CALIFORNIA
ENERGY
COMMISSION

REVISED INVESTOR-OWNED UTILITY RESOURCE PLAN SUMMARY ASSESSMENT

Prepared for the
2005 Integrated Energy Policy Report
Proceeding Docket # 04-IEP-1

NOTE: THIS VERSION INCORPORATES THE JUNE 24, 2005, ERRATA INTO THE ORIGINAL JUNE 17, 2005, STAFF REPORT.

STAFF REPORT

June 2005
CEC-700-2005-014

STATE OF CALIFORNIA
ENERGY COMMISSION

Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

Ross Miller
Principal Author

Al Alvarado
Project Manager

David Ashuckian
Manager
ELECTRICITY ANALYSIS OFFICE

Terry O'Brien
Deputy Director
SYSTEMS ASSESSMENT & FACILITIES SITING

Kevin Kennedy
Program Manager
2005 Energy Report

Scott W. Matthews
Acting Executive Director

Acknowledgements

Many thanks are due to the following contributing authors of this report: Sylvia Bender (Energy Efficiency), David Hungerford (Price-Sensitive Demand Response), Drake Johnson, Melinda Merritt, Pamela Doughman and Todd Lieberg (RPS-Eligible Renewables), and Mark Rawson (Distributed Generation).

Technical editors Karen Griffin and Mike Jaske gave valuable assistance to the authors.

Thanks are also due for the professional technical support provided by Heather Raitt, Jim Hoffsis (RPS-Eligible Renewables); Connie Leni, Richard Jensen, Adam Pan, David Vidaver, Jim Woodward, Angela Tanghetti (IOU Resource Planning); Barbara Byron (Nuclear Facilities); Ruben Tavares (Resource Plan Costs); Pierre duVair (Greenhouse Gas Adder); Jairam Gopal (Natural Gas Price Forecast); Joel Klein (Electricity Price Forecast); Mark Hesters (Transmission); Lynn Marshall and Tom Gorin (Demand Analysis); and Micah Fuller (Environmental Effects).

Lastly, the report benefited greatly from the able clerical, administrative and editorial support given by Barbara Crume, MaryAnn Miller, Tom Glaviano, Kevin Kennedy, and Carolyn Walker.

This report is dedicated to the memory of the Energy Commission's Editor:

Elizabeth Parkhurst
July 8, 1953 - May 13, 2005

Table of Contents

Page

List of Appendices

CHAPTER 1: INTRODUCTION

To help evaluate electricity demand and supply, the California Energy Commission (Energy Commission) directed load-serving entities (LSEs) with a peak demand over 200 megawatts (MW) to file retail price forecasts, demand forecasts, resource plans, and related materials. The three largest investor-owned utilities (IOUs)—Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E)—were asked to file a number of "resource plans" to identify their expected electricity peak demand and energy requirements and to explain how they planned to meet those requirements under a variety of contingencies.

Energy Commission staff has prepared this report in support of one of the key goals for the *2005 Integrated Energy Policy Report* (*Energy Report*): the close coordination between the *Energy Report* proceeding and the California Public Utilities Commission's (CPUC) pending 2006 long-term procurement proceeding (LTPP). In this report, Energy Commission staff provides a summary of these resource plan filings (to the extent possible given confidentiality constraints). This report also adds value to the IOUs' raw filings with respect to these features:

- Transparency: staff has identified assumptions not explicit in the IOU analyses.
- Conformity: staff has described specific procurement mandates and assessed the extent to which the IOUs plans comply with them, including a description of the decision-making criteria used by the IOUs to select resources to meet the mandates.
- Validity: staff has evaluated the IOU's conclusions for coherence, consistency, and plausibility.
- Veracity: staff has compared factual statements to reference information where available and checked computations for accuracy.
- Consistency: staff has described inconsistencies that appear across IOU analyses.

An Integrated Energy Policy Report Committee (Committee) scheduled a workshop June 29, 2005, at the Energy Commission to discuss the IOU resource plans and staff's review of them. On June 30, 2005, a Committee workshop will be held to discuss the demand forecasts developed by staff and those submitted by the various load serving entities.

This chapter explains the planning conventions and formats for these resource plan filings, including confidentiality considerations that limit the public disclosure of much of the information filed by the utilities. The report also identifies a wide variety of issues that affect IOU procurement activities. Staff expects further discussion of these issues in other reports and workshops in the *Energy Report* proceeding.

CPUC Regulation of IOU Procurement

Assembly Bill 57 (Chapter 835, Statutes of 2002, Wright) directs the CPUC to review and approve electric utility plans to procure electrical generation capacity, energy services and generation fuel supplies. The procurement plans are to include at least one of the following: (1) a competitive procurement process; (2) a procurement incentive mechanism; or (3) upfront standards and criteria. The CPUC's approval eliminates the need for "after-the-fact" reasonableness reviews of individual procurement transactions. When implementing their procurement plans, the CPUC has required the IOUs to consult a Procurement Review Group (PRG), which is comprised of CPUC and Energy Commission representatives, various consumer representatives, and other non-market participant parties. The IOUs then demonstrate that they have conducted their procurement activities in compliance with the CPUC-approved procurement plan by filing quarterly compliance advice letter filings, which are reviewed by the CPUC's Energy Division. This process ensures that the utility can recover from its customers the costs of procurement activities that comply with the CPUC-approved procurement plan. This mechanism also allows some measure of public review of IOU procurement without revealing the IOUs' sensitive information to other market participants.

Electricity resource procurement by PG&E, SCE and SDG&E, as overseen by the CPUC, is broadly characterized by two key features. First, the IOU must meet electricity generation and transmission system constraints and a variety of energy policy constraints. These constraints include:

- Individual generation resource operation constraints,
- Transmission system reliability requirements that require control area operators to maintain a minimum level of operating reserves,
- Resource adequacy requirements of Load Serving Entities (LSEs),
- Energy efficiency resource procurement requirements,
- Electricity retailers' Renewable Portfolio Standard obligations,
- Environmental regulations governing power plant emissions, and
- CPUC-approved upfront procurement standards or specific requirements.

Second, the IOUs have been given limited discretion by the CPUC to select resources based on least-cost best-fit selection criteria. The CPUC's decisions help define the criteria and impose specific requirements, such as including an "adder" representing the financial risk of a future greenhouse gas emissions cost. Least-cost best-fit criteria include market valuation, portfolio fit, technology risk, credit risk, and transmission and environmental factors. Specific details of the least-cost best-fit decision criteria vary by IOU and are considered confidential. Sometimes, least-cost best-fit decisions may be subordinated to long-term policy decisions that take more social and strategic factors into account. A specific example is the policy requirement for the minimum renewables energy procurement obligation of the

Renewables Portfolio Standard Program. Other times, policy requirements give the least-cost best-fit criteria precedence; for example, once the minimum RPS obligation has been fulfilled, the IOUs must select resources using the least-cost best-fit criteria.

Resource Plan Conventions

The Electricity Resources Forms and Instructions[1] (or Forms and Instructions) direct the three large IOUs to submit long-term electricity resource plans to the Energy Commission. The Forms and Instructions organize the IOUs' plans to present trends, uncertainties and issues of ongoing interest to parties monitoring the IOUs' long-term electricity resource procurement activities.

These resource plans demonstrate that the IOUs plan to meet the constraints imposed on their future procurement activities. The do not predict the specific resources IOUs will procure as a result of those activities. The mix of specific resources that will ultimately result from competitive all-source solicitations depends on what projects are bid into the solicitations, and how well they meet the least-cost, best-fit selection criteria. Since these resource plans are not predictions of what specific resources will actually be procured, they cannot provide estimates of resource-specific impacts, such as environmental attributes. Least-cost, best-fit procurement creates an opportunity for the widest menu of resource options to compete in the solicitations. Therefore, the results of competitive all-source solicitations will not be predictable today.

In general, the resource plans directed by the Forms and Instructions describe potential future portfolios of dependable capacity and energy resources that the IOUs estimate would meet their forecasted peak demand and energy requirements, but only for their bundled-service customers. The IOUs' resource plans do not include resources that would serve the peak demand and energy requirements of customers who choose energy service providers—customers choosing direct access, community choice aggregation, non-core energy service, or municipalization. As a result, these plans do not identify the amount of additional resources that might be required by the IOU to meet the peak demand and energy requirements for any customers returning to the IOU as their power provider of last resort.

Utility Viewpoint: Links Between Procurement Plan and Procurement Volume Limits - In SCE's Words

In 2004, the CPUC adopted a Resource Adequacy Requirement (RAR) to ensure [that] load serving entities procure 115-117 percent of their forecasted annual peak demand. Southern California Edison (SCE) sets its maximum annual capacity volume limits as the difference between a 117 percent of forecasted peak demand (1-in-2) and SCE's capacity position based on SCE's current resources. This volume limit enables SCE to procure sufficient capacity to meet RARs adopted by the CPUC but it is not an obligation or commitment to purchase that level of capacity. The energy purchase and sales volume limits as well as the natural gas purchase and sales volume limits are based on similar methods.

By setting the volume limits in this manner, SCE defines a boundary wide enough to ensure it has the authority to procure/sell all of its short or long positions in capacity, energy, or natural gas. These limits, are not necessarily SCE's targets, they are set at a reasonable bound above what procurement targets may be. There are no minimum limits.

Source: Marc Ulrich, SCE staff, personal communication

Format of the IOUs' Resource Plan Filings

The 2005 Energy Commission Forms and Instructions required the IOUs to file a Reference Case Resource Plan by March 1, 2005. Some of the key assumptions of the Reference Case were expressly determined by the Energy Commission in the Forms and Instructions:

- Energy efficiency savings will reduce demand by the targets set by the CPUC in D.04-09-060.

- Eligible renewable generation will reach 20 percent of retail sales no later than the year 2010, according to the Joint Agency Energy Action Plan.

- Price-responsive demand savings will reduce peak load by four percent in 2006 and five percent in 2007 and afterwards.

- No customers currently under bundled service will switch to direct access and no customers currently under direct access will return to the IOU for energy services.

- Beginning no earlier than 2007—but no later than 2013—the IOU must assume that it will lose some amount of bundled load to Community Choice Aggregation, and that the total amount during the planning period must be at least four percent, but no more than 10 percent, of bundled load.

As part of the description of this case, the IOUs are to provide detailed information as specified by the following five Supply Forms:

- S-1 Capacity Resource Accounting Table: This capacity supply and demand balance table includes monthly dependable (not nameplate) capacity for the years 2006 through 2016.
- S-2 Energy Resource Accounting Table: This energy supply and demand balance table includes monthly expected energy for the years 2006 through 2016.
- S-3 Generic Renewable Capacity and Energy Locations: These annual dependable-capacity-and-expected-energy tables provide an estimated geographic and technology breakout of the new generic renewable resources that would be procured (over and above generation from existing and planned renewable generation) to meet the IOU's Renewables Portfolio Standard annual procurement targets. These tables should be consistent with the S-1 and S-2 tables.
- S-4 QF Energy and Cost Projections: Individually, for each qualifying facility (QF) contract included in the resource plan, these forms are to provide a description of the contract and contract-pricing mechanism, dependable capacity, expected annual energy generation, annual energy cost and annual fixed costs. These tables should be consistent with the S-1 and S-2 tables.
- S-5 Bilateral Contracts: These forms provide information about existing bilateral contracts with suppliers of capacity or energy, excluding QF and California Department of Water Resources (CDWR) contracts (which are treated separately) and contracts with public utilities for the integration of hydroelectric generation facilities.

To better explain the information requested, the blank Supply Forms are reproduced as they appear in the Electricity Resources Forms and Instructions in Appendix A of this report. The resource plan compares expected electricity demand against expected supply from existing and planned (or committed) resources, identifying either a surplus or a gap in supply. Where demand is higher than existing and planned resources, the IOU identified the amount of the gap. This gap is indicative of the IOU's long-term "net open position," which reflects of the resources the CPUC will authorize the utility to procure. The Forms and Instructions require the IOU to identify how much of its net open position would be procured from the following "generic" resource categories:

- RPS-Eligible Renewables (to meet its minimum RPS annual procurement targets)
- Base Load
- Load-Following and Peaking
- Year-Round Load Following

- Seasonal Peaking

These resources would be procured by the IOUs through open, all-source solicitations. These are subject to the CPUC's long-term procurement rules, which reflect various resource-specific proceedings and legislative requirements.

The Supply Forms' description of the Reference Case were supposed to "include assessments of the major uncertainties which influence resource planning decisions, along with some discussion of their actual influence on the reference case resource plan."[2] As it turned out, however, the three IOUs filed their narrative descriptions of their Reference Cases as part of their descriptions of the additional scenarios that were requested by April 1 (see below).

In addition to the Reference Case the IOUs were directed to file, by April 1, 2005, additional materials, including an "Accelerated Renewables Scenario," which increased the Renewable Portfolio Standard annual procurement targets beyond what was required in the Reference Case. The IOUs were also requested to file a "Preferred Resource Plan," in which an IOU may depart from the Commission-specified assumptions in the Reference Case. In addition to alternative versions of Supply Forms S-1 through S-5, the "Preferred Resource Plan" should include a narrative that "incorporates the preferences, assessments, strategies, and judgments of the IOU."[3] Each of three IOUs submitted all three of these cases, although both SCE and SDG&E substituted an Alternate Case for the Preferred Resource Plan, explaining that these cases do not necessarily reflect their preferences.

If an IOU's Reference Case assumed a major new transmission project, then it was asked to provide an additional case without the transmission project, to help explain the project's impact on the resource plan. In their Reference Cases, SCE assumed the Devers Palo Verde 2 Transmission Project and SDG&E assumed a new 500 k-V transmission interconnection project. Both SCE and SDG&E filed variations on their Reference Cases without the new transmission projects. Since PG&E's Reference Case included only network reinforcements contained in its California Independent System Operator (CA ISO)-approved Grid Expansion Plan, it did not provide a "without transmission" alternative Reference Case.

Table of Definitions:
Defining Different Classes of Electricity Service Providers and Customers

Utility Distribution Company (UDC)	The utility that distributes electrical energy to end use customers connected to its distribution system. The UDC may or may not also be the customer's Energy Service Provider (ESP, see below).
Bundled Service Customer	A distribution customer of a UDC that also receives energy services from the UDC. This customer's distribution and energy services are said to be "bundled" together.
Publicly-Owned Utilities (POUs)	Locally owned and locally-controlled not-for-profit entities that supply and distribute electricity to retail loads using an integrated and interconnected system. This includes cooperatives, municipal utilities, and irrigation districts. It does not include Community Choice Aggregators, Power Pools, or water agencies that have generation to serve their own loads and/or for sale to others (e.g. MWD, CDWR, and USBR). POUs are subject to limited state-level regulation. POUs have a self-defined obligation to serve a local territory in which they are normally the sole provider of electric service.
Energy Service Provider (ESP)	An entity that provides energy services to a UDC's customers instead of the UDC performing that function. The UDC still distributes to the customers the energy that the ESP provides for them.
Load Serving Entity (LSE)	An umbrella term including all of the various classes of entities that provide energy services to end use customers. These include: • IOUs that are the LSEs for their bundled service end-use customers in their distribution service territories; • ESPs that are the LSEs for a UDC's direct access customers or a UDC's customers choosing non-core service; • Community Choice Aggregators that are the LSEs for a UDC's customers choosing community choice aggregation; • POUs that are the LSEs for the end use customers in their own distribution service territories; • Rural Electric Cooperatives that purchase wholesale power on behalf of their end-use customers; • Power Pools, such as Northern California Power Authority (NCPA), that plan, procure, schedule and operate like other LSEs
Provider of Last Resort	The UDC is the customers' energy services "provider of last resort" (should an LSE be unable to provide electricity to its customers as promised).
Community Choice Aggregation Customers	A UDC's end-use customers that receive their energy services from a Community Choice Aggregator under conditions of Community Choice Aggregation.
Community Choice Aggregator (CCA)	Any city or county whose governing board elects to combine the loads of its residents, businesses, and municipal facilities in a community wide electricity buyers' program; or any group of cities or counties whose governing boards have elected to combine the loads of their programs, through the formation of a joint powers agency .
Non-Core Customers	A UDC's end-use customers that receive their energy services from ESPs under conditions of Non-Core service. This class of service does not yet exist but is being considered as a policy option.
Core Customer	Another name for a UDC's bundled service customer, if non-core service has been implemented.
Returning Customers	Customers of an ESP or CCA that return to their UDC for energy services.
Departing Municipal Load	UDC customers that leave the UDC through the process of municipalization and become bundled service (distribution and energy) customers of a new or expanded POU.

Utility Viewpoint: “Bottom’s Up” Planning – In PG&E’s Words

PG&E employed a planning process substantively identical to that used in the development of its 2004 Integrated Resource Plan. This approach begins with the development of fundamental assumptions regarding future electric demand and operating requirements. Through an iterative process PG&E then develops a least-cost best-fit portfolio of resources. PG&E notes the “best-fit” aspect of the portfolio design is critical in the current planning environment, as current requirements significantly constrain its flexibility in resource decision-making.

PG&E’s resource planning process is designed to meet all customer demand requirements with safe and reliable energy resources while simultaneously satisfying state procurement objectives. Procurement objectives and requirements that must be considered in the planning process include compliance with resource adequacy rules, implementing demand response programs to meet a minimum of 5 percent of customer peak demand, energy efficiency programs to meet CPUC targets, and ensuring the portfolio includes a minimum of 20 percent renewable energy by 2010.

All of the portfolios developed for the *Energy Report* process achieve these requirements and objectives. Further, PG&E has designed a portfolio to minimize the risk of stranded costs should PG&E experience substantial bundled-load departures in the future. Portfolios were also analyzed for their environmental attributes and carbon-equivalent emissions.

Portfolios were constructed in a “bottoms-up” manner consistent with the EAP loading order. Beginning with the forecast of capacity and energy requirements for expected bundled customers (i.e., net of existing Direct Access (DA) and projected Community Choice Aggregation (CCA) and non-core load), losses for transmission and distribution and Unaccounted For Energy (UFE) are added to derive expected capacity and energy requirements. Energy Efficiency (EE) programs and existing interruptible programs reduce these requirements. Existing resources including Utility-Retained Generation, Qualifying Facility (QF) contracts, California Department of Water Resources (DWR)-assigned resources, and other existing contracts were subtracted from the load. Planned resources are then added to the portfolio, further reducing the Net Open Position (NOP).

The remaining NOP is filled using the preferred resources identified in the EAP. PG&E first included the target level of EE programs. Distributed generation is then added based on PG&E and California Energy Commission (Energy Commission) forecasts. Next, state mandated programs are added to the portfolio, including Demand Response (DR) and renewable resources. Decision 03-06-032 requires that price-induced DR provide 5 percent of capacity requirements at time of system peak by 2007 and going forward through the planning horizon. A variety of renewable resources are then added to the portfolio to meet the RPS annual procurement target (APT) of an additional 1 percent of energy requirements met by these resources each year, with total renewables of at least 20 percent of total energy requirements in 2010. Finally, PG&E added conventional thermal resources to balance out the remainder of its capacity and energy requirements. Conventional thermal resources include contracts with existing resources and new and efficient dispatchable, shaping and peaking resources, which may be either contracted for or utility-owned. PG&E’s preferred resource plan assumes all new resources will be deliverable to load.

PG&E’s resource planning process incorporates transmission in an iterative process. All resource plans included here assume all existing and new transmission contained in its most recent CAISO-approved Electric Transmission Grid Expansion Plan, which includes all network reinforcements necessary to meet expected load and are expected to minimize CAISO Reliability Must Run (RMR) requirements in PG&E’s service territory. The next PG&E Electric Transmission Grid Expansion Plan will incorporate the procurement anticipated in this resource plan. This is consistent with I.00-11-001 in that the transmission plan is developed based on resources that have been identified.

Source: Energy Commission Integrated Energy Policy Report, PG&E Electric Resource Supply & Transmission Plan, April 26, 2005, pages 4-5.

In addition to the Resource Plans, the Forms and Instructions make other specific requests of the IOUs, ranging from quantitative sensitivity analyses to qualitative discussions. These include either forecasts, assessments or discussions of the costs of the submitted scenarios, natural gas and wholesale electricity prices, local area reliability, incorporating a greenhouse gas adder in procurement, significant amounts of core/noncore departing load, early retirement of San Onofre Nuclear Generating Station (SONGS), as well as other requests. These requests are identified in each of the sections below where the IOUs' responses to those requests are discussed.

Confidentiality Considerations

This report is based on staff's evaluation of the resource plans provided by PG&E, SCE, and SDG&E. The IOUs requested confidential treatment for much of the requested resource planning information. The Energy Commission's Executive Director has granted those requests, in part. Consequently, although staff has reviewed all of the submitted information in this assessment, both confidential and public alike, the results of staff's assessment must be conveyed without revealing protected information.

The resource plans include monthly capacity and energy resource accounting tables showing the expected peak and energy demands for each utility's bundled service customers for every month from 2006 through 2016, along with additional quantitative and qualitative information requested by the Energy Commission. The IOUs' estimates of the resources they would have to be authorized to procure to meet future resource requirements, and assuming a 15 percent planning reserve margin, are embodied by the renewable and non-renewable generic resource additions at the end of the capacity and energy supply forms. These estimates, which reflect their expected net open positions under the circumstances of each scenario, have been granted confidentiality protections and cannot be revealed in this report. Appendix B includes public versions of these tables provided by the three utilities, which include summary annual energy data for the years 2009 through 2016 and some limited annual capacity data for the same years.

In spite of this limitation, some useful information can be disclosed about the specifics of how net open positions are derived. This report focuses on providing that information. In the process, many issues have been identified that also can be investigated further and publicly debated.

On June 3, 2005, staff proposed to the IOUs, potential disclosure of aggregated energy and capacity data (see Appendix C). In accordance with Energy Commission regulations, the IOUs have until June 17 to accept or appeal those aggregations. Aggregated data which can be disclosed will be published as a supplement to this report and will be available prior to the June 29 workshop.

Review of the IOU Resource Plan Filings

The following chapters summarize staff's review of, and conclusions about, the IOUs' resource plans. The initial four chapters of this review focus on the IOUs' efforts to incorporate the Energy Action Plan's "loading order" into their long-term resource procurement activities. Chapters 2 through 5 focus on these loading order resources: energy efficiency, price sensitive demand response, renewable resources that are eligible to satisfy electricity retailers' obligations under the Renewable Portfolio Standard Program, and distributed generation. The Joint Agency Energy Action Plan has expressed a preference for these resources. The detailed implementation of these preferences in IOU resource procurement is administered by the CPUC in a variety of proceedings specializing in each resource type, and integrated into the long-term procurement proceeding.

Chapter 6 summarizes and assesses assumptions made in the resource cases about selected existing and planned resources, including California Department of Water Resources (CDWR) and qualifying facility (QF) contracts. The chapter ends with a brief description of the generic resource needs shown in the IOUs' resource plans, without revealing protected information.

Chapter 7 summarizes and assesses selected resource plan impacts (e.g., total resource plan costs, local reliability) and sources of uncertainty which can have a material effect on resource plans and their impacts (e.g., wholesale electricity and natural gas prices, large generating unit availability, and loss of load to a non-core market).

Chapter 8 concludes the staff assessment with a summary and discussion of the transmission-related aspects of the IOUs' resource plan filings, including the IOUs' responses to specific directions in the Forms and Instructions related to transmission.

CHAPTER 2: ENERGY EFFICIENCY RESOURCES

Introduction

The purpose of this assessment is to review the energy efficiency assumptions in the investor-owned utilities' ten-year resource plans. Each utility is mandated to design a portfolio of energy efficiency programs that will meet or exceed a ten-year goal over the period 2004-2013. The review focuses specifically on (1) the transparency of the filings, (2) the extent to which the IOUs comply with the mandate, (3) the consistency and plausibility of the explanations provided with the filings, (4) the accuracy of the facts, and (5) and a discussion of any inconsistencies across the IOU analyses.

The assessment is organized into four sections. The first section describes the mandate for energy efficiency savings from the California Public Utilities Commission The next three sections report the findings from the assessments for San Diego Gas and Electric, Pacific Gas & Electric, and Southern California Edison. Each utility section is divided into discussion of peak savings, energy savings, Demand Form efficiency reporting compared to the Supply forms, and proposed 2006-2008 efficiency portfolios.

The data used in this assessment is drawn from Supply and Demand Forms:

- Supply Form S-1 Capacity Resource Accounting Table: This capacity supply and demand balance table includes monthly dependable (not nameplate) capacity for the years 2006 through 2016.

- Supply Form S-2 Energy Resource Accounting Table: This energy supply and demand balance table includes monthly expected energy for the years 2006 through 2016.

- Demand Form 3.1a. Efficiency Program First Year Costs and Impacts. Separate forms were filed for committed and uncommitted efficiency impacts.

Key findings from this assessment include the following:

- Reviewers of the IOU program portfolios are confident that the 2006-2008 programs will achieve the near term goals. The longer-term goals, however, cannot be met without greater effort by the IOUs in creating more innovative programs, capturing comprehensive savings, and avoiding lost opportunities.

- SDG&E's reported uncommitted energy efficiency is on target to meet the goals. SDG&E will be ahead by 3 MW and short by 109 GWh in 2013, according to its resource plan. SDG&E's use of a six-month lag for program ramp-up accounts for the shortfall.

- PG&E's reported uncommitted energy efficiency appears to lag the CPUC goals in 2013 by 1,286 GWh and 717 MW. A slower program ramp-up could account for the shortfall in savings. PG&E is trying a new mass market program approach for the residential and small commercial sector that could take time to develop. This program is responsible for more than half of their projected peak savings over 2006-2008.

- SCE provides two different energy efficiency scenarios among its four cases. The Reference Case matches the efficiency goals, but the Alternate Case results in significant shortfalls from the goals for both GWh and MW. In both cases, near-term projections are far more aggressive than required by the goals. SCE believes the post-2008 goals are not credible and a resource plan based on them would expose ratepayers to unnecessary risk.

- Each utility used a slightly different method of reporting efficiency savings. Supply and Demand forms often reported different values.

Mandate for Energy Efficiency Savings 2004-2013

The California Public Utilities Commission (CPUC) implemented the joint-agency *Energy Action Plan* by setting specific goals, defining program administration, and setting monitoring rules to assure delivery of reliable and cost-effective energy and peak savings. The energy savings will be funded both by the Public Goods Charge and additional funds in the procurement rates.

By D.04-09-060 (September 23, 2004),[4] the CPUC established numerical goals for electricity and natural gas savings for the state's four largest investor-owned utilities for 2004-2013. The decision requires that the most recently adopted goals be incorporated into procurement plan cycles. It also requires a demonstration that any filings presenting projections of supply-side resource needs, pipeline or transmission needs, proposing new facilities or otherwise utilizing projections of energy demand be consistent with these goals or any updates to them. This is reinforced in D.04-12-048 which requires the IOUs to meet or exceed the Energy Commission's energy efficiency goals over the next ten years, and specifically over the next energy efficiency program funding cycle (2006-2008).

Based on an evaluation of previous program experience and trends in cost-effectiveness, the maximum achievable potential for all efficiency programs was estimated to be 30,000 GWh statewide over the next decade.[5] This level was set as a long-term goal. "Maximum achievable" represents that portion of cost-effective savings that can be achieved through the most aggressive programmatic effort. The goal takes into account limiting factors, including constraints to ramping up program funding and the trend in market saturation for certain measures.

The state goals achieve 90 percent of the maximum achievable potential and 70 percent of the economic achievable ("cost-effective") potential as documented in the statewide Kema-Xenergy study.[6] Those statewide goals were based on a review of the economic potential for energy efficiency programs, i.e., the magnitude of savings that could be achieved by programs at a cost equal to or less than the projected cost of supply alternatives. These percentages may be larger or smaller at the utility level and will be discussed in each individual section. The individual goals for the three utilities will meet between 50-59 percent of their incremental electric energy needs over 2004-2013.

As Table 2-1 shows, the IOUs are expected to ramp up programs sufficiently to obtain an incremental, cumulative savings of 23,183 GWh and 4,885 MW by 2013. This is the most ambitious energy efficiency program in the country.

A planned update to the 2003 potential studies was not completed in time for use in the 2006-2008 program planning cycle. Therefore, the utilities relied on potential data from the original 2003 studies. No emerging technologies were included in the potential study.

The adopted goals apply to the 2006-2008 program cycle, but the IOUs only have to meet the 2008 target rather than each of the two intervening years. This is due to the change in counting conventions for programs which are funded in one year, but may not reach their full impact for a year or two. Adjustments will be reviewed by the CPUC's Energy Division. The decision recognized that some differences between the near-term numerical goals and the proposed portfolio savings levels for 2006-2008 may be appropriate as programs ramp up.

Table 2-1
Adopted Energy Efficiency Savings Goals for IOUs

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Total Annual Electricity Savings (GWh/yr)	1,838	1,838	2,032	2,275	2,505	2,538	2,465	2,513	2,547	2,631
Total Cumulative Savings (GWh/yr)	1,838	3,677	5,709	7,984	10,489	13,027	15,492	18,005	20,552	23,183
Total Peak Savings (MW)	379	757	1,199	1,677	2,205	2,740	3,259	3,789	4,328	4,885

Note: These totals include both baseline savings already in the Energy Commission forecast and incremental savings beyond the base level of savings.

Megawatt savings are an estimate of average peak savings over 560 hours, not coincident peak. Megawatt savings were based on the relationship between GWh and megawatts over the 2004-2005 program years. The conversion factors for the three utilities ranged from .19 to .21.

The new Energy Efficiency Policy Rules adopted on April 21, 2005 (D.05-04-051) tighten the rules for counting savings and set a plan for updating the goals as more experience is gained. Key features include:

- Programs should be designed to displace or defer more costly supply-side resources.

- Starting in 2006, expected kW, kWh and therms will be re-evaluated through load impact studies to adjust performance of previous years unless the measures or programs have well-established deemed savings values.

- Recognizes that the conversion factors used to calculate MW peak energy efficiency goals may need to be revised upward.

- Only actual installations will be counted toward goals, not commitments to install. This change will impact savings from new construction and standard performance programs which typically take more than one year to achieve installed savings

Several of the key uncertainties associated with the achievement of the energy efficiency goals are listed below. Some of these uncertainties are reflected in the IOUs' *2005 Energy Report* filings, chiefly the likelihood of achieving the post-2008 goals. Individual concerns will be addressed in the IOU-specific sections. Key uncertainties include:

- New determinations of remaining economic potential may increase or decrease the long-term goals.

- Corrections to overstated savings values for some widely used measures (CFLs and programmable thermostats, for example) may make achieving the goals more difficult.

- Requiring that only actual savings, without commitments, be counted could lead to an over-emphasis on shorter-term investments.

- An emphasis on achieving current-year savings could dampen interest in longer-term investments in efficiency, such as new construction and standard performance contracting.

- New evaluation protocols for measuring actual load impacts from efficiency programs will need to be adopted and adequately funded to assure the savings projections are realistic.

- Accurate measurement and attribution of savings from some of the traditional non-resource programs, such as information and outreach, codes and standards support, and emerging technologies could prove difficult and costly. Additional levels of uncertainty may be added by counting these kinds of programs.

- Critical peak pricing could shift program emphasis toward kW savings.

- Variations in defining peak savings, whether for the full daytime, a subset of hours near the instantaneous peak, or the instantaneous peak, hour itself have not been standardized by the CPUC for efficiency programs.

- The ability of the utilities to expand their reach to customers, increase the level of savings achieved per customer, and increase the probability that customers will both sustain these savings and come back for more will be critical for achieving post-2008 goals.

A March 26, 2004 addendum to the 2003 goals study translated the statewide energy savings goals into the individual IOU service territory levels. These goals are discussed in the individual IOU sections which follow.

San Diego Gas & Electric's Energy Efficiency Assumptions

SDG&E states in its April 1 filing that the goals for their service territory authorized by the CPUC in D.04-09-060 are aggressive, but achievable for 2006 through 2008. For the years beyond 2009, however, they believe the CPUC's stated goals will be difficult to attain. As stated in D.04-09-060, "…adjustments result in an adopted trajectory of GWh savings goals for SDG&E that is 118 percent of the cumulative maximum achievable potential presented in the disaggregated *Secret Energy Surplus Study*…" published in 2003 by Kema-Xenergy.. The 10-year electricity goals are shown in Table 2-2.

Table 2-2
SDG&E Total Electricity Program Savings Goals from D.04-09-060

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Total Annual Electricity Savings GWh/yr	268	268	281	285	284	282	274	263	222	215
Total Cumulative Savings GWh/yr	268	537	817	1102	1387	1669	1943	2205	2427	2642
Total Peak Savings (MW)	50	101	155	210	264	317	369	419	461	502

Notes:

(1) Total savings = all savings from energy efficiency programs funded by public goods charge and procurement funding.
This total includes savings from Energy efficiency programs already in the Energy Commission forecast.

(2) MW savings derived by multiplying GWh Savings by .19, average value SDG&E GWH to peak savings for 2004/5 applications.

This is an estimate of average peak savings during all the peak hours; = GWh savings in peak period/560 hours in period.

As shown above in the Table 2-2 notes, the goals are the sum of the baseline savings projected from the continuation of PGC-funded energy efficiency programs funded at the rate of $225 million per year, which is already in the Energy Commission's demand forecast, and an increment above that baseline. For SDG&E, the baseline savings are expected to be 142 GWh per year. The goals are based on the achievable cost-effective potential in each service territory as documented in the Kema Xenergy report.

SDG&E has provided three cases as part of its April 1 filing, but the Uncommitted Energy Efficiency data is the same across all cases. Adjustments for Direct Access had no impact on the efficiency savings for the forecast period 2009-2016.

The energy efficiency projections in the SDG&E filings generally are consistent with the "total savings" values shown in the table above. Other utilities have reported only incremental savings above the baseline efficiency PGC savings that already are included in the demand forecast. SDG&E provides no explanation of how they have avoided "double-counting" the portion of these goals already accounted for in the Energy Commission's demand forecast.

It is not clear from the April 1 Supply filing if SDG&E used any assumptions other than meeting the goals in projecting these savings estimates. Form 5 of the March 1 Demand Forms filing, however, does offer the explanation that uncommitted energy efficiency savings impacts for 2014-2016 "were estimated by applying forward looking forecasting techniques and are not based on any previous filing made to the Energy Commission or CPUC." These years are beyond the range of the current goals. Committed and uncommitted impacts for the earlier years were based on the goals in D.04-09-060 and the work papers supporting the 2004-2005 energy efficiency program impacts filed with the CPUC.

Energy Savings

Table 2-3 compares the annual uncommitted GWh values from SDG&E Form S-2 Line 6 to the adopted goals for the years 2009-2013. Annual uncommitted savings are shown on Line 2 and the adopted goals are shown on Line 5. Savings from 2004-2008 are counted as committed and appear on the SDG&E's Demand Forms.

Over this period SDG&E lags the goals by 108 GWh, less than one year's incremental savings. SDG&E uses a six-month lagged average in calculating their annual targets. The lag compensates for the new policy rules which permit counting savings only in the year of actual realization. Achievement of actual savings in programs such as new construction programs and standard performance contract projects typically lag two to three years.

Despite the concern described earlier about exceeding achievable savings, SDG&E projects much more aggressive annual GWh savings over the period 2014-2016 from Supply Form S-2 (shown in Table 2-3 Line 2), averaging 20 percent higher than the goals and 35 percent higher than their projected savings reported for 2009-2013. It seems unlikely that these projections could be supported given the current potential estimates. The 2014-2015 savings appear more reasonable, however, if the savings include lagged savings from longer-term projects that are finally implemented over these later years.

Peak Savings (MW)

Table 2-4 contains a comparison of Supply Form S-1 Line 7 and the adopted peak demand goals. Uncommitted megawatts are shown on Line 1 and the adopted goals are on Line 4. There is a close approximation between the expected demand reductions from efficiency and the adopted peak goals when the base year for the megawatt goals is adjusted.

Before the Supply Forms can be compared to the adopted goals, the time bases must be made comparable as they each begin in a different year. The goals start in 2004, while the uncommitted savings on Supply Form S-1 begin in 2009. Removing the 263 MW added during the 2004-2008 period makes the two comparable. This adjustment is shown in Table 2-5 on Line 5. SDG&E will be ahead of the 2013 target by 3 MW in 2013.

SDG&E's Form S-1 reports a continuously increasing megawatt value across the months and years. The highest value always appears in December, not the expected peak month. SDG&E chooses to reflect their peak demand savings as the full amount of capacity available each month, incorporating incremental additions into the running cumulative total, rather than expressing capacity needed by season.

Table 2-3
San Diego Gas and Electric, Comparison of Supply Filings to Adopted Energy Efficiency Goals - Energy GWh

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	Uncommitted Energy Efficiency, 2006-2016 GWh From Form S-2	0	0	0	0	0	141	419	687	929	1,148	1,431	1,741	2,056
2	Annual Increment	0	0	0	0	0	141	278	268	242	218	283	310	314
3														
4	CPUC Energy Efficiency Goals													
5	Annual GWh Goal as Adopted	268	268	280	285	284	283	274	262	222	215			
6	Baseline Savings in Energy Commission Forecast	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
7	Incremental Savings Needed	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
8														
9	S-2 Annual Increment + Baseline (2+6)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
10	Difference From Goal (2-5)						**(142)**	**4**	**6**	**20**	**3**			
11	Difference of Annual Increment and Incremental Savings Needed for Goal (9-4)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Table 2-4
San Diego Gas and Electric, Comparison of Supply Filings to Adopted Energy Efficiency Goals - Peak MW

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	**Uncommitted Energy Efficiency, 2006-2016 Highest MW From Form S-1 Line 7**	0	0	0	0	0	48	103	152	196	242	300	363	423
2														
3	**CPUC Energy Efficiency Goals**													
4	**Total MW Goal as Adopted**	50	101	155	209	263	317	369	419	461	502			
5	**Adjusted Goal (2004-2009 MW Removed to Make Base Year Comparable**						54	106	156	198	239			
6														
7	**Difference From Adjusted Goal (1-5)**						**(6)**	**(3)**	**(4)**	**(2)**	**3**			

Comparison of GWh Supply and Demand Forms

SDG&E's GWh projections over the period are the same on both the Supply and Demand Forms. Table 2-5 compares the GWh first-year savings for 2004-2016 reported on Demand Form 3.1a with the goals in the adopted decision for the period 2004-2013; the decision has no goals projected past 2013. Committed savings were reported in the February 1, 2005 filing and uncommitted savings on March 1, 2005 as requested.

SDG&E comments that it expects the CPUC to reevaluate these goals before 2009 and that this reevaluation will likely result in "more realistic and achievable goals for SDG&E." [7] This is consistent with the decision, which states that the "adopted goals will be updated every three years in concert with a three-year program planning and funding cycle for energy efficiency…" The next update will be for the 2009-2011 program cycle and will be "based on updated savings potential estimates, accomplishment data and other evaluation studies, as appropriate."[8]

Table 2-5
Comparison of Demand Forms to SDG&E GWh Goals

Demand Form 3.1a 2/1/05	2004	2005	2006	2007	2008	Cum.Total 2004-2008
Committed GWh 2004-08	270	270	278	278	278	**1,374**
Decision Goals	268	268	280	285	284	**1,385**
Difference	2	2	(2)	(7)	(6)	**(11)**
Demand Form 3.1a 3/1/05	**2009**	**2010**	**2011**	**2012**	**2013**	**Cum.Total 2009-2013**
Uncommitted GWh 2009-13	141	278	268	242	218	**1,147**
Decision Goals	283	274	262	222	215	**1,255**
Difference	(142)	4	6	20	3	**(108)**
Demand Form 3.1a	**2014**	**2015**	**2016**			**Cum Total 2014-2016**
Uncommitted GWh 2014-16	284	311	314			**909**

Comparison of MW Supply Forms and Demand Forms

There is a difference in the savings reported on the Demand and Supply forms for the incremental MW added each year over the period 2009-2016.

Table 2-6 summarizes the committed and uncommitted peak savings reported on Demand Forms 3.1a by SDG&E on February 1, 2005 and March 1, 2005. SDG&E's projections are 10 MW over the goals for the period 2004-2008 and 20 MW less over the period 2009-2013 for a total shortfall of approximately 11 MW in 2013 due to the lagging effect. In comparison, SDG&E will surpass the 2013 goal by 3 MW according to the Supply Forms.

Table 2-6
Comparison of Demand Forms to SDG&E MW Goals

Demand Form 3..1a 2/1/05	2004	2005	2006	2007	2008	
Committed MW Annual	54	54	55	55	55	
Annual Goals	50	51	54	54	54	
Difference	4	3	1	1	1	
Demand Form 3.1a 3/1/05	**2009**	**2010**	**2011**	**2012**	**2013**	**2004-2013**
Uncommitted MW Annual	27	52	52	46	42	**491**
Annual Goals	54	52	50	42	41	**502**
Difference	(27)	0	2	4	1	**(11)**
	2014	**2015**	**2016**			
Uncommitted MW Incremental 2014-16	55	61	62			
Total MW in 2016						**669**

As it did for energy, SDG&E's forecast of peak savings from uncommitted efficiency incorporates a six-month lagged forecasting method to project progress toward meeting the goals. The projected 2009 MW savings anticipates that only one-half of the year's savings will actually be installed as the new program cycle begins. The larger increments over the period 2014-2016 likely represent the multi-year projects. It is doubtful that the increments shown for 2014-2016 are sustainable for SDG&E given the declining potential for additional savings shown in the original Kema-Xenergy study. In fact, these peak savings goals were set at 118 percent of the projected potential in the KEMA-Xenergy study. New potential data and/or the inclusion of new or emerging technologies into programs may offer additional achievable potential savings.

Preliminary 2006-2008 Program Plans

Preliminary 2006-2008 budget and savings estimates information presented on May 9, 2005 to SDG&E's Public Advisory Group (PAG) indicates that SDG&E will exceed its goals over the near term as shown in Table 2-7. Despite the concern over the potential for additional megawatts, these planned savings represent an aggressive reach beyond the goals. SDG&E surpassed their megawatt goal in 2004, but failed to meet the GWh goal in either 2003 or 2004.

These savings are estimated without program details on the 20 percent portion of the portfolio that will be bid to third-party implementers. Approximately 11 MW and 67 GWh are estimated to be delivered each year by these programs, but limited information about them is available at this time. Solicitations will begin after the June 1 compliance filing at the CPUC.

Table 2-7
SDG&E Preliminary 2006-2008 Portfolio Savings Estimates Compared to Goals

	2006		2007		2008	
	MW	GWH	MW	GWh	MW	GWh
Total Portfolio	57	294	63	323	69	353
CPUC Goals	55	281	54	285	54	284
Percentage	105%	105%	116%	113%	128%	124%

A Peer Review Group (PRG), a subset of representatives from the CPUC, Energy Commission, Office of Ratepayer Advocates and other financially disinterested members of the PAG, assessed these proposed programs. The PRG believes that, while the near-term goals are attainable, the longer-term goals will be much harder to reach. TecMarket Works, an evaluation consultant for the CPUC, also reviewed the program proposals in detail.[9] Issues identified by these groups with the SDG&E portfolio that could impact savings are:

- Difficulty in ramping up programs to the funding levels indicated,
- Possible inadequacy of local infrastructure to support programs (i.e., contractors, vendors), and
- Limited information on how well the goals will be supported by the reliance on bid programs (14 percent of budget), third-parties (19 percent of budget), and partnerships (10 percent of budget), whose efforts are beyond the direct control of SDG&E.

Pacific Gas and Electric's Energy Efficiency Assumptions

PG&E's *Electric Resource Supply and Transmission Plan* notes the following assumptions about energy efficiency: [10]

- The plan is designed to meet all customer demand requirements with "safe and reliable energy resources while simultaneously satisfying state procurement objectives."
- Energy efficiency programs will meet CPUC targets.
- All portfolios developed for the *2005 Energy Report* process achieve these requirements.
- Portfolios were constructed in a "bottoms-up" manner consistent with the *Energy Action Plan* loading order. Energy efficiency targets were included first.
- Energy efficiency targets are the same in all the resource plans

PG&E describes its energy efficiency in the preferred portfolio as consistent with the CPUC's targets in D.04-09-060. The portfolios are described as follows: [11]

- An aggressive ramp-up of multi-faceted programs in the residential, commercial and industrial markets"
- Air and space cooling and lighting equipment to meet net open needs for peaking power in the near-term
- Aggressive targeting of cost-effective energy savings during peak, off-peak and shoulder periods starting in 2007

Table 2-8 reports the PG&E savings goals.

Table 2-8
PG&E Total Electricity Program Savings Goals from D.04-09-060

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Total Annual Electricity Savings GWh/yr	744	744	829	944	1,053	1,067	1015	1,086	1,173	1,277
Total Cumulative Savings GWh/yr	744	1,487	2,317	3,260	4,313	5,381	6,396	7,483	8,656	9,993
Total Peak Savings (MW)	161	323	503	708	936	1,168	1,388	1,624	1,878	2,156

Notes:

(1) Total savings = all savings from energy efficiency programs funded by public goods charge and procurement funding.
This total includes savings from Energy efficiency programs already in the Energy Commission forecast

(2) MW savings derived by multiplying GWh Savings by .2.17, average value PG&E GWH to peak savings for 2004/5 applications.
This is an estimate of average peak savings during all the peak hours; = GWh savings in peak period/560 hours in period.

Energy Savings

PG&E's uncommitted energy efficiency forecast is compared to the adopted goals in Table 2-9. The adopted goals are separated into an annual base and additional incremental savings as calculated in the D.04-09-060 work papers.[12] This is shown on Lines 5-7 of Table 2-9. PG&E's baseline savings were projected to be 408 GWh per year in the adopted goals decision.

At first glance, the energy efficiency reported on Supply Form S-2 line 6 appears to vary from the adopted efficiency goals for PG&E by as much as 6,000 GWh in 2013. This is shown in Table 2-9. Closer inspection reveals several assumptions that account for part of this difference.

- Only incremental efficiency over the baseline is included in the PG&E efficiency GWh projections
- The base year is 2006 in the PG&E filing while it is 2004 for the efficiency goals

If these assumptions are modified, PG&E's projected savings align more closely with the adopted savings goals.

With these modifications, PG&E projections are 1,286 GWh short of the 2013 goal. This amount is comparable to one annual increment of savings. This could be a function of the actual installed date of program measures and the new rules for counting savings. PG&E's expectation that savings will be highest in the first year of a new three-year program cycle seems implausible unless the programs focus primarily on quick turn-around projects and installations. Ramping up new programs typically results in lower savings. Savings from new construction programs and other more comprehensive projects would take several years to be completed and counted.

Peak Savings

The peak values also start with a base year of 2006 for uncommitted savings as shown in Table 2-10. By adjusting the adopted goals to remove savings for 2004-2005, PG&E will be 717 MW short in 2013. This is a significant departure from the adopted goals.

The values shown in Table 2-10 on Line 1 represent the highest MW values for each year shown on Form S-1 that corresponds to the adopted goal years. MW values on PG&E's forms follow a seasonal pattern; peak values occur between June and October across the ten-year forecast period.

The modified goals were adjusted to remove the 323 MW of savings that is to be achieved over the period 2004-2005 as shown on Line 5 of Table 2-10. PG&E projects 1,116 MW over 2006-2013 compared to the 1,833 MW over 2006-2013 required by the goals. Line 7 on Table 2-10 shows the shortfall for each year.

Table 2-9
Pacific Gas and Electric, Comparison of Supply Filings to Adopted Energy Efficiency Goals - Energy GWh

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	**Uncommitted Energy Efficiency, 2006-2016 GWh From Form S-2**			433	736	1,151	1,680	2,215	2,693	3,246	3,895	4,638	5,365	6,074
2	**Annual Increment**			433	302	415	530	535	477	554	649	743	726	710
3														
4	**CPUC Energy Efficiency Goals**													
5	**Annual GWh Goal as Adopted (6+7)**	744	744	829	944	1053	1067	1015	1087	1173	1277			
6	**Baseline Savings in Energy Commission Forecast**	408	408	408	408	408	408	408	408	408	408			
7	**Incremental Savings Needed**	336	336	421	536	645	659	607	679	765	869			
8														
9	**S-2 Annual Increment + Baseline (2+6)**			841	710	823	938	943	885	962	1,057			
10	**Difference From Goal (5-9)**			**12**	**-234**	**-230**	**-129**	**-72**	**-202**	**-211**	**-220**			
11	**Difference of Annual Increment and Incremental Savings Needed for Goal (2-7)**			**12**	**-234**	**-230**	**-129**	**-72**	**-202**	**-211**	**-220**			

Table 2-10
Pacific Gas and Electric, Comparison of Supply Filings to Adopted Energy Efficiency Goals - Peak MW

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	**Uncommitted Energy Efficiency, 2006-2016 MW From Form S-1 Line 7**			117	198	311	439	578	709	871	1,116	1,258	1,402	1,596
2														
3	**CPUC Energy Efficiency Goals**													
4	**Total MW Goal as Adopted**	161	323	503	708	936	1,168	1,388	1,624	1,878	2,156			
5	**Adjusted Goal (2004-2005 MW Removed to Make Base Year Comparable)**			180	385	613	845	1,065	1,301	1,555	1,833			
6														
7	**Difference From Adjusted Goal (1-5)**			**-63**	**-187**	**-302**	**-406**	**-487**	**-592**	**-684**	**-717**			

While the goals require an average incremental addition of 230 MW, PG&E is only forecasting an additional 140 MW each year on average over the period 2006-2013. Line 1 in Table 2-10 represents PG&E's annual megawatts, while Line 5 is the adjusted annual goal. This does not appear to match the aggressive targeting of peak savings described in the resource plan.

Comparison of Supply and Demand Forms

The Supply and Demand forms appear to differ significantly. While the Supply Forms indicates that PG&E will be off target in meeting its 2013 goal, the Demand forms report that the goals for both gigawatt hours and megawatts will be met.

The Demand filing stipulates the following efficiency assumptions:

- 1996-2003 impacts are taken from the energy Efficiency Program Annual Report and Technical Appendix that is part of the annual Earnings Assessment proceeding.

- 2004 savings are derived from the Monthly Reports made to the CPUC's Energy Division. Both PGC and Procurement funded programs are included in the reported savings.

- 2006 and beyond has no adopted funding for the period and is uncommitted. The annual and cumulative targets as adopted in D.04-09-060 will apply to this period, but may be adjusted by the CPUC based on updated potential, changes to mandatory standards, and other evaluation studies.

The Table 2-11 reproduces the net recorded first-year savings from PG&E Demand Form 3.1a compared to the goals for the period 2004-2013. The historic period on the Demand Forms is 1996-2004; savings for 2005 forward are reported as forecasts/goals. The period 2004-2005 is designated as committed; 2006-2013 as uncommitted. This is contrary to what was requested in the Demand Forms and Instructions.

Form 3.1a indicates that PG&E will be slightly short on both GWh and MW in the committed period of 2004-2005. Starting in 2006, the values match exactly to the MW goals. The MW additions match the 2,156 MW goal in 2013, despite the 24 MW shortfall over 2004-2005. The slight energy savings shortfall is carried through to 2013.

Demand Form 3.2 shows cumulative impacts, designated by PG&E as "stream savings." While PG&E provides no specific definition of this term, it appears to refer to the inclusion of residual savings. Savings for 1996-2004 are first year savings plus residual savings from previous years (starting with 1996). The years 2005-2016 show only residual savings from the period 1996-2004. Here 2005 is counted as an uncommitted year, a difference from Form 3.1a. PG&E provides no information about how the uncommitted savings will be allocated by different programs or market sectors to meet the goals.

Table 2-11
PG&E Demand Forms Compared to Adopted Goals

Form 3.1a MW	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**Cumulative**
MW Total	117	188	503	708	936	1,168	1,388	1,624	1,878	2,156	2,158
GWh Annual	620	807	829	944	1,053	1,067	1,015	1,086	1,173	1,277	9,871
Goals Decision											
MW Total	161	323	503	708	936	1,168	1,388	1,624	1,878	2,156	2,158
GWh Annual	744	744	829	944	1,053	1,067	1,015	1,086	1,173	1,277	9,933

Preliminary 2006-2008 Programs

In their preliminary 2006-2008 program plans, filed on June 1, 2005, PG&E reported two different sets of projected savings. One set projects that the three-year goals will exceed the GWh/year by 12 percent and MW/year by 13 percent.[13] Later in another section of the filing, the annual energy savings exceed the target by 7 percent, but the demand savings show a shortfall of 8 percent.

PG&E is proposing to put two-thirds of its budget into a new Mass Market approach that will blend residential, multi-family residential and small business. This has potential to be very successful, but there is an increased risk in undertaking a change of this magnitude. At least half of their expected peak savings is projected to come from this program, so the consequence will be dramatic if it fails to deliver.

Southern California Edison's Energy Efficiency Assumptions

Southern California Edison (SCE) provides two different forecasts of energy efficiency in their Supply Form filings. The first is in the "reference case" as required by the Commission. The second is in an "alternate scenario" case based on different assumptions than those used in the "reference case." Energy efficiency projections in the Accelerated Renewables Case and the Reference Case w/o DPV-2 are identical to the Reference Case. SCE notes that in its Comments on the plans that "…the Energy Commission's Community Choice Aggregation and Energy Efficiency assumptions significantly alters future energy growth for SCE…"[14]

Table 1-1 in SCE's narrative comments compares the total efficiency energy savings over 2006-2016 for the four SCE cases. The values shown are 59,400 GWh for the Reference Case and 50,700 GWh for the Alternate Case. Since the statewide IOU total cumulative GWh goals for 2013 are 23,000 GWh with annual increments of less than 3,000 GWh, it is unclear why SCE reports these values.[15] They are the sum of the uncommitted values shown on Line 1 in Tables 2-13 and 2-14, however, these values are already accumulations of annual GWh savings.

SCE reports its efficiency goals as the sum of baseline savings projected from the continuation of committed PGC-funded energy efficiency programs through 2011 and an uncommitted increment above that baseline. In its Comments, SCE reports that it has "included the required levels of energy efficiency and demand response in its Reference Case."[16] SCE expresses doubt about meeting the adopted beyond 2011. "There is significant uncertainty, however, concerning whether these levels of EE and DR can be attained within the current cost-effectiveness guidelines."[17] SCE believes there is no credible analysis to support levels of efficiency beyond what it terms "Maximum Reliably Achievable Potential." Maximum Reliably Achievable Potential is defined as the portion of Maximum Achievable Potential that can be realistically and reliably attained for procurement planning purposes. This is the level used in the 2004 Long-Term Procurement Plan and the Alternate Case. SCE further comments that "directing SCE to implement a procurement plan based on the levels of EE and DR assumed by the Energy Commission could unnecessarily and unreasonably expose ratepayers to significant reliability and cost risk"[18]

The adopted goals, shown in Table 2-12 do require SCE to achieve a larger percentage of the remaining potential than either of the other utilities.

Table 2-12
SCE Total Electricity Program Savings Goals

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Total Annual Electricity Savings GWh/yr	826	826	922	1,046	1,167	1,189	1,176	1,164	1,151	1,139
Total Cumulative Savings GWh/yr	826	1,653	2,575	3,621	4,788	5,977	7,153	8,317	9,468	10,608
Total Peak Savings (MW)	167	334	541	760	1,006	1,255	1,502	1,747	1,988	2,228

Notes:

(1) Total savings = all savings from energy efficiency programs funded by public goods charge and procurement funding. This total includes savings from Energy efficiency programs already in the Energy Commission forecast. For incremental savings above the levels included in the Energy Commission forecast, see Attachment 9.
(2) GWh Savings converted to MW by multiplying by .21, average of utility GWh to peak savings for 2004/5 applications. This is an estimate of average peak savings not coincident peak = GWh savings in peak period/ 560 hours in period.

Energy Savings

In comparing what is reported on Supply Form S-2 line 6 for the Reference Case with the adopted goals, however, the savings do not at first appear to match up to the goals. Two adjustments must be made. First, the goals have to be adjusted up from sales level to generation level to match SCE's reported values. Second, committed savings from Demand Form 3.1a must be added to the annual uncommitted efficiency savings shown on the Supply forms.[19] These are added through 2011, which matches the PGC authorization period. The total of the uncommitted and committed energy savings are shown in Table 2-13 on Line 3. Comparing Line 3 to the generation level goals on Line 5b, SCE meets the adopted goals in its Reference Case as indicated on Line 10.

SCE proposes an Alternate Case based on its 2004 Long-Term Procurement Plan that uses utility-specific analysis of its "Maximum Reliably Achievable Potential (MRAP) for energy efficiency. This is the level that SCE believes can be attained reliably, and is, therefore, the appropriate level to include for procurement planning purposes."[20] SCE cites concerns of exposing customers to undue cost and reliability risks if the higher magnitudes of savings are used. The major reason for the difference in projected savings in this case is a steep decline in the annual increments of uncommitted savings as the market for some existing energy efficiency technologies becomes saturated toward the latter years of the forecast.

As shown below in Table 2-14, SCE's Alternate Case will fall below the adopted goals (adjusted to generation level) by approximately 1,448 GWh by 2013. SCE's annual GWh projections are shown on Line 2 and the annual goals on Line 5b of Table 2-14. With the combination of committed and uncommitted savings, SCE projects to be ahead of the goal at the end of 2008 by 497 GWh. This marks a much more aggressive effort over 2006-2008 than required by the goals. Post-2008, however, the projections of uncommitted savings exhibit a steady decline. When committed savings end in 2011, the decline becomes over 500 GWh per year.

SCE's assumption that it will be possible to add 970 new GWh in the first year of a new program cycle seems implausible based on the analysis of historic IOU savings and spending trends used to develop the goals. Coupled with the committed savings, the total will be 380 GWh above an already aggressive annual goal. Post-2011, SCE is adding half of the annual GWh needed to meet the goals. SCE's assumption that PGC funding will not be available after 2011 also seems unlikely.

Since both SCE's projections and the adopted goals relied on the same potential data, it is unclear why this difference of opinion about what is achievable is so large. The work papers for D.04-09-060 indicate that the cumulative goals in 2013 would represent approximately 89 percent of SCE's GWh maximum achievable potential and 99 percent of the MW maximum achievable potential.[21] An update to the previous potential study is due to be completed by September 2005. It is not yet clear whether the potential for SCE will increase or decrease.

Peak Savings

Peak savings in the Reference Case match the adopted goals. This is shown in Table 2-15 by comparing Line 3 with Line 6. Committed demand is added from Demand Form 3.1a through 2011. Adjustments are made for generation level projections.

In the Alternate Case, SCE will exceed the goals over the near term, but after 2009 the shortfalls grow steadily larger. This is shown in Table 2-16 on Line 7. Just as with the energy savings, the Alternate Case exceeds the Reference case over the near-term period. This would be consistent with the need for additional peak capacity in Southern California. Like the energy savings, once the committed savings end in 2011, the decline becomes steady as the incremental megawatt additions fail to keep pace with the goals.

Table 2-13
Southern California Edison, Comparison of Supply Filings to Adopted Energy Efficiency Goals - Energy GWh - IEPR Reference Case

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	**Uncommitted Energy Efficiency, 2006-2016 GWh From Form S-2**	0	0	591	1,323	2,189	3,096	4,013	4,939	6,186	7,421	8,656	9,890	11,125
2a	**Annual Increment**	0	0	591	732	907	866	917	925	1,248	1,235			
2b	**Annual Committed Incremental Energy Efficiency from Form 3.1a**			408	402	399	382	387	337					
3	**Total Annual Incremental EE (2a+2b)**			999	1,134	1,265	1,289	1,274	1,262	1,248	1,235			
4	**CPUC Energy Efficiency Goals**													
5a	**Annual GWh Goal as Adopted (sales level)**	826	826	922	1,046	1,167	1,189	1,176	1,164	1,151	1,139			
5b	**Annual GWh Goals as Adopted (generation level @ 1.084)**	895	895	922	1,134	1,265	1,289	1,274	1,282	1,248	1,235			
6	**Baseline Savings in Energy Commission Forecast**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA			
7	**Incremental Savings Needed**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA			
8														
9	**S-2 Annual Increment + Baseline**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA			
10	**Difference From Goal (3-5b)**			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**			
11	**Difference of Annual Increment and Incremental Savings Needed for Goal**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA			

Table 2-14
Southern California Edison, Comparison of Supply Filings
to Adopted Energy Efficiency Goals - Energy GWh - Alternate Case

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	**Uncommitted Energy Efficiency, 2006-2016 GWh on Form S-2, Line 6**			970	1,821	2,687	3,466	4,107	4,544	5,285	5,974	6,629	7,283	7,938
2a	**Annual Increment**			970	850	866	779	641	437	741	688			
2b	**Annual Committed Incremental Energy Efficiency from Form 3.1a**			408	402	399	382	357	337					
3	**Total Annual Incremental EE (2a+2b)**			1,378	1,252	1,265	1,161	1,176	1,164	741	688			
4	**CPUC Energy Efficiency Goals**													
5a	**Annual GWh Goal as Adopted**	826	826	922	1,046	1,167	1,189	1,176	1,164	1,151	1,139			
5b	**Annual GWh Goal as Adopted (generation level @1.084)**	895	895	999	1,134	1,265	1,289	1,274	1,262	1,248	1,235			
6	**Baseline Savings in Energy Commission Forecast**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA			
7	**Incremental Savings Needed**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA			
8														
9	**S-2 Annual Increment + Baseline (2+6)**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
10	**Difference From Goal (3-5b)**			**379**	**118**	**0**	**(128)**	**(277)**	**(487)**	**(507)**	**(547)**			
11	**Difference of Annual Increment and Incremental Savings Needed for Goal**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA			

Table 2-15
Southern California Edison, Comparison of Supply Filings to Adopted Energy Efficiency Goals - Peak MW - IEPR Reference Case

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	**Uncommitted Energy Efficiency, 2006-2016, Highest MW on Form S-1 Line 7**	0	0	149	311	502	698	895	1,093	1,354	1,614	1,874	2,134	2,395
2	**Committed Peak Demand from Form 3.1a**			75	150	226	300	371	439	439	439			
3	**Total Annual MW (1+2)**			224	461	728	998	1,266	1,532	1,793	2,053			
4	**Total MW Goal as Adopted**	167	334	541	760	1,006	1,255	1,502	1,747	1,988	2,228			
5	**Adjusted Goal (2004-2005 MW Removed to Make Base Year Comparable)**			207	426	672	921	1,168	1,413	1,654	1,894			
6	**Adjusted Goal (generation level @1.084)**			224	462	728	998	1,266	1,532	1,793	2,053			
7	**Difference From Adjusted Goal (3-6)**			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**			

Table 2-16
Southern California Edison, Comparison of Supply Filings to Adopted Energy Efficiency Goals - Peak MW - Alternate Case

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	**Uncommitted Energy Efficiency, 2006-2016, Highest MW on Form S-1 Line 7**			197	377	569	711	844	959	1,141	1,325	1,504	1,682	1,861
2	**Committed Peak Demand from Form 3.1a**			75	150	226	300	371	439	439	439			
3	**Total Annual MW (1+2)**			272	527	795	1,011	1,215	1,398	1,580	1,764			
4	**MW Goal as Adopted**	167	334	541	760	1,006	1,255	1,502	1,747	1,988	2,228			
5	**Adjusted Goal (2004-2005 MW Removed to Make Base Year Comparable)**			207	426	672	921	1,168	1,413	1,654	1,894			
6	**Adjusted Goal (generation level)**			224	462	728	998	1,266	1,532	1,793	2,053			
7	**Difference From Adjusted Goal (3-6)**			**48**	**65**	**67**	**13**	**(51)**	**(134)**	**(213)**	**(289)**			

Comparison of Supply Forms and Demand Forms

SCE filed their Demand Forms several months prior to the Supply Forms. Subsequent to their submission, an impact of 35 MW from additional funding for summer 2005 was incorporated into the Supply Forms as a one year adjustment in 2006.The values reported in Table 2-17 as uncommitted megawatts differ from the uncommitted megawatts shown on the Supply Forms across the entire period for that reason. For a comparison, refer to Line 1 on Table 2-15 for the Reference Case and Table 2-16 for the Alternate Case. The uncommitted energy savings vary from the Alternate Case only in 2006. Demand Form 3.1a projects 761 GWh for 2006 instead of 970 GWh shown on Line 2a of Table 2-14. This is also the result of the 2006 adjustment made for the added 209 GWh of summer 2005 activities. Aside from this adjustment and any rounding differences, the Demand Forms align with the Alternate Case Supply Forms.

Both MW and GWh savings are projected to exceed the goals over the near-term, but in 2009 a decline begins, as shown in Table 2-17.

Table 2-17
MW and GWh Projected Savings Compared to Goals from SCE Demand Forms

	2006	2007	2008	2009	2010	2011	2012	2013
Committed MW Form 3.1a	75	150	226	300	371	439	439	439
Uncommitted MW Form 3.1a	162	342	534	676	809	925	1108	1290
Total MW	237	492	760	976	1180	1364	1547	1729
Adopted Goal (generation level @1.084)	224	462	728	998	1266	1532	1793	2053
Difference	13	30	32	-22	-86	-168	-246	-324
Committed Annual GWh Form 3.1a	408	402	399	382	357	337		
Uncommitted GWh Form 3.1a	761	850	866	789	641	437	741	688
Total Annual GWh	1169	1252	1265	1171	998	774	741	688
Adopted Goal (generation level @1.084)	999	1,134	1265	1289	1274	1262	1248	1235
Difference	170	118	0	(118)	(276)	(488)	(507)	(547)

Preliminary 2006-2008 Programs

Over the three year period, SCE projects 4,071 GWh in savings, 130 percent of the CPUC goals and 784 MW, or about 108 percent of the peak savings goal. These projections are considerably higher than the efficiency forecasts in either the Reference Case or the Alternate Case.

SCE has put together a highly diversified portfolio of programs; only one program accounts for more than 10 percent of the portfolio savings. The CPUC consultants found too little information in the preliminary information to judge either the cost-effectiveness or the reasonableness of the savings associated with proposed program measures.[22] The vast majority of the kW and kWh savings estimates result from measures that are not included in the Database of Energy Efficient Resources, which is the source of the deemed cost and savings estimates used in calculating cost-effectiveness. This could indicate that SCE is including new or emerging technologies in their portfolio as a means of capturing additional savings.

CHAPTER 3: PRICE SENSITIVE DEMAND RESPONSE PROGRAMS

California Public Utilities Commission Decision 04-12-048[23] directs that the IOUs follow the target goals for Demand Response set forth in Decision 03-06-032[24] (Table3-1). Only load reductions anticipated from programs and tariffs categorized as “price responsive” can be counted toward those goals in procurement plans. The procurement decision defines “price responsive” programs as those “in which customers choose how much load reduction they can provide based on either the electricity price or a per-kW or kWh load reduction incentive.”[25] Decision 05-01-056, released in January 2005, revised the definition to include megawatts “from any program that provides a day-ahead demand reduction signal, whether it is based on a price, temperature, or reliability forecast, to count towards meeting the utilities’ price responsive demand program goals adopted in D.03-06-032 and D.04-12-048.”[26] This most recent definition draws a line between day-of and day-ahead demand response, reasoning that the purpose of day-of demand response is to support immediate system reliability. For procurement purposes, such demand response is accounted for separately.

Table 3-1
Price-Sensitive Demand Response Goals[27]

Year	PG&E	Edison	SDG&E
2003	150 MW	150 MW	30 MW
2004	400 MW	400 MW	80 MW
2004 (revised)	343 MW	141 MW	47 MW
2005[28]	450 MW	628 MW	125 MW
2006	4% of the annual system peak demand		
2007	5% of the annual system peak demand		

Reporting Price Sensitive Demand Response Progress to the CPUC

The IOUs are required to report monthly to the CPUC progress toward the achieving the goals.[29] D.03-06-032 directed that the programs and tariffs developed under R.02-06-001 be included in a modified version of the monthly report on interruptible and outage programs required under D.02-04-060 in proceeding R.00-10-002. Which demand response programs’ megawatts can count toward the Demand Response goals has been clarified; however, the definition of which reported megawatt number to count is still not clear. This ambiguity has significant impacts on how price sensitive demand response resources are integrated with overall electricity resource procurement.

Generally, there are three ways to report program megawatts. The first is enrolled megawatt, which tends to overstate available demand response by implicitly assuming that each customer will provide his maximum potential load reduction for each event based on either a contracted amount or some uniform proportion of an enrolled customer's peak demand. A second is to use historical performance, which tends to understate future performance with new and growing programs. In the particular case of current demand response programs, customer participation levels are expected to grow, customers have little experience and so have not yet settled on consistent strategies, and few events have been called on which to estimate their response.[30] A third method is to combine the other two methods with specific knowledge of enrolled customer plans and strategies to yield informed estimates of expected performance. These overlaps to some extent, depending on the program, and are interpreted somewhat differently within each IOU. The monthly reports tend to report enrolled megawatts. The IOUs' April 2005 monthly reports are summarized in Table 3-2.

Enrolled Megawatts reflects the maximum possible demand response available from customers enrolled in existing programs. The utilities assume that price-reducing tariffs will induce a 15 percent reduction in the total non-coincident peak demand of participating customers. For the Demand Bidding Program (DBP), their estimates reflect all customers' committed load reduction for an event. But, such total participation is unlikely, since bidding in any particular event is voluntary. The Demand Reserves Partnership numbers reflect the highest of monthly peak load nominations from each customer.

Table 3-2
IOU Demand Response Report Summary—as of April 2005[31]

	PG&E	SCE	SDG&E	Totals
Price Responsive Programs (MW)	370.8	150.3	34.6	555.7
Reliability Programs (MW)	334.9	1145.3	76.6	1556.8
Totals (MW)	705.7	1295.6	111.2	2112.5

Demonstrated Megawatts refer to actual performance data. Current performance data significantly underestimate available voluntary price responsive demand for two reasons. First, the population of participants is constantly changing and growing. Second, there have been few actual events on which to measure response. For instance, SCE reports low performance from artificial test events for the demand bidding program, but estimates higher performance numbers for actual events based on customer contacts. The customers report that they are unwilling to curtail production and incur economic losses under test conditions but, in the event of a call during a system alert, would curtail if necessary. Over time this measure will likely become the standard for forecasting demand response; however, the current programs have been in a state of flux as they have been altered in response to customer feedback, as marketing efforts have resulted in additional signups, and as customers have gained more experience in responding. These issues were complicated by a combination of design differences between programs and tariffs, untested triggering criteria, and mild weather—all if which resulted in very little actual experience that first summer with the new program designs.

Expected Megawatts refers to the utility resource planners' best estimates, using a variety of input including enrollment, actual performance, and customer input. Tables 3-3 and 3-4 below reflect expected megawatts, compiled and updated by Energy Commission and CPUC staff in preparation for the Energy Commission *2005 Energy Report* Workshop on Resource Planning, held April 29, 2005 and updated by Energy Commission staff in June, 2005 to reflect the most recent IOU monthly reports.

Table 3-3
Expected Response from Price Responsive Demand Programs--April 2005*

Category	PG&E	SCE	SDG&E	Total
Demand Bidding	40	67	1	108
Critical Peak Pricing	12	6	5	23
Power Authority Demand Response	200	31	5	236
20/20; Voluntary Programs	0		2	2
Total (MW)	251	104	13	368
*Numbers reflect demand response derated from reported enrollment/participation numbers that IOU resource planners consider reliable based on program experience, performance data, and customer self-report				

Table 3-4
Expected Demand Response from Reliability Programs--April 2005*

Category	PG&E	SCE	SDG&E	Total
Interruptible/Curtailable	305	639	2	947
Direct Load Control	0	294	2	296
Backup Generators	0	0	17	17
Total (MW)	305	934	21	1260
*Numbers reflect demand response derated from reported enrollment/participation numbers that IOU resource planners consider reliable based on program experience, performance data, and customer self-report				

In their April 2005 monthly reports, the IOUs reported a total of 556 MW of price responsive demand using the enrollment metric. This value is far short of the 2005 goal made more clear in D.04-12-048. Further, comparing Tables 3-2 and 3-3 reveals that an additional discount from the enrollment numbers to the “expected” number of 368 MWs reflects a difference of 33 percent between these two metrics.

When comparing the goals with the IOU April 2005 monthly report numbers, readers should note that the Demand Reserves Partnership program makes its largest contribution in the PG&E service territory and that the largest component of enrolled megawatts in the DRP program is California Department of Water Resources pumping load. These pumping loads have a long history of providing reliability services to PG&E—a resource that will continue to be available—but through the Demand Reserves Partnership Program.[32]

Despite definition adjustments and goal reductions approved in recent CPUC decisions, the IOUs are not likely to provide demand reductions consistent with these goals in 2005 or in the future through currently funded and approved demand response programs and tariffs in their current forms and under current market conditions. There are six primary explanations for this:

- First, the original goals were developed with the expectation that all customers would have the opportunity to contribute toward the demand response goals. Currently, only large customers (over 200 kW)—about 40 percent of system load—have interval meters and thus the ability to participate.

- Second, large customers, particularly the largest industrial customers, have already adapted their operations to minimize on-peak consumption in response to existing TOU rates and peak demand charges[33]. Further, most of those customers with the largest loads, and thus the largest demand response potential, already participate in existing reliability programs, which preclude participation in the current price responsive programs.

- Third, the programs and tariffs available to large customers are constrained by the requirements that participation be voluntary and that they be “class revenue neutral”; that is, collect no more (and, from the IOU’s perspective, no less) than the current utility revenue requirement allocations for that customer class. These constraints result in program designs that yield only small benefits to participating customers, so the incentive to participate is small, even for customers with advantageous load shapes.

- Fourth, larger customers with significant air conditioning load (as opposed to process load) face significant expense and effort to develop load management strategies compatible with their existing constraints (such as contractual obligations to tenants to provide comfortable levels of space conditioning). These costs, and customer perception of these costs, greatly exceed the potential benefits from program participation.

- Fifth, program stability is a concern for customers. Since first being approved in June, 2003, the programs have gone through a number of adjustments designed to improve both their demand response potential and customer satisfaction. Many of those customers who would consider investing in load management planning and equipment prefer to wait until such programs are stable enough to justify the time, effort and expense required.[34]

- Sixth, while the largest customers devote resources to load management, smaller customers do not necessarily have the expertise on staff and find load management to be outside their "core business." Thus even if there are potential savings available, it is not necessarily the case that these customers will take the time to learn about, then act on, the possibility.

Reporting Price Sensitive Demand Response Resources to the Energy Commission

When responding to the Forms and Instructions directives for the Capacity Demand and Supply Balance table (Form S-1), the IOUs are generally directed to submit plausible estimates of dependable capacity from each category of resource. The amount of dependable capacity assumed for each category of resource will directly affect the calculation of the IOUs' net open positions, as expressed by the amount of generic renewable and non-renewable resources required to meet the gap.

For their Reference Cases, the Forms and Instructions require the IOUs to complete Line 6 of Form S-1 with the goals set in D.03-06-032 under the assumption that those goals will be met.[35] Effectively, this direction assumes that the goals are met when the amount of estimated megawatts (i.e., the dependable capacity expected to be achieved from the DR program) equals the product of the IOUs annual system peak demand and the appropriate percentage target for that year. For their Preferred (or Alternate) Cases, the IOUs are free to assume another level of price-responsive demand, but to provide an explanation if it is lower than the level of the goal. The noted ambiguity about whether the goals are meant to refer to enrolled megawatts or to estimate megawatts (i.e., dependable capacity) necessarily affects the *2005 Energy Report* assessment of the amount of each IOU's net open position "under the assumption that the goals will be met."

Staff Review of Price Sensitive Demand Response Resource Assumptions

None of the IOUs' Reference Cases included as dependable resources in Line 6 an amount of capacity equal to the target percentage times their annual system peak demand. SDG&E calculates the "system peak" from which the percentage of system peak goals must be achieved as the Form S-1 Line 1 peak minus Direct Access

(Line 4)—that is, they use their *bundled* system peak as the basis for calculating their demand response goals. SDG&E's "goals" are between 15 percent and 25 percent lower over the planning period than if calculated using the CPUC's definition and assuming it refers to expected megawatts. SCE calculates their DR goal as the Line 1 peak minus Line 6 for Direct Access and Line 7 Uncommitted Energy Efficiency. SCE's "goals" are between 10 percent and 20 percent lower than the CPUC definition, again, assuming it refers to expected megawatts. PG&E, instead of calculating their DR contribution from system peak, modeled their growth in DR resources beginning with numbers from their October monthly report. This is essentially October's enrolled megawatts with an assumed growth rate. PG&E's "goals" are between 7 percent and 9 percent lower than the CPUC expected-megawatts definition of the goal.

San Diego Gas & Electric

San Diego's Reference, Accelerated Renewables, and No Transmission cases all report the same level of megawatts for DR resources. As noted above, these levels are between 15 percent and 25 percent lower over the planning period than the goals as would be using the CPUC's definition. The alternate case represents SDG&E's resource planners' best estimate of expected demand response resources from price responsive programs and tariffs. Although below the goals (using the CPUC definition) through 2008, SDG&E's DR resources exceed the CPUC-defined goals beginning in 2009. By 2016, DR resources are 17 percent higher than CPUC-defined goals. The growth in DR in later years reflects gains expected from installation of Advanced Metering Infrastructure and associated tariff changes. Low numbers in the early years reflect the inclusion only of programs funded at the time the resource plan filing was made. Demand Response programs that will be funded following the June 2, 2005 Demand Response and Energy Efficiency Program filings in R.02-06-001 and R.01-08-028 were not included.

Pacific Gas and Electric

All of PG&E's resource plan cases assume the same level of megawatts for DR resources, including its preferred case. PG&E extrapolated the enrolled megawatts from their price-responsive programs across the reporting period by taking current enrollment, assuming an additional 100 MW will enroll as a result of recently-enacted program changes, then growing that number by 1 percent per yr for 2006 and 2007, then by 1.5 percent thereafter. As reported above, PG&E's assumed levels are between 7 percent and 9 percent lower than the CPUC expected-MW definition of the goal.

Southern California Edison

SCE acknowledges in their discussion that there is “significant uncertainty” that the reference case DR goals “can be attained.” For its Alternate Case, SCE reports an expected megawatt quantity of demand response resource--the Maximum Reliably Achievable Potential (MRAP) calculated for their 2004 Long-Term Procurement Plan--the magnitude of demand response SCE believes can be “reasonably achieved.” SCE emphasizes that for resource planning purposes, “levels beyond MRAP cannot be considered reliable for a resource planning perspective.” The DR estimate presented in SCE’s alternate are consistent with “expected” rather than “enrolled” levels of demand response and should be considered reliable for resource planning purposes.

Conclusions

There is a fundamental disconnect between the current IOU reporting of megawatts to be counted toward meeting the demand response goals set forth in D.03-06-032 and the need of resource planners for measurable and reliable load reduction. In ordering paragraph 3, D.04-12-048 anticipates this issue in discussing utility suggestions to adjust the goals or institute an annual review process and concluding that the goals should stay as they are to encourage the IOUs to strive to meet them cost-effectively.

CPUC Decision 05-01-056 orders the IOUs to “report both demand response potential and expected/actual demand reduction when called” in their combined reports of demand response and reliability-triggered programs. The Decision also directs the IOUs to meet with Energy Commission and CPUC staff to identify ways of reporting the load reduction capability of demand response programs.

Representatives of the three IOUs met with Energy Commission and CPUC staff on May 18, 2005, to discuss this issue and potential changes to the monthly reporting form that would reflect both enrolled and expected load reduction capacity for both price-responsive and reliability demand response activities. Beginning with the June, 2005 reports, which will be filed July 20, the reports will have an additional column of information reflecting the IOU’s best estimate of available capacity from demand response programs.

Whether the goals are meant to refer to enrolled megawatts or to estimated megawatts (i.e., dependable capacity consistent with planning conventions for capacity procurement) needs to be clarified. Until this is clarified, staff cannot calculate how an IOU’s estimate of its net open position is affected by its meeting or not meeting its DR goals. Reporting the assumptions and analysis that link an IOU’s estimate of enrolled megawatts to its estimate of consequent expected megawatt will help to clarify this issue. These estimates, as detailed above, will be reported beginning in June, 2005 by the utilities in their Monthly Reports on Interruptible Load Programs, Rotating Outage Activities, and Demand Response Programs.

The inconsistency between enrolled and expected demand response capacity reflects two different purposes. There is little question that resource planners desire unambiguous, reliable estimates of demand response capacity in order to reduce the uncertainty about remaining resources they must procure to meet demand. Unfortunately, the immature nature of DR programs makes that desire impossible to satisfy.

The goals set in the Demand Response proceeding have the purpose of providing an incentive for the regulated utilities to take risks in developing and implementing innovative programs. Some of those programs will be successful and some will not—and the demand response achievable by any of those programs cannot be reliably estimated until more experience has been gained by both the IOUs and their customers.

Low estimates of reliable demand response capacity from these programs are to be expected, especially during the first few years of experimentation with these programs. This does not constitute failure, especially when the goals that serve as the measure of success are set to encourage the utilities to innovate. Nor does it suggest that the goals should be lowered to “more realistic” levels.

There is good reason to expect that reliable expected demand response will grow substantially over the next three years as efforts currently underway begin to show returns.

On August 1, 2005, the IOUs will file applications to implement default critical peak pricing tariffs for large customers beginning in summer 2006. Along with the tariff designs, the utilities will be developing customer education, assistance, and incentive plans to both ease the transition and increase the demand response that can be achieved from this customer class—moving the utilities closer to their demand response goals. At the same time, PG&E and SDG&E and SCE have filed plans for replacing their metering systems with advanced metering and communications systems that will support time-based tariffs for all customers. As the infrastructure is updated, substantial additional potential for demand response will be available and the goals will be more within reach.

From the resource planner perspective, only the “expected” demand response numbers can be integrated into capacity planning and the resulting definition of the net open position. Anticipating this problem, the CPUC authorized IOUs to make short term purchases to cover short falls in “expected” capability relative to policy goals, but directed them to not make long-term purchases or resource acquisitions that would “drive out” DR as a resource.[36] Perhaps what is unanticipated is that these problems would be at the level and persistence that is described in this report.

SDG&E appears to want to count upon DR because its Alternate case has larger quantities than the other cases. SCE appears to distrust DR, because its Alternate case has much smaller amounts of DR than the other cases. Even though the approaches revealed by SCE and SDG&E in the S-1 filings for the reference case and other scenarios are very different, there is not sufficient detail in their filings to be sure that they are complying with the intent of CPUC decisions. The S-1 filings from PG&E show the same level in all scenarios, so PG&E is not even acknowledging the difference between the resource planner's desire for realistic expectations that SCE and SDG&E address.

CHAPTER 4: RENEWABLE PORTFOLIO STANDARD AND THE ACCELERATED RENEWABLES SCENARIO

The Forms and Instructions generally describe the Renewable Portfolio Standard (RPS) annual procurement targets (APT) that each IOU is expected to assume in their Reference Cases. The APTs are expressed as percents—the annual amount of eligible renewable energy the IOU should have received from generators expressed as a percent of the IOU's annual retail sales:

> For the reference case in the 2005 Energy Report cycle, IOUs are asked to assume that in calendar year 2010, 20% of all retail energy sales will have been matched by energy produced from state-defined eligible renewable resources. To ramp up and maintain this 20% renewable energy target (ignoring contributions of large hydro), IOUs may assume that eligible hydro resources are generating under median (1-in-2) hydro conditions. However, IOUs may not assume that three-year averaging rules or tradable renewable credits (RECs) will be employed to meet these assumed targets.[37]

To help assess the implications of the 2004 Energy Report Update recommendation for a "longer term [RPS] goal of 33 percent by 2020," the Forms and Instructions also requested each IOU to submit an Accelerated Renewables Scenario:

> PG&E [and] SDG&E . . . should provide an alternate case that has 28% of retail sales served by eligible renewable energy by 2016 (28% is the 2016 value for the 33% by 2020 target). Southern California Edison is asked to provide and assess a scenario that has 31 percent of retail sales served by eligible renewable energy by 2016.[38]

The Forms and Instructions acknowledge that the IOUs' resource plan cases will identify only generically the amount of renewable generation necessary to meet the annual renewable energy procurement targets. Nevertheless, the technology and location assumptions that each IOU uses are expected to be plausible.

As a benchmark against which to compare the annual percentages of eligible renewable energy included in each resource case, staff developed two illustrative series of annual procurement targets for each year of the planning period for each IOU. The first series, the "20 percent by 2010 path," extrapolates linearly backward from 20 percent in 2010 to each individual IOU's 2003 annual procurement target, as established by the CPUC. The second series, called the "28 percent by 2016 Path" for PG&E and SDG&E or the "31 percent by 2016 Path" for SCE, extrapolates linearly among the Commission-determined specific APTs described above. Both of these two RPS attainment paths should be considered illustrative because the

CPUC has not established the official RPS annual procurement targets for the IOUs beyond 2005.

Renewable Assumptions and Results in SCE's Resource Plans

SCE submitted four resource plans, all conforming to the Forms and Instructions specification for renewable resource assumptions:

- "Reference Case" including the Devers-Palo Verde #2 500kV transmission project (DPV2) wherein SCE reaches 20 percent by 2007 and retains that percentage through 2016.

- "Reference Case without DPV2" wherein SCE reaches 20 percent by 2007 and retains that percentage through 2016.

- "Alternate Case", with demand and resource assumptions different from the reference case, but assuming SCE reaches 20 percent by 2007 and retains that percentage through 2016.

- "Accelerated Renewables Case" wherein SCE reaches 31 percent by 2016.

Figures 4-1 and 4-2 show how the total annual supply of eligible renewable energy included in SCE's resource plans compares to the appropriate illustrative RPS attainment path for each case. The amount of eligible renewables in SCE's Reference Case was the same with or without the Palo Verde Devers 2 transmission project.

Plausibility of Renewable Assumptions in SCE's Resource Cases

In each of the four scenarios, SCE assumes a mix of location-specific generic renewable resources would be used to meet its RPS obligations. As a way to ensure SCE's assumptions are not implausible, the total GWh by resource/location was compared to the "remaining potential" from the Energy Commission's 2003 Renewable Resources Development Report (RRDR). SCE's assumptions are plausible.

All the QF contracts listed in the "Reference Case" Form S-4 were compared with the Renewable Portfolio Standard (RPS) Certification Database as a check for eligibility. The QF resources SCE includes as eligible renewables meet the eligibility criteria.

Figure 4-1

Compliance of SCE Resource Cases with RPS Annual Procurement Targets on Path to 20 Percent by 2010

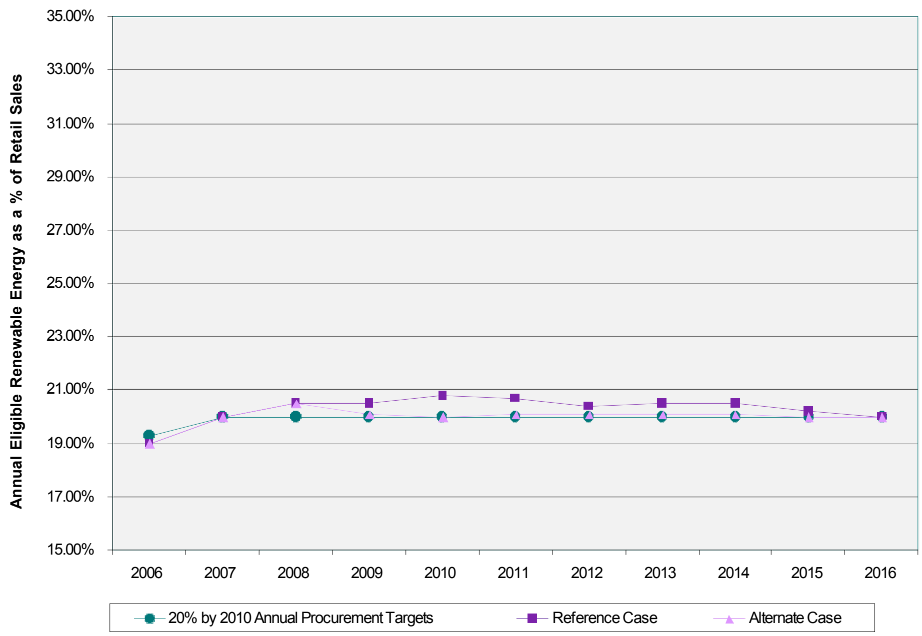


Figure 4-2
Compliance of SCE Accelerated Renewables Case with RPS Annual Procurement Targets on Path to 31 Percent by 2016

The “Reference Case” with and with out DPV2, and the “Accelerated Case” all used the same assumption of 100 percent continuation of the identified QF Contracts. The list of contracts provided agrees with the list of contracts provided in the January 21, 2005 Qualifying Facilities Semi-Annual Status Report to the CPUC.

The “Alternative Case” assumed that only 90 percent of the identified QF contracts would continue throughout the study period. A detailed review of the QF contracts throughout the study period indicated changes to the level of production of some of the contracts, but did not reveal which contracts would not remain with SCE throughout the study period. There was no discussion by SCE of how it determined which contracts to change the production levels. However, SCE’s alternate assumption of 90 percent QF contract extension is plausible, given the contingencies described.

Some of SCE’s existing QF contracts supply eligible renewable energy towards SCE’s compliance with current RPS annual procurement targets. SCE states that assuming 10 percent of existing QF contracts are not extended in its “Alternate Case” causes SCE’s procurement of eligible renewables to exceed the Reference Case levels by an additional 600 GWh annually, resulting in the addition of 100 - 200 MW of substituted renewables resources, depending on the mix of technology types actually procured. SCE’s filing does not explain why the Alternative Case goes beyond just replacing the renewable QFs and adding more total renewables than in the Reference Case.

SCE provided little description or discussion of the models, spreadsheet tools or other analytic methods used in characterizing their renewable resource procurement and RPS compliance, other than replacing/procuring resources with least-cost best-fit options available at the time or during the planning period.

At this time, staff does not have access to modeling simulation results, spreadsheet detail, specific resource or cost data or assumptions used by SCE to arrive at the characterizations of renewable generation and costs for the various scenarios. It is difficult to respond to assertions, particularly regarding the Accelerated Renewable Scenario, in the absence of SCE’s own detailed analysis that addresses or quantifies the set of issues or cost impacts SCE identifies.

SCE’s March 7, 2005 filing with the CPUC contains more detailed information describing SCE’s 10 year RPS Compliance Plan – key assumptions, compliance with existing RPS requirements, development of renewable resource portfolio and the ten-year plan, minimum transmission facilities needed to accommodate planned procurement activities, renewable resource repowering and expansions and lessons learned from SCE’s 2003-2004 procurement efforts. This information is confidential and only available to RPS collaborative or PRG staff.

SCE's March 25, 2005 Updated Long-Term Procurement Plan filing contains little additional information while referring to other documents (CPUC decisions, advice letters, and workshop reports) not found in SCE's 2005 Energy Report filings.

SCE states that the Accelerated Renewables Scenario appears to be the most expensive of the scenarios presented either on a present value of costs basis or an average scenario cost per megawatt-hour basis. SCE's narrative also reports that the accelerated renewables scenario exhibits lower marginal energy prices than the other cases because of an abundance of energy coming from must-take renewable resources that are tied to long-term contracts and do not impact system marginal costs. SCE offers an admittedly incomplete quantification and comparison of costs in each scenario. Data, assumptions and methods used to derive the scenario costs estimates were not provided. A more detailed assessment of the resource plan costs is presented in Chapter 7 of this report.

Issues Raised by SCE's Renewables Assumptions and Comments

SCE raised serious concerns about renewable goals beyond 20 percent in 2010 and requested the Energy Commission to "undertake a detailed analysis, with meaningful stakeholder input" that considers the following areas of potential impact:

- Deliverability: the transmission additions or upgrades needed to deliver renewable power to end users, particularly if RPS obligations are enforced on a statewide level.
- Dispatchability: the electrical system reliability consequences of intermittent and non-dispatchable procurement obligations.
- LTPP requirements: the CPUC-directed requirements of the 2006 long-term procurement plans.
- Rate Impacts: the effect of the above-market RPS costs on rates and whether a public goods charge fund is necessary to fund them.
- IOU Progress: the results of IOUs' ongoing CPUC-directed RPS bid solicitations,
- Other LSE and Publicly-owned utilities (POU) progress: the efforts and results of all other LSEs to achieve 20 percent renewables by 2010.[39]

SCE's transmission submittal also notes the challenges that development of renewable energy poses for transmission development and operation.[40]

The *2005 Energy Report* proceeding has included numerous reports and Committee workshops addressing the integration of renewable resources, the need for transmission upgrades, and the renewable resource potential in California and the west. The Committee workshops completed to date include:

- September 14, 2004: Renewables Transmission Planning Workshop
- October 14, 2004: Evaluating the Cost of Integrating Renewables
- February 3, 2005: Transmission - Renewables Integration Issues
- April 11, 2005: Transmission Constraints to Geothermal Resource Development.
- May 9, 2005: Renewable Resource Potential in California and Interstate Renewable Resources
- May 10, 2005: Renewables Operational Integration Issues

Transcripts of these workshops and related reports, papers and presentations are available at the Energy Commission's web site at http://www.energy.ca.gov/2005_energypolicy/documents/index.html. Additional Committee workshops that address renewables issues will be held in July.

Staff and consultant reports, combined with active participation and input from the IOUs and other stakeholders, will contribute additional information regarding renewable policy choices.

Renewable Assumptions and Results in PG&E's Resource Plans

PG&E submitted four resource plans, all conforming to the Forms and Instructions specification for renewable resource assumptions:

- "Reference Case" wherein PG&E reaches 20 percent by 2010 and retains that percentage through 2016.
- "Preferred Case" includes the same renewable resource plan as in the Reference Case but has lower loads, so the percent of renewables increases to 23 percent by 2013, maintaining that percentage through the planning period.
- Core/Non-core Scenario also includes the same renewable resource plan as in the Reference Case, but has even lower loads than in the Preferred Case, causing the percent of renewables to increase to almost 25 percent by 2013, maintaining that percentage through 2016.

- "Accelerated Renewables Case" wherein PG&E reaches 28 percent in 2016. The Accelerated Renewable Scenario appears to use the same other assumptions as PG&E's Preferred Case.

In its narrative, PG&E indicates that all of the resource portfolios developed for the *2005 Energy Report* process includes a minimum of 20 percent renewable energy by 2010. Figures 4-3 and 4-4 show how the total annual supply of eligible renewable energy included in PG&E's resource plans compares to the appropriate illustrative RPS attainment path for each case. Although the percentages of retail sales change, the amount of eligible renewable annual energy generation remains the same in the Preferred and Core/Non-core cases as in the Reference Case.

PG&E states that it has proposed renewable resources based on their likely availability and value to the system, though actual procurement of renewable generation will occur based on least-cost best-fit analysis of bids received through its proposed RPS Procurement Plan and accompanying RFO for Renewable Resources. In describing its supply resource options, PG&E states that it relied primarily on renewable resource information published by the Energy Commission as part of its *2004 Energy Report Update*.

Figure 4-3
Compliance of PG&E Resource Cases
with RPS Annual Procurement Targets on Path to 20 Percent by 2010

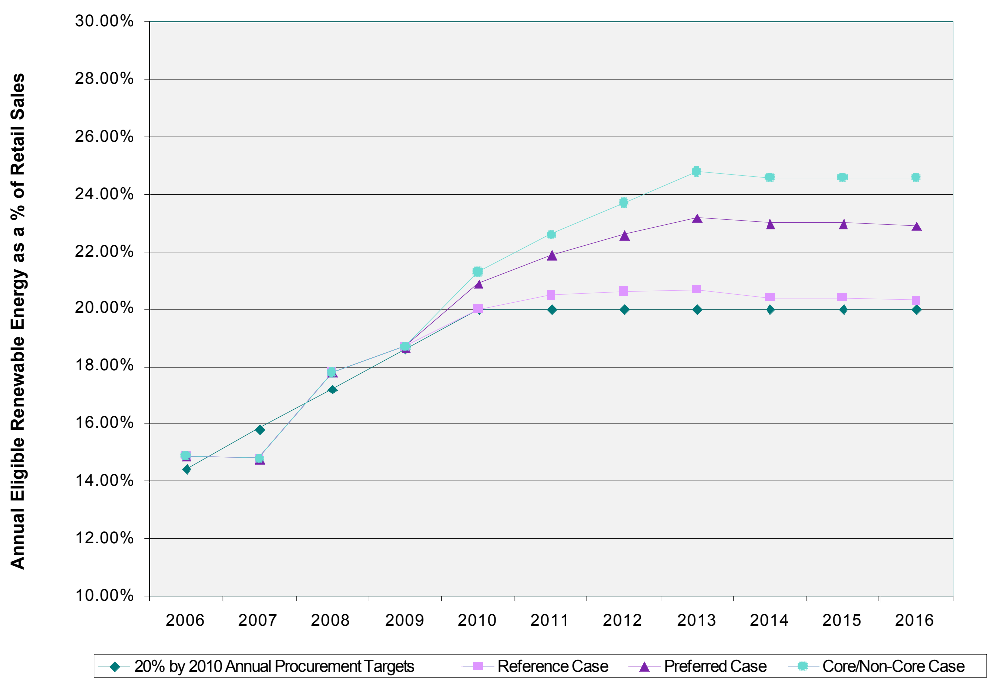
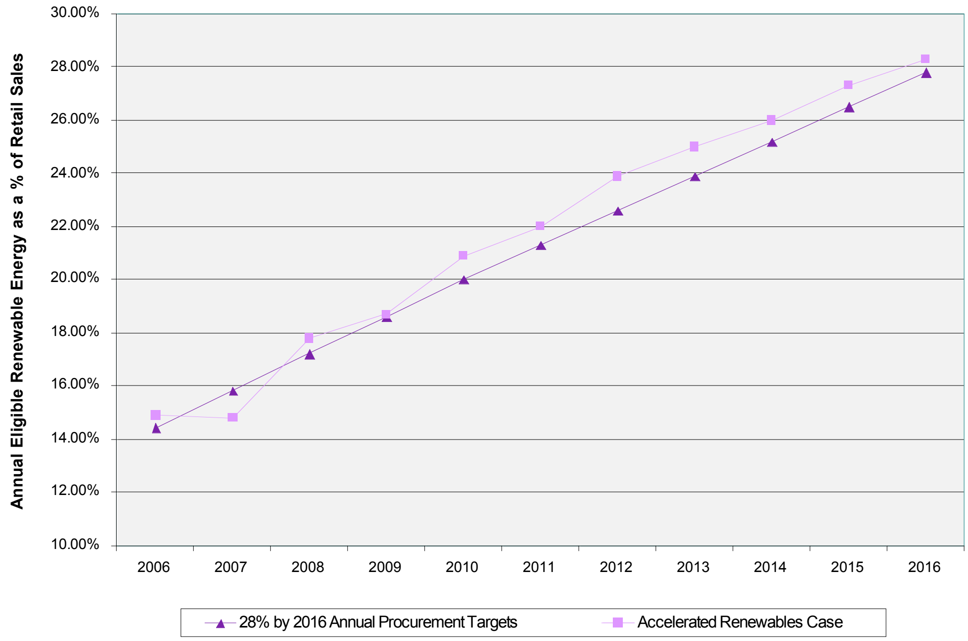


Figure 4-4
Compliance of PG&E Accelerated Renewables Resource Case with RPS Annual Procurement Targets on Path to 28 Percent by 2016



Plausibility of Renewable Assumptions in PG&E's Resource Cases

PG&E calculated the renewables percentage by dividing the sum of all renewable energy in one year by the total retail sales of the *previous* year. The other utilities calculated their annual renewable procurement percentages by dividing the sum of the renewables by the *current* year's retail sales. When calculating the benchmark attainment path and assessing the IOUs' resource plans, staff calculated the annual percentages the way SCE and SDG&E did. The difference in methods results in differences in annual percentages of between 0 percent to 0.7 percent.

In its March 1 filing, PG&E provides "an illustrative renewable procurement plan" that presents a mix of generic renewable resources generally located either in the NP15 zone or generated from a facility that will be deliverable to NP15. This same renewables portfolio is assumed in the April 26 filing's Preferred and Core/Non-Core Cases. Staff found the renewable development assumptions used in these plans to be plausible after comparing the plans by technology and location to the remaining technical potential in the Energy Commission's 2003 Renewable Resources Development Report (RRDR). For this purpose, "remaining potential" is defined as total technical potential minus on-line projects. For the RRDR, "remaining potential" also subtracted out proposed projects; but that was not done in this situation so as to provide a more accurate picture of the amount of renewables that could actually be developed.

While the above three resource cases all use the same quantities and mix of renewables, there are differing assumptions, of which the most significant is the expectation of future load departure due to reinstatement of a non-core market structure (direct access). In the Reference Case, no departing load is assumed. In the PG&E Preferred Case, 50 percent of customers with a peak demand greater than 500 kW by 2012 are assumed to depart. The Core/Non-core scenario increases this departing load to 75 percent by 2012. The lower the expected future load departure, the higher the retail sales for utility bundled-service customers, then the higher the retailer's RPS obligations will be. Given the amount of renewables is the same in each plan and the amount of retail sales is different, the reported differences across the plans in percent renewables is consistent.

In the Accelerated Renewables Scenario, PG&E makes the same assumptions for NP 15 resources as above, with a few exceptions. Including the renewable technical potential found out of state and in SP 15, PG&E's Accelerated Renewables Case assumptions appear to be plausible.

PG&E made no assumptions regarding the future of specific QFs with expiring contracts but assumed in all cases that, in aggregate, 90 percent of all expiring QF energy and capacity would remain in operation and sell energy to PG&E for the duration of the planning period. A detailed review of the QF contracts throughout the study period did not indicate any changes in production between the four cases.

QF contracts listed in the "Reference Case" Form S-4 were compared with the Renewable Portfolio Standard (RPS) Certification Database as a check for eligibility. All the listed QF contracts greater then 10 MW did match up with certified generators. The QF contracts listed were compared and do agree with the Cogeneration and Small Power Production Semi-Annual Report, January 2005 to the CPUC listing QF contracts. PG&E's assumptions regarding QF resource persistence seem plausible.

PG&E's Preferred Case is consistent with their Updated 2005 Long Term Procurement Plan filed March 25, 2005 with the CPUC. In the March 25, 2005 Updated Long-Term Procurement Plan, PG&E notes that it is in the process of procuring additional renewable resources in accordance with the state's Energy Action Plan (EAP),[41] including the recently completed 2004 RPS solicitation and imminent 2005 RFO, consistent with its RPS Procurement Plan submitted to the CPUC on March 7. These RPS compliance filings contain much greater detail and discussion of assumptions, methods and observations regarding renewable resource procurement than what was provided in the *2005 Energy Report* process to date. Strict confidentiality concerns apply to most of the information, however.

PG&E's Attachment E, Table 1 offers a partial quantification and comparison of generation costs for the four scenarios developed for the *2005 Energy Report* process. Data, assumptions and methods used to derive the scenario costs estimates were not provided. A more detailed assessment of the resource plan costs is presented in Chapter 7.

Issues Raised by PG&E's Renewables Assumptions and Comments

PG&E developed a resource portfolio to reach 33 percent by 2020 but states that

> Based on information currently available this portfolio is theoretically possible, but PG&E is concerned that this portfolio will be extremely difficult to realize and the costs of achieving a 33 percent renewable portfolio are very likely to be substantially understated. PG&E believes the total cost of the Accelerated Renewable portfolio is much greater than the costs presented here reflect. PG&E assumed the resource potential and costs for renewable development are based on CEC-developed technical potential information. This cannot however, provide sufficiently detailed information regarding the type and location of the renewables that will ultimately constitute PG&E's portfolio, and as a result specific cost estimates have not been developed.[42]

For example, PG&E reported that in addition to the generation costs reported in Attachment E, Table 2, "to achieve the 20 percent renewable resources level in all scenarios, it will incur approximately $170-$230 million in incremental transmission costs (other than interconnection) which will increase the transmission component of its rates."[43]

PG&E qualitatively identified potential sources of incremental cost impacts associated with the Accelerated Renewables Scenario Plan that it did not quantify in its resource plan cost estimates. These potential additional renewables costs could include:

- Higher cost of energy if renewable suppliers use more expensive technology or if the remaining more marginal renewable resources are less productive,

- Higher transmission and interconnection costs if new renewables are located farther from load pockets or existing transmission routes,

- Higher direct integration costs (non-transmission) if substantial additional operating infrastructure is required for the grid to absorb larger quantities of intermittent and must-run energy from renewables,

- Higher indirect integration costs if firming capacity is required or if the portfolio is "subject to substantially greater market price volatility if the utility cannot plan purchases and sales and is forced to buy or sell in the market in response to the generation by intermittent resources in its portfolio."[44]

While PG&E states the amount of renewable resources located and available in the NP 15 transmission zone is sufficient to meet the 20 percent renewable procurement target,

> PG&E believes it will likely need to procure renewable resources from other areas to achieve a 33 percent target. Based on its renewable resource stack preferences, PG&E would require base load resources that may be located in Southern California or out of state. This will require additional transmission and/or the use of Renewable Energy Credits (RECs). . . . PG&E believes it may be more efficient, environmentally beneficial and less expensive to ratepayers to allow the use of RECs for demonstrating renewable energy target compliance rather than building additional transmission. [45]

PG&E discusses some of the same technical and policy issues identified in the consultant report prepared by the Consortium for Electric Reliability Technology Solutions (CERTS) for the May 10, 2005 IEPR Committee workshop, "Assessment of Reliability and Operational Issues for Integration of Renewables." PG&E highlighted some of the challenges that accelerated development of renewable energy poses for transmission grid development and operation. Delivery of eligible renewable resources from outside the service area and to load centers is identified as a particular challenge.

The IEPR Committee has held workshops in May and has scheduled workshops in July intended to focus analysis and public dialogue on several of the topics PG&E has identified including renewable resource potential (in-state and interstate), proximity to load, and reliability and operational issues for integration of renewable generation resources. Staff and consultant reports, combined with active participation and input from the IOUs and other stakeholders, will contribute additional information about potential impacts of renewable policy choices.

Renewable Assumptions and Results in SDG&E's Resource Plans

SDG&E's resource plan submittals describe the following four cases with specific RPS assumptions and narrative:

- "Reference Case" wherein SDG&E reaches 20 percent by 2010 and retains that percentage through 2016.

- "No New Major Transmission Interconnection Scenario" wherein SDG&E fails to meet the 20 percent target until 2015. The mix and amount of renewable power is changed to recognize SDG&E will not have access to the same amount and type of renewables as if an assumed upgrade to the bulk transmission grid were built.

- “Alternate Scenario” wherein SDG&E reaches 20 percent in 2010 and increases that to 28 percent in 2016.

- “Accelerated Renewables Scenario” wherein SDG&E reaches 28 percent in 2016, but with significant qualifications.

Figures 4-5 and 4-6 show how the total annual supply of eligible renewable energy included in SDG&E’s resource plans compares to the appropriate illustrative RPS attainment path for each case. SDG&E generally describes its resource planning methodology and assumptions in its April 1 filing that lead to development of a least-cost best-fit portfolio of resources. The resources first added are those preferred in the Energy Action Plan. SDG&E’s resource plan process attempts to incorporate all current resource adequacy and procurement objectives. SDG&E assumes all new resources will be deliverable to load, however, this assumption points to the need for upgrade and expansion of existing and new transmission.

Although both SDG&E’s Reference Case and Alternate Case assume 20 percent of retail sales from eligible renewables by 2010, neither plan follows the hypothetical, uniform procurement path to get there. In fact, both cases assume a doubling of eligible renewable energy in the portfolio mix during the last year between 2009 and 2010. The Reference case stays at 20 percent after 2010 throughout the planning period, while the Alternate Case continues to increase uniformly to 28 percent eligible renewables by 2016. Although the No Transmission Case has more renewables than the Reference Case in 2008 and 2009, it lags behind afterward, not meeting the 20 percent level until 2015.

SDG&E’s Accelerated Renewables Case closely tracks its Alternate Case, both reaching almost 28 percent eligible renewables by 2016.

SDG&E concludes that achieving the renewable percentages expected cannot be achieved without construction of a major bulk transmission project. In one scenario, the No Transmission Interconnection Case, SDG&E cannot meet the expected 20 percent by 2010 RPS target. SDG&E emphasizes and further explains the link between the new transmission line and the state’s renewable goals in its transmission filings.

Figure 4-5
Compliance of SDG&E Resource Cases

with RPS Annual Procurement Targets on Path to 20 Percent by 2010

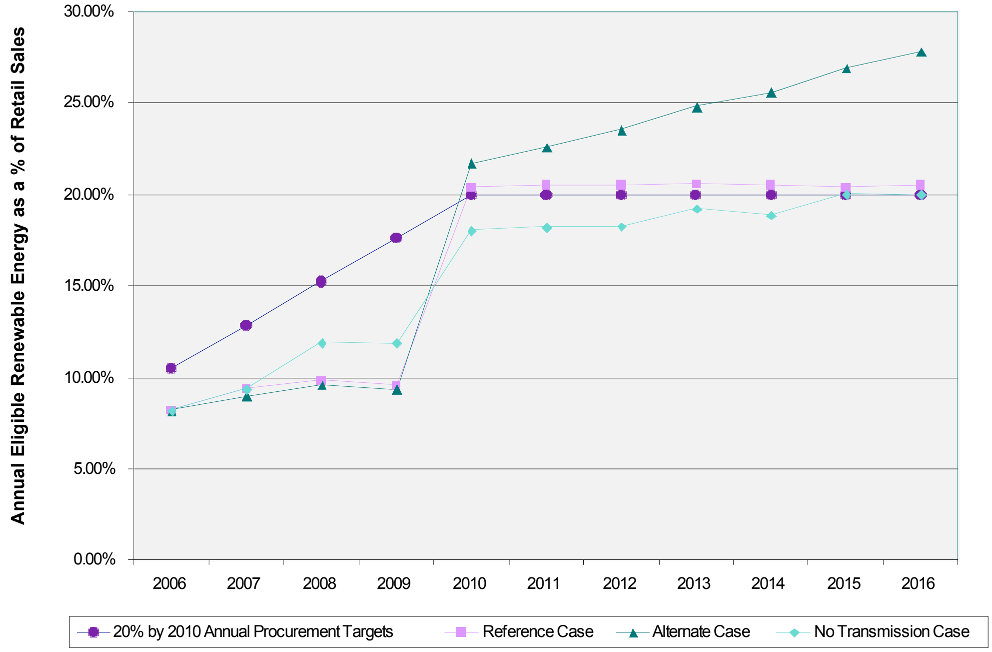
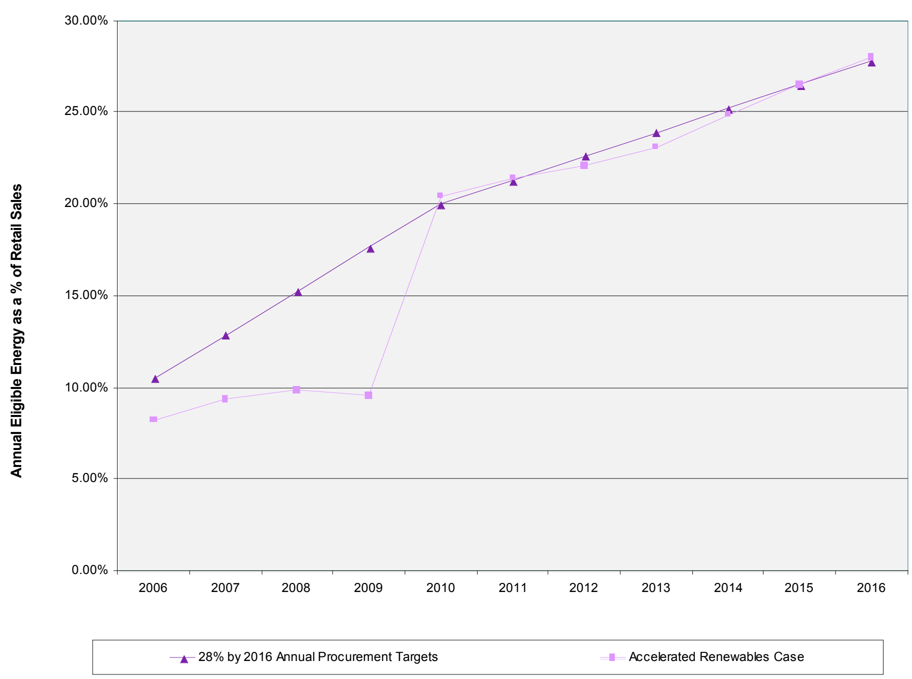


Figure 4-6
Compliance of SDG&E Accelerated Renewables Case
with RPS Annual Procurement Targets on Path to 28 Percent by 2016



Plausibility of Renewable Assumptions in SDG&E's Resource Cases

SDG&E provided four energy resource scenarios (Form S-2) to comply with the RPS assumptions specified in the Forms and Instructions, relying on existing, planned and future generic renewable resources. The amount of existing and planned renewable energy is the same in all cases, while the amount of generic renewable additions varies in each case. Four of the eighteen generators listed have obtained the Energy Commission's RPS certification. The balance of the generators will need to become certified to ultimately count toward RPS compliance. The generators listed under existing and planned renewable are supported by the bilateral contracts identified in Forms S-5 section.

In its March 1 and April 1 filings, SDG&E provides a renewable procurement plan and discussion that underscores the challenges facing SDG&E specifically. They present a mix of generic renewable resources generally located either in the SP15 zone or generated from facilities that will be located within their service territory or adjacent ones and deliverable to their system and load center.

As a way to check the plausibility of SDG&E's assumptions, the total GWh by resource/location of the Generic Renewables (S-3) was compared to the "remaining potential" from the 2003 RRDR the Energy Commission published. For this purpose, "remaining potential" is defined as total technical potential minus on-line projects. For the RRDR, "remaining potential" also subtracted out proposed projects; that was not done in this situation, to provide a more accurate picture of the amount of renewables that could actually be developed. When compared to the RRDR, all of these assumptions appear plausible.

In the "No Transmission Case", SDG&E makes different assumptions than compared to the "Reference Case." Specifically, SDG&E assumes there will be no change in their current import capability; the mix and amount of renewable power changed to reflect the lack of transmission; and more in-basin generation is required. The major result of these differing assumptions is that SDG&E does not reach 20 percent in 2010, but rather, 2015. When compared to the RRDR all of these assumptions appear plausible.

In the "Alternate Case," SDG&E has differing assumptions than in the "Reference Case." Specifically, SDG&E assumes that no CCA load departures occur during the 10-year planning horizon; differing demand based on advanced metering; reallocation of a DWR contract; and continued increases of renewables until 28 percent is reached in 2016.

In the "Accelerated Case", SDG&E is instructed to project a trajectory that would have 33 percent renewables by 2020 (28 percent by 2016). SDG&E states that they have "not conducted the necessary analysis to know if such a portfolio is achievable." When compared to the RRDR, all of these assumptions initially appear plausible except the Local Biofuel assumption. According to the RRDR, the remaining biofuel potential in the SDG&E service territory is smaller than assumed. However, it should be noted that the PIER group is updating the biomass total technical potential. This update will include more biomass resources, and as such, is expected to increase the potential significantly. Therefore, SDG&E's Local Biofuel assumption is not cause for alarm.

SDG&E assumes that all QFs with expiring contracts would remain in operation and sell energy to SDG&E for the duration of the planning period. This is consistent with instructions in the Forms and Instructions. SDG&E assumes that all existing QF contracts are extended and sold to SDG&E in all cases. SDG&E's procurement of eligible renewables is unaffected. SDG&E's assumptions regarding QF contract extensions seem plausible.

SDG&E's RPS compliance filings with the CPUC provide "a complete, detailed and concise picture of SDG&E's residual net open position for the next ten years". Strict confidentiality concerns apply to most of the information, however. Comparable detail and discussion of assumptions, methods and observations regarding renewable resource procurement have not been provided in the *2005 Energy Report* process to date.

Data, assumptions and methods used to derive the scenario costs estimates were only generally described. In calculating costs for the scenarios, SDG&E assumed new renewable resources cost no more than non-renewable resources. SDG&E capped renewable costs at the level of an assumed RPS market price referent (MPR), which was based on existing and forecasted fuel and capacity costs. The cost analysis omitted the following:

1. The energy costs for the dispatch of RMR units;
2. Costs for energy efficiency and demand response programs, including AMI;
3. Costs of transmission, both existing and new, needed to make resources deliverable; and
4. Congestion and other ISO costs

The analysis also did not include any price hedging.[46]

A more detailed assessment of the resource plan costs is presented later in this report.

In its April 12, 2005, Updated Long-Term Procurement Plan in compliance with D.04-12-048, SDG&E notes that it is in the process of procuring additional renewable resources to meet the EAP target of 20 percent by 2010. The current renewables RFP (2004 RPS solicitation), is SDG&E's primary procurement activity. SDG&E states that the preliminary results from that RFP are reflected in its RPS Compliance Plan filing, to the extent practical. The Compliance Plan differs slightly from the *2005 Energy Report* Reference Case and, particularly, renewable power as a percentage of fuel mix continues to grow after 2010.

SDG&E notes that it has proposed renewable resources based on their likely availability and value to the system, though actual procurement of renewable generation will occur based on least-cost best-fit analysis of bids received through its proposed RPS Procurement Plan and accompanying 2005 RFO for Renewable Resources, submitted to the CPUC on April 15, 2005.

SDG&E's Updated 2005 Long Term Procurement Plan filed March 25, 2005 with the CPUC is not entirely consistent with the Reference Case filing.

SDG&E has not concluded negotiations for power purchase agreements out of its 2004 RPS procurement activity.

Issues Raised by SDG&E's Renewables Assumptions and Comments

Noting that it "has not conducted the necessary analysis to know if such a portfolio is achievable," SDG&E complied with the Energy Commission's request to provide an "accelerated renewables scenario" reaching 28 percent renewable energy in 2016 in keeping with a target of 33 percent renewable energy by 2020. SDG&E also provided an alternative scenario reaching 20 percent by 2010 and 28 percent by 2016.[47]

In general, SDG&E identified the following factors as affecting whether it would be able to achieve this portfolio:

> ….how contracted resources perform, whether sufficient renewable resources will be available for purchase by SDG&E, whether renewable resources will be cost effective pursuant to the least cost, best fit criteria when including the cost adder for transmission, whether sufficient PGC funds are available for Supplemental Energy Payments (SEP) for above market renewable resources, and whether SDG&E can procure and count unbundled Renewable Energy Credits (RECs) towards meeting its renewable requirements.[48]

Elaborating on issues of particular concern, much of SDG&E's discussion of renewable energy focused on the need for transmission and concern about the availability of economic renewable resources consistent with least-cost best-fit criteria. Regarding transmission, SDG&E emphasized the importance of transmission to interconnect and import renewables from out of its service area, as well as the need for transmission, including radial lines, to "economically access potential renewable resources in remote areas of SDG&E's own system."[49]

SDG&E's resource plan cases that achieve their RPS targets presume sufficient transmission to access renewable resources located in-basin, from the SCE service territory, and from the Imperial Valley. On the need to import renewables, SDG&E writes:

> Based on the results of SDG&E's renewables Request for Offers (RFO), SDG&E does not know of a mix of renewable power that would allow it to meet the goal of 20% by 2010 absent the addition of a new major transmission interconnection," assuming that unbundled RECs are not eligible to "fill any shortfalls between bundled purchases and State goals.[50]

Regarding the availability of an economic and balanced mix of renewables, SDG&E "is concerned that as all three IOUs move towards 20 percent, especially in the accelerated 2010 scenario, that the cost of renewables available in the market will continue to rise," potentially affecting the number of economic projects, sufficiency of SEP funding, and ability of SDG&E to take below MPR renewable resource projects "and still maintain an overall balanced portfolio of products.[51]

SDG&E also discussed regulatory uncertainty regarding unbundled RECs to meet RPS requirements:

> Without a new major transmission interconnection, SDG&E is concerned that it will not be able to achieve the EAP goal of 20% by 2010. Unbundled RECs could contribute to achieving this goal, but there is uncertainty as to whether unbundled REC purchases will be allowed under the RPS program, the rules that would govern such REC purchases in relation to meeting RPS goals, and the volume of RECs that would be available in the market.[52]

In addition, SDG&E noted that there is no geothermal power that could support reliability within the existing transmission constraints; however, if additional transmission is built, geothermal generation in Mexico and the Imperial Valley could contribute to system reliability in the San Diego area.[53]

SDG&E discusses some of the same technical and policy issues identified in the consultant report prepared by the Consortium for Electric Reliability Technology Solutions (CERTS) for the May 10, 2005 IEPR Committee workshop, "Assessment of Reliability and Operational Issues for Integration of Renewables." SDG&E highlighted some of the challenges that accelerated development of renewable energy poses for transmission grid development and operation. Delivery of eligible renewable resources from outside the service area and to load centers is identified as a particular challenge.

The IEPR Committee held workshops in May and has scheduled workshops in July intended to focus analysis and public dialogue on several of the topics SDG&E has identified including renewable resource potential (in-state and interstate), proximity to load, and reliability and operational issues for integration of renewable generation resources. Staff and consultant reports, combined with active participation and input from the IOUs and other stakeholders, will contribute additional information about potential impacts of renewable policy choices.

CHAPTER 5: DISTRIBUTED GENERATION

This chapter evaluates the assumptions and methods used by IOUs to characterize the role of distributed generation (DG) in their resource plans. This evaluation only covers DG facilities that are fired with nonrenewable fuels such as natural gas, diesel, propone, and waste gas. In this analysis, staff uses the working definition being used in various policy activities at the Energy Commission and CPUC. This definition defines DG as electricity production that is on-site or close to the load center and is interconnected to the utility distribution system. Staff uses a rule of thumb that DG is no larger than 20 MW because, based on the typical substation and feeder ratings and capacities for California IOU distribution systems, DG larger than 20 MW would likely be interconnected at transmission voltages and not distribution voltages.

There are no mandates for IOUs to procure DG resources. Nor has the State established any explicit capacity or energy goal for DG resources. The State does encourage development of DG resources through various policies and incentive programs. Current State policy expresses a general preference for DG over traditional central station, transmission and distribution resources. This general preference is expressed in legislation, previous Integrated Energy Policy Reports, the Energy Commission DG Strategic Plan, the Energy Action Plan and several CPUC regulations.

The supply Forms and Instructions ask the IOUs to report dependable capacity and energy from existing DG installations as a reduction to load. This load forecast of total peak demand reduction is reported on Forms S-1 and S-2, and is distinct from the detailed demand forecasts. The detailed assumptions about existing DG resources are requested in the Demand Forms. This “customer side of the meter” DG reduces the IOU’s need to acquire capacity and energy resources to distribute to customers.

The supply Forms and Instructions ask the IOUs to report dependable capacity and energy from plausible estimates of new “customer side of the meter” DG installations as a resource on Forms S-1 and S-2, respectively. The capacity and energy supplied by these new “customer side” DG installations is not counted as part of the IOU’s bundled customer load (it is counted as part of the distribution service area load). The resource plans defined by the Supply Forms assume the power from these new DG installations also reduces the IOU’s need to acquire capacity and energy resources to distribute to customers. If the IOU expects there to be any “utility side of the meter” DG that would be injected into the grid to distribute to bundled service customers, that DG resource should be listed separately under “Existing and Planned Resources.”[54]

Southern California Edison’s DG Assumptions

SCE reports no new DG resources on its Supply Forms, either new “utility side” or “customer side” DG resources. No DG information is provided in their supply forecast forms. SCE’s forecast of dependable capacity and energy from future DG resources is all reported as demand reductions in the Demand Forms and therefore is already reflected in the Total Peak Demand and Total Energy Demand forecasts used in the Supply Forms.

Additionally, on its public version of the demand forms, SCE aggregates renewable and nonrenewable DG so that staff cannot discern the difference between the two, assumptions used for each, etc. It is unclear from SCE’s submittal what criteria it uses to define DG versus QFs, independent power producers, bilateral contracted resources, etc. No back up information is provided.

Regarding energy in SCE’s DG forecast, no information is provided on energy produced from DG. No backup information is provided on assumptions used for hours of operation or performance of the different DG systems. Demand Form 3.3 has no information on gas consumption information as well. Availability of DG varies by technology or application of that technology. For example, natural gas-fired internal combustion engines (ICE) or micro turbines (MTG) may be used for electrical peaking. These same technologies could also be used in a base load application to provide for electric and thermal loads if used in a combined heat and power application. Larger applications could rely on gas turbines. In agricultural applications, biogas ICEs and MTGs are being used to meet electric, and electric and thermal needs. In wastewater treatment facilities, methane is used for ICEs and supplies both electric and thermal loads. In each of these different applications, availability varies.

Lastly, SCE provides no cost information in Demand Form 3.3. Its estimates of Self-Generation Incentive Program incentive amounts by year are available elsewhere and should have been included here. Without gas consumption information, it is difficult to determine the validity of the operational assumptions for purposes of calculating energy production from DG. It is not clear from the submitted information how SCE arrived at its yearly forecasts for the represented end use sectors. What information SCE did provide on Demand Forms 1.7a, 1.7b and 3.3 is computationally accurate and internally consistent.

For comparative purposes, Table 5-1 provides data collected on existing DG interconnections.[55] Table 5-1 summarizes the actual interconnections by year and by sector. Columns labeled CEC show nameplate capacity (MW) of nonrenewable DG facilities. Columns labeled SCE show dependable capacity as reported by SCE on Demand Form 1.7b. The “%diff” columns show how SCE’s yearly forecast of DG dependable capacity in commercial, industrial and agricultural sectors differs from installed (nameplate) capacity according to actual interconnection data.

Table 5-1

LOCAL PRIVATE SUPPLY BY SECTOR OR CLASS COINCIDENT PEAK DEMAND (MW) From Redacted Form 1.7b compared with interconnection data									
YEAR	Commercial (SCE)	Commercial (CEC)	%diff	Industrial (SCE)	Industrial (CEC)	%diff	Agricultural (SCE)	Agricultural (CEC)	%diff
2000	23	23	0%	384	384	0%	0.4	0.4	0%
2001	24	32	-33%	356	410	-15%	0.4	0.4	0%
2002	29	49	-68%	386	465	-21%	2.8	0.5	81%
2003	46	77	-67%	445	487	-9%	4.3	0.5	88%
2004	64	86	-35%	462	502	-9%	5.4	2.0	63%

For the commercial sector, SCE's forecast in 2001, 2002, 2003 and 2004 is anywhere from 33 percent to 68 percent less than expected using nameplate capacity. For the industrial sector, SCE's forecast dependable capacity is anywhere from 9 percent to 21 percent less than nameplate. For the agricultural sector however, SCE's forecast is considerably higher than interconnection data supports, which might reflect the aggregation of renewable and nonrenewable DG. The total difference in 2004 between what SCE included and what the interconnection data show is 60 MW. Staff did not evaluate residential DG in this case.

While staff's comparison here is for past years, it suggests SCE's future annual forecasts (years 2005 – 2016) for commercial and industrial end use sectors could be low, or the agricultural end use sector forecasts for 2005-2016 could be high, or both.

Pacific Gas and Electric's DG Assumptions

It is unclear from PG&E's submittal what criteria is used to define what is DG versus QFs, independent power producers, bilateral contracted resources, etc. No back up information is provided. Staff cannot determine how plausible PG&E's forecasts are for DG energy production because of lack of backup information on DG technologies included. What information that is provided appears to be computationally accurate and internally consistent.

Regarding energy in PG&E's DG forecast, no backup information is provided on assumptions they use for hours of operation or performance of the different DG systems. Energy production of DG varies by technology or application of that technology as discussed above in staff's assessment of SCE's DG energy production. Based on PG&E's forecast information, the DGs have an availability of 70% to 90%. Without backup information about which DG technologies PG&E includes in their forecasts, staff can not determine if these availability numbers are realistic.

It is not clear from the submitted information how PG&E arrives at its yearly forecasts. Staff analysis of actual public interconnection data for the years 2002-2004 shows an average monthly increase in DG nameplate MW capacity of 2.5 MW per month, with a cumulative installed capacity over this period of 164.5 MW. All three of PG&E's forecasts (i.e., the Accelerated Renewables Case, Preferred Resource Case, and Core- Noncore Case) have an average monthly dependable capacity increase lower than this over the forecast period of January 2006 through December 2016. Additionally, PG&E's dependable capacity at the beginning of the forecast period (January 2006) is considerably below the 164.5 nameplate MW that the public interconnection data suggests.

San Diego Gas and Electric's DG Assumptions

It is unclear from SDG&E's submittal what criteria is used to define what is DG versus QFs, independent power producers, bilateral contracted resources, etc. No back up information is provided. Without backup information about which DG technologies SDG&E includes in their forecasts, staff cannot determine how plausible SDG&E's forecasts are for DG energy production. What information that SDG&E did provide is computationally accurate and internally consistent

Regarding energy in SDG&E's DG forecast, no backup information is provided on assumptions used for hours of operation or performance of the different DG systems. Energy production of DG varies by technology or application of that technology as discussed above in staff's assessment of SCE's DG energy production. Based on SDG&E's forecast information, the DGs have an availability factor of 46 percent to 51 percent.

It is not clear from the submitted information how SDG&E arrives at their yearly forecasts. Staff analysis of actual public interconnection data for the years 2001-2004 shows an average monthly increase in DG nameplate MW capacity of 1.2 MW per month, with a cumulative installed capacity over this period of 84.7 MW. All three of SDG&E's forecasts (i.e., the Accelerated Renewables Case, Alternate Case, and No Transmission Case) have an average monthly dependable capacity increase this is significantly less than 1.2 MW per month over the entire forecast period (January 2006 through December 2016). Additionally, SDG&E's Supply Form estimate of its installed dependable capacity at the beginning of the forecast period is significantly less than the 84.7 MW of nameplate capacity reported in their public interconnection reports. It is unclear why SDG&E's forecast starting point is substantially less than actual installed capacity. This difference is much larger than can be explained by nameplate and dependable capacity counting conventions. It is also unclear why SDG&E monthly capacity increase rates are significantly less than public interconnection data suggests.

CHAPTER 6: EXISTING, PLANNED GENERIC RESOURCES AND THE IOUS' NET OPEN POSITIONS

This chapter reviews IOU assumptions about existing or planned resources that are otherwise not called out for a special uncertainty assessment by the Forms and Instructions. It then discusses, in general terms, the IOUs' net open positions.

Impact of Existing DWR Contracts on Procurement Plans

The large DWR contracts, which play such a significant role in current utility procurement will end during the period of this analysis. As these contracts end, the IOUs resource profiles and procurement needs will shift considerably.

The DWR contracts provide both must-take and dispatchable energy and capacity. The dispatchable contracts are used when they are economic in the merit order, and hence are like other dispatchable bilateral contracts. In contrast, the must-take contracts are just what the name implies; the utility must take and pay for the power from the supplier regardless of other options available to it at the time.

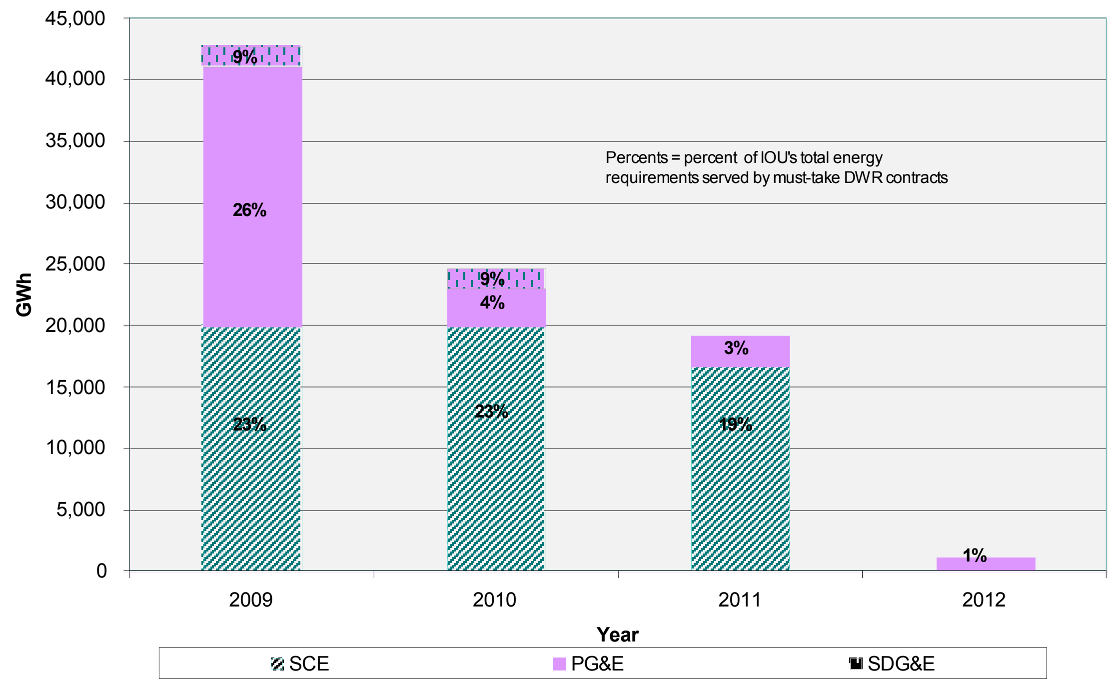
In the reference case, which assumes some departing load after 2007, the DWR must-take contracts will provide an average 23 percent of all energy the IOUs will need in 2009. Within this average, SDG&E has a much lower share of its total energy needs met by DWR must-take contracts. Contracts start ending in 2009, and are essentially over by 2012. For PG&E, most contracts end in 2009; for SCE and SDG&E 2011 is the last year of any major must-take commitments (see Figure 6-1). Replacing one-fifth of all IOU energy resources will be a major procurement focus.

Resources which replace the DWR contracts will be more shaped to meet the IOUs' portfolio needs and other procurement constraints than the CDWR contracts. They will also need to conform to resource adequacy and deliverability requirements.

Qualifying Facility Contracts

In the Reference Case, the IOUs were to make their own assumptions about the persistence in their resource portfolios of existing generating units that currently sell their power to the IOU under terms of Qualifying Facility (QF) contracts. To the extent these units were assumed to be included in the portfolio as an existing or planned resource, the amount of resources that would need to be authorized to meet the net open position would be smaller. The IOU might assume that these existing units have their expiring current QF standard contracts extended by CPUC action, or negotiate a new bilateral nonstandard contract with the IOU. Alternately, the IOU might assume the unit left its portfolio when the existing QF standard contract expired. In that case, the unit would be considered as a potential bidder in the IOU's open all source solicitation.

Figure 6-1
DWR Must-Take Energy as Percent of Total Energy Requirement (Reference Case)



Source: IOU Public Form S-2

In addition to describing the QF assumptions the IOU made in its Reference Case, the Forms and Instructions ask the IOUs "to indicate how future resource procurement might be affected given continued purchase of must-take energy from all existing QF resources." Estimates of the difference in costs between these "blanket QF renewal" cases and the Reference Cases were not requested.[56]

Because PG&E assumed nearly all of its existing QF capacity continued operation after contract extension, it did not assess the impact of QF contract expirations. In all of its resource plan cases PG&E assumed that, in aggregate, 90 percent of all expiring QF energy and capacity would remain in operation and sell energy to PG&E for the plan term. PG&E assumed the remaining 10 percent would either sell to alternate suppliers or shut down after contract expiration.[57]

Likewise, SDG&E did not assess the impact of QF contract expirations because all of its scenarios assume that all of SDG&E's existing QFs continue to provide SDG&E power throughout the planning period.

> All but one of the contracts have terms that extend beyond the 2016 planning horizon. The only contract that expires during the planning period was recently renegotiated to the satisfaction of both parties. Thus, SDG&E fully expects to be able to renegotiate it again once its current term expires.[58]

SCE assumed that 100 percent of its expiring QF contracts would be renewed in its Reference Case. SCE's filing emphasizes:

> ...that the continued procurement of power from existing facilities may occur either through contract "extensions" (*i.e.,* amendments extending the term of existing contracts), through contract restructurings (in which not only the term, but other elements of the contract are modified), or through new contracts resulting from solicitations or bilateral negotiations.[59]

It its Alternate Case, SCE assumed a 10 percent QF attrition rate, meaning that "90 percent of the capacity currently associated with contracts terminating during the planning period will remain under contract with SCE from the date of contract expiration at least through the end of the planning period."[60]

As requested, SCE assessed the impact of this QF attrition on future resource procurement. Because some of the QFs assumed to be leaving had been contributing eligible renewable energy towards meeting SCE's RPS annual procurement targets,

> …this assumption increases SCE's procurement of eligible renewables by an additional 600 GWh of Renewable Portfolio Standard-eligible resources annually in order to timely achieve, and then maintain, 20 percent of retail sales attributed to renewable generation during the planning period. Achieving this level of procurement could result in the addition of between 100 and 200 MW of substituted renewable resources over the 100 percent retention scenario, depending on the mix of technology types actually procured.[61]

SCE states that an additional 140 MW of non-renewable QF capacity would have to be replaced during the planning period through competitive solicitations. To the extent additional renewable resources are needed to meet its RPS annual procurement targets, the 140 MW could be replaced either by new renewables or by a mix of renewables and least cost/best fit resources.

As SCE points out, there can be considerable uncertainty about whether an IOU will continue to procure power from existing QF units after their contracts begin to expire. When contracts expire, SCE points out that owners may choose to terminate their projects for their own reasons. Or they may choose to sell their power to other utilities or energy service providers. On the other hand, SCE points out that its 90 percent persistence assumption is supported by the following reasons:

> …projects with expiring contracts will have a competitive advantage to submit successful bids in upcoming solicitations conducted by SCE. These reasons include existing interconnection facilities, existing transmission pathways, paid-down capital, *etc.* Further, SCE has long-standing contractual relations with these parties, and therefore believes that it is favorably situated to extend these relationships under mutually agreeable terms.[62]

PG&E's 90 percent persistence assumption and SDG&E's 100 percent retention success are both consistent with this view.

For all three IOUs, to the extent that QF persistence assumptions affect the calculation of their net open position and authorized procurement limits, and if these assumptions turn out to be high, then the IOUs could be procuring insufficient resources to meet their minimum reserve margins. A CPUC proceeding is underway to set new QF policies and prices.

Other Existing and Planned Supply Resources

Staff also reviewed the IOUs' assumptions about existing and planned supply resources other than those previously mentioned or discussed below and found them to be plausible. These include utility-owned thermal and hydroelectric resources and bilateral contracts. In Chapter 7 staff discusses the information the IOUs provided about the uncertainties associated with their in-state nuclear power plants and the Mohave coal-fired power plant.

Generic Additions in the Resource Plan and the IOUs' Net Open Positions

The capacity Supply Forms are designed to identify generically the amount, timing and type of resource additions the IOU would need to meet a 15 percent planning reserve margin under the assumed conditions of each scenario. The energy Supply Forms are similarly designed, assuming expected conditions for key assumptions such as energy demand and hydroelectric generation, though without any planning reserve margin. The combination of renewable and non-renewable generic resource additions that are identified in the forms are effectively the amount of future resources that each IOU needs, assuming all of the other existing and planned resources in the resource plan come to fruition, including the level of loading order resources assumed.

As previously discussed, the IOUs have requested and been granted confidential treatment protecting their detailed future resource needs from public disclosure. None of the IOUs provided a qualitative description identifying the generic resource additions in their resource cases. They did provide publicly disclosable capacity tables and energy balance tables for each scenario (see Appendix B). These tables begin in the year 2009 and aggregate the monthly information provided in the Supply Forms into annual amounts. To protect disclosure of commercially sensitive information, the tables also collapse the Supply Forms' many different resource type line items into just over a dozen categories. None of these categories reveals the generic resource additions identified in the filed Supply Forms. Rather, these publicly-disclosable forms offered by the IOUs embed the energy generation from generic resource additions along with energy from existing resources. For example, PG&E and SCE include all energy from generic new resource additions along with dispatchable energy from existing CDWR contracts and energy from other bilateral contracts not reported elsewhere in the table (e.g., QF contract energy).

Net Open Position

The IOUs have generally disclosed that they are "long" in energy for most hours over the next few years. This means that their must-take resources exceed their demands, so they are selling energy. As the CDWR contracts come to an end in 2010-2012, the IOUs will have a major shift in their energy needs, as CDWR contracts account for roughly one-fifth of total energy requirements. Some of this replacement will be met by energy efficiency program goals, which fill approximately 50 – 59 percent of incremental demand. Combining energy efficiency, energy-rich renewables and demand response, leaves a relatively small role for new base load generation. On the other hand, the IOUs will have needs throughout the forecast period for short-term, mid-term and long-term dispatchable and shapeable capacity. Exact capacity levels are protected by confidentiality restrictions. Since fossil resources are the 'resource of last resort', the IOUs must have contingency plans should energy efficiency, DR and renewable programs exceed or miss their target levels.

The IOUs have been authorized by the CPUC pursuant to the last cycle of procurement proceedings (short-term, mid-term, long-term and RPS) to procure future new resources that are not all included in these resource plans as existing or planned resources. This means that portions of the generic new resource additions identified in these resource plans are already being procured. The incremental amount of new resources that the IOUs need to be authorized to procure on top of those amounts is not identified in the IOUs' resource cases developed for this proceeding. When the results of current solicitations become known, and as that new information becomes available, it will be compared to this cycle's assessment of resource needs and the amount of resources needed going forward will be better understood. Resource needs for the early years of the planning period could be substantially met by resources procured in the ongoing round of solicitations. Since the IOUs are currently authorized to procure a fraction of future need in each procurement cycle, less of the resource need identified in later years of the resource cases will be met by this ongoing round of procurement.

For other reasons, one of which is identified below, the amounts of renewable and non-renewable generic resources additions identified in the resource plans are not the same quantity as the IOUs' net open positions, which are specifically defined for each utility through the CPUC's administration of AB 57. But the identified generic resource additions are generally indicative of net open positions (with the true-up for last cycle's procurement) and can help inform the determination of net open positions in the next cycle. One reason for the difference between these resource plan generic resource additions and the net open position is that a reserve margin different from 15 percent may be used to calculate the net open position. SCE reports that its procurement volume limits are determined assuming a 17 percent reserve margin. This gives SCE the flexibility to procure up to that limit, assuming all other procurement constraints and criteria are followed.

To the extent that confidentiality constraints allow the IOUs' generic resource additions to be included in aggregations with other LSE's resource needs, the IOUs' generic resource additions will be reflected in the upcoming Staff Statewide and WECC Resource Outlook Report to be published in July.

CHAPTER 7: REVIEW OF RESOURCE PLAN POTENTIAL IMPACTS AND UNCERTAINTIES

Resource Plan Cost Estimates

The Forms and Instructions ask the IOUs to provide estimates of the annual costs of meeting the load obligations in all of the resource plan cases they provide.[63] The IOUs are asked to

Provide estimates of or qualitatively explain each scenario's annual costs of meeting load obligations, including:

- "All in" generation cost (including variable costs of operating utility-owned generation, contract costs, and the net revenue from activity in wholesale markets),
- Transmission and delivery cost,
- Any additional, significant and quantifiable costs which facilitate comparisons between the reference case resource plan and additional scenarios should also be presented,
- Significant costs whose determination is beyond the scope of the analysis requested, and also to

Describe:

- The potential cost (direct costs, additional transmission, etc.) to ratepayers of meeting these RPS goals,
- Barriers which are limiting their ability to implement RPS policies, including barriers to achieving specific RPS targets,
- What might be done to reduce, overcome, or better assess each such barrier,
- How procurement of additional intermittent resources could affect or impact the remainder of its portfolio.

Only SCE provided disclosable resource plan cost estimates. All three IOUs requested confidential treatment for some of the resource plan cost information. Since the Executive Director denied these requests and the IOUs did not appeal, the resource plan costs can be disclosed. The cost estimates are included in Appendix D as they were filed by the IOUs.

None of the three IOUs submitted total resource plan “annual costs of meeting the load obligations.” Categories of costs were omitted either by design (to place the emphasis on relative rather than absolute cost differences among scenarios), or due to lack of information (e.g., transmission project locations), or for lack of time. Thus, the cost estimates filed are incomplete estimates of total revenue requirements and would not be reflective of electricity rates. Because so many categories of costs are excluded that would be expected to vary across scenarios, the resource plan cost estimates are generally not useful for comparing scenario cost impacts.

SCE’s Resource Plan Cost Estimates

SCE’s reported resource plan cost estimates (see Table 7-1) “do not cover every aspect of the costs expected for serving all of the IOU electricity customers and represent only the items which may vary between cases.” For example, the cost of the steam generator replacement at San Onofre Nuclear Generating Station is excluded because the project is included in all resource cases. Another example is transmission cost estimates, which include only costs that vary across scenarios and are based on conceptual planning estimates.[64]

Table 7-1
SCE Scenario Cost Estimates

Scenario	Present Value, $Billion 10.5% discount rate	Average Cost per MWh, $2006
Reference	33.6	53.0
Reference w/o DPV2	33.2	52.3
Accelerated Renewables	34.8	55.1
Alternative	34.1	52.6

Source: Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, page 15.

SCE makes the following observations and conclusions about its cost estimates:

> While a more complete analysis would be required to analyze the effects of all the effects of the individual assumptions, the data in [Table 7-1] shows that the “accelerated renewables scenario” appears to be the most expensive of the scenarios presented either on a present value of costs basis or an average scenario cost per megawatt-hour basis. As discussed in Section II, comparison of the “reference case” with and without DPV2 is an incomplete picture of the benefits of DPV2.[65]
>
> It should also be noted that all of the various scenarios do not reflect the expected additional integration and infrastructure costs associated

> with the significant amounts of intermittent and non-dispatchable renewable resources. The actual integration costs and requirements are uncertain at this point, but as discussed in Section IV, the State needs to: (a) understand the full breadth of the impacts; (b) develop and work out methods to resolve the operational issues; and (c) establish equitable protocols and methods to recover the costs.[66]

Because some costs are excluded and so little detail is provided on the wide variety of line item cost components included, staff is unable to provide an independent assessment of the plausibility of SCE's cost estimates. For the same reason, staff finds that the cost estimates are likely to be a similarly incomplete indication of potential cost differences among the other scenarios. Consequently, staff has no objection to ignoring these cost impact estimates as being indicative of the cost-effectiveness of DPV2.

PG&E's Resource Plan Cost Estimates

PG&E submitted only the generation component of the resource plan costs. The resource plan costs exclude transmission and distribution costs.[67] PG&E did not provide a present value analysis of costs, but did provide future annual generation costs. Using a 10.5 percent discount rate as did SCE, staff calculated the present value of PG&E's annual resource plan costs, which are shown in Table 7-2.

Table 7-2
PG&E Scenario Cost Estimates

Scenario	Present Value, $2005 Billion 10.5% discount rate
Reference	33.1
Preferred	32.0
Accelerated Renewables	32.3
Core/Non-Core	31.2

Source: PG&E table, *Resource Plan Generation Costs* (see Appendix D). Staff calculated the present value of future annual nominal costs shown here using a 10.5% discount rate.

This limits the utility of PG&E's resource plan cost estimates for making comparisons across scenarios that have significant transmission and distribution cost differences, as do the Reference Case and the Accelerated Renewables Case. PG&E is aware of this limitation and

> …notes that in addition to the generation costs, to achieve the 20% renewable resources level in all scenarios [PG&E] will incur approximately $170-$230 million in incremental transmission costs (other than interconnection) which will increase the transmission component of its rates.[68]

> The Accelerated Renewable scenario is likely to require substantial transmission system upgrades to expand [the] system to project locations and transport renewable energy to load centers. The magnitude of these costs will depend on the location of the resources and the use and costs of Renewable Energy Credits, when and if these are authorized for RPS compliance.[69]

As with the SCE cost estimates, staff is unable to provide an independent assessment of the plausibility of PG&E's cost estimates because of the exclusion of key components of costs and the lack of detail provided on each component. staff finds PG&E's costs estimates to be an incomplete indication of potential cost differences among PG&E's scenarios and are therefore of limited usefulness.

SDG&E's Resource Plan Cost Estimates

As did SCE, SDG&E provided a present value analysis of both annual costs and average energy-adjusted scenarios costs per MWh (see Table 7-3). SDG&E also provided these measures of scenario costs assuming the high and low gas price forecasts.

Table 7-3
SDG&E Scenario Cost Estimates

Scenario	Present Value, $Billion 8.18% discount rate	Average Cost per MWh, $2006
Reference	9.912	76.6
Alternate	9.949	74.1
Accelerated Renewables	9.912	76.6
High Gas Price	10.810	83.9
Low Gas Price	8.994	69.2

Source: SDG&E tables, *2005 IEPR Scenario Costs* and *Average Energy-Adjusted Scenario Costs* (see Appendix D).

For similar reasons, SDG&E's resource plan costs estimates are also of limited usefulness.

> These results reflect the cost of serving load, but the future cost of fuel could substantially change these estimates. The costs included in the analysis are comprised of existing and forecasted fuel and capacity costs, and they are based on paying no more than the assumed MPR [Market Price Referent] for renewable power. The costs also include the fixed capacity costs for RMR units while they are needed. The analysis does not include (1) the energy costs for the dispatch of RMR [Reliability Must Run] units; (2) costs for energy efficiency and demand response programs, including AMI [advanced Metering Infrastructure];

> (3) costs of transmission, both existing and new, needed to make resources deliverable; and (4) congestion and other ISO costs.[70]
>
> This analysis did not include changes in total costs that could occur if prices moved and stayed near these higher levels. These changes could include increases in the cost of renewable power because the MPR would increase, or changes in the portfolio mix, such as the amounts of cost effective energy efficiency. The analysis also did not include any price hedging, which is a normal part of utility procurement.[71]

To illustrate, consider the cost estimates SDG&E provided for their Reference Case and Accelerated Renewables cases. Both cases are reported to have the same resource plan costs (in terms of net present value of annual costs over the period 2006-2016). But staff suspects that this is an artifact of input assumptions (i.e., "paying no more than the assumed MPR" for renewable power") and omissions of some cost categories (i.e., "costs of transmission," "other ISO costs,"). These results, taken on face value, would indicate that SDG&E should be indifferent to an increase in their RPS obligations. But, SDG&E's previously discussed narrative on the Accelerated Renewables Scenario is clearly not indifferent to the potential costs of overcoming hurdles to achieve either the current or higher levels of RPS obligations.

As with the SCE and PG&E cost estimates, staff is unable to provide an independent assessment of the plausibility of SDG&E's cost estimates because of the exclusion of key components of costs, and because of the lack of detail provided on each component. Staff finds that SDG&E's costs estimates are also an incomplete indication of potential cost differences among SDG&E's scenarios and are therefore of limited usefulness.

Sensitivity Analysis of Resource Plan Costs

The Forms and Instructions ask the IOUs to estimate how the resource plan costs of meeting their load obligations are affected by:

> ….an estimate of long-run changes in natural gas and wholesale electricity prices . . . . . Bounding estimates should be based on prices in the tenth and ninetieth percentiles. The resulting effects on assumed wholesale electricity prices should reflect appropriate input price elasticity's.[72]

Despite the limitations previously discussed in the IOUs' resource plan cost estimates, some insight can be gained from their assessment of the sensitivity of their resource plan costs to the high and low natural gas and wholesale electricity market prices. First, PG&E and SCE interpreted the request to mean that they were to report the 10^{th} and 90^{th} percentiles from a range of resource plan costs estimates. Both PG&E and SCE used Monte Carlo simulations that take hundreds of random draws of values of correlated variables that affect resource plan costs (e.g., gas price, electricity price, load, etc.) to derive a distribution of hundreds of estimates of resource plan costs from which they reported the estimates at, or near, the 10^{th} and 90^{th} percentiles of that range. SDG&E interpreted the request to mean that it was to recalculate resource plan costs assuming a low (10^{th} percentile) gas price with a correspondingly low electricity price assumption, then to repeat the plan cost calculation assuming a high (90^{th} percentile) gas price with correspondingly high electricity price assumptions. In addition, SDG&E lowered or increased the cost of the QF energy component, respectively, when recalculating resource plan costs.

As previously mentioned, SDG&E submitted sensitivity analysis estimates of it resource plan costs in Table 7-3. In the simulations SDG&E conducted,

> …natural gas prices, market prices, and QF costs are increased due to the fuel price changes. Total costs only increased about 5-10% depending on the year. This relatively small change in total costs is due to the fact that many of the costs are fixed, such as fixed demand payments or costs that are not subject to fluctuations in gas prices, such as fixed energy cost resources.[73]

SCE conducted a “250-iteration stochastic analysis with variable natural gas price, power price and load” assumptions and reported that its resulting Reference Case costs (i.e., net present value of annual costs for the years 2006 through 2016) were reduced by more than 7 percent near the 10^{th} percentile iteration and were increased by more than 8 percent near the 90^{th} percentile iteration. SCE notes that these sensitivity study results were “not the actual 10^{th} and 90^{th} percentile iterations, but the average of the five closest.”[74]

PG&E conducted Monte Carlo simulations of its Reference Case generation revenue requirements (i.e., its reported resource plan generation costs) and reported that the 10^{th} percentile plan costs were reduced by more than 13 percent, while the 90^{th} percentile plan costs were increased by about 5 percent[75]

> …relative to the projected (deterministic) revenue requirement. Relative to the probabilistically derived expected revenue requirement, the cost variability ranges approximately 90% to 100% of the expected value.[76]

Caution is warranted in interpreting these results. First, the percent changes reported in “total costs” are actually only changes in a smaller number—the portion of total costs that were actually tallied. The percent change of the actual “total cost” figure will necessarily be smaller than the percent change reported. Second, since each IOU calculated its estimated plan costs differently, including and omitting different components of "total costs," the reported percent changes in plan costs are also not directly comparable across utilities.

Local Reliability Areas Assessment

All load serving entities within the CAISO control area, including the three large IOUs, must procure sufficient resources in the CA ISO's Local Reliability Areas to meet local deliverability requirements. SCE's filing quotes the CPUC's D.04-07-028 requirement that the IOUs meet this responsibility in the procurement process:

> Each utility is responsible for scheduling and procuring sufficient and appropriate resources (both system-wide and locally within its service area) to meet its customers' needs, and to permit the [CAISO] to maintain reliable grid operations . . . [and that] [e]ach utility shall use a comprehensive approach to scheduling and procuring resources that reasonably minimizes the need for reliability must-run contracts.[77]

The Forms and Instructions ask the IOUs to:

- Present an assessment in which they procure sufficient resources in the ISO's Local Reliability Areas to meet local deliverability requirements.
- Discuss the transmission implications and options of this requirement, *i.e.*, what upgrades to bulk transmission would be needed to assure local reliability through non-local resources.
- Discuss the impact of these local reliability procurement constraints on the costs of meeting load obligations.
- Compare the cost of contracting with existing resources, building a new resource in the LRA, and increasing the transfer capability into the LRA.

SCE's filing points out the challenge that individual LSEs face in incorporating local area reliability into their long-term procurement planning:

> The CAISO RMR and transmission grid operating requirements are always changing, however, and there are no explicit formulas to calculate the exact amount of capacity that might be needed in each geographical area each year in the future.[78]
>
> Because it is currently impossible to determine the exact types of resources and the exact locations of the resource needs without more discussions with the CAISO, and/or finalization of the CAISO studies, SCE used general rules of thumb in filling the various scenarios to meet these requirements. In order to finalize the determination of exact

> needs both deliverability and other operating considerations studies are needed to better define what local reliability requirements might actually entail in the future.[79]

SCE states that its resource plan scenarios do have "a sufficient amount of capacity that is either contracted, generic, QF, or SCE-owned in this plan to meet what could be represented as a reasonable estimate of the amount of resources needed to meet the intent of D.04-07-028 in the future."[80] SCE further explains its method:

> In developing the scenarios used in these updates, SCE started by including resources that have most recently been reflected as required in the current CAISO reliability must run (RMR) solicitations. SCE also recognized that it was necessary to meet other requirements, outside pure RMR needs, so that the CAISO could adequately operate the transmission grid. These plans include, in the short term, specific contracts that meet these operating requirements. In the long term, these plans have attempted to identify future local needs and included generic resources that could be used to meet the anticipated requirements. Future plans include various generic resources as place holders for the actual resources or contracts that might be used to meet these requirements.[81]

PG&E's only comments on the local reliability areas assessment are as follows:

> As PG&E currently contracts with Reliability Must Run (RMR) units within its service territory, the costs of this are subsumed in its operating costs and an additional assessment is unnecessary. PG&E further notes that it is currently soliciting additional generating resources, which it anticipates will reduce local-reliability concerns in its service territory in the future.[82]

SDG&E's resource cases add enough planned in-basin generation to eliminate the need for separate RMR units by 2011, except for its No Major Transmission Interconnection Scenario.

> SDG&E plans to add transmission import capability that reduces the amount of local generation that is required as must-run. In addition, construction is underway and/or completed for the Miramar CT (formerly called RAMCO) and Palomar. The Otay Mesa power plant is waiting for a CPUC decision approving the necessary transmission upgrades before restarting construction. These units will reduce the requirement for separate RMR units.[83]

SDG&E points out that the Energy Commission should emphasize reducing RMR costs rather than reducing RMR units:

> Any proposals that would require the IOUs to add resources beyond their resource need in the short term just to eliminate RMR units would be counter productive and potentially increase costs to customers. The current method to address local needs is for the ISO to contract with local units in these areas. [84]

SDG&E argues that the obligation to meet local area reliability requirements was assigned to the CA ISO for three reasons, all of which still apply today:

> First, these units are located in an area that requires their operation. Thus, to mitigate potential market power concerns, the ISO established cost-based FERC-regulated RMR contracts.
>
> Second, these units are dispatched for the needs of the grid overall and not for the energy needs of a single LSE. If these units are solely contracted for through the local IOU, they will not necessarily be operated when needed most to serve the grid. These units would need to be operated to meet not only the needs of the IOU's customers, but also the needs of other LSEs who serve load in the load pocket and other IOUs in the state because the units are dispatched to meet infra-zonal congestion. Thus, the ISO needs to continue to have direct dispatch rights over these units.
>
> A third consideration is cost allocation. Because these units are operated for the benefit of many, the costs need to be allocated to all parties that benefit from their operation, including bundled and direct access customers. Thus, a contract like the current RMR contract is needed to properly allocate costs.[85]

The Forms and Instructions also specifically requested SDG&E to discuss the potential for new geothermal generation to support reliability in the San Diego area and to provide a description of SDG&E interconnections with Mexico and Imperial Valley. SDG&E’s supply filing responds as follows:

> …there is no geothermal power located within the transmission constraints. Thus, these projects do not directly provide reliability support. In order to have them support SDG&E's needs, additional transmission must be built. Trying to force additional geothermal power onto the existing constrained transmission system does nothing to improve the reliability situation as compared to today.[86]

SDG&E’s description of interconnections with Mexico and Imperial Valley are described in detail in its transmission filings. SDG&E imports from Mexico, Arizona and IID are limited by both the Southwest Power Link (SWPL) and the lines connecting the Miguel Substation to load centers in San Diego. There is currently significant congestion on these transmission facilities which will be reduced by the

Miguel-Mission #2 230 kV transmission line which is scheduled for partial operation in 2005. Any new generation, including renewable generation, would compete with power produced in Arizona, IID and Mexico for limited space on the transmission facilities serving San Diego loads.

Potential Impact of a Greenhouse Gas Adder on Bid Evaluations

The CPUC decision (D.04-12-048) of December 21, 2004 in R.04-04-003 requires that the IOUs apply a greenhouse gas (GHG) adder to bids received in response to future solicitations for energy and capacity, as well as to consider GHG emissions in their long-term planning process. The GHG adder for financial risk exposure from future GHG emission costs that might be imposed by regulations such as a cap-and-trade system to reduce emissions. The GHG adder will be used only in the evaluation of bids to develop a more accurate price comparison between and among fossil, renewable and demand-side bids.

IOUs are asked to submit a discussion of the potential obstacles, benefits, and impacts of using GHG adders to influence future procurement choices. IOUs are asked to discuss how an adder for GHG emissions might be used, and to suggest a methodology for incorporating the adder into the procurement evaluation process.

The Forms and Instructions anticipated that the value of the GHG adder was to be determined in R.04-04-025 in March 2005, but suggested that a reasonable range of values should be discussed, from at least $7/ton carbon dioxide ($CO_2$) to as much as $25/ton. After both the Forms and Instructions were published and the IOUs' resource plans were filed, the CPUC determined that the most appropriate value of the GHG adder was to be $8/ton CO_2 (D.05-04-024, April 7, 2005).

PG&E provided a brief description of their recommended methodology for incorporating the GHG adder in the bid evaluation process:

> Given the many factors that are used in the evaluation and the broad range of reasonable CO_2 values, $8 to $25 per ton, PG&E is using a comparative process that it refers to as a "tipping point" analysis. Under the process, PG&E will evaluate the RFO respondent projects using its least cost best fit analysis, which includes market value, portfolio fit, credit, and other factors to rank all of the offers received and select the best portfolio. Projects within that portfolio will then be compared to projects that were not chosen to determine what price of CO_2 would be necessary for a project not selected to displace a selected project (i.e., to "tip" the results of the evaluation). If the resulting CO_2 value is over the $8 to $25 range, no additional work is needed as CO_2 would clearly not be a factor. If the tipping point analysis shows that a value within the range affects the evaluation,

> then CO_2 is a factor and additional discussion is necessary, including with PG&E's Procurement Review Group.[87]

PG&E's filing says it intends to use a GHG adder when evaluating resource offers in its current Request for Offers. Presumably, PG&E's implementation of their methodology will take into account the CPUC's decision setting the adder at $8/ton. PG&E did not comment on obstacles, benefits or impacts of using a GHG adder in the procurement evaluation process. PG&E does state that its approach has the benefit of not requiring the selection or justification of a specific value within the range of potential adder values until the effect on the results is understood. That is, once the results of PG&E's evaluation of the bid without including a GHG adder has been completed, PG&E can assess how close competing bids are, and then determine whether or not a GHG adder within the range would make a difference.

SDG&E's filing acknowledges that a benefit of using a GHG adder now is to help reduce financial risks associated with potential future GHG emission cost constraints. Another desirable impact expected is the selection of lower-GHG emitting energy resources. SDG&E emphasizes that implementing the "preferred loading order" will also reduce GHG emissions.

SDG&E states there are no specific obstacles to implementing a GHG adder in the procurement evaluation process. However, SDG&E warns:

> Unless appropriately designed and implemented, however, the addition of a GHG adder could create inefficiencies and perverse outcomes. Also, the application of such an adder to IOU procurement activities only can create a cost disadvantage when comparing the costs of utility service to other options.[88]

SDG&E states that one undesirable impact is the potential for low-GHG resource bidders to strategically raise their prices.

> Inappropriate implementation of a GHG adder, however, could have the impact of raising the price of lower-GHG emitting resources (both renewable and nonrenewable) above what they would otherwise be because the bidders will know that a GHG adder will be used to compare with fossil generation. The GHG adder value selected will likely be the determinant of how much or how little market prices for energy could be distorted. The higher the value selected, the more likely a renewable or other low-GHG emitting resource could consider raising their prices and still be evaluated as "competitive" with a fossil resource.[89]

SDG&E's filing argues that, based on current market prices and National Commission on Energy Policy recommendations, the GHG adder used in procurement ought to be close to the bottom of the range specified in the Forms and

Instructions and the CPUC's long-term procurement decision. The CPUC's decision setting the GHG adder at $8/ton is consistent with SDG&E's position.

SDG&E's filing provided no specific methodology to implement a GHG adder in procurement, but does specify desirable features of an implementation methodology. SDG&E states the methodology employed should "achieve the desired benefits with little or no distortion in the outcome," should have a time dimension so the value of reducing CO_2 should be the same regardless of when the reduction occurs, and should "include some discount to the GHG adder to account for the non-availability of a particular type of resource because during those periods (particularly peak periods) there may not be a reduction in GHG emissions."[90]

SCE believes the use of a GHG adder absent national or California legislative direction is "speculative" and could have adverse impacts if not applied "with caution." Nevertheless, the CPUC has stated that taking action to address the financial risks associated with future GHG emission controls is no longer speculative.

SCE provides no direct comment on obstacles to implementing a GHG adder in the IOU procurement processes, nor any description of actual or potential benefits of using a GHG adder in procurement. SCE does provide input on potential impacts of using a GHG adder. SCE's filing cites the primary impact as a potential for utility customers to pay higher prices for power.

> It is generally recognized that the carbon [GHG] adder is not paid to the supplier of electricity. However, the beneficiaries of this program are likely to be the [higher priced] suppliers who otherwise could not sell energy to the utility but for the addition of an imputed cost to the competitors' prices. This outcome would more likely occur at the higher end of the carbon [GHG] adder range than the lower end. [91]

SCE recommends a methodology to "determine the impact of a specific contract on the global emissions of GHG [by] rewarding additions that reduce emissions while penalizing those that increase emissions."[92] For a given demand scenario, SCE would assume a resource plan or "supply stack" adequate to meet the demand. When comparing competing resource contracts in procurement:

> …[C]ontracts that would decrease greenhouse gas emissions relative to the assumed supply stack receive an emissions benefit in a bid evaluation that would increase the value of the contract. Conversely, contracts that would increase greenhouse gas emissions relative to the assumed supply stack would receive an emissions cost in a bid evaluation that would decrease the value of the contract.[93]

It is not clear from SCE's description exactly how comparison of the proposed contract "relative to the assumed supply stack" would be accomplished. It could be consistent with the methodology the Energy Commission has used in the past to incorporate GHG emissions into resource planning, in which the emissions of the resource stack were measured with and without the proposed contracts (i.e., potential new resources). If the proposed resource reduced total GHG emissions when added to the stack, that resource was "rewarded" by associating with it an emission cost credit (the product of the emissions reduced and the dollar per ton emission value.) The relative performance of all potential new resources was then compared against each other.

Since the three IOUs took fundamentally different approaches to methodologies for incorporating a GHG adder into procurement, staff thinks the Energy Commission would benefit from the IOUs providing more detailed descriptions of their proposals so a more comprehensive comparison of relative advantages and disadvantages can be assessed.

Sensitivity to Natural Gas and Wholesale Electricity Prices

This report previously discussed the results of the sensitivity studies that assess the impact on resource plan costs caused by variations in natural gas and wholesale electricity price assumptions. The Forms and Instructions also request the IOUs to provide the natural gas and wholesale electricity price forecasts themselves. The instructions specify how the gas price forecast should be conducted:

> Natural gas prices should be based on current forward prices in the near-term, but may, at the utility's discretion, be based on a fundamentals model over the longer term. Should such a model be used, any significant differences between forecasted prices and those indicated by current forward prices and their extrapolation should be explained. Should an IOU use yet another methodology for determining long-run gas prices, it should be explained in documentation which accompanies the price forecast.[94]

IOUs' Natural Gas and Electricity Price Forecasts

This section summarizes how each of the IOUs conducted their natural gas price forecasts then provides staff comments. Next, the IOUs' forecasts of wholesale electricity prices are summarized, with staff comments following. The IOUs disclosed different levels of details on their natural gas and wholesale electricity price forecasts, so staff's summary and comments are consistent with each approach.

Southern California Edison

SCE's natural gas price forecast is based on market-derived prices for the initial years (February 1, 2005 quotes for NYMEX Henry Hub plus SoCal basis differential) which linearly blend with longer-term prices from consultant Global Insight's October 2004 fundamentals-based outlook.[95] SCE disclosed its natural gas price forecast for 2009-2016 in its public narrative (see Table 7-4).

Table 7-4
SCE's Natural Gas Price Forecast
Nominal Dollars per mmBtu

Year	SoCal Gas Border	SoCal Gas Burner tip
2009	4.47	4.86
2010	4.67	5.05
2011	4.91	5.30
2012	5.08	5.47
2013	5.26	5.66
2014	5.39	5.80
2015	5.61	6.02
2016	5.76	6.18

Source: Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, p. 20.

SCE developed and disclosed three different forecasts of SP15 marginal energy prices that are all consistent with their gas price forecast (see Table 7-5). The price forecast for power available to SCE becomes higher beginning in 2009 in SCE's variation of the Reference Case without the Devers Palo Verde 2 transmission project than in the forecast used in the Reference and Alternate Cases. The price forecast used in the Accelerated Renewables Case has lower marginal energy prices because a larger portion of the resources in the portfolio are must-take energy contracts with pricing terms that do not affect system marginal costs.[96]

SCE notes that the natural gas price has a significant impact on the variable cost component of its resource plans costs because

> ….natural gas is the primary fuel used to generate the electricity that SCE uses to meet its end-use demand. Therefore, SCE's portfolio cost is very sensitive to the natural gas price forecast. Wholesale electricity prices are correlated to natural gas prices because gas-fired generators are the dominant marginal resource in Southern California. Gas and electricity also exhibit strong short-term mean reversion tendencies and do not follow a true random walk pattern.[97]

Table 7-5
SCE's Wholesale SP15 Marginal Energy Prices
Nominal Dollars Per Megawatt-Hour

Year	Reference & Alternate	Reference w/o DPV2	Accelerated Renewables
2009	37.2	37.6	36.8
2010	39.6	40.3	39.1
2011	42.3	43.2	41.4
2012	43.4	44.3	42.3
2013	45.0	46.0	43.8
2014	46.2	47.2	44.7
2015	47.5	48.8	45.8
2016	48.7	50.0	46.9

Source: Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, p. 20.

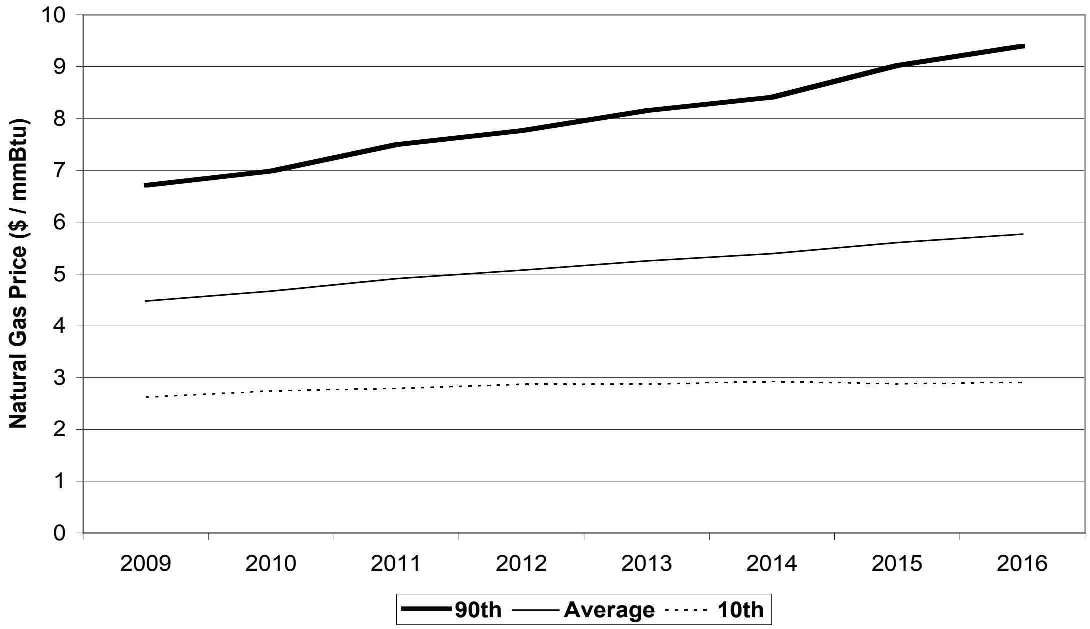
SCE creates its SP 15 power price forecasts with a simulation model (Global Energy Decisions' Marketsym) that produces "an hourly forecast of regional market prices based on market fundamentals and incremental operating costs."[98]

SCE used the RiskSym model to develop its sensitivity studies of natural gas and wholesale power prices, as well as its total resource plan costs. The model uses Monte Carlo simulations to generate probability distributions of the price forecasts based on random draws of values for short-term and long-term variables that affect gas and electricity prices. Short-term volatility variables include weather (i.e., temperature) effect on demand and facility outages. Long-term volatility variables include effect of the annual level of snow pack on hydroelectric generation availability, regulatory or market changes, changing facilities in the portfolio, and new technologies.[99]

Figures 7-1 and 7-2 show the results of SCE's natural gas and SP15 Power Price uncertainty analyses, respectively.

Figure 7-1

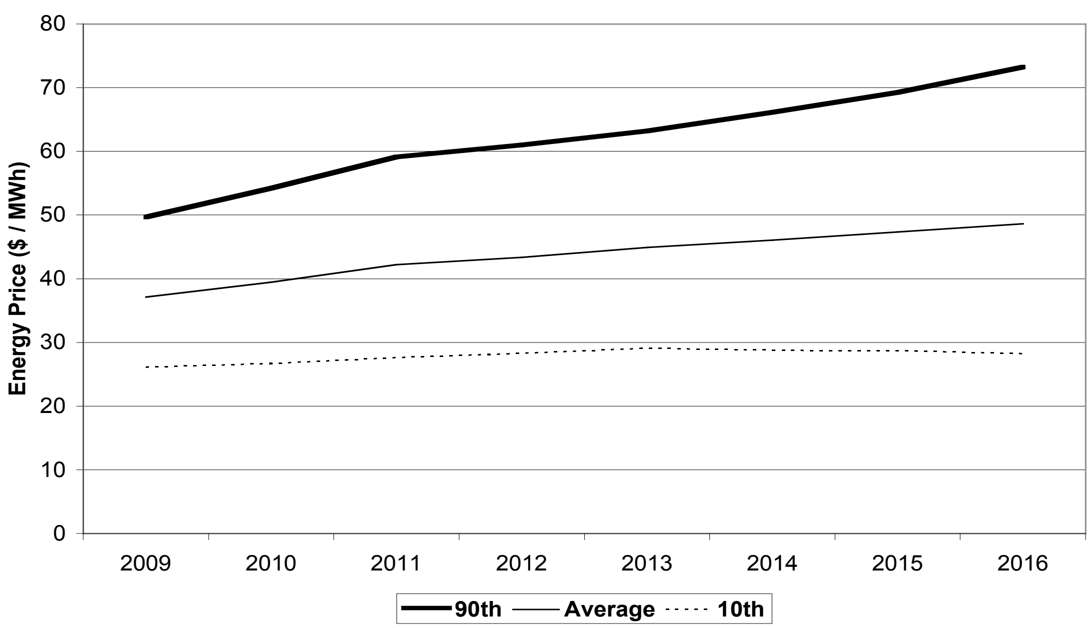
Figure VIII-1: SoCalGas Border Natural Gas Price Uncertainty



Source of both figures: Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, pages 22-23.

Figure 7-2

Figure VIII-2: SP15 Power Price Under Uncertainty



Pacific Gas and Electric

PG&E's resource planning relies on gas and power prices developed by their Risk Management Department, which creates "a forward view of electricity and gas prices, as well as volatilities and correlations between these prices." PG&E's power prices are based entirely on broker quotes for monthly electricity forward prices extending out to 2015. From these quotes, PG&E's Risk Management Department developed monthly and hourly forward prices through the end of 2015. PG&E linearly extrapolated 2016 monthly forward power prices from corresponding months in 2014 and 2015 (e.g., ". PG&E calculated the May 2016 forward price as twice the May 2015 price minus the May 2014 price.")[100]

PG&E then used hourly shape factors to convert the monthly forward prices into hourly forward prices by multiplying

> the appropriate monthly forward price (peak or off-peak depending on whether the hour is peak or off-peak) by the shape factor for that hour. Since shape factors for hours in 2016 were not available, PG&E used shape factors for earlier years selected from years where both the date within the year and the day of the week matched.[101]

PG&E's natural gas price forecast is based on monthly gas forward prices through December 2010 but afterwards is derived directly from their monthly power price forecasts and an implied heat rate assumption. In describing its methodology for its 2006-2010 monthly gas price forecast, PG&E states that

> PG&E developed its forecast using gas commodity prices based on the December 20, 2004, closing price of forward contracts traded in the New York Mercantile Exchange (NYMEX) plus location basis obtained from broker quotes for gas delivery at PG&E Citygate, AECO, Topock and Malin for the period through December 2010, which marks the end of NYMEX availability.[102]

PG&E then describes how it developed its post-2010 monthly gas curves. First it calculated implied monthly heat rates in the following way:

> Monthly heat rates were calculated by dividing the monthly NP15 peak forward power price by the PG&E Citygate monthly forward gas price for the corresponding month. Past December 2010, the heat rate from the corresponding month in the prior year was employed. Thus the January heat rates for 2011 thru 2016 are all identical to the January 2010 heat rate.[103]

Next, PG&E describes the methodology it used to extend the forward PG&E Citygate gas prices beyond 2010 by

> …dividing the monthly forward peak NP15 power price by the heat rate projected for that month. Malin, Topock, AECO and SRAC forward monthly gas prices were extended beyond December 2010 by simply assuming that they increased by the same percentage amount from the corresponding month in the prior year as the projected change in PG&E Citygate forward prices.[104]

In addition to these natural gas and electricity price forecasts that PG&E used in its estimate of Reference Case costs (i.e., generation revenue requirements), PG&E used Monte Carlo simulation to develop high (90th percentile) and low (10th percentile) natural gas price forecasts and high and low electricity price forecasts.

San Diego Gas and Electric

SDG&E's natural gas price forecast is based on NYMEX prices for 2006 and 2007, escalating thereafter to the averaged results of four fundamental model forecasts generated by Energy Commission, EIA, PIRA and the NEB. The market prices are based on a 60-day trading average of Henry Hub prices for 10/26/04 to 1/24/05 with an adjustment based on price differentials to provide the final California border price. SDG&E describes its natural gas price forecast as follows:

> SDG&E's natural gas price forecast was prepared according [to] the MPR gas price forecast methodology adopted by the [Public Utilities] Commission in D.04-06-015. The near-term natural gas price forecast from January 2006 to December 2007 at Henry Hub is based on the most recent 60-day trading average of NYMEX futures prices from 10/26/2004 to 1/24/2005. Basis swaps trading contract settlements from NYMEX ClearPort, are then added to the Henry Hub futures prices to arrive at the natural gas price forecasts at producing basins and at the California border. Starting in the years 2008 to 2016, natural gas price forecasts are then escalated based on the annual average growth of four fundamentals-based forecasts applied to the last year of NYMEX price forecasts. The fundamentals-based forecasts are from three public sources: EIA, NEB, CEC, and one private source, PIRA.[105]

SDG&E also provided a high and low gas price forecast sensitivity. SDG&E describes the methodology as follows:

> Based on a normal distribution, the upper 90% and lower 10% prices are 1.65 standard deviations from the base forecasted prices. The standard deviation was calculated using monthly prices from 2002 to 2004. The 90/10 price range is about plus or minus $2 at Henry Hub in 2003 constant dollars or 33% of the base forecasted price. To arrive at the 90/10 price ranges at producing basins and California border

> prices, the same basis swaps trading contract settlements from the base case are added to the 90/10 price range at Henry Hub.[106]

SDG&E states that its two-step methodology for developing electricity market clearing prices takes into account both engineering fundamentals and market dynamics.

> First, SDG&E adopted Henwood's most recent WECC database as of January [2005], and updated the database with the latest information available for electric generating resources, fuel prices, electric load demands, and hydro conditions. Instead of second-guessing which future generating resources will be built throughout the study, however, SDG&E focused on resources that are in operation, under construction, or in the advanced development phase. From this load and resource analysis, SDG&E determined the resources that are sufficient to meet reserve margin and reliability through 2009. Beyond 2009, SDG&E assumes that the electric market would continue to add sufficient generating resources to maintain similar reserve margin and reliability.
>
> Second, SDG&E performed a Marketsym simulation from 2005 through 2009 based on variable cost dispatch (fuel, variable O&M, and start-up costs). SDG&E compared the cost-based MCP results with the electricity futures for the next 12 months, and SDG&E developed a bidding strategy to account for the differences between cost-based MCPs and market-based MCPs. SDG&E then applied this bidding strategy in Marketsym and re-ran the simulation through 2009. Beyond 2009, SDG&E escalated the MCPs at the same rates as the United States gross domestic product index.[107]

SDG&E repeated this same methodology to create the high and low wholesale electric price forecasts, by respectively substituting the high and low natural gas price forecasts previously discussed.

Staff Assessment of Natural Gas Price Forecasts

The common feature in all of the IOUs' natural gas price forecasts is the declining price in the early years of the forecast, until about 2008 to 2009. Following the dip in the early years, forecasts of SCE and SDG&E increase at about similar rates over the rest of the forecast period. This is consistent with the assumptions made by each IOU about the escalation of prices after the initial years, and about the average growth rates of a combination of one or more prescribed fundamental forecasts.

PG&E's forecast on the other hand, follows a different methodology of extrapolating the monthly prices as reported by the NYMEX into the future periods. Since the

NYMEX shows a declining price projection until 2010, a projection of these trends would suggest either a continued declining trend or a flattening trend depending on the monthly prices as reported on the quote day for NYMEX. This is what PG&E's forecast shows over the entire planning period.

While the pattern of early gas price decline is the same in all three IOUs' forecasts in the early years, there is a 50 cent to $1.50 per MMBtu spread between the actual prices being forecast in the near term. This difference across the IOUs' filings has two causes. First, the date on which the market price quotes were gathered differ. Second, quotes were used differently across the IOUs' forecasts—a single day quote was used in one method and a 60-day average of daily quotes was used in another. The NYMEX price trends for the future changed between the dates on which the IOUs' each selected their quotes and have continued to change from when the IOUs' filed their forecasts and when staff reviewed them. This is reasonable as Henry Hub or NYMEX prices are dynamic and change continuously depending on market interests and perceptions.

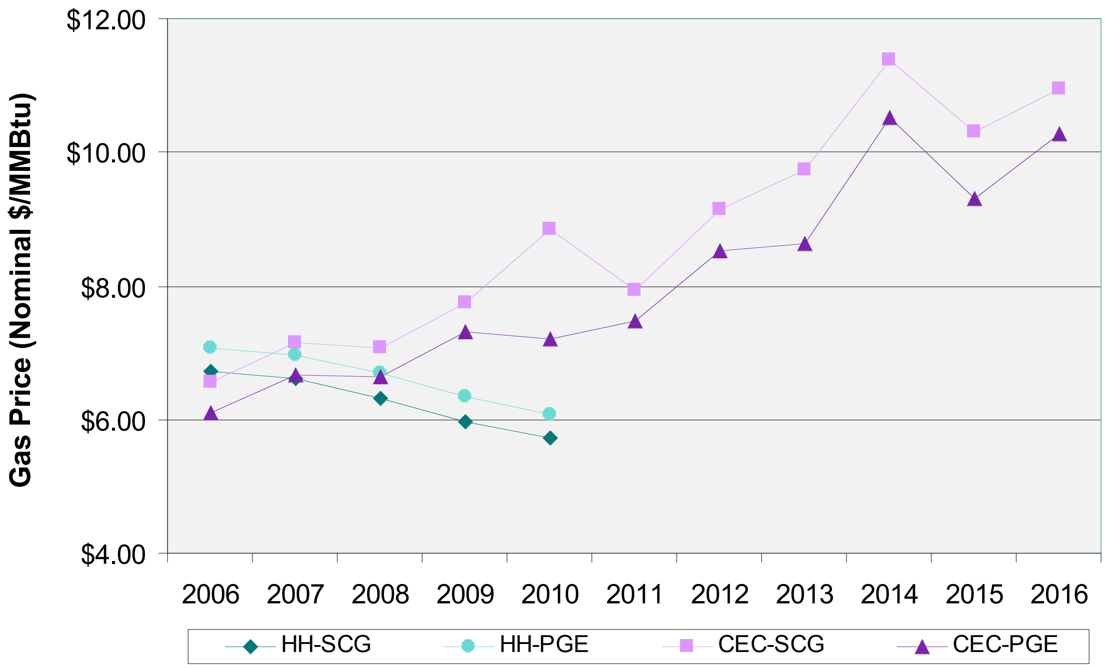
Figure 7-3 includes NYMEX prices, as of May 19, 2005, (obtained from the NYMEX ClearPort basis swaps for SCG and PG&E). The prices for PG&E, Citygate and SoCal gas regions are higher than the prices indicated in the IOUs estimates, which were based on earlier NYMEX quotes. Figure 7-3 also compares Henry Hub estimates as of May 19, 2005, with the preliminary draft staff natural gas price forecasts for the Southern California Gas and PG&E regions. This comparison is made only to illustrate the potential effect on gas price forecasts of the date on which the forecaster chooses the quote and whether the forecasting method employs single day quotes or averages of quotes over a series of days.

While SCE's and SDG&E's gas price forecasts both decline over the short term and both begin to increase at about the same rate after 2009, as mentioned above, the increases begin from significantly different bases. The result is that SDG&E's gas price forecast is significantly higher than SCE's throughout the later planning period. Also as mentioned previously, PG&E's late-period forecast does not increase at all during the planning period, staying relatively flat after 2001 and being even lower than SCE's after 2012. By 2016, there is more than a $2.00 MMBtu spread between the highest (SDG&E's) and lowest (PG&E's) gas price demand forecasts. Staff's preliminary gas price forecast is significantly higher than even SDG&E's throughout the planning period, reflecting different fundamentals assumptions in the later years.

Staff Assessment of Electricity Price Forecasts

As the IOUs have noted, their electricity price forecasts are directly influenced by their assumed natural gas price forecasts. The Energy Commission expects the IOUs' wholesale electricity price forecasts to be consistent with their natural gas price forecasts. And all three IOUs report this is the case with their forecasts. Staff's assessment of the reasonableness of the IOUs' electricity price forecast methodologies and results involved backing out each of the IOU's gas input assumptions and substituting a staff gas price forecast. Staff also compared the IOUs forecasts to the results of the E3 report[108] to the CPUC.

Figure 7-3
Energy Commission Draft Natural Gas Price Forecast



Source: Energy Commission Preliminary Draft

Overall, the IOUs electricity price forecasts methods are reasonable, given each IOU's assumed natural gas price input assumptions. Essentially, these power price forecasts are as good as the natural gas forecasts that underlie them. In general then, staff's comments regarding the results of the IOUs' natural gas price forecasts apply to their power price forecasts as well. Since PG&E's forecast of natural gas prices declines over time, so does its electricity price forecast. As when comparing the gas price forecasts across IOUs and other sources, this leaves PG&E's forecast in the anomalous position of declining over time while all of the rest increase over time.

Other Major Uncertainties and Risk Analysis

The Forms and Instructions ask the three IOUs

> …to provide narrative and qualitative assessments of how major uncertainties would impact either their reference case or their preferred resource plan. Each LSE should identify and list individual uncertainties that result in significant risk or opportunity. The major

> uncertainties to address are those affecting forecast loads, wholesale energy prices, and LSE resource portfolios.[109]

The following sections summarize the IOUs responses to the specific uncertainties and risks identified by the Forms and Instructions as well as those the IOUs identified. Uncertainties about resource portfolios include availability of large existing units (nuclear units and the Mojave coal-fired power plant), transmission upgrades, and compliance options for meeting the Renewable Portfolio Standards annual energy procurement obligations. Uncertainties affecting forecast loads include the amount and timing of bundled service customer load that might depart to non-core service, community choice aggregation, or direct access or municipalization. Uncertainties about how wholesale electricity prices affect resource choices and the ultimate costs and benefits realized by those choices have been previously discussed.

Nuclear Unit Early Retirement

Both of California's large operating commercial nuclear power plants - San Onofre Nuclear Generating Station (SONGS) Units 2 and 3 (2,150 MW and Diablo Canyon Power Plant Units 1 and 2 (2,220 MW) - have experienced degradation of their steam generators. Steam generator replacements are required to keep these plants operating through the remaining terms of their nuclear operating licenses. (These licenses expire in 2022 for SONGS Units 2 and 3, and expire in 2021 for Diablo Canyon Unit 1 and 2025 for Unit 2.) SCE has filed an application with the CPUC for authorization to replace the existing steam generators at SONGS Units 2 and 3. SDG&E, Anaheim, and Riverside are currently part owners of SONGS 2 and 3. (Riverside owns 20 MW from each unit, and expects that to continue through 2016. Anaheim owns 35 MW from each unit, but expects that to terminate by 2010.) Hearings on cost-effectiveness have concluded and a CPUC decision regarding cost-recovery is expected in September 2005 for SONGS and in August 2005 for Diablo Canyon. The CPUC has given preliminary approval for cost-recovery for a similar steam generator replacement at Diablo Canyon Units 1 and 2. Draft Environmental Impact Reports on both projects are currently out for review.

The Forms and Instructions ask the three IOUs to

> …assess the possibility these base load resources may face early retirement or prolonged scheduled outages. IOUs are asked to describe the desirable characteristics of the resources that would be needed to replace what these facilities now provide in terms of base load capacity and energy, ancillary services, transmission support, grid stability, and local reliability.[110]

PG&E did not respond to this request regarding Diablo Canyon Units 1 and 2. SDG&E points out two sources of uncertainty it faces related to the SONGS Steam

Generator Replacement Project (SGRP). The first uncertainty is when the replacement will occur. SCE's application schedules the replacements in 2009 for SONGS Unit 2 and 2010 for SONGS Unit 3. The CPUC may approve that schedule or require a different deferred schedule. Each of SDG&E's resource plan cases assume the SGRP is completed as proposed.[111]

The second uncertainty SDG&E faces is what their share of SONGS generating output will be after the SGRP is completed. SDG&E currently owns 20 percent of the output of SONGS, but, SDG&E has chosen not to participate in the SGRP in exchange for a reduction in its share of SONGS output to 14 percent. This is the level of SONGS output that SDG&E has assumed in each of its resource plan cases. However, SDG&E notes that

> SDG&E's election and the amount of its ownership reduction are both subject to CPUC approval. The CPUC could approve SDG&E's election and reduce its ownership of SONGS to some amount ranging from its current 20% to 0%. Conversely, the CPUC could require SDG&E to participate in the SGRP. Another potential outcome, which SDG&E has requested in the current SGRP cost-effectiveness proceeding, is that SCE purchase SDG&E's 20% ownership of SONGS and enter into a purchase power agreement under which SCE sells to SDG&E 430 MW of power, an amount equivalent to SDG&E's current 20% share.[112]

SCE provided a brief description of the impact of losing SONGS that is consistent with its comprehensive cost-effectiveness and impacts analysis in its application to the CPUC (A.04-02-026, Exhibits 1, 4, & 5). SCE describes the impacts of not replacing the SONGS steam generators as follows:

> [T]he Southern California region would lose 2,150 MW of dependable generating capacity (1,614 MW owned by SCE) at about the 2009-2010 timeframe and beyond. In order to replace the capacity and energy from SONGS Units 2 and 3, SCE would need to acquire an equivalent amount of resources. Much of the replacement generation would also need to be located within the geographical area known as "in-basin" to satisfy local area reliability needs and maintain the ability to import electricity into the Southern California region. There would be significant additional gas demand since it is expected that the majority of the replacement generation would most likely come from gas-fired generation.
>
> Due to the size of SONGS Units 2 and 3 and their location in northern San Diego County, between the SCE and SDG&E service territories, SONGS Units 2 and 3 provide substantial grid reliability services. Removing SONGS Units 2 and 3 from service could lead to transmission line overloading, low voltage situations, and system

> instability that in turn could cause local blackouts and other service reductions if left unmitigated. Potential mitigation solutions would include upgrades to the transmission grid of SDG&E and SCE, including the potential installation of 500kV transmission lines, Static VAR Compensators (SVC), and other system upgrades.
>
> If SONGS Units 2 and 3 were shut down, a combination of replacement generation and transmission system upgrades would be necessary to mitigate the effect on the electric system grid. The potential costs associated with these mitigation measures and the benefits to SCE's ratepayers are detailed in A.04-02-026.

The assessments of SCE and SDG&E with respect to a SONGS early retirement are consistent with the application filed at the CPUC and are considered plausible by staff familiar with that proceeding. The unit outages for the Steam Generator Replacement Project are planned for 115 days each in 2009 and 2010 and avoid the summer peak period. The unit outages for replacing the steam generators at Diablo Canyon are for 75-80 days per unit and are scheduled for 2008 (Unit 2) and 2009 (Unit 1) and also avoid the summer peak period.

Mohave Generating Station Return to Service

The Forms and Instructions asked SCE to "assess the possibilities and uncertainties of returning Mohave Generating Station to service as early as 2010, and what the potential portfolio impacts would likely be."[113] SCE does not include this coal-fired generating unit in its resource portfolio beyond December 31, 2005 "because of the uncertainty surrounding Mohave's operating, thermal, and cost characteristics after potential refurbishment."[114] The unit is not included in any of the requested cases, all of which begin in the year 2006.

SCE provides an assessment of likely portfolio impacts if Mojave Generation Station were to be returned to service.

> Including Mohave within the reference case would have several effects. First, including Mohave in the portfolio would reduce the resource gap (forecasted load obligations less existing resources) by approximately 884 MW – SCE's anticipated share of Mohave's capacity after the plant is refurbished. Mohave's capacity would displace an equivalent amount of baseload, intermediate, or peaking resources (depending on the least-cost best-fit of resource types). Second, Mohave would be dispatched at relatively low variable costs, translating into a high capacity factor compared to resources with baseload and intermediate production profiles. The anticipated low variable costs are directly attributable to Mohave's fuel supply being provided under a long-term contract with much of the associated fuel

> costs being fixed, resulting in low marginal costs to dispatch the facility. Third, Mohave's fixed costs, including fixed operating costs and capital costs could potentially displace the capacity payments associated with any generic resources that Mohave replaces.[115]

SCE notes that a detailed discussion of the impact of having their anticipated share of the Mohave Generating Station either in or out of their procurement plan can also be found in the record of the CPUC's proceeding (A.02-05-046).

Core/Non-core – Departing Load

The Forms and Instructions identify uncertainties regarding departing load as a major source of risk for IOU resource procurement.

> One of the largest uncertainties facing the state's IOUs is how future load obligations will be affected by policy decisions related to core/non-core, community choice aggregation, and municipalization. If IOUs procure supply resources in excess of those ultimately needed by IOU bundled customers, there may be a need to sell surplus energy in a buyers' market, or to dispatch utility-controlled capacity resources in a less efficient manner. Reducing or managing this risk in the face of load uncertainty may require a portfolio of resources with diverse durations.[116]

The Forms and Instructions provide a specific set of straw man assumptions for the IOUs to use to evaluate potential departing load in response to future core/non-core policy decisions. The IOUs are to

> …submit a "low load" resource plan assuming 75% of customers with peak demand of 500 kW or more will depart during 2009 – 2012 (30% in 2009, 15% in each of 2010 –2012).[117]

In addition, the IOUs may submit alternate scenarios they think illustrate risks they face or state why the straw man assumptions do not accurately reflect their risks.

SCE did not submit a "low load" resource plan. SCE assumes the current level of direct access persists in all resource cases. SCE's total generation level energy requirement is the same for its Reference Case, reflecting total additional departing load (CCA and other) equal to only 5 percent of bundled load by 2013. These assumptions yield a 0.7 percent average annual growth rate for the period 2006-2016. In SCE's Alternate Case, there is even less departing load than what was specified by the Commission for the Reference Case. SCE's Alternate Case has no additional departing load, which yields a higher annual demand growth rate of 1.6 percent.[118]

SCE states that it lacks the information required to make a "reasoned estimate" of departing load for planning purposes and cautions that doing so may increase portfolio risks.

> Including speculative estimates for departing load in connection with CCAs and municipalization is risky for resource planning purposes. Insofar as any scenario is used to establish procurement limits, speculative assumptions concerning possible load migration could lead to reduced reliability and increased ratepayer costs. Accordingly, the load forecast used for the "alternate scenario" does not exclude any load whose departure is speculative. Only those entities that have a documented commitment to leaving the SCE system [i.e., Cerritos] are reflected in the load forecast shown on row 1 of SCE's Capacity Resource Accounting Table (CRAT).[119]

SDG&E agrees with SCE that it is difficult to forecast departing load and that departing load could have a significant effect on the resource plan, which is especially a problem for a utility that bears the obligation of being the provider of last resort. SDG&E lists several uncertainties affecting their ability to forecast departing load, including "the demand threshold, the ability to aggregate load, the timing of implementation, and the switching and notification rules." SDG&E also notes that

> ...like CCA, absent resolution of these issues it is difficult to forecast the potential for the amount of future core and noncore load and/or the manner in which the load is likely to move between the core and noncore status. Both the amount of load switching and under what rules the noncore load is able to switch between an energy service provider and the utility will have a direct impact on the resource plan as to what future resources are required and what obligations the utility must plan for in order to fulfill its obligation of "provider of last resort."[120]

SDG&E prepared an estimate of departing load that conforms to the Commission's "low load straw man" assumptions and filed the estimates in their Confidential Supplemental Tables. SDG&E reports the following effect of such low load on their resource procurement activities:

> The impact of such a scenario would obviously reduce the amount of resources SDG&E would need, but it would not reduce the need for in-basin resources or transmission to meet grid reliability needs because these needs are driven by total load in the area regardless of who is serving the load. The actual impact on the utility plan will have a lot to do with the timing of the decision to implement the split. Should the core/noncore splits be known well in advance, SDG&E could adjust its procurement decisions to minimize stranded costs. Should it be

> implemented with a short lead time, then stranded resources are highly likely given the pending resource adequacy requirements.[121]

SDG&E notes that as its CDWR contracts expire, "any core/noncore implementation . . . will result in excessively high reserve margins for SDG&E"[122] and:

> …[u]ntil then, SDG&E will be long on resources due to implementing the State's directives in the area of energy efficiency, demand response, and renewable power. Beginning in 2012 as the DWR contracts continue to expire, the potential to balance the loss of load with resource requirements improves, assuming adequate notice of departing load.

PG&E's Reference Case assumes no departing load above current direct access levels, as specified in the Forms and Instructions. PG&E used the "low load" straw man assumptions, where 75 percent of current customers with demand of 500 kW and above opt for non-core service, to develop an "IEPR Core/Non-Core" Resource Case:

> PG&E believes these two cases represent a bandwidth of demand the utility will serve in the future. PG&E developed an alternative scenario (PG&E Preferred) that assumes 50% of current large (500kW and above demand) customers opt for non-utility procurement service in the future. This assumption is consistent with PG&E's 2004 Integrated Resource Plan.[123]

For each of these three demand scenarios, PG&E provided Supply Forms identifying a corresponding resource plan. To help manage the risks associated with uncertainty of the amount of departing load, PG&E proposes that its

> …proposed portfolio will include long-term, mid-term and short-term resources, which can be adjusted in response to changing requirements. This should minimize potential stranded costs resulting from a loss of load.[124]

PG&E also explains in more detail how a mix of long-, mid-, and short-term resources provides the flexibility to respond to higher or lower than expected loads:

> Given the assumptions made on Demand Response, and CCA and non-core load migration there is a risk that procurement anticipated in the preferred portfolio may not be sufficient to meet actual requirements. Should there be less customer departure, higher load growth, or less Demand Response in the early years of the plan (up to 2010), PG&E would seek to contract with existing generation under short-term contracts to balance its requirements. Sustained loads above expected amounts after 2010 could be met by re-contracting

> with existing resources with expiring contracts or contracting with new resources. Conversely, if CCA or non-core departures are greater or if energy efficiency is more successful than assumed, short-term contracts would be allowed to expire when their terms are complete.[125]

Additional Important Uncertainties

PG&E emphasizes both policy-driven and market-driven uncertainties in its procurement planning. The policy-driven uncertainties—core/non-core legislation, expanded renewable procurement, and community choice aggregation—have been discussed previously. PG&E identifies the important market-driven uncertainties as follows:

> Operating in a competitive market inherently includes risk from competition, changes in demand, supply variability and fuel cost risks. In addition to these, we face some unique market risks in the 2006-2016 timeframe. The most significant include the uncertainty of the impact resulting from the implementation of Locational Market Pricing (LMP) by the California Independent System Operator (CAISO), and PG&E's ability to achieve the demand response targets in the future.[126]

SCE and SDG&E also identified other important uncertainties. These are discussed in the individual sections of this report to which they apply.

CHAPTER 8: TRANSMISSION

The Forms and Instructions provide the following directions to IOUs about assumptions in their resource plans concerning major transmission upgrades:

> The reference case should include an assessment of transmission constraints that may adversely affect the ability of delivering planned resources to forecast loads. IOUs are asked to submit information on how desired upgrades to the bulk transmission system would affect their preferred resource plans.
>
> If the reference case submitted by an LSE assumes an upgrade to the bulk transmission grid that has yet to receive regulatory approval, the Energy Commission also requests submittal of a modified version of the same resource plan without the upgrade. Essentially this means a "with and without" analysis. The reference case analysis should detail the changes in the direct costs of meeting load and reserve obligations that the upgrade makes possible, assess any additional benefits that the upgrade may provide, and explicitly state the changes in assumptions (e.g., import capability and quantities, changes in wholesale prices) in the two cases.[127]
>
> Information on the major upgrades to the bulk power transmission system must include a discussion of the benefits, costs, and risks involved, while examining connected yet interchangeable aspects of reliability, rates, and environmental performance. [128]

PG&E

PG&E's "iterative" resource planning process starts with the most recently approved transmission expansion plan, which is based on previously identified generation resources. Therefore, all of PG&E's submitted resource plans use the same transmission assumptions, which include:

> …all existing and new transmission contained in its most recent CAISO-approved Electric Transmission Grid Expansion Plan, which includes network reinforcements necessary to meet expected load and are expected to minimize CAISO Reliability Must Run (RMR) requirements in PG&E's service territory.[129]

PG&E does not propose any additional bulk transmission system upgrades in its resource plans because the new resources in the plans "are not sited hence the transmission requirements or the cost for these transmission upgrades are unknown."[130]

SCE

SCE provided a reference case with and without the Devers-Palo Verde No. 2 500 kV transmission line (DPV2) project. The DPV2 project was approved by the CAISO and SCE has filed an application for a Certificate of Public Convenience and Necessity (CPCN) at the CPUC. Although SCE provides scenario costs for the reference case with and without the DPV2 project, SCE recommends the Commission ignore these scenarios costs as being incomplete. Instead, SCE refers the Commission to the CA ISO's analysis[131] and SCE's CPCN application as the "most up to date and comprehensive information regarding the benefits and costs of constructing DPV2." [132] Staff will analyze these analyses in staff's transmission white paper for the *2005 Energy Report, Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond*.

There was no difference in the amount of capacity resources between SCE's Reference cases with and without DPV2. SCE does not include any spot capacity imports in either case. This is consistent with the SCE position in its CPCN application for the DPV2 project in which SCE assumes that load growth in the southwest limits the availability of capacity imports (page 4 Appendix G-1, CPCN app). This is a reasonable, conservative assumption. If capacity imports are available, they would be able to compete in procurement solicitations.

SCE includes more spot energy imports in the Reference case with DPV2 than without. The annual net energy imports in 2009 are 400 GWh more in the reference case than the case without DPV2. The difference in net imports increases every year from 2009-2016 with 1,300 GWh more imported in the reference case than the case without DPV2 in 2016. The 1,300 GWh increase in imports due to the DPV2 project equates to a 13-percent usage factor[133] in 2016 for the new facilities, under the Energy Commission's directed assumptions for the reference case (e.g., 1-in-2 hydroelectric availability).

SDG&E

SDG&E provided a reference case with and without a new 500 kV bulk power transmission project. The 500 kV transmission project is expected to be completed by 2010 and would increase current import limits into SDG&E by 700 MW (SDG&E 2004 Grid Assessment Study & Transmission Expansion Plan, pages 28 and 29). SDG&E is analyzing routes and interconnections for this 500 kV transmission project. Because a final route has not been chosen, a cost estimate is not provided in their filing. A final cost benefit analysis will be completed when a route is chosen. More details about the SDG&E 500 kV project and the associated transmission studies will be discussed in staff's transmission white paper for the *2005 Energy Report, Upgrading California's Electric Transmisison System: Issues and Actions for 2005 and Beyond.*

This additional import capability would influence the mix of resources available to serve SDG&E's loads. A resource plan without the new 500 kV interconnection would require significant amounts of new local generation and other transmission upgrades in the San Diego area to deliver the generation to loads.[134] But SDG&E cautions that more local generation may not be viable due to limited availability of offsets for air pollutant emissions. No detailed information is provided about the potential availability or cost of offsets that might be generated for new or upgraded local generation.

SDG&E's filing claims that based on their current information they would not be able to meet renewable resource targets by 2010 without the 500 kV transmission project. SDG&E analyzed the responses to their renewables request for offers and, "does not know of a mix of renewable power that would allow it to meet the 20 percent (renewables) goal by 2010 absent the addition of a new major transmission interconnection."[135]

Staff does not have enough information to analyze whether or not capacity requirements could be met without the new transmission project. Resource development in the San Diego area could be limited by the availability of air emissions credits. If new generation cannot be built in the San Diego area, then new transmission would be required.

The reference resource cases with and without the transmission project do differ in the reported capacity and energy expected from various resource types. SDG&E's capacity tables with and without the transmission project show that without the transmission project SDG&E expects to rely less on renewable resources and seasonal capacity, and to rely more on load following and peaking capacity than it would with the transmission project. The SDG&E capacity tables essentially replace 'generic renewable' capacity and 'seasonal peaking' capacity with 'year-round load following and peaking' capacity.

The energy tables show that if the transmission project is not available SDG&E expects the mix of generation to change. Without the transmission project, generation from renewable generators decreases and is replaced by generation from contracts and the mix of resources from generic non-renewable resources changes. 'Year-round load following energy' in the reference case with the 500 kV transmission project is replaced by 'seasonal peaking energy' and 'generic load following and peaking energy' in the case without the transmission project. Because the types of generic, non-renewable resources are similar, it is difficult to tell whether the generation replacement is significant.

Deliverability

As stated in the Forms and Instructions, "effective resource planning requires that energy generated by projected resources be deliverable to load."[136] However, no specific demonstration of deliverability was required in the resource plans. The Commission proposed

> ...revisiting this issue at such time that consultation between the Energy Commission, CPUC, CA ISO, and IOUs can provide additional direction regarding the procurement constraints that need to be met by the IOUs to ensure local reliability, as well as the data needed to assess whether a given resource plan meets local reliability requirements.[137]

In their filings, all three IOUs confirm that they will conduct their future electricity procurement activities in conformance with the deliverability criteria ultimately established by the CPUC in its Resource Adequacy and procurement proceedings. The planned and generic resources included in the resource plans were all assumed to be deliverable.

ENDNOTES

[1] This report uses the phrases "Electricity Resources Forms and Instructions" or "Forms and Instructions" to refer to two separate Commission documents that together comprise the filing requirements for long-term resource plans. These reports are the *Forms And Instructions For The Electricity Resources And Bulk Transmission Data Submittal*, Commission report CEC-100-2005-002-CMF, January 2005, and the *Supplemental Instructions and Errata to the Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal*, Commission Report CEC-100-2005-002-AD, March 2005.
[2] *Supplemental Instructions and Errata to the Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal*, Commission Report CEC-100-2005-002-AD, March 2005, page 6.
[3] *Supplemental Instructions and Errata to the Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal*, Commission Report CEC-100-2005-002-AD, March 2005, page 6.
[4] *Interim Opinion: Energy Savings Goals for Program Year 2006 and Beyond*, D. 04-09-040, September 23, 2004, in Energy Efficiency Rulemaking 01-08-028.
[5] *Proposed Energy Savings Goals for Energy Efficiency Programs in California*, California Energy Commission staff report, 100-03-021, October 27, 2003,
[6] *California's Secret Energy Surplus: The Potential for Energy Efficiency 2002*, prepared by KEMA-Xenergy for the Energy Foundation and the Hewlitt Foundation.
[7] SDG&E Supply Resource Plan, April 1, 2005, p.9.
[8] D.04-09-060, p.4
[9] The *California 2006-2008 Energy Efficiency Portfolio, A Review of Early IOU Planning Documents*, May 27, 2005, prepared for CPUC Energy Division by TecMarket Works.
[10] *PG&E Integrated Electric Resource Supply and Transmission Plan*, April 1, 2005, pp. 4-5.
[11] *PG&E Integrated Electric Resource Supply and Transmission Plan*, April 1, 2005, p.9.
[12] D.04-09060, Attachment 9, p 2.
[13]. *Peer Review Group Assessment of Pacific Gas and Electric's Proposed 2006-2008 Energy Efficiency Portfolio*, Submitted to the California Public Utilities Commission, June 8, 2005, p.12.
[14] *Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report*, April 1, 2005., p.2.
[15] *Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report*, April 1, 2005., p.3
[16] *Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report*, April 1, 2005., p.6.
[17] *Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report*, April 1, 2005., p.6.
[18] *Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report*, April 1, 2005., p.7
[19] Frank Schultz, Southern California Edison, June 10, 2005, personal communication.
[20] *Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report*, April 1, 2005., p.7
[21] D.04-09-060, Attachment 9, p.5.
[22] *The California Portfolio 2006-2008*, p.59.
[23] D.04-12-048 in Rulemaking 04-04-003, the *Opinion Adopting Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas and Electric Company's Long-Term Procurement Plans,* filed December 16, 2004.
[24] D.03-06-032 in Rulemaking R.02-06-001, *the Interim Opinion in Phase 1 Addressing Demand Response Goals and Adopting Tariffs and Programs for Large Customers*, filed June xx, 2003.
[25] D.04-12-048, p. 57
[26] D.05-01-056, in R.02-06-001, p. 8
[27] The goals were to be achieved by July 1st of each year. Goals for 2004 were revised in an Assigned Commissioner's Ruling dated June 2, 2004.

[28] 2005 goals were originally described as 3 percent of annual system peak, but in D.04-12-048 were converted to numeric goals for each IOU, p. 60

[29] Monthly reports, now filed under R.02-06-001, On Interruptible Load Programs, Rotating Outage Activities, and Demand Response Programs, are filed by each IOU on a monthly basis.

[30] For current performance estimates, see the “WG2 2004 Demand Response Evaluation Final Report” by Quantum Consulting at http://www.energy.ca.gov/demandresponse/documents/index.html#eval-large

[31] This table is compiled from the three IOU monthly reports on Interruptible load Programs, rotating Outage Activities, and Demand Response Programs for April 2005.

[32] The California Power Authority (CPA) administers the Demand Reserves Partnership program under contract with the California Department of Water Resources (DWR). DRP participants are paid a reservation payment in return for a commitment to shed pre-designated amounts of load when called upon. Like IOU interruptible programs, there are limits on the frequency and an annual cap on the total number of hours load can be curtailed. Unlike IOU programs, there are several private contractors that conduct settlement and participant recruitment activities.

[33] Evaluation of California’s Real-Time Metering (RTEM) Program, Energy Commission Consultant Report. CEC-400-2005-021.

[34] Working Group 2 Demand Response Program Evaluation—Nonparticipant Market Survey Report. August 2004. http://www.energy.ca.gov/demandresponse/documents/working_group_documents/2005-03-07_WG2_DR_NON-PART_SURVEY.PDF

[35] *Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal*, Energy Commission report CEC-100-2005-002-CMF, January 2005, page 11.

[36] D.03-06-032, OP#1c as interpreted by Energy Commission staff.

[37] *Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal*, Energy Commission report CEC-100-2005-002-CMF, January 2005, page 34

[38] *Supplemental Instructions and Errata to the Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal*, Commission Report CEC-100-2005-002-AD, March 2005, page 7.

[39] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the *2005 Integrated Energy Policy Report*, April 1, 2005, pages 10 - 11.

[40] Southern California Edison Company’s 2005 IEPR Transmission Submittal, Docket No. 04-IEPR-IEP-1D.

[41] EAP I can be viewed at the CPUC’s website at http://www.cpuc.ca.gov/PUBLISHED/REPORT/28715.htm or at the Energy Commission’s website at http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF

[42] Energy Commission Integrated Energy Policy Report PG&E Electric Resource Supply & Transmission Plan, April 26, 2005, page 13.

[43] Energy Commission Integrated Energy Policy Report PG&E Electric Resource Supply & Transmission Plan, April 26, 2005, pages 12 – 13.

[44] Energy Commission Integrated Energy Policy Report PG&E Electric Resource Supply & Transmission Plan, April 26, 2005, page 14.

[45] Energy Commission Integrated Energy Policy Report PG&E Electric Resource Supply & Transmission Plan, April 26, 2005, page 14.

[46] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, pages 21 - 22.

[47] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, page 7.

[48] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, page 3.

[49] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, pages 3 – 5.

[50] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, page 5.

[51] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, page 4.

[52] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, pages 13 - 14.

[53] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, page 16.

[54] Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal, CEC-100-2005-002-CMF, pages 11-12 and page 27.

[55] http://www.energy.ca.gov/distgen/interconnection/SCE_RULE_21_ACTIVITY.XLS)

[56] *Supplemental Instructions and Errata to the Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal*, Commission Report CEC-100-2005-002-AD, March 2005, page 9.
[57] Energy Commission Integrated Energy Policy Report PG&E Electric Resource Supply & Transmission Plan, April 26, 2005, pages 9-10.
[58] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, page 14.
[59] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, page 8.
[60] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, page 9.
[61] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, page 9.
[62] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, pages 8-9.
[63] *Supplemental Instructions and Errata to the Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal*, Commission Report CEC-100-2005-002-AD, March 2005, pages 6-7.
[64] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, page 14.
[65] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, page 15.
[66] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, page 16.
[67] PG&E notes that they submitted transmission and distribution costs to the Commission as part of the January 18, 2005 submittal of cost for the retail electricity price forecast. PG&E also notes that these costs are not anticipated to change substantively under each of these scenarios, except for the Accelerated Renewables Scenario.
[68] Energy Commission Integrated Energy Policy Report PG&E Electric Resource Supply & Transmission Plan, April 26, 2005, page 12.
[69] Unnumbered footnote on PG&E's Table 2, Resource Plan Generation Costs, submitted as part of Attachment E, April 26, 2005.
[70] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, page 21.
[71] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, page 22.
[72] *Supplemental Instructions and Errata to the Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal*, Commission Report CEC-100-2005-002-AD, March 2005, page 9.
[73] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, pages 21-22.
[74] Confidential Table C-3, Reference Case Scenario Cost Sensitivity, transmitted with Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005
[75] Confidential Table 4, Attachment E, Annual Average Revenue Requirement, Gas Price Reference Case, 10% Case, 90% Case, transmitted with Energy Commission Integrated Energy Policy Report PG&E Electric Resource Supply & Transmission Plan, April 26, 2005.
[76] Personal communication between Ross Miller and Osman Sezgen, PG&E staff, June 6, 2005.
[77] D.04-07-038, Ordering Paragraph 1, page 31, Items a) and d) as excerpted in Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, page 16.
[78] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, page 17.
[79] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, page 17.
[80] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, page 17.
[81] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, page 16.

[82] Energy Commission Integrated Energy Policy Report PG&E Electric Resource Supply & Transmission Plan, April 26, 2005, page 14.
[83] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, pages 14-15.
[84] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, page 15.
[85] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, pages 15-16.
[86] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, page .
[87] Energy Commission Integrated Energy Policy Report PG&E Electric Resource Supply & Transmission Plan, April 26, 2005, page 15.
[88] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, page 19.
[89] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, pages 19-20.
[90] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, pages 21-22.
[91] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, page 18.
[92] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, page 18.
[93] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, page 18.
[94] Supplemental Instructions and Errata to the Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal, Commission Report CEC-100-2005-002-AD, March 2005, page 9.
[95] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, pages 19-20.
[96] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, page 21.
[97] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, page 21.
[98] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, page 20.
[99] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, pages 21-22.
[100] Energy Commission Integrated Energy Policy Report PG&E Electric Resource Supply & Transmission Plan, April 26, 2005, page 8.
[101] Energy Commission Integrated Energy Policy Report PG&E Electric Resource Supply & Transmission Plan, April 26, 2005, pages 8-9.
[102] Energy Commission Integrated Energy Policy Report PG&E Electric Resource Supply & Transmission Plan, April 26, 2005, page 9.
[103] Energy Commission Integrated Energy Policy Report PG&E Electric Resource Supply & Transmission Plan, April 26, 2005, page 9
[104] Energy Commission Integrated Energy Policy Report PG&E Electric Resource Supply & Transmission Plan, April 26, 2005, page 9.
[105] Energy Commission Integrated Energy Policy Report PG&E Electric Resource Supply & Transmission Plan, April 26, 2005, page 10.
[106] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, page 11.
[107] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, pages 11-12.
[108] Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs, E3, October 2004.
[109] Supplemental Instructions and Errata to the Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal, Commission Report CEC-100-2005-002-AD, March 2005, page 9.
[110] Supplemental Instructions and Errata to the Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal, Commission Report CEC-100-2005-002-AD, March 2005, page 9.
[111] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, page 13.
[112] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, page 13.

[113] Supplemental Instructions and Errata to the Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal, Commission Report CEC-100-2005-002-AD, March 2005, page 10.

[114] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, page 26.

[115] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, pages 26-27.

[116] Supplemental Instructions and Errata to the Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal, Commission Report CEC-100-2005-002-AD, March 2005, page 10.

[117] Supplemental Instructions and Errata to the Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal, Commission Report CEC-100-2005-002-AD, March 2005, pages 10-11.

[118] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, pages 3-5.

[119] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, page 6.

[120] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, pages 16-17.

[121] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, page 17.

[122] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, pages 17-18.

[123] Energy Commission Integrated Energy Policy Report PG&E Electric Resource Supply & Transmission Plan, April 26, 2005, pages 16-17.

[124] Energy Commission Integrated Energy Policy Report PG&E Electric Resource Supply & Transmission Plan, April 26, 2005, page 17.

[125] Energy Commission Integrated Energy Policy Report PG&E Electric Resource Supply & Transmission Plan, April 26, 2005, page 16.

[126] Energy Commission Integrated Energy Policy Report PG&E Electric Resource Supply & Transmission Plan, April 26, 2005, page 16.

[127] Supplemental Instructions and Errata to the Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal, Commission Report CEC-100-2005-002-AD, March 2005, page 12.

[128] Forms and Instructions For The Electricity Resources And Bulk Transmission Data Submittal, Commission report CEC-100-2005-002-CMF, January 2005, page 7.

[129] Energy Commission Integrated Energy Policy Report PG&E Electric Resource Supply & Transmission Plan, April 26, 2005, page 5.

[130] Energy Commission Integrated Energy Policy Report PG&E Electric Resource Supply & Transmission Plan, April 26, 2005, page 17.

[131] PVD2 Economic Assessment Report, CAISO, http://www.caiso.com/docs/2005/02/02/200502022104311761.pdf

[132] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, page 4.

[133] The DPV2 project would increase the transfer capability into California by 1,200 MW starting in 2009, if the added capacity was fully used in a year, approximately 10,500 GWh/year could be imported because of the new line.

[134] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, page 5.

[135] Electricity Resources Data Submittal, SDG&E, Docket 05-SDO-1, April 1, 2005, page 5.

[136] Supplemental Instructions and *Errata to the Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal*, Commission Report CEC-100-2005-002-AD, March 2005, page 12.

[137] Supplemental Instructions and *Errata to the Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal*, Commission Report CEC-100-2005-002-AD, March 2005, page 13.

APPENDIX A:
SAMPLE RESOURCE ACCOUNTING TABLES

Source: Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal, CEC-100-2005-002-CMF, January 2005

Electricity Resource Planning Form S-1

Dependable Capacity Resource Accounting Table (CRATs) (page 1 of 3)

California Energy Commission

Filing LSE:

Date:

Contact Name:

Contact Number:

	Applies To:	**PEAK DEMAND CALCULATIONS (MW):**	Sum of lines:	Jan-06	Feb-06	Mar-06	Apr-06	….	Dec-16
1	All	Forecast Total Peak Demand							
2	ESP	Peak Demand: Existing Contracts							
3	ESP	Peak Demand: New & Renewed Contracts							
4	IOU	Direct Access (-)							
5	IOU	CCA & Departing Municipal Load (-)							
6	IOU	Uncommitted Price Sensitive DR Programs (-)							
7	IOU	Uncommitted Energy Efficiency (2009-2016) (-)							
8	IOU	Distributed Generation (-)							
9	All	Net Peak Demand for Bundled Customers	1 - (sum 4 thru 8)						
10	IOU/ESP	Net Peak Demand + 15% Planning Reserve Margin	Product Line 9 x 1.15						
11	IOU/Muni	Firm Sales Obligations							
12	All	Firm Peak Resource Requirement	Sum 10 + 11						
		EXISTING & PLANNED RESOURCES							
		Utility-Controlled Fossil and Nuclear Resources:							
13	IOU/Muni	Unit 1 [List each fossil and nuclear resource.]							
14	IOU/Muni	…..							
15	IOU/Muni	Unit N							
16	IOU/Muni	Total Dependable Fossil and Nuclear Capacity	Sum 13 thru 15						
		Utility-Controlled Hydroelectric Resources (1-in-2):							
17	IOU/Muni	Total for all plants over 30 MW nameplate							
18	IOU/Muni	Total for all plants 30 MW nameplate or less							
19	IOU/Muni	Hydro Derate (-) for 1-in-5 conditions							
20	IOU/Muni	Hydro Derate (-) for 1-in-10 conditions							
21	IOU/Muni	Total Dependable Hydro Capacity	Sum 17 + 18 - 19						

Electricity Resource Planning Form S-1: Dependable Capacity Resource Accounting Table (CRATs) (page 2 of 3)									
	Applies To:	**Existing & Planned Renewable Resources:**	Sum of lines:	Jan-06	Feb-06	Mar-06	Apr-06	….	Dec-16
22	IOU/Muni	Unit 1 (fuel) [List each non-hydro resource.]							
23	IOU/Muni	…							
24	IOU/Muni	Unit N (fuel)							
25	IOU/Muni	Total Renewable Dependable Capacity	Sum 22 thru 24						
26	IOU/Muni	**Total Utility-Controlled Physical Resources**	Sum 16 + 21 + 25						
		EXISTING & PLANNED CONTRACTUAL RESOURCES							
		DWR Contracts:							
27	IOU	Contract A							
28	IOU	….							
29	IOU	Contract N							
30	IOU	Total DWR Contracts	Sum 27 thru 29						
		QF Contracts by fuel types:							
31	IOU, LADWP	Natural gas							
32	IOU, LADWP	Biofuels							
33	IOU, LADWP	Geothermal							
34	IOU, LADWP	Small Hydro							
35	IOU, LADWP	Solar							
36	IOU, LADWP	Wind							
37	IOU, LADWP	Other							
38	IOU, LADWP	Total QF Dependable Capacity	Sum 31 thru 37						
		Existing & Planned Renewable Contracts:							
39	All	Contract A							
40	All	….							
41	All	Contract N							
42	All	Total Existing & Planned Renewable Contracts	Sum 39 thru 41						

Electricity Resource Planning Form S-1: Dependable Capacity Resource Accounting Table (CRATs) (page 3 of 3)									
	Applies To:	**Other Bilateral Contracts:**	Sum of lines:	Jan-06	Feb-06	Mar-06	Apr-06	….	Dec-16
43	All	Contract A							
44	All	….							
45	All	Contract N							
46	All	Total Other Bilateral Contracts	Sum 43 thru 45						
		Short Term and Spot Market Purchases:							
47	All	Short Term and Spot Market Purchases							
48	All	**TOTAL: EXISTING & PLANNED CAPACITY**	= 26+30+38+42+46+47						
49	IOU/Muni	Existing Interruptible / Emergency (I/E) Programs							
50	IOU	Uncommitted Dispatchable Demand Response							
51	All	**TOTAL CAPACITY + I/E and UDDR**	48 + 49 + 50						
		FUTURE GENERIC RESOURCE NEEDS							
52	All	Generic Renewable Resources							
		Non-Renewable Generic Resources:							
53	All	Capacity for Baseload Energy							
54	All	Capacity for Load-following and Peaking Energy							
55	All	Load-Following (year-round) Capacity							
56	All	Peaking (seasonal) Capacity							
57	All	Total Capacity of Non-Renewable Generic Resources	Sum 53 thru 56						
58	All	Total Capacity of Future Generic Resources	Sum 52 + 57						

Electricity Resource Planning Form S-2

Energy Balance Resource Accounting Table (page 1 of 3)

California Energy Commission

Filing LSE:

Date:
Contact
Name:

Contact Number:

	Applies To:	ENERGY DEMAND CALCULATIONS (GWh)	Sum of lines:	Jan-06	Feb-06	Mar-06	Apr-06	….	Dec-16
1	All	Forecast Total Energy Demand							
2	ESP	Energy Demand: Existing Contracts							
3	ESP	Energy Demand: New & Renewed Contracts							
4	IOU	Direct Access (-)							
5	IOU	CCA & Departing Municipal Load (-)							
6	IOU	Uncommitted Energy Efficiency (2009-2016) (-)							
7	IOU	Distributed Generation (-)							
8	All	Net Energy Demand for Bundled Customers	1 - (sum 4 thru 7)						
9	IOU/Muni	Firm Sales Obligations							
10	All	Total Energy Requirement	Sum 8 + 9						
		EXISTING & PLANNED RESOURCES							
		Utility-Controlled Fossil and Nuclear Resources:							
11	IOU/Muni	Unit 1 [List each fossil and nuclear resource.]							
12	IOU/Muni	…..							
13	IOU/Muni	Unit N							
14	IOU/Muni	Total Fossil and Nuclear Energy Supply	Sum 11 thru 13						
		Utility-Controlled Hydroelectric Resources (1-in-2):							
15	IOU/Muni	Total for all plants over 30 MW nameplate							
16	IOU/Muni	Total for all plants 30 MW nameplate or less							
17	IOU/Muni	Hydro Derate (-) for 1-in-5 conditions							
18	IOU/Muni	Hydro Derate (-) for 1-in-10 conditions							
19	IOU/Muni	Total Hydro Energy Supply	Sum 15 + 16 -17						

Electricity Resource Planning Form S-2: Energy Balance Resource Accounting Table (page 2 of 3)									
	Applies To:	**Existing & Planned Renewable Energy:**	Sum of lines:	Jan-06	Feb-06	Mar-06	Apr-06	….	Dec-16
20	IOU/Muni	Unit 1 (fuel) [List each non-hydro resource.]							
21	IOU/Muni	…							
22	IOU/Muni	Unit N (fuel)							
23	IOU/Muni	Total Renewable Energy Supply	Sum 20 thru 23						
24	IOU/Muni	**Total Utility-Controlled Physical Resources**	Sum 14 + 19 + 23						
		EXISTING & PLANNED CONTRACTUAL RESOURCES							
		DWR Contracts:							
25	IOU	Contract A							
26	IOU	….							
27	IOU	Contract N							
28	IOU	Total Energy Supply from DWR Contracts	Sum 25 thru 27						
		QF Contracts by fuel types:							
29	IOU, LADWP	Natural gas							
30	IOU, LADWP	Biofuels							
31	IOU, LADWP	Geothermal							
32	IOU, LADWP	Small Hydro							
33	IOU, LADWP	Solar							
34	IOU, LADWP	Wind							
35	IOU, LADWP	Other							
36	IOU, LADWP	Total Energy Supply from QF Contracts	Sum 29 thru 35						
		Existing & Planned Renewable Contracts:							
37	All	Contract A							
38	All	….							
39	All	Contract N							
40	All	Total Existing & Planned Renewable Contracts	Sum 37 thru 39						

Electricity Resource Planning Form S-2: Energy Balance Resource Accounting Table (page 3 of 3)									
	Applies To:	**Other Bilateral Contracts:**	Sum of lines:	Jan-06	Feb-06	Mar-06	Apr-06	….	Dec-16
41	All	Contract A							
42	All	….							
43	All	Contract N							
44	All	Total Energy Supply from Other Bilateral Contracts	Sum 41 thru 43						
		Short Term and Spot Market Purchases:							
45	All	Short Term and Spot Market Purchases							
46	All	**TOTAL: EXISTING & PLANNED ENERGY**	= 24+28+36+40+44+45						
		FUTURE GENERIC RESOURCE NEEDS							
47	All	Generic Renewable Energy							
		Non-Renewable Generic Resources:							
48	All	Generic Baseload Energy							
49	All	Generic Load-following and Peaking Energy							
50	All	Generic Load-Following (year-round) Energy							
51	All	Generic Peaking (seasonal) Energy							
52	All	Total Non-Renewable Generic Energy Needs	Sum 48 thru 51						
53	All	Total Future Generic Resource Needs	Sum 47 + 52						

APPENDIX B:
PUBLIC VERSIONS OF ENERGY BALANCE AND DEPENDABLE CAPACITY RESOURCE ACCOUNTING TABLES

Electricity Resource Planning Form S-7: Energy Balance Resource Accounting Table
Annual GWh
Public Version

Filing LSE:	Pacific Gas and Electric Company
Date:	March 1, 2005
Contact Name:	Kathy Treleven
Contact Number:	415-973-4185

	ENERGY DEMAND CALCULATIONS (GWh)	2009	2010	2011	2012	2013	2014	2015	2016
1	Net Energy Demand for Bundled Customers	81,179	81,381	81,668	81,898	81,986	82,502	82,961	83,433
2	Firm Sales Obligations	413	413	413	413	413	413	413	413
3	Total Energy Requirement	81,592	81,794	82,081	82,311	82,399	82,915	83,374	83,846
	EXISTING & PLANNED RESOURCES								
	Utility-Controlled Resources:								
4	Nuclear	15,573	17,546	17,597	16,797	17,584	17,551	16,746	17,624
5	Hydro	15,983	15,290	15,023	15,061	14,174	13,534	13,347	12,471
6	Fossil	3,613	3,640	3,520	3,566	3,631	3,622	3,801	3,682
7	Total Nuclear, Fossil and Hydro Energy Supply	35,169	36,476	36,140	35,424	35,389	34,706	33,894	33,777
	Must-take DWR Contracts:								
11	Total Energy Supply from DWR Must take Contracts	21,203	3,079	2,482	1,190	0	0	0	0
	QF Contracts:								
12	Total Energy from QF Contracts	19,727	19,939	19,873	19,769	19,708	19,592	19,463	19,387
12	**Bilateral Contracts, Other Resources & New Resources:**								
13	Total Energy Supply Bilateral Contracts and New Resources	7,162	17,178	16,426	20,230	22,155	22,582	24,009	24,120
	Existing & Planned Renewable Resources:								
14	Total Existing & Planned Renewable Energy	7,843	6,778	6,393	6,234	6,153	6,235	6,086	6,008
	Net Short Term and Spot Market Transactions:								
15	Net Short Term and Spot Market Tranactions	-9,513	-1,656	767	-534	-1,005	-201	-78	554
16	**TOTAL: EXISTING & PLANNED ENERGY**	81,592	81,794	82,081	82,311	82,399	82,915	83,374	83,846

Notes:

Line 13: Includes energy from dispatchable DWR-contracted resources

Line 14: Net of RPS-eligible utility-controlled hydro included in line 5, RPS-eligible QFs included in Line 12 and RPS-eligible Bilateral Contracted generation included in Line 13

Electricity Resource Planning Form S-7: Energy Balance Resource Accounting Table (Accelerated Renewables Case)

Annual GWh

Public Version

Filing LSE: Pacific Gas and Electric Company
Date: 5/25/2005 (Supplement to 4/1/2005 tables)
Contact Name: Kathy Treleven
Contact Number: 415-973-4185

	ENERGY DEMAND CALCULATIONS (GWh)	Sum of lines:	2009	2010	2011	2012	2013	2014	2015	2016
1	Net Energy Demand for Bundled Customers		77,944	76,386	74,792	73,050	72,948	73,265	73,521	73,819
2	Firm Sales Obligations		413	413	413	413	413	413	413	413
3	Total Energy Requirement	Sum 1 + 2	78,357	76,799	75,205	73,463	73,361	73,678	73,934	74,232
	EXISTING & PLANNED RESOURCES									
	Utility-Controlled Resources:									
4	Nuclear		15,573	17,546	17,597	16,797	17,584	17,551	16,746	17,624
5	Hydro		15,979	15,985	15,998	16,042	15,991	15,834	15,647	15,701
6	Fossil		177	178	171	173	171	174	174	180
7	Total Nuclear, Fossil and Hydro Energy Supply	Sum 4 thru 6	31,730	33,709	33,765	33,011	33,745	33,559	32,567	33,505
	Must-take DWR Contracts:									
11	Total Energy Supply from DWR Must take Contracts		21,203	3,079	2,482	1,190	0	0	0	0
	QF Contracts:									
12	Total Energy from QF Contracts		19,727	19,939	19,873	19,769	19,708	19,592	19,463	19,387
	Bilateral Contracts, Other Resources & New Resources:									
13	Total Energy Supply Bilateral Contracts and New Resources		14,039	20,435	21,178	22,217	23,165	24,392	26,033	26,632
	Existing & Planned Renewable Resources:									
14	Total Existing & Planned Renewable Energy		519	526	528	528	527	300	66	31
	Net Short Term and Spot Market Transactions:									
15	Net Short Term and Spot Market Tranactions		-8,860	-890	-2,622	-3,252	-3,783	-4,165	-4,196	-5,324
16	**TOTAL: EXISTING & PLANNED ENERGY**		78,357	76,799	75,205	73,463	73,361	73,678	73,934	74,232

Notes:

Line 13: Includes energy from dispatchable DWR-contracted resources

Line 14: Net of RPS-eligible utility-controlled hydro included in line 5, RPS-eligible QFs included in Line 12 and RPS-eligible Bilateral Contracted generation included in Line 13

Electricity Resource Planning Form S-7: Energy Balance Resource Accounting Table (Preferred Case)
Annual GWh
Public Version

Filing LSE:	Pacific Gas and Electric Company
Date:	5/25/2005 (Supplement to 4/1/2005 tables)
Contact Name:	Kathy Treleven
Contact Number:	415-973-4185

	ENERGY DEMAND CALCULATIONS (GWh)	Sum of lines:	2009	2010	2011	2012	2013	2014	2015	2016
1	Net Energy Demand for Bundled Customers		77,944	76,386	74,792	73,050	72,948	73,265	73,521	73,819
2	Firm Sales Obligations		413	413	413	413	413	413	413	413
3	Total Energy Requirement	Sum 1 + 2	78,357	76,799	75,205	73,463	73,361	73,678	73,934	74,232
	EXISTING & PLANNED RESOURCES									
	Utility-Controlled Resources:									
4	Nuclear		15,573	17,546	17,597	16,797	17,584	17,551	16,746	17,624
5	Hydro		15,979	15,985	15,998	16,042	15,991	15,834	15,647	15,701
6	Fossil		177	178	171	173	171	174	174	180
7	Total Nuclear, Fossil and Hydro Energy Supply	Sum 4 thru 6	31,730	33,709	33,765	33,011	33,745	33,559	32,567	33,505
	Must-take DWR Contracts:									
11	Total Energy Supply from DWR Must take Contracts		21,203	3,079	2,482	1,190	0	0	0	0
	QF Contracts:									
12	Total Energy from QF Contracts		19,727	19,939	19,873	19,769	19,708	19,592	19,463	19,387
	Bilateral Contracts, Other Resources & New Resources:									
13	Total Energy Supply Bilateral Contracts and New Resources		14,039	20,435	21,082	21,451	22,223	22,707	23,600	23,653
	Existing & Planned Renewable Resources:									
14	Total Existing & Planned Renewable Energy		519	526	528	528	527	300	66	31
	Net Short Term and Spot Market Transactions:									
15	Net Short Term and Spot Market Tranactions		-8,860	-890	-2,525	-2,485	-2,841	-2,480	-1,763	-2,344
16	**TOTAL: EXISTING & PLANNED ENERGY**		78,357	76,799	75,205	73,463	73,361	73,678	73,934	74,232

Notes:

Line 13: Includes energy from dispatchable DWR-contracted resources

Line 14: Net of RPS-eligible utility-controlled hydro included in line 5, RPS-eligible QFs included in Line 12 and RPS-eligible Bilateral Contracted generation included in Line 13

Electricity Resource Planning Form S-7: Energy Balance Resource Accounting Table (Core_Noncore Case)
Annual GWh
Public Version

Filing LSE: Pacific Gas and Electric Company
Date: 5/25/2005 (Supplement to 4/1/2005 tables)
Contact Name: Kathy Treleven
Contact Number: 415-973-4185

	ENERGY DEMAND CALCULATIONS (GWh)	Sum of lines:	2009	2010	2011	2012	2013	2014	2015	2016
1	Net Energy Demand for Bundled Customers		76,327	73,875	71,336	68,608	68,396	68,604	68,758	68,953
2	Firm Sales Obligations		413	413	413	413	413	413	413	413
3	Total Energy Requirement	Sum 1 + 2	76,740	74,288	71,749	69,021	68,809	69,017	69,171	69,366
	EXISTING & PLANNED RESOURCES									
	Utility-Controlled Resources:									
4	Nuclear		15,573	17,546	17,597	16,797	17,584	17,551	16,746	17,624
5	Hydro		15,979	15,985	15,998	16,042	15,991	15,834	15,647	15,701
6	Fossil		177	178	171	173	171	174	174	180
7	Total Nuclear, Fossil and Hydro Energy Supply	Sum 4 thru 6	31,730	33,709	33,765	33,011	33,745	33,559	32,567	33,505
	Must-take DWR Contracts:									
11	Total Energy Supply from DWR Must take Contracts		21,203	3,079	2,482	1,190	0	0	0	0
	QF Contracts:									
12	Total Energy from QF Contracts		19,727	19,939	19,873	19,769	19,708	19,592	19,463	19,387
	Bilateral Contracts, Other Resources & New Resources:									
13	Total Energy Supply Bilateral Contracts and New Resources		14,039	18,036	17,580	17,560	18,255	18,823	19,476	19,599
	Existing & Planned Renewable Resources:									
14	Total Existing & Planned Renewable Energy		519	526	528	528	527	300	66	31
	Net Short Term and Spot Market Transactions:									
15	Net Short Term and Spot Market Tranactions		-10,477	-1,001	-2,479	-3,036	-3,426	-3,257	-2,402	-3,156
16	**TOTAL: EXISTING & PLANNED ENERGY**		76,740	74,288	71,749	69,021	68,809	69,017	69,171	69,366

Notes:

Line 13: Includes energy from dispatchable DWR-contracted resources

Line 14: Net of RPS-eligible utility-controlled hydro included in line 5, RPS-eligible QFs included in Line 12 and RPS-eligible Bilateral Contracted generation included in Line 13

Electricity Resource Planning Form S-2

Energy Balance Resource Accounting Table (Annual GWh)
California Energy Commission - IEPR Reference Case w/o DPV2

Filing LSE: Southern California Edison
Date: April 1, 2005
Contact Name: Janos Kakuk
Contact Number: (626) 302-2342

	ENERGY DEMAND CALCULATIONS (GWh):	Sum of lines:	2009	2010	2011	2012	2013	2014	2015	2016
1	Net Energy Demand for Bundled Customers		84,177	84,211	84,180	84,526	84,657	85,802	86,980	87,991
2	Firm Sales Obligations		2,144	2,144	2,144	2,151	2,144	2,144	2,144	2,151
3	Total Energy Requirement	Sum 1 thru 2	86,322	86,356	86,325	86,677	86,802	87,947	89,124	90,141
	EXISTING & PLANNED RESOURCES									
	Utility-Controlled Resources:									
4	Nuclear		16,234	15,862	17,596	17,468	17,520	17,509	17,280	17,293
5	Hydro		4,673	4,670	4,704	4,597	4,591	4,602	4,626	4,641
6	Fossil		9,703	9,146	10,156	10,668	10,365	9,613	9,915	9,475
7	Total Nuclear, Fossil and Hydro Energy Supply	Sum 4 thru 6	30,610	29,678	32,455	32,733	32,476	31,724	31,822	31,410
	Must-take DWR Contracts:									
8	Allegheney		7,237	7,237	7,237	0	0	0	0	0
9	Centennial (Wind)		193	193	157	0	0	0	0	0
10	El Paso		0	0	0	0	0	0	0	0
11	Sempra		12,515	12,515	9,360	0	0	0	0	0
12	Total Energy Supply from DWR Must take Contracts	Sum 8 thru 11	19,946	19,946	16,755	0	0	0	0	0
	QF Contracts:									
13	Total Energy from QF Contracts		25,033	24,993	24,956	24,987	24,892	24,864	24,838	24,879
	Bilateral Contracts, Other Resources & New Resources:									
14	Total Energy Supply Bilateral Contracts and New Resources		11,422	12,404	11,546	26,238	26,767	29,556	31,733	32,478
	Existing & Planned Renewable Contracts:									
15	Total Existing & Planned Renewable Energy		2,841	2,841	2,841	2,848	2,841	2,841	2,841	2,848
	Net Short Term and Spot Market Purchases:									
16	Net Short Term and Spot Market Purchases		-3,301	-3,282	-1,962	3	-51	-900	-1,939	-1,285
17	**TOTAL: EXISTING & PLANNED ENERGY**		86,550	86,579	86,591	86,808	86,925	88,085	89,294	90,330

Notes:

Line 1: Assumes community choice aggregation and uncommitted energy efficiency levels as defined by the CEC for the Reference case.

Line 5: Hydroelectric generation based on average hydro conditions (1-in-2).

Line 14: Includes bilateral, inter-utility, dispatchable DWR contracts and generic renewable and non-renewable future resources.

Line 15: Net of RPS-eligible utility-controlled hydro included in line 5, RPS-eligible QFs included in Line 13 and RPS-eligible Bilateral Contracted generation included in Line 14

Line 16: Includes spot market purchases and sales.

Line 17: Includes generation from pumping stations, but not load required to pump water back. This is the reason for the difference between lines 3 and 17.

Electricity Resource Planning Form S-2

Energy Balance Resource Accounting Table (Annual GWh)
California Energy Commission - IEPR Accelerated Renewables Case

Filing LSE: Southern California Edison
Date: April 1, 2005
Contact Name: Janos Kakuk
Contact Number: (626) 302-2342

	ENERGY DEMAND CALCULATIONS (GWh):	Sum of lines:	2009	2010	2011	2012	2013	2014	2015	2016
1	Net Energy Demand for Bundled Customers		84,177	84,211	84,180	84,526	84,657	85,802	86,980	87,991
2	Firm Sales Obligations		2,144	2,144	2,144	2,151	2,144	2,144	2,144	2,151
3	Total Energy Requirement	Sum 1 thru 2	86,322	86,356	86,325	86,677	86,802	87,947	89,124	90,141
	EXISTING & PLANNED RESOURCES									
	Utility-Controlled Resources:									
4	Nuclear		16,234	15,862	17,596	17,468	17,520	17,509	17,280	17,293
5	Hydro		4,674	4,685	4,660	4,590	4,598	4,576	4,617	4,606
6	Fossil		9,681	8,989	9,735	10,376	9,854	9,422	9,674	9,154
7	Total Nuclear, Fossil and Hydro Energy Supply	Sum 4 thru 6	30,588	29,536	31,990	32,434	31,972	31,507	31,571	31,053
	Must-take DWR Contracts:									
8	Allegheney		7,237	7,237	7,237	0	0	0	0	0
9	Centennial (Wind)		193	193	157	0	0	0	0	0
10	El Paso		0	0	0	0	0	0	0	0
11	Sempra		12,515	12,515	9,360	0	0	0	0	0
12	Total Energy Supply from DWR Must take Contracts	Sum 8 thru 11	19,946	19,946	16,755	0	0	0	0	0
	QF Contracts:									
13	Total Energy from QF Contracts		25,033	24,993	24,956	24,987	24,892	24,864	24,838	24,879
	Bilateral Contracts, Other Resources & New Resources:									
14	Total Energy Supply Bilateral Contracts and New Resources		12,309	13,642	13,132	25,802	26,945	27,633	30,347	31,340
	Existing & Planned Renewable Contracts:									
15	Total Existing & Planned Renewable Energy		2,841	2,841	2,841	2,848	2,841	2,841	2,841	2,848
	Net Short Term and Spot Market Purchases:									
16	Net Short Term and Spot Market Purchases		-4,166	-4,359	-3,138	729	284	1,207	-314	166
17	**TOTAL: EXISTING & PLANNED ENERGY**		86,551	86,598	86,535	86,800	86,933	88,051	89,283	90,285

Notes:

Line 1: Assumes community choice aggregation and uncommitted energy efficiency levels as defined by the CEC for the Reference case.

Liine 5: Hydroelectric generation based on average hydro conditions (1-in-2).

Line 14: Includes bilateral, inter-utility, dispatchable DWR contracts and generic renewable and non-renewable future resources.

Line 15: Net of RPS-eligible utility-controlled hydro included in line 5, RPS-eligible QFs included in Line 13 and RPS-eligible Bilateral Contracted generation included in Line 14

Line 16: Includes spot market purchases and sales.

Line 17: Includes generation from pumping stations, but not load required to pump water back. This is the reason for the difference between lines 3 and 17.

Electricity Resource Planning Form S-2

Energy Balance Resource Accounting Table (Annual GWh)
California Energy Commission - IEPR Alternate Case

Filing LSE: Southern California Edison
Date: April 1, 2005
Contact Name: Janos Kakuk
Contact Number: (626) 302-2342

	ENERGY DEMAND CALCULATIONS (GWh):	Sum of lines:	2009	2010	2011	2012	2013	2014	2015	2016
1	Net Energy Demand for Bundled Customers		84,736	85,920	87,255	89,044	90,693	92,453	94,247	95,866
2	Firm Sales Obligations		2,144	2,144	2,144	2,151	2,144	2,144	2,144	2,151
3	Total Energy Requirement	Sum 1 thru 2	86,881	88,064	89,399	91,195	92,838	94,598	96,392	98,017
	EXISTING & PLANNED RESOURCES									
	Utility-Controlled Resources:									
4	Nuclear		15,890	15,527	17,209	17,086	17,137	17,125	16,902	16,916
5	Hydro		4,754	4,775	4,763	4,733	4,695	4,665	4,687	4,654
6	Fossil		10,390	10,101	10,283	11,024	10,869	10,539	10,816	10,559
7	Total Nuclear, Fossil and Hydro Energy Supply	Sum 4 thru 6	31,034	30,403	32,255	32,843	32,701	32,329	32,404	32,129
	Must-take DWR Contracts:									
8	Allegheney		7,237	7,237	7,237	0	0	0	0	0
9	Centennial (Wind)		193	193	157	0	0	0	0	0
10	El Paso		0	0	0	0	0	0	0	0
11	Sempra		12,515	12,515	9,360	0	0	0	0	0
12	Total Energy Supply from DWR Must take Contracts	Sum 8 thru 11	19,946	19,946	16,755	0	0	0	0	0
	QF Contracts:									
13	Total Energy from QF Contracts		23,834	23,581	23,479	23,451	23,346	23,303	23,208	23,014
	Bilateral Contracts, Other Resources & New Resources:									
14	Total Energy Supply Bilateral Contracts and New Resources		10,348	11,265	15,223	30,910	32,039	33,161	36,016	36,978
	Existing & Planned Renewable Contracts:									
15	Total Existing & Planned Renewable Energy		2,438	2,438	2,438	2,445	2,438	2,435	2,434	2,441
	Net Short Term and Spot Market Purchases:									
16	Net Short Term and Spot Market Purchases		-401	777	-422	1,838	2,559	3,578	2,563	3,649
17	**TOTAL: EXISTING & PLANNED ENERGY**		87,199	88,410	89,729	91,486	93,083	94,805	96,626	98,211

Notes:
Line 1: Assumes community choice aggregation and uncommitted energy efficiency levels as defined for the Alternate case.
Line 5: Hydroelectric generation based on average hydro conditions (1-in-2).
Line 14: Includes bilateral, inter-utility, dispatchable DWR contracts and generic renewable and non-renewable future resources.
Line 15: Net of RPS-eligible utility-controlled hydro included in line 5, RPS-eligible QFs included in Line 13 and RPS-eligible Bilateral Contracted generation included in Line 14
Line 16: Includes spot market purchases and sales.
Line 17: Includes generation from pumping stations, but not load required to pump water back. This is the reason for the difference between lines 3 and 17.

Electricity Resource Planning Form S-2

Energy Balance Resource Accounting Table (Annual GWh)
California Energy Commission - IEPR Reference Case

Filing LSE: Southern California Edison
Date: March 1, 2005
Contact Name: Janos Kakuk
Contact Number: (626) 302-2342

	ENERGY DEMAND CALCULATIONS (GWh):	Sum of lines:	2009	2010	2011	2012	2013	2014	2015	2016
1	Net Energy Demand for Bundled Customers		84,177	84,211	84,180	84,526	84,657	85,802	86,980	87,991
2	Firm Sales Obligations		2,144	2,144	2,144	2,151	2,144	2,144	2,144	2,151
3	Total Energy Requirement	Sum 1 thru 2	86,322	86,356	86,325	86,677	86,802	87,947	89,124	90,141
	EXISTING & PLANNED RESOURCES									
	Utility-Controlled Resources:									
4	Nuclear		16,234	15,862	17,596	17,469	17,520	17,509	17,280	17,293
5	Hydro		4,679	4,675	4,705	4,597	4,591	4,602	4,625	4,642
6	Fossil		9,671	9,095	10,063	10,610	10,280	9,534	9,859	9,414
7	Total Nuclear, Fossil and Hydro Energy Supply	Sum 4 thru 6	30,584	29,632	32,364	32,675	32,391	31,645	31,764	31,349
	Must-take DWR Contracts:									
8	Allegheney		7,238	7,238	7,238	0	0	0	0	0
9	Centennial (Wind)		193	193	157	0	0	0	0	0
10	El Paso		0	0	0	0	0	0	0	0
11	Sempra		12,515	12,515	9,360	0	0	0	0	0
12	Total Energy Supply from DWR Must take Contracts	Sum 8 thru 11	19,946	19,946	16,755	0	0	0	0	0
	QF Contracts:									
13	Total Energy from QF Contracts		25,033	24,993	24,956	24,987	24,892	24,864	24,838	24,879
	Bilateral Contracts, Other Resources & New Resources:									
14	Total Energy Supply Bilateral Contracts and New Resources		11,054	12,010	11,215	25,585	26,087	28,658	30,859	31,238
	Existing & Planned Renewable Contracts:									
15	Total Existing & Planned Renewable Energy		2,841	2,841	2,841	2,848	2,841	2,841	2,841	2,848
	Net Short Term and Spot Market Purchases:									
16	Net Short Term and Spot Market Purchases		-2,900	-2,836	-1,538	713	714	78	-1,009	17
17	**TOTAL: EXISTING & PLANNED ENERGY**		86,558	86,585	86,593	86,809	86,925	88,085	89,293	90,331

Notes:
Line 1: Assumes community choice aggregation and uncommitted energy efficiency levels as defined by the CEC for the Reference case.
Line 5: Hydroelectric generation based on average hydro conditions (1-in-2).
Line 14: Includes bilateral, inter-utility, dispatchable DWR contracts and generic renewable and non-renewable future resources.
Line 15: Net of RPS-eligible utility-controlled hydro included in line 5, RPS-eligible QFs included in Line 13 and RPS-eligible Bilateral Contracted generation included in Line 14
Line 16: Includes spot market purchases and sales.
Line 17: Includes generation from pumping stations, but not load required to pump water back. This is the reason for the difference between lines 3 and 17.

Electricity Resource Planning Form S-7: Energy Balance Resource Accounting Table
Annual GWh

Filing LSE: SDG&E
Date: 3/1/05
Contact Name: Rob Anderson
Contact Number: 858-650-6183

	ENERGY DEMAND CALCULATIONS (GWh)	Sum of lines:	2009	2010	2011	2012	2013	2014	2015	2016
1	Net Energy Demand for Bundled Customers		17,814	18,173	18,527	18,941	19,268	19,664	20,062	20,506
2	Firm Sales Obligations		-	-	-	-	-	-	-	-
3	Total Energy Requirement	Sum 1 + 2	17,814	18,173	18,527	18,941	19,268	19,664	20,062	20,506
	EXISTING & PLANNED RESOURCES									
	Utility-Controlled Resources:									
4	Nuclear		3,164	2,338	2,554	2,563	2,387	2,715	2,394	2,561
5	Hydro		-	-	-	-	-	-	-	-
6	Fossil		4,003	3,956	3,869	3,931	3,962	3,993	4,016	4,087
7	TotalNuclear, Fossil and Hydro Energy Supply	Sum 4 thru 6	7,167	6,294	6,423	6,494	6,348	6,708	6,410	6,649
	Must-take DWR Contracts:									
8	Williams Contract (A)		0	0	0	0	0	0	0	0
9	Williams Contract (B)		1346	1345	0	0	0	0	0	0
10	Williams Contract (C)		245	244	0	0	0	0	0	0
11	Total Energy Supply from DWR Must take Contracts	Sum 8 thru 10	1,590	1,589	0	0	0	0	0	0
	QF Contracts:									
12	Total Energy from QF Contracts		1,718	1,718	1,716	1,716	1,714	1,713	1,718	1,721
	Bilateral Contracts, Other Resources & New Resources:									
13	Total Energy Supply Bilateral Contracts and New Resources		5,150	4,623	7,888	7,463	6,824	6,270	6,515	7,070
	Renewable Contracts:									
14	Total Renewable Energy		1,583	3,457	3,546	3,621	3,696	3,761	3,816	3,920
	Net Short Term and Spot Market transaction:									
15	Net Short Term and Spot Market transactions		606	493	-1,045	-352	686	1,212	1,603	1,147
16	**TOTAL: EXISTING & PLANNED ENERGY**		17,814	18,173	18,527	18,942	19,268	19,664	20,062	20,506

Notes:

Line 13: Includes energy fron dispatchable DWR-contracted resources

Line 14: Net of RPS-eligible utility-controlled hydro included in line 5, RPS-eligible QFs included in Line 12 and RPS-eligible Bilateral Contracted generation

(1) Total Energy Requirements (Line 3) and Total: Existing & Planned Energy (Line 16) may not match due to rounding

Electricity Resource Planning Form S-7 No Trans Case: Energy Balance Resource Accounting Table
Annual GWh

Filing LSE: SDG&E
Date: 4/1/05
Contact Name: Rob Anderson
Contact Number: 858-650-6183

	ENERGY DEMAND CALCULATIONS (GWh)	Sum of lines:	2009	2010	2011	2012	2013	2014	2015	2016
1	Net Energy Demand for Bundled Customers		17,814	18,173	18,527	18,941	19,268	19,664	20,062	20,506
2	Firm Sales Obligations		-	-	-	-	-	-	-	-
3	Total Energy Requirement	Sum 1 + 2	17,814	18,173	18,527	18,941	19,268	19,664	20,062	20,506
	EXISTING & PLANNED RESOURCES									
	Utility-Controlled Resources:									
4	Nuclear		3,164	2,338	2,554	2,563	2,387	2,715	2,394	2,561
5	Hydro		-	-	-	-	-	-	-	-
6	Fossil		3,993	3,955	3,937	3,968	3,955	3,980	4,000	4,063
7	TotalNuclear, Fossil and Hydro Energy Supply	Sum 4 thru 6	7,157	6,293	6,491	6,531	6,342	6,696	6,394	6,625
	Must-take DWR Contracts:									
8	Williams Contract (A)		0	0	0	0	0	0	0	0
9	Williams Contract (B)		1346	1345	0	0	0	0	0	0
10	Williams Contract (C)		245	244	0	0	0	0	0	0
11	Total Energy Supply from DWR Must take Contracts	Sum 8 thru 10	1,590	1,589	0	0	0	0	0	0
	QF Contracts:									
12	Total Energy from QF Contracts		1,718	1,718	1,716	1,716	1,714	1,713	1,718	1,721
	Bilateral Contracts, Other Resources & New Resources:									
13	Total Energy Supply Bilateral Contracts and New Resources		4,847	4,528	7,547	7,368	7,000	6,694	6,794	7,253
	Renewable Contracts:									
14	Total Renewable Energy		1,969	3,058	3,148	3,224	3,458	3,460	3,747	3,827
	Net Short Term and Spot Market transaction:									
15	Net Short Term and Spot Market transactions		534	987	-376	103	753	1,099	1,410	1,080
16	**TOTAL: EXISTING & PLANNED ENERGY**		17,815	18,173	18,527	18,942	19,268	19,663	20,062	20,506

Notes:

Line 13: Includes energy fron dispatchable DWR-contracted resources

Line 14: Net of RPS-eligible utility-controlled hydro included in line 5, RPS-eligible QFs included in Line 12 and RPS-eligible Bilateral Contracted generation

(1) Total Energy Requirements (Line 3) and Total: Existing & Planned Energy (Line 16) may not match due to rounding

Electricity Resource Planning Form S-7 Accelerated Renewables Case: Energy Balance Resource Accounting Table
Annual GWh

Filing LSE: SDG&E
Date: 4/1/05
Contact Name: Rob Anderson
Contact Number: 858-650-6183

	ENERGY DEMAND CALCULATIONS (GWh)	Sum of lines:	2009	2010	2011	2012	2013	2014	2015	2016
1	Net Energy Demand for Bundled Customers		17,814	18,173	18,527	18,941	19,268	19,664	20,062	20,506
2	Firm Sales Obligations		-	-	-	-	-	-	-	-
3	Total Energy Requirement	Sum 1 + 2	17,814	18,173	18,527	18,941	19,268	19,664	20,062	20,506
	EXISTING & PLANNED RESOURCES									
	Utility-Controlled Resources:									
4	Nuclear		3,164	2,338	2,554	2,563	2,387	2,715	2,394	2,561
5	Hydro		-	-	-	-	-	-	-	-
6	Fossil		4,003	3,956	3,866	3,920	3,947	3,981	3,993	4,063
7	TotalNuclear, Fossil and Hydro Energy Supply	Sum 4 thru 6	7,167	6,294	6,420	6,483	6,333	6,696	6,387	6,624
	Must-take DWR Contracts:									
8	Williams Contract (A)		0	0	0	0	0	0	0	0
9	Williams Contract (B)		1346	1345	0	0	0	0	0	0
10	Williams Contract (C)		245	244	0	0	0	0	0	0
11	Total Energy Supply from DWR Must take Contracts	Sum 8 thru 10	1,590	1,589	0	0	0	0	0	0
	QF Contracts:									
12	Total Energy from QF Contracts		1,718	1,718	1,716	1,716	1,714	1,713	1,718	1,721
	Bilateral Contracts, Other Resources & New Resources:									
13	Total Energy Supply Bilateral Contracts and New Resources		5,151	4,623	7,868	7,412	6,691	5,987	6,312	6,464
	Renewable Contracts:									
14	Total Renewable Energy		1,583	3,457	3,688	3,892	4,144	4,393	4,650	4,966
	Net Short Term and Spot Market transaction:									
15	Net Short Term and Spot Market transactions		606	493	-1,164	-562	386	874	996	731
16	**TOTAL: EXISTING & PLANNED ENERGY**		17,815	18,173	18,527	18,942	19,268	19,664	20,062	20,506

Notes:

Line 13: Includes energy fron dispatchable DWR-contracted resources
Line 14: Net of RPS-eligible utility-controlled hydro included in line 5, RPS-eligible QFs included in Line 12 and RPS-eligible Bilateral Contracted generation
(1) Total Energy Requirements (Line 3) and Total: Existing & Planned Energy (Line 16) may not match due to rounding

Electricity Resource Planning Form S-7 Alternative Case: Energy Balance Resource Accounting Table
Annual GWh

Filing LSE: SDG&E
Date: 4/1/05
Contact Name: Rob Anderson
Contact Number: 858-650-6183

	ENERGY DEMAND CALCULATIONS (GWh)	Sum of lines:	2009	2010	2011	2012	2013	2014	2015	2016
1	Net Energy Demand for Bundled Customers		18,566	18,939	19,307	19,736	20,079	20,492	20,907	21,370
2	Firm Sales Obligations		-	-	-	-	-	-	-	-
3	Total Energy Requirement	Sum 1 + 2	18,566	18,939	19,307	19,736	20,079	20,492	20,907	21,370
	EXISTING & PLANNED RESOURCES									
4	Nuclear		3,164	2,338	2,554	2,563	2,387	2,715	2,394	2,561
5	Hydro		-	-	-	-	-	-	-	-
6	Fossil		4,038	3,987	3,977	3,969	3,942	3,964	3,985	4,055
7	TotalNuclear, Fossil and Hydro Energy Supply	Sum 4 thru 6	7,202	6,325	6,531	6,532	6,328	6,679	6,379	6,617
	Must-take DWR Contracts:									
8	Williams Contract (A)		0	0	0	0	0	0	0	0
9	Williams Contract (B)		1346	1345	0	0	0	0	0	0
10	Williams Contract (C)		245	244	0	0	0	0	0	0
11	Total Energy Supply from DWR Must take Contracts	Sum 8 thru 10	1,590	1,589	0	0	0	0	0	0
	QF Contracts:									
12	Total Energy from QF Contracts		1,718	1,718	1,716	1,716	1,714	1,713	1,718	1,721
	Bilateral Contracts, Other Resources & New Resources:									
13	Total Energy Supply Bilateral Contracts and New Resources		4,054	3,091	6,934	7,036	7,083	6,676	6,672	6,784
	Renewable Contracts:									
14	Total Renewable Energy		1,614	3,838	4,070	4,336	4,648	4,898	5,255	5,551
	Net Short Term and Spot Market transaction:									
15	Net Short Term and Spot Market transactions		2,388	2,377	56	117	306	526	883	698
16	**TOTAL: EXISTING & PLANNED ENERGY**		18,566	18,939	19,308	19,736	20,079	20,492	20,907	21,370

Notes:
Line 13: Includes energy fron dispatchable DWR-contracted resources
Line 14: Net of RPS-eligible utility-controlled hydro included in line 5, RPS-eligible QFs included in Line 12 and RPS-eligible Bilateral Contracted generation included in
(1) Total Energy Requirements (Line 3) and Total: Existing & Planned Energy (Line 16) may not match due to rounding

Electricity Resource Planning Form S-6: Dependable Capacity Resource Accounting Table (CRATs)
Annual MW

PUBLIC VERSION

Filing LSE: Pacific Gas and Electric Company
Date: March 1, 2005
Contact Name: Kathy Treleven
Contact Number: 415-973-4185

		2009	2010	2011	2012	2013	2014	2015	2016
	PEAK DEMAND CALCULATIONS (MW):								
1	Distributed Generation (-)	242	282	314	339	357	375	392	409
	EXISTING & PLANNED RESOURCES								
	Utility-Controlled Fossil and Nuclear Resources:								
2	Nuclear	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214
3	Fossil	150	150	150	150	150	150	150	150
4	Total Dependable Fossil and Nuclear Capacity	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364
	Utility-Controlled Hydroelectric Resources:								
5	Total for all plants over 30 MW nameplate	4,495	4,495	4,495	4,495	4,495	4,400	4,400	4,400
6	Total for all plants 30 MW nameplate or less	430	430	430	430	430	420	420	420
7	Total Hydro Capacity	4,925	4,925	4,925	4,925	4,925	4,820	4,820	4,820

	DWR Contracts:								
8	Calpine #1 Product 1	1,000	0	0	0	0	0	0	0
9	Calpine #2 Product 1	1,000	0	0	0	0	0	0	0
10	Coral	925	925	925	0	0	0	0	0
11	El Paso	0	0	0	0	0	0	0	0
12	Soledad	0	0	0	0	0	0	0	0
13	Calpine #3	495	495	0	0	0	0	0	0
14	Calpine 4	0	0	0	0	0	0	0	0
15	CalPeak Panoche	52	52	52	0	0	0	0	0
16	CalPeak Vaca Dixon	52	52	52	0	0	0	0	0
17	Wellhead Fresno	21	21	21	0	0	0	0	0
18	GWF	361	361	361	173	0	0	0	0
19	PacifiCorp	300	300	0	0	0	0	0	0
20	Wellhead Gates	46	46	46	0	0	0	0	0
21	Wellhead Panoche	50	50	50	0	0	0	0	0
22	Kings River	90	90	90	90	90	90	0	0
23	Total DWR Contracts	4,392	2,392	1,597	263	90	90	0	0
	Demand Reduction Programs:								
24	Existing Interruptible / Emergency (I/E) Programs	374	374	374	374	374	374	374	374
25	Uncommitted Dispatchable Demand Response	257	261	265	269	273	277	282	286
26	Total Demand Reduction Programs	632	636	640	644	648	652	656	660

PG&E filed no public capacity tables for cases other than the Reference Case

Electricity Resource Planning Form S-1

Dependable Capacity Resource Accounting Table (Annual MW)
California Energy Commission - IEPR Reference Case

Filing LSE: Southern California Edison
Date: March 1, 2005
Contact Name: Janos Kakuk
Contact Number: (626) 302-2342

	PEAK DEMAND CALCULATIONS (MW):	Sum of lines:	2009	2010	2011	2012	2013	2014	2015	2016
1	Distributed Generation (-)		0	0	0	0	0	0	0	0
	EXISTING & PLANNED RESOURCES									
	Utility-Controlled Fossil and Nuclear Resources:									
2	Nuclear		2,289	2,289	2,289	2,289	2,289	2,289	2,289	2,289
3	Fossil		1,648	1,645	1,643	1,641	1,638	1,637	1,637	1,637
4	Total Dependable Fossil and Nuclear Capacity	Sum 2 thru 3	3,937	3,934	3,932	3,930	3,927	3,926	3,926	3,926
	Utility-Controlled Hydroelectric Resources:									
5	Total for all plants over 30 MW nameplate		819	819	819	819	819	819	819	819
6	Total for all plants 30 MW nameplate or less		127	127	127	127	127	127	127	127
7	Pump Storage Generation		207	207	207	207	207	207	207	207
8	Total Hydro Capacity	Sum 5 thru 8	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153
	DWR Contracts:									
9	Allegheney		800	800	800	0	0	0	0	0
10	Centennial (Wind)		15	15	15	0	0	0	0	0
11	Colton		72	72	0	0	0	0	0	0
12	El Paso		0	0	0	0	0	0	0	0
13	High Desert		730	730	0	0	0	0	0	0
14	Sempra		1,600	1,600	1,600	0	0	0	0	0
15	Total DWR Contracts	Sum 9 thru 14	3,217	3,217	2,415	0	0	0	0	0
	Demand Reduction Programs:									
16	Existing Interruptible / Emergency (I/E) Programs		1,037	1,037	1,037	1,037	1,037	1,037	1,037	1,037
17	Uncommitted Dispatchable Demand Response		86	107	129	150	172	193	214	236
	Total Dispatchable Demand Reduction Programs	Sum 16 thru 17	1,122	1,144	1,165	1,187	1,208	1,230	1,251	1,272
	Existing & Planned Renewable Resources:									
18	Total Renewable Dependable Capacity		476	603	603	603	623	650	650	654

Line	Note
1	Impacts of distributed generation is embedded in SCE's retail load forecast.
8	Total capacity from hydroelectric generation does not account for adverse conditions.
18	Includes current, planned & generic renewable resources. Excludes small hydroelectric generation, Centennial (DWR) wind and RPS-eligible qualified facilities.

Electricity Resource Planning Form S-1

Dependable Capacity Resource Accounting Table (Annual MW)
California Energy Commission - IEPR Reference Case w/o DPV2

Filing LSE: Southern California Edison
Date: April 1, 2005
Contact Name: Janos Kakuk
Contact Number: (626) 302-2342

	EXISTING & PLANNED RESOURCES (MW)	Sum of lines:	2009	2010	2011	2012	2013	2014	2015	2016
	Utility-Controlled Fossil and Nuclear Resources:									
1	Nuclear		2,289	2,289	2,289	2,289	2,289	2,289	2,289	2,289
2	Fossil		1,648	1,645	1,643	1,641	1,638	1,637	1,637	1,637
3	Total Dependable Fossil and Nuclear Capacity	Sum 2 thru 3	3,937	3,934	3,932	3,930	3,927	3,926	3,926	3,926
	Utility-Controlled Hydroelectric Resources:									
4	Total for all plants over 30 MW nameplate		819	819	819	819	819	819	819	819
5	Total for all plants 30 MW nameplate or less		127	127	127	127	127	127	127	127
6	Pump Storage Generation		207	207	207	207	207	207	207	207
7	Total Hydro Capacity	Sum 5 thru 8	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153
	DWR Contracts:									
8	Allegheney		800	800	800	0	0	0	0	0
9	Centennial (Wind)		15	15	15	0	0	0	0	0
10	Colton		72	72	0	0	0	0	0	0
11	El Paso		0	0	0	0	0	0	0	0
12	High Desert		730	730	0	0	0	0	0	0
13	Sempra		1,600	1,600	1,600	0	0	0	0	0
14	Total DWR Contracts	Sum 9 thru 14	3,217	3,217	2,415	0	0	0	0	0
	Demand Reduction Programs:									
15	Existing Interruptible / Emergency (I/E) Programs		1,037	1,037	1,037	1,037	1,037	1,037	1,037	1,037
16	Uncommitted Dispatchable Demand Response		86	107	129	150	172	193	214	236
	Total Dispatchable Demand Reduction Programs	Sum 16 thru 17	1,122	1,144	1,165	1,187	1,208	1,230	1,251	1,272
	Existing & Planned Renewable Resources:									
17	Total Renewable Dependable Capacity		476	603	603	603	623	650	650	654

Line	Note
7	Total capacity from hydroelectric generation does not account for adverse conditions.
17	Includes current, planned & generic renewable resources. Excludes small hydroelectric generation, Centennial (DWR) wind and RPS-eligible qualified facilities.

Electricity Resource Planning Form S-1

Dependable Capacity Resource Accounting Table (Annual MW)
California Energy Commission - IEPR Accelerated Renewables Case

Filing LSE: Southern California Edison
Date: April 1, 2005
Contact Name: Janos Kakuk
Contact Number: (626) 302-2342

	EXISTING & PLANNED RESOURCES (MW)	Sum of lines:	2009	2010	2011	2012	2013	2014	2015	2016
	Utility-Controlled Fossil and Nuclear Resources:									
1	Nuclear		2,289	2,289	2,289	2,289	2,289	2,289	2,289	2,289
2	Fossil		1,648	1,645	1,643	1,641	1,638	1,637	1,637	1,637
3	Total Dependable Fossil and Nuclear Capacity	Sum 2 thru 3	3,937	3,934	3,932	3,930	3,927	3,926	3,926	3,926
	Utility-Controlled Hydroelectric Resources:									
4	Total for all plants over 30 MW nameplate		819	819	819	819	819	819	819	819
5	Total for all plants 30 MW nameplate or less		127	127	127	127	127	127	127	127
6	Pump Storage Generation		207	207	207	207	207	207	207	207
7	Total Hydro Capacity	Sum 5 thru 8	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153
	DWR Contracts:									
8	Allegheney		800	800	800	0	0	0	0	0
9	Centennial (Wind)		15	15	15	0	0	0	0	0
10	Colton		72	72	0	0	0	0	0	0
11	El Paso		0	0	0	0	0	0	0	0
12	High Desert		730	730	0	0	0	0	0	0
13	Sempra		1,600	1,600	1,600	0	0	0	0	0
14	Total DWR Contracts	Sum 9 thru 14	3,217	3,217	2,415	0	0	0	0	0
	Demand Reduction Programs:									
15	Existing Interruptible / Emergency (I/E) Programs		1,037	1,037	1,037	1,037	1,037	1,037	1,037	1,037
16	Uncommitted Dispatchable Demand Response		86	107	129	150	172	193	214	236
	Total Dispatchable Demand Reduction Programs	Sum 16 thru 17	1,122	1,144	1,165	1,187	1,208	1,230	1,251	1,272
	Existing & Planned Renewable Resources:									
17	Total Renewable Dependable Capacity		1,241	1,459	1,561	1,635	1,858	1,890	2,143	2,277

Line	Note
7	Total capacity from hydroelectric generation does not account for adverse conditions.
17	Includes current, planned & generic renewable resources. Excludes small hydroelectric generation, Centennial (DWR) wind and RPS-eligible qualified facilities.

Electricity Resource Planning Form S-1

Dependable Capacity Resource Accounting Table (Annual MW)
California Energy Commission - IEPR Alternate Case

Filing LSE: Southern California Edison
Date: April 1, 2005
Contact Name: Janos Kakuk
Contact Number: (626) 302-2342

	EXISTING & PLANNED RESOURCES (MW)	Sum of lines:	2009	2010	2011	2012	2013	2014	2015	2016
	Utility-Controlled Fossil and Nuclear Resources:									
1	Nuclear		2,236	2,236	2,236	2,236	2,236	2,236	2,236	2,236
2	Fossil		1,648	1,645	1,643	1,641	1,638	1,637	1,637	1,637
3	Total Dependable Fossil and Nuclear Capacity	Sum 2 thru 3	3,884	3,882	3,879	3,877	3,875	3,874	3,874	3,874
	Utility-Controlled Hydroelectric Resources:									
4	Total for all plants over 30 MW nameplate		819	819	819	819	819	819	819	819
5	Total for all plants 30 MW nameplate or less		127	127	127	127	127	127	127	127
6	Pump Storage Generation		207	207	207	207	207	207	207	207
7	Total Hydro Capacity	Sum 5 thru 8	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153
	DWR Contracts:									
8	Allegheney		800	800	800	0	0	0	0	0
9	Centennial (Wind)		15	15	15	0	0	0	0	0
10	Colton		72	72	0	0	0	0	0	0
11	El Paso		0	0	0	0	0	0	0	0
12	High Desert		730	730	0	0	0	0	0	0
13	Sempra		1,600	1,600	1,600	0	0	0	0	0
14	Total DWR Contracts	Sum 9 thru 14	3,217	3,217	2,415	0	0	0	0	0
	Demand Reduction Programs:									
15	Existing Interruptible / Emergency (I/E) Programs		1,037	1,037	1,037	1,037	1,037	1,037	1,037	1,037
16	Uncommitted Dispatchable Demand Response		172	193	214	236	257	279	300	322
	Total Dispatchable Demand Reduction Programs	Sum 16 thru 17	1,208	1,230	1,251	1,272	1,294	1,315	1,337	1,358
	Existing & Planned Renewable Resources:									
17	Total Renewable Dependable Capacity		467	596	657	718	769	815	856	909

Line	Note
7	Total capacity from hydroelectric generation does not account for adverse conditions.
17	Includes current, planned & generic renewable resources. Excludes small hydroelectric generation, Centennial (DWR) wind and RPS-eligible qualified facilities.

Electricity Resource Planning Form S-6: Dependable Capacity Resource Accounting Table (CRATs)

Annual MW

Filing LSE: SDG&E
Date: 3/1/05
Contact Name: Rob Anderson
Contact Number: 858-650-6183

			2009	2010	2011	2012	2013	2014	2015	2016
	PEAK DEMAND CALCULATIONS (MW):									
1	Distributed Generation (-)		12	14	16	18	20	22	24	26
	EXISTING & PLANNED RESOURCES									
	Utility-Controlled Fossil and Nuclear Resources:									
2	Nuclear		377	311	311	311	311	311	311	311
3	Fossil		588	588	588	588	588	588	588	588
4	Total Dependable Fossil and Nuclear Capacity	Sum 2 thru 3	965	899	899	899	899	899	899	899
	Utility-Controlled Hydroelectric Resources:									
5	Total for all plants over 30 MW nameplate									
6	Total for all plants 30 MW nameplate or less									
7	Pump Storage Generation		40	40	40	40	40	40	40	40
8	Total Dependable Hydro Capacity	Sum 5 thru 7	40	40	40	40	40	40	40	40
	DWR Contracts:									
9	Calpeak Border		45	45	45	0	0	0	0	0
10	Calpeak El Cajon		42	42	42	0	0	0	0	0
11	Calpeak Escondido		45	45	45	0	0	0	0	0
12	Sunrise 1		560	560	560	0	0	0	0	0
13	Whitewater Energy Corp Cabazon		11	11	11	11	11	0	0	0
14	Whitewater Energy Corp Whitewater Hill		15	15	15	15	15	0	0	0
15	Williams Contract (A)		0	0	0	0	0	0	0	0
16	Williams Contract (B)		275	275	0	0	0	0	0	0
17	Williams Contract (C)		50	50	0	0	0	0	0	0
18	Williams Contract (D) - Alamitos 1		175	175	0	0	0	0	0	0
19	Williams Contract (D) - Alamitos 5		485	485	0	0	0	0	0	0
20	Williams Contract (D) - Alamitos 6		0	0	0	0	0	0	0	0
21	Williams Contract (D) - Huntington Beach 1		225	225	0	0	0	0	0	0
22	Williams Contract (D) - Redondo Beach 6		175	175	0	0	0	0	0	0
23	Total DWR Contracts	Sum 9 thru 22	2,103	2,103	718	26	26	0	0	0
	Demand Reduction Programs:									
24	Existing Interruptible / Emergency (I/E) Programs		0	0	0	0	0	0	0	0
25	Uncommitted Dispatchable Demand Response		86	86	86	86	86	86	86	86
	Total Demand Reduction Programs	Sum 24 thru 25	86	86	86	86	86	86	86	86
	Renewable Resources:									
26	Total Renewable Dependable Capacity		178	540	588	620	655	661	666	674

(1) Dependable Capacity at time of peak

Electricity Resource Planning Form S-6 No Trans Case: Dependable Capacity Resource Accounting Table (CRATs)
Annual MW

Filing LSE: SDG&E
Date: 04/01/05
Contact Name: Rob Anderson
Contact Number: 858-650-6183

			2009	2010	2011	2012	2013	2014	2015	2016
	PEAK DEMAND CALCULATIONS (MW):									
1	Distributed Generation (-)		12	14	16	18	20	22	24	26
	EXISTING & PLANNED RESOURCES									
	Utility-Controlled Fossil and Nuclear Resources:									
2	Nuclear		377	311	311	311	311	311	311	311
3	Fossil		588	588	588	588	588	588	588	588
4	Total Dependable Fossil and Nuclear Capacity	Sum 2 thru 3	965	899	899	899	899	899	899	899
	Utility-Controlled Hydroelectric Resources:									
5	Total for all plants over 30 MW nameplate									
6	Total for all plants 30 MW nameplate or less									
7	Pump Storage Generation		40	40	40	40	40	40	40	40
8	Total Dependable Hydro Capacity	Sum 5 thru 7	40	40	40	40	40	40	40	40
	DWR Contracts:									
9	Calpeak Border		45	45	45	0	0	0	0	0
10	Calpeak El Cajon		42	42	42	0	0	0	0	0
11	Calpeak Escondido		45	45	45	0	0	0	0	0
12	Sunrise 1		560	560	560	0	0	0	0	0
13	Whitewater Energy Corp Cabazon		11	11	11	11	11	0	0	0
14	Whitewater Energy Corp Whitewater Hill		15	15	15	15	15	0	0	0
15	Williams Contract (A)		0	0	0	0	0	0	0	0
16	Williams Contract (B)		275	275	0	0	0	0	0	0
17	Williams Contract (C)		50	50	0	0	0	0	0	0
18	Williams Contract (D) - Alamitos 1		175	175	0	0	0	0	0	0
19	Williams Contract (D) - Alamitos 5		485	485	0	0	0	0	0	0
20	Williams Contract (D) - Alamitos 6		0	0	0	0	0	0	0	0
21	Williams Contract (D) - Huntington Beach 1		225	225	0	0	0	0	0	0
22	Williams Contract (D) - Redondo Beach 6		175	175	0	0	0	0	0	0
23	Total DWR Contracts	Sum 9 thru 22	2,103	2,103	718	26	26	0	0	0
	Demand Reduction Programs:									
24	Existing Interruptible / Emergency (I/E) Programs		0	0	0	0	0	0	0	0
25	Uncommitted Dispatchable Demand Response		86	86	86	86	86	86	86	86
	Total Demand Reduction Programs	Sum 24 thru 25	86	86	86	86	86	86	86	86
	Renewable Resources:									
26	Total Renewable Dependable Capacity		230	341	389	398	450	450	478	486

(1) Dependable Capacity at time of peak

Electricity Resource Planning Form S-6 Accelerated Renewables Case: Dependable Capacity Resource Accounting Table (CRATs)
Annual MW

Filing LSE: SDG&E
Date: 06/08/05
Contact Name: Rob Anderson
Contact Number: 858-650-6183

			2009	2010	2011	2012	2013	2014	2015	2016
	PEAK DEMAND CALCULATIONS (MW):									
1	Distributed Generation (-)		12	14	16	18	20	22	24	26
	EXISTING & PLANNED RESOURCES									
	Utility-Controlled Fossil and Nuclear Resources:									
2	Nuclear		377	311	311	311	311	311	311	311
3	Fossil		588	588	588	588	588	588	588	588
4	Total Dependable Fossil and Nuclear Capacity	Sum 2 thru 3	965	899	899	899	899	899	899	899
	Utility-Controlled Hydroelectric Resources:									
5	Total for all plants over 30 MW nameplate									
6	Total for all plants 30 MW nameplate or less									
7	Pump Storage Generation		40	40	40	40	40	40	40	40
8	Total Dependable Hydro Capacity	Sum 5 thru 7	40	40	40	40	40	40	40	40
	DWR Contracts:									
9	Calpeak Border		45	45	45	0	0	0	0	0
10	Calpeak El Cajon		42	42	42	0	0	0	0	0
11	Calpeak Escondido		45	45	45	0	0	0	0	0
12	Sunrise 1		560	560	560	0	0	0	0	0
13	Whitewater Energy Corp Cabazon		11	11	11	11	11	0	0	0
14	Whitewater Energy Corp Whitewater Hill		15	15	15	15	15	0	0	0
15	Williams Contract (A)		0	0	0	0	0	0	0	0
16	Williams Contract (B)		275	275	0	0	0	0	0	0
17	Williams Contract (C)		50	50	0	0	0	0	0	0
18	Williams Contract (D) - Alamitos 1		175	175	0	0	0	0	0	0
19	Williams Contract (D) - Alamitos 5		485	485	0	0	0	0	0	0
20	Williams Contract (D) - Alamitos 6		0	0	0	0	0	0	0	0
21	Williams Contract (D) - Huntington Beach 1		225	225	0	0	0	0	0	0
22	Williams Contract (D) - Redondo Beach 6		175	175	0	0	0	0	0	0
23	Total DWR Contracts	Sum 9 thru 22	2,103	2,103	718	26	26	0	0	0
	Demand Reduction Programs:									
24	Existing Interruptible / Emergency (I/E) Programs		0	0	0	0	0	0	0	0
25	Uncommitted Dispatchable Demand Response		86	86	86	86	86	86	86	86
	Total Demand Reduction Programs	Sum 24 thru 25	86	86	86	86	86	86	86	86
	Renewable Resources:									
26	Total Renewable Dependable Capacity		178	540	653	674	699	742	783	821

(1) Dependable Capacity at time of peak

Electricity Resource Planning Form S-6 Alternative Case: Dependable Capacity Resource Accounting Table (CRATs)
Annual MW

Filing LSE: SDG&E
Date: 04/01/05
Contact Name: Rob Anderson
Contact Number: 858-650-6183

			2009	2010	2011	2012	2013	2014	2015	2016
	PEAK DEMAND CALCULATIONS (MW):									
1	Distributed Generation (-)		12	14	16	18	20	22	24	26
	EXISTING & PLANNED RESOURCES									
	Utility-Controlled Fossil and Nuclear Resources:									
2	Nuclear		377	311	311	311	311	311	311	311
3	Fossil		588	588	588	588	588	588	588	588
4	Total Dependable Fossil and Nuclear Capacity	Sum 2 thru 3	965	899	899	899	899	899	899	899
	Utility-Controlled Hydroelectric Resources:									
5	Total for all plants over 30 MW nameplate									
6	Total for all plants 30 MW nameplate or less									
7	Pump Storage Generation		40	40	40	40	40	40	40	40
8	Total Dependable Hydro Capacity	Sum 5 thru 7	40	40	40	40	40	40	40	40
	DWR Contracts:									
9	Calpeak Border		45	45	45	0	0	0	0	0
10	Calpeak El Cajon		42	42	42	0	0	0	0	0
11	Calpeak Escondido		45	45	45	0	0	0	0	0
12	Sunrise 1		0	0	0	0	0	0	0	0
13	Whitewater Energy Corp Cabazon		11	11	11	11	11	0	0	0
14	Whitewater Energy Corp Whitewater Hill		15	15	15	15	15	0	0	0
15	Williams Contract (A)		0	0	0	0	0	0	0	0
16	Williams Contract (B)		275	275	0	0	0	0	0	0
17	Williams Contract (C)		50	50	0	0	0	0	0	0
18	Williams Contract (D) - Alamitos 1		175	175	0	0	0	0	0	0
19	Williams Contract (D) - Alamitos 5		485	485	0	0	0	0	0	0
20	Williams Contract (D) - Alamitos 6		0	0	0	0	0	0	0	0
21	Williams Contract (D) - Huntington Beach 1		225	225	0	0	0	0	0	0
22	Williams Contract (D) - Redondo Beach 6		175	175	0	0	0	0	0	0
23	Total DWR Contracts	Sum 9 thru 22	1,543	1,543	158	26	26	0	0	0
	Demand Reduction Programs:									
24	Existing Interruptible / Emergency (I/E) Programs		0	0	0	0	0	0	0	0
25	Uncommitted Dispatchable Demand Response		86	86	86	86	86	86	86	86
	Total Demand Reduction Programs	Sum 24 thru 25	86	86	86	86	86	86	86	86
	Renewable Resources:									
26	Total Renewable Dependable Capacity		180	582	695	722	752	776	812	842

(1) Dependable Capacity at time of peak

APPENDIX C:
STAFF PROPOSAL FOR RELEASE OF AGGREGATED CONFIDENTIAL INFORMATION

ENERGY COMMISSION EXECUTIVE DIRECTOR NOTICE OF INTENT TO RELEASE AGGREGATED DATA

Background

The information provided by the state's load serving entities (LSEs) is a key part of the record for the *2005 Energy Report* proceeding. Evaluation of this information by Energy Commission staff and other parties will help inform the findings and recommendations in the *2005 Energy Report*, which in turn will form the basis for the transmittal of data and recommendations to the California Public Utilities Commission for the 2006 long-term procurement proceeding.

Much of the data supplied by investor-owned utilities (IOUs) and electricity service provider (ESPs) is being treated as confidential, either because the Executive Director determined that filers had made a reasonable claim that the information is entitled to protection, or because the process for resolving LSE appeals of Executive Director determinations that the data is not entitled to confidential protections is not yet complete.

The Energy Commission is committed to ensuring that the *2005 Energy Report* policy proceeding is conducted in an open and public manner. The *Energy Report* Committee expects that all the information that it considers in developing findings and recommendations in the *2005 Energy Report* and accompanying transmittal report for the CPUC will be part of the public record. While monthly demand and monthly specific resource data at the IOU bundled service load level has been granted confidentiality, the CPUC expects the Energy Commission to transmit information on the IOU positions through the *2005 Energy Report* process, and expects that all parties will have the opportunity to review and comment on this information. In order to meet this objective, the Energy Commission staff is developing summaries and aggregations of the confidential data for outside parties and Energy Commissioners to review. These summaries and aggregations will allow all parties to understand the supply/demand picture for the state and for the individual utilities. They protect the confidentiality of any underlying data that is confidential.

The IOUs have suggested that the Energy Commission's collaboration with the CPUC in the procurement process binds the Energy Commission to follow the CPUC's confidentiality determinations. While similar data has been provided to the CPUC for past proceedings, the data filed by the LSEs for the *2005 Energy Report* proceeding has not itself been reviewed for confidentiality by any other agencies. It therefore falls on the Energy Commission to determine whether this data should be shielded from release under the Public Records Act based on applicable laws and regulations. Even if it were appropriate for the Energy Commission to apply the

CPUC's requirements to this data, the CPUC has been directed by legislation to revisit its own approach to confidentiality, and expects to do so before the 2006 procurement proceeding begins.

Overview of Staff Proposals

The staff plans to release to the public aggregated data tables described in the three proposals below, which have been designed to mask the underlying resource plan data that has been designated as confidential. Each of the three proposals address both projected energy production and productive capacity of resources. Further, each of these tables will have annual and quarterly versions.

In all three sets of tables, the data will be aggregated in two dimensions: (1) along the time dimension, and (2) along the specificity of resource dimension by combining data about individual resources into categories of resources. The temporal aggregation will be from the monthly data submitted to quarterly and annual values. For the capacity tables, this aggregation will be developed by selecting values for the single month in which the forecast total peak demand is highest during the period, without identifying what month was selected. For example, in preparing an annual capacity from S-1 data if peak demand is highest in August for a specific year, all values for that year will be from August. For the energy tables, the data will be summed over the months in the relevant period. The quarterly data would be based on calendar quarters, and the annual data would be based on calendar years.

In addition, individual rows of resource-specific data from the submittals would be combined into various category subtotals. In these aggregated tables, staff will include all the rows relating to demand that do not reveal supplier categories, but will combine the specific resource listings (e.g. individual power plants, or individual contracts) into categories of resources (e.g. utility-controlled fossil resources, or existing & planned renewable contracts). Tables 1 and 2 at the end of this document summarize the categories staff will use for release of capacity and energy data, respectively. Staff has also prepared a template Excel spreadsheet similar to the public versions of forms S-1 and S-2 that the IOUs provided with their resource plan filings to use as a visual image of the annual version of the proposed tables. The quarterly version would simply have more columns.

The three sets of aggregated data tables differ based on the degree of geographic aggregation, and whether the scenarios filed by the LSEs are reported separately or are only shown as a range across scenarios. These differences are summarized as follows:

1. **IOU-specific tables for each scenario**: For each resource plan scenario, the staff will aggregate individual IOU bundled service customer data by aggregating monthly resource-specific entries to produce annual and quarterly subtotals by resource categories;

2. **Planning area tables for each scenario**: For each resource plan scenario, the staff will aggregate monthly resource-specific data for all LSEs serving load within a transmission planning area to produce annual and quarterly subtotals by resource categories; and

3. **Planning area tables showing capacity scenario ranges**: The staff will combine the results of the individual capacity scenarios for each planning area in the previous proposal to create a single table that shows the range of values.

These three proposals are discussed in more detail below. The staff believes that the first two proposals together provide the most appropriate level of disclosure consistent with protection of confidential data. The tables in the third proposal will only be produced if one or more LSE objects to either of the first two proposals.

The LSEs whose data is being aggregated can appeal the decision to release some or all of these tables to the full Energy Commission. No release of aggregated information that is the subject of an appeal to the full Commission will be allowed until the appeal is settled. In agreeing to or appealing the release of these three sets of aggregated data tables, the LSEs should consider the annual and quarterly versions separately, e.g. there are six proposed ways in which the data will be aggregated.

Proposal 1: IOU Bundled Customer Data

Under this proposal, staff will produce data tables consistent with Tables 1 and 2 for each of the IOUs, as described above. The tables will show annual and quarterly aggregated energy and capacity information for each IOU's bundled loads, for each of the four resource plan scenarios provided by the IOUs. These tables would be similar to the public versions of forms S-1 and S-2 that each IOU voluntarily provided, though they would provide more detailed information on categories of resources, particularly on the capacity side. The staff accepts the IOU suggestion that near term values have special sensitivity, so the tables would begin with year 2009.

The information included on these tables does not reveal the confidential data from the IOU filings, and is not itself entitled to confidential treatment. Aggregating supply data across the two dimensions (from monthly to annual and quarterly data and from individual resources to resource categories) does not reveal confidential monthly resource-specific data. Nor can these data aggregations be combined with other publicly available data to identify confidential monthly, individual resource-specific data for an individual IOU. This is due to the fact that in most of the resource categories, many individual resource entries are aggregated together into a single value. The only instances in which the number of individual resources comprising a category is small are when the resources are utility-owned. Substantial information is publicly available about these resources. IOU concerns about revealing how such resources might be used to meet demand over time are addressed by providing only annual and quarterly values, and by keeping monthly patterns confidential.

The quarterly and annual demand aggregations for the top rows of the S-1 and S-2 forms are not themselves confidential for two reasons. First, the various adjustments from gross load to net load resulting from shifts in supplier from IOU to other LSEs have been aggregated into a single "load adjustment" row that does not reveal alternative supplier. Even for the individual sources of adjustment, in most instances the resource plan forms and instructions directed the nature of the adjustment. The magnitudes of these values as submitted in the S-1 and S-2 forms reveal more about implementation of Commission direction rather than predictions of loss of load from modeling and analyses reflecting the business assessments of the IOU. Second, the demand-side load adjustments resulting from energy efficiency, demand response, and distributed generation are largely a matter of public knowledge having been issued as programmatic goals by CPUC orders. At this level of aggregation, staff does not believe any confidential information is being released.

Finally, for the same reasons as those underlying the Executive Director's determination that annual demand forecast data should be public, the portions of Tables 1 and 2 that show Future Generic Resource Need should also be made public. In upholding that determination, the Commission focused on whether knowledge of the extent of the gap between supply and demand during the single hour of highest demand would affect a utility's bargaining power vis-à-vis its potential suppliers and purchasers. The Commission found the answer to this question was no. IOUs have already agreed that the energy version of this Generic Resource Need can be made public by SCE furnishing its Public S-2 tables, and PG&E and SDG&E furnishing their S-7 tables.

While this aggregation proposal adds information on resources, and further disaggregates demand and resource information to a quarterly level, the same principles lead to the conclusion that the information revealed under this proposal, at either the annual or quarterly level, is not a trade secret:

- data similar to most of the disputed information is publicly available;
- release of the annual or quarterly demand and resource data without specificity about when the single hour of peak demand will occur and how similar that hour is to any other hour during the period diminishes the value of the information; and
- potential sellers can offer a variety of products to meet the utilities needs, and the utilities have additional options for meeting peak demand in addition to purchases from third parties.

Limiting the release of the IOU-specific aggregated data to the years 2009 and beyond also minimizes any potential value of the data because additional suppliers will be able to enter the energy market by that time.

While the demand forecast determination upheld by the Energy Commission related only to annual data, we note that a recent CPUC administrative law judge ruling issued in R.04-04-003 and R.04-04-025 addresses confidential versus public designations for a wide range of data of similar data.[1] We understand this ruling to uphold the confidentiality of hourly and monthly data, but that it orders the IOUs to release quarterly demand forecasts and quarterly forecasts of utility-retained generation costs and production. While the Energy Commission is not bound by CPUC determinations on the public or confidential nature of similar data, this decision does demonstrate that the CPUC, which the Energy Commission has encouraged to be less protective of IOU data, believes that releasing quarterly demand data does not reveal trade secret information.

In discussing these aggregation proposals, IOUs have indicated that they believe any LSE-specific data aggregations should apply equally to all LSEs. Staff plans to apply this proposal only to the IOU data, and not to the ESP data. In general, the staff agrees that similarly situated entities should be treated in similar fashion. However, in this instance, the staff is attempting to provide information to the CPUC on regulated utility activity, and to allow parties that may participate in the CPUC's 2006 long-term procurement proceeding to have access to aggregated data that may be used in that proceeding. The staff does not anticipate including ESP data in the transmittal report to the CPUC, and so does not plan to release a set of ESP-specific aggregation tables based on this proposal. Finally, ESPs have justified their claims for confidentiality of data submitted into this proceeding by noting that they compete against each other, even though under the current suspension of direct access, the ESPs may not compete to acquire additional customers from IOUs. Thus, IOUs and ESPs are not similarly situated, and what is a trade secret for one is not necessarily a trade secret for another. Accordingly, staff believes that making distinctions between the treatment of different subsets of LSEs is justified.

Proposal 2: Aggregation of all LSE Loads and Resources within a Geographic Region

In this proposal, the load forecast and resource plan data from all LSEs serving load within a control area will be aggregated, with the exception of the California Independent System Operator (CAISO) control area. For that control area, the unit of aggregation will be the participating transmission owner (PTO) transmission planning area. Under this proposal, the IOU data would be combined with the data for all ESPs and municipal utilities within that IOU's planning area. As with Proposal 1, data tables would be created in this proposal for each of the four resource plan scenarios provided by the IOUs.

[1] R.04-04-003 and R.04-04-025, Administrative Law Judges' Ruling on Protective Order and Remaining Discovery Disputes, May 9, 2005.

Aggregation of LSE Load Data within Planning Areas

Specifically, staff plans to release aggregated load forecast data for the four major control areas (CAISO, LADWP, SMUD/ WAPA, and a grouping of the smallest control area and fragments of the state in non-California control areas). Table 3 identifies the four control areas and the assignment of LSEs to them and to the subsidiary planning areas of the CAISO control area. Three of these CAISO planning areas are based on the large IOU dominating that geographic region, while one consists of the State Water project within the Department of Water Resources (DWR).

Staff plans to use this aggregation of LSE loads in its demand forecast comparison report, which will compare the staff demand forecast to those provided by the LSEs. This report is scheduled for public release on June 13 and will be discussed at a workshop on June 29. Because LSEs with a peak demand of less than 200 MW were not required to submit demand forecasts, using planning area requires estimation of the loads associated with these small suppliers. Staff has prepared an estimate of peak demand for 2005 for determining the proportion that these loads represent of the total planning area; this estimate is sufficiently small that the smaller entities can be approximated without introducing appreciable error into the overall total.

This aggregation of IOU, ESP and municipal utility load data into three IOU-centric planning areas could create disclosure problems for any of the component LSE elements that need to be protected.[2] However, previous informal discussions with IOUs and ESPs found support for this general approach. Staff's assessment of the confidential data along with public data from municipal utilities and smaller ESPs and municipals that were not required to file in this *2005 Energy Report* cycle indicates that IOU load forecasts are in the range of 80 - 85% of planning area totals for year 2005. This percentage combined with the fact that the number of entities included in the aggregation is at least 10 or more LSEs per planning area sufficiently masks the underlying confidential data of each one of the LSEs.

Aggregation of Individual Resource Plan Scenarios within Planning Areas

LSEs were requested to provide monthly tabulations of individual resources for capacity and energy to serve load in Forms S-1 and S-2, respectively, for four scenarios. As with the reference case resource plans, the S-1 and S-2 forms for each of these alternative scenarios were granted confidentiality. Recognizing that some access to these data were necessary, the three IOUs provided public versions of these resource plan data by aggregating in two dimensions – from monthly to annual, and from resource-specific to resource-category.

---

[2] PG&E and SCE planning areas contain several municipal utilities that filed load forecasts and several more that did not. All three IOU-centric planning areas contain loads of small ESPs <200 MW peak demand that did not submit load forecasts.

Staff plans to provide separate aggregated tables for the individual resource plan scenarios for capacity and for energy on an annual and quarterly basis. These scenarios reveal how each IOU proposes to adapt should an alternative future other than the reference case materialize. The size of the adjustments to load most fully characterizes each of the uncertainties about load (core/ non-core, community choice aggregation/ municipal departing load and levels of preferred loading order resources). The resulting resource plan scenario reveals how the IOUs would need to adapt their procurement actions to match such a load forecast when they identified it. The annual and quarterly resource category subtotal values are needed to understand the nature of the differences among the scenarios and the public policy consequences of the various scenarios.

Proposal 3: Further Aggregation Across IOU Resource Plan Scenarios

As a result of informal discussions with IOUs, the staff proposes a third aggregation proposal for capacity values that utilizes broader groupings. The tables in this proposal would collapse the separate capacity scenario tables for a given planning area into a single capacity table. The entries in this table would be the range of corresponding values from the separate scenario tables. If the values were common across all four scenarios, then a single value would be present in the cell. If there were four different values in the corresponding cells of each scenario, then the lowest and highest would be chosen and that range of values shown in the cell. Thus, the more that particular types of resources were affected in the development of the resource plan scenarios, the more that ranges would appear in the table rather than single values and the more that ranges would widen through time.

The interpretation of these tables would be difficult, since changes reflecting multiple sources of uncertainty would be intermingled. Because this proposal can be readily created from the tables in Proposal 2 and provides less information, staff would produce tables under this proposal only in cases where a pending appeal prevents the release of the corresponding Proposal 2 scenario tables. Staff has not included an energy version of this proposal, since the LSEs have informally agreed to Proposal 2 for the energy data.

Timing

The aggregations discussed above will appear as part of staff reports released in June commenting upon LSE submittals. These reports will be discussed in workshops in late June or July. Because of this schedule, and the need for 2005 *Energy Report* participants to utilize the results of these aggregation proposals in lieu of any access to underlying data that has been classified as confidential, it is critical that LSEs express agreement with those portions of this proposal they support as soon as possible, even if there are other portions they intend to oppose.

These plans to release aggregated data may be appealed to the Energy Commission within fourteen days. (Cal. Code Regs., tit. 20, 2507(e)(2).). Any appeal should specify which proposal, or which portion of a proposal, is being appealed. Those specific portions of any proposal that is appealed will not be released while that appeal is pending. In addition to docketing an appeal, copies should be provided to Kevin Kennedy, *Energy Report* project manager and Caryn Holmes, *Energy Report* Committee counsel.

Table 1. Proposed level of detail for release of aggregated annual and quarterly capacity resource data

PEAK DEMAND CALCULATIONS (MW):

Reference Case Forecast Total Peak Demand
Load Adjustment for a Scenario (-)
Uncommitted Price Sensitive DR Programs (-)
Uncommitted Energy Efficiency (2009-2016) (-)
Distributed Generation (-)
Net Peak Demand for Bundled Customers
Net Peak Demand + 15% Planning Reserve Margin
Firm Sales Obligations
Firm Peak Resource Requirement

EXISTING & PLANNED RESOURCES

Utility-Controlled Fossil and Nuclear Resources:

Nuclear
Fossil
Total Dependable Fossil and Nuclear Capacity

Utility-Controlled Hydroelectric Resources (1-in-2):

Total for all plants over 30 MW nameplate
Total for all plants 30 MW nameplate or less
Pump Storage Generation
Total Dependable Hydro Capacity

Total Utility-Controlled Physical Resources

EXISTING & PLANNED CONTRACTUAL RESOURCES

DWR Must-take Contracts:

Contract A
….
Contract N
Total DWR Contracts

QF Dependable Capacity
Renewable Contracts
Other Bilateral Contracts
Short Term and Spot Market Purchases

TOTAL: EXISTING & PLANNED CAPACITY

Existing Interruptible / Emergency (I/E) Programs
Uncommitted Dispatchable Demand Response

TOTAL CAPACITY + I/E and UDDR

FUTURE GENERIC RESOURCE NEEDS

Generic Renewable Resources
Capacity of other Generic Additions
Total Capacity of Future Generic Resources

Note: Dispatchable DWR contracts are included in the Other Bilateral Contracts.

Table 2. Proposed level of detail for release of aggregated annual and quarterly energy resource data

ENERGY DEMAND CALCULATIONS (GWh)

Reference Case Forecast Total Energy Demand
Load Adjustment for Scenario (-)
Uncommitted Energy Efficiency (2009-2016) (-)
Distributed Generation (-)
Net Energy Demand for Bundled Customers
Firm Sales Obligations
Total Energy Requirement

EXISTING & PLANNED RESOURCES
Utility-Controlled Fossil and Nuclear Resources:

Nuclear
Fossil
Hydro
Total Fossil and Nuclear Energy Supply

EXISTING & PLANNED CONTRACTUAL RESOURCES
Must-take DWR Contracts:

Contract A
….
Contract N
Total Energy Supply from DWR Contracts

Total Energy Supply from QF Contracts
Total Existing & Planned Renewable Contracts
Short Term and Spot Market Purchases

TOTAL: EXISTING & PLANNED ENERGY

FUTURE GENERIC RESOURCE NEEDS

Generic Renewable Energy
Generic Resource Addition Energy
Total Future Generic Resource Needs

Note: Dispatchable DWR contracts are included in the **Other Bilateral Contracts**.

Table 3. Definitions of proposed geographic areas for release of aggregated load forecast and resource plan data

Control Area	Component Planning Areas	Filings from LSEs in Area	Implementation Issues
CAISO	PG&E Planning Area (PA)[3]	IOU, ESPs >200 MW, ESPs < 200 MW, Munis	Requires effort to estimate loads for minor Munis and ESPs not submitting data
	SCE PA	IOU, ESPs >200 MW, ESPs < 200 MW, Munis, and MWD	Requires effort to estimate loads for minor Munis and ESPs not submitting data
	SDG&E PA	IOU, ESPs >200 MW, ESPs < 200 MW	Requires effort to estimate loads for minor ESPs not submitting data
	DWR (split into North and South)		Neither staff nor DWR have prepared a DWR demand forecast. DWR is busy with a major water study preceding a load forecast/resource plan effort.
LADWP	Single area	LADWP, Burbank and Glendale	None
SMUD	Single area	SMUD, Roseville, Redding and WAPA direct service	WAPA has not submitted data, but staff received a forecast via the PG&E transmission planning process
Other	Single area	IID, small portions of the Sierra Pacific and PacifiCorp service areas	Some aggregation necessary to protect IID resource plan data granted confidentiality

[3] IOU bundled customers average from 81-85% of the peak load in these planning areas.

Staff Proposed Aggregation for
Dependable Capacity Resource Accounting Table - Annual Version

6/3/2005

PEAK DEMAND CALCULATIONS (MW):		2009	2010	2011	2012	2013	2014	2015	2016
Reference Case Forecast Total Peak Demand									
Load Adjustment for This Scenario(-)									
Uncommitted Price Sensitive DR Programs (-)									
Uncommitted Energy Efficiency (2009-2016) (-)									
Distributed Generation (-)									
Net Peak Demand									
Net Peak Demand + 15% Planning Reserve Margin									
Firm Sales Obligations									
Firm Peak Resource Requirement									
EXISTING & PLANNED RESOURCES									
Utility-Controlled Fossil and Nuclear Resources:									
Nuclear									
Fossil									
Total Dependable Fossil and Nuclear Capacity									
Utility-Controlled Hydroelectric Resources (1-in-2):									
Total for all plants over 30 MW nameplate									
Total for all plants 30 MW nameplate or less									
Pump Storage Generation									
Total Dependable Hydro Capacity									
Total Utility-Controlled Physical Resources									
EXISTING & PLANNED CONTRACTUAL RESOURCES									
DWR Must-take Contracts:									
Contract A									
….									
Contract N									
Total DWR Contracts									
QF Dependable Capacity									
Renewable Contracts									
Other Bilateral Contracts									
Short Term and Spot Market Purchases									
TOTAL: EXISTING & PLANNED CAPACITY									
Existing Interruptible / Emergency (I/E) Programs									
Uncommitted Dispatchable Demand Response									
TOTAL CAPACITY + I/E and UDDR									
FUTURE GENERIC RESOURCE NEEDS									
Generic Renewable Resources									
Capacity for other Generic Resources									
Total Capacity of Future Generic Resources									

Note: Dispatchable DWR contracts are included in the **Other Bilateral Contracts**.

Staff Proposed Aggregation for
Energy Resource Accounting Table - Annual Version

6/3/2005

ENERGY DEMAND CALCULATIONS (GWh)		2009	2010	2011	2012	2013	2014	2015	2016
Refeence Case Forecast Total Energy Demand									
Load Adjustments for this Scenario(-)									
Uncommitted Energy Efficiency (2009-2016) (-)									
Distributed Generation (-)									
Net Energy Demand for Bundled Customers									
Firm Sales Obligations									
Total Energy Requirement									
EXISTING & PLANNED RESOURCES									
Utility-Controlled Fossil and Nuclear Resources:									
Nuclear									
Fossil									
Hydro									
Total Fossil and Nuclear Energy Supply									
EXISTING & PLANNED CONTRACTUAL RESOURCES									
Must-take DWR Contracts:									
Contract A									
….									
Contract N									
Total Energy Supply from DWR Contracts									
QF Contracts:									
Total Energy Supply from QF Contracts									
Existing & Planned Renewable Contracts:									
Total Existing & Planned Renewable Contracts									
Other Bilateral Contracts:									
Total Energy Supply from Other Bilateral Contracts									
Short Term and Spot Market Purchases:									
Short Term and Spot Market Purchases									
TOTAL: EXISTING & PLANNED ENERGY									
FUTURE GENERIC RESOURCE NEEDS									
Generic Renewable Energy									
Other Generic Additione for Energy									
Total Future Generic Resource Needs									

Note: Dispatchable DWR contracts are included in the Other Bilateral Contracts

STATE OF CALIFORNIA – THE RESOURCES AGENCY ARNOLD SCHWARZENEGGER, *Governor*

CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET
SACRAMENTO, CA 95814-5512

June 3, 2005

Ms. Laura Genao
Southern California Edison Company
2244 Walnut Grove Avenue
Rosemead, CA 91770

Dear Ms. Genao:

RE: Plans to release aggregated confidential data

Energy Commission staff has reviewed the various data filings provided by the state's load serving entities (LSEs) over the last several months. Because much of this data is being treated as confidential, staff plans to present aggregated data in our staff reports on the electricity supply and demand situation in California. Kevin Kennedy, the Energy Report program manager, discussed a draft of this proposal with the affected LSEs in meetings two weeks ago, and all of you filed comments on the draft after the meetings. I appreciate your willingness to provide comments and recommendations quickly. As you know, a key Energy Commission goal is to conduct the 2005 *Energy Report* proceeding in as open and transparent a manner as possible. At the same time, we are bound to protect any information that has been provided that is entitled to confidential treatment. After considering the responses from the LSEs, I believe that the attached plan for release of aggregated data succeeds in balancing those two principles.

Release of aggregated information is important to providing the necessary foundational material to support the Energy Commission's recommendations relating to the state's electricity system. The aggregation plan includes geographic aggregation that will be useful in the Commission's development of statewide energy policy recommendations. In addition, because the Energy Commission and the California Public Utilities Commission (CPUC) have agreed that the 2005 *Energy Report* proceeding will be the start of a new integrated statewide planning process, we need to address LSE-specific information. As stated in President Peevey's September 16, 2004, Assigned Commissioner Ruling (ACR), the 2005 Energy Report process "will estimate need for resource additions, evaluate policies and recommend appropriate resource strategies for the state to meet forecasted load on a biennial cycle. All load serving entities will provide load forecasts, resource plans and transmission assessment as input." The CPUC expects the Energy Commission to provide a transmittal report that is "based on the comments and information provided by all the participants regarding the issues, and will identify the likely range of statewide and LSE-specific need [and] a discussion of issues relevant to this determination." (March 14, 2005, ACR) To fulfill these requirements, the Energy Commission must provide participants in the 2005 Energy Report proceeding with sufficient information to allow an understanding of its recommendations on LSE-specific range of need.

I believe the current proposal protects confidential information while providing the public with an adequate opportunity to review and discuss the information that we will transmit to the CPUC along with the Energy Commission's findings and recommendations. Nonetheless, I recognize that some LSEs may have concerns about the degree of disclosure that would result from this plan. If you believe that any of the proposals in the plan will result in the release of information that is entitled to confidential treatment, you should file an appeal with the Commission in the Energy Report docket (04-IEP-1D) within fourteen days of this letter. (Cal. Code Regs., tit. 20, 2507(e)(2).) Please provide copies to Kevin Kennedy, Energy Report Program Manager, and Caryn Holmes, Energy Report Committee Counsel. While it is not required, if you decide before the deadline for filing an appeal that you are satisfied with a portion of our proposals and will not file an appeal for these, it would be helpful to staff in preparing key reports for a mid-June publication date if you notified us of that decision as soon as it is made.

Thank you for the work you and your staff have done in providing information for this proceeding. I look forward to your continued cooperation in the future. If you have questions or concerns about this proposal, please contact Kevin Kennedy at (916) 651-8836.

Sincerely,

SCOTT W. MATTHEWS
Acting Executive Director

cc: Docket Unit, 04-IEP-1D

APPENDIX D:
IOUS’ REPORTED RESOURCE PLAN COSTS

SCE Reported Resource Plan Cost

Table C-1: 2005 IEPR Scenario Costs[1], 2006 $B

California Energy Commission

Filing LSE: Southern California Edison
Date: April 1, 2005
Contact Name: Janos Kakuk
Contact Number: (626) 302-2342

Case	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	NPV (10.5%)
Reference Case	$4.8	$5.0	$4.9	$5.2	$5.4	$5.4	$5.4	$5.5	$5.8	$6.0	$6.1	$33.6
Reference Case w/o DPV2	$4.8	$5.0	$4.9	$5.1	$5.3	$5.3	$5.2	$5.4	$5.7	$5.9	$6.0	$33.2
Accelerated Renewables Case	$4.8	$5.0	$5.1	$5.4	$5.6	$5.7	$5.6	$5.8	$6.1	$6.3	$6.5	$34.8
Alternate Case	$4.8	$5.0	$4.8	$5.2	$5.5	$5.5	$5.5	$5.8	$6.0	$6.2	$6.4	$34.1

Table C-2: Average Scenario Costs Per Megawatt-Hour[1,2], $/MWh

California Energy Commission

Filing LSE: Southern California Edison
Date: April 1, 2005
Contact Name: Janos Kakuk
Contact Number: (626) 302-2342

Case	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Inflation-Adjusted Average (2006 $)
Reference Case	$57.2	$58.3	$55.3	$58.2	$59.8	$60.0	$58.2	$59.5	$61.0	$61.5	$61.3	$53.0
Reference Case w/o DPV2	$57.2	$58.3	$55.3	$57.6	$58.5	$58.6	$56.8	$58.2	$59.8	$60.4	$60.3	$52.3
Accelerated Renewables Case	$57.2	$58.4	$57.4	$60.7	$62.5	$62.8	$60.9	$62.4	$63.9	$64.7	$65.0	$55.1
Alternate Case	$57.1	$58.4	$54.7	$57.9	$59.5	$59.5	$58.0	$58.8	$59.6	$60.4	$60.9	$52.6

Notes

Based on deterministic analysis with expected load, natural gas price, and power price inputs.

1: Scenario costs capture only the fixed and variable costs from the production simulations, and additional costs due to 1) energy efficiency, 2) demand response, 3) new renewables, 4) qualified facilities, and 5) incremental transmission to support plans. This analysis does not include utility A&G, asset depreciation, base T&D costs, ISO-related costs, major capital adjustments, return on ratebase and other non-core business related costs - these costs are assumed to be the same across all cases; does not include the cost of mitigating debt equivalence beyond new renewables.

2: Inflation adjusted annual scenario costs divided by the SCE bundled customer & load obligation energy requirement (generation level), excluding the impacts of uncommitted energy efficiency.

SDG&E Reported Resource Plan Cost

Table B-1: 2005 IEPR Scenario Costs

California Energy Commission

Filing LSE: San Diego Gas & Electric Co.
Date: April 1, 2005
Contact Name: Robert Anderson
Contact Number: (858) 650-6183

Case	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	NPV (8.18%)
Reference Case	$1,279	$1,287	$1,282	$1,346	$1,402	$1,420	$1,444	$1,497	$1,520	$1,603	$1,642	$9,912
Alternative Case	$1,276	$1,322	$1,260	$1,325	$1,412	$1,432	$1,446	$1,523	$1,540	$1,608	$1,643	$9,949
Accelerated Renewables Case	$1,279	$1,287	$1,282	$1,346	$1,402	$1,429	$1,449	$1,497	$1,514	$1,596	$1,638	$9,912
High Gas Price Case	$1,347	$1,350	$1,387	$1,470	$1,515	$1,576	$1,605	$1,663	$1,695	$1,789	$1,835	$10,810
Low Gas Price Case	$1,208	$1,228	$1,165	$1,221	$1,294	$1,268	$1,278	$1,328	$1,336	$1,407	$1,444	$8,994

Average Energy-Adjusted Scenario Costs, $/MWh,

California Energy Commission

Filing LSE: San Diego Gas & Electric Co.
Date: April 1, 2005
Contact Name: Robert Anderson
Contact Number: (858) 650-6183

Case	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Average
Reference Case	$73.3	$75.3	$73.3	$75.6	$77.2	$76.6	$76.2	$77.7	$77.3	$79.9	$80.1	$76.6
Alternative Case	$73.2	$74.3	$69.1	$71.4	$74.6	$74.2	$73.3	$75.9	$75.1	$76.9	$76.9	$74.1
Accelerated Renewables Case	$73.3	$75.3	$73.3	$75.6	$77.2	$77.1	$76.5	$77.7	$77.0	$79.6	$79.9	$76.6
High Gas Price Case	$77.3	$79.0	$79.4	$82.5	$83.4	$85.1	$84.8	$86.3	$86.2	$89.2	$89.5	$83.9
Low Gas Price Case	$69.3	$71.9	$66.6	$68.5	$71.2	$68.4	$67.5	$68.9	$67.9	$70.1	$70.4	$69.2

Notes

Based on deterministic analysis with expected load, natural gas price, and power price inputs, except for High and Low Gas Price Cases which used the high and low gas and market clearing prices

Captures only the fixed and variable costs from the production simulations. This analysis does not include energy efficiency program costs, demand response program costs, incremental transmission costs needed to make all resources deliverable, utility A&G, base T&D costs, ISO-related costs, and does not include the cost of mitigating debt equivalence.

PG&E Reported Resource Plan Cost

Resource Plan Generation Costs				
(2005 $B)				
Year	CEC Reference	PG&E Preferred	CEC Core/Non Core	CEC Accelerated Renewable
2006	5.3	5.3	5.3	5.3
2007	5.1	5.1	5.1	5.1
2008	5.5	5.4	5.4	5.4
2009	5.3	5.2	5.1	5.2
2010	5.0	4.9	4.8	4.9
2011	5.2	4.9	4.7	5.0
2012	5.0	4.7	4.4	4.7
2013	5.2	4.8	4.5	4.9
2014	5.3	4.9	4.6	5.0
2015	5.3	4.9	4.6	5.0
2016	5.2	4.8	4.5	4.9

Notes:

Table includes only generation costs. Remaining PG&E electric revenue requirement estimates were provided to the CEC on January 18, 2005. PG&E has not estimated the changes in non-generation revenue requirements for each resource plan, except as noted below.

All scenarios require an estimated incremental $170-230 million in transmission upgrades in order to achieve 20% RPS, which are not included in the above costs.

Generation cost estimates do not include potential RPS integration costs.

Renewable costs in the CEC Reference, PG&E Preferred and CEC Core/Non-core scenario plans based on same renewable resource plan. This plan results in the following renewable energy contribition in 2016: CEC Reference - 20%, CEC Preferred - 23%; and CEC Core/Non-core - 25%. Renewable costs in the Accelerated Renewable scenario based on a renewable plan that results in 28% renerwable energy in 2016.

The Accelerated Renewable scenario is likely to require substantial transmission system upgrades to expand system to project locations and transport renewable energy to load centers. The magniture of these costs will depend on the location of the resources and the use and costs of Renewable Energy Credits, when and if these are authorized for RPS compliance.

Accelerated Renewable scenario may over-value PG&E market revenues. Modeling assumed renewable resources would have no impact on market prices, though substantial quantities of excess intermittent off-peak renewable energy will likely impact market prices.