' Positions

PG&E asserts that their Increased Reliability and Preferred Resources Plan have slightly lower CO_2 emissions than the other two alternative plans at the end of the planning horizon. However, long-term changes in load and resources which are represented in the scenarios increase emission volumes by 15% to 25%, depending on the scenario or plan. Hydro swings contribute to volatility in CO_2 emission in a given year.[256]

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[256] PG&E estimated CO_2 emissions generated by its portfolio under each plan and scenario combination. Forecasts were calculated by adding the CO_2 emissions associated with the amount of natural gas used for PG&E's existing resources, the CO_2

Footnote continued on next page

PG&E claims that the attribution of an emissions rate to unspecified resources remains unclear, thus it is unknown whether system purchases done on an aggregate or regional basis will pass the EPS or not. PG&E has long-term system contracts among its DWR contracts that will expire during the 2006 LTPP.

PG&E argues that although the actual ramifications of AB 32 are as of now unclear due to regulatory uncertainties, PG&E is committed to maintaining a portfolio emissions rate that is among the lowest in the nation through pursuit of DR, EE and renewable generation.

PG&E acknowledges that its recommended plan may require significant revision and updating in the future to reflect the impacts and requirements of AB 32 and other GHG emissions reduction legislation in the next few years; however, PG&E feels that its recommended plan attempts as practicably as possible to anticipate, consider and incorporate the results and priorities of AB 32. PG&E states that it will inform the Commission and revise its procurement plan as appropriate to reflect the actual requirements of AB 32.

From PG&E's perspective, the Commission should consider focusing on one GHG reduction goal consistent with state policy, rather than creating further separate targets in renewables, DG, solar roofs, DR, repowering or EE. Increased flexibility in choosing among a suite of GHG reducing tools should result in

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emissions estimate for fossil-fuel burning QFs, and the CO_2 emissions estimate for other market purchases of electricity and for new natural gas burning generic resources needed to cover the open position. Two metrics were presented for measuring the performance of its procurement plans: (1) average annual metric tons per year of CO_2 emissions from each plan under different scenarios; and (2) average carbon efficiency in pounds per megawatt-hour of load plus avoided load associated with CEE and DG included in the plan.

reaching policy objectives at a much lower cost than if specific targets are created in several programs.

SCE, however, contends that the main impact of applying a GHG Emissions Performance Standard (EPS) to contracts greater than five years will be a continued and higher reliance on natural gas because the EPS eliminates new coal contracts. SCE feels that this will result in higher utility prices for customers.[257]

SCE acknowledges that R.06-04-009 is addressing the implementation of an "Interim Emissions Performance Standard Program Framework," and at such time that a decision is in place, SCE will have a better understanding of how the EPS will affect procurement practices and may need to update its Procurement Plan or other testimony.

SDG&E presents its estimated total (metric tons/year) and rate (tons/GWh) of GHG emissions in its LTPP. They acknowledge that the amounts are estimates since the Commission has not yet developed official measurement and reporting protocols for all types of generation sources; however, overall

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[257] SCE, for each candidate plan, measured the total portfolio emissions of CO_2, which was used as a proxy for the overall GHG emissions of the portfolio. To measure environmental sensitivity, SCE did a stochastic analysis of total emission production over the ten-year planning horizon for the Required Plan and the Best Estimate Plan at the expected level (stochastic average), using a set of input assumptions for emission rates for current and future resources. SCE's calculations show that the Required Plan yields an emissions rate that is 9% lower than the Best Estimate Plan, which SCE feels is a close comparison between plans. SCE also feels that the emissions rate found in the Required Plan would come at a considerable cost to customers due mainly to the new transmission infrastructure needed to deliver additional renewable power. SCE feels that there are much more cost effective GHG offsets including coal-mine methane flaring, landfill methane flaring, SF6 leak management, anaerobic digestion and forestation projects.

GHG emissions decline over the procurement period. SDG&E estimates that its emissions will drop by 1 $MMTCO_2E$[258] over the planning period.[259]

SDG&E urges the Commission to use a flexible compliance mechanism to meet GHG targets and to take a leadership role in the creation of international trading mechanisms. SDG&E also recommends that the Commission work with sister agencies in implementing the State GHG policy. The utility sector should not be required to undertake mitigation (and impose the associated costs upon customers) that is disproportionate to the energy sector's contribution to the State's GHG emissions. If the utility reduces more than its proportionate share, it should be allowed to sell excess GHG reductions to those entities that cannot

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[258] Measurement is changed from SDG&E's original plan filing to correct a typographical error.

[259] SDG&E makes the following assumptions to determine its GHG emissions:

1) All renewable resources, including wind, solar, bio-mass, bio-gas and geothermal were assigned no GHG emissions. Nuclear was also assigned no emissions.
2) Natural gas fueled emissions were determined based on fuel usage at a rate of 117 lbs/MMbtu.
3) Coal emissions (one existing contract) were based on fuel usage and were assigned an emissions rate of 205 lbs/MMbtu.
4) QFs were assigned an emissions rate of 639 lbs/MWh. (Most contracts are combined heat and power).
5) For the three DWR contracts, SDG&E assumed an emissions rate of 915 lbs/MWh.
6) The LTPP assumes that SDG&E will periodically make economy energy purchases from the market. For this plan, SDG&E assumes that all energy is purchased from the market, rather than from direct suppliers, and assigns an emissions rate of 915 lbs/MWh.
7) For SDG&E economic sales, SDG&E deducted from its total emissions the amount of emissions associated with those sales at the same rate as purchases (915 lbs/MWh).

meet their reduction obligations through technological fixes applied within their industry. This would allow ratepayers to be compensated for over-compliance and may incent IOUs to do as much as possible to realize ratepayer value from such efforts.

Aglet recommends that the GHG adder that is currently required to be included in contracts over five years in duration (D.04-12-048) should be applied to contracts of more than one year in duration. Aglet believes that the adder has a positive effect on IOU procurement activities through the selection of efficient plants with low GHG emissions.

AReM believes that SCE's concerns about high compliance costs would be better addressed by flexible compliance and market-based solutions (e.g., GHG credit trading), as recommended by SDG&E. AReM also recommends that the Commission reject SCE's proposal to use the CAM adopted in D.06-07-029 to recover from all customers the costs of new generation resources that are procured to meet GHG emissions reduction requirements. AReM states that GHG limits are not a requirement to procure new resources, rather they are a mandate to reduce GHG- a mandate that all LSEs must meet. Since all LSEs will bear their own compliance costs, it would be unfair to allow the IOUs to spread such costs to DA customers as that would require those customers to pay twice for GHG compliance- once to their ESP, and a second time to their local IOU.

DRA urges the Commission to direct the utilities to present a probabilistic analysis of the carbon impact of their plans incorporating the $8 per ton price adder that represents the "avoided cost value" of carbon in new physical resources. DRA believes that without such analyses, the long-term plans leave a significant cost volatility associated with GHG unanalyzed, thereby introducing an unknown amount of unqualified price risk into the proposed LTPPs. DRA

mentions that the IOUs have undergone similar analyses for other factors in the LTPPs (i.e., managing market price volatility risk, hydro availability risk, etc.) in order to place the utility in a position to meet the CRT expectations as measured by the TeVaR; therefore, there is no reason they should not do the same for the GHG impact. DRA's proposed probabilistic analyses would refine the $8 per ton adder rather than replace it. They suggest a low, middle and high projection developed using a Delphi methodology or other nominal group process. DRA believes that a probabilistic analysis of future carbon risk would capture the uncertainties surrounding the future development of carbon policies in California and around the world better than the $8 per ton single price model. DRA notes that all other types of future risk hedging in the LTPP are done with probabilistic projections rather than a single price trajectory.

CEERT recommends that the Commission find that the IOUs 2006 LTPPs do not comply with the GHG emission reductions mandated in AB 32 nor do they plan for "uncertainties" in AB 32 GHG regulations. While utilities were mandated to plan for uncertainties associated with the implementation of AB 32, CEERT believes that Commission policy also mandates that the IOUs submit LTPPs that are on course for reducing GHG emissions. CEERT argues that the IOUs did not effectively demonstrate how and to what extent the IOUs will achieve California's mandated GHG emissions reductions. The three IOUs, while acknowledging Commission and legislative actions, state that there is too much regulatory uncertainty to plan or account for GHG emissions reductions in the LTPPs.

In D.04-12-048, the Commission adopted an NRDC proposal to require the IOUs to "develop and implement a comprehensive GHG reduction plan in their (2006) LTPPs, which include "resource scenarios" that allow comparison

between existing and expected GHG emissions characteristics of the utilities' portfolios with and without the new resource additions proposed in the procurement plans. D.06-02-032 directed the IOUs to establish a baseline for the GHG emissions cap on a historical basis, with 1990 as the preferred referenced year. For the 2006 LTPPs, IOUs were directed to include information about existing GHG emissions profiles and future GHG emissions of their procurement plans.

CEERT initially recommended that the Commission order the current LTPPs be amended to reflect the changes in resource planning that will be required to achieve AB 32 goals and mandates. Given tight deadlines and the fact that GHG implementation rules will be developed in Phase II of the GHG proceeding (R.06-04-009), CEERT recommends that the Commission provides instructions to the IOUs in the 2006 LTPP decision as to the planning approach to be used by the IOUs in their 2008 LTPPs to ensure AB 32 compliance for the 2009-2019 planning period.

CEERT, along with DRA, believes that given the compressed time between approval of final 2006 LTPPs and IOU filing of 2008 LTPPs, the Commission should limit the approval of procurements in this cycle to those that must be initiated prior to the next LTPP cycle, so that "policymaking development… can inform the next LTPP proceeding" regardless of "planning uncertainties" If IOUs wait until a final AB 32 GHG emissions cap is in place to even begin planning for changes, there will not be enough time left to meet AB 32 GHG reduction goals.

CEERT believes that a key method for reducing GHG emissions is to actively plan for and meet the 33% renewables target for 2020, and that these mandates, while separate, are inextricably linked. CEERT also believes that

express direction should be included in the 2008 LTPPs to analyze scenarios that focus on GHG emissions reduction.

CEERT suggests that the Commission should direct the IOUs to analyze and include into their 2008 LTPPs three basic supply scenarios that can be expected to achieve AB 32 goals and targets to be established by the Commission and/or CARB (using portfolio analysis). These scenarios meet the goals of (1) providing projections on the flexibility allowed in meeting targets, and (2) producing an energy resource mix that results in emissions at or below required levels and includes realistic assessments of generation projected to be procured from existing, commercially available technologies:

- A least-cost scenario that increases renewable energy content on a trajectory that could reasonably be expected to result in increasing the utility's renewable energy content to 33% by 2020.

- A least-cost scenario that reduced GHG emissions on a trajectory that could reasonably be expected to reduce the utility's GHG emissions to the utility's 1990 levels by the year 2020.

- A least-cost scenario that reduces GHG emissions on a trajectory that could reasonably be expected to reduce the utility's GHG emissions to 90% of the utility's 1990 levels by the year 2020.

GPI contends that an important question that must be asked is whether the limitation of greenhouse gasses through a strong incentive mechanism consistent with AB 32 can be used to achieve all of the preferred procurement goals simultaneously (i.e., EE, RPS). GPI feels that using GHG reduction as a unifying theme of procurement policy would help to ensure that all utilities control their costs to consumers while pursuing an overall program of preferred procurement;

however, they recognize that more research is needed into the subject. Until such time as further research is conducted, GPI recommends that the Commission continue to pursue its established preferred resource programs (EE, renewables, etc.) while developing an overall program of GHG limitation.

In response to the IOUs' arguments that a GHG program should not distort the electricity market, GPI states that the essential purpose of AB 32 is to change the state's electricity markets in fundamental ways. It is necessary for the IOUs to expand the bundle criteria by which they judge the efficiency of resource choices to include considerations of carbon content in addition to the traditional considerations of cost and logistic factors. IOUs should take carbon intensity into account as an essential component of the decision matrix used to select resources.

NRDC wants the Commission to require SCE to include in its LTPP its current and forecasted *absolute* GHG emissions under various scenarios stating that SCE failed to do so in its initial filing. SCE presents a forecast of GHG emission rates on a pound per MWh basis instead of presenting current and forecasted GHG emissions. NRDC states that while SCE presents a forecast of declining emissions rates, there is no information about whether absolute emissions will increase or decrease over the 10-year period. NRDC feels that it is impossible to adequately evaluate SCE's plan given this methodology.

NRDC also suggests that the Commission should require the IOUs to utilize portfolio analysis in developing their 2008 LTPPs stating that such methodology allows the IOU to assess potential changes to a portfolio's risks and costs brought about by adding assets that have their own individual risk and cost profiles. At a minimum, the Commission should require the IOUs to

provide detailed information about resource types planned for and the emissions characteristics of the preferred plan compared to other resource scenarios.

NRDC claims that the Commission needs detailed information about planned resource fuel and technology types in order to determine whether the IOUs' emissions trajectory will meet the goals of AB 32. Such planning allows the Commission to answer the following questions: If the path outlined is pursued, what will California's fuel mix be in 10 years? Will it be adequately diverse? What will be the overall cost to customers? What risks will customers face? Will the environmental impacts associated with the electricity industry increase or decrease?

WEM recommends that the Commission not approve any 2006 LTPP that does not make some adjustment for or accommodation to AB 32. WEM notes that PG&E's preferred procurement plan, despite having lower emissions than the other submitted, would result in 15% to 25% more GHG emissions in 2016 than in 2006. WEM states that Scenario 4, which is PG&E's basis for the 2,300 MW resource request, has the least reduction in GHG emissions. In fact, WEM feels that PG&E's assertion that all plans would result in reduced GHG emissions is false; Scenario 2 and Scenario 4 result in increased emissions. WEM is especially concerned that PG&E's 2,300 MW resource request will be primarily powered by natural gas. WEM is also concerned that in the future, this natural gas may be supplied in part by liquefied natural gas (LNG), a fuel that has large upstream GHG emissions that overwhelm the claimed reductions in emissions. In particular, the claimed reductions in the Preferred Plan under Scenario 4 and the Basic and Increased Reliability Plans under Scenario 3 are so slim that introducing LNG could result in significant increases in GHG.

IEP states that the Commission should affirm during the transitional period when information needed to estimate future costs is unavailable, GHG regulations are covered by the PPA's change in law or *force majeure* provisions, and that costs that the supplier reasonably incurs in purchasing necessary GHG allowances or otherwise complying with future GHG regulations are appropriately passed through to ratepayers.

4.4.2. Discussion

The Commission indicated that the 2006 LTPPs should include the key planning decisions that the utilities would need to make in the next few years in order to ensure that the Commission's energy policy objectives would be maintained and pursued in the future, including reducing GHG emissions to 1990 levels by 2020. Furthermore, this proceeding directed the IOUs to include GHG forecasts as part of their 10-year resource plans and to specify which methodology and assumptions they used to make their GHG calculations. In addition to evaluating their plans for minimizing environmental impacts, the IOUs were explicitly directed to weigh the ratepayer costs and reliability impact of each proposed plan.

We find that all three LTPPs could have been strengthened by building into their calculations of future need for electric resources a methodology for analyzing the GHG implications of the different resources the IOUs can utilize to fill that net short position. While the implementation details are still under consideration in R.06-04-009, it appears improbable that the IOUs can reduce their carbon emissions from electric generation resources back to 1990 levels without a focused reliance on preferred resources. We share the concern raised by many Intervenors that the IOUs are filling, and are projecting to fill, their respective net short positions with conventional base-load resources so that

either there is no room in an IOUs' portfolio for other resources, or the conventional resources will be obsolete and result in large stranded costs. We agree with CEERT that while utilities were mandated to plan for uncertainties associated with the implementation of AB 32, Commission policy also mandates that the IOUs submit LTPPs that are on course for reducing GHG emissions.

The IOUs did not fully comply with the Scoping Memo's requirements to account for AB 32 in their procurement plans. All IOUs offered emissions projections, and PG&E evaluated ratepayer cost versus reliability; however, the plans could have been strengthened by undertaking a vigorous analysis of the potential procurement impacts of operating in a GHG-constrained landscape. While it is true that many of the major decisions have not yet been made regarding the elements of the GHG cap, the utilities should be actively engaged in projecting absolute emissions for various procurement scenarios, estimating the costs of those plans for various GHG allowance prices, and making procurement decisions based on these assessments. Regardless of the ultimate specifics of the GHG cap, it is apparent that to help the State reach 1990 GHG emission levels, the IOUs will need to "raise the bar" on their loading order procurement when filling net short positions. Procurement of zero- or low-GHG resources should be given preference over other resources since these are the types of resources that AB 32 regulations will favor. Also, as discussed in the need determination section of this decision, we will require the IOUs to provide ED and the PRG with a description of the resources they are soliciting based on the procurement authority granted in this decision and how these resources support its transition to a GHG-constrained portfolio.

To further flesh out IOU plans for GHG reductions, we will provide directions in upcoming LTPP proceedings concerning the development of a

consistent evaluation of the costs and risks of GHG-reduction to be included in the subsequent LTPPs. These analyses will be based on the recommendations provided by CEERT in this proceeding, modified based on the results of Phase II of D.06-04-009.

The Commission agrees with NRDC that the analyses presented by the IOUs should be detailed enough to enable adequate analysis of fuel mix under various scenarios, overall cost to customers, risks faced by customers and environmental impact. When building the requirements for the future LTPPs, we will consider DRA's recommendation that IOUs employ a probabilistic analysis of the carbon impact of their plans in order to ensure that the significant cost volatility associated with GHG is thoroughly analyzed. We anticipate that Phase II of D.06-04-009 will provide guidance on an appropriate range of costs for this evaluation.

We agree with SCE that plans may require modifications based upon the outcome of D.06-04-009, but as stated earlier, this is not a sufficient reason to delay fully planning for GHG reductions. We support GPI's assertion that the essential purpose of AB 32 is to change the state's electricity markets in fundamental ways. IOUs should take carbon intensity into account as an essential component of the decision matrix used to select resources.

We acknowledge that the IOUs did provide an estimate of overall GHG emissions for the 2006 planning horizon; however, a great deal of inconsistency existed between plans on forecasting methodology employed. To provide clarity going forward, the Commission adopts NRDC's suggestion that all three IOUs be required to provide absolute GHG emissions under various scenarios. In order to accurately measure overall emissions of proposed LTPPs, absolute

emissions are necessary along with cost implications of those emission levels at various price points for CO_2 allowances.

PG&E and SDG&E request that the Commission allow for maximum flexibility for compliance with AB 32 by using GHG reduction goals as an overarching state policy superseding all existing EE, RPS and DG requirements. GPI supports this approach but acknowledges that until such time as enough research is conducted into the subject, the Commission should continue to follow the current trajectory. While procedures may change in the future, for now, existing legislation mandates compliance with these programs and we will continue to operate under these guidelines. Thus, IOUs are responsible for meeting the goals of each respective State mandated energy program. It goes without saying, though that the actions mandated by each of these programs will assist the IOUs in meeting their GHG requirements. The scenario analyses the IOUs develop need to ascertain what mix of procurement choices beyond these mandated actions will maximize GHG reductions at the least cost to ratepayers.

We acknowledge SDG&E's concern that the electricity industry should not be made to overcompensate for other sectors in meeting AB 32 goals or should be duly compensated for doing so. This is a matter that requires further research and analysis; however, it is best addressed in the GHG proceeding and is out of the scope of this proceeding. We further acknowledge SDG&E's request that the Commission take a leadership role in the creation of international trading mechanisms, and this idea is also best addressed in the GHG proceeding.

Regarding SCE's concern about the considerable cost of new renewable sources that is attributed to transmission, we agree that sufficient transmission is of the utmost importance to the development of renewable energy. The State of California is addressing this issue through renewable energy transmission

planning, and it is therefore out of the scope of this proceeding. We also acknowledge IEP's suggestion that the costs that the supplier reasonably incurs in purchasing necessary GHG allowances or otherwise complying with future GHG regulations are appropriately passed through to the ratepayer; however, we believe that at this time it is premature to make such a ruling without regulatory certainty. This issue is more appropriately addressed within the GHG proceeding.

Finally, we agree with AReM that each LSE will be responsible for meeting the ultimate GHG compliance requirements, and the CAM developed in D.06-07-029 for system reliability should not be utilized to pass along any costs associated with achieving reductions on behalf of the IOUs' bundled customers to other non-bundled customers. However, to the extent that an IOU procures a resource for system reliability that is also consistent with the direction of state GHG policy, this cost is certainly recoverable from all benefiting customers through the CAM.

4.5. The 33% Renewables Target

California has taken a progressive and forward-thinking approach toward the achievement of reduced greenhouse gas emissions and increased renewable energy procurement. The Scoping Memo in this proceeding directed the IOUs to describe how the EAP II goal of 33% renewables by 2020 will be achieved. In particular, Key Action # 5 of EAP II requires that IOU's "evaluate and develop implementation paths for achieving renewable resource goals beyond 2010, including 33% renewables by 2020, in light of cost-benefit and risk analysis, for all load serving entities." D.04-12-048 FOF #55 further supports a 33% renewable stretch target: "We find that RPS targets are a floor—not a ceiling. The EAP loading order places renewables above conventional generation."

4.5.1. Parties' Positions

PG&E believes that the Commission should not at this time establish goals beyond 20%. PG&E states that further analysis and study of policy goals, feasibility, and cost impacts is necessary before the current 20% RPS goal is exceeded. PG&E suggests that the Commission should consider combining the GHG reduction and renewable achievement objective goals by setting a GHG reduction goal and allowing the IOUs flexibility in how that goal is achieved. Furthermore, PG&E recommends that the Commission should explore incentives as a more effective mechanism through which to achieve expanded RPS goals. PG&E also suggests that the Commission should work with the CEC and IOUs to explore the operational feasibility of any goal beyond 20%.[260]

PG&E further requests that the Commission approve its proposal for an Emerging Renewable Resources Program or "ERRP." PG&E states that ERRP is a funding mechanism through which PG&E can assist in the demonstration of the commercial viability of emerging renewable resources beyond its 20% RPS goal. PG&E requests that the ERRP initially be authorized as a two-year program with a maximum budget of $30 million subject to balancing account recovery.[261]

SCE states that SB 107 specifically left intact existing law which prohibits the Commission from requiring an LSE to procure additional renewable resources in a year following a year in which the LSE achieves the 20% standard.

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[260] PG&E Volume II at I-15.

[261] The May 2, 2007 R.06-02-013 ruling determined that PG&E's ERRP proposal would be more appropriately submitted as a separate application. PG&E and SDG&E subsequently filed a joint application, A.07-07-015.

Footnote continued on next page

Thus, increasing the level of procurement beyond 20% to 33% would require additional legislation.[262]

SCE contends that reaching 33% renewables is potentially feasible provided that sufficient transmission exists to accommodate this build out of resources. However, SCE notes that both transmission and the increasing price of renewable energy could render a 33% goal extremely costly.[263] For the scenarios provided, SCE has assumed that adequate transmission and SEP funding[264] will exist to achieve the 33% goal. SCE does not assume that renewable procurement will increase by a fixed amount each year, citing transmission access as a possible hindrance.[265] SCE demonstrates plans to reach 33% renewables in each of the SCE and CEC load forecast scenarios; however, SCE acknowledges that many uncertainties could potentially hamper the viability of this forecast, including: potential fluctuations in load growth due to customer migration; potential fluctuations in renewable output resulting from resource depletion and contract attrition at levels higher than 10% attrition rate assumed for the 33% scenario; delays in obtaining State or local transmission permits; missed milestones by project developers; and other unanticipated causes.[266] SCE notes that, to meet a goal of 33% renewables by 2020, SCE would

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[262] SCE Volume 1B at 74.

[263] SCE Volume 1B at 80.

[264] We note that SB 1036, effective January 1, 2008, abolishes the current SEP process and redistributes PGC money among the large utilities.

[265] SCE Volume 1B at 81.

[266] SCE Volume 1B at 86.

most likely have to pursue contracts with less economic projects that it would otherwise not consider.[267]

SDG&E supports the Commission's goals expressed in Energy Action Plan II, and that its efforts to reduce GHG emissions include voluntarily expanding its renewable procurement beyond the mandatory 20%. SDG&E states that it plans to increase its renewables beyond 20% in its current LTPP, but the lumpiness of major resource additions makes it difficult to predict exact renewable addition trajectories year over year.[268] SDG&E notes that actual procurement as well as SDG&E's possible use of RECs during the course of the plan will likely result in a different resource mix than the one projected. SDG&E argues that whether it is able to achieve a 20% resource mix by 2010, or greater in future years, will depend in part on how contracted resources perform, whether sufficient renewables will be available for purchase by SDG&E, whether SDG&E can procure and count unbundled RECs towards its renewable requirements and whether additional transmission will become available to allow SDG&E to import renewable energy and capacity from outside its service area. SDG&E states that lack of transmission is a major impediment to achieving 20% by 2010 and higher percentages in future years.[269]

Aglet recommends that the Commission establish a policy goal of 33% renewables by 2020, consistent with EAP II. Aglet argues that until enabling legislation is passed, the IOUs should volunteer to make a good faith effort to

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[267] SCE Volume 1B at 88.

[268] SDG&E Volume 1 at 191.

[269] SDG&E Volume 1 at 192.

reach a goal of 33% renewables by 2020. The Commission should also take action to ensure that the utilities are able to meet the 33% goal. Thus, the Commission cannot require IOUs to meet a 33% renewable goal by 2020 without enabling legislation, but it can establish a policy goal of 33% renewables in this proceeding.[270]

AReM is concerned that the goal of 33% renewable energy sales will not be easy, if it is even feasible. AReM therefore supports SDG&E's recommendation that the Commission move as expeditiously as possible to approve the use of fully unbundled, tradable RECs for RPS compliance.[271]

DRA finds that none of the three IOUs provide a plan to continue increasing their renewable percentages after 2010 at a rate which would reach 33% renewables by 2020. This lack of planning does not comply with the State's renewable energy goals as directed by the Commission's EAP II, and it appears to be inconsistent with estimated renewable energy levels that will be required to meet the State's GHG cap as required by AB 32. DRA argues that none of the three IOUs appear to be giving serious consideration to constructing their own future renewable energy sources, although they have constructed and planned natural gas fueled combined cycle and peaking plants.

DRA recommends that the Commission require the IOUs to plan to meet the State's renewable energy goals as directed by the Commission's EAP II and be consistent with the estimated renewable energy levels required to meet the

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[270] Aglet Testimony.

[271] AReM Testimony.

AB32 GHG cap by requiring the IOUs to adjust their plans to continue to move toward the 33% renewable energy by 2020 goal.[272]

CEERT argues that effective planning by the IOUs to meet the 33% by 2020 target will play a central role in also achieving GHG emissions reductions. CEERT states that the IOUs have largely ignored the direction of the Commission to address the attainment of a 33% renewables target by 2020.[273]

GPI is concerned that PG&E and SCE oppose instituting the 33% renewables by 2020 goal, though it is an important component of the Governor's energy policy and embraced by EAP II. GPI has long argued that the only compelling rationale for accelerating the State's 20% RPS target deadline from 2017 to 2010 is so that the accelerated goal can be backed up by a higher, longer-term goal for renewables. Otherwise, the policy would result in a quick burst of development activity in the state's renewable energy sector, followed by an abrupt halt. These are not conditions conducive to the development of a stable, sustainable renewable energy industry in the state. Moreover, GPI suggests that the long lead time associated with the 33% goal and the head-start provided by the original 20% goal will actually make it easier for LSEs to reach the 33% by 2020 standard than it will have been to reach the 20% by 2010 goal.

GPI states that PG&E and SCE both argue in their LTPPs that California is experiencing shortages of renewables, which, if true, would put the 33% by 2020 stretch standard seriously in doubt. PG&E's LTPP argues that the pool of reasonably priced renewables is already being depleted. GPI strongly disagrees

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[272] DRA Testimony.

[273] CEERT Testimony.

with the assertion that California is experiencing renewable resource shortages at this early stage of the RPS program. Considering the minimal amount of new renewables development that has actually occurred in California since the enactment of the RPS program, asserting that the pool of renewables is already being depleted is equivalent to saying that the pool was nearly empty from the start.

GPI states that PG&E argues that the coming AB 32 GHG reduction program will provide all of the incentive that the utilities need to continue procuring renewables beyond the mandated twenty percent level, while providing more flexibility in reducing GHGs than is provided by a structured set of specific program mandates (renewables, efficiency, etc.). However, AB 32 rules will not be finalized for several years into the future. Renewable energy generation is a highly capital-intensive enterprise, and in order to sustain a flow of investment capital into the renewable energy sector in California pending the maturation of the AB 32 program, a long-term stretch goal for renewables is highly desirable. Long-term market uncertainty is a major impediment to attracting investment capital. Failure to follow a trajectory towards the 33% stretch goal will jeopardize the ability of the utilities to meet the AB 32 standards throughout the course of the 10-year LTPP planning horizon.

GPI finds that SCE's "Required" plan, which is the plan designed to achieve 33% renewables by 2020, foresees a large amount of biomass development in the out years of the LTPP planning horizon, because carrying a 33% level of renewables in their system would require the stabilizing influence of the additional biomass generators. There is, however, no indication offered about where this biomass will come from, or how. A few pages prior to the above mentioned passage, SCE notes that there is an insufficient amount of

biomass resources, either under existing contracts or planned pursuant to the 2003, 2005 and 2006 RPS solicitations, to achieve 20% of the overall ERR portfolio from biomass resources at any time during the planning period. In GPI's opinion, the most important unresolved issue for future biomass development is less one of transmission availability than it is one of resource availability and cost.

NRDC states that PG&E sets a proxy annual renewable procurement target in its preferred plan, the Increased Reliability and Preferred Resource Plan, of 25% in 2016. No analysis is provided as to whether this will put PG&E on track to achieving 33% renewables by 2020, as is required by the Scoping Memo. PG&E only states that it "believes any specific expanded targets, beyond the 20% goal, would be premature until policy goals concerning GHG emissions standards are clarified and a detailed feasibility analysis can be conducted."[274]

The CEC contends that three of PG&E's four scenarios assume renewable energy procurement at levels below the trajectory that would hit the 33% by 2020 target; only in Scenario 4 was this path realized.[275] The CEC argues that SDG&E does not evaluate nor develop a plan to put it on a path to 33% renewables by 2020.[276] SDG&E does not explain why its preferred plan does not achieve 33% by 2020 nor does it demonstrate what would need to change to achieve the target. Thus, SDG&E did not comply with the Scoping Memo's direction to demonstrate

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[274] PG&E Testimony.

[275] Based on a 2016 target of 28% and a capacity factor of 50%, the assumed shortfalls in 2016 ranged from 481 MW (Scenario 3) to 1,074 MW (Scenario 1).

[276] SDG&E's preferred plan yields 22% renewable deliveries in 2010, increasing to 25% in 2013, and declining to 21% in 2020.

how they were working towards achieving the 33% policy goal. While SDG&E's plan contemplates increases beyond 20% after 2010, its preferred approach is that future additions should be based on cost-effectiveness, resource fit, green house gas targets, and other factors.[277]

4.5.2. Discussion

The State of California is in a unique position to lead the nation in procuring renewable resources and achieving greenhouse gas reductions. Achievement of these aggressive goals, however, requires cooperation and a forward-thinking, innovative approach on the part of all parties involved. Increasing the amount of renewables is a clearly stated component of the Governor's energy policy and one that has been adopted by the CEC and the Commission through EAP II. The Commission recognizes SCE's argument that, today, no legislation has been passed mandating that the IOU procure towards a 33% renewables target by 2020. However, the Commission agrees with Aglet that pursuing a 33% target is a policy goal of the Commission and one that should be pursued by the IOUs at this time. We acknowledge GPI's argument that accelerating the 20% renewables target from 2017 to 2010 suggests that higher future levels of renewable energy procurement are a goal of the Commission.

The Scoping Memo clearly directs the IOUs to describe how the EAP II goal of 33% renewables by 2020 will be achieved. The Commission agrees with DRA that all three IOU's 2006 LTPPs provide insufficient information for the Commission to accurately assess how the IOUs will achieve a 33% renewables

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[277] CEC Testimony.

target by 2020. We acknowledge SDG&E's comment, however, that the time between issuance of the Scoping Memo and delivery of plans was quite short, and we expect that future LTPP schedules will better accommodate the IOUs' ability to more fully reflect on these issues.

We do not believe that a GHG target should be the single overarching policy goal, with utilities allowed full flexibility regarding their use of renewable resources to achieve that goal. While reduction of GHG emissions is clearly one of the key drivers for increasing the RPS goal, the RPS program was established in recognition of several other benefits to renewable energy development, as well. We agree with PG&E, however, that further analysis is needed regarding the feasibility and cost of a 33% renewables target. We direct parties to work with ED staff to refine a methodology for resource planning and analysis that will allow them to adequately address the issue of a 33% renewables target by 2020 in subsequent LTPPs.

The Commission recognizes that there are many challenges associated with achieving a 33% renewables target. SDG&E, backed by AReM, suggests that RECs may be a necessary component to achieving such targets. However, the consideration of RECs is out of the scope of this proceeding and is being addressed in R.06-02-012. The Commission further appreciates the IOUs' discussions of the need for transmission to reach the 33% goal. As noted in this decision's section on the 20% by 2010 goal, however, we found that these discussions did not include the detail, integrated approach, or forward-thinking suggested in the Scoping Memo. We expect these sections to be much more robust in subsequent LTPPs and expect that parties will work to make RETI useful in this regard.

4.6. Implementation of MRTU

In late 2001, the CAISO instituted a program of comprehensive market redesign called "MRTU" (Market Redesign and Technology Upgrade – formerly known as MD02) intended to enhance performance of the CAISO's core functions (reliable, nondiscriminatory transmission). This was to be effected, in part, by resolving congestion caused by the CAISO's zonal congestion management through the use of a Full Network Model (FNM), which the CAISO claims will accurately model the grid, and an Integrated Forward Market (IFM) based on Locational Marginal Pricing (LMP).

Under MRTU, there will be a day-ahead market, which will be an integrated CAISO market for energy and ancillary services, as well as congestion management, and, if necessary, Residual Unit Commitment (RUC); an hour-ahead scheduling process (HASP), which is an opportunity to make scheduling adjustments (but is not a full-settlement market); and a real-time imbalance market with optimized economic dispatch. The CAISO will also impose Market Power Mitigation measures, including a damage control bid cap and procedures to address local market power.

MRTU implementation is currently scheduled for March 31, 2008, although it is possible that implementation may be delayed. According to the CAISO, MRTU represents important, incremental improvements to the existing market design, improves price signals to allow for more efficient generation dispatch, and it does so in a way that protects customers, and should lower costs by increasing the efficiency of the CAISO's transmission grid operations.

Some of the most important elements of MRTU are to:

- fix market design flaws;

- eliminate infeasible schedules;
- use a more comprehensive model of the transmission grid;
- add a financially binding day-ahead market;
- adopt locational marginal pricing for suppliers and for improved congestion management;
- improve transmission rights;
- require compliance with the Long-Term Firm Transmission Rights Final Rule;
- increase bid caps incrementally;
- provide local market power mitigation; and
- build upon resource adequacy.

Precise procedures to be used by the CAISO and market participants to implement MRTU are proposed for the CAISO's Business Practices Manuals (BPM). At the time of this decision, some BPMs are still being developed and finalized. Therefore, the exact processes and procedures that market participants will need to comply with are, as of yet, unknown.

The Scoping memo directed the IOUs to describe the impact of MRTU implementation on procurement practices and procedures.

4.6.1. Parties' Positions

In comments, PG&E represents that the CAISO's "new and improved" markets will not significantly alter its procurement processes. However, PG&E does, based on current MRTU market designs, seek Commission approval to update the description of two existing authorized products to assure

compatibility with specific new aspects of MRTU. In particular, PG&E requests the following:

Proposed Modified Description	
Transaction	Description
Electricity Transmission Products	Purchase or sale of transmission rights, products (e.g., LT-FTRs, CRRs, losses), or the use of locational spreads.
Financial Swaps	An agreement to exchange one type of pricing for another. Examples include fixed-for-floating swaps, basis swaps, and payment obligation swaps (e.g., CAISO IFM Uplift Load Obligations). Swaps are financially settled directly with a counterparty or may be financially cleared through a financial clearing house.

PG&E explains that, under MRTU, the CAISO will assure bid cost recovery for suppliers selling into the CAISO markets; to the extent market revenues are insufficient to recover bid costs the CAISO will provide suppliers with uplift payments to guarantee bid cost recovery. The CAISO will in turn collect the uplift payments through cost allocations to Scheduling Coordinators ("SC").

PG&E further requests that the Commission modify the existing approved Electricity Transmission Product description, as provided for in D.02-10-062 and D.04-12-048, to clarify that this existing product is adequate to address transmission congestion and loss aspects of MRTU. The primary feature of the CAISO's proposed market redesign is an integrated market that involves the simultaneous optimization of energy and ancillary services procurement based

on LMP in a process that will also manage transmission congestion and transmission losses. PG&E states, in testimony, that MRTU will provide for the ability to hedge transmission losses through Long-Term Firm Transmission Rights (FTRs) and Congestion Revenue Rights (CRRs).[278] While similar hedging products for transmission losses do not exist at this time, these have been presented for consideration at the CAISO and may develop in the future. To address these MRTU market design features, PG&E requests a modification and clarification to the existing product description for Electricity Transmission Product.

With the above requested product modifications PG&E states that it will have sufficient Commission authority to participate in new transactions significant to the current CASIO scope of MRTU.

However, PG&E further requests Commission approval for new products that may be needed during the CAISO's finalization of MRTU which the CAISO considers mandatory for MRTU market participation. PG&E states that for the time being, it will identify these new products as "Non-Discretionary Products Required by MRTU."

[278] These products can be obtained through allocations and auctions from the CAISO and additionally through secondary bilateral trading.

	Product	Description(a)	Prior Authorization
28	Non-Discretionary Products Required by MRTU	MRTU Products, which may be created by the CAISO during the finalization of MRTU that would be mandatory in order to participate in MRTU.	New transaction requested in Volume 2, Section I.B.3 Impact of MRTU on Procurement Practices.

PG&E requests authority for "Non-Discretionary Products Required by MRTU" since there may be insufficient time to seek and obtain Commission approval through an advice letter filing between MRTU design finalization and MRTU market initiation. However, if there is adequate time for such a filing, PG&E will do so.

SDG&E claims that while MRTU will be a "sea change" for the CAISO's systems and operations, its impact on SDG&E procurement as outlined in its LTPP will be minimal. The changes in MRTU will be limited to the mechanics of scheduling and settlements. It will not significantly alter the major elements of its plan, such as SDG&E's positions or the manner in which SDG&E procures because IOUs are encouraged to procure most of their resources outside of spot markets. With the introduction of a CAISO day-ahead market (which would fall within the Commission definition of "spot" markets), SDG&E suggests that the Commission abandon the current guideline of "5% or justify" in the spot market.

SCE's testimony regarding the implementation of MRTU focuses on two main themes: (1) the way that LSEs meet their RA requirements,[279] and;

[279] SCE's testimony regarding this issue digresses into a discussion of centralized capacity markets. The ALJ, on May 2, 2007, ruled that this issue was currently being

Footnote continued on next page

(2) implementation of virtual bidding.[280] SCE argues that these two elements of the CAISO's new system will impact the way in which it conducts business with the CASIO markets, and thereby how it complies with Commission procurement policies and practices.

SCE asks for specific authority to modify its procurement plan to include virtual bidding once sufficient information regarding the details of virtual bidding rules have been established.

TURN believes that it is clear that the implementation of the CAISO's MRTU project will have dramatic impacts on the California electricity market. However, predicting exactly what those impacts will be is at best an uncertain endeavor. TURN believes that this Commission should continue to closely monitor the MRTU process and take appropriate positions on behalf of ratepayers in the CAISO stakeholder process.

4.6.2. Discussion

There is no doubt that MRTU will greatly impact the CAISO's markets. We note that this is precisely the point of this endeavor. As a result of the redesign effort there are a number of elements of MRTU that may impact the procurement practices or costs of the IOUs. As an example, the CAISO created

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addressed in R.05-12-013 and therefore is outside the scope of this proceeding. Therefore, we will not address it in this decision.

[280] "Virtual bidding" is a practice by which an entity can participate in the day-ahead and real-time markets without any physical generation or load. A virtual bid into the day-ahead market is coupled with an equal and opposite transaction in the real-time market. Thus, a virtual load bid in the day-ahead market, if successful, will result in an obligation to pay the awarded amount at the day-ahead price, and a corresponding right to be paid the same amount at the real-time price (in the case of a virtual load bid in the day-ahead market, the equal and opposite transaction is a virtual real-time sale).

CRRs to be financial obligations that can be utilized by market participants to hedge transmission congestion.[281] Other MRTU design elements will have additional impacts on the CAISO and market participants.[282]

Additional market design features are planned for implementation after the initial start of MRTU. The FERC has ordered the CAISO to develop scarcity pricing whereby prices for both reserves and energy would increase automatically as shortages increase. Scarcity pricing is intended by FERC to increase the participation of demand response, among other things. The CAISO must also incorporate Virtual Bidding (also referred to as Convergence Bidding); a process by which virtual supply can be sold and virtual demand purchased in the Day-Ahead market and subsequently settle as deviations in the real time market.[283]

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[281] We note that all three IOUs have sought Commission approval for the use of LT - CRRs in AL 2142 (SCE), AL 3095 (PG&E) and AL 1920 (SDG&E; and for CRRs in AL 2141 (SCE), AL 3106 (PG&E) and AL 4124 (SDG&E).

[282] For example, the CAISO intends to impose constraints in order to ensure that the required amounts of ancillary services are reasonably distributed across the system and, if system conditions merit, it may identify sub-regions within the CAISO Control Area to ensure appropriate distribution and effectiveness of the procured ancillary services. The CAISO is in the process of establishing the process to define the regions or regional targets.

[283] With Virtual Bidding, the actual price differences between the Day-Ahead market and real time market will determine if the holder makes or loses money. FERC has suggested that convergence bidding mitigates market power and provides other benefits. While convergence bidding does not create either real added supply or demand, these bids do contribute to the determination of market clearing prices. To the extent convergence bidding is implemented by the CAISO, it may be necessary and important for California's IOUs to participate and therefore, this Commission's procurement rules may need to be augmented.

Currently, it does not appear that MRTU will significantly impact the resource planning and the majority of the procurement processes that typically happen in time frames that begin a substantial length of time prior to the day-ahead and day-of focus of the MRTU market changes. However, what does occur in the MRTU time frame are the least-cost-dispatch processes and decisions carried out by the IOUs. In D.02-09-053, the Commission reiterated the importance and requirements to perform the scheduling and dispatch of utility portfolios in a least cost manner. In an attempt to comply with this Commission decision, the IOUs dispatch resources and utilize market purchases to manage the short-term needs of their portfolio. The CAISO's new day-ahead market represents one additional option along with the other existing bilateral exchanges, brokers and direct transactions in executing least-cost dispatch. All of these markets may legitimately be used. At this time, it does not appear that the MRTU spot market reforms and new market elements will significantly alter the results of the least-cost-dispatch process. However, we will closely monitor the implementation of MRTU process and, if necessary, make appropriate changes to our procurement rules.

We now turn to the specific authorization requests of each of the IOUs. SDG&E suggests that the Commission abandon the current guideline that not more than 5% of an IOUs market purchases should be conducted in the spot market. If an IOU exceeds the 5% limit it is required to submit justification in the quarterly compliance filings. SDG&E's reason for suggesting this policy change is that the CAISO day-ahead market would fall within the Commission's definition of spot markets. Therefore, SDG&E essentially concludes that the 5% limit on spot transactions may be set too low. While we agree that the new day-ahead market administered by the CAISO may prove to be attractive means for

the IOUs to manage its portfolio on a short term basis, we do not find compelling evidence to change our current regulations. We do not believe that the requirement that IOUs justify any spot purchases over a 5% threshold is burdensome. We will continue to monitor the impact of the CAISO's market reforms and adjust our rules if deemed necessary.

SCE asks for authority to modify its procurement plan to include virtual bidding once sufficient information regarding the details of virtual bidding rules have been established.

We understand that the CAISO is currently undergoing the process of defining the rules under which it plans to implement virtual bidding. Once those rules have been established and approved, it may be necessary for the Commission to revisit the procurement polices in place. We see no reason to modify our procurement polices to allow SCE to include virtual bidding at this time. Once more detailed information regarding virtual bidding is available, each of the IOUs can file for a modification to its procurement plan using the appropriate forum.

PG&E is seeking authority to modify the description of two existing products that were previously approved by the Commission, and to add a new MRTU-related product. PG&E states that it is actively seeking to manage the challenges that full implementation of MRTU may present and is seeking Commission approval of products that will allow it to more effectively do so. We find PG&E's request to modify the existing product definitions of "Financial Swap" and "Electricity Transmission Products" to be reasonable. However, we will impose reporting requirements upon PG&E associated with these products. PG&E is directed to include details regarding transactions that involve these products in its Quarterly Compliance Reports. If PG&E determines a need to

procure transmission related products that fall outside this approved definition it is directed to file an Advice Letter before engaging in procurement activities.

PG&E further requests Commission approval for new products that may be needed during the CAISO's finalization of MRTU which the CAISO considers mandatory for MRTU market participation. PG&E states that for the time being, it will identify these new products as "Non-Discretionary Products Required by MRTU." We do not find this request by PG&E to be reasonable. This request would essentially allow PG&E to procure any product that it deems necessary for participation in the CAISO market without seeking further Commission approval. PG&E's reasoning for making this request also appears to be flawed. PG&E requests authority for "Non-Discretionary Products Required by MRTU" since there may be insufficient time to seek and obtain Commission approval through an advice letter filing between MRTU design finalization and MRTU market initiation. However, if there is adequate time for such a filing, PG&E will do so. We note that MRTU redesign has been an ongoing process since early 2001. We, therefore, see little basis for the assumption that there might not be enough time to seek approval for additional procurement authority through an advice letter filing. To the extent that PG&E requires additional procurement authority pursuant to the implementation of MRTU it is instructed to follow Commission procedure for seeking such additional authority.

4.7. Confidentiality

The IOUs, intervenors and the Commission continue to weigh the competing interests of confidentiality versus open and transparent filings and decisions. In D.04-12-048, we referenced an Amended Protective Order (APO) that had been issued by an ALJ, and we determined that that APO controlled confidentiality issues in R.04-04-003. We acknowledged that we knew more

work was needed by the parties and the Commission to move towards the more open and transparent decision making that would foster the competitive, hybrid market we envisioned.

Between the 2004 and 2006 LTPP filings, we initiated a Rulemaking to thoroughly vet the competing positions on confidentiality, and in June, 2006, we issued D.06-06-066 that established guidelines for the treatment of certain categories of procurement-related information and created a Matrix of the types of information that warranted confidential treatment. To further provide guidance on the treatment of confidential information, and in particular on the topic of Protective Orders, the Commission issued D. 06-12-030 on December 14, 2006—three days after the IOUs filed their LTPPs.

When each IOU filed its LTPP on December 11, 2006, they each concurrently filed a Motion to File Under Seal. On May 2, 2007, per ALJ ruling, the Motions to File Under Seal were granted, with modifications. First, to the extent a utility complied with the requirements of D.06-06-006 and set forth data that falls within the categories of the Matrix, the data was allowed to be filed Under Seal. Following the direction from D.06-12-030, parties that were authorized to see the data filed Under Seal, were to be allowed to do so under a Protective Order that was consistent with D.06-12-030.

It appears, however, that there is no solution to the confidentiality debate that will satisfy all parties. The IOUs still filed two sets of LTPP plans: one set complete with all the data and a redacted version. Even if the IOUs are complying with Commission directives, the market participant parties still allege that they are hobbled in their ability to review or challenge the data that supports the plans. All parties are aware of the continuing tension that

confidentiality issues raise, especially as the IOUs and the market participants are often competing head-to-head.

In particular, some intervenors ask the Commission to require the IOUs to release more data than the IOUs voluntarily circulate. AReM would like to review the IOUs' percentage of total load in their service territories served by DA. CAC/EPUC are concerned that their customers may be asked to pay stranded costs, yet the models and data used by the IOUs to derive the stranded costs is not available for review or challenge by the very parties who have to pay the costs.

There is not a consensus among the intervenors and IOUs on whether or not the names of winning bidders from a RFO should be released, and if so, when. The release of the winning bid information would provide more transparency to the bidding process and would allow non-selected participants in the RFO process to see why their bids were not accepted. Parties such as WPTF advocate requiring the release of the winning bid information, but understand the need for a utility to keep the information confidential until key elements of the bidder's project have been secured. However, while a utility might need some flexibility on when to release the bid information, WPTF is concerned that unless the Commission requires the release of the information within some time limit, the information might never be released. Aglet recommends that the Commission direct the IOUs to release the bid information at the time the IOU files an application.

We are convinced by the arguments presented by intervenors that some direction is needed from the Commission on the subject of release of winning bid information. We find that that it is reasonable for the IOU to keep the identity of the winning bidder confidential until key commercial elements have been

finalized. However, we also find it reasonable that the IOU must publicly reveal the names of winning bidders, a description of the product, and the contract term, within 90 days of when the IOU files an application with the Commission for approval of the contract. As WPTF recommends, if an IOU has filed an application, but key commercial terms have not been finalized within the 90-day time frame, the IOU should withdraw the application and re-apply once it can release the bidder's identity and key. The IOU does not have to publicly reveal the actual contract.

While we continue to wrestle with other vexing issues on the topic of confidentiality and how to promote an open, competitive market, and protect the ratepayer, we do not find it necessary, or prudent, to make any further findings on the topics of confidentiality or Protective Orders in this decision. We have an open docket, R.05-06-040, to address those issues.

5. Motions

Throughout the course of the proceedings there were numerous motions filed and ruled on by the ALJ. In particular, many motions for Party Status were granted in rulings made over the course of the proceeding. If there are any motions for Party Status that have been filed and not yet ruled on, they are granted. Any other motions filed in this proceeding to date that have not been the subject of a separate ruling or specifically addressed in this decision are deemed denied.

6. Next Steps

This decision addresses the 2006 LTPPs filed by the three IOUs. It is anticipated that a new OIR will issue soon initiating the next LTPP proceeding that will build off of the orders and directives contained in this decision. This decision closes this proceeding, R.06-02-013.

7. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on December 10, 2007, and reply comments were filed on December 17, 2007. We have weighed parties' comments and in the situations deemed appropriate we have modified our proposed decision.

8. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Carol A. Brown is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. The purpose of this decision is to review the long-term procurement plans submitted by PG&E, SCE and SDG&E on December 11, 2006, and approve the plans to the extent they comply with the directives given in the February 16, 2006 OIR and the September 25, 2006 ACR/Scoping Memo to give the utilities the authorization necessary to plan and procure to provide reliable service for the 2007 – 2016 planning period.

2. The primary principal guiding the Commission in its review of the plans is whether the IOUs are procuring preferred resources as set forth in the Energy Action Plan, in the order of energy efficiency, demand response, renewables, distributed generation and clean fossil-fuel resources.

3. The IOUs were directed to prepare different candidate plans and to provide for each plan the expected GHG emissions; the RPS percentages; the percentage of demand response as a percentage of RA; and the energy efficiency savings from committed and uncommitted programs.

4. The IOUs were further directed to weigh the different plans for ratepayer costs and reliability.

5. An overarching problem in all the IOUs' plans is the absence of any scenario analysis regarding the types of resources the IOUs should use to fill their net short positions to best transition to the forthcoming GHG-constrained world.

6. The IOUs plan on filling and projecting to fill their net short positions with conventional resources, without providing a highly developed analysis to support this conclusion.

7. We find that in general all three LTPPs do not fully reflect our goals in regards to addressing preferred resources and the EAP loading order and GHG reductions.

8. Preferred resources are those resources that are procured in accordance with the State's preferred loading order of energy efficiency, demand response, renewables and distributed generation in order to meet the State's environmental goals.

9. Going forward, the IOUs will be required to reflect in the design of their RFOs compliance with the preferred resource loading order and GHG reduction goals and to demonstrate how each application for fossil generation filed based on the procurement authority granted in this proceeding fits into each IOU's GHG reduction strategy.

10. This decision establishes a skeleton upon which future LTPP filings in the biennial cycle may build and grow and identifies key issues and areas of planning for the IOUs to address in their 2008 LTPP filings.

11. With our approval of the 2006 LTPPs, these plans supersede all previous procurement plan authority and the IOUs may no longer continue to conduct

procurement under the short-term plans originally submitted in April/May 2003.

12. The IOUs were directed to use the CEC's IEPR load forecast in preparing their need assessments.

13. We based findings for the IOU need determination tables on the CEC's base case, 1 in 2 summer temperature demand forecast.

14. We established PG&E's need determination using the CEC's base case, and adjusted PG&E's preferred plan demand forecast.

15. We established SCE's need determination using the CEC's base case and adjusted SCE's recommended plan accordingly.

16. We established SDG&E's need determination using the CEC's base forecast and adjusted SDG&E's preferred plan accordingly.

17. We find that PG&E, SCE and SDG&E's assessment that system need is not impacted by possible future load shifting to DA and CCA is reasonable and that future DG and MDL is captured by the historical trends used to develop the forecast.

18. We do not intend to relitigate EE treatment in the CEC load forecast in this proceeding.

19. We concur with DRA's recommendation that the CEC and the IOUs need to come to a consensus on what proportion of the Commission's EE goals are embedded in the CEC load forecast, and with TURN's position that the IOUs accurately reflect their EE goals in their LTPPs.

20. We agree with the CEC's recommendation that the portion of IOU's EE goals not included in the forecast (i.e., the uncommitted EE that does not overlap with EE-induced reductions embedded in the CEC forecast in the years beyond the Commission EE programs' three-year program cycle) should be treated as a

resource in the LTPPs. We conform to these principles in the following IOU-specific EE treatments.

21. It is important to clarify the definition of "uncommitted" EE in the context of the LTPPs.

22. In this Decision, we define "committed EE" as only those savings attributed to the IOUs' 2006-2008 and earlier EE programs, which meet or exceed Commission-adopted EE goals. We define "uncommitted" EE as the projected savings attributable to future EE program cycles (2009-2011 and beyond) that meet or exceed the Commission-adopted EE goals.

23. Due to the mechanics in the CEC's demand forecasting methodology discussed above, uncommitted EE (in this Commission's use of the term) is reflected in one of two places in the 2006 LTPPs: either: (1) embedded as a reduction in the load forecast (to the extent that uncommitted EE *does* overlap with the CEC's concept of committed effects); or (2) forecasted as an available resource (to the extent that uncommitted EE does *not* overlap with the CEC's concept of committed effects.

24. In its "California Energy Demand 2008-2018 Staff Revised Forecast (November 16, 2007), the CEC undertook additional analysis of this issue, developing quantifications explicitly for the 2006-2008 portfolios. Tables in Appendix A of the document provide quantifications of the direct program impacts (i.e., the portion of uncommitted EE goals not embedded in the forecast based on past and existing measures). Using the same methodology employed by the CEC to develop the 60% overlap, with the updated data included in the Staff Revised Forecast, results in overlap factors for PG&E and SCE of 85% and 95%, respectively.

25. Based on the CEC's analyses and our direction to the IOUs in D.07-10-032, there is evidence that suggests that the overlap factors may be in the range of 60% to 95%. Until a methodology is developed to more accurately estimate future EE savings in the CEC forecast, we will apply an 80% overlap factor to PG&E and SCE. This is a reasonable adjustment to properly balance between reliability concerns that could result from underestimating the overlap factor and over-procurement that could result from overestimating the overlap factor.

26. Based on the CEC's analyses and our direction to the IOUs in D.07-10-032, there is evidence that suggests that the overlap factors may be in the range of 60% to 95%. Until a methodology is developed to more accurately estimate future EE savings in the CEC forecast, we will apply an 80% overlap factor to PG&E and SCE. This is a reasonable adjustment to properly balance between reliability concerns that could result from underestimating the overlap factor and over-procurement that could result from overestimating the overlap factor.

27. SDG&E adds its uncommitted EE goals to the CEC forecast and then subtracts them back out as a resource. Although this approach is not consistent with the CEC's methodology for EE, the CEC acknowledges that this is an appropriate treatment of SDG&E's EE goals at this time.

28. We find the IOUs' projections on demand response forecasts and expectations based on enrollment and percentage of enrollment that is expected to actually participate to be an acceptable estimate of firm DR reductions for the purposes of seven-year forward planning for new supply-side resources.

29. We find the IOUs' LTPPs provide mostly sufficient information for us to check for compliance with the RPS program targets, including such issues as procurement, resource mix and resource potential. Despite the directives provided to the IOUs in the Scoping Memo, the IOUs did not adequately address

rate impacts. In addition, the plans could have been strengthened by fully providing the timing and parameters of the expected RFOs or other means to fill identified renewable needs; addressing the possibility of contract failure; providing for assessments that are informed by general and resource-specific uncertainties and risks; and making other resource need determinations based on "reasonable expectations" of renewable supply.

30. We approve PG&E, SCE and SDG&E's treatment of renewables, with noted exceptions, because of recognized uncertainty in the scenario analyses and the fact that the renewable market in California is dynamic and the 2006 LTPPs do not capture developments in the past year. In addition, we direct the IOUs to work with ED staff to refine the long term planning methodology.

31. We do not require a margin of safety for the procurement of renewable energy sources because any non-compliance with renewable targets will result in sanctions as established in D.06-05-039.

32. The IOUs did not adequately address how to integrate long-range transmission planning beyond transmission already slated to come on-line into the long-term procurement process for all resource categories, including renewables, and we anticipate more discussion in subsequent LTPPs.

33. We anticipate that the statewide Renewable Energy Transmission Initiative will provide critical output for the IOUs to use in drafting their future renewable procurement plans.

34. We defer to existing or new proceedings related to RPS, transmission planning, or to consideration in other forums, many topics that impact the IOUs renewable portfolio including the following: whether there is a shortage of renewable sources; hurdles associated with the ISO queue process; the MPR methodology and the difficulty of properly assessing the value and costs of RPS

procurement; utility-owned renewable generation; qualifying capacity of wind generation; rolling RPS procurement beyond 20% into an all-source RFO; and the development of Energy Parks.

35. We find that the IOUs followed the OIR and Scoping Memo directives and included forecasts for DG in their LTPPs that are consistent with existing Commission directives.

36. We find the IOUs treatment of QF resources for system reliability purposes to be reasonable given the information available to the IOUs at the time of their filing. However, on September 20, 2007, the Commission issued D.07-09-040 adopting pricing and policy mechanisms for the IOUs' purchase of energy and capacity from the QFs and we require each IOU to maintain its current level of QF capacity throughout the planning cycle. We anticipate that the IOUs will incorporate the new directives in subsequent LTPP filings.

37. We revised PG&E's anticipated retirement schedule to reflect a more gradual pace of retirements, but this adjustment does not impact our need determination for PG&E in the 2015 timeframe. We increase SCE's retirement assumptions by 500 MW annually, beginning in 2009, resulting in a total of 6,350 MW of retirement in the 2015 need determination timeframe. We made no revisions to SDG&E's retirement assumptions.

38. We do not adopt any system reliability reserve margin methodology at this time and do not make any changes to the existing 15%-17% PRM and in particular do not adopt the change requested by PG&E for its PRM.

39. We do not adopt the contingencies requested by PG&E for contracted resource uncertainty, anticipated revisions to the RA counting rules, additional backup or for RFO optionality since we find that PG&E did not provide an analysis for us to make an assessment that these additional resources will be

needed during the 10-year planning cycle, or that they would be optimal for a future, GHG-constrained portfolio. We do not find that it would be prudent to grant this additional requested contingency amount at this time.

40. We must make need determinations today that will result in sufficient system resources to permit all jurisdictional LSEs to meet their PRM obligations in the seven-year new resource procurement timeframe. Seven years is a reasonable time to develop and carry out competitive RFOs and then finance, permit and construct new generation and to avoid "just-in-time" procurement.

41. A need determination is made for each IOU based on (1) the load, resource and PRM assessments discussed in this decision; (2) relevant information the IOUs and intervenors provided; and (3) the principle that each IOU should provide approximately the same level of system reliability to its customers.

42. Table PGE-1 provides a need determination for PG&E for the 10-year planning period using the assumptions and conclusions reached in this decision without any additional contingencies. Based on Table PG&E-1, our need determination analysis indicates that PG&E's service area shows a need of 800 – 1,200 MW by 2015.

43. To support the types of needs we anticipate in a GHG-constrained portfolio, we require PG&E to procure dispatchable ramping resources that can be adjusted for the morning and evening ramps created by the intermittent types if renewable resources.

44. SCE's service area need determination included POUs' contributions to system load or POU resources. We therefore, backed-out the POU resource data for SP-26 so SCE does not over-procure system resources.

45. Table SCE-1 calculates SCE's proportion of system resources based on its regional (bundled plus DA) forecast divided by the system forecast and provides

SCE's service area need determination based on its recommended plan, with revisions addressed in this decision. Table SCE-1 also divides in half the DPV2 resource. SCE can update its next LTPP to reflect any updates in the DPV2 situation.

46. Based on Table SCE-1, our need determination analysis indicates that SCE's service area shows a need of 1,200 – 1,700 MW by 2015. We find this is in addition to the 305 MW remaining from SCE's standard-track RFO.

47. Table SDG&E-1 provides SDG&E's service area need determination which indicates that SDG&E does not have any new system capacity need by the 2015 timeframe. However, we note that SDG&E's need determination is constrained by local capacity requirements.

48. The need SDG&E identified is a physical local capacity need, and counting the 130 MW of peaking units recently approved, SDG&E requests approximately 530 MW of new local capacity procurement authority.

49. Because there is insufficient information at this time to determine if or when the Sunrise Powerlink project will be available to meet local capacity needs, we authorize 530 MW of additional procurement for SDG&E in the San Diego local area only if its Sunrise Powerlink application is denied.

50. SDG&E is also authorized to procure the equivalent quantity of local capacity associated with any retirements of local area resources that occur beyond the amount of retirements it forecasts in its LTPP.

51. To support the types of needs we anticipate in a GHG-constrained portfolio, we require SDG&E to procure dispatchable ramping resources that can be adjusted for the morning and evening ramps created by the intermittent types of renewable resources.

52. SDG&E is the only IOU that provides an explicit comparison of its bundled customers' need and its system need.

53. We continue to acknowledge the value of PRGs and direct that the utilities continue to use them as advisors for their procurement activities.

54. We find that a PRG calendar would be a useful process tool and direct the IOUs to individually set up and maintain a web-based PRG calendar that can be accessed and updated by a representative of each IOU. The calendar is to include dates of expected solicitation milestones and only contain non-confidential information. This will enable each IOU to efficiently schedule meetings with full knowledge of other IOU PRG meeting dates and times.

55. We find that it would aid PRG members in effectively organizing and focusing their participation if the IOUs provided PRG members with a PRG meeting agenda and materials a minimum of 48 hours in advance of the PRG meeting, unless there is an unusual, extenuating circumstance where an IOU notices a meeting on a tighter time schedule.

56. We adopt DRA's recommendation that IOUs provide (confidential) meeting summaries to PRG members that include a list of attending members, including the organizations represented, a summary of topics presented and discussed, and a list of information requested or offered to be supplied after the meeting, and the identity of the requesting party. We do not, however, require the IOUs to develop detailed PRG meeting minutes at this time and the meeting summaries are not admissible in hearings as evidence or to be cited in testimony.

57. We adopt the Transparency Working Group's information-sharing proposals designed to make the PRG process more transparent for the public and the IOUs may provide the following information to the public through a web-based forum: date, meeting time and duration of the meeting; the individuals

participating in the meeting and organization represented by the individual; and a list of non-confidential items discussed.

58. We adopt the PRG Participation Working Group proposal to create a CAM Group for procurement for which IOUs recover costs from bundled and unbundled customers using the D.06-07-027 CAM. The CAM PRG shall include one member representing CCA customers, two members representing Direct Access customers. If a future definition of the CAM identifies non-bundled customers in addition to CCA customers and DA customers, they shall be represented by one member in the CAM Group.

59. We find it reasonable to continue the use of IE and we refine the existing process to have the IOUs, in conjunction with each respective PRG, develop a pool of at least three, but preferably more, IEs to be used beginning January 1, 2009. The particulars for development of the IE pool are set forth in the decision and we find it reasonable to adopt those provisions.

60. We adopt SCE's proposal that ED should be involved during the selection process, the development of the scope of work and the drafting of the terms of the contracts with the IE and have the right to final approval of such engagements.

61. We adopt DRA's recommendation, with modifications, that the name and information of the IE for each IOU, type of solicitation the IE was used for and the amount of money involved in the procurement solicitation be reported to the IOU's PRG before and after the solicitation takes place.

62. It is reasonable to find that an IE should continue to be contracted with and retained for all competitive solicitations that involve affiliate transactions or utility-owned or utility-turnkey bids, and for all competitive RFOs seeking products greater than three months in length regardless of the bidders.

Competitive RFOs include RFOs issued to satisfy service area need and supply-side resources not including EE and DR. For solicitations of less than five years, the IE report shall be filed with the QCR.

63. We find it reasonable to require the IOUs, in consultation with the PRG and ED to develop comprehensive conflict of interest disclosure requirements for the IE. An IE may be disqualified from participating in an RFO process if there are particular egregious conflicts of interest that arise during the contract.

64. To address the fact that currently there is no consistency in the reports submitted by the IEs in support of applications for resources procured in competitive solicitations, we direct ED to develop a template for IEs to use when developing their reports, and the template will include the information and address the questions set forth in the decision.

65. We find it is reasonable to allow the IOUs to tailor their RFOs to address particular needs, such as system reliability needs or RA requirements, as ratepayers and competitors both benefit from this responsiveness. However, IOUs are not to create false barriers to participation or attempt to limit the competitive process by manipulating the RFO product descriptions.

66. We find that the RFO process would benefit from requiring the IOUs to hold a meeting with the IE, PRG and ED to outline their plans and solicit feedback prior to drafting RFO bid documents so that the RFO process is improved by the identification of data gaps, confirmation of the fairness of the confidential components of the RFO, and of the compliance with the letter and spirit of Commission policies on procurement practices.

67. Draft RFO bid documents are to be developed under the oversight of an IE, vetted through the PRGs and any differences resolved by ED staff in advance of the public issuance of the bid documents.

68. We find it reasonable to direct the IOUs that they may not initiate an RFO for new fossil resources that have not been formally authorized in a LTPP decision, unless the IOU makes a strong showing in advance, via an approved Advice Letter, that unusual or extreme circumstances warrant such an action.

69. We direct ED to develop a template that includes the information set forth in this decision, for IOUs to use when developing an application for approval of winning bid projects.

70. We find it reasonable to encourage SDG&E and the other IOUs to solicit renewable resource bids in their RFOs, as long as all resources within the RFO are compared against one another on a consistent, LCBF basis using the GHG adder to compare the bids of fossil resources relative to renewables and decisions regarding whether to continue conducting separate RPS solicitations are to be addressed in existing or new proceedings related to RPS.

71. We find that SCE's request to increase its collateral exposure limit to $2.0 billion is reasonable.

72. After reviewing the credit and collateral requirements used by the IOUs and utilizing the audit results from an audit contracted by the Commission, we determine that no other changes are warranted, at this time, on the subject of C&C.

73. When the Commission considered Debt Equivalence in the last procurement proceeding [R.04-04-003], it authorized the utilities to "take into account the impact of DE when evaluating individual bids . . ." and directed the utilities to use a 20% "risk factor" for all PPAs, based on a discount of the 30% risk factor developed by Standard and Poor's (S&P) for the California utilities. The Commission also acknowledged, however, that "(a)s the rating agencies' views on DE change or as we gain more experience with DE evaluation in the

[cost of capital] proceedings, we may adjust the DE methodology used in [the] future."

74. Since the issuance of D.04-12-048, the Commission has gained more experience with debt equivalence.

75. We find that DE in and of itself, is not a real cost that the utilities directly incur by entering into a PPA.

76. In order to further encourage fair, head-to-head competition between PPAs and utility-owned projects, as it stated in D.04-12-048 and numerous times throughout this decision, the bid adder for PPAs should be eliminated.

77. We do not make any findings at this time on how a utility should weigh the FIN 46(R) impacts of a PPA when evaluating competing bids.

78. We do not make any findings or orders at this time on how transmission costs and benefits are to be evaluated for specific generation projects in the RFO process.

79. We adopt the following ED recommendations for revisions to contract pre-approval guidelines: Provided the procurement complies with a procurement limit methodology developed by the IOU and approved by the Commission, an IOU may execute a contract of under five years without pre-approval for which deliveries end at any point within the 10-year LTPP procurement cycle. Absent a Commission-approved procurement limit methodology, the five-year duration clock begins either at the time the contracted resources begin delivery, if delivery begins within one year of contract execution; or at the time of contract execution if delivery does not begin within one year of contract execution. Calendar days are used for calculating contract duration.

80. We find that PG&E and SCE's descriptions of how they calculate TEVaR and make use of it conforms to the Commission's directives to use a rolling

12-month TEVaR and make appropriate comparisons for purposes of determining whether to take steps to level price volatility within the CRT threshold. SDG&E's approach should be modified as set forth in this decision.

81. We adopt a TEVaR 95% as a more robust metric for risk than TEVaR 99% for guiding hedging decisions. We do not change the CRT level or the 125% threshold metric and maintain the looking forward up to five years reporting requirement.

82. We adopt the recommendation to coordinate the updates for the portfolios for the scheduling of gas supply and hedging plans by the IOUs, and direct that the updates be made annually at the time of the ERRA filings. The IOUs are also authorized to update their gas supply and hedge plans with the Commission for their DWR portfolios annually, instead of twice a year. This does not affect the IOUs obligations to DWR.

83. The nuclear and coal fuel plans proposed by the IOUs are adopted as presented.

84. The gas supply procurement proposals of the IOUs are not adopted because the Commission must address and review proposals by the IOUs more thoroughly than we have in this current proceeding and asses the proposals in conjunction with other rulemaking proceedings.

85. While we agree in principle with a number of PG&E and SCE's proposed changed to their respective gas and electricity product risk management approaches we determine that more analysis is necessary before they can be adopted by the Commission.

86. Until revised risk management approaches are formally adopted by the Commission, we require the IOU's to continue operating under their existing Commission approved risk management practices.

87. Outside of the IOUs' LTPPs and their initial briefs, the Commission received virtually no input regarding how and to what extent the Commission could improve and/or streamline the reporting requirements. We will rely on the record available and the Commission's own experience and expertise to make incremental changes to the compliance rules.

88. Having a tariff-like numbering system in place combined with a redline strikeout method of proposing updates to the LTPP will improve the compliance review. We direct the IOUs to develop a common numbering system, similar to the one used to track tariff revisions, to track revisions to each Commission-approved LTPP.

89. All IOU updates or modifications to their procurement plans proposed between the biennial procurement plan filings, via the Advice Letter process, are to include redlined pages of the existing procurement plan as well as "cleaned up" replacement pages which include the tariff-like numbering ordered above.

90. Currently, we require Commission staff to review the IOU's QCRs for compliance with the Commission-approved procurement plan and its upfront and achievable standards and criteria within 30 days of their receipt. It is reasonable to increase the timeframe for approving the QCRs from the current 30-day requirement to 60 days.

91. We find the results of the review and approval process for the QCRs completely unacceptable and amend the QCR process as follows. We direct the ED, in conjunction with the external auditors and the IOUs to continue the collaborative effort formed earlier this year and develop a reformatted QCR. We delegate authority to ED to authorize the implementation of the reformatted and streamlined QCRs and to make ministerial changes to the content and format of the report as needs arise.

92. We clarify our decision, D.07-04-020, on SCE and PG&E's Petition to Modify D.02-12-074 and D.04-12-048 to reiterate that while we denied the request to change the monthly ERRA filing to quarterly filings, we granted the request that the utilities only supply a breakdown of costs with their ERRA monthly filings and make all supporting documentation available to Commission Staff and interested parties upon request.

93. In order to capture all the modifications we made to the proposed LTPPs of the IOUs, we require conformed 2006 LTPPs via a compliance filing no later than 90 days from the date of this decision. The conformed 2006 LTPPs shall incorporate all of our directives contained in the body of this decision as well as any updates filed through the Commission's Advice Letter process between the issuance of this decision and the due date of the compliance filing. In the interim, the 2006 LTPPs are adopted with the requirements stipulated in this decision and summarized in the Ordering Paragraphs and the Compliance Table provided as Appendix E. The IOUs are directed to modify their hedging plans to conform to our TeVaR 95% metric and to include those modifications in their 2006 LTPP compliance filings.

94. We do not prohibit UOG in this decision, but we find it reasonable to no longer allow head-to-head competition between IPP and Utility build bids until we develop a fair, publicly-vetted comparison methodology.

95. We prohibit IOUs from recouping from ratepayers any bid development costs associated with losing PSA or EPC bids, in the event that any such costs are incurred.

96. UOG applications by the IOUs must fit into a unique circumstance, such as market power mitigation, reliability, preferred resources, expansion of existing facilities, or be a unique opportunity, as described in the decision, and each

application will be considered on a case-by-case basis. If a competitive solicitation for a PSA or EPC contract to build the UOG is not appropriate, the application must explain why a utility-build approach is required.

97. We find that allowing the IOUs to require or include as an option in their competitive PPA RFOs the option of transfer of the fully depreciated resource underlying a PPA to the IOUs distorts the market and we will no longer allow the IOUs to consider such an option in competitive PPA RFOs.

98. We find it reasonable to prohibit communications of competitively sensitive information to the utility project development group from other utility departments if the utility is potentially bidding in an RFO.

99. We find it reasonable to require a functional separation between the individuals performing the bid evaluation and the individuals preparing the bids for UOG and prohibit the utility employees developing the bids for utility-owned projects from having access to evaluation protocols, input assumptions, or bid information that is not made available to outside bidders.

100. If an IOU proposes a UOG project outside of a competitive RFO, it is reasonable to require the IOU to make a showing that holding a competitive RFO is infeasible.

101. We find it reasonable to eliminate the "50/50 cost cap" directed in D.04-12-048 and will consider cost- and saving-sharing ratemaking mechanisms, such as proposed by PG&E and SCE, on a case-by-case basis and the requested treatment must be justified by unique circumstances.

102. We do not adopt SCE's Rulebook at this time, but endorse the concept in principle and direct ED staff to continue to work with the IOUs and other interested parties to create a Commission-endorsed "AB 57 Procurement Plan Implementation Manual" for each IOU that includes the comprehensive set of

procurement rules, including any IOU-specific requirements, that can be accessed by all interested market participants to determine each IOU's compliance with its AB 57 Procurement Plan.

103. We are not making any new findings in regards to AB 1576 repowering projects, but reiterate our order from D.04-12-048 that the IOUs are ". . . to consider the use of Brownfield sites first and take full advantage of their location before they consider building new generation on Greenfield sites. If IOUs decide not to use Brownfield, they must make a showing that justifies their decision." All the benefits and impacts of AB 1576 projects should be properly considered and evaluated in an RFO - including quantifiable economic benefits and impacts, and non-quantifiable social and environmental benefits and impacts. This direction applies to repowered or replacement options presented in a RFO, not just UOG projects.

104. We find that all three IOUs' LTPPs could have been strengthened by building into their calculations of future need for electric resources a methodology for analyzing the GHG implications of the different resources the IOUs can utilize to fill that net short position. While the implementation details are still under consideration in R.06-04-009, it appears improbable that the IOUs can reduce their carbon emissions from electric generation resources back to 1990 levels without a focused reliance on preferred resources. We further find that the LTPPs rely heavily on fossil-fuel generation for expected needed resources and the IOUs did not explain how these resources fit into a GHG reduction strategy.

105. We find that procurement of zero- or low-GHG resources should be given preference over other resources since these are the types of resources that AB 32 regulations will favor.

106. We adopt NRDC's suggestion that all three IOUs be required to provide absolute GHG emissions, with cost implications of those emissions levels at various price points for CO_2 allowances, under various scenarios in their future LTPP filings. Subsequent LTPPs should also include a thorough evaluation and analysis of the costs and risk of GHG emissions reductions.

107. We find it reasonable to approve the three IOUs' 2006 treatment of the 33% renewables target since the target has yet to be adopted and full implementation details will be addressed in existing or new RPS proceedings. However, we note that all three LTPPs could have provided more detailed information such that the Commission could more accurately assess how or if the IOUs could achieve a 33% renewables target by 2020. To ensure that the goal is incorporated into subsequent LTPPs, IOUs will work with ED staff to address refinements to the methodology for resource planning and analysis to adequately address the issue of a 33% renewables target by 2020.

108. In late 2001, the CAISO instituted a program of comprehensive market redesign called "MRTU" intended to enhance performance of the CAISO's core functions (reliable, nondiscriminatory transmission). Under MRTU, there will be a day-ahead market, which will be an integrated CAISO market for energy and ancillary services, as well as congestion management, and, if necessary, Residual Unit Commitment (RUC); an hour-ahead scheduling process (HASP), which is an opportunity to make scheduling adjustments (but is not a full-settlement market); and a real-time imbalance market with optimized economic dispatch.

109. We anticipate that the MRTU will be in place in Spring 2008 and that it will greatly impact the CAISO's markets, and the procurement practices and costs of the IOUs, and we will closely monitor the implementation of MRTU and make any appropriate and necessary changes to our procurement rules.

110. We find it reasonable to adopt PG&E's proposed modifications to the definitions of "Financial Swap" and "Electricity Transmission Products," but PG&E is to include details regarding transactions that involve these products in its QCR.

111. A key goal of this proceeding is to review the procurement process of the RFOs to consider whether any refinements are necessary to further the goal of open, transparent and competitive procurements.

112. An open, transparent and competitive procurement process is the king-pin to a successful hybrid market and we will provide guidance and procedures to effectuate this market.

113. We find it reasonable that an IOU must publicly reveal the names of winning bidders, a description of the product, and the contract term, within thirty days of when the IOU files an application for approval of the contract. The IOU may keep the identity of the winning bidder confidential until key commercial terms have been finalized and if that does not occur within the thirty day time frame, the IOU should withdraw the application and re-file once it can release the bidder's identity and other required information. The IOU does not have to publicly reveal the actual contract.

Conclusions of Law

1. Pursuant to Pub. Util. Code § 454.5 the Commission reviewed the LTPPs filed by PG&E, SCE and SDG&E. We direct the IOUs to make a compliance filing conforming their 2006 LTPPs with the directives contained in this decision. The LTPPs filed by the IOUs on December 11, 2006, when conformed, are approved, subject to the exceptions and modifications set forth in this decision.

2. The EAP contains explicit direction regarding the state's preference for meeting identified resource needs and we reviewed the LTPPs for compliance

with the EAP and found some deficiencies that must be corrected as directed in the decision.

3. The IOUs were directed to provide different candidate plans and to provide for each plan the expected GHG emissions; the RPS percentages; the percentage of demand response as a percentage of RA; and the energy savings from committed and uncommitted programs. Each plan was to be weighed for ratepayer costs and reliability.

4. We find that the LTPPs in general were inadequate in regards to addressing preferred resources, the EAP loading order and GHG reductions, in that the IOUs planned to fill their net short positions with conventional resources without a highly developed analysis to support this conclusion.

5. It is reasonable to direct the IOUs to correct their LTPPs to indicate how they should fill their net short positions to transition to a forthcoming GHG-constrained world in light of the absence of any scenario analysis in this regard.

6. Going forward, the IOUs will be required to reflect in the design of their RFOs compliance with the preferred resource loading order and GHG reduction goals and to demonstrate how each application for fossil generation filed based on the procurement authority granted in this proceeding fits into each IOU's GHG reduction strategy.

7. Based on our analysis of the CEC's IEPR load forecast, as updated, and the preferred/recommended plans of the IOUs, we make the following need determinations:

- PG&E has a range of need of 800 – 1,200 MW of new resources by 2015;
- SCE has a range of need of 1,200 – 1,700 MW of new resources by 2015, in addition to the 305 MW remaining from SCE's standard-track RFO; and

- SDG&E has a need of 530 MW of new resources in its local area (including the 130 MW already approved by this Commission) if its Sunrise Powerlink application is denied.

8. System need is not impacted by possible future load shifting to DA and CCA, and future DG and MDL is captured by the historical trends used to develop the IOUs' forecasts.

9. EE and DR targets and goals are set in separate proceedings and the IOUs projections of meeting EE and DR targets are not reviewed for compliance purposes in this proceeding.

10. We do not intend to relitigate EE treatment in the CEC load forecast in this proceeding.

11. We concur with DRA's recommendation that the CEC and the IOUs need to come to a consensus on what proportion of the Commission's EE goals are embedded in the CEC load forecast, and with TURN's position that the IOUs accurately reflect their EE goals in their LTPPs.

12. We agree with the CEC's recommendation that the portion of IOU's EE goals not included in the forecast (i.e., the uncommitted EE that does not overlap with EE-induced reductions embedded in the CEC forecast in the years beyond the Commission EE programs' three-year program cycle) should be treated as a resource in the LTPPs. We conform to these principles in the following IOU-specific EE treatments.

13. It is important to clarify the definition of "uncommitted" in the context of the LTPPs.

14. In this Decision, we define "committed EE" as only those savings attributed to the IOUs' 2006-2008 and earlier EE programs, which meet or exceed Commission-adopted EE goals. We define "uncommitted" EE as the projected

savings attributable to future EE program cycles (2009-2011 and beyond) that meet or exceed the Commission-adopted EE goals.

15. Due to the mechanics in the CEC's demand forecasting methodology discussed above, uncommitted EE (in this Commission's use of the term) is reflected in one of two places in the 2006 LTPPs: either: (1) embedded as a reduction in the load forecast (to the extent that uncommitted EE *does* overlap with the CEC's concept of committed effects); or (2) forecasted as an available resource (to the extent that uncommitted EE does *not* overlap with the CEC's concept of committed effects.

16. In its "California Energy Demand 2008-2018 Staff Revised Forecast (November 16, 2007), the CEC undertook additional analysis of this issue, developing quantifications explicitly for the 2006-2008 portfolios. Tables in Appendix A of the document provide quantifications of the direct program impacts (i.e., the portion of uncommitted EE goals not embedded in the forecast based on past and existing measures). Using the same methodology employed by the CEC to develop the 60% overlap, with the updated data included in the Staff Revised Forecast, results in overlap factors for PG&E and SCE of 85% and 95%, respectively.

17. Based on the CEC's analyses and our direction to the IOUs in D.07-10-032, there is evidence that suggests that the overlap factors may be in the range of 60% to 95%. Until a methodology is developed to more accurately estimate future EE savings in the CEC forecast, we will apply an 80% overlap factor to PG&E and SCE. This is a reasonable adjustment to properly balance between reliability concerns that could result from underestimating the overlap factor and over-procurement that could result from overestimating the overlap factor.

18. Renewable targets and goals are established in a separate proceeding and the LTPPs were reviewed to determine if the IOUs had accounted for renewables in their portfolios, but we did not review RPS-eligible deliveries for compliance purposes.

19. DG treatment by the IOUs in their LTPPs was reasonable and followed Commission directives.

20. Treatment of QFs by the IOUs in their LTPPs was reasonable in light of the information available to the IOUs at the time of their filings, but QF policy and pricing issues are now established by D.07-09-040. To be consistent with the QF policies now established by D. 07-09-040, the IOUs shall modify their LTPPs to include maintenance of the current level of QF capacity.

21. Some IOU retirement assumptions were revised.

22. We do not make any changes to the PRM currently authorized by the IOUs.

23. PRGs are valuable for the IOUs' procurement process and we direct the IOUs to continue to use them in an advisory capacity for their procurement activities, including for procurement when an IOU is considering recovering costs from bundled and unbundled customers using the D.06-07-029 CAM.

24. IEs are valuable to the procurement process and we direct the IOUs to utilize IEs according to the parameters established in this decision and in D.04-12-048.

25. IOUs may tailor their RFOs to address particular procurement needs but are prohibited from creating false barriers to participation or attempting to limit or manipulate the competitive process.

26. IOUs are to utilize IEs, the PRG and ED as early as practicable in the procurement cycle, including prior to drafting RFO documents.

27. No IOU may initiate a RFO for new fossil resources that have not been formally authorized in a LTPP decision, unless the IOU makes a strong showing to ED in an Advice Letter that unusual or extreme circumstances warrant such action.

28. The IOUs, and in particular SDG&E, may solicit renewable bids in their RFOs, as long as resources within the RFO are compared against one another on a consistent LCBF basis using the GHG adder to compare the bids of fossil resources relative to renewables and decisions regarding whether to continue conducting separate RPS solicitations are to be addressed in the RPS proceeding.

29. SCE's request to increase its collateral exposure limit to $2.0 billion is approved.

30. IOUs may no longer apply a 20% DE "bid adder" as a bid evaluation tool when for PPAs.

31. We revise the contract pre-approval guidelines: Provided the procurement complies with a procurement limit methodology developed by the IOU and approved by the Commission, an IOU may execute a contract of under five years without preapproval for which deliveries end at any point within the 10-year LTPP procurement cycle. Absent a Commission-approved procurement limit methodology, the five-year duration clock begins either at the time the contracted resources begin delivery, if delivery begins within one year of contract execution; or at the time of contract execution if delivery does not begin within one year of contract execution. Calendar days are used for calculating contract duration.

32. IOUs are to use a rolling 12-month TEVaR and then make appropriate comparisons for purposes of determining whether to take steps to level price volatility within the CRT threshold.

33. We revise the TEVaR from 99% to 95%, but make no changes to the CRT level or 125% threshold metric.

34. IOUs are to coordinate the updates for their portfolios for scheduling gas supply and hedging plans which updates are to be made annually at the time of the ERRA filings.

35. IOUs are authorized to update their gas supply and hedge plans with the Commission for their DWR portfolios annually, instead of twice a year.

36. While we agree in principle with a number of PG&E and SCE's proposed changed to their respective gas and electricity product risk management approaches we determine that more analysis is necessary before they can be adopted by the Commission.

37. Until revised risk management approaches are formally adopted by the Commission, we require the IOU's to continue operating under their existing Commission approved risk management practices.

38. The nuclear and coal fuel plans proposed by the IOUs are adopted as presented.

39. The gas supply procurement proposals of the IOUs are not adopted because the Commission must address and review proposals by the IOUs more thoroughly than we have in this current proceeding and asses the proposals in conjunction with other rulemaking proceedings.

40. In order for the IOUs to continue necessary gas supply procurement for their electric generation requirements, the Commission authorizes the IOUs to continue operation under existing gas supply plans approved in the 2004 LTPP and 2005 Short-Term Procurement Plans until new supply plans are approved by the Commission.

41. If an IOU needs to propose specific gas supply procurement contract(s) that are not authorized by their existing gas supply plans beforehand, an IOU can file an application with the Commission to receive such authorization.

42. ED, in conjunction with the external auditors and the IOUs are to continue their collaborative effort to reformat and streamline the QCR process.

43. It is reasonable for ED to implement the reformatted and streamlined QCRs and to make ministerial changes to the content and format of the report as needs arise.

44. It is reasonable to increase the timeframe for approving the QCRs from the current 30-day requirement to 60 days.

45. Conformed 2006 LTPPs are due no later than 90 days from the date of this decision.

46. Head-to-head competition between IPP and Utility build bids is not allowed unless procedures are established and implemented that provide a more transparent comparison between the bids.

47. We prohibit IOUs from recouping from ratepayers any bid development costs associated with losing PSA or EPC bids, in the event that any such costs are incurred.

48. Each application for UOG will be reviewed on a case-by-case basis pursuant to the criteria set forth in the decision.

49. IOUs may no longer consider in a RFO an option of the transfer of the fully depreciated resource underlying a PPA to the IOU.

50. We prohibit IOUs from sharing competitively sensitive information between the utility project development group and other utility departments if the utility is potentially bidding in an RFO.

51. We require a functional separation between the individuals performing the bid evaluation and the individuals preparing the bids for UOG and prohibit the utility employees developing the bids for utility-owned projects from having access to evaluation protocols, input assumptions, or bid information that is not made available to outside bidders.

52. An IOU proposing a UOG project outside of a competitive RFO must make a showing that holding a competitive RFO is infeasible.

53. We eliminate the 50/50 cost cap directed in D.04-12-048 and will consider cost-and saving-sharing ratemaking mechanisms on a case-by-case basis.

54. We do not adopt a Rulebook at this time, but encourage ED, IOUs and other parties to work towards a Commission endorsed "AB 57 Procurement Plan Implementation Manual" for each IOU.

55. We do not adopt any new rules regarding implementation of AB 1576 repowering projects, but reiterate our order from D.04-12-148 ". . . to consider the use of Brownfield sites first and take full advantage of their location before they consider building new generation on Greenfield sites. If IOUs decide not to use Brownfield, they must make a showing that justifies their decision." All the benefits and impacts of AB 1576 projects should be properly considered and evaluated in an RFO - including quantifiable economic benefits and impacts, and non-quantifiable social and environmental benefits and impacts. This direction applies to re-powered or replacement options presented in a RFO, not just UOG projects.

56. All three LTPPs could have been strengthened by the inclusion of a methodology for analyzing the GHG implications of the different resources the IOUs can use to fill their net-short positions.

57. Zero-or low-GHG resources are to receive priority over other procurement options.

58. IOUs are to provide absolute GHG emissions, with cost implications, under various scenarios in their future LTPP filings.

59. Given that a 33% renewables target has not been adopted, it is reasonable to approve the IOUs' treatment of this target in their 2006 LTPPs.

60. Given that MRTU is anticipated to be in place in Spring 2008, we will monitor its implementation and make any appropriate and necessary changes to our procurement rules.

61. It is reasonable to adopt PG&E's proposed modifications to the definitions of Financial Swaps" and "Electricity Transmission Products," but PG&E is to include details regarding transactions that involve these products in its QCR.

62. We find it reasonable that an IOU must publicly reveal the names of winning bidders, a description of the product, and the contract term, within thirty days of when the IOU files an application for approval of the contract. The IOU may keep the identity of the winning bidder confidential until key commercial terms have been finalized and if that does not occur within the ninety day time frame, the IOU should withdraw the application and re-file once it can release the bidder's identity and other required information. The IOU does not have to publicly reveal the actual contract.

63. The utilities propose a number of policies, some of which we specifically address in this decision. We express no opinion on the merit of the policies and positions presented in the LTPPs which we have not specifically addressed in this decision, and we do not adopt, modify or reject any of them.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) shall make a compliance filing conforming their 2006 long-term procurement plans (LTPP) no later than 90 days from the date of this decision. The conformed 2006 LTPPs shall incorporate all of our directives contained in the body of this decision as well as any updates filed through the Commission's Advice Letter process between the issuance of this decision and the due date of the compliance filing. We direct each IOU to separately file a Tier 3 Advice Letter when it submits its Compliance Filing for approval.

2. In the interim, the 2006 LTPPs are adopted with the requirements stipulated in this decision and summarized in the Ordering Paragraphs and the Compliance Table provided as Appendix E.

3. When executing procurement plans in response to this decision, PG&E, SCE and SDG&E shall reflect in the design of their requests for offers (RFO) compliance with the Energy Action Plan (EAP) preferred resource loading order and with greenhouse gas (GHG) reductions goals. Any application for fossil generation filed in response to this decision, shall demonstrate how the resource fits into the investor owned utility's (IOU) GHG reduction strategy.

4. PG&E is authorized to procure 800 – 1,200 MW of new resources (including fossil fuel resources) by 2015.

5. SCE is authorized to procure 1,200 – 1,700 MW of new resources (including fossil fuel resources), in addition to the 305 MW remaining from its standard-track RFO, by 2015.

6. SDG&E is authorized to procure 530 MW of new resources (including fossil fuel resources) by 2015 in its local area if its application for the Sunrise Powerlink is denied. This authorization includes the 130 MW of local peakers already approved by the Commission. SDG&E is also authorized to procure the equivalent quantity of local capacity associated with any retirements of local area resources that occur beyond the amount of retirements it forecasts in its LTPP.

7. PG&E, SCE and SDG&E are directed to continue utilizing procurement review groups (PRG) as advisors for their procurement activities and to implement the following:

- a web-based PRG calendar with expected solicitation milestones;
- a PRG meeting agenda and materials delivered to members 48 hours in advance of a meeting;
- Meeting summaries; and
- Web-based forum for public dissemination of meeting information.

8. For any procurement for which an IOU seeks to recover costs from bundled and unbundled customers using the Cost Allocation Method (CAM) from Decision (D.) 06-07-029, the PRG shall include one member representing community choice aggregator (CCA) customers and two members representing direct access (DA) customers. If future Commission definition of the CAM identifies non-bundled customers in addition to CCA customers and DA customers, they shall be represented by one member in the CAM Group.

9. PG&E, SCE and SDG&E are directed to continue using an Independent Evaluators (IE), subject to the modifications and revisions adopted in this decision to the process initiated in D.04-12-048. IEs are to be used for all long-term solicitations that involve affiliate transactions or utility-owned or utility-turnkey bids and for all competitive RFOs seeking products greater than three months in length regardless of the bidders. Competitive RFOs include RFOs

issues to satisfy service area need and supply-side resources not including EE and DR.

10. PG&E, SCE and SDG&E shall do the following regarding the IEs:

- Develop a pool of at least three, but preferably more, IEs to be used beginning January 1, 2009, and rotate through the IEs for its RFOs, following the directives set forth in full in the decision.
- Energy Division (ED) should be involved during the selection process, the development of the scope of work and the drafting of the terms of the contracts with the IE and have the right to final approval of such engagements. ED has the right to final approval of the selection of an IE for each RFO.
- Information on each IE used in a procurement solicitation, type of solicitation the IE was used for and the amount of money involved in the procurement solicitation be reported to the IOU's PRG before and after the solicitation takes place.
- For solicitations of less than five years, the IE report shall be filed with the IOU's Quarterly Compliance Report (QCR).
- The IOUs, in conjunction with the PRG and ED, shall develop comprehensive conflict-of-interest disclosure requirements for the IE.
- An IE may be disqualified from participating in the RFO process if there are particular egregious conflicts of interest that arise during the contract.

11. These directives regarding IEs shall continue until further Commission order.

12. ED is directed to develop a template for IEs to use when developing their reports. This template is to be developed through a public process and is to be submitted for public comment no later than 30 days after this decision is issued.

13. The Executive Director may hire and manage one or more contractors to perform tasks described in this order for the purpose of advancing the goals of the Commission's Long-Term Procurement Planning Process. Such costs, if any, shall not exceed a total annual amount of $400,000, and the total shall be paid by

PG&E, SCE and SDG&E on a proportional basis in relation to procurement related costs as reported in the Annual Energy Resource Recovery Account (ERRA) reports. SCE, PG&E and SDG&E are authorized to establish an LTPP Technical Assistance Memorandum Account (LTAMA) for the purpose of recording such payments. PG&E, SCE, SDG&E are authorized to record these LTPP technical contractor costs into the LTAMA. These costs shall be recorded when paid, and each company may later apply for recovery in rates.

14. The IOUs are not to create any false barriers to participation in RFOs or to attempt to limit the competitive process by manipulating RFO product descriptions.

15. The IOUs are to hold a meeting with the IE, PRG and ED to outline their plans and solicit feedback prior to drafting RFO bid documents so that the RFO process is improved by the identification of data gaps, confirmation of the fairness of the confidential components of the RFO, and of the compliance with the letter and spirit of Commission policies on procurement practices.

16. Draft RFO bid documents are to be developed under the oversight of an IE, vetted through the PRGs and any differences resolved by ED staff in advance of the public issuance of the bid documents.

17. IOUs may not initiate an RFO for new fossil resources that have not been formally authorized in a LTPP decision, unless the IOU makes a strong showing in advance, via an approved Advice Letter, that unusual or extreme circumstances warrant such an action.

18. ED is to develop a template that includes the information set forth in this decision, for IOUs to use when developing an application for approval of winning bid projects. This template is to be developed through a public process

and is to be submitted for public comment no later than 30 days after this decision is issued.

19. Provided the procurement complies with a procurement limit methodology developed by the IOU and approved by the Commission, an IOU may execute a contract of under five years without preapproval for which deliveries end at any point within the 10-year LTPP procurement cycle. Absent an approved procurement limit methodology, the five-year duration clock begins either at the time the contracted resources begin delivery, if delivery begins within one year of contract execution; or at the time of contract execution if delivery does not begin within one year of contract execution. Calendar days are used for calculating contract duration.

20. The IOUs are to use a rolling 12-month to calculate TEVaR and make appropriate comparisons for purposes of determining whether to take steps to level price volatility within the CRT threshold.

21. IOUs are to use a TEVaR 95% rather than TEVaR 99% for guiding hedging decisions. We do not change the CRT level or the 125% threshold metric and maintain the looking forward up to five years reporting requirement.

22. The IOUs are authorized to coordinate the updates for the portfolios for the scheduling of gas supply and hedging plans and the updates are to be made annually at the time of the ERRA filings. The IOUs are also authorized to update their gas supply and hedge plans with the Commission for their Department of Water Resources (DWR) portfolios annually, instead of twice a year. This does not affect the IOUs obligations to DWR.

23. While we agree in principle with a number of PG&E and SCE's proposed changed to their respective gas and electricity product risk management approaches we determine that more analysis is necessary before they can be

adopted by the Commission. Until revised risk management approaches are formally adopted by the Commission, we require the IOU's to continue operating under their existing Commission approved risk management practices.

24. The nuclear and coal fuel plans proposed by the IOUs are adopted as presented. We do not adopt the gas supply procurement proposals of the IOUs because the Commission must address and review proposals by the IOUs more thoroughly than we have in this current proceeding and asses the proposals in conjunction with other rulemaking proceedings. In order for the IOUs to continue necessary gas supply procurement for their electric generation requirements, the Commission authorizes the IOUs to continue operation under existing gas supply plans approved in the 2004 LTPP and 2005 Short-Term Procurement Plans until new supply plans are approved by the Commission.

25. We direct the IOUs to develop a common numbering system, with a redline strikeout method, similar to the one used to track tariff revisions (General Order 96-B 8.4.2.), to track revisions to each Commission-approved LTPP.

26. All IOU updates or modifications to their procurement plans proposed between the biennial procurement plan filings, via the Advice Letter process, are to include redlined pages of the existing procurement plan as well as "cleaned up" replacement pages which include the tariff-like numbering ordered above.

27. We direct the ED, in conjunction with the external auditors and the IOUs to continue the collaborative effort formed earlier this year and develop a reformatted QCR. We delegate authority to ED to authorize the implementation of the reformatted and streamlined QCRs and to make ministerial changes to the content and format of the report as needs arise.

28. We increase the timeframe for approving the QCRs from the current 30-day requirement to 60 days.

29. D.07-04-020 allows that the utilities only supply a breakdown of costs with their ERRA monthly filings and make all supporting documentation available to Commission Staff and interested parties upon request.

30. IOUs can not issue RFOs that seek both Power Purchase Agreements (PPAs) and Utility build bids.

31. UOG applications by the IOUs outside of an RFO must fit into a unique circumstance, which are limited to market power mitigation, reliability, preferred resources, expansion of existing facilities, or be a unique opportunity, as described in the decision, and each application will be considered on a case-by-case basis. The IOU is required to make a showing that holding a competitive RFO is infeasible.

32. IOUs will no longer be allowed to consider as an option in their competitive PPA RFOs the transfer of the fully depreciated resource underlying a PPA to the IOUs.

33. We eliminate the "50/50 cost cap" directed in D.04-12-048 and will consider cost- and saving-sharing ratemaking mechanisms on a case-by-case basis and the requested treatment must be justified by unique circumstances.

34. ED staff is to continue to work with the IOUs and other interested parties to create a Commission-endorsed "AB 57 Procurement Plan Implementation Manual" for each IOU that includes the comprehensive set of procurement rules, including any IOU-specific requirements, that can be accessed by all interested market participants to determine each IOU's compliance with its AB 57 Procurement Plan.

35. IOUs are to consider the use of Brownfield sites first and take full advantage of their location before they consider building new generation on Greenfield sites. If IOUs decide not to use Brownfield, they must make a showing that justifies their decision. All the benefits and impacts of AB 1576 projects should be properly considered and evaluated in an RFO - including quantifiable economic benefits and impacts, and non-quantifiable social and environmental benefits and impacts. This direction applies to re-powered or replacement options presented in a RFO, not just UOG projects.

36. IOUs may no longer apply a 20% DE "bid adder" as a bid evaluation tool when evaluating PPAs.

37. We find it reasonable to adopt PG&E's proposed modifications to the definitions of "Financial Swaps" and "Electricity Transmission Products" but PG&E is to include details regarding transactions that involve these products in its QCR.

38. An IOU must publicly reveal the names of winning bidders, a description of the product, and the contract term, within 30 days of when the IOU files an application for approval of the contract. The IOU may keep the identity of the winning bidder confidential until key commercial terms have been finalized and if that does not occur within the 30-day time frame, the IOU should withdraw the application and re-file once it can release the bidder's identity and other required information. The IOU does not have to publicly reveal the actual contract.

39. The utilities propose a number of policies, some of which we specifically address in this decision. We express no opinion on the merit of the policies and positions presented in the LTPPs which we have not specifically addressed in this decision, and we do not adopt, modify or reject any of them.

This order is effective today.

Dated December 20, 2007, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners