California Public Utilities Commission

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

June 2013

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I. Executive Summary

A. Statutory Mandate

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

Section 748 states:

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

The 2013 edition of this report is hereby submitted by the CPUC to the Governor and Legislature.

B. Challenges

Perhaps the greatest challenge facing the CPUC is apparent in the above language of the law: "to limit utility cost and rate increases, consistent with the state's energy and environmental goals". The least-cost methods of producing and delivering electricity and gas to customers, if one considers only direct, short-run costs, are often not the cleanest, safest, or most reliable methods. California has made many separate decisions over the past decades in consideration of the costs imposed by health effects of producing and delivering energy, and its lawmakers have embedded such decisions in a number of state legal codes, including the Public Utilities

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

Code. Striking a balance between competing and sometimes conflicting legislated and judicially ordered goals and procedures is the daily work of the CPUC.

Another challenge in developing this report as mandated is the fact that the content is necessarily limited by the quasi-judicial nature of the agency, which makes formal decisions based on evidence presented by the parties involved. A CPUC report must be careful to not prejudge issues that are the subject of open cases, since to do so could interfere with due process. Working within this limitation, this report describes the policies the CPUC already *has* recommended or chosen to limit utility cost and rate increases while addressing the state's energy and environmental goals. The report also describes many areas where the implementation of adopted policies is undergoing further examination or revision to improve the efficacy or efficiency of the policy or program delivery.

C. Structure of Report

This report consists of four main parts. First, the report discusses the electric utilities' annual proposed or recently adopted revenue requirements to provide service. The CPUC reviews these requests in General Rate Case (GRC) and Energy Resource Recovery Account (ERRA) proceedings. This section provides the Legislature a snapshot of the scope and financial implications of the proceedings and how the CPUC reviews proposals with the goal of limiting costs and rate increases. Then the report describes programs the CPUC uses to promote reliable, robust, low-risk, and low-cost electricity strategies, and to advance the State's environmental and public purpose goals. To better determine the efficacy of its programs and to determine whether ratepayers benefit from the programs, the CPUC conducts a variety of benefit-cost studies. Next, the report addresses the same issues for the natural gas utilities. Lastly, the report contains an appendix of utility submissions detailing their future revenue requirements, demand forecasts, pending and anticipated proceedings, and recommendations to limit costs and rate increases.

II. Electric Utility Costs and Revenue Requirements

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

Table II-1
Total Authorized Electric Revenue Requirements effective January 1, 2013
($ Million)

PG&E	SCE	SDG&E
$12,370	**$12,015**	**$3,141**

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

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

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

A more detailed description of how utility revenue requirements are established can be found in the 2013 AB 67 Report.[2]

A. Requests for Revenue Requirement Increases Under CPUC Consideration

1. Electricity General Rate Cases

The major components of costs that are reviewed and determined in the GRCs include operations and maintenance, depreciation, return on rate base, and taxes. The revenue requirements for 2013 authorized by the CPUC in recent GRCs for the three major utilities are listed below.

Table II-2
2013 Authorized Electric General Rate Case Revenue Requirements ($ Million)

	PG&E	SCE	SDG&E
Operations and Maintenance	$1,947	$2,272	$659
Depreciation	$1,099*	$1,222	$274
Return on Rate Base	$1,246	$1,465	$300
Taxes	$734	$712	$207
Attrition **	$295	$358	$40
Total	**$5,321**	**$6,029**	**$1,481**

* Includes $38 million for fossil and nuclear decommissioning.
** PG&E's attrition allowances apply to years 2012 and 2013; attrition for both years is shown above. SCE's attrition allowances apply to years 2013 and 2014; only the 2013 attrition amount is shown above. SDG&E's attrition allowances apply to years 2013 – 2015; only the 2013 attrition amount is shown above and is estimated to be $40 million, 2.75% of the 2012 authorized GRC revenue requirement, based on the attrition mechanism (CPI-urban index plus 75 basis points) adopted for SDG&E in its 2012 GRC.

PG&E 2014 GRC: PG&E's authorized 2013 GRC revenue requirement is $5,321 million, as authorized by the CPUC in the 2011 GRC. In November 2012, PG&E filed its 2014 GRC application. PG&E is seeking an increase of $796 million over the currently authorized electric revenue requirement in that case. PG&E cites safety and reliability related reasons for its requested increase including the need for investments in its electric distribution system, and expenditures on its nuclear and hydroelectric facilities. The CPUC will address PG&E's GRC application during 2013, with a decision expected at the end of 2013 or in early 2014.

SCE 2012 GRC: In November 2012, the CPUC authorized a 2012 revenue requirement of $5,671 million for SCE. This represented an increase of $272 million over 2011 rates, roughly a 5% increase. The CPUC also authorized an attrition increase of $358 million in 2013, and an increase of $356 million in 2014. The increases are needed to accommodate increased customer and load growth, replace aging distribution infrastructure, and the continuing need to provide safe and reliable service. SCE will file its 2015 GRC application in the 4th quarter of 2013, and the CPUC will review SCE's 2015 GRC in 2014.

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[2] Electric and Gas Utility Cost Report to the Governor and Legislature, available at http://www.cpuc.ca.gov/NR/rdonlyres/26E020D9-D7D1-45B3-A637-0E89456F1F9C/0/AB67CostReport201204252013.pdf

SDG&E 2012 GRC: In May 2013, the CPUC authorized a 2012 revenue requirement of $1,441 million for SDG&E. This represented an increase of $115 million over 2011 rates, roughly an 8.7% increase. The CPUC also authorized an attrition increase of $40 million in 2013 and an increase of $41 million in 2014. These increases are needed for distribution capital investments, insurance premiums, and other projects needed to operate SDG&E's system in a safe and reliable manner. The CPUC authorized SDG&E to file its next GRC in late 2014 for test year 2016.

2. Electric Fuel and Purchased Power Costs

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

Utilities' actual fuel and purchased power costs, and the revenues they collect from customers to pay these costs, are tracked in a balancing account and addressed in a subsequent ERRA or related CPUC proceeding. In the event that the revenues exceed the costs, then the account balance (difference between costs and revenues) is returned to the customers. If the costs exceed the revenues then the costs are recovered from customers.

The CPUC also has rules in place to ensure that the revenue requirement collected by the utilities tracks closely with the CPUC'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 CPUC in an advice letter, but is not required to file an expedited application.

The utilities' current authorized annual revenue requirements to recover fuel and purchased power costs adopted in the CPUC's ERRA forecast proceedings are shown below.

Table II-3
Annual Electric Revenue Requirements for Fuel and Purchased Power Costs
($ Million)

PG&E	SCE	SDG&E
$4,377	**$3,672**	**$1,052**
Effective Jan. 2013	**Effective Aug. 2012**	**Effective Jan. 2013**

PG&E's ERRA: In December 2012 the CPUC approved PG&E's fuel and purchased power revenue requirement for 2013 as shown above. In June 2013 PG&E will file its ERRA application to request a fuel and purchased power revenue requirement for 2014.

SCE's ERRA: In August 2012 SCE filed its 2013 ERRA application in which it requests a fuel and purchased power revenue requirement of $4,520 million for 2013. A CPUC decision in that case is expected in the 2nd quarter of 2013. SCE will file its ERRA application for 2014 fuel and purchased power costs in August 2013.

SDG&E's ERRA: SDG&E is requesting a fuel and purchased power revenue requirement of $1,057 million in its pending 2013 ERRA forecast proceeding. A CPUC decision in that case is expected in the 3rd quarter of 2013. SDG&E will file its ERRA application for 2014 fuel and purchased power costs in October 2013.

The CPUC also reviews each utility's energy procurement operations and purchased power contract administration activities for a prior annual period in a separate annual ERRA compliance proceeding for each utility.

a) Investigation of the Outage at the San Onofre Nuclear Generating Station

Units 2 and 3 at the San Onofre Nuclear Generating Station (SONGS) have been shut down since January 2012 due to problems with new steam generators that were recently installed. SCE owns about 78% of SONGS and operates the plant; SDG&E owns 20%, and the remaining share is owned by the City of Riverside. SCE manages SONGS and has recently announced that it plans to permanently shut down SONGS.

In late 2012 the CPUC opened an investigation to consider removing the plant from SCE's and SDG&E's rate base and to review the steam generator replacement project costs. As of Jan 1, 2013, SCE is collecting more than $600 million in rates for owning and operating the plant. These costs as well as SDG&E's share of SONGS costs in rates will be reviewed by the CPUC for reasonableness in the CPUC's investigation and could be refunded to ratepayers.

B. Plans to Improve CPUC Efficacy in Ratemaking

The CPUC has committed to improving the efficacy of its rulemakings, particularly in the areas of safety and accountability.

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

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

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

In its decision in PG&E's 2011 GRC, the CPUC emphasized that the utility has the responsibility to spend what is necessary to ensure safe and reliable service despite any financial implications of exceeding authorized cost levels. The CPUC required PG&E to submit reports on authorized revenues versus actual expenditures for major electric and gas work categories, including explanations of significant differences between authorized and recorded spending for each category. Similar reporting requirements were required by the CPUC in SCE's 2012 GRC.

In PG&E's 2014 GRC the CPUC has required that independent consultants hired by the Safety and Enforcement Division evaluate risk assessments, risk mitigation, programs and policies, as well as PG&E's corporate policies, goals, culture, and efforts being made to bolster system safety and security.

C. Other Rate Related Proceedings in the Next 12 Months

Over the next 12 months, the CPUC will review several requests filed by the utilities through formal applications and advice letters. Details of the formal applications are provided in the Appendix, which contains tables of the current and anticipated proceedings, with descriptions and case numbers. Two proceedings worth noting and discussed below are the smart meter opt-out proceeding and the annual revenue requirement determination of the Department of Water Resources.

1. Annual Revenue Requirement Determination of Department of Water Resources

The CPUC opened R.13-02-019 to consider issues related to the annual revenue requirement determination of the California Department of Water Resources (DWR) in connection with its procurement of energy for the electricity customers of PG&E, SDG&E and SCE. In August, 2013, CDWR is expected to file its 2014 revenue requirement and a CPUC decision will be issued in December 2013. The CPUC's approval and allocation of DWR revenue requirements will affect the rates of PG&E, SDG&E and SCE customers.

2. Modifications to the SmartMeter Program

In A.11-03-014, A.11-03-015, A.11-07-020, PG&E, SCE and SDG&E filed applications to give residential customers the option to opt out of the SmartMeter program. After addressing the legal issues in Phase I, the CPUC adopted D.12-02-014, which sets forth an advanced meter opt-out provision along with procedures and interim fees for opting out. In April 2012, the assigned commissioner ruled to consolidate the SmartMeter opt-out applications within a single proceeding and to consider in Phase II all cost and cost allocation issues. The CPUC held evidentiary hearings in November 2012, and the parties filed opening and reply briefs in January 2013. The IOUs' updated fee proposals are for initial fees ranging from $75 to $189, monthly fees ranging from $10 to $24, and exit fees ranging from $43 to $90. A decision is expected later this year.

III. Program-Specific Proceedings and Activities

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

This chapter discusses the following CPUC programs and initiatives. Some of these initiatives involve gas costs and rates, but most of these are primarily aspects of electricity policy.

Supply-Side Initiatives

- Resource Adequacy and Long-term Procurement
- Renewables Portfolio Standard

Demand-Side Initiatives

- Energy Efficiency
- Demand Response
- Rate Design and Time-Varying Pricing
- Customer-Sited Distributed Generation and California Solar Initiative
- Energy Savings Assistance

This year two new sections have been added:

- Emerging Procurement Strategies
- CPUC Advocacy for California Electric Interests at FERC

A. Resource Adequacy and Long Term Procurement

The Resource Adequacy (RA) program is a CPUC planning and procurement program to secure sufficient commitments from owners of actual, physical resources to ensure system reliability. The CPUC adopted a System and Local RA policy framework in 2004 in order to ensure the reliability of electric service in California.[3] R.11-10-023 is the current CPUC proceeding implementing and improving the RA program. The CPUC RA program covers three investor-owned utilities (IOUs), fourteen energy service providers (ESPs), and one community choice aggregator (CCA), which collectively are known as Load Serving Entities (LSEs). Each LSE's year-ahead RA requirement is calculated using its California Energy Commission (CEC) forecast load by month, plus a reserve margin of 15%, for a total of 115% of forecast load.

[3] Public Utilities Code Section 380.

In addition, the CPUC administers the Long Term Procurement Plan proceeding (LTPP) which implements AB 57, passed in 2002[4], by overseeing IOUs procurement plans, and evaluates the need for new resources. This proceeding is initiated every two years and serves as the "umbrella" proceeding to consider all the CPUC's EAP II loading order policies and programs. When specific projects are approved by the CPUC and constructed, the cost of these resources will be included in rates, expected between 2018 and 2021.

1. Activities over the Next 12 Months That May Affect Rates

Current RA proceedings at the CPUC are unlikely to increase or decrease rates significantly 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 procurement proceedings and processes are not expected to raise or lower rates within the next 12 calendar months. In addition, virtually all Department of Water Resources energy contracts have expired with no impacts beyond the next 12 months.

The current LTPP proceeding is examining the need for flexible capacity and what needs will occur with the permanent retirement of SONGS. If additional flexibility is required to maintain system reliability with increased penetration of intermittent renewable resources, then significant new costs may also be incurred. These costs would not appear in rates until new resources are constructed several years in the future.

Several proceedings within the next 12 months in this program area have the potential to affect future ratepayer costs, either by raising or lowering the required level of reserves, or by authorizing new generation to meet reliability requirements. The combined effects of Long Term Procurement and RA policies as well as other changes to California's energy market are not expected to change rates within the next 12 months, but as discussed below, could result in future rate increases beyond the next 12 months.

a) Long Term Procurement and RA Market Structure

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

Currently procurement of capacity and energy is accomplished mostly through open and competitive markets. The CAISO operates short-term markets for energy and ancillary

[4] Public Utilities Code Section 454.5

services. Longer term transactions are through direct contracting between the LSEs and resource owners (bilateral contracting) or utility run auctions (generally with the utility as buyer). There is significant variation in contract prices resulting from different energy and capacity values that depend on location, ability to respond quickly to system needs, plant efficiency, and market competitiveness.

b) Construction of New Generation via the LTPP program

The LTPP program contains two main sections: 1) evaluating the need for new resources to ensure reliability and authorizing utilities to construct new resources to meet those needs and 2) developing procurement plans that demonstrate the utilities' plans meet reliability needs (energy and capacity) of customers while balancing the state policy priorities, such as energy efficiency, GHG reduction, etc. The IOUs submit procurement plans, based on the LTPP, which includes procurement limits, procurement products and processes, rules, and risk mitigation strategies.

When the CPUC authorizes new resources to protect reliability, the utilities undertake the procurement, but the cost is shared by all benefitting customers. Before approval, the CPUC examines carefully the added cost for the construction of these new resources.[5] There are three categories of activities that will impact utility costs and rates.

First, there is new generation that will come online during 2013. Two major new natural gas fueled generators have already begun operation in 2013 in SCE's service territory: Walnut Creek (500MW) and Sentinel Energy (850MW). In addition, a new 560MW unit will soon replace the existing 335MW El Segundo unit 3, also in SCE's territory. One major new natural gas fueled generator has already begun operation in 2013 in PG&E's service territory, Marsh Landing (760MW), which replaced the recently retired Contra Costa units 6 and7. In addition, later this year, the Russell City plant (600 MW) will become operational in Hayward, and the Los Esteros plant will add an incremental 140 MW by converting to combined cycle. As each of these plants come online, their costs will be included in rates, and the combined capacity and energy costs of the new resources will exceed the cost of the resources they replace.

Second, in a recent LTTP decision (D.13-02-015) the CPUC authorized SCE to procure between 1400 and 1800 MW of new resources in the west Los Angeles Basin and between 215 and 290 MW in the Big Creek / Ventura local areas. In addition, D.13-03-029 authorized SDG&E to procure 308 MW of new resources.

Third, the permanent shut down of SONGS will have rate impacts, but the magnitude of those rate impacts is unknown at this point since responsibility for the problems at SONGS is currently being litigated.

c) Variability of Intermittent Resources

A major element expected to drive the RA program costs is the variability of intermittent resources. It is difficult to accurately predict the amount of energy that will be delivered by intermittent resources during times of peak demand as well as short-term changes in demand.

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

Therefore, in order to ensure reliability, other resources need to be procured and ready to perform based on these two factors. Customers pay for these resources even if they only operate for a limited amount of time. As intermittent resources increase to meet renewables goals, the resources required for renewable integration may also increase. Continued improvements in energy forecasting should ultimately reduce or minimize the impacts intermittent resources have on RA costs. The CPUC is an active participant in both the California Independent System Operator's (CAISO) and the CEC's stakeholder processes related to these efforts.

d) Cost Minimization in LTPP

Three basic cost minimization approaches are taken in the LTPP. The first is that the CPUC views procurement authorizations as part of a least-regrets approach. For example, in D.13-02-015, instead of authorizing a larger procurement total, the CPUC indicated that if any future needs exist in the LA Basin or Big Creek / Ventura then they would be re-examined in the 2014 LTPP, rather than authorizing the full amounts. The second cost-minimization approach is the use of competitive auctions and other tools to ensure that the ratepayers do not overpay for resources. Lastly, the CPUC is working on better integration of planning information from the LTPP into other resource proceedings, such as energy efficiency, and developing consistent assumptions with other agencies and entities, such as the CEC and the CAISO.

e) Impacts of Once Through Cooling Mitigation Regulations Promulgated by SWRCB

The CPUC in consultation with the CAISO and CEC has, since 2004, authorized the construction of new resources to replace the OTC plants. In 2010, the State Water Resources Control Board (SWRCB) adopted rules to phase out the use of OTC. A significant number of the OTC plants were built in the 1960s and 1970s and would need to be replaced regardless of the OTC policy. Many of the resources coming online in 2013 and 2014 were authorized in anticipation of the OTC plants retiring. In D. 13-02-015, the CPUC authorized new resources primarily based on forecasting reliability needs with OTC plants retired. As replacement resources come online and other OTC mitigation are implemented, such as transmission improvements, replacement of cooling systems on existing units, increased distributed generation, and demand side alternatives (e.g. energy efficiency and demand response), the costs of these resources will be included in rates. Rate impacts from these mitigation measures will be spread over several years as large infrastructure investments come online and existing facilities are retired.

2. Trends Beyond the 12 Month Reporting Period

Significant new infrastructure developments are taking place in 2013 and beyond. They will address reliability concerns associated with integration of variable resources. Changes to the RA program to incorporate a need for additional flexibility and dispatchability are expected to increase procurement costs. Development of large scale commercial storage (other than the existing pump storage technologies) could significantly affect the ability of California to integrate renewable resources, but the costs impacts are not known at this time. The 2013 rates will include contract costs of the Walnut Creek, Sentinel, El Segundo, Marsh Landing and Los Esteros plants as these facilities come on line.

Beyond the next 12 months LTPP will focus on the need for resources in the local areas to ensure compliance with the OTC Policy, on the status of the state's nuclear resources, and ongoing needs for integrating renewable resources into the energy grid. Furthermore, the rates will include the resources discussed previously when they come online.

B. Renewables Portfolio Standard

Established in 2002 under Senate Bill 1078 (Sher), accelerated in 2006 under Senate Bill 107 (Simitian) and expanded in 2011 under Senate Bill 2 (1X) (Simitian), California's Renewables Portfolio Standard (RPS) is one of the most ambitious renewable energy standards in the country. The RPS program requires investor-owned utilities (IOUs), electric service providers (ESPs), publicly owned utilities (POUs), and community choice aggregators (CCAs) to increase retail sales from eligible renewable energy resources to 33% of total procurement by 2020. The CPUC and the CEC are jointly responsible for implementing the RPS program. The CPUC will continue to implement efforts to minimize the cost associated with increased procurement of renewable energy through the measures discussed below.

The RPS statute requires utilities to select renewable resources that provide the greatest value at the least cost, pursuant to least cost, best fit (LCBF) RPS contract evaluation methods. The LCBF methodology includes the direct costs of renewable energy procurement and any indirect costs due to the addition of new renewable capacity (e.g., transmission network upgrades). In addition, utilities are required to consider renewable resources that best fit their system needs.[6]

As described in past reports, the RPS program is structured to minimize ratepayer costs. First, it sets up a technology-neutral, competitive renewable procurement process where investor-owned utilities select energy products that meet their needs at the lowest cost. The CPUC then reviews RPS contract prices based on bid supply curves from competitive solicitations, least-cost best-fit analysis, consistency with each IOU CPUC-approved RPS Procurement Plan, and additional data as needed. Bilateral contracting is also allowed under the program, but the CPUC has emphasized that competitive solicitations are preferred in order to encourage greater price competition. Second, the vast majority of RPS contracts are long-term (greater than 10 years) with fixed-prices, which provides a hedging benefit for ratepayers against price volatility in the natural gas markets. Thus, with a target of 33% RPS by 2020, California utilities will have a diversified electricity portfolio that provides a hedging benefit to ratepayers.

A recent Energy Division report to the Legislature, pursuant to Public Utilities Code section 911, demonstrates that the average cost for new RPS power purchase agreements is declining.[7]

1. Activities over the Next 12 Months That May Affect Rates

a) System-Side Distributed Generation

The CPUC implements and administers California's distributed generation (DG) policies and programs on both the customer side of the meter (retail) and utility side of the meter (wholesale). On the utility side of the meter, utilities procure wholesale DG resources through a

[6] Least-cost best-fit criteria were determined in D.04-07-029.
[7] March 2013 Padilla Report, available at http://www.cpuc.ca.gov/NR/rdonlyres/F0F6E15A-6A04-41C3-ACBA-8C13726FB5CB/0/PadillaReport2012Final.pdf

variety of procurement programs, including the Renewable Auction Mechanism (RAM), the utility solar photovoltaic programs, and the Feed-in-Tariff (FiT) and RPS solicitations.

The RAM is a simplified, market-based procurement mechanism for renewable DG projects between 3 MW[8] and 20 MW in size on the system-side of the meter. RAM offers a streamlined procurement process with a cumulative program capacity of 1,299 MW[9] over four utility lead auctions. Contract prices have declined on average in each of the first three RAM solicitations. The fourth RAM auction is expected to close in June 2013. Energy Division staff summarized recent RAM activities in its latest RPS Quarterly report to the Legislature.[10]

In order to minimize the costs of renewable DG procurement programs, the CPUC granted in part SCE's and SDG&E's respective petitions for modification to merge their solar PV programs into the RAM program. The IOU solar PV programs were restricted to one technology (solar PV). SCE's program targeted small rooftop projects (1-2 MW) and SDG&E's program targeted small ground-mount (1-5 MW) projects. By merging the utility solar PV programs into RAM, the CPUC is attempting to minimize ratepayer expenditures on renewable DG and provide a more efficient DG procurement process.

The FiT program offers standard tariffs and contracts for the purchase of eligible renewable generation from renewable projects not greater than 3 MW. SB 32 (Negrete McLeod, 2009) and SB 2 (1X) (Simitian, 2011) amended the FiT program, most notably, to revise the pricing mechanism and to increase the eligible project size from 1.5MW to 3 MW. In May 2012, the CPUC adopted new program rules and a new market based pricing mechanism, known as ReMAT or the renewable market-adjusting tariff, for the FiT program (See D.12-05-035). In May of 2012 the CPUC adopted a revised standard contract for the FiT. The FiT program has a statewide cumulative available capacity of 750 MW, divided between the IOUs and the POUs based on share of total retail sales – approximately two-thirds of the capacity will be procured by IOUs.

SB 1122 (Rubio, 2012) also recently amended the FiT program, creating a separate incremental procurement authorization for 250 MW of capacity from bioenergy FiT projects up to 3 MW in size. The CPUC has begun its work to implement this new statute and will have the program in place by the end of the year. A targeted procurement requirement like this will increase procurement from bioenergy resources that otherwise may not be cost competitive relative to all RPS-eligible resources.

Additionally, the CPUC authorized utility-specific solar photovoltaic (PV) procurement programs to procure 776 MW[11] over five years from projects sized in the 1 MW to 20 MW

[8] Decision (D.) 10-12-048 originally allowed for projects sized between 1 MW and 20 MW to participate in RAM. In D.12-05-035, the CPUC's most recent Feed-in-Tariff decision, the minimum eligible project size for RAM was modified from 3 MW to 20 MW to avoid program overlap between RAM and the FIT program.

[9] The original RAM MW allocation was 1,000 MW. The MW allocation was subsequently increased by D.12-02-002, which moved 74 MW of capacity from SDG&E's PV Program into RAM, and D.12-02-035, which moved 225 MW of capacity from SCE's PV Program into RAM.

[10] Renewables Portfolio Standard Quarterly Report to the Legislature, 3rd and 4th Quarter 2012, available at http://www.cpuc.ca.gov/NR/rdonlyres/4F902F57-78BA-4A5F-BDFA-C9CAF48A2500/0/2012_Q3_Q4RPSReportFINAL.pdf.

[11] In February 2012, D.12-02-002 authorized SDG&E to move its remaining 74 MW from the independent power producer portion of its PV Program into RAM, effectively ending its PV Program. D.12-2-035 authorized SCE to transfer 250 MW from its entire program to RAM.

range, depending on the utility. Through these programs, the CPUC authorized the IOUs to own and operate PV facilities as Utility Owned Generation (UOG) as well as to execute solar PV power purchase agreements (PPAs) with independent power producers through a competitive solicitation process. The IOUs are approximately half-way through these five-year programs. These programs have helped diversify utility RPS portfolios and allowed utilities and their ratepayers to benefit from declining costs in solar PV.

b) Review of IOUs' Bid Selection Criteria and Methods and Implementation of RPS Procurement Standards of Review

The maturation of the California renewables market since the program's inception 10 years ago have resulted in an increase in the number of experienced developers submitting power purchase agreements for renewable energy projects at increasingly competitive prices. The lessons learned from public and private stakeholders have resulted in more projects achieving commercial operation, thus the investor-owned utilities are on track to achieve the state's 33% by 2020 RPS goal.

The CPUC will implement a new RPS cost containment mechanism outlined in SB 2 (1X) (Simitian, 2011), which established 33% RPS procurement requirements including new guidelines for limiting total RPS procurement expenditures. Public Utilities Code section 399.15(c) requires that the CPUC establish a limit for each electrical corporation on the procurement expenditures for all eligible renewable energy resources used to comply with the RPS program. Consistent with Public Utilities Code section 399.15(d)(1) the CPUC will set the RPS procurement expenditure limitation "…at a level that prevents disproportionate rate impacts."

The CPUC is considering a number of changes to the standard of review (SOR) for renewable power purchase agreements (PPA) that are submitted to the CPUC for approval, as an effort to streamline the RPS contract review process to facilitate three objectives; 1) decrease the cost of renewable procurement, 2) establish clearer standards for utility procurement, and 3) refine the CPUC's approval process for RPS contracts.

In conjunction with revising the standards of review, the CPUC is also developing a standardized Renewable Net Short (RNS) method that will more accurately depict the RPS compliance positions of California's three major IOUs in an attempt to 1) limit the risk of over-procurement, and 2) better inform the CAISO's Transmission Planning Process to better coordinate that process with RPS procurement. A clearer picture of each IOU's RNS will inform the CPUC's understanding of that IOU's need for additional RPS procurement and any associated transmission development to achieve the RPS goals at the lowest cost to ratepayers.

Lastly, the CPUC is reviewing the various components of the least cost, best fit (LCBF) RPS bid evaluation methodology to determine if changes are necessary to account for the proper valuation of new and existing resources. A robust LCBF will allow the utilities to select RPS contracts that maximize the value of each IOU's total electricity portfolio.

c) Use of RPS Sales Contracts

The IOUs are currently forecasted to exceed the RPS procurement requirements on a risk-adjusted basis over the next several years.[12] All three large IOUs have included in their approved 2012 RPS Procurement Plans the intent to sell excess RPS generation if it is consistent with their RPS position and provides value to ratepayers.[13] By selling any excess contracted renewable generation the IOUs could lower total costs to ratepayers. The CPUC has approved RPS sale contracts for both SCE and SDG&E.

d) Transmission costs

Due to the location of many of the RPS facilities and/or the generation that they add to the transmission system, projects may require significant transmission upgrades which result in costs to ratepayers. In D.12-11-016, the CPUC adopted requirements to minimize transmission upgrade costs related to RPS procurement. Specifically, the CPUC adopted the requirement that all projects bidding into the annual RPS solicitation must have at least a completed CAISO Generator Interconnection Protocol (GIP) Phase I transmission study. By having a completed CAISO GIP Phase I study, the utilities and the CPUC have a more accurate estimate of a project's transmission upgrade costs and resulting costs and value to ratepayers prior to contract execution. In addition, the CPUC authorized the IOUs' pro forma RPS contracts to include terms that allow for contract termination if negotiated termination cost caps are exceeded, which will set a limit on total cost that ratepayers may incur.

2. Trends beyond the 12 month reporting period

As the utilities approach the 33% RPS target, the pace of their renewable procurement will slow. The CPUC will continue to focus on optimizing the utilities' electricity supply portfolios to maximize the value and minimize the cost of RPS procurement. Additionally, the CPUC will continue to seek improvements in the coordination of RPS procurement with system resource need determination and procurement authorization in the long-term procurement proceeding.

C. Emerging Procurement Strategies

1. Electricity Program Investment Charge

After the expiration of the Public Goods Charge in 2012, the CPUC established a framework for the deployment of next generation clean energy technologies. The EPIC program focuses primarily on supporting pre-commercial efforts to develop emerging clean energy technology, filling in funding gaps left by private investments and moving a technology from the early stages of development to commercial viability.

EPIC monies support the following activities:

- **Applied Research:** Activities supporting pre-commercial technologies and approaches that are designed to solve specific problems in the electricity sector. (Administered by the CEC.)

[12] Renewables Portfolio Standard Quarterly Report to the Legislature, 3rd and 4th Quarter 2012
[13] D.12-11-016 approved the IOUs' 2012 RPS Procurement Plans.

- **Technology Demonstration and Deployment:** The installation and operation of pre-commercial technologies or strategies at a scale sufficiently large and in conditions sufficiently reflective of anticipated actual operating environments to enable appraisal of the operational and performance characteristics and the financial risks. (Administered by the CEC and the three IOUs.)
- **Market Facilitation:** A range of activities including program tracking, market research, education and outreach, regulatory assistance and streamlining, and workforce development to support clean energy technology and strategy deployment. (Will be administered by the CEC.)

The EPIC Program has three investment plan cycles: 2012-2014, 2015-2017, and 2018-2020. Four Program Administrators ("PAs") carry out program functions, including creating investment plans, dispensing of grants and working with private sector companies to execute projects. The four PAs are the CEC, PG&E, SCE and SDG&E, with the CEC having the lion's share of the EPIC budget. All four PAs must develop and submit investment plans to the CPUC for approval in each investment plan cycle.

After the CPUC approves the plans, the PAs implement their respective investment plans without the CPUC's "project specific" oversight. All administrators of EPIC funds are subject to the same requirements, including an administrative expenditure cap of 10%, and annual reporting requirements. The IOUs cannot use EPIC funds for generation projects, and a minimum of 20% of the CEC's technology demonstration and deployment budget needs to be allocated to support bioenergy projects.

In 2012, the EPIC budget was $143 million, based on the CPUC's Phase I decision in the EPIC proceeding. In 2013, EPIC has an overall budget of $162 million, adjusted every three years to account for inflation using the consumer price index. Currently, the CPUC is deliberating on the PAs' plans, and a decision is anticipated in June 2013 for the first Investment Plan Cycle.

The PAs will file annual reports that will summarize the PAs' annual EPIC budget spending starting on February 28, 2014 and continuing through February 28, 2020. In 2016, the CPUC will hire a consultant to conduct an independent review of the program.

EPIC and Utility Costs

EPIC is currently funded at $162 million per year, which is collected from utility customers in rates. The current cost allocation method is on a per kilowatt-hour basis that varies by class or rate group. IOUs recover costs associated with EPIC spending via the EPIC surcharge.

The CPUC Phase I decision (D.11-12-035) concluded that "this surcharge [EPIC] shall reflect the same allocation among classes as the rates for the system benefits charge, and shall be collected in the Public Purpose Program component of rates as with the current system benefits charge."[14] D.11-12-035 ordered that PG&E, SCE, and SDG&E institute the surcharge on January 1, 2012. The Phase II decision (D.12-05-037) does not change that determination. The EPIC funding amounts collected in rates are the default budgets for the EPIC program in each investment plan.

[14] D.11-12-035, Ordering Paragraph 3 at 40.

2. Cap & Trade

In 2011, the CPUC began a proceeding to implement the Air Resources Board (ARB)'s carbon cap-and-trade program for California's investor-owned utilities.[15] To meet the carbon emission reduction goals of the Global Warming Solutions Act of 2006 (AB 32), ARB released regulations establishing a carbon cap-and-trade program in December 2011. The cap-and-trade program requires compliance entities to purchase allowances equal to their annual carbon emissions. While some of these allowances are issued freely to industrial entities and to utilities on behalf of ratepayers, the majority of allowances are issued through auctions held by the Air Resources Board. Investor-owned utilities are obligated to sell at auction all allowances freely allocated to their ratepayers, and ratepayers are the recipients of these proceeds, which are forecasted to result in $5.7 to $22.6 billion in revenue between 2012 and 2020.[16]

Cap and Trade and Utility Costs

The cap-and-trade program is expected to increase utility costs. Between 2013 and 2020, carbon cost will lead to an estimated system average rate increase of 2.0 – 8.6% for California's investor-owned utilities.[17] These costs will come in the form of a direct compliance obligation for utility-owned generators and generators under contract, as well as indirect costs experienced through wholesale market transactions. However, as discussed below, the cost will not have a directly proportional impact on customers' bills.

Cap and Trade and Customer Impact

In D.12-12-033, the CPUC determined how to use allowance auction proceeds. The CPUC found that a carbon price signal in rates is an important means to incent users to reduce emissions, but it also recognized that some customer types needed protection from carbon costs in electricity rates. This decision defined priority uses of allowance auction revenue. It determined that entities identified by ARB as eligible for industry assistance (often referred to as emissions-intensive and trade-exposed, or EITE, entities) should be protected from carbon costs in their electricity rates for the purpose of addressing emissions and economic leakage, as well as to provide transition assistance to help industries invest in means to reduce their exposure to carbon costs. Importantly, the CPUC decided that allowance revenue should be returned to industrial entities in a manner that does not interfere with the carbon price signal in rates; though this revenue will have the effect of directly compensating industrial entities for carbon costs. The formulas used to allocate revenue to these industries are currently being developed in the implementation phase of this decision. Additional studies will be conducted to determine if other industrial sectors, aside from those identified by ARB, pose a risk of emissions and economic leakage as a result of the CPUC's decision that electricity rates should, in general, reflect a carbon price signal.

In further compliance with SB 1018, the CPUC allocated allowance revenue to small businesses for the purpose of providing transition assistance.[18] In this case, the CPUC decided to use allowance revenue to directly buy-down carbon costs in rates, given the practical

[15] Rulemaking 11-03-012.
[16] CPUC Decision (D.)12-12-033, p. 20.
[17] D. 12-12-033, p. 228-29.
[18] A small business is defined as a non-residential business entity with energy demand that does not exceed 20 kW for more than 3 months during the previous 12 month period.

difficulties of returning revenue to these customers in a manner that does not interfere with the carbon price signal.

Finally, in recognition of the limitations of the existing tiered residential rate structure, and the wide disparity between lower-tier and upper-tier electricity rates, the CPUC decided to use allowance revenue to directly offset all carbon costs in residential rates to avoid adding to the disproportionate cost burden born by upper-tier residential customers.

Remaining auction proceeds will be used to provide semi-annual bill-credits to residential customers in an amount that is equal per household. The intent of this bill credit is to help defray the indirect costs of the cap and trade program that residential customers will experience in the broader economy. The bill-credit approach allows the CPUC to preserve a household's spending power while avoiding returning revenue in a manner that would erode existing price signals in rates to use electricity efficiently.

During the next twelve months, the CPUC will finalize details necessary to implement D.12-12-033. CPUC staff is working with stakeholders to develop education and outreach programs, to finalize the utilities' implementation plans, and to develop the methods for returning revenue to EITE customers and small businesses. Utilities will begin including carbon costs in rates after these implementation details are finalized in subsequent CPUC decisions.

D. Energy Efficiency

The CPUC has a decades-long history of policy support for ratepayer investment in cost-effective energy efficiency resources. This policy directs IOUs to first satisfy their "unmet resource needs through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible."[19] By law, the utilities' energy efficiency portfolios must be cost-effective and program expenditures must be just and reasonable. In addition, the CPUC is required to "identify all potentially achievable cost-effective electricity and natural gas energy efficiency savings" and set targets for the IOUs to achieve that potential.[20] In 2003, the Energy Action Plan further established energy efficiency as the priority resource for meeting California's energy needs in the future.

In order to understand the cost containment steps the CPUC is pursuing, it is important to first understand how cost-effectiveness is determined for energy efficiency measures and programs. In estimating the cost-effectiveness of energy efficiency programs, we compare the actual costs of those programs (e.g., administration and equipment costs) with the avoided costs of providing the energy that would have been needed if the program did not exist.[21] The avoided cost estimates include the avoided cost of generating the energy as well as the deferral or avoidance of power plants, transmission and distribution lines, GHG emissions, and (beginning

[19] PU Code Sec 454.5(b)(9)(C).
[20] PU Code Sections 454.55 and 454.56.
[21] The term "avoided costs" refers to the marginal cost avoided when a resulting decrease in demand for electric or gas services defers or avoids generation from existing or new utility supply-side investments or energy purchases in the market.

with the 2013-2014 portfolio) the reduced need for Renewables Portfolio Standard compliance resources.[22]

The California Standard Practice Manual identifies the costs and benefits that should be included in several different tests as seen from different perspectives; the cost-effectiveness of a particular measure or program will vary depending on the perspective of the test.[23] The CPUC has determined that the efficiency portfolios must pass both the Total Resource Cost (TRC) and Program Administrator Cost (PAC) tests. The TRC test measures cost-effectiveness from the perspective of program participants and the utility together, including customers who do not participate in efficiency programs. The PAC test includes only the perspective of the utility. Energy efficiency portfolios as a whole must have both a TRC and PAC benefit cost ratio greater than one (i.e., the benefits must exceed the costs).

Prior to each energy efficiency portfolio cycle, the CPUC issues a portfolio guidance decision based on broad stakeholder input. The utilities submit budget applications based on this guidance, and the CPUC reviews these portfolios in order to verify compliance with prior decisions, including the cost-effectiveness requirements.

The TRC ratios of the utilities' 2013-14 energy efficiency portfolios are between 1.2 and 1.4, meaning that every dollar of energy efficiency funds spent is estimated to produce $1.20 to $1.40 in benefits to ratepayers.

1. Activities over the Next 12 Months That May Affect Rates

In D.12-11-015 the CPUC adopted the budget for the 2013-14 portfolio cycle at $1.9 billion, $92 million less annually than the budget adopted for the 2010-12 portfolio. Additionally, the utilities were directed to apply all remaining uncommitted funds they held in balancing accounts from previous years to the 2013 revenue requirement, which further reduced the energy efficiency revenue requirements by $248 million in 2013 relative to recent years. These adjustments result in a reduction of 0.2–1.2% in 2013 rates, depending on utility and customer class.

a) 2013-2014 EE Portfolio Implementation

In November 2012, the CPUC adopted new utility program budgets and portfolios affirming several changes to address rate impacts and control costs. These are the highlights:

- **Scale Up and Leverage Energy Efficiency Finance:** The utilities are continuing the popular and successful On Bill Finance program for non-residential customers while at the same time piloting a number of statewide and local finance models that leverage private capital through a variety of financial institutions. These pilots offered by the IOUs and local governments (through Regional Energy Networks, or RENS) are intended to broaden the reach and affordability of energy efficiency measures and retrofits for commercial and residential customers. Finance programs reduce rate impacts of energy efficiency programs

[22] The energy efficiency avoided cost calculator was adopted in D.05-04-024, and updated in D.06-06-063, D.09-09-047, and D.12-05-015.
[23] http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF.

because some of the finance dollars used to pay for efficiency measures replace program funds that would otherwise have needed to come from rates.

- **Cost Caps:** In 2009, the CPUC imposed a 10% hard cap on administrative costs in order to control utility personnel and overhead costs associated with energy efficiency. In 2012, the CPUC affirmed this effort to limit costs by setting additional targets to reduce "direct implementation" costs and directed a review of this cost category. The same decision reduced the IOUs' overall budget request by $167 million.

b) Interagency Coordination Regarding Energy Efficiency Impacts on Grid Planning

The CPUC, the CEC and CAISO have increased their inter-agency cooperation in order to more effectively follow the "loading order," which prioritizes demand side resources over new fossil fuel generation in generation and transmission planning. This requires properly accounting for the impacts that energy efficiency programs have on load reduction and reflecting this in determinations of need for new electric infrastructure. Steps taken to enhance cooperation include:

- Beginning this year, the three agencies will implement a joint work plan in each CEC Integrated Energy Policy Report proceeding. The work plan will align the key milestones of the demand forecasting process, including projections for energy efficiency, with the agencies' planning proceedings.
- The CEC is developing new modeling methods to more robustly capture efficiency impacts. The new models are being developed in close consultation with the CPUC and CAISO and will be vetted through the Demand Analysis Working Group (DAWG) collaborative process, which was established to include a wide variety of stakeholders in technical discussions about the forecasting process and methods.
- The CPUC will use the current efficiency portfolio cycle to investigate additional planning improvements, from authorizing longer term efficiency portfolio cycles to better integrating efficiency into system wide and regional operational needs.

As demand-side resources are better accounted for in forecasting and grid planning processes, it is expected that fewer new supply-side resources will be authorized than otherwise would have, decreasing transmission and generation revenue requirements and, in turn, rates.

c) Post-2014 Portfolio Planning Proceeding

In 2013, the CPUC will begin planning for the post-2014 portfolio authorization, with a guidance decision expected later in the year. Among other things, the proceeding will review the cost effectiveness methodology, provide updates to savings and cost assumptions used to plan portfolios, and update the energy savings goals. These reviews will continue to ensure that the energy efficiency programs deliver the maximum level of energy savings for the lowest cost.

d) Audits and Evaluation

The CPUC's Division of Water and Audits performs financial, management and regulatory compliance audits of the IOUs' energy efficiency portfolios. All issues identified in the audits are then addressed by CPUC staff and the IOUS, though recent audits have not revealed major problems with program implementation. In addition, the Energy Division oversees a comprehensive suite of evaluations of the portfolio activities. These evaluations identify improvements in design and implementation of the programs to improve their efficacy and cost-effectiveness. In the 2013-2014 portfolio cycle, the Energy Division will work with the utilities to incorporate findings from these audits and evaluations into the 2013-2014 portfolio implementation and post-2014 planning activities.

E. Demand Response

Demand response (DR) is a reduction or shift in electricity consumption by customers in response to either economic or reliability signals. Demand Response programs and tariffs help to reduce peak electricity consumption and manage demand. In the short run, DR lowers wholesale energy costs because reduced demand forces power suppliers to adjust their prices downward in the energy market. DR can also provide load reductions when the grid is strained, reducing the likelihood of blackouts. In the long run, DR enables utilities to avoid building or buying expensive new generating plants that are used for only a small number of hours per year. DR is at the top of the CPUC's "loading order,"[24] next to energy efficiency.

DR programs may be offered by a Utility, a Load Serving Entity, a Community Choice Aggregator, or a third party Demand Response Provider. The IOUs operate a suite of DR programs and have contracts with third-party DR providers (also known as aggregators) to operate other DR programs. In total, the IOUs have approximately 1,950 MW of DR, approximately the capacity of four large power plants.

1. Activities over the Next 12 Months That May Affect Rates

- **Budget for IOUs' DR Programs:** In 2012, the CPUC approved the IOUs' 3-year (2012-2014) DR program portfolios and budgets, with an approximate cost of $1 billion in total for the three years. The DR portfolio includes price-responsive programs that offer bill credits to participating customers, rebates to help off-set the cost of enabling technologies, marketing and education programs, and contracts with third-party DR providers. Ratepayers pay these program costs through rates.
- **Measuring Cost-Effectiveness:** In D.10-12-024, the CPUC adopted a protocol for estimating the cost-effectiveness of DR programs. This protocol is a tool to ensure that current DR incentive programs cost less than a new peaker plant (which could otherwise be needed if not for the DR resource). The CPUC is working to refine and improve the protocol to increase its accuracy when evaluating the cost-effectiveness of future DR programs.
- **Finalize Rule & Implement Direct Participation:** The active bidding of DR into wholesale energy markets can benefit ratepayers as DR puts downward pressure on the bids offered by supply-side resources in those markets. The CPUC is working with stakeholders to finalize rules under which utilities, third-party DR operators or end-use utility customers can bid their DR capacity directly into wholesale markets (Electric Rule 24). When the rule is complete, demand response providers are to register with the CPUC, and follow the service agreements with the CAISO and the CPUC-regulated utilities, and can then begin bidding into CAISO energy markets.

[24] "Loading order" is discussed in Chapter III, Section A.

- **Integration with Energy Efficiency Programs:** The IOUs also implement ratepayer-funded energy efficiency portfolios. Utility end-use customers stand to benefit if the IOUs can create combination energy efficiency and demand response offerings that can be presented to and chosen by customers. Such integration of energy efficiency and demand response can lead to better economic choices by customers to reduce their energy bills as well as savings in IOU marketing and education costs.

2. Trends beyond the 12 month reporting period

- **New Demand Response Rulemaking:** The Commission will be starting a new DR rulemaking that will explore potentially new procurement and delivery models for DR that could begin in 2016. Under consideration are new policy goals, framework and evaluation methods for DR. One of the key new goals for DR is to use it as a tool to better integrate renewable resources on the grid (more details on this below). The goals of the new DR OIR will be coordinated closely with the CAISO's Demand Response Roadmap and the CEC's Integrated Energy Policy Report (IEPR) chapter on DR.
- **Integration of Renewable Power:** Conventional DR has focused exclusively on reducing peak demand. While that remains an important goal of the CPUC's DR policy, DR could also play a new role in California's energy landscape. The state's mandate to obtain 33% renewable power by 2020 is anticipated to bring new operational challenges for grid reliability and efficiency because of the intermittent nature of renewable power. DR resources could provide critical ramping[25] capability that makes up for shortfalls when renewable energy supplied is insufficient to meet demand, helping the CAISO integrate renewable power into the grid. The CPUC will be developing policies that address this need in a demand response rulemaking in the next 12 months.

F. Rate Design and Time-Varying Pricing

The CPUC's dynamic pricing principles seek to increase customer involvement in managing California's energy supply and managing future power plant development costs, by providing economic incentives to reduce electric demand during peak periods.[26] Time-Varying Pricing (TVP) prices electricity at higher rates during peak and partial peak periods, and encourages customers to shift their energy demand to off-peak times when electricity is less costly. Because peak demand determines how much generation and transmission capacity is necessary, a utility and its customers can lower costs by shifting load away from the peak demand period and reducing the number of new generation and transmission facilities needed. Ratepayers can benefit from TVP by using less energy in response to price signals or shifting their load to off-peak times. In addition, TVP encourages long-term behavioral changes increasing energy efficiency, load shifting, and conservation.

TVP includes time-of-use (TOU) rates, and two forms of dynamic pricing: critical peak pricing (CPP), and real-time pricing (RTP). TOU rates are predictable, while CPP and RTP are adjusted on short notice (typically a day or hour ahead) as a function of system conditions. CPP

[25] Ramping: changing the loading level of a supply-side or a demand-side resource in a constant manner over a fixed time in order to balance energy supply and demand.
[26] Decision 10-02-032 February 25, 2010.

charges a higher price on a few critical peak demand days per year, for a specified few hours when demand is high or supply is short.

Each utility is on a slightly different time line for implementing time-of-use and critical peak pricing rates for their customers. Large agricultural, commercial, and industrial customers have had mandatory TOU rates for between five and thirty years, and default CPP rates for two to five years. Small and medium commercial and industrial customers will transition to mandatory TOU by 2014, and to default CPP by 2014 for PG&E and SDG&E, and by 2016 for SCE. TOU and CPP programs continue to be optional for residential customers. The current implementation status is reflected in the table below.

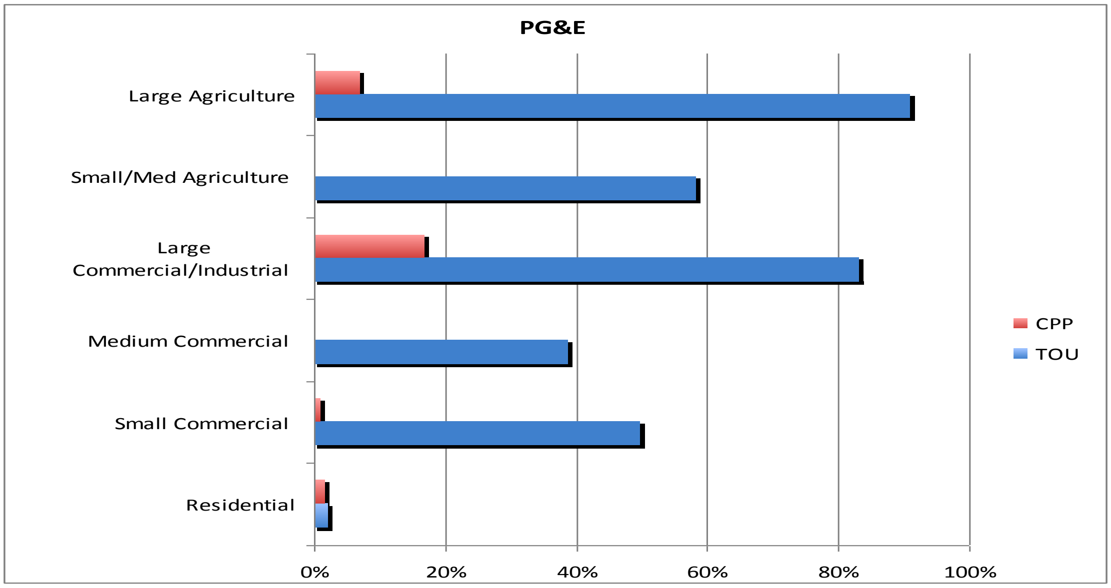
Table III-1
Status of TOU and CPP Rate Implementation[27]

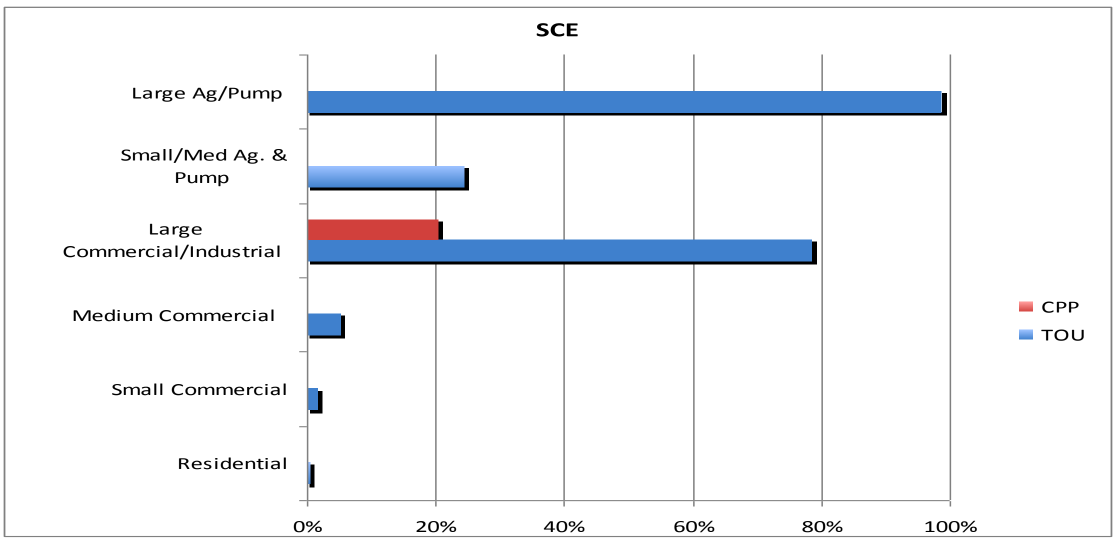
	PG&E		SCE		SDG&E	
RATE CLASS	**TOU**	**CPP**	**TOU**	**CPP**	**TOU**	**CPP**
Residential	Optional	Optional	Optional	Optional	Optional	Optional Nov. 2013
Small & Medium Commercial (< 200 kW)	Defaulting in two waves: Nov. 2012, Nov. 2013	Default Nov. 2014, can opt out to TOU	Defaulting in two waves: Jan. 2014, Jan. 2015	Default Jan. 2016, can opt out to TOU	Optional Nov. 2013. Mandatory Nov. 2014[28]	Optional Nov. 2013. Default Nov. 2014, can opt out to TOU
Large Commercial & Industrial (≥ 200 kW)	Mandatory	Default May 2010, can opt out to TOU	Mandatory	Default Oct 2009, can opt out to TOU	Mandatory	Default May 2008, can opt out to TOU
Small & Medium Agriculture (< 200 kW)	Default March 2013	Optional	Defaulting in two waves: Feb. 2014, Feb. 2015	Optional	Optional Nov. 2013. Mandatory Nov. 2014	Optional Nov. 2013
Large Agriculture (≥ 200 kW)	Mandatory	Default March 2011, can opt out to TOU	Mandatory	Default Feb. 2016, can opt out to TOU	Mandatory 2013	Default May 2008, can opt out to TOU

The percentages of each utility's customers now using TOU or CPP rates are shown graphically in Table III-2, and in tabular form in Table III-3.

[27] Details of the implementation schedules are in the following CPUC decisions:
PG&E – D.11-11-008 and D.12-08-005; SCE – D.13-03-031; SDG&E – D.12-12-004
[28] TOU is already mandatory for customers > 20 kW.

Table III-2
Percentage of Customers Using TOU or CPP Rates





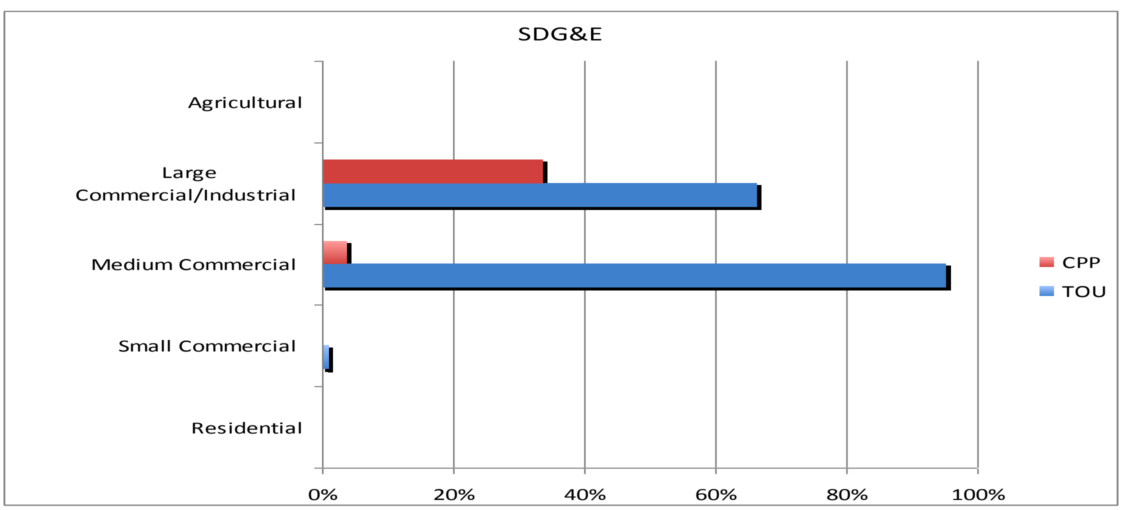


Table III-3
Customers on Time-Varying Rates

PG&E	Total Customers	% on TOU	% on CPP
Residential	4,877,600	2	2
Small Commercial	490,500	50	1
Medium Commercial	67,300	39	< 0.5
Large Commercial/Industrial	8,300	83	17
Small/Med Agriculture	92,312	58	< 0.5
Large Agriculture	1,688	91	7
TOTAL	5,537,700	8	2

SCE	Total Customers	% on TOU	% on CPP
Residential	4,281,750	< 0.5	< 0.5
Small Commercial	490,829	2	< 0.5
Medium Commercial	120,209	5	< 0.5
Large Commercial/Industrial	11,503	79	20
Small/Med Ag. & Pump	26,149	25	< 0.5
Large Ag/Pump	1,253	99	< 0.5
TOTAL	4,931,693	1	< 0.5

SDG&E	Total Customers	% on TOU	% on CPP
Residential	1,245,652	< 0.5	0
Small Commercial	122,188	1	< 0.5
Medium Commercial	23,417	95	4
Large Commercial/Industrial	682	66	34
Agricultural	3,376	0	< 0.5
TOTAL	1,395,315	2	< 0.5

PG&E was the first California utility to default small and medium commercial customers to time-of-use rates. To date, approximately 270,000 PG&E small or medium commercial customers are on a TOU rate. Of the 270,000, roughly 41,000 voluntarily enrolled on the rate. An additional 250,000 customers will default to a TOU rate in November of 2013. Small Agricultural customers are being defaulted to a TOU rate in spring of 2013. For SDG&E, there are currently more than 23,000 small and medium commercial customers on TOU rates and by

November 2014 more than 100,000 small commercial customers will be placed on TOU rates. Currently SCE has more than 14,000 small and medium commercial customers on TOU rates and by January 2014, the remaining small and medium commercial customers, almost 600,000, will be on TOU rates.

> **What is Peak Day Pricing?**
>
> Peak Day Pricing (PDP) is a Time-Varying Pricing plan offered by PG&E that combines time-of-use pricing with critical peak pricing. The time-of-use portion of this plan offers lower prices during the daily periods when electric demand is usually low and higher prices when demand is usually high. The critical peak pricing portion of the plan consists of Peak Day Pricing Event Day surcharges on days when demand is exceptionally high, and credits during all other summer hours. Customers experience between 9 and 15 Peak Day Pricing Event Days annually when the rate per kWh increases by a fixed amount for usage between 2:00 PM and 6:00 PM.

1. Activities Over the Next 12 Months That May Affect Rates

a) Time-varying Pricing

- **PG&E Default Residential Rate Programs** (A.10-08-005): PG&E proposed Peak Day Pricing rates, described above, as the default residential critical peak pricing rates PG&E was required by D.08-07-045 to propose. PG&E simultaneously proposed that the CPUC defer consideration of default residential PDP until Phase 2 of its 2014 GRC. At issue is whether the CPUC can authorize PG&E to adopt default TVP rates for all residential customer usage or only for usage in excess of Tiers 1 and 2. The parties have submitted testimony and briefs. A decision will be issued in 2014.
- **PG&E Proposal for a Peak Time Rebate Program** (2010 Rate Design Window Proceeding A.10-02-028, consolidated with the DRRP Proceeding above): PG&E proposed implementing residential Peak Time Rebate (PTR) for all eligible customers starting May 1, 2013. A rebate would be offered for demand reductions during PTR event hours (up to 15 event days per year). In updated testimony, PG&E later proposed to not implement PTR and instead continue to promote PG&E's "SmartRate" voluntary CPP for residential customers. A decision is anticipated in the summer of 2013.
- **PG&E Transition to Default PDP Rates** (A.09-02-022): The remaining issues in this case are about education and outreach for mandatory TOU rates and default (opt-out) PDP rates for small and medium business and agricultural customers. Despite five petitions for modification filed by PG&E and other parties since 2010, implementation of this rate transition is well underway. PG&E filed another petition for modification in March 2013, still pending. The utility is requesting (1) to extend the timeframe for cost recovery, and (2) to reduce the number of customers they are required to contact whose bills will be most affected by the change. A decision on this petition is still pending; expected later this year.
- **SDG&E Application for Approval of its Proposals for Dynamic Pricing** A.10-07-009: D.12-12-004 orders optional TOU and CPP rates for residential and small commercial customers on November 1, 2013, mandatory TOU rates and default CPP rates for small

commercial customers in November 2014, and mandatory TOU rates and optional critical peak pricing rates for small and medium agricultural customers in November 2014. SDG&E filed an application for rehearing on issues of allocation of dynamic pricing implementation costs early in 2013. The application for rehearing has not been accepted as timely-filed, pending ruling on SDG&E's motion to accept.

b) CPP Load Impacts

As discussed above, Critical Peak Pricing (CPP) incentivizes customers to shift load away from peak periods with the year's highest demands, charging a higher price on a few critical peak days for a specified few hours. Typically, CPP event days are called 5 to 15 times a year when demand is high and supply is short. The table below summarizes the load reduction due to large customers on CPP for the average event day for 2010 through 2012.

Table III-4

Summary of Statewide CPP Impacts[29]
Average Event Day

Utility	Year	Number of Event Days	Approximate Customer Count	Reference Load[30] (MW)	Load Impact[31] (MW)	Percent Impact
PG&E	2010	9	1,650	592	23	3.9%
	2011	9	1,750	473	28	5.9%
	2012	9	1,627	437	30	6.9%
SCE	2010	12	4,100	1,077	31	2.9%
	2011	12	3,000	615	35	5.7%
	2012	12	2,508	554	33	6.0%
SDG&E	2010	4	1,350	357	19	5.3%
	2011	2	1,300	359	19	5.3%
	2012	7	1,117	268	16	6.0%
Total	2010		7,100	2,026	73	3.6%
	2011		6,050	1,448	82	5.7%
	2012		5,252	1,259	79	6.3%

The aggregate statewide CPP load impact increased from 73 MW in 2010 to 82 MW in 2011, and decreased slightly to 79 MW in 2012. The decrease was caused by customers dropping out

[29] Freeman, Sullivan & Co., 2011 California Statewide Non-residential Critical Peak Pricing Evaluation (June 1, 2012), available at http://fscgroup.com/reports/2011-statewide-cpp-evaluation.pdf
Freeman, Sullivan & Co., 2012 California Statewide Non-residential Critical Peak Pricing Evaluation (April 1, 2013), available at http://fscgroup.com/reports/2012-non-res-cpp-statewide-evaluation.pdf

[30] The aggregate load of CPP customers on non-CPP-event days.
[31] The estimated amount by which CPP customers reduced their demand during CPP events.

of the program when the one-year bill protection expired[32]. Despite the lower enrollment, customers remaining on the CPP program delivered higher percent load reductions. On average, customers increased their load reduction from 3.6% in 2010 to 6.3% in 2012. It appears that customers who remain on the program learn over time how to become more responsive to CPP events.

c) Residential Rate Changes Since SB 695

SB 695, enacted in 2009, loosened some restrictions on the CPUC's authority to set residential electric rates that the legislature enacted in AB 1X in the wake of the 2000-2001 energy crisis. Some of the stated legislative intentions underlying SB 695 were to relieve the upward pressure on residential electricity rates for upper tier usage, to reduce the large differential between electricity rates for lower tiers (tiers 1 and 2) and upper tiers (tiers 3 through 5), to allow for modest increases to CARE rates, and to ultimately bring retail residential rates more in line with the cost of providing residential service. Table III-5 shows the changes in tiered rates from before SB 695 was enacted to the present. This data provide some evidence on how well this law is meeting its rate design goals.

Looking first at non-CARE rates, both PG&E and SDG&E have been able to reduce their upper-tier rates to some extent since SB 695 took effect. PG&E eliminated its Tier 5 rate in 2010, and has reduced its Tier 4 rate on a cumulative basis over this period; both of these changes significantly reduced the average rates and bills paid by the largest users, bringing the top rate back a bit closer to the cost to serve. On the other hand, while PG&E's tier 4 and tier 5 rates have declined, its tier 3 rate has risen consistently, which takes back some of the gains that customers with usage in tiers 4 and 5 have seen. SDG&E had already eliminated its tier 5 rate by 2009, and has managed, over this timeframe, to reduce both its tier 3 and tier 4 rates on a cumulative basis.

SCE's tiered rates appear to have been least influenced by the loosening of some rate design restrictions that SB 695 accomplished, with its rates for tiers 3, 4, and 5 all rising substantially in 2011, 2013, and on a cumulative basis. One explanation for this is that SCE's tiered rates were much less unbalanced at the beginning of this period than were PG&E's or SDG&E's tiered rates; PG&E's top tier rate was 3.5 times its tier 1 rate in 2009, while SCE's was only 2.3 times its tier 1 rate. Precisely because SCE's tier 1 rate in 2009 bore a closer relation to its cost to serve (its system average rate) than was true for PG&E and SDG&E, P.U. Code Section 739.9(b) enacted by SB 695 prohibited SCE from raising its tier 1 rate by the otherwise allowable 3% to 5% in 2011 and 2012[33], while it did not similarly limit PG&E and SDG&E.

[32] For large customers defaulted onto CPP rates, bill protection expired in 2009 for SDG&E, 2010 for SCE and 2011 for PG&E.

[33] Note that the cap in Sec. 739.9(b) applies generally, and has limited SCE rate changes not specifically related to the annual SB 695 rate changes.

Table III-5
Annual Changes in Residential Tiered Rates, 2009 to 2013

PG&E

	% Change in Non-Care Rates					% Change in CARE Rates		
	Tier 1	Tier 2	Tier 3	Tier 4	Tier 5*	Tier 1	Tier 2	Tier 3**
2009-2010	3	3	12	15	15	0	0	
2010-2011	3	3	2	-4	-18	0	0	
2011-2012	5	5	5	-14	-14	0	0	30
2012-2013	3	3	2	2	2	0	0	12
Cumulative	15	15	22	-4	-17	0	0	46

* PG&E Non-CARE Tier 5 rate was eliminated in June 2010
** PG&E CARE Tier 3 rate was created in 2012

SCE

	% Change in Non-Care Rates					% Change in CARE Rates		
	Tier 1	Tier 2	Tier 3	Tier 4	Tier 5*	Tier 1	Tier 2	Tier 3
2009-2010	1	1	1	1	1	0	0	2
2010-2011	2	1	14	12	11	0	0	14
2011-2012	2	8	0	0	0	0	0	0
2012-2013	2	3	23	20	18	0	0	10
Cumulative	6	14	42	36	31	0	0	27

* SCE Non-Care Tier 5 rate was eliminated in April 2013

SDG&E

	% Change in Non-Care Rates				% Change in CARE Rates		
	Tier 1	Tier 2	Tier 3	Tier 4	Tier 1	Tier 2	Tier 3
2009-2010	4	4	-12	-12	-1	0	-13
2010-2011	3	3	4	3	-1	-1	-1
2011-2012	4	4	-11	-11	0	0	0
2012-2013	3	3	7	6	0	0	0
Cumulative	15	15	-14	-13	-2	-1	-13

* SDG&E Non-Care Tier 5 rate was eliminated in late 2008

d) CARE Rates

California Alternate Rates for Energy (CARE) is a low-income energy rate assistance program instituted in 1989 to provide eligible low-income households a 20% discount on electric and natural gas bills. However, since CARE customers are not subject to the high rates for tiers 4 and 5, the discount for CARE customers can be above 20% depending on their usage. For example, in 2013 PG&E estimates that some of their CARE customers receive up to a 59%

discount, SDG&E estimates a discount rate up to 40%, and SCE estimates a discount rate up to 45% off their energy bills.

Returning to Table III-5, the changes in CARE rates since SB 695 have varied even more between the three IOUs than the changes in non-CARE rates. SB 695 limited changes in tier 1 and 2 CARE rates to the lesser of: (1) the annual change in CalWORKS benefits, or (2) 3%. Soon after SB 695 was enacted, the legislature suspended annual changes in CalWORKS benefits, effectively prohibiting the CPUC from allowing any increase in tier 1 and 2 CARE rates. The table shows that the CPUC and utilities have obeyed these two colliding laws; tier 1 and 2 CARE rates have not increased during this period (nor have they since 1997.) Notably, SDG&E has slightly lowered its tier 1 and 2 CARE rates, based on its interpretation, not shared by the other two IOUs, of how this restriction in SB 695 must be implemented.

Changes to tier 3 CARE rates have varied widely by IOU and by year. PG&E had no tier 3 CARE rate in 2009, but instituted it in 2011. The CPUC approved PG&E's requests to set its initial tier 3 CARE rate 30% above its tier 2 CARE rate, and to further increase this tier 3 rate by 12% in 2013. The bill impact of this cumulative 46% increase in the rate over two years depends entirely on what proportion of the customer's usage is in tier 3. A PG&E CARE customer with 10% of her usage in tier 3 would have seen a 4.6% bill increase over two years. A PG&E CARE customer with 50% of his usage in tier 3 (thus using a total of 260% of baseline allowance) would have had a 23% bill increase over these two years. These increases shrink to 1% and 5% when spread over the four years covered by Table III-5. Furthermore, when combined with the decreases to CARE rates in all tiers between 1998 and 2009, these bill impacts shrink further to average annual changes of -0.8% and +0.4%, respectively.

SCE and SDG&E already had tier 3 CARE rates in 2009. SCE's tier 3 CARE rate has increased a cumulative 27% over the four years in the table, considerably less than SCE's non-CARE rates. SDG&E's tier 3 CARE rate has declined a cumulative 13%, about the same as its tier 3 non-CARE rate. In summary, bill impacts of these rate changes for CARE customers from 2009 to 2013 range from substantial increases for high-usage PG&E CARE customers, to substantial decreases for high-usage SDG&E CARE customers.

When judging the extent to which SB 695 is achieving its rate design goals or at least is allowing tiered rates to move in generally rational directions, it is important to keep in mind that the observed increases in some upper tier rates would have been markedly higher and the modest decreases in others would not have occurred at all if SB 695 had not enabled the modest increases to tier 1 and tier 2 rates that it did. A fair assessment of SB 695 might be that it has kept residential rates for PG&E and SDG&E from getting too much more imbalanced than they were in 2009, and that it has created a modest linkage between tier 3 CARE rates and non-CARE residential rates for all three utilities.

e) CARE Program

For the 2012-2014 program cycle, the CPUC adopted a total CARE budget of $3.8 billion, or $1.25 billion annually, funded by ratepayers through the Public Purpose Program (PPP) Charge. Two of the CARE program goals include achieving higher penetration rates over time without substantially increasing the CARE outreach budget, and increasing enrollment efficiencies by streamlining the screening, eligibility, and retention of participants. As of

December 2012, PG&E reported a CARE penetration rate at 89.7%, SCE at 96.3%, SCG at 90.1%, and SDGE at 85% penetration.

f) Residential Rate Reform Rulemaking

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

To address this and other challenges of residential rates, the CPUC issued an order instituting rulemaking (OIR) in June 2012 to examine current IOU residential rate structures and proposals to transition to TVP and dynamic rates. In September 2012, a ruling highlighted the following OIR guiding principles to be used in formulating rate proposals for this proceeding:

1. Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost;
2. Rates should be based on marginal cost;
3. Rates should be based on cost-causation principles
4. Rates should encourage conservation and energy efficiency;
5. Rates should encourage reduction of both coincident and non-coincident peak demand;
6. Rates should provide stability, simplicity and customer choice;
7. Rates should avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals;
8. Rates should encourage economically efficient decision-making;
9. Incentives should be explicit and transparent; and
10. Transitions to the new rate structure should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates.

The November 2012 scoping ruling outlined the December 2012 workshop, and a March 2013 ruling requested rate design proposals by May 2013. Parties are invited to propose either changes to residential rate design that could be made under existing law, changes that would require legislation, or both. Parties are also asked to address how their proposed rate design would affect the value of net energy metered facilities for participants and non-participants compared to current rates. After the rate design proposals have been reviewed and comments and briefs have been filed and reviewed, a proposed decision is expected to be issued by the end of 2013.

G. Customer-Sited Distributed Generation and California Solar Initiative

The CPUC's Energy Division oversees the Self-Generation Incentive Program (SGIP) and the California Solar Initiative (CSI).[34] Together these two key distributed generation (DG) programs foster development of renewable energy, and emerging and highly efficient technologies on the *customer side* of the electric meter. Utility-side, or "wholesale" DG programs, including the Renewable Auction Mechanism (RAM), the Feed-in-Tariff (FiT), and utility solar photovoltaic programs, were discussed earlier in this report.

a) The Self Generation Incentive Program

Established in 2001, The Self Generation Incentive Program (SGIP) provides incentives to support existing, new, and emerging distributed energy resources installed on the customer's side of the utility meter (excluding solar technologies, which are incentivized under the California Solar Initiative.) Qualifying technologies include wind turbines, waste heat to power technologies, pressure reduction turbines, internal combustion engines, microturbines, gas turbines, fuel cells, and advanced energy storage systems. The SGIP has 1,480 completed projects for a total capacity of 428 MW.[35]

b) The California Solar Initiative

Established in 2006 by SB 1 (Murray), the California Solar Initiative offers solar incentives to non-residential and residential[36] customers in investor-owned utility territories of PG&E, SCE, SDG&E and SoCalGas. The CSI Program will stimulate the installation of 1,940 MW of distributed solar generation by 2017. The CSI Program is comprised of five distinct program components: General Market Program, Single-family Affordable Solar Homes (SASH) Program, Multi-family Affordable Solar Housing (MASH) Program, Research, Deployment and Demonstration (RD&D) Program, and CSI-Thermal Program.[37] The CPUC also has jurisdiction over Pacific Power's Northern California service territory, and in 2011 granted approval of the Pacific Power California Solar Incentive Program's $4.2 million revenue requirement. New home construction and solar programs within POUs are not under the CPUC's jurisdiction.

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

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[34] CPUC Rulemaking (R.) 10-05-004 oversees the SGIP and CSI programs.
[35] Source: SGIP Online Database, data through March 11, 2013.
[36] Residential CSI incentives are limited to existing housing stock; solar incentives for new residential construction fall under the New Solar Homes Partnership, managed by the California Energy Commission. The program was previously funded by the Public Goods Charge which expired at the end of 2011.
[37] For more information on the five CSI Program components, please visit http://www.cpuc.ca.gov/PUC/energy/Solar/.

As a market transformation policy, a critical goal of CSI is to drive down the cost of solar systems. The cost of completed solar systems has declined over 25 percent from 2007.[38] Through the first quarter of 2013, the CSI program has installed 1,105 MW at nearly 98,000 sites throughout California's IOU service territories.[39]

The CSI-Thermal program is the newest CSI program component. It provides rebates for solar water heating and other solar thermal technologies that offset either electric or natural gas systems. Established in D.10-01-022, the $530.8 million program features residential, commercial/multi-family and low-income sub-components. In April 2013, the CPUC modified the CSI-Thermal Program to include additional solar thermal technologies, including process heat, solar cooling, and combination systems.

c) Program Budgets

Pursuant to AB 1150 (Perez, 2011), the CPUC has authorized annual collections for SGIP through December 31, 2014 at a rate of $83 million, to be allocated among the four large IOUs according to each utility's relative percentage of customers. Any unspent funds will be refunded to ratepayers in 2016. Funds are distributed on a first-come basis to qualified projects.

SB 1 (Murray, 2006) established a CSI Program budget of $2.167 billion. Subsequent CPUC Decisions established budgets for the CSI program sub-components: SASH and MASH were each allocated $108.3 million, and the RD&D program was allocated $50 million. SB 585 (Kehoe, 2011), allocated an additional $200 million to the CSI Program budget to address an unforeseen shortfall in the CSI incentive budget. The bill also requires the CPUC to use accumulated interest from customer collections prior to collecting additional ratepayer funds.

In 2007, AB 1470 (Huffman, 2007) and SB 1 established the CSI-Thermal program budget of $350.8 million, from which $250 million was collected through gas rates and $100.8 million through electric rates.

d) Net Energy Metering

Net Energy Metering (NEM) is a tariff that allows a customer-generator to receive a billing credit for power generated by their onsite system. The credit is used to offset the customer's electricity bill at full bundled retail rates. NEM is an important element of the policy framework supporting direct customer investment in grid-tied distributed renewable energy generation, including customer-sited solar PV systems.

1. Activities Over the Next 12 Months That May Affect Rates

CPUC Decision Regarding Calculation of the Net Energy Metering Cap: The NEM cap, as established in Public Utilities Code Section 2827(c)(1), limits the availability of electric utility NEM programs to eligible customer-generators in the utility service territory on a first-come-first-served basis until the total rated generating capacity used by eligible customer-generators exceeds five percent of the utility's "aggregate customer peak demand." D.12-05-036 clarifies the denominator of the equation, defined in the statute as "aggregate customer peak demand," that the IOUs should use to calculate the five percent NEM cap. By this decision, the CPUC

[38] Source: http://californiasolarstatistics.ca.gov/reports/quarterly_cost_per_watt/. Data as of 3/6/13.
[39] Includes CSI data for IOU territories only.

clarifies that "aggregate customer peak demand" means the aggregation, or sum, of individual customers' peak demands, i.e., their non-coincident peak demands, rather than the utility's aggregate customer demand at the time of system peak, as the utilities had previously assumed.

NEM Benefit-Cost Evaluation Study: AB 2514 (Bradford, 2012) requires the CPUC to complete a benefit-cost study "to determine who benefits from, and who bears the economic burden, if any, of, the net energy metering program …and to determine the extent to which each class of ratepayers and each region of the state receiving service under the net energy metering program is paying the full cost of the services provided to them by electrical corporations, and the extent to which those customers pay their share of the costs of public purpose programs." In 2012, the CPUC hired the consulting firm Energy and Environmental Economics, Inc. (E3) to complete the NEM benefit-cost study pursuant to AB 2514. The study is required to be completed by October 2013.

The outcome of the NEM study will not only inform future modifications to the NEM tariff, but may also be used to inform the proceeding on Residential Rate Reform.

H. Energy Savings Assistance

The Energy Savings Assistance program began in the 1980s as a direct assistance program provided by some of the investor-owned utilities (IOUs), and was formally adopted by the legislature in 1990 through Public Utilities Code Section 2790.

The Energy Savings Assistance program is a resource program designed to garner significant energy savings in California while providing an improved quality of life for the low-income population. Participants include single family, multi-family, mobile homes, and non-profit group living customers. The program allows for home weatherization services for low-income households and includes the following measures and services: (1) heating ventilation air conditioning; (2) infiltration and space conditioning; (3) weatherization; (4) water heating conservation; (5) energy education; and (6) other miscellaneous measures including refrigerator replacements and lighting measures. The program may also include other building conservation measures, installation of energy efficient appliances and energy education programs. Each IOU's portfolio of measures is evaluated for cost-effectiveness during the budget application process and all measures are provided at no cost to the resident, with the exception of a few measures owned by the landlords. In those instances, landlord co-payments are required. Installing such measures helps customers reduce energy consumption, resulting in bill savings for program participants.

For the 2012-2014 program cycle, the CPUC adopted a total Energy Savings Assistance program budget of $1.1 billion, or approximately $370 million annually, funded by ratepayers through the Public Purpose Program (PPP) Charge. In 2012, the four large IOUs treated approximately 270,000 homes statewide, with PG&E treating 110,500 homes at an average cost of $1100/home, SCE treating 68,900 homes at an average cost of $571/home, SCG treating 86,300 homes at an average cost of $970/home, and SDGE treating 20,900 homes at an average cost of $1000/home.

The Energy Savings Assistance program is an energy resource program that aims to enroll all eligible and willing customers into the program by 2020, while delivering increasingly cost-effective and longer-term savings to low-income customers. Challenges continue to include striking the right balance between achieving cost-effective energy savings, (and as a result bill savings), versus providing health, comfort, and safety benefits to participants, fully leveraging this program with other energy efficiency programs (including other Utility, State, Federal and local programs), and providing the right education to all participants on the benefits of energy efficiency that form long term conservation behaviors.

1. Activities Over the Next 12 Months That May Affect Rates

D.12-08-044 adopted new initiatives and improvements for the Energy Savings Assistance program to encourage and facilitate greater program efficiencies, collaborations and overall benefits to the low-income population as well as the rest of the state. The implementation of these efforts will continue to be central to the CPUC's activities over the next 12 months, and beyond. These initiatives include the following:

- Better understand the multifamily community and enhance outreach to property owners of these complexes;
- Increase the overall cost effectiveness of the program; and
- Focus and promote relevant workforce education and training.

2. Trends beyond the 12 month reporting period

Through the Energy Savings Assistance program the state's low-income population receives benefits that include decreased energy bills, increased energy conservation, increased health, comfort, and safety benefits, better 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.

I. CPUC Advocacy for California Electric Interests at FERC

The CPUC advocates for California retail ratepayers at the Federal Energy Regulatory Commission (FERC) to seek just and reasonable rates in proceedings addressing transmission and sale of electricity in wholesale markets. This is pursued by filing testimony, litigating complaints and rate increases and participating in settlement talks or hearings. In addition, the CPUC has been participating in initiatives led by the CAISO, the independent system operator regulated by FERC that coordinates, controls, and monitors the operation of the electrical power grid system within the state of California.

1. Refunds to CA Ratepayers from the Energy Crisis

The California Energy Crisis in 2000-2001 was a result of a combination of a shortage of capacity, high energy prices, market manipulation by some electricity wholesale market participants, and other factors. To satisfy electricity demand during the Crisis, the utilities were compelled to buy electricity in the spot market at high prices, while being restricted on how much they could charge retail ratepayers. This extreme imbalance led to a lack of liquidity that forced the bankruptcy of one major utility (on April 6, 2001) and the near bankruptcy of another. The State intervened and financially backed billions of dollars in electricity purchases in the wholesale electricity market to keep the lights on in California.

Litigation regarding the Energy Crisis began in August 2000 when SDG&E filed a complaint with the FERC seeking a cap on the escalating wholesale energy prices in California. Following the FERC's denial of a complaint for relief from overcharges occurring in the summer of 2000, the CPUC filed a complaint at the FERC representing California ratepayers in a case against a dozen electricity wholesale market participants accused of market manipulation. This case completed its long arduous journey on February 15, 2013, when a FERC administrative law judge (ALJ) ruled in favor of the complainants (CPUC, California Attorney General, SDG&E, PG&E, and SCE) and determined a set of mitigation methods to apply to the transactions to calculate refund amounts. If the ALJ's decision is adopted by FERC, it is expected to yield nearly $1.6 billion in refunds to California ratepayers. The refunds would be passed on to ratepayers as an offset against current electric bills.

In addition, the CPUC has been pursuing refund claims against Bonneville Power Administration (BPA) and the Western Area Power Administration (WAPA) for the past 11 years for the large quantities of electricity they sold from federal dams at extremely high prices during the crisis. An ALJ of the United States Court of Claims in Washington, D.C. issued a decision in that case on April 2, 2013 holding the two federal agencies BPA and WAPA liable for upwards of $1 billion in refunds for electricity they sold to California at unreasonable prices.

The two decisions taken together, if sustained on subsequent review, could net nearly $2.6 billion in refunds to California consumers. In that case, these funds would likely flow back to electric customers by offsetting their generation costs. The potential reductions to rates are substantial: $2.6 billion would amount to over 9% of the three major electric IOUs' annual total revenue requirements. Nonetheless, these cases may be litigated for several more years before all appeals are exhausted and rate reductions could be ordered.

2. Transmission Cases at FERC

The CPUC intervenes in transmission rate cases at the FERC to advocate for just and reasonable rates by active participation in the FERC proceedings. In 2013, the CPUC's FERC-related work includes three Transmission Owner (TO) rate cases involving PG&E, SCE, and SDG&E. The total revenue being requested by the three utilities is approximately $5.2 billion[40]. The CPUC's advocacy role in FERC proceedings is a critical factor in FERC's decision-making process as it considers the appropriate amount of transmission revenue requirements for the IOUs. As a result of the CPUC's participation, the FERC has reduced the IOUs' requests for retail rate revenue requirement increases by approximately $788 million (1998-2009), thereby limiting the amount of transmission rate increases in California.

[40] SDG&E is requesting $1.3 Billion in revenue requirement in TO4; SCE is requesting $1.8 Billion in TO6**;** and PG&E is requesting $2.1 Billion in TO14.

IV. Natural Gas Rates and Costs

Natural gas utility rates in California consist of three main components for typical "core"[41] gas ratepayers:

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

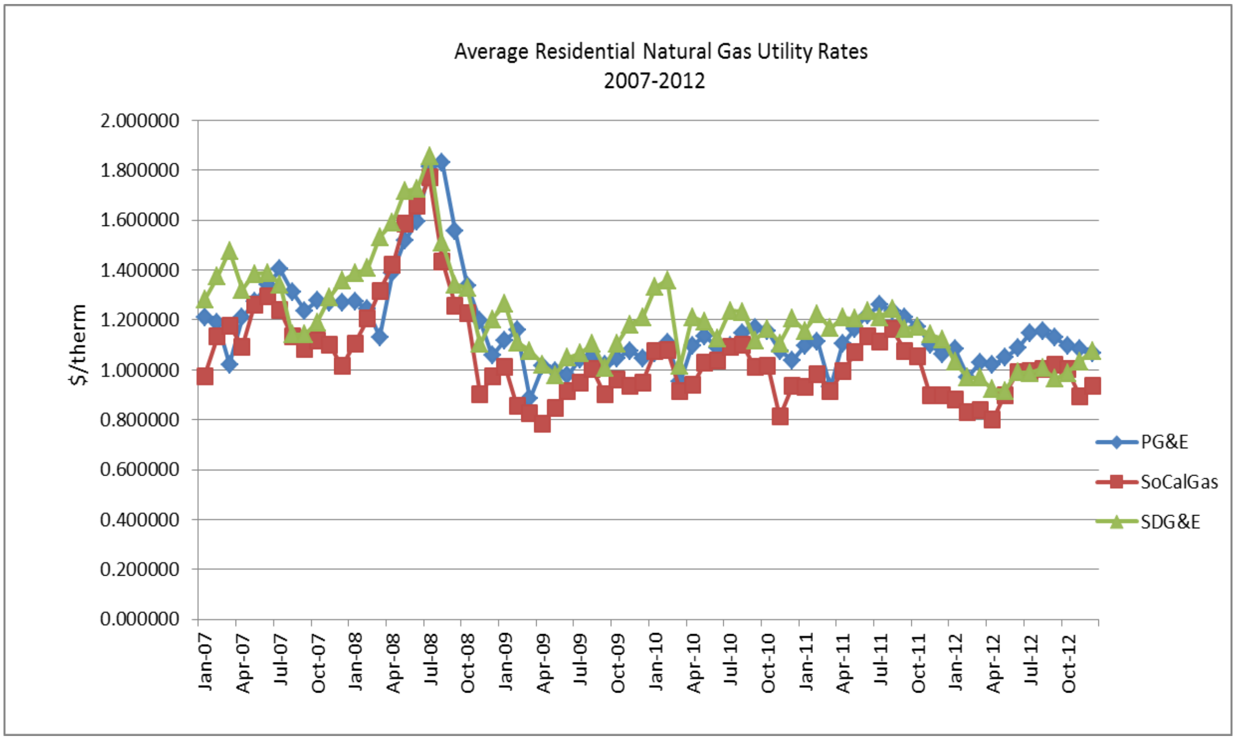
Larger volume gas customers, called "noncore" customers, such as industrial and electric generation (EG) customers, typically procure their own gas supply and don't pay a procurement rate to the utility. In addition, electric generation customers are exempt from the gas public purpose program (PPP) surcharge.

Due to low natural gas prices, and only modest increases in utility transportation costs, gas utility customers of natural gas utilities continued to experience low natural gas costs in 2012. Total utility gas costs were 25% lower in 2012 than in 2008. While the CPUC does not regulate the price of natural gas, it allows the IOUs to pass their wholesale gas costs directly to customers. In addition, the CPUC sets the revenue requirements for the natural gas distribution utilities' natural gas transmission, distribution, storage, customer service, and natural gas PPP costs. The continuing low commodity price of natural gas is the result of developments in the natural gas market, which is influenced by both national and international market conditions.

Total core natural gas rates on average remained low in 2012. The decline in procurement costs has caused total core natural gas utility rates to remain at low levels, as shown in the graph below for residential gas rates. As of the date of this report, market indications of the futures price of natural gas price show that prices are expected to modestly rise but remain low (less than 50 cents/therm) in the coming 12 months.

[41] Core customers are mainly residential and small commercial customers.

Table IV-1



Total approved natural gas utility *costs* for pipelines, storage and customer service have moderately increased (by about 11%) since 2008. However, there are significant differences between different customer classes and utilities in the changes in *rates* over that time period. For example, the average natural gas transportation rate for PG&E residential customers increased by 37% while the average transportation rate for SDG&E residential gas customers increased by only 3%.

Approved gas PPP costs have increased by 45% during the 2008 to 2012 time period. Again, there are significant differences between different customer classes and utilities in the change in the gas PPP rate over that time period. For example, the average residential PPP surcharge increased by 57% for SDG&E and by 62% for SoCalGas.

A. CPUC Actions to Limit Gas Cost and Rate Increases

In the coming year, the CPUC will be facing a challenge to maintain natural gas utility transportation rates at reasonable levels. Procurement costs are expected to remain at low levels, but natural gas utilities have proposed large additional pipeline safety costs in addition to other operational costs, which amount to billions of dollars. (The CPUC has already approved, in December 2012, some of those expenditures.) These additional costs will increase the utilities' transportation rates in 2013 and future years. In addition, gas PPP costs have risen significantly in recent years.

1. Gas Utility Operational Costs and Rates

During the next 12 months, in order to ensure that utility revenue requirements and rates for gas pipelines, 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, or address issues that could affect costs, in the following proceedings, and in many cases will issue a final decision during 2013.

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

The CPUC issued this rulemaking in early 2011 in response to the San Bruno pipeline rupture "to establish a new model of natural gas pipeline safety regulation applicable to all California pipelines." In addition to addressing gas pipeline safety issues, the rulemaking considered how the CPUC can align ratemaking policies, practices, and incentives to better reflect safety concerns and ensure ongoing commitments to public safety. In August 2011, PG&E, SoCalGas, SDG&E, and Southwest Gas filed their Gas Pipeline Safety Enhancement Plans (PSEPs) to propose how they intend to ensure that their gas transmission pipeline systems are safe. The utilities proposed spending over $4 billion in the subsequent 3-4 years in just the first phase of their plans, and proposed that ratepayers pay for virtually all of these costs.

In early 2012, the CPUC determined that it should first focus on the PG&E proposed plan in this proceeding. The plans and associated costs for SoCalGas and SDG&E were examined in a separate proceeding, A.11-11-002, discussed below.

In December 2012, the CPUC approved much of PG&E's PSEP, but also determined that much of the costs that had been and would be incurred should be borne by PG&E shareholders, rather than PG&E ratepayers. The CPUC's decision resulted in an approved revenue requirement increase through 2014 that is $469 million lower than what PG&E had requested. Core gas rates were raised by 2.4 cents per therm in 2013, as a result of the CPUC's decision rather than the 4.5 cents per therm sought by PG&E.

The CPUC also ordered PG&E to update the status of its PSEP and the associated costs in order to more accurately assess the expected PSEP costs. PG&E's update is expected in mid-2013, and the CPUC will be examining the updated PSEP in the latter half of 2013.

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

SoCalGas is proposing to conduct work at its Aliso Canyon Storage Field, and estimates the cost to be $200.9 million. The project would result in a slight increase in core gas rates of 0.3 cents per therm. SoCalGas requests approval of its revenue requirement and its proposed allocation of the project costs to various customer classes. A draft environmental impact report (EIR) has been prepared by a consultant working for the CPUC. The final EIR is expected in the spring of 2013, and the CPUC expects to determine if it should adopt SoCalGas's proposal in 2013.

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

The CPUC will determine the revenue requirement in this proceeding for SoCalGas's 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). SoCalGas estimated that, if its proposal is adopted, average gas transportation rates would increase by 12.5 % in 2012 compared to 2011. Core gas rates would increase by 5.8 cents per therm. Hearings in this proceeding are complete. The CPUC will likely reach a decision in this proceeding in spring 2013.

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

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

As noted above, the CPUC examined the SoCalGas and SDG&E gas safety implementation plans in the TCAP in 2012. SoCalGas estimated that residential customers would face an additional average rate increase of about 5.4 cents per therm in 2012 if its plan is adopted by the CPUC. This amounts to about a 14% increase from the average residential transportation rate. The CPUC will likely issue a decision on the SoCalGas/SDG&E gas safety implementation plan in mid-2013.

6. PG&E 2014 General Rate Case Application (A.12-11-009)

In November 2012, PG&E submitted its 2014 General Rate Case (GRC) Application (A.12-11-009). PG&E is seeking CPUC approval for a significant increase in spending on gas distribution pipeline operation and maintenance expenses and capital spending. PG&E is seeking approval for a 100% increase in gas operation and maintenance expenses and a 173% increase in the level of gas distribution capital expenditures. PG&E indicates that the primary reason for this increased spending is to improve gas distribution pipeline safety. PG&E's request would increase gas distribution revenue requirement by 41% in 2014 and by additional amounts in 2015 and 2016. The CPUC will be examining PG&E's request in 2013.

7. Southwest Gas 2014 General Rate Case Application (A.12-12-024)

In December 2012, Southwest Gas submitted its 2014 General Rate Case application. Southwest Gas operates in three different areas in California: Southern California, Northern California, and Lake Tahoe. Southwest Gas is requesting an increase in authorized operating revenue of 5.4%, 10.7% and 13.9% for those areas, respectively. The CPUC will be examining Southwest Gas's request in 2013.

8. Gas Public Purpose Programs

The cost associated with the natural gas PPPs has grown significantly in recent years due to large increases in the costs for energy efficiency programs and the CARE subsidy. In 2012, the cost of the gas-related PPPs was about $622 million. Gas PPP costs have increased for several reasons, including the following: increases in CPUC-approved energy efficiency portfolio budgets, along with a larger portion of the EE budgets being allocated to natural gas; increases in low-income energy efficiency budgets related to the goal of treating all eligible and willing customers; and, an increase in the number of CARE customers.

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

The CPUC attempts to ensure that public purpose programs are conducted efficiently and provide the maximum benefits for which they are intended. For example, the gas R&D budget is examined by the CPUC annually and has not been increased since 2009. The other main components of the gas PPP surcharge, energy efficiency and CARE programs, are discussed in other sections of this report.

9. Gas Procurement Costs

Although the CPUC does not regulate the wholesale price of natural gas, these costs are passed through to utility customers, and the CPUC will continue to implement measures that:

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

For example, in 2012 and early 2013 several new interstate pipeline capacity contracts for PG&E were approved that will reduce costs for its core gas customers by about $20 million.

B. CPUC Advocacy for California Natural Gas Interests at FERC

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

In the next 12 months, the CPUC expects to participate in El Paso FERC proceedings in which El Paso may propose reductions in pipeline capacity to California.

V. Appendix

Utility Reports on Recommended Measures to Limit Costs and Rate Increases

A. Pacific Gas and Electric Company

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

Pursuant to the requirements of Public Utilities Code Section 748, Pacific Gas and Electric Company (PG&E) appreciates the opportunity to provide its annual study and report to the California Public Utilities Commission (CPUC or Commission) on measures PG&E recommends be undertaken to limit costs and rate increases. This report includes:

- PG&E's overall rate policies;
- A discussion of PG&E's management of its costs and rates;
- A discussion of PG&E's recommendations;
- Data and forecasts related to PG&E's gas and electric revenue requirements and load; and
- A schedule of PG&E's filings that may or will affect rates in 2013 and 2014.

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

One of the biggest obstacles to this goal of creating fair and equitable rates while keeping costs down is the statutory mandate for tiered residential electric rate design. PG&E's upper-tier residential rates (i.e., rates for usage in Tiers 3 and 4) are far in excess of cost of service and are among the highest of all the large investor-owned utilities in the country. This inequity is due to legislative mandates set forth initially in Assembly Bill (AB) 1X (Chpt. 4, Stats of 2001, First Extraordinary Session), enacted during the energy crisis in 2001. AB 1X placed a cap on residential rates for lower-tier usage (i.e., usage in Tiers 1 and 2, below 130% of the baseline quantity). This statutory language was later modified in 2009 by Senate Bill (SB) 695 (Chpt. 337, Stats of 2009), which permitted very limited annual increases to lower-tier rates. To reduce this inequity, PG&E proposed numerous measures as part of Phase 2 of its 2011 GRC, but received Commission approval only for some of these proposals. Consequently, while some progress has been made, upper-tier rates are still excessively higher than the cost of providing service. Since significant tier reform is currently limited by state law (SB 695), the Commission's limited ability to consider adequate adjustments to non-CARE Tier 1 and 2 rates will exacerbate the already very high and inequitable upper-tier residential electricity rates affecting millions of residential electricity consumers. To put upper-tier rate increases into context, usage in the lower two tiers (non-CARE and CARE) accounts for about 70% of the total annual electric usage for the residential class, which results in the remaining 30% of upper tier usage paying for most of the increased cost of residential electric service. This inequity is further widened by the fact that CARE rates have remained substantially below the cost of service, and have actually decreased on average, since 1993. PG&E is currently supporting legislation (AB 327, Perea) that would remove the restrictions of AB 1X and SB 695 that limit rate increases for Tier 1 and Tier 2 usage, as well as CARE. AB 327 also proposes to codify the Commission's principles in residential rate design including providing low income and medical baseline customers with access to a supply of electricity that is sufficient to ensure basic needs are met at an affordable cost.

Another area of concern regarding impacts on electricity rates is the overall cost-shift associated with customer-owned generation, particularly residential solar photovoltaic (PV) generation. The State's rate policies regarding Net Energy Metering (NEM) allow electricity customers with their own generation (primarily rooftop solar equipment) to reduce their billed usage by "spinning the meter backwards" (receiving an above-market full bundled rate credit for generation that is sent out to the grid to offset future consumption within the month and potentially in other months). Through the NEM rates, customers that install renewable on-site generation are compensated at rates that substantially exceed the market-based costs of generation that PG&E and non-participating customers save from not having to generate or purchase that power. While PG&E fully supported the enactment of the NEM program and subsequent expansion to meet the policy goals of the California Solar Initiative as embodied in SB 1 (Chpt.132, Stats of 2006), the program was established to assist in developing a solar PV market. That market is now developed and the continued compensation for customer-owned generation should not shift costs to other customers but should be fair, equitable and transparent.

Independent of NEM, the statutorily-mandated residential rate designs magnify the impact of the cost-shift associated with customer-owned generation. Residential customers' renewable on-site generation not only shifts to other customers the above-market costs of their output to the grid, but they also avoid paying the excessively high rates that non-NEM customers pay in the upper tier residential rates. This shifts additional fixed costs to other customers by increasing the already high upper-tier rates to make up for the reduced revenue, and magnifies the overall cost-shift impact and subsidies from other customers associated with customer-owned generation. This inequity is exacerbated by the fact that customer-owned generation, particularly rooftop solar PV systems, are generally owned by customers with higher than average incomes. Now that the solar PV market is developed, customer-owned generation technologies mature, and adoption increases, these subsidies and cost-shifts provided to existing NEM must be reformed to sustainably accommodate the growth in such generation for the benefit of all customers.

In addition to the rate design issues described above, PG&E also looks for ways to manage and reduce its costs. While its 2014 General Rate Case (GRC) forecast includes significant expenditures to improve safety, reliability and customer service, the forecast includes offsetting reductions to capture efficiencies throughout its operations. Notably, the forecast includes significant operational savings brought about by the implementation of SmartMeter™ technology, which are reflected as reductions in PG&E's forecasted costs. The 2014 GRC forecast also reflects efforts to reduce costs and improve efficiencies in many areas of operations. For example, PG&E's electric distribution operation expects to offset cost pressure from normal inflation through 2015. Finally, while PG&E believes that its plans ensure safe operations for its customers, the public and employees, the CPUC has hired independent consultants to assess those plans and make recommendations related to the safety and security of the plans.

Also, PG&E has embarked on a multi-year program to enhance the safety and reliability of the natural gas transmission pipelines in communities throughout its service area, as approved in CPUC Decision 12-12-030. This program will improve the delivery of safe, reliable and affordable natural gas to customers. Hydrostatic pressure testing is one of several important measures PG&E is taking to enhance the safety and strength of its natural gas system. Through the end of 2014, phase one of the Pipeline Safety Enhancement Plan (PSEP) program, PG&E plans to pressure test or validate 783 miles of gas transmission pipeline, replace 185 miles of pipeline, automate more than 220 valves, and upgrade nearly 200 miles of pipeline to accommodate advanced in-line inspection tools known as "smart pigs." PG&E estimates that this program, which is partially funded through shareholder dollars, will increase customer bills by less than a dollar per month.

In parallel, PG&E has recommended modifications to certain aspects of CPUC energy procurement requirements, market structure, and statewide mandates. However, certain components of gas and electric rates are largely beyond the direct control of utilities, and instead result from policy or regulatory mandates, many of which PG&E and the CPUC supported for broader public policy goals. Among these regulatory mandates and requirements that are creating further cost pressures on PG&E's electric and gas costs and rates are the Renewables Portfolio Standards (RPS) program and greenhouse gas (GHG) emissions restrictions resulting from AB 32.

These legislative and regulatory mandates and policies are all well-intentioned and seek to achieve worthy overall goals. However, to the extent that the mandates and policies add costs to retail electricity and gas rates, or restrict the ability of PG&E and other utilities to manage or mitigate costs, then the Legislature and Commission should periodically review the mandates and policies to ensure that they appropriately balance the benefits to customers with the overall costs of implementation and compliance that customers pay in their monthly bills. To mitigate the impact of AB32 costs, PG&E, SCE, and SDG&E in the Greenhouse Gas OIR (R.11-03-012) proposed to return the entire amount of allowance auction revenues directly to utility customers. However, under SB 1018 (Chpt. 39, Stats of 2012) and consequently in CPUC Decision 12-12-033, certain customers are excluded from receiving GHG allowance credits. Consequently, non-residential and non-"emissions-intensive trade exposed" (EITE) customers with demands greater than 20 kilowatts will not have their bill increases mitigated. In addition, development of a RPS procurement expenditure limitation is currently being addressed in the Renewables Portfolio Standard OIR (R.11-05-005). A proposed decision on a RPS procurement expenditure limitation is currently scheduled for the end of 2013.

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

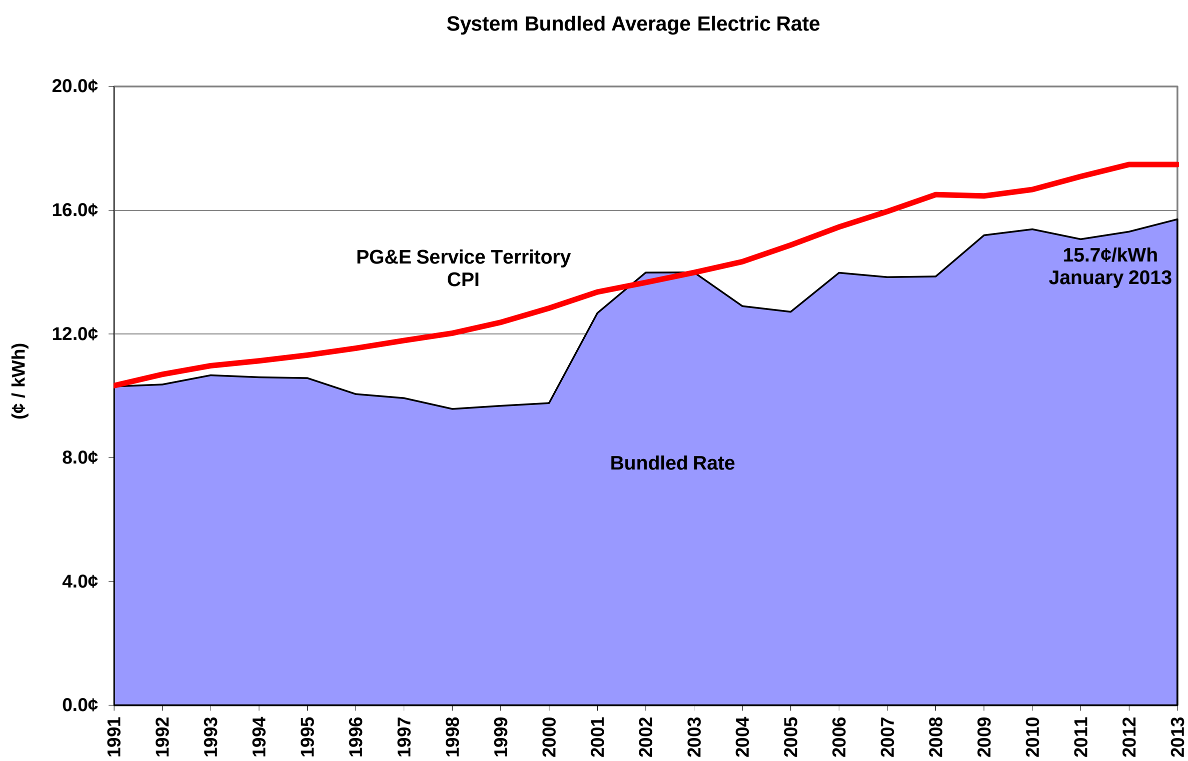
2. Overall Rate Policy

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

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

PG&E also undertakes efforts to manage the timing of revenue changes and subsequent rate changes. For example, in 2007 and 2011, PG&E proposed and received approval for a "rate stabilization adjustment" plan that eliminated a looming rate roller coaster situation where electric rates would have dropped precipitously in January only to be increased later in the year. As illustrated in Figure 1 below, PG&E's system bundled average electric rate over the last 22 years has increased at a lower rate than the service territory's consumer price index (CPI) growth. It is also worth noting that rates in the upper tiers for residential service have far outpaced CPI, which is of great concern to PG&E.

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



3. Management Control of Rate Components

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

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

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 and transparent in order to accomplish other public policy objectives. Such objectives may include energy efficiency, benefits provided to low income customers, mitigation of rate changes from year to year, promotion of renewable generation, GHG emissions reductions, and encouraging innovation and developing technologies.

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

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

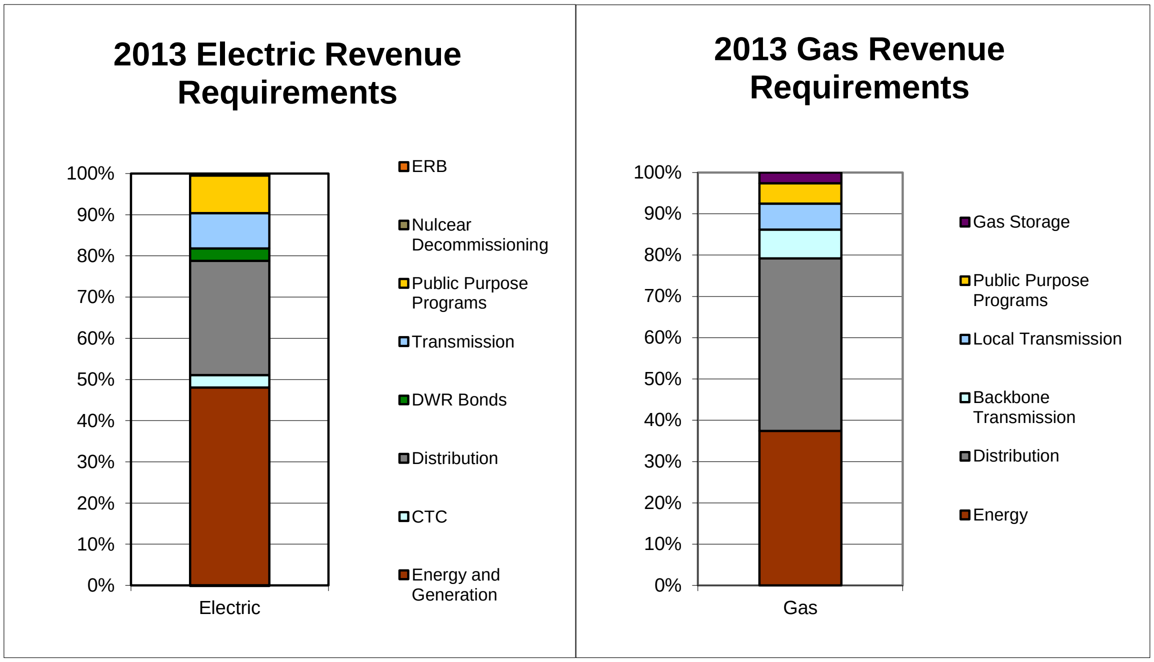
Of the issues listed above, the most immediate area of concern is the statutory mandate for tiered residential electric rate design, where a four tier rate structure is employed. This structure, first put in place in the form of five tiers guided by statute during the energy crisis ten years ago, has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

PG&E respectfully requests the Commission's support by approving rate proposals in future proceedings that are designed to reduce the extremely high levels of upper-tier rates. Even with complete support from the Commission, though, the underlying legislation, that allows only limited increases to Tier 1 and 2 rates and effectively no increase to CARE rates, will continue to constrain the Commission's ability to fix the excessively high upper-tier rate problem. Without legislative rate reform, upper-tier rates will remain at punitive levels. PG&E recommends that legislative changes be considered this coming year to reform the tiered electric rate structure, untie the Commission's hands, and provide it the flexibility to address and modify residential rate structures to be more fair and equitable with rates set at more reasonable levels that more closely reflect cost of service. Absent meaningful reform this year, upper-tier rates are projected to continue growing at unsustainable levels, potentially resulting in resistance to adopted public policy goals such as the 33 percent RPS, AB 32, and replacement of aging infrastructure.

5. Description of Revenue Requirements

PG&E's electric and gas authorized January 2013 revenue requirement (RRQ) key categories are provided in Figure 1 below. A description of each category and the percent contribution to the total RRQ is provided separately for electric and gas. The key categories of RRQs are based on PG&E's major rate components.

Figure 1: High Level Breakdown of PG&E's 2013 Revenue Requirements



a. Electric RRQs are grouped into the following major rate categories: (1) Energy and Generation, (2) Competition Transition Charge (CTC) and New System Generation Charge (NSGC), (3) Distribution, (4) Department of Water Resources (DWR) bonds, (5) Transmission, (6) Public Purpose Programs, (7) Nuclear Decommissioning, and (8) Energy Recovery Bonds (ERB). For reference, an excerpt from the Advice 4096-E-A Annual Electric True-Up filing is provided as Table 1 below. For 2013 authorized RRQs, below is a description of each category:

(1) The Energy and Generation electric RRQs contribute approximately 48 percent of the total authorized revenue requirement in 2013. The generation rate component recovers the following energy and generation related RRQs:

- Procurement costs that are not determined to be above-market in the ERRA Proceeding;
- Utility Owned Generation; and
- DWR Power Charges and associated franchise fees.

(2) The CTC RRQ contributes approximately 3 percent of the total authorized RRQ in 2013. This represents the above-market cost of procuring energy. This category includes the New System Generation (NSG) RRQ, which recovers program and other contracts for which PG&E is authorized to recover net capacity costs from Direct Access, Community Choice Aggregation, and departing load customers through the NSGC rate.

(3) The Electric Distribution RRQ contributes approximately 28 percent of the total authorized RRQ in 2013.The Electric Distribution RRQs include the 2011

General Rate Case (GRC), California Solar Initiative, the SmartMeter™ program, and several other programs that are recovered through the distribution rate component.[42]

(4) The DWR bonds RRQ contributes 3 percent of PG&E's authorized 2013 RRQ.

(5) The Electric Transmission RRQs contribute 9 percent of the total authorized revenue requirement in 2013. Transmission RRQs include those related to the following:

- Transmission Owner;
- Transmission Access Charges;
- Transmission Revenues;
- Reliability Services; and
- Electric Customer Refund Account.

(6) The Electric Public Purpose Programs RRQs contribute 9 percent of PG&E's total authorized revenue requirement in 2013. These RRQs include the funding of energy efficiency programs and the CARE discount.

(7) The Nuclear Decommissioning RRQ contributes less than 1 percent of PG&E's total authorized revenue requirement in 2013.

(8) The Energy Recovery Bonds RRQ contributes less than 1 percent of PG&E's authorized revenue requirement in 2013. The 2013 ERB RRQ represents the return of the ERBBA balance to customers.

[42] The CARE discount shifts RRQs from the distribution rate component to the PPP rate component. The RRQs shown here do not reflect that shift.

Table 1: Excerpt from Advice 4096-E-B Annual Electric True-Up filing for Electric Rates Effective January 1, 2013

Advice 4096-E-A - 11 - December 31, 2012

Table 2: Annual Electric True-Up Projected 2013 Revenue Requirements

Line #		Test Year 2013 RRQ A	12/31/12 Forecast BA Amortization B	Total Projected 2013 Revenues C = A + B
1	**CPUC Jurisdictional**			
2	**Distribution**			
3	Distribution/DRAM	3.601.876.000	124.958.706	3.726.834.706
4	Demand Response (D.12-04-045)	75.940.993	0	75.940.993
5	Demand Response Statewide ME&O	0	0	0
6	Demand Response IDSM	3.299.219	0	3.299.219
7	Cost of Capital adj to base Distribution & Generation [1]	(165.301.000)	0	(165.301.000)
8	Self Generation Incentive Program	30.566.290	0	30.566.290
9	Environmental Enhancement	10.107.900	0	10.107.900
10	CPUC Fee	20.556.674	0	20.556.674
11	Advanced Metering/SBA	158.800.000	(28.349.152)	130.450.848
12	Meter Reading Cost Balancing Account	0	34.996.756	34.996.756
13	California Solar Initiative	85.917.150	0	85.917.150
14	HSM	0	16.935.536	16.935.536
15	ATFA	0	0	0
16	CEMA	0	0	0
17	PCBA	0	0	0
18	CEEIA/RRIM	17.250.415	1.585.574	18.835.989
19	NTBA	0	(338.974)	(338.974)
20	CIPBA (Cornerstone)	54.033.000	(8.748.040)	45.284.960
21	Default Residential Pricing	0	0	0
22	Peak Time Pricing	0	0	0
23	Smart Grid Pilot Project	0	0	0
24	SGMA (Compressed Air Energy Storage)	0	2.462.721	2.462.721
25	RCSEBA	0	361.596	361.596
26	Lawrence Livermore National Laboratory	0	0	0
27	**Generation**			
28	Utility Retained Generation Base/UGBA	1.767.527.000	97.258.442	1.864.785.442
29	Photovoltaic Program	87.200.000	0	87.200.000
30	DCSSBA	0	0	0
31	DCSSBA - Additional Request	0	0	0
32	Electric Procurement/ERRA	4.107.388.531	(104.619.795)	4.002.768.736
33	DWR--Power Charge/PCCBA	(26.188.125)	69.202.250	43.014.125
34	DWR Franchise Fees	3.204.260	0	3.204.260
35	BCRSBA	0	0	0
36	FERABA (Distribution & Generation) [2]	0	7.902.356	7.902.356
37	HA	0	0	0
38	LTAMA	0	21.262	21.262
39	MRTUMA	0	0	0
40	RPSCMA	0	0	0
41	AB 32 Cost Implementation Fees	0	0	0
42	LCPERMA	0	858.316	858.316
43	**Ongoing CTC/MTCBA**	87.827.902	186.210.525	274.038.427
44	**Cost Allocation Mechanism/NSGBA**	142.129.015	(42.572.541)	99.556.474
45	**Greenhouse Gas Allowance**	0	0	0
46	**Energy Cost Recovery Bonds**	0	0	0
47	Dedicated Rate Component Series 1	0	0	0
48	Dedicated Rate Component Series 2	0	0	0
49	ERB Balancing Account (ERBBA)	27.600.000	(43.900.000)	(16.300.000)
50	**Nuclear Decommissioning**	44.270.000	279.533	44.549.533
51	**Public Purpose Programs**			
52	(1) Energy Efficiency (former PGC Legacy)	120.734.365	0	120.734.365
53	(2) ESA (formerly known as LIEE)	92.138.801	0	92.138.801
54	(3) PPPRAM	0	(7.455.857)	(7.455.857)
55	Electric Program Investment Charge (EPIC)	82.037.738	1.127.930	83.165.668
56	Procurement EE/PEERAM	169.430.087	5.174.738	174.604.825
57	PEERAM Statewide ME&O	0	0	0
58	CAREA	11.804.192	6.743.631	18.547.823
59	**DWR Bonds**	375.788.710	0	375.788.710
60	**Total CPUC Jurisdictional**	10,985,939,117	320,095,513	11,306,034,630
61	***CPUC Revenues at Present Rates***			11,091,052,144
62	***Change in CPUC Jurisdictional***			214.982.486
63	***Total FERC Jurisdictional***			1.063.900.547
64	***FERC Revenues at Present Rates***			1,032,758,501
65	***Change in FERC Jurisdictional***			31.142.046
66	**Grand Total Projected Revenues**			12,369,935,177
67	**Total Revenues at Present Rates**			12,123,810,645
68	**Total Change**			246,124,532

Notes to Table 2:

1 Of the Cost of Capital Revenue requirement reduction per D.12-04-018, $(117,555,000) is allocated to distribution and $(47,746,000) is allocated to generation.

2 Of the December 2012 forecast FERABA balance, $3,846,865 is allocated to distribution and $4,056,491 is allocated to generation.

b. Natural gas RRQs are commonly grouped into the following six major categories: (1) Energy, (2) Distribution, (3) Backbone Transmission, (4) Local Transmission, (5) Public Purpose Programs, and (6) Gas Storage. For reference, an excerpt from the Advice 3353-G Annual Gas True-Up filing on December 24, 2012 is provided as Table 2. For 2013 authorized RRQs, below is a description of each category:

(1) The Energy gas RRQs contribute about 37 percent of the total gas RRQ. Authorized RRQs include:

- Gas supply portfolio costs
- Interstate capacity costs
- Gas Hedging
- Winter Gas Savings Program
- Purchased Gas Account
- Core Procurement Incentive Mechanism

(2) The distribution gas RRQs contribute about 42 percent of the total authorized gas RRQ. It includes the GRC, Pension, California Solar Initiative, SmartMeter™ program, and several other programs recovered through the distribution rate component.[43]

(3) The backbone transmission gas RRQs contribute approximately 7 percent of the total authorized gas RRQ. It includes unbundled backbone and intrastate capacity costs.

(4) The local transmission gas RRQs contribute approximately 6 percent of the total authorized gas RRQ.

(5) The Public Purpose Programs gas RRQs contribute about 5 percent of the total authorized gas RRQ. These RRQs include California Alternate Rates for Energy (CARE) Discount and Energy Efficiency.

(6) The gas storage RRQ contributes about 3 percent of the total authorized gas RRQ. It includes core storage, core carrying cost of working gas in storage, and unbundled storage.

On February 1, 2013, PG&E changed gas rates to increase RRQs by $130.7 million for PG&E's Pipeline Safety Implementation Plan and California Air Resource Board's AB32 Cost of Implementation Fee submitted in Advice Letter 3360-G. This increase does not materially change the percent contributions shown above.

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

Table 2: Excerpt from Advice 3353G Annual Gas True-Up filing for Gas Rates Effective January 1, 2013

Pacific Gas and Electric Company
San Francisco, California
U 39

	Revised	*Cal. P.U.C. Sheet No.*	30170-G
Cancelling	Revised	*Cal. P.U.C. Sheet No.*	29457-G

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

Sheet 2

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

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

Description	Core	Noncore	Unbundled	Core Procurement	Total
	Amount ($000)				
BASE REVENUES (incl. F&U) :					
Authorized GRC Distribution Base Revenue (1)					1,195,641 (I)
Pension (2)					52,691 (I)
Less: Other Operating Revenue					(22,922)
Authorized Distribution Revenues in Rates	1,182,821 (I)	42,589 (I)			1,225,410 (I)
BCAP ALLOCATION ADJUSTMENTS AND CREDITS TO BASE:					
G-10 Procurement-Related Employee Discount	(1,025) (I)				(1,025) (I)
G-10 Procurement Discount Allocation	404 (R)	621 (R)			1,025 (R)
Less: Front Counter Closures	0				0
Core Brokerage Fee Credit	(6,583)				(6,583)
Distribution Base Revenue with Adj. and Credits	1,175,617 (I)	43,210 (I)			1,218,827 (I)
TRANSPORTATION FORECAST PERIOD COSTS & BALANCING ACCOUNT BALANCES (3):					
Transportation Balancing Accounts	77,137 (R)	28,949 (R)			106,086 (R)
Self-Generation Incentive Program Revenue Requirement	2,283 (R)	3,477 (R)			5,760 (R)
CPUC Fee	1,970	1,240			3,210 (D)
SmartMeter™ Project	79,202 (R)				79,202 (R)
Winter Gas Savings Plan (WGSP) – Transportation	2,474 (I)				2,474 (I)
Franchise Fees and Uncollectible Expense (F&U) (on items above)	2,117 (R)	446 (R)			2,563 (R)
CARE Discount included in PPP Funding Requirement	(112,382) (I)				(112,382) (I)
CARE Discount not included in PPP Surcharge Rates	0				0
Transportation Forecast Period Costs & Balancing Account Balances	52,801 (R)	34,112 (R)			86,913 (R)
GAS ACCORD REVENUE REQUIREMENT (incl. F&U) (4):					
Local Transmission	132,854 (R)	72,789 (I)			205,643 (R)
Customer Access Charge – Transmission		4,860 (I)			4,860 (I)
Storage	47,513 (R)		34,083 (R)		81,596 (R)
Carrying Cost on PG&E Working Gas in Storage	1,978 (I)		532 (I)		2,510 (I)
Backbone Transmission/L-401	92,765 (R)		133,171 (R)		225,936 (R)
Gas Accord Revenue Requirement	275,110 (R)	77,649 (I)	167,786 (R)		520,545 (R)

(1) The authorized GRC amount includes the distribution base revenue and F&U approved effective January 1, 2011, in General Rate Case D. 11-05-018. The GRC distribution base revenue is allocated to core and noncore customers in Cost Allocation Proceedings, as shown in Part C.3.a. This amount also includes the gas Distribution portion of the Cost of Capital authorized in D.12-12-034. (T) (T)

(2) PG&E's 2013 pension revenue requirement was updated and approved by the Energy Division in Advice Letter 3344-G/4147-E. These revenue requirement adjustments are in compliance with the terms of the Pension Cost Recovery Mechanism Settlement Agreement approved by the Commission in D.09-09-020. This adjusted amount was updated: (1) to conform to the capitalization factor and the operations and maintenance labor allocations used in determining the 2011 GRC revenue requirement adopted in D.11-05-018 and (2) for changes to the adopted cost of capital authorized by D.12-12-034. (T) (T)

(3) -The total 2013 SGIP revenue requirement (RRQ) was approved in D.11-12-030.
-D.06-07-027 authorized Advanced Metering Infrastructure ("AMI")/SmartMeter™ Project deployment. The Energy Division approved PG&E's AL 3210-G which included a revised 2013 revenue requirement.
-The Energy Division approved PG&E's AL 3222-G to continue PG&E's Winter Gas Savings Program (WGSP). The approved marketing, outreach and administration costs are shown here allocated between transportation and procurement. (T) (T)

(4) The Gas Accord V RRQ effective January 1, 2013, was adopted in D.11-04-031. Storage revenues allocated to load balancing are included in unbundled transmission rates. (T)

*Some numbers may not add precisely due to rounding.

(Continued)

Advice Letter No: 3353-G	*Issued by*	*Date Filed*	December 24, 2012
Decision No. 05-06-029	***Brian K. Cherry***	*Effective*	January 1, 2013
	Vice President	*Resolution No.*	
2H11	*Regulatory Relations*		

Table 2 (continued.): Excerpt from Advice 3353G Annual Gas True-Up filing for Gas Rates Effective Jan. 1, 2013

Pacific Gas and Electric Company *San Francisco, California* U 39		Revised	*Cal. P.U.C. Sheet No.* 30171-G
	Cancelling	Revised	*Cal. P.U.C. Sheet No.* 29458-G

GAS PRELIMINARY STATEMENT PART C

Sheet 3

GAS ACCOUNTING TERMS & DEFINITIONS

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

2. ANNUAL GAS REVENUE REQUIREMENT AND PPP FUNDING REQUIREMENTS: (Contd.)

Amount ($000)

Description	Core	Noncore	Unbundled	Core Procurement	Total	
ILLUSTRATIVE CORE PROCUREMENT REVENUE REQUIREMENT (5):						
Illustrative Gas Supply Portfolio				1,015,537 (R)	1,015,537 (R)	
Interstate and Canadian Capacity				188,107 (I)	188,107 (I)	
WGSP – Procurement – Residential				1,826 (R)	1,826 (R)	
F&U (on items above and Procurement Account Balances Below)				15,631 (R)	15,631 (R)	
Backbone Capacity (incl. F&U)	(64,098) (I)			64,098 (R)	0	
Backbone Volumetric (incl. F&U)	(28,668) (I)			28,668 (R)	0	
Storage (incl. F&U)	(47,513) (I)			47,513 (R)	0	
Carrying Cost on PG&E Working Gas in Storage (incl. F&U)	(1,978) (R)			1,978 (I)	0	
Core Brokerage Fee (incl. F&U)				6,583	6,583	
Procurement Account Balances				(2,426) (R)	(2,426) (R)	
Illus. Core Procurement Revenue Requirement	(142,257) (I)			1,367,515 (R)	1,225,258 (R)	
TOTAL GAS REVENUE REQUIREMENT (without PPP) IN RATES	**1,361,271** (R)	**154,971** (R)	**167,786** (R)	**1,367,515** (R)	**3,051,543** (R)	
PUBLIC PURPOSE PROGRAM (PPP) FUNDING REQUIREMENT (F&U exempt) (6):						
Energy Efficiency (EE)	50,551 (R)	5,627 (R)			56,178 (R)	
Energy Savings Assistance (ESA)	58,677 (R)	6,531 (R)			65,208 (R)	
Research, Demonstration and Development (RD&D)	6,742 (I)	3,817 (I)			10,559 (I)	
CARE Administrative Expense	1,625 (I)	1,114 (I)			2,739 (I)	
BOE and CPUC Administrative Cost	206 (I)	117 (I)			323 (I)	
PPP Balancing Accounts	(28,057) (R)	(12,770) (R)			(40,827) (R)	
CARE Discount Recovered from non-CARE customers	66,681 (R)	45,701 (R)			112,382 (R)	
Total PPP Funding Requirement in Rates	**156,425** (R)	**50,137** (R)			**206,562** (R)	
TOTAL GAS REVENUE AND PPP FUNDING REQUIREMENT IN RATES	**1,517,696** (R)	**205,108** (R)	**167,786** (R)	**1,367,515** (R)	**3,258,105** (R)	
Implementation Plan – Local Transmission not included in rates (7)	59,009	32,303			91,312	(N)
Implementation Plan – Backbone not included in rates (7)	9,542	12,873			22,415	(N)
Implementation Plan – Storage not included in rates (7)	950	666			1,616	(N)
TOTAL AUTHORIZED GAS REVENUE AND PPP FUNDING REQUIREMENT	**1,587,197** (R)	**250,950** (I)	**167,786** (R)	**1,367,515** (R)	**3,373,448** (R)	

(5) The credits shown in the Core column represent the core portion of the Gas Accord RRQ that is included in the illustrative Core Procurement RRQ, and are shown here to avoid double counting these costs in the total. The Gas Supply Portfolio cost is an annual illustrative amount. Actual gas commodity costs change monthly. WGSP costs, approved in AL 3222-G, is recovered in residential rates effective April 1, 2013. (T)

(6) The PPP funding requirement is recovered in gas PPP surcharge rates pursuant to D.04-08-010 and 2013 PPP surcharge AL 3337-G-A, and includes ESA program funding adopted in D.12-08-044, EE program funding adopted in D.12-11-015, CARE annual administrative expense adopted in D.12-08-044, and excludes F&U per D.04-08-010. (T) (T)

(7) The Pipeline Safety Implementation Plan was authorized in D.12-12-030. These revenue requirements will be included in rates effective February 1, 2013, or as soon as practical thereafter, and are included in this presentation for illustrative purposes. (N)

(Continued)

Advice Letter No:	3353-G	*Issued by*	*Date Filed*	December 24, 2012
Decision No.	05-06-029	***Brian K. Cherry***	*Effective*	January 1, 2013
		Vice President	*Resolution No.*	
3H12		*Regulatory Relations*		

6. Description of Rates (Gas and Electric)

The RRQs discussed in the previous section directly align with rate components. At the highest level, electric and gas rates can be described as RRQ divided by sales. Therefore, both RRQ 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 expected to decrease, rates similarly will be reduced. The rate pressures created by RRQ changes are moderated when sales are forecasted to increase. Adjustments in the allocation of RRQs across customer classes and rate tiers also impact the rates experienced by individual customers. Table 3 below provides a summary.

Table 3: Summary of RRQs and Percentage Distribution for 2013

RATE COMPONENT	Electric		Gas	
	RRQ $M	Jan 2013 %	RRQ $M	Jan 2013 %
Energy and Generation	$5,958	48%	$1,219	37%
CTC	374	3%	-	-
Distribution (1)	3441	28%	1362	42%
DWR Bonds	376	3%	-	-
Transmission / Backbone Transmission	1064	9%	226	7%
Local Transmission (Gas)	-	-	206	6%
Public Purpose Programs (2)	1130	9%	161	5%
Nuclear Decommissioning	45	0%	-	-
Energy Recovery Bond	(16)	0%	-	-
Gas Storage	-	-	84	3%
Total Authorized Revenue Requirement	$12,370	100%	$3,258	100%

(1) Includes 2013 CARE discount of approximately $648M for electric.
(2) Includes 2013 CARE discount of approximately $112M for gas.
(3) As of January 1, 2013. Values are approximated to the nearest million.

7. Published Load/Demand Forecasts

Customer sales volatility over time directly impacts the rates experienced by gas and electric customers. PG&E updates sales forecasts for its service territory on a regular basis to include in rate change filings with the Commission. In the past, aggregate customer sales usually increased at a pace which partly offset annual increases to RRQ. However, in recent years (2009 through 2011), the combination of weak economic conditions and very mild temperatures have resulted in a decline in sales compared to 2008 levels. This has meant that fixed costs were spread across lower sales resulting in higher rates for most customers. Sales rebounded in 2012, driven by an improving economy and favorable weather conditions. The following section discusses the forecast trends for Electric and Gas sales for 2013.

A. Electric

Although the PG&E service area economy has rebounded from the recessionary trough of late 2009, the expansion has been sluggish and uneven. The year 2012 saw modest improvement in the PG&E area economy, with increased job growth and incomes, and a housing sector that finally turned around after many years of decline. For 2013, Moody's Analytics projects only modest improvement. Despite a robust technology sector and an improving building industry, national trends, such as the end of payroll tax holiday, reduced government spending, and a European recession will tend to offset regional gains. Furthermore, the Central Valley region of the service area is still feeling the residual effects of the housing collapse and has not yet benefitted from expanding technology sector of the immediate Bay Area. With this backdrop, PG&E's forecast is actually projecting a decline in sales of -0.5 percent compared to 2012 observed sales. This decline, however, is somewhat misleading, as a large industrial customer has left PG&E's system and will result in a 600 GWh drop (about 0.7% of sales) in sales.

Electric customer (billings) growth was also dramatically impacted by the recession. PG&E added only 18,000 customers during the 2009-2010 period, but has since observed a rebound, adding over 70,000 customers since 2010. For 2013, PG&E expects to see continued growth in customers, adding over 50,000 customers in 2013.

As described above, two exceptional factors push expected sales down in 2013 compared to actual sales in 2012. Still, residential and commercial sales are forecast to rise in 2013 – residential by 0.2 percent and commercial by 2.4 percent. The office space boom in San Francisco and Silicon Valley areas is driving the increase in commercial sales despite modest overall economic growth. The industrial sector will see a substantial decline in 2013 sales, mostly a reflection of the customer departure mentioned above. Agricultural sales are also projected to decline (-3.1 percent), with an assumed return to normal precipitation levels after a dry 2011-2012 winter that pushed agricultural usage past 6,000 GWh.

B. Gas

As described in the Electric subsection above, PG&E's service area economy is expected to continue with slow growth through 2013. This slow pace and the return to assumed normal temperatures after a colder than normal 2012 will impact projected natural gas throughput. Based on PG&E's preliminary new forecast, 2013 gas sales for all three major gas customer classes - residential, commercial, and industrial – will show modest declines in usage. Residential, commercial, and industrial demands are expected to change very little from 2013 to 2015.

The residential gas sales forecast incorporates real residential gas rates, the number of households in PG&E's service territory, heating degree days and the percentage of households built after 1978 (when title 24 multifamily energy efficiency standards went into effect). Unlike electricity, which has innumerable residential uses, the main residential use for gas are space and water heating, gas sales requires customer growth to drive usage growth. With slow customer growth combined with building standards and energy efficiency programs that continue to reduce overall residential usage, residential demand is projected to drop by about 3 percent in 2013. The majority of that decline is due to the assumed return to normal temperatures in 2013 after the colder than normal 2012. After 2013, customer growth will tend to offset lower usage per household. Since space heating is the principle use of gas in the commercial sector (as it is for residential use), growth is dependent on the level of business activity within the sector. With high existing commercial vacancy rates and a return to assumed normal temperatures, gas usage in this sector is projected to decline by 2 percent this year. The historically volatile industrial class saw a modest uptick in sales during 2012, but uncertainty within the economy elicits a return to more normal levels with a 4% drop compared to 2012.

Finally, demand for gas used in electric generation is expected to decline significantly in 2013 following the drier and warmer than normal 2012. Many factors drive the volatility in gas demanded for electric generation, including the economy, gas prices, hydroelectric generation capacity, new generation facilities coming online, and nuclear generating capacity. In 2013, however, the main factors impacting electric generation will be the continuing slow economic recovery and a drier than normal 2012-2013 winter in the west resulting in lower than normal hydroelectric output.

Appendix: Outlook from May 1, 2013 to April 30, 2014

Please see the table below for a list that contains information on PG&E's significant rate changes for 2013- 2014. The table reflects currently anticipated rate filings schedule for 2013 and the revenue requirement or rate components that are primarily affected by each filing. This is not an exhaustive list of PG&E's filings; rather it incorporates planned regulatory filings which are known at this time to have a rate impact for PG&E's electric and/or gas 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.

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implemen-tation date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2013 RRQ *	2014 RRQ *			
	Q3 2010									
1	Default Residential Rate Programs (Peak Day Pricing)	A.10-08-005	Aug 9, 2010	5/1/2014	141	5	25	Per D.08-07-045, Ordering Paragraph (OP) 8, by August 9, 2010, PG&E needs to file an application proposing a default Critical Peak Pricing (CPP) rate for residential customers, subject to their ability to opt-out of the CPP rate.	Electric	Distribution
	Q1 2011									
2	GHG OIR	R.11-03-012	Mar 24, 2011	Implementation workshops currently underway	N/A	N/A	N/A	OIR evaluating proposals for allocation of revenues associated with auction of GHG revenues. D.12-12-033 adopted a revenue allocation methodology, but the revenue allocation formulas and implementation are currently being addressed in workshops with Energy Division.	Electric	New rate component, yet to be determined
	Q3 2011									
3	CEMA 2011	A.11-09-014	Sep 21, 2011	1/1/2014	41	27	N/A	Requests authority to recover in rates the costs recorded in the CEMA associated with seven catastrophic events that occurred between August 2009 and March 2011. An all-party settlement was filed on October 31, 2012, and the settlement amounts are reflected here.	Electric	Distribution; Generation

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implemen-tation date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2013 RRQ *	2014 RRQ *			
	Q4 2011									
4	Rate Design Window 2010/Peak Time Rebate (Revised Testimony)	A.10-02-028	Oct 28, 2011	TBD	34	1	(2)	Requests approval for PTR program that provides incentives for customers to respond to price signals on event days when demand is expected to be high.	Electric	Distribution
5	Smart Grid Pilot Deployment Project	A.11-11-017	Nov 21, 2011	1/1/2014	109	6	8	The application requested authority to recover costs associated with six Smart Grid projects that will test, evaluate and deploy select Smart Grid technologies and initiatives on a pilot basis. The Proposed Decision issued on February 15, 2013 denied funding for two of the projects.	Electric	Distribution; Generation
	Q1 2012									
6	Market Redesign and Technology Upgrade (MRTU) 2010 (re-filing)	A.12-01-014	Jan 31, 2012	1/1/2014	19	65 [incl. 2010 and 2012 RRQ]	N/A	Request for recovery of costs PG&E incurred for projects that became operative in 2010, to comply with the mandated Market Redesign and Technology Upgrade (MRTU) initiatives and a forecasted revenue requirement for 2012 and 2013.	Electric	Distribution; Generation
7	Smart Grid – Customer Data Access	A.12-03-002	Mar 5, 2012	1/1/2014	19	1	(2)	Requests authority for recovery of costs to implement a customer data access project that will provide third parties with access to customer usage data via the utility when authorized by the customer.	Electric	Distribution

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implemen-tation date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2013 RRQ *	2014 RRQ *			
	Q2 2012									
9	Market Redesign and Technology Upgrade (MRTU) 2011	A.12-04-009	Apr 16, 2012	1/1/2014	15	8	N/A	Request for recovery of costs PG&E incurred for projects that became operative in 2011, to comply with the mandated Market Redesign and Technology Upgrade (MRTU) initiatives.	Electric	Distribution; Generation
10	CPIM 2011 Annual Report (Yr. 18)	N/A	May 11, 2012	TBD		5	N/A	Compliance report for gas core procurement incentive mechanism for November 1, 2010 through October 31, 2011.	Gas	Procurement
11	GHG Compressor Stations	A.12-06-010	Jun 18, 2012	TBD	8	3	4	Addresses PG&E's compliance obligation to procure allowances for compressor stations on our backbone gas transmission system under AB32.	Gas	Backbone Transmission
	Q3 2012									
12	2013 DWR Revenue Requirement	R.11-03-006	Aug 2, 2012	1/1/2013		(26)	N/A	Annual recovery/credit for power and bond charges with DWR. 2013 RRQ, shown here, is adopted in D.12-11-040. Separately, as part of this proceeding, the CPUC has been considering whether to reallocate to all utilities the costs under the firm gas transportation service agreement between Kern River Gas Transmission Company and DWR that had been previously assigned to SDG&E. This matter is currently awaiting a proposed decision.	Electric	Generation

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implemen-tation date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2013 RRQ *	2014 RRQ *			
13	Statewide Marketing, Education, and Outreach (ME&O) Program	A.12-08-007	Aug 3, 2012	1/1/2014	25	12	12	Application for a statewide marketing, education, and outreach (ME&O) program for 2013-2014, separate from the 2013-2014 energy efficiency and demand response portfolio applications. RRQ is allocated $22M electric and $3M gas.	Electric; Gas	Electric Distribution; Electric PPP; Gas Public Surcharge
14	SmartMeter™ Opt-Out (Phase 2)	A.11-03-014	Aug 10, 2012 [Ph.2 Filing Date]	1/1/2014	38	7 [incl. 2012 RRQ]	N/A	Per D.12-02-014, PG&E filed updated RRQs and a cost recovery proposal in Phase 2 of the proceeding on August 10, 2012. The RRQ shown is net of revenues received from customer fees. RRQ allocated 55% electric and 45% gas.	Electric; Gas	Electric Distribution; Gas Distribution
	<u>Q4 2012</u>									
15	Transmission Owner (TO) 14	FERC Docket No. ER12-2701	Sept 28, 2012	5/1/2013		158	N/A	Annual filing to recover transmission costs.	Electric	Transmission
16	2014 General Rate Case (GRC), Phase I	A.12-11-009	Nov 15, 2012	1/1/2014			1,282	Application to request approval of electric and gas distribution and utility-owned electric generation base revenues for the 2014 test year and the 2015-2016 attrition years. RRQ allocated $587M electric distribution, $209M electric generation, and $486 gas distribution.	Electric; Gas	Electric Distribution; Electric; Generation; Gas Distribution
17	Nuclear Decommission-ing Cost Triennial Proceeding (NDCTP)	A.12-12-012	Dec 21, 2012	1/1/2014			169	Review of PG&E's updated Nuclear Decommissioning (ND) cost studies and ratepayer contribution analyses necessary to fully fund the ND master trusts to the level needed to decommission PG&E's nuclear plants.	Electric	Nuclear Decommissioni ng

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implemen-tation date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2013 RRQ *	2014 RRQ *			
	Q1 2013									
17	ERRA Compliance 2012 (incl. MRTU and Diablo Canyon Seismic Studies)	A.13-02-XXX	Feb 28, 2013	1/1/2014	44	25 [incl. 2012 RRQ]	N/A	Annual proceeding to review the utility-owned generation operations, economic dispatch of electric resources, utility retained generation fuel procurement, and entries to the ERRA balancing account for the 2012 record period. Additionally, CPUC ordered PG&E to include review of incremental costs and cost recovery proposal of MRTU projects and Diablo Canyon Seismic Studies projects.	Electric	Generation
18	CPIM 2011 Annual Report (Yr. 19)	N/A	Mar 2013	TBD		N/A	TBD	Compliance report for gas core procurement incentive mechanism for November 1, 2011 through October 31, 2012.	Gas	Procurement
	Q2 2013									
19	ERRA 2014 Forecast	TBD	Jun 2013	1/1/2014	TBD	N/A	TBD	An annual application that requests approval of PG&E's forecasted procurement related revenue requirement, including Competition Transition Charge (CTC), Power Charge Indifference Amount (PCIA) and Cost Allocation Mechanism (CAM) non-bypassable charges.	Electric	Generation; CTC; NSGC; PCIA
	Q3 2013									
20	Transmission Owner 15	TBD	Jul 2013	3/1/2014			TBD	Annual filing to recover transmission costs.	Electric	Transmission

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implemen-tation date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2013 RRQ *	2014 RRQ *			
21	2015 Gas Transmission & Storage Rate Case	TBD	Oct 2013	1/1/2015	TBD	N/A	N/A	General rate case for the Gas Transmission and Storage assets for the 2015 test year.	Gas	Backbone Transmission; Local Transmission; Storage; Customer Access Charge (CAC)
22	2014 Annual Electric True-up (AET) Advice Letter (Tier 3)	TBD	Sep 2013	1/1/2014	TBD	N/A	TBD	Annual filing to adjust for balancing account over/under collections, ERRA forecast and other electric proceeding decisions.	Electric	CTC; Distribution; DWR; ECRA; Generation; NSGC; ND; PPP; PCIA; Transmission
23	2014 Public Purpose Programs Surcharge Rate Advice Letter	TBD	Oct 2013	1/1/2014	TBD	N/A	TBD	Annual filing for cost recovery of gas public purpose programs, gas research and demonstration, and Board of Equalization administrative costs.	Gas	Gas Public Purpose Program Surcharge
24	2014 Annual Gas True-Up (AGT) Advice Letter (Tier 2 Preview)	TBD	Nov 2013	1/1/2014	TBD	N/A	TBD	Annual filing of consolidation of gas transportation rate changes authorized by CPUC. This will be superseded by the advice letter submitted in December.	Gas	Distribution; Backbone Transmission; Local Transmission; Gas Storage; CAC

25	2014 AGT Advice Letter (Tier 1 Final)	TBD	Dec 2013	1/1/2014	TBD	N/A	TBD	Supplemental filing of consolidation of gas transportation rate changes authorized by CPUC.	Gas	Distribution; Backbone Transmission; Local Transmission; Gas Storage; CAC
26	2014 AET Supplemental Advice Letter filing	TBD	Dec 2013	1/1/2014	TBD	N/A	TBD	Supplemental filing to adjust for balancing account over/under collections, ERRA forecast and other electric proceeding decisions.	Electric	CTC; Distribution; DWR; ECRA; Generation; NSGC; ND; PPP; PCIA; Transmission
27	2014 DWR Revenue Requirement	TBD	TBD	1/1/2014	TBD	N/A	TBD	Annual recovery/credit for power and bond charges with DWR. Separately, to be included as part of this proceeding following issuance of the OIR, the CPUC will be considering whether to reallocate to all utilities the costs under the firm gas transportation service agreement between Kern River Gas Transmission Company and DWR that had been previously assigned to SDG&E. This matter is currently awaiting a proposed decision.	Electric	Generation
28	Energy Efficiency Risk-Reward Incentive Mechanism (RRIM) OIR	R.12-01-005	PG&E to File Tier 3 Advice Letter by Q3 2013 with Commission approval by Q4 2013 for approval of 2011 Program year Incentive Award	1/1/2014		N/A	TBD	Rulemaking to address modifications to the Energy Efficiency Incentive for the 2010-2012 program cycle, 2013-2014 program cycle, and beyond. A proposed decision for the 2013-2014 mechanism is anticipated shortly.	Electric; Gas	Electric Distribution; Gas Transportation

*As-filed annual revenue requirements shown for all listed filings, except for TO14, GRC 2014, and NDCTP, which reflect requested increases over currently authorized.
[TBD] – To be determined
[N/A] – No RRQ or rate impact

B. Southern California Edison Company

1. Opening Comments

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

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

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

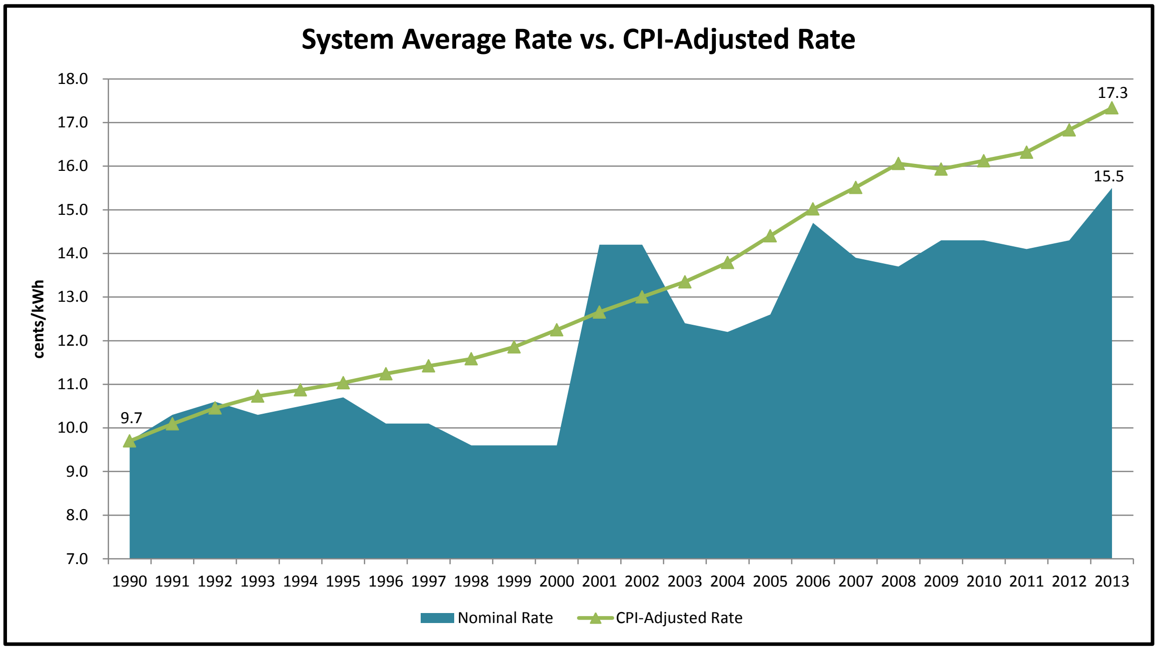
In addition, SCE has provided data contained in Appendix A to this Report that describes SCE's revenue requirements and provides an outlook for pending rate changes from May 1, 2013 to April 30, 2014.

2. Overall Rate Policy

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

Figure 1 below shows a comparison of SCE's actual System Average Rate as compared to what the average rate would have been if it had changed commensurate with the Consumer Price Index.[44]

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



3. <u>Management Control of Revenue Requirements</u>

SCE requests in CPUC and FERC General Rate Cases funding to operate its generation, transmission and distribution businesses in order to provide safe, reliable, and affordable electric service to all customers in its service territory. Based on the funding authorized by the Commission, SCE has the ability to manage those core utility businesses. However, funding has not always been adequate to fulfill all infrastructure replacement requirements on the company's planned schedule. Another portion of SCE's total revenue requirement is associated with its power procurement function. Based on a set of assumptions that reflect regulatory and legislative requirements, SCE requests funding to procure enough power to meet its customers' load. Although there are procurement cost components that are driven by market forces outside of SCE's control, such as natural gas prices, SCE has been given some authority by the CPUC to use hedging tools to reduce the variability in cost of power to its customers. A third category of costs are associated with policies driven by Commission and the Legislature for funding programs such as Demand Response, Energy Efficiency, Solar Initiatives, Self Generation and Low Income programs. In compliance with these policies, SCE makes initial requests for funding these programs but the final authorized funding amounts are determined by the Commission based on its policy objectives. Finally, there are costs included in the total revenue requirement that are fully outside of SCE's management control such as DWR Power and Bond Charge revenue requirements and other costs whose magnitude are prescribed by the legislature or a regulatory agency (e.g., while the requirement in Assembly Bill (AB) 1890 to collect revenue for the California Energy Commission to fund its Renewable, and Research, Development and Demonstration programs expired at the end of 2011, the CPUC issued a decision that continues funding for RD&D programs through 2020.

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

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

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

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

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

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

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

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

To minimize the rate impact of a cap & trade system SCE and the other IOUs advocated in Rulemaking (R.) 11-03-012 that cap & trade related revenues be returned to the utility's customers in form of lower rates and are not spent on additional state-or Commission-mandated programs. However, the Commission issued a decision in R.11-03-012 that primarily will return the cap & trade revenue to residential customers and excludes many businesses including universities, and hospitals.

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

APPENDIX A

1. Description of Rate Components and Revenue Requirements

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

a. **Generation** – Through the Generation rate component, SCE recovers the costs of its generation portfolio which include the cost of SCE's Utility Owned Generation (UOG) consisting of the fuel, base O&M and capital-related revenue requirements associated with its nuclear, coal, gas, and hydro plants. In addition, SCE recovers all of its purchased power costs required to meet its load not met by its UOG.[45] The purchased power costs include the costs of Qualifying Facilities (QFs), and all other bilateral contracts that SCE has entered into since 2003 when the company was authorized to resume the power procurement function and make purchases and sales through the wholesale markets. The impact of renewable contracts entered into to meet the Renewables Portfolio Standard and Greenhouse Gas costs will be reflected in generation rates.

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

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

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

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

(R.11-03-012), SCE will return a portion of the proceeds that result from the cap-and-trade market through the distribution rate component to residential and certain small business customers.[46]

e. **Public Purpose Programs Charge (PPPC)** – Prior to 2012, SCE recovered the legislatively mandated Public Goods Charge funding for the California Energy Commission administered Research Development and Demonstration and Renewable programs, plus a portion of the SCE- administered Energy Efficiency programs through the PPPC. The funding for these three programs expired on December 31, 2011 as mandated by P.U Code 399. The Commission issued a decision in December 2011 that continued this funding in 2012 through 2020 using the name Electric Program Investment Charge. In addition, through the PPPC rate component SCE recovers additional program funding authorized by the Commission for Procurement Energy Efficiency, and Low-Income programs. The Commission has authorized SCE to recover the costs of the CARE program including the discount provided to CARE-eligible customers from all non-CARE customers through the PPPC.

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

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

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

h. **DWR Power Charge and Bond Charge** – In early 2001, as the result of the energy crisis and AB1X, DWR entered into long term power contracts that were necessary to meet the state's Investor Owned Utilities' (IOUs') net short requirements. The Commission authorized SCE to recover on behalf of DWR, the revenue requirement associated with these contracts through the DWR Power Charge. As mentioned above, all of the remaining DWR contracts that had been allocated to SCE's bundled service customers expired as of December 31, 2011. In addition, in order to recover the costs DWR

[46] The remainder of the proceeds will be returned to residential customers through a semi-annual Climate Dividend (i.e. a credit included on customer's bills) and to certain large customers defined as Energy Intensive Trade Exposed through an annual bill credit.

incurred in early 2001 to purchase energy on behalf of IOUs' customers from dysfunctional wholesale markets which were initially financed by the State's General Fund, the Commission authorized SCE to bill the DWR Bond Charge. All of the revenues associated with the DWR Power and Bond Charges are collected by SCE and passed on to DWR.

Since 2001, DWR was required to maintain high levels of operating reserves such that DWR would have enough cash on hand to fulfill its contractual obligations in case power prices skyrocketed. As the power contracts are expiring, DWR no longer is required to maintain this level of reserves and is returning them to customers. As a result of returning the operating reserves to bundled service customers, the Commission-allocated DWR Power Charge Revenue Requirement to SCE's bundled service customers in 2013 is a negative $70 million. In other words, on behalf of DWR, SCE will refund $70 million to its bundled service customers in 2013 through a negative (i.e. or credit) DWR Power Charge. The DWR Bond Charge will remain at approximately $0.005/kWh in 2012.

2. Summary of Revenue Requirements by Rate Component

a. Revenue Requirements and System Average Rate for Bundled Service customers estimated as of January 1, 2013:

	Rate Component	($millions)	%	SAR c/kWh
1.	Generation	5,872	48.9%	7.9
2.	New System Generation	143	1.2%	0.2
3.	Distribution	4,246	35.3%	5.3
4.	Public Purpose Programs	608	5.1%	0.7
5.	Nuclear Decommissioning	12	0.1%	-
6.	FERC Transmission	829	6.9%	1.0
7.	DWR Power and Bond	305	2.5%	0.4
8.	TOTAL System	12,015	100.0%	15.5

3. Sales Forecasts

It is expected that the Commission will adopt SCE's 2013 total sales forecast of 84,225 GWhs in Application (A.)11-08-002 (SCE's 2013 ERRA Forecast Proceeding). This represents a decrease from recorded 2012 sales of approximately 2.6%. SCE estimates sales to decrease in 2013 primarily as a result of normal weather patterns, as 2012 was warmer than normal.

2013 Outlook from May 1, 2013 to April 30, 2014

Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Dollar Amount ($millions)			Description	Impacted Rate Component
				Total Cost	2012 RRQ	2013 RRQ		
2012 GRC	D.12-11-051	11/01/13	1/01/14	Est. 6,159	5,671	5,810	Post Test Year (2014) Increase in O&M and capital revenue requirement.	Generation, Distribution, and New System Generation
SONGS 2&3 Steam Generator Removal and Disposal	D.05-12-040 (A.04-02-026) (By Advice Letter)	11/01/13	1/01/14	Est. 127	116	130	Revenue requirement for Units 2&3 Replacement and Removal and Disposal Rev. Rqmts.	Generation
2013 ERRA Forecast[47] (Excludes GHG Cost per D.12-12-033)	A.12-08-001	8/01/12	6/01/13	Est. 4,118	3,880		Recovery of estimated 2013 fuel and purchased power costs (Excludes cost of GHG)	All Rate Components
2013 ERRA Forecast – GHG Costs	A.12-08-001	8/01/12	6/01/13	Est. 271	0	0	Add recovery of estimated 2013 GHG	Generation

[47] The cost estimate for 2013 assumes that one unit will be operating at 70% capacity in 2013. However, that is now uncertain and what the impact will be on 2013 rates depends on replacement power costs that are not predictable.

Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Dollar Amount ($millions)			Description	Impacted Rate Component
				Total Cost	2011 RRQ	2012 RRQ		
GHG Revenue Return	D.12-12-033	8/01/13	8/01/13	Est. (441)	0	0	Return of GHG Allowance Revenue (Some volumetrically and some to residential customers only through Climate Dividend)	Distribution and credit on bills
Four Corners Gain-On Sale	A.10-11-010	11/15/10	8/01/13	Est. (87)	0	0	Refund gain-on-sale to customers over a 2-year period as a result of the sale of SCE's ownership share of Four Corner's Generating Station	Generation
2014 ERRA Forecast	A.13-08-XXX	8/1/13	1/01/143	TBD	3,880	4,389	Will request recovery of estimated 2014 fuel and purchased power costs	All Rate Components

2014 DWR Revenue Requirement Determination	N/A	TBD	1/01/13	Est. (50)	(341)	(70)	Refund of large Operating Reserve in 2012 will not continue in 2013	DWR Power Charge
FERC Formula Rate Change	N/A (Advice Letter)		10/01/13	TBD	722	899	Pursuant to FERC approved formula	Transmission Revenue Requirement
FERC Transmission Balancing Accounts	N/A (Advice Letter)		6/01/13 and 1/01/14	(11) 6/01/13 TBD 1/01/14	(89)	(71)		Transmission Owner's Tariff Charge Adjustment
Century Energy Systems (CES)-21	D.12-12-031	07/18/11	7/01/13	Est. 52 (divide by 5 for annual amount)	0	0	R&D partnership between the Joint Utilities and Lawrence Livermore Laboratory	Distribution
Statewide Marketing, Education & Outreach (SME&O)	A.12-08-008	08/03/12	06/01/13	Est. 21 (divide by 2 for annual amount)	0	0	SME&O activities include Energy Efficiency and Demand Response programs (e.g. Flex Alert)	Public Purpose Programs Charge
ESP Interface/3rd Party Data Access	A.12-03-004	3/05/12	07/31/13	Est. 9	0	0	ESPI platform will provide customer-authorized	Distribution

							3rd parties access to usage data	

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

C. Southern California Gas Company

Southern California Gas Company (SoCalGas) appreciates the opportunity, pursuant to Senate Bill (SB) 695 and PUC Section 748, to recommend actions that can be undertaken during the next 12 months to limit utility cost and rate increases. SoCalGas' objective in developing the 2013 report is to provide useful information that the California Public Utilities Commission (CPUC or Commission) may consider as it prepares its annual report for the Governor and Legislature.

I. Introduction

This report addresses PUC Section 748 (a) and provides data related to gas revenue requirements and rates. The report is structured according to the Energy Division's request: (1) a description of the key categories of revenue requirements, trends for each category in the coming 12 months and load/demand forecasts, and (2) the outlook of anticipated rate changes during 2013 and the amount of the change if it is known. Within the framework approved by the CPUC and the Legislature, SoCalGas seeks to allocate costs fairly across its customer classes. However, SoCalGas recognizes that allocations of certain components of gas service costs in rates are beyond its direct control.

II. Section 748 (a) Study and Report

1. Description of Revenue Requirement Components

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

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

	2012		**2013**	
Revenue Component	**Revenue Requirement** $000	**Percentage**	**Revenue Requirement** $000	**Percentage**
Energy	$1,077,598 [1]	32.3%	$1,338,093 [2]	37.2%
Transportation [3]	$1,951,413	58.6%	$1,940,966	53.9%
Storage [4]	$27,530	0.8%	$27,911	0.8%
Public Purpose Program	$302,505	9.1%	$319,252	8.9%
Total	$3,331,517	100%	$3,598,310	100%

[1] Actual recorded revenue.

[2] Represents estimates of the residential, core commercial and industrial, and natural gas vehicles energy revenue and was derived by multiplying the *2012 California Gas Report* throughput projection for 2013 by the gas price forecast for the year 2013.

[3] The transportation component includes Authorized Base Margin, amortization of regulatory accounts, other operating costs, SoCalGas' and SDG&E's Gas Transmission System Integration, and other Sempra-wide adjustments.
[4] A subset of transportation revenue requirement, represents costs allocated to be recovered from the Unbundled Storage Program

(B) Trends in Revenue Components

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

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

1) Gas energy revenue requirements are forecast to represent approximately 37.2% of the total gas revenue requirement in 2013. In 2012, the gas energy revenue requirements represented about 32.3% of the total authorized gas revenue. The revenue requirements are expected to increase significantly from 2012 to 2013 due to forecasted higher natural gas prices.

2) Transportation revenue requirements are estimated to constitute about 53.9% of the total gas revenue requirements in the upcoming 12 months. For 2012, the transportation revenue requirement constituted about 58.6% of the total authorized gas revenue requirement. Part of the decrease in the revenue requirements is due to the decrease in amortization of balancing accounts and the decrease in revenue from the Cost of Capital decision in December 2012. SoCalGas is also expecting a decision in its General Rate Case sometime in 2013, which will have an impact on the transportation revenue requirement.

3) Costs allocated to the unbundled storage program comprised approximately 0.83% of the total revenue requirement in 2012, and this level is forecasted to decrease by less than 0.1% in 2013.

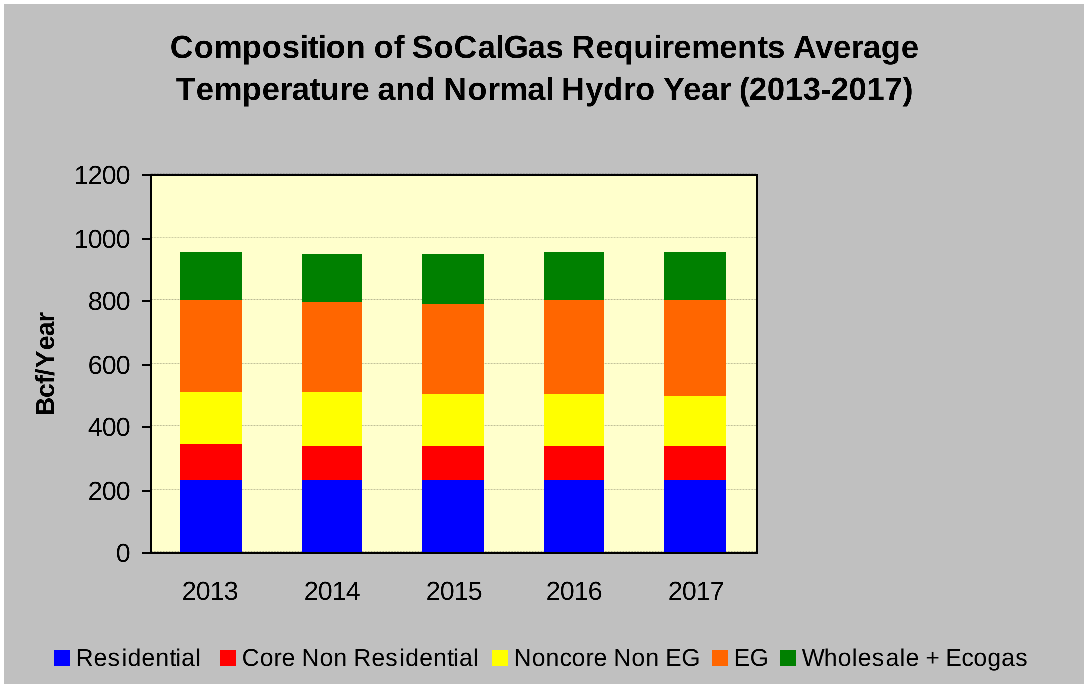
4) Public Purpose Program (PPP) revenue requirements, including California Alternate Rates for Energy (CARE) Discount and Energy Efficiency, represent approximately 8.9% of the total gas revenue requirements for

2013. The revenue requirement is expected to trend upward mainly due to increases in expected gas program penetration levels for the Low Income Energy Efficiency program. For 2012, these programs contributed about 9.1% of the total authorized gas revenue requirements.

(C) Demand Forecasts

This section outlines major categories of gas demand and the load forecast through 2017.

Composition of SoCalGas' Requirements (Bcf/Year)
Average Temperature and Normal Hydro Year (2013-2017)



SoCalGas Demand Forecasts (Bcf/Year)
Average Temperature and Normal Hydro Year (2013-2017)

Bcf	2013	2014	2015	2016	2017
Residential	231	229	227	227	227
Core Non Residential	110	109	109	109	109
Noncore Non EG	168	167	165	164	162
EG	294	286	288	298	299
Wholesale	152	152	153	154	153
TOTAL	955	943	943	951	950

The table above shows the projected gas demand over the five year period covering 2013 to 2017. Gas demand in 2013 is expected to total 955 Bcf. The average, annual rate of growth from 2013 to 2017 is anticipated to be - 0.237% based on the 2012 California Gas

Report demand forecast. Demand is expected to be virtually flat in the future due to modest economic growth, CPUC-mandated energy efficiency goals and renewable electricity goals[48], declines in commercial and industrial demand and continued increased use of non-utility pipeline systems by enhanced oil recovery customers and savings linked to advanced metering modules.

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

2. Rate Outlook from May 1, 2013 to April 30, 2014

(A) Listing of Pending Proceedings

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

[48] The EG gas demand forecast is surrounded by much uncertainty, given electricity demand, relatively few customers with potential large swings in usage, and sensitivity to changes in assumptions regarding new entrants. The electricity demand forecast, upon which the EG gas demand forecast is based, was agreed to by the IOU's, the CEC, and the CPUC. (Source: California Energy Commission's California Energy Demand 2010-2020, Staff Adopted Forecast.)

Filing Name	Proceeding Reference (e.g. Application #)	Filing Date	Requested/Expected Implementation date	Requested Dollar Amount			Description	Impacted Rate
				Total Cost	2012 RRQ	2013 RRQ		
Ammendment of Certificate of Public Convenience and Necessity for Aliso Canyon Gas Storage Facility	A. 09-09-020	9/28/2009	Expected 2016	$200.9 million		Expected 2016 revenue requirement of $23-$30 million, $8-$11 million for core rates	Amend the SoCalGas Aliso Canyon CPCN in order to authorize replacement of the three existing gas turbine compressors and associated equipment with a new electric compressor station and other improvements.	Transportation Core rates increase of 0.3 cents/therm.
SoCal Gas 2012 GRC Filing	A. 10-12-006	12/15/2010, revised 07/2011, updated testimony 02/17/2012	2013	$268 million (14.5%) increase in base revenue requirement compared to 2011.		$2.112 billion	SoCalGas filed its most recent GRC for test year 2012.	Tranportation Core rates increase 6.0 cents/therm; noncore rates increase 0.5 cents/therm
Master Meter Rulemaking	R. 11-05-018			$52 million ($4,000 per space, 12,923 spaces)		N/A	SoCalGas, SDG&E, Edison, TURN and DRA reached an agreement and sponsored testimony proposing to convert, up to 10% of the master-metered mobile home park spaces in a five-year period to utility service. Workshop and public meeting scheduled.	
Gas Pipeline Safety Rulemaking	R. 11-02-019	8/26/2011, amended 12/2/2011, updated 09/18/2012	2013	$1,675 million for Phase 1A at SoCalGas		$162 million	In response to the commissions OIR regarding gas pipeline safety, SoCalGas filed a proposed Pipeline Safety Enhancement Plan (PSEP)	Res bills increase $1.79 per month in 2013 and $2.17 per month in 2014; Core C&I rates increase up to $0.020 per therm in 2013 and $0.024 per therm2014.
Triennial Cost Allocation Proceeding	A. 11-11-002	11/1/2011, updated 9/18/2012	2013				Cost Allocation Proceedings reallocate costs between customer classes to determine cost-based transportation rates.	Core transportation rates decrease 1.1 cents/therm; noncore rates decrease 0.7 cents/therm
2013-2014 Statewide Marketing, Education and Outreach	A.12-08-010	8/3/2012	2013, 2014	$4 million		$2 million in 2013; $2 million in 2014	SCG, SDG&E, PG&E and Edison filed applications proposing funding for certain statewide marketing, education and outreach activities that support their demand-side programs for 2013-2014.	PPPS residential rates decrease 0.002 cents/therm; Core C&I rates decrease 0.006 cents/therm

The following is a list of the timing of all new proceedings as well as those proceedings that are anticipated to affect rates during 2013.

SoCalGas Aliso Canyon Storage Field Expansion

On September 30, 2009, SoCalGas filed application (A.) 09-09-020 to amend its Certificate of Public Convenience and Necessity for the Aliso Canyon Gas Storage Facility. SoCalGas proposes to conduct work at its Aliso Canyon Storage Field to replace three gas turbine compressors with three electric compressors. The project, when completed, will expand storage injection capacity by 145 million cubic feet per day (MMcf/d). SoCalGas estimates the expansion cost to be $200.9 million. The increase in revenue requirements is estimated to be $23-$30 million per year starting in 2016. Once the project is complete, the expected initial core rate increase is forecast at 0.3 cents per therm. A final CPUC decision is expected later in 2nd quarter 2013.

General Rate Case

In December 2010, SoCalGas filed its 2012 General Rate Case (GRC) Phase I application, A.10-12-006, to establish its authorized 2012 revenue requirement and the ratemaking mechanism by which this requirement will change on an annual basis over the subsequent three year (2013-2015) period. In July 2011, SoCalGas filed amendments to revise its original application, primarily to reflect the impact of the Tax Relief Unemployment Insurance Reauthorization and Job Creation Act of 2010. In February, 2012, SoCalGas filed updates to the amendments, primarily for escalation, postage, and taxes. With these updates, SoCalGas is requesting a revenue requirement in 2012 of $2.112 billion, an increase of $268 million (or 14.5%) over 2011. While the CPUC will determine the total amount of money SoCalGas can collect in rates in the GRC Phase 1 decision, the design of the actual rates themselves (that is, the allocation of costs between customer classes and the structure of charges) will be determined in the upcoming Tri-annual Cost Allocation Proceeding. A final decision is expected in 2013.

2013 Triennial Cost Allocation Proceeding- Phase 1 (Gas Pipeline Safety)

CPUC Decision (D).11-06-017 ordered all California natural gas transmission operators to develop and file for Commission consideration a Natural Gas Transmission Pipeline Comprehensive Pressure Testing Plan (Implementation Plan) to achieve the goal of orderly and cost effectively replacing or testing all natural gas transmission pipelines that have not been pressure tested. SoCalGas and San Diego Gas & Electric Company (SDG&E) jointly filed their comprehensive "test or replace" Implementation Plan on August 26, 2011, as directed by the CPUC. SoCalGas and SDG&E subsequently amended their Implementation Plan on December 2, 2011. SoCalGas and SDG&E propose to spend $1.944 billion (loaded & escalated dollars, $1.675 billion for SCG; $269 million for SDG&E) over the 2012-2015 time period. The request is separate from their GRC Phase 1 proposals. In the December 21, 2011 Ruling, the Assigned Commissioner indicates that "[u]pon further review, [he] now believe[s] that the pending Triennial Cost Allocation Proceeding. . . is the most logical proceeding for the SDG&E and SoCalGas reasonableness and ratemaking review" and directs SoCalGas and SDG&E to address the issue of "reassignment of the reasonableness and ratemaking issues to the Cost Allocation

Proceeding versus the pending or a future general rate case." The rate impact by customer class will depend on the level, cost allocation and timing of safety-related investment that is ultimately adopted by the Commission. A decision is expected in 2013.

2013 Triennial Cost Allocation Proceeding – Phase 2

On November 1, 2011, SoCalGas and SDG&E filed their Triennial Cost Allocation Proceeding application, A.11-11-002, to update their gas demand forecasts, cost allocation and rate design for the 2013 through 2015 period. On September 18, 2012, the testimonies were updated to incorporate final costs of the Honor Rancho Expansion Project. The utilities propose continuation of 100% balancing account treatment for noncore revenues and extension of the 2009 Biennial Cost Allocation Proceeding Phase 1 Settlement through 2015. SDG&E is also proposing a $5 per month residential customer charge. The rate impact by customer class will depend on what cost allocation is ultimately adopted by the Commission. A CPUC decision is expected in 2013. Phase II also will address the Gas Pipeline Safety Plan (PSEP) cost allocation.

2013-2014 Statewide Marketing, Education and Outreach

On August 3, 2012 SoCalGas filed a proposal for funding of certain statewide marketing, education and outreach activities that support their demand-side programs for 2013-2014. SoCalGas utilities requested $4 million. The proceeding will be managed in two phases. Phase 1 will address budgets and proposals for the Flex Alert program in 2013-2014. A CPUC decision is expected to be issued by 2nd Quarter of 2013. Phase 2 will address all other issues.

Gas Public Purpose Program Surcharge

The state's natural gas and electric utilities collect funds from core and non-EG noncore customers for gas related energy efficiency programs, low-income programs including the California Alternative Rates for Energy (CARE) subsidy, and for the California Energy Commission's natural gas research and development program. The annual budget for these public purpose programs is set in various recurring program-related Commission proceedings. The CARE program revenue requirement for SoCalGas' customers in 2013 was $118.8 million.

Honor Rancho Storage Field Expansion

On July 13, 2009, SoCalGas filed application A.09-07-014 with the Commission for the expansion of the Honor Rancho natural gas storage facility. D.10-04-034, approved SoCalGas' request to amend the Certificate of Public Convenience and Necessity for the Honor Rancho natural gas storage facility. The proposed capital cost of $37.4 million for the expansion project, excluding the cost of cushion gas, was deemed reasonable by the Commission. SoCalGas obtained approval in November 2011 to establish a memorandum account to record costs that exceed the previously authorized $37.4 million cap for capital expenditures. The approved memorandum account is consistent with the CPUC decision granting SoCalGas authority to expand its Honor Rancho storage field. The estimated additional costs of the expansion are $16.2 million. SoCalGas has requested CPUC approval to recover the excess costs as part of its Triennial Cost Allocation Proceeding application filed on November 1, 2011 and updated September 17, 2012. A decision in the Triennial Cost Allocation Proceeding is expected in 2013. The Honor Rancho project increased the 2013 revenue requirement by $2.24 million.

Advanced Metering Infrastructure (AMI)

AMI will enable our customers to better control and manage their energy bills with access to timely natural gas usage information and to realize the substantial operational and environmental benefits. The AMI deployment period as approved in D.10-04-027 runs from 2010-2017. The approved AMI deployment costs are $1.051 billion, consisting of $876 million in capital expenses and $175 million in O&M expenses. The AMI project's 2013 revenue requirement is $85 million.[49]

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

The Commission opened a new rulemaking in February 2011 to examine what the Commission can and should do to encourage the replacement by direct utility service of the sub-meter systems that supply electricity, natural gas or both to mobile home parks and manufactured housing communities located within the franchise areas of electric and natural gas corporations. SoCalGas, SDG&E, Edison, TURN and DRA reached an agreement and sponsored testimony proposing to convert, at limited ratepayer expense, up to 10% of the master-metered mobile home park spaces in a five-year period to utility service. PG&E, Southwest Gas, the Coalition of CA Utility Employees and various mobile home park interests jointly sponsored an open-ended program to replace existing facilities, including those beyond the utility meter, with new utility systems at a ratepayer expense. A ruling was issued February 8, 2013 setting aside the submission of the case and scheduling a workshop, on natural gas mobile home park system prioritization, and public meeting to discuss ratepayer financing. The potential future rate impacts, as a result, are unknown at this time.

(B) New Proceedings Likely to be Filed Between Now and April 30, 2014

SoCalGas will file its Gas Cost Incentive Mechanism (GCIM) Year 19 application in June 2013. SoCalGas will request a shareholder award consistent with the established sharing mechanism for the purchases below the GCIM benchmark. At this time, this encompasses the new proceedings likely to be filed before April 30, 2014.

[49] The $85 million will NOT be part of the $2.112 billion 2012 GRC revenue requirement.

Appendix A

Southern California Gas Company
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Appendix A

Description	Filed	Expected Implementation	Impacted Rate	Directional Impact	Revenue Requirement Impact ($000)	Reason for Revenue Requirement Request
Gas Regulatory Account Update AL	October 2013	January 2014	Gas Transportation	Decrease	($88,303)	(1)
Gas Consolidated AL	December 2013	January 2014	Gas Transportation	Decrease	($10,448)	(1) (2)
Gas Public Purpose Program Update AL	October 2013	January 2014	PPP Surcharge	Increase	$16,746	(1)

(1) Shows change from 2012 to 2013. This is an annual routine filing in which the specific financial impact for 01/2014 has not been determined.
(2) Gas Consolidated AL 4442 shows change from 2012 to 2013.

SB 695 Compliance Report – Part II

On February 25, 2013, SoCalGas submitted to the Energy Division data addressing PUC Section 748 (a) related to gas revenue requirements and rates, including: (1) a description of the key categories of revenue requirements, trends for each category in the coming 12 months, and load/demand forecasts, and (2) the outlook of anticipated rate changes during May 1, 2013 to April 2014 and the amount of the change if it is known.

In this submittal, SoCalGas addresses PUC Section 748 (b) and provides an overview of key filings which may have a significant impact on gas customer rates, an overview of SoCalGas' overall rate policy, an overview of management control of rate components, and a summary of policies and recommendations for limiting customer rate impacts while meeting the State's energy and environmental goals for reducing greenhouse gases. SoCalGas hopes that the CPUC will consider the recommendations set forth in this report, which SoCalGas believes can have a measurable near-term impact on its total cost of delivering safe, reliable, cost-effective gas services to its customers in California.

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

1. Opening Comments

Attached for your reference is Appendix A, which reflects data from key filings provided previously to the Energy Division. This is not an exhaustive list of SoCalGas' filings that may occur in 2013. Rather, the list incorporates regulatory filings that are known at this time to have a significant rate impact for gas customers. Actual filing dates, amounts of requests, and actual revenue requirements authorized are subject to change via the normal regulatory approval processes of the CPUC and the Federal Energy Regulatory Commission.

2. Overall Rate Policy

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

3. Management Control of Rate Components

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

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

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

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

The impact to SoCalGas' customers from energy efficiency, low income energy efficiency, CARE, technology research, development, and demonstration (RD&D) is shown below.

COMPONENT	ANTICIPATED COSTS AS OF 1/1/13		
	Core	Non-Core	Total
Energy Efficiency/DSM	$39,359,000	$3,259,000	$48,618,000
Low Income Energy Efficiency/DAP	$146,869,433	$0	$146,869,433
CARE	$78,411,340	$40,383,809	$118,795,149
RD&D	$10,119,846	$488,098	$10,607,944

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

1. AB 32 Cap and Trade Implementation: Residential and small commercial natural gas customers have already achieved a reduction to 1990 emission levels through existing energy efficiency programs and, therefore, should be exempted from the AB 32 Cap and Trade Regulation. If they are not exempted, they should be given a free allocation of allowances to recognize this history of maintaining natural gas related emissions at 1990 levels since 1990. It would be inappropriate, and damaging to the California economy to unnecessarily impose costs of GHG regulation on customers that have already achieved the objectives of AB 32.

2. Combined Heat and Power (CHP): CHP reduces overall energy use by using waste heat to generate power. CHP entails low carbon generation and its widespread use will have carbon reducing benefits. Both the CPUC and the Energy Commission have supported the development of CHP to meet

California's energy needs. This source has contributed substantially to reducing California's Greenhouse Gas Emissions.[50]

3. Performance-Based Incentives Mechanisms: Continue to support the utilization of performance based mechanisms to motivate utilities to implement programs that will lead to an overall reduction in costs and improve the efficiency of utility operations. These mechanisms work because (1) they align customers' and shareholder interests; (2) they measure a utility's performance relative to a market based benchmark; and (3) they reduce the regulatory burden.

4. California Alternative Rates for Energy (CARE): CARE customers now comprise one third of SoCalGas' customer base. Non-CARE customers must cover the CARE shortfall, which leads to a 10% increase of non-CARE costs. Safeguards should be taken to ensure only qualified customers are participating in the program.

5 Public Interest Energy Research (PIER) Program Costs: The program allows the utilities to shift funds from the Public Purpose Program Surcharge and transfer it to the CEC for studies. SoCalGas is concerned about the potential overlap between PIER priorities and research with the work done by other publicly funded research organizations. Optimizing the effectiveness of the PIER program would help reduce the PPP rate, which has had the largest impact on non-core rates. Almost 40% of the transportation rate for non-core customers is attributable to the PPP.

6. Utility Rate Cases: The CPUC, intervenors and customers would save money if the General Rate Cases continue to be kept on a four-year cycle, instead of a three-year cycle.
7. Reporting Requirements: Mandated reporting requirements should be reviewed to make sure they are useful and non-duplicative.

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

[50] Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to examine the Integration of GHG Standards in its Procurement Policies, pp. 221, R.06-04-009.

APPENDIX A

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D. San Diego Gas and Electric Company

Part I: Section 748(a) CPUC Study and Report

San Diego Gas & Electric (SDG&E) appreciates the opportunity to provide input to the California Public Utilities Commission (CPUC or Commission) in response to Senate Bill (SB) 695 enacted changes to Public Utilities Code (PUC) Section 748. SDG&E's objective in developing this report is to provide useful information that the CPUC may consider as it prepares its annual report for the Governor and Legislature. This report addresses PUC Section 748(a) and provides data related to both gas and electric revenue requirements and rates. SDG&E's response addressing PUC Section 748(b) is to be provided separately. This report is structured as per the Energy Division's request: (1) description of revenue requirements describing key categories of revenue requirements, trends for each category in the coming 12 months, and load/demand forecasts, and (2) outlook from May 1, 2013 to April 30, 2014 listing of pending and anticipated revenue requirements.

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

A. Key Revenue Requirement Categories

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

Electricity cost categories include:

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

This means enough generation facilities available to meet the demand for electricity at all times.

- Distribution – This charge reflects the costs to distribute power to customers and includes power lines, poles, transformers, repair crews and emergency services. In addition, distribution rates recover program costs related to California Solar Initiative (CSI), Self-Generation Incentive Program (SGIP), and demand response.
- Public Purpose Programs (PPP) – This charge reflects the costs of certain state-mandated programs (such as low income and energy efficiency programs).
- Total Rate Adjustment Component (TRAC) – This charge reflects the subsidies that result from capped residential tiered rates under Assembly Bill 1X Legislation.

Relative ranges for each electric RRQ category as a percent of total authorized 2012 RRQ, and 2013, for rates effective on January 1st of each year are provided and discussed below. Note that the focus is not on specific filings brought forth to the Commission, but rather categories of revenue requirements that could have a potential impact on future rates.

	2012*			2013*		
Revenue Component	**Revenue Requirement ($000)**		**Percent**	**Revenue Requirement ($000)**		**Percent**
Commodity	1,266,780		41.22%	1,469,728		45.70%
DWR-BC	96,271		3.13%	92,518		2.88%
CTC	70,786		2.30%	60,903		1.89%
ND	9,124		0.30%	(7,142)		-0.22%
Transmission	359,801		11.71%	377,486		11.74%
RS	(4,754)		-0.15%	366		0.01%
Distribution	1,076,717		35.03%	1,050,251		32.66%
PPP	145,683		4.74%	134,719		4.19%
TRAC	52,899		1.72%	37,287		1.16%
Total	3,073,306		100%	3,216,116		100%

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

1) The largest piece of SDG&E's revenue requirement is Commodity/ Generation which constitutes 45.70% of the total revenue requirement up from 41.22% in 2012. The Commodity/Generation revenue requirement is generally expected to trend upward primarily due to increasing electricity procurement costs related to renewable energy costs and increasing natural gas prices. With the expiration of DWR contracts, DWR charges are a declining portion of Commodity/Generation revenues, from 3% in 2012 to 2% in 2013.

2) DWR-BC represents 2.88% of the total revenue requirement in 2013 down from 3.13% in 2012.

3) CTC contributes 1.89% of the total revenue requirement in 2013 down from 2.30% in 2012.

4) Transmission related revenue requirements constitute 11.74% of the total revenue requirement in 2013 up from 11.71% in 2012.

5) Distribution revenue requirements comprise approximately 32.66% of the total revenue requirement in 2013, down from 35.03% in 2012. This decrease is primarily due to the 2013 Cost of Capital decision which decreased the electric distribution base margin revenue requirement and the roll off of Electric Distribution Fixed Cost Account (EDFCA) amortization offset by the roll off of Advanced Metering Infrastructure (AMI) amortization. SDG&E is expecting a decision in Phase 1 of its 2012 General Rate Case sometime in 2013, which will have an impact on distribution revenue requirement when it is anticipated to be implemented later this year.

6) PPP revenue requirements, including California Alternate Rates for Energy (CARE) Discount and Energy Efficiency, represent 4.19% of SDG&E's total revenue requirement in 2013 down from 4.74% in 2012.

7) ND and RS revenue requirements each represented less than 1% of SDG&E's total revenue requirement during 2012 and remain less than 1% in 2013.

8) TRAC was 1.72% of SDG&E's total revenue requirement in 2012 decreasing to 1.16% in 2013 due to actual Tier 3 and Tier 4 sales being lower than authorized sales.

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

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

	2012		2013	
Revenue Component	**Revenue Requirement** $000	**Percentage**	**Revenue Requirement** $000	**Percentage**
Energy	$142,972 [1]	33.1%	$196,683 [2]	39.7%
Transportation [3]	$242,747	56.2%	$272,324	55.0%
PPP	$46,062	10.7%	$25,996	5.3%
Total	$431,782	100%	$495,004	100%

[1]Actual recorded revenue.

[2]Represents estimates of the residential, core C&I, and NGV energy revenue and was derived by multiplying the 2012 CGR throughput projection for 2013 by the gas price forecast for 2013.

[3]The transportation component includes Authorized Base Margin, amortization of regulatory accounts, other operating costs, System Integration, and Sempra-wide adjustments.

1) Energy revenue requirements are forecast to represent approximately 39.7% of the total gas revenue requirement for 2013. The revenue requirements are expected to increase from 2012 to 2013 due to forecasted higher natural gas prices. The energy revenue requirement represented about 33.1% of the total authorized gas revenue requirements in 2012.

2) Transportation revenue requirements will constitute about 55.0% of the total gas revenue requirements in 2013. For 2012, the transportation revenue requirement constituted about 56.2% of the total authorized gas revenue requirements. The increase in the revenue requirement is primarily due to larger balancing accounts, but the decrease in its relative percentage of total revenue requirement is due to higher energy costs. SDG&E is expecting a decision in Phase 1 of its 2012 General Rate Case sometime in 2013, which will have an impact on transportation revenue requirement when it is anticipated to be implemented later this year.

3) PPP revenue requirements, including CARE Discount and Energy Efficiency, will represent approximately 5.3% of the total gas revenue requirements in 2013. The revenue requirement is expected to trend downward mainly due to decreases in expected gas program penetration levels of Energy Efficiency. CARE costs are decreasing due to the decrease in the Gas forecast rate, even though participation is expected to increase from last year. For 2012, these programs contributed about 10.7% of the total authorized gas revenue requirements.

B. Trends in Rate Components

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

Customer sales volatility across time directly impacts the rates charged to natural gas and electricity customers. If revenues collected from customers are impacted (higher or lower) due to volatility in sales, future rates will be adjusted (decreased or increased) in order to ensure revenues collected are at authorized levels. SDG&E reviews load forecasts for its service territory on a regular basis. The following section discusses the general trends for gas and electricity loads through 2017.

C. Load and Demand Forecasts

This section outlines major categories of electric and gas demand and the load forecasts through 2017.

SDG&E is a combined gas and electric distribution utility serving more than three million people in San Diego and the southern portions of Orange counties. In 2012, SDG&E delivered 20 billion kWh of electricity to 1.4 million customers. Approximately 83% of sales were delivered to bundled service customers (commodity, transmission and distribution), and 17% to Direct Access customers (transmission and distribution only). On September 14, 2012, SDG&E's recorded peak demand was 4,600 megawatts.

Looking ahead to the next five years, the number of electric customers is expected to increase at an average rate of 1.1% per year, gradually recovering from a historic low growth rate of 0.5 percent in 2012 to nearly 1.1 percent by 2017. Electric sales and peak demand for the same period are projected to grow, from 2012, at an average of 1.5 percent per year.

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

Sales in GWh	2013	2014	2015	2016	2017
Residential	7,908	7,998	8,072	8,171	8,326
Small Commercial	1,991	1,982	1,977	1,979	1,984
Med & Large Com/Ind	10,412	10,591	10,745	10,898	11,046
Agricultural	81	80	79	79	79
Lighting	115	115	116	116	117
Total System	**20,508**	**20,766**	**20,989**	**21,244**	**21,552**

Source: *California Energy Demand 2012-2022 Adopted Forecast*, June 2012, California Energy Commission

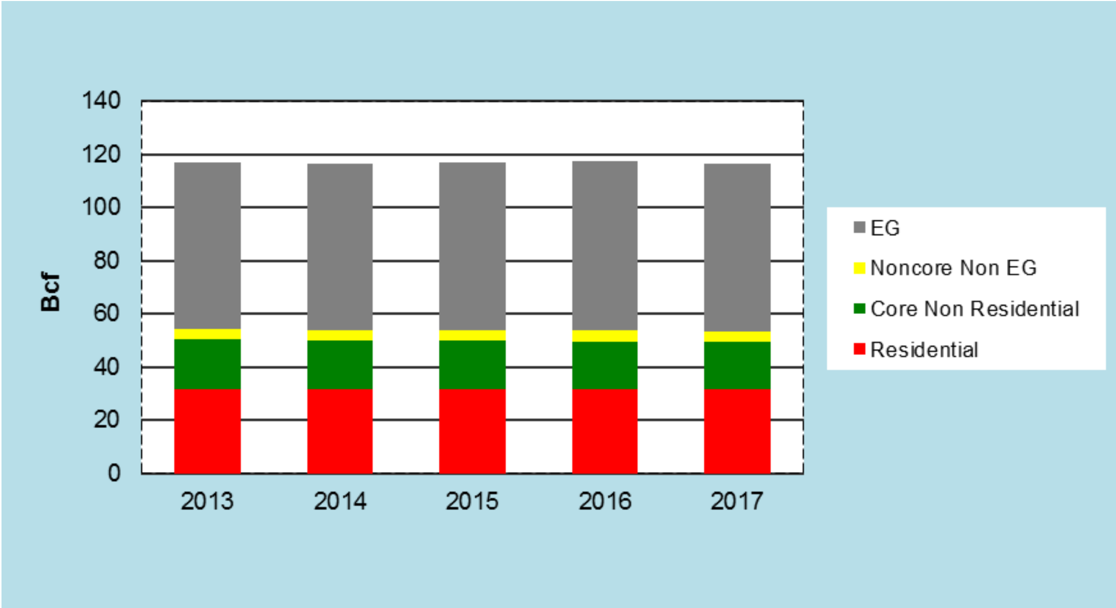
On the natural gas side, SDG&E delivers natural gas to over 845,000 customers in San Diego County, including the power plants and turbines previously owned and operated by the company. Total gas sales and transportation through SDG&E's system for 2012 were approximately 124 billion cubic feet (Bcf), which is an average of 339 million cubic feet per day (MMcf/day). Gas demand for 2013 is expected to be 117 Bcf and the forecast is expected to remain flat over the next 5 years.

Composition of SDG&E Gas Requirements (Bcf)

Average Temperature and Normal Hydro Year (2013-2017)

Bcf	2013	2014	2015	2016	2017
Residential	32	32	32	32	32
Core Non Residential	19	19	18	18	18
Noncore Non EG	4	4	4	4	4
EG	63	63	63	64	63
TOTAL	117	117	117	118	117

Composition of SDG&E's Gas Requirements (Bcf)
Average Temperature and Normal Hydro Year (2013-2017)



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

2. May 1, 2013 to April 1, 2014 CPUC Filing Outlook

A. Outlook from May 1, 2013 to April 30, 2014 – Pending Proceedings

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

<u>Electric Proceedings</u>

Energy Resource Recovery Account (ERRA) Compliance Application (A.11-06-003)

On June 1, 2011, SDG&E filed an application for Energy Resource Recovery Account (ERRA) compliance review (ERRA Application) with the CPUC. The application pertains to SDG&E's electric procurement contract administration and related activities and costs for the 12-month record period of January 1, 2010 through December 31, 2010. In addition to presenting SDG&E's recorded costs for review, SDG&E's ERRA Application requests CPUC approval to recover the revenue requirement associated with the balances accrued during 2010 in three memorandum accounts authorized by the CPUC, including the: (1) Market Redesign and Technology Upgrade Memorandum Account (MRTUMA); (2) Independent Evaluator Memorandum Account (IEMA); and (3) Renewables Portfolio Standard Memorandum Account (RPSMA). Specifically, SDG&E's ERRA Application requests cost recovery of approximately $2.15 million, representing the combined total 2010 activity of all three of these accounts. SDG&E's prior request for approval of recovery of balances in these accounts generated prior to 2010 is pending at the CPUC.

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

SDG&E filed its 2012 GRC Phase 2 on October 3, 2011 and re-submitted its filing on February 17, 2012 with the exclusion of the Network Use Charge. This proceeding is to allocate authorized costs to the different customers' classes; and, to then design the rate structure within each class and does not address revenue requirements. Costs are allocated based on the concept of cost causation to determine marginal costs, revenue allocation, and rate design for electric customers. Cost causation seeks to determine which customer or group of customers causes the utility to incur particular types of costs.

Joint Application for Adoption of Electric Revenues and Rates Associated with MRTU (A.12-01-014)

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

ERRA Compliance Application (A.12-06-003)

On June 1, 2012, SDG&E filed an application for Energy Resource Recovery Account (ERRA) compliance review (ERRA Application) with the CPUC. The application pertains to SDG&E's electric procurement contract administration and related activities and costs for the 12-month record period of January 1, 2011 through December 31, 2011. The ERRA Application involves compliance review of SDG&E's electric procurement, contract administration and related activities and costs for the 12-month record period of January 1, 2011 through December 31, 2011. Additionally, SDG&E's ERRA Application requests CPUC approval to recover the revenue requirement associated with the balances accrued during 2011 in two memorandum accounts authorized by the CPUC, including the Market Redesign and Technology Upgrade Memorandum Account (MRTUMA), and the Independent Evaluator Memorandum Account (IEMA). Specifically, SDG&E's ERRA Application requests cost recovery of approximately $2.93 million[51], representing the combined total 2011 activity of these two accounts.

2013 ERRA Forecast Application (A.12-10-022)

On October 1, 2012, SDG&E filed an application with the CPUC for approval of its forecasted electric procurement revenue requirement for 2013, referred to as SDG&E's 2013 ERRA Application. SDG&E requested approval of a forecasted 2013 ERRA revenue requirement of $1,103.7 million and a 2013 Competition Transition Charge Revenue Requirement of $51.8 million, an increase from 2012 levels. These revenue requirements cover the costs of acquiring power for retail customers, including costs to purchase power under contracts with various power suppliers, California Independent System Operator charges and collateral requirements associated with electric procurement, as well as the cost responsibility of Direct Access (DA) and Community Choice Aggregation customers for above-market power costs.

2012 Nuclear Decommissioning Cost Triennial Proceeding (A.12-12-013)

On December 21, 2012, SDG&E and Southern California Edison Company (SCE) filed a joint application (A.12-12-013) with the CPUC to set contribution levels for each company's nuclear decommissioning trust fund and other related issues in connection with SONGS Units 1, 2 and 3[52]. In this application, SDG&E requests the CPUC to approve increased contribution to its Nuclear Decommissioning Trust Funds for SONGS Units 2 and 3 from $8.17 million to $16.43 million annually beginning January 1, 2014.

Electric Procurement Investment Charges (EPIC) Investment Plan (A.12-11-002)

On November 1, 2012, SDG&E filed a proposed application to submit its First Triennial Electric Program Investment Charges (EPC) to the CPUC in compliance with Decisions 12-05-037 and 11-12-035. EPIC is designed to be the primary vehicle for utility RD&D proposals other than proposals submitted by the utilities for demand response and electric efficiency RD&D projects.

Demand Response Augmentation Application (A.12-12-016)

On December 21, 2012 SDG&E filed a proposed application with the CPUC for a request for authorization of Demand Response (DR) 2013 – 2014 program augmentations

[51] Excludes Franchise Fees and Uncollectibles

[52] SCE owns an 80% interest in SONGS 1 and a 78.21% interest in SONGS 2 & 3. SDG&E owns a 20% interest in SONGS 1, 2 and 3. The City of Riverside owns the remaining 1.79% interest in SONGS 2 & 3.

and associated funding, in accordance with direction received from the Director of Energy Division. Authorized changes will be implemented in rates in 2014 and 2015. SDG&E is requesting approval of an additional $100,000 in 2013 and 2014 to fund additional community-based organization outreach targeted at low income and hard-to-reach communities and $1.4 million, for 2014, to fully restore the Capacity Bidding Program (CBP) funding level which was authorized for the 2012-2014 program cycle.

Product 2 Application (A.11-05-023)

On May 19, 2011, SDG&E filed a request for approval of three long-term contracts for new electric generation resources, and cost recovery for the cost of the contracts. The three resources are identified as Pio Pico Energy Center (305 MW), Quail Brush Project (100 MW) and Escondido Energy Center (45 MW). If these facilities come on line as expected, SDG&E's cost recovery plan as filed for these new generation resources would result in annual costs of approximately $4 million in 2012, $7 million in 2013, $64M in 2014 and $88 million in 2015, excluding the cost of fuel, start-up charges, financing charges, and variable operation and maintenance.

Greenhouse Gas Rulemaking (R.11-03-012)

The Commission opened a new rulemaking in March 2011 to address potential utility cost and revenue issues associated with greenhouse gas (GHG) emissions including the possible use of revenues that electric utilities may generate from auction of allowances allocated to them by the California Air Resources Board and the treatment of possible GHG compliance costs associated with electricity procurement, as well as other GHG issues, particularly those affecting utility costs and revenues related to GHG emission regulations and statutory requirements. The potential future rate impacts, as a result, are unknown at this time.

San Onofre Nuclear Generating Station (I.12-10-013)

On November 1, 2012, the CPUC initiated a proceeding to investigate the extended outages at SONGS and the resulting effects on the provision of safe and reliable electric service at just and reasonable rates. The potential future rate impacts, as a result, are unknown at this time.

<u>**Gas Proceedings**</u>

2013 Triennial Cost Allocation Proceeding (TCAP) - Phase 1 (Gas Pipeline Safety) (R.11-02-019)

CPUC Decision 11-06-017 ordered all California natural gas transmission operators to develop and file for CPUC consideration a Natural Gas Transmission Pipeline Comprehensive Pressure Testing Plan (Implementation Plan) to achieve the goal of orderly and cost effectively replacing or testing all natural gas transmission pipelines that have not been pressure tested. Southern California Gas (SoCalGas) and SDG&E jointly filed their comprehensive "test or replace" Implementation Plan on August 26, 2011, as directed by the CPUC. SoCalGas and SDG&E subsequently amended their Implementation Plan on December 2, 2011. SoCalGas and SDG&E propose to spend $1.944 billion ($1.675 billion for SCG; $269 million for SDG&E) over the 2012-2015 time period. The request is separate from their GRC Phase 1 proposals. In the December 21, 2011 Ruling, the Assigned Commissioner indicates that "[u]pon further review, [he] now believe[s] that the pending

Triennial Cost Allocation Proceeding. . . is the most logical proceeding for the SDG&E and SoCalGas reasonableness and ratemaking review" and directs SoCalGas and SDG&E to address the issue of "reassignment of the reasonableness and ratemaking issues to the Cost Allocation Proceeding versus the pending or a future general rate case."

The rate impact by customer class will depend on the level, cost allocation and timing of safety-related investment that is ultimately adopted by the CPUC. A decision is expected in 2013.

Triennial Cost Allocation Proceeding (TCAP) – Phase 2 (A.11-11-002)

According to Decision 09-11-006, SoCalGas and SDG&E are required to file their Triennial Cost Allocation Proceeding ("TCAP") no later than September 1, 2011. This proceeding is to allocate authorized costs to the different customer classes; and, to then design the rate structure within each class (i.e. customer charge, baseline, nonbaseline, etc). Costs are allocated based on the concept of cost causation to determine marginal costs, revenue allocation, and rate design for gas customers. Cost causation seeks to determine which customer or group of customers causes the utility to incur particular types of costs. The utilities propose continuation of 100% balancing account treatment for noncore revenues and extension of the 2009 Biennial Cost Allocation Proceeding Phase 1 Settlement through 2015. SDG&E is also proposing a $5 per month residential customer charge. The rate impact by customer class will depend on what cost allocation is ultimately adopted by the CPUC. A CPUC decision is expected in 2013.

<u>Combined Gas & Electric Applications</u>

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

On December 15, 2010, SDG&E filed its 2012 GRC Phase I application, A.10-12-005, to establish its authorized 2012 revenue requirement and the ratemaking mechanism by which this requirement will change on an annual basis over the subsequent three year (2013-2015) period. In February 2012, SDG&E filed updates to revise its application, primarily to reflect the impact of changes to Escalations, Postage, and Taxes. With these updates, SDG&E is requesting a revenue requirement in 2012 of $1.849 billion, an increase of $235 million (or 14.6%) over 2011. While the CPUC will determine the total amount of money SDG&E can collect in rates in the GRC Phase 1 decision, the design of the actual rates themselves (that is, the allocation of costs between customer classes and the structure of charges) will be determined in the upcoming Triennial Annual Cost Allocation Proceeding (TCAP). A final decision is expected in 2013 with rates effective in 2013.

2013-2014 Statewide Marketing, Education and Outreach (A.12-08-009)

On August 3, 2012, SDG&E filed a proposed application with the CPUC requesting approval of a 2013-2014 Statewide Marketing, Education, and Outreach (SWME&O) Program in accordance with Decision 12-05-015. The proposed filing is designed to support statewide awareness of energy efficiency, demand response, distributed and solar generation, and other programs offered by investor-owned utilities across California. To fund its portion of the SWME&O program, SDG&E seeks approval of annual incremental energy efficiency funding in the amounts of $2.973 million for 2013 and 2014. SDG&E also seeks approval of annual incremental demand response funding in the amounts of $1.000 million for 2013 and 2014.

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

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

B. Outlook from May 1, 2013 to April 30, 2014 – Potential Proceedings

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

<u>Electric Proceedings</u>

2014 ERRA Forecast

SDG&E will file its annual application with the CPUC for approval of its forecasted electric procurement revenue requirement for 2014.

Demand Response Program Application

SDG&E will be filing its request for authorization of demand response (DR) programs to be implemented over the next program cycle, 2015-2016. DR programs encourage customers to reduce electricity use during peak or critical times. By doing this, customers can help manage their energy costs and help improve the reliability of the electric system. Reducing peak electric loads also helps keep costs down by limiting the need to purchase electricity when prices spike.

C. Rate Change Implementation

The following provides the expected timing of anticipated rate changes during 2013 and the amount of increase if it is known.

SDG&E typically has three electric rate changes a year: (1) January 1st for implementation of its Consolidated rates for electric, (2) a mid-year change for implementation of its annual ERRA Forecast, and (3) September 1st Transmission rate change for the implementation of its base transmission revenue requirements. In order to provide customers with greater rate stability, SDG&E attempts to coordinate the implementation of any other authorized rate changes with these established rate changes. For 2013, we anticipate at this time the following:

Implementation of GRC Phase 1

Summer implementation of the 2013 ERRA Forecast

September 1st Transmission Rate Change for the implementation of TO4 Cycle 1 filing.

San Diego Gas & Electric Company
2013 CPUC Filing Outlook
Outlook from May 1, 2013 to April 30, 2014
Appendix A

Description	Filed	Expected/Requested Implementation	Status	Impacted Rate	System Average Directional Impact	Revenue Requirement Impact w/FF&U ($M)	If Revenue Requirement Impact not available Current Revenue Requirement ($M)
Pending Applications							
Electric							
Product 2 Application (A.11-05-023)[1]	May 2011	2013	Still Pending	Local Generation Charge[1]	Increase	$ 11	
2010 ERRA Compliance Filing (A.11-06-003)[2]	June 2011	2013	Still Pending	Electric Commodity	Increase	$ 0.573	
2011 ERRA Compliance Filing (A.12-06-003)	June 2012	2014	Still Pending	Electric Commodity	Increase	$ 2.969	
2013 ERRA Forecast Application (A.12-10-002)	October 2012	Mid-2013	Still Pending	Electric Commodity	Increase	$ 194.061	
				On-going CTC	Decrease	$ (7.162)	
2012 Nuclear Decommissioning Cost Triennial Proceeding (A.12-12-013)	December 2012	Late 2013	Still Pending	Electric Commodity	Increase	$ 8.266	
2013-2014 Demand Response Augmentation Application (A.12-12-016)[3]	December 2012	2013	Still Pending	Electric Distribution	Increase	$ 1.631	
Gas							
SDG&E Trienniel Cost Allocation Proceeding (A.11-11-002)[4]	Updated September 2012	2013	Still Pending	All Transportation Rates	Neutral	$ 272.324	
Pipeline Safety Enhancement Plan (R. 11-02-019)[5]	Updated September 2012	2013	Still Pending	Proposed New Surcharge	Increase	$ 6.309	
Combined Gas and Electric							
2012 GRC Phase 1 (A.10-12-005)[6]	December 2010	2013	Still Pending	Electric Distribution/Commodity	Increase	$ 199	
	Revised July, 2011, Updated February, 2012	2013	Still Pending	Gas Transportation	Increase	$ 36	
Joint Application for Adoption of Electric Revenues and Rates Associated with MRTU (A.12-01-014)	January 2012	2013	Still Pending	Electric Commodity	Increase	$ 1.578	
2013-2014 Statewide Marketing, Education and Outreach (A.12-08-009)[7]	August 2012	2013	Still Pending	Electric Distribution/PPP	Increase	$ 7.352	
	August 2012	2013	Still Pending	Gas/PPP	Decrease	$ 0.595	
First Triennial EPIC Investment Plan (A.12-11-002)[8]	November 2012	2013	Still Pending	N/A	N/A	N/A	

San Diego Gas & Electric Company
2013 CPUC Filing Outlook
Outlook from May 1, 2013 to April 30, 2014
Appendix A

Description	Filed	Expected/Requested Implementation	Status	Impacted Rate	System Average Directional Impact	Revenue Requirement Impact w/FF&U ($M)	If Revenue Requirement Impact not available Current Revenue Requirement ($M)
Potential Applications							
Electric							
Demand Response Application	2014	2015		Electric Transmission	---	N/A	
FERC TO4 Cycle 1[9]	To be Filed early 2013	September 2013		Electric Transmission	---	N/A	$ 614.513
2014 FERC RS Filing[10]	To be Filed late 2013	January 2014		Reliability Service	---	N/A	$ 0.366
2014 FERC TACBAA/TRBAA Filing[11]	To be Filed late 2013	January 2014		Electric Transmission	---	N/A	$ (237.027)
Electric Regulatory Account Update AL[13]	To be Filed 2013	January 2014		Various Electric	---	---	
2014 DWR Implementation AL[13]	To be Filed 2013	January 2014		Electric Commodity/ DWR-BC	---	---	
Electric Public Purpose Program Update AL[13]	To be Filed 2013	January 2014		Public Purpose Program	---	---	
Non-fuel Generation BA Update AL[13]	To be Filed 2013	January 2014		Electric Commodity	---	---	
SB695 Residential Rate Change[13]	To be Filed 2013	January 2014		Electric Residential	No change	---	
Electric Consolidated AL[12, 13]	To be Filed 2013	January 2014		All Electric	---	---	
Gas							
Gas Regulatory Account Update AL[13, 14]	To be Filed 2013	January 2014		Gas Transportation	Increase	$29.106	
Gas Consolidated AL[13, 14, 15]	To be Filed 2013	January 2014		Gas Transportation	Increase	$29.577	
Gas Public Purpose Program Update AL[13, 14]	To be Filed 2013	January 2014		PPP Surcharge	Decrease	($20.066)	
Combined Gas and Electric							
N/A							

[1] The Product 2 application includes a proposal to recover costs through a new charge (Local Generation Charge). Revenue requirements reflect 2012 and 2013 request.
[2] The amount of $0.573M shown in Appendix A excludes the MRTU revenue requirement of $1.578M that was originally included in this application. The revenue requirement of $1.578M was moved to its own filing called Joint Application for Adoption of Electric Revenues and Rates Associated with MRTU (A.12-01-014
[3] Includes revenue requirement impacts proposed for 2013 and 2014.
[4] In the SDG&E Trienniel Cost Allocation Proceeding , the 2013 revenue requirement is shown.
[5] Pipeline Safety Enhancement Plan shows the 2013 Pipeline Safety Enhancement Plan revenue requirement.
[6] In the 2012 GRC Phase 1, the revenue requirement reflects the amounts filed in the February 2013 updated testimony and include miscellaneous revenues.
[7] 2013-2014 Statewide Marketing, Education and Outreach (A.12-08-009) is total cost proposed in the application.
[8] 2013-2014 EPIC funds have already been authorized and are being collected pursuant to D.11-12-035 and D.12-05-037. However, the First Triennial EPIC Investment Plan (A.12-11-002) is still pending California Public Utilities Commission approval.
[9] Reflects current revenue requirement w/FFU per FERC TO3 Cycle 6.
[10] Reflects current revenue requirement w/FFU per 2013 FERC RS Filing.
[11] Reflects current revenue requirement w/FFU per 2013 TACBAA/TRBAA Filing.
[12] Electric Consolidated reflects the incorporation of electric rate changes authorized for implementation on January 1st.
[13] This is an annual routine filing in which the specific revenue requirement impact for 01/2014 has not been determined.
[14] The amounts presented show the change from 2012 to 2013.
[15] Gas Consolidated AL 2160-G includes the changes from 2012 to 2013.

Part II: Section 748(b) Utility Study and Report

San Diego Gas & Electric (SDG&E) appreciates the opportunity to provide input to the California Public Utilities Commission (CPUC or Commission) in response to SB 695-enacted changes to PUC Section 748. This report addresses PUC Section 748(b). SDG&E's response addressing PUC Section 748(a), which provided data related to both gas and electric revenue requirements, was submitted separately.

SDG&E's objective in this response is to provide information that the CPUC may find useful as it prepares its annual report for the Governor and Legislature. Accordingly, SDG&E's report provides data related to both gas and electric revenue requirements and rates. With respect to overall presentation, SDG&E's report is structured as per the Energy Division's request under the following headings:

- Overall Rate Policy
- Management Control of Rate Components
- Utility Policies and Recommendations for Limiting Costs and Rate Increases While Meeting State's Energy and Environment Goals for Reducing Greenhouse Gases.

1. Recommendations to the CPUC and Legislature

A. Opening Comments

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

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

SDG&E continues to support renewable energy, including distributed renewable energy. But SDG&E also recognizes that long-term growth in this market requires fair and equitable allocation of utility costs in a manner that accurately reflects the services that SDG&E provides to customers. The current levels of subsidization of NEM is dependent upon rate design that is not cost-based, is overly reliant on cost recovery through volumetric charges ($/kWh) and fails to reflect the services SDG&E provides to NEM customers. In the initial filing of SDG&E's General Rate Case (GRC) Phase 2, Application (A.) 11-10-002, SDG&E presented rate design proposals that reflected more accurate price signals such as a $/kW Network Use Charge for the recovery of costs associated with distribution demand on the basis of both imports and exports. Providing residential customers with more accurate price signals had the additional benefit of reducing pressure on residential upper tiered rates.

In SDG&E's 2012 SB 695 report, SDG&E provided further information regarding the cost shifts that can occur when rates are not cost-based. SDG&E specifically addressed the unintended consequences of the current residential rate structure under NEM. SDG&E identified the cost shift at that time to fund the NEM subsidy to be approximately $34 per year[53] for the average Tier 3 & 4 customer on top of their otherwise applicable bill. By the end of 2012, that amount has increased to $47 per year.

In its 2012 comments, SDG&E noted:

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

Since SDG&E's 2012 comments, the CPUC and Legislature have recognized that this is not a SDG&E-only issue. For example:

- On June 21, 2012, the CPUC issued Rulemaking (R.) 12-06-013, *Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations*, determining that after almost a decade of heavily legislated rate design triggered by the California Energy Crisis, there is now a need to re-examine the current residential rate design to determine whether it is able to meet the Commission's rate and policy objectives. The Commission's examination comes at a time of rapid growth in the rooftop solar market together with the introduction of many new technologies that will help customers better manage their energy use in response to price signals. Currently, the statutory constraints on utility ratemaking force customers that deploy these technologies to rely on extremely inaccurate price signals, both for considering potential investments in rooftop solar and for utilizing after meter services to better manage energy demand.
- D.12-05-036, in addition to determining the NEM program cap to be the highest sum of all customer' non-coincident peak demand, directed Energy Division to oversee the preparation of an updated NEM cost-effectiveness study by October 1, 2013.[54]
- Assembly Bill (AB) 2514 directed the Commission to prepare a study on NEM by October 1, 2013 to determine the extent to which NEM customers pay for the full cost of services provided by electrical corporations and the cost of public purpose programs, requiring that the analysis include exported energy compensated through NEM and the entire generation output of the NEM generator. [55]

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

[54] http://www.cpuc.ca.gov/NR/rdonlyres/886057CB-4A9E-4D43-84FC-B679046712FF/0/EnergyDivisionNEMStudyWorkshopIntroduction.pdf

[55] http://www.cpuc.ca.gov/NR/rdonlyres/886057CB-4A9E-4D43-84FC-B679046712FF/0/EnergyDivisionNEMStudyWorkshopIntroduction.pdf

B. Overall Rate Policy

In 2012, SDG&E stated that ensuring accurate price signals is the foundation of its overall rate policy:

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

SDG&E also identified the following three policy objectives:

1. Create Clear and Accurate Price Signals
2. Promote Fairness and Equity
3. Empower and Inform Customers

Consistent with these objectives, in the November 26, 2012 Scoping Memo and Ruling (Scoping Ruling) in R.12-06-013, the CPUC identified the following principles to guide residential rate design:

1. Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost;
2. Rates should be based on marginal cost;
3. Rates should be based on cost-causation principles;
4. Rates should encourage conservation and energy efficiency;
5. Rates should encourage reduction of both coincident and non-coincident peak demand;
6. Rates should be stable and understandable and provide stability, simplicity and customer choice;
7. Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals;
8. Incentives should be explicit and transparent;
9. Rates should encourage economically efficient decision-making; and
10. Transitions to the new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions, avoids the potential for rate shock.

SDG&E supports these rate design principles.

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

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

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

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

SDG&E is committed to controlling costs while providing safe and reliable gas and electric service to its customers. However, there are many key drivers that affect customers' rates which fall outside of SDG&E's control, including, but not limited to, the market price of the gas commodity (which also affects the price of the electricity commodity), actual sales volumes, weather, natural disasters, interest rates, and permitting process delays. Despite these factors, SDG&E diligently seeks to manage its costs across all categories to make efficient and effective use of revenues collected from customers.

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

1. List the Policies the Utility is Advocating

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

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

- Utility Rates – Accurate Price Signals: Provide the direction and flexibility to design rates that accurately value the service provided so that benefits from technology investments can be realized.
- Distributed Generation – Net Energy Metering: Address the shifting of fixed costs by NEM customers in order to create a sustainable distributed renewable policy.
- Energy Storage Policy –Send accurate price signals so that the benefit of different technologies and applications can be weighed.
- Distributed Generation: Review the socio-economic impacts of Virtual Net Metering prior to expanding.
- California Alternative Rates for Energy (CARE): CARE customers now comprise approximately 23% of SDG&E's residential customer base. Non-CARE customers must cover the CARE shortfall, which leads to a 10% increase of non-CARE costs. Restoration of income verification practices would help to optimize the integrity of the program and reduce rate increases for non-CARE customers.

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

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

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

a. The Legislature

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

Owned Utilities (IOUs), Publicly Owned Utilities (POUs), and other Load Serving Entities (LSEs) in determining how best to achieve proper cost allocation under conditions at the time of implementation. The current legislative constraints to residential rate design limit the abilities of the utilities as well as the CPUC to address potential unintended consequences. Accordingly, SDG&E recommends the removal of existing legislative constraints and the general return of ratemaking authority to the CPUC.

b. CPUC

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

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

SDG&E believes that the principles identified in the Scoping Ruling in R.12-06-013 provide a proper framework for policies that support a transition to rates based on accurate price signals. Accordingly, SDG&E recommends that these principles not be limited to the residential class, but should guide rate design for all customers. If ultimately adopted in R.12-06-013, policies promoting accurate price signals will allow the IOUs to propose the most optimal rate designs in their respective General Rate Cases and/or rate design window proceedings. As new rate designs are adopted, the CPUC should also promote a policy of reasonable transition so that customers have time to benefit from the education and understanding they will need to make the transition to the cost-based rates and avoid rate shock. Further, SDG&E cautions against a piece-meal approach to rate design, looking at individual customer classes rather than comprehensively looking at the impacts to all customer classes. As noted above, rate design is a zero-sum game, and therefore, subsidies or incentives to one class will push cost burdens into another class.