California Public Utilities Commission

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

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Public Utilities Commission · Eureka · State of California

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I. Introduction

On October 11, 2009 Governor Schwarzenegger signed Senate Bill 695. Among other things, SB 695 added Section 748 to the Public Utilities Code:

> 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.
>
> (c) The commission shall post the report required by subdivision (a) in a conspicuous area of its Internet Web site.

This report is submitted by the Public Utilities Commission in compliance with Section 748.

II. CPUC Actions to Limit Utility Cost and Rate Increases

The California Public Utilities Commission (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] Through its oversight of these utilities, the CPUC develops and administers energy policy and programs to serve the public interest, and ensures compliance with statutory mandates and CPUC decisions, resulting in reliable, safe and environmentally sound energy services at the lowest reasonable rates for the people of California.

The Commission's regulatory process is governed by the Public Utilities Code and by the Commission's Rules of Practice and Procedure. Each formal proceeding is conducted by the Commission following due process that affords various parties the opportunity to present their position and recommendations in prepared written and oral testimony before the Commission. Evidentiary hearings are held when warranted and a proposed decision is prepared by the presiding officer (an Administrative Law Judge or an assigned Commissioner, depending on the categorization of a proceeding) for a vote by the Commission. Given this statutory regulatory process, the Commission must be careful not to prejudge issues in any pending proceedings and make specific recommendations about likely outcomes of individual cases.

The CPUC's cost-setting and ratemaking proceedings over the next 12 months will continue to be consistent with the Energy Action Plan (EAP) II, adopted by the CPUC and California Energy Commission in 2005, and updated in February 2008. The Energy Action Plan 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 to the extent that these resources are inadequate, clean and efficient fossil-fired electric generation.

The EAP identifies six sets of actions of critical importance which are listed below. The CPUC is at the helm of many of these action areas, as will be described later in this report.

- 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

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

This report focuses on a description of pending proceedings that are under consideration before the Commission, as well as some annually recurring rate applications that are likely to be filed later in the year. The report provides dollar amounts requested by the utilities in the pending cases along with a summary of the reasons for the requested amounts. This should give the legislature a sense of the magnitude of the utilities' requests that this Commission will evaluate within the next 12 months. In addition, this report provides a description of various program areas that contribute to utility costs, along with any actions that the Commission is considering to continually improve the efficacy of those program areas.

The following is a list of some actions that the Commission will be taking in the next 12 months to ensure that the costs and rates authorized by the Commission are reasonable and the many statutorily mandated programs and public policy initiatives that the Commission is entrusted to administer are implemented efficiently.

Electricity

- The Commission conducts an in-depth review of all infrastructure-related investments and operations and maintenance (O&M) costs related to utility owned generation and distribution in each utility's general rate case (GRC). The Commission is currently considering adopting a proposed revenue requirement for PG&E's 2011 GRC (A. 09-12-020) of approximately $6 billion. Out of this total, $1.131 billion is for gas distribution. PG&E had requested to recover $6.157 billion for both electric and gas. Over the next 12 months, the CPUC will be processing and evaluating SCE's GRC 2012 (A.10-11-015) requesting $6.285 billion revenue requirement for its test year 2012 and SDG&E's 2012 GRC (A.10-12-005) requesting recovery of $1.867 billion for Test year 2012.[2] Typically, the review results in a scaling back of the utilities' total requested GRC revenue requirement. The Commission will diligently review SCE's and SDG&E's GRC revenue requirement request along with the input from a large number of interveners that will provide testimony and recommendations in the case.
- PG&E, SCE and SDG&E anticipate they will file their requests to recover fuel and purchased power costs in the Energy Resource Recovery Account (ERRA) proceedings around the second half of 2011. These proceedings involve large amounts of money as fuel and purchased power comprises approximately 37% of their total revenue requirements. There is no mark-up or profit for the utilities in their recovery of purchased power and fuel costs. The Commission will scrutinize the utilities' power purchase and fuel cost recovery requests in the ERRA proceedings and provide for refunds for customers when specified triggers warrant.
- The CPUC administers a Long Term Procurement Proceeding (LTPP) which implements AB 57, passed in 2002.[3] Every two years, the CPUC holds a Long Term Procurement Plan (LTPP) proceeding to evaluate the system's need for new conventional resources. The most recent LTPP decision (D.07-12-052) authorized 2,130 to 3,430 MW of new

[2] SDG&E's GRC (A.10-12-005) will be considered together with SoCalGas' GRC (A.10-12-006) as both utilities filed their respective applications on December 15, 2010 and predominantly share common witnesses.

[3] PU Code Section 454.5

generation to be constructed to support system reliability needs going out to 2018. These new resources will be more expensive than continued operation of existing resources, but will be more efficient and more environmentally friendly. No major new natural gas fueled generation is expected to begin operation in 2011. Several facilities are scheduled for 2012-2013. When new generating facilities become operational, their costs are likely to result in an increase in rates.

- Listed first in the State's Energy Action Plan (EAP) loading order, energy efficiency is the most preferred resource to meet growing demands for energy in California. In September 2009, the Commission approved $3.1 billion in cost-effective energy investments for the 2010-12 program cycle. The CPUC requires rigorous measurement and verification of the reported savings and evaluation of the largest programs by independent contractors. This process verifies reported savings for specific measures and uses these savings to determine cost-effectiveness of the utilities' portfolios and specific energy efficiency programs. When the CPUC approved the IOUs' 2010-2012 energy efficiency portfolios, the Commission imposed several cost controls resulting in 20% (approximately $1 billion) lower costs than the IOUs requested in their applications. As part of the 2010-2012 EM&V process, Commission staff is planning to conduct management audits and organizational assessments, using management consultants, to better understand the drivers for trends in the overall cost-effectiveness of utility energy efficiency portfolios.[4] The assessment will consist of an examination of management systems, organizational structure, cost-tracking systems, staff and management incentives (e.g., bonus structures), use of information technology and other factors. In the next 12 months, the Commission will consider improvements to the Risk/Reward Incentive Mechanism (RRIM) framework in Rulemaking 09-01-019.

- California's Renewables Portfolio Standard Program (RPS**)** is the most ambitious in the country. Governor Jerry Brown signed SB X1-2 on April 12, 2011 that will require electric utilities in California to source 33 percent of their electricity from renewable sources by 2020. In 2009 and 2010, the CPUC approved five-year programs for SCE, PG&E, and SDG&E to build, own, and operate solar PV projects, and to execute contracts for solar PV projects with independent power providers (IPPs). The CPUC has approved PG&E's and SCE's implementation plans for utility-owned and IPP PV programs. SCE held its first auction in 2010 and will hold a second auction in 2011. PG&E is holding its first auction during the first quarter of 2011. SDG&E has submitted its PV program implementation advice letters, which are currently under review. In the next 12 months, the Commission's actions to reduce costs in this area will center around implementation of cost containment to renewable power purchase agreements, use of Tradable Renewable Energy credits (TRECs), the Renewable Auction mechanism (RAM) and review of utilities' bid selection criteria and methodologies.

- Senate Bill (SB) 1 (Murray, 2006) created the California Solar Initiative and established a budget of $2.167 billion for the installation of solar electric energy systems. In addition to incentivizing more than 400 megawatts of installed solar energy in the first four years of the program (with a goal of 1,750 megawatts by 2016) the CSI has supported the

[4] See 2010-2012 Energy Efficiency Evaluation, Measurement and Verification Work Plan, available at www.calmac.org/events/2010-2012_Energy_Efficiency_EM&V_Plan_12-20-10.pdf

growth of a multi-billion dollar industry that has created more than 36,000 skilled jobs in California. Presently, there are no new costs in implementing the CSI program under SB 1. However, as the program continues, the CPUC will regularly monitor the trends in expenditures from CSI relative to costs and will adjust the necessary utility revenue collections accordingly.

- The Commission recently adopted the Qualifying Facility (QF)/Combined Heat and Power (CHP) Program settlement on December 16, 2010 in D.10-12-035 to encourage the use of old and new CHP facilities. The CHP Program will meet the state's goal of supporting cogeneration technology to enhance the reliability of local energy supplies and meet CHP and greenhouse gas reduction targets. The Commission will consider future contracts through Advice Letters and Applications for CHP facilities to balance rate increase impacts with state environmental and reliability goals.

- The Commission is currently considering a range of program modifications to the Self Generation Incentive Program (SGIP) pursuant to SB 412 (Kehoe, 2009) and granted a motion filed by SGIP Program Administrators to temporarily halt the issuance of SGIP incentives, effective December 31, 2010, in order to preserve SGIP incentives for future technologies that the Commission may opt to include in the program upon completion of SB 412 implementation.

- 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 through dynamic rates. 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 for direct DR participation and modifications to Emergency DR programs to reduce costs.

- In 2010, the CPUC also approved Decision 10-12-048, which created the Renewable Auction Mechanism (RAM) for projects up to 20 MW. The RAM requires the use of a standard contract and a competitive auction to select the lowest cost projects that meet the program's criteria. The RAM decision authorized the three large utilities to procure 1000 MW collectively over a two year period, beginning in 2011.

- The Commission has low income assistance program comprised of California Alternate Rate for Energy (CARE) which provides rate discounts and the Energy Savings Assistance Program which provides energy efficiency measures to qualified low income customers. For the 2009-2011 budget period, the Commission authorized through Decision 08-11-031, a $2.6 billion budget for CARE and $885 million budget for the Energy Savings Assistance Program. The expected benefits of this spending are projected energy savings (yearly average) of 81,266 MWh; 22.3 MW of capacity and 5.3 million Therms of gas. The Commission will be monitoring and evaluating the many 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.

- The Commission will examine various proposals to encourage replacement of sub-meter systems that supply electricity and natural gas to mobile home parks and manufactured housing communities that are located within the franchise areas of electric and natural gas corporations.

- In the wake of the Fukushima 9.0 magnitude earthquake and the subsequent tsunami that has resulted in the nuclear disaster at the Fukushima Daiichi Nuclear Power Plant, the Commission has suspended the hearing schedule that had previously been set to consider the joint settlement filed by TURN, DRA and PG&E recommending the Commission authorize $85 million to PG&E for Diablo Canyon Power Plant (DCPP) relicensing activities. The Commission is expected to consider safety issues as part of its authorization for recovery of relicensing related expenses of DCPP and San Onofre Nuclear Generating Station (SONGS).

Natural Gas

- Following the devastating impact of the San Bruno gas pipeline explosion in PG&E's service territory, the Commission instituted Rulemaking 11-02-019 to adopt new safety and reliability regulations for natural gas transmission pipelines and related ratemaking mechanisms. The Commission will develop and adopt safety regulations that address topics such as gas pipeline construction standards, shut-off valves, maintenance requirements, record management retention, ratemaking and penalty provisions. The Commission adopted D.11-04-031 on April 14, 2011 to require PG&E to provide gas transmission and storage (GT&S) safety reports in order to prevent future gas pipeline tragedies.
- Although the Commission does not regulate the market price of natural gas, in the coming year, the Commission expects to continue to implement measures that will help keep gas procurement costs at reasonable levels, including measures that:
  - provide incentives to utilities to keep natural gas procurement costs low
  - allow expeditious approval of a diverse and reasonably-priced portfolio of interstate pipeline capacity
  - provide core customers with adequate amounts of natural gas storage capacity, and allow utilities to engage in efficient natural gas hedging practices.
- The Commission approved a settlement in PG&E's Gas Transmission and Storage Rate Case (A.09-09-013) that set rates for PG&E's gas transmission pipeline and storage business for years 2011 to 2014. The proceeding is still open as the Commission reviews implementation of gas safety measures. In 2011, the Commission will scrutinize natural gas utility operational costs and rates for transmission pipelines, distribution pipelines and storage in several other proceedings, including the SoCalGas/SDG&E 2012 GRC (A.10-12-005). The Commission recently completed its review of natural gas costs for PG&E in PG&E's GRC Phase I proceedings and is considering authorization of $1.131 billion for gas costs in A.09-12-020.
- The CPUC will ensure that public purpose programs are conducted efficiently and provide the maximum benefits for which they are intended. The CPUC will also be reviewing and approving the budget for the natural gas research and development program that was entrusted by the CPUC to the California Energy Commission (CEC) to administer.

Utilities' Recommendations to Limit Cost and Rate Increases

Pursuant to Section 748(b), the four major electric and gas companies submitted their reports to the Energy Division on various components of costs and their recommendations to limit costs and rate increases.

Reports provided by the utilities in response to the requirements of 748(b) are attached as an Appendix to this report.

III. Electric Utility Revenue Requirements

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 electric utility customers' needs for safe, reliable, and environmentally responsible service and the financial health of the utility, while achieving the lowest possible rates. Since energy services are essential, the CPUC ensures that access is universal and affordable. The bulk of the utility's revenue requirements is requested in General Rate Cases (GRCs) and the Energy Resource Recovery Account (ERRA) proceedings. GRCs address a utility's request 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.

As part of energy restructuring, the California Independent System Operator (CAISO) was created and given operational control over the utilities' high voltage lines on January 1, 1998. With that, the authority for determining transmission revenue requirements was transferred to the Federal Energy Regulatory Commission (FERC). However, the CPUC, through its Constitutional authority, represents the ratepayers of California at FERC in Transmission Owner (TO) Rate Cases. The transmission revenue requirements authorized by FERC involve the same major revenue requirement components (O&M, depreciation and return on rate base) as seen in general rate cases at the CPUC, including Return on Equity (ROE), Capital Additions, Operations and Maintenance Expense (O&M), Administrative and General Expense (A&G), Depreciation, Income Tax and Rate Base calculation.

In recent years, transmission-related revenue requirement and rate increases have largely been driven by capital additions and O&M.

All of the approved costs are recovered through three main types of rate charges—generation, distribution and transmission -- with some other charges such as the Public Purpose Charge (PPP), power and bond charges payable to the Department of Water resources (DWR) shown on customer bills as separate line items. 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 need to be paid for by all customers who use the utility distribution system.

General Rate Cases

Approximately 45% of the utilities' revenue requirements are set in Phase I of general rate cases (GRCs) at the CPUC and at FERC. GRC Phase II follows the completion of GRC Phase I and determines how to allocate revenue requirements to each customer class. The transmission revenue requirement is determined by the Federal Energy Regulatory Commission (FERC) in transmission owner rate cases following similar test year ratemaking.

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 the 2010 General Rate Cases for the three major utilities are listed below.

2010 General Rate Case Revenue Requirements (000)

	PG&E	SCE	SDG&E
Operations and Maintenance	$1,933,573	$1,978,951	$466,066
Depreciation	$1,148,688	$1,194,692	$316,259
Return on Rate Base	$909,993	$1,187,557	$251,958
Taxes	$617,138	$758,290	$178,960
Total	**$4,609,392**	**$5,119,489**	**$1,213,243**

(Excludes FERC determined transmission revenue requirements)

In December 2009, PG&E filed its test year 2011 GRC application which was reviewed by the Commission in 2010 and is currently in Phase 2 GRC proceedings. The Commission is considering PG&E's request and other parties' testimony on issues related to revenue allocation. The Commission will decide how PG&E will allocate the revenue requirement to each customer class to provide safe and reliable service at just and reasonable rates. SDG&E, SoCalGas, and SCE filed test year 2012 GRC applications in late 2010. The Commission is addressing similar issues in SCE, SDG&E, and SoCalGas GRC Phase I applications.

Electric Fuel and Purchased Power

Fuel and purchased power costs are handled by the Commission in two phases. In the first phase, the ERRA forecast phase, 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. The Commission establishes an ERRA rate component based on a forecast of the costs and sales. In the second phase, the ERRA Reasonableness of Operations phase, the Commission determines the reasonableness of operations involving these fuel and purchased costs. These costs 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. Annual fuel and purchased power costs included in the utilities' electric rates for PG&E, SCE and SDG&E currently are $4.085 billion, $3.708 billion and $875 million respectively.

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. The account balance (difference between costs and revenues) is returned to customers if revenues exceed costs, or recovered from customers if costs exceed revenues, in a subsequent ERRA or other Commission proceeding. 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 of that fact by filing an advice letter and it is not required to file an expedited application in that event.

The Commission also reviews the utilities' 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 activities.

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, two, Wildfire Insurance Costs and AB 32 Administrative Fee Recovery proceedings, are joint proceedings involving all the four major energy utilities.

Joint Utility Requests

Wildfire Insurance Costs

On August 2009, PG&E, SDG&E, SoCalGas, and SCE jointly filed Application 09-08-020 to request the establishment of a Wildfire Expense Balancing Account to record future recovery of uninsured wildfire costs. These costs include payments to third parties for damage or loss claims associated with wildfires, outside legal expenses associated with any third-party claims, payments to government authorities for fire suppression costs and environmental damage, and changes in wildfire premium amounts from the amount assumed in the last GRC. The utilities supported their request by citing significant increases in wildfire insurance premiums. For example, SDG&E's and SoCalGas's annual insurance premium that expired in June 2009 was $13.6 million; it had a liability limit of $1.2 billion, and a $1 million deductible. Their current annual premium is $55.2 million with a general liability limit of $800 million, a wildfire liability limit of $399 million, and a $35 million deductible for wildfires.

The assigned Commissioner and Administrative Law Judge issued a ruling in late 2009 following concerns that the utilities' proposal would provide no financial motivation to defend wildfire claims and that ratepayers would bear the cost of the claims with no practical means of defending the claims. The utilities filed an amended application mid 2010 to alleviate some of these concerns by setting limitations on the amount of wildfire damage or loss claims borne by ratepayers and increasing the amounts shareholders would absorb from such claims. However, the Assigned Commissioner and the Administrative Law Judge ruled that the application still failed to remedy the deficiencies outlined in the 2009 ruling. Presently, the application is suspended.

AB 32 Administrative Fee Recovery

PG&E, SDG&E, SoCalGas, and SCE jointly filed Application 10-08-002 with the Commission on August 2, 2010 to recover administrative fees paid to the California Air Resources Board (CARB) as a result of AB 32, the Global Warming Solutions Act. Under AB 32, California is required to reduce greenhouse gas emissions to 1990 levels by 2020. Under the legislation, CARB is required to adopt a schedule of fees to be paid by various sources of greenhouse gas. In late 2010, the Commission approved the utilities' request for regulatory accounts to record the AB 32 administration fees for later recovery and established a second phase of the proceeding to determine whether costs incurred prior to a utility's next GRC would be recoverable in rates.

Requested Recovery:

PG&E:	$4.8 million.
SCE:	$2.4 million
SDG&E:	$0.5 million
SoCalGas:	$4.5 million

Utility Specific Rate Requests

SCE

SCE has following applications with potential rate impacts pending before the Commission:

- **2009 ERRA Compliance A.10-04-002 (memorandum account recovery):** In this application, the Commission is reviewing various balancing and memorandum accounts for reasonableness and for compliance with Commission decisions and tariffs.

  Requested Recovery: $29.9 million which is associated with recovering costs recorded in four memorandum accounts.

- **CEMA Wind and Firestorm A.10-04-026:** SCE has requested to recover incremental O&M and capital revenue requirement associated with the 2007 wind and firestorms. Presently, SCE has filed a motion for the Commission to accept a settlement agreement that would reduce SCE's total requested recovery by $2.317 million.

  Requested Recovery: $10.6 million.

- **Demand Response Programs A.11-03-003:** On May 1, 2011 SCE filed application for approval of Demand Response (DR) programs, activities and budgets for the years 2012-2014. SCE aims to increase DR participation to 1,900 MW by 2014, aided by the full deployment of smart meters to all its customers, and to transform its DR program from being primarily reliability based to price responsive.

  Requested Recovery: $229 million.

- **Summer Discount Plan Program A.10-06-017:** In this application, SCE has requested rate recovery to implement a price responsive element into the Summer Discount Plan program so that the program could be bid into the California Independent System Operator's markets in order to achieve Demand Response objectives.

  Requested Recovery: $13 million.

- **2012 General Rate Case Phase 1 A.10-11-015:** SCE has requested an increase in revenue requirement for operation and maintenance as well as capital to replace aging infrastructure. In addition, SCE seeks increased revenue requirement to expand its system to accommodate increasing load.

  Requested Recovery: $6.285 billion. Amount represents an increase of $866 million over currently authorized base revenues.

SCE Rate Related Requests expected later this year

- **2012 ERRA Forecast:** In this application. which will be filed on August 1, 2011, the Commission will authorize the fuel and purchased power revenue requirement to be included in 2011 rate levels.

  Requested Recovery: Not known yet. Recovery amount depends on the fuel price forecast and purchased power costs. The ERRA-related revenue requirement approved in SCE's last ERRA decision and embedded in current rates is $3.708 billion. This filing will include the 2012 cost of various power purchase contracts that the Commission has already approved in the past. To the extent that the cost of 2012 power contracts is higher, this filing may request a higher amount than last year.

- **2010 ERRA Compliance:** SCE will file an application to seek recovery of costs recorded in various memorandum accounts for 2010.
- ***Requested Recovery:*** Not known yet.

- **DWR Revenue Requirement Determination**: Due to the termination in 2011 of the SCE allocated Sempra DWR contract and the established transfer payment schedule, SCE is anticipating a negative power charge in 2012. The 2012 bond and power charges will be allocated to SCE in late 2011 via the DWR revenue requirement determination in R.11-03-006, subject to approval by the Commission.

  Estimated Requested Recovery: Not known yet.

PG&E Rate Requests

PG&E has following rate requests pending before the Commission:

- **2009 ERRA Compliance Filing A.10-02-012 (MRTU):** PG&E filed an application on February 12, 2010 to recover costs incurred through the end of 2009 for compliance with the Market Redesign and Technology Upgrade initiative.

  Requested Recovery: $18.3 million.

- **Rate Design Window – Peak Time Rebate A.10-02-028:** PG&E requests approval of a two part peak time rebate pricing for residential customers to provide incentives for customers to shift peak time load usage during certain event days called by PG&E during the year.

  Requested Recovery: $33 million**.** None in 2011.

- **Default Residential Rate Programs – Peak Day Pricing A.10-08-005:** PG&E filed this application seeking to comply with D.08-07-045, Ordering Paragraph 8, whereby PG&E is required to propose a default peak day pricing proposal by August 9, 2010. PG&E seeks a deferral to introduce peak day pricing until PG&E's 2014 GRC. If its request is denied PG&E proposes a peak day price based on a four tier rate overlaid with time of use pricing with peak day pricing during certain event days.

  Requested Recovery: $141 million. None in 2011.

- **Demand Response Programs A.11-03-001:** On May 1, 2011 PG&E filed its application for approval of Demand Response (DR) programs, activities and budgets for the years 2012-2014.[5] For the program cycle 2012-2014, PG&E proposes to update its programs to be compatible with California Independent System Operator's (CAISO's) Proxy DR requirements, to modify its Base Interruptible Program so it can participate in the CAISO markets, leverage one of its programs to provide ancillary services and deliver an array of varied DR Programs.

  Requested Recovery: $234 million.

- **Pumped Storage Project A.10-08-011:** PG&E requests cost recovery for feasibility studies for federal hydropower project licensing.

  Requested Recovery: $33 million. None in 2011.

- **2011 Gas Transmission and Storage Rate Case A.09-09-013:** In April 2011, the CPUC approved a settlement that sets rates, terms and conditions of service for PG&E's gas transmission pipeline and storage business for the period 2011 to 2014. The proceeding is still open to consider certain gas safety measures.

  Requested Recovery: $514 million in 2011.

- **Silicon Valley Technology Center A.10-11-002**: Application seeks approval to support a photovoltaic manufacturing development facility in San Jose, California.

  Requested Recovery: $35.6 million.

- **Diablo Canyon Power Plant License Renewal A.10-01-022:** Request for authority to recover in rates $85 million in costs associated with obtaining the federal and state approvals required to seek a 20- year license renewal for Diablo Canyon Power Plant

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[5] PG&E filed its Demand Response 2012-2014 application in A.11-03-001, SDG&E filed its application in A.11-03-002, and SCE filed its application in A.11-03-003.

Requested Recovery: $80 million. None in 2011.

- **ERRA 2010 Compliance Filing A.11-02-011 (MRTU):** Recovery of costs related to the Market Redesign and Technology Upgrade (MRTU) initiatives.

  Requested Recovery: $47.2 million.

- **2011 General Rate Case Phase 3 A.10-03-014:** Request includes $2.7 million in revenue requirements for new voluntary Real Time Pricing rate options, and $0.3 million in revenue requirements for Revised Customer Energy Statement.

  Requested Recovery: $3 million.

PG&E's rate related requests expected later this year

PG&E is expected to file the following rate related requests later this year. The requested amounts are not known at this time.

- Winter Gas Savings Program (2011-2012)
- Core Procurement Incentive Mechanism Shareholder Award
- Pipeline 2020
- FERC - TO14 (TY 2012)
- FERC TRBA/ECRA/RSBA Filing
- Public Purpose Program Surcharge Gas Rate Filing 2011 - Advice Letter
- SB 695 Res Rate Change (T1 & T2) Advice Letter
- Energy Resource Recovery Account (ERRA) 2012 Forecast – Requested Recovery depends on the fuel price forecast and purchased power costs. The ERRA-related revenue requirement approved in PG&E's last ERRA decision and embedded in current rates is $4.085 billion. This filing will include the 2012 cost of various power purchase contracts that the Commission has already approved in the past. To the extent that the 2012 cost of power contracts is higher, this filing may request a higher amount than last year.
- Annual Electric True-Up (AET) 2012 - Advice Letter Update
- Annual Gas True-Up (AGT) 2012 - Advice Letter Update
- FERC TACBA Filing

SDG&E Rate Requests

SDG&E has the following rate requests pending before the Commission:

- **ERRA Compliance Application A.10-06-001 (MRTU):** SDG&E seeks recovery of revenue requirement associated with balances in the Market Redesign and Technology Upgrade Memorandum Account, Procurement Transaction Auditing Memorandum Account, Independent Evaluator Memorandum Account, Generation Divestiture Transaction Cost Memorandum Account, and Renewables Portfolio Standard Memorandum Account (RPSMA).

  Requested Recovery: $4.32 million.

- **Rim Rock Tax Equity A.10-07-017:** SDG&E filed a petition 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.

  Requested Recovery: $600 million.

- **Dynamic Pricing A.10-07-009:** SDG&E requests recovery of incremental costs to extend time varying rate options to small non-residential and residential customer classes.

  Requested Recovery: $118 million. $30 million is requested for 2011.

- **Demand Response Programs A. 11-03-003:** On May 1, 2011 SDG&E filed an application for approval of Demand Response (DR) programs, activities and budgets for the years 2012-2014. SDG&E seeks to develop its Demand Response portfolio, simplify its program, and promote automated controls to maximize customer response and enhance the reliability of Demand Response resources.

  Requested Recovery: $69 million.

- **2011 ERRA Forecast A.10-10-001:** SDG&E requests approval of revenue requirements to cover the costs of acquiring power for retail customers, including costs to purchase power under contracts with various power suppliers. Specifically, SDG&E requested authority to decrease ERRA and Competitive Transition Charge (CTC) rates.

  Requested Decrease: $56.1 milllion.

- **El Cajon Peaker A.11-01-004:** SDG&E requests approval of cost recovery for ownership and operation of the El Cajon 52 MW peaking facility.

  Requested Increase: $16.8 million.

- **2012 GRC Phase 1 A.10-12-005:** SDG&E requests an increase in revenue requirement for improvements in energy distribution system and increases in fire insurance premiums. The Commission will complete the review and approval process over the next 12 months.

  Requested Increase: $1.867 billion, an increase of $216 million over currently authorized base revenues.

SDG&E rate related requests expected later this year

SDG&E is expected to file the following rate related requests later this year. The requested amounts are not known at this time.

- Demand Response Application
- Non-fuel generation balancing account update Advice Letter
- FERC Transmission Owner 3 true-up filing
- Electric Public Purpose Program Update Advice letter
- Energy Resource Recovery Account (ERRA) 2012 Forecast – SDG&E anticipates filing an application in October, 2011. Requested Recovery depends on the fuel price forecast and purchased power costs. The ERRA-related revenue requirement approved in

SDG&E's last ERRA decision and embedded in current rates is $875 million. This filing will include the 2012 cost of various power purchase contracts that the Commission has already approved in the past. To the extent that the 2012 cost of power contracts is higher, this filing may request a higher amount than last year.

- Electric Regulatory Account Update Advice letter
- SB 695 Residential Rate Change
- Electric Consolidated Advice letter
- FERC RS Filing
- FERC TACBAA/TRBAA Filing
- Z-Factor 2010-2012 Insurance Premiums Advice Letter
- DWR Implementation Advice Letter
- Gas Regulatory Account Update Advice Letter
- Gas Consolidated Advice Letter
- Gas Public Purpose Program Update Advice Letter
- Triennial Cost Allocation Proceeding: September 1, 2011
- Energy Efficiency Application
- CARE Application
- GRC Phase 2: September 1, 2011

IV. Program Specific Proceedings and Activities

The Commission implements a wide array of energy policies in accordance with the Energy Action Plan (EAP), various statutes and California's energy policy initiatives. The Commission continually strives to improve the efficacy of these programs by making sure the programs are cost-effective and are managed efficiently by the utilities. In some cases the programs may not be as cost-effective in the short run but are justified by their cost-effectiveness over the long run as the programs spur market development and innovation which can bring down costs over time.

Long Term Procurement and Resource Adequacy

Background

The CPUC adopted a System and Local Resource Adequacy (RA) policy framework in 2004 in order to ensure the reliability of electric service in California.[6] R.09-10-032 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.[7] Every two years, the CPUC holds a Long Term Procurement Plan (LTPP) proceeding to evaluate the system's need for new conventional resources and to serve as the "umbrella" proceeding to consider, in an integrated fashion, all of the Commission's EAP loading order resource policies and programs.

Proceedings in next 12 months that will impact revenue requirements or rates

Current proceedings at the CPUC are unlikely to have rate impacts either positive or negative 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.

Future revenue requirements and rates

A major element that drives costs of the RA program is renewables integration. Wind and solar resources only produce electricity when the sun shines or the wind blows. It is difficult to accurately predict the amount of energy that will be delivered by intermittent resources during times of peak demand. Therefore, in order to ensure reliability other resources need to be procured and ready to perform if intermittent resources are not available. Customers pay for these resources even if they only operate a limited amount of time. As the amount of intermittent resources increases to meet renewables goals, the amount of resources required for renewable integration also increases. The CPUC is working with the CAISO and other parties to more accurately forecast, and minimize the need for renewable integration.

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[6] PU Code Section 380
[7] PU Code Section 454.5

Procurement of capacity and energy is currently accomplished mostly through direct contracting between the load serving entities (LSEs) and generators (bilateral contracting). LSEs then bid resources into the CAISO markets. There is significant variation in contract prices. This variation between contract prices results from different energy and capacity values that depend on location, ability to respond quickly to system needs, vintage of plant, and market competitiveness. There are also a few longer term contracts, such as DWR contracts, that contribute to overall ratepayer costs.

Several proceedings within the next 12 months in this program area have the potential to affect 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, and the gradual expiration of Department of Water Resources energy contracts that may have rate impacts within the next 12 months. CPUC staff expects the combined effects of Long Term Procurement and RA policies as well as other changes to California's energy market to lead to no increase in rates within the next 12 months, but will raise rates in the 12 months thereafter. These rate increases will however prevent further costs later, 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 forecast of needs over the next ten years. If need exceeds forecast supply and preferred resources can not meet the requirements, the CPUC authorizes the IOUs to hold an auction for the right to build new generation. IOUs develop projects that benefit the entire CAISO controlled system, including ESPs and CCAs. Because 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 is needed to allow the retirement of generators that may be inefficient and/or environmentally harmful.

Construction of New Generation via the LTPP program

The LTPP program requires IOUs to assume the task of constructing conventional thermal generation apart from their other procurement activities (RPS, DR, and EE) to meet projected infrastructure needs in their service territories. Added costs for the construction of these new resources are reasonable, given the approval of procurement policies and authorized amounts in CPUC LTPP decisions. The most recent LTPP decision (D.07-12-052) authorized 2,130 to 3,430 MW of new generation to be constructed to support system reliability needs going out to 2018. These new resources will be more expensive than continued operation of existing resources, but will be more efficient and more environmentally friendly. No major new natural gas fueled generation is expected to begin operation in 2011. Several facilities are scheduled for 2012-2013. When new generating facilities become operational their costs result in an increase in rates.

The CPUC authorized this new procurement amount partially due to the possibility that the benefits, such as cleaner air, less fuel use, and less water use, from retiring older and less efficient plants would outweigh the costs of new construction from a policy perspective. Without procurement designed to offset retiring generation, however, there would be no need for new construction however. California has made this a policy preference, and done so by enacting AB 32 which is designed to, among other things, decrease GHG emissions from the electricity generation sector. Future procurement decisions may authorize additional procurement for the IOUs due to the need for renewable integration, the failure of contracted generation to perform or come online as planned, or other reasons.

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 existing facilities comprise over 30% of the total generating capacity within the state of California. They are concentrated in the Los Angeles Basin, the Greater Bay Area, and San Diego and many are currently needed to ensure reliability in those areas. The majority of the units that use OTC are in Southern California, and present 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. Mitigation will be done via a variety of approaches, 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 on-line and existing facilities are retired. It should be noted that a significant amount of the units using OTC were built in the 1960s and 1970s and would need to be replaced regardless of OTC policy.

Energy Efficiency

The CPUC has a decades-long history of policy support for ratepayer investment in cost-effective energy efficiency resources which enables investor-owned utilities to first meet 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 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 potential" and set targets for the IOUs to achieve that potential.[9] In 2003, the Energy Action Plan further established energy efficiency as the priority resource to meet California's energy needs in the future.

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[8] PUC Sec 454.5(b)(9)(C)
[9] PUC Sec 454.55

IOU Administration of Energy Efficiency Programs

In January 2005,[10] the CPUC adopted an administrative structure for post-2005 energy efficiency programs designed to meet the objectives of the Energy Action Plan via energy savings goals adopted in September 2004.[11] The Commission authorized a three-year program cycle beginning with the 2006-2008 period in order to capture short-term savings from specific measures, such as lighting, and encourage longer term demand side resource planning. The Commission also directed that utility energy efficiency performance be evaluated based on overall portfolio energy savings achievements, rather than on the performance of each individual program or measure, in order to "encourage innovation, and allow for some risk-taking on pilot programs and/or measures in the portfolio."[12]

The adopted structure returned to the utilities the functions of selecting the activities and implementers for the portfolio of energy efficiency programs and the daily tasks associated with administering and coordinating program activities during funding cycles. The CPUC Energy Division became responsible for program oversight as well as managing and contracting for all Evaluation, Measurement and Verification (EM&V).

Strategic Plan

In 2007, the Commission 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 Plan*,[14] adopted in 2008,[15] set forth a roadmap for energy efficiency in California through the year 2020 and beyond. The Strategic Plan supports the Commission's goal of moving beyond programs that create near-term energy savings into a mode of market transformation-focused programs that achieve all cost-effective energy efficiency over the long-term.

2010-2012 Energy Efficiency Programs

In September 2009, the Commission approved $3.1 billion in cost-effective energy efficiency investments for the 2010-2012 program cycle.[16] The utilities' portfolios struck a balance between short-term programs, such as the replacement of incandescent light bulbs with compact fluorescent light bulbs, with longer-term strategies and comprehensive programs, such as whole-building energy retrofits. In certain instances, programs (or program components and measures) implemented and evaluated during the 2006-2008 program cycle that were shown to not be cost-effective were modified or eliminated from the current program cycle. Energy Division has the responsibility to evaluate program performance and make recommendations for changes in portfolio content or program delivery in the subsequent program cycle.

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[10] D.05-01-055, available at http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/43628.PDF
[11] D.04-09-060, available at http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/40212.PDF
[12] D.05-04-051, available at: http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/45783.PDF.
[13] D.07-10-032, available at http://docs.cpuc.ca.gov/published/Final_decision/74107.htm
[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] See D.09-09-047 at http://docs.cpuc.ca.gov/PUBLISHED/Graphics/107829.PDF

Evaluation and Cost Effectiveness

The CPUC requires rigorous measurement and verification of the reported savings and evaluation of the largest programs by independent contractors. This process verifies that reported savings for specific measures and uses these savings to determine cost-effectiveness of the utilities' portfolios and specific energy efficiency programs.

Energy Division measures cost-effectiveness by the Total Resource Cost (TRC) and Program Administrator Cost (PAC) tests.[17] A TRC or PAC ratio that is larger than "1" means that the benefits of a program (expressed as the value of energy savings in dollars) exceed the costs of that program.

Energy Division's evaluation of the 2006-2008 energy efficiency programs determined that the utilities' portfolios earned back each dollar of ratepayer money invested in energy efficiency, plus $.14 in additional benefits.[18] The evaluation included a detailed list of recommendations regarding program changes that could be made in order to improve program delivery and cost-effectiveness. In an effort to balance Commission directive to pursue both short-term energy savings and long-term planning, certain programs that were not cost-effective were either modified or removed from the 2010-2012 program cycle while some programs with a long-term focus, though not cost-effective at an early stage, were continued.

For the 2010-2012 program cycle, Energy Division is leading a $120 million evaluation effort that will again look at the utilities' program portfolios to determine energy savings and cost-effectiveness.

Additionally, the Commission will consider a number of issues related to the 2010-2012 and future energy efficiency program cycles that may affect future revenue requirements and/or rates:

- **Energy efficiency portfolio guidance decision.** The Commission is currently developing policy guidance for the IOUs' post-2012 energy efficiency portfolio, including establishing new energy savings goals and updating inputs and methodologies for evaluating program cost-effectiveness. This policy guidance will shape the total budget and estimated net benefits of the IOUs' post-2012 energy efficiency portfolio applications. Likely impact on future rates is unknown at this time.
- **2013 energy efficiency "bridge year."** In order to accommodate a more comprehensive review of its energy efficiency guidance policies, the Commission is considering a one-year extension of the current 2010-2012 portfolio. Thus, the IOUs are expected to file a request for 2013 bridge year funding, with a Commission decision on funding authorization by the fourth quarter of 2011. Estimated impact on future rates is approximately $1 billion for a cost-effective portfolio of energy

[17] The TRC measures the net resource benefits to ratepayers, including costs of supply-side resources avoided or deferred, by combining the net benefits of the program to participants and non-participants. Under the PAC, program benefits are the same as those related to determining the TRC, but costs are limited to those incurred by the program administrator, including all incentives and all other program costs and exclude customer costs.

[18] See the full report at ftp://ftp.cpuc.ca.gov/gopher-data/energy%20efficiency/2006-2008%20Energy%20Efficiency%20Evaluation%20Report%20-%20Full.pdf

efficiency programs, based on assumed continuation of 2010-2012 funding levels (currently averaging $1 billion annually).

Improving Program Efficacy for 2010-2012 and Beyond

When the CPUC approved the IOUs' 2010-2012 energy efficiency portfolios, the Commission imposed several cost controls resulting in 20% (approximately $1 billion) less than the IOUs requested in their applications. The CPUC reduced proposed expenditures by capping administrative costs at 10% of overall budgets (down from 14% proposed), which was consistent with national averages for other jurisdictions. A 20% target was placed on support costs associated with incentive-based programs, such as education and training, engineering support and project management. The CPUC reduced marketing, education and outreach costs to 6% (down from 9% proposed) again based on national averages. Finally, the Commission halved the IOUs proposed Evaluation, Measurement and Verification budget to 4% of the overall budget.

Since 2005, the CPUC has required the Commission's Energy Division and Division of Water and Audits to perform financial, management and regulatory compliance audits.[19] In September 2009 the CPUC made this activity a core regulatory activity to be funded through the EM&V budget approved by the for the current 2010-2012 portfolio cycle. The Commission recognizes that rigorous audits overseen by CPUC staff are critical to ensuring that the IOUs' general and administrative costs and other program expenditures are prudent and reasonable. Key audit task areas include program accounting and reporting, program processes and controls, program implementation and costing, and program oversight.

As part of the 2010-2012 EM&V process, Commission staff is planning to conduct management audits and organizational assessments, using management consultants, to better understand the drivers for decreasing trends in the overall cost-effectiveness of utility energy efficiency portfolios.[20] The assessment will consist of an examination of management systems, organizational structure, cost-tracking systems, staff and management incentives (e.g., bonus structures), use of information technology and other factors.

In mid-2012, the IOUs are expected to file their applications for the post-2012 portfolio cycle, after a 2013 bridge year. In order to ensure a timely initiation of portfolio implementation beginning in 2014, the Commission is anticipated to authorize a new round of energy efficiency program funding in late 2013. Likely impact on future rates of the prospective post-2012 portfolio application is unknown at this time.

Demand Response

Program Summary

Demand response (DR) is the ability of a customer to reduce his peak load (or shift his usage to a different time of the day) in response to a price signal, an emergency alert or an incentive payment. The intent of DR programs is to reduce demand during the peak hours (approximately between the hours of 2 pm and 6 pm in the summer months) when it is very expensive for utilities to provide electricity. DR benefits ratepayers in that it enables utilities to avoid building

[19] D.05-01-055 available at http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/43628.PDF
[20] See 2010-2012 Energy Efficiency Evaluation, Measurement and Verification Work Plan, available at www.calmac.org/events/2010-2012_Energy_Efficiency_EM&V_Plan_12-20-10.pdf

expensive new electric generating capacity (such as peak power plants) that are used for only a small percentage of the hours in a year. The avoidance of greenhouse gas emissions from those peaker plants is an additional benefit DR provides.

DR also lowers wholesale power costs since 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 is ranked as one of the most important resources in the Commission's "loading order," second only 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 developed approximately 2,200 MWs of DR, which is slightly more than the capacity of four large power plants.

Starting in 2002, the Commission has been developing policies to encourage the growth of DR programs. Key CPUC decisions that have further shaped current DR policy and programs include:

- D.09-08-027: approved 3-year (2009-2011) budgets for utility-operated DR programs.
- D.08-07-045: provided the utilities rate design guidance and a timetable for the implementation of time-varying/dynamic rates, which incent customers to shift their demand away from peak hours by charging higher prices for peak time energy consumption. (As noted in the 2010 SB 695 Report, time-varying and dynamic rates are the most economical means of delivering DR.)
- D.06-07-027: found PG&E's proposed smart meter system to be cost-effective and approved its deployment. In 2007 and 2008, the Commission made similar findings for SDG&E and SCE and approved the deployment of smart meter systems for those utilities. Smart meters measure electricity usage in hourly increments and are necessary for customers to participate in DR programs or time-varying/dynamic rates. By 2012, all customers of PG&E, SCE and SDG&E are scheduled to have a smart meter.

Identification of activities and proceedings in next 12 months (from May 1, 2011 through April 30, 2012) that will affect the program areas' future revenue requirement and/or rates.

- R.07-01-041, Phase 4: this rulemaking is establishing policies and rules that will govern the bidding of DR directly into wholesale energy markets by end-use customers and third-party DR operators.
- 2012-2014 DR budget applications: in March 2011, the utilities will be filing 3-year DR program proposals for the Commission's consideration. The program proposals will include incentive programs that offer bill credits to customers who participate in DR programs, rebate incentives to help off-set the cost of enabling technologies, marketing/education programs and pilots that will test how DR programs could be used to integrate intermittent renewable resources into the grid.

- A.10-08-005, A.10-02-028, A.10-09-002, and A.10-07-009: these proceedings are considering utility proposals to implement dynamic pricing tariffs for various customer classes.
- D.10-02-032: PG&E filed a Petition for Modification to delay implementation of time-varying/dynamic pricing to residential, small business and certain agricultural customers.

Plans to improve the efficacy of the program (e.g. improving cost/benefit ratios, cutting costs).

- **Measuring Cost-Effectiveness:** In Decision (D.)10-12-024, the Commission adopted a protocol that will estimate the cost-effectiveness of DR programs. This protocol will be a tool in ensuring that future DR incentive programs will be cost-effective relative to a new peaker plant (which would otherwise be needed if not for the DR resource). The protocol will be used by the Commission for the first time when the utilities' 2012-2014 DR budget applications are submitted in March 2011. The protocol will enable staff to identify DR program proposals that are not cost-effective so that such proposals are either rejected or adjusted by the Commission (such as lowering incentive payments or administrative costs) to ensure they are cost-effective and thus beneficial to ratepayers.
- **Align DR programs with Resource Adequacy (RA) values.** Through its RA framework, the Commission sets the 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. The Commission is addressing this inefficiency by directing 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 RA must be available to be called for a block of at least four consecutive hours on three consecutive days. The utilities' 2012-2014 DR programs will be examined by the Commission to ensure they contain the same requirements.
- **Approve rules and policies for DR direct participation.** In 2010, the California ISO implemented a new market product called "Proxy Demand Response" or PDR. PDR essentially is the gateway by which DR can be bid into wholesale energy markets in competition against supply side resources (generators). The utilities have already been directed by the Commission to make the necessary changes to its procurement processes so that their DR programs can be used as bids in PDR. The active bidding of DR into wholesale energy markets benefits ratepayers as DR will force downward pressure on the bids offered by supply-side resources in those markets.

  Additionally, the Commission is now in the process of developing policies and rules by which third-party DR operators or even end-used 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 existing contracts between these entities and the utilities. Those contracts are funded by ratepayers as part of the utilities' DR program portfolios.

- **Begin Modifications to Emergency DR programs.** Of the 2,200 MWs in the utilities' DR portfolios, about 1,400 MWs are categorized as "emergency" DR programs. Emergency programs 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 in that the participants (large commercial and industrial customers) are paid substantial 'standby' or capacity payments to be ready to drop their load when called by the utility.

  In 2010 the Commission determined that the utilities are oversubscribed with emergency DR and have since ordered the utilities to reduce enrollment in these programs starting in 2012 with further reductions occurring in 2013 and 2014. Additionally the Commission directed the utilities to modify their emergency programs so that they could be integrated in wholesale energy markets through a CAISO market product specifically designed for emergency programs. These changes reduce costs for ratepayers in two significant ways: (1) the CAISO will now recognize emergency programs as an RA resource (in previous years, CAISO did not recognize emergency programs as a legitimate RA resource and thus procured additional capacity equivalent to the capacity represented by these programs thereby causing ratepayers to "pay twice"), and (2) the reduction in enrollment of emergency programs will eliminate the current overcapacity and simultaneously transition participants to DR programs that can more actively participate in wholesale energy markets or to time-varying rates.

Qualitative discussion of trends beyond the 12 month reporting period.

It is anticipated that the Commission will be paying close attention to the utilities' implementation of time-based and dynamic rates in 2012. Customer education will be critical to customer acceptance of these new rates. Additionally, the integration between DR and other demand-side resources, such as energy efficiency, is likely to increase in 2012. 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.

Renewables Portfolio Standard Program (RPS)

California's Renewables Portfolio Standard Program (RPS) is the most ambitious in the country in terms of total procurement required from renewable energy resources, with a goal to supply 20 percent of the retail electricity provided by investor owned utilities, energy service providers, and community choice aggregators from eligible renewable resources by 2010.[21] The CPUC and the California Energy Commission are jointly responsible for implementing the program. Governor Schwarzenegger's Executive Orders S-14-08 and S-21-09 established a further goal of 33% renewable energy by 2020.

[21] Pursuant to the RPS legislation, the CPUC implemented flexible compliance rules that allow LSEs to bank excess renewable energy and defer deficits in any year for up to three years when using an allowable excuse.

Cost Minimization

The RPS program is structured to minimize ratepayer costs. First, it sets up a technology-neutral, competitive renewable procurement process where obligated entities select 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's Commission-approved RPS Procurement Plan and additional data as needed. While bilateral contracting is also allowed under the program, the Commission has emphasized that competitive solicitations are preferred, thereby encouraging greater price competition. Second, long-term fixed-price renewables contracts provide a hedging benefit for ratepayers against price volatility in natural gas markets.

Cost Containment

Third, the program includes a specific cost containment mechanism. The CPUC is required to calculate a market price referent (MPR) annually, which represents the long-term ownership, operating, and fixed-price fuel costs for a new 500 MW natural gas-fired combined cycle gas turbine. RPS statute directs the CPUC to calculate a total amount of eligible above-MPR funds (AMFs) available to all electrical corporations to cover above-MPR costs for RPS contracts. The CPUC calculated that the above-MPR funds would be approximately $775 million, allocated collectively to Bear Valley Electric Service, PG&E, SCE and SDG&E.

By the fall of 2009, the three large IOUs had exhausted their AMFs. IOUs have no obligation to purchase RPS contracts at above-MPR prices once their AMFs are exhausted; however, they can still choose to do so based on their assessment of remaining renewables need, and request a determination of price reasonableness from the CPUC.

Since ratepayers do not pay for RPS generation until it is actually delivered and since most of the projects resulting from RPS contracts are still in development, the rate impacts of the RPS program are currently small. However, it appears likely that, while some RPS-eligible technology costs are decreasing (e.g. solar photovoltaic), RPS contract prices for delivered energy will continue to move upward in general. The number of RPS contracts with prices above the MPR has increased in recent solicitations. The first above-MPR contract was approved in 2007, and since then, approximately half of the projects submitted for CPUC approval have been above the MPR. Price increases are due to at least two factors: many of the better-resourced wind projects in California are already under contract, and relatively expensive utility-scale solar thermal projects may continue to make up a large portion of new RPS bids. However, further improvements in technology or other developments may also cause average bid prices to decrease.

Proceedings in next 12 months that will impact revenue requirements or rates

- **RPS Implementation Proceeding (R.08-08-009):** In between the RPS program and self-generation programs is an important market segment for system-side renewable distributed generation (DG). In 2011, CPUC began implementation per SB 32 (2009) of Public Utilities Code 399.20, which expands the existing feed-in tariff for renewable DG systems from 1.5 MW to 3 MW. The modified statute changes the pricing mechanism, which may increase the contract price. . The CPUC will explore a new feed-in tariff price through its implementation proceeding. In addition, since larger projects are eligible for the feed-in contract and more energy may be purchased through this program, total program costs will likely increase.

In 2010, the CPUC also approved Decision 10-12-048, which created the Renewable Auction Mechanism (RAM) for projects up to 20 MW. The RAM requires the use of a standard contract and a competitive auction to select the lowest cost projects that meet the program's criteria. The RAM decision authorized the three large utilities to procure 1000 MW collectively over a two year period, beginning in 2011. On February 25, 2011, the utilities filed advice letters to implement the program; once the advice letters or advice letter modifications are approved by the Commission, the first utilities will begin their solicitations.

Approval of Utility Solar Photovoltaic (PV) Programs: In 2009 and 2010, the CPUC approved five-year programs for SCE, PG&E, and SDG&E to build, own, and operate solar PV projects, and to execute contracts for solar PV projects with independent power providers (IPPs). The CPUC has approved PG&E's and SCE's implementation plans for utility-owned and IPP PV programs. SCE held its first auction in 2010 and will hold a second auction in 2011. PG&E is holding its first auction during the first quarter of 2011. SDG&E has submitted its PV program implementation advice letters, which are currently under review.

Actions for reducing rate impacts in the next 12 months and beyond

- **Implementation of Cost Containment in Current RPS Legislation:** The Legislature is considering legislation to increase renewable energy purchase requirements above 20% of retail sales, and the bill includes a new cost containment provision. Should the bill be enacted into law, the CPUC will implement any cost containment mechanism as directed.

- **Use of Tradable Renewable Energy Credits (TRECs):** In March 2010, the Commission authorized the use of TRECs for RPS compliance whereby the LSEs can choose to receive only RECs (and not the underlying energy) for some portion of their renewable obligation. Allowing the use of TRECs for RPS compliance will provide more renewable procurement options and flexibility for LSEs, potentially resulting in lower costs to ratepayers. A transitional price cap for TRECs was included through 2013, protecting ratepayers from potential high prices in the early stages of a TREC market. In 2011, the CPUC will develop and implement a process for reviewing and approving REC-only contracts.

- **Implementation of DG-Focused RAM and Utility PV Programs:** The Renewable Auction Mechanism and the utility PV programs approved by the CPUC in 2009 and 2010 could both serve to minimize renewables procurement costs. PV prices have decreased substantially in recent years and are often cheaper than utility-scale solar thermal project prices. If these programs are successful at spurring significant increases in PV capacity, developer experience and economies of scale could prompt installed PV costs to decline further. In addition, the RAM decision prohibits projects that meet the criteria of the RAM program from executing bilateral contracts, instead requiring competitive auctions that will put downward pressure on prices.

- **Review of Utilities' Bid Selection Criteria and Methodology:** Within the scope of the RPS implementation proceeding, the Commission may consider requiring changes to the utilities' least cost-best fit bid selection processes, potentially resulting in lower costs to ratepayers.

Distributed Generation/ California Solar Initiative

California's Energy Action Plan ranks renewable energy number two in the state's loading order[22], and in Rulemaking (R.) 10-05-004 the CPUC performs ongoing oversight of the Self Generation Incentive Program (SGIP) and the California Solar Initiative (CSI), two key renewable energy programs designed to foster the development of renewables from distributed generation.

The Self Generation Incentive Program (SGIP)

Since 2001, the SGIP has provided financial incentives for the installation of new, qualifying self-generation equipment installed to meet all or a portion of the electric energy needs of a facility. Wind turbines, fuel cells, and corresponding advanced energy storage systems are the technologies currently eligible for SGIP incentives. The program is administered by PG&E, SCE, SoCalGas and CCSE.

The SGIP was designed to complement the CEC's Emerging Renewables Program (ERP) by providing incentive funding to larger renewable and non-renewable self generation units up to the first three megawatts of capacity. SGIP technologies offset the demand for both electricity and natural gas; thus, program costs are recovered by electric and gas ratepayers. The SGIP program budget is $83 million a year, with 2011 being the last year for SGIP collections, allowed under PU Code 379.

When the SGIP program was created, solar PV was among the distributed generation technologies eligible for funding; however, with the passage of SB1 (Murray, 2006) solar PV was separated from the SGIP and included in the California Solar Initiative.

The Commission is currently considering a range of program modifications pursuant to SB 412 (Kehoe, 2009) and granted a motion filed by SGIP Program Administrators to temporarily halt the issuance of SGIP incentives, effective December 31, 2010, in order to preserve SGIP incentives for future technologies that the Commission may opt to include in the program upon completion of SB 412 implementation.

The California Solar Initiative

Senate Bill (SB) 1 (Murray, 2006) created the California Solar Initiative and established a budget of $2.167 billion for the installation of solar electric energy systems. In D.06-12-033 the CPUC authorized cost recovery for the CSI through electric rate collections by the State's regulated

[22] 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

investor-owned electric utilities: Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE) and SDG&E.

The CSI Program demonstrates the State's strong support for solar technology and since 2006 the statewide *Go Solar, California!* campaign has attracted tremendous attention from solar industry leaders, the national media and from utility customers that choose to go solar with CSI rebates. In addition to incentivizing more than 400 megawatts of installed solar energy in the first four years of the program (with a goal of 1,750 megawatts by 2016) the CSI has supported the growth of a multi-billion dollar industry that has created more than 36,000 skilled jobs in California.

The CSI is funded in two different ways, depending on the type of energy that is being displaced. Electric ratepayers support solar energy systems that displace onsite consumption of electricity, and gas ratepayers support solar energy systems that displace onsite consumption of natural gas. In both cases, CSI provides upfront incentives for solar systems installed on existing residential homes, as well as existing and new commercial, industrial, government, non-profit, and agricultural properties within the service territories of the large IOUs.

CSI incentives are performance-based, which means that system owners receive payments based on either expected or actual performance of their solar systems. Residential customers and those with systems smaller than 10 kW may receive their payments upfront under the Expected Performance Based Buydown (EPBB) while customers with larger systems between 10kW and one megawatt receive monthly Performance Based Incentive (PBI) payments over the course of five years. EPBB incentives are priced per Watt, and PBI incentives are priced per kilowatt hour (kWh) of actual energy generated. Both incentive tracks decline by a minimum of 7 percent in a series of ten steps; when the megawatt capacity for each step is reached, the incentives decline to the next level. Incentives have declined seven times since 2007. Each time incentives decline, ratepayers benefit because the total program cost declines relative to the installed megawatts achieved.

The CSI focuses on onsite, grid-connected[23] solar technologies used by utility customers to offset some portion of their own load. The CSI does not fund wholesale solar power plants, designed to serve the electric grid or help utilities meet Renewable Portfolio Standard (RPS) obligations.[24]

In January 2010, after an 18-month pilot program managed by CCSE in San Diego, the Commission adopted D.10-01-022 establishing the CSI-Thermal program pursuant to Assembly Bill (AB) 1470 (Huffman, 2007). This $350.8 million program provides incentives to customers who currently heat their water with either electricity or natural gas in the service territories of Pacific Gas and Electric, Southern California Edison, San Diego Gas & Electric, and Southern California Gas Company. Monies collected under AB 1470 from gas ratepayers fund incentives

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[23] Strictly speaking, solar thermal systems are not grid connected, but back-up hot water or thermal service is provided by the gas distribution network.
[24] The California utilities contract for a variety of renewable resources, including large and small solar power plants as part of the RPS Program. Updates on the progress of the RPS program can be found at http://www.cpuc.ca.gov/PUC/energy/Renewables/.

to solar water heating systems that displace natural gas water heaters; monies collected under SB1 from electric ratepayers fund electric-displacing water heating systems.[25]
The primary CSI program goals are to:

- Install 1,940 MW of distributed solar energy systems in the large IOU service territories;
- Install solar water heating systems that displace the use 585 million therms of natural gas in homes and businesses in the large IOU service territories;
- Transform the market for solar energy systems so that it is price competitive and self-sustaining.

The CSI Program currently has five program components, as shown in Table 1, each with their own Program Administrators and budgets that are overseen by the CPUC:

- **The CSI General Market Solar Program** is administered through three Program Administrators: PG&E, SCE, and CCSE in SDG&E territory. The goal is 1,750 MW with a ten-year budget of $1.8 billion.
- **The CSI Single-family Affordable Solar Homes (SASH) Program** provides solar incentives to qualifying single-family low income housing owners. The SASH Program is administered through a statewide Program Manager, GRID Alternatives, with a budget of $108 million through 2015.
- **The CSI Multifamily Affordable Solar Housing (MASH) Program** provides solar incentives to multifamily low income housing facilities. The MASH Program also has a $108 million budget through 2015 and is administered through the same Program Administrators as the general market solar program: PG&E, SCE, and CCSE.
- **The CSI Research, Development, Demonstration and Deployment (RD&D) Program** provides grants to develop and deploy solar technologies that can advance the overall goals of the CSI Program, including achieving both targets for capacity, cost, and a self-sustaining solar industry in California. The RD&D Program is administered through the RD&D Program Manager, Itron, Inc., and has a budget of $50 million.
- **The CSI Thermal Program** provides rebates for solar water heating installations on new and existing homes and businesses, including multi-tenant buildings. The program pays incentives towards solar water heating systems that displace natural gas water heating on new[1] and existing homes and businesses, and towards solar water heating systems that displace electric water heating on existing homes and businesses. The goal is 585 million therms of natural gas displacement with a budget of $250 million on the gas side, and 275.7 million kWh per year of electricity displacement (the equivalent of 150 MW of electric generating capacity) with a budget of $100.8 million on the electric side.

[25] SB1 limited funds for CSI to $2.176 billion per PU Code 2851 (e) but included a provision allowing up to $100.8 million of total CSI funds to be used for electric-displacing solar thermal technologies such as solar water heating systems; AB 1470 authorized $250 million from gas ratepayers to provide incentives for gas-displacing solar thermal technologies.
[1] If solar water heating becomes mandatory for new home construction, new homes shall not be eligible for incentives under CSI Thermal.

In D.10-09-046, the Commission adjusted the program budget to ensure that more funds were available to meet the incentive obligations for the program (
Table 1).

Table 1: Revised CSI Budget by Program Component, 2007-2016

	Budget ($ Millions)	**Goal**
CSI Electric Budget (2007-2016)	**$2,167**	1,940 MW
General Market Solar Program (includes PV and electric-displacing CSI-Thermal program)	$1,897	1,750 MW
Single-family Affordable Solar Homes (SASH)	$108	~15 MW
Multifamily Affordable Solar Housing (MASH)	$108	~30 MW
Research, Development, Demonstration, and Deployment (RD&D)	$50	~
CSI Gas Budget (2010-2017)		
CSI-Thermal Program (Gas-Displacing solar thermal/hot water)	***$250***	*585 million therms*
Total CSI Budget	**$2,417**	

Source: CPUC D.06-12-033, p.26,CPUC D.10-01-022, Appendix A and D.10-09-046 Ordering Paragraph 1, p.32. . Figures may not sum to total because of rounding.

CSI Program Balancing Accounts

In 2006, the Commission established a total budget of $2.167 billion over ten years for the CSI, including all program components, as shown in Table 1, above. The large IOUs were authorized to collect the CSI Program funds from electric ratepayers according to the schedule as shown in Table 2.[26] The CSI funds are held by each utility in a balancing account, which is a standard utility accounting practice. The CSI schedule of collection is slightly front-loaded for a number of reasons, including ensuring that participants applying for CSI incentives today can be confident that the funds will be available for their projects upon completion.

[26] The CPUC modified the CSI Program rate collections schedule in December 2008, in D.08-12-004.

Table 2: Authorized CSI Balancing Account Rate Collection Schedule

Year	PG&E	SCE	SDG&E	Total
Transfer from SGIP on 12/31/2006	$ -	$ 104,600,000	$ 37,200,000	$ 141,800,000
2007	$ 140,000,000	$ 147,000,000	$ 33,000,000	$ 320,000,000
2008	$ 140,000,000	$ 147,000,000	$ 33,000,000	$ 320,000,000
2009	$ 140,000,000	$ -	$ -	$ 140,000,000
2010	$ 105,000,000	$ 110,000,000	$ 25,000,000	$ 240,000,000
2011	$ 105,000,000	$ 110,000,000	$ 25,000,000	$ 240,000,000
2012	$ 105,000,000	$ 110,000,000	$ 25,000,000	$ 240,000,000
2013	$ 70,000,000	$ 74,000,000	$ 16,000,000	$ 160,000,000
2014	$ 70,000,000	$ 74,000,000	$ 16,000,000	$ 160,000,000
2015	$ 70,000,000	$ 74,000,000	$ 12,800,000	$ 156,800,000
2016	$ 2,000,000	$ 45,400,000	$ -	$ 47,400,000
Total	$ 947,000,000	$ 996,000,000	$ 223,000,000	$ 2,166,000,000

Source: D.10-04-017

Actions for reducing rate impacts in the next 12 months

As the program continues, the CPUC will regularly monitor the trends in expenditures from CSI relative to costs and will adjust the necessary utility revenue collections accordingly.

CARE and Energy Savings Assistance Program

The Commission's low income assistance is conducted through two programs. The California Alternate Rate for Energy (CARE) Program provides eligible low-income households with a discount on electric and natural gas bills and the Energy Savings Assistance Program (formerly known as the Low Income Energy Efficiency Program) provides eligible low-income households with energy education, energy efficient appliances, and weatherization measures at no cost.

CARE -CARE is a low-income energy rate assistance program instituted in 1989 to address energy insecurity and fuel poverty of California's low income populations. The program provides a 20% discount on electric and gas rates. However, since CARE customers were not subject to the high rates for tiers 4 and 5, the subsidy for CARE has grown substantially above 20% as tiers 3, 4 and 5 rates have risen over time while tiers 1 and 2 were frozen. The CARE subsidy is particularly high for PG&E which has only two CARE tiers. Both Energy Savings Assistance Program & CARE are funded by ratepayers through the Public Purpose Program (PPP) Charge. According to the KEMA Low Income Needs Assessment 2007 report, one in three of California's households (33%) qualified for the CARE and LIEE Programs in 2006, (or approximately 4 million households statewide).

Energy Savings Assistance Program - The Energy Savings Assistance Program began in the 1980s as a direct assistance program provided by some of the Investor Owned Utilities (IOUs), and was formally adopted by the legislature in 1990 through Public Utilities Code Section 2790. The Energy Savings Assistance Program provides home weatherization services for low-income households and includes the following measures: (1) heating ventilation 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 other building conservation measures, installation of energy efficient appliances and energy education programs. The IOU's measure portfolio is evaluated for cost-effectiveness during the budget application process. All measures are provided at no cost to the resident. As articulated in the *Energy Efficiency Strategic Plan,* the Energy Savings Assistance Program pursues two goals: 1) By 2020, all eligible customers will be given the opportunity to participate in the program, and 2) The program will be an energy resource by delivering increasingly cost-effective and longer-term savings.

Relevant Decisions that impact revenue requirements or rates

Decision 08-11-031 - CARE and the Energy Savings Assistance Program are funded for a 3-year planning cycle. For the 2009-2011 budget period, the Commission authorized through Decision 08-11-031, a $2.6 billion budget for CARE and $885 million budget for the Energy Savings Assistance Program. The expected benefits of this spending are projected energy savings (yearly average) as follows: 81,266 MWh; 22.3 MW of demand; and 5.3 million Therms. The tables below show the annual targets for the Energy Savings Assistance Program and the 2009-11 authorized budgets for both low-income programs.

LIEE Goals: Number of homes to be treated from 2009-2011

Utility	2009	2010	2011	Cycle
PG&E	91,099	125,261	125,261	341,622
SCE	83,612	83,612	83,612	250,837
SoCalGas	111,211	143,973	146,301	401,485
SDG&E	20,384	20,384	20,384	61,152
Total	306,307	373,230	375,559	1,055,096

Adopted Budget Summary 2009-2011				
	LIEE			
Utility	2009	2010	2011	Cycle Total
PG&E	$109,056,366	$151,067,347	$156,789,038	$416,912,752
SCE	$60,242,000	$61,561,082	$63,413,860	$185,216,942
SoCalGas	$49,571,908	$76,872,816	$78,256,269	$204,700,993
SDG&E	$21,184,008	$21,184,009	$20,327,606	$62,695,622
Total	$240,054,283	$310,685,254	$318,786,772	$869,526,309
	CARE			
	2009	2010	2011	Cycle Total
PG&E	$470,314,651	$479,331,337	$489,228,435	$1,438,874,423
SCE	$208,541,000	$213,312,000	$216,885,000	$638,738,000
SoCalGas	$139,132,786	$140,737,280	$142,489,637	$422,359,704
SDG&E	$49,961,816	$51,516,795	$53,064,454	$154,543,065
Total	**$867,952,262.40**	**$884,899,422.01**	**$901,669,537.33**	**$2,654,515,191.74**

Order Instituting Rulemaking 10-02-005 and Decision 10-07-048 - Both aim to continue efforts to identify cost-effective methods to reduce the number of customer utility service disconnections in the territories of the IOUs. Between the two, they require the IOUs to revamp and extend their bill payment plans, prohibit CARE and FERA customers from paying additional reestablishment of credit deposits for either slow-payment/no-payment of bills or following a disconnection, prohibit disconnection of medical baseline or life support customers disconnected without an in-person visit from a utility representative. They authorize the IOUs to charge significant costs associated with complying with the new practices in this decision to their memorandum accounts.

Plans to improve the efficacy of the program

With D.08-11-031, The Commission adopted new goals, initiatives, and improvements to the program to encourage and facilitate greater program efficiencies, collaborations and overall benefits to the low income population as well as the rest of the state. The implementation of these efforts has been and continues to be central to the Commission's activities over the next 12 months, and beyond. These major initiatives include the following:

- Focus outreach of the Energy Savings Assistance Program on customers with high energy-use, burden and insecurity to reach those customers in greatest need first.
- Enhance outreach to the disabled to better reach this group that makes up approximately 20% of the low-income population.
- Implement a 90% CARE penetration goal of the low income population for all IOUs in the 2009-2011 period. Currently the CARE penetration levels are as follows- PGE at 93%, SDGE at 88%, SoCalGas at 89%, and SCE at 97%.
- Increase the overall cost effectiveness of the program by implementing a 0.25 benefit-cost ratio threshold on measures.
- Focus and promotion of relevant workforce education and training.

Focus on increasing internal and external efficiencies for the IOUs. The Commission will assess the IOU's efforts to leverage the Energy Savings Assistance Program marketing activities with other government and private programs as well as assess the IOU's efforts in integrating their own demand side programs. The Commission authorized budgets for the following pilots and studies 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.

- PILOTS: Microwaves, online training modules for contractors, smart meter and in-home display pilots.
- Workforce Education and Training: A contractor and an educational institution will work with a utility to develop and implement an in-class and hands-on curriculum to be used as part of a certificated program through the educational institution.
- 2009 Impact Evaluation Study to determine the electric and gas energy savings impacts of the Energy Savings Assistance Program.
- 2009 Process Evaluation Study of the effectiveness of the overall Energy Savings Assistance Program that will make recommendations for improved program design and delivery.
- Non-Energy Benefits Study of the potential non energy benefits of the program other than direct energy savings.

Trends beyond the 12 month reporting period

As noted above, the current budget cycle spans three years, through the end of 2011. Thus, the expected costs and rate impacts are known for the next 9 months or so. The IOUs will submit applications for a 2012-2014 planning cycle in May 2011. Through the programs described above, the state's low-income population receives benefits that include: increased health, comfort, and safety; increased education and awareness to energy efficiency and environmental issues; and greater workforce education and training opportunities within the developing green economy. The program's purpose is to improve the welfare of California's low-income population, by subsidizing and managing energy efficiency improvements for both rented and owned residences. These initiatives will yield greater efficiencies, collaborations and overall benefits to the low income population as well as the rest of the state.

V. Natural Gas Rates and Costs

Due to low natural gas prices, customers of natural gas utilities continue to experience low natural gas costs. 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, customer service, and public purpose program (PPP) costs. The recent 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"[27] gas ratepayers:

- the procurement rate, which recovers the cost of procurement of the natural gas itself,
- the transportation rate, which recovers the operations cost of the utility to deliver natural gas and provide various customer services, and
- the gas public purpose program surcharge, which recovers the cost of various public purpose programs such as the CARE discount, natural gas energy efficiency programs, and natural gas research and development.

Larger 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 <u>costs</u> for transmission, distribution, storage and customer service have moderately increased by about 8% since 2006. However, there are significant differences between different customer classes and utilities in the changes in <u>rates</u> over that time period. For example, the average natural gas transportation rate for PG&E residential customers increased by 27% while the average transportation rate for electric generation customers not directly served off PG&E's backbone transmission system <u>decreased</u> by 16%.

Approved gas PPP costs have increased by 25% during the 2006 to 2010 time period. Again, there are significant differences between different 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 26% for SDG&E, 37% for SoCalGas, and 64% for PG&E.

Current Trends in Gas Rates

Total core natural gas rates on average remained low in 2010. As one can see in the tables presented by the CPUC in its April 2011 Electric and Gas Utility Cost Report[28], the natural gas procurement costs in 2010 were 30% lower than the procurement costs in 2006. Even with this decrease in procurement costs, these costs represented about 49% of total utility costs. Because

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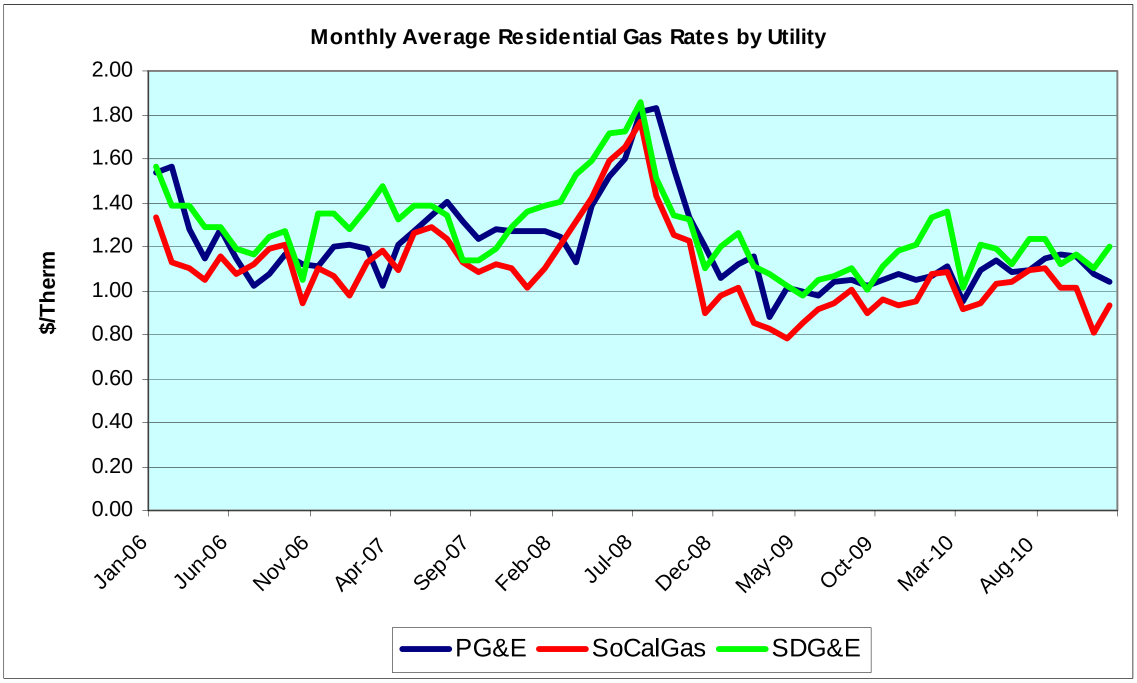
[27] Core customers are mainly residential and small commercial customers.
[28] http://www.cpuc.ca.gov/NR/rdonlyres/3828C51D-FE77-4439-ADB0-8790D5E9EC92/0/2010AB67CostReport_FINAL_32911.pdf

natural gas costs fell so much in 2009, and into 2010, procurement rates also fell dramatically. The decline in the procurement rate has caused the total core natural gas rate to remain at low levels, for example 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 moderate on average in the coming 12 months.



CPUC Actions to Limit Utility Cost and Rate Increases

In the coming year, the Commission expects to maintain natural gas utility rates at reasonable levels in the following manner:

Procurement Costs

Although the Commission can not regulate the market 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.

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 are reasonable, the CPUC will be scrutinizing these costs and rates in several major proceedings to ensure that only reasonable costs and rates are authorized. The CPUC has recently issued decisions in several major natural gas proceedings, as described below. During the next 12 months, the CPUC expects to examine natural gas utility costs, or address issues that could affect costs, in other proceedings described below, and in many cases will issue a final decision during 2011:

Gas Utility Safety Rulemaking 11-02-019 (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." While the rulemaking will primarily be concerned with pipeline safety issues, the rulemaking will also consider how the CPUC can align ratemaking policies, practices, and incentives to better reflect safety concerns and ensure ongoing commitments to public safety. It is expected that the CPUC would adopt such ratemaking practices by 2012, if not in 2011.

PG&E Gas Transmission and Storage (GT&S) Rate Proceeding (A.09-09-013)

PG&E's revenue requirement and rates for its gas transmission and storage system for the years 2011 through 2014 were determined in the 2011 GT&S proceeding. The revenue requirement would be used for GT&S operating and maintenance expenses and capital expenditures. A settlement was reached in this proceeding among almost all parties, and was adopted by the CPUC in April 2011. PG&E's authorized revenue requirements were increase from the 2010 level of $462 million to $514 million in 2011 and to higher amounts in subsequent years, reaching $582 million in 2014.

Gas transmission pipeline safety reporting requirements for PG&E were also included in the CPUC's decision. These reporting requirements should allow the CPUC to determine if PG&E is properly prioritizing its gas pipeline safety projects and spending the funds authorized by the CPUC for such projects.

The CPUC also expects PG&E to soon file an application requesting additional funding for its Pipeline 2010 Program. Under this program, PG&E could incur additional costs, beyond those approved in A.09-09-013, to ensure that its gas transmission pipeline system is operated safely and in compliance with new government safety regulations.

PG&E 2011 General Rate Case (GRC) (A.09-12-020)

PG&E 2011 gas distribution pipeline revenue requirement will be determined in the 2011 GRC. The utility is also requesting additional amounts for future, "attrition" years 2012 and 2013. A settlement was reached in this proceeding with regard to the revenue requirements for PG&E's electric department (except for one issue), and for PG&E's gas distribution pipeline department. If adopted by the CPUC, this settlement would increase gas distribution revenue requirements by $47 million in 2011, another $35 million in 2012, and another $35 million in 2013, amounting to about an 11% increase from current levels by 2013.

Gas distribution pipeline safety reporting requirements for PG&E, similar to those described above for the transmission system, are expected to be included in the CPUC's decision.

The CPUC expects to reach its decision in the 2011 PG&E GRC in the spring of 2011.

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. SoCalGas requests approval of its revenue requirement and its proposed allocation of the project costs to various customer classes. The CPUC expects to determine if it should adopt SoCalGas' proposal in 2011.

SoCalGas/SDG&E Off-System Delivery (A.08-06-006)

SoCalGas and SDG&E requested approval from the Commission to make gas deliveries to outside of California from its transmission system. SoCalGas and SDG&E argued that its proposed "Off-System Delivery" (OSD) service will not degrade service to its in-state customers, will encourage storage expansion, and will increase usage on its system, which will in turn lower rates for its customers. Other parties contested aspects of the utilities' proposal, and made a variety of alternative proposals for off-system delivery services and rates. Interveners wanted assurance that OSD is not subsidized by on-system customers and does not impact their rates, and one party asserted that the CPUC should reject the SoCalGas proposal. In March 2011, the CPUC authorized SoCalGas and SDG&E to make out-of-state interruptible off-system deliveries, and adopted several modifications to the utilities' proposal.

SoCalGas/SDG&E Firm Access Rights Review (A.10-03-028)

In the CPUC decision that approved the firm access rights (FAR) system, the CPUC required a review of the system's implementation to make sure that it was operating as intended. This review was to be conducted beginning 18 months after implementation. With A.10-03-028, SoCalGas/SDG&E filed its FAR review application on March 29, 2010. In 2010, the CPUC examined the proper revenue requirement and rate associated with firm access rights, as well as various operational issues associated with FAR. In April 2011, the CPUC issued its decision in this proceeding, adopting several operational modifications to the FAR framework, establishing the revenue requirement associated with the SoCalGas/SDG&E backbone transmission system, and increasing the FAR reservation rate.

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' gas system (excluding the cost of gas) and for SDG&E's gas and electric system (excluding the cost of gas and electricity and electric transmission).The CPUC likely will not reach a decision in this proceeding until late 2011 or early 2012.

Gas Public Purpose Programs

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. In 2010, the costs of the gas related PPPs was about

$553 million. These costs are collected by the utilities through the gas PPP surcharge that appears on customer gas bills. Gas PPP costs have increased by 25% since 2006, due to increases in energy efficiency and gas R&D costs.

The CPUC will 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.

Public purpose programs benefit customers in a variety of ways. The Energy Action Plan lists energy conservation and efficiency as the first undertaking to help ensure that Californians receive safe, reliable utility service at least cost. While the energy efficiency program costs are borne by customers, the program should lower customer utility bills as they reduce their energy consumption. The low-income programs (CARE and LIEE) serve to lower the gas bills of the utilities' financially disadvantaged customers. The Gas R&D program is administered by the CEC with the goal of the funding projects that will benefit the public at-large. Such projects may be related to energy efficiency, renewable energy production, and environmental enhancements.

CPUC Advocacy for California Interests at the 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.

It is possible that within the next 12 months another interstate pipeline company that makes significant deliveries to California, Transwestern, will file a GRC at the FERC.   If it does, the CPUC fully expects to participate in that GRC as well.

Appendix:

Utility Reports on Recommended Measures to Limit Costs and Rate Increases

A. Pacific Gas and Electric Company

B. Southern California Edison

C. Southern California Gas Company

D. San Diego Gas and Electric Company

A. *Pacific Gas and Electric Company*

SB 695 Report To California Public Utility Commission Energy Division
Reporting Entity: Pacific Gas and Electric Company
Year: 2011

I. 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 to 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 at PG&E; 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 2011 and 2012 (Table 3 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. PG&E understands that electricity and gas are a fundamental need and PG&E is also working hard to help our customers save money. Early in 2010, PG&E filed the Summer 2010 Rate Relief Application (A.10-02-029) with the California Public Utilities Commission that included an overall electricity rate reduction that took effect before the summer of 2010 and changes to the tiered residential electric rate structure in ways that would reduce costs for our highest use residential electricity customers. This Application was approved by the CPUC and the rate changes became effective on June 1, 2010, providing effective rate relief for these highest use residential electricity customers.

More recently 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 only to be brought back up later in the year.

Current state law mandates that electric utilities in California must charge more per unit of electricity as a residential customer's use increases. Under the tiered-rate system, electricity use is divided into tiers, with higher prices for each higher level of use. In 2001, the Legislature and the CPUC essentially capped the amounts by which rates for the lowest tiers' could increase -- tiers 1 and 2 – and, as a result, those lower tier rates have remained largely unchanged during 2001-2009, resulting in lower tier electricity rates that are 19% lower than in 2001 on an inflation-adjusted basis. That means rate increases during that period fell almost exclusively to the higher tiers.

We are committed to helping limit or reduce costs to our customers, and it is our intent that through the recommendations in this report, PG&E can help customers during these tough times. The June 1, 2010 rate changes resulting from PG&E's Summer 2010 Rate Relief Application reduced prices for usage in the highest residential electricity rate tier category from nearly 50 cents per kWh to approximately 40 cents, and brought our residential electricity rates more closely into alignment with other utilities in the state. This has allowed us to make progress towards distributing electricity costs more equitably among all our customers, and has eliminated some of the "sticker shock" that can occur when a customer's usage crosses into the top rate tier, especially during peak summer months. However, electricity rates for usage in the highest tiers remain very high (for example, the tier 4 rate is over three times as high as the tier 1 rate), and continuing constraints on rates for tier 1 and 2 usage still leave the upper tiers at significant risk of future electricity rate increases. For these reasons, PG&E has proposed additional changes to the residential tier structure in the currently pending Phase 2 of our 2011 General Rate Case, with the goal of affording further reductions to our rates for usage in the highest tiers while also achieving more stability for the upper-tier rates in upcoming years.

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 cost pressures on PG&E's electric and gas costs and rates are California's Renewables Portfolio Standard, including legislation and regulations to expand the amount of renewable energy PG&E is obligated to procure;[29] expenditures on public purpose programs mandated by state law; the costs for compliance with greenhouse gas (GHG) emissions regulations and goals under AB 32; the costs of mandated subsidies or set-asides for preferred energy resources, such as distributed generation, combined heat and power, and small renewables under so-called "feed-in" tariffs or "net energy metering;" mandates for considering a requirement to phase-out once-through-cooling for nuclear and non-nuclear power plants; regulatory mandates to default customers onto particular "dynamic" pricing time-of-use rates whether the customers voluntarily choose the rates or not; and delays in permitting for major utility infrastructure projects, such as new electric transmission facilities.

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.

In addition to these 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 category of customer. 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 to benefit a specific set of customers, but are paid for by non-participating customers.

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

[29] See PG&E comments on RPS legislation, attached to this letter as Appendix 1.

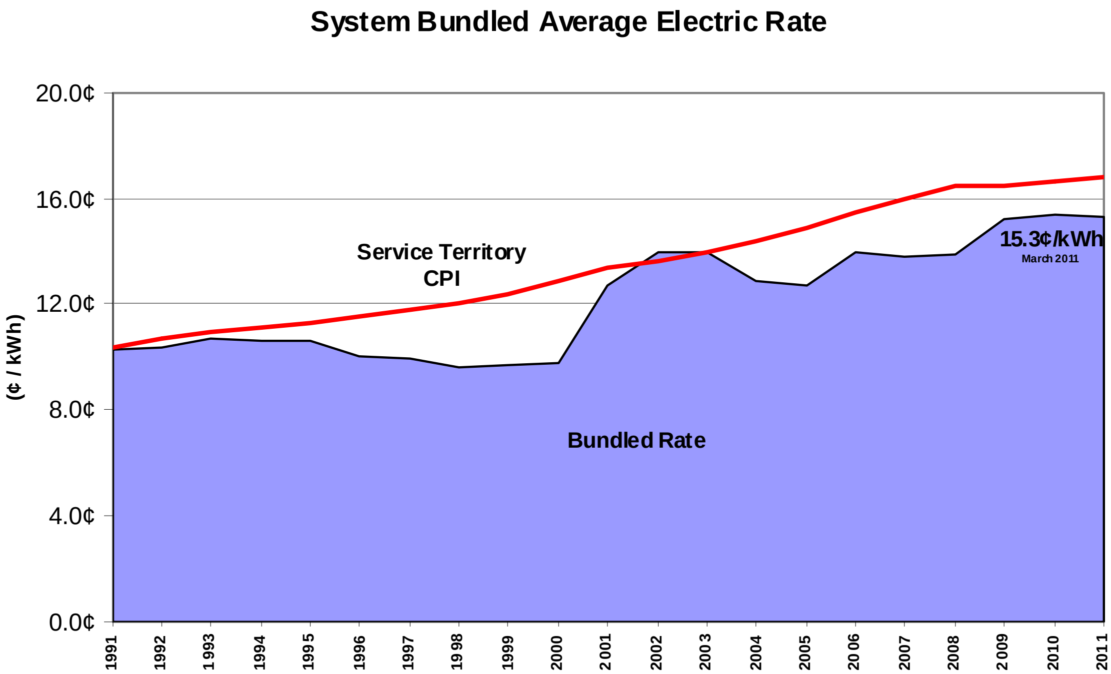
II. Overall Rate Policy

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 October). 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 twenty years, PG&E has been successful at managing electric customer rate increases. As illustrated in Figure 1, PG&E's system bundled average electric rate over the last twenty years has increased at a lower rate than the service territory's consumer price index growth (CPI) (See Figure 1). This modest rate growth over time has resulted from careful utility cost containment and a general increase in sales (which moderate the upward pressure of revenue requirement growth). From time to time, PG&E also manages revenue collection through balancing accounts - tempering rate swings driven by differences in sales used to set rates and actual demands experienced. For example, in 2009 PG&E minimized swings in customer rates and bills via adjusting the timing of certain California Department of Water Resources-related payments and implementing a one-time Energy Resource Recovery Account bill credit to electric customers related to a balancing account over-collection. Similarly, to decrease pressure on customer bills during 2010, PG&E proposed and received CPUC approval to accelerate credits of balancing account over-collections and defer collection of certain approved revenue requirements. PG&E also proposed and received approval for a "rate stabilization adjustment" plan that resulted in a 0.7% net increase from December 2010 and avoided what would have been a 4% decrease in January 2011 followed by a 5% increase over the remainder of the year. These are recent examples of how PG&E and the CPUC can work together to achieve increased predictability and stability for our customer's gas and electricity bills.

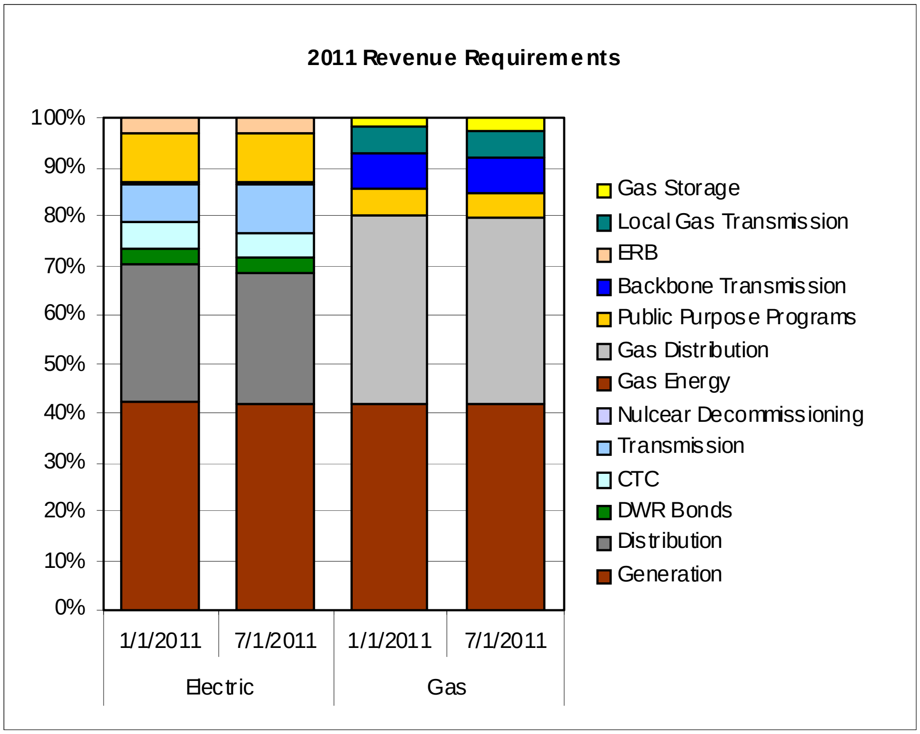
Figure 1. Historic Service Territory CPI vs. System Bundled Average Electric Rate. CPI provided by Economy.com



III. <u>Description of Revenue Requirements (Gas and Electric)</u>

This section summarizes the major components of PG&E's gas and electric revenue requirements (RRQ) and how changes in those components are forecast to affect overall rates. For example, Energy/Generation includes purchased power costs, utility-owned generation, and pension revenue requirements linked to generation, among other items. Relative ranges for each RRQ category as a percent of total authorized 2011 RRQ, and analogous forecast trends for 2011, are provided for each RRQ section. A summary is provided in Figure 2 below. Percentage ranges are calculated by comparing the category's revenue requirement to the total authorized revenue requirement during the course of the year (e.g. Authorized 2011 Electric Transmission RRQ divided by Total Authorized 2011 Electric RRQ). This calculation provides a means to discuss the relative magnitude of the major revenue requirement categories and the trend over time. Note that the focus is not on specific filings brought forth to the CPUC, but rather categories of revenue requirements that could have a potential impact on future rates.

Figure 2. High Level Breakdown of PG&E Revenue Requirements in 2011



Electric

Electric revenue requirements are grouped into the following major rate categories: (1) Energy and Generation, (2) Competition Transition Charge (CTC), (3) Distribution, (4) Department of Water Resources (DWR) bonds, (5) Transmission, (6) Public Purpose Programs, (7) Nuclear Decommissioning, and (8) Energy Revenue Bonds. For reference, an excerpt from the Advice 3727-E-A Annual Electric True-Up filing and December 30, 2010 is provided as Table 1 in the Appendix. The following statements reflect PG&E's expectations as of February 1, 2011, and may change throughout the course of the coming year.

1) Energy and Generation-related electric revenue requirements constitute approximately 42 percent of the total forecast revenue requirement in 2011. (For ratemaking purposes, DWR power costs are treated as a part of the generation rate component.) Energy Resource Recovery Account (ERRA) costs represent roughly 28 percent, DWR power represents -2 percent, and utility-owned generation represents 16 percent of PG&E's total forecasted revenue requirements in 2011. During 2010, generation revenue requirements comprised 50 percent to 52 percent of PG&E's total authorized revenue requirement. The year-over-year change in generation-related revenue requirements reflects large decreases in the costs of energy procurement (ERRA and DWR power) and decreases in undercollections in the energy-related balancing accounts (ERRA, UGBA, and DWR power).

2) Competition Transition Costs revenue requirements constitute approximately 5 percent of the total forecasted revenue requirement in 2011. This represents the above-market cost of procuring energy. In 2010, CTC revenue requirements were about 3 percent of the total revenue requirements. The year over year change in the revenue requirements is a result of higher above market cost driven primarily by lower market benchmark price caused by lower gas prices.

3) Distribution-related electric revenue requirements include the California Solar Initiative and the SmartMeter™ program. The CARE discount has been transferred to the Public Purpose Program revenue requirements where it is recovered through the CARE surcharge. This remaining distribution revenue requirement comprises approximately 27 percent of the total revenue requirements in 2011. In 2010, Distribution revenue requirements were also approximately 25 percent of the total authorized revenue requirements. The increase year-over-year is primarily due to the reinstitution of the CSI revenue requirement and the expected settlement in PG&E's 2011 Test Year General Rate Case.

4) The DWR bond revenue requirements comprise 3 percent of PG&E's forecast 2011 revenue requirement which is the same as in 2010.

5) Transmission-related electric revenue requirements contribute 8 percent to 10 percent of the total forecast revenue requirement in 2011. In 2010, transmission revenue requirements accounted for approximately 6 percent to 8 percent of the authorized total. Investments undertaken by other California utilities and PG&E both contribute to the transmission revenue requirement growth over 2010. Transmission revenue requirements are generally expected to increase over time due to electric transmission investments undertaken by PG&E and the other California utilities to comply with North American Electric Reliability Corporation (NERC) reliability requirements, upgrades to existing assets, expansion of new service, and providing access to RPS-eligible power.

6) Public Purpose Program-related electric revenue requirements include the CARE discount which is recovered through the CARE surcharge. These revenue requirements comprise 10 percent of PG&E's total forecast revenue requirement in 2011. PPP represented about 8 percent of the total during 2010. Growth in Public Purpose Program revenue requirements from 2010 to 2011 is tied to the expansion of the CARE Program. The CARE discount projected for 2011 reflects the increase in forecasted customer discounts due to this expansion in enrollment. In addition, there is a carryover of the CARE shortfall not recovered in 2010. This was due to the CARE surcharge being set on a forecasted CARE shortfall which was much lower than what was actually provided in due to the expansion of CARE enrollment.

7) Nuclear Decommissioning-related electric revenue requirements represented less than 1 percent of PG&E's total authorized revenue requirement during 2010. That level is forecast to remain constant in 2011.

8) Energy Recovery Bond-related electric revenue requirements represent roughly 3 percent of PG&E's forecast revenue requirement in 2011 and will come to the end of their life during

2012. During 2010, Energy Recovery Bonds comprised between 2 percent to 2.5 percent of the total revenue requirement.

Natural Gas

Natural gas revenue requirements 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 3165-G-A Annual Gas True-Up filing on December 22, 2010 is provided as Table 2 in the Appendix. The following statements reflect PG&E's expectations as of February 1, 2011, and may change throughout the course of the coming year due to various internal and external factors.

1) For 2010, energy-related gas revenue requirements represented about 43 percent of the total gas revenue requirements. The revenue requirements are expected to trend upward, consistent with the market price of natural gas. However, the forecasted revenue requirements could range from approximately 36 percent to 46 percent of the total forecast gas revenue requirements in the upcoming 12 months if natural gas prices change by $1 per Decatherm (Dth) from PG&E's forecast.

2) For 2010, distribution-related gas revenue requirements constituted about 38 percent of the total authorized gas revenue requirements. Distribution revenue requirements are expected to trend upward primarily due to the implementation of PG&E's 2011 General Rate Case and SmartMeter program costs. The forecasted revenue requirements could range from 35 percent to 42 percent of the total forecast gas revenue requirements in the upcoming 12 months if natural gas prices change by $1 per Dth from PG&E's forecast.

3) For 2010, Mandated Public Purpose Programs gas revenue requirements, including California Alternate Rates for Energy (CARE) Discount and Self-Generation Incentive Program, and Energy Efficiency represented about 5 percent of the total authorized gas revenue requirements. The forecast revenue requirements constitute approximately 5 percent to 6 percent of the total forecast gas revenue requirements and are expected to trend upward in the upcoming 12 months, mainly due to increased total discounts provided to customers on CARE. The increase in forecast CARE discounts is driven by the cost of gas and CARE participation.

4) For 2010, backbone transmission-related gas revenue requirements constituted approximately 7 percent of the total authorized gas revenue requirements. The forecasted backbone transmission revenue requirements will comprise about 6 percent to 8 percent of the total forecast gas revenue requirements in the coming year, and are generally expected to trend slightly downward in 2011 but increase in 2012. Increases in 2012 are driven by replacement of aging facilities and retrofits/replacements for environmental regulations as provided in PG&E's Gas Transmission and Storage Rate Case.

5) For 2010, local transmission-related gas revenue requirements represented approximately 5 percent of the total authorized gas revenue requirements. The forecasted gas revenue

requirements will generally contribute 5 percent to 6 percent of PG&E's total forecast gas revenue requirement in the upcoming 12 months primarily due to capital additions for reinforcement projects, as well as operating and maintenance costs, particularly for integrity management as provided in PG&E's Gas Transmission and Storage Rate Case.

6) For 2010, gas storage-related revenue requirements contributed about 2 percent of the total gas revenue requirements. Forecasted gas storage revenue requirements comprise approximately 1 percent to 3 percent of the total forecast gas revenue requirement in the coming year and are generally expected to trend upward. The revenue requirements are driven by new infrastructure and upgrades to existing facilities to ensure reliable, safe services, and access to diverse gas supplies as provided in PG&E's Gas Transmission and Storage Rate Case.

IV. Description of Rates (Gas and Electric)

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

Table 1. Summary of Rate Components for 2011

COMPONENT	**Electric 2011**		**Gas 2011**	
	RRQ $M	**% Range**	**RRQ $M**	**% Range**
Energy / Generation	$5,152	42	$1,367	36-46
Distribution	$3,367	27-28	$1,254	35-42
CTC	$652	5	N/A	N/A
Transmission / Backbone Transmission	$927	8-10	$241	6-8
Local Transmission (Gas)	N/A	N/A	$172	5-6
Public Purpose Programs	$1,194[1]	10	$189[2]	5-6
Gas Storage	N/A	N/A	$52	1-3
Nuclear Decommissioning	$59	0.5	N/A	N/A
DWR Bonds	$389	3	N/A	N/A
Energy Recovery Bond	$405	3	N/A	N/A
Total Authorized Revenue Requirement[3]	$12,144		$3,275	

1. Reflects CARE shortfall of approximately $516M for electric.
2. Reflects CARE shortfall of approximately $110M for gas.

3. As of February 1, 2011. Values are approximated to the nearest million.

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 increased at a pace which largely offset annual increases to revenue requirements. However, in recent years (2009 and 2010), as a result of the economic recession, declining sales has meant that most customers have shouldered a larger portion of revenue requirement increases. The following section discusses the forecast trends for Electric and Gas loads for 2011.

Electric

Although the PG&E service area economy has finally improved, the forecast, as projected by Moody's Analytics, shows an economy that will remain quite soft for 2011. The economy will continue to lose jobs, but not at rates observed over the last three years, and the unemployment rates should finally top out. Real income is projected to grow at nearly 4 percent this year, as job growth in the higher salaried Bay Area expands. With this outlook as a backdrop, PG&E's forecast projects electric sales for 2011 increasing at 1.4 percent relative to 2010 observed sales. This is a bit misleading, however, with 2010 being one of the coolest years in recent memory. Adjusting 2010 observed sales for normal temperatures implies sales growth in 2011 of just 0.6 percent, a rate consistent with the weak economy. Even as the economic recovery gains some traction in 2012, many risks to the recovery remain, and are likely to inhibit what would be a normal expansion in the historical sense. PG&E sales growth are likely to remain modest even in 2012 and beyond.

Electric customer (billings) growth has also been dramatically impacted by the recession. PG&E has added only 18,000 customers over the past 2 years, when adding 60,000 to 80,000 annually was the norm for much of the past decade. For 2011, customer growth will rebound somewhat, with a projected 38,000 customers being added. Thereafter, customer growth will approach more typical values, with about 60,000 customers added annually.

Among the four major electric customer classes (residential, agricultural, industrial, commercial) three are projected to show increased sales in 2011. Although residential sector sales are projected to increase by a seemingly robust 2.4 percent, it should be remembered that this is compared to observed 2010 sales, and as mentioned above, the mild 2010 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 over 3 percent, but this comes after a steep plunge in industrial usage of 10 percent over the past 2 years. Agricultural sales (primarily groundwater pumping) are expected to decline modestly (about 3 percent) owing to the normal-to-above-normal precipitation levels being experienced during the 2010-2011 wet season

Gas

As described in the Electric subsection above, PG&E's service area economy is expected to remain rather soft through 2011. This will impact both electricity demand (described above) and gas throughput. PG&E's forecast projects 2011 gas sales for all three major gas customer classes - residential, commercial, and industrial - to show modest declines in usage this year. Beyond 2011, residential, commercial, and industrial demand are expected to change very little from 2011 to 2015.

The residential gas demand forecast incorporates real residential rates, the number of households in PG&E's service territory, heating degree days and the percentage of households built after 1978, or when title 24 multifamily energy efficiency standards went into effect. Unlike electricity, which has innumerable residential uses, the main residential use for gas is space and water heating, therefore requiring customer growth to drive usage growth. With modest 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 4 percent in 2011. Thereafter, customer growth will tend to offset lower usage per household. Since space heating is the principle 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, gas usage in this sector is projected to decline by nearly 2 percent this year. The soft economy will also drive industrial sales lower in 2011 by about 1 percent.

Finally, demand for gas used in electric generation is also expected to be lower in 2011. 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 2011, however, the main factors impacting electric generation will be the soft economy and the wet winter of 2010-2011 that will likely lead to abundant hydroelectric generation.

V. Management of Electric and Gas Rates and Costs

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, 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.

VI. 2011/12 Significant PG&E Rate Initiatives and Changes

Table 3 in the Appendix contains information on PG&E's significant rate initiatives and changes for 2011- 2012. The table has been modified to reflect the currently anticipated rate filing schedule for 2011, and the revenue requirement or rate components (see Section III) 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.

VII. Recommendations to the CPUC and Legislature on Ratemaking Policies

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 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 that support these ends (such as net metering and standby waivers) 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 difference shortfall is paid by other customers. Because PG&E's current rate structure recovers a portion of fixed costs via a variable rate, any program that reduces participants' costs can create upward pressure on rates for other customers.

In the next 12 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 spread in residential tiered rates, and 2) incentives and costs associated with distributed generation.

The most immediate area of concern that should be evaluated over the next 12 months is the statutory mandate for tiered residential electric rate design, where a five "tier" rate structure is employed (although reduced to four tiers with the June 1, 2010 rate changes described in Section 1 of this report). This structure, first put in place 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 most recently 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 has proposed further changes in the currently pending Phase 2 of its 2011 General Rate Case. These changes would reduce the current structure to just three tiers, adjust current baseline quantities, and incorporate a modest monthly customer charge, among other changes, all with the goal of distributing electricity costs more equitably among all our customers. PG&E respectfully requests the Commission's support to make these changes. While legislation was recently passed to allow limited increases to tier 1 and tier 2 rates, the Commission and Legislature should be mindful that this approach alone will not prevent upper tier rates from continuing to be punitive in the longer term. PG&E recommends that legislative changes be considered this coming year to reform the tiered electric rate structure and return the responsibility for reviewing and approving equitable and reasonable electricity rate designs to the CPUC.

Tables and Appendices

Table 1. Excerpted from Advice 3518-E-A Annual Electric True-Up filing for Rates Effective January 1, 2010.

Line #		Test Year 2010 RRQ A	12/31/09 Forecast Under/(Over) collected BA Amortization B	Total Projected 2010 Revenues C = A + B
1	**CPUC Jurisdictional**			
2	**Distribution**			
3	Distribution/DRAM [1]	3,058,541,472	140,907,862	3,199,449,334
4	Self Generation Incentive Program	30,186,419	0	30,186,419
5	Environmental Enhancement	10,102,550	0	10,102,550
6	CPUC Fee	20,644,796	0	20,644,796
7	Advanced Metering/SBA	107,497,541	32,573,331	140,070,872
8	Demand Response/DREBA/DRRBA	35,914,565	715,457	36,630,022
9	Air Conditioning Cycling/ACEBA/DRRBA	48,613,035	0	48,613,035
10	ClimateSmart	0	0	0
11	California Solar Initiative	106,076,775	0	106,076,775
12	HSM	0	8,986,589	8,986,589
13	ATFA	0	(254,962)	(254,962)
14	CEMA	0	5,922,000	5,922,000
15	PCBA	0	0	0
16	CEEIA	29,382,897	2,031,108	31,414,005
17	NTBA	0	0	0
18	LCPERMA	0	346,248	346,248
19	DPMA	0	0	0
20	**Generation**			
21	Utility Retained Generation Base/UGBA	1,340,530,602	324,313,742	1,664,844,344
22	Electric Procurement/ERRA	3,731,717,921	81,210,898	3,812,928,819
23	DWR--Power Charge/PCCBA	930,339,038	73,825,458	1,004,164,496
24	DWR Franchise Fees	10,822,923	0	10,822,923
25	BCRSBA	0	(976,899)	(976,899)
26	FERABA [2]	0	4,499,049	4,499,049
27	HA	0	0	0
28	LTAMA	0	290,941	290,941
29	MRTUMA	0	0	0
30	RPSCMA	0	0	0
31	CARB	0	0	0
32	**Ongoing CTC/MTCBA**	353,029,017	47,732,678	400,761,695
33	**Rate Reduction Bond Memorandum Account** [1]	0	0	0
34	**Energy Cost Recovery Bonds**			
35	(1) Dedicated Rate Component Series 1	303,859,661	0	303,859,661
36	(2) Dedicated Rate Component Series 2	152,788,191	0	152,788,191
37	(3) ERB Balancing Account (ERBBA)	(23,686,226)	(117,415,768)	(141,101,994)
38	**Nuclear Decommissioning**	25,697,000	336,624	26,033,624
39	**Public Purpose Programs**	0	0	0
40	(1) Energy Efficiency	120,670,462	0	120,670,462
41	(2) RDD	35,217,516	0	35,217,516
42	(3) Renewables	36,826,418	0	36,826,418
43	(4) LIEE	90,043,760	0	90,043,760
44	PPPRAM	0	(5,077,665)	(5,077,665)
45	CAREA	7,448,408	52,070,991	59,519,399
46	Procurement EE/PEERAM	250,724,532	4,076,633	254,801,165
47	**DWR Bonds**	411,132,926	0	411,132,926
48	**Total CPUC Jurisdictional**	**11,224,122,199**	**656,114,315**	**11,880,236,514**
49	***CPUC Revenues at Present Rates***			**11,456,693,992**
50	***Change in CPUC Jurisdictional***			**423,542,522**
51	***Total FERC Jurisdictional***			**719,546,627**
52	***FERC Revenues at Present Rates***			**751,113,742**
53	***Change in FERC Jurisdictional***			**(31,567,115)**
54	**Grand Total Projected Revenues**			**12,599,783,141**
55	**Total Revenues at Present Rates**			**12,207,807,734**
56	**Total Change**			**391,975,407**

Notes:

1 The 12/31/09 forecast Distribution/DRAM balance includes the 12/31/09 forecast Rate Reduction Bond Memorandum Account balance as authorized in AL 3602-E.

2 The 12/31/09 forecast FERABA balance of $4,499,049 includes a discount portion of $3,835,228, which gets allocated to generation rates; and administrative costs of $663,821 which gets allocated to distribution rates.

Table 2. Excerpt from Advice 3165-G-A Annual Gas True-Up filing for Rates Effective January 1, 2011.

Pacific Gas and Electric Company
San Francisco, California
U 39

	Revised	*Cal. P.U.C. Sheet No.*	28685-G
Cancelling	Revised	*Cal. P.U.C. Sheet No.*	28412-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.)

Description	Amount ($000) Core	Noncore	Unbundled	Core Procurement	Total	
BASE REVENUES (Incl. F&U) :						(T)
Authorized GRC Distribution Base Revenue (1)					1,110,089 (R)	
Pension (2)					35,009 (N)	(N)
Less: Other Operating Revenue					(26,023)	
Authorized Distribution Revenues in Rates	1,080,225 (I)	38,850 (I)			1,119,075 (I)	(T)
BCAP ALLOCATION ADJUSTMENTS AND CREDITS TO BASE:						
G-10 Procurement-Related Employee Discount	(1,132) (I)				(1,132) (I)	
G-10 Procurement Discount Allocation	447 (R)	685 (R)			1,132 (R)	
Less: Front Counter Closures	(355)				(355)	
Core Brokerage Fee Credit	(6,583) (I)				(6,583) (I)	
Distribution Base Revenue with Adj. and Credits	1,072,602 (I)	39,535 (R)			1,112,137 (I)	(T)
TRANSPORTATION FORECAST PERIOD COSTS & BALANCING ACCOUNT BALANCES (3):						(T)
Transportation Balancing Accounts	91,716 (R)	15,049 (I)			106,765 (R)	
Self-Generation Incentive Program Revenue Requirement	2,569 (I)	3,911 (I)			6,480 (I)	
CPUC Fee	1,970	1,240			3,210	
ClimateSmart	0	0			0	
SmartMeter™ Project	45,997				45,997	
Winter Gas Savings Plan (WGSP) – Transportation	2,179 (R)				2,179 (R)	
Franchise Fees and Uncollectible Expense (F&U) (on items above)	1,747 (R)	253 (I)			2,000 (R)	
CARE Discount included in PPP Funding Requirement	(110,499)(R)				(110,499)(R)	
CARE Discount not included in PPP Surcharge Rates	0				0	
Transportation Forecast Period Costs & Balancing Account Balances	35,679 (R)	20,453 (I)			56,132 (R)	
GAS ACCORD REVENUE REQUIREMENT (Incl. F&U) (4):						(T)
Local Transmission	120,734 (I)	51,662 (I)			172,396 (I)	
Customer Access Charge – Transmission		5,174			5,174	
Storage	42,093		7,499		49,592	
Carrying Cost on Noncycled Storage Gas	1,757		251		2,008	
Backbone Transmission/L-401	80,394		160,593		240,987	
Gas Accord Revenue Requirement	244,978 (I)	56,836 (I)	168,343		470,157 (I)	

(1) The authorized GRC amount includes the distribution base revenue and F&U approved effective January 1, 2007, in General Rate Case D.07-03-044, and $22M for Attrition as approved in AL 2877-G, 2954-G, and AL 3050-G. 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. (N)

(2) D.09-09-020 authorized a $140.5 million total revenue requirement, of which $35 million is allocated to gas distribution. (N)

(3) - The total 2011 SGIP revenue requirement (RRQ) was approved in D.09-12-047. (T)
- On April 27, 2009, PG&E filed an Application requesting a 2-year extension of the ClimateSmart program. PG&E seeks no additional customer funding. I
- D.06-07-027 authorized Advanced Metering Infrastructure ("AMI")/SmartMeter™ Project deployment. The gas portion of the adopted 2010 SmartMeter™ RRQ is $46 million. The Phase 1 of the GRC settlement agreement resolves most issues including several related to SmartMeter™. This RRQ amount remains the same as 2010 and will be revised once the Phase 1 GRC decision is issued. (T)
- The Energy Division approved PG&E's AL 3130-G-A 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 on an estimated basis pending the results of the WGSP. The estimated program credits are collected in rates, resulting in a net zero revenue requirement. (N)(T) (N) (N)

(4) D.10-12-037 authorized PG&E's alternative request in its October 8, 2010 Motion to allow the Gas Accord V revenue requirements, which are to be approved in a subsequent decision, to become effective as of January 1, 2011, even if the Gas Accord V decision is issued after that date. Pursuant to Article 2.3.2, the 2010 Gas Accord IV rates remain in effect on January 1, 2011, plus a two percent escalator for Local Transmission rates and an increase in Local Transmission rates to reflect the negotiated Gas Accord IV rate adjustment for the Line 406 "LT Adder" project. Storage revenues allocated to load balancing are included in unbundled transmission rates. (N)

(Continued)

Advice Letter No:	3165-G-A	*Issued by*	*Date Filed*	December 22, 2010
Decision No.	05-06-029	***Jane K. Yura***	*Effective*	January 1, 2011
		Vice President	*Resolution No.*	
2C18		*Regulation and Rates*		

Table 2 (continued). Excerpt from Advice 3165-G-A Annual Gas True-Up filing for Rates Effective January 1, 2011.

Pacific Gas and Electric Company
San Francisco, California
U 39

Cancelling Revised *Cal. P.U.C. Sheet No.* 28686-G
Revised *Cal. P.U.C. Sheet No.* 28413-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):						(T)
Illustrative Gas Supply Portfolio				1,174,638 (R)	1,174,638 (R)	
Interstate and Canadian Capacity				178,209 (R)	178,209 (R)	
WGSP – Procurement – Residential				2,122 (R)	2,122 (R)	
F&U (on items above and Procurement Account Balances Below)				16,370 (R)	16,370 (R)	
Backbone Capacity (incl. F&U)	(61,697)			61,697	0	
Backbone Volumetric (incl. F&U)	(18,698)			18,698	0	
Storage (incl. F&U)	(42,093)			42,093	0	
Carrying Cost on Noncycled Storage Gas (incl. F&U)	(1,757)			1,757	0	
Core Brokerage Fee (incl. F&U)				6,583 (R)	6,583 (R)	
Procurement Account Balances				(3,984) (R)	(3,984) (R)	
Illus. Core Procurement Revenue Requirement	(124,245)			1,498,183 (R)	1,373,938 (R)	
TOTAL GAS REVENUE REQUIREMENT (without PPP) IN RATES	1,229,014 (R)	116,824 (I)	168,343	1,498,183 (R)	3,012,364 (R)	
PUBLIC PURPOSE PROGRAM (PPP) FUNDING REQUIREMENT (F&U exempt) (6):						(T)
Energy Efficiency (EE)	70,052 (I)	7,798 (I)			77,850 (I)	
Low Income Energy Efficiency (LIEE)	57,845 (I)	6,439 (I)			64,284 (I)	
Research, Demonstration and Development (RD&D)	6,586 (R)	3,762 (R)			10,348 (R)	
CARE Administrative Expense	1,128 (I)	776 (I)			1,904 (I)	
BOE and CPUC Administrative Cost	181 (R)	103 (R)			284 (R)	
PPP Balancing Accounts	2,268 (I)	(4,568) (R)			(2,300) (I)	
CARE Discount Recovered from non-CARE customers	65,447 (R)	45,052 (I)			110,499 (I)	
Total PPP Funding Requirement In Rates	203,507 (I)	59,362 (I)			262,869 (I)	
TOTAL GAS REVENUE AND PPP FUNDING REQUIREMENT IN RATES	1,432,521 (R)	176,186 (I)	168,343	1,498,183 (R)	3,275,233 (R)	
TOTAL AUTHORIZED GAS REVENUE AND PPP FUNDING REQUIREMENT	1,432,521 (R)	176,186 (I)	168,343	1,498,183 (R)	3,275,233 (R)	

(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 3130-G-A, will be recovered in residential rates effective April 1, 2011. (T)

(6) The PPP funding requirement is recovered in gas PPP surcharge rates pursuant to D.04-08-010 and 2010 PPP surcharge AL 3057-G and includes LIEE program funding adopted in D.08-11-031, EE program funding adopted in D.08-10-027, CARE annual administrative expense adopted in D.08-11-031, and excludes F&U per D.04-08-010. (T)

(Continued)

Advice Letter No: 3165-G-A
Decision No. 05-06-029

Issued by
Jane K. Yura
Vice President
Regulation and Rates

Date Filed December 22, 2010
Effective January 1, 2011
Resolution No.

3C17

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.

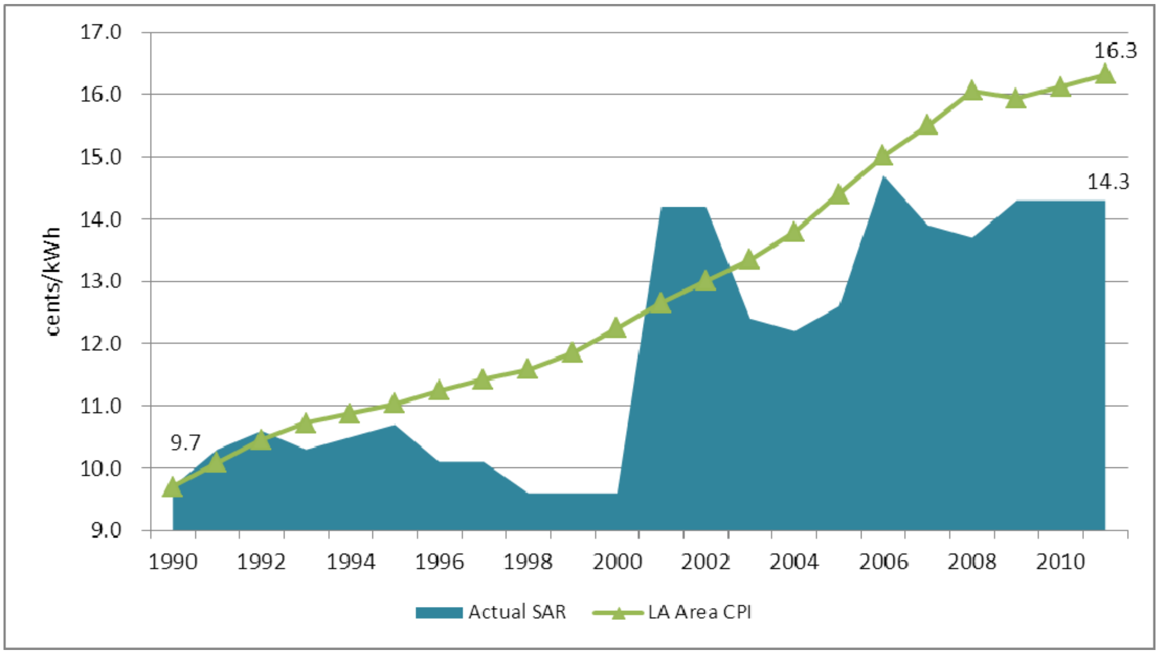
In addition, SCE has provided data contained in Appendix A to this Report that describes SCE's revenue requirements and provides an outlook for pending rate changes from May 1, 2011 to April 30, 2012.

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.[30]

[30] 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 and reliable 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. Another portion of SCE's total revenue requirement is associated with its power procurement function. Based on a set of assumptions that adhere to regulatory and legislative policies, SCE requests funding to procure enough power to meet its customers' load. Although there are procurement cost components that are outside of SCE's control, such as natural gas prices, SCE can use hedging tools to minimize 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 (e.g., Assembly Bill 1890 required payments of certain amounts by SCE to the California Energy Commission for funding its Renewable, and Research, Development and Demonstration programs).

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

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 economy 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 repower some of the older coastal facilities with efficient gas generation 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 of us 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 has the nation's leaders in energy efficiency, due in no small part to its decoupling of utility earnings 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".

Furthermore, recently an issue has arisen as to how the revenues derived by the utility from selling its allocation of allowances will be treated. 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.

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 bill 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 or DWR Power contracts through this rate component. The purchased power costs include the costs of Qualifying Facility (QF) contracts, 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 new renewable contracts 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 component.

e. **Public Purpose Programs Charge (PPPC)** – Through the PPPC component, SCE recovers the legislatively mandated Public Goods Charge funding for the California Energy Commission administered Research Development and Demonstration and Renewable programs, plus SCE- administered Energy Efficiency programs. In addition, through this 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 Assembly Bill (AB)1X, DWR entered into long term power contracts that were necessary to meet the state's Investor Owned Utilities' (IOUs') net short requirements. The Commission has authorized SCE to recover on behalf of DWR, the revenue requirement associated with these contracts through the DWR Power Charge. 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.

For the past several years, the DWR Power Charge for SCE's customers included various refunds that have artificially and temporarily reduced the Power Charge that customers ultimately paid (i.e. DWR contract costs – Refund amounts). During 2010, the net SCE DWR Power Charge was 3.763 c/kWh and included approximately $450 million transfer payment from PG&E's and SDG&E's customers to SCE's customers. The transfer payment reflected amounts that PG&E's and SDG&E's customers owed SCE's customers because SCE's customer's paid a higher than average Power Charge in the earlier years of the contracts.[31] In 2011, although the large transfer payment has gone away, the SCE DWR Power Charge of 3.952 cents/kWh now includes a significant refund associated with amounts that were previously collected by DWR and placed in its Operating Reserve Account.[32] Without the refund, SCE estimates that the DWR Power Charge in 2011 would be approximately 7.5 cents/kWh. During 2011, DWR will supply approximately 21% or 15.6 billion kWhs of SCE's bundled service customers' energy requirements. All of the DWR contracts that have been allocated to SCE's customers terminate by the end of 2011. Once these contracts terminate, SCE will have to increase its procurement to replace this energy (i.e. 15.6 billion kWhs) at a higher price. Although SCE expects to receive a proportional share of DWR's remaining Operating Reserves in 2012 to return to its customers, the magnitude of such refund will be significantly reduced.

2. Summary of Revenue Requirements by Rate Component

Revenue Requirements and System Average Rate for Bundled Service customers estimated as of June 1, 2011:

	Rate Component	($millions)	%	SAR c/kWh
1.	Generation	4,740	42.4%	6.3
2.	New System Generation	172	1.5%	0.2
3.	Distribution	3,902	34.9%	4.9
4.	Public Purpose Programs	695	6.2%	0.8
5.	Nuclear Decommissioning	8	0.1%	-
6.	FERC Transmission	648	5.8%	0.8
7.	DWR Power and Bond	1,004	9.0%	1.3
8.	TOTAL System	11,169	100.0%	14.3

3. Sales Forecasts

It is expected that the Commission will adopt SCE's 2011 total sales forecast of 85,111 GWhs in Application (A.)10-08-001 (SCE's 2011 ERRA Forecast Proceeding). This represents an increase from recorded 2010 sales of approximately 2.4%. SCE estimates sales to increase in 2011 as the result of: 1) assuming normal weather patterns as 2010 was cooler than normal, and 2) an increase in customer additions between 2010 and 2011. Regarding the second factor, the increase is expected as a result of the reconnection of previously vacant homes (i.e. homes that were in foreclosure).

4. 2011 Outlook from May 1, 2011 to April 30, 2012

Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation	Requested Dollar Amount ($millions)	Description	Impacted Rate Component

[31] D.08-11-056
[32] [ADD FOOTNOTE ABOUT PURPOSE OF OPERATING RESERVE]

			Date					
				Total Cost	2010 RRQ	2011 RRQ		
SONGS 2&3 Steam Generator Replacement	A.04-02-026 (By Advice Letter)	11/01/11	1/01/12	Est. 114	0	57	Add revenue requirement for Unit 3	Generation
2009 ERRA Compliance	A.10-04-002	4/01/10	1/01/12	30	0	0	Recovery of costs recorded in various Memo Accts.	Generation
2007 CEMA Wind and Firestorm	A.10-04-026	4/22/10	6/01/11	10	0	0	Incremental O&M and capital	Distribution
Summer Discount Plan	A.10-06-017	6/30/10	1/01/12	13	0	0	Modify certain DR programs from reliability based to price-responsive	Distribution
ARB AB 32 Fee	A.10-08-002	8/2/10	1/01/12	3	0	0	New fee	Generation
2012 GRC	A.10-11-015	11/23/10	1/01/12	6,285	5,049	5,348	Increase in O&M and capital to replace aging infrastructure and expand system to accommodate increasing load.	Generation, Distribution, and New System Generation
FERC Transmission Access Charge Balancing Account	N/A (Advice Letter)	2/28/11 & 11/1/11	6/01/11 & 1/01/12	TBD	(20)	13		Transmission Owner's Tariff Charge Adjustment

Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Dollar Amount ($millions)			Description	Impacted Rate Component
				Total Cost	2010 RRQ	2011 RRQ		
2012 – 2014 Demand Response Programs	A.11-03-XXX	3/01/11	1/01/12	77	72	72	Continue DR Program	Distribution
2010 ERRA Compliance	A.11-04-XXX	4/01/11	1/01/13	TBD	0	0	Recovery of costs recorded in various Memo Accts.	Generation, and Distribution
2012 GRC Phase 2	A.11-06-XXX	6/01/11	1/01/13	N/A	N/A	N/A	Revenue Allocation and Rate Design	All
2012 ERRA Forecast	A.11-08-XXX	8/01/11	1/01/12	Range: 4,700 – 5,000	3,818	3,708	Assumes natural gas price of $4 - $5/MMBTu. Increase also partially due to DWR contract expiration	Generation
2012 DWR Revenue Requirement Determination	N/A	TBD	1/01/12	Range: 0 – (200)	1,242	1,004	Refund share of Operating Reserve	SCE Generation, and DWR Bond Charge

C. Southern California Gas Company

SB 695 Compliance Report
To California Public Utilities Commission(CPUC), Energy Division

Southern California Gas Company

2011

Southern California Gas Company (SoCalGas) appreciates the opportunity to provide input to the California Public Utilities Commission (CPUC or Commission) in response to SB 695, which enacted changes to PUC Section 748 that invokes the utilities to recommend actions which can be undertaken during the succeeding 12 months to limit utility cost and rate increases. SoCalGas' objective in developing the 2011 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 gas revenue requirements and rates. This report is structured as per the CPUC's Energy Division request: description of revenue requirement components, listing of all pending proceedings affecting revenue requirements, listing of new proceedings, and the recommendations to limit costs and rate increases. SoCalGas' recommendations for actions that can be undertaken to reduce cost and rate increases while meeting the State's energy and environmental goals for reducing greenhouse gases are provided at the conclusion of this report.

II. Introduction

The information provided in this report includes SoCalGas' overall rate policy, a description of the rate components, a listing of all pending proceedings affecting revenue requirements and rates, the current revenue requirements and the anticipated changes during 2011. Finally, SoCalGas has included a summary of policies for limiting customer rate impacts while meeting the State's energy and environmental goals for reducing greenhouse gases.

Within the framework approved by the CPUC and the Legislature, SoCalGas seeks to fairly allocate costs across its customer classes. However, SoCalGas recognizes that allocations of certain components of gas service costs in rates are beyond its direct control. SoCalGas hopes that the CPUC will consider the recommendations set forth in later sections of this report, which SoCalGas believes can have a measureable near-term impact on its total cost of delivering safe, reliable, cost-effective gas services to its customers in California.

III. Section 748 (a) Study and Report

1. Description of Revenue Requirement Components

(A) This section outlines major categories of gas revenue requirements (RRQ) 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.

	2010			2011		
Revenue Component	**Revenue Requirement $(000)**		**Percentage**	**Revenue Requirement $(000)**		**Percentage**
Energy[1]	1,603,081	1	44.09%	1,465,654	2	40.61%
Transportation	1,801,694		48.95%	1,895,384		51.95%
Gas Storage	25,615	3	0.70%	26,470	3	0.73%
PPP	276,241		7.60%	287,565		7.97%
Total	3,636,197		100.00%	3,608,830		100.00%

[1]Actual recorded revenue.
[2]Represents estimates of the residential and core C&I energy revenue and was derived by multiplying the 2011 CGR throughput projection by the gas price forecast for 2011.
[3]A subset of Transportation

(B) Trends in Revenue Components

The revenue requirements (RRQ) discussed 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 RRQ will impose upward pressure on rates and decreases in the forecasted RRQ will impose downward pressure on rates. The rate pressures created by RRQ are modulated by differences between actual sales and the prior estimates that were 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 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 on a regular basis.

1) WACOG revenue requirements represent approximately 40.61% of the total gas revenue requirement in the upcoming 12 months. The revenue requirements are expected to decline from 2010 to 2011 but they are expected to trend upward after 2011. The energy revenue requirement represented about 44.09% of the total authorized gas revenue requirements in 2010.

2) Transportation revenue requirements constitute about 51.95% of the total gas revenue requirements in the upcoming 12 months. For 2010, the transportation revenue

requirement constituted about 48.95% of the total authorized gas revenue requirements. The increase in the revenue requirement is primarily due to attrition and amortization of balancing accounts.

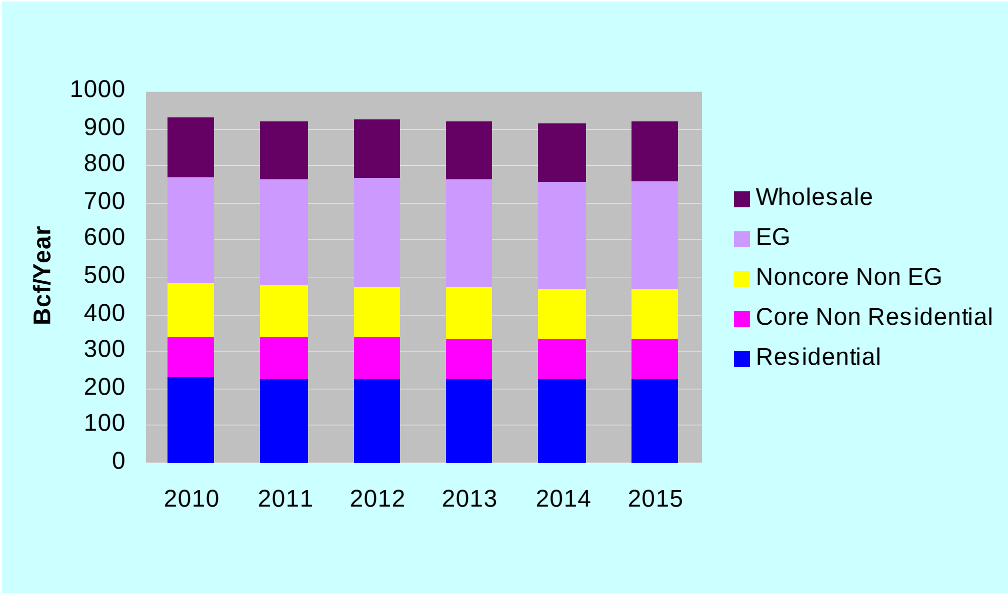
3) Gas storage revenue requirements comprise approximately 1% of the total revenue requirement in 2010, and that level is forecast to remain fairly constant in 2011.

4) PPP revenue requirements, including California Alternate Rates for Energy (CARE) Discount and Energy Efficiency, represent approximately 7.97% of the total gas revenue requirements. The revenue requirement is expected to trend upward mainly due to increases in expected gas program penetration levels (Energy Efficiency goals) and the CARE shortfall, which is driven by the cost of gas and CARE participation. For 2010, these programs contributed about 7.60% of the total authorized gas revenue requirements.

(C) Demand Forecasts

This section outlines major categories of gas demand and the load forecast through 2015.

Composition of SoCalGas Requirements (Bcf)
Average Temperature and Normal Hydro Year (2010-2015)



Composition of SoCalGas' Requirements (Bcf)
Average Temperature and Normal Hydro Year (2010-2015)

	2010	2011	2012	2013	2014	2015
Residential	231	228	228	226	225	225
Core Non Residential	109	109	109	109	109	109
Noncore Non EG	142	140	138	136	135	133
EG	285	287	292	290	290	293
Wholesale	165	157	156	157	157	158
TOTAL	931	921	923	918	916	918

The table above shows the projected gas demand over the five year period covering 2010 to 2015. Gas demand in 2011 is expected to total 921 Bcf. The average, annual rate of growth over this time period is -0.28%. Demand is expected to be virtually flat in the future due to modest economic growth, CPUC-mandated energy efficiency goals and renewable electricity goals[33], declines in commercial and industrial demand and continued 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. As of mid-2010, Southern California's economy seems to have bottomed out of its most severe slump since the 1930's. After peaking in 2007, area employment shrank by 1.6% in 2008 and plummeted 4% in 2009. Employment is expected to rise 2.1% in 2011.

Since 2007, SoCalGas' service area has been mired in a serious housing slump. Home building was depressed by a glut of existing-home short sales and foreclosures, tight credit conditions, and potential buyers' uncertainty in the job market. As a result, new gas meter hookups dropped drastically from nearly 85,000 in 2006 to under 32,000 in 2009. In the coming years, as foreclosures clear and employment recovers, new housing and meter growth should rebound. SoCalGas expects its future active meters to increase an average of 1.2% annually.

2. <u>Rate Outlook From May 1, 2011 to April 30, 2012</u>

(A) Below is a list of all pending proceedings that have the potential to affect rates over the next year beginning May 2011. Ultimately, the timing and level of impact of these pending proceedings on rates will be determined by the Commission.

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[33] The EG 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 electric demand forecast was agreed to by the IOU's, 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	Impacted Rate Component
				Total Cost	2010 RRQ	2011 RRQ			
Amendment of Certificate of Public Convenience and Necessity for Aliso Canyon Gas Storage Facility	A.09-09-020	28-Sep-09	Requested Implementation 2013, expected 2015	$200.9 million	N/A	N/A for 2011, Expected 2015 and beyond Increase of revenue requirement, $23 - $30 million per year Core revenue requirement increases $8 - $11 Million/year	Amend the SoCalGas Aliso Canyon Certificate of Public Convenience and Necessity (“CPCN”) in order to authorize replacement of the existing three obsolete gas turbine driven centrifugal compressors (“TDCs”) and associated equipment with a new electric compressor station and construction of other improvements at the Aliso Canyon Storage Field	Increase of 0.3 cents/therm/year	Core
Application of SDG&E and SoCalGas on Updating Firm Access Rights Service and Rates	A.10-03-028	29-Mar-10	2011	N/A	1801.7 million	$1,801.1 million	In the FAR system decision, the CPUC required a review of the system’s implementation to make sure that it was operating as intended.	Decrease of $0.008-$0.009/therm/year Increase of 5 cents/dth/day	All classes transportation rates BTS/FAR Charge

Filing Name	Proceeding Reference (e.g. Application #)	Filing Date	Requested/Expected Implementation date	Requested Dollar Amount			Description	Impacted Rate	Impacted Rate Component
				Total Cost	2010 RRQ	2011 RRQ			
SoCalGas 2012 GRC Filing, December 15, 2010	A.10-12-006	15-Dec-10	January, 2012	$308 million in bundled rates revenue compared to 2010	N/A	N/A	The CPUC ordered SoCalGas and SDG&E to file another GRC for the forecast year of 2012.	Increase of 7.6 cents/therm Increase of 0.7 cents/therm	Core transportation rates Noncore transportation rates
Application SoCalGas Advanced Metering Infrastructure (AMI)	A.08-09-023, D.10-04-027, AL 4110	AL filing Aug. 10, 2010	January, 2012	$1,050.7 million of costs and $185 million of O&M benefits		N/A for 2011, 2012 and beyond - Increase of revenue requirement on average $88 million/year	On April 8, 2010, the Commission issued D.10-04-027 approving SoCalGas' AMI Application	Increase of 1.3 – 4.4 cents/therm Increase of 0.4 – 1.3 cents/therm	Residential transportation rates Core C&I transportation rates
AB32 Administrative Fee Recovery	AL 4184	17-Dec-10	January, 2012	$5 million			AB 32 administrative fees paid to the California Air Resources Board (ARB).	increase $.00077/therm increase $.00031/therm	Core Noncore

Filing Name	Proceeding Reference (e.g. Application #)	Filing Date	Requested/Expected Implementation date	Requested Dollar Amount			Description	Impacted Rate	Impacted Rate Component
				Total Cost	2010 RRQ	2011 RRQ			
Application (A.) 09-07-014, to amend the Honor Rancho Certificate of Public Convenience and Necessity (CPCN)	(A.) 09-07-014, D.10-04-034, AL 4112	AL filing May 17, 2010	January, 2012	$49 million		N/A for 2011, For 2012 and beyondIncrease of revenue requirement of around $7 million/year (per application)	On July 13, 2009, SoCalGas filed Application (A.) 09-07-014, to amend the Honor Rancho Certificate of Public Convenience and Necessity (CPCN). This application was part of the implementation of the Commission-approved settlement of Phase I of the 2009 Biennial Cost Allocation Proceeding (BCAP) (see D.08-12-020) and proposes the improvements necessary to Adds 5 billion cubic feet (Bcf) of inventory expansion at the Honor Rancho storage field.	$0.001/therm	Core transportation rates
SoCalGas TRIENNIAL COST ALLOCATION PROCEEDING		1-Sep-11	January 1, 2013 to December 1, 2016			2011 RRQ $1,895 million	Per D.09-11-006, SoCalGas and SDG&E are required to file their Triennial Cost Allocation Proceeding ("TCAP") no later than September 1, 2011		

SoCalGas Storage Field Expansion

In A.09-09-020, SoCalGas proposed 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 over 2011 revenue requirements is $34 million. Once the project is complete, it is expected to increase core gas rates by 0.3 cents per therm, or about $10 million per year.

Firm Access Rights and Service

In A.10-03-028, SoCalGas and SDG&E filed its application updating firm access rights, service and rates. The utilities seek to: i) assist the Commission in assessing the efficacy of the FAR service to reduce the scheduling uncertainty existing on the SDG&E/SoCalGas system prior to FAR implementation; ii) propose no fundamental change to the existing FAR service but instead recommend various minor and incidental modifications to further streamline and improve the provision of the service; and, iii) propose to establish and update gas transportation rates to reflect a fully unbundled, cost-based FAR reservation and in-kind fuel charge. The decision for the Application of SDG&E and SoCalGas on updating Firm Access Rights Service and Rates is expected in 2011. Once complete, the project is expected to decrease gas transportation rates by $0.008-$0.009/therm. The BTS/FAR charge is expected to increase by 5 cents/dth/day.

General Rate Case

On December 15, 2010, SoCalGas and SDG&E filed their 2012 General Rate Case Application, A.10-12-006. SoCalGas proposes a revenue requirement of $2.12 billion, or a $254 million (13.4%) increase over the 2011 gas transportation revenues. Both utilities propose a four-year GRC term, with post-test year revenue requirement adjustments for inflation and other costs, an earnings sharing mechanism, a productivity sharing mechanism and revisions to non-tariffed products and services rules. The rate impact is expected to increase core transportation rates by 7.6 cents per therm and noncore transportation rates by 0.7 cents per therm.

Triennial Cost Allocation Proceeding

According to D.09-11-006, SoCalGas and SDG&E are required to file their Triennial Cost Allocation Proceeding ("TCAP") no later than September 1, 2011. This proceeding is to allocate authorized costs to the different customer classes; and, to then design the rate structure within each class (i.e. customer charge, baseline, nonbaseline, etc). Costs are allocated based on the concept of cost causation to determine marginal costs, revenue allocation, and rate design for gas customers. Cost causation seeks to determine which customer or group of customers causes the utility to incur particular types of costs.

AB32

On September 27, 2006, Governor Schwarzenegger signed into law AB 32, the "California Global Warming Solutions Act of 2006." Among other provisions, AB 32 authorizes the 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 California Air Resources Board (ARB) approved the AB 32 Cost of Implementation Fee regulation at the public hearing and directed the Executive Officer to take final action to adopt the regulation. As specified in the regulation, the administration 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 June 24, 2010, the California Public Utilities Commission issued Resolution G-3447, requiring the Joint IOUs to file formal applications in order to request approval of their proposals 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. On August 2, 2010, the utilities filed A.10-08-002, the Joint Application of SDG&E, SoCalGas, PG&E, and Southern California Edison to recover California Air Resources Board Assembly Bill 32 Cost of Implementation Fees. 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 establishes 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' annual administrative fees for implementing AB32 are currently projected to be $4,542,423. The costs are being tracked in the Environmental Fee Balancing Account (EFBA).

Energy Efficiency

The CPUC adopted the alternate decision of President Peevey on December 16, 2010. The decision addressed the true-up awards for the 2006-08 program cycle. The final decision awards incentives of $9.9 million for SoCalGas.

Future Mechanism – A draft decision was issued November 15, 2010 recommending future changes to the risk/reward incentive mechanism. The draft decision intends to modify and streamline the process for measuring incentive amounts and to reduce the utility's downside risk but also lower its potential upside gains. If adopted, the new mechanism would take effect for the first installment of incentive awards covering the 2010-12 program period. The CPUC will hold workshops to address specific EM&V issues. A ruling was issued requesting comments on a CPUC staff white paper regarding the schedule for establishing post-2012 savings goals and other matters. Comments were filed in December 2010. Most parties support extending the current cycle by one year and future program cycles of four years. DRA and TURN continue to raise the issue of program administration.

The 2011 cost of administering energy efficiency and low income energy efficiency is expected to total $144 million for SoCalGas and $30 million for SDG&E.

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 annual cost of administering the CARE program for SoCalGas is $130,641,177 and $14,081,230 for SDG&E.

Honor Rancho Storage Field Expansion

On July 13, 2009, SoCalGas filed an application (A.09-07-014) with the California Public Utilities Commission for the expansion of the Honor Rancho natural gas storage facility. The Decision, D.10-04-034, approved SoCalGas' request to amend the Certificate of Public Convenience and Necessity for the Honor Rancho natural gas storage facility. As a result of this approval, SoCalGas may proceed with modifications needed to increase the storage capacity of the Honor Rancho Facility. The project will help ensure a stable and reliable supply of natural gas within SoCalGas' service area and to develop additional in-state storage resources. SoCalGas will drill up to six new wells at the Honor Rancho storage facility located near Valencia, California. All activities will take place within the Honor Rancho facility's existing property boundaries. The project will take approximately 24 months to complete. The proposed capital cost of $37.5 million for the expansion project, excluding the cost of cushion gas, was deemed reasonable by the Commission.

Pursuant to D.10-04-034, the project is expected to raise the 2012 revenue requirement by $14 million. The impact on a residential customer's monthly summer bill for 32 therms of gas will be an increase of 4.0 cents/month. Based on a 12-month period, a residential customer's average monthly bill will increase by 6.0 cents.

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 AMI deployment costs are $1.051 billion, consisting of $876 million in capital expenses and $175 million in O&M expenses. The project is anticipated to begin raising the revenue requirement in 2012 by $35 million.

Mobile Home Park System Transfers (OIR P.10-08-016)

The Commission opened a new rulemaking in February 2011 to examine what the Commission can and should do to encourage the replacement by direct utility service of the sub-meter systems that supply electricity, natural gas or both to mobile home parks and manufactured housing communities located within the franchise areas of electric and natural gas corporations. The potential future rate impacts, as a result, are unknown at this time.

Pipeline Safety (R.11-02-019)

On February 24, 2011, the Commission instituted a new rulemaking on the Commission's own motion to adopt new safety and reliability regulations for natural gas transmission pipelines and related ratemaking mechanisms. Through the new OIR, the Commission will develop and adopt safety regulations that address topics such as construction standards, shut-off valves, maintenance requirements, record management retention, ratemaking and penalty provisions. The potential future rate impacts are unknown at this time.

(B) New Proceedings Likely to be Filed Between Now and April 30, 2012

The one proceeding SoCalGas knows will be filed between now and April 30, 2012 is SoCalGas' triennial Cost Allocation Proceeding (TCAP) which, pursuant to Phase II of the 2009 Biennial Cost Allocation Proceeding (BCAP D.09-11-006), must be filed no later than September 1, 2011. SoCalGas' TCAP filing will be made concurrently with SDG&E.

(C) Expected Timing of Anticipated Rate Changes in 2011

The decision for the Application of SDG&E and SoCalGas on Updating Firm Access Rights Service and Rates, A.10-03-028 is expected in October 2011. The expected rate changes include a transportation rate decrease of $0.008-$0.009/therm/year and a rate increase of 5 cents/dth/day for the BTS/FAR charge.

IV. <u>Section 748 (b) Study and Report</u>

1. Opening Comments

Attached for your reference is Appendix A, which reflects key filings' data, provided previously to the Energy Division. This is not an exhaustive list of SoCalGas' filings that may occur in 2011. Rather, the list incorporates regulatory filings which 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 Commission and FERC.

2. Overall Rate Policy

SoCalGas strives to provide its customers with reasonable rates for 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 made throughout the year. SoCalGas, like the other gas utilities in California, makes monthly advice letter filings to change the gas commodity rate based on the monthly cost of gas. SoCalGas seeks an annual gas transportation and Public Purpose Program (PPP) 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, to ensure that SoCalGas provides reliable and cost effective service to its customers.

3. Management Control of Rate Components

SoCalGas is committed to controlling costs while providing safe and reliable gas service to its customers. For example, in order to keep rates as low as possible, SoCalGas buys low cost gas and performs continuous reviews of its systems and operations. Additionally, performance based incentive mechanisms, such as the Gas Cost Incentive Mechanism (GCIM), that align shareholder and customer interests result in operational efficiencies and lower rates. However, there are many key drivers that affect customers' rates that fall outside of SoCalGas' control. Among these include: the market price of the gas commodity, actual sales volumes, weather, natural disasters, interest rates and economic growth, and permitting process delays. Despite these factors, SoCalGas seeks 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 (GHG) 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 AB32 Cap and Trade program is fair and as cost-effective as possible. SoCalGas is also seeking regulatory approval to participate in the development of renewable energy sources, such as biogas, that will reduce GHG emissions in California. In addition, SoCalGas is exploring the use of new technology, to shape an overall more cost-effective and efficient energy use model, including empowering customers to manage their bills by evaluating their usage through the installation of Advanced Meters.

The impact to SoCalGas' core customers which arise from energy efficiency, low income energy efficiency, CARE, and the implementation of AB 32 is shown below.

Component	Anticipated Cost as of 1/1/11
Energy Efficiency	$66,027,000
Low Income Energy Efficiency	$78,256,269
CARE	$130,641,177
AB 32 (EFBA)	$4,542,423

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' 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 AB32.

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.[34]

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.

4. California Alternative Rates for Energy (CARE): CARE customers now comprise one third of SoCalGas' 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 were on a four-year cycle, instead of a three-year cycle.

[34] 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.

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 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 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

Southern California Gas Company
Requests Impacting Customer Rates
During the Year of 2011
Appendix A

Description	Filed	Expected Implementation	Impacted Rate	Directional Impact	Revenue Requirement Impact ($000)	If Revenue Requirement Impact not available **Current Revenue Requirement ($000)**	Reason for Revenue Requirement Request
Gas Regulatory Account Update AL	October 2011	January 2012	Gas Transportation	Increase	$28,729		***
Gas Consolidated AL	December 2011	January 2012	Gas Transportation	Increase	$93,690		****
Gas Public Purpose Program Update AL	October 2011	January 2012	PPP Surcharge	Increase	$11,324		***
SDG&E and SoCalGas on Updating Firm Access Rights Service and Rates AL	To be filed 2011	To be filed 2011	Gas Transportation	Neither		$1,895,384	To establish and update gas transportation rates to reflect a fully unbundled, cost-based FAR reservation and in-kind fuel charge.

*** Shows increase from 2010 to 2011. This is an annual routine filing in which the specific financial impact for 01/2012 has not been determined.
*** Gas Consolidated AL 4190 includes the Gas Regulatory Account Update AL, GRC Post-Test Year Rate Adjustment for 2011, and other changes

D. San Diego Gas and Electric Company

SB 695 Report
To California Public Utility Commission (CPUC) *Energy Division*
San Diego Gas and Electric Company
2010

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. 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 2011 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.

V. Introduction

This report summarizes SDG&E's overall rate policy and provides a description of our rate components, current revenue requirements and anticipated changes during 2011. This Report also includes a summary of policies that SDG&E suggests be considered to limit customer rate impacts while meeting the State's energy and environmental goals for reducing greenhouse gases.

Within the frameworks outlined by the CPUC and the Legislature, SDG&E seeks to fairly allocate costs across its customer classes. However, SDG&E recognizes that allocation of certain components of electric and gas service costs in rates are beyond its direct control. SDG&E hopes that the CPUC will consider the recommendations put forth in later sections of this report, which SDG&E believes can have a measureable near and long-term impact on its total cost of delivering safe, reliable, cost-effective gas and electric services to its customers in California.

II. Section 748(a) Study and Report

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

This section provides a summary of 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 revenues requirements outlines major categories of gas and electricity revenue requirements (RRQ) 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 Legislation.

Relative ranges for each RRQ category as a percent of total authorized 2010 RRQ, and 2011, 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.

	2010*			2011*		
Revenue Component	**Revenue Requirement ($000)**		**Percent**	**Revenue Requirement ($000)**		**Percent**
Commodity	1,490,656		48.03%	1,285,589		41.36%
DWR-BC	96,861		3.12%	94,770		3.05%
CTC	45,271		1.46%	28,394		0.91%
ND	9,372		0.30%	8,353		0.27%
Transmission	255,659		8.24%	328,904		10.58%
RS	12,447		0.40%	21,318		0.69%
Distribution	1,058,447		34.10%	1,174,504		37.79%
PPP	138,395		4.46%	131,862		4.24%
TRAC	-3,546		-0.11%	34,609		1.11%
Total	3,103,560		100.00%	3,108,302		100.00%

*Reflects rates effective January 1st. DWR-BC represents estimated rate revenues based on authorized rates and sales.

1) The largest piece of SDG&E's revenue requirement is Commodity/Generation which is currently 41.36% 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. Most recently, favorable gas prices and delays in contracted renewable resources coming on-line have caused commodity prices to trend downward. In total, DWR charges comprise approximately 13% of SDG&E's forecast 2011 revenue requirement, and are expected to continue to decline on January 1, 2012 due to the expiration of DWR contracts and timing of indifference (transfer) payments between California's investor-owned utilities. During 2010, DWR-associated revenue requirements were approximately 23% of the total authorized revenue requirement.

2) CTC contributes 0.91% of the total revenue requirement in 2011. CTC revenue requirements were 1.46% during 2010.

3) Transmission related revenue requirements constitute 10.58% of the total authorized revenue requirement up from 8.24% in 2010.

4) Distribution revenue requirements, including CSI, SGIP and Smart Meter, comprise approximately 37.79% of the total revenue requirement, up from 34.10% in 2009 primarily due to CEMA, Z-Factor, attrition and balancing account amortizations.

5) PPP revenue requirements, including California Alternate Rates for Energy (CARE) Discount and Energy Efficiency, represent 4.24% of SDG&E's total revenue requirement during 2011. In comparison, PPP revenue requirements represented 4.46% of the total authorized revenue requirement during 2010.

6) Nuclear Decommissioning and Reliability Services revenue requirements each represented less than 1% of SDG&E's total authorized revenue requirement during 2010 and remained less than 1% in 2011.

7) TRAC was slightly negative in 2010 increasing to just over 1% in 2011 due to actual Tier 3 and Tier 4 sales being lower than authorized sales.

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 four major categories: Energy Costs or Weighted Average Cost of Gas (WACOG), Transportation, Gas Storage, and Public Purpose Programs.

	2010			2011		
Component	Revenue Requirement ($000)		Percentage	Revenue Requirement ($000)		Percentage
Energy[1]	202,209	1	37.62%	209,577	2	38.77%
Transportation	297,745		55.39%	285,363		52.79%
Gas Storage	7,533	3	1.40%	7,785	3	1.44%
PPP	37,568		6.99%	45,583		8.43%
Total	537,522		100.00%	540,523		100.00%

[1]Actual recorded revenue

[2]Represents estimates of Res and Core C&I energy revenue by multiplying
2011 CGR estimated throughput by the 2011 average gas price forecast.

[3]A subset of Transportation, represents SCG Core Storge & Load Balance allocated to SDG&E

1) WACOG revenue requirements represent approximately 38.77% of the total gas revenue requirement in the upcoming 12 months. The revenue requirements are expected to slightly increase from 2010 to 2011. The energy revenue requirement represented about 37.62% of the total authorized gas revenue requirements in 2010.

2) Transportation revenue requirements, including SmartMeter, constitute about 52.79% of the total gas revenue requirements in the upcoming 12 months. For 2010, the transportation revenue requirement constituted about 55.39% of the total authorized gas revenue requirements. The decrease in the revenue requirement is primarily due to lower balancing accounts.

3) Gas storage revenue requirements comprise approximately 1% of the total revenue requirement in 2010, and that level is forecast to remain fairly constant in 2011.

4) PPP revenue requirements, including California Alternate Rates for Energy (CARE) Discount and Energy Efficiency, represent approximately 8.43% of the total gas revenue requirements. The revenue requirement is expected to trend upward mainly due to increases in expected gas program penetration levels (Energy Efficiency goals) and the CARE shortfall, which is driven by the cost of gas and CARE participation. For 2010, these programs contributed about 6.99% of the total authorized gas revenue requirements.

B. Trends in Rate Components

The revenue requirements (RRQ) discussed in the previous section directly align 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 2011.

C. Load and Demand Forecasts

This section outlines major categories of electric and gas demand and the load forecasts through 2015.

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 2010, SDG&E delivered 19.5 billion kWh of electricity to 1.4 million customers. Approximately 84% of sales were delivered to bundled service customers (commodity, transmission and distribution), and 14% to Direct Access customers (transmission and distribution only). On September 27, 2010, SDG&E's reached an all-time record peak demand of 4,687 megawatts. However, on a weather-adjusted basis, the peak was the lowest since 2005.

Looking ahead to the next five years, the number of electric customers is expected increase an average rate of 1.1% per year, gradually recovering from a historic low growth rate of 0.5 percent in 2010 to nearly 1.3 percent by 2015. Electric sales and peak demand for the same period are projected to grow at an average 1.5 percent per year.

Composition of SDG&E'S Electric Requirements (GWh)

Sales in GWh	2,011	2,012	2,013	2,014	2,015
Residential	7,773	7,839	7,969	8,094	8,230
Small Commercial	1,937	1,953	1,967	1,973	1,982
Med & Large Com/Ind	10,580	10,818	11,043	11,189	11,328
Agricultural	84	84	84	84	84
Lighting	114	115	116	116	117
Total System	**20,488**	**20,809**	**21,179**	**21,457**	**21,742**

Source: *California Energy Demand 2010-2020 Adopted Forecast*, December 2009, California Energy Commission

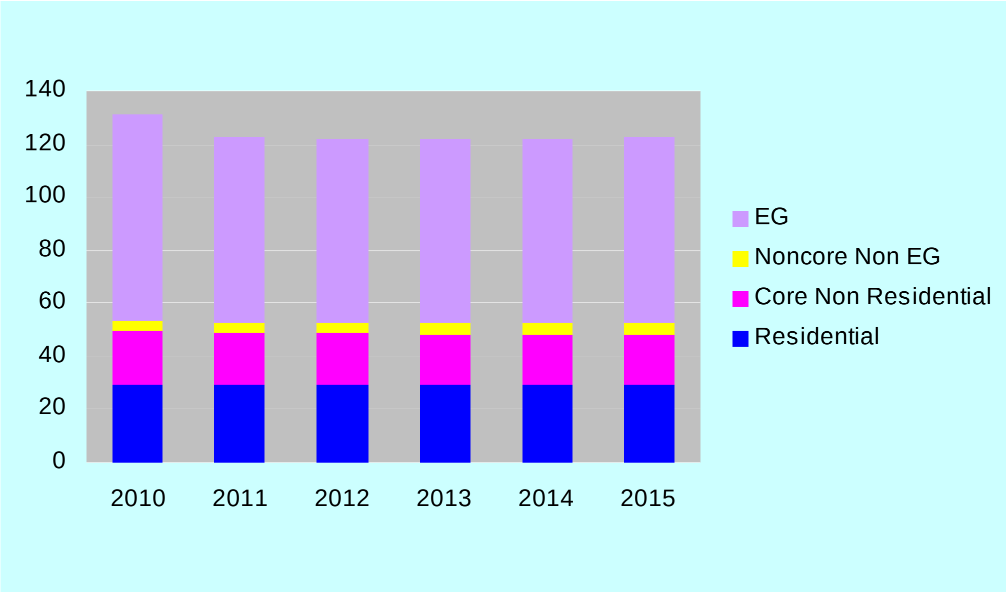
On the natural gas side, SDG&E delivers natural gas to over 845,000 customers in San Diego County, including the power plants and turbines previously owned and operated by the company. Total gas sales and transportation through SDG&E's system for 2010 were approximately 120 billion cubic feet (Bcf), which is an average of over 329 million cubic feet per day (MMcf/day). Gas demand for 2011 is 123 Bcf and the forecast is expected to remain 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 (2010-2015)

Sales in Bcf	2,011	2,012	2,013	2,014	2,015
Residential	29	29	29	29	29
Core NonResidential	19	19	19	19	10
Noncore Non-EG	4	4	4	4	4
EG	70	69	69	69	70
Total System	**123**	**122**	**122**	**122**	**122**

Composition of SDG&E's Gas Requirements (Bcf)
Average Temperature and Normal Hydro Year (2011-2015)



III. 2011 CPUC Filing Outlook

A. Outlook from May 1, 2011 to April 30, 2012 – 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.

Mobile Home Park System Transfers (OIR P.10-08-016)

The Commission opened a new rulemaking in February 2011 to examine what the Commission can and should do to encourage the replacement by direct utility service of the sub-meter systems that supply electricity, natural gas or both to mobile home parks and manufactured housing communities located within the franchise areas of electric and natural gas corporations. The potential future rate impacts, as a result, are unknown at this time.

Pipeline Safety (R.11-02-019)

On February 24, 2011, the Commission instituted a new rulemaking on the Commission's own motion to adopt new safety and reliability regulations for natural gas transmission pipelines and related ratemaking mechanisms. Through the new OIR, the Commission will develop and adopt safety regulations that address topics such as construction standards, shut-off valves, maintenance requirements, record management retention, ratemaking and penalty provisions. The potential future rate impacts are unknown at this time.

ERRA Compliance Application (A.10-06-001)

On June 1, 2010, SDG&E filed an application for Energy Resource Recovery Account (ERRA) compliance review (ERRA Application) with the California Public Utilities Commission (CPUC). The application pertains to SDG&E's electric procurement contract administration and related activities and costs for the 12-month record period of January 1, 2009 through December 31, 2009. In addition to presenting SDG&E's recorded costs for review, SDG&E's ERRA Application requests CPUC approval to recover the revenue requirement associated with the balances accrued in five memorandum accounts authorized by the CPUC including the: (1) Market Redesign and Technology Upgrade Memorandum Account (MRTUMA); (2) Procurement Transaction Auditing Memorandum Account (PTAMA); (3) Independent Evaluator Memorandum Account (IEMA); (4) Generation Divestiture Transaction Cost Memorandum Account (GDTCMA); and the (5) Renewables Portfolio Standard Memorandum Account (RPSMA). Accordingly, SDG&E's ERRA Application requests cost recovery of $4.32 million representing the combined total balance of all five of these accounts

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

On July 15, 2010, SDG&E filed a request with the California Public Utilities Commission (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 it's Dynamic Pricing Application with the California Public Utilities Commission (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.

2011 ERRA Forecast Application (A10-10-001)

On October 1, 2010, SDG&E filed an application for approval of its forecasted electric procurement revenue requirement for 2011, referred to as SDG&E's 2011 Energy Resource Recovery Account (ERRA) Forecast Application (A.10-10-001). SDG&E requested approval of revenue requirements to cover the costs of acquiring power for retail customers, including costs to purchase power under contracts with various power suppliers.

El Cajon Peaker Cost Recovery (A.11-01-004)

On January 5, 2011, San Diego Gas & Electric Company filed a request with the California Public Utilities Commission (CPUC) for approval of cost recovery for SDG&E to own and operate the El Cajon 52 MW peaking facility (the "Peaker"). This Peaker will allow SDG&E to continue to provide a reliable supply of electricity to its bundled customers. The application seeks approval of a revenue requirement
that would take effect on January 1, 2012, at the expiration of the current contract for this Peaker with the California Department of Water Resources.

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

On December 15, 2010, SDG&E filed an application requesting an increase in the amount of money it needs to collect in rates to cover the costs of improvements in the energy distribution system and to cover increasing costs for fire insurance. The CPUC will need the next 12 months to complete the review and approval process. The new rates are expected to be effective on January 1, 2012. 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 upcoming rate design proceedings, SDG&E's GRC Phase 2 for electric and Tri-annual Cost Allocation Proceeding for gas.

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

On August 2, 2010, SDG&E, Southern California Gas Company, Pacific Gas and Electric Company and Southern California Edison Company (the Utilities) jointly filed an application (A.10-08-002) with the California Public Utilities Commission (CPUC) for authority to recover administrative fees paid to the California Air Resources Board (CARB) as a result of the passage of Assembly Bill 32 (AB 32), the Global Warming Solutions Act of 2006. AB 32 legislation requires a reduction of greenhouse gas (GHG) emissions to 1990 levels by 2020. AB 32 authorizes CARB to adopt a schedule of fees to be paid by sources of GHG emissions to support the administrative costs of implementation. 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 establishes a second phase of the proceeding to determine whether the costs incurred prior to a utility's next GRC would be recoverable in rates.

Smart Grid OIR

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, 2011 to April 30, 2012 – 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.

Low-Income Program Application

SDG&E will be filing its request for approval of proposed funding for the next program cycle for the Low-Income Energy Efficiency (LIEE) Program and administrative costs associated with the California Alternate Rates for Energy Program (CARE). These programs are directed at assisting qualified low-income customers with their energy bills and helping customers use energy more efficiently.

Demand Response Program Application

SDG&E will be filing its request for authorization of demand response (DR) programs to be implemented over the next program cycle. DR programs encourage customers to reduce electricity use during peak or critical times. By doing this, customers can help manage their energy costs and help improve the reliability of the electric system. Reducing peak electric loads also helps keep costs down by limiting the need to purchase electricity when prices spike.

Energy Efficiency Program Application

SDG&E will be filing its request for approval of energy efficiency (EE) programs and budgets for the next program cycle. The purpose of this filing is to provide energy efficiency programs and services to all customers, help reduce their gas and electric usage and achieve the utility's established energy savings and demand reduction goals.

Z-Factor Advice Letter: *Insurance Cost Recovery*

SDG&E filed a request with the CPUC in August 2009 seeking to recover higher liability insurance costs, which SDG&E began incurring on July 1, 2009. SDG&E requested a $29 million revenue requirement to address the 2009/2010 policy period, given the increase in its liability and wildfire insurance premium costs above what is currently authorized in rates. SDG&E also proposed a mechanism for the recovery of future liability insurance costs that it would incur prior to its next GRC. SDG&E asked that the increase in its liability insurance costs for subsequent policy periods be deemed a single Z-Factor event, subject to one $5 million deductible. The CPUC issued a decision in December 2010 granting the requested $29 million revenue requirement and the proposed treatment of future policy periods, with the exception that the $5 million deductible be applied to each policy renewal. SDG&E expects to file its request for the 2010/2011 policy period in the first quarter of 2011, and its request for the first six months of the 2011/2012 period in the second half of 2011.

2012 GRC Phase 2 – Electric

SDG&E will be filing its 2012 GRC Phase 2 on September 1, 2011. 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.

Triennial Cost Allocation Proceeding - Gas

According to D.09-11-006, SoCalGas and SDG&E are required to file their Triennial Cost Allocation Proceeding ("TCAP") no later than September 1, 2011. This proceeding is to allocate authorized costs to the different customers classes; and, to then design the rate structure within each class (i.e. customer charge, baseline, nonbaseline, etc). Costs are allocated based on the concept of cost causation to determine marginal costs, revenue allocation, and rate design for gas customers. Cost causation seeks to determine which customer or group of customers causes the utility to incur particular types of costs.

Smart Grid Deployment Plan

SDG&E will be filing 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.

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.

C. Rate Change Implementation

The following provides the expected timing of anticipated rate changes during 2011 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, 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 2011, we anticipate at this time the following:

- April 1st Transmission Rate Adjustment to reflect the final order in our TO3 Cycle 4 filing
- Late summer/early fall implementation of the 2011 ERRA Forecast
- September 1st Transmission Rate Change for the implementation of TO3 Cycle 5 filing.

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

A. Opening Comments

SDG&E supports renewable energy, including distributed renewable energy. But we also support fair and equitable allocation of utility costs. Unfortunately, existing tiered rate design for residential customers prevents 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. As a result of these distorted price signals, residential Net Energy Metering 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/reliability 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 them 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?

We have analyzed the impact of existing cross-subsidies under 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. SDG&E does not believe that customers that lack competitive alternatives should be required to subsidize customers that do opt for such alternatives. Customers that utilize PV under a net metering program should pay for the costs that are incurred to provide them with distribution integration and reliability services - - customers that lack access to PV (due to financial reasons, lack of home ownership, lack of south-facing roof space or other reasons) should not be required to pay these costs on their behalf.

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.

B. Overall Rate Policy

SDG&E seeks with its' rate policy to advance state policy objectives, providing more flexible and value driven options desired by our customers. SDG&E rates need to be designed with the intent to enable benefits to be realized from new energy supply and energy management alternatives. Accurate price signals are necessary to maintain cost control for customers while advancing CA'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 bundled 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 lead to the inequity in current distributed renewable programs.

As 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 CA's leadership in the renewable and smart grid arena. The current combination of statues creating subsidized tiers and allowing bypass of unavoidable costs for distributed renewables shifts costs from all CA 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 the legislature and Commission act to ensure that the burden of CA'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.

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 CA 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 CA Policy implementation alternatives; and (2) implementing accurate pricing in rates so that technology benefits can be realized. [Shouldn't we add the need to ensure management's focus is on cost management and that that is something we maintain a focus on inj our ongoing operations?] These two factors can identify more resilient courses of action.

SDG&E is looking within it's GRC Phase 2 to establish rates that more accurately reflect cost causation while expanding flexibility and options to consumers. SDG&E believes that accurate rates and ensuring the availability of utility alternatives that are desired by customers are critical to achieving CA's environmental policy agenda, particularly to the long term sustainability to CA as a leader in advanced energy solutions.

SD&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 shareholder 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 its Smart Grid Deployment Plan, SDG&E will describe its 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. While authority to pursue investments will not be sought, this filing will present an opportunity for the Commission to set policy on these and other related issues in a manner that could impact future electricity rates.

- 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 shareholder 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 one third of SoCalGas' 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.

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 CA 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 CA'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 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 CA 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, IOUs, POUs, and other LSEs determine how best to achieve that under conditions at the time of implementation.

b. CPUC

Energy supply and delivery is changing rapidly. CA policy programs have expanded consumer options, and in doing so have turned the regulatory compact on it's 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 CA 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. CA 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 CA's environmental policy objectives.