Actions to Limit Utility Cost and Rate Increases in Compliance with Public Utilities Code 748

ENERGY DIVISION

REPORT TO THE GOVERNOR AND LEGISLATURE

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CALIFORNIA PUBLIC UTILITIES COMMISSION

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Executive Summary

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 (SoCalGas). 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.

A. Statutory Mandate

Public Utilities Code 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 2014 edition of this report is hereby submitted by the CPUC to the Governor and Legislature.

B. Highlights of Actions to Limit Utility Cost and Rate Increases

In this report CPUC identifies *actions* that are being taken in the next 12 months to limit utility cost and rate increases. These actions include Commission decisions expected to be voted out

[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.

within the next 12 months as well as proceeding activities to address applications, rulemakings, and/or other regulatory activities under Commission review.

Highlights of key actions the Commission expects to take are enumerated below:

1) Residential Rate Reform

AB 327 (Perea), the landmark rate reform bill enacted in 2013, authorizes the CPUC to approve residential rate structures that more closely resemble cost to serve, while maintaining affordability for income-qualifying customers and protected classes of ratepayers (e.g., medical needs) and promoting load shifting and conservation. Notably, the utilities submissions to CPUC for this report (provided in the appendix) contend that rate reform will have the single largest impact on rates for most customers.

2) Investigation of San Onofre Nuclear Generating Station (SONGS) Units 2 and 3

In late 2012 the CPUC opened an investigation to consider removing the SONGS plant from SCE's and SDG&E's rate base and to review the steam generator replacement project costs. SCE is collecting more than $600 million in rates for owning and operating the plant. Some or all of these costs, as well as SDG&E's share of SONGS costs in rates, could be subjected to a refund to ratepayers pending a CPUC decision in this case.

3) California Climate Credit

The California Climate Credit is a credit on customer's electricity bills to help defray the indirect costs of the Cap-and-Trade Program that residential customers will experience in the broader economy. This credit will appear in April and October bills each year.

4) Renewable Auction Mechanism (RAM) and Utility-Specific Solar Photovoltaic programs

The RAM is a simplified, market-based procurement mechanism for renewable Distributed Generation projects between 3 MW and 20 MW in size on the system-side of the meter. Contract prices have declined on average in each of the first four RAM solicitations. Additionally, the CPUC authorized utility-specific solar photovoltaic procurement programs to procure 776 MW over five years from projects sized in the 1 MW to 20 MW range. These programs have helped diversify utility Renewables Portfolio Standard portfolios and allowed utilities and their ratepayers to benefit from declining costs in solar photovoltaic. The future of RAM and possible further improvements to program efficacy and transparency is currently under Commission review.

5) Gas Utility Safety Rulemaking

The CPUC issued a 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. While not explicitly an action to limit cost increases this proceeding reflects CPUC's commitment to accountability for safety outcomes in ratepayer-funded infrastructure investment plans.

C. Report Caveats

The greatest 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 as well as actions the agency has taken to review in open proceeding possible future actions to limit cost and rate increases. Finally, it is important for the reader to focus on actions being taken to that limit the costs and impacts to customer *bills* and how to reduce them, independent of specific rate increases. For example, California customers have some of the lowest energy bills in the country, despite higher-than-average rates.[2]

D. 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. Second, 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. Third, the report addresses natural gas utility operational costs and rates.

Finally the appendix to this report provides utility submissions detailing their future revenue requirements, demand forecasts, pending and anticipated proceedings, and recommendations to

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[2] In 2012, California residential electric bills were nearly 20 percent lower than the average U.S. residential electric bill, and the rest of the U.S. paid $20 more per month on residential bills than do California residents. (From EIA's 2012 electricity bill data in Table 5a: Residential average monthly bill by Census Division, and State, published on November 8, 2013, www.eia.gov/electricity/sales_revenue_price/xls/table5_a.xls)

limit costs and rate increases. This year the utilities focused on their position for the open residential retail rate design proceeding.

I. Electric Utility Costs and Revenue Requirements

A. Work Area

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, 2014
($ Million)

PG&E	SCE	SDG&E
$13,032	$12,063	$3,545

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 2014 AB 67 Report.[3]

B. Activities and Proceedings in the next 12 months

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 2014 authorized by the CPUC in recent GRCs for the three major utilities are listed below.

Table II-2
2014 Authorized Electric General Rate Case Revenue Requirements ($ Million)

	PG&E*	SCE	SDG&E
Operations and Maintenance	$2,202	$2,272	$658
Depreciation	$1,800**	$1,222	$274
Return on Rate Base	$1,008	$1,465	$300
Taxes	$451	$712	$207
Attrition ***		$478	$79
Total	**$5,461**	**$6,149**	**$1,518**

* The revenue requirements shown for PG&E do not reflect any increases proposed by PG&E in its pending 2014 GRC Application. The CPUC is expected to issue a decision in that case in the 2nd quarter of 2014.

**Includes $36 million for fossil decommissioning.

*** SCE's attrition allowances apply to years 2013 and 2014; attrition for both years is shown above. SDG&E's attrition allowances apply to years 2013 – 2015; attrition for years 2013 and 2014 is shown above.

[3] Electric and Gas Utility Cost Report to the Governor and Legislature, available at _____________

a) PG&E 2014 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 is expected to issue a decision in PG&E's 2014 GRC application in the 2nd quarter of 2014.

b) SCE 2015 GRC

In November 2013, SCE filed its 2015 GRC application. SCE is seeking an increase of $206 million over the currently authorized electric revenue requirement in that case. SCE cites the need to connect new customers to the system, upgrade its distribution infrastructure and business systems, test and replace distribution poles, and the increase in cost for removing depreciated assets as reasons for the increase it has requested. The CPUC is expected to issue a decision in SCE's 2015 GRC in late 2014 or early 2015.

c) SDG&E 2016 GRC

In the 4th quarter of 2014, SDG&E will file its 2016 GRC application. The CPUC will consider testimony and conduct hearings in that case during 2015. A decision is expected in late 2015 or early 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
$5,109	**$3,797**	**$1,094**
Effective Jan. 2014	**Effective Nov. 2013**	**Effective April 2014**

a) PG&E's ERRA

In December 2013 the CPUC approved PG&E's fuel and purchased power revenue requirement for 2014 as shown above. In June 2014 PG&E will file its ERRA application to request a fuel and purchased power revenue requirement for 2015.

b) SCE's ERRA

In November 2013 the CPUC authorized SCE's to recover its 2013 fuel and purchased power expenses shown above. SCE filed its 2014 ERRA application in which it requests a fuel and purchased power revenue requirement of $5,412 million for 2014. A CPUC decision in that case is expected in the 2nd quarter of 2014. SCE is currently scheduled to file its ERRA application for 2015 fuel and purchased power costs in August 2014. SCE has requested to change the filing date of its ERRA forecast applications to May; the CPUC is considering SCE's request.

c) SDG&E's ERRA

SDG&E fuel and purchased power revenue requirement of $1,094 million includes that approved in its 2013 ERRA forecast proceeding ($945 million effective Dec 2013) plus an additional $149 million that the CPUC authorized effective April 2014 in SDG&E's 2013 ERRA trigger proceeding to recover an under-collection accrued in SDG&E's ERRA balancing account. In April 2014 SDG&E will file its ERRA application to request a fuel and purchased power revenue requirement for 2015.

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.

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3. Investigation of San Onofre Nuclear Generating Station Units 2 and 3

Units 2 and 3 at the San Onofre Nuclear Generating Station (SONGS) were shut down in January 2012 due to problems with new steam generators that were installed in 2010 (Unit 2) and 2011 (Unit 3). 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 announced in June 2013 that it would 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. 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. The CPUC has separated the SONGS investigation into phases: In Phase 1 the CPUC reviewed the 2012 expenditures for SONGS, with a decision expected in March or April 2014. A proposed decision of the administrative law judges in Phase 1 orders a refund of $94 million for 2012 SONGS related costs that were collected in rates. In Phase 2 the CPUC is considering reductions to rate base for SONGS, and in Phase 3 the CPUC will consider the reasonableness of the steam generator replacement program. CPUC decisions in Phases 2 and 3 are expected in the 3rd and 4th quarters of 2014, respectively.

4. Plans to Improve Efficacy in Ratemaking

The CPUC has committed to improving the efficacy of its rulemakings, particularly in the areas of safety and accountability. In the wake of the 2010 San Bruno tragedy, the CPUC is reexamining its ratemaking processes, focusing primarily on safety and risk management.

In PG&E's 2014 GRC the CPUC 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. These reports are part of the record in the GRC and will be addressed in the CPUC's decision in the case.

In November 2013 the CPUC opened a rulemaking to develop a risk-based decision-making framework to evaluate safety and reliability improvements in GRCs. A decision is expected in this rulemaking at the end of 2014 which will make modifications to the GRC rate case scheduling plan and process so that the CPUC can more effectively consider safety and reliability programs and their costs in GRCs.

II. 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 (or minimize costs) 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

Rate Design

Energy Efficiency

Demand Response

Customer-Sited Distributed Generation and California Solar Initiative

California Alternate Rates for Energy

Energy Savings Assistance

Other Initiatives

Emerging Procurement Strategies

CPUC Advocacy for California Electric Interests at Federal Energy Regulatory Commission

A. Resource Adequacy and Long Term Procurement

1. Work Area

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.[4] 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

[4] Public Utilities Code Section 380.

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.

In addition, the CPUC administers the Long Term Procurement Plan proceeding (LTPP) which implements AB 57, passed in 2002,[5] by overseeing IOUs procurement plans and evaluating 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.

2. Activities and Proceedings in the next 12 months

a) D.14-02-016

This decision grants SDG&E authority to enter into a 25 year power purchase tolling agreement with Pio Pico Energy Center, LLC. The tolling agreement begins on June 1, 2017, but the 305 MW gas-fired generation facility will be operational in 2015 and SDG&E and Pio Pico intend to enter into a RA contract in 2016 through the start date of the plant. Costs will be recovered over time, consistent with the PPA and any RA agreement that is signed.

b) R.12-03-014

2012 LTPP Proceeding: The Track I decision (D. 13-02-015) of this proceeding authorizes SCE to procure between 1,400 – 1,800 MW in the West LA sub-area of the LA local reliability area and 215 – 290 MW in the Moorpark sub-area of the Big Creek/Ventura local reliability area. These resources are primarily authorized to replace once-through cooling plants that are retiring. In the LA basin local area, 1,000 MW – 1,200 MW may be procured from conventional gas-fired generation resources; the remainder is to be from preferred resources and/or energy storage. SCE is negotiating with bidders and will submit an application to the Commission for approval of contracts. The proposed decision in Track IV of the LTPP would authorize SCE and SDG&E to procure an additional 500 – 700 MW to meet local capacity needs stemming from the closure of SONGS, with SCE required to procure 400 – 700 MW from preferred resources or energy storage and SDG&E required to procure between 200 – 700 MW from preferred resources or energy storage. The costs for these resources will be placed into rates when new generation is brought on-line, which will likely occur between 2016 and 2022.

c) R.13-12-010

2014 LTPP Proceeding: The 2014 LTPP proceeding opened in December 2013 and will address, among other issues, the possible need for new flexible resources to accommodate the increasing

[5] Public Utilities Code Section 454.5

penetration of intermittent resources. As with the 2012 LTPP, the costs for any new generation resources will be placed into rates when, and if, any new flexible resources are brought on line.

d) R.11-10-023

In D.13-06-024, in coordination with the CAISO, the CPUC adopted a monthly flexible capacity procurement requirement for load serving entities (LSEs) to address the increasing penetration of intermittent resources, which will likely increase the ramping requirements in the coming years. The flexibility requirement was voluntary for 2014, but the LSEs must demonstrate that they have sufficient flexible resources for the 2015 compliance year. To the extent that the LSEs need to procure additional resources to meet flexible RA requirements and to the extent that these resources are more costly that system or local RA, rates could be affected.

B. Renewables Portfolio Standard

1. Work Area

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 to ratepayers 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)

[6] Least-cost best-fit criteria were determined in D.04-07-029 and the methodology for performing the LCBF analysis was most recently addressed in D.12-11-016.

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.

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.

Pursuant to Public Utilities Code sections 910 and 911, Energy Division annually reports RPS costs and expenses to Legislature.[7] 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.[8]

2. Activities and Proceedings in the next 12 months

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

(1) *Renewable Auction Mechanism (RAM)*

The RAM is a simplified, market-based procurement mechanism for renewable DG projects between 3 MW[9] and 20 MW in size on the system-side of the meter. RAM offers a streamlined and competitive procurement process with a cumulative program capacity of 1,330 MW[10] . The fourth RAM auction closed June 28, 2013. The Commission authorized a fifth auction on May 15, 2014 in Resolution E-4655. Contract prices have declined on average in each of the first four RAM solicitations.

[7] These Legislative reports are available on the CPUC's RPS website. Last accessed on June 2, 2014. http://www.cpuc.ca.gov/PUC/energy/Renewables/index.htm

[8] March 2014 Padilla Report, available at http://www.cpuc.ca.gov/NR/rdonlyres/692D7F29-5F32-4691-B31B-7607C2D28639/0/PadillaReport2014FINAL.PDF

[9] 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.

[10] The Commission authorized 1,000 MW of procurement under RAM in D.10-12-048, the Commission has increased the capacity of the program to 1,330 MW by D.12-02-002, D.12-02-035, and D.13-05-033.

On December 31, 2013, the Commission issued a ruling that revisits the past successes of RAM and the future of the RPS RAM program.[11] The ruling notes that the RAM program has created a robust market for renewable energy projects sized 3 - 20 MW, and that competition in this market has resulted in cost-effective procurement of viable projects, while simultaneously minimizing transaction costs for developers, utilities, and regulators. Additionally, the ruling requests stakeholder feedback on how the Energy Division staff can improve future RAM solicitations to increase program efficiency and transparency.

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.

(2) *Feed-in-Tariff (FiT)*

The feed-in tariff (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 California's renewable feed-in tariff program, most notably, to revise the pricing mechanism and to increase the eligible project size from 1.5MW to 3 MW. 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. 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).

SB 1122 (Rubio, 2012) 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 the new statute. 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.

(3) *Utility-Specific Solar Photovoltaic (PV) programs*

Additionally, the CPUC authorized utility-specific solar photovoltaic (PV) procurement programs to procure 776 MW[12] over five years from projects sized in the 1 MW to 20 MW 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

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[11] The Commission December 31, 2013 ruling on the future of the RAM program can be found at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M084/K331/84331873.PDF

[12] 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.

power purchase agreements (PPAs) with independent power producers through a competitive solicitation process. The IOUs are nearly 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.[13]

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 is working to implement a RPS cost containment mechanism outlined in SB 2 (1X) (Simitian, 2011), which established 33% RPS procurement requirements including 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." This effort is ongoing and will seek to inform cost containment policy for future renewable procurement.

Also, the CPUC is considering a number of changes to the standard of review 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 requires that the IOUs use 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 the associated costs, and 2) better inform the California Independent System Operator's (CAISO) 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

[13] See the December 31, 2013 RAM ruling, which requests stakeholder opinion of whether or not the Solar PV programs should be consolidated into RAM to increase program efficiency and transparency. The RAM ruling can be found on the Energy Division webpage at:

http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M084/K331/84331873.PDF 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.[14] All three large IOUs have included in their approved 2013 RPS Procurement Plans the intent to sell excess RPS generation if it is consistent with their RPS position and provides value to ratepayers.[15] 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 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 II transmission study. By having a completed CAISO GIP Phase II 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.

C. Rate Design

1. Work Area

The CPUC regulates electricity pricing for IOU residential, small commercial, small and large commercial, industrial and agricultural customers. The CPUC mandate is to authorize rates and tariffs that result in affordable bills, ensure safe and reliable service, and permit the IOUs to collect revenues that recover fixed and variable costs, and meet statewide policy goals (e.g. compliance with AB 32 GHG emission reduction targets).

In the year ahead the Commission will administer a number of policy and ratemaking proceedings that will have a direct impact on rates, most notably the residential rate reform OIR (R.12-06-013), which is implementing AB 327 (Perea, 2013). Further, retail rates have pervasive impacts on price signals for investment in energy-efficiency (EE), demand response (DR),

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[14] Renewables Portfolio Standard Quarterly Report to the Legislature, 4th Quarter 2013 http://www.cpuc.ca.gov/NR/rdonlyres/71A2A7F6-AA0E-44D7-95BF-2946E25FE4EE/0/2013Q4RPSReportFINAL.pdf

[15] D.13-11-024 approved the IOUs' 2013 RPS Procurement Plans.

customer-side distributed generation (DG), electric vehicles (EV), and energy storage which help to manage customer bills.

2. Activities and Proceedings in the next 12 months

a) Residential Rate Reform

Insert revised language from Exec Summary subject to check from Bob.

The following rate levers are currently being litigated in the Residential Rate Reform Order Instituting Rulemaking (R.12-06-013):

(1) Possible Fixed Charges

One rate element that will be considered is the inclusion of a fixed charge, capped at $10 for Non-CARE customers and $5 for CARE customers with future CPI adjustments, and potentially based upon customer income level and demand. Fixed charges are intended to collect revenues to fund fixed transmission, distribution and customer costs. For low-income, low-usage, and net energy metering customers, fixed charges may impact bill affordability and investment in customer-side distributed generation.

(2) Tier Collapse

Another rate structure change being considered is the reduction in the number of tiers along a five-year glide path. Since authorized revenues do not change, lower tiers rates will rise and upper tier rates will decline in this scenario. For lower usage customers, this scenario may send a price signal for investment in EE, DR, and customer-side grid-tied DG that could mitigate the impact of future bill increases.

(3) Possible Default Time of Use (TOU) Rates

Currently, the California PUC is considering (in R.12-06-013) how, and whether, to reform IOU rate structures, and possibly to authorize or require the IOUs to offer TOU rates as a default rate, with all of the consumer protections afforded under AB 327.16Possible adoption of default TOU rates for residential customers is intended to increase customer involvement in managing California's energy supply and future generation, transmission and distribution (T&D) infrastructure capacity costs, by providing economic incentives to reduce electric demand during peak periods.17 TOU

[16] Consumer safeguards required by AB 327 include: (1) ability to opt-out of TOU rates and incur no additional charges; (2) "shadow billing" to show what individual customer bills would be under available tariffs; and (3) bill protection to ensure that customers pay no more than they would have under their previously applicable tariff.

[17] Decision 10-02-032 February 25, 2010.

pricing sets higher electricity rates during peak and partial peak periods (periods immediately before or after peak periods) when electricity is more costly, and encourages customers to shift their energy demand to off-peak periods when electricity is less costly. Utilities reduce their energy and capacity procurement costs and customers experience lower energy prices when load is shifted to off-peak hours.

D. Energy Efficiency

1. Work Area

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

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. 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.

2. Activities and Proceedings in the next 12 months

The 2013-14 portfolio cycle has a budget of $1.9 billion, $92 million less annually than the budget adopted for the 2010-12 portfolio. All remaining uncommitted funds the utilities held in balancing accounts from previous years were applied to the 2013-2014 revenue requirement, which further reduced the energy efficiency revenue requirements for the two year period relative to recent years. These adjustments result in a reduction of 0.2–1.2% in 2013 rates, depending on utility and customer class. The Commission opened a new rulemaking (R.13-11-005) in which it will consider portfolio filings for 2015. Next year's report will include information on how 2015 energy efficiency programs will affect rates.

a) 2013-2014 EE Portfolio Implementation

The utilities' 2013-2014 program budgets and portfolios address rate impacts and control costs in a number of ways. These are the highlights:

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

(2) *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. The CPUC cost cap remains in place for the 2013-2014 program cycle, having reduced the IOUs' overall budget request by $167 million, and limits costs by setting additional targets to reduce "direct implementation" costs as well as review of this cost category.

b) Relevant Phase 3 Issues in the Energy Efficiency proceeding

The Commission recognizes that ratepayers must get the highest value out of the roughly $1 billion annual investment ratepayer currently make in energy efficiency. The current energy efficiency proceeding, Rulemaking (R.) 13-11-005 provides a forum for stakeholders to discuss the overall effectiveness of the energy efficiency portfolio, both in terms of cost and energy savings. In Phase 3 of the proceeding the CPUC will provide a forum to discuss alleged waste, fraud and cost-effectiveness of portfolios, programs, and measures. This is part of an overall effort to protect the integrity of ratepayer funded programs. The Rulemaking will be an opportunity to both identify issues and propose broad, portfolio-wide solutions. Additionally, the Rulemaking will explore ways to increase targeting of energy efficiency programs to transmission- or generation-constrained geographical areas where energy and demand savings may be more valuable. Further, the Rulemaking will look at the relationship between the energy efficiency portfolio and the marketplace, including the extent to which portfolio offerings need to adapt to market signals and how the market is transformed by portfolio offerings. Focus in these issues areas will help the Commission direct necessary improvements to protect ratepayer interests.

c) 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 by modifying program activities and reporting requirements, as needed. Energy Division also relies on the audit results to help inform the utilities' energy efficiency incentive award calculations.

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 is working with the utilities to incorporate findings from these audits and evaluations into improving the 2013-2014 portfolio implementation and planning the post-2014 program design.

E. Demand Response

1. Work Area

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,"[18] next to energy efficiency.

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 2,300 MW of DR[19], approximately the capacity of four large power plants.

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

[19] Ex ante estimate for summer 2014

2. Activities and Proceedings in the next 12 months

a) Implement Bidding of DR into Wholesale Markets

In early 2014, the CPUC adopted rules that govern the bidding of DR into wholesale energy markets. 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. Over the next 12 months, the IOUs will be implementing internal processes in order to bid their DR resources in wholesale markets (one utility will start as early as summer 2014). Third party demand response providers and large end-use customers will also be able to bid DR.

b) Procurement of Additional DR in Southern California

Over the next 12 months, the CPUC is anticipated to review the results of competitive solicitations to address long term local area capacity requirements in Southern California (retirement of the San Onofre Nuclear Generating Station and other power plants). These solicitations could include additional demand response resources. The new demand response rulemaking (described in Plans to Improve the Efficacy of the Program section) could also issue additional demand response procurement requirements for the near term. The CPUC's approval of demand response capacity contracts with third parties could impact utility revenue requirements.

c) New Demand Response Rulemaking

In September 2013, the CPUC initiated a new DR Rulemaking (R.13-09-011) that is exploring 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 enhance its role in meeting the state's resource planning needs and operational requirements. Key actions that are taking place within the rulemaking are:

(1) Refining Cost-Effectiveness Tools

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 DR programs cost less than a new peaker plant (which could otherwise be needed if not for the DR resource). As part of the DR Rulemaking, the CPUC is working to refine and improve the protocol to increase its accuracy when evaluating the cost-effectiveness of future DR programs. This work will be completed by the end of 2014.

(2) Improvements to IOUs' DR Programs

The CPUC is currently reviewing existing demand response programs to improve their effectiveness. By middle of 2014, the CPUC is expected to approve various changes to the programs that will go into effect by January 2015. Such improvements will lead to increased benefits to ratepayers, but do not increase the costs of the programs.

F. Customer-Sited Distributed Generation

1. Work Area

CPUC oversees a number of customer generation programs including the Self-Generation Incentive Program, the California Solar Initiative, and the CSI-Thermal Program. In addition, the Commission implements the Net Energy Metering tariff.

Established in 2001, the Self-Generation Incentive Program (SGIP) provides incentives to support customer-sited distributed energy resources that contribute to reductions in greenhouse gas emissions. Established in 2006 by SB 1 (Murray), the California Solar Initiative (CSI) offers solar incentives to non-residential and residential 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: the 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 the CSI-Thermal Program.
The General Market Program is expected to meet its 1,750 MW target well before the program deadline of January 1, 2017. Partly due to the CSI Program, the cost of installed solar systems has fallen nearly by half from the beginning of 2009 to the end of 2013.[20]

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 electricity or natural gas usage. Established in Commission D.10-01-022, the program features residential, commercial/multi-family and low-income sub-components. Initially focused on domestic hot water, in 2013 the CPUC modified the CSI-Thermal Program to include additional technologies, such as process heating, cooling, and non-single-family residential swimming pools.[21] Pursuant to Senate Bill (SB) 412 (Kehoe, 2009), the CPUC authorized annual collections for SGIP through December 31, 2014. SGIP is funded at $83 million per year, allocated among the four large IOUs according to each utility's relative percentage of electric and gas sales. 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. 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. The total CSI budget is therefore $2.984 billon.

[20] From www.californiasolarstatistics.ca.gov: from $10.61/W (Q1'09) to $5.53/W (Q3'13).

[21] D.13-02-018 and D.13-08-004.

Net Energy Metering (NEM) is a tariff that allows customer-generators to receive a billing credit for any power generated by their onsite system that is exported to the grid during times when the system is not serving onsite load. In response to AB 2514 (Bradford, 2012), in October 2013 the CPUC completed a cost-benefit study "to determine who benefits from, and who bears the economic burden, if any, of, the net energy metering program …." The study evaluated the costs and benefits of the NEM program using two separate measures: a cost-benefit analysis using the traditional California Standard Practices Manual Ratepayer Impact Measure test, which estimates the net benefits (or costs) of a demand-side resource or program from the perspective of non-participating customers, and a cost of service test, which compares the utility cost of serving NEM customers with their actual bill payments. The study found that NEM generation currently results in a net cost to other ratepayers (those not participating in NEM) of $79 to $252 million, reaching costs of $370 million to $1 billion per year in 2020 with a complete build out of systems to a 5% NEM program cap. With regard to the cost of service analysis, the study found that NEM customers appear to be paying slightly more than their full cost of service.[22]

2. Activities and Proceedings in the next 12 months

a) SGIP:

The SGIP is at an inflexion point. It is currently scheduled to be terminated after the 2015 program year, but the legislature may extend funding and administration of the program if legislation passes. Should the program continue, the SGIP Program Administrators and Energy Division staff will oversee the preparation of a cost-effectiveness study to reevaluate the incentive levels and market transformation impacts of the program.

b) CSI Oversight:

As in the past year, Energy Division will continue to diligently watch activity in the CSI. In addition to monitoring PBI payments[23], program administrators may file a motion to allow for an accelerated payment schedule for the PBI payments, which would save the program a large number of administrative dollars if, for example, PBI payments were to be spread over 24 months instead of 60 months. Such a change would continue to reward higher performing systems with higher rebates, while passing administrative program savings back to ratepayers.

Because CPUC Energy Division manages the CSI program data, we are in a unique position to help researchers improve the models that are now used to estimate photovoltaic system output.

[22] http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm

[23] CSI incentives are designed to encourage high-performing systems and are paid in two ways: (1) the Expected Performance-Based Buydown (EPBB) incentive, an upfront 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.

The PV Watts model was developed by the National Renewable Energy Laboratory (NREL), and it is the core of the estimating model used by the CSI.[24] Staff has been in discussions with NREL researchers about their efforts to improve the accuracy of the PV Watts model. Improved estimates of system output will help regulators provide more accurate forecasts of ratepayer exposure for rebate programs, and help private investors more accurately and profitably size their systems.

c) CSI-Thermal Oversight

Assembly Bill 2249 required the Commission to issue a report to the Legislature no later than February 1, 2014, stating whether the incentives being offered in the CSI-Thermal Program were sufficient to achieve the program's goal of avoiding the equivalent of 200,000 home water heating systems. The report, delivered in January 2014,[25] found that while the multifamily and commercial general market program low income program are achieving modest success, the single-family residential program is unlikely to reach its objectives. The report recommended that the CPUC consider revising incentive levels, which it may do in the next twelve months. If the Commission does revise these incentive levels, then it will be considering ways to optimize the use of ratepayer dollars for maximal environmental effect.

d) NEM – Implementing AB 327 (Perea, 2013):

Implementation of AB 327 provisions related to NEM is expected to have significant impacts on rates, in particular to extent to which non-NEM customers bear the cost of NEM will be subject to Commission review. In passing AB 327, the Legislature granted the Commission some flexibility in implementing residential rate reform, potentially authorizing fixed or minimum monthly customer charges (up to ten dollars a month, with later inflation adjustments allowed), and redesigning the NEM policy. In adopting the new NEM tariff, AB 327 requires the Commission to balance the ratepayer costs of the program with the need to maintain a growing and sustainable distributed generation industry.

G. California Alternate Rates for Energy Program

1. Work Area

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 bills26. However, since CARE customers were not subject to the higher rates for tiers

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[24] The EPBB Calculator incorporates the PV Watts model.

[25] The report can be found here -- http://www.cpuc.ca.gov/PUC/energy/Solar/legreports.htm

[26] The CARE program was initially referred to as the Low Income Ratepayer Assistance (LIRA) Program, authorized pursuant to decisions D. 89-07-062 and D. 89-09-044 and provided a 15% discount to households with incomes at or below 150% of the Federal Poverty Guidelines (FPG). D.01-06-010 increased the discount from 15%

4 and 5, the effective CARE rate discount exceeded 20% and ranged between 30-47% depending on customer energy usage levels.

D.12-08-044 adopted a cumulative IOU CARE budget of approximately $1.25 billion annually, funded by ratepayers through the Public Purpose Program (PPP) Charge. CARE program goals include achieving higher program participation leading to higher penetration rates over time without substantially increasing the CARE outreach budget. CARE goals also cover increasing enrollment efficiencies by streamlining the screening, eligibility, retention of eligible participants and effectively addressing high energy usage. As of December 2013, PG&E reported a CARE penetration rate at 88%, SCE at 94.7%, SCG at 89.2%, and SDGE at 84.9% penetration.

2. Activities and Proceedings in the next 12 months

Efforts are underway within the upcoming year to implement Assembly Bill (AB) 327, which became effective January 1, 2014. Additionally, the current CARE 2012-2014 program cycle will come to a close in December 2014 in preparation for another 3- year (2015-2017) program cycle. During this transition period between CARE program cycles, the utilities will receive guidance about the content of their application via Commission decision; submit budget applications for the Commission's review. The Commission will also issue a final decision, authorizing new program budgets; anticipated during the 4th quarter of 2014.

AB 327 activities will affect future CARE revenue requirements and/or rates. Specifically, AB 327 requires that the average effective CARE discount now range between 30-35 percent of the revenues that would have been produced for the same billed usage by non-CARE customers. AB 327 also requires that effective excesses in existing discounts, greater than 35 percent, be reduced by a reasonable amount on an annual basis. Finally, AB 327 also mandates a Low Income Needs Assessment (LINA) study every 3 years which is funded with ratepayer dollars. The authorized budget for the 2012 LINA study was $700M, however future LINA studies will be targeted to address specific issues and/or expand on aspects of the existing LINA findings in effort to reduce costs moving forward by not conducting a full comprehensive LINA studies each cycle.

During the upcoming 2015-2017 CARE program cycle, the Commission will continue to direct the utilities to strive towards the goals of 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 eligible participants. The Commission will also ensure that the utilities continue to effectively address high energy usage households. The Commission monitors the utilities' progress in these areas regularly and has observed declines in CARE participation across the utilities in the past year. Recent reductions in CARE participation signal the effectiveness of tightening program rules directed in D.12-08-044 including; enhancements to recertification, post enrollment verification (PEV) processes and

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to 20% and changed the income eligibility criteria from 150% of Federal Poverty Guidelines to 175% of Federal Poverty Guidelines implementation of the CARE high usage policy in an effort to retain eligible customers and identify and remove those who are found to be ineligible for the CARE program.

H. Energy Savings Assistance Program

1. Work Area

The ESA 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 appropriate energy education to all participants as it relates to the benefits of energy efficiency that form long term conservation behaviors have also been identified as obstacles.

Each IOU's portfolio of measures is evaluated for cost-effectiveness during the budget application process in an effort to determine whether certain program measures should continue to be offered or retired. The existing cost effectiveness tests are currently being revisited by the Commission in an effort to identify potential opportunities to minimize cost to ratepayers while striking the appropriate balance between cost effectiveness energy savings and health, comfort and safety of ESA program participants.

The Energy Savings Assistance (ESA) program began in the 1980s as a direct assistance program provided by the electric and gas utilities in California. ESA was formally adopted by the legislature in 1990 through Public Utilities Code Section 2790. The ESA program is a resource program designed to garner energy savings while providing an improved quality of life for the low-income population. Participants include income qualified single family, multi-family, mobile homes, and non-profit group living customers27. The program provides 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.

D.12-08-044 adopted a cumulative IOU ESA program budget of approximately $370 million annually, funded by ratepayers through the Public Purpose Program (PPP) Charge. In 2013, the four large IOUs treated approximately 300,698 homes statewide, with PG&E treating 120,408 homes, SCE treating 69,031, SCG treating 98,225 homes, and SDGE treating 13,034 homes.

[27] As with the CARE program, the total combined household income must not exceed 200 percent of FPG.

2. Activities and Proceedings in the next 12 months

D.12-08-044 adopted new initiatives and improvements for the ESA program to encourage and facilitate greater program efficiencies, collaborations and overall benefits to the low-income population. 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; a better understanding the multifamily sector to enhance outreach to multi-family property owners; a review of the overall cost effectiveness of the program; and a focus on best practices and potential enhancements to the existing ESA program delivery model.

The potential rate impact from May 2, 2014 through April 30 2015 is expected to be an increasing trend (to the PPP surcharge) by approximately 12% over 2013 levels based on an annual trend analysis of the authorized ESA budgets for 2012-2014.

I. Emerging Procurement Strategies

1. Summary of Cap & Trade Program

In 2011, the CPUC began a proceeding to address cost and revenue issues associated with how California's investor-owned electric and natural gas utilities will participate in the Air Resources Board (ARB)'s Greenhouse Gas (GHG) Cap-and-Trade program, which became effective January 1, 2012.[28] The Cap-and-Trade program requires compliance entities, including electric and natural gas utilities regulated by the CPUC, to purchase a combination of allowances and offsets equal to their annual carbon emissions. Electric utilities became regulated under Cap-and-Trade beginning January 1, 2013, and natural gas utilities will become regulated on January 1, 2015. ARB allocates some allowances directly to at-risk industrial entities, and it also grants some to utilities on behalf of ratepayers. Under ARB's Cap-and-Trade regulation the investor-owned utilities are obligated to sell all of these allowances at ARB's quarterly allowance auctions, and the proceeds must be used exclusively for ratepayer benefit, consistent with the goals of AB 32, and subject to limitations imposed by the CPUC.

2. Activities and Proceedings in the next 12 months

a) Cap and Trade and Customer Impact

In D.12-12-033, the CPUC established that electricity rates should reflect a carbon price signal, and it determined how utilities should distribute 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 need special protection. D.12-12-033 defined priority uses of allowance auction revenue and it reflected guidance the Legislature provided in SB 1018 (2012).

[28] Rulemaking 11-03-012.

The CPUC decided to allocate revenue to certain at-risk industries (often referred to as emissions-intensive and trade-exposed, or EITE, entities) to address the risk of economic and emissions leakage. ARB provides these industries with assistance to cover a portion of their costs associated with direct emissions (i.e. those from the combustion of fuels), and the CPUC will provide a complimentary allocation of revenue to these same industries to offset a portion of the GHG costs they will experience in electricity rates. 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 so that industries still have an incentive to operate efficiently. 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 already 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 directed the utilities to provide allowance revenue to small businesses[29] for the purpose of providing transition assistance. The intent of this assistance is to gradually introduce these customers to a carbon price signal; it will give small businesses an opportunity to invest in measures that can reduce their exposure to GHG costs, for example by investing in energy efficiency. In this case, the CPUC decided to use allowance revenue to directly buy-down carbon costs in rates, given the practical difficulties of returning revenue to these customers in a manner that does not interfere with the carbon price signal. This credit will appear as a line-item on customers' bills as the small business "California Climate Credit."

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 temporarily withhold all GHG costs from the residential rates of PG&E, SCE and SDG&E to avoid adding to the disproportionate cost burden born by upper-tier residential customers. Allowance revenue will be used to offset these costs.

All remaining auction proceeds – approximately 60% of revenue - will be returned to households as a semi-annual bill credit called the "California Climate Credit" that is equal per household in each utility's territory. This credit will appear in April and October bills each year. The intent of this 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.

Throughout 2013 the CPUC finalized implementation details necessary to introduce allowance revenue and carbon pricing into electricity rates. Ongoing implementation details include efforts to finalize formulas and methods to return revenue to EITE customers, as well as a broad-based public outreach and education campaign in partnership with the CPUC's Energy Upgrade

[29] A small business is defined as a non-residential customer with energy demand that does not exceed 20 kW in more than 3 months during the previous 12 month period. Agricultural customers, non-profits and schools are also eligible for this assistance.

California umbrella marketing program to raise Californians' awareness about state efforts to fight climate change and actions they can take to reduce their energy costs and shift toward cleaner sources of energy.

b) Cap and Trade and Utility Costs

The Cap-and-Trade program will increase each utility's procurement costs. 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. All GHG costs have been deferred from electricity rates in 2013 while the CPUC finalized details to implement D.12-12-033. However, beginning in April 2014, utilities will begin introducing Cap-and-Trade-related costs and allowance revenues in electricity rates.

In 2014, the five regulated electric IOUs (PG&E, SCE, SDG&E, PacifiCorp and Liberty Utilities) will collectively introduce approximately $841 million in GHG costs into rates, but they will also return $1.2 billion in allowance revenue proceeds to customers. Cost and revenue allocations by utility and customer class remain confidential pending completion of an ongoing CPUC proceeding (A.13-08-002, et al). Of all the allowance revenue being returned to customers, approximately 4.3% will be returned to EITE customers; 5.3% will be returned to small business customers, and 91% will be returned to residential customers.

J. CPUC Advocacy for Reasonable Rates for Electric Transmission

1. Work Area

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. The CPUC actively pursues these goals by analyzing Transmission Owner rate case filings, filing testimony, litigating, and intervening on behalf of California ratepayers in FERC settlement talks or hearings. Additionally, the CPUC has been participating in initiatives proposed by the California Independent System Operator (CAISO). Regulated by FERC, CAISO is the transmission system operator that coordinates, controls, and monitors the operation of the electrical power grid system within the state of California.

2. Activities and Proceedings in the next 12 months

a) Transmission Rate Cases before the FERC

The CPUC actively participates in Transmission Owner (TO) rate cases before the FERC to advocate for just and reasonable rates in federal wholesale electric market proceedings. In 2013, most of the CPUC's electric FERC-related work consisted of TO rate cases for PG&E, SCE and SDG&E. Due to the importance and intricacies of these TO rate cases, CPUC legal staff and Energy Division regulatory analysts' partner together to examine a multitude of cost of service and capitalization issues for adequacy, cost effectiveness and prudence. The FERC determines the appropriate amount of transmission revenue requirement for the Investor Owned Utilities

(IOUs) after the CPUC team, other joint interveners, and FERC staff conduct discovery on the utilities filings to collect evidence and develop a fact-based fair and reasonable alternative revenue requirement recommendation. The proceeding continues under a FERC settlement Administrative Law Judge where the parties either negotiate a settlement, or if the negotiation process does not result in a settlement of the rate case, the parties are ordered to proceed to hearings where a final revenue requirement is determined.

The fundamental objectives of the CPUC's advocacy role in FERC proceedings is of ensuring safety, prudence, adequacy, and containing ratepayer costs in the TO rate case decision-making process. As a result of the CPUC's persistence and expertise, the IOUs' requests for increasing their revenue requirement have been reduced by $409 million[30] by the FERC in the TO rate case proceedings during 2013. Looking forward in to 2014 and beyond, the CPUC will be representing California ratepayers in other FERC TO rate case proceedings from the IOUs and other transmission owner entities. In 2014, the pending TO rate cases at FERC are for PG&E; SCE; SDG&E; Trans Bay Cable LLC; Duke American Transmission Company (DATC) Path 15; and other transmission companies.

b) Future 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 electrical power capacity, high energy prices, significant market manipulation by some electricity wholesale market participants, and other factors. To meet electricity demand during this period, the utilities were compelled to buy electricity in the spot market at high prices, while being capped on the price they could sell the very same electricity to their retail ratepayers. This sustained extreme imbalance depleted the financial liquidity of all of the electric utility companies and forced the bankruptcy of one major utility (on April 6, 2001) and the near bankruptcy of another major utility company. The State of California intervened and provided a backstop by financially backing billions of dollars in electricity purchases in the wholesale electricity market to prevent the collapse of this key market.

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 the California electric market. Following the FERC's denial of this complaint for relief from overcharges occurring in the summer of 2000, the CPUC, representing California ratepayers, filed a complaint at the FERC, in a case against more than 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 that the accused electricity sellers engaged in a variety of illicit market actions. Many of these actions had the effect of artificially inflating the energy prices in the California wholesale electricity market. The initial decision sets a method for computing overcharges to be refunded to retail customers. If the ALJ's decision[31] is

[30] Revenue requirement reductions for the PG&E TO14 case is $181 million, for the SCE TO7 case $111 million, and for the SDG&E TO4 case $117 million.

[31] 142 FERC ¶ 63,011 , Docket EL00-95-248, Initial Decision (Feb. 15, 2013)

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.

c) Other Ongoing Proceedings:

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[32] 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.

d) Possible Litigation Results:

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. Nonetheless, these cases may be litigated for several more years before all appeals are exhausted and rate reductions could be ordered.

[32] U.S. Court of Federal Claims, Case 07-184C

III. Gas Utility Rates and Costs

A. Work Area

Natural gas utility rates in California consist of three main components for typical "core"[33] gas ratepayers:

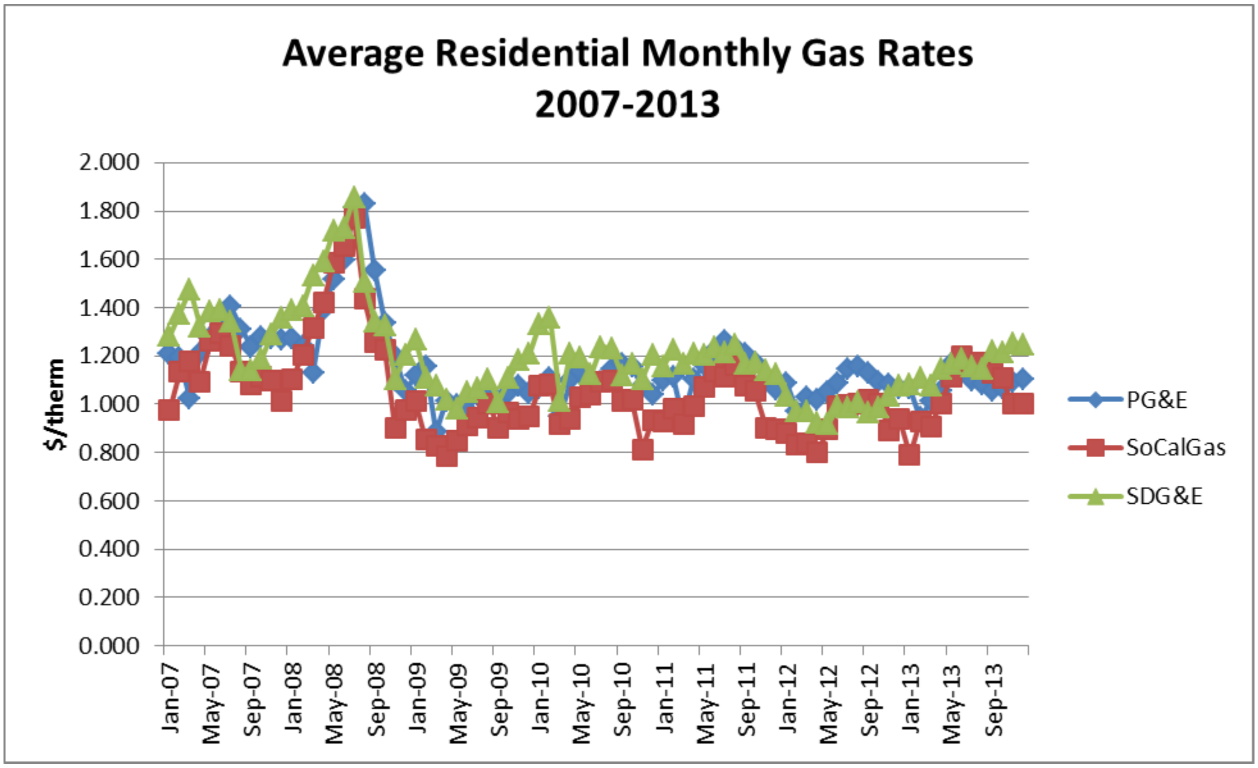
- the procurement rate, which recovers the cost of procurement of the natural gas itself,
- the transportation rate, which recovers the cost of the utility to deliver natural gas and provide various customer services, and
- the gas public purpose program surcharge, which recovers the cost of various 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 PPP surcharge.

Due to relatively low natural gas prices, and only modest increases in utility transportation costs, gas utility customers of natural gas utilities continued to experience moderately low natural gas costs in 2013. Total utility gas costs were only slightly higher in 2013 than in 2009, and were much lower than in 2008 when gas prices spiked. However, the CPUC does not regulate the price of natural gas. The CPUC authorizes the revenue requirements for the natural gas distribution utilities primarily in the areas of natural gas transmission, distribution, storage, and customer service costs and natural gas public purpose program (PPP) costs. The continuing low commodity price of natural gas is the result of developments in the natural gas market, which is influenced by both national and international market conditions.

Total core natural gas rates on average remained fairly stable in 2013. Low, stable procurement costs have allowed 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 commodity prices are expected to only slightly in the coming 12 months. But, natural gas prices have shown a high degree of volatility in recent months, so it is possible that higher prices could occur.

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



Total approved natural gas utility <u>costs</u> for pipelines, storage and customer service have steadily increased (by about 23%) since 2008, with much of that increase (9.4%) occurring in the last year. However, there are significant differences between different customer classes and utilities in the changes in transportation <u>rates</u> over that time period.

Approved gas PPP costs have increased by 28% during the 2008 to 2013 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.

B. Activities and Proceedings in the next 12 months

In the coming year, the CPUC will be facing a significant challenge to maintain natural gas utility transportation rates at reasonable levels. Procurement costs are expected to remain at moderate levels, but, natural gas procurement costs rose by 9% in 2013 compared to 2012, and as noted above, natural gas prices have exhibited significant volatility in recent months. In addition, natural gas utilities have continued to propose large incremental pipeline safety costs in addition to other operational costs. These additional costs could increase the utilities' transportation rates in 2014 and future years.

1. Gas Utility Operational Costs, Rates and Safety

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. In recent months, and during the next 12 months, the CPUC has been examining and will continue 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 2014:

a) 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 application was submitted to the CPUC in October 2013. In that application, PG&E proposed a revenue requirement that is $52 million lower than the amount adopted in the CPUC's December 2013 decision. The CPUC will be examining the updated PSEP in 2014, and expects to issue a decision by the end of the year.

The CPUC also approved Southwest Gas' pipeline safety plan in October 2013, and disallowed a small portion of the costs.

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

In A.09-09-020, SoCalGas proposed to conduct work at its Aliso Canyon Storage Field, and estimates the cost to be $200.9 million. The project will result in a slight increase in core gas rates of 0.3 cents per therm. SoCalGas requested approval of its revenue requirement and its proposed allocation of the project costs to various customer classes. The final EIR was issued in 2013, and the CPUC then adopted SoCalGas' proposal in November 2013.

c) 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 Commission. 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-2014.

d) 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 examined PG&E's request in 2013, and will likely issue a decision in mid-2014.

e) 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 examined Southwest Gas' request in 2013, and will likely issue a decision in early 2014

f) PG&E Core Interstate Pipeline Capacity (A.13-06-011)

In CPUC Decision 12-12-006, the CPUC lowered the amount of interstate pipeline capacity required to be held by PG&E for its procurement customers on an interim basis. This should result in lower PG&E core interstate pipeline costs, by roughly 5%. The CPUC also ordered PG&E to propose a more permanent requirement for the holding of interstate pipeline capacity. PG&E made its proposal in A.13-06-011. The amount of interstate pipeline capacity held by PG&E impacts the core procurement rate.

g) PG&E Gas Transmission and Storage (A.13-12-012)

In December 2013, PG&E proposed a very large increase in the 2015 revenue requirement for its gas transmission pipeline and storage system. PG&E's proposed revenue requirement of $1.286 billion is 76% higher than the amount authorized for 2014. The primary driver for PG&E's proposed increase is increased safety-related spending. The CPUC will be examining PG&E's proposal in 2014.

h) SoCalGas North-South Project (A.13-12-013)

In December 2013, SoCalGas requested rate recovery for a proposed new transmission pipeline, called the North-South Project. It is intended to improve the reliability of deliveries into the southern part of the SoCalGas system and into the SDG&E service territory. The pipeline project is estimated to cost over $625 million, and would take about 6 years to construct. The CPUC will be examining SoCalGas' proposal in 2014.

2. Gas Public Purpose Programs (PPPs)

In 2013, the costs of the gas related PPPs was about $552 million. The costs associated with the natural gas PPPs has generally grown in recent years but in 2013 decreased by 11% from 2012.

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

3. Procurement Costs

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

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

For example, in 2013 and early 2014 , as noted above, the CPUC has been examining a PG&E proposal to revise the amount of interstate pipeline capacity held by PG&E for delivering supplies to core customers who buy gas from PG&E.

4. CPUC Advocacy for California Natural Gas Interests at the FERC

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

The CPUC has been participating in an El Paso Pipeline FERC proceeding. The rate case may result in a significant increase in El Paso transportation rates to California.

IV. Appendix B - Utility Reports on Recommended Measures to Limit Costs and Rate Increases.

Pacific Gas and Electric Company

Southern California Edison Company

San Diego Gas and Electric Company

Southern California Gas Company

SB 695 Compliance Report

Pacific Gas and Electric Company

Year 2014

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 SB 695, which was codified into 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 2014 and beyond.

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 nonparticipating customers.

One of the biggest obstacles to this goal of creating fair and equitable rates while keeping costs down has been the statutory mandate for tiered residential electric rate design that included protected tiers. 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.

Last year, the Governor signed into law AB 327 (Perea), which removes many (though not all) of the restrictions on the Commission's ability to adjust non-CARE Tier 1 and 2 rates and reduce the large gap between upper-tier and lower-tier rates. AB 327 also mandates that, after a reasonable transition period, PG&E's average CARE discount be reduced from its current level of just below 50 percent to between30 to 35 percent. With the restoration of much of its pre-energy crisis ratemaking authority, the Commission is now able, over a reasonable period of time, to restore residential rates – both their structures and the levels of specific rate components -- to more equitable levels that more closely reflect cost of service. On January 28, 2014, PG&E filed a proposal for summer 2014 rate reform which, if approved, will take an initial step toward reducing the upper vs. lower tier rate differentials, as well as beginning to reduce the CARE discounts toward the 30 to 35 percent range now mandated by statute. Then on February 28, 2014, PG&E filed a proposal for further rate reform in 2015 and beyond, which includes implementing a monthly fixed charge, collapsing tiers, further reducing the upper vs. lower tier rate differential, and reducing the average CARE discount.

Another area of concern regarding impacts on electricity rates is the overall cost-shift associated with customer-owned generation, particularly residential renewable generation that participates in the Net Energy Metering (NEM) program. The NEM tariff allows electricity customers with their own generation (primarily rooftop solar photovoltaic (PV) equipment) to reduce their billed usage by "spinning the meter backwards" (receiving a full retail rate credit (i.e., generation rate plus transmission and distribution rates) for their generation that is sent out to the grid to offset future consumption within the month and within an annual true-up period). Through the NEM rates, customers that install renewable on-site generation are compensated at rates that substantially exceed the market-based costs of generation otherwise paid by PG&E and non-participating customers. The effect of paying a fully bundled retail rate to NEM customers is that these customers are not paying their fair share of the fixed costs associated with accessing the grid. These fixed costs are then shifted to customers for whom roof-top generation is not feasible or affordable.

While PG&E 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 reflect fair wholesale market prices that do not shift fixed costs to other customers.

Independent of NEM, the statutorily-mandated residential rate designs magnify the impact of the cost-shift associated with customer-owned generation. Until very recently, any increases in rates were limited to the upper tiers. Customers with on-site generation 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, and magnifies the overall cost shift impact and subsidies from other customers associated with customer-owned generation. Three-fourths of NEM customers do not pay the average cost to serve a residential customer. 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 are mature, the costs of PV installations have dropped significantly, and PV adoption has increased dramatically, these subsidies and cost-shifts provided to existing NEM must be reformed to sustainably accommodate continued growth in such generation for the benefit of all customers.

AB 327 addressed the NEM cost shift in addition to the general rate design issues discussed above. With respect to NEM, AB 327 charged the CPUC with two tasks. First, the CPUC must (by December 31, 2015) complete a redesign of the NEM program to ensure protection of a sustainable renewable generation market for our customers; ensure the economic interests of participating customers; and protect the economic interests of nonparticipating customers. Second, the CPUC must (by March 31, 2014) determine a transition plan for customers participating in the current NEM program. This transition plan must ensure that participating customers have the opportunity to recover the costs of their investment in renewable generation.

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 increased 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, beginning in 2011 PG&E 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 improves 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, per its Pipeline Safety Enhancement Plan (PSEP) program as updated on October 29, 2013, in Application 13-10-017, PG&E plans to pressure test 658 miles of gas transmission pipeline, replace 143 miles of pipeline, automate around 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 AB 32 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 (less allowable expenses, i.e. outreach and administration costs) 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, nonresidential 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 an RPS procurement expenditure limitation is currently being addressed in the Renewables Portfolio Standard OIR (R.11-05-005).

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

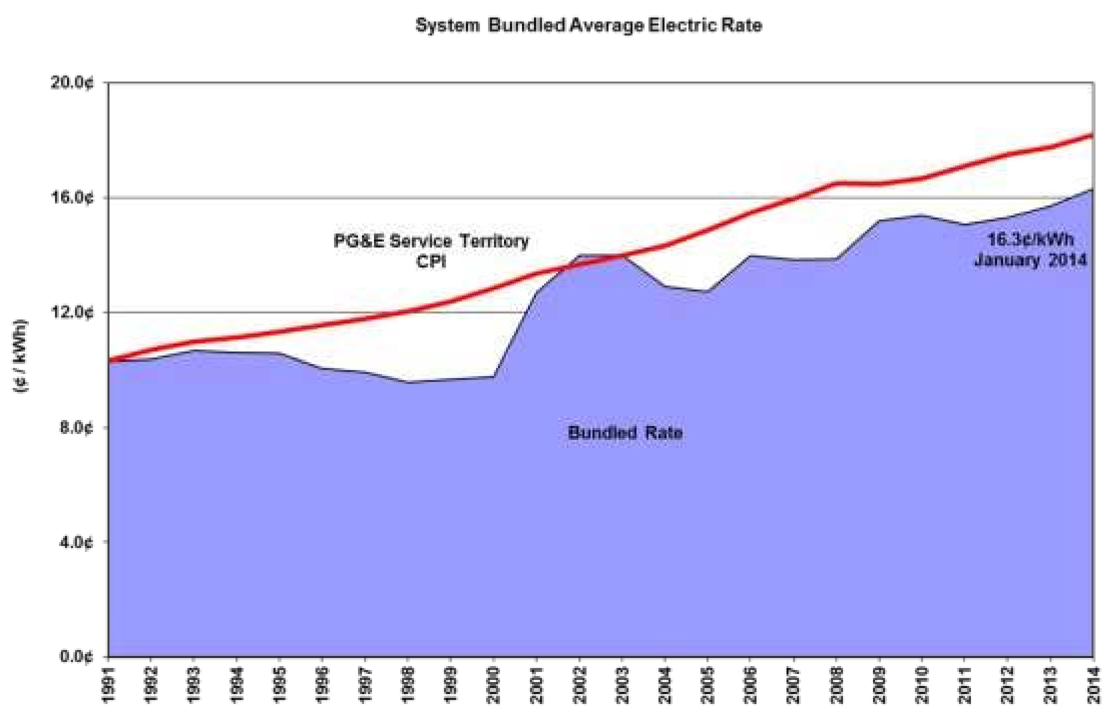
2. Overall Rate Policy

PG&E strives to provide its customers with reasonable rates for gas and electric service. PG&E's overall rate policy 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 23 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 that fall outside of PG&E's control. Among these are the market price of natural gas and electricity, actual retail sales volumes, uncollectible accounts, weather (including the impacts on hydroelectric operations), interest rates, the cost of implementing state mandates, and permitting process delays. Despite these factors, PG&E diligently seeks to manage its costs across all categories to make efficient and effective use of revenues collected from customers.

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

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 at one time from a policy perspective, programs such as NEM 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.

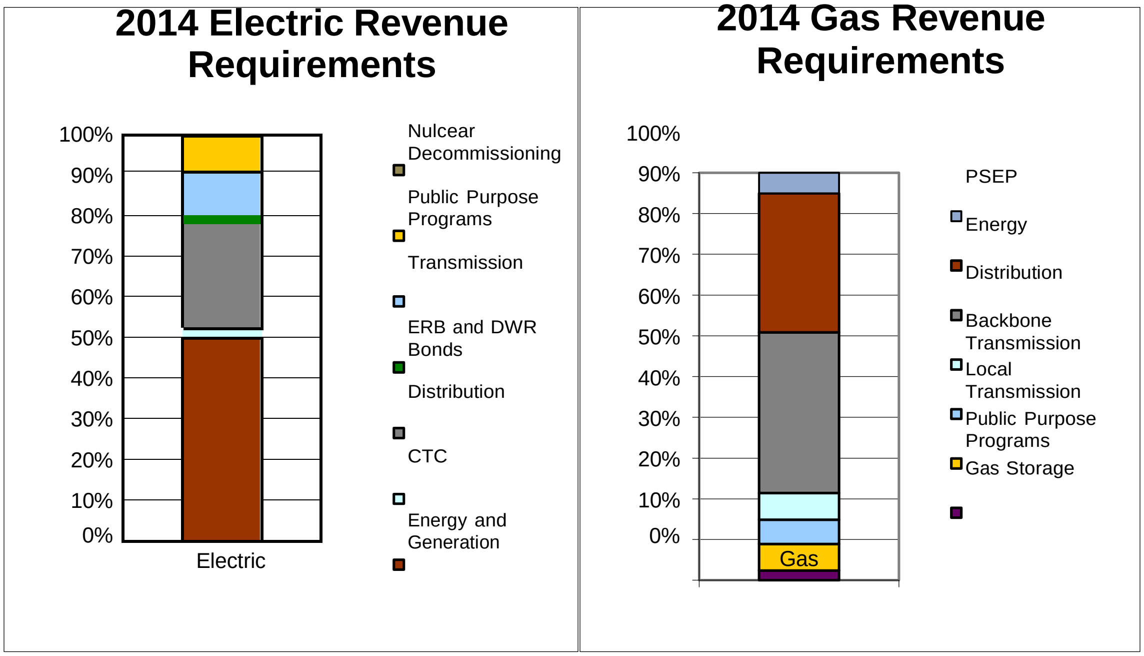
Absent reform of residential rates, to bring upper-tier non-CARE rates down to a level that more closely reflects cost of service, rates will continue to have a punitive effect on high-usage customers, and result in high bill complaints -- particularly in the Central Valley where prolonged periods of high temperatures push usage into very high priced upper tiers and lead to large, disproportionate, bill increases.

PG&E respectfully requests the Commission's support by approving rate proposals in current and future rate proceedings that are designed to reduce the extremely high levels of upper-tier rates. If these proposals are not approved, upper-tier rates are projected to continue growing, 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 2014 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 2014 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) Energy Recovery Bonds (ERB) and Department of Water Resources (DWR) bonds, (5) Transmission, (6) Public Purpose Programs (PPP), and (7) Nuclear Decommissioning. For reference, an excerpt from the Advice 4278-E-B Annual Electric True-Up filing is provided as Table 1 below. For 2014 authorized RRQs, below is a description of each category:

1) The Energy and Generation electric RRQs contribute approximately 51 percent of the total authorized revenue requirement in 2014. 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 2014. 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 26 percent of the total authorized RRQ in 2014. 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.[1] On November 15, 2012, PG&E filed its 2014 GRC Application (A.12-11-009), including a proposed distribution and generation revenue requirement. Upon issuance of the 2014 GRC decision, PG&E will consolidate all of its then-authorized revenue requirements and implement the resulting rate changes.

4) The ERB and DWR bond RRQ contributes 2 percent of PG&E's authorized 2014 RRQ.

5) The Electric Transmission RRQs contribute 10 percent of the total authorized revenue requirement in 2014. 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 8 percent of PG&E's total authorized revenue requirement in 2014. 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 2014.

[1] 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 4278-E-B Annual Electric True-Up filing for Electric Rates Effective January 1, 2014

Table 2: Annual Electric True-Up Projected 2014 Revenue Requirements (In $)

Line #		Test Year 2014 RRQ A	12/31/13 Forecast BA Amortization B	Total Projected 2014 Revenues C = A + B
1	**CPUC Jurisdictional**			
2	**Distribution**			
3	Distribution/DRAM	3,377,029,000	56,762,136	3,433,791,136
4	Pension Contribution (Distribution & Generation) [1]	134,046,000		134,046,000
5	FERABA (Distribution & Generation) [2]		7,712,113	7,712,113
6	Demand Response	64,953,632		64,953,632
7	Statewide ME&O/Demand Response	895,307		895,307
8	Self Generation Incentive Program	29,838,521		29,838,521
9	CPUC Fee	20,862,925		20,862,925
10	Advanced Metering/SBA	158,800,000	(44,230,470)	114,569,530
11	Meter Reading Cost Balancing Account		33,036,295	33,036,295
12	California Solar Initiative	85,917,150		85,917,150
13	HSM		22,429,243	22,429,243
14	CEEIA	17,680,833	1,652,812	19,333,645
15	NTBA		(258,323)	(258,323)
16	CIPBA (Cornerstone)	54,033,000	(13,121,253)	40,911,747
17	Default Residential Pricing	0		0
18	Peak Time Rebates	0		0
19	SGPDPBA (Distribution and Generation) [3]	1,068,874		1,068,874
20	SGMA (Compressed Air Energy Storage)		6,186,737	6,186,737
21	RCSEBA		(5,530,051)	(5,530,051)
22	CES21BA-E		0	0
23	Customer Data Access Balancing Account		9,132	9,132
24	SmartMeter™ Opt-Out Memorandum Account (SOMA)		0	0
25	Hercules Municipal Utility Acquisition	0		0
26	Mobile Home Park	0		0
27	GHG Revenue Balancing Account	0		0
28	**Generation**			
29	Utility Retained Generation Base/UGBA	1,666,510,000	46,596,546	1,713,106,546
30	Photovoltaic Program	121,600,000		121,600,000
31	DCSSBA		0	0
32	Electric Procurement/ERRA	4,583,141,008	133,479,945	4,716,620,953
33	ERRA GHG SubAccount (D.12-12-008)		0	0
34	DWR--Power Charge/PCCBA	228,010	(1,399,007)	(1,170,997)
35	DWR Franchise Fees	3,040,524		3,040,524
36	MRTUMA (Distribution& Generaion) [3]		0	0
37	LCPERMA		687,943	687,943
38	**Ongoing CTC/MTCBA**	72,204,590	61,361,012	133,565,602
39	**Cost Allocation Mechanism/NSGBA**	234,680,632	12,985,109	247,665,741
40	**ERB Balancing Account (ERBBA)**	27,600,000	(161,075,938)	(133,475,938)
41	**Nuclear Decommissioning**	44,270,000	(109,383)	44,160,617
42	**Public Purpose Programs**			
43	(1) Energy Efficiency (Formerly PGC)	120,734,365		120,734,365
44	(2) ESA (formerly known as LIEE)	94,892,989		94,892,989
45	(3) PPPRAM		(17,748,417)	(17,748,417)
46	Electric Program Investment Charge (EPIC)	82,037,738	1,760,137	83,797,875
47	Procurement EE/PEERAM	220,370,805	(9,181,712)	211,189,094
48	Statewide ME&O/PEERAM	1,350,163		1,350,163
49	CAREA	12,089,933	(12,738,355)	(648,422)
50	**DWR Bonds**	398,573,134		398,573,134
51	**Total CPUC Jurisdictional**	11,628,449,134	119,266,251	11,747,715,385
52	**CPUC Revenues at Present Rates**			11,602,351,598
53	**Change in CPUC Jurisdictional**			145,363,787
54	**Total FERC Jurisdictional**			1,284,766,041
55	**FERC Revenues at Present Rates**			1,284,766,041
56	**Change in FERC Jurisdictional**			0
57	**Grand Total Projected Revenues**			**13,032,481,426**
58	**Total Revenues at Present Rates**			**12,887,117,639**
59	**Total Change**			**145,363,787**

Notes to Table 2:

1 Of the Pension revenue requirement, $85,684,000 is allocated to distribution and $48,362,000 is allocated to generation.

2 Of the December 2013 forecast FERABA balance, $7,714,820 is allocated to distribution and $(2,707) is allocated to generation.

3 Of the SGPDPBA projected revenue, $576,721 is allocated to distribution and $492,153 is allocated to generation.

b. Natural gas RRQs are grouped into the following seven major categories: (1) Energy, (2) Distribution, (3) Backbone Transmission, (4) Local Transmission, (5) Public Purpose Programs, (6) Gas Storage, and (7) PSEP. For reference, an excerpt from the Advice 3447-G Annual Gas True-Up filing on December 24, 2013 is provided as Table 2. For 2014 authorized RRQs, below is a description of each category:

1) The Energy gas RRQs contribute about 34 percent of the total gas RRQ. Authorized RRQs include:
   - Gas supply portfolio costs
   - Interstate capacity costs
   - Gas Hedging

2) The distribution gas RRQs contribute about 39 percent of the total authorized gas RRQ. It includes the 2011 GRC, California Solar Initiative, SmartMeter™ program, and several other programs recovered through the distribution rate component.[2] PG&E filed its 2014 GRC Application (A.12-11-009), including a proposed distribution and generation revenue requirement. Upon issuance of the 2014 GRC decision, PG&E will consolidate all of its then-authorized revenue requirements and implement the resulting rate changes.

3) The backbone transmission gas RRQs, including intrastate capacity costs, contribute approximately 7 percent of the total authorized gas RRQ.

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 7 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 2 percent of the total authorized gas RRQ. It includes core storage, core carrying cost of working gas in storage, and unbundled storage.

7) The Pipeline Safety Enhancement Plan (PSEP) gas RRQ contributes about 5 percent of the total authorized gas RRQ.

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[2] 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 3447-G Annual Gas True-Up filing for Gas Rates Effective January 1, 2014

Pacific Gas and Electric Company
San Francisco, California
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	Revised	*Cal. P.U.C. Sheet No.*	30981-G
Cancelling	Revised	*Cal. P.U.C. Sheet No.*	30382-G

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

Sheet 2

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

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

	Amount ($000)				
Description	Core	Noncore	Unbundled	Core Procurement	Total
BASE REVENUES (incl. F&U) :					
Authorized GRC Distribution Base Revenue (1)					1,195,641
Pension (2)					46,015 (R)
Less: Other Operating Revenue					(22,922)
Authorized Distribution Revenues in Rates	1,176,359 (R)	42,375 (R)			1,218,734 (R)
BCAP ALLOCATION ADJUSTMENTS AND CREDITS TO BASE:					
G-10 Procurement-Related Employee Discount	(1,042) (R)				(1,042) (R)
G-10 Procurement Discount Allocation	411 (I)	631 (I)			1,042 (I)
					(D)
Core Brokerage Fee Credit	(6,583)				(6,583)
Distribution Base Revenue with Adj. and Credits	1,169,145 (R)	43,006 (R)			1,212,151 (R)
TRANSPORTATION FORECAST PERIOD COSTS & BALANCING ACCOUNT BALANCES (3):					
Transportation Balancing Accounts	132,406 (I)	42,407 (I)			174,813 (I)
Self-Generation Incentive Program Revenue Requirement	2,569 (I)	3,911 (I)			6,480 (I)
CPUC Fee	1,970	1,240			3,210
SmartMeter™ Project	79,202				79,202
Winter Gas Savings Plan (WGSP) – Transportation	0 (R)				0 (R)
Franchise Fees and Uncollectible Expense (F&U) (on items above)	2,808 (I)	627 (I)			3,435 (I)
CARE Discount included in PPP Funding Requirement	(108,850) (I)				(108,850) (I)
CARE Discount not included in PPP Surcharge Rates	0				0
Transportation Forecast Period Costs & Balancing Account Balances	110,105 (I)	48,185 (I)			158,290 (I)
GAS ACCORD REVENUE REQUIREMENT (incl. F&U) (4):					
Local Transmission	135,339 (I)	76,861 (I)			212,200 (I)
Customer Access Charge – Transmission		5,026 (I)			5,026 (I)
Storage	48,236 (I)		34,344 (I)		82,580 (I)
Carrying Cost on PG&E Working Gas in Storage	2,367 (I)		636 (I)		3,003 (I)
Backbone Transmission/L-401	96,207 (I)	0	135,405 (I)		231,612 (I)
Gas Accord Revenue Requirement	282,149 (I)	81,887 (I)	170,385 (I)		534,421 (I)

(1) The CPUC has not issued a final decision for the 2014 GRC before the end of 2013. As a result, January 1 revenue requirements for GRC Distribution and SmartMeter are kept at the same level as the 2013 AGT amounts as a placeholder. The amount includes the authorized distribution base revenue and F&U approved in GRC D.11-05-018 and changes to PG&E's cost of capital authorized in D.12-12-034. (T)

(2) Pursuant to D.09-09-020, PG&E will maintain the annual contribution to the Company's retirement plan trust fund at the adopted 2013 amount.

(3) -The total 2014 SGIP revenue requirement (RRQ) was approved in D.11-12-030.
-Since the 2014 GRC decision (see note 1) has not been issued and the ongoing revenue requirements associated with the SmartMeter™ is included in the 2014 GRC forecast, the 2013 revenue requirements is used as a placeholder. This treatment was authorized by Res. E-4620 on December 19, 2013 for the 2014 Annual Electric True-up.
-The WGSP has ended, thus there are no costs shown in Line 24. However, an undercollected balance relating to the WGSP is included in 2014 rates.

(4) The Gas Accord V RRQ was adopted in D.11-04-031. Storage revenues allocated to load balancing are included in unbundled transmission rates. Some amounts include changes to PG&E's cost of capital authorized in D.12-12-034. The backbone transmission amounts include the implementation of the AB32-related gas compressor station costs (D.13-03-017). (T)

*Some numbers may not add precisely due to rounding.

(Continued)

Advice Letter No: 3447-G		*Issued by*	*Date Filed*	December 24, 2013
Decision No. 05-06-029		*Brian K. Cherry*	*Effective*	January 1, 2014
		Vice President	*Resolution No.*	
2C13		*Regulatory Relations*		

Table 2 (continued.): Excerpt from Advice 3447-G Annual Gas True-Up filing for Gas Rates Effective January 1, 2014

Pacific Gas and Electric Company | | Revised | *Cal. P.U.C. Sheet No.* | 30982-G
San Francisco, California | *Cancelling* | Revised | *Cal. P.U.C. Sheet No.* | 30383-G
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GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

Sheet 3

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

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

Description	Core	Noncore	Unbundled	Core Procurement	Total
	Amount ($000)				
ILLUSTRATIVE CORE PROCUREMENT REVENUE REQUIREMENT (5):					
Illustrative Gas Supply Portfolio				1,032,199 (I)	1,032,199 (I)
Interstate and Canadian Capacity				160,081 (R)	160,081 (R)
WGSP – Procurement – Residential				0 (R)	0 (R)
F&U (on items above and Procurement Account Balances Below)				15,560 (R)	15,560 (R)
Backbone Capacity (incl. F&U)	(65,974) (R)			65,974 (I)	0
Backbone Volumetric (incl. F&U)	(30,233) (R)			30,233 (I)	0
Storage (incl. F&U)	(48,236) (R)			48,236 (I)	0
Carrying Cost on PG&E Working Gas in Storage (incl. F&U)	(2,367) (R)			2,367 (I)	0
Core Brokerage Fee (incl. F&U)				6,583	6,583
Procurement Account Balances				3,452 (I)	3,452 (I)
Illus. Core Procurement Revenue Requirement	(146,810) (R)			1,364,685 (R)	1,217,875 (R)
TOTAL GAS REVENUE REQUIREMENT (without PPP) IN RATES	1,414,589 (I)	173,078 (I)	170,385 (I)	1,364,685 (R)	3,122,737 (I)
IMPLEMENTATION PLAN REVENUE REQUIREMENT (7)					
Implementation Plan – Local Transmission	85,881 (I)	48,735 (I)			134,616 (I)
Implementation Plan – Backbone	17,462 (I)	23,308 (I)			40,770 (I)
Implementation Plan – Storage	3,291 (I)	2,281 (I)			5,572 (I)
Total Implementation Plan	106,634 (I)	74,324 (I)			180,958 (I)
PUBLIC PURPOSE PROGRAM (PPP) FUNDING REQUIREMENT (F&U exempt) (6):					
Energy Efficiency (EE)	66,657 (I)	7,420 (I)			74,077 (I)
Energy Savings Assistance (ESA)	61,173 (I)	6,809 (I)			67,982 (I)
Research, Demonstration and Development (RD&D)	6,846 (I)	3,854 (I)			10,700 (I)
CARE Administrative Expense	1,678 (I)	1,128 (I)			2,806 (I)
Statewide Marketing, Education & Outreach – EE Flex Alert	229 (N)	26 (N)			255 (N)
BOE and CPUC Administrative Cost	242 (I)	137 (I)			379 (I)
PPP Balancing Accounts	(2,706) (I)	(6,589) (I)			(9,295) (I)
CARE Discount Recovered from non-CARE customers	65,072 (R)	43,778 (R)			108,850 (R)
Total PPP Funding Requirement in Rates	199,191 (I)	56,563 (I)			255,754 (I)
TOTAL GAS REVENUE AND PPP FUNDING REQUIREMENT IN RATES	1,720,414 (I)	303,965 (I)	170,385 (I)	1,364,685 (R)	3,559,449 (I)

(5) The credits shown in the Core column represent the core portion of the Gas Accord RRQ that is included in the Illustrative Core Procurement RRQ, and are shown here to avoid double counting these costs in the total. The Gas Supply Portfolio cost is an annual illustrative amount. Actual gas commodity costs change monthly.

(6) The PPP funding requirement is recovered in gas PPP surcharge rates pursuant to D.04-08-010 and 2014 PPP surcharge AL 3426-G; 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)

(7) The Pipeline Safety Implementation Plan was authorized in D.12-12-030. (T)

(Continued)

Advice Letter No: 3447-G		*Issued by*	*Date Filed*	December 24, 2013
Decision No. 05-06-029		*Brian K. Cherry*	*Effective*	January 1, 2014
		Vice President	*Resolution No.*	
3C9		*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 sales 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 of electric and gas RRQs.

Table 3: Summary of RRQs and Percentage Distribution for 2014

RATE COMPONENT	Electric		Gas	
	RRQ $M	Jan 2014 %	RRQ $M	Jan 2014 %
Energy and Generation	$6,603	51%	$1,211	34%
CTC	381	3%	-	-
Distribution (1)	3402	26%	1406	39%
ERB and DWR Bonds	265	2%	-	-
Transmission / Backbone Transmission	1285	10%	232	7%
Local Transmission (Gas)	-	-	212	6%
Public Purpose Programs (2)	1053	8%	232	7%
Nuclear Decommissioning	44	0%	-	-
Gas Storage	-	-	86	2%
PSEP	-	-	181	5%
Total Authorized Revenue Requirement	$13,032	100%	$3,559	100%

(1) Includes 2014 CARE discount of approximately $566M for electric.
(2) Includes 2014 CARE discount of approximately $109M for gas which is collected in PPP rates.
(3) As of January 1, 2014. Values are approximated to the nearest million.

7. Published Load/Demand Forecasts

Customer sales volatility over time directly impacts the rates borne by gas and electric customers. PG&E updates sales forecasts for its service territory on a regular basis to include 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 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. While sales rebounded in 2012, driven by an improving economy and favorable weather conditions, sales were approximately flat between 2012 and 2013. The following sections discuss the forecast trends for electric and gas sales for 2014.

a. Electric

Based on Moody's Analytics economic forecast for PG&E service territory, economic recovery will accelerate in 2014 bolstered by technology, professional services, and a strong housing recovery. Coastal areas are booming while the Central Valley still struggles to create jobs. Low inventory, fewer foreclosures, rising median home prices, and increasing applications for building permits suggest that the housing market is heating up again, primarily in the Bay Area. The unemployment rate is expected to be relatively high compared with historical averages, with only moderate improvement to the unemployment rate from 8.4% by the end of 2013 Q4 to 7.2% by the end of 2014 Q4. This is slightly deceptive however, as more job opportunities entice those who had stopped looking for work back into the job market. Total employment in PG&E territory is forecast to increase 1.8%, from 5,908,800 jobs to 6,015,100 jobs.

In 2013, the agricultural sector endured the driest calendar year on record in California, which drove record agricultural sector sales driven primarily by increased groundwater pumping. Given the extremely dry start to the 2013/2014 water year, higher than normal agricultural sales are expected in 2014.

PG&E electric sales increased by 0.3 percent in 2013 compared to 2012 sales. Given improvement in the economy and drought conditions, we expect an increase in electric sales of 0.1 percent in 2014.

b. Gas

As described in the Electric subsection above, most of PG&E's service area economy is in economic recovery and should continue growing through 2014. Based on PG&E's filed 2015 Gas Transmission and Storage Rate Case gas throughput forecast, 2014 core and noncore gas sales show a slight decline in usage.

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 uses for gas are space and water heating, thus gas sales requires customer growth to drive usage growth. Despite the economic recovery, the return to presumed normal temperatures after a colder than normal 2013 and the effects of continuing energy efficiency improvements, residential demand is projected to drop by about 3 percent in 2014. After 2014, 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. Despite the return to assumed normal temperatures and continuing energy efficiency impacts, commercial sales are bolstered by the recovering economy and are projected to remain flat through 2014 at 2013 levels. The historically volatile industrial class saw a historically high sales level in 2013, sales in 2014 are projected to decline 3%, but still remain high compared with prior years. While this forecast will not be used to calculate 2014 rates, any shortfalls will generate balancing account under collections that will be included in 2015 rates.

Finally, demand for gas used in electric generation is expected to remain high in 2014. 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 2014, however, the main factors impacting electric generation will be the continuing slow economic recovery, the retirement of both units at SONGS, and a drier than normal 2013-2014 winter in the west resulting in lower than normal hydroelectric output.

Appendix: Outlook from May 1, 2014 to April 30, 2015.

Please see the table below for a list that contains information on PG&E's significant rate changes for 2014- 2015. The table reflects currently anticipated rate filings schedule for 2014 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	2014 RRQ *	2015 RRQ *			
	Q3 2010									
1	Default Residential Rate Programs (Peak Day Pricing)	A.10-08-005	August 9, 2010	TBD	141	29.2	101.4	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. Amounts shown reflect PG&E's 2010 filed position. Should the CPUC decide to move forward on this application, amounts would need to be updated.	Electric	Distribution
	Q3 2011									
2	Lawrence Livermore National Laboratory for 21st Century Energy Systems	A.11-07-008	July 18, 2011	2014	19.25	4	4	Joint IOU Application to recover the costs associated with a five-year cooperative research and development agreement with the Lawrence Livermore National Laboratory (LLNL). This public-private collaborative agreement is known as the "California Energy Systems for the 21st Century Project" (CES-21 Project).	Electric	DRAM
	Q4 2011									
3	Rate Design Window 2010/Peak	A.10-02-028	October 28, 2011	TBD	34	(1)	23.4	Requests approval for PTR program that provides incentives for customers to respond to price	Electric	Distribution

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested / Expected Implemen-tation date	Requested Amount ($ millions) Total Cost	2014 RRQ *	2015 RRQ *	Description	Affected Rate	Affected Rate Component
	Time Rebate (Revised Testimony)							signals on event days when demand is expected to be high.		
	Q1 2012									
4	Market Redesign and Technology Upgrade (MRTU) 2010 (re-filing)	A.12-01-014	January 31, 2012	2014	46	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 MRTU initiatives and a forecasted revenue requirement for 2012 and 2013.	Electric	Distribution; Generation
	Q2 2012									
5	Market Redesign and Technology Upgrade 2011	A.12-04-009	April 16, 2012	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 MRTU initiatives.	Electric	Distribution; Generation
6	CPIM 2011 Annual Report (Yr. 18)	N/A	May 11, 2012	TBD		N/A	5	Compliance report for gas core procurement incentive mechanism for November 1, 2010 through October 31, 2011.	Gas	Procurement
	Q3 2012									
7	SmartMeter Opt-Out (Phase 2)	A.11-03-014	August 10, 2012 [Ph.2 Filing Date]	2014	38	7 [incl. 2012 and 2013 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

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested / Expected Implemen-tation date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2014 RRQ *	2015 RRQ *			
	Q4 2012									
8	2014 General Rate Case (GRC), Phase I	A.12-11-009	November 15, 2012 Amounts based on October 4, 2013 Updated Testimony	2014		1,160	436	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 $514M electric distribution, $200M electric generation, and $446 gas distribution.	Electric; Gas	Electric Distribution; Electric; Generation; Gas Distribution
9	Nuclear Decommissio ning Cost Triennial Proceeding (NDCTP)	A.12-12-012	December 21, 2012	2014		211	211	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 Decommission ing
10	Mobile Home Park OIR	R.11-02-018	October 5, 2012 (filed testimony)	2014	TBD	TBD	TBD	PG&E is proposing a voluntary 10-year program whereby PG&E will work with participating MHP owners and residents to install new direct service gas and/or electric utility systems parallel to existing MHP systems, and switch the MHP residents to the new utility system. The newly installed systems up to and including the meter, will be owned and operated by PG&E.	Electric; Gas	Electric Distribution; Gas Distribution
	Q1 2013									
11	ERRA Compliance	A.13-02-023	Feb 28, 2013	2014	29	25 [incl.	N/A	Annual proceeding to review the utility-owned generation operations,	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	2014 RRQ *	2015 RRQ *			
	2012 (incl. MRTU and Diablo Canyon Seismic Studies)					2012 and 2013 RRQ]		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.		
12	CPIM 2012 Annual Report (Yr. 19)	N/A	May 17, 2013	TBD		N/A	5	Compliance report for gas core procurement incentive mechanism for November 1, 2011 through October 31, 2012.	Gas	Procurement
	Q3 2013									
13	Hercules Municipal Utility	A.13-07-001	July 1, 2013	2014	7.4	1	1	Application requesting authorization to recover costs associated with the acquisition and transfer of the assets of the Hercules Municipal Utility from the City of Hercules to PG&E. The acquisition and transfer of City of Hercules assets will improve safety, reliability, and provide additional benefits to existing PG&E customers, current HMU customers, and the City of Hercules. Cost and RRQ includes only the net book value adopted in Decision 14-01-009. Additional $3.6M in costs currently pending before the CPUC.	Electric	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	2014 RRQ *	2015 RRQ *			
14	GHG OIR Track I	A.13-08-003	August 1, 2013	4/1/2014	N/A	(454)	N/A	OIR evaluating proposals for implementing the return of revenues associated with auction of GHG revenues. Associated costs were addressed separately in the 2014 ERRA Application 13-05-015.	Electric	Electric Distribution; Electric; Generation
15	2015 GHG Track III	A.13-09-015	September 30, 2013	1/1/15		N/A	63	Application requesting cost recovery for Assembly Bill 32 Cap-and-Trade compliance costs for PG&E as a natural gas supplier, as well as authorization to recover a total revenue requirement for 2015 for these compliance costs and to recover future revenue requirements in subsequent years. The current ARB regulations do include revenue returns for the benefit of customers, however, the revenue return methodology will be decided with the Commission at a future date.	Gas	Gas Distribution
	Q4 2013									
16	Pipeline Safety Enhancement Plan Update (PSEP)	A.13-10-017	October 29, 2013	2014		($53) (inc. 2012 thru 2014 RRQ)	N/A	Based on new information learned from Maximum Allowable Operating Pressure (MAOP) records validation, PG&E is seeking a 125-mile reduction it its strength testing program and a 43-mile reduction in its pipe replacement program. PG&E is requesting a $53 million reduction in its authorized revenue requirement for 2012-2014.	Gas	Gas 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	2014 RRQ *	2015 RRQ *			
17	2014 FERC Rate Filing for Annual Updates to the Transmission Balancing Accounts	FERC Docket No. ER14-81-000	October 31, 2013	5/1/14		(84)		PG&E annually files with the Federal Energy Regulatory Commission (FERC) requesting a transmission rate change for its retail electric customers, in compliance with Resolution E-3930. The purpose of PG&E's FERC filing is to request the annual update to the Transmission Revenue Balancing Account Adjustment, the Reliability Services rates and the End-Use Customer Refund Balancing Account Adjustment, for an effective date on or after January 1 of each year.	Electric	Transmission
18	2015 Gas Transmission & Storage Rate Case	A.13-12-012	December 19, 2013	1/1/2015		N/A	1,286	The GT&S rate case sets the rates, terms and conditions of service for PG&E's gas transmission (backbone and local transmission) and storage business.	Gas	Backbone Transmission; Local Transmission; Storage; Customer Access Charge (CAC)
	Q2 2014									

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested / Expected Implemen-tation date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2014 RRQ *	2015 RRQ *			
19	Energy Efficiency 2015 and Beyond	R.13-11-005	TBD	1/1/2015	TBD	N/A	TBD	This Rulemaking establishes a proceeding in which to fund current energy efficiency portfolios through 2015, implement energy efficiency “Rolling Portfolios,” and address various policy issues relating to energy efficiency.	Electric; Gas	Electric PPP; Gas PPP
20	2015 DWR Revenue Requirement	TBD	TBD	1/1/2015	TBD	N/A	TBD	The DWR revenue requirement is an annual proceeding that determines the portion of DWR power purchases that will be recovered from the customers of each IOU.	Electric	Generation
21	ERRA 2015 Forecast	TBD	June 2014	1/1/2015	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
22	Demand Response /Rule 24 Cost Recovery Application	TBD	June 2014	1/1/2015	TBD	N/A	TBD	Per D.12-11-025, PG&E will file an application to request recovery of costs to implement the direct participation of Demand Response resources in CAISO wholesale markets. This application will forecast the capital and expenses that PG&E will incur, so Demand Response resources may be bid into wholesale electricity markets.	Electric	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	2014 RRQ *	2015 RRQ *			
	Q3 2014									
23	Transmission Owner 16	FERC Docket No. TBD	July 2014	3/1/2015	TBD	N/A	TBD	Annual filing to recover transmission costs.	Electric	Electric Transmission
24	2015-2017 Energy Savings Assistance Program and California Alternate Rates for Energy Application	TBD	July 2014	1/1/2015	TBD	N/A	TBD	Application seeking approval of PG&E's proposed Energy Savings Assistance (ESA) program and California Alternate Rates for Energy (CARE) administrative activities and budgets for 2015-2017. The ESA and CARE programs are statutorily established programs that provide assistance to qualifying low-income customers. Gas and Electric allocation TBD.	Electric; Gas	Electric PPP; Gas PPP
25	Energy Efficiency Risk-Reward Incentive Mechanism (RRIM) OIR	R.12-01-005	PG&E to File Tier 3 Advice Letter by Q3 2014 with Commission approval by Q4 2014 for approval of 2012 Program year Incentive Award	1/1/2015		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
	Q4 2014									

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested / Expected Implemen-tation date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2014 RRQ *	2015 RRQ *			
26	2015 FERC Rate Filing for Annual Updates to the Transmission Balancing Accounts	FERC Docket No. TBD	October 2014	1/1/2015		N/A	TBD	PG&E annually files with the Federal Energy Regulatory Commission (FERC) requesting a transmission rate change for its retail electric customers, in compliance with Resolution E-3930. The purpose of PG&E's FERC filing is to request the annual update to the Transmission Revenue Balancing Account Adjustment, the Reliability Services rates and the End-Use Customer Refund Balancing Account Adjustment, for an effective date on or after January 1 of each year.	Electric	Electric Transmission
27	2015 Public Purpose Programs Surcharge Rate Advice Letter	TBD	October 2014	1/1/2015		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
28	Transmission Access Charge Balancing Account Adjustment (TACBAA)	FERC Docket No. TBD	December 2014	3/1/2015	TBD	N/A	TBD	The TACBAA is a ratemaking mechanism designed to ensure that the difference in the amount of costs billed to PG&E as a load-serving entity and the revenues paid to PG&E as a Participating Transmission Owner under the California Independent System Operator Corporation Tariff is recovered from or returned to PG&E's End-Use customers.	Electric	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	2014 RRQ *	2015 RRQ *			
29	2015 Annual Gas True-Up (AGT) Advice Letter (Tier 2 Preview) and 2015 AGT Advice Letter (Tier 1 Final)	TBD	November 2014 and December 2014	1/1/2015		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. Supplemental filing of consolidation of gas transportation rate changes authorized by CPUC.	Gas	Distribution; Backbone Transmission; Local Transmission; Gas Storage; CAC
30	2015 AET Advice Letter and Supplemental Advice Letter filing	TBD	September 2014 and December 2014	1/1/2015		N/A	TBD	Annual filing to adjust for balancing account over/under collections, ERRA forecast and other electric proceeding decisions. 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

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

SB 695 Report

Southern California Edison Company

Year: 2014

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."

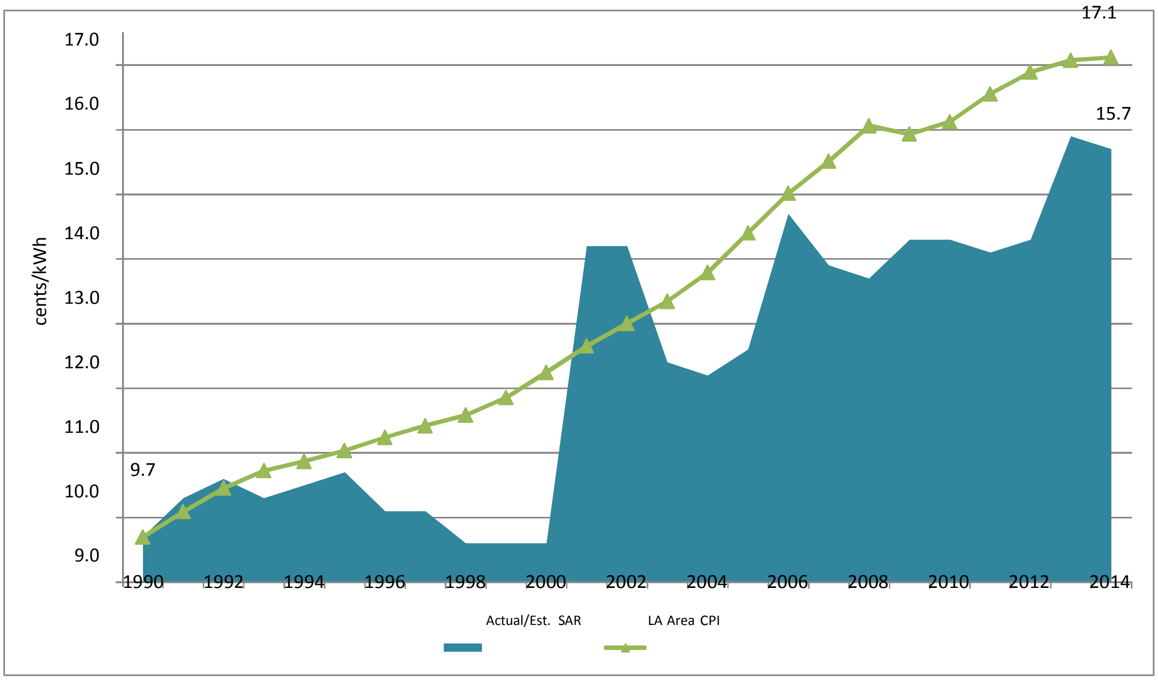
The information provided includes SCE's overall rate policy, a discussion of SCE management's policies to control costs and control rate increases for customers and, a discussion of SCE's policies and recommendations for limiting rate increases while meeting the State's energy and environmental goals 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, 2014 to April 30, 2015.

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.[1]



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

3. Management Control of Revenue Requirements

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

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

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

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

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

Market design and rules matter. In the case of AB-32 cap & trade regulations, there are elements of the market design that could result in excessive costs of the program. One danger in relying on market solutions is that if the markets are competitive, then low costs will result, but if they are subject to manipulation or generally are not competitive then high cost solutions are possible. This situation can be prevented by having effective rules and oversight. For example, if the goal of

AB-32 is to put in place a GHG reduction program that can be an example for the rest of the nation or world to follow, then we must succeed in achieving GHG reduction goals without undue costs. One very visible measure of the cost of the program will be the GHG price that results from the cap & trade market structure. Currently, there is no limit (other than an ever increasing floor price) on the price that can result from that market. Yet we know that if the price rises to too great a level, the program will not be viewed as an example to be followed, but - like California's electricity market that failed - an example to be avoided. As such, it only makes sense to design this market so as to not allow prices to rise to unreasonable levels. Yet there is no limit on prices in this market – no limit that could mitigate rate impacts and ensure that the program does not "blow up".

To minimize the rate impact of a cap & trade system 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.[2] 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.

[2] 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.

b. **<u>Cost Responsibility Surcharge</u>** – 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. **<u>New System Generation</u>** – 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. **<u>Distribution</u>** – 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 (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.[3]

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

[3] The remainder of the proceeds will be returned to residential customers through a semi-annual Climate Credit (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.

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 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 2014 is a negative $27 million. In other words, on behalf of DWR, SCE will refund $27 million to its bundled service customers in 2014 through a negative (i.e. or credit) DWR Power Charge. The DWR Bond Charge will remain at approximately $0.005/kWh in 2014.

2. Summary of Revenue Requirements by Rate Component

a. Revenue Requirements and System Average Rate for Bundled Service customers estimated as of January 1, 2014:

Rate Component	($millions	%	SAR c/kWh
Generation	5,673	47.0%	7.8
New System Generation	426	3.5%	0.5
Distribution	4,443	36.8%	5.6
Public Purpose Programs	301	2.5%	0.4
Nuclear Deccommissioning	33	0.3%	0.0
FERC Transmission	823	6.8%	1.0
DWR Power and Bond	364	3.0%	0.4
TOTAL System	12,063	100.0%	15.7

3. Sales Forecasts

The Commission adopted SCE's 2014 total sales forecast of 84,225 GWhs in D.13-10-052 (SCE's 2013 ERRA Forecast Proceeding). This represents a decrease from recorded 2012 sales of approximately 2.6%. SCE expects to file an updated sales forecast for 2014 of 84,698 GWhs on June 1, 2014, representing less than half a percent increase over 2013 sales.

2014 Outlook from May 1, 2014 to April 30, 2015

Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Dollar Amount ($millions)		Description	Impacted Rate Component
				2015 RRQ	2014 RRQ		
GRC	A.13-11-003	11/01/13	1/01/15	6,383	6,259	2015 GRC Increase in O&M and capital revenue requirement.	Generation, Distribution, and New System Generation
ERRA Forecast (Excludes GHG Cost per D.12-12-033)	Jan 2014 D.13-10-052 2015 N/A	8/01/12	4/01/14	Est. 6,060	5,157	Recovery of estimated fuel and purchased power costs (Excludes cost of GHG)	All Rate Components
2014 ERRA Forecast – GHG Costs	A.12-08-001	8/01/12	4/01/14	TBD	420	Add recovery of estimated 2014 GHG	Generation
GHG Revenue Return	D.12-12-033	8/01/13	4/01/14	TBD	(593)	Return of GHG Allowance Revenue (Some volumetrically and some to residential customers only through Climate Dividend)	Distribution and credit on bills
FERC Formula Rate Change	N/A (Advice Letter)		10/01/13	Est. 978	821		
FERC Transmission Balancing Accounts	N/A (Advice Letter)		6/01/13 and 1/01/14	TBD	2		

SB 695 Report

San Diego Gas and Electric Company

2014

SB 695 Report
To California Public Utility Commission (CPUC) *Energy Division*
San Diego Gas and Electric Company
2014

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) An outlook from May 1, 2014 to April 30, 2015 listing the pending and anticipated proceedings affecting 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 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 SDG&E and includes purchased power costs, utility-owned generation costs, and other revenue requirements linked to generating and procuring the electricity commodity.

For 2014, SDG&E's generation charge does not include a revenue requirement for the Department of Water Resources (DWR) since it is a net negative revenue requirement. The net negative revenue requirement is returned to customers as a volumetric credit which appears as a separate line item on a customer's bill. However, for reporting purposes, SDG&E will include the net negative revenue requirement in the commodity/generation category.

- 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 there are 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 reflect the cost shift that results from capped residential tiered rates previously legislated under Assembly Bill

1X and Senate Bill 695.

Relative ranges for each electric revenue requirement category as a percent of total authorized 2013 and 2014 revenue requirements 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.

	2013[1]			**2014[1]**		
Revenue Component	**Revenue Requirement $000**		**Percent**	**Revenue Requirement $000**		**Percent**
Commodity[2]	1,469,728		45.70%	1,383,807		38.68%
DWR-BC	92,518		2.88%	96,271		2.69%
CTC	60,903		1.89%	54,540		1.52%
ND	-7,142		-0.22%	9,239		0.26%
Transmission	377,486		11.74%	384,090		10.74%
RS	366		0.01%	5,410		0.15%
Distribution	1,050,251		32.66%	1,415,604		39.57%
PPP	134,719		4.19%	178,980		5.00%
TRAC	37,287		1.16%	49,622		1.39%
Total	3,216,116		100%	3,573,810		100%

[1] 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).
[2] 2014 Commodity revenue requirement includes the DWR Net Negative Revenue Requirement

1) Commodity represents 38.68% of the total revenue requirement in 2014, down from 45.70% in 2013. The key drivers in this decrease are the inclusion of the DWR credit to customers in the commodity revenue requirement and the roll-off of regulatory account balances. The DWR credit is largely the result of DWR power contracts expiring. The commodity revenue requirement is expected to increase later in the year due to the Energy Resource Recovery Account (ERRA) and Greenhouse Gas (GHG) proceedings. The key drivers behind the ERRA increases include higher gas prices, expired DWR contracts, more renewable energy, the San Onofre Nuclear Generating Station (SONGS) plant closure and the ERRA Trigger balance.

2) DWR-BC represents 2.69% of the total revenue requirement in 2014, down from 2.88% in 2013, a 0.19% decrease from last year.

3) CTC contributes 1.52% of the total revenue requirement in 2014, down from 1.89% in 2013.

4) Transmission related revenue requirements constitute 10.74% of the total revenue requirement in 2014, down from 11.74% in 2013.

5) In 2014, distribution replaced commodity as the largest component of the total revenue requirement comprising approximately 39.57% of the total revenue requirement in 2014, up from 32.66% in 2013. This increase is primarily due to increases to the electric distribution base margin.

6) PPP revenue requirements, including California Alternate Rates for Energy (CARE) Discount and Energy Efficiency, represent 5.00% of SDG&E's total revenue requirement in 2014, up from 4.19% in 2013.

7) ND and RS revenue requirements each represented less than 1% of SDG&E's total revenue requirement during 2013 and remain less than 1% in 2014.

8) TRAC was 1.16% of SDG&E's total revenue requirement in 2013 increasing to 1.39% in 2014.

This section outlines major categories of gas revenue requirements as commonly monitored within SDG&E.

Gas revenue requirements are commonly grouped into the following three major categories: Energy Costs (i.e., cost of natural gas at citygate), Transportation, and Public Purpose Programs.

	2013		**2014**	
Revenue Component	**Revenue Requirement** $000	**Percentage**	**Revenue Requirement** $000	**Percentage**
Energy	$184,872[1]	34.7%	$213,745[2]	38.1%
Transportation [3]	$321,902	60.4%	$308,951	55.1%
Public Purpose Program	$25,996	4.9%	$38,254	6.8%
Total	$532,770	100%	$560,951	100%

1 Actual recorded revenue for natural gas at citygate.
2 Represents estimates of the residential, core C&I, and NGV energy revenue and was derived by multiplying the 2012 CGR throughput projection for 2014 by the gas price forecast for 2014.
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 38.1% of the total gas revenue requirement for 2014. The revenue requirements are expected to increase from 2013 to 2014 due to forecasted higher natural gas prices. The energy revenue requirement represented about 34.7% of the total authorized gas revenue requirements in 2013.

2) Transportation revenue requirements will be about 55.1% of the total gas revenue requirement in 2014. For 2013, the transportation revenue requirement was about 60.4% of the total authorized gas revenue requirement. The decrease in relative costs is occurring for two reasons. First, the transportation revenue requirement is decreasing due to balancing accounts that are overcollected and returning funds to ratepayers.

Second, the decrease in the relative percentage of transportation revenues to total revenues is due to higher energy costs increasing forecasted gas energy revenues.

3) PPP revenue requirements, including California Alternate Rates for Energy (CARE) Discount and Energy Efficiency, will represent approximately 6.8% of the total gas revenue requirements in 2014. The revenue requirement is trending upward mainly due to increases in estimates for CARE discounts and changes in regulatory account amortizations. CARE costs are increasing due to an increase in the gas price forecast. For 2013, these programs contributed about 4.9% of the total authorized gas revenue requirements.

B. Trends in Rate Components

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

Customer sales volatility across time directly impact the rates 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 actual and forecasted sales through 2015.

SDG&E is a combined gas and electric distribution utility company serving approximately 3.5 million people in San Diego and the southern portion of Orange County, California. In 2013, SDG&E delivered 19.8 billion kWh of electricity to 1.4 million customers. Approximately 83% of sales were delivered to bundled service customers (commodity, transmission and distribution), and 18% to direct access customers (transmission and distribution only). On August 30, 2013, SDG&E's recorded peak demand was 4,604 megawatts.

Looking ahead to the next two years, electric sales are forecasted to grow from normalized 2013 by an average annual rate of 0.92%.

SDG&E Forecast of Electric Sales (GWh)

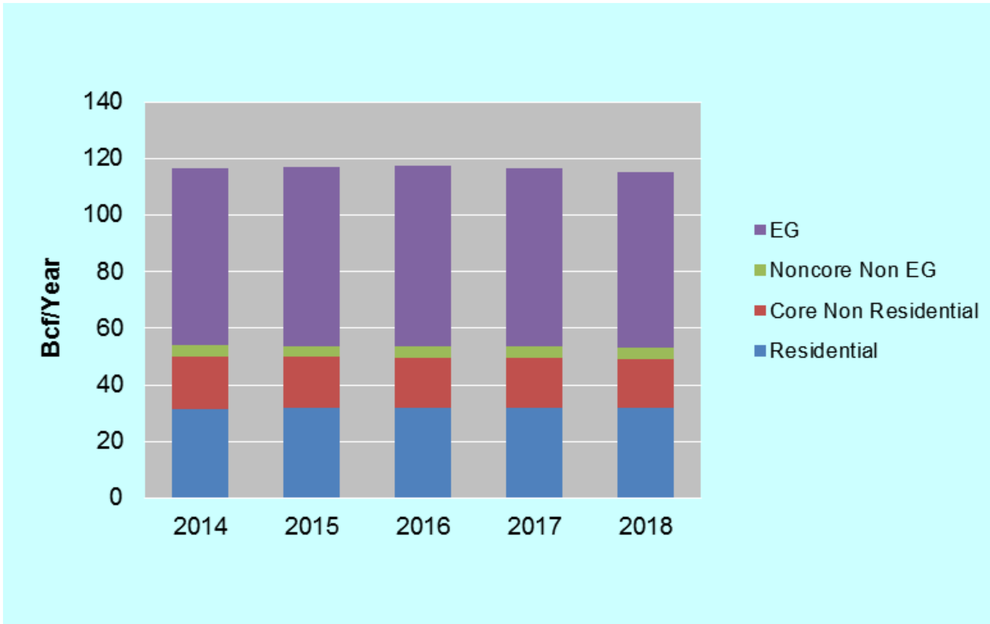
Sales in GWh	**2014**	**2015**
Residential	7,424	7,385
Small Commercial	2,016	2,047
Med & Large Com/Ind	10,232	10,374
Agricultural	322	324
Lighting	103	104
Total GWh Sales	20,097	20,234

Source: Rate Design Window Application of San Diego Gas and Electric (A.14-01-027, January 31, 2014).

Composition of SDG&E Gas Requirements (Bcf)
Average Temperature and Normal Hydro Year (2014-2018)

Bcf	2014	2015	2016	2017	2018
Residential	32	32	32	32	32
Core Non Residential	19	18	18	18	17
Noncore Non EG	4	4	4	4	4
EG	63	63	64	63	62
TOTAL	117	117	118	117	115

Composition of SDG&E's Gas Requirements (Bcf)
Average Temperature and Normal Hydro Year (2014-2018)



The table above shows the projected gas demand over the five-year period covering 2014 to 2018. Gas demand in 2014 is expected to be 117 Bcf. By 2018, gas demand is expected to decline to 115 Bcf. Based on the 2012 *California Gas Report*, the load is expected to decline at an average annual rate of 0.4%. Gas demand is expected to decline modestly in the future due to modest economic growth, CPUC-mandated energy efficiency goals and renewable electricity goals, declines in commercial and industrial demand and savings linked to advanced metering modules.

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 Southern California Gas area, reflecting a gradual recovery from the current multi-year economic slowdown.

2. May 1, 2014 to April 1, 2015 CPUC Filing Outlook

A. Outlook from May 1, 2014 to April 30, 2015 – Pending Proceedings

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

Electric Proceedings

2010 Energy Resource Recovery Account (ERRA) Compliance Application (A.11-06-003)

On June 1, 2011, SDG&E filed an application for 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). Subsequent to filing this application, the request for MRTUMA cost recovery was bifurcated to A.12-01-014, discussed below. SDG&E's cost recovery request of $2.15 million, less the $1.6 million for MRTUMA, results in a revised request of $0.55 million which represents the combined total 2010 activity of IEMA and RPSMA.

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 MRTUMA 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.

2014 ERRA Forecast Application (A.13-09-017)

On September 27, 2013, SDG&E filed an application with the CPUC for approval of its forecasted electric procurement revenue requirement for 2014, referred to as SDG&E's 2014 ERRA Application. SDG&E requested approval of a forecasted 2014 ERRA revenue requirement of $1,228.0 million, a 2014 Competition Transition Charge Revenue Requirement of $14.6 million and a 2014 Local Generation Balancing Account revenue requirement of $5.2 million, a total increase of $272.0 million from 2013 authorized 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 a revenue requirement and contribution levels for each company's nuclear decommissioning trust funds and other related issues in connection with SONGS Units 1, 2 and 3[1]. In this application, SDG&E seeks Commission approval for a revenue requirement of $16.4 million for contributions to its trust funds.

ERRA Trigger (A. 13-04-017)

On April 30, 2013, SDG&E filed its Expedited ERRA Trigger application to recover the undercollection in the ERRA balancing account. As of August 31, 2013, the balance was forecasted to be $108.5 million. SDG&E requested to recover the recorded balance known at the time of implementation of the final decision and to add the best estimate of the balancing account activity through the implementation date.

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

On October 25, 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

[1]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.

at just and reasonable rates. The potential future rate impacts, as a result, are unknown at this time.

Pio Pico Energy Center, LLC (Pio Pico) (305 MW) (A.13-06-015)

On June 21, 2013, SDG&E filed its long-term contract for approval of a new electric generation resource and cost recovery for the cost of the contract Application with the CPUC. Deliveries are expected to begin on June 1, 2017 and will remain under contract for 25 years. The total cost of this contract over the term of its life is expected to be $1,634 million. If the CPUC approves SDG&E's request, a typical non-CARE residential customer living in the inland climate zone and using 500 kWh per month could see a monthly summer bill increase of 0.7% or $0.63. The Pio Pico application was approved on February 5, 2014 in D.14-02-016.

2015 Rate Design Window (A.14-01-027)

On January 31, 2014, SDG&E file its Rate Design Window application with the CPUC asking for approval to change certain rate designs. This change may lead to rate increases for certain electric customers and decreases for certain other electric customers. The RDW Application requests no changes to gas rates and no changes to total electric and gas revenues. SDG&E requests changes to rate designs to take effect January 1, 2015. The rate design changes include the following: (1) reduce the residential baseline allowance; and, (2) change the Time-of-Use (TOU) periods for its time-variant rates and includes the implementation of mandatory TOU rates for all non-residential customers.

Residential Rate Order Instituted Rulemaking (R.12-06-013)

In October 2013, Assembly Bill 327 was signed into law. AB 327 made significant changes to residential rate structures that are permitted by removing the constraints to rate design previously legislated by AB 1X and Senate Bill ("SB") 695 while continuing to contain some limits intended to protect certain classes of vulnerable customers. Additionally AB 327 addressed CARE and Net Energy Metering reform. On October 25, 2013, Commissioner Peevey issued an Assigned Commissioner's Ruling ("ACR") inviting the Investor-Owned Utilities ("IOUs") to file applications for interim rate relief in 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 ("RROIR"), defined as Phase 2 of this proceeding. Prior to the ACR, the RROIR to date had already established in a Ruling issued on November 11, 2012, Principles for the evaluation of residential rate design. On January 28, 2014, SDG&E filed its proposal for residential rate reform now permitted under AB 327 to be implemented 2014. On February 28, 2014, SDG&E will filed its proposal for residential rate reform beginning 2015 and the roadmap to 2018.

Gas Proceedings

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

In Rulemaking (R.) 11-02-019, the CPUC issued Decision (D.) 11-06-017 and ordered all California natural gas transmission operators to develop and file for Commission consideration a Natural Gas Transmission Pipeline Comprehensive Pressure Testing 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 SDG&E jointly filed their comprehensive "test or replace" Pipeline Safety Enhancement Plan (PSEP) on August 26, 2011, as directed by the CPUC. SoCalGas and SDG&E subsequently amended their PSEP 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 April 2012, the CPUC issued a decision that transferred the SoCalGas and SDG&E PSEP to the SoCalGas/SDG&E Triennial Cost Allocation Proceeding (A.11-11-002) and phased the proceeding—such that PSEP scope and reasonableness will be considered in Phase 1 and all cost allocation issues (including PSEP cost allocation) will be considered in Phase 2.

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 sometime in 2014.

2013 Triennial Cost Allocation Proceeding (TCAP) – Phase 2 (A.11-11-002)

On November 1, 2011, SoCalGas and SDG&E filed their Triennial Cost Allocation Proceeding application, A.11-11-002, to update their gas demand forecasts, cost allocation and rate design for the 2013 through 2015 period. The utilities propose continuation of 100% balancing account treatment for noncore revenues and extension of the 2009 Biennial Cost Allocation Proceeding Phase 1 Settlement through 2015. SDG&E is also proposing a $5 per month residential customer charge. The rate impact by customer class will depend on what cost allocation is ultimately adopted by the Commission. A CPUC decision is expected sometime in 2014. Phase 2 will also address the PSEP cost allocation.

Southern Gas System Reliability Project (A.13-12-013)

SoCalGas and SDG&E filed a joint application with the CPUC in December 2013 seeking authority to recover the revenue requirement associated with the North-South Gas Transmission Pipeline Project and related cost allocation and rate design proposals. The project will support Southern System reliability and ensure the utilities' ability to fulfill their mission to provide safe and reliable gas service to their customers. The estimated $629 million project consists of three components: (1) constructing a 36-inch gas transmission pipeline between the Adelanto and Moreno compressor stations; (2) upgrading the Adelanto compressor station; and (3) constructing a 36-inch pipeline from Moreno to Whitewater. The proposed project has a projected in-service date of 4th quarter 2019. A Commission decision is not expected until 2015.

Cap and Trade Program Cost Recovery

SDG&E will file an application in 2014 to address cost recovery of greenhouse gas (GHG) costs for GHG emission allowances in compliance with AB 32's Cap and Trade Program. Costs related to greenhouse gas (GHG) emission allowances will likely be proposed to be recovered through a new line-item surcharge. The GHG costs will likely be allocated on an Equal Cents Per Therm basis consistent with the allocation for the ARB fee cost recovery. These costs are estimated to begin at around $75 million/year in 2015 and increase each year thereafter. The estimated rate impact is 2¢/therm for all end-users for which SDG&E manages their GHG allowances. SDG&E plans to manage the emission allowances, per CARB instructions, of customer's emitting under 25,000 metric tons of CO_2.

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

Master Meter Mobile Home Park Rulemaking (R.11-02-018)

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. A proposed decision was issued by the CPUC on February 11, 2014 that, if adopted, would approve a three-year pilot program to incentivize voluntary conversions. Each utility would convert approximately10% of its mobile home park spaces to direct utility service on a "to-the-meter" and "beyond-the-meter" basis. A final Commission decision in this proceeding is expected in March 2014. If the proposed decision is adopted as written, the increase in gas revenue requirements is estimated to begin at $1 million per year starting in 2015 and increase up to $5 million per year in 2018. The expected gas core rate increase is forecast to be between 0.21 and 0.93 cents per therm and gas noncore rates will increase between 0.005 and 0.03 cents per therm.

B. Outlook from May 1, 2014 to April 30, 2015 – 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>

2015 ERRA Forecast

SDG&E will file its annual application with the CPUC for approval of its forecasted electric procurement revenue requirement for 2015 on April 15, 2014.

2015 Greenhouse Gas Forecast

SDG&E will file its annual application with the CPUC for approval of its forecasted greenhouse gas costs and allowance returns for 2015 on April 15, 2014.

Combined Electric & Gas Proceedings

General Rate Case (GRC)

By July 2014, SDG&E intends to file a Notice of Intent (NOI) to file its 2016 GRC. The 2016 GRC application will be filed November 2014. The rate impact won't take effect until 2016.

C. Rate Change Implementation

The following provides the expected timing of anticipated rate changes during 2014 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 2014, we anticipate the following:

- April implementation of 2014 Greenhouse Gas (GHG) Forecast
- Summer implementation of the 2014 ERRA Forecast and ERRA Trigger
- September implementation of T04 Cycle 2 Transmission filing.

The following provides the expected timing of anticipated rate changes during 2014 and the amount of increase if it is known.

Rates are updated each year through the advice letters listed in table below.

Description	To Be Filed	Expected Implementation	Impacted Rate	Reason for Revenue Requirement Request
Gas Regulatory Account Update AL	October 2014	January 2015	Gas Transportation	(1)
Gas Consolidated AL	December 2014	January 2015	Gas Transportation	(1) (2)
Gas Public Purpose Program Update AL	October 2014	January 2015	PPP Surcharge	(1)

(1) Change from 2013 to 2014. This is a routine annual filing in which the specific financial impact for 2015 has not been determined.
(2) Gas Consolidated AL 2258-G reflecting change from 2013 to 2014.

Gas Regulatory Account Update AL - This advice letter serves to update the amounts in the regulatory accounts to be amortized in rates over the next year.

Gas Consolidated AL - This advice letter consolidates advice letters that are routinely filed each year to be placed in rates the next year. This includes items such as the regulatory Account Update, authorized cost changes for the Advanced Meter Infrastructure and attrition index authorized in the 2012 General rate Case to be applied to the revenue requirement.

Gas Public Purpose Program Update AL - 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.

San Diego Gas & Electric Company
2014 CPUC Filing Outlook
Outlook from May 1, 2014 to April 30, 2015
Appendix

Description	Filed	Expected/Requested Implementation	Status	Impacted Rate	System Average Directional Impact	Requirement Impact w/FF&U ($M)	If Revenue Requirement Impact not available Current Revenue Requirement ($M)
Pending Applications							
2010 Energy Resource Recovery Account (ERRA) Compliance Application (A.11-06-003)[1]	June 2011	Unknown	Still Pending	Electric Commodity	Increase	$ 0.6	
Joint Application for Adoption of Electric Revenues and Rates Associated with MRTU (A.12-01-014)	January 2012	Unknown	Still Pending	Electric Commodity	Increase	$ 1.6	
2014 ERRA Forecast Application (A. 13-09-017)	Sept 2013	April 2014	Still Pending	Electric Commodity, Ongoing CTC, Local Generation Charge	Increase	$ 272.0	
2012 Nuclear Decommissioning Cost Triennial Proceeding (A.12-12-013)	December 2012	Unknown	Still Pending	Nuclear Decommissioning	Increase	$ 8.3	
ERRA Trigger (A. 13-04-017)	April 2013	May 2013	Still Pending	Electric Commodity	Increase	$ 108.5	
San Onofre Nuclear Generating Station (I.12-10-013)	October 2012	Unknown	Still Pending	Electric Commodity		Unknown	$ 195.0
Pio Pico Energy Center, LLC (Pio Pico) (305 MW) (A.13-06-015)	June 2013	2018	Approved D.14-02-016	Local Generation Charge	Increase	$ 61.2	
Gas							
2013 Triennial Cost Allocation Proceeding (TCAP) - Phase 1 (Gas Pipeline Safety) (R.11 02-019)[2]	Updated September 2012	2014	Still Pending	All Transportation Rates	Neutral	$23.98 for 2015	
2013 Triennial Cost Allocation Proceeding (TCAP) – Phase 2 (A.11-11-002)[3]	November 2011	2014	Still Pending	Proposed New Surcharge	Increase	N/A	
Cap and Trade Program Cost Recovery	To be Filed 2014	2015		Proposed New Surcharge	Increase	$12 for 2016	
Combined Gas and Electric							
Master Meter Mobile Home Park Rulemaking (R.11-02-018)	August 2013	2015	Still Pending	All Transportation Rates	Increase	$1.029 for gas in 2015	
Potential Applications							
2015 ERRA Forecast	To be Filed Late 2014	April 2014		Electric Commodity			
2015 Greenhouse Gas Forecast	To be Filed Mid 2014	Jan 2015		Electric Commodity			
Gas							
Gas Regulatory Account Update AL[4]	To be Filed 2014	January 2015		Gas Transportation			
Gas Consolidated AL[4]	To be Filed 2014	January 2015		Gas Transportation			
Gas Public Purpose Program Update AL[4]	To be Filed 2014	January 2015		PPP Surcharge			

[1] Subsequent to filing this application, the request for MRTUMA cost recovery was bifurcated to A.12-01-014. SDG&E's original cost recovery request of $2.2 million less the $1.6 million for MRTUMA results in a revised request of $0.6 million.
[2] Pipeline Safety Enhancement Plan shows the Pipeline Safety Enhancement Plan revenue requirement for 2015.
[3] Cost Allocation Proceedings reallocate costs between customer classes to maintain cost-based transportation rates.
[4] This is an annual routine filing in which the specific revenue requirement impact for 01/2015 has not been determined.

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

California is the most populous state in the nation and the 8th largest economy in the world. It is fitting that California is also a national leader in innovative energy policies. California's law and policy makers have kept this state on the leading edge of new developments in the utility and energy industry, including in the areas of energy efficiency, renewable energy, greenhouse gas reduction, demand response, and the smart grid. These policies have resulted in some significant achievements. Per the Integrated Energy Policy Report, "A wide array of energy efficiency programs for utility customers has contributed to keeping energy use per person in California relatively constant, while use in the rest of the United States has increased by roughly 40 percent." California also has a 33% renewable portfolio standard, one of the most ambitious in the country, but at a significant cost. California's recognition of the transportation sectors contribution to greenhouse gas emissions has also lead to tangible outcomes. “As a result of the Alternative and Renewable Fuel and Vehicle Technology Program, California now has the largest network of electric vehicle charging systems and the largest number of hydrogen fueling stations in the country.” This great success has led to positive changes for utility customers in lower usage and our environment in reduced emissions, but has come with higher rates. In order to maintain the pace of new development and to ensure California’s future as a leader among states pushing the envelope toward a cleaner, more efficient and affordable electric system, some of the mechanics of how customers pay for electric service must change as well.

California seeks to continue to build on the past success of its energy policies. One of the means by which California seeks to accomplish this is through the state’s “Loading Order”. “The state’s Loading Order’ is a guiding policy which places energy efficiency (using less energy to do the same job) and demand response (modifying energy usage when needed for optimal grid operation) as top priorities for meeting California’s energy needs. Next, the loading order calls for renewable resources and distributed generation.” In order to maximize the benefit of the “Loading Order” and keep pace with changes caused by the “Loading Order” priorities, utility rate design must change. That is, rate design must evolve hand-in-hand with advances in energy efficiency, demand response, renewable energy and distributed generation. By updating utility rate design, the Commission can help ensure that as customers experience and live within the more modern and advanced energy world, they are provided accurate price signals that provide them with necessary information to understand the costs of a lower carbon energy supply and to make economically efficient decisions about when and how to use energy. Adoption of rate design that is more consistent with the reality of modern energy use and generation will also further the development and deployment of new low carbon technologies.

Key as we move forward to continue to meet the state goals and to continue the path to innovation, will be the ability to tie the prices customers see to the services they receive. Accurate prices are necessary for customers to understand the costs of a lower carbon energy supply and for economically efficient decision-making. The broad and universal application of rate design characterized by the following will be critical to continue on this path.

- Utilities charge for the services they provide;
- Rates are designed to recover costs on the same basis as they are incurred; and,
- Incentives or subsidies that have been deemed necessary to further public policy objectives are separately and transparently identified and charged to customers in a fair manner.

Such rate design changes will limit cost and rate increases for residential customers with greater than average usage.

B. Overall Rate Policy

In SDG&E's 2012 GRC Phase 2 (Application ("A.") 11-10-002), SDG&E identified the following policy goals to guide rate design necessary to "create a clear and smooth path forward for implementation of the state's low carbon policies":

1. Create Clear and Accurate Price Signals;
2. Promote Fairness and Equity;
3. Empower and Inform Customers; and,
4. Mitigate Customer Impacts Associated with Rate Proposals.

In the November 26, 2012 Scoping Memo and Ruling in 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* ("RROIR"), 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.

While these principles are in the rulemaking for residential rate design, SDG&E supports these principles for the rate design applied to all customers. In SDG&E's May 29, 2013 RROIR proposal, SDG&E identified Optimal Residential Rate Design to meet the following criteria:

- Utilities charge for the services they provide;
- Rates are designed to recover costs on the same basis as they are incurred; and,
- Incentives or subsidies that have been deemed necessary to further public policy objectives are separately and transparently identified and charged to customers in a fair manner.

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

SDG&E's rate components can be broken down into the following broad categories of services that they provide:

- Generation service: provision of energy service, including reliability and ancillary services. The costs associated with generation services are in addition to the costs of providing energy services to meet customer load are heavily compliance driven - both legislative compliance (i.e., RPS) and regulatory compliance from various regulatory agencies (i.e., GHG under ARB).
- Transmission service: provision of system delivery and reliability. These costs are addressed at the Federal Energy Regulatory Commission (FERC).
- Distribution services: provision of local delivery and reliability and customer services.

- Public Policy programs.

Additionally power quality requires the coordination of distribution, transmission and generation resources.

Being a regulated utility, all changes to revenues recovered through rates or the recovery structure through which revenues are collected is subject to the authority of the CPUC or the Federal Energy Regulatory Commission (FERC). Rate increases are a necessary consequence of the State's policies to reduce usage through energy efficiency and increase costs through a myriad of mandates to achieve a low carbon energy supply. A rate structure that accurately reflects cost of service will be necessary to limit unintended consequences, such as hidden cost shifts between different customer groups. Sending accurate price signals will allow customers to understand the costs of a low carbon energy supply and make economically efficient decisions which can lower costs for all customers by reducing the need to build additional infrastructure.

In addition, SDG&E rates in have recently experienced volatility associated with regulatory balances, in particular balances associated with SDG&E's Energy Resource Recovery Account (ERRA). SDG&E's current regulatory mechanism to address balances in excess of the trigger threshold amounts is through a trigger application that has created rate volatility. SDG&E hopes to reduce the rate volatility by moving the ERRA application to April 15 from October 1 in order to get a timely decision and avoid triggers.

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

SDG&E recommends a rate design for all customers, where

- Utilities charge for the services they provide;
- Rates are designed to recover costs on the same basis as they are incurred; and,
- Incentives or subsidies that have been deemed necessary to further public policy

objectives are separately and transparently identified and charged to customers in a fair manner, be applied to all customers and for the implementation of all programs to ensure customers' continued support of the State's policy goals with full recognition of the costs of these programs.

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

The expected rate increases in the near future are the result of mandates adopted to reduce GHG emissions. Multiple, often conflicting, mandates are an inefficient way to reach a target. Each mandate increases costs compared to allowing more flexibility for utilities to meet the specific goal. A more flexible approach to meeting the goal could reduce utility costs and rates.

SDG&E recommends that the rate design described above be applied to all customers and for the implementation of all programs to ensure continued support of the State's policy goals.

Under AB 327, the Legislature has made significant strides in allowing for movement towards such a rate design. Removal of the legacy caps to residential Tier 1 and Tier 2 rates, allows for the ability to move away from a rate design that has resulted in a current highest upper tier rate of approximately 75% higher than the class average cost of service and shielding many customers from the costs of California's GHG reduction programs. Allowing fixed charge recovery for fixed costs, allows for movement towards a rate design that begins to recover costs on the same basis as they are incurred for residential customers. Moving CARE subsidies out of rate design into a line item discount provides for greater transparency regarding the effective discount CARE customers receive while ensuring that CARE customers continue to receive the same price signals as other residential customers. A key benefit of transparent incentives is the ability to achieve CA policy objectives at a lower cost. By combining accurate pricing with an incentive, to the extent one is necessary, tied to the market price of a technology that meets a CA policy objective, the incentive can be right sized to both ensure the policy is met without overspending to achieve that policy.

The legislation and Governor have provided the opportunity for a rate design that better supports the state's goals and initiatives. The CPUC in the RROIR has developed principles to guide implementation of rate reform.

SB 695 Compliance Report

Southern California Gas Company

2014

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

Southern California Gas Company
2014

Southern California Gas Company (SoCalGas) appreciates the opportunity, pursuant to Senate Bill (SB) 695 and Cal. Pub. Util. Code §748 (PUC Section 748), to recommend 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. Within the framework approved by the California Public Utilities Commission (CPUC or Commission) 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. SoCalGas' objective in developing the 2014 report is to provide useful information that the CPUC may consider as it prepares its annual report for the Governor and Legislature.

This report is structured according to the Energy Division's request. Part I of this report addresses PUC Section 748 (a) and provides a description of SoCalGas' gas revenue requirements and rates as well as the outlook of anticipated rate changes from May 1, 2014 through April 30, 2015, and the amount of the change if it is known.

Part II of this report addresses PUC Section 748 (b) and provides 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.

I. Section 748 (a) Study and Report

1. Description of Revenue Requirements

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.

Major Categories of Revenue Requirements				
	2013		**2014**	
	Revenue Requirement $000's	**Percent of Total**	**Revenue Requirement $000's**	**Percent of Total**
Energy [1& 2]	$1,348,303	36%	$1,500,962	38%
Transportation [3]	$2,122,016	55%	$2,202,326	54%
Storage [4]	$29,699	1%	$30,516	1%
Public Purpose Program	$319,252	8%	$287,905	7%
Total	$3,789,570	100%	$3,991,193	100%

[1] 2013 is actual recorded revenue.

[2] 2014 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 2014 by the gas price forecast for the year 2014.

[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 allocated costs to be recovered from the Unbundled Storage Program

B. Trends in Gas Revenue Requirements 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 38% of the total gas revenue requirement in 2014. In 2013, gas energy revenue requirements represented about 36% of the total authorized gas revenue. The revenue requirements are expected to increase from 2013 to 2014 due to forecasted higher natural gas prices.

2) Transportation revenue requirements are estimated to be about 54% of the total gas revenue requirements in 2014. For 2013, the transportation revenue requirement was about 55% of the total authorized gas revenue requirement. The revenue requirement increase for 2014 was due primarily to the attrition mechanism authorized in SoCalGas' General Rate Case, an authorized increase in the revenue requirement for the Advanced Meter project, and increases in the amortizations of regulatory accounts. Despite the increase, transportation revenues are slightly decreasing as a percentage of total gas revenues due to forecasted increases in gas energy revenues.

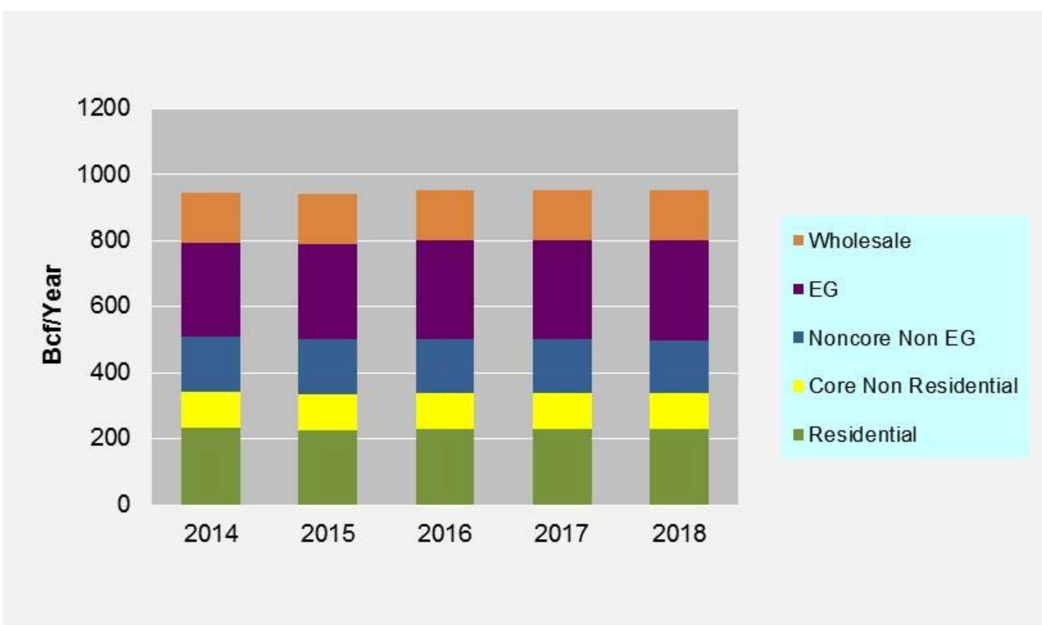
3) Costs allocated to the unbundled storage program comprised approximately 1% of the total revenue requirement in 2013, and this level is forecasted to remain relatively unchanged in 2014.

4) Public Purpose Program (PPP) revenue requirements, including California Alternate Rates for Energy (CARE) Discount and Energy Efficiency, will represent approximately 7% of the total gas revenue requirements for 2014. For 2013, these programs comprised about 8% of the total authorized gas revenue requirement. This decrease is occurring because decreases in the amortizations of regulatory accounts related to PPP are reducing the PPP revenue requirement and because increases in gas prices are causing PPP revenues to decrease as a percentage of total gas revenues.

C. Demand Forecasts

This section outlines major categories of gas demand and the load forecast through 2018.

Composition of SoCalGas' Requirements (Bcf/Year)
Average Temperature and Normal Hydro Year (2014-2018)



SoCalGas Demand Forecasts (Bcf/Year)
Average Temperature and Normal Hydro Year (2014-2018)

Bcf	2014	2015	2016	2017	2018
Residential	233	227	229	229	230
Core Non Residential	109	109	109	109	109
Noncore Non EG	167	165	164	162	160
EG	286	288	298	299	301
Wholesale	152	153	154	153	152
TOTAL	947	942	954	953	952

The table above shows the projected gas demand over the five year period covering 2014 to 2018. Gas demand in 2014 is expected to total 947 Bcf. By 2018, the load is expected to have grown to 952 Bcf. Based on the 2012 *California Gas Report,* the load is expected to decline initially, rise slightly in year 2016 and then remain pretty flat thereafter. The *average,* annual rate of growth from the initial year of 2014 to the year 2018 is anticipated to be 2.2%. Gas demand is expected to be virtually flat in the future due to modest economic growth, CPUC-mandated energy efficiency goals and renewable electricity goals[3], 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.

[3] 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.)

2. Rate Outlook from May 1, 2014 to April 30, 2015

(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 2014. Ultimately, the timing and level of impact of these pending proceedings on rates will be determined by the Commission.

Listing of Pending Proceedings

	Filing Name	Proceeding Reference (e.g., application #)	Filing Date	Requested/ Expected Implementation Date	Requested $ Amount			Description	Impacted Rate
					Total Cost	2014 RRQ	2015 RRQ		
1	Amendment of Certificate of Public Convenience and Necessity for Aliso Canyon Gas Storage Facility	A. 09-09-020	9/28/2009	Late 2016/ Early 2017	$201 million	n/a	n/a	Replacement of obsolete compressors.	Core rates increase of 0.3 cents/therm upon completion.
2	Master Meter Rulemaking	R. 11-02-018	Joint Testimony 8/19/2013	2015	$142 million per Proposed Decision issued 2/11/2014	n/a	$2 million	Three-year pilot program to convert approx. 10% of MHP spaces to direct utility service at ratepayer expense.	Residential Rate increase $0.0006/therm Core C&I rate increase $0.0004/therm Noncore rate increases $0.00003/therm.
3	2013 Triennial Cost Allocation/ Pipeline Safety Enhancement Plan Proceeding- Phase 1	R. 11-02-019	Filed 8/26/2011 amended 12/2/2011 updated 9/18/2012	2014	$1,675 million for Phase 1A at SoCalGas	$162 million /year	$179 million / year	In response to the OIR regarding gas pipeline safety, SoCalGas filed a proposed Pipeline Safety Enhancement Plan (PSEP).	Residential bills may increase from $1.79/month to $2.91/month Core C&I rates may increase $0.020/therm to $0.033/therm.
4	2013 Triennial Cost Allocation/ Pipeline Safety Enhancement Plan Proceeding – Phase 2	A. 11-11-002	11/1/ 2011	2014	n/a	n/a	n/a	Cost Allocation Proceedings reallocate costs between customer classes to maintain cost-based transportation rates.	Core transportation rates decrease 1.1¢/therm noncore rates decrease 0.7¢/therm.

Listing of Pending Proceedings									
	Filing Name	Proceeding Reference (e.g., application #)	Filing Date	Requested/ Expected Implementation Date	Requested $ Amount			Description	Impacted Rate
					Total Cost	2014 RRQ	2015 RRQ		
5.	Southern Gas System Reliability Project	A.13-12-013	12/20/13	2019	$629 million	n/a	n/a	Authority to collect in customer rates $629 million to construct North/South Pipeline project to enhance the reliability of the southern portion of SoCalGas' natural gas system.	Core transportation rate increase for residential customers of 1.2% for SoCalGas.
6.	GCIM Year 19 Application	A. 13-06-013	6/14/2013	2014	$5.8 million	$5.8 million	n/a	Authority to collect GCIM reward for gas purchases between April 1, 2012 and March 31, 2013.	Core rates increase $0.002/therm.

The following is a short summary of the requested amount of revenue requirement change for each of the above pending proceedings and the reasons for it.

1) SoCalGas Aliso Canyon Storage Field Compressor Replacement Project

On September 28, 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 obsolete gas turbine compressors with three electric compressors. The project, when completed, is expected to expand storage injection capacity by 145 million cubic feet per day (MMcf/d).

A CPUC decision was issued in November 2013 authorizing the project subject to a cost cap of $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.

2) Master Meter Rulemaking

The Commission opened a new rulemaking (R.11-02-018) 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. A proposed decision was issued by the CPUC on February 11, 2014 that, if adopted, would approve a three-year pilot program to incentivize voluntary conversions. Each utility would convert approximately10% of its mobile home park spaces to direct utility service on a "to-the-meter" and "beyond-the-meter" basis. A final Commission decision in this proceeding is expected in March 2014. If the proposed decision is adopted as written, the increase in revenue requirements is estimated to begin at $2 million per year starting in 2015 and increase up to $21 million per year in 2018. The expected core rate increase is forecast to be between 0.04 and 0.40 cents per therm and noncore rates will increase between 0.003 and 0.03 cents per therm.

3) 2013 Triennial Cost Allocation/ Pipeline Safety Enhancement Plan Proceeding-Phase 1

In Rulemaking (R.) 11-02-019, the CPUC issued Decision (D.) 11-06-017 and ordered all California natural gas transmission operators to develop and file for Commission consideration a Natural Gas Transmission Pipeline Comprehensive Pressure Testing 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 SDG&E jointly filed their comprehensive "test or replace" Pipeline Safety Enhancement Plan (PSEP) on August 26, 2011, as directed by the CPUC. SoCalGas and SDG&E subsequently amended their PSEP 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 April 2012, the CPUC issued a decision that transferred the SoCalGas and SDG&E PSEP to the SoCalGas/SDG&E Triennial Cost Allocation Proceeding (A.11-11-002) and phased the proceeding such that PSEP scope and reasonableness will be considered in Phase 1 and all cost allocation issues (including PSEP cost allocation) will be considered in Phase 2.

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 sometime in 2014.

4) 2013 Triennial Cost Allocation/ Pipeline Safety Enhancement Plan 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. 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 sometime in 2014. Phase 2 will also address the PSEP cost allocation.

5) Southern Gas System Reliability Project

SoCalGas and SDG&E filed a joint application (A.13-12-013) with the CPUC in December 2013 seeking authority to recover the revenue requirement associated with the North-South Gas Transmission Pipeline Project and related cost allocation and rate design proposals. The project will support Southern System reliability and enhance the utilities' ability to fulfill their mission to provide safe and reliable gas service to their customers. The estimated $629 million project consists of three components: (1) constructing a 36-inch gas transmission pipeline between the Adelanto and Moreno compressor stations; (2) upgrading the Adelanto compressor station; and (3) constructing a 36-inch pipeline from Moreno to Whitewater. The proposed project has a projected in-service date of 4th quarter 2019. A Commission decision is not expected until 2015.

6) Gas Cost Incentive Mechanism (GCIM) Year 19

On June 14, 2013, SoCalGas filed its GCIM Year 19 application (A.13-06-013) with the CPUC requesting approval of a shareholder reward of $5.8 million for its Year 19 performance. During GCIM Year 19, SoCalGas was able to purchase gas at $34.7 million below the GCIM benchmark. The performance rewards shareholders and ratepayers for purchases below the GCIM benchmark.

(B) **New Proceedings Likely to be Filed Between Now and April 30, 2015**

GCIM Year 20

SoCalGas will file its GCIM Year 20 application in June 2014. SoCalGas is required to file an application and report in June of each year to address its performance under the GCIM for the previous April 1- March 31 period (GCIM Year).

Cap and Trade Program Cost Recovery

SoCalGas will file an application in 2014 to address cost recovery of greenhouse gas (GHG) costs for GHG emission allowances in compliance with Assembly Bill (AB) 32's Cap and Trade Program. SoCalGas may propose to recover these costs through a new line-item surcharge. The GHG costs will likely be allocated on an Equal Cents Per Therm basis consistent with the allocation for the California Air Resources Board (ARB) fee cost recovery. These costs are estimated to begin at around $75 million/year in 2015 and increase each year thereafter. The estimated rate impact is 2¢/therm for all end-users for which SoCalGas manages their GHG allowances. Per ARB regulations, SoCalGas plans to manage the emission allowances of customers emitting under 25,000 metric tons of carbon dioxide (CO_2) emissions per year.

General Rate Case (GRC)

By July 2014, SoCalGas intends to file a Notice of Intent (NOI) to file its 2016 GRC. The 2016 GRC application will be filed November 2014. The rate impact won't take effect until 2016.

(C) **Anticipated Rate Changes During 2014**

Rates are updated each year through the advice letters listed in table below.

Anticipated Rate Changes During 2014						
Description	**To Be Filed**	**Expected Implementation**	**Impacted Rate**	**Directional Impact**	**Revenue Requirement Impact $millions**	**Reason for Revenue Requirement Request**
Gas Regulatory Account Update AL	October 2014	January 2015	Gas Transportation	Increase	$19	(1)
Gas Consolidated AL	December 2014	January 2015	Gas Transportation	Increase	$80	(1) (2)
Gas Public Purpose Program Update AL	October 2014	January 2015	PPP Surcharge	Decrease	($31)	(1)

(1) Change from 2013 to 2014. This is a routine annual filing in which the specific financial impact for 2015 has not been determined.
(2) Gas Consolidated AL 4586 reflecting change from 2013 to 2014.

Gas Regulatory Account Update AL - This advice letter serves to update the amounts in the regulatory accounts to be amortized in rates over the next year.

Gas Consolidated AL - This advice letter consolidates advice letters that are routinely filed each year to be placed in rates the next year. This includes items such as the regulatory Account Update, authorized cost changes for the Advanced Meter Infrastructure and attrition index authorized in the 2012 General Rate Case to be applied to the revenue requirement.

Gas Public Purpose Program Update AL - 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 and is $102.4 million in 2014.

II Section 748 (b) Study and Report

1. Opening comments

In this part, SoCalGas addresses PUC Section 748 (b) and provides 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.

2. Overall Rate Policy

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, stability, and safety. 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 that are publicly available 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. Also, 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 and CPUC requirements. 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 has also received regulatory approval to participate in the development of renewable energy sources, such as biogas, that will reduce GHG emissions in California.

Biogas and renewable energy resources provide environmental benefits and are useful alternatives to contracting for capacity on interstate pipelines.

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

REVENUE REQUIREMENT AS OF 1/1/14 $ millions			
	Core	**Non-Core**	**Total**
Energy Efficiency	$48	$4	$52
Low Income Energy Efficiency	$121	$0	$121
CARE	$68	$34	$102
RD&D	$11.5	$0.5	$12

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 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: The draft amendments to the AB32 Cap and Trade Regulation include a free allocation of allowances to natural gas suppliers on behalf of their residential and small commercial customers. SoCalGas supports this amendment to the regulation as it will help mitigate the rate impact to customers of the Cap and Trade program. ARB has indicated that they expect final approval of the proposed amendments in 2014. The allocation is based on 100% of 2011 emissions and includes the application of the cap adjustment factor listed in the Regulation. In addition, natural gas suppliers are required to consign 25% of their allocation at ARB auctions in 2015. This percentage increases 5% a year to 50% in 2020. Revenue from the consigned allowances will be returned to customers in a manner to be determined by the CPUC.

2. Combined Heat and Power (CHP): CHP reduces overall energy use by using waste heat to generate power. Efficient CHP entails low carbon generation and its widespread use will have greenhouse gas reducing benefits. Both the CPUC and the Energy Commission have supported the development of CHP to meet California's energy needs. Because this source has the potential to contribute substantially to reducing California's Greenhouse Gas Emissions.[4] SoCalGas supports policies and programs that encourage the installation of CHP.

3. Recommend that State policy regarding the promotion of renewable energy to generate electricity does not overlook the benefits of fuel cell technology. Fuel cell technology allows for more reliable generation of electricity. A State policy promoting this use at the residential level for the generation and water heating has the potential for significant emission reductions.

4. Recommend that flexibility be given to utilities in their energy efficiency and greenhouse gas programs in order to respond quickly to customer and market demands. The regulatory application process could expedite the launch of new products and services (such as Biogas and Compression Services). By authorizing more limited market or technology applications and pilot programs an expedited decision process may be achieved.

5. 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.

6. California Alternative Rates for Energy (CARE): CARE customers now comprise one quarter of SoCalGas' residential volume. Non-CARE customers must cover the CARE

[4] 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.

shortfall, which is 6% of transportation costs. Safeguards should be taken to ensure only qualified customers are participating in the program.

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 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.