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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.

(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 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. 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 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, with each formal proceeding conducted by the Commission following due process affording 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 each section on specific programs being implemented by the CPUC.

- 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

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.
Ensure Reliable Supply of Reasonably Priced Natural Gas

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 requests by the utilities that this Commission will be evaluating 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 reviewing PG&E’s test year 2011 GRC. Typically, the review results in a scaling back of the utilities’ total requested GRC revenue requirement. The Commission will diligently review PG&E’s 2011 GRC revenue requirement request along with the input from a large number of interveners that will provide testimony and recommendations in the case.

- The Commission will scrutinize the utilities’ power purchase and fuel cost recovery requests in the Energy Resource Recovery Account (ERRA) proceedings and provide for refunds for customers when the ERRA triggers warrant.

- Listed first in the State’s Energy Action Plan (EAP) loading order, energy efficiency is the least cost, most reliable, and most environmentally sensitive resource available to meet growing demands for energy in California. The Commission is continually looking for improvements in the evaluation, measurement and verification (EM&V) studies to ensure the programs achieve maximum cost-effectiveness and the goals of the programs are met. Beginning with the 2006-2008 program cycle, the Commission also adopted a Risk/Reward Incentive Mechanism (RRIM), which was intended to reward IOUs for the successful procurement of cost-effective energy efficiency programs. In the next 12 months, the Commission will consider improvements to the RRIM framework in Rulemaking 09-01-019.

- The Commission will be considering a number of measures and protocols to ensure the cost-effectiveness of demand response programs and to better enable customers to reduce demand in response to price signals through dynamic rates.
• The Commission will be considering a number of enhancements to the low income programs, such as outreach to customers with high energy use and to increase the over-all cost-effectiveness of the program. 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.

Natural Gas

• In the coming year, the Commission expects to maintain natural gas utility rates at reasonable levels in the following manner:
  o provide incentives to utilities to keep natural gas procurement costs low
  o allow expeditious approval of a diverse and reasonably-priced portfolio of interstate pipeline capacity
  o provide core customers with adequate amounts of natural gas storage capacity, and
  o allow utilities to engage in efficient natural gas hedging practices.

• The Commission will scrutinize natural gas utility operational costs and rates for transmission, distribution and storage in several major proceedings, including the PG&E 2011 General Rate Case (GRC), the PG&E Gas Transmission and Storage proceeding, and the SoCalGas/SDG&E 2012 GRC.

• 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.
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 due to capital additions, O&M and lesser amounts of A&G, and special FERC incentives.

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 general rate cases at the CPUC and at FERC. The transmission revenue requirement is determined by the Federal Energy Regulatory Commission (FERC) in transmission owner rate cases following similar test year rate making.
The major components of costs that are reviewed and determined in the GRCs include the following major elements:

### 2009 General Rate Case Revenue Requirements (000)

<table>
<thead>
<tr>
<th></th>
<th>PG&amp;E</th>
<th>SCE</th>
<th>SDG&amp;E</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operations and Maintenance</td>
<td>$1,827,122</td>
<td>$1,853,119</td>
<td>$445,646</td>
</tr>
<tr>
<td>Depreciation</td>
<td>$1,019,254</td>
<td>$1,106,992</td>
<td>$285,756</td>
</tr>
<tr>
<td>Return on Rate Base</td>
<td>$909,993</td>
<td>$1,066,918</td>
<td>$246,799</td>
</tr>
<tr>
<td>Taxes</td>
<td>$617,138</td>
<td>$819,612</td>
<td>$176,474</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$4,373,507</strong></td>
<td><strong>$4,846,641</strong></td>
<td><strong>$1,154,675</strong></td>
</tr>
</tbody>
</table>

In December 2009, PG&E filed its test year 2011 GRC application which will be reviewed by the Commission in 2010. The Commission will carefully consider PG&E’s request and other parties’ testimony in the case, and decide what level of revenues PG&E will need to recover from customers to provide safe and reliable service at just and reasonable rates. SDG&E, SoCalGas, and SCE are currently scheduled to file test year 2012 GRC applications in late 2010. The Commission will address similar issues in 2011 after SCE, SDG&E, and SoCalGas file their test year 2012 GRC 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 are shown below.

### Annual Fuel and Purchased Power Cost Forecasts Included in Commission Authorized Electric Rates ($ million)

<table>
<thead>
<tr>
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<tbody>
<tr>
<td><strong>Total</strong></td>
<td>$3,732</td>
<td>$3,310</td>
<td>$875</td>
</tr>
</tbody>
</table>

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**

The Commission will be reviewing several requests filed by the utilities through formal applications and advice letters in the next 12 months. Some of these proceedings are already filed and pending while others are likely to be filed later in the year.

Most of these are utility specific rate filings. However, two -Wildfire Insurance Costs and Economic Development Rate proceedings -are joint proceedings involving all the four major energy utilities.

**Wildfire Insurance Costs**

In August 2009, PG&E, SDG&E, SoCalGas, and SCE jointly filed an application requesting to establish balancing accounts to recover from ratepayers costs paid by the utility arising from wildfires. 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 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 and a wildfire liability limit of $399 million, and a $35 million deductible for wildfires.

The Commission will consider the utilities’ proposal in 2010. The Assigned Commissioner and ALJ issued a ruling in late 2009 in this case which expressed concerns about the utilities’ proposal. The ruling notes 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 ruling directs parties to confer on alternative approaches with the goals of developing proposals that reduce risk and limit revenue requirements.

**Economic Development Rates**

In 2005, the Commission approved an electric economic development rate (EDR) program for large commercial and industrial customers of SCE and PG&E. The program provided discounted rates to customers to attract businesses to locate in California or expand their operations in the State, and to retain businesses which would otherwise close or leave the State. The program was originally scheduled to terminate at the end of 2009, but the sunset date was postponed while the Commission reviews PG&E’s and SCE’s applications to extend the program through 2012. The program has a limit of 100 MW of total load eligible to participate for each utility. SCE currently has 47.5 MW of load enrolled in the program and PG&E has 88.3 MW of load enrolled. In their applications to extend the program, SCE requested to increase the eligible limit to 250 MW and PG&E proposes to increase the limit to 200 MW.

The EDR programs can potentially benefit ratepayers by increasing revenues available to contribute to the utilities’ fixed costs of doing business and thus lower rates to other customers. The Commission is expected to issue a decision on PG&E’s and SCE’s applications to extend the EDR program by the end of 2010.

**SCE Rate Requests**

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

- **2008 ERRA Compliance A.09-04-002**: In this application, the Commission is reviewing SCE’s procurement activities during 2008 to ensure that the procurement costs recorded in 2008 are in compliance with SCE’s adopted procurement plan. The Commission is also reviewing various balancing and memorandum accounts, including the ERRA, to ensure that the recorded entries are appropriate and are in compliance with Commission decisions and tariffs.
  
  **Requested Increase**: $35.8 million which is associated with recovering costs recorded in four memorandum accounts.

- **2009 ERRA Compliance A.10-04-002**: In this application, the Commission is reviewing SCE’s procurement activities during 2009 to ensure that the procurement costs recorded in 2009 are in compliance with SCE’s adopted procurement plan. The Commission is also reviewing various balancing and memorandum accounts, including the ERRA, to ensure that the recorded entries are appropriate and are in compliance with Commission decisions and tariffs.
  
  **Requested Increase**: $29.9 million which is associated with recovering costs recorded in four memorandum accounts.

- **CEMA Bark Beetle A.09-11-011**: SCE has requested to recover O&M costs recorded in the Catastrophic Event Memorandum Account (CEMA) associated with mitigating the unprecedented fire hazard caused by the bark beetle infestation during 2007 and 2008.
Requested Increase: $16.6 million

- **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.
  
  *Requested Increase:* $10.6 million

- **Nuclear Decommissioning Cost Triennial Proceeding A.09-04-009:** In this application SCE has requested a decrease in the annual nuclear decommissioning trust funding requirements and addresses other related decommissioning issues.
  
  *Requested decrease:* ($22.6) million

**SCE Rate Related Requests expected later this year**

- **2011 ERRA Forecast A.10-07-XXX:** In this application which will be filed on July 30, 2010, the Commission will authorize the fuel and purchased power revenue requirement to be included in 2011 rate levels.
  
  *Requested Increase:* Not known at this time. Depends on the fuel price forecast and purchased power costs. The ERRA-related revenue requirement approved in SCE’s last ERRA decision (D. 10-02-019) and embedded in current rates is $3.31 billion.

- **2009 GRC Post Test Year: Request to Implement already authorized GRC increase:** In D.09-03-025, the Commission authorized SCE to increase its 2009 authorized GRC revenue requirement of $4.830 billion by 4.25% in 2010, and an additional 4.35% in 2011. The increase will be implemented on January 1, 2011 through an advice letter that will be filed on November 1, 2010.
  
  *Requested increase:* $219 million

- **DWR Revenue Requirement:** In this proceeding, the Commission will authorize the 2011 DWR Power and Bond Charges. It is expected that there will be an increase in SCE’s DWR Power Charge due to the removal of the “transfer payment” from the other IOUs that is currently reflected in SCE’s 2009 Power Charge revenue requirement. The removal of the transfer payment could result in an increase of approximately $500 million to SCE’s customers assuming no other change in DWR’s revenue requirements. This increase could partially be offset by the termination of DWR contracts allocated to SCE, as well as the refund of any DWR over-collections and operating reserve. DWR’s revenue requirements currently account for 11.3% of SCE’s total system revenue requirement.
  
  *Requested Increase:* Not known yet

- **SONGS 2&3 Steam Generator Replacement:** The Commission has authorized SCE (D.05-12-040) to put in rates the revenue requirement associated with replacing the steam generators for both SONGS 2&3 on January 1st after the units return to commercial operation. The generators for Unit 2 have been replaced and the unit is back in service. SCE expects the generators for Unit 3 will be replaced and the unit will return to commercial operation by December 31, 2010. SCE is expected to include the associated
revenue requirement with the replacement of the steam generators in both units in rates on January 1, 2011.

Requested Increase: Not known yet

PG&E Rate Requests

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

- **Distribution Reliability (Cornerstone) Update - A.08-05-023:** PG&E requested $2.051 billion in capital additions to improve electric distribution reliability Electric Base/Distribution.
  
  **Requested Recovery:** $41 million

- **Fuel Cell Project - A.09-02-013:** D.10-04-028 authorized up to $20.3 million of capital costs for utility ownership of 3 MW of fuel cell facilities.
  
  **Requested Recovery:** $8 million

- **Photovoltaic Program - A.09-02-019:** D.10-04-052 authorized up to $1.45 billion of capital costs for 250 MW of utility owned solar PV projects. The decision also authorized PG&E to enter into Power Purchase Agreements for an additional 250 MW of solar PV projects to be owned and operated by independent power producers.
  
  **Requested 2011 Recovery:** $3 million

- **2010-2012 Nuclear Decommissioning A.09-04-007:** Triennial request for approval of updated nuclear decommissioning revenue requirements. Partial settlement agreement filed for ~$25M per year revenue requirement. Total cost in 2008 dollars for HBPP & DCPP: $2.34B
  
  **Requested Recovery:** $50 million

- **SmartAC 2009 Update A. 09-08-018:** PG&E requested authorization to update 2010-2011 SmartAC program and related budget of $123 million.
  
  **Requested Recovery:** $32 million

- **2008 Long-term RFO - A. 09-09-021:** Requests approval of $1,168 million of capital costs for a 580 MW purchase and sale agreement (Oakley Power Generating Facility) that is scheduled to go online in mid-2014. The procurement costs associated with the remaining power purchase agreements (Mirant Marsh Landing and Midway Sunset) under this same LTRFO application will flow through ERRA upon CPUC approval or plant operational.
  
  **Requested Recovery:** None in 2011
- **Smart Grid Compressed Air Energy Storage (CAES) Project - A.09-09-019:** D.10-01-025 authorized $24.9 million of costs to fund the design and feasibility studies for a 300 MW compressed air energy storage demonstration project.
  
  *Requested recovery:* $18 million

- **Manzana Wind Project - A.09-12-002:** Requests approval of $911 million of capital costs for a 246 MW wind project.
  
  *Requested Recovery:* None in 2011

- **PG&E 2011 General Rate Case A.09-12-020:** PG&E requests a revenue requirement of $5.391 billion effective January 1, 2011 in its gas and electric distribution and generation base revenue requirement as compared to 2011 projected revenue requirement. The request amounts to an increase of 19.7% for gas distribution, 17.3% for electric distribution and 19% for electric generation over 2011 projected revenue requirements. PG&E requests this increase in revenue requirement for activities such as maintaining and upgrading its electric and gas distribution systems, enhancing its customer support and energy supply functions, and maintaining a qualified workforce.
  
  *Requested Increase:* $1.048 billion

- **Rate Design Window 2010 - Peak Time Rebate A. 10-02-028:** PG&E requests approval for Peak Time Rebate (PTR) program that provides incentives for customers to respond to price signals on event days when demand is expected to be high.
  
  *Requested Increase:* $33 million

- **Diablo Canyon Power Plant Seismic Survey (3D) A.10-01-014:** PG&E requests to recover costs associated with performing additional seismic studies at and around Diablo Canyon Power Plant (DCPP) as recommended by the California Energy Commission in their Commission Report, “An Assessment of California’s Nuclear Power Plants: AB 1632 Report”
  
  *Requested Increase:* $17 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
  
  *Requested Increase:* $85 million

- **ERRA 2009 Compliance Filing A.10-02-012:** Recovery of costs related to the Market Redesign and Technology Upgrade (MRTU) initiatives.
  
  *Requested Increase:* $60 million out of which $18 million is for recovery in 2011.

- **Accelerate Generator Settlement Refunds (1)- Advice 3625-E:** Request to reduce bundled average electric rate by 3% as part of summer rate relief.
  
  *Requested Decrease:* $121 million
• Accelerate TO11 Refunds (1) Advice 3633-A: Request to reduce bundled average electric rate by 3% as part of summer rate relief  
  Requested decrease: $121 Million

• CSI rate suspension D.10-04-017: PG&E filed a Petition to Modify D. 08-12-004 requesting a temporary suspension in CSI collections which the Commission approved on April 8th  
  Requested decrease: $106 million

• General Rate Case (GRC) 2011 Phase II - Dynamic Pricing A.10-03-014: The request includes $7 million in revenue requirements for new voluntary Real Time Pricing rate options available May 1, 2012, and $6 million in revenue requirements for a new Revised Customer Energy Statement  
  Requested Increase: $53 million

• TO 12 (TY 2010) Settlement ER09-1521-000: Annual transmission settlement with FERC  
  Requested decrease: $73 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.

  • Energy Resource Recovery Account (ERRA) 2011 Forecast  
  • Annual Electric True-Up (AET) 2011  
  • DWR 2011 Revenue Requirement Forecast Filing  
  • Default Residential Rate Programs  
  • FERC TRBA/ECRA/RSBA Filing  
  • Public Purpose Program Surcharge Gas Rate Filing 2010 - Advice Letter  
  • SB 695 Res Rate Change (T1 & T2) Advice Letter  
  • Energy Resource Recovery Account (ERRA) 2010 Forecast – Update  
  • Annual Electric True-Up (AET) 2011 - Advice Letter Update  
  • FERC TACBA Filing

SDG&E Rate Requests

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

• CEMA Application-2007 Wildfires filed March 2009: SDG&E is requesting recovery for incremental expenses and capital related costs incurred to restore service or repair facilities as a result of damages caused by the 2007 Wildfires.  
  Requested Increase: Approx $ 32 million.
• **Nuclear decommissioning triennial application filed April 2009:** To update contribution amounts made to nuclear decommissioning trust funds for San Onofre Nuclear Generating Station Units # 2 and 3.
  
  *Requested Increase:* Approx. $5.8 million.

• **Z- Factor Application-Insurance Premiums filed August 2009:** SDG&E is seeking recovery for unforeseen costs related to increases in liability insurance policy premiums through the Z-factor mechanism.
  
  *Requested Increase:* Approx. $28.9 million

• **2010 ERRA Forecast Application filed October 2009:** Recovery of SDG&E’s energy procurement costs including expenses associated with fuel and purchased power, utility retained generation, CAISO related costs and costs associated with net short procurement requirements to serve SDG&E’s bundled customers.
  
  *Requested decrease:* Approx. $44 million

• **2010 ERRA Trigger Application filed in April 2010:** SDG&E is seeking approval to return over-collected balance.
  
  *Requested Decrease:* Approx. $75 million

**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.

- 2011 DWR Implementation Advice letter to be filed in Nov/Dec 2010
- Non-fuel generation balancing account update: November 2010
- FERC Transmission Owner 3 true-up filing: August 2010
- Electric Public Purpose Program Update Advice letter: October 2010
- Electric Regulatory Account Update Advice letter: October 2010
- SB 695 Residential rate change: November 2010
- Electric Consolidated Advice letter: December 2010
IV. Program Specific Proceedings and Activities

The Commission implements a wide array of energy policies in accordance with the Energy Action Plan (EAP) and as mandated by various statutes and state’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

The CPUC adopted a System and Local Resource Adequacy (RA) policy framework (PU Code Section 380) in 2004 in order to ensure the reliability of electric service in California. R.09-10-032 is the most recent CPUC proceeding to refine the RA program. In addition, the CPUC administers a Long Term Procurement Proceeding (LTPP) which implements AB 57 (PU Code Section 454.5), passed in 2002. 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.

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. Therefore, it is difficult to accurately predict the amount of energy that will be delivered by intermittent resources during times of peak demand. Therefore, other generation needs to be procured in order to ensure reliability if intermittent resources are not available. Some generation is procured in order to be ready if intermittent resource cannot produce. Customers pay for these resources even if they only operate a limited amount of time.

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 value depending on location, ability to respond quickly to system needs, vintage of plant, and market competitiveness. There are also many longer term contracts, such as DWR contracts, that contribute to overall rate payer 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 higher rates within the next 12 months, and continue to 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.

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

Current proceedings at the CPUC may have rate impacts both positive and 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 that may have positive or negative rate impacts within the next 12 calendar months are listed below.

- Current LTPP and RA market structure (R.05-12-013)
- Study and determination of the appropriate Planning Reserve Margin (R.08-04-012)
- Construction of New Generation via the LTPP program (R.08-02-007)
- Impacts of Once Through Cooling regulations promulgated by the SWRCB
- Impacts of expiring DWR contracts and reduced reliability must run contracting since the Energy Crisis

**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.

**Study and determination of the appropriate Planning Reserve Margin (PRM)**

In 2003, the CPUC adopted a PRM of 15-17%. This is the amount of resources in addition to resources directly serving peak load that LSEs are required to maintain in order to protect the system from generator failures, inaccurate load forecasts and other contingencies. The CPUC is currently evaluating the most efficient level of the PRM in R.08-04-012. Generally, lowering the reliability standard of the system will lower costs and increase the chance of an outage while raising the PRM will increase costs and reduce the chance of firm load drop. Analytical studies aimed at determining precise values of customer risk tolerance and risk preferences relative to economic costs of service interruption have not yet been undertaken. A study of this sort would provide a more analytical means by which the CPUC could calibrate the amount of reliability provided by CPUC policies, and the amount of reserves that LSEs are required to carry. An example of customer tolerance for service interruption is Demand Response (DR) programs, where certain customers are willing to trade service interruption for an incentive payment.
**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.

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

**Impacts of Once Through Cooling mitigation regulations promulgated by SWRCB**

Currently the State Water Resources Control Board (SWRCB) is considering adoption of rules to phase out the use of Once Through cooling (OTC) at existing generating plants. These existing plants comprise over 30% of the total generating capacity within the state of California. The plants 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 plants that use OTC are in Southern California, and present unique problems of 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 plants, replacing the cooling systems on existing plants, increased distributed generation, and demand side alternatives (e.g. energy efficiency and demand response), but there will be rate impacts of this OTC policy, as mitigation activities require large infrastructure investments.

**Impacts of expiring DWR contracts and reduced CAISO reliability backstop contracting since Energy Crisis**

Since the advent of the RA program, there has been a significant decrease in the amount of CAISO reliability backstop contracts executed by the CAISO. From a high of over 10,000 MW of capacity in 2005 to a low of around 1,000 MW for 2010, this decrease in MW has represented a decrease in the CAISO’s portfolio and financial commitment. It is uncertain whether overall the rate impacts of decreased CAISO reliability backstop contracts are offset by an increase in costs relative to LSE contracts with those particular units. Several former CAISO reliability
backstop contracts units are also impacted by the SWRCB rules governing OTC, so the situation with these units is likely to be complicated.

During the Energy Crisis, DWR entered into energy contracts to ensure electric reliability. Since the signing of these contracts, changes in the market have made these contracts somewhat incompatible with current grid operations. Ratepayers have incurred costs to account for these incompatible contract terms, such as increased CAISO backstop contracting. Over the next 12 months, several DWR contracts will expire, reducing these costs.

**Energy Efficiency**

In January 2005, the CPUC adopted an administrative structure for post-2005 energy efficiency programs designed to meet the objectives of the Energy Action Plan, the load reduction reflected in the energy savings goals adopted in September 2004, and the importance of energy efficiency as the priority resource to meet California’s energy needs in the future. The Commission replaced the design of previous program cycles, which occurred either annually or, in the case of the 2004-2005 cycle, over the course of two years, with a three-year program cycle to encourage longer term planning. The Commission directed that utility energy efficiency performance be evaluated based on overall portfolio energy savings achievements, rather than on the performance of each individual program, in order to “encourage innovation, and allow for some risk-taking on pilot programs and/or measures in the portfolio.”

Listed first in the loading order, energy efficiency is the least cost, most reliable, and most environmentally sensitive resource available to meet growing demands for energy in California.

For the 2006-2008 and future program cycles, 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) studies to:

- Measure and verify energy and peak load savings for individual programs, groups of programs and at the portfolio level;
- Generate the data for savings estimates and cost-effectiveness inputs;
- Measure and evaluate achievements of energy efficiency programs, groups of programs and/or the portfolio terms of the “performance basis” established under the CPUC-adopted EM&V protocols;
- Evaluate whether programs or portfolio goals are met.

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2 D.05-01-055, available at http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/43628.PDF
3 D.04-09-060, available at http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/40212.PDF
4 D.05-04-051, available at: http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/45783.PDF.
5 The California Energy Efficiency Evaluation Protocols are guidance tools policymakers use to plan and structure evaluation efforts and that staff of the California Public Utilities Commission’s Energy Division (CPUC-ED) and the California Energy Commission (CEC) (collectively the Joint Staff), and the portfolio (or program) administrators (Administrators) use to plan and oversee the completion of evaluation efforts. The Protocols are also guidance documents for the design and evaluation of programs implemented after December 31, 2005. The Protocols are available at http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/EM+and+V/
Evaluation

The data representing the actual energy efficiency savings generated by the IOU programs undergo a process of refinement over the course of each program cycle. Initially, the IOUs file their proposed portfolio of programs and project the savings achievable from each program and for the entire portfolio. Typically this indicates that their program offerings will exceed the annual and cumulative CPUC goals set for that program cycle.

Once approved, programs begin operation, achieve actual savings and the IOUs report these savings to the CPUC/EEGA website monthly, quarterly and annually until the completion of the program cycle. The reported figures are referred to as “ex-ante” because they use some savings assumptions for the purposes of reporting and projected energy savings. Over the course of a program cycle, these ex-ante figures may be updated and used to determine verified energy savings results.

The CPUC requires rigorous measurement and verification of the reported savings and evaluation of the largest programs by independent contractors. This process allows for actual savings to be determined for certain measures and verifies that savings that were reported were actually installed. This “true-up” process adjusts the savings achievements reported by IOUs and results in the “ex-post” (actual post-installation) energy savings totals.

In early 2009, the CPUC Energy Division issued the “Energy Efficiency 2006-2007 Verification Report”, which analyzed the IOU-reported energy savings for the two-year 2004-2005 program cycle and the first two years of the 2006-2008 program cycle. The Verification Report analyzed IOU reported energy savings using actual energy efficiency measure installations and various parameter values used to calculate energy savings from the IOUs’ program portfolios.

Cost-Effectiveness

The IOUs also estimate the cost-effectiveness of their respective portfolios/programs, as measured by the Total Resource Cost (TRC) and Program Administrator Cost (PAC) tests. The TRC measures the net resource benefits from the perspective of all ratepayers by combining the net benefits of the program to participants and non-participants. Benefits are the costs of supply-side resources avoided or deferred, while the costs include all those paid by both the utility and participant and encompass costs of the measures and installed equipment and the costs incurred to start and administer the program. Under the PAC, program benefits are the same as those related to determining the TRC, but costs include all costs incurred by the program administrator, including all incentives and all other program costs. Cost-effectiveness is achieved when the value of energy savings (in dollars) is greater than the cost of utility financial incentives to customers and all other program costs. A TRC or PAC ratio that is larger than “1” means that the benefits of a program exceed the costs of that program.

The Risk-Reward Incentive Mechanism (RRIM)

Beginning with the 2006-2008 program cycle, the Commission also adopted a Risk/Reward Incentive Mechanism (RRIM), which was intended to reward IOUs for the successful procurement of cost-effective energy efficiency programs and address an inherent utility bias
towards supply-side procurement under cost-of-service regulation and investment in “steel in the ground” as a means of generating earnings for shareholders.

The RRIM seeks to align ratepayer and shareholder interests by creating “incentives of a sufficient level to insure that utility investors and managers view energy efficiency as a core part of the utility’s regulated operations that can generate meaningful earnings for its shareholders.”\(^6\) The incentive mechanism also aimed to protect ratepayers’ financial investment in energy efficiency, ensure that program savings are real and verified, and impose penalties for substandard performance.

The RRIM includes a Minimum Performance Standard (MPS), which is the minimum level of savings that IOUs must achieve relative to the Commission-adopted savings goal before accruing any earnings. IOU savings are based on overall portfolio performance, rather than the energy savings performance of each individual measure and program. The IOUs must achieve a minimum of 80% of the savings goals for each of three individual savings metrics (MW, GWh, and MTherms), and achieve a minimum of 85% of the savings goals, based on a simple average of the percentage achieved for each individual goal.\(^7\)

If a utility meets the MPS and is eligible for shareholder incentive rewards, the specific amount is determined by applying a “shared savings rate” associated with a given level of goal achievement to the Performance Earnings Basis (PEB), which represents an estimate of the net benefits created by the utility portfolios.

Earnings begin to accrue at a 9% sharing rate if the utility meets the individual thresholds and 85% of the Commission’s savings goals adopted in D04-09-060. If the utility meets 100% of the goals, earnings increase from 9% to 12%. Conversely, if utility portfolio performance falls to 65% of the adopted savings goals or lower, financial penalties begin to accrue. There are two penalty provisions and the greater of the two applies when savings fall to (or below) the 65% threshold. “Per unit” penalties are $.05 per kWh, $.45 per therm and $25 per kW for each unit below the savings goal. Should performance fall below 50% of the savings goals, penalties associated with the cost-effectiveness guarantee are expected to become larger than per-unit penalties and shareholders are obligated to pay ratepayers back dollar-for-dollar for negative net benefits. There are no earnings penalties within what is called a “deadband” range of performance greater than 65% and less than 85% of goals achievement. The earnings and penalties are capped at $450 million for all four IOUs.

Over the course of a three-year program cycle, there are two “progress payment” interim earnings claims from the IOUs, based on verified measure installation and cost reports combined with \textit{ex ante} (pre-installation) performance estimates, with a final true-up claim to determine the level of net benefits (PEB) and MW, GWH and MTherm savings produced by the portfolio over the three year period. Thirty percent of the interim claims are held back with their ultimate disbursement dependent upon the final true-up, which is based on \textit{ex post} (after installation)

\(^6\) D.07-09-043, available at http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/73172.PDF, as modified by D.08-01-042, available at http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/78370.PDF

\(^7\) In D.07-09-043, the Commission established an MPS of 80% for SoCalGas, because it is subject to a single goal (for MTherms) and consequently has less flexibility than the other IOUs in meeting an average MPS of 85%.
performance review at the end of the three-year cycle. All of these claims are linked to the Energy Division’s Verification and Performance Basis Reports.\(^8\)

The Commission intended that the RRIM be used for the 2006-2008 and subsequent program cycles, and also envisioned that it be revisited as warranted in the future. In 2009, the Commission opened Rulemaking 09-01-019 in consideration of a new RRIM framework for the 2010-2012 program cycle.

**Demand Response**

Listed second, in the loading order Demand Response enhances electric system reliability, reduces need for peak power, and benefits the environment by avoiding use of less efficient peaking plants. The investor owned utilities operate a suite of demand response programs, which have had an aggregated impact of 2,517 MW, the equivalent of five large power plants. Demand response (DR) is the ability of a customer to reduce his electricity usage (or shift his usage to a different time of the day) in response to a trigger such as a price signal, an emergency alert or an environmental event like changes in temperature. The intent of traditional demand response 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. Demand response benefits ratepayers in that it enables utilities to avoid building expensive new electric generating capacity (such as peak power plants) that are used for only a small percentage of the hours in a year. The avoidance of greenhouse gas emissions from those peaker plants is an additional benefit for the state. Demand response can also lower wholesale power costs as lowered demand forces power suppliers to adjust their prices downward in the energy markets. Demand response can also prevent rolling blackouts by providing additional reductions in demand when the grid is strained to meet demand. Demand response is ranked as one of the most important resources in the Commission’s “loading order” second only to energy efficiency.

In June 2002, the Commission began a policy rulemaking to develop demand response as a resource to enhance electric system reliability, reduce power purchases (thereby lowering consumer costs), and to protect the environment.\(^9\) Prior to 2002, demand response programs were limited to programs that were useful only for avoiding rotating outages. The Commission outlined several policy objectives from the 2002 rulemaking that remain today:

- Emphasizing “price-responsive” demand response programs,
- Affirming the importance of time-based rates to incent demand response programs,
- Implementing cost-effective advanced metering systems with enough functionality to support demand response programs, and
- Promoting the importance of customer education and technology assistance to help customers understand and participate in demand response programs.

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\(^9\) D0511009 at section 1.
Demand response is administered in the form of retail incentive programs and retail electricity rates operated by California’s three regulated investor-owned utilities (IOUs): PG&E, SCE, and SDG&E. Aggregators, otherwise known as curtailment service providers, also play a role by operating DR incentive programs on behalf of the IOUs. Most demand response programs target large commercial and industrial (C&I) customers that are already equipped with advanced (smart) meters that are capable of measuring and reporting energy usage in one hour intervals or less. The ability to track energy usage at such detailed levels is necessary for a customer to participate in demand response programs. By 2012, all IOU customers will be equipped with advanced (smart) meters thereby enabling demand response participation for all customer classes.

**Commission’s Actions to Improve the Efficacy of the Demand Response Programs**

- **Measuring Cost-Effectiveness:** The Commission is in the process of developing demand response (DR) cost-effectiveness protocols to provide a method for measuring the cost-effectiveness of demand response resources. 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 protocols support the fact that electricity customers, due to smart meter deployment and dynamic rates, are able to adjust their electricity loads to provide different levels of load reduction in response to price signals or other incentives. These load reductions provide value to the grid not only during emergencies, but also during times of high energy prices or in the ancillary services market. The protocols also acknowledge the fact that the methods we use to measure the costs and benefits of demand response must be flexible enough to capture these newly emerging benefits. Specifically, the protocols aim to a) address the broad variety of DR resources, including current programs and anticipated future activities; b) identify all relevant quantitative and qualitative inputs that are important for determining the cost-effectiveness of DR; c) recommend methods for determining the value of the inputs; and d) determine a useable overall framework and methods for evaluating the cost effectiveness of each of the different types of DR activities.

- **Implementing Dynamic Rates:** In addition to ensuring that DR incentive programs are evaluated for cost-effectiveness, the Commission, as noted previously, is emphasizing the use of time-based or dynamic rates to efficiently reduce demand. Time-based rates are rates that are designed to more accurately reflect the “real-time” cost of electricity. One example of a time-based rate is “Critical Peak Pricing” or CPP. CPP contains a very high energy rate that is triggered by extreme conditions such as high temperatures. The customer is warned a day in advance that the peak hour energy rate (typically from 2 pm to 6 pm) will increase significantly and the customer is advised to reduce their demand during those peak hours. The intent of this rate is send end-use customers accurate price signals for their energy use.

Dynamic rates can further reduce costs for ratepayers when compared to traditional demand response programs. Traditional demand response programs often pay participants a financial incentive for the amount of energy they reduce during periods of peak demand. A dynamic rate eliminates the costs, both direct and administrative, of paying incentives,
and instead uses an accurate price signal as the decision point for ratepayers to make choices about their energy use.

Dynamic rates will provide ratepayers with options that will reduce upward pressure on electricity rates. As customers respond to dynamic price signals, system-wide electricity demand will be lowered during peak demand periods. In the short run this will reduce prices paid by utilities to power generators in the, more expensive, short-term electricity market. In the long run, this will reduce the need for new generation plants to provide power and for transmission infrastructure to deliver that power.

The Commission has adopted a policy of “default” dynamic rates for most customer classes. Default means that the affected customer class is placed on the rate, with an opportunity to opt-out. Over the next few years, default dynamic rates will be rolled out by each IOU, starting with the largest customers in 2010.

- **Smart Meter Deployment**: The Commission has authorized the three IOUs to replace existing electricity and gas meters with smart meters over the five period spanning 2008-2012. While the cost of the new meter systems is about $4.5 billion, the Commission authorized the investment because the anticipated benefits of the new system are expected to exceed the costs over the 20-year life of the meters. The meter rollout effort will lay the groundwork for a more modern, reliable and flexible electricity grid. For example, smart meters will enable the IOUs to detect outages on the system, which means quicker restoration of service and thus less disruption to homes and businesses. As noted earlier, smart meters will measure electricity usage in time increments which enable customers to participate in demand response programs and time-based rates. Smart meters also enable customers to see their daily electricity usage and in the near future customers will be able to pre-program appliances that communicate directly with the smart meter. Armed with better information and technology, IOU electricity customers will be better able to influence their electricity usage and thus save money on their monthly electric bills.

- **Wholesale market initiatives**: In 2009, the California Independent System Operator (CAISO) implemented several major enhancements to California wholesale energy markets through its Market Redesign and Technology Upgrade (MRTU) program. MRTU is predicted to bring increased grid and market efficiencies, reduces barriers to alternative resources of power such as demand response and green generators, and gives grid operators new tools for managing transmission bottlenecks and dispatching the least cost power plants. The Commission and CAISO are working together to design and/or modify existing retail demand response programs so that the demand response MWs generated from these programs can participate in the various wholesale markets for electricity, including ancillary services. The ability to bid demand response as a resource into wholesale markets can help to mitigate local transmission constraints, provide economic benefit, and enhance grid reliability at lower costs.
Renewable Portfolio Program (RPS)

Listed third in the loading order, California’s Renewable Portfolio Program (RPS) is the most ambitious in the country 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.

Public Utilities Code Section 399.11 – 399.19 (established in 2002 under Senate Bill (SB) 1078 and modified in 2006 under SB 107), requires investor-owned utilities (IOUs), electric service providers (ESPs) and community choice aggregators (CCAs) regulated by the California Public Utilities Commission (CPUC) to procure an additional 1% of retail sales per year from eligible renewable sources until 20% target is reached in 2010. The CPUC and the California Energy Commission are jointly responsible for implementing the program. Governor Schwarzenegger’s Executive Orders S-14-08, issued on November 17, 2008, and S-21-09, issued on September 15, 2009, established a further goal of 33% renewable energy by 2020.

Cost Containment

SB 1078 established the supplemental energy payments (SEPs) program to contain the total costs of the RPS program. Under the SEPs program, renewable generators could request SEPs from the California Energy Commission, which held a limited amount of funds available for eligible above-market costs. In 2007, SB 1036 modified the cost containment program. Instead of generators requesting SEPs, electrical corporations are now required to seek approval of both the contract and cost recovery of any eligible above-market contract costs from the CPUC at the same time.

The CPUC calculates 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. Pursuant to SB 1036, the total amount of eligible above-market funds (AMFs) available to all electrical corporations to cover above-MPR costs for RPS contracts was the amount of SEPs that already had been collected plus the SEPs that would have been collected through January 1, 2012. The CPUC calculated that the above-MPR funds would be approximately $775 million, and they were allocated to Bear Valley Electric Service, Pacific Gas and Electric, San Diego Gas & Electric, and Southern California Edison in proportion to their contribution to the SEPs fund. 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 and request a determination of price reasonableness from the CPUC. The CPUC continues to review 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.

As of January 2010, the CPUC had approved 137 RPS contracts for more than 12,000 MW of renewable capacity; as of the same date, about 1,050 MW of that renewable capacity was online,
including 357 MW that began operation in 2009. 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.

Assuming the 33% by 2020 RPS requirement remains in place, RPS solicitations are likely to continue to receive robust responses. For example, the IOUs’ 2009 RPS solicitation bids resulted in more proposed renewable generation than any other solicitation in RPS history. Developers offered to supply enough renewable generation to provide 50% of the IOUs’ total load in 2020.

It also 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, nearly 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 solar thermal technologies are making up a large portion of new RPS bids. The CPUC has estimated that in 2020, the total statewide electricity expenditures of achieving a 33% RPS utilizing the current procurement strategy will be 10.2% higher compared to an all-gas scenario. However, improvements in technology or other developments may create downward pressure on prices.

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

- **RPS policy development proceeding (R.06-02-012):** The CPUC will consider whether to authorize the procurement and use of tradable renewable energy credits (TRECs) for RPS compliance. As discussed in the next section, allowing TRECs for compliance could significantly reduce program costs by increasing procurement flexibility.

- **RPS implementation proceeding (R.08-08-009):** In between the RPS program and self-generation programs is an important, untapped market segment for system-side renewable distributed generation (DG). In 2010, CPUC will begin implementation of SB 32, enacted in 2009, which expands the existing feed-in tariff (FIT) for renewable DG systems of up to 1.5 MW to become available to systems up to 3 MW. Because the market price referent that stands as the current FIT price already reflects the cost of fossil fuel generation and the value of environmental compliance costs, Energy Division staff does not anticipate price increases as a result of SB 32 requirements. In 2010, CPUC may also consider approving a staff proposal to create a renewable auction mechanism for systems of 1 to 20 MW (separate from the general RPS procurement process of one annual solicitation per IOU, so that smaller projects do not have to compete on price with large) that uses a standard contract and a market-based pricing structure to set competitive contract prices that are high enough to support substantial numbers of new projects.

- **Renewable transmission proceedings (R. 08-03-009 and I. 08-03-010):** As more wind and solar comes online, the State will face a growing challenge to integrate higher intermittent renewable penetration without decreasing system reliability. As a result, the California Independent System Operator (CAISO) has initiated a study of the ancillary resources necessary to maintain grid reliability with a 33% RPS. In 2010, the CPUC’s
renewable transmission proceeding may determine whether ISO’s results warrant an integration cost adder greater than zero for RPS contracts. To the extent that the application of such a cost adder in the IOUs’ bid review processes results in changes to the IOUs’ procurement decisions, it may affect the overall cost of the RPS program.

- **Applications for utility solar photo voltaic (PV) programs (A.08-03-015, A.08-07-017, and A.09-02-019):** In 2010, the CPUC will consider whether to approve requests from PG&E and SDG&E to a) build, own and operate hundreds of megawatts of PV, and 2) execute contracts for several hundred more megawatts of PV to be owned and operated by independent power providers. The CPUC approved SCE’s PV program in 2009.

**Actions for reducing rate impacts in the next 12 months:**

- ** Tradable Renewable Energy Credits (TRECS):** In March 2010, the Commission authorized the use of TREC’s for RPS compliance whereby the LSEs can choose not to receive delivered energy for some portion of their renewable obligation. Allowing the use of TREC’s for RPS compliance generally will provide more renewable procurement options and flexibility for LSEs, potentially resulting in lower costs to ratepayers. A transitional price cap for TREC’s was included, protecting ratepayers further from high prices in the early stages of a TREC market. However, due to industry opposition to the CPUC decision and numerous requests to modify the decision filed shortly after it was rendered, the decision has been stayed to allow the CPUC to evaluate further TREC policy. This reevaluation is expected to be completed in 2010.

- **Renewable Auction Mechanism:** CPUC staff’s proposed renewable auction mechanism and the utility PV programs could both be helpful in minimizing program costs. PV prices have decreased substantially in the last year and are often cheaper than bid prices for utility-scale solar thermal projects, which currently represent a large portion of proposed new RPS projects. If these programs are successful at spurring significant increases in PV capacity, economies of scale could prompt installed PV costs to decline further.

**Distributed Generation/ California Solar Initiative**

The California Solar Initiative (CSI) is overseen by the California Public Utilities Commission (CPUC) and provides incentives for installation of solar energy systems to customers of the state’s large regulated utilities. The CSI Program demonstrates the State’s strong support for solar technology and is an outgrowth of Governor Schwarzenegger’s call for a “Million Solar Roofs” vision for the State of California.10

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10 The Million Solar Roofs goal was not adopted by the Legislature as an explicit number of projects goal in its authorization of the State’s solar programs. Instead, the Legislature adopted a 3,000 MW capacity goal. However, if the entire capacity goal were installed (hypothetically) in only small residential systems averaging 3 kW in size, it would cover approximately one million roofs. In practice, the CPUC expects its CSI-electric portion of the statewide program to be approximately one-third residential, and two-thirds non-residential projects. Since non-residential systems are fewer in number, but larger in terms of per-project capacity, the number of systems installed will not reach one million even when the capacity targets are achieved.
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 electricity, and gas ratepayers support 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.

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

In early 2006, the Commission, in collaboration with the California Energy Commission, established the CSI as a $2.5 billion incentive program to promote solar development through 2016, to be funded from the distribution rates of gas and electric ratepayers. At that time, the Commission stated its intent to consider incentives for solar water heating as part of the CSI program, and directed San Diego Gas & Electric Company (SDG&E) to contract with California Center for Sustainable Energy (CCSE) (formerly the San Diego Regional Energy Office) to administer a pilot program for SWH incentives in the SDG&E territory.

Subsequently, with the passage of Senate Bill (SB) 1 (Murray, 2006) in August of 2006, funds for CSI were limited to $2.167 billion and could no longer be collected from gas ratepayers. The CPUC authorized rate collections for the three large electric investor-owned utilities (large IOUs): Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE) and SDG&E. At the same time, SB 1 included a provision allowing $100.8 million of total CSI funds to be used for incentives for solar thermal technologies, such as solar water heating. With CSI funding now limited to collections from electric ratepayers, the Commission concluded in Decision (D).06-12-033 that CSI should only pay incentives to solar thermal technologies that displace electric usage. The SWH pilot in the SDG&E territory, budgeted at $3 million, was allowed to proceed to provide useful information on SWH incentives in general.

In late 2007, the Governor signed Assembly Bill (AB) 1470 (Stats. 2007, Ch. 536), authorizing the creation of a $250 million incentive program to promote the installation of 200,000 SWH systems in homes and businesses that displace the use of natural gas by 2017. The statute requires the Commission to evaluate data from the SWH pilot and determine whether an SWH program is “cost effective for ratepayers and in the public interest” before designing and implementing an incentive program for gas customers.

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11 Strictly speaking, solar thermal systems are not grid connected, but back-up hot water or thermal service is provided by the gas distribution network.

12 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/](http://www.cpuc.ca.gov/PUC/energy/Renewables/).

13 See Decision (D.) 06-01-024.


15 D.06-12-033, Conclusion of Law 19 at 38.

16 Public Utilities Code Section 2863(a)
The CSI Thermal Program will provide incentives to promote the installation of solar water heating systems in the territories of PG&E, SCE, SDGE and Southern California Gas Company (SoCalGas). The CSI Thermal Program will be funded by $250 million in collections from gas ratepayers, pursuant to AB 1470, as well as up to the $100.8 million in funds already authorized for solar thermal projects. The latter is currently being collected through the larger CSI program for electric displacing solar technology as authorized by SB 1 and Commission decisions. Monies collected under AB 1470 from gas ratepayers will fund incentives to solar water heating systems that displace natural gas usage, while funds collected under SB 1 from electric ratepayers will fund electric displacing solar water heating systems.

The CSI Thermal Program will be administered by PG&E, SCE, SoCalGas, and by CCSE in SDG&E territory. PG&E and SDG&E, in coordination with its program administrator, CCSE, will disburse incentives to both electric and gas ratepayers who install eligible solar water heating systems in their territories. SCE will disburse incentives through the CSI Thermal Program to customers who install electric displacing solar water heating systems. SoCalGas will disburse incentives to customers in its territory who install gas displacing solar water heating systems.

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

The electric displacing portion of the CSI Program has a budget of $2.167 billion over 10 years, from 2007-2016. The CSI Thermal Program has an additional budget of $250 million through 2017. Together, this funding is intended to:

- Install 1,940 MW of distributed solar energy systems in the large IOU service territories;
- Install solar water heating systems that displace 275.7 million kWh per year of electricity;
- 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 has seven program components, as shown in Table 1, each with their own Program Administrator 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 Solar Water Heating Pilot Program (SWHPP)** provides solar hot water incentives through a pilot program for residences and businesses in the San Diego area only; the SWHPP is administered through CCSE with a budget of $2.6 million.

- **The CSI Thermal Program** provides rebates for solar water heating (SWH) installations on new and existing homes and businesses. The program will pay incentives towards SWH systems that displace natural gas water heating on new and existing homes and businesses, and towards SWH 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.

<table>
<thead>
<tr>
<th>Table 1: CSI Budget by Program Component, 2007-2017</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Budget</strong> ($ Millions)</td>
</tr>
<tr>
<td>--------------------------</td>
</tr>
<tr>
<td>General Market Solar Program</td>
</tr>
<tr>
<td>Single-Family Affordable Solar Homes (SASH)</td>
</tr>
<tr>
<td>Multifamily Affordable Solar Housing (MASH)</td>
</tr>
<tr>
<td>Research, Development, Demonstration, and Deployment (RD&amp;D)</td>
</tr>
<tr>
<td>Solar Hot Water Pilot Program (SWHPP)</td>
</tr>
<tr>
<td>Solar Thermal Program, Gas-displacing</td>
</tr>
<tr>
<td>Solar Thermal Program, Electric-displacing</td>
</tr>
<tr>
<td><strong>Total CPUC CSI Budget</strong></td>
</tr>
<tr>
<td></td>
</tr>
</tbody>
</table>

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

1 If SWH becomes mandatory for new home construction, new homes shall not be eligible for incentives under CSI Thermal.

17 The 150 MW goal for the Thermal Program Electric-displacing portion of CSI is already included in the MW goals for the CSI General Market Program.
CSI Program Balancing Accounts

In D.06-12-033, the Commission established a total budget of $2.167 billion over ten years for the CSI, including all program components. The large IOUs were authorized to collect the CSI Program funds from electric ratepayers according to the schedule as shown in Table 2. 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.

Table 2: Authorized CSI Balancing Account Rate Collection Schedule

<table>
<thead>
<tr>
<th>Year</th>
<th>PG&amp;E</th>
<th>SCE</th>
<th>SDG&amp;E</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2007</td>
<td>$140,000,000</td>
<td>$147,000,000</td>
<td>$33,000,000</td>
<td>$141,800,000</td>
</tr>
<tr>
<td>2008</td>
<td>$140,000,000</td>
<td>$147,000,000</td>
<td>$33,000,000</td>
<td>$320,000,000</td>
</tr>
<tr>
<td>2009</td>
<td>$140,000,000</td>
<td>$147,000,000</td>
<td>$33,000,000</td>
<td>$320,000,000</td>
</tr>
<tr>
<td>2010</td>
<td>$105,000,000</td>
<td>$110,000,000</td>
<td>$25,000,000</td>
<td>$240,000,000</td>
</tr>
<tr>
<td>2011</td>
<td>$105,000,000</td>
<td>$110,000,000</td>
<td>$25,000,000</td>
<td>$240,000,000</td>
</tr>
<tr>
<td>2012</td>
<td>$105,000,000</td>
<td>$110,000,000</td>
<td>$25,000,000</td>
<td>$240,000,000</td>
</tr>
<tr>
<td>2013</td>
<td>$70,000,000</td>
<td>$74,000,000</td>
<td>$16,000,000</td>
<td>$160,000,000</td>
</tr>
<tr>
<td>2014</td>
<td>$70,000,000</td>
<td>$74,000,000</td>
<td>$16,000,000</td>
<td>$160,000,000</td>
</tr>
<tr>
<td>2015</td>
<td>$70,000,000</td>
<td>$74,000,000</td>
<td>$12,800,000</td>
<td>$156,800,000</td>
</tr>
<tr>
<td>2016</td>
<td>$2,000,000</td>
<td>$45,400,000</td>
<td>$-</td>
<td>$47,400,000</td>
</tr>
<tr>
<td>Total</td>
<td>$947,000,000</td>
<td>$996,000,000</td>
<td>$223,000,000</td>
<td>$2,166,000,000</td>
</tr>
</tbody>
</table>

Source: D.08-12-004

Actions for reducing rate impacts in the next 12 months

Over the next few years, the CPUC will continue to monitor the trends in expenditures from CSI relative to costs and will adjust the necessary revenue collections by the utilities accordingly.

CARE and Low Income Energy Efficiency (LIEE)

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 Low Income Energy Efficiency (LIEE) Program provides eligible low-income households with energy education, energy efficient appliances, and weatherization measures at no cost.

California Alternative Rate for Energy (CARE)

18 The CPUC modified the CSI Program rate collections schedule in December 2008, in D.08-12-004.
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. Initially, the program provided a 15% discount on electric and gas rates. The discount was increased to 20% in 2001 (D. 01-06-010). However, because of the fact that CARE customers were not subject to the high rates for Tier 4 and 5, the subsidy for CARE has grown substantially above 20% as Tier 3, 4 and 5 rates have risen over time and Tier 1 and 2 were frozen. The CARE subsidy is particularly high for PG&E which has only two CARE Tiers. Both LIEE & 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).

**Low-income Energy Efficiency (LIEE)**

The Low Income Energy Efficiency 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. Since their inception, these programs have grown significantly in size and scope. The LIEE program provides home weatherization services for low-income households and includes the following measures: (1) Heating Ventilation Air Conditioning Measures; (2) Infiltration and Space Conditioning; (3) Weatherization; (4) Water Heating Savings; (5) Energy Education; and (6) other Miscellaneous Measures including Refrigerator Replacements, Compact Fluorescent Light bulbs (CFLs) and Compact Fluorescent hardwired fixtures. Weatherization services may also include other building conservation measures, energy efficiency appliances and energy education programs, with each IOU’s program portfolio being evaluated during the budget application process. All measures are provided at no cost to the resident.

As articulated in the *Energy Efficiency Strategic Plan*, the LIEE program pursues two goals:

- By 2020, all eligible customers will be given the opportunity to participate in the LIEE program

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

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

The CARE and LIEE programs are funded for a 3-year planning cycle. For the 2009-2011 budget period, the Commission authorized a $2.6 billion budget for CARE and $885 million for the LIEE (see Decision 08-11-031). This Decision also established a CARE penetration goal of 90% and an LIEE goal for all the IOUs to treat 1 million homes in California during the 2009-2011 period. 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 LIEE targets and the annual CARE and LIEE budgets.
LIEE Goals: Number of homes to be treated from 2009-2011

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

Commission Actions in the Next 12 Months

While the Commission’s Decision 08-11-031 significantly increased the budgets for the 2009-2011 program years, it also 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. Implementation of these efforts will be central to the Commission’s activities over the next 12 months, and beyond. These major initiatives will include the following:

**Program Delivery, Marketing & Outreach**

- Focus outreach on customers with high energy-use, burden and insecurity to reach those customers in greatest need first.
- Develop a whole neighborhood approach to market and install LIEE measures to increase program delivery efficiencies and effectiveness.
- Enhance outreach to the disabled to better reach this group that makes up approximately 20% of LIEE-eligible population.
- Implement a 90% CARE penetration goal for all IOUs in the 2009-2011 period.
• Increase the overall cost effectiveness of the program by implementing a 0.25 benefit-cost ratio threshold on measures.
• Strengthening of rules to ensure cost efficiencies, such as the requirement to at least install three measures in one visit to a household in order to achieve a threshold of energy saving.
• Focus and promotion of relevant workforce education and training.
• Focus on increasing internal and external efficiencies for the IOU’s. The CPUC will assess the IOU’s efforts to leverage LIEE marketing activities with other government and private programs as well as assess the IOU’s efforts in integrating their own demand side programs.

Studies & Pilots to further improve program effectiveness
The CPUC 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 LIEE Training Modules for Contractors, Smartmeter and In-Home Display Pilots.
• WE&T: Workforce Education and Training: A LIEE 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 LIEE program
• 2009 Process Evaluation Study of the effectiveness of the overall LIEE 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.

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 18 months or so. The IOUs are likely to submit applications for a 2012-2014 planning cycle in mid-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 are experiencing their lowest natural gas rates in over five years. However, the CPUC does not regulate the price of natural gas. 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” 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.

California natural gas utilities operate over 100,000 miles of transmission and distribution pipelines, and deliver natural gas to over 10.5 million customers. They also operate large natural gas storage fields. The CPUC authorizes the revenue requirements for the natural gas distribution utilities primarily in the areas of natural gas transmission, distribution, storage, and customer service costs and natural gas public purpose program (PPP) costs. Natural gas utility costs for transmission, distribution, storage and customer service have moderately increased by about 3% since 2006. Gas PPP costs have increased by 20% since that time.

CPUC Actions to Limit Utility Cost and Rate Increases

The CPUC will rely on successful programs to ensure that natural gas procurement costs are reasonable. However, changes in utility core customer gas rates and costs are most heavily influenced by the price of natural gas supply.

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

- Although the Commission can not regulate the price of natural gas, it will continue to implement measures that:
  - Provide incentives to utilities to keep natural gas procurement costs low,
  - 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.

19 Core customers are mainly residential and small commercial customers.
• The Commission will scrutinize natural gas utility operational costs and rates for transmission, distribution and storage in several major proceedings, including the PG&E 2011 General Rate Case (GRC), the PG&E Gas Transmission and Storage proceeding, and the SoCalGas/SDG&E 2012 GRC.

• 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 2010. The other main components of the gas PPP surcharge, energy efficiency and CARE programs, are discussed in other sections of this report.

Almost all larger, “noncore” natural gas consumers (such as industrial customers or electric generators) procure their own natural gas supplies using non-utility suppliers, so they are not charged the procurement rate by the utility. In addition, electric generation and other exempt customers are not charged the gas PPP surcharge, pursuant to the Public Utilities Code Section 896.

Although core gas customers in California have the option to choose a non-utility natural gas supplier, natural gas utilities in California provide procurement service for over 98% of core customers. The major natural gas utilities recover procurement costs in a component of the total gas rate called the gas procurement rate. The gas procurement rate is changed every month to reflect the most current price of natural gas. This helps send customers a price signal, so they may adjust their usage accordingly. The procurement rates are changed routinely in monthly filings at the CPUC called advice letters.

The utility does not receive a return or mark-up for the procurement service, but the CPUC has approved gas cost incentive mechanisms for each of the four large natural gas utilities (PG&E, SoCalGas/SDG&E, and Southwest Gas). Under these mechanisms, the utility can achieve small shareholder rewards if it can procure supplies at prices below the Commission approved benchmarks which are the monthly market indices.

Natural gas procurement costs have the most significant impact on the month-to-month and year-to-year changes in utility core gas customer rates for two reasons. First, the natural gas procurement rate is a large component of the total core natural gas rate. Second, natural gas prices fluctuate far more than the other two core rate components, the delivery (or “transportation”) rate and the natural gas public purpose program surcharge.

**Current Trends in Gas Rates**

Total core natural gas rates on average are at their lowest level in at least the last five years. As one can see in the tables presented by the CPUC in its April 2010 Gas and Electric Utility Cost Report, the natural gas procurement costs in 2009 were 37% lower than the procurement costs in 2008. Even with the dramatic decrease in procurement costs in 2009, these costs represented about 47% of total utility costs. Because natural gas costs fell so much in 2009, and into 2010,

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20 SoCalGas procures natural gas for both its own core customers as well as for SDG&E core gas customers.  
procurement rates also fell dramatically. The decline in the procurement rate has caused the total core natural gas rate to fall to its lowest average level in at least 5 years, as shown in the graph below. 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.

![Average Residential Natural Gas Rates](chart)

**The CPUC Can Only Influence the Bulk of Procurement Costs Indirectly**

The bulk of the utility gas procurement costs consist of the costs of the natural gas supply itself. Other costs in the gas procurement rate include: the costs of interstate pipeline capacity, the costs or gains associated with hedging, and some intrastate transmission costs. (PG&E also includes the costs of storage capacity allocated to core customers in the gas procurement rate.) The major natural gas utilities change the procurement rate they charge core gas customers every month.

Noncore customers directly buy their own gas, so the CPUC doesn’t have knowledge about what specific noncore customers pay. But, as confirmed by data from the Energy Information Administration, noncore customers are also generally experiencing their lowest natural gas costs in about six or seven years.

The price of natural gas is not regulated by the CPUC or the Federal Energy Regulatory Commission (FERC), and is generally determined by market forces. The CPUC does not have the jurisdiction to regulate natural gas prices, and the FERC deregulated the price of natural gas in the 1980’s.

The CPUC also cannot directly impact the cost of interstate pipeline capacity used to transport core gas supplies to California from out-of-state basins. The tariff rates of interstate pipelines are determined by the FERC. The utilities can occasionally obtain discounted rates for interstate
pipeline capacity but this is largely influenced by market forces. (However, as explained below, the CPUC does intervene at FERC on pipeline rate cases, and the CPUC tries to ensure that the utilities obtain pipeline capacity at low cost.)

The CPUC works to ensure that the utilities do a reasonable job procuring natural gas supplies at low cost for core customers. The CPUC does this by:

- Adopting gas cost incentive mechanisms, which provide a financial incentive to the utilities to procure natural gas supplies at the lowest cost,
- Adopting an expeditious process for approvals of beneficial interstate pipeline capacity contracts for transportation of supplies from out-of-state supply basins to California,
- Allocating adequate utility storage capacity to core customers, and
- Allowing efficient natural gas hedging of gas prices.

During the next 12 months, the CPUC will continue to utilize the above practices to keep procurement costs reasonable.

Gas Cost Incentive Mechanisms

The CPUC expects that the utilities will continue in the coming year to diligently endeavor to achieve natural gas savings relative to monthly gas price indices, as they have done in the past, under their gas cost incentive mechanisms. Gas cost incentive mechanisms have been adopted for PG&E, SoCalGas, and SDG&E since the mid-1990’s, and for Southwest Gas since the mid-2000’s. These mechanisms provide a financial incentive for the utilities to procure natural gas for core customers at below monthly market prices. (When utilities do a poor job procuring natural gas supplies, they face a penalty.) The CPUC has made various modifications to the mechanisms over the years, but at this time does not anticipate making any significant changes to these mechanisms during the next year. The gas cost incentive mechanisms have been successful because, in almost every year since their adoption, utilities have procured gas supplies at a savings relative to market prices.

Gas Hedging

The CPUC recently ordered a major change in how the utilities’ hedging costs or gains are treated to encourage efficient use of hedging. Since 2005, the CPUC has allowed a significant increase in the winter hedging activity conducted by the utilities in order to guard against the risk that natural gas prices will dramatically increase during the winter. Along with the increase in hedging activity, the CPUC allowed the utilities to pass on all hedging costs/gains to procurement customers. While the hedging programs helped insure that core customers would not pay extremely high prices, these hedging programs came with big costs. As the CPUC’s April 2010 Gas and Electric Utility Cost Report shows, the utilities have been incurring hedging costs that amounted to tens of millions of dollars per year. In order to ensure that the utilities manage their hedging programs efficiently, in January 2010 the CPUC required utilities to include a portion of these costs or gains under the gas cost incentive mechanisms. This

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effectively places the utilities at some risk for the hedging costs/gains. With the change ordered by the CPUC in January 2010, we expect that future hedging activity will be more efficiently managed than in the past.

**Interstate Pipeline Capacity Contracts**

During the next 12 months, the CPUC expects that the utilities will continue to obtain reasonable interstate pipeline capacity contracts under the expedited approval process. In 2004, the CPUC authorized an expedited process for approvals of new interstate pipeline capacity contracts held between the natural gas utilities and large interstate pipeline companies. The CPUC also specified a minimum level of capacity to be held by the utilities in order to reliably serve core gas customers’ supply needs. These contracts allow the utilities to transport natural gas supplies from out-of-state gas supply basins to California with a high degree of reliability. Under the expedited approval process, the utilities have gradually diversified their interstate pipeline portfolios. Formerly, the utilities held a small number of long-term contracts, but they now have in place a variety of contracts with different terms, better prices, and greater supply access. In addition, the approval process takes much less regulatory time for both the CPUC and the utilities, and allows the utilities to act more quickly to obtain the best deals.

In order to maintain adequate transportation capacity to the supply basins, a number of contracts will need to be signed in the coming year by the utilities, as old contracts expire. As discussed later in this report, the CPUC also intervenes at the FERC on interstate pipeline general rate cases in order to keep pipeline rates down for all California gas consumers.

**The Ruby Pipeline**

A major new interstate pipeline, the Ruby Pipeline, is expected to begin deliveries to California in early 2011. The CPUC approved major PG&E contracts on the Ruby Pipeline in 2008. The Ruby Pipeline will be the first new major interstate pipeline to California in over 15 years, and is expected to begin operation in the first quarter of 2011 if FERC approval of a construction permit is gained soon. The Ruby Pipeline will further improve California’s access to a diverse portfolio of supplies, including for PG&E’s core gas customers. Diversity of supplies not only helps to ensure adequate supply, but also over time helps to keep procurement costs moderated, as utilities can shift from higher priced basins to lower-priced basins when market conditions change. The Ruby Pipeline will provide the first significant supplies from the Rockies to northern California.

The CPUC approved two large interstate capacity contracts for PG&E on the Ruby Pipeline back in late 2008. One of these contracts is for core gas supply, and the other contract is for gas supplies for PG&E electric generation. The CPUC approval of the PG&E contracts was a critical component in the development of the Ruby Pipeline project.

**Storage Capacity**

Core customers have reasonable amounts of storage capacity and may be obtaining additional storage in the near future. The utilities own large storage fields, and significant portions of that capacity are allocated to the utilities’ core customers. The remainder of the capacity is made available to larger “noncore” customers and marketers. This allocation not only helps to ensure
deliveries to core customers with a high degree of reliability, but also allows the utilities to take advantage of the economic benefits of storage, which can then be passed on to their procurement customers. Natural gas prices fluctuate daily and are typically lower in the summer than in the winter. Storage allows the utilities flexibility to buy more gas when prices are low and withdraw the gas when prices are high. From time to time, the utilities may also be authorized to obtain additional storage from the independent storage utilities, Wild Goose Storage and Lodi Gas Storage.

In the coming year, the CPUC does not expect a significant shift in utility storage capacity allocated to core customers, but some additional capacity could be authorized. The allocation of PG&E and SoCalGas storage capacity to core customers has already been set in various past CPUC proceedings, and some additional capacity has been authorized from the independent storage operators. The CPUC recently approved an application by SoCalGas which provides for additional core storage capacity at its Honor Rancho storage field. In addition, it is possible that storage capacity could be obtained from independent storage providers or utility-owned storage if it is economic and/or improves delivery reliability.

Rate Related Proceedings in Next 12 Months

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. During the next 12 months, the CPUC expects to examine natural gas utility costs in the following proceedings:

PG&E

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

PG&E is proposing its revenue requirement for its gas transmission and storage system for the years 2011 through 2014. The revenue requirement would be used for GT&S operating and maintenance expenses and capital expenditures. In the proceeding, the utility also is proposing the rates it would assess its customers for the recovery of its GT&S revenue requirement.

PG&E’s gas transmission and storage system is critical infrastructure. The utility’s gas transmission pipelines (referred to as “backbone” pipelines) consist of large-diameter, high pressure pipelines, which receive gas from various interstate pipelines, California gas producers, and storage fields, and deliver this gas to PG&E’s local transmission system, directly to end-use customers, or to off-system markets, primarily in southern California. PG&E’s local transmission facilities, which are interconnected with the utility’s backbone system, deliver gas to many large end-use customers as well as to PG&E’s distribution system. The utility also operates gas storage fields that serve both residential and nonresidential customers.
PG&E’s Gas Transmission and Storage Revenue Requirement Request ($ millions)

<table>
<thead>
<tr>
<th>Service Component</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
</tr>
</thead>
<tbody>
<tr>
<td>Backbone transmission</td>
<td>241.0</td>
<td>234.0</td>
<td>247.5</td>
<td>260.1</td>
<td>263.7</td>
</tr>
<tr>
<td>Local transmission</td>
<td>164.0</td>
<td>202.8</td>
<td>219.5</td>
<td>235.3</td>
<td>252.7</td>
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<td>Storage</td>
<td>51.6</td>
<td>87.6</td>
<td>89.5</td>
<td>91.8</td>
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</tr>
<tr>
<td>Customer Access</td>
<td>5.2</td>
<td>4.7</td>
<td>5.0</td>
<td>5.1</td>
<td>5.3</td>
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<tr>
<td><strong>Total</strong></td>
<td>461.8</td>
<td>529.1</td>
<td>561.5</td>
<td>592.2</td>
<td>614.8</td>
</tr>
</tbody>
</table>

PG&E says its requested revenue requirement increase is needed to provide its customers with safe, reliable and efficient service as well as to meet growing demand. In particular, PG&E claims that it is experiencing increased capital outlays for its gas transmission pipelines well above historical levels, primarily due to the age of its facilities, and is proposing capital outlays for the four year period of $843.9 million.

Operating and maintenance expenses are expected to escalate for a variety of reasons. These include compliance with a federal pipeline safety inspection mandate, compressor maintenance and overhaul expenses, and costs associated with the operation of PG&E’s Gill Ranch gas storage facility, currently under construction.

PG&E is also proposing the creation of a revenue sharing incentive mechanism. Under this mechanism, PG&E will share with its gas transmission customers 50% of the difference between its adopted and recorded GT&S revenue requirement. This means that if collected GT&S revenues exceed the adopted revenue requirement, PG&E will return half this amount back to its transmission customers through a rate adjustment. On the other hand, if collections are fall below the GT&S revenue requirement, the utility will recover half of the shortfall from its transmission customers and absorb the remainder. Currently, PG&E is at-risk for most of its GT&S revenue requirement with the utility retaining collected GT&S revenues.

PG&E has projected that the recovery of its proposed GT&S revenue requirement will result in a 1.4% increase in residential bundled core rates.

The CPUC’s Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN, a consumer advocacy group), and other parties have intervened in the proceeding to represent the interests of PG&E’s ratepayers. The CPUC expects to issue its decision in this proceeding in late 2010 or early 2011.

**PG&E Biennial Cost Allocation Proceeding (BCAP)**
In A. 09-05-026, PG&E is presenting its proposed allocation of the adopted gas distribution revenue requirement among its core and noncore customer classes. PG&E’s gas distribution revenue requirement is $1.09 billion and was adopted in D.07-03-044, in the utility’s last General Rate Case. In this proceeding, the Commission will adopt the cost allocation and gas rates PG&E will assess its customers to recover its gas distribution revenue requirement. The cost allocation will affect the level of rates PG&E will charge its residential, commercial and industrial customers.

Adopting PG&E’s proposals will result in a 2.0% increase in the rates for the utility’s bundled residential customers. DRA, TURN and others have intervened in the proceeding to represent the interests of ratepayers. An agreement has been reached on the majority of the contested issues. The CPUC expects to issue its decision in this proceeding in 2010.

PG&E 2011 General Rate Case (GRC)

In A.09-12-020 (2011 General Rate Case), PG&E is, among other things, requesting an increase in its authorized 2011 gas distribution revenue requirement. The utility is also requesting additional amounts for the future, “attrition” years 2012 and 2013. PG&E’s gas distribution system consists of pipelines with operating pressure at 60 pounds per square inch (psi) or less and generally connect local transmission lines to its end-use customers.

The following table summarizes PG&E’s A.09-12-020 gas distribution revenue requirement request. ($ in thousands)

<table>
<thead>
<tr>
<th>Gas Distribution Revenue Requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td>2011</td>
</tr>
<tr>
<td>$1,297,444</td>
</tr>
</tbody>
</table>

As noted above, PG&E’s current gas distribution revenue requirement is $1.09 billion, so PG&E is requesting a significant increase in its gas distribution revenue requirement. PG&E’s request would result in a 5.7% increase in a typical bundled residential core monthly bill. The 2011 gas distribution revenue requirement is based on costs PG&E forecasts it will incur to:

- Own, operate, and maintain its distribution plant and a portion of its common and general plant;
- Perform the transactions necessary to acquire gas supplies for its core gas customers; and
- Provide services to its gas customers.

DRA and TURN as well as numerous other parties typically intervene in PG&E’s GRCs. The CPUC expects to hear evidence from PG&E and interested parties in this proceeding. The CPUC hopes to issue its decision in December 2010.

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23 In the PG&E BCAP, the revenue requirement for the gas distribution pipeline system is allocated, and rates are set. The rates and revenue requirement for the larger-volume transmission system and storage assets are determined in the “Gas Transmission and Storage” proceeding.

24 A.09-12-020, Table 2-1
PG&E Rate related request expected later this year

- Winter Gas Savings Program (2010-2011)
- Core Procurement Incentive Mechanism Shareholder Award
- Annual Electric True-Up (AET) 2011 - Advice Letter Update
- FERC TACBA Filing

SoCalGas/SDG&E

SoCalGas Storage Field Expansion

In A.09-09-020, SoCalGas is proposing to conduct work at its Aliso Canyon Storage Field Project, to replace 3 gas turbine compressors with 3 electric compressors. This project 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 project would result in an increase in core gas rates of about 0.3 cents per therm, or about $10 million per year. SoCalGas requests approval of its revenue requirement and its proposed allocation of the project costs to various customer classes. SoCalGas requests that approval of the actual costs be obtained through the Advice Letter process.

The CPUC expects to determine if it should adopt SoCalGas’ proposal in 2011.

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

In June 2008, SoCalGas requested approval from the Commission to make gas deliveries to outside of California from its transmission system. (At this time, SoCalGas may only make deliveries to points in California.) SoCalGas and SDG&E argue 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 have submitted testimony in the proceeding that contests SoCalGas proposal, and have made a variety of alternative proposals for off-system delivery services and rates. Interveners want assurance that OSD is not subsidized by on-system customers and does not impact their rates, and one party asserts that the CPUC should reject the SoCalGas proposal.

The CPUC expects to issue its decision in this proceeding in 2010.

Firm Access Rights Review - A.10-03-028

As authorized by the CPUC, SoCalGas allows customers to obtain and pay for “firm access rights” (FAR). These rights ensure customers, including the company’s core procurement department acting on behalf of core customers, that their supplies will be delivered onto the SoCalGas transmission system at various receipt points with a high degree of reliability. The framework is somewhat similar to the PG&E GT&S (or “Gas Accord”) framework discussed above. The firm access rights framework was implemented on October 1, 2008.
In the decision that approved the 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 filed its FAR review application on March 29, 2010.

Although the scope of the proceeding has not yet been officially set, the CPUC expects as part of this proceeding to determine the proper revenue requirement associated with firm access rights and to set rates accordingly.

At this time, it is unclear whether the CPUC would reach a decision in this proceeding in 2010 or whether a decision would be reached in 2011.

**SoCalGas and SDG&E 2012 General Rate Case**

In D.08-07-046, the last SoCalGas/SDG&E GRC decision, the CPUC ordered SoCalGas and SDG&E to file another GRC for the forecast year of 2012. Thus, the CPUC expects that SoCalGas and SDG&E will file another GRC application toward the end of 2010 or possibly in early 2011. The CPUC will determine the revenue requirement in that 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.

**Gas Public Purpose Program (PPP) Surcharge**

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 2009, the costs of the gas related PPPs was about $531 million. These costs are collected by the utilities through the gas PPP surcharge appearing on customer gas bills. Gas PPP costs have increased by 20% since 2006, due to increases in energy efficiency and gas R&D costs.

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 LIIE) 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. Energy efficiency costs and low-income costs are discussed elsewhere in this report.

**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.

California obtains more than 85% of its natural gas supply via pipelines from out-of-state, chiefly from natural gas basins in Canada, the Rocky Mountain states, and the southwest states of New Mexico and Texas. 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). 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.

California gas consumers, including public utilities such as PG&E and Southern California Gas Company, typically negotiate short-term and long-term (i.e., multi-year) natural gas capacity contracts for capacity rights on the pipelines operated by the aforementioned interstate pipelines companies.

In the next 12 months, the CPUC will continue to represent California interests in the GRC for El Paso Natural Gas (EPNG). EPNG is the single largest interstate natural gas pipeline to California. California shippers typically hold about half the capacity on EPNG, with east-of-California customers (chiefly in Arizona) holding the other half. California utilities directly hold capacity rights on El Paso for core customer supply requirements. This GRC has been ongoing since 2009.

On March 11, 2010, EPNG customers submitted a settlement to FERC for reservation rates that would establish California maximum firm reservation rates. Several issues have been carved out of the settlement for separate litigation tentatively scheduled to commence in May 2010.

EPNG may submit a new GRC shortly after the current one concludes. It is also 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
Utility Studies And 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

SEE ATTACHED PDF DOCUMENT
March 19, 2010

Ms. Julie Fitch  
Director  
Energy Division  
California Public Utilities Commission  
505 Van Ness Avenue  
San Francisco, CA 94102


Dear Ms. Fitch:

Attached, please find PG&E's final version of the 2010 SB 695 Section 8 (PUC Section 748) compliance report. We hope you will find it useful in compiling the Energy Division's report to the Legislature.

Sincerely,

Amrit Singh

cc: (via e-mail)  
Steve Roscow, Energy Division

Attachment
I. Introduction

Pursuant to the requirements of Public Utilities Code section 748(b), Pacific Gas and Electric Company (PG&E) appreciates the opportunity to provide its initial 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 requirement components, a discussion of PG&E’s rate components, PG&E’s management of its rate components, and a schedule of PG&E’s 2010 rate filings (as an appendix).

Last summer PG&E heard from many electricity customers that electricity rates for customers who use the most energy were just too high. In these tough economic times, PG&E knows how important it is for our customers to keep monthly costs to a minimum. PG&E understands that electricity is a fundamental need and PG&E is also working hard to help our customers save.

Last month, PG&E filed a number of actions with the California Public Utilities Commission asking for rate relief for customers in two forms. First, PG&E has requested an overall rate reduction to take effect on June 1. Second, PG&E has asked the CPUC to change the tiered residential rate structure in a way that reduces the costs for our highest use residential customers.

Current state law mandates that electric utilities in California must charge more per unit of electricity as a household'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 lowest tiers from increases -- tiers 1 and 2 -- and those lower tier rates remained largely unchanged during 2001-2009. That means rate increases during that period fell almost exclusively into the higher tiers. This amplified the impact of rate increases on people who use more electricity in every part of our service area and, in turn, increased the cost of their electricity bills.

We are committed to helping limit or reduce costs to our customers, and it is our hope that through the recommendations in this report, PG&E can help customers during these tough times. PG&E's request to restructure rate tiers will bring our residential rates more closely into alignment with other utilities in the state. Our proposal to reset the residential rate tiers distributes electricity costs more equitably among all our customers. PG&E hopes this eliminates some of the "sticker shock" that can occur when a customer's usage crosses into the top rate tier, especially during peak summer and winter months.
In order to manage utility costs and rate increases, PG&E recommends 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 market factors or policy mandates. Among these are the market price of natural gas used to supply retail customers and power generators; expenditures on public purpose programs mandated by law; the rate of uncollectible costs attributable to economic conditions faced by customers; the overall need for statewide infrastructure investment; the costs of Renewable Portfolio Standard (RPS) compliance; and the costs for compliance with greenhouse gas (GHG) emissions regulations and goals.

In addition, 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 the measures and actions in this report 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.

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. 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 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 moderates 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 from balancing account overcollections. Similarly, to decrease pressure on customer bills during 2010, PG&E has requested approval to accelerate credits of balancing account over-collections and defer collection of certain approved revenue requirements.

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

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

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 2009 RRQ, and analogous forecast trends for 2010, 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 2009 Electric Transmission RRQ divided by Total Authorized 2009 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.
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 3060-G-A Annual Gas True-Up filing on December 22, 2009 is provided as Table 1 in the Appendix. The following statements reflect PG&E’s expectations as of February 1, 2010, and may change throughout the course of the coming year due to various internal and external factors.

1) **Energy-related gas revenue requirements** represent approximately 44 percent to 55 percent of the total forecast gas revenue requirement in the upcoming 12 months. The revenue requirements are expected to trend upward, consistent with the market price of natural gas. For 2009, the energy revenue requirement represented about 46 percent of the total authorized gas revenue requirements.

2) **Distribution-related gas revenue requirements** constitute about 30 percent to 38 percent of the total forecast gas revenue requirements in the upcoming 12 months, and are expected to trend upward primarily due to additional maintenance and replacement work and system reliability-driven projects. For 2009, the distribution revenue requirement constituted about 36 percent of the total authorized gas revenue requirements.

3) **Public Purpose Programs or Mandated-related gas revenue requirements**, including California Alternate Rates for Energy (CARE) Discount and Self-Generation Incentive...
Program, and Energy Efficiency, represent approximately 6 percent to 7 percent of the total forecast gas revenue requirements in 2010. The revenue requirements are expected to trend slightly 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. For 2009, mandated programs contributed about 7 percent of the total authorized gas revenue requirements.

4) Forecasted backbone transmission-related gas revenue requirements comprise approximately 5 percent to 7 percent of the total forecast revenue requirement in the coming year, and are generally expected to trend slightly upward in 2010. Increases in 2011 and 2012 are driven by replacement of aging facilities and retrofits/replacements for environmental regulations. For 2009, backbone transmission revenue requirements constituted about 7 percent of the total authorized gas revenue requirements.

5) Local transmission-related gas revenue requirements generally contribute 4 percent to 5 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. For 2009, local transmission represented approximately 5 percent of the total authorized gas revenue requirements.

6) Forecasted gas storage-related revenue requirements comprise approximately 1 percent to 2 percent of the total forecast 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. For 2009, gas storage revenue requirements contributed about 2 percent of the total gas revenue requirements.

Electric

Electric revenue requirements are commonly grouped into the following seven major categories: (1) Energy/Generation, (2) Distribution, (3) Department of Water Resources (DWR), (4) Transmission, (5) Public Purpose Programs, (6) Nuclear Decommissioning, and (7) Energy Revenue Bonds (ERB). For reference, excerpts from the December 31, 2009 Annual Electric True-Up filing are provided as Table 2 in the Appendix. The following statements reflect PG&E’s expectations as of February 1, 2010, and may change throughout the course of the coming year.

1) Energy/Generation-related electric revenue requirements constitute approximately 48 percent to 52 percent of the total forecast revenue requirement in the coming 12 months. Of that, energy procurement costs represent roughly 67 percent of PG&E’s generation revenue requirement in 2010. In contrast, utility-owned generation represents 22 percent of the generation revenue requirement. CTC (Competition Transition Charge) represents 2 percent to 3 percent of the total forecast revenue requirement in 2010 and remains relatively flat through the year. During 2009, generation revenue requirements comprised 50 percent to 51 percent of PG&E’s total authorized revenue requirement, and 68 percent of that was attributable to energy.
procurement. The CTC revenue requirement was 5 percent during 2009, due largely to undercollections resulting from differences in actual sales versus forecast sales. The year-over-year change in total generation-related revenue requirements reflects new utility-owned generation (e.g., Colusa) becoming operational during the 2010, projected reductions in purchased power, as well as attrition adjustments for inflation.

2) **Distribution-related electric revenue requirements**, including the California Solar Initiative and the SmartMeter™ program, comprise approximately 25 percent to 29 percent of the total and trend upward in the coming year. For 2009, Distribution revenue requirements represented 27 percent to 29 percent of the total authorized revenue requirement. The increase year-over-year is primarily due to balancing account adjustments made to compensate for differences in sales used to set rates and the actual sales levels experienced, which were lower than forecast.

3) **The DWR-related electric revenue requirements** (including DWR bond) comprise 11 percent of PG&E’s forecast 2010 revenue requirement and are expected to decline on January 1, 2011, due to the expiration of DWR contracts and timing of indifference (transfer) payments between California’s investor-owned utilities. During 2009, DWR-associated revenue requirements ranged from 9 percent to 13 percent of the total authorized revenue requirement. It should be noted that for ratemaking purposes, DWR is treated as a Generation cost.

4) **Transmission-related electric revenue requirements** contribute 6 percent to 8 percent of the total forecast revenue requirement in the coming year. Through 2009, transmission revenue requirements accounted for approximately 5 percent to 6 percent of the authorized total. Investments undertaken by other California Utilities and PG&E both contribute to the transmission revenue requirement growth over 2009. 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.

5) **Public Purpose Program-related electric revenue requirements** comprise 5 percent of PG&E’s total forecast revenue requirement during 2010. In comparison, PPP represented less than 2 percent of the total during 2009. Growth in PPP revenue requirements from 2009 to 2010 is tied to inflation of base costs as well as the expansion of key policy programs such as CARE and Energy Efficiency 2010 -2012 Programs which incorporate key elements of the Commission’s Energy Efficiency Long Term Strategic Plan. In particular, the CARE shortfall projected for 2010 reflects the unexpected increase in actual customer discounts provided versus assumptions made when setting the CARE surcharge. And, the nearly $268 million energy efficiency refund provided in 2009 which does not carry through to 2010 also causes a major shift in revenue requirements year over year.
6) Nuclear Decommissioning-related electric revenue requirements represented less than 1 percent of PG&E’s total authorized revenue requirement during 2009. That level is forecast to remain constant in 2010.

7) Energy Recovery Bond-related electric revenue requirements represent roughly 2.5 percent of PG&E’s forecast revenue requirement in 2010 and will come to the end of their life during 2011. During 2009, ERB comprised between 1 percent and 2 percent of the total revenue requirement.

IV. Description of Rate Components (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 requirement 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 2010

<table>
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<tr>
<th>COMPONENT</th>
<th>Electric 2010</th>
<th>Gas 2010</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>RRQ SM</td>
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<td>Distribution</td>
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<td>Public Purpose Programs /</td>
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<td>Nuclear Decommissioning</td>
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<td>Energy Recovery Bond</td>
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<tr>
<td>Total Authorized</td>
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</tbody>
</table>

1. As of February 1, 2010. Gas applies new 2010 BCAP core procurement volumes. Values are approximated to the nearest million.
2. Reflects CARE shortfall of approximately $65M.
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 taken to the Commission. Historically, aggregate customer sales increased at a pace which largely offset annual increases to revenue requirements. However, in recent years (2008 and 2009) as a result of the economic recession, the softening of sales growth means each customer has shouldered a larger portion of revenue requirement increases. The following section discusses the forecast trends for Gas and Electric loads during 2010.

**Gas**

As described in the Electric subsection below, PG&E’s service area economy is expected to remain weak through 2010. This will impact both electricity demand and gas throughput. PG&E’s forecast projects 2010 gas sales for all three major gas customer classes - residential, commercial, and industrial - to show modest declines in usage this year. Looking further out, residential and commercial demand are expected to change very little from 2010 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 little customer growth and unemployment remaining high, residential demand is projected to be essentially flat over 2009 totals (-0.1 percent). 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 commercial vacancy rates already high, and with the potential for them to climb even higher in 2010, 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 2010 by 1.4 percent.

Conversely, demand for gas used in Electric Generation is expected to be higher by 10 percent in 2010 than 2009. Many factors drive the volatility in gas demanded for electric generation, including the economy, gas prices, hydroelectric generation capacity, new generation facilities coming online, nuclear generating capacity, and others.

**Electric**

For 2010, economic growth within PG&E’s service territory, as forecast by Economy.com, is projected to remain soft. The economy will continue to lose jobs, and household income will continue to decline. With this outlook as a backdrop, PG&E’s forecast projects electric sales for 2010 declining at 0.6 percent relative to 2009 observed sales. If the economic rebound gains traction in 2011, PG&E expects to see electric sales growth turn positive, increasing by 1.1 percent. Consistent with the notion that 2010 represents a “rocky bottom” to this recession, PG&E’s sales projections for 2010 are mixed.

Electric customer (billings) growth has also been dramatically impacted by the recession. For 2010, customer growth will exhibit the same sluggishness as the economy at large. PG&E’s forecast shows an addition of about 25,000 customers in 2010, which pales
next to the 70,000-80,000 PG&E regularly observed annually during the middle of the last decade. By 2011, a recovering economy should yield stronger customer growth.

Among the four major electric customer classes (residential, agricultural, industrial, commercial) two are projected to show declining sales, one is projected to be flat, and one is projected to show an increase compared to 2009. With household incomes still declining and job security tenuous, residential usage is projected to decline by 1.3 percent in 2010. Agricultural sales (primarily groundwater pumping) have grown substantially during the last 3 years in response to below normal rainfall levels. With assumed normal rainfall built into the forecast, however, agricultural demand is projected to decline in 2010 (-5.5 percent), but remain at a high level of usage by historical standards. Industrial sales, after declining a dramatic 9 percent in 2009, will essentially remain flat in 2010 (-0.2 percent). The commercial sector is the one sector projected to show any growth at all, and even this will be meager at just 0.6 percent. Increased consumer spending and higher service sector output are the main drivers here, but both are on shaky footing and any erosion of this sector’s growth could turn commercial sales negative as well.

V. Management of Key Rate Components

PG&E is committed to controlling costs 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, uncollectable accounts, weather, interest rates, 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. 2010 CPUC Filing Outlook

Attached for your reference is Appendix A, which reflects key filings data provided previously to the Energy Division (December 2009). The table has been modified per the currently anticipated filing schedule for 2010, and now also reflects 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 2010 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

In this section, PG&E provides its recommendations for measures that can be undertaken in the next 12 months to limit utility cost and rate increases, in addition to the recommendations in the Introduction. These recommendations address factors related to the economy, state and federal energy policy, and regulatory policies and orders, which PG&E believes significantly impact utility costs and resulting customer rates in the near to medium-term.
PG&E is committed to meeting California’s energy and environmental goals for reducing greenhouse gases (GHG); enhancing its infrastructure and improving its operations. However, PG&E believes environmental goals should not be met at any cost – care should be taken to address rate impacts of choices as GHG emissions goals are defined. In the coming year, PG&E recommends that several key State policies and procedures could be modified or clarified to support more effective, efficient and beneficial deployment of revenues collected from PG&E customers. PG&E believes that adoption of these recommendations at the State level will help to alleviate significant upwards cost pressures and ultimately reduce customer rates for gas and electric service.

1. Gas procurement policies

PG&E procures natural gas for direct consumption by a large portion of residential and small business customers (commonly referred to as core procurement gas customers) and to supply PG&E-owned as well as third-party owned electric generation facilities which supply electricity to PG&E’s bundled electric customers. To minimize costs of natural gas procurement and to meet reliability targets, PG&E purchases from various supply sources and also negotiates long-term contracts on a variety of transportation and storage systems. PG&E also employs financial hedging instruments to maintain cost stability and to limit the impact of spikes in natural gas prices on customer bills.

PG&E supports the implementation of initiatives that provide PG&E and its customers with expanded access to diverse supply regions for natural gas, such as the long-term transportation contracts on the proposed Ruby Pipeline. These transportation contracts, which were approved by the CPUC in 2008 and executed by the company in 2009, will provide PG&E customers with direct access to natural gas from the Rockies region beginning in 2011. PG&E also supports continued State energy policies and initiatives to expand and evaluate new options for natural gas supply, transportation and storage in order to effectively manage the costs of procuring natural gas for PG&E’s customers.

2. Retail Electricity Dynamic Pricing

The CPUC has initiated an ambitious policy toward implementation of dynamic retail electricity pricing in PG&E’s service territory. Dynamic pricing is defined as pricing that reflects real time system costs and therefore requires the functionality of the newly installed SmartMeter™ infrastructure (which provides hourly usage data). Dynamic pricing is expected to have a number of benefits including: lowering costs by more closely aligning retail rates and wholesale system conditions, thereby promoting economically efficient decision making; improving system reliability by providing an incentive to lower usage when the supply and demand balance is strained or in times of system emergencies; reducing greenhouse gas emissions by reducing the need to operate inefficient resources; and finally, providing a key building block of the smarter energy grid.

In 2010, PG&E will begin to default its largest customers to a form of dynamic pricing called Peak Day Pricing, which provides specific rates for peak energy days, and lower rates during other days. Though customers will be able to opt out, with the availability of first year bill protection, participation is expected to be much higher than it would be otherwise.
2011, this initiative extends to all non-residential commercial mass market customers (about 500,000 customers), who will lose the option to take service on rates that are not time-differentiated.

In addition, changes in law enacted in SB 695 would afford the opportunity to default all residential customers (about 4.5 million customers) to “Peak Day Pricing,” (a form of dynamic pricing) as early as 2013. PG&E recommends that any such effort be undertaken carefully and only after customers, utilities, and regulators can evaluate to the rate impacts of defaulting residential customers onto these new rates. PG&E, customers and the Commission can learn from the efforts to default commercial mass market customers in 2011. Further, PG&E recommends that the default options should be studied carefully to ensure the best approaches and options are determined before any such program is implemented.

Finally, closely following the implementation of Peak Day Pricing, all customers will be offered the option of Real Time Pricing, which charges customers for energy indexed to the California Independent System Operator’s day-ahead market prices. Over the next 12 months, the CPUC, other energy policymakers, customers and PG&E need to proactively work together so that the full benefits of dynamic pricing can be realized without excessive cost or unanticipated impacts on customers.

3. Other Electric Rate Design 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 first and most immediate area of concern that should be evaluated over the next 12 months is residential electric rate design, where a 5 “tier” rate structure is employed. This structure, first put in place 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 are expected to be close to 50 cents per kWh. PG&E has asked for expedited treatment of several initiatives designed to lower upper tier rates for the summer of 2010, and 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 the spread in tiered rates be monitored over time and legislative change be sought to more fully address this issue.

The second area of concern that should be evaluated is the non-cost-based subsidies by retail customers to owners or operators of distributed electricity generation systems. The California Legislature has required policies such as retail net metering; above-market payments for generation exports to the grid; incentive programs; and exemptions from standby related charges. As a result, rates for non-participating customers have increased, resulting in rates which do not reflect true cost-of-service. Subsidies that do not reflect true economics do not promote efficient deployment of resources. Increased penetration of distributed generation beyond today’s relatively modest levels will call for a deliberate consideration of rate design changes to moderate rate increases to non-participating customers. Ultimately, these cost shifts may not be sustainable, reasonable or fair. Therefore, PG&E recommends policymakers explore and adopt alternative ways to provide transparency and fairly allocate the transmission, distribution and above-market energy costs associated with distributed generation across all system customers.


Assembly Bill (AB) 32 requires the gradual reduction of greenhouse gas (GHG) emissions in California to 1990 levels by 2020 on a schedule beginning in 2012. In December 2008, the California Air Resources Board (CARB) adopted a scoping plan that contains recommendations for achieving the 2020 target which include developing a multi-sector cap-and-trade program, achieving a 33 percent renewable portfolio standard (RPS) by 2020, increasing energy efficiency, and expanding the use of combined heat and power facilities. In addition, the California Legislature, Governor and CPUC are all considering separate legislation, policies and programs that would increase renewable electricity to 33% as part of the renewable portfolio standard as well as increase the availability of “combined heat and power” generating facilities.

As state policymakers move forward with implementation of these environmental and energy goals, PG&E continues to stress the importance of managing costs to California
consumers and businesses by pursuing cost-effective reduction strategies and cost containment provisions. The ultimate success of such efforts will depend largely on key design issues for the cap-and-trade program, -- such as the number of emission allowances allocated to the Utility for the benefit of our customers, the development of robust cost containment tools for the price of emission allowances, use of emission offsets, and the ability to link to other cap-and-trade programs -- in addition to renewable and energy efficiency issues as described in this section.

5. Once-Through Cooling Policy for Existing Powerplants

Since 2006, the State Water Resources Control Board (SWRCB) has issued four preliminary proposals outlining the reduction of once-through cooling (OTC) technology in generation facilities. There are currently 18 California power plants that use OTC, including PG&E’s Diablo Canyon facility (Humboldt goes off-line in 2010 when the new facility begins operations). The SWRCB is now considering the adoption of a policy to phase out the use of once-through cooling at electric generation facilities. In particular, the SWRCB has proposed that these plants can either be retrofit or re-powered with another cooling technology or shut down completely. Compliance deadlines under the proposal range from 2011 to 2024 with compliance deadlines staggered in a manner to help assure system reliability.

The California utilities have procurement contracts with a number of entities that employ once-through cooling, and also operate two nuclear power plants which rely on once-through cooling. A change in the state's policy to disallow the use of once-through cooling could result in billions of dollars in power plant retrofitting costs to utility customers. PG&E has submitted an engineering study to the SWRCB that indicates retrofitting costs for Diablo Canyon alone could amount to $4.5 billion. PG&E continues to advocate for an orderly transition away from OTC through planned repowering, replacement or retirement of the state's fossil plants, and for cost-benefit analysis at the nuclear facilities to determine whether retrofit is appropriate given the substantial costs and collateral environmental impact of moving to closed-cycle cooling in terms of GHG emissions and other air quality impacts.


Studies prepared by the CPUC, California’s Renewable Energy Transmission Initiative (RETI) and the California Independent System Operator (CAISO) have all identified the need for substantial investment in electric transmission to achieve the state’s RPS and GHG emission reduction targets. Planning, siting and constructing electric transmission infrastructure requires navigating a complex and costly maze of regulations and requirements. In order to limit the costs of delay and “red tape” being imposed on utility customers for these essential project, the Energy Commission, CPUC, California Legislature and involved state agencies should immediately speed these processes and reduce the overall cost of developing the infrastructure necessary to achieve California’s energy policy goals.

While not as high profile as the electric transmission expansion studies, upgrades will be needed to the electric distribution system to support higher penetration of distributed generation and electric vehicles. The underlying generation projects and the distribution
system upgrades will also require permitting by various federal, state and local agencies. Existing planning and siting approval processes require between seven and ten years to complete an electric transmission project. Achieving the targeted RPS and GHG policy goals will be impossible if the current processes are not improved. California policymakers and various permitting agencies should also immediately speed the processes of developing these projects.
Table 1. Excerpt from Advice 3060-G-A Annual Gas True-Up filing for Rates Effective January 1, 2010.

<table>
<thead>
<tr>
<th>Description</th>
<th>Core</th>
<th>Noncore</th>
<th>Unbundled</th>
<th>Procurement</th>
<th>Total</th>
</tr>
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<tbody>
<tr>
<td>Authorized GRC Distribution Base Revenue (incl. F&amp;U) (1):</td>
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<td></td>
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<td>1,139,444(R)</td>
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<td>Authorized GRC Distribution Revenue in Rates (incl. F&amp;U) (1):</td>
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<td>(2,425(R))</td>
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<td>G-10 Procurement-Related Employee Discount</td>
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<td>G-10 Procurement Discount Allocation</td>
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<td>(2,425(R))</td>
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<td>Less: Front Counter Charges</td>
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<td>(2,425(R))</td>
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<td>Core Brokerage Fee Credit</td>
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<td>(2,425(R))</td>
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<td>GRC Distribution Base Revenue with Adj. and Credits</td>
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<td>(2,425(R))</td>
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<td>TRANSPORTATION FORECAST PERIOD COSTS &amp; BALANCING ACCOUNT BALANCES (2):</td>
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<td>CPUC Fee</td>
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<td>Climate Meas.</td>
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<td>Winter Gas Savings Plan (WGSP) – Transportation</td>
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<td>franchise Fees and Uncollectible Expense (F&amp;U) (on items above)</td>
<td>2,191</td>
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<td>2,191(R)</td>
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<td>CARE Discount included in PPP Funding Requirement</td>
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<td>(109,433(R))</td>
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<tr>
<td>CARE Discount not included in PPP Surcharge Rates</td>
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<td>Transportation Forecast Period Costs &amp; Balancing</td>
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<td>GAS ACCORD REVENUE REQUIREMENT (incl. F&amp;U) (3):</td>
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<td>Local Transmission</td>
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<td>7,499</td>
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<td>251</td>
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<td>2,008(R)</td>
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<td>Pipeline Transmission 60,455,455/401</td>
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<td>Gas Accord Revenue Requirement</td>
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<td>(54,130)</td>
<td>(183,343)</td>
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<td>413,701(R)</td>
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(1) The authorized GRC amount includes the distribution base revenue and F&U approved effective January 1, 2007, for General Rate Case D.07-07-044, and $22M for Affliten as approved in AL 0977-G, 2004-G, and AL 3650-G. The GRC distribution base revenue is allocated to core and noncore customers in Cost Allocation Proceedings, as shown in Part C.3.a. (T)

(2) The total 2009 SGIP revenue requirement (RRQ) was approved in D.09-12-047. Per D.09-05-011, SGIP costs were removed from wholesale gas rates on July 1, 2009. The Climate Protection Tariff RRQ for 2009 was approved in D.06-06-032. 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. The SmartMeter Project RRQ was approved in D.06-07-027 and AL 0752-G0-A. The Energy Division approved PG&E's AL 303-G for the WGSIP costs, which are recovered in commercial customers' rates beginning January 1, 2010. (T)

(3) The Gas Accord IV RRQ, effective January 1, 2009, was adopted in D.06-09-045. Storage revenues allocated to load balancing are included in unbundled transmission rates. (T)
Table 1(continued). Excerpt from Advice 3060-G-A Annual Gas True-Up filing for Rates Effective January 1, 2010.

### GAS PRELIMINARY STATEMENT PART C
#### GAS ACCOUNTING TERMS & DEFINITIONS

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

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

<table>
<thead>
<tr>
<th>Description</th>
<th>Core</th>
<th>Noncore</th>
<th>Unbundled</th>
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<th>Total</th>
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<td><strong>ILLUSTRATIVE CORE PROCUREMENT REVENUE</strong></td>
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<td>Illustrative Gas Supply Portfolio</td>
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<td>Interstate and Canadian Capacity</td>
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<td>Gas Barring - Procurement - Residential</td>
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<td>FSU (all items above and procurement account balances)</td>
<td>25,270 (R)</td>
<td>25,270 (R)</td>
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<tr>
<td><strong>(Retail)</strong></td>
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<td>Backzone Capacity incl. FSU</td>
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<td>61,687 (I)</td>
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<td>Backzone Volumetric (incl. FSU)</td>
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<td>Storage (incl. FSU)</td>
<td>4,093 (R)</td>
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<td>Carrying Cost Noncyclic Storage Gas (incl. FSU)</td>
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<td>Core Brokerage Fee (incl. FSU)</td>
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<td>Procurement Account Balances</td>
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<td>11,692 (I)</td>
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<td>Illus. Core Procurement Revenue Requirement</td>
<td>(121,245) (R)</td>
<td>7,262,238 (R)</td>
<td>2,119,683 (R)</td>
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<td><strong>TOTAL GAS REVENUE REQUIREMENT</strong></td>
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<tr>
<td>(without PPP in Rates)</td>
<td>1,983,494 (R)</td>
<td>116,719 (R)</td>
<td>189,945 (R)</td>
<td>2,245,298 (R)</td>
<td>3,726,643 (R)</td>
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<td><strong>PUBLIC PURPOSE PROGRAM (PPP) FUNDING REQUIREMENT</strong> (in parentheses)</td>
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<td>Energy Efficiency (EE)</td>
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<td>64,875 (R)</td>
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<td>Low Income Energy Efficiency (LIEE)</td>
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<td>Research, Demonstration and Development (RD&amp;D)</td>
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<td>10,581 (R)</td>
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<td>CARE Administrative Expense</td>
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<td>733 (R)</td>
<td>1,843 (R)</td>
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<td>BOE and CPUC Administrative Cost</td>
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<td>108 (R)</td>
<td>296 (R)</td>
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<td>PPP Balancing Accounts</td>
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<td>(2,490) (R)</td>
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<td>CARE Discount Recovered from non-CARE customers</td>
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<td>43,348 (R)</td>
<td>109,433 (R)</td>
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<td><strong>TOTAL GAS REVENUE AND PPP FUNDING REQUIREMENT IN RATES</strong></td>
<td>1,924,058 (R)</td>
<td>50,563 (R)</td>
<td>242,468 (R)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note: (I) indicates interest, (R) indicates revenue requirement, and (D) indicates total authorized gas revenue and PPP funding requirement.

- The credits shown in the Core column represent the core portion of the Gas Account ROR that is included in the illustrative Core Procurement ROR, and are shown here to avoid double counting these credits in the table. The Gas Supply Portfolio to be refund includes foregone carrying cost on cyclic gas in storage, and an illustrative commodity and shrinkage cost based on the Weighted Average Cost of Gas (WACOG) of $0.093 per therm. Actual gas commodity costs change monthly. WACOG costs, approved in AL 3039-9, will be recovered in residential rates effective April 1, 2010.
- The PPP funding requirement is included in gas PPP surcharge rates pursuant to D.04-09-010 and 2010 PPP surcharge AL 3057-G and includes LIEE program funding adopted in D.08-11-031, EE program funding adopted in D.08-11-031, and CARE annual administrative expense adopted in D.09-11-031, and excludes FSU per D.04-09-010.

(Continued)

Advice Letter No: 3060-G-A
Decision No.: 05-08-029
Issued by: Brian K. Cherry, Effective: January 1, 2010
Date Filed: December 22, 2009
Vice President: Regulatory Relations
Resolution No.: 3C15

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3/19/2010
Table 2. Excerpted from Advice 3518-E-A Annual Electric True-Up filing for Rates Effective January 1, 2010.

<table>
<thead>
<tr>
<th>Line #</th>
<th>Test Year 2010 RRQ A</th>
<th>12/31/09 Forecast Under/(Over) collected B</th>
<th>Total Projected 2010 Revenues C = A + B</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>CRUC Jurisdictional</td>
<td>3,069,541,472</td>
<td>3,199,448,334</td>
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<tr>
<td>2</td>
<td>Distribution</td>
<td>30,136,419</td>
<td>30,136,419</td>
</tr>
<tr>
<td>4</td>
<td>Self Generation Incentive Program</td>
<td>10,102,550</td>
<td>10,102,550</td>
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<tr>
<td>4</td>
<td>CRUC Fee</td>
<td>20,644,796</td>
<td>20,644,796</td>
</tr>
<tr>
<td>7</td>
<td>Advanced Metering/GBA</td>
<td>107,497,541</td>
<td>140,570,872</td>
</tr>
<tr>
<td>8</td>
<td>Demand Response/CREBA/DRRBA</td>
<td>35,914,555</td>
<td>36,630,022</td>
</tr>
<tr>
<td>9</td>
<td>All Conditioning Cyng/GACEBA/DRRBA</td>
<td>48,613,035</td>
<td>48,613,035</td>
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<tr>
<td>10</td>
<td>ClimateSmart</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>11</td>
<td>California Solar Initiative</td>
<td>106,576,775</td>
<td>106,576,775</td>
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<tr>
<td>12</td>
<td>DSM</td>
<td>0</td>
<td>8,966,569</td>
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<tr>
<td>13</td>
<td>HTFA</td>
<td>0</td>
<td>(254,962)</td>
</tr>
<tr>
<td>14</td>
<td>CEVA</td>
<td>0</td>
<td>5,522,000</td>
</tr>
<tr>
<td>15</td>
<td>PBCB</td>
<td>0</td>
<td>0</td>
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<tr>
<td>16</td>
<td>SCBA</td>
<td>29,382,897</td>
<td>31,414,005</td>
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<td>17</td>
<td>NTPA</td>
<td>0</td>
<td>0</td>
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<td>18</td>
<td>CPERMA</td>
<td>0</td>
<td>346,248</td>
</tr>
<tr>
<td>19</td>
<td>DPNA</td>
<td>0</td>
<td>0</td>
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<tr>
<td>20</td>
<td>Generation</td>
<td>1,340,530,602</td>
<td>1,654,344,744</td>
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<tr>
<td>21</td>
<td>Utility Retained Generation Base/UBA</td>
<td>73,258,458</td>
<td>73,258,458</td>
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<tr>
<td>22</td>
<td>Electric Procurement/EMA</td>
<td>3,731,717,921</td>
<td>3,912,928,819</td>
</tr>
<tr>
<td>23</td>
<td>SWR—Power Charge/PBCB</td>
<td>930,136,038</td>
<td>1,004,164,456</td>
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<tr>
<td>24</td>
<td>SWR Franchise Fees</td>
<td>10,822,923</td>
<td>10,822,923</td>
</tr>
<tr>
<td>25</td>
<td>SCREBA</td>
<td>0</td>
<td>(976,899)</td>
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<tr>
<td>26</td>
<td>UERBBA</td>
<td>0</td>
<td>4,499,049</td>
</tr>
<tr>
<td>27</td>
<td>PA</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>28</td>
<td>ITMWA</td>
<td>0</td>
<td>250,941</td>
</tr>
<tr>
<td>29</td>
<td>ARTUWA</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>30</td>
<td>ROSSCA</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>31</td>
<td>CARE</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>32</td>
<td>Ongoing CTC/TCBBA</td>
<td>353,525,017</td>
<td>400,761,695</td>
</tr>
<tr>
<td>33</td>
<td>Rate Reduction Bond Memorandum Account*</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>34</td>
<td>Energy Cost Recovery Bonds</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>35</td>
<td>1) Dedicated Rate Component Series 1</td>
<td>303,689,661</td>
<td>303,689,661</td>
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<tr>
<td>36</td>
<td>2) Dedicated Rate Component Series 2</td>
<td>152,178,191</td>
<td>152,178,191</td>
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<tr>
<td>37</td>
<td>3) ERB Balancing Account (ERBBA)</td>
<td>(33,696,225)</td>
<td>(141,101,594)</td>
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<tr>
<td>38</td>
<td>Nuclear Dist/Repositing</td>
<td>25,677,000</td>
<td>25,677,000</td>
</tr>
<tr>
<td>39</td>
<td>Public Purpose Programs</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>40</td>
<td>1) Energy Efficiency</td>
<td>120,670,462</td>
<td>120,670,462</td>
</tr>
<tr>
<td>41</td>
<td>2) RDO</td>
<td>35,217,516</td>
<td>35,217,516</td>
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<tr>
<td>42</td>
<td>3) Renewables</td>
<td>36,826,418</td>
<td>36,826,418</td>
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<tr>
<td>43</td>
<td>4) UUE</td>
<td>90,043,765</td>
<td>90,043,765</td>
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<tr>
<td>44</td>
<td>EEPROM</td>
<td>0</td>
<td>(5,077,655)</td>
</tr>
<tr>
<td>45</td>
<td>CARFA</td>
<td>7,418,429</td>
<td>56,070,691</td>
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<td>46</td>
<td>Procurement EE/PEERAM</td>
<td>250,724,532</td>
<td>254,801,165</td>
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<td>47</td>
<td>SWR Bonds</td>
<td>411,132,926</td>
<td>411,132,926</td>
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<tr>
<td>48</td>
<td>DGM CRUC Jurisdictional</td>
<td>10,224,122,183</td>
<td>10,986,236,514</td>
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<tr>
<td>49</td>
<td>CRUC Revenues at Present Rates</td>
<td>11,456,593,302</td>
<td>11,456,593,302</td>
</tr>
<tr>
<td>50</td>
<td>Change in CRUC Jurisdictional</td>
<td>203,642,922</td>
<td>203,642,922</td>
</tr>
<tr>
<td>51</td>
<td>Total FERC Jurisdictional</td>
<td>715,545,627</td>
<td>715,545,627</td>
</tr>
<tr>
<td>52</td>
<td>FERC Revenues at Present Rates</td>
<td>731,131,142</td>
<td>731,131,142</td>
</tr>
<tr>
<td>53</td>
<td>Change in FERC Jurisdictional</td>
<td>11,567,115</td>
<td>11,567,115</td>
</tr>
<tr>
<td>54</td>
<td>Grand Total Projected Revenues</td>
<td>12,595,783,141</td>
<td>12,595,783,141</td>
</tr>
<tr>
<td>55</td>
<td>Total Revenues at Present Rates</td>
<td>12,207,807,224</td>
<td>12,207,807,224</td>
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<tr>
<td>56</td>
<td>Total Change</td>
<td>391,575,467</td>
<td>391,575,467</td>
</tr>
</tbody>
</table>

Notes:
1. The 12/31/09 forecast Distribution/EMA balance includes the 12/31/09 forecast Rate Reduction Bond Memorandum Account balance as authorized in AL 9300-E.
2. The 12/31/09 forecast FERC balance of $4,499,049 includes a discount of $9,101,594, which gets allocated to generation rates, and administrative costs of $993,821, which gets allocated to distribution rates.
### Appendix A. Key Filings Table

#### Requests Impacting Customer Rates
Filed During the Year of 2010

**SB 695 Reporting Requirement**

<table>
<thead>
<tr>
<th>Filing Description</th>
<th>Anticipated Filing Date</th>
<th>Expected Implementation</th>
<th>Impacted Rate</th>
<th>Impacted Rate Component</th>
</tr>
</thead>
<tbody>
<tr>
<td>Q1 2010</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>March 1 Rate Change (To Implement TO12 Rates)</td>
<td>Jan</td>
<td>3/1/10</td>
<td>Electric</td>
<td>Transmission</td>
</tr>
<tr>
<td>Rate Design Window 2010 (Peak Time Rebate)</td>
<td>Jan</td>
<td>5/1/11</td>
<td>Electric</td>
<td>Energy/Generation</td>
</tr>
<tr>
<td>Diablo Seismic Survey (3D)</td>
<td>Jan</td>
<td>1/1/12</td>
<td>Electric</td>
<td>Energy/Generation</td>
</tr>
<tr>
<td>ERRA 2009 Compliance Filing - Includes MRTU Cost Recovery</td>
<td>Feb</td>
<td>--</td>
<td>Electric</td>
<td>Energy/Generation, Competition Transition Charge (CTC)</td>
</tr>
<tr>
<td>Rate Design Window 2010' Peak Time Rebate</td>
<td>Feb</td>
<td>5/1/11</td>
<td>Electric</td>
<td>Distribution</td>
</tr>
<tr>
<td>Rate Relief Summer 2010</td>
<td>Feb</td>
<td>6/1/10</td>
<td>Electric</td>
<td>All rate components</td>
</tr>
<tr>
<td>Accelerate Generator Settlement Refunds (1)</td>
<td>Feb</td>
<td>6/1/10</td>
<td>Electric</td>
<td>Energy Revenue Bonds</td>
</tr>
<tr>
<td>Accelerate TO11 Refunds (1)</td>
<td>Mar</td>
<td>6/1/10</td>
<td>Electric</td>
<td>Transmission</td>
</tr>
<tr>
<td>General Rate Case (GRC) 2011 Ph II - Dynamic Pricing</td>
<td>Mar</td>
<td>5/11</td>
<td>Electric</td>
<td>PPP, Distribution, Energy/Generation, Competition Transition Charge (CTC)</td>
</tr>
<tr>
<td>General Rate Case (GRC) 2011 Ph II - Gas</td>
<td>Mar</td>
<td>5/11</td>
<td>Gas</td>
<td>Energy, Distribution, Public Purpose Programs/Mandated Programs</td>
</tr>
<tr>
<td>Q2 2010</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Core Procurement Incentive Mechanism Sharehold Award</td>
<td>TBD</td>
<td>10/1/10</td>
<td>Gas</td>
<td>Energy (gas procurement)</td>
</tr>
<tr>
<td>Q3 2010</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>FERC - TO13</td>
<td>Jul</td>
<td>3/1/11</td>
<td>Electric</td>
<td>Transmission</td>
</tr>
<tr>
<td>Winter Gas Savings Program (2010-2011)</td>
<td>Aug</td>
<td>9/13/10</td>
<td>Gas</td>
<td>Energy (gas procurement), Distribution</td>
</tr>
<tr>
<td>Annual Electric True-Up (AET) 2011</td>
<td>Sep</td>
<td>1/11</td>
<td>Electric</td>
<td>Transmission, PPP, Distribution, Energy/Generation, DWR, CTC, ERB</td>
</tr>
<tr>
<td>DWR 2011 Revenue Requirement Forecast Filing</td>
<td>TBD</td>
<td>TBD</td>
<td>Electric</td>
<td>DWR</td>
</tr>
<tr>
<td>Real Time Pricing - Residential Default</td>
<td>TBD</td>
<td>TBD</td>
<td>Electric</td>
<td>Energy/Generation</td>
</tr>
<tr>
<td>Q4 2010</td>
<td>Oct</td>
<td>1/1/11</td>
<td>Electric</td>
<td>Transmission</td>
</tr>
<tr>
<td>Public Purpose Program Surcharge Gas Rate Filing 2010 - Advice Letter</td>
<td>Oct</td>
<td>1/1/11</td>
<td>Gas</td>
<td>Public Purpose Programs/Mandated Programs</td>
</tr>
<tr>
<td>SB 695 Res Rate Change (T1 &amp; T2) Advice Letter</td>
<td>Nov</td>
<td>1/11</td>
<td>Electric</td>
<td>Distribution, Energy/Generation</td>
</tr>
<tr>
<td>Annual Gas True-Up (AGT) 2011</td>
<td>Nov</td>
<td>1/11</td>
<td>Gas</td>
<td>Distribution, Local Transmission, Backbone Transmission, Gas Storage</td>
</tr>
<tr>
<td>FERC TRBA/ECRARSSBA Filing</td>
<td>Dec</td>
<td>3/1/11</td>
<td>Electric</td>
<td>Transmission</td>
</tr>
</tbody>
</table>
Southern California Edison

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 description of SCE’s rate components included on customers’ bills, the current revenue requirement included in rates plus anticipated changes during the rest of 2010. SCE has provided information that includes known filings that will be made throughout the next twelve months that will affect future rates. And finally, SCE has included a summary of policies for limiting rate increases while meeting the State’s energy and environmental goals for reducing greenhouse gases and recommendations for the Commission and legislature to help minimize rate increases in the future.

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.

3. 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).

- **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.

- **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.

- **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.

- **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.

- **Public Purpose Programs Charge (PPPC)** – Through the PPC 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.

g. **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.

h. **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.

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.

4. **Summary of Revenue Requirements by Rate Component**

   a. Revenue Requirements and System Average Rate for Bundled Service customers as of March 1, 2010:
### Rate Component

<table>
<thead>
<tr>
<th>Rate Component</th>
<th>($millions)</th>
<th>%</th>
<th>SAR c/kWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Generation</td>
<td>4,691</td>
<td>42.6%</td>
<td>6.3</td>
</tr>
<tr>
<td>2. New System Generation</td>
<td>109</td>
<td>1.0%</td>
<td>0.1</td>
</tr>
<tr>
<td>3. Distribution</td>
<td>3,719</td>
<td>33.8%</td>
<td>4.7</td>
</tr>
<tr>
<td>4. Public Purpose Programs</td>
<td>578</td>
<td>5.3%</td>
<td>0.7</td>
</tr>
<tr>
<td>5. Nuclear Decommissioning</td>
<td>53</td>
<td>0.5%</td>
<td>0.1</td>
</tr>
<tr>
<td>6. FERC Transmission</td>
<td>614</td>
<td>5.6%</td>
<td>0.8</td>
</tr>
<tr>
<td>7. DWR Power and Bond</td>
<td>1,242</td>
<td>11.3%</td>
<td>1.6</td>
</tr>
<tr>
<td>8. TOTAL System</td>
<td>11,006</td>
<td>100.0%</td>
<td>14.3</td>
</tr>
</tbody>
</table>

b. Revenue Requirement/Rate Changes in the coming 12 months

As shown in Appendix A, the only revenue requirement and rate change planned at this time to be implemented during the rest of 2010, is a reduction in the FERC jurisdictional Transmission Access Charge Balancing Account Adjustment scheduled for June 1, 2010. This rate change will be implemented concurrently with the change from winter to summer rates.

c. 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 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).

5. Sales Forecasts

The Commission adopted SCE’s 2010 total sales forecast of 83,435 GWhs in Decision (D.)10-02-019 (SCE’s 2010 ERRA Forecast Proceeding). This represents a
decrease from recorded 2009 sales of approximately 3%. SCE estimates sales to fall in 2010 as the result of: 1) assuming normal weather patterns, 2) continuing negative impacts of the economic recession, 3) slower customer growth, and 4) increased levels of energy efficiency. The effect of the economy’s decline is reflected in both the 2010 forecast of per capita personal income and in the number of customer additions. Employment growth is not expected to turn positive in SCE’s service area until mid-2010. Although decreases in the sales/load forecast results in lower procurement costs; overall, a decrease in sales puts upward pressure on rate levels because all of the “fixed” costs of the system must be recovered over fewer kWh sales.

6. **2010 Outlook**

See Appendix A for a list and timing of known cases affecting rates during 2010.

7. **Utility’s Policies For Limiting Rate Increase While Meeting State’s Energy and Environment Goals for Reducing Greenhouse Gases**

To achieve these goals, SCE promotes all cost-effective energy efficiency and demand response measures. SCE also delivers more renewable energy to its customers than any other utility in the nation and seeks to achieve the State’s goals at the lowest cost. In addition, SCE is exploring the use of new technologies such as energy storage to more cost-effectively integrate the intermittent renewable energy sources into its system. Lastly, SCE is undertaking strategies to improve the load factor on its system by supporting off-peak use of energy by plug-in electric vehicles and by empowering customers to manage their bills by shifting their usage to off-peak hours through the installation of Edison SmartConnect meters and promotion of efficient and dynamic pricing structures. Improving the system load factor will result in more efficient utilization of the existing generation capacity and lower rates.

8. **Recommendations for CPUC and Legislature to Help Minimize Rate Increases in the future**

California leads the nation in promoting reduction in GHG emissions, use of renewable energy, adoption of advanced technologies and social programs to help the needy families. The costs associated with implementing these policies place upward pressure on utilities’ rates. In addition, due to mild weather and implementation of energy efficiency measures, the electricity usage per residential customer in California is well below the national average. These factors also lead to higher rates.

SCE supports these policies, but believes that the utilities should be provided more flexibility in implementing them to achieve lower costs for customers. For example, policies which create significant artificial limitations on accessing the markets for renewable energy will result in less renewable development, slower implementation, and higher costs to customers. Alternatively, broad access to markets with high levels of competition will provide greater opportunities for renewable projects, earlier achievement of the State’s goals, and lower prices for customers. Flexible policies will benefit customers; rigid policies hamper achievement of the State’s goals and increase customer costs.
In addition, SCE’s rate levels could increase if the Commission requires SCE to procure resources to maintain system reliability on behalf of all benefiting customers but does not implement an appropriate cost allocation mechanism to allocate the cost of such resources to all such customers, or disproportionately imposes costs on SCE’s bundled service customers.

Lastly, customers are generally focused on their bills rather than rate levels. The legislature and the CPUC should promote measures that empower customers to manage their energy usage and minimize the distortion in rates that result in significant hidden subsidies in rate structures from some customers to others. SCE believes that the cost of subsidies to needy customers or subsidies to customers taking advantage of programs such as Net Energy Metering (NEM) should be transparent as a separate rate component and the rate structures should not deviate from their cost basis to provide additional hidden subsidies to a particular group of customers.
Appendix A: list and timing of known cases affecting rates during 2010.

<table>
<thead>
<tr>
<th>Key Regulatory Filings with Rate Impacts - Southern California Edison Co.</th>
<th>Estimated Filing Timing</th>
<th>Rates Effective</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Q1 2010</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jan 1 Rate Change (To Implement DWR and FERC Balancing Accounts)</td>
<td>Dec '09</td>
<td>1/1/10</td>
</tr>
<tr>
<td>2009 Rate Design Window Filing (capping DR credits)</td>
<td>Dec '09</td>
<td>6/1/10</td>
</tr>
<tr>
<td>March 1 Rate Change (Consolidated Rate Change, including 2010 FERC GRC)</td>
<td>Feb</td>
<td>3/1/10</td>
</tr>
<tr>
<td><strong>Q2 2010</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ERRA 2009 Compliance Filing</td>
<td>Apr</td>
<td>--</td>
</tr>
<tr>
<td>- Includes MRTU Cost Recovery and review of Mohave-related costs</td>
<td></td>
<td></td>
</tr>
<tr>
<td>FERC Transmission Access Charge Balancing Account Rate Change</td>
<td>Feb</td>
<td>6/1/10</td>
</tr>
<tr>
<td><strong>Q3 2010</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energy Resource Recovery Account (ERRA) 2011 Forecast</td>
<td>Aug</td>
<td>1/1/11</td>
</tr>
<tr>
<td>FERC - 2011 GRC</td>
<td>Aug</td>
<td>10/1/2010 or 03/1/2011</td>
</tr>
<tr>
<td>DWR 2011 Revenue Requirement Forecast Filing</td>
<td>TBD</td>
<td>TBD</td>
</tr>
<tr>
<td>Dynamic Pricing Filing (per D.09-08-028)</td>
<td>Sep</td>
<td>1/1/12</td>
</tr>
<tr>
<td><strong>Q4 2010</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>FERC TRBA/RSBA Filing</td>
<td>Oct</td>
<td>1/1/11</td>
</tr>
<tr>
<td>SB 695 Res Rate Change (T1 &amp; T2) Advice Letter</td>
<td>Nov</td>
<td>1/1/11</td>
</tr>
<tr>
<td>Energy Resource Recovery Account (ERRA) 2011 Forecast - Update</td>
<td>Nov</td>
<td>1/1/11</td>
</tr>
<tr>
<td>Jan 1 Rate Change (To Implement DWR and FERC Balancing Accounts)</td>
<td>Dec</td>
<td>1/1/11</td>
</tr>
<tr>
<td>2012 GRC Phase 1 Application</td>
<td>Dec</td>
<td>1/1/12</td>
</tr>
</tbody>
</table>
B. Southern California Gas Company

SB 695 Report To California Public Utilities Commission

Southern California Gas Company (SCG) 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. SCG’s objective in developing this inaugural 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 Energy Division’s request: overall rate policy at SCG, description of revenue requirement components, discussion of rate components, management of rate components, and 2010 CPUC filing outlook (as appendix). SCG’s recommendations for actions that can be undertaken to reduce cost and rate increases are provided at the conclusion of this report.

I. Introduction

The information provided in this report includes SCG’s overall rate policy, a description of the rate components, current revenue requirements and anticipated changes during 2010. And finally, SCG 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 frameworks outlined by the CPUC and the Legislature, SCG seeks to fairly allocate costs across its customer classes. However, SCG recognizes that allocations of certain components of gas service costs in rates are beyond its direct control. SCG hopes that the CPUC will consider the recommendations put forth in later sections of this report, which SCG believes can have a measurable near-term impact on its total cost of delivering safe, reliable, cost-effective gas services to its customers in California.

II. Overall Rate Policy

SCG strives to provide its customers with reasonable rates for safe and reliable gas service while understanding that its customers value transparency and stability. Therefore, SCG also seeks to minimize the impact of rate adjustments made throughout the year. SCG 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 and seeks an annual gas transportation and Public Purpose Program (PPP) surcharge rate change in January of each year. In addition, SCG submits various filings to the Commission throughout the year in response to specific Commission directives or changes to the utility business, to ensure that SCG provides reliable and cost effective service to its customers.
III. Description of Revenue Requirement Components

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

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.

<table>
<thead>
<tr>
<th>Revenue Component</th>
<th>2009 Revenue Requirement $(000)</th>
<th>Percentage</th>
<th>2010 Revenue Requirement $(000)</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy1</td>
<td>1,393,951</td>
<td>42.75%</td>
<td>2,042,363</td>
<td>50.43%</td>
</tr>
<tr>
<td>Transportation</td>
<td>1,594,112</td>
<td>48.89%</td>
<td>1,731,329</td>
<td>42.75%</td>
</tr>
<tr>
<td>Gas Storage</td>
<td>24,575</td>
<td>0.75%</td>
<td>25,615</td>
<td>0.63%</td>
</tr>
<tr>
<td>PPP</td>
<td>272,410</td>
<td>8.35%</td>
<td>276,241</td>
<td>6.82%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>3,260,473</strong></td>
<td><strong>100.00%</strong></td>
<td><strong>4,049,933</strong></td>
<td><strong>100.00%</strong></td>
</tr>
</tbody>
</table>

1Actual recorded revenue that reflects the sum of the procurement rate multiplied by the corresponding consumption for each month from January 2009-December 2009.
2Represents estimates of Res and Core C&I usage based on average monthly consumption for years 2008 and 2009 multiplied by average monthly approved GPC rate for years 2008 and 2009.
3A subset of Transportation

1) WACOG revenue requirements represent approximately 50.43% of the total gas revenue requirement in the upcoming 12 months. The revenue requirements are expected to continue to trend upward, consistent with the market price of natural gas. For 2009, the energy revenue requirement represented about 42.75% of the total authorized gas revenue requirements.

2) Transportation revenue requirements, constitute about 42.75% of the total gas revenue requirements in the upcoming 12 months. For 2009, the transportation revenue requirement constituted about 48.89% 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 2009, and that level is forecast to remain fairly constant in 2010.

4) PPP revenue requirements, including California Alternate Rates for Energy (CARE) Discount and Energy Efficiency, represent approximately 6.82% of the total gas revenue requirements. The revenue requirements are 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 2009, these programs contributed about 8.35% of the total authorized gas revenue requirements.

IV. Description of Rate Components

Revenue requirements (RRQ) discussed in the previous section directly aligns 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 the actual rates for gas service. So, those RRQ expected to increase in the coming twelve months, will tend to drive rates up. For those RRQ which trend down, rates similarly will be reduced. And, 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 impact the rates experienced 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. SCG reviews load forecasts for its service territory on a regular basis.

V. Management of Key Rate Components

SCG is committed to controlling costs while providing safe and reliable gas service to its customers. However, there are many key drivers that affect customers’ rates which fall outside of SCG’s control. Among these include: the market price of the gas commodity actual sales volumes, weather, natural disasters, interest rates, and permitting process delays. Despite these factors, SCG diligently seeks to manage its costs across all categories to make efficient and effective use of revenues collected from customers.
VI. 2010 CPUC Filing Outlook

Attached for your reference is Appendix A, which reflects key filings’ data provided previously to the Energy Division (December 2009). This is not an exhaustive list of SCG’s filings that may occur in 2010; rather it incorporates regulatory filings which are known at this time to have a 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.

VII. Recommendations to the CPUC and Legislature

In this section, SCG 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.

SCG continues to use best operating and infrastructure investment practices to limit rate increases while still meeting California’s energy efficiency and environmental goals, in order to reduce greenhouse gases (GHG). To achieve these goals, SCG adheres to the State’s Energy Action Plan by promoting all mandated energy efficiency programs in pursuit of State and CPUC approved goals. In addition, SCG is exploring the use of new technology helping to shape an overall more cost effective energy model including empowering customers to manage their bills by evaluating their usage through the installation of Smart Meters.

In the coming year, SCG recommends that several key State policies and procedures should be shaped to support more effective, efficient and beneficial use of revenues collected from SCG’s customers. SCG believes that the State will have to weigh its environmental goals and desire for reliability that cause significant upwards 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. Smart Meter Policy
2. GHG Compliance Policies
3. Combined Heat and Power (CHP)
4. Performance-Based Incentives Mechanisms

In summary, California leads the nation in promoting reduction in GHG emissions, adoption of advanced technologies and social programs. The associated with implementing these policies place upward pressure on utilities’ rates. 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 also lead to higher rates. SCG supports these policies, however, believes that the utilities should be provided more flexibility in implementing them to achieve lower costs for customers.
### Southern California Gas Company
#### Requests Impacting Customer Rates During 2010

<table>
<thead>
<tr>
<th>Description</th>
<th>Filed</th>
<th>Expected Implementation</th>
<th>Rate Impacted</th>
<th>Directional Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas Regulatory Account Update AL</td>
<td>October 2010</td>
<td>January 2011</td>
<td>Gas Transportation</td>
<td>Increase</td>
</tr>
<tr>
<td>Gas Consolidated AL</td>
<td>December 2010</td>
<td>January 2011</td>
<td>Gas Transportation</td>
<td>Increase</td>
</tr>
<tr>
<td>Gas Public Purpose Program Update AL</td>
<td>October 2010</td>
<td>January 2011</td>
<td>PPP Surcharge</td>
<td>Increase</td>
</tr>
</tbody>
</table>
C. San Diego Gas and Electric Company

SB 695 Report To California Public Utilities Commission

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 inaugural 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 2010 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.

II. Introduction

The information provided in this report includes SDG&E’s overall rate policy, a description of the rate components, current revenue requirements and anticipated changes during 2010. And finally, SDG&E 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 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-term impact on its total cost of delivering safe, reliable, cost-effective gas and electric services to its customers in California.

II. Overall Rate Policy

SDG&E strives to provide its customers with reasonable rates for safe and reliable gas and electric service while understanding that its customers value transparency and stability. Therefore, SDG&E also seeks to minimize the impact of rate adjustments made throughout the year. Generally, SDG&E requests CPUC jurisdictional electricity rate changes two times per calendar year (January and May). For gas rate changes, SDG&E 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 and seeks an annual gas transportation and Public Purpose Program (PPP) surcharge rate change in January of each year. In addition, SDG&E submits various filings to the Commission throughout the year in response to specific Commission directives or changes to the utility business, to ensure that SDG&E provides reliable and cost effective service to its customers.
SDG&E also undertakes efforts to manage the timing of revenue changes and subsequent rate changes. For example, in 2009, SDG&E minimized swings in customer’s rates and bills via implementation of a one-time Energy Resource Recovery Account bill credit to electricity customers from balancing account overcollections\(^1\). Also, to decrease pressure on customer bills during 2009, SDG&E, along with Southern California Edison (SCE), requested and received authorization to defer collection of the approved revenue requirements for the California Solar Initiative (CSI) benefiting electricity customers during these tough economic times without jeopardizing the payment of CSI incentives or the future success of the program\(^2\).

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

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

Electricity cost categories include Commodity/Generation (including DWR), Competition Transition Charge (CTC), Nuclear Decommissioning, Transmission, Distribution, and Public Purpose Programs (PPP). For example, Commodity/Generation would include 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. Relative ranges for each RRQ category as a percent of total authorized 2009 RRQ, and analogous forecast trends for 2010, 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.

\(^1\) Authorized in CPUC D.09.09.042 on September 24, 2009.
\(^2\) Authorized in CPUC D.08.12.004 on December 4, 2008.
<table>
<thead>
<tr>
<th>Revenue Component</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>com</td>
<td>Revenue</td>
<td>Requirement</td>
</tr>
<tr>
<td>Commodity</td>
<td>$1,688,530</td>
<td>54.64%</td>
</tr>
<tr>
<td>CTC</td>
<td>$44,414</td>
<td>1.44%</td>
</tr>
<tr>
<td>ND</td>
<td>$10,298</td>
<td>0.33%</td>
</tr>
<tr>
<td>Transmission</td>
<td>$236,759</td>
<td>7.66%</td>
</tr>
<tr>
<td>Distribution</td>
<td>$1,034,362</td>
<td>33.47%</td>
</tr>
<tr>
<td>PPP</td>
<td>$75,640</td>
<td>2.45%</td>
</tr>
<tr>
<td>Total</td>
<td>$3,090,003</td>
<td>100.00%</td>
</tr>
</tbody>
</table>

1) The largest piece of SDG&E’s revenue requirement is Commodity/Generation which is currently 47.67% 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 22% of SDG&E’s forecast 2010 revenue requirement, and are expected to decline on January 1, 2011 due to the expiration of DWR contracts and timing of indifference (transfer) payments between California’s investor-owned utilities. During 2009, DWR-associated revenue requirements were approximately 34% of the total authorized revenue requirement.

2) CTC (Competition Transition Charge) contributes 1.55% of the total revenue requirement in 2010. CTC revenue requirements were 1.44% during 2009.

3) Nuclear Decommissioning revenue requirements represented less than 1% of SDG&E’s total authorized revenue requirement during 2009, and that level is forecast to remain fairly constant in 2010.

4) Transmission related revenue requirements constitute 9.07% of the total authorized revenue requirement trending slightly upward.

5) Distribution revenue requirements, including CSI and Smart Meter, comprise approximately 36.83% of the total revenue requirement, up from 33.47% in 2009 primarily due to re-establishing the collection of the CSI revenue requirement in 2010, as discussed previously, and attrition.

6) PPP revenue requirements, including California Alternate Rates for Energy (CARE) Discount and Energy Efficiency, represent 4.57% of SDG&E’s total revenue requirement during 2010. In comparison, PPP revenue requirements represented 2.45% of the total authorized revenue requirement during 2009.
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.

<table>
<thead>
<tr>
<th>Revenue Component</th>
<th>2009 Revenue Requirement $(000)</th>
<th>2009 Percentage</th>
<th>2010 Revenue Requirement $(000)</th>
<th>2010 Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy 1</td>
<td>183,234</td>
<td>36.43%</td>
<td>248,797</td>
<td>42.48%</td>
</tr>
<tr>
<td>Transportation</td>
<td>282,327</td>
<td>56.12%</td>
<td>299,256</td>
<td>51.10%</td>
</tr>
<tr>
<td>Gas Storage</td>
<td>5,205</td>
<td>1.03%</td>
<td>5,205</td>
<td>0.89%</td>
</tr>
<tr>
<td>PPP</td>
<td>37,482</td>
<td>7.45%</td>
<td>37,568</td>
<td>6.42%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>503,043</strong></td>
<td><strong>100.00%</strong></td>
<td><strong>585,621</strong></td>
<td><strong>100.00%</strong></td>
</tr>
</tbody>
</table>

1Actual recorded revenue that reflects the sum of the procurement rate multiplied by the corresponding consumption for each month from January 2009-December 2009.
2Represents actual recorded revenue up to February 2010. March-Dec 2010 reflects forecasted commodity revenues based on 5 year plan.
3A subset of Transportation

5) WACOG revenue requirements represent approximately 42.48% of the total gas revenue requirement in the upcoming 12 months. The revenue requirements are expected to continue to trend upward, consistent with the market price of natural gas. For 2009, the energy revenue requirement represented about 36.43% of the total authorized gas revenue requirements.

6) Transportation revenue requirements, including SmartMeter, constitute about 51.10% of the total gas revenue requirements in the upcoming 12 months. For 2009, the transportation revenue requirement constituted about 56.12% of the total authorized gas revenue requirements. The increase in the revenue requirement is primarily due to attrition and amortization of balancing accounts.

7) Gas storage revenue requirements comprise approximately 1% of the total revenue requirement in 2009, and that level is forecast to remain fairly constant in 2010.

8) PPP revenue requirements, including California Alternate Rates for Energy (CARE) Discount and Energy Efficiency, represents approximately 6.42% of the total gas revenue requirements. The revenue requirements are expected to trend upward in the near future mainly due to increases in the expected gas program penetration levels (Energy Efficiency goals) and the CARE shortfall, which is driven by the cost of gas and CARE participation. For 2009, these programs contributed about 7.45% of the total authorized gas revenue requirements.
IV. Description of Rate Components (Gas and Electric)

Revenue requirements (RRQ) discussed in the previous section directly aligns with rate components. At the highest level, gas and electricity rates can be described as revenue requirements divided by sales, so both revenue requirement changes and demand variations impact the actual rates for gas and electric service. So, those RRQ expected to increase in the coming twelve months, will tend to drive rates up. For those RRQ which trend down, rates similarly will be reduced. And, 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 impact the rates experienced by 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 2010.

VIII. Management of Key Rate Components

SD&E is committed to controlling costs while providing safe and reliable gas and electricity service to its customers. 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.

IX. 2010 CPUC Filing Outlook

Attached for your reference is Appendix A, which reflects key filings’ data provided previously to the Energy Division (December 2009). This is not an exhaustive list of SDG&E’s filings that may occur in 2010; rather it incorporates regulatory filings which are known at this time to have a rate impact for gas or electricity 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.

X. Recommendations to the CPUC and Legislature

In this section, SDG&E 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.

SDG&E continues to use best operating and infrastructure investment practices to limit rate increases while still meeting California’s energy efficiency and environmental goals, in order to reduce greenhouse gases (GHG). To achieve these goals, SDG&E adheres to the State’s Energy Action Plan by promoting all mandated demand response and energy efficiency programs in pursuit of State and CPUC approved goals. SDG&E balances the procurement of renewable energy while following the least-cost, best-fit approach to minimize the cost to customers. In addition, SDG&E is exploring the use of new technology helping to shape an overall more cost effective energy model including empowering customers to manage their bills by shifting their usage to off-peak hours through the installation of Smart Meters and the implementation of dynamic pricing structures.

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 upwards cost pressures 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.

1. Smart Grid Policy /Smart Meter Policy
2. Distributed Generation
3. GHG/RPS Compliance Policies
4. Once-Through Cooling Policy
5. Combined Heat and Power (CHP)
6. Performance-Based Incentives Mechanisms

In summary, California leads the nation in promoting reduction in GHG emissions, use of renewable energy, adoption of advanced technologies and social programs. The associated with implementing these policies place upward pressure on utilities’ rates. In addition, due to the mild weather and implementation of energy efficiency measures, the electric and gas usage per customer in California is below the national average. These factors also lead to higher rates. SDG&E supports these policies, however, believes that the utilities should be provided more flexibility in implementing then to achieve lower costs for customers.
## Appendix A - Key Filings Table

San Diego Gas & Electric Company  
Requests Impacting Customer Rates During the Year of 2010

<table>
<thead>
<tr>
<th>Description</th>
<th>Filed</th>
<th>Expected Implementation</th>
<th>Rate Impacted</th>
<th>System Average Directional Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010 ERRA Forecast Application</td>
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