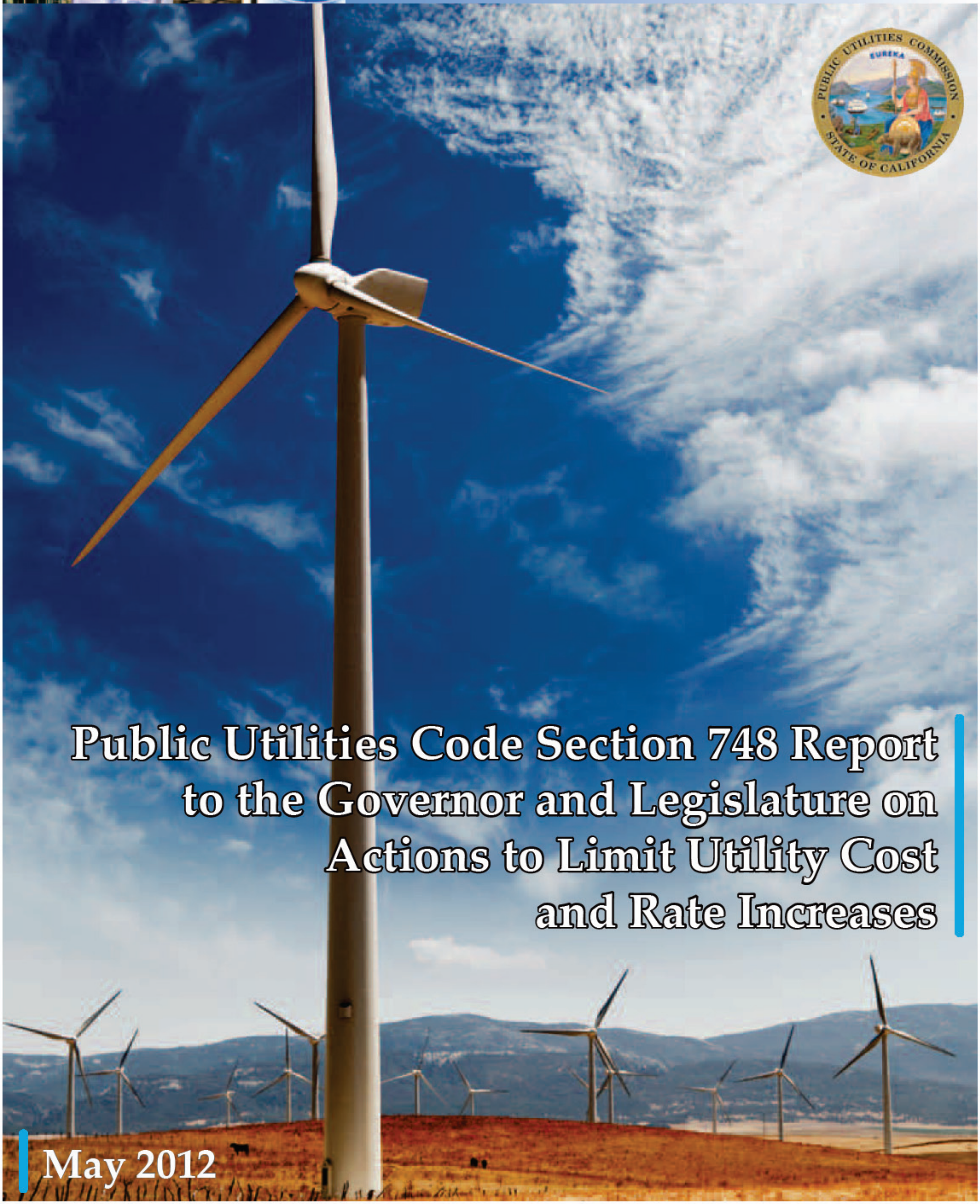
California Public Utilities Commission



Public Utilities Code Section 748 Report to the Governor and Legislature on Actions to Limit Utility Cost and Rate Increases

May 2012

I. Executive Summary

Purpose of Report and Statutory Mandate

On October 11, 2009 Governor Schwarzenegger signed Senate Bill (SB) 695. Among other things, SB 695 added Section 748 to the Public Utilities Code, which requires the California Public Utilities Commission (CPUC or Commission) to furnish an annual report on its actions to limit the costs of utility programs, operations, and activities. The specific provisions of Section 748 are as follows:

> 748. (a) The commission, by May 1, 2010, and by each May 1 thereafter, shall prepare and submit a written report, separate from and in addition to the report required by Section 747, to the Governor and Legislature that contains the commission's recommendations for actions that can be undertaken during the succeeding 12 months to limit utility cost and rate increases, consistent with the state's energy and environmental goals, including goals for reducing emissions of greenhouse gases.
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> (b) In preparing the report required by subdivision (a), the commission shall require electrical corporations with 1,000,000 or more retail customers in California, and gas corporations with 500,000 or more retail customers in California, to study and report on measures the corporation recommends be undertaken to limit costs and rate increases.
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> (c) The commission shall post the report required by subdivision (a) in a conspicuous area of its Internet Web site.

The 2012 edition of this report is hereby submitted by the CPUC to the Governor and Legislature, in compliance with Public Utilities Code Section 748.

CPUC Regulatory Authority and Energy Policy Objectives

The CPUC regulates investor-owned electric and natural gas utilities within the State of California, including Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), San Diego Gas and Electric Company (SDG&E), and Southern California Gas (SoCalGas). Collectively, these utilities serve over two-thirds of total electricity demand and over three-quarters of natural gas demand throughout California.[1] The CPUC develops and administers energy policies and programs to serve the public interest, and ensures compliance with statutory mandates and CPUC decisions that promote reliable, safe and environmentally sound energy services at the lowest reasonable rates for the people of California.

The Commission's regulatory processes are governed by the Public Utilities Code and the Commission's Rules of Practice and Procedure. Each formal proceeding follows due process

[1] In addition to the four large utilities, the CPUC also regulates a number of small and multi-jurisdictional energy utilities; however, these utilities are not subject to the reporting requirements of Public Utilities Code Section 748.

that affords parties the opportunity to present their positions and recommendations in comments and prepared testimony before the Commission. Evidentiary hearings are held when warranted, and a proposed decision (PD) is prepared by an Administrative Law Judge (ALJ) or an assigned Commissioner, depending on the categorization of a proceeding for a vote by the Commission.

The CPUC's ratesetting proceedings over the next 12 months will continue to be consistent with the Energy Action Plan (EAP), adopted by the CPUC and California Energy Commission (CEC) in 2005, and updated in February 2008. The EAP established a "loading order," or priority sequence for actions to address California's increasing energy needs. The EAP's loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs, followed by renewable resources and distributed generation, and finally clean and efficient fossil-fired electric generation.

The EAP identifies six sets of actions of critical importance for the CPUC, as follows:

- Optimize Energy Conservation and Resource Efficiency
- Accelerate the State's Goal for Renewable Generation
- Ensure Reliable, Affordable Electricity Generation
- Upgrade and Expand the Electricity Transmission and Distribution Infrastructure
- Promote Customer and Utility Owned Distributed Generation
- Ensure Reliable Supply of Reasonably Priced Natural Gas

Summary of CPUC Actions to Limit Utility Cost and Rate Increases

This report focuses on a description of pending proceedings before the Commission, as well as certain annual rate applications that are likely to be filed later this year. Included in this inventory of relevant pending proceedings are the dollar amounts requested by the utilities along with a summary of the rationale for these requested amounts. This should provide the Legislature with a snapshot of the scope and financial implications of the proceedings before this Commission. Finally, this report offers a detailed description of various program areas that contribute to utility costs, as well as any actions the Commission is considering to contain ratepayer costs and to meet the state's environmental and public purpose goals. As illustrated in the pages that follow, the Commission seeks to continuously improve the efficacy and cost-effectiveness of its energy policies and programs. Below is a summary of key actions and regulatory tools that the Commission will implement in the next 12 months to ensure that these objectives are met.

Supply Side Programs and Regulatory Actions

Long Term Procurement Planning and Resource Adequacy

CPUC Actions: The Resource Adequacy (RA) and Long Term Procurement Planning (LTPP) programs ensure sufficient conventional energy supply and reliability of electric service in California. The cost of these programs hedge against costs related to lost productivity during system emergencies and emergency resource procurement. In the next 12 months, RA and LTTP efforts are not expected to increase utility or ratepayer costs. The CPUC is acting to limit costs in the medium term by maximizing the use of existing and pending generation and transmission resources, improvements in interconnection processes, cost-effective replacement of Once Through Cooling (OTC) infrastructure, increasing reliability of renewables, and improved demand-side measures to reduce load.

Specific activities in this program area in the next 12 months include:

- Every two years, the CPUC administers a Long Term Procurement Planning (LTPP) proceeding to evaluate the system's need for new conventional generation resources. The pending 2010 LTPP decision in R.10-05-006 finds no clear evidence of need for new generation infrastructure for system reliability needs through 2020.
- In 2010, the State Water Resources Control Board (SWRCB) adopted rules to phase out the use of OTC at existing generating facilities, mostly by 2020. Approximately 2500 MW of OTC generation needs to be brought into compliance with this policy, which has significant potential cost implications.
- Two new natural gas generating facilities are scheduled to be operational in 2012. While the impact on utility costs and rates is not yet known, the CPUC's Demand Side Management (DSM) programs assist in mitigating increased expenses.

Renewable Portfolio Standard

CPUC Actions: The CPUC will continue to minimize the cost associated with increased procurement of renewable energy.

Specific activities in this program area in the next 12 months include:

- Conduct an in-depth review of a series of modifications to the Renewable Portfolio Standard (RPS) bid selection criteria and methodology designed to streamline the procurement process and improve overall cost-effectiveness of RPS compliance.

- Implementation of a new cost containment mechanism as mandated by passage of SB 2 (1X) in 2011 which establishes new guidelines for renewable energy procurement in California.

Demand-Side Programs and Regulatory Actions

Energy Efficiency

CPUC Actions: Energy efficiency results in net savings to utilities and ratepayers, and CPUC actions are focused on improving results further. The Commission will implement aggressive energy savings targets and market transformation measures in accordance with new legislation and long term strategic planning.

Specific activities in this program area in the next 12 months include:

- To better align the Energy Efficiency program design with the Strategic Plan and AB 758 goals for more robust and long lasting energy savings, the CPUC directed the utilities to reorient their portfolios, beginning with the 2013-14 "Transition Portfolio," to target deeper energy savings and promote market transformation.[2]

- Specific activities in the next 12 months include: developing untapped energy savings potential and improving energy efficiency finance options.

Demand Response

CPUC Actions: Demand response results in net savings to utilities and ratepayers, and CPUC actions are focused on improving results further. The Commission will be considering a number of measures and protocols to ensure the cost-effectiveness of demand response (DR) programs and to better enable customers to reduce demand in response to price signals, emergency alerts, or incentive payments.

Specific activities in this program area in the next 12 months include:

- Refining cost-effectiveness measurement, aligning DR programs with Resource Adequacy values, approving rules and policies to allow for direct DR participation in wholesale markets, and modifying Emergency DR programs to reduce costs.

Time-Variant Pricing

CPUC Actions: Where implemented, Time-Variant Pricing (TVP) has saved utility and customer costs and resulted in peak load reduction in the large commercial market. CPUC actions are focused on completing the transition underway of small commercial and residential customers to TVP rates with the objective of reducing and shifting peak demand, reducing costs for utilities and customers, and advancing state environmental goals.

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[2] ACR 2013-2014 Scoping Memo, available at http://docs.cpuc.ca.gov/efile/RULC/146158.pdf.

Specific activities in this program area in the next 12 months include:

- **PG&E Default Residential Rate Program (DRRP Proceeding A.10-08-055):** At issue is whether the CPUC can authorize PG&E to adopt default TVP rates for all customer usage or only for usage in excess of 130 percent of baseline (Tiers 1 & 2). This will affect pending residential TVP rate design proposals of SCE and SDG&E.

- **Investor Owned Utilities' (IOU) Transition to Default Time of Use (TOU) Rates for Small and Medium Non-Residential Customers**: All IOUs have pending applications for transitioning small and medium business and agriculture to default TOU rates in the 2012-2014 time frame.

Customer-Sited Distributed Generation and California Solar Initiative

CPUC Actions: As the CPUC's customer-sited distributed generation (DG) programs accelerate toward achieving their goals, the programs are focused on improving program efficiencies, studying the costs and benefits of Net Energy Metering (NEM), expanding access to more customers via Virtual Net Metering, and expanding the scope of technologies participating in NEM via implementation of SB 489.

Specific activities in this program area in the next 12 months include:

- **California Solar Initiative (CSI):** By incentivizing more than 757 megawatts of installed solar energy in the first five years of the program (with a goal of 1,940 megawatts by 2017), the CSI program helped to support the growth of a multibillion dollar solar industry that has created more than 25,000 jobs in California. (insert footnote to). Presently, there are no new costs in implementing the CSI program under Senate Bill (SB) 1 (Murray, 2006). The CPUC will continue to regularly monitor trends in expenditures from CSI and will adjust utility revenue collections accordingly.
- **Net Energy Metering (NEM) Expansion and Cost-Benefit Studies:** The scope of technologies eligible for NEM is expanded with passage of SB 489, and NEM access is increased by expansion of Virtual Net Metering to multi-meter and multi-tenant properties. The CPUC issued a cost benefit study in 2010 on the ratepayer impacts of NEM based on market data through 2008. Now the study is being revised based on recent expansions of NEM.

CARE and Energy Savings Assistance Program

CPUC Actions: The California Alternate Rates for Energy (CARE) program provides rate discounts and the Energy Savings Assistance Program (ESAP) provides energy efficiency measures to low-income customers. The Commission will be monitoring and evaluating the many CARE and ESAP pilot programs and studies it has authorized, with the intent to use the results to further improve program delivery, customer marketing and outreach efforts, program efficiencies, and cost effectiveness, all while maximizing customer benefits.

General Rate Cases and Energy Resource Recovery Account Proceedings

CPUC Actions: The CPUC will carefully manage the costs of utility operations and energy procurement, and address ratepayer impacts through the rate design phase of General Rate Cases (GRC) and Energy Resource Recovery Account (ERRA) proceedings.

Specific activities in this program area in the next 12 months include:

- The Commission is in the process of reviewing SCE's and SDG&E's GRC rate design proposals along with the input from a large number of intervenors that will provide testimony and recommendations in the case.
- PG&E, SCE and SDG&E will file their requests to recover fuel and purchased power costs in the ERRA proceedings around the second half of 2012. The Commission will scrutinize the utilities' power purchase and fuel cost recovery requests in the ERRA proceedings and provide for refunds to customers when specified triggers warrant.

Natural Gas Programs and Proceedings

CPUC Actions: In the wake of the San Bruno transmission pipeline explosion in 2010, ratepayers will be asked to fund major natural gas pipeline infrastructure upgrades in order to enhance safety and security. The Commission will manage the rate impacts of such investments through effective risk management, project prioritization, and by assessing whether and to what extent IOU shareholders should be responsible for such costs.

Specific activities in this program area in the next 12 months include:

- **Gas Utility Safety Rulemaking (R.11-02-019):** This rulemaking will consider how the CPUC can align ratemaking policies, practices, and incentives to improve safety standards and risk management practices. In August 2011, PG&E, SoCalGas, SDG&E, and Southwest Gas filed their Gas Safety Implementation Plans to propose how they intend to ensure that their transmission pipeline systems are safe. <u>The utilities propose spending over $4 billion in the next 3-4 years in just the first phase of their plans, and propose that ratepayers pay for virtually all of these costs</u>.

- The Commission expects to continue to implement measures that will help keep gas procurement costs at reasonable levels, including:
  - Incentives to utilities to keep natural gas procurement costs low;
  - Expeditious approval of a diverse and reasonably-priced portfolio of interstate pipeline capacity;
  - Providing core customers with adequate amounts of natural gas storage capacity, and allow utilities to engage in more efficient natural gas hedging practices.
- **SoCalGas Advanced Metering Infrastructure:** In D.10-04-027, the Commission authorized SoCalGas to install advanced metering infrastructure for its customers, at a cost of $1.05 billion. The deployment period will through 2017, and is intended to allow ratepayers to monitor and conserve usage to better manage bills.

Increasing Transparency of Cost Data to Better Serve the Public

> **CPUC Actions**: Over the next 12 months, Energy Division and the Commission will strive to make more cost data available and accessible to the public. Increased transparency will not decrease rates in and of itself, but increased access to this information will give the public more tools to understand and engage with CPUC efforts to keep rates affordable.

Specific activities to fulfill this objective in the next 12 months include:

- **Energy Division Rate Forecasting Project**: This study will evaluate trends in the various components of the bundled retail rate through 2017, identifying the primary cost drivers among energy programs and activities as well as mechanisms for mitigating such costs.

- **Incremental Decision Rate Impact Analysis:** This analysis will examine the rate impacts of the Commission's priority decisions, and may be subsumed within the above forecasting project. Energy Division will look at ways to incorporate this analysis as a routine practice of the CPUC going forward.

Utilities' Recommendations to Limit Cost and Rate Increases

Pursuant to Section 748(b), the four major electric and gas companies submitted program cost updates to the Energy Division, including their recommendations to limit potential costs and rate increases. These updates and recommendations are attached as an Appendix to this report.

II. Electric Utility Costs and Revenue Requirements

Summary

Utilities file detailed descriptions of the costs of providing service (commonly referred to as revenue requirement to be collected from customers) in various proceedings and request the Commission to approve their proposed revenue requirement. The CPUC strives to balance the electric utility customers' needs for safe, reliable, and environmentally responsible service and the utilities' financial health, while achieving the lowest possible rates. Since energy services are essential, the CPUC ensures that access is universal and affordable. The bulk of utility revenue requirement is requested in General Rate Cases (GRCs) and the Energy Resource Recovery Account (ERRA) proceedings. GRCs address a utility's revenue requirement for maintaining and enhancing their generation and distribution infrastructure. ERRA costs are primarily fuel and purchased power costs which carry no mark-up or rate of return for the utility. In addition to the GRCs and ERRA proceedings, some costs are requested by the utilities in specific proceedings related to program areas such as energy efficiency, renewable portfolio standard (RPS), solar initiative, distributed generation and demand response, which are described in Chapter IV of this report.

Total Authorized Electric Revenue Requirements effective January 1, 2012
($ Million)

PG&E	SCE	SDG&E
$12,370	$11,218	$3,005

The utilities file GRC applications every three or four years. Commission decisions on utilities' GRC applications establish revenue requirements for an initial forecast year (test year), and two or three subsequent "attrition years" to account for cost escalation during the GRC cycle.

PG&E, SCE, and SDG&E file ERRA forecast applications annually to recover fuel and purchased power costs expected during a future annual period. Each utility also files an annual ERRA compliance application to address actual ERRA costs incurred during a prior annual period. The ERRA proceedings were established by the Commission in 2002 in response to AB 57 (2001), which required that the utilities receive timely recovery of their electricity procurement costs.

All of the Commission-approved GRC and ERRA costs are recovered through two main types of rate charges -- generation and distribution -- which appear on customer bills as separate line items. Transmission-related costs and revenue requirements are under the jurisdiction of the Federal Energy Regulatory Commission (FERC) and are recovered in the transmission component of rates. The grouping of rates into generation, distribution, and transmission is primarily based on the costs of each of these functional areas of utility business. However, the distribution rate component includes costs of many public policy programs that should be paid for by all customers who use the utility distribution system.

Requests for Revenue Requirement Increases Under CPUC Consideration in 2012

Electricity General Rate Cases

The major components of costs that are reviewed and determined in the GRCs include operations and maintenance, depreciation, return on rate base, and taxes. The revenue requirements for 2011 authorized by the Commission in recent GRCs for the three major utilities are listed below.

2011 Authorized Electric General Rate Case Revenue Requirements ($ Million)

	PG&E	SCE	SDG&E
Operations and Maintenance	$1,947	$1,951	$480
Depreciation	$1,099*	$1,037	$216
Return on Rate Base	$1,246	$1,117	$242
Taxes	$734	$724	$171
Attrition **		$424	$103
Total	**$5,026**	**$5,254**	**$1,212**

* Includes $38 million for fossil and nuclear decommissioning.
** PG&E's attrition allowances apply to years 2012 and 2013; SCE's attrition includes amounts authorized for 2010 and 2011; SDG&E's attrition includes amounts authorized for 2009, 2010, and 2011.

In May 2011, the Commission adopted PG&E's test year 2011 GRC revenue requirement which is shown in the table above. As part of the 2011 GRC decision, the Commission authorized PG&E an attrition increase in 2012 of $145 million, so PG&E's GRC revenue requirement for 2012 is $5,171 million. In the 4th quarter of 2012, PG&E will file its test year 2014 GRC. The Commission will address PG&E's GRC application during 2012 and a decision is expected at the end of 2013 or in early 2014.

SCE filed its 2012 GRC in November 2010 requesting a 2012 GRC revenue requirement of $6,214 million. This represents an increase of about $800 million or 7% of total authorized revenues. According to SCE, the increase is needed to accommodate increased customer and load growth, replace aging distribution infrastructure, make contributions to employee pension funds, and for other projects needed to operate its system. The Commission is expected to adopt a decision in the revenue requirements phase in the 2nd quarter of 2012.

SDG&E filed its 2012 GRC application in December 2010 requesting a 2012 electric GRC revenue requirement of $1,523 million. This represents an electric revenue increase of about $260 million or 9% of total authorized revenues. According to SDG&E, the increase is needed for distribution capital investments, insurance premiums, and other projects needed to operate its system. The Commission is expected to adopt a decision in the revenue requirements phase in the 3rd quarter of 2012.

After the Commission reviews and determines the utility's authorized revenues, the Commission begins a Phase 2 of each General Rate Case. In this rate design phase, parties propose and the Commission considers the various methods of allocating the total authorized revenue among the different classes of ratepayers, and methods of designing the specific rates the utility should use to collect its authorized revenue requirement. As discussed in more detail in Chapter 3 under "Time Variant Pricing", the specific rate design proceedings currently under consideration by the Commission.

Forecasting Electric Fuel and Purchased Power Costs

The Commission establishes PG&E's, SCE's, and SDG&E's revenue requirements to recover their costs for fuel for their power plants and to procure electricity under purchased power contracts in the annual ERRA forecast proceeding. The Commission establishes an ERRA rate component based on a forecast of the costs, which are passed through to customers without any mark-up or profit for the utility. Fuel and purchased power costs fluctuate with the market price of natural gas. The utilities' current authorized annual revenue requirements to recover fuel and purchased power costs adopted in Commission ERRA forecast proceedings are shown below.

Annual Electric Revenue Requirements for Fuel and Purchased Power Costs ($ Million)

PG&E	SCE	SDG&E
$3,990	**$3,708**	**$829**
Effective Jan. 2012	**Effective June 2011**	**Effective Sept. 2011**

PG&E's 2012 ERRA forecast proceeding was concluded last December, resulting in the fuel and purchased power revenue requirement shown above. SCE is requesting a fuel and purchased power revenue requirement of $4,017 million for 2012. A Commission decision in SCE's 2012 ERRA forecast proceeding is expected in the 2nd quarter. SDG&E requested a fuel and purchased power revenue requirement of $953 million, later amended to $871 million, for 2012. A Commission decision in SDG&E's 2012 ERRA forecast proceeding is expected in the 3rd quarter of this year.

Utilities' actual fuel and purchased power costs, and the revenues they collect from customers to pay these costs, are tracked in a balancing account with interest and addressed in subsequent ERRA or related Commission proceeding. In the event that the revenues exceed the costs, then the account balance (difference between costs and revenues) is returned to the customers. If the costs exceed the revenues then the costs are recovered from customers. The costs shown above do not include ERRA account balances that are returned to or recovered from customers.

The Commission also has rules in place to ensure that the revenue requirement collected by the utilities tracks closely with the Commission's pre-specified market price benchmarks for gas and actual purchased power costs. If a utility's ERRA account balance exceeds 4% of its actual generation revenues in the prior year (i.e., the "trigger" level) and the balance is expected to exceed 5% of those revenues, the utility is generally required to file an expedited application to propose to amortize the balance in rates, resulting in a rate reduction. If the balance is expected to decline below the 4% trigger level within 120 days, the utility may inform the Commission in an advice letter, but is not required to file an expedited application.

Electric Fuel and Purchased Power – Review of Actual Costs

The Commission also reviews each utility's energy procurement operations and purchased power contract administration activities for a prior annual period in a separate annual ERRA compliance proceeding for each utility. This allows the Commission to ensure that the utilities are prudently managing these costs. In 2011, the Commission issued decisions in PG&E's, SCE's and SDG&E's ERRA 2010 compliance proceedings, which addressed fuel and purchased power costs and operations during 2009. The Commission determined that the utilities' dispatching operations, power contract administration, and fuel and purchased power costs incurred during 2009 were prudent. Likewise, in 2011, the utilities filed ERRA compliance applications addressing energy costs and operations during 2010, and the Commission will issue decisions in these applications in 2012. PG&E and SCE filed ERRA compliance applications in February and April 2012, respectively, addressing 2011 energy costs and operations, with decisions anticipated in 2013.

Plans to Improve Commission Efficacy in Ratemaking

A Heightened Focus on Safety and Accountability

In the GRC, a utility must present detailed evidence regarding how much revenue it needs to safely and reliably operate its system. After reviewing the utility's request, the Commission establishes an authorized revenue requirement which is included in rates for the GRC cycle.

If the utility spends more than the revenue authorized in the GRC, it absorbs the excess costs. If the utility spends less than authorized it is allowed to retain the revenue, but the spending reductions will be reflected in the next GRC cycle since authorized revenues are based in part on historic spending levels. This is intended to provide an incentive to the utility to manage its operations efficiently and reduce costs where possible.

The utility has discretion to reprioritize projects approved for funding in the GRC, and defer spending in certain areas in favor of spending on other activities to ensure safe and reliable service. In the wake of the 2010 San Bruno tragedy, the Commission is reexamining its ratemaking processes with a primary focus on safety and risk management.

In its decision in PG&E's 2011 GRC, the Commission emphasized that the utility has the responsibility to spend what is necessary to ensure safe and reliable service despite any financial implications of exceeding authorized cost levels. The Commission required PG&E to submit reports on authorized revenues versus actual expenditures for major electric and gas work categories, including explanations of significant differences between authorized and recorded spending for each category.

In January 2012, the Commission held a workshop to initiate discussion among all gas and electric utility stakeholders on how to improve the ratemaking process to focus on safety. There will be a follow-up to this workshop, which may include a new rulemaking to address changes to GRC ratemaking.

Consolidated Review of Market Redesign and Technology Upgrade Costs

In 2007 the Commission allowed PG&E, SCE, and SDG&E to establish memorandum accounts to record costs for implementing the California Independent System Operator's (CAISO) Market Redesign and Technology Upgrade (MRTU) initiative. Costs recorded in these memorandum accounts through 2009 were reviewed by the Commission separately for each utility in their ERRA compliance proceedings.

To identify best practices and to clearly identify and compare cost differences among the utilities, in 2011 the Commission required PG&E, SCE, and SDG&E to jointly file applications addressing costs incurred for implementing the CAISO's MRTU initiative. Costs recorded in the MRTU memorandum accounts from 2010 and beyond will be reviewed by the Commission in the consolidated proceeding initiated in 2011. In January 2012 the utilities filed their joint application on 2010 MRTU costs, A.12-01-014, requesting a total recovery of approximately $85 million in MRTU costs recorded in 2010.

Other Rate Related Proceedings in the Next 12 Months

Over the next 12 months, the Commission will review several requests filed by the utilities through formal applications and advice letters. Some of these proceedings are already filed and pending while others are likely to be filed later in the year. Most of the proceedings are utility specific rate filings. However, the first five proceedings described below are joint proceedings involving all or several of the four major energy utilities.

Joint Utility Requests

- **Wildfire Insurance Costs**

  PG&E, SDG&E, SoCalGas, and SCE jointly filed A.09-08-020 to request balancing accounts to record uninsured wildfire costs for possible future recovery. An Assigned Commissioner's Ruling in January, 2012 granted the motion of PG&E and SCE to withdraw from this case, and denied their motion to retain their associated memorandum accounts. SDG&E and SoCalGas are still pursuing this application. Briefs were filed in February and March 2012.

- **AB 32 Administrative Fee Recovery**

  D.10-12-026 (A.10-08-002) authorized PG&E, SCE, SDG&E, and SoCalGas to establish memorandum accounts to record the costs of this administrative fee assessed by CARB. The decision does not prejudge any issues regarding recovery by the utilities of these costs. Briefs were filed in October 2011, and the case was submitted to the Commission.

- **Cost and Revenue Issues associated with GHG Emissions**

  The Commission opened R.11-03-012 to address potential utility cost and revenue issues associated with greenhouse gas (GHG) emissions. The initial focus of the rulemaking is how to use revenues that electric utilities may generate from auction of allowances allocated to them by the California Air Resources Board (CARB), how to use revenues that electric utilities may receive from sale of Low Carbon Fuel Standard credits they may receive from CARB, and the treatment of possible GHG compliance costs associated with electricity procurement. In

January 2012, parties filed proposals on the appropriate use of GHG allowance auction revenues, and in March parties filed proposals on allocating revenue from the sale of low carbon fuel standard credits. Proposed decisions in these two portions of the proceeding are scheduled to be issued in June and October 2012, respectively.

➢ **Annual Revenue Requirement Determination of Department of Water Resources**

The Commission opened R.11-03-006 to consider issues related to the annual revenue requirement determination of the California Department of Water Resources (DWR) in connection with its procurement of energy for the electricity customers of PG&E, SCE, and SDG&E. Each year around August, DWR submits its revenue requirement for the following year to the Commission for adoption and subsequent collection from ratepayers through the DWR Power Charge. A proposed decision allocating the 2012 DWR revenue requirement and refunds from two lawsuit settlement agreements was issued on April 3, 2012.

➢ **Funding and Program Issues Related to Renewables and RD&D**

Funding authorized in Public Utilities Code Section 399.8, which governs the system benefits charge, expired as of January 1, 2012. Public benefits provided by the expired funding are in the areas of energy efficiency, renewable energy, and research, development, and demonstration (RD&D). The Commission opened R.11-10-003 to address funding and program issues related to the renewables and RD&D portions of the expiring public goods charge funding.

Requested Revenue: PG&E; 2012--$70 million, 2013--$25 million.

Common Utility-Specific Rate Requests

➢ **Future ERRA Forecast Applications**

- **PG&E 2013 ERRA Forecast:** This application will be filed in June, 2012.
- **SCE 2013 ERRA Forecast:** This application will be filed in August, 2012.
- **SDG&E 2013 ERRA Forecast:** This application will be filed in September, 2012.

➢ **ERRA Compliance Review Applications**

- **General:** In these applications, the Commission reviews each utility's energy procurement and purchased power contract administration for a prior year.
- **PG&E 2010 ERRA Compliance A.11-02-011:** Recovery of costs related to the Market Redesign and Technology Upgrade (MRTU) initiatives, and other procurement-related costs.

  Requested Recovery: $47.2 million.

Pursuant to ALJ ruling in this case, PG&E moved its request for $47.2 million for MRTU costs from this case to A.12-01-014, joint application by PG&E, SCE, and SDG&E for costs associated with MRTU. Briefs were filed in March and April 2012 on issues remaining in this ERRA compliance case.

- **PG&E 2011 ERRA Compliance A.12-02-010:** Application seeks recovery of costs recorded in PG&E's Renewables Portfolio Standard memorandum account for 2011.

- **SCE 2010 ERRA Compliance A.11-04-001:** In this application, the Commission is reviewing procurement-related operations during 2010, as well as other memorandum accounts for reasonableness and for compliance with Commission decisions and tariffs.

  Requested Recovery: *$25.6 million which is associated with recovering costs recorded in three memorandum accounts.*

- **SCE 2011 ERRA Compliance A.12-04-001:** Application seeks recovery of costs recorded in various memorandum accounts for 2011.

  Requested Recovery: *Reduction of $26.8 million***.**

- **SDG&E 2010 ERRA Compliance Application A.11-06-003:** SDG&E seeks recovery of revenue requirement associated with fuel and purchased power costs as well as balances in various memorandum accounts.

  Requested Recovery: *$2.2 million.*

➢ **SB 695 Residential Rate Change**

- General: Advice Letters to be filed in November, 2012 to propose annual increase in residential Tiers 1 and 2 rates with corresponding decrease in Tiers 3 and 4 rates, as allowed under SB 695.

Recently Decided or Pending Cases

➢ **PG&E**

- **Silicon Valley Technology Center A.10-11-002:** Application seeks approval to support a photovoltaic manufacturing development facility in San Jose, California. The ALJ issued a PD denying this application on February 7, 2012, and an Alternate PD was issued on the same date approving this application and a revenue requirement of $16.9 million.

  Requested Recovery: $35.6 million.

- **Modifications to the SmartMeter Program A.11-03-014:** PG&E filed this application in response to a directive from Commission President Peevey to prepare a proposal for Commission consideration that would allow opt-out by residential customers who object to having an advanced, digital meter that communicates using radio frequency signals. D.12-02-014 adopted an advanced meter opt-out provision along with procedures and interim fees for customers who choose to opt-out and use analog meters. It also determined that a second phase in this proceeding would be necessary to consider cost and cost allocation issues for providing the analog meter opt-out option.

  Estimated Recovery: $113 million.

- **Diablo Canyon Seismic Studies Costs, A.11-01-014:** Request to spend $64 million on seismic studies.

- **California Solar Initiative, D.11-12-019:** Approved 2012 CSI revenue requirement for PG&E of $120 million (increase of $15 million) is pending next regularly scheduled electric and gas rates changes. The 2013 CSI revenue requirement of $85 million will be reflected in rates in early 2013.

- **SCE**
  - **California Solar Initiative, D.11-12-019:** Approved 2012 CSI revenue requirement of $110 million, unchanged from 2011, and 2013 revenue requirement of $74 million, which will reduce rates by $36 million.

- **SDG&E**
  - **Rim Rock Tax Equity, A.10-07-017:** SDG&E filed an application for approval of a tax equity investment in the NaturEner Montana Wind Energy 3 (Rim Rock) in order to take advantage of Federal Production Tax Credits and produce more economic contract terms for ratepayers. D.11-07-002 approved a settlement in the case. The associated revenue requirement will take effect when the Rim Rock project is put into commercial operation, anticipated to be late 2012.

    Requested Recovery: *$21.9 million annual revenue requirement.*

Other Rate-Related Utility Requests Expected Later This Year

- **PG&E**
  - **Energy Efficiency 2013-2014 Bridge Funding:** to be filed in April, 2012.
  - **Annual Electric True-Up (AET) 2013:** Advice Letter to be filed late this year; to adjust for balancing account over-/under-collections and the effects of other decisions.

- **SDG&E**
  - **Non-fuel generation balancing account update Advice Letter**
  - **Electric Regulatory Account Update Advice letter**
  - **Electric Consolidated Advice Letter**

III. Program Specific Proceedings and Activities

Chapter Overview

The CPUC implements a wide array of energy policies in accordance with the Energy Action Plan (EAP), various statutes and California's energy policy initiatives. The CPUC continually strives to improve the efficacy of these programs by making sure the programs are cost-effective and are efficiently managed by the utilities. In some cases, programs may not be cost-effective in the short run, but may be cost-effective in the longer-term if they spur market development and innovation that bring down ratepayer costs and achieve the State's public purpose and environmental goals over time.

This chapter discusses the following CPUC programs and initiatives:

Supply-Side Initiatives:
- Long-term Procurement and Resource Adequacy
- Renewable Portfolio Standard

Demand-Side Initiatives:
- Energy Efficiency
- Demand Response
- Time-Variant Pricing
- Customer-Sited Distributed Generation and California Solar Initiative
- CARE and Energy Savings Assistance Program

Resource Adequacy and Long Term Procurement

Program Summary

The Resource Adequacy (RA) program is a CPUC planning and procurement program to secure sufficient commitments from actual, physical resources to ensure system reliability. The CPUC adopted a System and Local RA policy framework in 2004 in order to ensure the reliability of electric service in California.[3] The CPUC currently has RA jurisdiction over three investor owned utilities (IOU), twelve energy service providers (ESPs), and one community choice aggregator (CCA), which collectively are known as Load Serving Entities (LSEs). Each LSE's year ahead RA requirement is calculated using their California Energy Commission (CEC) forecast load by month, plus a reserve margin of 15%, for a total of 115% of forecast load. R.11-10-032 is the current CPUC proceeding implementing and improving the RA program.

In addition, the CPUC administers a Long Term Procurement Proceeding (LTPP) which implements AB 57, passed in 2002.[4] Every two years, the CPUC initiates a proceeding to evaluate the system's need for new conventional resources and to serve as the "umbrella"

[3] Public Utilities Code Section 380.
[4] Public Utilities Code Section 454.5.

proceeding to consider all of the CPUC's EAP loading order policies and programs. The 2010 LTPP (R.10-05-006) is currently before the Commission for a final decision, and the 2012 LTPP (R.12-03-014) began in March 2012.

Proceedings & Activities Over the Next 12 Months That Will Impact Revenue Requirements or Rates

Current proceedings at the CPUC are unlikely to increase or decrease rates in the near term. Although the RA and LTPP programs have the effect of stabilizing and hedging energy prices by requiring sufficient capacity construction and bilateral contracts for that capacity, it is difficult to quantify the overall rate impacts of these hedges. These programs hedge against the danger of added emergency costs related to lost productivity during system emergencies and emergency resource procurement. Specific proceedings and other processes are not expected to have positive or negative rate impacts within the next 12 calendar months.

Several proceedings within the next 12 months in this program area have the potential to affect future ratepayer costs, either by raising or lowering the required level of reserves, or by authorizing new generation to meet system reliability requirements. There are also continuing policy developments such as State Water Resource Control Board regulations related to the use of "once through cooling" (OTC). In addition, the gradual expiration of the Department of Water Resources' energy contracts may have rate impacts beyond the next 12 months. The combined effects of Long Term Procurement and RA policies as well as other changes to California's energy market are not expected to change rates within the next 12 months, but could result in future rate increases. Such rate increases, however, may reduce costs in the future, as aging infrastructure is replaced with new, more effective and less polluting electricity infrastructure.

Long Term Procurement and RA Market Structure

The CPUC ensures that the IOUs have adequate capacity and energy to serve their customers' electricity needs reliably and at reasonable cost. The CPUC analyzes IOU plans for developing preferred resources, evaluates current resources and the prospect of retirements and compares the overall supply to the CEC's demand forecast over the next ten years. If need exceeds forecast supply and preferred resources cannot meet the requirements, the CPUC authorizes the IOUs to hold an auction for the right to build new generation. IOUs develop projects that benefit all LSEs in the CAISO controlled system. Since contracting authority is based on forecasts of need, retirements, and construction schedules, at any specific time the amount of infrastructure may exceed current demand, but this excess is needed to allow the retirement of generators that may be inefficient and/or environmentally harmful.

Procurement of capacity and energy is currently accomplished mostly through direct contracting between the LSEs and generators (bilateral contracting). Scheduling coordinators (often the LSEs) then bid resources (both energy and ancillary services) into the CAISO markets. The significant variation in contract prices results from different energy and capacity values that depend on location, ability to respond quickly to system needs, vintage of the plant, and market competitiveness.

Construction of New Generation via the LTPP program

The LTPP program requires IOUs to assume the task of constructing generation apart from their other procurement activities (RPS, DR, and EE) to meet projected infrastructure needs in their service territories. The IOUs submit AB 57 bundled procurement plans, based on the LTPP, which includes procurement limits, procurement products and processes, rules, and risk mitigation strategies. Added cost for the construction of these new resources is examined carefully before Commission approval.[5] The pending 2010 LTPP decision in R.10-05-006 finds no clear evidence of need for new generation infrastructure for system reliability needs through 2020, although many issues including reliability needs associated with variability in renewable generation were deferred to the 2012 LTPP proceeding (R.12-03-014). Two major new natural gas fueled generators are expected to begin operation in 2012, Mariposa and GWF Tracy, both in PG&E's service territory. In addition, the Walnut Creek plant in SCE's territory, as well as several other facilities in state, are scheduled to come online in 2013-2014.

Variability of Intermittent Resources

A major element expected to drive costs of the RA program is the variability of intermittent resources. Wind and solar resources only produce electricity when the sun shines or the wind blows, while load constantly changes. It is difficult to accurately predict the amount of energy that will be delivered by intermittent resources during times of peak demand as well as short-term operational changes in demand. Therefore, in order to ensure reliability, other resources need to be procured and ready to perform based on these two factors. Customers pay for these resources even if they only operate for a limited amount of time. As intermittent resources increase to meet renewables goals, the resources required for renewable integration may also increase. Continued improvements in energy forecasting, both for load and renewable energy, should ultimately lower RA costs. The CPUC is an active participant in both the California Independent System Operator's (CAISO) and the CEC's stakeholder processes related to these efforts.

Impacts of Once Through Cooling Mitigation Regulations Promulgated by SWRCB

In 2010, the State Water Resources Control Board (SWRCB) adopted rules to phase out the use of Once Through Cooling (OTC) at existing generating facilities. These facilities comprise over 30% of the total generating capacity in California, and are located primarily in the Los Angeles Basin, the Greater Bay Area, and San Diego. The majority of the units that use OTC are critical resources that are typically located in transmission-constrained areas. In view of this, the OTC mitigation plan presents unique problems of reliability, jurisdiction, air quality restrictions, and coordinated planning.

OTC mitigation, particularly in the Los Angeles Basin, is likely to be quite expensive, as current CAISO studies indicate that approximately 2,500 MW of OTC generation needs to be brought into compliance with the policy. Mitigation will be done via a variety of approaches,

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[5] AB 57, enacted in 2002 and codified as PU Code Section 454.5, requires that "upfront and achievable criteria by which the acceptability and eligibility of rate recovery for a proposed procurement transaction will be known by the electrical corporation prior to the execution of the bilateral contract for the transaction."

such as transmission improvements, construction of new units, replacement of cooling systems on existing units, increased distributed generation, and demand side alternatives (e.g. energy efficiency and demand response). Rate impacts from these mitigation measures will be spread over several years as large infrastructure investments come online and existing facilities are retired. A significant number of the OTC plants were built in the 1960s and 1970s and would need to be replaced regardless of the OTC policy. Replacement costs will likely be reflected in rates closer to the actual SWRCB compliance dates at the end of this decade.

Trends Beyond the 12 Month Reporting Period

Significant new infrastructure development is possible beyond the next twelve months as reliability concerns associated with variable resources become better understood. Changes to the RA program to incorporate a need for additional flexibility and dispatchability could increase procurement costs while other trends such as decreased energy revenues for generation could decrease procurement costs. Beyond this 12 month period, the rate impacts of the Tracy and Mariposa plants will be better understood.

Renewables Portfolio Standard Program

Program Summary

Established in 2002 under Senate Bill 1078, accelerated in 2006 under Senate Bill 107 and expanded in 2011 under Senate Bill 2, California's Renewables Portfolio Standard (RPS) is one of the most ambitious renewable energy standards in the country. The RPS program requires IOUs, ESPs, publically owned utilities (POUs), and CCAs to increase retail sales from eligible renewable energy resources to 33% of total procurement by 2020. The CPUC and the California Energy Commission are jointly responsible for implementing the RPS program. The CPUC will continue to minimize the cost associated with increased procurement of renewable energy through the following measures discussed below.

Cost Minimization

The RPS statute requires utilities to select renewable resources that are least cost, including the direct costs of renewable energy generation and any indirect costs due to integration of the resource and needed transmission investment. In addition, utilities are required to consider renewable resources that best fit their system needs.[6]

The RPS program is structured to minimize ratepayer costs. First, it sets up a technology-neutral, competitive renewable procurement process where obligated entities select energy products that meet their needs for the lowest cost. The CPUC then reviews RPS contract prices based on bid supply curves, least-cost best-fit analysis, consistency with each IOU Commission-approved RPS Procurement Plan, and additional data as needed. Bilateral contracting is also allowed under the program, but the Commission has emphasized that competitive solicitations are preferred in order to encourage greater price competition. Second,

[6] Least-cost best-fit criteria were determined in D.04-07-029.

long-term fixed-price renewables contracts provide a hedging benefit for ratepayers against price volatility in the natural gas markets.

System-Side Distributed Generation

The CPUC regulates distributed generation (DG) policies and programs on both the customer (retail) and utility (wholesale) side of the electric meter. On the utility side of the meter, utilities procure "wholesale" or "system-side" DG resources through a variety of procurement programs, including the Renewable Auction Mechanism (RAM), the Feed-in-Tariff (FiT), and utility solar photovoltaic programs.

The RAM is a simplified, market-based procurement mechanism for renewable DG projects up to 20 MW in size on the system-side of the meter. RAM offers a streamlined procurement process with a cumulative program capacity of 1,000 MW over four auctions.

The FiT program offers standard tariffs and contracts for the purchase of eligible renewable generation from projects less than 1.5 MW. SB 32 (2009) and SB 2 (2011) recently amended the FiT program, to revise the pricing mechanism and increase project size to 3 MW, but those changes have yet to be implemented by the CPUC. The FiT program has a cumulative available capacity of 750 MW.

Additionally, the Commission authorized IOUs to own and operate solar photovoltaic (PV) facilities as Utility Owned Generation (UOG) as well as to execute solar PV power purchase agreements (PPAs) with independent power producers (IPP) through a competitive solicitation process. The total program capacity for these IOU solar PV programs is 1,100 MW over the next five years.

Proceedings & Activities Over the Next 12 Months That Will Impact Revenue Requirements or Rates

Proceeding R.11-05-005 continues implementation and administration of the California RPS.

- **Review of IOUs' Bid Selection Criteria and Methodology and Implementation of RPS Procurement Standards of Review:** The maturation of the California renewables market has resulted in an increase in the number of experienced developers submitting viable renewable energy projects at increasingly competitive prices. Wind and solar PV are the most cost competitive resources being bid. In addition, the IOUs have made significant progress in contracting for RPS-eligible generation. As a result of the more robust and competitive RPS market and the IOUs' diminishing need for RPS-eligible generation, the CPUC is considering modifications to the RPS program to ensure that any additional RPS procurement is done at the lowest cost to ratepayers.
- Specifically, the CPUC will consider modifications to the following program features: the IOUs' least-cost, best-fit bid selection processes; improving reporting requirements for projects that are both in the evaluation process and previously approved by the CPUC; standardizing review of RPS procurement contracts; and streamlining CPUC's contract approval process. These reforms should result in lower costs to ratepayers by maximizing the cost-effectiveness of IOU procurement consistent with RPS procurement objectives.

- **Use of Sales Contracts**: It is possible that the IOUs have contracted for more renewable energy than they need to meet their RPS requirements. By selling the excess contracted renewable generation the IOUs could potentially lower costs to ratepayers. The CPUC will work with parties to implement an efficient review and approval process of contract sales to make sure that ratepayer costs are lowered to the extent feasible.

Plans to Improve the Program's Efficacy and Cost/Benefit Ratios

- **Renewable Distributed Generation Cost-Minimization:** In order to minimize the costs of renewable DG RPS procurement programs, the Commission granted in part SCE's and SD&E's respective petitions for modification[7] to merge their solar PV programs into the Renewable Auction Mechanism (RAM). The IOU solar PV programs were restricted to one technology (solar PV). SCE's program targeted small rooftop projects (1-2 MW) and SDG&E's program targeted small ground-mount (1-5 MW) projects. The RAM program maximizes competition for renewable DG resources by allowing all RPS-eligible technologies to participate and by not restricting the program to small project sizes (RAM is available for projects up to 20 MW). The IOU's held the first RAM solicitation in November 2011 and received very competitively priced proposals. The two decisions which grant in part the petitions for modification retain each IOU's total program capacity target, but move those megawatts into the RAM program, thereby expanding the scope of RAM to include all RPS-eligible technologies up to 20 MW in size. By merging utility solar PV programs into RAM, the CPUC is attempting to minimize ratepayer expenditures on renewable DG.

- **Cost Containment:** The CPUC will implement a new cost containment mechanism as mandated by passage of SB 2 (1X) in 2011 which establishes new guidelines for renewable energy procurement in California. SB 2 (1X) requires that the CPUC establish a limitation for each electrical corporation on the procurement expenditures of all eligible renewable energy resources used to comply with the RPS program. In establishing this limitation SB 2 (1X) mandates that the CPUC rely on the following assumptions: (1) the most recent renewable energy procurement plan, (2) procurement expenditures that approximate the expected cost of building, owning, and operating eligible renewable energy resources, and (3) the potential that some planned resource additions may be delayed or cancelled. The CPUC is currently developing a cost containment mechanism that incorporates these statutory parameters.

Energy Efficiency

Program Summary

The CPUC has a decades-long history of policy support for ratepayer investment in cost-effective energy efficiency resources. This policy directs IOUs to first satisfy their "unmet resource needs through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible."[8] By law, the utilities' energy efficiency portfolios must

[7] D.12-02-002 and D.12-02-035 respectively.
[8] PUC Code Sec 454.5(b)(9)(C).

be cost-effective and program expenditures must be just and reasonable. In addition, the CPUC is required to "identify all potentially achievable cost-effective electricity and natural gas energy efficiency savings" and set targets for the IOUs to achieve that potential.[9] In 2003, the EAP further established energy efficiency as the priority resource for meeting California's energy needs in the future.

How is Cost-Effectiveness Determined for Energy Efficiency?
In estimating the cost-effectiveness of energy efficiency programs, we compare the actual costs of those programs (e.g., administration and equipment costs) with the avoided costs of providing the energy that would have been needed in the program's absence.[10] The avoided cost estimates also encompass the deferral or avoidance of transmission – and distribution – related costs such as GHG emissions and (beginning with the 2013-2014 portfolio) the reduced need for Renewable Portfolio Standard (RPS) compliance resources.[11]

The Total Resource Cost (TRC) and Program Administrator Cost (PAC) cost-effectiveness tests are used to determine the cost-effectiveness of the energy efficiency portfolio and are described in the California Standard Practice Manual.[12] Energy efficiency portfolios as a whole must have a TRC benefit cost ratio greater than one (i.e. the net benefit must be positive).

Prior to each energy efficiency portfolio cycle, the CPUC develops a portfolio guidance document based on broad stakeholder input. The utilities develop draft portfolios based on this guidance, and the CPUC reviews these portfolios and adopts final versions for IOU implementation. The CPUC then oversees the implementation and evaluation of the IOUs' energy efficiency programs.

Cost-effective energy efficiency programs decrease customers' overall bills due to reduced energy consumption. The energy savings more than pay for the cost of the programs. The following provides a discussion of activities and proceedings underway during and beyond the 12 month reporting period that will affect rates. Actual rate and bill impacts resulting from these activities will be better understood after the utilities' 2013-14 energy efficiency portfolios are adopted later this year.

Strategic Plan

In 2007, the CPUC directed the IOUs to develop a long-term strategic plan to achieve "all cost-effective energy efficiency potential."[13] The *California Long-Term Energy Efficiency Strategic*

[9] PUC Code Sec 454.55.
[10] The term "avoided costs" refers to the incremental costs avoided by energy efficiency programs when the resulting decrease in demand for electric or gas services defers or avoids generation from existing or new utility supply-side investments or energy purchases in the market.
[11] The energy efficiency avoided costs methodology was adopted in D.05-04-024, and updated in D.06-06-063 and D.09-09-047.
[12] http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF.
[13] D.07-10-032, available at http://docs.cpuc.ca.gov/published/Final_decision/74107.htm.

Plan,[14] adopted in 2008,[15] set forth a roadmap for energy efficiency in California through 2020 and beyond. The Strategic Plan supports the CPUC's goal of moving beyond programs that create near-term energy savings into market transformation-focused programs that achieve comprehensive and sustainable cost-effective energy efficiency over the long-term. Most importantly, the Strategic Plan sets forth the roadmap for achieving the state's aggressive energy efficiency goals and incorporates a "new approach that transcends regulatory, programmatic and jurisdictional constraints" in order to leverage the IOUs' program activities and maximize cost-effectiveness of ratepayer investments.[16]

AB 758

In 2009, the Legislature passed AB 758[17] which requires the CEC to develop and implement a program to achieve greater energy savings in California's existing residential and non-residential building stock. The program is to be comprised of a complementary portfolio of techniques, applications, practices, and strategies, which include:

- Energy assessments,
- Building benchmarking,
- Building energy use ratings and labels,
- Cost-effective energy efficiency improvements,
- Public and private sector energy efficiency financing,
- Public outreach and education, and
- Green workforce training.

In developing and implementing the AB 758 program, the Energy Commission will coordinate with the CPUC and consult with: (1) local governments, (2) the construction, finance, and real estate industries, (3) the utilities, (4) workforce development entities, and (5) small businesses and other industries.[18]

Proceedings & Activities Over the Next 12 Months That Will Impact Revenue Requirements or Rates

To better align program design with the strategic plan and AB 758 goals for more robust and long lasting savings, the CPUC directed the utilities to reorient their portfolios, beginning with the 2013-14 "Transition Portfolio," to target deeper energy savings and promote market transformation.[19] Some key directions the CPUC provided to the utilities to guide program design for the Transition Portfolio (and beyond)[20] include:

- **Untapped Energy Savings Potential:** A study coordinated by the Energy Division to develop the goals for the 2013-2014 portfolios found that a number of measures which accounted for a significant portion of the savings from past IOU portfolios are reaching their potential as the market becomes saturated with these products and many measures are

[14] Available at http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/eesp/.
[15] D.08-09-040, available at http://docs.cpuc.ca.gov/published/FINAL_DECISION/91068.htm.
[16] D.07-10-032, available at http://docs.cpuc.ca.gov/published/Final_decision/74107.htm.
[17] PUC Code Sec 381.2 and 385.2.
[18] California Energy Commission at http://www.energy.ca.gov/ab758/.
[19] ACR 2013-2014 Scoping Memo, available at http://docs.cpuc.ca.gov/efile/RULC/146158.pdf.
[20] CPUC R.09-11-014 Proposed Decision available at: http://docs.cpuc.ca.gov/efile/PD/162141.pdf.

adopted into codes and standards. To expand the savings potential for future cycles, the utilities are directed to:

1. Develop a variety of market transformation focused programs that will improve the uptake and cost-effectiveness of the Energy Upgrade California program, which is focused on retrofitting existing residential buildings;

2. Improve their planning and development of a "diversified portfolio" approach to their emerging technologies activities; and

3. Pilot incentive programs designed to achieve higher code compliance in targeted areas with high savings potential and chronically low compliance rates.

- **Improving Energy Efficiency Finance:** As required by statute, utilities' energy efficiency portfolios must be cost-effective, delivering energy savings benefits in excess of their costs to ratepayers. The CPUC recognizes the limited ability of ratepayers to continue funding such programs, especially in view of the state's aggressive carbon reduction and energy efficiency goals. By engaging stakeholders, the Energy Division is now exploring mechanisms to leverage ratepayer funding with potential private financing to broaden the reach and affordability of energy efficiency measures for residential and commercial customers.

- **Expansion of Local Government and Third Party Program Delivery:** D.05-01-055 directed the utilities to bid a portion of their statewide portfolios to third party implementers and initiate partnerships with local governments. In view of the progress made in this area after two portfolio cycles, the CPUC supports the continuation of this strategy for the 2013-2014 portfolio cycle. Furthermore, looking at 2015 and beyond, the Commission will place a greater emphasis on third party opportunities to help achieve the state's energy efficiency objectives while delivering greater value to ratepayers.

- **Consolidation and Simplification of Programs:** The utilities are instructed to exclude several existing statewide programs from their Transition Portfolio, and instead incorporate them into other existing programs. The utilities are encouraged to make further program cuts, using a "best bang-for-the-buck" screening process.

Plans to Improve the Program's Efficacy and Cost/Benefit Ratios

The CPUC's Energy Division and Division of Water and Audits perform financial, management and regulatory compliance audits of the IOUs' energy efficiency portfolios. These audits have identified the need for additional portfolio improvements. In addition, the Energy Division oversees a comprehensive suite of evaluations of the portfolio activities. These evaluations identify improvements in design and implementation of the programs to improve their efficacy and cost-effectiveness.

In the 2013-2014 portfolio cycle, the Energy Division will work with the utilities to incorporate findings from these audits and evaluations into transition portfolio implementation activities. Further, findings from these audits and the organizational assessment will inform post-transition portfolio design.

Demand Response

Program Summary

Demand Response (DR) is the ability of a customer to reduce their peak load (or shift usage to a different time of the day) in response to a price signal, an emergency alert or an incentive payment. The intent of conventional DR programs is to reduce demand during peak hours (e.g. 2 pm to 6 pm during summer months) when it is expensive for utilities to provide electricity. DR benefits ratepayers in that it enables utilities to avoid building expensive new electric generating capacity (such as peak power plants) that are used for only a small percentage of the hours in a year. Avoiding new generation capacity also avoids the relatively high greenhouse gas emissions from those peaker plants.

DR also lowers wholesale power costs because reduced demand forces power suppliers to adjust their prices downward in the energy markets, and it can prevent rolling blackouts by providing additional reductions in demand when the grid is strained. DR ranks at the top of the Commission's "loading order," next to energy efficiency. The IOUs operate a suite of DR programs and have contracts with third-party DR providers (also known as aggregators). In total, the IOUs have approximately 2,200 MWs of DR, which is slightly more than the capacity of four large power plants.

Since 2002, the Commission has been developing and refining its DR policies, and in 2004 it began authorizing many ratepayer-funded programs. Between 2006 and 2008, the Commission began authorizing the IOUs to deploy smart meter systems. Smart meters measure electricity usage in hourly increments and are necessary for customers to participate in DR programs or time-variant rates. By the end of 2012, all customers of PG&E, SCE and SDG&E are scheduled to have a smart meter. As addressed in more depth elsewhere in this report, the Commission has also emphasized time-variant pricing and dynamic rates as another key mechanism for advancing DR in California.

Proceedings & Activities Over the Next 12 Months That Will Impact Revenue Requirements or Rates

- **A.11-03-001:** In March 2011, the utilities submitted three-year (2012-2014) DR program and budget proposals totaling approximately $1 billion for the Commission's consideration. The program proposals include incentive programs that offer bill credits to customers who participate in DR programs, rebate incentives to help offset the cost of enabling DR technologies, as well as marketing and education programs that will test how DR programs could be used to integrate intermittent renewable resources into the grid. The Commission approved a final decision detailing the utilities' proposed programs and budgets in April 2012. <u>The decision authorized three-year budgets of approximately $192 million for PG&E, $196 million for SCE, and $66 million for SDG&E.</u>
- **R.07-01-041, Phase 4:** This rulemaking is establishing policies and rules that will govern the direct participation or bidding of DR into wholesale energy markets by end-use customers and third-party DR operators.

- **New DR Rulemaking:** Conventional DR has focused exclusively on reducing peak demand. That purpose remains an important feature of the Commission's DR policy. However, DR could play a new role in California's energy landscape. Specifically, the State's mandate to obtain 33% renewable power by 2020 is anticipated to bring new operational challenges for grid reliability and efficiency because of the intermittent nature of renewable power. DR resources could provide critical 'ramping' capability that the CAISO could use to ensure that renewable power is successfully integrated into the grid. The Commission will be developing policies that address this need in a demand response rulemaking in the next 12 months.

Plans to Improve the Program's Efficacy and Cost/Benefit Ratios

- **Measuring Cost-Effectiveness:** In D.10-12-024, the Commission adopted a protocol that estimates the cost-effectiveness of DR programs. The Commission used the protocol for the first time in evaluating the utilities' 2012-2014 DR budget applications (A.11-03-001). The protocol enables the Commission to ensure that all programs within the portfolio are cost-effective (and thus beneficial to ratepayers) through a reduction in program costs or a re-design of the program to expand its benefits. The Commission approved a Decision in April 2012 which applied a version of the cost effectiveness protocol that resulted in elimination of one program, budget cuts to several others, and program design changes to increase program benefits to ratepayers.
- **Align Demand Response Programs with Resource Adequacy Values:** The Commission sets the Resource Adequacy (RA) requirements for each IOU as well as other load serving entities within the IOUs' territories. DR programs are counted in the RA framework as net Qualifying Capacity, which reduces the utilities' short-term capacity procurement obligations. However, DR programs historically have not been completely aligned with all RA rules and requirements. This misalignment results in a proration of the DR programs' net Qualifying Capacity which in turn leads to the utility being obligated to procure an additional amount of capacity to compensate for the prorated amount. To address this inefficiency, the Commission has directed the utilities to design their 2012-2014 DR programs with requirements that are aligned with various RA requirements. For example, all supply resources that seek eligibility for local RA credit must be locally dispatchable. The utilities' 2012-2014 DR programs will be examined by the Commission to ensure they have the same capability.
- **Approve Rules and Policies for DR Direct Participation:** In 2010, the CAISO implemented a new market product called "Proxy Demand Response" or PDR, which would allow DR to be bid into wholesale energy markets in competition against supply side resources (generators). The utilities have already been directed by the Commission to enhance their procurement processes so that their DR programs can be used as bids in PDR. The active bidding of DR into wholesale energy markets could be a potential benefit to ratepayers if it results in lowering the wholesale market clearing price of energy supply.

  Additionally, the Commission is now developing policies and rules by which third-party DR operators and end-use customers can bid their DR capacity directly into wholesale markets. Enabling third-party DR operators to participate directly with wholesale markets could reduce the need for continuing the ratepayer-funded contracts between these entities and the utilities.

- **Ensure Enrollment Cap on Emergency DR programs:** Of the 2,200 MWs in the utilities' DR portfolios, about 1,400 MWs are categorized as "emergency" DR programs. These are legacy programs that have been in existence for several decades, and are rarely used as they are designed to respond to emergency situations such as avoiding a rotating outage. The emergency programs are very expensive to maintain because the participants (large commercial and industrial customers) are paid substantial 'standby' or capacity payments to be ready to curtail their load when called upon by the utility.

  In 2010, the Commission determined that the utilities are oversubscribed with emergency DR and have since ordered the utilities to cap enrollment in these programs starting in 2012, with further reductions occurring in 2013 and 2014. Additionally, the Commission directed the utilities to modify and integrate their emergency DR programs into wholesale energy markets through a new CAISO market product designed for this purpose. These changes reduce costs for ratepayers in two significant ways: (1) by enabling the CAISO to recognize emergency programs as a RA resource for the first time, thereby avoiding the procurement of duplicative capacity through the RA program; and, (2) by eliminating the current overcapacity and simultaneously transition participants to DR programs, allowing them to actively participate in wholesale energy markets and/or to time-varying rates.

Time-Variant Pricing

Program Summary

Time-Variant Pricing (TVP) rate schedules price electricity at higher rates during peak and partial peak periods to encourage customers to shift their energy demand to off-peak times when electricity is less costly. TVP includes time-of-use (TOU) rates, critical peak pricing (CPP), and real-time pricing (RTP), but does not include DR programs that provide customers with rebates and incentives to reduce consumption at certain event-specific times, including peak time rebates.[21] CPP and RTP are also dynamic rates in which rates can be adjusted on short notice (typically a day or hour ahead) as a function of system conditions.

The cost of producing electricity varies throughout the year and throughout the day. TVP helps shift load away from the peak demand period and lowers a utility's costs, because peak demand determines how much generation, transmission, and distribution capacity must be available. Shifting energy consumption can help reduce the number of new generating facilities required. Ratepayers can benefit from TVP by shifting their load to off-peak times and using less energy in response to price signals. TVP offers many of the same benefits as DR (see previous discussion), but also encourages longer-term behavioral changes encouraging energy efficiency, load shifting, and conservation.

California's TOU rates typically charge customers time-varying and sometimes season-varying rates. Rates vary by time of day with peak, partial-peak, and off-peak rate components. TOU rates are predictable, whereas CPP rates have a dynamic attribute.

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[21] Though Peak Time Rebate (PTR) is not by definition a dynamic rate program, it is discussed in this section because PTR is being litigated as part of the consolidated PG&E Default Residential Rate Program (DRRP Proceeding A.10-08-005).

For residential customers, TOU and CPP rates are optional and largely under subscribed. SB 695 prohibits the IOUs from defaulting residential customers to time-variant rates until 2013 with bill protection and 2014 without bill protection. The IOUs are transitioning residential customers to default TOU and CPP subject to resolution of pending proceedings and legal resolution of SB 695 provisions.

Large Commercial and Industrial (C&I) customers have default TOU and CPP rates dating back several years. Small and medium business and agriculture customers are transitioning to default TOU and CPP rates on different timelines according to each IOU rate schedule.

California's CPP programs provide participating customers with lower rates during non-CPP summer season hours and higher rates during CPP periods when a "critical peak pricing" event is called usually with 24-hours' notice through a variety of notification channels. These "dynamic" pricing rates are designed to encourage price-responsive demand reductions during critical periods. Customers benefit from lower rates for electricity use outside of the CPP periods. Customers may also be eligible for bill protection for an initial period, such as 12 months.

Summary Table: Status of TOU and CPP Rate Implementation

	PG&E		SCE		SDG&E	
RATE CLASS	**TOU**	**CPP**	**TOU**	**CPP**	**TOU**	**CPP**
Residential	Optional	Optional	Optional Oct 2012	Optional Oct 2012	Optional Mar 2013	Optional Mar 2013
Small Commercial & Ag (< 20 kW)	N/A	N/A	N/A	N/A	Optional Mar 2013, Default March 2014, Can still opt out to flat rates	Optional Mar 2013
Small & Medium Commercial (< 200 kW)	Optional Now, Default Nov 2012 - Flat rates no longer avail.	Optional Now, Default Nov 2014 - Can opt out to another TOU rate.	Proposed Mandatory Oct 2012	Optional CPP and CPP-Lite	Mandatory	Default Mar 2013 can opt out of CPP
Large Commercial, Industrial & Ag (>200 kw)	Default May 2010 - Flat rates no longer avail.	Default May 2010 - Can opt out to another TOU rate.	Mandatory Oct 2009	Default Oct 2009 can opt out of CPP	Mandatory	Default Oct 2008 can opt out of CPP
Small & Medium Agriculture (<= 200 kW)	Optional Now, Default March 2013 - Flat rates no longer avail.	Optional	Proposed Mandatory Oct 2012	Optional CPP and CPP-Lite	Mandatory	Default Mar 2013 can opt out of CPP
Large Agriculture (> 200 kW)	Default Feb 2011 - Flat rates no longer avail.	Default Feb 2011 - Can opt out to another TOU rate.	Proposed Mandatory Oct 2012	Optional CPP with CRL	Mandatory	Default Oct 2008 can opt out of CPP

What is Peak Day Pricing?
Peak Day Pricing (PDP) is a Time-Varying Pricing plan offered by PG&E that combines a time-of-use pricing plan with Peak Day Pricing Event Day surcharges and summer credits. The time-of-use portion of this plan offers lower daily prices during periods when electric demand is low and higher prices when demand is high. When paired with Peak Day Pricing, customers will experience between 9 and 15 Peak Day Pricing Event Days annually in addition to time-of-use pricing. When non-residential customers default to PDP, flat rates will no longer be available, but they may opt out to another time variant rate that does not include Peak Day Pricing Event Days.

Proceedings & Activities Over the Next 12 Months That Will Impact Revenue Requirements or Rates

The primary activities that will affect TVP rates over the next 12 months include the following:

- Proceedings to determine the rate design and implementation schedule of residential TVP rates for all three IOUs;
- Proceedings to determine the legal authority of CPUC to require default residential TVP rates consistent with provisions of SB 695.
- Proceedings to determine the IOUs' Transition to Default Time of Use (TOU) Rates and default or opt-in Critical Peak Pricing (CPP) rates and timelines for Small and Medium Non-Residential Customers. All IOUs have pending applications for transitioning small and medium business and agriculture to default TOU rates in the 2012-2014 time-frame.

- **PG&E Default Residential Rate Program (DRRP Proceeding A.10-08-005):** involves PG&E's proposal for CPP together with TOU rates, which PG&E calls Peak Day Pricing (PDP) rates, as the default residential rate. Before deciding on this proposal the Commission will hear legal briefs from parties on whether the PDP rate design contravenes SB 695 rate provisions, including Public Utilities Codes Sections 739.9 and 745(d). At issue is whether the CPUC can authorize PG&E to adopt default TVP rates for all customer usage or only for usage in excess of 130 percent of baseline (Tiers 1 & 2). This question will affect pending residential TVP rate design proposals of SCE and SDG&E.

- **PG&E Proposal for a Peak Time Rebate Program (2010 Rate Design Window Proceeding A.10-02-028 is consolidated with the DRRP Proceeding above)** – PG&E submitted its proposal to implement two-part residential Peak Time Rebate (PTR) for all eligible customers starting May 1, 2013, pursuant to D.09-03-026. Under PG&E's proposal, customers without enabling technology would qualify for rebates of $0.75 per kWh for demand reductions during PTR event hours (up to 15 event days per year). Enrolled customers with enabling technology could receive rebates of $1.25 per kWh. PTR represents a risk-free incentive for residential customers to save money if they reduce demand during PTR event days. PG&E has asked the Commission for permission to cancel PTR and instead adopt voluntary opt-in CPP for residential customers. While customers who enroll in CPP would have bill protection for the first year, an enrolled CPP customer could experience a rate increase if they do not reduce demand during CPP event days.

- **PG&E Transition to Default PDP for SMB & Small Ag Customers (A.09-02-022):** D.10-02-32 approved PG&E's mandatory default to PDP for Small Agriculture and SMB customers, and approved $30.78 million for PG&E's outreach and education activities, which are intended to prepare customers for the new rates. A staff report found that despite being directed in February 2010 to prepare SMB customers for the transition to default PDP rates previously scheduled for November 2011, PG&E made little effort to reach customers and prepare them for the rate change. PG&E's inability to act contributed to the delay of the default, which is now scheduled for November 2012. The Commission is closely monitoring PG&E's efforts to prepare these customers for the transition using prescribed metrics.
- **SDG&E Application for Approval of its Proposals for Dynamic Pricing A.10-07-009:** Under the terms of a settlement, which is currently being considered, the timing of dynamic rates is staggered so that optional Time of Day (TOD) rates become available in 2013, along with optional PeakShift at Home (PSH) and PeakShift at Work (PSW)[22] for residential and small non-residential customers. Default TOD rates for small non-residential customers become effective in 2014, but these customers can opt out to flat rates. All other non-residential customers have been on mandatory TOD rates for many years and they will default to PSW in 2013 with the ability to opt out of PSW.
- **SDG&E 2012 GRC Phase 2 A.11-10-002:** SDG&E filed the rate design phase of its GRC on October 1, 2011 to allocate authorized costs to customer classes and then to design the rates within each class. In response to the assigned commissioner's ruling of January 18, 2012, SDG&E resubmitted its application with the exclusion of a proposed Network Use Charge.
- **SCE Application for Approval of its Proposals for Dynamic Pricing A.11-06-007:** Under SCE's GRC Phase II proposal, which is currently being considered by the Commission, the timing of dynamic rates is staggered so that optional TOU and optional CPP rates become available to residential customers in October 2012, along with mandatory TOU rates for small and medium non-residential customers in October 2012. All other non-residential customers have been on mandatory TOU rates for many years and they have had access to optional CPP as well.

Plans to Improve the Program's Efficacy and Cost/Benefit Ratios

The Commission's dynamic pricing principles seek to increase customer involvement in (a) managing California's energy supply in real time, (b) reducing greenhouse gas emissions, and (c) managing California's future power plant development costs by providing real economic incentives to reduce electric demand during peak periods.[23]

[22] SDG&E's TOU rate is called Time of Day (TOD), and its CPP rates PeakShift at Work (PSW) for non-residential and PeakShift at Home (PSH) for residential customers.
[23] Decision 10-02-032 February 25, 2010.

- **Statewide Load-Impact Evaluation of TOU/CPP in California:** By the summer of 2010, all three IOUs had defaulted 15,000 C&I customers (peak demand > 200kW) onto a CPP tariff layered over a time-of-use (TOU) rate. Approximately 7,100 of those customers remained on CPP by the end of 2010. IOUs conducted a statewide annual ex-post CPP load reduction impact study which revealed positive load reductions from non-residential customers in 2010:
    - PG&E: 23 MW reduction, or 3.9% of reference load
    - SCE: 30.7 MW reduction, or 2.8% of reference load
    - SDG&E: 18.8 MW reduction, or 5.3% of reference load

  Despite the experience with defaulting large customers onto CPP, uncertainty remains for the future transition of small and/or medium C&I customers. By the end of 2012, an additional 220,000 medium and 1,000,000 small non-residential accounts are scheduled to default onto CPP in IOU territories. The degree of uncertainty is largest for SMB customers. To date, there is limited factual data on what works and what doesn't in helping SMB customers migrate to default dynamic pricing simply because there is little precedent for such a shift among these customers. Furthermore, there is little empirical data on the share of customers that will try out CPP if defaulted, how customers will react and the extent to which they will reduce load under default CPP or choose to opt out to TOU. It is still early on in the process of evaluating the efficacy of CPP, but each year the IOUs are required to furnish a statewide load-impact evaluation report. Some of the research questions for subsequent load impact analyses will include:
    - Research to improve load responsiveness among customers defaulted onto CPP;
    - Research to determine the price responsiveness of customers with enabling technology; and
    - Increasing efforts to enhance customer understanding of how they can shift or reduce loads, in addition to promoting general awareness of the rate transition.

Trends Beyond the 12 Month Reporting Period

It is anticipated that the Commission will be paying close attention to the utilities' implementation of time-variant pricing rates in 2012-2013. Customer education will be critical to customer acceptance of these new rates. Additionally, the integration between TVP and other demand-side resources, such as energy efficiency, is likely to increase in 2012-2013. This means that customers will soon be provided more education and marketing materials designed to simultaneously provide all demand-side options for the customer to consider.

- **Tiered Rates and Time-Varying Rates:** If default time varying rates have tiers, requiring Tiers 1 and 2 to conform to rate increase limitations of SB 695 legislation would make effective implementation very challenging. Combining flat Tier 1 and 2 rates with TVP rates would likely compromise the goals of TVP, because there would be no cost-based price signal for Tier 1 and 2 usage. During a peak TOU period a customer might not know what rate would apply, and the customer may not know whether their efforts to shift or reduce load out of peak period would result in a bill savings or not.

  When customers have the choice between inclining block pricing (tiered rates) and non-tiered TOU rates, self-selection bias will make rate design very challenging. Low consumption customers that remain in Tier 1 and 2 usage pay below average rates and would be unlikely to shift to non-tiered TOU rates which would more closely reflect average rates. High consumption customers in the higher tier usage would likely switch in large numbers to TOU rates because they would pay less. This would further exacerbate the rate differential between the lower and upper tiers.

Customer-Sited Distributed Generation and California Solar Initiative

Program Summary

The CPUC's Energy Division's Customer Generation Programs section administers the Self-Generation Incentive Program (SGIP) and the California Solar Initiative (CSI).[24] Together these two key distributed generation (DG) programs foster development of renewables, and emerging and highly efficient technologies on the *customer side* of the electric meter. Utility-side, or "wholesale" DG programs, including the Renewable Auction Mechanism (RAM), the Feed-in-Tariff (FiT), and utility solar photovoltaic programs, are discussed elsewhere in this report.

California's Energy Action Plan ranks renewable energy number two in the state's loading order[25], and Governor Brown has set a statewide goal of developing 12,000 MW of local renewable energy by 2020.

The Self Generation Incentive Program

Established in 2001, The Self Generation Incentive Program (SGIP) provides incentives to support existing, new, and emerging distributed energy resources installed on the customer's side of the utility meter (excluding solar technologies, which are incentivized under the California Solar Initiative.) Qualifying technologies include wind turbines, waste heat to power technologies, pressure reduction turbines, internal combustion engines, microturbines, gas turbines, fuel cells, and advanced energy storage systems. With 441 completed projects for a total capacity of 227 megawatts, the SGIP is one of the longest-running and most successful DG incentive programs in the country. In 2010 alone, these facilities provided over 680,000 MWh of electricity to California, enough electricity to meet the needs of over 100,000 homes. With another 111 projects under development for an additional 79 megawatts of capacity, SGIP continues to make strides towards a cleaner, distributed-energy future.

The California Solar Initiative

Established in 2006 by SB 1 (Murray), the California Solar Initiative offers solar incentives to non-residential and residential[26] customers in investor-owned utility territories of PG&E, SCE,

[24] CPUC Rulemaking (R.) 10-05-004 oversees the SGIP and CSI programs.
[25] Final Energy Action Plan II, Implementation Roadmap for Energy Policies, September 21, 2005, available at http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF.
[26] Residential CSI incentives are limited to existing housing stock; solar incentives for new residential construction fall under the New Solar Homes Partnership, managed by the California Energy Commission. The program was previously funded by the Public Goods Charge which expired at the end of 2011.

SDG&E and SoCalGas. The CSI Program will stimulate the installation of 1,940 MW of distributed solar generation by 2017. The CSI Program is comprised of five distinct program components: General Market Program, Single-family Affordable Solar Homes (SASH) Program, Multi-family Affordable Solar Housing (MASH) Program, Research, Deployment and Demonstration (RD&D) Program, and CSI-Thermal Program.[27] The Commission also has jurisdiction over Pacific Power's Northern California service territory, and in 2011 granted approval of the Pacific Power California Solar Incentive Program's $4.2 million revenue requirement. New home construction and solar programs within POUs are not under the CPUC's jurisdiction.

The CSI incentives are designed to encourage high-performing systems and are paid in two ways: (1) the Expected Performance-Based Buydown (EPBB) incentive, an up-front rebate ($/Watt) paid to smaller systems; and (2) Performance-Based Incentive (PBI) payment streams, paid over 60 months ($/kWh) according to actual metered production. All incentives decline in steps as solar capacity grows within the program.

As a market transformation policy, a critical goal of CSI is to drive down the cost of solar. The cost of solar has declined 20 percent from 2007.[28] Through the first quarter of 2012, the CSI program has installed 757 MW at over 66,000 sites throughout California's IOU service territories.[29] The CSI helped to support the growth of a multibillion dollar solar industry that has created more than 25,000 jobs in California.[30]

The CSI-Thermal program is the newest CSI program component. It provides rebates for solar water heating and other solar thermal technologies that offset either electric or natural gas systems. Established in D.10-01-022, the $530.8 million program features residential, commercial/multi-family and low-income sub-components. On April 16, 2012, the program launched a $5 million public relations campaign designed to increase awareness of solar water heating technologies and the rebates are available through a web portal called www.WaterHeatedByTheSun.com which links customers to the appropriate utility web site.

Program Budgets

Pursuant to AB 1150, the Commission has authorized annual collections for SGIP through December 31, 2014 at a rate of $83 million, to be allocated among the four large IOUs according to each utility's relative percentage of utility customers. Any unspent funds will be refunded to ratepayers in 2016. Funds are distributed on a first-come basis to qualified projects.

SB 1 (Murray, 2006) established a CSI Program budget of $2.167 billion. Subsequent CPUC Decisions established budgets for the CSI program sub-components: SASH and MASH were each allocated $108.3 million, and the RD&D program was allocated $50 million. In 2010, CPUC staff noted that several unforeseen factors had impacted the original budget, resulting in a forecast shortfall of $260 million. The CPUC shifted $40 million from the Program

[27] For more information on the five CSI Program components, please visit http://www.cpuc.ca.gov/PUC/energy/Solar/.
[28] Source: http://californiasolarstatistics.ca.gov/reports/quarterly_cost_per_watt/. Data as of 2/15/12.
[29] Includes CSI data for IOU territories only. Statewide CSI data includes 1,164 MW at 111,890 sites.
[30] *National Solar Jobs Census 2011: A Review of the U.S. Solar Workforce*, Solar Foundation, 2011.

Administration budget, $20 million from the CSI Measurement and Evaluation budget, and $20 million in unallocated funding to augment the incentives.[31] SB 585, which passed in 2011, allocated an additional $200 million to the CSI Program budget. The bill also requires the CPUC to use accumulated interest from customer collections prior to collecting additional ratepayer funds.

In 2007, AB 1470 (Stats. 2007, Ch. 536) established the CSI-Thermal program budget of $350.8 million, from which $250 million was collected through gas rates and $100.8 million through electric rates.

Net Energy Metering

Net Energy Metering (NEM) is a tariff that allows a customer-generator to receive a billing credit for power generated by their onsite system. The credit is used to offset the customer's electricity bill at fully bundled retail rates. NEM is an important element of the policy framework supporting direct customer investment in grid-tied distributed renewable energy generation, including customer-sited solar PV systems. The NEM program is currently capped at 5% of utility system peak load (known as the NEM "cap").[32]

In its cost-effectiveness study of the NEM program in March 2010, the CPUC found that the net cost to ratepayers in 2008 (for all NEM systems interconnected as of 2008) was $20 million per year.[33] All ratepayers pay for NEM program costs in the form of billing credits, administrative costs, and interconnection costs, and all ratepayers receive some benefit from the NEM program in the form of avoided capacity and avoided RPS purchases.

However, the CPUC also found that the net cost of the NEM program is largely driven by the electricity rate design of the participating NEM customer-generator. A NEM customer-generator's billing credits are equal to the value of the electricity they would have purchased from the IOU had the electricity not been generated onsite.

The Current and Potential Future Rate Impacts of NEM

It is important to note that NEM costs for installations through 2008 total approximately 0.08% of total utility revenues on an annual basis. Given an overall average rate of $0.144 per kWh, this implies an average rate impact of $0.00011 per kWh is necessary to cover NEM costs.[34] While the cost of NEM is currently small compared to utility revenues, the cost of NEM will grow as the number of customers on NEM tariffs continues to grow. If the total installed capacity of NEM solar generation reached 2,550 MW of solar capacity by 2017, the total cost of the program would be $137 million per year (in 2008 dollars). This is approximately 0.38%

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[31] D.10-09-046.

[32] The statutory definition of the NEM cap is the point where "total rated generating capacity used by eligible [NEM] customer-generators exceeds 5 percent of the electric utility's aggregate customer peak demand." Public Utilities Code Section 2827(c)(1).

[33] Net Energy Metering Cost-Effectiveness Evaluation ("NEM Cost-Effectiveness Evaluation") (March 2010). http://www.cpuc.ca.gov/PUC/energy/DistGen/nem_eval.htm.

[34] Ibid.

of projected IOU revenues in 2020, which would imply an average rate increase of $0.00064 per kWh.[35]

Virtual Net Metering

Until recently, the benefits of distributed generation and NEM were limited to property owners, leaving utility customers who rent without a mechanism to receive any direct benefits. Metering requirements pursuant to Public Utilities Code Section 780.5[36] further precluded those in multi-tenant buildings from DG benefits because the costs and complexities associated with installing a separate system for each meter were prohibitive. To create a means of distributing the benefits of DG to as many ratepayers as possible, the Commission adopted a pilot tariff in the MASH program called Virtual Net Energy Metering (VNM). This unique utility billing arrangement allows the output of a single DG system, sized to offset an entire building's multi-meter load, to be allocated as bill credits among multiple tenant meters on a property in the same fashion as NEM. In addition to expanding customer access to DG programs and providing direct tenant benefits, the VNM arrangement encourages installation of larger systems, which represent a lower marginal cost to ratepayers.[37]

Net Surplus Compensation

The CSI program requires DG systems to be sized to offset customer's on-site load; however, there are some customers who generate more energy than they consume on an annual basis. In 2011, in response to AB 920 (Huffman, 2009) the Commission adopted a Net Surplus Compensation (NSC) rate to compensate NEM customers for electricity they produce in excess of their on-site load at the end of a 12-month true-up period.

The NSC rate strikes a balance between system owners receiving compensation and ratepayers who pay these costs. Specifically, the NSC rate is calculated using an avoided cost derived from an hourly day-ahead electricity market price known as the "default load aggregation point" (DLAP) price, which is significantly lower than the full retail rate under the NEM tariff. A utility's DLAP price reflects the costs the utility avoids in procuring power during the time period net surplus generators are likely to produce their excess power.

Proceedings & Activities Over the Next 12 Months That Will Impact Revenue Requirements or Rates

- **Expansion of Scope of Eligible Technologies for NEM**
  SB 489 (2011, Wolk) expanded the scope of eligible generation technologies for the NEM program to include all technologies eligible under the California RPS. Previously NEM was limited mainly to solar and small wind technologies and to date 99+ percent of all NEM applications have come from solar projects. Expansion of NEM program eligibility is

[35] Ibid.
[36] Public Utilities Code Section 780.5 required individual utility metering in multi-unit residential buildings that received building permits after July 1, 1982.
[37] The CPUC analyzed the net cost of the NEM program to ratepayers in March 2010, and found that commercial customer-generators cost comparatively less per kWh of exported generation than do residential customer-generators.

likely to accelerate the advance toward the 5% NEM cap, which could increase pressure on the Legislature to raise it.

- **Expansion of VNM to General Market Multi-Meter Multi-Tenant Properties**
  In 2011, D.11-07-031 expanded VNM beyond the affordable multi-family housing sector and directed the utilities to file tariffs for the general market VNM. Energy Division issued a draft resolution to the advice letters and expects Commission approval within the second quarter 2012. Expansion of VNM will accelerate penetration of NEM toward the 5% cap. Viewing the 5% NEM cap as fixed, ratepayers will incur lower costs when a greater proportion of the megawatts installed within that cap are from larger systems. Furthermore, VNM allows a much greater cross-section of ratepayers to receive the benefits of DG and NEM by extending such opportunities to occupants in multi-metered properties.

- **Proposed Decision Regarding Calculation of the Net Energy Metering Cap**
  The "Net Energy Metering cap," as established in Public Utilities Code Section 2827(c)(1), limits the availability of electric utility NEM programs to eligible customer-generators in the utility service territory on a first-come-first-served basis until the total rated generating capacity used by eligible customer-generators exceeds five percent of the utility's "aggregate customer peak demand." This proposed decision clarifies the denominator of the equation, defined in the statute as "aggregate customer peak demand," that the IOUs should use to calculate the five percent NEM cap. By this decision, the Commission clarifies that "aggregate customer peak demand" means the aggregation, or sum, of individual customers' peak demands, i.e., their non-coincident peak demands. This proposed decision does not change CPUC policy - rather it clarifies how existing policy should be implemented.

- **NEM Cost-Benefit Evaluation Study**
  Public Utilities Code 2827 (c)(4) requires the CPUC to "submit a report to the Governor and the Legislature on the costs and benefits of net energy metering." The CPUC 2010 NEM study evaluated the total net costs to ratepayers from solar customers participating in solar NEM tariffs. Since the 2010 NEM Evaluation, the number of participating NEM customers has increased from 40,000 to over 100,000 customers. Several recent policy and legislative changes will likely have a significant impact on NEM participation levels. The CPUC issued an RFP for a 2012 study designed to: 1) reevaluate the expanded NEM program based on current available data, 2) estimate any cost shifts between participants and non-participating customers, and 3) to provide guidance to the CPUC as they consider further changes to net metering policies.

Plans to Improve the Program's Efficacy and Cost/Benefit Ratios

In 2011, Energy Division staff, in coordination with CSI Program administrators and stakeholders, identified numerous opportunities to improve the program's efficacy and cost-effectiveness. The proposed CSI program modifications were organized by priority level, with the Phase 1 approved by the Commission in D.11-07-031. Staff continues to work with stakeholders on other issues related to the CSI Program, and expects Commission approval in 2012. Key streamlining measures underway include simplification of the application process, which will reduce administrative time while still maintaining effective oversight.

The SGIP program imposed a $5 million per project cap in an effort to distribute the benefits of SGIP among more programs. This has no impact on the program budget or rates since the amount of the SGIP budget is fixed through 2014.

Trends Beyond the 12 Month Reporting Period

The SGIP program was expanded in September 2011, to broaden the scope of eligible technologies. To maximize efficient use of ratepayer funds, projects are now paid based on a hybrid performance-based-incentive structure: 50% of the incentive is given at project completion and 50% is paid based on kWh generated over the first five years of operation. This less prescriptive and more performance-based approach aims to support emerging technologies which show potential for improved performance in the future but are already commercially viable today. Noteworthy is the increased participation of advanced energy storage applications, which went from a small minority of installations to the most prolific technology class in SGIP.

CPUC staff has proposed a series of recommendations to adjust and streamline the program as it develops over time. The proposals were initially presented in a 2010 Ruling[38] and identified as Phase 2 and 3 issues, to be addressed in 2012. Issues include NEM billing costs and billing simplification; NEM calculation methodology;[39] administrative funding issues; reporting requirements, including Measurement and Evaluation issues; SASH cost recovery; SASH/MASH megawatt goals; warranty requirements; workforce development benefits and PPAs for SASH. An update to the CPUC NEM cost benefit study will be conducted in 2012.

The popularity of CSI has caused some parts of the state to reach the prescribed megawatt goals more quickly than originally anticipated. For example, the residential solar sectors in SDG&E and PG&E territories are in the tenth and last incentive step, with four more years left in the program and no apparent decrease in application volume. While state rebates and federal tax incentives continue to play a role in solar's economic viability, new financing models are emerging that drive sustained demand for solar. Program Administrators are discussing ways to reduce administrative costs and streamline processes as the program reaches its final steps, and to provide optimal market support for continuing solar customers.

CARE and Energy Savings Assistance Program

Program Summary

The Commission has two low income assistance programs: the California Alternate Rates for Energy (CARE) and the Energy Savings Assistance Program (ESAP) (formerly known as Low Income Energy Efficiency or LIEE). The purpose of these programs is to act as an energy resource, providing energy savings, while improving the welfare of California's low-income population, by subsidizing and managing energy efficiency improvements for both rented and owned low-income residences. Both programs provide significant relief in reducing the

[38] ALJ Ruling July 26, 2010, http://docs.cpuc.ca.gov/EFILE/RULINGS/121092.htm.
[39] Due to the complexities related to this topic, NEM calculation methodology will be addressed in a separate decision from other Phase 2/3 issues.

hardships of low income families across California. The programs' benefits include: increased education and awareness of energy efficiency and environmental issues among low-income customers; increased health, comfort, and safety; and greater workforce education and training opportunities within the developing green economy. According to KEMA's Low Income Needs Assessment 2007 report,[40] one in three California households or approximately 4.1 million of the 12.53 million households in California qualify for low income programs.

CARE is a low-income energy rate assistance program instituted in 1989 to provide eligible low-income households with a 20% discount on electric and natural gas bills. However, since CARE customers are not subject to the higher rates for tiers 4 and 5, the effective discount for CARE can reach above 20% as tiers 3, 4 and 5 rates have risen over time while tiers 1 and 2 were frozen from 2001-2009 per AB 1X. In addition, the following features apply under the provisions of SB 695 (Kehoe, 2009):

- Rates for CARE participants are limited to no more than three tiers;
- CARE rates can be no higher than a maximum of 80% of the Tier 1, Tier 2, and Tier 3 rates charged to non-CARE customers; and
- Tier 1 and 2 CARE rates can increase by the annual percentage increase in benefits under the CalWORKS program, but not more than 3%.

The net effect of SB 695 has resulted in modest increases in CARE rates since 2009.

For the 2009-2011 program cycle the Commission adopted a total CARE budget of $2.6 billion, funded by ratepayers through the Public Purpose Program (PPP) Charge.

CARE Program Goals & Accomplishments

- Achieve higher penetration rates over time without substantially increasing the CARE outreach budget.
- Increase enrollment efficiencies by streamlining screening, eligibility, and retention.
- Enrollments as of December 2011:

IOU	Participants Enrolled	Eligible Participants	Penetration rate
PG&E	1,532,692	1,699,660	90.2%
SCE	1,437,537	1,451,325	99%
SoCalGas	1,716,495	1,847,296	92.9%
SDG&E	308,596	362,551	85.1%

CARE Program Challenges

- Achieving 100% CARE penetration among eligible customers may be unattainable. It is estimated that 10% of all low income households would be unwilling or unlikely to

[40] *Final Report on Phase 2 Low Income Needs Assessment*, CPUC, 2007.

participate in CARE. Targeting and reaching this last 10% is incrementally expensive for several reasons:

  - The difficulty of identifying and reaching certain customers;
  - Customers with a low energy burden may not benefit from the program; and/or
  - Some customers are unwilling or unlikely to participate.

- Per CARE program rules, a small proportion of enrolled customers must "re-apply" every two to four years to the CARE program to maintain eligibility. Recertification rates have been low, and the CPUC and IOUs are investigating ways to improve the rate.

- The magnitude of the CARE discount conflicts with the state's energy efficiency goals. Customers in the higher tiers may receive up to a 50% CARE discount, which lessens their incentive to reduce consumption.

Energy Savings Assistance Program (ESAP) began in the 1980s as a direct assistance program provided by some IOUs, and was formally adopted by the Legislature in 1990.[41] Formerly known as the Low Income Energy Efficiency Program or LIEE, ESAP is a resource program designed to garner significant energy savings in California while providing an improved quality of life for the low income population. Participants include single family, multi-family, and non-profit group living customers. The program provides home weatherization services for low-income households and includes the following types of measures: (1) heating, ventilation, and air conditioning; (2) infiltration and space conditioning; (3) weatherization; (4) water heating conservation; (5) energy education; and (6) other miscellaneous measures including refrigerator replacements and lighting measures. The program may also include installation of energy efficient appliances. The IOUs' portfolio of measures is evaluated for cost-effectiveness during the budget application process and all available cost effective measures are provided at no cost to the low income resident. However in tenant occupied homes, a co-payment is required by the landlord for some of the more expensive measures. Installing such measures help customers reduce energy consumption, resulting in bill savings for program participants. For the 2009-2011 program cycle the Commission adopted a total ESAP budget of $869 million funded by ratepayers through the Public Purpose Program (PPP) Charge.

Energy Savings Assistance Program Goals & Accomplishments

The Low Income Energy Efficiency Strategic Plan Vision[42] states that by 2020, 100 percent of eligible and willing customers will have received all cost-effective low income energy efficiency measures. The Strategic Plan goals include:

- By 2020, all eligible customers will be given the opportunity to participate in ESAP;

- ESAP will be an energy resource by delivering increasingly cost-effective and longer-term savings.

ESAP reached over 300,000 low-income California homes in 2011.

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[41] Public Utilities Code Section 2790.
[42] With the change in name from LIEE to ESAP, all references to LIEE are changed to ESAP.

ESAP Challenges

- Striking the right balance between achieving cost-effective energy savings versus providing health, comfort, and safety benefits (i.e., beyond cost-effective savings measures) to participants;
- Fully leveraging and integrating the ESA Program with other utility core energy efficiency programs and other State, Federal and local programs to streamline and improve program delivery and achieve maximum energy efficiency savings for the state;
- Providing the right level of education to all participants about the benefits of energy efficiency that fosters long term conservation behaviors.

Proceedings & Activities Over the Next 12 Months That Will Impact Revenue Requirements or Rates

For the 2012-2014 program cycle, the IOUs have proposed the following budgets and goals:

Funding Requests by Utility for FY 2012-2014

Energy Savings Assistance Program					
	2011	**2012**	**2013**	**2014**	**2012-2014 Total**
PGE	$156,789,038	$138,000,000	$167,500,000	$173,400,000	$478,900,000
SCE	$63,414,000	$57,700,000	$64,500,000	$63,000,000	$185,200,000
SoCalGas	$67,184,000	$99,910,000	$82,120,000	$84,180,000	$266,210,000
SDG&E	$20,250,000	$22,040,000	$22,460,000	$22,830,000	$67,330,000
	307,637,038	$317,652,012	$336,582,013	$343,412,014	$997,640,000
CARE Program Admin.					
	2011	**2012**	**2013**	**2014**	**2012-2014 Total**
PGE	$9,521,000	$12,081,000	$11,287,000	$11,650,000	$35,018,000
SCE	$5,485,000	$5,351,000	$5,465,000	$5,622,000	$16,438,000
SoCalGas	$6,587,988	$7,990,000	$7,750,000	$7,860,000	$23,600,000
SDG&E	$3,144,517	$3,730,000	$3,950,000	$3,970,000	$11,650,000
	24,738,505	$29,154,012	$28,454,013	$29,104,014	$86,706,000
CARE Program Subsidies and Benefits					
	2011	**2012**	**2013**	**2014**	**2012-2014 Total**
PGE	$479,707,435	$660,220,000	$633,029,000	$605,950,000	$1,899,199,000
SCE	$211,400,000	$330,200,000	$376,900,000	$416,800,000	$1,123,900,000
SoCalGas	$135,901,649	$128,773,189	$129,892,840	$131,142,177	$389,808,206
SDG&E	$48,231,658	$73,857,625	$82,630,988	$83,614,933	$240,103,546
	875,240,742	$1,193,050,814	$1,222,452,828	$1,237,507,110	$3,653,010,752
Projected Homes Treated					
	2011	**2012**	**2013**	**2014**	**2012-2014 Total**
PGE	110,000	110,000	132,500	132,500	375,000
SCE	73,800	68,200	77,000	74,800	220,000
SoCalGas	125,000	129,106	100,249	100,249	329,604

SDG&E	20,000	20,000	20,000	20,000	60,000
	328,800	327,306	329,749	327,549	984,604

- The 2009-2011 program cycle budget was authorized in D.08-11-031 at $2.6 billion for CARE and $885 million for the Energy Savings Assistance Program with the expected average yearly benefits of 81,266 MWh; 22.3 MW; and 5.3 million therms.

- The PD authorizing the 2012-2014 program cycle budgets is scheduled to be issued in April 2012.

Plans to Improve the Program's Efficacy and Cost/Benefit Ratio

D.08-11-031 adopted budgets and policies for the existing ESAP and CARE programs. The Commission, in the pending Decision to authorize the 2012-2014 program cycle budgets, will adopt new goals, initiatives, and improvements to the program to encourage and facilitate greater program efficiencies, collaboration and overall benefits to the low income population. The implementation of these efforts continues to be central to the Commission's activities over the next 12 months, and beyond. These major initiatives include the following:

- Focused ESAP outreach to customers with high energy use or high energy burden and insecurity due to high bills. Reaching those customers in greatest need first;
- Streamlined program rules to detect ineligible participants to ensure that only those that qualify for the program remain in the program;
- Enhanced outreach to disabled customers who comprise approximately up to 20% of the low-income population;
- Improved outreach to those living in multifamily buildings to better serve this population;
- Increased ESAP measures' cost effectiveness; and,
- Targeted promotion of relevant workforce education and training.

Trends Beyond the 12 Month Reporting Period

The IOUs have submitted applications for a 2012-2014 planning cycle which is currently under Commission review. These initiatives will yield greater efficiencies, collaborations and overall benefits to the low income population as well as the rest of the state. Current programs are operating under bridge year funding.

IV. Natural Gas Rates and Costs

Chapter Overview

Due to falling natural gas prices, customers of natural gas utilities continue to experience low natural gas costs. In fact, total utility gas costs were 17% lower in 2011 than in 2007. However, the CPUC does not regulate the price of natural gas. The CPUC authorizes the revenue requirements for the natural gas distribution utilities primarily in the areas of natural gas transmission, distribution, storage, and customer service costs and natural gas public purpose program (PPP) costs. The continuing low commodity price of natural gas is the result of developments in the natural gas market, which is influenced by both national and global market conditions.

Natural gas utility rates in California consist of three main components for typical "core"[43] gas ratepayers:

- Procurement rate, which recovers the cost of procurement of the natural gas itself,
- Transportation rate, which recovers the cost to the utility of delivering natural gas and providing various customer services, and
- Gas PPP surcharge, which recovers the cost of various programs such as the CARE discount, natural gas energy efficiency programs, and natural gas research and development.

Larger volume gas customers, called "noncore" customers, such as industrial and electric generation (EG) customers, typically procure their own gas supply and don't pay a procurement rate to the utility. In addition, electric generation customers are exempt from the gas PPP surcharge.

Total approved natural gas utility costs for transmission, distribution, storage and customer service have moderately increased (by approximately 9%) since 2007. However, there are significant differences between customer classes and utilities in the changes in rates over that time period. For example, the average natural gas transportation rate for PG&E residential customers increased by 25% while the average transportation rate for electric generation customers not directly served by PG&E's backbone transmission system increased by only 4%.

Approved gas PPP costs have increased by 59% during the 2007 to 2011 time period. Again, there are significant differences between customer classes and utilities in the change in the gas PPP rate over that time period. For example, the average residential PPP surcharge increased by 48% for SDG&E and SoCalGas, and by 115% for PG&E.[44]

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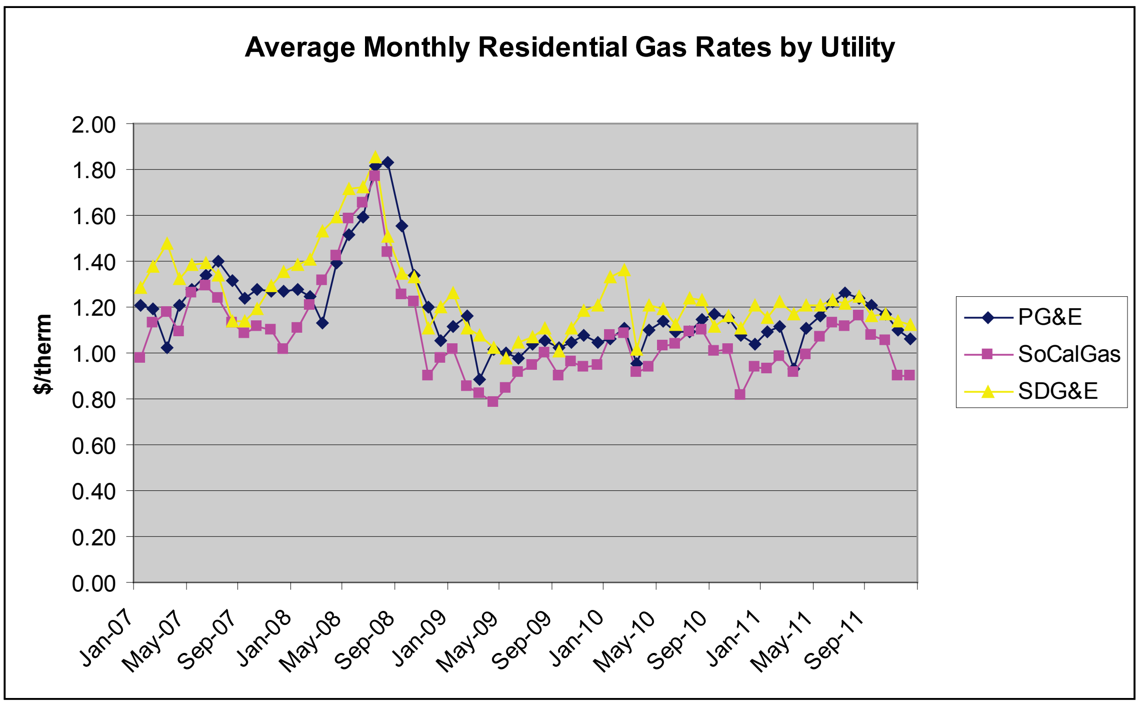
[43] Core customers are mainly residential and small commercial customers.
[44] From 2007 to 2011, gas PPP <u>costs</u> increased by 98% for PG&E, 34% for SoCalGas, and 66% for SDG&E. These cost increases have resulted in variations in the surcharges for these utilities.

Current Trends in Gas Rates

Total core natural gas rates on average remained low in 2011. As one can see in the tables presented by the CPUC in its April 2012 Gas and Electric Utility Cost Report, the natural gas procurement costs in 2011 were 40% lower than the procurement costs in 2007. As natural gas costs decreased substantially in the 2009-2011 period, so too did procurement rates. This decline in the procurement rate has caused the total core natural gas rate to remain at low levels, as shown in the graph below for residential gas rates. As of the date of this report, market indications of the futures price of natural gas price show that prices are expected to remain low over the next 12 months.

Almost all noncore customers procure their own gas supplies rather than have the utility procure gas supplies for them. Noncore transportation rates have increased in California since 2007. For example, the average transportation rate for PG&E industrial distribution customers increased by 12.6% by the end of 2011.



CPUC Actions to Limit Utility Cost and Rate Increases

In the coming year, the Commission will face the challenge of maintaining natural gas utility transportation rates at reasonable levels. Procurement costs are expected to remain at low levels, but our natural gas utilities have proposed large additional pipeline safety costs in addition to other operational costs, which amount to billions of dollars. These additional costs may increase the utilities' transportation rates in 2012 and future years.

Gas Utility Operational Costs and Rates

During the next 12 months, in order to ensure that utility revenue requirements and rates for transmission, distribution, storage, and customer services remain reasonable, the CPUC will evaluate these costs and rates in several major proceedings. The CPUC expects to examine natural gas rates and address issues that could affect costs, in the following proceedings:

Gas Utility Safety Rulemaking (R.11-02-019)

The CPUC issued this rulemaking in early 2011 in response to the San Bruno pipeline rupture "to establish a new model of natural gas pipeline safety regulation applicable to all California pipelines." The rulemaking will consider how the CPUC can align ratemaking policies, practices, and incentives to improve safety standards and risk management practices. In August 2011, PG&E, SoCalGas, SDG&E, and Southwest Gas filed their Gas Safety Implementation Plans to propose how they intend to ensure that their transmission pipeline systems are safe. <u>The utilities propose spending over $4 billion in the next 3-4 years in just the first phase of their plans, and propose that ratepayers pay for virtually all of these costs.</u>

PG&E estimates that its initial costs through 2014 will amount to $2.2 billion, and proposes that its shareholders pay for about $200 million of those costs. PG&E's proposal would result in a rate increase of 5.2 cents per therm for core customers, or an increase of approximately 11% in the average transportation rate for residential customers. Noncore customers potentially face an even larger percentage rate increase. Intervening parties have filed testimony, most of which strongly opposes allowing PG&E to recover all of these costs from ratepayers.

The Commission will be examining the proposed PG&E plan, associated costs, and ratemaking proposal related to these cost in 2012. As discussed below, the plans and ratemaking proposals for SoCalGas and SDG&E will be examined in A.11-11-002.

SoCalGas Storage Field Expansion (A.09-09-020)

SoCalGas is proposing to conduct work at its Aliso Canyon Storage Field, and estimates the cost to be $200.9 million. The project would result in a slight increase in core gas rates of 0.3 cents per therm. Increased storage capacity in California benefits ratepayers by providing a natural hedge against potential volatility in natural gas prices, and thus helps to manage the cost of service. SoCalGas requests approval of its revenue requirement and its proposed allocation of the project costs to various customer classes. An environmental impact report is being prepared, and the CPUC expects to determine if it should adopt SoCalGas's proposal in 2012.

SoCalGas and SDG&E 2012 General Rate Case (A.10-12-005 and A.10-12-006)

The CPUC will determine the revenue requirement in this proceeding for SoCalGas (excluding the cost of gas) and for SDG&E (excluding the cost of gas and electricity and electric transmission). SoCalGas estimates that, if its proposal is adopted, average transportation rates would increase by 12.5 % in 2012 compared to 2011. Core gas rates would increase by 5.8 cents per therm. Hearings in this proceeding are complete. The CPUC likely will not reach a decision in this proceeding until mid-2012.

SoCalGas Triennial Cost Allocation Proceeding (TCAP) A.11-11-002

In the SoCalGas/SDG&E TCAP, the approved gas revenue requirement for the two utilities is allocated to different customer classes, and rates are designed to allow the recovery of the allocated revenue requirement. Prior to the inclusion of the SoCalGas and SDG&E gas safety implementation plans in this proceeding, SoCalGas and SDG&E estimated that their proposals would result in a core transportation rate increase of about 3.4 cents per therm for SoCalGas residential customers, and 4.4 cents per therm for SDG&E residential customers.

As noted above, the Commission will also be examining the SoCalGas and SDG&E gas safety implementation plans in the TCAP. SoCalGas estimates that residential customers could face an additional average rate increase of about 5.4 cents per therm in 2012 if its plan is adopted by the Commission. This amounts to a 14% increase from the average residential transportation rate.

AB 32 Administrative Fee Recovery (A.10-08-002)

In August 2010, PG&E, SoCalGas, SDG&E and Southern California Edison, requested authorization to increase their electric and gas rates and charges to collect the revenue requirements associated with the costs of Air Resources Board Assembly Bill 32 implementation fees. The initially estimated annual gas revenue requirement for the three gas utilities amounted to about $9.6 million in 2010, but the three major utilities are now estimating the 2012 costs to be much higher. The Commission expects to issue a decision on this application in 2012.

SoCalGas Advanced Metering Infrastructure

In Decision 10-04-027, the Commission authorized SoCalGas to install advanced metering infrastructure for its customers, at a cost of $1.05 billion. The deployment period runs through 2017. This project increases SoCalGas's 2012 revenue requirement by $35 million. Rate payer impacts are not known and depend on whether SoCalGas's customers can leverage the AMI infrastructure to reduce costs.

Gas Public Purpose Programs

Gas Public Purpose Programs (PPP) costs have increased by 59% since 2007, due to large increases in the costs for all PPPs. In 2011, the costs of the gas related PPPs was about $596 million. Gas PPP costs have increased for several reasons: increases in Commission-approved energy efficiency portfolio budgets, along with a larger portion of the EE budgets being allocated to natural gas; increases in low-income energy efficiency budgets related to the goal of treating all eligible and willing customers; and, an increase in the number of CARE customers.

The state's natural gas utilities collect funds from core and non-EG noncore customers for gas related energy efficiency programs, low-income programs including the CARE subsidy, and for the California Energy Commission's (CEC) natural gas research and development (R&D) program. The annual budget of these public purpose programs are set in various recurring program-related Commission proceedings. These costs are collected by the utilities through the gas PPP surcharge that appears on customer gas bills.

The CPUC attempts to ensure that public purpose programs are conducted efficiently and provide the maximum benefits for which they are intended. For example, the CPUC staff will be investigating the costs of the natural gas research and development program in 2011. The other main components of the gas PPP surcharge, energy efficiency and CARE programs, are discussed in other sections of this report.

Procurement Costs

Although the Commission can not regulate the price of natural gas, it will continue to implement measures that:

- Provide incentives to utilities to keep natural gas procurement costs low, under adopted gas cost incentive mechanisms,
- Allow expeditious approval of a diverse and reasonably-priced portfolio of interstate pipeline capacity,
- Provides core customers with adequate amounts of natural gas storage capacity, and
- Allows utilities to engage in efficient natural gas hedging practices.

CPUC Advocacy for California Interests at FERC

The CPUC represents California gas interests at FERC Gas proceedings. In the last few years, CPUC intervention at the FERC has been primarily on interstate pipeline general rate cases. Interstate pipelines are regulated by the FERC and are thus outside of California's direct regulatory control. FERC oversees general rate cases (GRCs) for interstate pipeline companies. The main interstate pipeline companies supplying natural gas to California are El Paso Natural Gas (from New Mexico and Texas gas basins), Transwestern (from New Mexico and Texas gas basins), GTN (from Canadian gas basins), and Kern River (from Rocky Mountain gas basins).

In the next 12 months, the CPUC will continue to represent California interests in the current GRC for El Paso Natural Gas (EPNG). EPNG is the single largest interstate natural gas pipeline to California. This GRC has been ongoing since 2010. The CPUC also expects to participate in El Paso FERC proceedings in which El Paso has proposed reductions in pipeline capacity to California.

V. Conclusion

The CPUC has broad authority to effectively manage utility costs in an effort to protect California ratepayers while advancing other policy priorities across a wide range of energy programs and activities. We believe this report offers useful information about the spectrum of proceedings, as well as the regulatory mechanisms and tools at the CPUC's disposal for ensuring that utility revenue requirements are reasonable and allocated equitably. However, just as the CPUC must continue to refine its portfolio of strategies for addressing increasing utility costs, it must also seek to improve the way it reports these actions to the Governor and to the Legislature. Therefore, over the next 12 months, Energy Division will solicit comments on how this report can be enhanced in order to best meet the mandates of SB 695.

VI. Appendix

Utility Reports on Recommended Measures to Limit Costs and Rate Increases

A. Pacific Gas and Electric Company

1 Summary of Report and Recommendations to CPUC and Legislature to Reduce Utility Costs and Rates

Pursuant to the requirements of Public Utilities Code section 748(b), Pacific Gas and Electric Company (PG&E) appreciates the opportunity to provide its annual study and report to the California Public Utilities Commission (CPUC or Commission) on measures PG&E recommends be undertaken to limit costs and rate increases. This report provides data and forecasts related to PG&E's gas and electric revenue requirements and rates, and is structured to include PG&E's overall rate policies; a description of PG&E's current revenue requirements; a discussion of PG& E's management of its costs and rates; and a schedule of PG&E's filings that affect rates in 2012 and 2013 (in the Appendix).

In these tough economic times, PG&E knows how important it is for our customers to keep monthly electricity and gas costs to a minimum. In addition to mitigating cost pressures, within the framework for the allocation of costs and rate design mandated by the Legislature and the CPUC, PG&E seeks to equitably allocate costs among its customers based on energy usage and customer class. Crafting equitable allocation rules for revenue requirements across customer classes also poses challenges, largely due to rate designs mandated by law and the need to collect revenues to fund programs that benefit a specific set of customers which are paid for by non-participating customers.

The most immediate area of concern that should be evaluated over the next twelve months is the statutory mandate for tiered residential electric rate design. Residential customers are experiencing prices for usage in the highest tiers that are far in excess of cost of service and are the highest in the country compared of any large investor-owned utility. This inequity is due to legislative mandates set forth initially in Assembly Bill (AB) 1X enacted during the energy crisis in 2001, later modified in 2009 by Senate Bill (SB) 695 that limited increases to lower-tier rates. PG&E proposed numerous measures as part of Phase 2 of its 2011 GRC to reduce this inequity, but received Commission approval only for some of these proposals. Consequently, while some progress was made, upper-tier rates are still at excessive levels above the cost of providing service. Since significant tier-reform is currently limited by state law (SB 695), the limited ability of the Commission to consider significant adjustments to non-CARE Tier 1 and 2 rates will exacerbate the already very high and inequitable upper-tier residential electricity rates affecting millions of residential electricity consumers. To put upper-tier rate increases into context, usage in the lower two tiers accounts for about 72% of the total usage, meaning the remaining 28% of upper tier usage has to pay for most of the increased cost of residential electric service. This inequity is further widened by the fact that virtually no increase is being allocated to residential CARE rates, which have actually decreased on average compared to 1993. PG&E is currently supporting legislation that would provide the Commission the authority to approve a customer charge on residential customers to recover fixed costs of providing electric utility service if the Commission finds that the customer charge is reasonable and necessary to provide rate relief.

Another area of concern regarding impacts on electricity rates is the overall cost-shift associated with customer-owned generation, and particularly residential solar photovoltaic generation. The State's rate policies regarding Net Energy Metering (NEM) allows electricity customers with their own generation (primarily rooftop solar equipment) to reduce their billed usage by "spinning the meter backwards" (receiving full bundled rate credit for generation that is sent out to the grid to offset future consumption within the month and potentially in other months). In principle, this compensation for customer-owned generation should be fair and equitable. However, through the NEM rates, customers that install renewable on-site generation are compensated at rates that substantially exceed the market-based costs of generation that PG&E and non-participating customers save from not serving that marginal electricity usage. Independent of net metering, PG&E's distorted residential rate design, which relies almost exclusively on variable rates to recover fixed costs and charge variable rates for upper-tier usage far in excess of cost of service, magnifies the cost-shift impact and subsidies from other customers associated with customer-owned generation; further increasing the already high upper-tier residential rates for all customers. These high marginal rates, consequently, lead to distorted price signals to potential customer-owned generators, and perpetuate inequitable allocations associated with adoption of customer-owned generation. This inequity is exacerbated by the fact that solar adoption is positively correlated to income. Thus, high usage customers with lower-moderate incomes above the maximum level for CARE qualification are subject to increasingly higher upper-tier rates. As customer-owned generation technologies mature and adoption increases, the subsidy and cost-shifts provided by existing NEM and retail rate design must be reformed to sustainably accommodate that growth for the benefit of all customers.

PG&E understands that electricity and gas are a fundamental need and along with helping our customers save money, PG&E is mindful of the need for safe and reliable electric and gas service. In 2011, PG&E proposed a comprehensive natural gas Pipeline Safety Enhancement Plan that outlined steps we intend to take over the next several years to rigorously verify and upgrade the integrity of all of our nearly 6,000 miles of gas transmission pipelines to meet strict new statewide safety standards. The planned measures include:

- Strength testing all pipe segments that have not been previously strength tested (including those previously exempted by federal regulations), replacing segments that should be replaced, and retrofitting pipelines to allow internal inspections, or "pigging";
- Enhancing electronic monitoring of the gas system to identify operational issues and prevent or quickly locate pipeline ruptures;
- Expanding the use of automated valves to isolate and minimize damage if pipeline ruptures do occur; and
- Transitioning away from traditional paper records and consolidating all of its gas transmission pipeline data into an integrated electronic data management system to strengthen system operations, maintenance, inspections and regulatory compliance.

Furthermore, PG&E intends to focus on investments in safety improvements to its gas and electric distribution and generation operations and infrastructure in its 2014 GRC request

In order to manage utility costs and rate increases, PG&E has recommended modifications to certain aspects of CPUC energy procurement requirements, market structure, and statewide mandates. However, certain components of gas and electric rates are largely beyond the direct control of utilities, and instead result from policy or regulatory mandates. Among these regulatory mandates and requirements that are creating further cost pressures on PG&E's electric and gas costs and rates are the Renewable Portfolio Standards (RPS) program and greenhouse gas (GHG) emissions restrictions resulting from Assembly Bill (AB) 32. These legislative and regulatory mandates and policies are all well-intentioned and seek to achieve worthy overall goals. However, to the extent that the mandates and policies add costs to retail electricity and gas rates, or restrict the ability of PG&E and other utilities to manage or mitigate costs, then the Legislature and Commission should periodically review the mandates and policies to ensure that they appropriately balance the benefits to customers with the overall costs of implementation and compliance that customers pay in their monthly bills. To mitigate the impact of AB32 costs, PG&E, SCE, and SDG&E in the Greenhouse Gas OIR (R.11-03-012) have proposed to return the entire amount of allowance auction revenues directly to utility customers. Under this proposal, the primary goal of the cap-and-trade system of incorporating a carbon price signal will be achieved in wholesale electricity markets, where prices will reflect the cost of carbon and power purchasers will respond accordingly to those price signals. In addition, PG&E strongly supports the development of a clear, stable, and meaningful RPS procurement expenditure limitation in the ongoing Renewables Portfolio Standard OIR (R.11-05-005).

PG&E believes that review of these measures and issues can have a beneficial near-term impact on its total cost of delivering safe, reliable, and cost-effective gas and electric services to its customers.

2 Overall Rate Policy

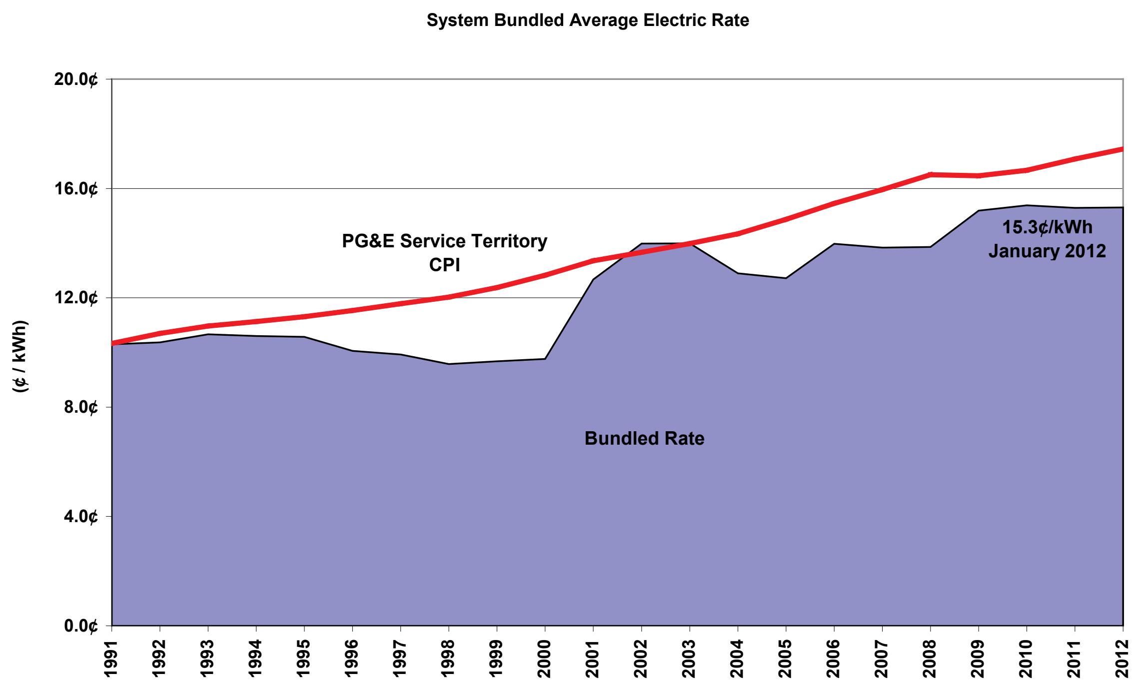
PG&E strives to provide its customers with reasonable rates for gas and electric service. PG&E's overall rate policy is to fully recover the costs of efficiently serving its customers, while considering cost-based pricing, equity within and among customer classes, and public policy objectives.

PG&E understands that its customers value transparency and stability in the rates they are charged for energy. Therefore, PG&E seeks to minimize the impact of rate adjustments made throughout the year. Generally, PG&E requests electric rate changes two to three times per calendar year (January and March, and sometimes in summer/fall). For gas rate changes, PG&E files monthly advice letter filings to change the gas commodity rate and seeks an annual gas transportation and public purpose program rate change. In addition, PG&E submits various filings to the CPUC throughout the year in response to specific Commission directives or changes to the utility business, to ensure that PG&E provides reliable and cost-effective service to its customers.

PG&E also undertakes efforts to manage the timing of revenue changes and subsequent rate changes. Over the past 20 years, PG&E has been successful at managing electric customer rate increases. As illustrated in Figure 2-1, PG&E's system-bundled average electric rate over the last 20 years has increased at a lower rate than the service territory's consumer price index growth (CPI). It is worth noting that the rates in the upper tiers for residential service have far outpaced CPI which is of great concern to PG&E as noted previously.

This modest growth in system-bundled average rate over time has resulted from careful utility cost containment and a general increase in sales (which moderate the upward pressure of revenue requirement growth). In 2011, PG&E proposed and received approval for a "rate stabilization adjustment" plan that eliminated a looming rate roller coaster situation where electric rates would have dropped precipitously in January 2011 only to be brought back up later in the year. Further cost increases from other cases were mitigated by decreases in natural gas prices and electric transmission revenue requirements to result in system-bundled average electric rates increasing by about 1.3%.

Figure 2-1: Historic Service Territory CPI vs. System Bundled Average Electric Rate CPI provided by Economy.com



3 Management of Rate Components

PG&E is committed to controlling costs and managing rates while providing safe and reliable gas and electric service to its customers. However, there are many key drivers that affect customer rates which fall outside of PG&E's control. Among these are the market price of natural gas, actual retail sales volumes, uncollectible accounts, weather (including the impacts on hydroelectric operations), interest rates, the cost of implementing state mandates, and permitting process delays. Despite these factors, PG&E diligently seeks to manage its costs across all categories to make efficient and effective use of revenues collected from customers.

4 PG&E's Policies and Recommendations for Limiting Costs and Rate Increases While Meeting the State's Energy and Environment Goals for Reducing Greenhouse Gases

Table 2-1 in the Appendix contains information on PG&E's significant rate initiatives and changes for 2012- 2013. The table reflects the currently anticipated rate filing schedule for 2012 and the revenue requirement or rate components that are primarily affected by each filing. This is not an exhaustive list of PG&E's filings; rather it incorporates planned regulatory filings which are known at this time to have a rate impact for gas or electric customers. Actual filing dates, amounts of requests, and actual revenue requirements authorized or settled are subject to change via the normal regulatory approval processes of the CPUC and other regulatory agencies.

PG&E and the Commission have endorsed rate policies based on cost of service. PG&E believes that such policies are appropriate and should continue. Such policies are sustainable because they encourage efficient decision making by customers. At times, departing from cost-based rates can be appropriate if justified in order to accomplish other public policy objectives. Such objectives may include energy efficiency, benefits provided to low income customers, mitigation of rate changes from year to year, promotion of renewable generation, GHG emissions reductions, and encouraging innovation and developing technologies.

However, each departure from cost-based rates carries with it the risk that one set of customers—the non-benefiting customers—will be paying higher than cost-based rates to subsidize another set of customers—the benefiting customers. Thus, each departure from cost-based rates needs to be carefully evaluated to determine whether the rate increases to non-benefiting customers are reasonable in light of the overall benefits to benefiting customers and society at large. While perhaps beneficial from a policy perspective, programs such as net-metering and the statutory structure in place relating to tiered rates for residential customers that support policy objectives can result in costs being shifted to other customers. When a customer reduces their own contribution to cost of service to below avoided costs, the shortfall is paid by other customers. Because PG&E's current residential rate structure recovers all of the fixed costs through variable rates, any program that reduces participants' consumption can create upward pressure on rates for other customers and may lead to a rate revolt.

In the next twelve months, PG&E recommends that the California Legislature and other energy policymakers carefully evaluate and re-examine several examples of non-cost-based ratemaking that are significantly impacting the level of current rates and costs to customers, including 1) the distortion in residential tiered electricity rates (where upper-tier consuming households are paying rates much higher than their costs of service in order to subsidize lower-tier consuming and CARE households), and 2) incentives and costs associated with customer-owned generation, such as rooftop solar (where customers without generators are subsidizing those with generators through artificially high compensation received).[45]

The most immediate area of concern is the statutory mandate for tiered residential electric rate design, where a four tier rate structure is employed. This structure, first put in place in the form of five tiers guided by statute during the energy crisis ten years ago, has grown to have a punitive effect on customers, and does not reflect the true cost of service. The effects of this structure were seen in customers' adverse reaction to bills in the Central Valley during the summer of 2009. One significant driver of these complaints was the rate change from summer of 2008 to summer of 2009, when the Tier 5 rate increased from 36 to 44 cents per kWh. Without modification, rates projected for the summer of 2010 were expected to be close to 50 cents per kWh. PG&E's Summer 2010 Rate Relief Application that went into effect in June 2010 reduced prices for usage in the highest tier to approximately 40 cents by collapsing Tiers 4 and 5 into one single Tier 4. PG&E proposed further changes in the Phase 2 of its 2011 GRC with the goal of distributing electricity costs more equitably among all our customers. Some of these key changes were not approved, i.e., reducing the current structure to just three tiers and incorporating a modest monthly customer charge.

PG&E respectfully requests the Commission's support to continue approving rate proposals in future proceedings that are designed to reduce the extremely high levels of upper-

[45] This compensation takes the form of bill savings from avoided consumption that are valued at artificially high upper-tier rates, and by having exports to the grid valued at full bundled rates which are in excess of the market value of the power.

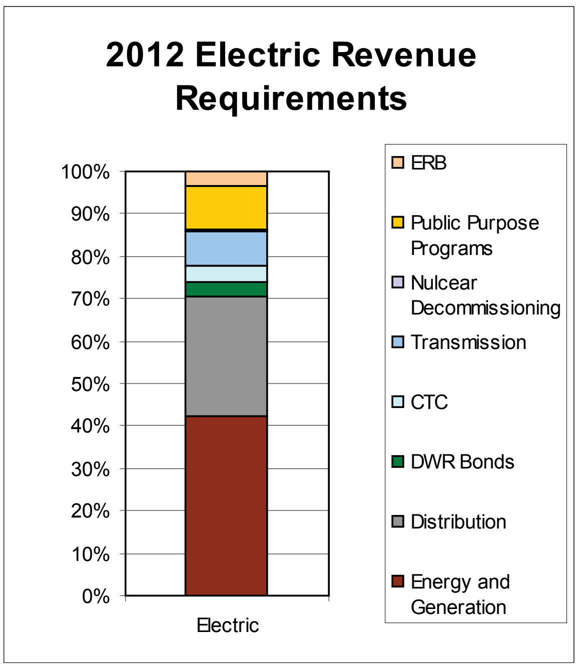
tier rates. Even with complete support from the Commission, though, the underlying legislation, that allows only limited increases to Tier 1 and 2 rates and no increase to CARE rates, will continue to constrain the Commission's ability to fix the excessively high upper-tier rate problem. Without legislative rate reform upper-tier rates will remain at punitive levels. PG&E recommends that legislative changes be considered this coming year to reform the tiered electric rate structure, untie the Commission's hands, and provide it the flexibility to address and modify residential rate structures to be more fair and equitable, with rates set at more reasonable levels that more closely reflect cost of service. Absent meaningful reform this year, upper-tier rates are projected to continue grow at an unsustainable level potentially resulting in resistance to adopted public policy goals such as the 33 percent RPS and AB 32. For example, absent meaningful tiered rate reform, residential customers in the upper tiers may be forced to shoulder the burden of an additional five to six cents per kilowatt hour rate just to pay for the increased renewable energy requirements.

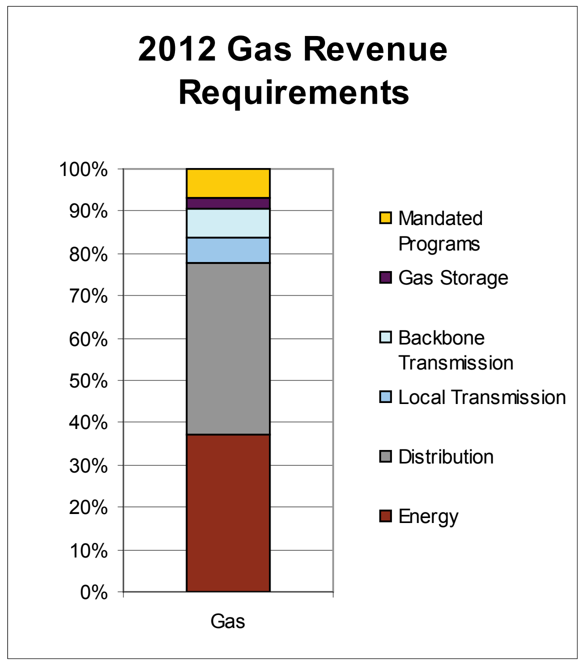
Appendix I Description of Revenue Requirements

I.1 Key Categories of Revenue Requirements

This section summarizes the major components of PG&E's gas and electric revenue requirements (RRQ). For example, Energy/Generation includes purchased power costs, utility-owned generation, and pension RRQ linked to generation, among other items. Each RRQ category as a percent of total authorized 2012 RRQ is provided for each RRQ section. A summary is provided in Figure I-1 below. Note that the focus is not on specific filings brought forth to the CPUC, but rather categories of RRQ that could have a potential impact on future rates.

Figure I-1: High Level Breakdown of PG&E Revenue Requirements in 2012





I.1.1 Electric

Electric RRQ are grouped into the following major rate categories: (1) Energy, Utility Owned Generation and Procurement, (2) Competition Transition Charge (CTC) and New System Generation Charge, (3) Distribution, (4) Department of Water Resources (DWR) bonds, (5) Transmission, (6) Public Purpose Programs, (7) Nuclear Decommissioning, and (8) Energy Recovery Bonds. For reference, an excerpt from the Advice 3896-E-B Annual Electric True-Up filing is provided as Table I-1. For 2012, below is a detail breakout of the RRQ:

1) Energy and Generation-related electric RRQ constitute approximately 43 percent of the total forecast revenue requirement in 2012. The generation rate component recovers RRQ associated with the following:
   - Procurement costs in the ERRA Proceeding;
   - Utility Retained Generation; and

- DWR Power and franchise fees.

2) Competition Transition Costs RRQ constitute approximately 4 percent of the total forecast revenue requirement in 2012. This represents the above-market cost of procuring energy. Included in this segment are the New System Generation Charge revenue requirement and program and other contracts for which PG&E is authorized to recover net capacity costs from DA, CCA, and departing load customers through the CAM rate.
3) Distribution-related electric RRQ include the 2011 General Rate Case (GRC), California Solar Initiative, the SmartMeter™ program, and several other programs whose RRQ are to be recovered through the distribution rate component.46 The distribution revenue requirement comprises approximately 28 percent of the total RRQ in 2012.
4) The DWR bond RRQ comprise 3 percent of PG&E's forecast 2012 total.
5) Transmission-related electric RRQ contribute 8 percent of the total forecast revenue requirement in 2012. Transmission RRQ include those related to the following:
   - Transmission Owner;
   - Transmission Access Charge Balancing Account;
   - Transmission Revenue Balancing Account;
   - Reliability Services Balancing Account; and
   - Electric Customer Refund Account.
6) Public Purpose Program-related electric RRQ include the funding of energy efficiency programs and the CARE discount. These RRQ comprise 10 percent of PG&E's total forecast revenue requirement in 2012.
7) Nuclear Decommissioning-related electric RRQ represent less than 1 percent of PG&E's total authorized revenue requirement during 2012.
8) Energy Recovery Bond-related electric RRQ represent roughly 4 percent of PG&E's forecast revenue requirement in 2012 and will come to the end of their life during 2012.

[46] The Electric Distribution RRQ does not reflect the CARE discount that is recovered through the CARE surcharge in the Public Purpose Program rate component. Correspondingly, PPP RRQ does not reflect CARE discount revenue.

Table I-1: Excerpted from Advice 3896-E-B Annual Electric True-Up filing for Rates Effective January 1, 2012

Advice 3896-E-B - 11 - December 30, 2011

Table 2: Annual Electric True-Up Projected 2012 Revenue Requirements

Line #		Test Year 2012 RRQ A	12/31/11 Forecast Under/(Over) collected BA Amortization B	Total Projected 2012 Revenues C = A + B
1	CPUC Jurisdictional			
2	Distribution			
3	Distribution/DRAM	3.460.698.000	187.010.825	3.647.708.825
4	Self Generation Incentive Program (SGIP)	29.838.521	0	29.838.521
5	Environmental Enhancement	10.107.900	0	10.107.900
6	CPUC Fee	20.728.571	0	20.728.571
7	Advanced Metering/SBA	176.800.000	43.608.009	220.408.009
8	Demand Response/DREBA/DRRBA	0	(2.262.765)	(2.262.765)
9	Air Conditioning Cycling/ACEBA/DRRBA	0	0	0
10	California Solar Initiative	121.294.800	0	121.294.800
11	HSM	0	17.328.583	17.328.583
12	ATFA	0	0	0
13	CEMA	0	0	0
14	PCBA	0	0	0
15	CEEIA	21.981.747	495.885	22.477.632
16	NTBA	0	(231.169)	(231.169)
17	CIPBA	32.537.000	(9.172.293)	23.364.707
18	MRCBA	0	40.703.645	40.703.645
19	Revised Customer Energy Statement	0	0	0
20	Smart Grid Memorandum Account	0	978.393	978.393
21	Generation			
22	Utility Retained Generation Base/UGBA	1.776.720.000	211.747.229	1.988.467.229
23	Electric Procurement/ERRA	3.609.186.342	(134.714.086)	3.474.472.256
24	DWR--Power Charge/PCCBA	(251.876.519)	24.661.121	(227.215.398)
25	DWR Franchise Fees	1.268.663	0	1.268.663
26	BCRSBA	0	62.616	62.616
27	Diablo Canyon Seismic Study	11.907.106	0	11.907.106
28	FERABA[1]	0	7.692.445	7.692.445
29	HA	0	0	0
30	LTAMA	0	16.037	16.037
31	RPSCMA	0	0	0
32	AB 32 Cost Implementation Fees	0	0	0
33	LCPERMA	0	2.387.908	2.387.908
34	Mokelumne Pumped Storage Project	0	0	0
35	Ongoing CTC/MTCBA	409.014.528	(7.517.467)	401.497.061
36	NSGBA	86.952.375	0	86.952.375
37	Energy Cost Recovery Bonds	0	0	0
38	Dedicated Rate Component Series 1	332.982.261	0	332.982.261
39	Dedicated Rate Component Series 2	166.598.886	0	166.598.886
40	ERB Balancing Account (ERBBA)	40.299.264	(105.781.219)	(65.481.955)
41	Nuclear Decommissioning	44.270.000	4.283.365	48.553.365
42	Public Purpose Programs			
43	Energy Efficiency (PGC Legacy)	120.734.365	0	120.734.365
44	ESA (formerly known as LIEE)	87.765.637	0	87.765.637
45	PPPRAM	0	2.875.372	2.875.372
46	Procurement EE/PEERAM	248.931.753	7.577.363	256.509.116
47	CAREA	7.698.985	68.534.278	76.233.263
48	Electric Program Investment Charge	72.082.085	0	72.082.085
49	DWR Bonds	393.032.067	0	393.032.067
50	Total CPUC Jurisdictional	11,031,554,337	360,284,077	11,391,838,414
51	*CPUC Revenues at Present Rates*			11,007,067,203
52	*Change in CPUC Jurisdictional*			384.771.211
53	*Total FERC Jurisdictional*			978.581.536
54	*FERC Revenues at Present Rates*			1,200,741,002
55	*Change in FERC Jurisdictional*			(222.159.466)
56	Grand Total Projected Revenues			12,370,419,950
57	Total Revenues at Present Rates			12,207,808,205
58	Total Change			162,611,745

Notes to Table 2:

1 The 12/31/11 forecast FERABA balance of $7,692,445 includes a discount portion of $7,107,566, which is allocated to generation rates; and administrative costs of $584,879 which is allocated to distribution rates.

I.1.2 Natural Gas

Natural gas RRQ are commonly grouped into the following six major categories: (1) Energy, (2) Distribution, (3) Public Purpose Programs/Mandated Programs, (4) Backbone Transmission, (5) Local Transmission, and (6) Gas Storage. For reference, an excerpt from the Advice 3257-G-A Annual Gas True-Up filing on December 22, 2011 is provided as Table I-2. For 2012, below is a detail breakout of the RRQ:

1) Energy-related gas RRQ represent about 37 percent of the total gas RRQ. The energy related RRQ include:
    a. Gas supply portfolio costs
    b. Interstate capacity costs
    c. Gas Hedging
    d. Winter Gas Savings Program
    e. Purchased Gas Account
    f. Core Procurement Incentive Mechanism
2) Distribution-related gas RRQ constitute about 40 percent of the total authorized gas RRQ. They include the GRC, Pension, the SmartMeter™ program, and several other programs whose RRQ are to be recovered through the distribution rate component.[47]
3) Mandated Public Purpose Programs gas RRQ, including California Alternate Rates for Energy (CARE) Discount and Self-Generation Incentive Program, and Energy Efficiency represent about 7 percent of the total authorized gas RRQ.
4) Backbone transmission-related gas RRQ constitute approximately 7 percent of the total authorized gas RRQ. They include unbundled backbone and intrastate capacity costs.
5) Local transmission-related gas RRQ represent approximately 6 percent of the total authorized gas RRQ.
6) Gas storage-related RRQ contribute about 2 percent of the total gas RRQ. They include core storage, core carrying cost of non-cycled gas in storage, and unbundled storage.

[47] The Gas Distribution RRQ reflect the CARE discount that is recovered through the CARE surcharge in the Public Purpose Program rate component. Correspondingly, PPP RRQ reflect CARE discount revenue.

Table I-2: Excerpt from Advice 3257G-A Annual Gas True-Up filing for Rates Effective January 1, 2012

Pacific Gas and Electric Company
San Francisco, California
U 39

	Revised	*Cal. P.U.C. Sheet No.*	29457-G
Cancelling	Revised	*Cal. P.U.C. Sheet No.*	29037-G

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

Sheet 2

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

2. ANNUAL GAS REVENUE REQUIREMENT AND PPP FUNDING REQUIREMENTS: (Cont'd.)

	Amount ($000)				
Description	Core	Noncore	Unbundled	Core Procurement	Total
BASE REVENUES (incl. F&U) :					
Authorized GRC Distribution Base Revenue (1)					1,189,351 (I)
Pension (2)					43,764 (I)
Less: Other Operating Revenue					(22,922)
Authorized Distribution Revenues in Rates	1,168,152 (I)	42,041 (I)			1,210,193 (I)
BCAP ALLOCATION ADJUSTMENTS AND CREDITS TO BASE:					
G-10 Procurement-Related Employee Discount	(1,070) (I)				(1,070) (I)
G-10 Procurement Discount Allocation	422 (R)	648 (R)			1,070 (R)
Less: Front Counter Closures	0				0
Core Brokerage Fee Credit	(6,583)				(6,583)
Distribution Base Revenue with Adj. and Credits	1,160,921 (I)	42,689 (I)			1,203,610 (I)
TRANSPORTATION FORECAST PERIOD COSTS & BALANCING ACCOUNT BALANCES (3):					
Transportation Balancing Accounts	130,973 (I)	36,948 (I)			167,921 (I)
Self-Generation Incentive Program Revenue Requirement	2,569	3,911			6,480
CPUC Fee	1,970	1,240			3,210
ClimateSmart	0	0			0
SmartMeter™ Project	82,514 (I)				82,514 (I)
Winter Gas Savings Plan (WGSP) – Transportation	2,355 (I)				2,355 (I)
Franchise Fees and Uncollectible Expense (F&U) (on items above)	2,863 (I)	556 (I)			3,419 (I)
CARE Discount included in PPP Funding Requirement	(118,884) (R)				(118,884) (R)
CARE Discount not included in PPP Surcharge Rates	0				0
Transportation Forecast Period Costs & Balancing Account Balances	104,360 (I)	42,655 (I)			147,015 (I)
GAS ACCORD REVENUE REQUIREMENT (incl. F&U) (4):					
Local Transmission	137,013 (I)	71,593 (I)			208,606 (I)
Customer Access Charge – Transmission		4,821 (I)			4,821 (I)
Storage	48,269 (I)		35,231 (R)		83,500 (R)
Carrying Cost on PG&E Working Gas in Storage	1,852 (I)		498 (I)		2,350 (I)
Backbone Transmission/L-401	95,901 (I)		139,103 (I)		235,004 (I)
Gas Accord Revenue Requirement	283,035 (I)	76,414 (I)	174,832 (I)		534,281 (I)

(1) The authorized GRC amount includes the distribution base revenue and F&U approved effective January 1, 2011, in General Rate Case D.11-05-018. The GRC distribution base revenue is allocated to core and noncore customers in Cost Allocation Proceedings, as shown in Part C.3.a. Prior to 2011, Pension was included in GRC Distribution Base Revenue. Going forward, Pension is shown as its own line item.

(2) PG&E's 2012 pension revenue requirement was updated and approved by the Energy Division in Advice Letter 3241-G. These revenue requirement adjustments are in compliance with the terms of the Pension Cost Recovery Mechanism Settlement Agreement approved by the Commission in D.09-09-020. This adjusted amount was updated to conform to the capitalization factor and the operations and maintenance labor allocations used in determining the 2011 GRC revenue requirement adopted in D.11-05-018. (T)

(3) -The total 2012 SGIP revenue requirement (RRQ) was approved in D.11-12-030. (T)
-D.10-10-025 established a sunset date of the ClimateSmart™ program of December 21, 2011. (T)
-D.06-07-027 authorized Advanced Metering Infrastructure ("AMI")/SmartMeter™ Project deployment. The Energy Division approved PG&E's AL 3210-G which included a revised 2012 revenue requirement. (T)
-The Energy Division approved PG&E's AL 3222-G to continue PG&E's Winter Gas Savings Program (WGSP). The approved marketing, outreach and administration costs are shown here allocated between transportation and procurement. Procurement is estimated pending the results of the WGSP. The estimated program credits are collected in rates, resulting in a net zero revenue requirement. (T)

(4) The Gas Accord V RRQ effective January 1, 2012, was adopted in D.11-04-031. Storage revenues allocated to load balancing are included in unbundled transmission rates.

*Some numbers may not add precisely due to rounding.

(Continued)

Advice Letter No:	3257-G-A	*Issued by*	*Date Filed*	December 22, 2011
Decision No.		***Brian K. Cherry***	*Effective*	January 1, 2012
		Vice President	*Resolution No.*	
2C11		*Regulation and Rates*		

Table I-2 (contd.): Excerpt from Advice 3257G-A Annual Gas True-Up filing for Rates Effective January 1, 2012

Pacific Gas and Electric Company
San Francisco, California
U 39

	Revised	Cal. P.U.C. Sheet No.	29458-G
Cancelling	Revised	Cal. P.U.C. Sheet No.	29038-G

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

Sheet 3

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

2. ANNUAL GAS REVENUE REQUIREMENT AND PPP FUNDING REQUIREMENTS: (Cont'd.)

	Amount ($000)				
Description	Core	Noncore	Unbundled	Core Procurement	Total
ILLUSTRATIVE CORE PROCUREMENT REVENUE REQUIREMENT (5):					
Illustrative Gas Supply Portfolio				1,077,473 (R)	1,077,473 (R)
Interstate and Canadian Capacity				173,390 (R)	173,390 (R)
WGSP – Procurement – Residential				1,945 (R)	1,945 (R)
F&U (on items above and Procurement Account Balances Below)				16,483 (R)	16,483 (R)
Backbone Capacity (incl. F&U)	(66,759) (R)			66,759 (I)	0
Backbone Volumetric (incl. F&U)	(29,142) (R)			29,142 (I)	0
Storage (incl. F&U)	(48,269) (R)			48,269 (I)	0
Carrying Cost on PG&E Working Gas in Storage (incl. F&U)	(1,852) (R)			1,852 (I)	0
Core Brokerage Fee (incl. F&U)				6,583	6,583
Procurement Account Balances				15,678 (I)	15,678 (I)
Illus. Core Procurement Revenue Requirement	(146,022) (R)			1,437,574 (R)	1,291,552 (R)
TOTAL GAS REVENUE REQUIREMENT (without PPP) IN RATES	1,402,294 (I)	161,758 (I)	174,832 (I)	1,437,574 (R)	3,176,458 (I)
PUBLIC PURPOSE PROGRAM (PPP) FUNDING REQUIREMENT (F&U exempt) (6):					
Energy Efficiency (EE)	72,239 (I)	8,041 (I)			80,280 (I)
Energy Savings Assistance (ESA)	62,953 (I)	7,007 (I)			69,960 (I)
Research, Demonstration and Development (RD&D)	6,655 (I)	3,767 (I)			10,422 (I)
CARE Administrative Expense	1,128	776			1,904
BOE and CPUC Administrative Cost	188 (I)	107 (I)			295 (I)
PPP Balancing Accounts	(7,017) (R)	(1,640) (I)			(8,657) (R)
CARE Discount Recovered from non-CARE customers	70,456 (I)	48,428 (I)			118,884 (I)
Total PPP Funding Requirement in Rates	206,602 (I)	66,486 (I)			273,088 (I)
TOTAL GAS REVENUE AND PPP FUNDING REQUIREMENT IN RATES	1,608,896 (I)	228,244 (I)	174,832 (I)	1,437,574 (R)	3,449,546 (I)
TOTAL AUTHORIZED GAS REVENUE AND PPP FUNDING REQUIREMENT	1,608,896 (I)	228,244 (I)	174,832 (I)	1,437,574 (R)	3,449,546 (I)

(5) The credits shown in the Core column represent the core portion of the Gas Accord RRQ that is included in the Illustrative Core Procurement RRQ, and are shown here to avoid double counting these costs in the total. The Gas Supply Portfolio cost is an annual illustrative amount. Actual gas commodity costs change monthly. WGSP costs, approved in AL 3222-G, is recovered in residential rates effective April 1, 2012. (T)

(6) The PPP funding requirement is recovered in gas PPP surcharge rates pursuant to D.04-08-010 and 2012 PPP surcharge AL 3256-G; and includes ESA program funding (T) adopted in D.11-11-010, EE program funding adopted in D.09-09-047, CARE annual administrative expense adopted in D.11-11-010, and excludes F&U per D.04-08-010. (T)

(Continued)

Advice Letter No:	3257-G-A	Issued by	Date Filed	December 22, 2011
Decision No.		**Brian K. Cherry**	Effective	January 1, 2012
		Vice President	Resolution No.	
3C11		Regulation and Rates		

I.2 Description of Rates (Gas and Electric)

RRQ discussed in the previous section directly align with rate components. At the highest level, gas and electric rates can be described as RRQ divided by sales. Therefore, both revenue requirement changes and demand variations impact the actual rates for gas and electric service. RRQ expected to increase in the coming twelve months will tend to drive rates up. For those RRQ which trend down, rates similarly will be reduced. The rate pressures created by RRQ are modulated by differences in actual sales versus prior estimates (used to set rates). Adjustments in the allocation of RRQ across customer classes and rate tiers also impact the rates experienced by individual customers. Table II-1 below provides a summary.

Table I-3. Summary of Rate Components for 2012

COMPONENT	Electric Jan 2012 RRQ $M			Gas Jan 2012 RRQ $M		% Range
Energy and Generation	$	5,258	43%	$	1,285	37%
Distribution	$	3,487	28%	$	1,396	40%
CTC	$	488	4%			
Transmission / Backbone Transmission	$	979	8%	$	235	7%
Local Transmission (Gas)				$	209	6%
Public Purpose Programs	$	1,282	10%	$	239	7%
Gas Storage				$	86	2%
Nuclear Decommissioning	$	49	0%			
DWR Bonds	$	393	3%			
Energy Recovery Bond	$	434	4%			
Total Authorized Revenue Requirement	$	12,370	100%	$	3,450	100%

1. Reflects CARE discount of approximately $653M for electric.
2. Reflects 2012 forecast CARE discount of approximately $119M for gas.
3. As of January 1, 2012. Values are approximated to the nearest million.

I.3 Published Load/Demand Forecasts

Customer sales volatility over time directly impacts the rates experienced by gas and electric customers. PG&E reviews load forecasts for its service territory on a regular basis to inform rate change filings with the Commission. Historically, aggregate customer sales usually increased at a pace which partly offset annual increases to RRQ. However, in recent years (2009 through 2011), the combination of weak economic conditions and very mild temperatures have resulted in a decline in sales compared to 2008 levels. This has meant that fixed costs are spread across lower sales that result in higher rates for most customers. The following section discusses the forecast trends for Electric and Gas loads for 2012.

I.3.1 Electric

Although the PG&E service area economy has rebounded from the recessionary trough of late 2009, the expansion has been sluggish and uneven. For 2012, Moody's Analytics projects continued improvement and a recovery that becomes more broadly-based. This will be the first year since the recovery took hold that sustained job growth will be observed, leading to a meaningful drop in the unemployment rate. Real incomes will continue to expand at about 3 percent this year. The recovery remains uneven across the service area, however, with the economy of the Bay Area growing more robustly with the vibrant high technology sector.

Elsewhere, and especially across the Central Valley, the economy has yet to recover from the collapse of housing and the building sector. With this backdrop, PG&E's forecast projects sales growth of 2 percent in 2012 compared to observed 2011 sales. This growth rate is a bit misleading, however, with mild summer temperatures depressing residential and commercial usage in 2011, and the wet winter of 2010-2011 pushing down agricultural usage. Adjusting for these elements adds about 800 GWh to the 2011 total, and thereby reduces the normalized growth rate by about one-half. With the continued drag of the construction sector, and the state's budget issues yet to be resolved, PG&E sales growth is likely to remain modest in 2012 and beyond.

Electric customer (billings) growth was also dramatically impacted by the recession. PG&E added only 18,000 customers during the 2009-2010 period, but did observe a rebound in customer growth in 2011, with about 30,000 net new customers. PG&E expects to see additional growth in customers in 2012, expecting close to 60,000 net additions.

PG&E expects to see sales growth among all four major electric customer classes (residential, agricultural, industrial, commercial) in 2012. Although residential sector sales are projected to increase by a seemingly robust 1.7 percent, it should be remembered that this is compared to observed 2011 sales and, as mentioned above, the mild 2011 summer reduced residential demand. Under normal conditions, the residential sales growth rate would likely be ½ to ⅔ lower. Commercial sales are projected to grow modestly at about ½ percent this year, as vacancy rates remain high and consumers spend carefully. Industrial sales are expected to show fairly robust growth of nearly 3 percent, but this comes after a steep plunge in industrial usage of 10 percent during the 2009-2010 period. Industrial usage will still fall well short of the level achieved during the middle part of the past decade. Agricultural sales (primarily groundwater pumping) are expected to rise significantly (about 13 percent) owing to depressed usage in 2011 combined with the makings of a very dry 2011-2012 winter period.

I.3.2 Gas

As described in the Electric subsection above, PG&E's service area economy is expected to continue the slow pace toward recovery through 2012. This slow pace and the return to assumed normal temperatures after a colder than normal 2011 will impact projected natural gas throughput. Based on PG&E's preliminary new forecast, 2012 gas sales for all three major gas customer classes - residential, commercial, and industrial – will show modest declines in usage. Residential, commercial, and industrial demands are expected to change very little from 2012 to 2015.

The residential gas demand forecast incorporates real residential gas rates, the number of households in PG&E's service territory, heating degree days and the percentage of households built after 1978 (when title 24 multifamily energy efficiency standards went into effect). Unlike electricity, which has innumerable residential uses, the main residential uses for gas are space and water heating, therefore requiring customer growth to drive usage growth. With slow customer growth combined with building standards and energy efficiency programs that continue to reduce overall residential usage, residential demand is projected to drop by about 6 percent in 2012. The majority of that decline is due to the assumed return to normal temperatures in 2012 after the colder than normal 2011. After 2012, customer growth will tend to offset lower usage per household. Since space heating is the principal use of gas in the commercial sector (as it is for residential use), growth is dependent on the level of business activity within the sector. With high existing commercial vacancy rates and a return to assumed normal temperatures, gas usage in this sector is projected to decline by 4 percent this year. The soft economy will also drive industrial sales lower in 2012 by about 1 percent.

Finally, demand for gas used in electric generation is expected to be more than 5 percent higher in 2012. Many factors drive the volatility in gas demanded for electric generation, including the economy, gas prices, hydroelectric generation capacity, new generation facilities coming online, and nuclear generating capacity. In 2012, however, the main factors impacting electric generation will be the continuing slow economic recovery and a drier than normal 2011-2012 winter in the west resulting in lower than normal hydroelectric output.

Appendix II Outlook from May 1, 2012 to April 30, 2013.

Table II-1: Key Filings Affecting Rates

Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Amount ($ millions)			Description	Impacted Rate	Impacted Rate Component
				Total Cost	2012 RRQ *	2013 RRQ *			
Q3 2010									
CARB AB32 Implementation Fee, Joint IOU App	A.10-08-002	Aug 2010	TBD	20	15	5	Application asking approval to pass the cost of AB32 Cost of Implementation Fee through to customers.	Gas/Electric	Distribution/ Generation
Default Residential Rate Programs (Peak Day Pricing)	A.10-08-005	Aug 2010	5/1/2014	141	-	5	In compliance with D.08-07-045, Ordering Paragraph 8, by Aug 9, 2010 PG&E needs to file an application proposing a default Critical Peak Pricing rate for residential customers, subject to their ability to opt-out of the rate.	Electric	Energy/ Generation
Q1 2011									
General Rate Case (GRC) 2011 Ph III - Dynamic Pricing	A.10-03-014	Jan 2011	1/1/2012	50	-	3	The request includes $2.7 million in RRQ for new voluntary Real Time Pricing rate options, and $0.3 million for Revised Customer Energy Statement.	Electric	PPP, Distribution, Energy/ Generation, Competition Transition Charge
Demand Response Program Years 2012-2014	A.11-03-001	Mar 2011	TBD	234	76	74	PG&E filed its application to support Demand Response programs and expenses for the 2012-14 program cycle.	Electric	Distribution
Modifications to the SmartMeter Program	A.11-03-014	Mar 2011	1/1/2014	113	59	26	Per D.12-02-014, PG&E will file updated RRQ and a cost recovery proposal in Phase 2 of the proceeding, scheduled to begin at the end of Q1 2012.	Electric/Gas	Distribution

Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Amount ($ millions) Total Cost	2012 RRQ *	2013 RRQ *	Description	Impacted Rate	Impacted Rate Component
GHG OIR	A.11-03.012	Mar 2011	1/1/2013	N/A	-	-	OIR evaluating proposals for allocating revenues associated with auction of GHG allowances. The Utilities propose to return 100% of revenues to customers volumetrically.	Electric	Distribution
2012 DWR Bond Settlement	R.11-03-006	Mar 2011	1/1/2013	(50)	(50)	-	Annual recovery/credit for power and bond charges with DWR. Cost reflects settlement adjustment with SCE.	Electric	Generation
Q2 2011									
Energy Savings Assistance Program and CARE Administrative Budget for 2012-2014	A.11-05-019	May 2011	TBD	514	150	179	Application seeking approval for Low Income Energy Efficiency Program and CARE Admin. Budget for the 2012-14 Cycle. The CPUC authorized PG&E to recover in rates the amount authorized for 2011 until a final decision is issued.	Electric/Gas	Public Purpose Programs
Q3 2011									
Lawrence Livermore National Laboratory (LLNL) Partnership	A.11-07-008	Jul 2011	1/1/2013	84	17	17	Requests authority to recover in rates the costs associated with a five-year cooperative research anddevelopment agreement with the LLNL, known as the "California Energy Solutions for the 21st Century Project".	Electric/Gas	Electric Distribution, Gas Distribution
Gas Pipeline Safety OIR - Implementation Plan Ph.1 (PSEP)	R.11-02-019	Aug 2011	7/1/2012	1,963	247	221	Application requesting a program to modernize PG&E's gas transmission infrastructure.	Gas	Local Transmission, Backbone Transmission
Sempra Gas Index	R.09-07-029	Aug 2011	TBD	N/A	-	-	Petition to modify allocation of Sempra gas settlement to Core customers	Gas	Procurement

Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Amount ($ millions)			Description	Impacted Rate	Impacted Rate Component
				Total Cost	2012 RRQ *	2013 RRQ *			
CEMA 2011	A.11-09-014	Sep 2011	1/1/2013	49	-	32	Requests authority to recover in rates the costs recorded in the CEMA associated with seven catastrophic events that occurred between August 2009 and March 2011.	Electric	Distribution (DRAM and UGBA)
Silicon Valley Technology Center (SVTC) Amended Application	A.10-11-002	Nov 2011	1/1/2012	18	13	5	Application seeking approval to support a photovoltaic (PV) Manufacturing Development Facility in San Jose, California.	Electric	Distribution
Q4 2011									
Rate Design Window 2010/ Peak Time Rebate (Revised Testimony)	A.10-02-028	Oct 2011	1/1/2013	34	1	(2)	Requests approval for PTR program that provides incentives for customers to reduce usage on event days when demand is expected to be high.	Electric	Energy/ Generation
PGC OIR	R.11-10-003	Oct 2011	1/1/2012	70	70	25	Upon Completion of Phase 2 of the PGC OIR, the Commission will determine funding levels for RDD and Renewable Programs.		Public Purpose Programs
GRC Phase 3 (RCES Cost Recovery) Settlement Agreement	A.10-03-014	Nov 2011	1/1/2014	19	-	-	PG&E cost recovery request to develop and implement a revised customer energy statement in the second half of 2013.	Electric/Gas	Distribution
Smart Grid Pilot Deployment Project	A.11-11-017	Nov 2011	1/1/2013	109	-	6	Requests authority to recover costs associated with six Smart Grid projects that will test, evaluate and deploy select Smart Grid technologies and initiatives on a pilot basis.	Electric	Distribution

Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Amount ($ millions)			Description	Impacted Rate	Impacted Rate Component
				Total Cost	2012 RRQ *	2013 RRQ *			
Request to Increase Diablo Canyon Seismic Studies Costs (Testimony)	A.11-01-014	Dec 2011	1/1/2013	64	-	64	PG&E originally requested and received approval to spend up to $16.73M on seismic studies. In December 2011, PG&E filed an updated request for $64.25M.	Electric	Generation
Community Choice Aggregation and Direct Access Service Fees	A.11-12-009	Dec 2011	1/1/2013	N/A	-	-	Application meeting 2011 GRC Settlement requirement to have a comprehensive review of fees charged to DA and CCA service providers for billing and metering services.	Electric	No projected impact to bundled rates; may result in updated fees for DA / CCA service providers.
Q1 2012									
Market Redesign and Technology Upgrade (MRTU) 2010 (re-filing)	A.12-01-014	Jan 2012	1/1/2013	109	18	65	Request for recovery of costs PG&E incurred for projects that became operative in 2010, to comply with the mandated MRTU initiatives and a forecast revenue requirement for 2012 and 2013. Total cost includes RRQ of $18.3M approved in MRTU 2009.	Electric	Energy/ Generation/ Distribution
Rate Design Window 2012	TBD	Feb 2012	1/1/2013	N/A	-	-	Request to modify electric rates for residential customers (baseline quantities and customer charge) and optional dynamic pricing programs	Electric	Distribution
Smart Grid - Automated Data Exchange	TBD	Mar 2012	TBD	TBD	TBD	TBD	Requests authority to recover costs to implement a customer data access project that will provide third parties access to customer usage data via the utility when authorized by the customer.	Electric	Distribution

Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Amount ($ millions)			Description	Impacted Rate	Impacted Rate Component
				Total Cost	2012 RRQ *	2013 RRQ *			
Market Redesign and Technology Upgrade (MRTU) 2011	TBD	Mar 2012	1/1/2013	TBD	N/A	TBD	Request for recovery of costs PG&E incurred for projects that became operative in 2011, to comply with the mandated MRTU initiatives	Electric	Energy/ Generation/ Distribution
Q2 2012									
CPIM 2011 Annual Report (Yr. 18)	TBD	Apr 2012	TBD	TBD	TBD	TBD	Compliance report for gas core procurement incentive mechanism	Gas	Procurement
Cost of Capital 2013	TBD	Apr 2012	1/1/2013	N/A	N/A	TBD	Establishes capital structure, cost of debt, cost of preferred equity, and rate of return on common equity for all IOUs, and will evaluate the Annual Cost of Capital Adjustment Mechanism for possible modifications. Filed in compliance with D.09-10-016.	Electric/Gas	All except FERC-governed rate components (e.g. electric transmission).
Energy Efficiency 2013-2014 Bridge Funding	R.09-11-014	Apr 2012	1/1/2013	TBD	-	-	PG&E will file an application to request authorization for Energy Efficiency Programs and Budget for the 2013-14 program cycle.	Electric/Gas	Public Purpose Programs
DOE Spent Nuclear Fuel Litigation Refund	TBD	Apr 2012	TBD	TBD	TBD	TBD	PG&E will propose refund treatment of DOE settlement proceeds of ~$260M in an application in April/May of 2012.	Electric	ERRA, Nuclear Decommissioning
Advice letter to flatten Generation and Distribution components of Residential Electric Rates	TBD	May 2012	7/1/2012	N/A	-	-	PG&E will file advice letter in compliance with D.11-05-047 which approved flat generation rates and separation of distribution rates into tiered Conservation Incentive Adjustment (CIA) and flat distribution rate components. No change expected for overall tiered rates.	Electric	Generation and Distribution

Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Amount ($ millions) Total Cost	2012 RRQ *	2013 RRQ *	Description	Impacted Rate	Impacted Rate Component
ERRA 2013 Forecast	TBD	Jun 2012	1/1/2013	TBD	N/A	TBD	An annual application that requests approval of PG&E's forecast procurement related revenue requirement, including CTC, PCIA and CAM.	Electric	Energy/ Generation, Competition Transition Charge
Advice Letter for CPIM Awards (2009 and 2010)	TBD	TBD	1/1/2013	TBD	N/A	-	Credit for gas core procurement incentive for 2009/2010	Gas	Procurement
Q3 2012									
TO 14	TBD	Jul 2012	3/1/2013	TBD	N/A	TBD	Annual filing to recover transmission costs	Electric	Transmission
2013 Annual Electric True-up AL	TBD	Sep 2012	1/1/2013	TBD	N/A	-	Annual filing to adjust for balancing account over/under collections, ERRA forecast and other electric proceeding decisions	Electric	Transmission, PPP, Distribution, Energy/ Generation, DWR, CTC, ERB
Q4 2012									
Public Purpose Programs Surcharge Rate AL	R.09-11-014 R.11-05-019	Oct 2012	1/1/2013	TBD	-	-	Annual filing for cost recovery of gas public purpose programs, gas research and demonstration, and Board of Equalization administrative costs		Gas Public Purpose Surcharge
SB 695 Res. Rate Change (T1 & T2) Advice Letter	TBD	Nov 2012	1/1/2013	N/A	N/A	-	Annual increase to residential rates for Tier 1 and Tier 2 in compliance with SB695 and corresponding decrease in Tier 3 and Tier 4 rates	Electric	Distribution, Energy/ Generation
Annual Gas True-Up (AGT) 2013	TBD	Nov 2012	1/1/2013	TBD	N/A	-	Consolidation of gas transportation rate changes authorized by CPUC	Gas	Distribution, Local Transmission, Backbone Transmission, Gas Storage

Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Amount ($ millions)			Description	Impacted Rate	Impacted Rate Component
				Total Cost	2012 RRQ *	2013 RRQ *			
Rate Design Window 2013	TBD	Nov 2012	TBD	N/A	-	-	Request to modify electric rates	Electric	Distribution
2013 DWR Bond	TBD	Nov 2012	1/1/2013	TBD	N/A	-	Annual recovery/credit for power and bond charges with DWR	Electric	Generation
2014 GRC	TBD	Dec 2012	1/1/2014	TBD	N/A	N/A	Triennial cost recovery for Electric Distribution/Generation and Gas Distribution costs	Electric/Gas	Electric Distribution, PPP, Generation, Gas Distribution
Annual Gas True-up Supplemental AL (noncore portion)	TBD	Dec 2012	1/1/2013	TBD	N/A	-	Consolidation of gas transportation rate changes authorized by CPUC	Gas	Distribution, Local Transmission, Backbone Transmission, Gas Storage
<u>Ongoing</u>									
Distributed Generation OIR	R.10-05-004	N/A	1/1/2012	1,787	159	140	Authorized funding for the California Solar Initiative (CSI, 2012 RRQ - $120M, 2013 RRQ - $85M), Self Generation Incentive Program (SGIP, 2012/13 RRQ - $36M) and CSI Thermal Programs (2012 RRQ - $3M, 2013 RRQ - $19M.	Electric/Gas	Distribution
<u>TBD</u>									
Mobile Home Park OIR	TBD	TBD	TBD	TBD	-	-	Cost recovery for conversion of master meter MHPs to Direct Utility Service	Gas/ Electric	Distribution

*Annualized change in revenue requirements
[TBD] – To be determined
[N/A] – No RRQ or rate impact
[-] – No RRQ, but rate impact

B. Southern California Edison Company

1. Opening Comments

In support of Senate Bill (SB) 695, SCE is providing the following information to assist the Commission in preparing its annual report to the Governor and Legislature. Specifically, SB 695 requires:

> "that by May 1, 2010, and by May 1 of each year thereafter, the commission also report to the Governor and Legislature with its recommendations for actions that can be undertaken during the upcoming year to limit cost and rate increases, consistent with the state's energy and environmental goals, including the state's goals for reduction in emissions of greenhouse gases. The bill would require the commission to annually require electrical and gas corporations to study and report to the commission on measures that they recommend be undertaken to limit costs and rate increases."

The information provided includes SCE's overall rate policy, a discussion of SCE management's policies to control costs and control rate increases for customers and, a discussion of SCE's policies and recommendations for limiting rate increases while meeting the State's energy and environmental goals for reducing greenhouse gases.

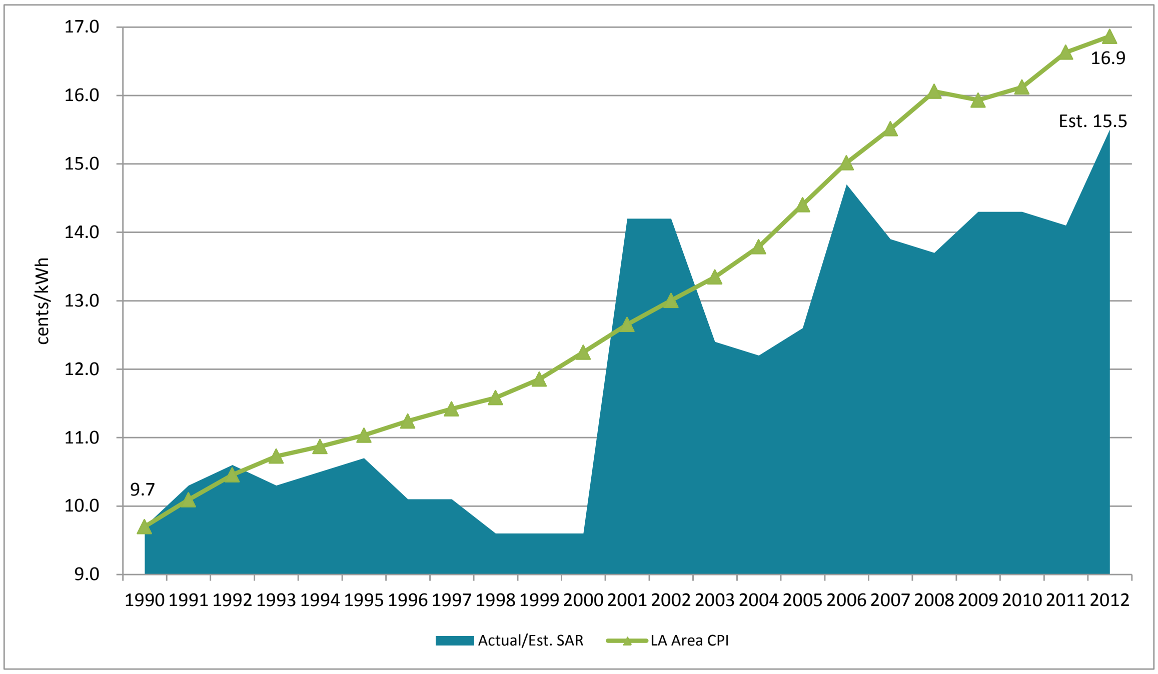
In addition, SCE has provided data contained in Appendix A to this Report that describes SCE's revenue requirements and provides an outlook for pending rate changes from May 1, 2012 to April 30, 2013.

2. Overall Rate Policy

SCE's overall rate policy is to fully recover the costs of efficiently serving its customers in an equitable manner while considering public policy objectives. SCE designs its rates to meet the traditional design objectives (e.g., recovery of revenue requirement, cost of service foundation and stable rates) while supporting the various public policy objectives established by the legislature and regulators. By recovering its authorized revenue requirement, SCE can properly maintain and rebuild its distribution system, provide power as needed, and meet customer service needs as they arise. Recovering these costs equitably from customers ensures that those customers who are more costly to serve pay appropriately higher rates. Rates that are equitable and cost-based also send the correct price signals to customers and prevent uneconomic decisions regarding energy usage.

Figure 1 below shows a comparison of SCE's actual System Average Rate as compared to what the average rate would have been if it had changed commensurate with the Consumer Price Index.[48]

[48] CPI based on US Bureau of Labor Statistics for all urban consumers in LA-Riverside-Orange County, CA.



3. Management Control of Revenue Requirements

SCE requests in CPUC and FERC General Rate Cases funding to operate its generation, transmission and distribution businesses in order to provide safe, reliable, and affordable electric service to all customers in its service territory. Based on the funding authorized by the Commission, SCE has the ability to manage those core utility businesses. However, funding has not always been adequate to fulfill all infrastructure replacement requirements on the company's planned schedule. Another portion of SCE's total revenue requirement is associated with its power procurement function. Based on a set of assumptions that reflect regulatory and legislative requirements, SCE requests funding to procure enough power to meet its customers' load. Although there are procurement cost components that are driven by market forces outside of SCE's control, such as natural gas prices, SCE has been given some authority by the CPUC to use hedging tools to reduce the variability in cost of power to its customers. A third category of costs are associated with policies driven by Commission and the Legislature for funding programs such as Demand Response, Energy Efficiency, Solar Initiatives, Self Generation and Low Income programs. In compliance with these policies, SCE makes initial requests for funding these programs but the final authorized funding amounts are determined by the Commission based on its policy objectives. Finally, there are costs included in the total revenue requirement that are fully outside of SCE's management control such as DWR Power and Bond Charge revenue requirements and other costs whose magnitude are prescribed by the legislature or a regulatory agency (e.g., while the requirement in Assembly Bill (AB) 1890 to collect revenue for the California Energy Commission to fund its Renewable, and Research, Development and Demonstration programs recently expired, the CPUC has issued a decision that continues funding during 2012 and a Rulemaking to determine future funding requirements for a new program).

It should be noted, that SCE is committed to fulfill its core mission of providing safe, reliable and affordable electricity to its customers through operating and service excellence across all business and functional areas.

4. <u>Utility's Policies and Recommendations for Limiting Costs and Rate Increases While Meeting State's Energy and Environmental Goals for Reducing Greenhouse Gases</u>

First, SCE believes that it is important for the State to understand what its environmental goals are so that they can be pursued most effectively and efficiently. Since the goals appear to be primarily focused on GHG reduction, then our policymakers must consider the fact that if businesses and residents leave the "clean" State of California, and move to a higher emitting State or country (almost anywhere else), then the net impact on the environment will be negative while the appearance of a cleaner California might belie this. Conversely, attracting businesses and people to California will have a clear net positive effect on GHG in almost all circumstances. Given the historical success California has enjoyed in becoming clean, and the current economic climate, our environmental policy should be more focused on maintaining our clean status and growing, rather than taking further potentially costly actions to "clean" beyond what our neighbors are doing.

California's environmental policies need to be coordinated to be effective. Simultaneously pursuing GHG reduction, local air emissions reductions, water use restrictions, and land use restrictions requires a comprehensive and coordinated process. Otherwise, we waste time, money, and resources resolving conflicts, and we risk the reliability and affordability of electricity. The State wants to mitigate the impact of once-through cooling on marine habitat, so we may need to build some new efficient gas generation facilities to maintain electric system reliability. But developers will struggle to license the new gas generation due to particulate emissions restrictions, even though the emissions meet the federal standards. There are not sufficient permits for particulate emissions because one agency's program for such was found through the courts to violate another California environmental law. However, the State wants to add more renewable power to displace fossil fuel generation, but siting renewable facilities encounters costs and delays due to land use restrictions or habitat impacts from the transmission needed to bring the generation to customers. But, even if successful in adding more renewable projects, the State will need additional conventional resources to integrate these projects. The costs associated with conflicting environmental policies are substantial, whether looking at customer costs, time, or the resources of those working in this space. The only solution is a more coordinated effort to establish consistent and comprehensive goals, and determine least cost and most efficient means to achieve these goals. Such is not the current process.

Generally, market solutions will tend to lead to lower cost solutions to meet policy goals. As such, the goals should be broadly defined, such as "reduction of GHG to 1990 levels by 2020", as opposed to mandates to procure specific technologies. Furthermore, the impacts on the ability to maintain a reliable electric grid should be part of the original debate in developing State policies, rather than an afterthought whose solutions either conflict with other State mandates, or receive broad opposition from parties who are not knowledgeable or concerned about maintaining a reliable grid.

Broader markets will lead to lower costs. As we develop and implement market solutions, we should seek to achieve broader market solutions wherever possible, if we want to minimize the rate impacts of achieving State environmental policy goals. This means allowing out of State resources to help California meet its goals if they are lower cost. This means allowing any GHG reductions means to be used, including broad use of offsets, as long as they can be appropriately verified.

Aligning incentives with desired outcomes will lead to greater success in reaching targets. California is the nation's leaders in energy efficiency, due in no small part to its decoupling of utility revenues from electricity sales. This was the result of recognition that entities will always be resistant to acting against their own interests, and in this case fiduciary responsibilities. The converse of this example is to impose a mandate with serious financial consequences such that it provides an incentive to reach the goal at any cost. Such structures are not conducive to reaching State environmental goals at least cost.

Market design and rules matter. In the case of AB-32 cap & trade regulations, there are elements of the market design that could result in excessive costs of the program. One danger in relying on market solutions is that if the markets are competitive, then low costs will result, but if they are subject to manipulation or generally are not competitive then high cost solutions are possible. This situation can be prevented by having effective rules and oversight. For example, if the goal of AB-32 is to put in place a GHG reduction program that can be an example for the rest of the nation or world to follow, then we must succeed in achieving GHG reduction goals without undue costs. One very visible measure of the cost of the program will be the GHG price that results from the cap & trade market structure. Currently, there is no limit (other than an ever increasing floor price) on the price that can result from that market. Yet we know that if the price rises to too great a level, the program will not be viewed as an example to be followed, but - like California's electricity market that failed - an example to be avoided. As such, it only makes sense to design this market so as to not allow prices to rise to unreasonable levels. Yet there is no limit on prices in this market – no limit that could mitigate rate impacts and ensure that the program does not "blow up".

To minimize the rate impact of a cap & trade system it is imperative that such revenues are returned to the utility's customers in form of lower rates and are not spent on additional state-or Commission-mandated programs. SCE and the other IOUs have been advocating this position in the current Rulemaking (R.11-03-012) pending before the Commission.

Finally, achieving environmental goals without undue rate impacts requires flexibility: the flexibility to relax time constraints on achieving goals if doing so prevents undue cost implications; the flexibility to change rules when we learn there were unintended and adverse consequences of the rules we originally imposed; the flexibility to change to incorporate new ideas that will help achieve our environmental and cost goals, even if those ideas arise after our programs are already in place; the flexibility to adapt California's programs to National programs as they emerge.

APPENDIX A

1. Description of Rate Components and Revenue Requirements

SCE recovers its revenue requirements through the following retail rate components: Generation, Cost Responsibility Surcharge (CRS), New System Generation, Distribution, Public Purpose Programs, Nuclear Decommissioning and Federal Energy Regulatory Commission (FERC) jurisdictional Transmission. In addition, SCE is authorized to include on customer bills the DWR Power Charge and Bond Charge on behalf of the California Department of Water Resources (DWR).

a. **Generation** – Through the Generation rate component, SCE recovers the costs of its generation portfolio which include the cost of SCE's Utility Owned Generation (UOG) consisting of the fuel, base O&M and capital-related revenue requirements associated with its nuclear, coal, gas, and hydro plants. In addition, SCE recovers all of its purchased power costs required to meet its load not met by its UOG.[49] The purchased power costs include the costs of Qualifying Facilities (QFs), and all other bilateral contracts that SCE has entered into since 2003 when the company was authorized to resume the power procurement function and make purchases and sales through the wholesale markets. The impact of renewable contracts entered into to meet the Renewables Portfolio Standard and Greenhouse Gas costs will be reflected in generation rates.

b. **Cost Responsibility Surcharge** – Through the CRS, SCE recovers from customers that have elected to purchase their generation service from other providers (e.g. Direct Access (DA) customers), the above market costs of the combined SCE and DWR generation portfolios. The revenue generated from the CRS is credited back to SCE's bundled service customers so that they remain indifferent to the departure of those customers, and are not burdened with paying for the above-market costs of the procurement SCE had planned and incurred to serve the departed customers.

c. **New System Generation** – Through the New System Generation (NSG) rate component, SCE recovers the costs of those "new generation" assets that the Commission has required SCE to procure in order to maintain system reliability for the benefit of all customers. The NSG revenue requirement includes the contracted procurement costs less the value of the energy produced. The net cost, or capacity cost, is recovered from all customers who benefit from the additional system capacity provided by the new generation, including DA and Community Choice Aggregation (CCA) customers.

d. **Distribution** – Through the Distribution rate component, SCE primarily recovers its base distribution O&M costs and its capital-related revenue requirement. In addition, the Commission has authorized SCE to recover its Edison SmartConnect revenue requirement, Demand Response program funding, California Solar Initiative program funding and some Energy Efficiency incentives through the Distribution rate component. The Commission has authorized SCE to provide the California Alternate Rate for Energy (CARE) discount to the income-qualified customers through the Distribution rate

[49] By the end of 2011, all of the DWR purchased power contracts that were allocated to SCE's bundled service customers expired. Therefore, in 2012, SCE is supplying 100% of its bundled service customers' generation requirements.

component. SCE along with the other Investor Owned Utilities are advocating in Rulemaking (R.)11-03-012 that proceeds that result from the cap-and-trade market should be returned to customers through the distribution rate component.

e. **Public Purpose Programs Charge (PPPC)** – Prior to 2012, SCE recovered the legislatively mandated Public Goods Charge funding for the California Energy Commission administered Research Development and Demonstration and Renewable programs, plus a portion of the SCE- administered Energy Efficiency programs through the PPPC. The funding for these three programs expired on December 31, 2011 as mandated by P.U Code 399. The Commission issued a decision in December 2011 that continued this funding in 2012 at the 2011 levels using the name Electric Program Investment Charge. In addition, through the PPPC rate component SCE recovers additional program funding authorized by the Commission for Procurement Energy Efficiency, and Low-Income programs. The Commission has authorized SCE to recover the costs of the CARE program including the discount provided to CARE-eligible customers from all non-CARE customers through the PPPC.

f. **Nuclear Decommissioning** – Through the Nuclear Decommissioning rate component, SCE recovers the customers' portion of the Nuclear Decommission Trust funding authorized by the Commission to be used to decommission SCE's share of the San Onofre and Palo Verde Nuclear Generating Stations. In addition, SCE recovers costs associated with the storage of spent nuclear fuel through this rate component.

g. **FERC-Jurisdictional Transmission** – SCE's FERC-jurisdictional transmission rate is comprised of five components: 1) Base Transmission which recovers the O&M and capital-related revenue requirement associated with typically higher voltage transmission assets under FERC's jurisdiction; 2) Construction Work in Progress incentives; 3) flow-through to customers of transmission revenues generated through wholesale customers' use of the transmission system; 4) Reliability Services costs related to contracts signed by the California Independent System Operator (CAISO) with certain generators needed to maintain system reliability; and 5) Transmission Access Charge which reflects the net contribution by SCE's customers to the transmission revenue requirements of all participating transmission owners in the CAISO system.

As SCE moves forward to meet the State's renewable goals, it must construct new transmission lines to bring the renewable generation from out-lying areas to the load centers. The construction of additional transmission facilities will increase SCE's FERC-jurisdictional Transmission rates.

h. **DWR Power Charge and Bond Charge** – In early 2001, as the result of the energy crisis and AB1X, DWR entered into long term power contracts that were necessary to meet the state's IOUs' net short requirements. The Commission authorized SCE to recover on behalf of DWR, the revenue requirement associated with these contracts through the DWR Power Charge. As mentioned above, all of the remaining DWR contracts that had been allocated to SCE's bundled service customers expired as of December 31, 2011. In addition, in order to recover the costs DWR incurred in early 2001 to purchase energy on behalf of IOUs' customers from dysfunctional wholesale markets which were initially financed by the State's General Fund, the Commission authorized SCE to bill the DWR

Bond Charge. All of the revenues associated with the DWR Power and Bond Charges are collected by SCE and passed on to DWR.

Since 2001, DWR was required to maintain high levels of operating reserves such that DWR would have enough cash on hand to fulfill its contractual obligations in case power prices skyrocketed. As the power contracts are expiring, DWR no longer is required to maintain this level of reserves and is returning them to customers. As a result of returning the operating reserves to bundled service customers, the Commission-allocated DWR Power Charge Revenue Requirement to SCE's bundled service customers in 2012 is a negative $441 million. In other words, on behalf of DWR, SCE will refund $441 million to its bundled service customers in 2012 through a negative (i.e. or credit) DWR Power Charge.[50] The DWR Bond Charge will remain at approximately $0.005/kWh in 2012.

2. Summary of Revenue Requirements by Rate Component

a. Revenue Requirements and System Average Rate for Bundled Service customers estimated as of June 1, 2012:

	Rate Component	($millions)	%	SAR c/kWh
1.	Generation	5,897	49.3%	7.9
2.	New System Generation	170	1.4%	0.2
3.	Distribution	4,596	38.4%	5.8
4.	Public Purpose Programs	641	5.4%	0.8
5.	Nuclear Decommissioning	13	0.1%	-
6.	FERC Transmission	631	5.3%	0.8
7.	DWR Power and Bond	15	0.1%	-
8.	TOTAL System	11,963	100.0%	15.5

3. Sales Forecasts

It is expected that the Commission will adopt SCE's 2012 total sales forecast of 85,141 GWhs in Application (A.)11-08-002 (SCE's 2012 ERRA Forecast Proceeding). This represents an increase from recorded 2011 sales of approximately 1.6%. SCE estimates sales to increase in 2012 as the result of: 1) assuming normal weather patterns as 2011 was cooler than normal, and 2) an increase in customer additions between 2011 and 2012.

[50] This amount could be reduced by approximately $60 million if the Commission adopts a settlement between the IOUs filed on February 10, 2012 that revises the 2012 DWR revenue requirement allocation between the IOUs.

2012 Outlook from May 1, 2012 to April 30, 2013

Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Dollar Amount ($millions)			Description	Impacted Rate Component
				Total Cost	2011 RRQ	2012 RRQ		
2012 GRC	A.10-11-015	11/23/10	Request: 1/01/12 Expect: 6/01/12	6,294	5,333	N/A	Increase in O&M and capital to replace aging infrastructure and expand system to accommodate increasing load.	Generation, Distribution, and New System Generation
SONGS 2&3 Steam Generator Removal and Disposal	D.05-12-040 (A.04-02-026) (By Advice Letter)	11/01/12	1/01/13	Est. 22	0	0	Add revenue requirement for Units 2&3 Removal and Disposal Rev. Rqmt.	Generation
2010 ERRA Compliance	A.11-04-001	4/01/11	6/01/12	Est. 8	0	0	Recovery of costs recorded in various Memo Accts.	Generation
Summer Discount Plan	D.11-11-002 (A.10-06-017)	6/30/10	1/01/13	0	0	27	Completion of the recovery of Summer Discount Plan costs will result in a rev. rqmt. reduction	Distribution

Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Dollar Amount ($millions)			Description	Impacted Rate Component
				Total Cost	2011 RRQ	2012 RRQ		
Four Corners Gain-On Sale	A.10-11-010	11/15/10	1/01/13	Est. (87)	0	0	Refund gain-on-sale to customers over a 2-year period as a result of the sale of SCE's ownership share of Four Corner's Generating Station	Generation
CA Solar Initiative	D.11-12-019	NA	1/01/13	75	111	111	Decrease in CA Solar funding per Commission decision.	Distribution
2013 ERRA Forecast	A.12-08-XXX	8/1/12	1/01/13	TBD	3,274	3,878	Will request recovery of estimated 2013 fuel and purchased power costs	Generation
2013 DWR Revenue Requirement Determination	N/A	TBD	1/01/13	Range: 200 – 350	1,014	15	Refund of large Operating Reserve in 2012 will not continue in 2013	DWR Power Charge

Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Dollar Amount ($millions)			Description	Impacted Rate Component
				Total Cost	2011 RRQ	2012 RRQ		
DOE Litigation Proceeds	A.12-04-XXX	4/2/12	1/01/13	(111)	0	0	Proceeds resulting from litigation with DOE with respect to the storage of nuclear fuel	Nuclear Decommissioning
GHG – Costs and Revenues	A.12-08-XXX and R.11-03-012	8/1/12 and 3/24/11	1/01/13	TBD	0	0	Recovery of cap-and-trade costs and refund cap-and-trade revenue	Generation (cost) and Distribution (revenue)
Market Redesign and Technology Upgrade	A.12-01-014	01/31/12	01/01/13	17	0	11	Incremental O&M and capital revenue requirement associated with implementing MRTU	Generation
FERC Formula Rate Change	September 2012 Advice Letter	By Sept 15th	10/01/12	TBD	635	722	Pursuant to FERC approved formula	Transmission Revenue Requirement
FERC Transmission Balancing Accounts	April and November 2012 Advice Letters	TBD	6/01/12 1/01/13	TBD	(50)	(91)		Transmission Owner's Tariff Charge Adjustment

C. Southern California Gas Company

Southern California Gas Company (SoCalGas) appreciates the opportunity, pursuant to Senate Bill (SB) 695 and PUC Section 748, to recommend actions that can be undertaken during the next 12 months to limit utility cost and rate increases. SoCalGas's objective in developing the 2012 report is to provide useful information that the California Public Utilities Commission (CPUC or Commission) may consider as it prepares its annual report for the Governor and Legislature.

I. Introduction

This report provides data related to gas revenue requirements and rates. The report is structured according to the Energy Division's request: (1) a description of the key categories of revenue requirements, trends for each category in the coming 12 months and load/demand forecasts, and (2) the outlook of anticipated rate changes during 2012 and the amount of the change if it is known. Within the framework approved by the CPUC and the Legislature, SoCalGas seeks to allocate costs fairly across its customer classes. However, SoCalGas recognizes that allocations of certain components of gas service costs in rates are beyond its direct control.

II. Section 748 (a) Study and Report

1. Description of Revenue Requirement Components

(A) Major Categories of Gas Revenue Requirements as Commonly Monitored Within SoCalGas

Gas revenue requirements are commonly grouped into the following four major categories: Energy Costs or Weighted Average Cost of Gas (WACOG), Transportation, Gas Storage, and Public Purpose Programs.

	2011		2012	
Revenue Component	**Revenue Requirement** $000	**Percentage**	**Revenue Requirement** $000	**Percentage**
Energy	$1,537,456 [1]	41.3%	$1,115,141 [2]	33.1%
Transportation [3]	$1,895,384	50.9%	$1,951,413	57.9%
Storage [4]	$26,470	0.7%	$27,530	0.8%
Public Purpose Program	$287,565	7.7%	$302,505	9.0%
Total	$3,720,405	100%	$3,369,060	100%

[1] Actual recorded revenue.

[2] Represents estimates of the residential, core commercial and industrial, and natural gas vehicles energy revenue and was derived by multiplying the *2010 California Gas Report* throughput projection by the gas price forecast for the year 2012.

[3] The transportation component includes Authorized Base Margin, amortization of regulatory accounts, other operating costs, SoCalGas's and SDG&E's Gas Transmission System Integration, and other Sempra-wide adjustments.

[4] A subset of transportation revenue requirement, represents costs allocated to be recovered from the Unbundled Storage Program

(B) Trends in Revenue Components

The revenue requirements outlined in the previous section directly align with rate components. At the highest level, gas rates can be described as revenue requirements divided by sales, so both revenue requirement changes and demand variations impact actual rates for gas service. Increases in the forecasted revenue requirements will impose upward pressure on rates and decreases in the forecasted revenue requirements will impose downward pressure on rates. The rate pressures created by changes in the revenue requirements are modulated by differences between actual sales and the prior estimates that were used to set rates. Adjustments in the allocation of the revenue requirement across customer classes and tiers also impact the rates experienced by individual customers.

Customer sales volatility over time also directly impacts the rates paid by gas customers. If revenues collected from customers are impacted (higher or lower) due to volatility in sales, future rates will be adjusted (decreased or increased) in order to ensure revenues collected are at authorized levels. SoCalGas reviews load forecasts for its service territory during cost allocation proceedings, which are currently on a three year cycle.

1) Gas energy revenue requirements are forecast to represent approximately 33.1% of the total gas revenue requirement in 2012. In 2011, the gas energy revenue requirements represented about 41.3% of the total authorized gas revenue. The revenue requirements are expected to decline significantly from 2011 to 2012 due to forecasted lower natural gas prices.

2) Transportation revenue requirements are estimated to constitute about 57.9% of the total gas revenue requirements in the upcoming 12 months. For 2011, the transportation revenue requirement constituted about 50.9% of the total authorized gas revenue requirement. Part of the increase in the revenue requirements is due to the beginning of cost recovery for SoCalGas's Advanced Metering Infrastructure project and amortization of balancing accounts. SoCalGas is also expecting a decision in its General Rate Case sometime in 2012, which will have an impact on the transportation revenue requirement.

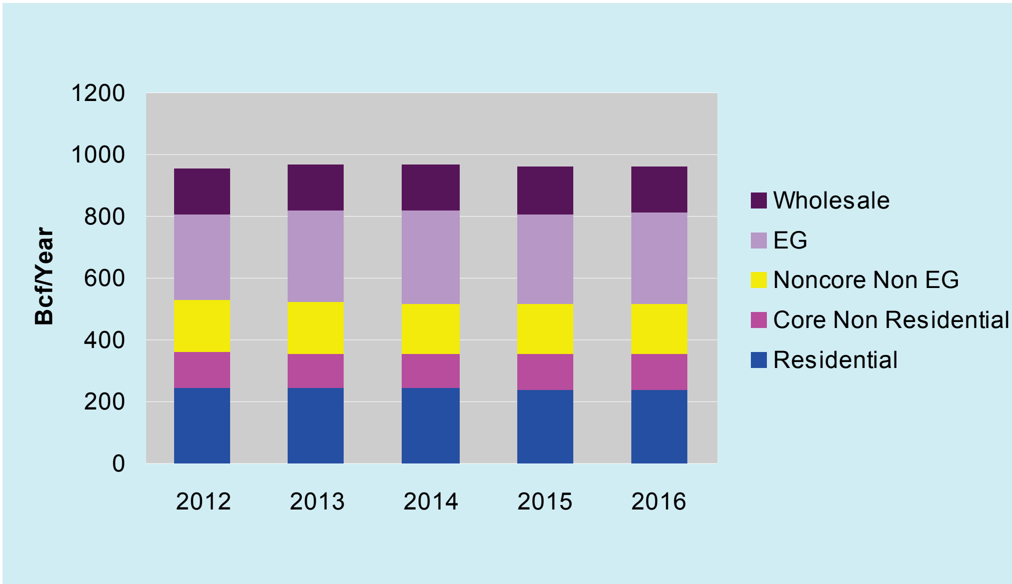
3) Costs allocated to the unbundled storage program comprised approximately 0.74% of the total revenue requirement in 2011, and this level is forecasted to increase by only 0.1% in 2012.

4) Public Purpose Program (PPP) revenue requirements, including California Alternate Rates for Energy (CARE) Discount and Energy Efficiency, represent approximately 9.0% of the total gas revenue requirements for 2012. The revenue requirement is expected to trend upward mainly due to increases in expected gas program penetration levels (Energy Efficiency goals) and CARE participation. Additionally, SoCalGas is anticipating a decision on its Low-Income Assistance budgets in early 2012, which may impact revenues through the rest of the year. For 2011, these programs contributed about 7.7% of the total authorized gas revenue requirements.

(C) Demand Forecasts

This section outlines major categories of gas demand and the load forecast through 2016.

Composition of SoCalGas's Requirements (Bcf/Year)
Average Temperature and Normal Hydro Year (2012-2016)



SoCalGas Demand Forecasts (Bcf/Year)
Average Temperature and Normal Hydro Year (2012-2016)

Bcf	2012	2013	2014	2015	2016
Residential	247	243	243	242	242
Core Non Residential	114	114	114	113	113
Noncore Non EG	165	164	162	160	158
EG	280	296	298	294	298
Wholesale	148	149	150	150	151
TOTAL	954	966	966	960	962

The table above shows the projected gas demand over the five year period covering 2012 to 2016. Gas demand in 2012 is expected to total 954 Bcf. The average, annual rate of growth from 2012 to 2016 is anticipated to be 0.2% based on the 2013 Triennial Cost Allocation Proceeding (TCAP) demand forecast. Demand is expected to be virtually flat in the future due to modest economic growth, CPUC-mandated energy efficiency goals and renewable electricity goals[53], declines in commercial and industrial demand and continued

[53] The EG gas demand forecast is surrounded by much uncertainty, given electricity demand, relatively few customers with potential large swings in usage, and sensitivity to changes in assumptions regarding new entrants. The electricity demand forecast, upon which the EG gas demand forecast is based, was agreed to by

increased use of non-utility pipeline systems by enhanced oil recovery customers and savings linked to advanced metering modules.

The gas demand projections shown above are in large part determined by the long-term economic outlook for the SoCalGas service territory. After several years of strong growth through 2006, the SoCalGas area's 12-county economy was hit by a severe housing slump starting in 2007, and a debt-related national financial crisis starting in 2008. From healthy 2.2% growth in 2006, the area's total employment grew by only 0.5% in 2007, then dropped by 1.6% in 2008 and plunged 6.4% in 2009, and a further fall of 1.4% in 2010. Recovery is expected to be gradual with local employment growth of 0.6% in 2011, 1.7% in 2012, then average annual growth of 1.9% from 2013 to 2015.

2. Rate Outlook from May 1, 2012 to April 30, 2013

(A) Listing of Pending Proceedings

Following is a listing of pending proceedings that have the potential to affect rates over the 12 month period beginning May 2012. Ultimately, the timing and level of impact of these pending proceedings on rates will be determined by the Commission.

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the IOUs, the CEC, and the CPUC. (Source: California Energy Commission's California Energy Demand 2010-2020, Staff Adopted Forecast.)

Filing Name	Proceeding Reference (e.g. Application #)	Filing Date	Requested/Expected Implementation date	Requested Dollar Amount			Description	Impacted Rate
				Total Cost	2011 RRQ	2012 RRQ		
Low Income Assistance Programs Budget for 2012-2014	A. 11-05-018	5/16/2011	Decision 2012, implementation 2013	$39 million increase in CARE and ESAP program costs over three years	$78.2 million for Low Income Energy Efficiency (ESAP) programs and $130.6 million for CARE programs, including the CARE subsidy	$90.4 million for Low Income Energy Efficiency (ESAP) programs and $131.1 million for CARE programs, including the CARE subsidy	This application requested the budgets for the CARE and ESAP programs, which constitute about 2/3 of the Public Purpose Program.	PPPS Residential rate increases 0.9 cents/therm
Energy Efficiency	R. 09-11-014				$66.0 million	$68.9 million	2010-2012 budgets established in D. 09-09-047. 2013-2014 budgets to be set via bridge extension funding in R. 09-11-014.	
Triennial Cost Allocation Proceeding	A. 11-11-002	11/1/2011	1/1/2013				Cost Allocation Proceedings reallocate costs between customer classes to determine cost-based transportation rates.	Core transportation rates increase 0.6 cents/therm; noncore rates decrease 0.4 cents/therm
AB32 Administrative Fee Recovery	A.10-08-002	10/1/2011	01/01/2013	$11.5 million			AB 32 administrative fees paid to the California Air Resources Board (ARB).	

Filing Name	Proceeding Reference (e.g. Application #)	Filing Date	Requested/Expected Implementation date	Requested Dollar Amount			Description	Impacted Rate
				Total Cost	2011 RRQ	2012 RRQ		
Amendment of Certificate of Public Convenience and Necessity for Aliso Canyon Gas Storage Facility	A. 09-09-020	9/28/2009	Expected 2015	$200.9 million (total project costs)		N/A, Expected 2015 revenue requirement of $23-$30 million, $8-$11 million for core rates	Amend the SoCalGas Aliso Canyon CPCN in order to authorize replacement of the three existing gas turbine compressors and associated equipment with a new electric compressor station and other improvements.	Transportation Core rates increase of 0.3 cents/therm.
SoCal Gas 2012 GRC Filing	A. 10-12-006	12/15/2010	mid-2012	$263 million (14.3%) increase over 2011 revenue requirement.		$2.107 billion	SoCalGas filed its most recent GRC for test year 2012.	Tranportation Core rates increase 5.8 cents/therm; noncore rates increase 0.5 cents/therm
Gas Pipeline Safety Rulemaking	R. 11-02-019	8/26/2011, amended 12/2/2011	mid-2012	$1,444 million Direct Costs for Phase 1A (Years 2012 - 2015) at SoCalGas		$58 million	In response to the commissions OIR regarding gas pipeline safety, SoCalGas filed a proposed Pipeline Safety Enhancement Plan (PSEP)	Res bills increase $0.68 per month in 2012 and $1.10 per month in 2013; non-res rates increase up to $0.008 per therm in 2012 and $0.013 per therm in 2013.

The following is a list of the timing of all new proceedings as well as those proceedings that are anticipated to affect rates during 2012.

SoCalGas Aliso Canyon Storage Field Expansion

On September 30, 2009, SoCalGas filed application (A.) 09-09-020 to amend its Certificate of Public Convenience and Necessity for the Aliso Canyon Gas Storage Facility. SoCalGas proposes to conduct work at its Aliso Canyon Storage Field to replace three gas turbine compressors with three electric compressors. The project, when completed, will expand storage injection capacity by 145 million cubic feet per day (MMcf/d). SoCalGas estimates the expansion cost to be $200.9 million. The increase in revenue requirements is estimated to be $23-$30 million per year starting in 2015. Once the project is complete, the expected initial core rate increase is forecast at 0.3 cents per therm. A final CPUC decision is expected later in 2012.

General Rate Case

In December 2010, SoCalGas filed its 2012 General Rate Case (GRC) Phase I application, A.10-12-006, to establish its authorized 2012 revenue requirement and the ratemaking mechanism by which this requirement will change on an annual basis over the subsequent three year (2013-2015) period. In July 2011, SoCalGas filed amendments to revise its original application, primarily to reflect the impact of the Tax Relief Unemployment Insurance Reauthorization and Job Creation Act of 2010. With these amendments, SoCalGas is requesting a revenue requirement in 2012 of $2.107 billion, an increase of $263 million (or 14.3%) over 2011. While the CPUC will determine the total amount of money SoCalGas can collect in rates in the GRC Phase 1 decision, the design of the actual rates themselves (that is, the allocation of costs between customer classes and the structure of charges) will be determined in the upcoming Tri-annual Cost Allocation Proceeding. A final decision is expected later in 2012.

Joint Utility Wildfire Cost Recovery Application (A.09-08-020)

SDG&E and SoCalGas filed an application, along with other related filings, with the CPUC in August 2009 proposing a mechanism for the future recovery of all wildfire-related expenses for claims, litigation expenses and insurance premiums that are in excess of amounts authorized by the CPUC for recovery in rates. This application was made jointly with Edison and PG&E. In July 2010, the CPUC approved SoCalGas's and SDG&E's requests for separate regulatory accounts to record the subject expenses while the joint utility application is pending before the CPUC. Several parties protested the original application, and in response, the four utilities jointly submitted an amended application in August 2010. In November 2011, SCE and PG&E requested to withdraw from the joint utility application due, in part, to the delays in the proceeding. In January 2012, the CPUC granted their requests to withdraw and held evidentiary hearings for SoCalGas and SDG&E, both of which are still moving forward with the application.

Gas Pipeline Safety

CPUC Decision (D).11-06-017 ordered all California natural gas transmission operators to develop and file for Commission consideration a Natural Gas Transmission Pipeline Comprehensive Pressure Testing Plan (Implementation Plan) to achieve the goal of orderly and cost effectively replacing or testing all natural gas transmission pipelines that have not been pressure tested. SoCalGas and San Diego Gas & Electric Company (SDG&E) jointly filed their comprehensive “test or replace” Implementation Plan on August 26, 2011, as directed by the CPUC. SoCalGas and SDG&E subsequently amended their Implementation Plan on December 2, 2011. SoCalGas and SDG&E propose to spend $1.681 billion ($1.444 billion for SCG; $237 million for SDG&E) over the 2012-2015 time period. The request is separate from their GRC Phase 1 proposals. The rate impact by customer class will depend on the level, cost allocation and timing of safety-related investment that is ultimately adopted by the Commission. A decision is expected in 2013.

2013 Triennial Cost Allocation Proceeding

On November 1, 2011, SoCalGas and SDG&E filed their Triennial Cost Allocation Proceeding application, A.11-11-002, to update their gas demand forecasts, cost allocation and rate design for the 2013 through 2015 period. The utilities propose continuation of 100% balancing account treatment for noncore revenues and extension of the 2009 Biennial Cost Allocation Proceeding Phase 1 Settlement through 2015. SDG&E is also proposing a $5 per month residential customer charge. The rate impact by customer class will depend on what cost allocation is ultimately adopted by the Commission. A CPUC decision is expected in 2013.

Assembly Bill 32

On September 27, 2006, Governor Schwarzenegger signed into law Assembly Bill (AB) 32, the "California Global Warming Solutions Act of 2006.” Among other provisions, AB 32 authorizes the California Air Resources Board (ARB) to adopt a schedule of fees to be paid by sources of greenhouse gas (GHG) emissions to fund the administrative costs of implementing AB 32. On September 25, 2009, the ARB approved the AB 32 Cost of Implementation Fee regulation at a public hearing. As specified in the regulation, the administrative fees shall apply to the public utility gas corporations and publicly owned natural gas utilities operating in California. Fees shall be paid for each therm of natural gas delivered to any end user in California, excluding that delivered to electricity generating facilities.

On August 2, 2010, SoCalGas, SDG&E, Pacific Gas and Electric Company and Southern California Edison Company filed a joint application, A.10-08-002, requesting approval to record and recover from their respective customers the fees they expect to pay to ARB under the AB 32 Cost of Implementation Fee regulation until such time these fees are included in their next GRC. The CPUC issued a decision on December 16, 2010 approving the utilities’ requests for regulatory accounts to record the AB 32 administration fees for possible later recovery. The decision established a second phase of the proceeding to determine whether the costs incurred prior to a utility’s next GRC would be recoverable in rates. SoCalGas’s annual administrative fees for implementing AB 32 are currently projected to be $5.5 to $6 million per year, which SoCalGas is proposing to recover in rates through its Environmental Fee Balancing Account.

In 2011, ARB invoiced SoCalGas approximately $11.5 million for administrative fees attributable to 2008 and 2009 emissions. Cost recovery of these fees is still pending a CPUC decision authorizing such recovery.

Energy Efficiency

The CPUC is proposing a two year bridge extension for 2013 and 2014 of the current energy efficiency programs. The expected 2012 cost of administering energy efficiency is $68.9 million and low income energy efficiency is $90.4 million, for a total of $159.3 million for SoCalGas.

Low Income Programs

A decision was issued on November 10, 2011 authorizing bridge funding from January 1, 2012 until June 30, 2012 so that the utilities could continue their CARE and Energy Savings Assistance Programs (ESAP) until the Commission adopts a final decision on their 2012-2014 program applications. SoCalGas and SDG&E filed their 2012-2014 program applications on May 16, 2011. SoCalGas is requesting three-year funding[54] of $290 million.

Gas Public Purpose Program Surcharge

The state's natural gas and electric utilities collect funds from core and non-EG noncore customers for gas related energy efficiency programs, low-income programs including the California Alternative Rates for Energy (CARE) subsidy, and for the California Energy Commission's natural gas research and development program. The annual budget for these public purpose programs is set in various recurring program-related Commission proceedings. The CARE program revenue requirement for SoCalGas's customers in 2011 was $130.6 million.

Honor Rancho Storage Field Expansion

On July 13, 2009, SoCalGas filed application A.09-07-014 with the Commission for the expansion of the Honor Rancho natural gas storage facility. D.10-04-034 approved SoCalGas's request to amend the Certificate of Public Convenience and Necessity for the Honor Rancho natural gas storage facility. The proposed capital cost of $37.4 million for the expansion project, excluding the cost of cushion gas, was deemed reasonable by the Commission. SoCalGas obtained approval in November 2011 to establish a memorandum account to record costs that exceed the previously authorized $37.4 million cap for capital expenditures. The approved memorandum account is consistent with the CPUC decision granting SoCalGas authority to expand its Honor Rancho storage field. The estimated additional costs of the expansion are $13.8 million. SoCalGas has requested CPUC approval to recover the excess costs as part of its Triennial Cost Allocation Proceeding application filed on November 1, 2011. A decision in the Triennial Cost Allocation Proceeding is expected in 2013. The Honor Rancho project increased the 2012 revenue requirement by $4 million.

Advanced Metering Infrastructure (AMI)

AMI will enable our customers to better control and manage their energy bills with access to timely natural gas usage information and to realize the substantial operational and environmental benefits. The AMI deployment period as approved in D.10-04-027 runs from 2010-2017. The approved AMI deployment costs are $1.051 billion, consisting of $876 million

[54] This represents the total program costs for the Energy Savings Assistance Program of $266 million and the CARE administrative costs of $24 million. CARE subsidy costs for the three years are estimated to be $390 million.

in capital expenses and $175 million in O&M expenses. The AMI project increased the 2012 revenue requirement by $35 million.[55]

(B) New Proceedings Likely to be Filed Between Now and April 30, 2013

SoCalGas anticipates filing a Cost of Capital (COC) application in April 2012 for a 2013 test year. A cost of capital proceeding determines the authorized capital structure, authorized rate of return and authorized rate for recovery of debt service costs on SoCalGas's natural gas transmission and distribution assets. SoCalGas's current CPUC authorized return on equity is 10.82 percent with authorized common equity capital structure of 48.00 percent.

SoCalGas will file its Gas Cost Incentive Mechanism (GCIM) Year 18 application in June 2012. SoCalGas will request a shareholder award consistent with the established sharing mechanism for the purchases below the GCIM benchmark.

SB 695 Compliance Report – Part II

I. Introduction

On February 17, 2012, SoCalGas submitted to the Energy Division data related to gas revenue requirements and rates, including: (1) a description of the key categories of revenue requirements, trends for each category in the coming 12 months, and load/demand forecasts, and (2) the outlook of anticipated rate changes during 2012 and the amount of the change if it is known.

In this submittal, SoCalGas provides an overview of key filings which may have a significant impact on gas customer rates, an overview of SoCalgas's overall rate policy, an overview of management control of rate components, and a summary of policies and recommendations for limiting customer rate impacts while meeting the States' energy and environmental goals for reducing greenhouse gases. SoCalGas hopes that the CPUC will consider the recommendations set forth in this report, which SoCalGas believes can have a measurable near-term impact on its total cost of delivering safe, reliable, cost-effective gas services to its customers in California.

II. Section 748 (b) Study and Report

1. Opening Comments

Attached for your reference is Appendix A, which reflects data from key filings provided previously to the Energy Division. This is not an exhaustive list of SoCalGas's filings that may occur in 2012. Rather, the list incorporates regulatory filings that are known at this time to have a significant rate impact for gas customers. Actual filing dates, amounts of requests, and actual revenue requirements authorized are subject to change via the normal regulatory approval processes of the CPUC and the Federal Energy Regulatory Commission.

2. Overall Rate Policy

SoCalGas seeks to allocate costs fairly across its customer classes within the framework approved by the CPUC and the Legislature. SoCalGas recognizes that allocations of certain

[55] The $35 million will NOT be part of the $2.107 billion 2012 GRC revenue requirement.

components of gas service costs in rates are beyond its direct control. Absent market based prices for natural gas transportation service, SoCalGas's overall rate policy is to follow the cost causation principle whereby rates are based on the costs required to provide its customers with safe and reliable gas service. SoCalGas understands that its customers value low rates, transparency, and stability. Therefore, SoCalGas also seeks to minimize the impact of rate adjustments when they are made by phasing in impacts to avoid rate shock whenever possible. SoCalGas, like the other gas utilities in California, makes monthly advice letter filings to change the gas commodity rate which is based on the monthly cost of gas. SoCalGas also files for an annual gas transportation and Public Purpose Program surcharge rate change in January of each year. In addition, SoCalGas submits various filings to the Commission throughout the year in response to specific Commission directives or changes to the utility business.

3. Management Control of Rate Components

In order to keep rates as low as possible, SoCalGas buys low cost gas and participates actively in interstate pipeline rate cases to make sure that transportation costs are just and reasonable. In addition to safety and reliability, SoCalGas prioritizes operational efficiency and cost containment. In light of these priorities, SoCalGas performs continuous reviews of its systems and operations to identify areas for improved performance. Performance based incentive mechanisms, such as the Gas Cost Incentive Mechanism, align shareholder and customer interests and result in operational efficiencies and lower rates. However, there are some key drivers that affect customers' rates that fall outside of SoCalGas's control. These include: gas commodity prices, actual sales volumes, weather, natural disasters, interest rates and economic growth, permitting process delays, and compliance with new environmental regulations. Despite these factors, SoCalGas works hard to manage its costs across all categories to make efficient and effective use of revenues collected from customers.

4. Utility Policies and Recommendations for Limiting Costs and Rate Increases While Meeting State's Energy and Environmental Goals for Reducing Greenhouse Gases

In this section, SoCalGas offers a set of recommendations for actions that the Commission may consider as it prepares its own annual report to the Legislature and Governor on measures that can be undertaken in the coming year to limit utility costs and rate increases. These recommendations center on factors largely out of the scope of the utilities' control, and are expected to have a significant impact on utility costs and resultant customer rates in the near- to medium-term.

SoCalGas continues to use best operating and infrastructure investment practices to limit rate increases while still meeting California's energy efficiency and greenhouse gas reduction goals. SoCalGas supports the State's Energy Action Plan by promoting all mandated energy efficiency programs. SoCalGas is working with regulators and other stakeholders to ensure that the regulation being developed by the California Air Resources Board to implement the AB 32 Cap and Trade program is fair and as cost-effective as possible. SoCalGas is also considering regulatory approval to participate in the development of renewable energy sources, such as biogas, that will reduce GHG emissions in California.

The impact to SoCalGas's customers from energy efficiency, low income energy efficiency, CARE, technology research, development, and demonstration (RD&D) and the implementation of the AB 32 administration fee is shown below.

COMPONENT	ANTICIPATED COSTS AS OF 1/1/12		
	Core	Non-Core	Total
Energy Efficiency/DSM	$63,630,575	$5,269,425	$68,900,000
Low Income Energy Efficiency/DAP	$90,374,200	$0	$90,374,200
CARE	$87,042,470	$44,088,027	$131,130,497
RD&D	$11,220,944	$541,206	$11,762,150
AB 32 Administrative Fee	~	~	$11.5 million[56]

In the coming year, SoCalGas recommends that several key State policies and procedures should be shaped to support more effective, efficient and beneficial use of revenues collected from SoCalGas's customers. SoCalGas believes that the State will have to weigh its environmental goals and desire for reliability that cause significant upward cost pressures against its desire to moderate impacts on customers' rates for gas service. Here is a list of items in which policy decisions could drive customer rate impacts.

1. AB 32 Cap and Trade Implementation: Residential and small commercial natural gas customers have already achieved a reduction to 1990 emission levels through existing energy efficiency programs and, therefore, should be exempted from the AB 32 Cap and Trade Regulation. If they are not exempted, they should be given a free allocation of allowances to recognize this history of maintaining natural gas related emissions at 1990 levels since 1990. It would be inappropriate, and damaging to the California economy to unnecessarily impose costs of GHG regulation on customers that have already achieved the objectives of AB 32.
2. Combined Heat and Power (CHP): CHP reduces overall energy use by using waste heat to generate power. CHP entails low carbon generation and its widespread use will have carbon reducing benefits. Both the CPUC and the Energy Commission have supported the development of CHP to meet California's energy needs. This source has contributed substantially to reducing California's Greenhouse Gas Emissions.[57]
3. Performance-Based Incentives Mechanisms: Continue to support the utilization of performance based mechanisms to motivate utilities to implement programs that will lead to an overall reduction in costs and improve the efficiency of utility operations. These mechanisms work because (1) they align customers' and shareholder interests; (2) they measure a utility's performance relative to a market based benchmark; and (3) they reduce the regulatory burden.

[56] Cost recovery is pending CPUC approval. This ongoing annual fee should be part of the GRC in 2012 and going forward.
[57] Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to examine the Integration of GHG Standards in its Procurement Policies, pp. 221, R.06-04-009.

4. California Alternative Rates for Energy (CARE): CARE customers now comprise one third of SoCalGas's customer base. Non-CARE customers must cover the CARE shortfall, which leads to a 10% increase of non-CARE costs. Safeguards should be taken to ensure only qualified customers are participating in the program.
5. Public Interest Energy Research (PIER) Program Costs: The program allows the utilities to shift funds from the Public Purpose Program Surcharge and transfer it to the CEC for studies. SoCalGas is concerned about the potential overlap between PIER priorities and research with the work done by other publicly funded research organizations. Optimizing the effectiveness of the PIER program would help reduce the PPP rate, which has had the largest impact on non-core rates. Almost 40% of the transportation rate for non-core customers is attributable to the PPP.
6. Utility Rate Cases: The CPUC, intervenors and customers would save money if the General Rate Cases continue to be kept on a four-year cycle, instead of a three-year cycle.
7. Reporting Requirements: Mandated reporting requirements should be reviewed to make sure they are useful and non-duplicative.

In summary, California leads the nation in promoting the reduction in GHG emissions, adoption of advanced technologies and expenditures on public purpose programs mandated by law. However, the costs associated with implementing these policies place upward pressure on utilities' rates. In order to manage utility costs and rate increases, SoCalGas recommends modifications to certain statewide mandates and to the frequency of various CPUC filing requirements. In addition, due to the mild weather and implementation of energy efficiency measures, the gas usage per customer in California is far below the national average. These factors lead to higher rates overall but also lower customers' bills. SoCalGas supports the above-referenced policies. However, SoCalGas believes that the utilities should be provided more flexibility in implementing mandates and requirements in order to achieve lower costs for all customers.

Appendix A

Requests Impacting Customer Rates
During the Year of 2012
Appendix A

Description	Filed	Expected Implementation	Impacted Rate	Directional Impact	Revenue Requirement Impact ($000)	Reason for Revenue Requirement Request
Gas Regulatory Account Update AL	October 2012	January 2013	Gas Transportation	↑	$6,017	(1)
Gas Consolidated AL	December 2012	January 2013	Gas Transportation	↑	$52,118	(1) (2)
Gas Public Purpose Program Update AL	October 2012	January 2013	PPP Surcharge	↑	$14,941	(1)

(1) Shows increase from 2011 to 2012. This is an annual routine filing in which the specific financial impact for 01/2013 has not been determined.
(2) Gas Consolidated AL 4314 includes the Gas Regulatory Account Update AL, AMI Revenue Requirement , and other changes

D. San Diego Gas and Electric Company

San Diego Gas & Electric (SDG&E) appreciates the opportunity to provide input to the California Public Utilities Commission (CPUC or Commission) in response to Senate Bill (SB) 695 enacted changes to PUC Section 748. SDG&E's objective in developing this report is to provide useful information that the CPUC may consider as it prepares its annual report for the Governor and Legislature. This report addresses PUC Section 748(a) and provides data related to both gas and electric revenue requirements and rates. SDG&E's response addressing PUC Section 748(b) is to be provided separately. This report is structured as per the Energy Division's request: (1) description of revenue requirements describing key categories of revenue requirements, trends for each category in the coming 12 months, and load/demand forecasts, and (2) outlook from May 1, 2012 to April 30, 2013 listing of pending and anticipated revenue requirements.

Section 748(a) Study and Report

1. Description of Revenue Requirement Components (Gas and Electric)

A. Key Revenue Requirement Categories

This section provides a summary outlining SDG&E's major revenue requirement (RRQ) categories for both electric and gas, including a description of key categories of revenue requirements, the associated revenue requirement amount and the percentage contribution to total revenue requirements as commonly monitored within SDG&E:

Electricity cost categories include:

- Commodity/Generation – This is the generation charge for the electricity you use and includes charges for the energy provided by both SDG&E and DWR and includes purchased power costs, utility-owned generation costs, Department of Water Resources charges (DWR), and other revenue requirements linked to generating and procuring the electricity commodity.
- Department of Water Resources Bond Charge (DWR-BC) – The Department of Water Resources (DWR) Bond Charge pays for bonds issued by DWR to cover the costs of purchased power during the electricity crisis.
- Competition Transition Charge (CTC) – Through this charge, SDG&E recovers costs for power contracts approved by state regulators that have been made uneconomic by the shift to competition.
- Nuclear Decommissioning – This charge pays for the retirement of nuclear power plants.
- Transmission – The purpose of this charge is to deliver high-voltage electricity from power plants to distribution points near your home or business. It includes the cost of high-voltage power lines and towers as well as monitoring and control equipment.

- Reliability Service – The Independent System Operator is required to ensure adequate generation to maintain electric system reliability. This means enough generation facilities available to meet the demand for electricity at all times.
- Distribution – This charge reflects the costs to distribute power to customers and includes power lines, poles, transformers, repair crews and emergency services. In addition, distribution rates recover program costs related to California Solar Initiative (CSI), Self-Generation Incentive Program (SGIP), and demand response.
- Public Purpose Programs (PPP) – This charge reflects the costs of certain state-mandated programs (such as low income and energy efficiency programs).
- Total Rate Adjustment Component (TRAC) – This charge reflects the subsidies that result from capped residential tiered rates under Assembly Bill 1X and SB695 Legislation.

Relative ranges for each RRQ category as a percent of total authorized 2011 RRQ, and 2012, for rates effective on January 1st of each year are provided and discussed below. Note that the focus is not on specific filings brought forth to the Commission, but rather categories of revenue requirements that could have a potential impact on future rates.

This table shows the revenue and percentage change for each of the major revenue components from 2011 to 2012.

	2011*		**2012***				
Revenue Component	**Revenue Requirement ($000)**		**Revenue Requirement ($000)**		**Revenue Change ($000)**		**Percent Change (%)**
Commodity	1,285,589		1,266,780		(18,808)		-1.46%
DWR-BC	94,770		96,271		1,501		1.58%
CTC	28,394		70,786		42,392		149.30%
ND	8,338		9,124		786		9.43%
Transmission	327,024		359,801		32,776		10.02%
RS	19,936		(4,754)		(24,690)		-123.85%
Distribution	1,241,965		1,076,717		(165,248)		-13.31%
PPP	128,033		145,683		17,650		13.79%
TRAC	34,609		52,899		18,290		52.85%
Total	3,168,657		3,073,306		(95,350)		-3.01%

The table below shows revenue requirements for each of the major components as a percent of total revenue year to year.

	2011*			2012*		
Revenue Component	**Revenue Requirement ($000)**		**Percent**	**Revenue Requirement ($000)**		**Percent**
Commodity	1,285,589		40.57%	1,266,780		41.22%
DWR-BC	94,770		2.99%	96,271		3.13%
CTC	28,394		0.90%	70,786		2.30%
ND	8,338		0.26%	9,124		0.30%
Transmission	327,024		10.32%	359,801		11.71%
RS	19,936		0.63%	(4,754)		-0.15%
Distribution	1,241,965		39.20%	1,076,717		35.03%
PPP	128,033		4.04%	145,683		4.74%
TRAC	34,609		1.09%	52,899		1.72%
Total	3,168,657		100%	3,073,306		100%

*Reflects rates effective January 1st. DWR-BC represents estimated rate revenues based on authorized rates and sales. Revenue requirements presented includes FF&U.

1) The largest piece of SDG&E's revenue requirement is Commodity/Generation which is currently 41.22% of total revenue requirement and is generally expected to increase over time primarily due to increasing electricity procurement costs related to renewable energy costs and increasing natural gas prices. Revenue requirements decreased by 1.46% from 2011. Most recently, favorable gas prices and delays in contracted renewable resources coming on-line have caused commodity prices to trend downward. With the expiration of DWR contracts, revenue requirements associated with DWR Power Charges are a declining portion, from 6% in 2011 to 3% in 2012. These costs, known as DWR Power Charge revenue requirement, are embedded in the commodity rate.
2) CTC contributes 2.30% of the total revenue requirement in 2012. CTC revenue requirements were 0.90% during 2011. In 2012, revenue requirements were $70.8 million. This represents an increase from 2011 of 149.30%. Above market costs of CTC resources increased in 2012 due to lower market price benchmark and lower gas prices.
3) Transmission related revenue requirements constitute 11.71% of the total authorized revenue requirement up from 10.32% in 2011. Revenue requirements increased by $32.8 million or 10.02% from 2011.
4) Distribution revenue requirements, including CSI, SGIP and Smart Meter, comprise approximately 35.03% of the total revenue requirement, down from 39.20% in 2011 primarily due to the roll off of AMI revenue requirement[56] and amortization, delay in receiving the 2012 GRC Phase 1 decision (A.10-12-005), and roll off of CSI. Pursuant to D. 11-12-019 dated December 12, 2011, SDG&E will not be collecting anything for CSI in 2012, as implemented in Advice Letter 2323-E. In 2012, revenue requirements decreased by 13.31% or $165 million.

[56] D. 07-04-043 as modified by D.11-03-042 approved a revenue requirement for AMI through 2011. Revenue requirement beyond 2011 will be addressed in SDG&E's 2012 GRC (A.10-12-005).

5) PPP revenue requirements, including California Alternate Rates for Energy (CARE) Discount and Energy Efficiency, represent 4.74% of SDG&E's total revenue requirement during 2012. In comparison, PPP revenue requirements represented 4.04% of the total authorized revenue requirement during 2011. The PPP revenue requirement of approximately $146 million for 2012 includes the amount to cover CARE discounts. The 2012 PPP revenue requirements represent an increase from 2011 of 13.79%.
6) Nuclear Decommissioning and Reliability Services revenue requirements each represented less than 1% of SDG&E's total authorized revenue requirement during 2011 and remained less than 1% in 2012. Nuclear Decommissioning revenue requirements increased by $0.8 million or 9.43% from 2011. In 2012, revenue requirements associated with Reliability Services decreased from 2011 by $24.7 million or 123.85%.
7) TRAC was just over 1% in 2011 increasing to 1.72% in 2012 due to actual Tier 3 and Tier 4 sales being lower than authorized sales. TRAC maintains rate caps for Tier 1 and Tier 2 and recovery of associated subsidies through Tier 3 and Tier 4. Revenue requirements increased from 2011 by $18.3 million or 52.9%.

This section outlines major categories of gas revenue requirements (RRQ) as commonly monitored within SDG&E:

Gas revenue requirements are commonly grouped into the following three major categories: Energy Costs or Weighted Average Cost of Gas (WACOG), Transportation, and Public Purpose Programs.

	2011		2012	
Revenue Component	**Revenue Requirement** $000	**Percentage**	**Revenue Requirement** $000	**Percentage**
Energy	$202,796 [1]	38.0%	$159,050 [2]	35.5%
Transportation [3]	$285,363	53.5%	$242,747	54.2%
PPP	$45,583	8.5%	$46,062	10.3%
Total	$533,742	100%	$447,860	100%

[1]Actual recorded revenue.
[2]Represents estimates of the residential, core commercial and industrial, and natural gas vehicles energy revenue and was derived by multiplying the *2010 California Gas Report* throughput projection by the gas price forecast for the year 2012.
[3]The transportation component includes Authorized Base Margin, amortization of regulatory accounts, other operating costs, System Integration, and Sempra-wide adjustments.

1) Energy revenue requirements are forecast to represent approximately 35.5% of the total gas revenue requirement for 2012. The revenue requirements are expected to decrease from 2011 to 2012 due to low natural gas prices. The energy revenue requirement represented about 38.0% of the total authorized gas revenue requirements in 2011.
2) Transportation revenue requirements will constitute about 54.2% of the total gas revenue requirements in 2012. For 2011, the transportation revenue requirement constituted about 53.5% of the total authorized gas revenue requirements. The decrease

in the revenue requirement is primarily due to lower balancing accounts, but the increase in its relative percentage of total revenue requirement is due to lower energy costs. SDG&E is expecting a decision in its General Rate Case sometime in early 2012, which will have an impact on transportation revenue requirement when it is anticipated to be implemented later this year.

3) PPP revenue requirements, including California Alternate Rates for Energy (CARE) Discount and Energy Efficiency, will represent approximately 10.3% of the total gas revenue requirements in 2012. The revenue requirement is expected to trend upward mainly due to increases in expected gas program penetration levels (Energy Efficiency goals) and CARE participation. Additionally, SDG&E is anticipating a decision on its Low-Income Assistance budgets in early 2012, which will slightly increase revenues when it is implemented. For 2011, these programs contributed about 8.5% of the total authorized gas revenue requirements.

B. Trends in Rate Components

The revenue requirements (RRQ) discussed in the previous section directly aligns with rate components. At the highest level, gas and electricity rates can be described as revenue requirements divided by sales, so both revenue requirement changes and demand variations impact the actual rates for gas and electric service. Forecasted increases in the RRQ over the next twelve months will impose upward pressure on rates; forecasted decreases in the RRQ will impose downward pressure on rates. The rate pressures created by RRQ are modulated by differences in actual sales versus prior estimates (used to set rates). Adjustments in the allocation of revenue requirement across customer classes and tiers also impact the rates experienced by individual customers.

Customer sales volatility across time directly impacts the rates charged to natural gas and electricity customers. If revenues collected from customers are impacted (higher or lower) due to volatility in sales, future rates will be adjusted (decreased or increased) in order to ensure revenues collected are at authorized levels. SDG&E reviews load forecasts for its service territory on a regular basis. The following section discusses the general trends for gas and electricity loads during 2012.

C. Load and Demand Forecasts

This section outlines major categories of electric and gas demand and the load forecasts through 2016.

SDG&E is a combined gas and electric distribution utility serving more than three million people in San Diego and the southern portions of Orange counties. In 2011, SDG&E delivered 19.5 billion kWh of electricity to 1.4 million customers. Approximately 83% of sales were delivered to bundled service customers (commodity, transmission and distribution), and 17% to Direct Access customers (transmission and distribution only). On September 7, 2011, SDG&E's record peak demand was 4,371 megawatts.

Looking ahead to the next five years, the number of electric customers is expected increase an average rate of 1.0% per year, gradually recovering from a historic low growth rate of 0.5 percent in 2010 to nearly 1.2 percent by 2016. Electric sales and peak demand for the same period are projected to grow at an average 1.0 percent per year.

Composition of SDG&E Electric Sales (GWh)

Sales in GWh	2012	2013	2014	2015	2016
Residential	7,716	7,802	7,912	8,039	8,121
Small Commercial	1,929	1,927	1,915	1,903	1,894
Med & Large Com/Ind	10,719	10,885	10,991	11,095	11,178
Agricultural	88	88	87	87	87
Lighting	113	114	115	116	117
Total System	**20,565**	**20,816**	**21,020**	**21,241**	**21,396**

Source: *SDG&E's 2011 Long-Term Procurement Plan*

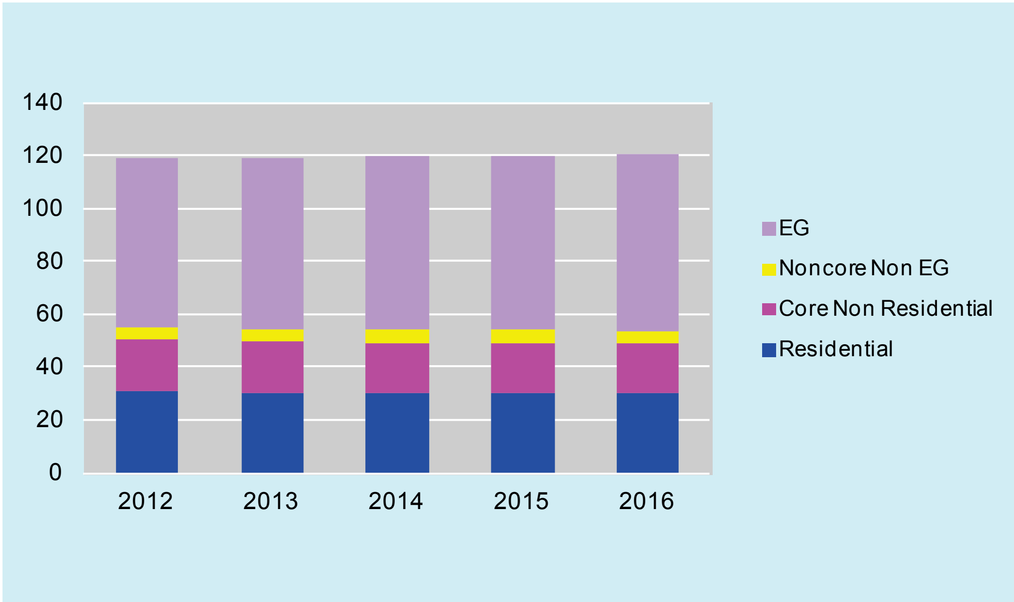
On the natural gas side, SDG&E delivers natural gas to over 845,000 customers in San Diego County, including the power plants and turbines previously owned and operated by the company. Total gas sales and transportation through SDG&E's system for 2011 were approximately 117 billion cubic feet (Bcf). Gas demand for 2012 is 119 Bcf and the forecast is expected to remain relatively flat over the next 5 years.

SDG&E's forecast of electric and gas demand is largely determined by the long-term economic outlook for its San Diego County service area. The county's economic trends are expected to generally parallel those of the larger SoCalGas area, reflecting a gradual recovery from the current recession.

Composition of SDG&E Gas Requirements (Bcf)
Average Temperature and Normal Hydro Year (2012-2016)

Sales in BCF	2012	2013	2014	2015	2016
Residential	31	30	30	30	30
Core Non-Residential	19	19	19	19	19
Noncore Non-EG	5	5	5	5	5
EG	64	65	65	66	66
Total	119	119	119	120	120

Composition of SDG&E's Gas Requirements (Bcf)
Average Temperature and Normal Hydro Year (2012-2016)



2. 2012 CPUC Filing Outlook

A. Outlook from May 1, 2012 to April 30, 2013 – Pending Proceedings

The following provides a list of pending proceedings that are likely to affect rates, including a short summary of the requested amount of the revenue requirement change and the reasons for it.

Joint Application of PG&E, SCE and SDG&E for Adoption of Electric Revenues and Rates Associated with Market Redesign & Technical Upgrade (MRTU) (A.12-01-014)

Pursuant to the August 12, 2011, *Ruling Providing Further Guidance for the Purpose of Reviewing MRTU Costs*, the Joint Utilities filed a Joint Application proposing the recovery of the actual, incremental costs each incurred in 2010 to implement the California Independent System Operator's (CAISO's) MRTU initiative. SDG&E requests $1.6 million associated with undercollections recorded in the MRTU Memorandum Account in 2010. The Joint Utilities request the Commission to authorize their respective proposed ratemaking mechanisms and procedural vehicles to permit MRTU-related costs to be considered in their respective General Rate Case (GRC) proceedings instead of their respective annual Electric Resource Recovery Account (ERRA) compliance cases.

SDG&E Connected.....To The Sun (A.12-01-008)

On January 17, 2012, SDG&E submitted an *Application For Authority To Implement Optional Pilot Program to Increase Customer Access to Solar Generated Electricity*. This Application submits for Commission approval two pilot programs which will give all customers the opportunity to access solar energy through their retail electric service by SDG&E. One program, "SunRate", is a green tariff program permitting bundled residential customers to purchase electricity from solar projects located in SDG&E's service territory. The other, entitled "Share the Sun", permits customers to contract directly with solar provider/developers for solar generated electricity to be delivered by SDG&E. If approved, the proposed programs would not impact distribution and commodity revenue requirements collected through current distribution and commodity rates**.**

Triennial Cost Allocation Proceeding – Gas (A.11-11-002)

On November 1, 2011, SoCalGas and SDG&E filed their Triennial Cost Allocation Proceeding application, A.11-11-002, to update their gas demand forecasts, cost allocation and rate design for the 2013 through 2015 period. The utilities propose continuation of 100% balancing account treatment for noncore revenues and extension of the 2009 Biennial Cost Allocation Proceeding Phase 1 Settlement through 2015. SDG&E is also proposing a $5 per month residential customer charge. The rate impact by customer class will depend on what cost allocation is ultimately adopted by the Commission. A CPUC decision is expected in 2013.

2012 GRC Phase 2 – Electric (A.11-10-002)

SDG&E filed its 2012 GRC Phase 2 on October 1, 2011 and re-submitting its filing on February 17, 2012 with the exclusion of the Network Use Charge. This proceeding is to allocate authorized costs to the different customers' classes; and, to then design the rate structure within each class. Costs are allocated based on the concept of cost causation to determine marginal costs, revenue allocation, and rate design for electric customers. Cost causation seeks to determine which customer or group of customers causes the utility to incur particular types of costs.

2012 ERRA Forecast Application (A.11-09-022)

On September 30, 2011, SDG&E filed an application for approval of its forecasted electric procurement revenue requirement for 2012, referred to as SDG&E's 2012 Energy Resource Recovery Account (ERRA) Forecast Application (A.11-09-022). SDG&E requested approval of its ERRA and CTC revenue requirements to cover the costs of acquiring power for retail customers, including costs to purchase power under contracts with various power suppliers. On February 24, SDG&E filed an amendment to its 2012 ERRA Forecast Application to update the market price benchmark and revise its gas price forecast, which decreased the revenue requirements originally requested.

Joint Application of SDG&E, PG&E & SCE for Lawrence Livermore National Laboratories for 21st Century Energy Systems (A.11-07-008)

The Joint Utilities submitted this Application to recover the costs associated with a five-year cooperative research and development agreement with the Lawrence Livermore National Laboratory (LLNL). This public-private collaborative agreement is known as the "California Energy Systems for the 21st Century Project" (CES-21 Project). The IOUs and LLNL propose the CES-21 Project with the objective of providing advanced tools, analyses, and training to guide and manage both California's power and natural gas systems. The project will utilize a joint team of technical experts from the IOUs and LLNL who will combine data integration with the nation's most advanced modeling, simulation, and analytical tools provided by LLNL to provide unprecedented problem-solving and planning necessary to achieve California's ambitious energy and environmental goals for the 21st century. The project activities will primarily center around Cyber Security, Electric Resource Planning, Electric and Gas System

Operations and Workforce Preparedness. This application specifically requests funding up to a maximum of $150 million over five years shared amount the IOS as follows: PG&E (55%), SCE (35%) and SDG&E (10%).

Smart Grid Deployment Plan (A.11-06-006)

SDG&E filed its Smart Grid Deployment Plan in compliance with D.10-06-047 in the second quarter of 2011. While this is not an application for authority to make smart grid investments, it will set forth a plan for future smart grid investments that may be pursued by SDG&E in the future.

SDG&E's Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power (A.11-05-023)

On May 19, 2011, SDG&E filed an application for the Commission's approval of three long-term Power Purchase Tolling Agreements (PPTAs) that would add a total of approximately 450 MW of needed local capacity to SDG&E's service area. These projects are necessary generation resources to meet both system and local resource adequacy (RA) requirements. SDG&E seeks the Commission's confirmation that SDG&E may pursue the cost recovery of its costs associated with these Agreements and the rebalancing of SDG&E's capital structure in accordance with Financial Accounts Standards Board (FASB) Interpretation No. 46 (R) (FIN 46(R)) in its next Cost of Capital proceeding. The Commission's approval of the three PPTAs will allow SDG&E to maintain existing local capacity required in order to meet peak energy needs.

SDG&E's Seismic Study Application (A.11-05-011)

San Diego Gas & Electric Company (SDG&E) filed this application to recover in electric rates its allocable share of the costs of seismic and tsunami research and studies related to the operation of the San Onofre Nuclear Generating Station Unit Nos. 2 and 3 (SONGS 2&3). SDG&E is a minority owner of SONGS 2&3, holding an undivided twenty-percent (20%) ownership interest in those units. The relevant research and studies would be performed for purposes of updating and reassessing seismic and/or tsunami hazards and risks relevant to the safe operation of SONGS 2&3. SCE, the majority owner, had originally included certain of these costs in its pending Test Year 2012 GRC, but was instructed by the Commission to file a separate application for these costs so that the costs could be reviewed separately and expeditiously. To the extent the Commission approves SCE's application to fund the research and studies described in Application 11-04-006, twenty percent of the costs of the research will be allocated to and reimbursed by SDG&E. SDG&E filed the instant application so that its allocable share of the research and/or study costs will be reflected in its Commission-jurisdictional electric rates. After adding contractual overheads pursuant to the terms of the Second Amended San Onofre Operating Agreement to this amount, SDG&E expects its share of post-2011 research and study costs will equal approximately $12.6 million.

Pipeline Safety (R.11-02-019)

CPUC Decision (D).11-06-017 ordered all California natural gas transmission operators to develop and file for Commission consideration A Natural Gas Transmission Pipeline Comprehensive Pressure Testing Plan (Implementation Plan) to achieve the goal of orderly and cost effectively replacing or testing all natural gas transmission pipeline that have not been pressure tested. SoCalGas and SDG&E jointly filed their comprehensive "test or replace"

Implementation Plan on August 26, 2011, as directed by the CPUC. SoCalGas and SDG&E subsequently amended their Implementation Plan on December 2, 2011. SoCalGas and SDG&E propose to spend $1.681 billion ($1.444 billion for SCG; $237 million for SDG&E) over the 2012-2015 time period. The request is separate from their GRC Phase 1 proposals. The rate impact by customer class will depend on the level, cost allocation and timing of safety-related investment that is ultimately adopted by the Commission. A decision is expected in 2013.

2012 GRC Phase 1 (A.10-12-005)

In December 2010, SDG&E filed its 2012 General Rate Case (GRC) Phase I application, A.10-12-005, to establish its authorized 2012 revenue requirement and the ratemaking mechanism by which this requirement will change on an annual basis over the subsequent three year (2013-2015) period. In July 2011, SDG&E filed amendments to revise its original application, primarily to reflect the impact of the Tax Relief Unemployment Insurance Reauthorization and Job Creation Act of 2010. With these amendments, SDG&E is requesting a revenue requirement in 2012 of $1.845 billion, an increase of $231 million (or 14.3%) over 2011. While the CPUC will determine the total amount of money SDG&E can collect in rates in the GRC Phase 1 decision, the design of the actual rates themselves (that is, the allocation of costs between customer classes and the structure of charges) will be determined in the upcoming Tri-annual Cost Allocation Proceeding for gas costs, and in the GRC Phase 2 (A.11-10-002) for electric costs. A final decision in the GRC Phase 1 is expected later in 2012.

AB 32 Administrative Fee Recovery (A.10-08-002)

On September 27, 2006, Governor Schwarzenegger signed into law Assembly Bill (AB) 32, the "California Global Warming Solutions Act of 2006." Among other provisions, AB 32 authorizes the California Air Resources Board (ARB) to adopt a schedule of fees to be paid by sources of greenhouse gas (GHG) emissions to fund the administrative costs of implementing AB 32. On September 25, 2009, the ARB approved the AB 32 Cost of Implementation Fee regulation at a public hearing. As specified in the regulation, the administrative fees shall apply to the public utility gas corporations and publicly owned natural gas utilities operating in California. Fees shall be paid for each therm of natural gas delivered to any end user in California, excluding that delivered to electricity generating facilities.

On August 2, 2010, SoCalGas, SDG&E, Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) filed a joint application, A.10-08-002, requesting approval to record and recover from their respective customers the fees they expect to pay to ARB under the AB 32 Cost of Implementation Fee regulation until such time these fees are included in their next GRC. The CPUC issued a decision on December 16, 2010 approving the utilities' requests for regulatory accounts to record the AB 32 administration fees for possible later recovery. The decision established a second phase of the proceeding to determine whether the costs incurred prior to a utility's next GRC would be recoverable in rates. Cost recovery of these fees is still pending a CPUC decision authorizing such recovery.

Rim Rock Tax Equity (A.10-07-017)

On July 15, 2010, SDG&E filed a request with the CPUC for approval to make an equity investment in the NaturEner Montana Wind Energy 3 (Rim Rock) project equal to the lesser of $600 million or eighty percent (80%) of the total cost of the project. This investment will reduce the financing costs of the Rim Rock project, which in turn will produce more economic contract terms for ratepayers under the existing Power Purchase Agreement (PPA) between NaturEner and SDG&E for 309 MW of renewable wind generation. In addition, SDG&E's investment will enhance the viability of the project which is expected to provide a significant quantity of renewable energy to SDG&E's portfolio. The application seeks approval of the revenue requirement associated with the equity investment that would take effect at the time the Rim Rock project is put into commercial operation, which is anticipated to be late 2012. The structure of the tax equity investment and the ratebase mechanism to recover the investment are detailed in SDG&E's application.

Dynamic Pricing Application (A.10-07-009)

On July 6, 2010, SDG&E filed its Dynamic Pricing Application with the CPUC. SDG&E's request extends rate options to the Small Nonresidential and Residential customer classes, in accordance with the Commission's policy to make dynamic pricing available for all customers. SDG&E's proposed rates presented in its application constitute "dynamic" or "time-differentiated" pricing rates in that they are priced based on electric usage according to the time-of-day and the demand response of electric customers. In addition, SDG&E will be able to activate a Reduce-Your-Use Day when it determines there is a genuine need to call on customers for temporary reductions in electricity demand. SDG&E is requesting authority to increase its base rates, effective 3rd Quarter 2011. SDG&E's application includes a detailed forecast of the incremental cost being requested and a description of why this increase is necessary and reasonable.

ERRA Compliance Application (A.11-06-003)

On June 1, 2011, SDG&E filed an application for Energy Resource Recovery Account (ERRA) compliance review (ERRA Application) with the CPUC. The application seeks approval of SDG&E's electric procurement activities and related accounting for the 12-month record period of January 1, 2010 through December 31, 2010. In addition to presenting SDG&E's recorded costs in its ERRA and Transition Cost Balancing Account (TCBA) for review, SDG&E's ERRA Application requests CPUC approval to recover the revenue requirement associated with the 2010 activity accrued in two memorandum accounts: (1) Renewables Portfolio Standard Memorandum Account (RPSMA) and (2) Independent Evaluator Memorandum Account (IEMA).

Joint Utility Wildfire Cost Recovery Application (A.09-08-020)

SDG&E and SoCalGas filed an application, along with other related filings, with the CPUC in August 2009 proposing a mechanism for the future recovery of all wildfire-related expenses for claims, litigation expenses and insurance premiums that are in excess of amounts authorized by the CPUC for recovery in rates. This application was made jointly with SCE and PG&E. In July 2010, the CPUC approved SoCalGas's and SDG&E's requests for separate regulatory accounts to record the subject expenses while the joint utility application is pending before the CPUC. Several parties protested the original application, and in response, the four utilities jointly submitted an amended application in August 2010. In November 2011, SCE and PG&E requested to withdraw from the joint utility application due, in part, to the delays in the proceeding. In January 2012, the CPUC granted their requests to withdraw and held evidentiary hearings for SoCalGas and SDG&E, both of which are still moving forward with the application.

Z-Factor Advice Letter: Insurance Cost Recovery (A.09-08-019)

In D.10-12-053, the Commission authorized SDG&E to collect in rates $28.884 million for liability insurance expenses incurred in the 2009-2010 policy period in excess of the amount currently authorized in rates. In addition, SDG&E requested (in Advice Letter 2251-E) and received approval to collect in rates $63.29 million for liability insurance expense incurred in the 2010-2011 policy period in excess of the amount currently authorized in rates. This second amount is to be amortized over 24-months ($31.645 annually). Lastly, SDG&E requested (in Advice Letter 2285-E) in September 2011 the recovery in rates of increased liability insurance amounts for the first six months of the 2011-2012 policy period in excess of the amount currently authorized in rates.

Smart Grid OIR (R.08-12-009**)**

The CPUC initiated this proceeding pursuant to federal legislation as well as its own motion to consider policies for California investor-owned electric utilities (IOUs) to enhance the ability of the electric grid to support important policy goals including reducing greenhouse gas emissions, increasing energy efficiency and demand response, expanding the use of renewable energy, and improving reliability. The proceeding will consider setting policies, standards and protocols to guide the development of a smart grid system and facilitate integration of new technologies such as distributed generation, storage, demand-side technologies, and electric vehicles.

B. Outlook from May 1, 2012 to April 30, 2013 – Potential Proceedings

The following provides a list of potential proceedings that are likely to affect rates, including a short summary of the requested amount of the revenue requirement change and the reasons for it.

SDG&E's Cost of Capital Proceeding

SDG&E's next CPUC cost of capital proceeding is scheduled to be filed in April 2012 for a 2013 test year. A cost of capital proceeding determines the authorized capital structure, authorized rate of return and authorized rate for recovery of debt service costs on SDG&E's electric distribution and generation assets and on natural gas transmission and distribution assets. SDG&E's current CPUC authorized return on equity is 11.10 percent, with authorized common equity capital structure of 49.00 percent.

Regulatory Framework

SDG&E may file an application requesting various changes in the regulatory framework applicable to SDG&E seeking an expedited mechanism for obtaining authority to offer new products and services that are desired by customers and provide greater financial certainty for SDG&E and its ratepayers and better align shareholder incentives with ratepayer interests and the goals of SB17. SB 17 was signed into law on October 11, 2009 establishing policy for smart grid deployment to modernize the state's electrical transmission and distribution systems. SDG&E filed its Smart Grid Deployment Plan on June 6, 2011 (A.11-06-006).

C. Rate Change Implementation

The following provides the expected timing of anticipated rate changes during 2012 and the amount of increase if it is known.

SDG&E typically has three electric rate changes a year: (1) January 1st for implementation of its Consolidated rates for electric, (2) a mid-year change, typically the first of April or May, anticipated this year mid-summer, for implementation of its ERRA Forecast, and (3) September 1st Transmission rate change for the implementation of its Transmission Rate Formula Mechanism. In order to provide customers with greater rate stability, SDG&E attempts to coordinate the implementation of any other authorized rate changes with these established rate changes. For 2012, we anticipate at this time the following:

- March 1st Transmission Rate Adjustment to reflect the Settlement in our TO3 Cycle 5 filing
- Summer implementation of the 2012 ERRA Forecast
- September 1st Transmission Rate Change for the implementation of TO3 Cycle 6 filing.

748(b): Utility Study and Report

San Diego Gas & Electric (SDG&E) appreciates the opportunity to provide input to the California Public Utilities Commission (CPUC or Commission) in response to SB 695-enacted changes to PUC Section 748. This report addresses PUC Section 748(b) and provides data related to both gas and electric revenue requirements and rates. SDG&E's response addressing PUC Section 748(a) was provided separately. SDG&E's objective in developing this report is to provide useful information that the CPUC may consider as it prepares its annual report for the Governor and Legislature. This report provides data related to both gas and electric revenue requirements and rates. This report is structured as per the Energy Division's request: overall rate policy at SDG&E, description of revenue requirement components, discussion of rate components, management of rate components, and 2012 CPUC filing outlook (as appendix). SDG&E's recommendations for actions that can be undertaken to reduce cost and rate increases are provided at the conclusion of this report.

3. Section 748(b) Study and Report: Recommendations to the CPUC and Legislature

A. Opening Comments

Comments in SDG&E's 2011 SB 695 Report addressed the growing conflict between existing Net Energy Metering (NEM) incentives and the current residential tiered rates structure. Specifically,

> "Absent adoption of an unbundled distribution integration and reliability service, elimination of existing tier differentials, or elimination of the NEM program, customers that lack competitive alternatives will be forced to subsidize those with competitive options, potentially at significant cost. This could generate tremendous opposition to California's renewable energy efforts, potentially stifling progress on an important long-term policy initiative. California's renewable energy programs should be designed to last."

SDG&E supports renewable energy, including distributed renewable energy. But we also support fair and equitable allocation of utility costs. The current levels of subsidization of NEM is dependent upon rate design that is not cost-based and overly reliant on cost recovery through volumetric charges ($/kWh). In the initial filing of SDG&E's General Rate Case (GRC) Phase 2, Application (A.) 11-10-002, SDG&E presented rate design proposals that reflected more accurate price signals such as a $/kW Network Use Charge for the recovery of costs associated with distribution demand on the basis of both imports and exports. Providing residential customers with more accurate price signals had the additional benefit of reducing pressure on residential upper tiered rates. On February 17, 2012, SDG&E refilled its GRC Phase 2 without the Network use Charge proposal, in accordance with the January 18, 2012 Assigned Commissioner's Scoping Memo and Ruling. Existing rate design already provided for the recovery of distribution demand costs through a demand charge applied to deliveries for SDG&E's medium and large commercial and industrial (M/L C&I) customer class. However, for SDG&E's residential and small commercial customers, these fixed costs are recovered through a volumetric charge rather than on a cost-causation basis that allocates these costs to customers in the basis on which they have been incurred. Because volumetric rates are entirely avoidable by NEM customers without regard to whether they include fixed cost components that continue to be incurred on a fixed cost basis to provide standby, reliability, storage and power quality services to NEM customers, this results in a situation in which non-NEM customers are required to pay for services received by NEM customers. Because the vast majority of these costs for the residential class must be reallocated to a declining amount of upper tier throughput, the upward impact on upper tier rates is substantial (currently the impact on upper tier rates of a re-allocation of costs is approximately three times as high as would be the case if these costs were re-allocated on a class-average basis). Because these increasing upper tier rates are avoidable by NEM customers, the costs they avoid in excess of the value of their distributed generation (DG) output continues to increase over time; this means that even as the cost of rooftop solar, for example, declines, NEM incentives continue to increase unnecessarily, with a disproportionate impact on remaining upper tier customers that are not in a position to invest in distributed solar generation.

Existing tiered rate design for residential customers also prevent customers from seeing or making decisions on the basis of the true cost of the electricity they consume; tier 3 and tier 4 customers pay well above cost, while tier 1 and tier 2 customers receive electricity service at deeply discounted rates. This means that the 2/3 of electricity demand that is served by lower tier rates is not willing to spend the actual value associated with demand reductions, contrary to California's policy support for Energy Efficiency investments and associated demand reductions. As a result of these distorted price signals, residential NEM customers can avoid tier 3 and tier 4 rates and receive service only at deeply discounted tier 1 and tier 2 rates. Such a customer then pays less than the cost SDG&E incurs for their tier 1 and tier 2 electricity service and receive storage, standby, reliability, power quality and renewable generation integration services for free. But SDG&E does not avoid these costs when a customer installs distributed generation - - instead, we are forced to reallocate these costs to other customers. This raises a fundamental policy question: who is paying these subsidies, who is benefitting from them and is this in the public interest? Therefore, the question of costs of NEM must address more than just the distribution-related costs but the subsidies borne by other customers and price signals that are created under current residential rate design as well. Chart 1 below presents an illustration of the breakout of residential class average rates by rate component and distribution further broken into distribution demand and distribution customer costs. Charts 2-4 show the declining proportion represented by distribution demand costs for tiers 1 through 3.

Chart 1

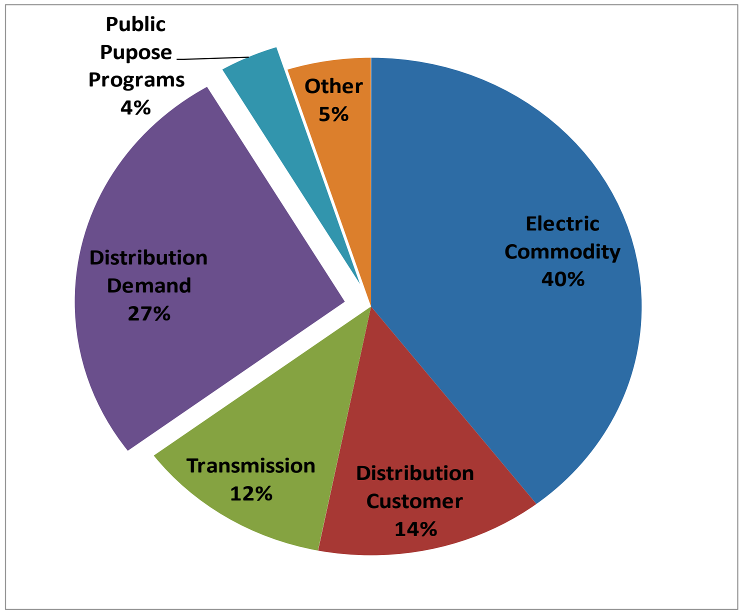


Chart 2

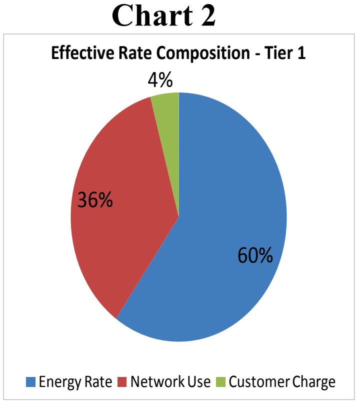


Chart 3

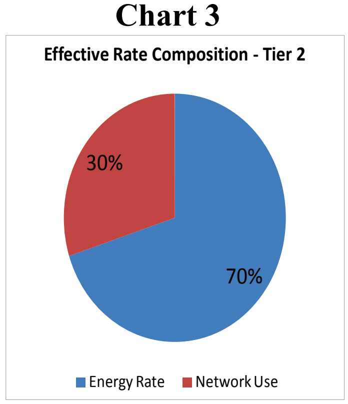
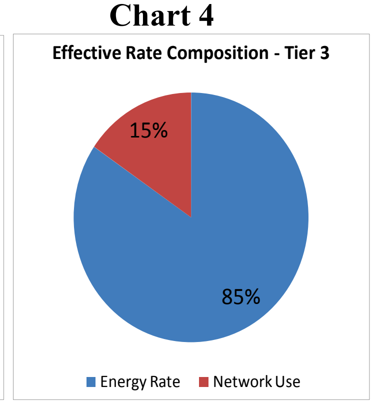


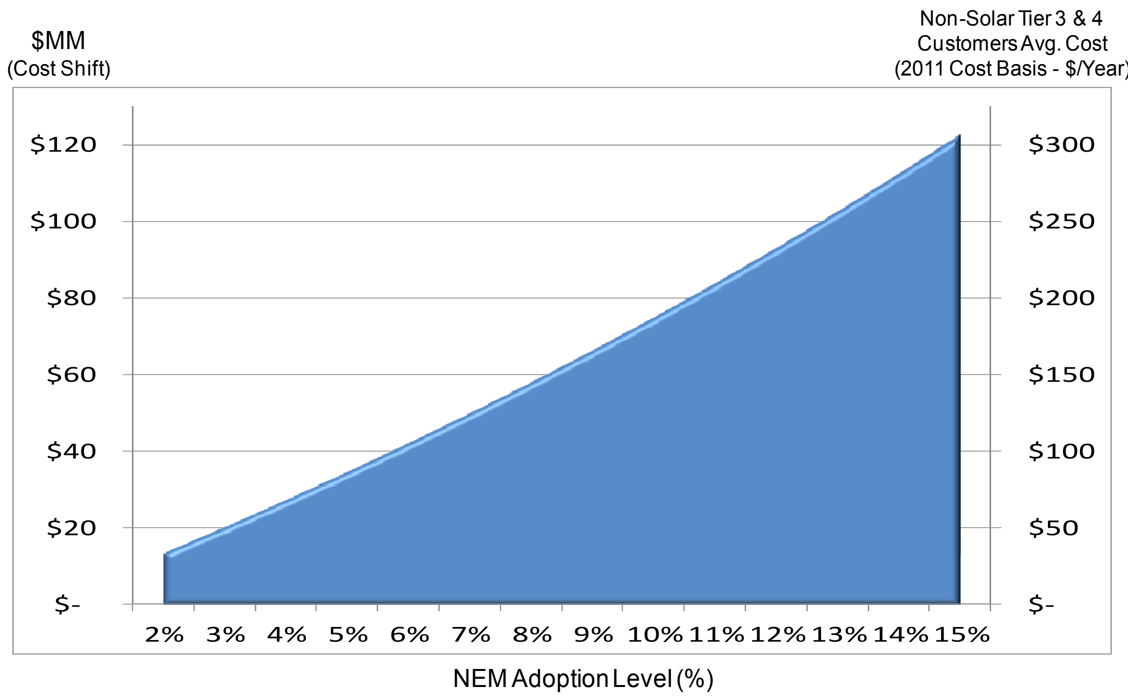
Chart 4



We have analyzed the impact of existing cross-subsidies from California's Net Energy Metering program under existing tiered rate design for residential customers to better understand the impacts. Unfortunately, but perhaps not surprisingly, the majority of residential PV that is being installed in San Diego is being installed on the roofs of wealthier customers that can afford it, and the majority of subsidies are being allocated to those that have not, or cannot install PV. The impact of these subsidies is that California law and regulation are now serving to protect customers that have competitive alternatives at the expense of customers that do not have access to competitive alternatives to utility service. This is inconsistent with the basic reason for utility regulation - - to ensure just and reasonable rates and service for customers that have no competitive alternatives to the services provided by a public utility monopoly. To the extent that customers that utilize PV under a net metering program do not pay the costs that are incurred to provide them with storage, standby, reliability, power quality and renewable generation integration services - - customers that lack access to PV (due to financial reasons, lack of home ownership, lack of south-facing roof space or other reasons) are required to pay these costs on their behalf. Because these costs are primarily re-allocated to upper tier rates, the rate impact is significant.

Under current rate design structure, the cost to non-NEM Tier 3 & 4 customers could grow substantially if residential rooftop solar generation constitutes less than a quarter of the State's targets for distributed generation. As shown in Chart 5 below, today we can calculate that the average Tier 3 & 4 customer pays approximately $34 per year[57] on top of their otherwise applicable bill in order to fund the NEM subsidy. If SDG&E customers were to reach 250 MW of residential rooftop solar, higher-tier customers would pay roughly $200/year to fund the NEM subsidy in 2011 dollars. The impact calculated is due to increased NEM customers receiving subsidies and declining sales from Tiers 3 & 4 and the corresponding upward rate pressure from spreading the same costs over fewer sales from fewer customers. The $200/yr does not include cost increases that could come from upward pressure on commodity costs due to the addition of renewable resources for Renewable Portfolio Standard (RPS) compliance.

Chart 5



When we look at general cost pressure on rates, because the lower tiers are capped at no more than a 3% to 5% increase per year, the higher tiers absorb a higher percentage of cost increases. Since the subsidy is calculated as the retail rate less the avoided cost, this leads to an increase in the subsidy to NEM customers as costs rise. This increase in subsidies occurs regardless whether one more solar panel is installed in SDG&E's service territory. As noted above, most residential customers who install solar are consuming electricity in the upper tiers. Thus, as more solar is adopted, there is a declining number of customers to pay increasing upper tier electricity rates to support growing NEM subsidies. Unless there is modification to the rate structure, growth in NEM is not sustainable.

[57] This is based on SDG&E's experience to date with 70% of NEM customers solar generation offsetting Tiers 3 & 4 and 55 MW of residential rooftop solar installed through August 2011. This is up from 45 MW and roughly $28 per Tier 3 & 4 Customer at the end of 2010.

The energy industry is in the midst of a transition that we have tried to spur in California. A transition in the way electricity is generated and used, and a transition in the services that are being required of utilities to support this transition. However, utility rate design remains much as it was designed to accommodate the ways in which electricity was generated and consumed for the past century. This can only stifle California's journey towards a low carbon energy future. Net Zero Energy (NZE) construction policies are an excellent example; if all homes were NZE, utility services would be essential to keep the lights on. However, under existing residential rate design, for example, utilities would not be paid a penny for providing these services and would not be able to do so. This demonstrates that NZE buildings require utility support to function, and that existing rate design would not support widespread deployment of NZE construction policies. It also makes clear that these costs are all paid by customers that do not utilize these kinds of technologies under existing rate design.

B. Overall Rate Policy

SDG&E seeks with its rate policy to advance state policy objectives, create a foundation on which state policy objectives can be pursued, and provide more flexible and value driven options desired by our customers. Simply stated, SDG&E wants rates that will contribute to a sustainable and innovative energy industry in San Diego. SDG&E rates need to create accurate price signals and be designed with the intent to empower customers to make well-informed decisions, and maximize benefits, not just for the short-term, but for the long-term from new energy supply and energy management alternatives. Accurate price signals are necessary to maintain cost control for customers while advancing California's environmental policy.

The foundation of SDG&E's overall rate policy is accurate price signals. Accurate price signals are critical in the development of sustainable solutions to California's policy objectives, in particular those that address our environment be they renewables, emissions, storage or otherwise. Without accurate price signals, ratepayers as a whole will not realize the benefits of technology investments in smart grids and advanced energy storage because consumers are not receiving the signal to value those costs in their decisions. It is the absence of accurate price signals that has led to the inequity in current distributed renewable programs.

Because rate design is fundamentally a zero sum game of cost allocation, deviations from accurate price signals are not sustainable in the long term. This is particularly true as we look to the future and California's leadership in the renewable and smart grid arena. The current combination of statutes creating subsidized rate tiers and allowing bypass of unavoidable costs for distributed renewables shifts costs from all California environmental policy programs to other customers. NEM customers bypass Tier 3 & 4 rates and with that any cost increases reflected in rates be they from the RPS, cap & trade, energy storage, transmission to access renewables, etc.

The CPUC and Legislature together have adopted policies to advance customer control and choice of their energy supply. While significant progress has been made in this area, it is critical to keep in mind that the overall purpose of regulation is to provide protection for customers who have no competitive alternatives, not to protect the rates of customers that do have competitive alternatives. Not all consumers can take advantage of emerging technologies, for any number of reasons. It is important that the legislature and Commission act to ensure that the burden of California's environmental policies is not born solely by customers who do not have the ability, or have not yet elected to, bypass the costs of those policies.

SDG&E seeks to achieve the following policy goals:

1. **Create Clear and Accurate Price Signals.** Underlying the proposals set forth in this application is SDG&E's policy goal of providing customers with clear, accurate signals for the services they receive. It is important that customers have the benefit of clear and accurate price signals regarding the services they need and receive so they can make good economic decisions regarding their electricity use and/or use of new technologies that are now entering the market. By sending customers clear price signals regarding the cost of electricity and the cost of using the electric grid for whatever services they receive, in conjunction with other tools (such as the online energy presentment tools that SDG&E plans to make available to its customers to track their real-time energy usage, and to understand how this impacts their electricity bills), customers would have the best possible opportunity to make good economic decisions about their energy use. Customers responding to accurate price signals would also allow for greater efficiency gains in system planning.

By providing the market with more accurate price signals, customers will be able to achieve greater long-term financial certainty when they make their energy decisions, and reduce existing cross-subsidies in our rates.

2. **Promote Fairness and Equity.** Fairness and equity dictate that customers are made responsible for the fixed costs that are incurred to provide them with service on a fixed cost basis. To the extent the fixed costs that are incurred to provide service to one customer are not paid by that customer, someone else has to pay these costs. This is not fair or equitable. Further, customers should be receiving the correct compensation for the benefits to the system in order to make economically sound decisions.

3. **Empower and Inform Customers.** SDG&E believes that customers should have readily accessible and reliable information regarding their energy usage and understand how and when energy is consumed. SDG&E has been seeking to employ tools to better inform customers for many years, including through our recent Smart Meter deployment. To further empower customers, pricing options and accurate price signals must be provided so that customers can make informed energy management decisions. In this way, consumers can better understand how they use electricity, reduce their consumption, and respond to information regarding the cost of electricity services at different times of day. This will help customers minimize bills and the emissions associated with their electricity use. This also comports with the goals of both SDG&E and the State to minimize the costs of, and emissions associated with, providing reliable, safe, and environmentally friendly electricity services.

C. Management Control of Rate Components (Utility Management's Policy to Control Costs and Control Rate Increases for Customers)

SDG&E continues to strive to provide its customers with reasonable rates for safe and reliable gas and electric service. Customers value transparency and stability while increasingly embracing energy supply alternatives and new energy management technologies and programs. In developing recommendations, SDG&E has taken California policy, technology and consumer trends into account. SDG&E seeks to identify the pressing issues that must be addressed in order to limit cost and rate increases.

In addressing rate pressure, there are two drivers, in addition to cost management, of concern in today's rates that are the focus of SDG&E's recommendations, revenue requirements from increasing costs and rate distortions created by inaccurate price signals. The key to managing rates going forward will be: (1) the ability to transparently weigh the costs and benefits associated with California Policy implementation alternatives; and (2) implementing accurate pricing in rates so that technology benefits can be realized. Further, as the California policy objectives continue to be pushed through utility rates, there are limits to the utilities ability to control rate increases for customers. Utilities must then look to measures to help customers control bill impacts.

SDG&E believes that accurate rates and ensuring the availability of utility alternatives that are desired by customers are critical to achieving California's environmental policy agenda, particularly to the long term sustainability to California as a leader in advanced energy solutions. Accurate price signals will also help customers gain greater control over their bills if they are truly paying for the cost of the services that they are using. The current reliance on flat volumetric rates ($/kWh) for the recovery of costs provides customers with only one option for being able to control their bills: reducing usage. For SDG&E's residential customers who have among the lowest usage in the country already, this doesn't provide them with many options. However, if rate components were structured to recover costs in the way they are incurred, customers would have the option of shifting load to time-of-use periods or flattening load to reduce demand. As customers respond to price signals that have a direct tie to cost-causation, utilities can better plan for greater system efficiencies and reduce costs in the long run.

SDG&E is committed to controlling costs while providing safe and reliable gas and electricity service to its customers. SDG&E believes performance based incentive mechanisms can align shareholders' and ratepayers' interests to the benefit of both by promoting operational efficiencies and lowering rates. However, there are many key drivers that affect customers' rates which fall outside of SDG&E's control. Among these include: the market price of the gas commodity (which also affects the price of the electricity commodity), actual sales volumes, weather, natural disasters, interest rates, and permitting process delays. Despite these factors, SDG&E diligently seeks to manage its costs across all categories to make efficient and effective use of revenues collected from customers.

D. Utility's Policies and Recommendations For Limiting Costs and Rate Increases While Meeting State's Energy and Environment Goals for Reducing Greenhouse Gases

1. List the Policies the Utility is Advocating

In the coming year, SDG&E recommends that several key State policies and procedures should be shaped to support more effective, efficient and beneficial use of revenues collected from SDG&E's customers. SDG&E believes that the State will have to weigh its environmental goals and desire for reliability that cause significant upward cost pressure, against its desire to moderate impacts on customers' rates for gas and electricity service. Here is a list of items in which policy decisions could drive customer rate impacts.

- Smart Grid Policy: In the Smart Grid Deployment Plan SDG&E filed last year, we described our vision for a future framework for making smart grid investments, which will present opportunities to shift and reduce energy demand and consumption and associated emissions, better integrate distributed renewable generation, accommodate increased electric vehicle market penetration and various other potential benefits.

- Utility Rates – Accurate Price Signals: Provide the direction and flexibility to design rates that accurately value the service provided so that benefits from technology investments can be realized.
- Distributed Generation – Net Energy Metering: Address the shifting of fixed costs by NEM customers in order to create a sustainable distributed renewable policy.
- Energy Storage Policy –Send accurate price signals so that the benefit of different technologies and applications can be weighed.
- Distributed Generation: Review the socio economic impacts of Virtual Net Metering prior to expanding.
- AB 32 Cap and Trade Implementation: Residential and small commercial natural gas customers have already achieved a reduction to 1990 emission levels through existing energy efficiency programs and, therefore, should be exempted from the AB 32 Cap and Trade Regulation. If they are not exempted, they should be given a free allocation of allowances to recognize this history of maintaining natural gas related emissions at 1990 levels since 1990. It would be inappropriate, and damaging to the California economy to unnecessarily impose costs of GHG regulation on customers that have already achieved the objectives of AB32.
- Performance-Based Incentive Mechanisms: Continue to support the utilization of performance based mechanisms to motivate utilities to implement programs that will lead to an overall reduction in costs and improve the efficiency of utility operations. These mechanisms work because: (1) they align customers' and shareholders' interests; (2) they measure a utility's performance relative to a market based benchmark; and (3) they reduce the regulatory burden.
- California Alternative Rates for Energy (CARE): CARE customers now comprise approximately 23% of SDG&E's residential customer base. Non-CARE customers must cover the CARE shortfall, which leads to a 10% increase of non-CARE costs. Restoration of income verification practices would help to optimize the integrity of the program and reduce rate increases for non-CARE customers.

In summary, California leads the nation in promoting reduction of GHG emissions, use of renewable energy, adoption of advanced technologies, energy efficiency and social programs. That, associated with the implementation of those policies, places upward pressure on utilities' rates. In addition, due to the mild weather, the electric and gas usage per customer in California is below the national average. This also leads to higher rates yet lower overall bills. SDG&E supports California policies, however, believes that the utilities should be provided more flexibility in implementing them to achieve lower costs for customers. In particular, there needs to be the flexibility to accurately price services so that consumers pay for what they get and get what they pay for. Accurate pricing is crucial to realizing, and sustaining, the benefits of California's policy programs.

2. Provide recommendations for the CPUC and Legislature to help minimize rate increases in the future

SDG&E's recommendations to the CPUC and legislature are driven by rate dynamics. SDG&E sees that there are two fundamental issues that can create rate pressures in both the near and long term: (1) upward pressure on revenue requirements and (2) Inaccurate price signals driven by statutory constraints on utility rate design.

a. The Legislature

The legislature has the responsibility to recognize the impact of existing NEM policies with current residential tiered rates and to determine whether it is necessary to adopt legislation to prevent customers that lack the ability to install PV from being forced to subsidize the customers - - usually wealthier customers - - that do. To the extent that existing laws are deemed an impediment to eliminating this inequity, the legislature should act.

Legislation also needs to account for the fact that utility rates are ultimately a zero sum game. Any incentive that ultimately creates an economic benefit for one creates an economic burden for another. As the energy industry transforms to one in which consumers have increasing options, greater consideration needs to be made for incentivizing California policy programs directly as opposed to using rate incentives. In this area, the Legislature can provide clear guidance on the objective while still maintaining the flexibility needed for the CPUC and utilities to react equitably to rapidly changing markets and technologies. It is extremely difficult to anticipate all of the repercussions of rate design given rapidly expanding alternatives to traditional utility service. In order to foster the growth of these markets, responsible allocation of costs is needed to send accurate price signals and provide the regulatory protection to customers. Sending clear messages on what the objective is can assist the CPUC, Investor Owned Utilities (IOUs), Publicly Owned Utilities (POUs), and other Load Serving Entities (LSEs) determine how best to achieve that under conditions at the time of implementation.

b. CPUC

Energy supply and delivery is changing rapidly. California policy programs have expanded consumer options, and in doing so, have turned the regulatory compact on its head. Regulation exists to protect those who have no options. However, current regulation forces ratepayers that lack competitive alternatives to subsidize those that have alternatives.

In the advancement of California policy, such as renewable DG, the CPUC is ultimately going to find itself faced with a transition period that moves between incentivizing technologies that provide greater consumer alternatives and protecting those consumers who are following behind. California finds itself at a point in time where a sustainable solution is both required and possible. Restructuring rates to reflect more accurate price signals allows energy consumers to make economic decisions to the benefit of all. If customers cannot see the benefits of decisions on energy management in their bills, then the full value of investments made in smart meters, smart grids, renewables, energy storage, time variant and dynamic pricing will not be realized. This will ultimately expose consumers to higher rates and hamper California's environmental policy objectives.

San Diego Gas & Electric Company
2012 CPUC Filing Outlook
Outlook from May 1, 2012 to April 30, 2013
Appendix A

Description	Filed	Expected/Requested Implementation	Status	Impacted Rate	System Average Directional Impact	Revenue Requirement Impact w/FF&U ($M)	If Revenue Requirement Impact not available Current Revenue Requirement ($M)
Pending Applications							
Electric							
2010 ERRA Compliance Filing (A.11-06-003)[1]	June 2011	May/June 2012	Still Pending	Electric Commodity	Increase	$ 2.151	
RimRock Tax Equity (A.10-07-017)[2]	July 2010	2013		Electric Commodity	Increase	$ 21.895	
Dynamic Pricing (A.10-07-009)[3]	July 2010	Beginning 2011	Still Pending	Distribution	Increase	$ 2.859	
2012 ERRA Forecast Application (A.11-09-022)	September 2011	July 2012	Still Pending	Electric Commodity On-going CTC	Increase Decrease	$ 153.222 $ (4.641)	
2009 ERRA Compliance Filing Phase 2 (A.10-06-001)	June 2010	Beginning 2012	Still Pending	Electric Commodity	Decrease	$ (0.369)	
Joint Utility Wildfire Cost Recovery Application	August 2009	June 2010	Still Pending	Electric Distribution	Increase	N/A	$ -
Joint Application for Adoption of Electric Revenues and Rates Associated with MRTU (A.12-01-014)	January 2012	January 2013	Still Pending	Electric Commodity	Increase	$ 1.599	
Joint Application for Lawrence Livermore National Laboratories for 21st Century Energy Systems (A.11-07-008)	July 2011	January 2012	Still Pending	Electric Distribution	Increase	$ 15.650	
SDG&E's Authority to Enter Into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power (A.11.-05-023)	May 2011	February 2012	Still Pending	Electric Distribution	Increase	N/A	$ -
SDG&E's Seismic Study Application (A.11-05-011)	May 2011	January 2012	Still Pending	Electric Commodity	Increase	$ 12.600	
GRC Phase 2 (A.11-10-002)	October 2011	January 2013	Still Pending	N/A	Neutral	N/A	
Gas							
SDG&E Triennial Cost Allocation Proceeding	November 2011	January 2013	Still Pending	All Transportation Rates	Neutral		$ 243
Pipeline Safety Enhancement Plan	August 2011	mid-2012	Still Pending	Proposed New Surcharge	Increase	$ 0.4	
Low Income Assistance Programs Budgets	May 2011	2012	Still Pending	Gas Public Purpose Program	Increase	$ 2.3	

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Combined Gas and Electric							
AB32 Administrative Fee Recovery[4]	August 2010		Still Pending	Electric Distribution	Increase	$ 0.7	
				Gas Transportation	Increase	$ 1.3	
2012 GRC Phase 1 (A.10-12-005)[5]	December 2010	January 2012	Still Pending	Electric Distribution/Commodity	Increase	$ 168	
				Gas Transportation	Increase	$ 25	
Smart Grid[6]	December 2010	January 2012	Still Pending	Electric Distribution/PTY	Increase	$ 50	
OpEx[6]	December 2010	January 2012	Still Pending	Electric Distribution/PTY	Increase	$ 6	
Potential Applications							
Electric							
Demand Response Application (A.11-03-002)	2011	2012		Electric Distribution	---	N/A	$ 30.437
FERC TO3 Cycle 6[7]	To be Filed mid-2012	September 2012		Electric Transmission	---	N/A	$ 406.900
2013 FERC RS Filing[8]	To be Filed late 2012	January 2013		Reliability Service	---	N/A	$ (4.754)
2013 FERC TACBAA/TRBAA Filing[9]	To be Filed late 2012	January 2013		Electric Transmission	---	N/A	$ (47.099)
Electric Regulatory Account Update AL[11]	To be Filed 2012	January 2013		Various Electric	---	---	
2013 DWR Implementation AL[11]	To be Filed 2012	January 2013		Electric Commodity/ DWR-BC	---	---	
Electric Public Purpose Program Update AL[11]	To be Filed 2012	January 2013		Public Purpose Program	---	---	
Non-fuel Generation BA Update AL[11]	To be Filed 2012	January 2013		Electric Commodity	---	---	
SB695 Residential Rate Change[11]	To be Filed 2012	January 2013		Electric Residential	No change	---	
Electric Consolidated AL[10, 11]	To be Filed 2012	January 2013		All Electric	---	---	

San Diego Gas & Electric Company
2012 CPUC Filing Outlook
Outlook from May 1, 2012 to April 30, 2013
Appendix A

Description	Filed	Expected/Requested Implementation	Status	Impacted Rate	System Average Directional Impact	Revenue Requirement Impact w/FF&U ($M)	If Revenue Requirement Impact not available Current Revenue Requirement ($M)
Gas							
Gas Regulatory Account Update AL[11, 12]	To be Filed 2012	January 2013		Gas Transportation	Decrease	($19,183)	
Gas Consolidated AL[11, 12, 13]	To be Filed 2012	January 2013		Gas Transportation	Decrease	($31,601)	
Gas Public Purpose Program Update AL[11, 12]	To be Filed 2012	January 2013		PPP Surcharge	Increase	$479	
Combined Gas and Electric							
Energy Efficiency Application (A.11-05-020)	2011	2012		Public Purpose Program	---		
CARE Application (A11-05-020)	2011	2012		Public Purpose Program	---		

[1] The 2010 ERRA Compliance Filing (A.11-06-003) includes a revenue requirement of $1.6M for MRTU.
[2] In RimRock Tax Equity (A.10-07-017), the revenue requirement w/FFU for 2013 implementation as filed.
[3] 2012 Dynamic Pricing revenue requirement reflects the combined 2011 and 2012 revenue requirements as filed.
[4] Includes accumulated balance
[5] In the 2012 GRC Phase 1, the revenue requirement reflects the amounts filed in the July 2011 revised testimony.
[6] As filed, reflects post test year (PTY) revenue requirements for 2013.
[7] Reflects current revenue requirement w/FFU per FERC TO3 Cycle 5.
[8] Reflects current revenue requirement w/FFU per 2012 FERC RS Filing
[9] Reflects current revenue requirement w/FFU per 2012 TACBAA/TRBAA Filing
[10] Electric Consolidated reflects the incorporation of electric rate changes authorized for implementation on January 1st.
including Electric Regulatory Account Update AL, 2013 DWR Implementation AL, Electric Public Purpose Program Update AL, Non-fuel Generation BA Update AL, SB695 Residential Rate Change AL, and others changes.
[11] This is an annual routine filing in which the specific revenue requirement impact for 01/2013 has not been determined.
[12] The amounts presented show the impact from the most recent Advice Letters.
[13] Gas Consolidated AL 2082-G includes the Gas Regulatory Account Update AL, and excludes AMI for 2012 along with other changes