California Public Utilities Commission

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

May 2015

INTRODUCTION

The California Public Utilities Commission (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.

The CPUC does this principally by regulating investor-owned electric and natural gas utilities in 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 investor-owned utilities (IOUs or utilities) serve over two-thirds of total electricity demand and over three-quarters of natural gas demand throughout California.

This report is published in accordance with the mandate of Public Utilities Code Section 748. Generally, Section 748 requires the CPUC to publish a report that contains its 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. Section 748 also requires the CPUC to direct the IOUs to report on measures that the IOUs recommend be taken to limit cost and rate increases. A summary of the IOU recommendations are included at the end of this report, as well as hyperlinks to the full IOU reports on the CPUC website.

The 2015 edition of the Section 748 report is hereby submitted by the CPUC to the Governor and Legislature.

Highlights of CPUC Actions that Impact Utility Cost and Rate Increases

Implementing Assembly Bill 327 (Perea, 2013)

Several CPUC actions in the next 12 months are geared toward implementing Assembly Bill (AB) 327 (Perea, 2013). This bill, codified in various Public Utilities Code (PU Code) sections, mandates that the CPUC implement or consider several important changes to California's electricity rate structure. These changes include:

- Revising the Net Energy Metering (NEM) statute to specify the maximum program capacity for customers in IOU service areas, and requiring the CPUC to develop a new NEM program by July 2015 and establish a transition to the new NEM program by 2017[1]
- Providing the CPUC with authority to require IOUs to procure renewable energy generation above that which is required in the 33% Renewable Portfolio Standard[2]
- Authorizing, but not requiring, the CPUC to approve fixed monthly charges no greater than $10 for residential customers and $5 for low-income customers beginning in 2016[3]

[1] PU Code Sec. 2827.1.
[2] PU Code Sec. 399.15.
[3] PU Code Sec. 739.9.

- Specifying that electricity rate discounts for low-income customers are not to exceed 30% to 35% of the average non-low-income customer[4]
- Authorizing default time-of-use electricity rates for ratepayers by 2018, and establishing provisions to protect seniors or other vulnerable customers, in hot climate zones, from unreasonable hardship[5]

Residential Rate Reform

As noted above, AB 327 authorizes the CPUC to approve a residential electricity rate structure that more closely reflects the cost to provide energy while maintaining affordability for low-income and other protected classes of ratepayers, and promoting conservation. On April 21st, 2015 an administrative law judge issued a proposed decision in this proceeding (Rulemaking (R.) 12-06-013) to implement a new electricity rate structure.

Net Energy Metering (NEM)

Implementation of AB 327 provisions related to NEM is expected to have an impact on rates. Specifically, the extent to which non-NEM customers bear the costs of NEM will be subject to CPUC review. In passing AB 327, the Legislature granted the CPUC 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 CPUC to balance the ratepayer costs of the program with the need to maintain a growing and sustainable distributed generation industry. The CPUC opened R.14-07-002, to consider changes to the California's NEM program.

Interagency Coordination Regarding Energy Efficiency Impacts on Grid Planning

The CPUC, the California Energy Commission (CEC) and California Independent System Operator (CAISO) have increased their inter-agency cooperation in order to more effectively follow the "loading order," which prioritizes demand side resources over new fossil fuel generation in generation and transmission planning. As demand-side resources are better accounted for in forecasting and grid planning processes, it is expected that fewer new supply-side resources will be authorized than otherwise would have, decreasing transmission and generation revenue requirements and, in turn, rates.

Continue Progress on the Bidding of Demand Response into Wholesale Markets

The active bidding of Demand Response (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 continue their efforts to bid their own DR resources into wholesale markets (SCE is anticipated to bid the majority of its DR portfolio in summer 2015). In March 2015 the CPUC approved funding for utility technology platforms and business processes that enable bidding of DR into wholesale energy markets by third party demand response providers and large end use customers starting in 2016.

Review of IOUs' Bid Selection Criteria and of RPS Procurement Standards of Review

Through D.14-11-042 the CPUC has implemented a number of changes to the standard of review (SOR) for renewable power purchase agreements (PPA) that are submitted to the CPUC for approval. This reflects an effort to streamline the RPS contract review process to facilitate three objectives; 1) decrease the cost of

[4] PU Code Sec. 739.1.
[5] PU Code Sec. 745.

renewable procurement, 2) establish clearer standards for utility procurement, and 3) refine the CPUC's approval process for RPS contracts.

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

Caveat on CPUC Recommendations

This report describes the policies previously recommended or chosen by the CPUC to limit utility cost and rate increases while addressing the state's energy and environmental goals. In doing so, this report often describes open CPUC proceedings that may impact future cost and rate increases.

The greatest challenge in developing this report as mandated by Section 748 is the fact that the content and recommended actions for limiting utility costs is necessarily limited by the deliberative process at the CPUC. Formal CPUC decisions must be based on evidence presented by the parties involved in a proceeding before the Commission. Therefore, this report must avoid the prejudgment of issues that are the subject of open cases, as doing so could interfere with due process.

Due process requires the CPUC to refrain from offering recommendations on issues that are currently being deliberated before it. For example, the proceeding dealing with retail rate reform will doubtless impact customer rates for electricity in the next 12 months. While this report summarizes the issues and policy alternatives considered in that proceeding, there are no recommendations offered here on how the proceeding should be resolved as it is still pending before the Commission.

Structure of the Report

This report consists of four main parts. First, the report discusses the IOUs' annual proposed or recently adopted costs to provide service. The CPUC reviews these costs in General Rate Case (GRC) and Energy Resource Recovery Account (ERRA) proceedings. This section provides a snapshot of the scope and financial implications of these IOU cost 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 safe, reliable, and least-cost electricity strategies, and to advance California's environmental and public purpose goals. Third, the report addresses natural gas utility operational costs and rates.

The final section of the report summarizes the IOU recommendations for addressing rate increases and includes hyperlinks to the complete IOU submissions detailing their future costs, demand forecasts, pending and anticipated proceedings, and recommendations to limit costs and rate increases.

CONTENTS

GLOSSARY OF ACRONYMS

AB	Assembly Bill	**NEM**	Net Energy Metering
CAISO	California Independent System Operator	**O&M**	Operations and Maintenance
CARE	California Alternate Rates for Energy	**ORA**	Office of Ratepayer Advocates
CEC	California Energy Commission	**PAC**	Program Administrator Cost
CPUC	California Public Utilities Commission	**PG&E**	Pacific Gas & Electric
CSI	California Solar Initiative	**PPP**	Public Purpose Program Charge
CTC	Competition Transition Charge	**RAMP**	Risk Assessment Mitigation Phase
DAWG	Demand Analysis Working Group	**RPS**	Renewables Portfolio Standard
DG	Distributed Generation	**S-MAP**	Safety Model Assessment Proceeding
DR	Demand Response	**SB**	Senate Bill
ERRA	Energy Resource Recovery Account	**SCE**	Southern California Edison
FERC	Federal Energy Regulatory Commission	**SDG&E**	San Diego Gas & Electric
GHGs	Greenhouse Gases	**SoCalGas**	Southern California Gas
GRC	General Rate Case	**SONGS**	San Onofre Nuclear Generating Station
IOU	Investor-Owned Utility	**TRC**	Total Resource Cost
ND	Nuclear Decommissioning Charge		

ELECTRIC UTILITY COSTS AND REVENUE REQUIREMENTS

The "Revenue Requirements" of the IOUs

Utilities file detailed descriptions of the costs of providing service (commonly referred to as "revenue requirements") in various proceedings and request the CPUC to approve these costs. 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 a utility's revenue requirement is requested in General Rate Cases (GRCs) and 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).

Total Authorized Electric Revenue Requirements effective January 1, 2015
($ Million)

PG&E	SCE	SDG&E
$13,567[6]	**$12,513**[7]	**$3,308**[8]

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. As noted above, the GRC application is meant to address the costs of utility-owned generation and distribution infrastructure.

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 (Wright, 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.

[6] PG&E Advice Letter 4484-E-A, filed 12/31/14.
[7] SCE Advice Letter 3155-E, filed 12/24/14.
[8] SDG&E Advice Letter 2685-E, filed 12/30/14, does not reveal this total number on its face, but worksheets accompanying the transmittal of the letter to the CPUC reveal this total revenue requirement for 2015.

A more detailed description of how utility revenue requirements are established can be found in the 2015 AB 67 Report, available on the CPUC website.[9]

Activities and Proceedings in the Next 12 Months

Electricity General Rate Cases

The major cost components reviewed and determined in the GRCs include operations and maintenance, depreciation, return on rate base, and taxes. The revenue requirements for 2015 authorized by the CPUC in recent GRCs for the three major utilities are listed below.

2015 Authorized Electric General Rate Case Revenue Requirements
($ Million)

	PG&E[10]	SCE[11]	SDG&E[12]
Operations and Maintenance	$2,052	$2,272	$658
Depreciation	$1,525	$1,222	$274
Return on Rate Base	$1,356	$1,465	$300
Taxes	$709	$712	$207
Attrition (for years up to 2015)[13]	$250	$478	$120
Total	**$5,892**	**$6,149**	**$1,559**

[9] Available online at: http://www.cpuc.ca.gov/NR/rdonlyres/A87AF775-6CBF-4076-984E-08675CE39332/0/2014AB67Final.pdf.

[10] As approved by D.14-08-032 for the 2014 test year – the 2015 total includes an "attrition" adjustment for 2015 on top of the 2014 authorization. The 2015 attrition amount was revised to include the updated 2015 Uncollectible Factor, which was filed as part of Advice Letter 4540-E.

[11] As approved by D.12-11-051. Attrition increases for 2013 and 2014 are shown above, and are in addition to the original 2012 authorization.

[12] As approved by D.13-05-010 (page B5 – B6) for the 2012 test year – the 2015 total includes "attrition" adjustments for 2013, 2014 and 2015 on top of the original 2012 authorization.

[13] "Attrition" refers to the increase in revenue that is authorized for each IOU after the first year of an approved GRC. For example, PG&E's 2014 GRC includes an approved revenue total for 2014, and the 2015 revenue is determined by adding an "attrition" amount to that 2014 total.

PG&E 2014 GRC

PG&E's 2014 GRC revenue requirement was approved in D.14-08-032. PG&E received an increase of about $200 million in its electric distribution and generation revenue requirement for 2014. As shown in the table above, the CPUC authorized PG&E an electric revenue increase of $250 million for attrition year 2015 in the GRC. PG&E is expected to file its 2017 GRC in the 3rd or 4th quarter of 2015.

SCE 2015 GRC

SCE's 2015 revenue request is pending and a CPUC decision is expected in the 2nd or 3rd quarter of 2015 (A.14-06-014). SCE is requesting about $5.8 billion in revenue for 2015, which is about $350 million lower than what was authorized in 2014[14]; however, the 2015 request excludes the San Onofre Nuclear Generating Station (SONGS) revenue requirement while the current authorized amount includes SONGS.

SDG&E 2016 GRC

SDG&E filed its 2016 GRC in November 2014, requesting a $1.59 billion electric GRC revenue requirement for 2016. That request is about $31 million higher than that authorized for 2015; but like SCE, the 2016 GRC request excludes the SONGS revenue requirement while the current authorized amount includes SONGS.

Electric Fuel and Purchased Power Costs

The CPUC establishes revenue requirements for each IOU to recover costs for fuel for utility-owned power plants and to procure electricity under purchased power contracts in the annual Energy Resource Recovery Account (ERRA) forecast proceeding. The CPUC establishes an ERRA rate component based on a forecast of these fuel and procurement costs, which are passed through to customers without any mark-up or profit for the utility. Fuel and purchased power costs fluctuate with market prices.

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. The utilities' current authorized annual revenue requirements adopted in the CPUC's ERRA forecast proceedings are shown below.

Annual Electric Revenue Requirements for ERRA Costs
($ Million)

PG&E	SCE	SDG&E
$5,359 Effective December 2014	$5,983 Effective March 2015	$1,224 Effective January 2015

PG&E's ERRA

In D.14-12-053, PG&E's ERRA revenue requirement of $5,359 million was approved by the CPUC in PG&E's ERRA 2015 forecast proceeding. The CPUC expects that in June 2015 PG&E will file its ERRA application to request a fuel and purchased power revenue requirement for 2016.

[14] Since SCE's 2015 test year GRC is still pending, the authorized GRC revenue requirement shown above is what was approved by the CPUC for 2014 in SCE's test year 2012 GRC.

SCE's ERRA

In A.14-06-011, SCE has requested an ERRA revenue requirement of $5,983 million, pending approval by the CPUC in SCE's 2015 ERRA forecast proceeding. The CPUC expects that in May 2015, SCE will file its new ERRA application to request a fuel and purchased power revenue requirement for 2016.

SDG&E's ERRA

An SDG&E ERRA revenue requirement of $1,224 million was approved by the CPUC in SDG&E's 2015 ERRA forecast proceeding. The decision outlining this approval is D.15-01-004. The CPUC expects that in April 2015 SDG&E will file its ERRA application to request a fuel and purchased power revenue requirement for 2016.

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 announced in June 2013 that it would permanently shut down SONGS.

In late 2012, the CPUC opened a proceeding to consider removing the plant from SCE's and SDG&E's ratebase and to review the steam generator replacement project costs. In November 2014, D.14-11-014 ratified a settlement between SCE, SDG&E and various other parties including the Office of Ratepayer Advocates (ORA), resulting in ratepayer credits and rebates of approximately $1.45 billion. SCE and SDG&E must also stop further collection of the Steam Generator Replacement Project (SGRP) costs in rates, return all SGRP costs collected after January 31, 2012 to ratepayers, and accept a substantially lower return on other prematurely retired SONGS assets.

Ratepayers will still pay some costs, including the recovery of the undepreciated net investment in SONGS assets (e.g., Base Plant), excluding the failed SGRP. However, instead of the usual authorized rate of return, the settlement reduces shareholders' return on SONGS investments to less than 3%. The effect is that ratepayers save approximately $420 million over the ten-year depreciation period.

Changes to the Ratemaking Process

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 incorporating safety and risk management into the General Rate Case Plan.

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. In December 2014, the CPUC issued a decision which adopted a new framework by adding two procedures to the GRC process, a Safety Model Assessment Proceeding (S-MAP), and a Risk Assessment Mitigation Phase (RAMP).

The S-MAP is a consolidated triennial proceeding, beginning May 1, 2015, that will evaluate the utilities' risk assessment models and methodologies, as well as their plans for risk mitigation. CPUC S-MAP decisions will determine the appropriate risk assessment approach to be used as the basis for each utility's RAMP filing in its respective GRC.

The RAMP will provide a transparent process to ensure that the utilities prioritize safety of the public and utility employees in their GRCs. The RAMP begins in September of the year prior to each utility's GRC application filing date, when the utility will request that an investigation be initiated by the CPUC. Safety and Enforcement Division issues a report on the utility's RAMP submission and workshops are held. The RAMP concludes in the middle of the year that the utility files its GRC application, incorporating the results of the RAMP.

The CPUC also approved annual verification and reporting requirements in the December 2014 decision. The utilities shall serve two reports at the end of each year: 1) the Risk Mitigation Accountability Report will compare the utility's GRC projections of the benefits and costs of the risk mitigation programs adopted in the GRC to the actual benefits and costs, and 2) the Risk Spending Accountability Report will compare the utility's GRC projected spending for approved risk mitigation projects to the actual spending on those projects. CPUC staff will review the utilities' reports and serve reports on staff's findings on March 31 of each year.

PROGRAM-SPECIFIC PROCEEDINGS AND ACTIVITIES

In this section the CPUC's Energy Division details the program-specific proceedings and activities due to take place in the next 12 months that may have an impact on energy rates. They are organized in this section as follows:

- Resource Adequacy and Long-Term Procurement
- Rate Design
- Renewables Portfolio Standard
- Energy Efficiency
- Demand Response
- Customer-sited Generation
- CARE/Energy Savings Assistance Program
- Cap & Trade Program
- CPUC Advocacy
- Gas Utility Rates and Costs

Resource Adequacy and Long-Term Procurement

The Resource Adequacy (RA) program is a CPUC planning and procurement program to secure sufficient commitments from owners of actual, physical resources to ensure system reliability. In addition, the CPUC administers the Long Term Procurement Plan proceeding (LTPP) that oversees IOUs' procurement plans and evaluating the need for new resources.

Activities and Proceedings in the next 12 months

The various proceedings described below relate to procurement by utilities that may have an impact on rates in the next 12 months.

SCE Procurement in LA Basin (R.12-03-014)

The Track I and IV Decisions (D.13-02-015 & D.14-03-004) of the 2012 LTPP Proceeding authorized SCE to procure between 1,900 to 2,500 MW in the LA Basin. The decisions also ordered that, of the total range authorized, a minimum of 50 MW be procured from Energy Storage, a minimum of 550 MW must be procured from preferred resources[15], and a minimum of 1,000 MW must come from gas fired generation resources. On November 21, 2014 SCE submitted an application for a total of 1,882.6 MW of procurement in the LA Basin (A.14-11-012). The application includes a total of 63 contracts for both preferred and conventional supply and demand-side resources. The application includes 500.6 MW of preferred and energy storage resources with online dates ranging from 5/1/2016 to 1/1/2021. Additionally, the application includes 1,382.00 MW of conventional generation resources with online dates ranging from 5/1/2020 to 7/1/2020. The costs for these resources, if approved, will be placed into rates when SCE incurs procurement costs. The Assigned Commissioner (Florio) issued a Ruling and Scoping Memo setting forth the issues and a schedule setting evidentiary hearings in early May and opening briefs due June 3, 2015.

[15] For example, energy efficiency, demand response and renewable power.

SCE Moorpark Procurement (A.14-11-016)

The Track I decision (D.13-02-015) of the 2012 LTPP Proceeding authorized SCE to procure 215 – 290 MW in the Moorpark sub-area of the Big Creek/Ventura local reliability area to replace retiring once-through cooling plants. The costs for these resources, if approved, will be placed into rates when new generation is brought on-line, which will likely occur between 2016 and 2022. The Assigned Commissioner (Florio) issued a Ruling and Scoping Memo setting forth the issues and a schedule setting evidentiary hearings in late May and opening briefs due July 22, 2015.

2014 LTPP Proceeding (R.13-12-010)

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 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.

LSE Capacity Procurement (R.11-10-023 (now closed) and R.14-10-010)

In D.14-06-050, 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 need for flexible resources in the coming years. LSEs were required to 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. R.14-10-010 will adopt local and flexible requirements for the 2016 compliance year.

SDG&E Carlsbad Procurement (A. 14-07-009)

The Track IV Decision (D.14-03-004) of the 2012 LTPP Proceeding authorized SDG&E to procure 500-800 MW by 2022 to meet local capacity requirement stemming from the retired San Onofre Nuclear Generating Station (SONGS). The Decision requires at least 25 MW to be energy storage and at least 175 MW to be preferred resources. The Decision also allows up to 600 MW to be from any source. SDG&E has bilaterally negotiated a tolling agreement with the Carlsbad Energy Center to meet the requirement ordered in the Track IV Decision.

SDG&E submitted the Power Purchasing Tolling Agreement (PPTA) with Carlsbad Energy Center in Application (A.14-07-009) on July 21, 2014. SDG&E has not executed the PPTA and expects to do so only after CPUC approval. As proposed by SDG&E, the Carlsbad Energy Center PPTA will provide approximately 600 MW of nominal capacity from a natural gas-fired, simple cycle peaking generating facility located in SDG&E's service territory adjacent to the existing Encina Power Station in Carlsbad, California. The project will consist of six generating units utilizing GE LMS 100 technology. The expected on-line date is November 1, 2017 and is expected to provide power for 20 years.

Renewables Portfolio Standard (R.15-02-020)

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

Activities and Proceedings in the next 12 months

Review of IOUs' Bid Selection Criteria and RPS Procurement Standards of Review

Through D.14-11-042 the CPUC has implemented a number of changes to the standard of review (SOR) for renewable power purchase agreements (PPA) that are submitted to the CPUC for approval, as an effort to streamline the RPS contract review process to facilitate three objectives: 1) decrease the cost of renewable procurement, 2) establish clearer standards for utility procurement, and 3) refine the CPUC's approval process for RPS contracts.

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

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

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.[16] All three large IOUs have included in their approved 2014 RPS Procurement Plans the intent to sell excess RPS generation if it is consistent with their RPS position and provides value to ratepayers.[17] 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.

Transmission Costs

Due to the location of many of the RPS facilities and/or the generation that they add to the transmission system, projects may require significant transmission upgrades which result in costs to ratepayers. In D.12-11-016, the CPUC adopted requirements to minimize transmission upgrade costs related to RPS procurement. Specifically, the CPUC adopted the requirement that all projects bidding into the annual RPS solicitation must have at least a completed CAISO Generator Interconnection Protocol (GIP) Phase II

[16] Renewables Portfolio Standard Quarterly Report to the Legislature, 4th Quarter 2014.
[17] D.14-11-042 approved the IOUs' 2014 RPS Procurement Plans.

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.

Rate Design

In the next 12 months, it is possible that the CPUC will issue a series of decisions that will fundamentally alter how electricity is priced for residential customers. These changes, if adopted, will not affect the overall revenue collected by IOUs from residential customers; but they may modernize the *structure* of rates after a long period of distortion and stagnation resulting from the responses to the energy crisis of 2001. The changes currently under consideration are intended to better align the cost of electricity with the rates paid by residential customers, and may therefore better align rates with state policies around energy efficiency, GHG reductions and conservation.

Activities and Proceedings in the next 12 months

Residential Retail Rate Reform

Assembly Bill (AB) 327 (Perea, 2013) authorizes the CPUC to approve residential energy rate structures that more closely reflect the cost to provide energy while maintaining affordability for low-income and other protected classes of ratepayers, and promoting conservation. There are various potential rate design reforms being considered as a part of this proceeding, including a "flattening" of the current tiered rates (ie, making energy more expensive for low-usage customers and less expensive for high-usage customers), the introduction of default time-of-use (TOU) rates and a fixed charge for residential customers. The CPUC expects to issue a decision on residential rate reform in R.12-06-013 by mid-2015.

Peak Period Definitions

Beyond this residential rate reform proceeding, the CPUC is considering changes to the peak periods used by the PG&E and SDG&E in their TOU rate schedules. These changes are being considered in the various Rate Design Window (RDW) proceedings currently before the CPUC.[18] As proposed, these changes may better align peak prices for electricity with the hours of the day and year when power is most expensive for the IOUs to procure.

Implementation of Option R for commercial and industrial customers

The CPUC is currently considering a new rate option for certain PG&E commercial and industrial customers. Known as Option R, this rate will create opportunities for medium and large businesses with solar photovoltaic installations to bring their electricity rates closer to cost, and for some customers this may result in an overall rate decrease. This optional rate may become effective on June 1, 2015.

Load forecasting and rate design

The CPUC is actively researching the question of future load patterns in California. Predicting future load patterns is critical, as the current rate structure may not be designed to most efficiently meet the cost of that load. Overall rates may decline, or at least more greatly align with cost of service, if these load patterns can be predicted with accuracy, and if the predictions are used to guide future rate design.

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[18] PG&E's RDW proceeding number is A.14-11-014 and SDG&E's RDW proceeding number is A.14-01-027.

Energy Efficiency

The CPUC has a decades-long history of policy support for ratepayer investment in cost-effective energy efficiency resources. This policy directs IOUs to first satisfy their "unmet resource needs through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible."[19]
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.[20] 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.[21]

The cost-effectiveness 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. Evaluation work currently underway will provide updates to these estimates.

Activities and Proceedings in the next 12 months

In October 2014, the CPUC extended the 2013-14 portfolio cycle by appending 2015 as a third program year, with additional funding of approximately $1 billion. The resulting three-year budget of approximately $2.8 billion is $100 million less annually than the $3.1 billion budget adopted for the 2010-12 portfolio. All remaining uncommitted funds the utilities held in balancing accounts from previous years have been applied to the 2013-2015 revenue requirement, which further reduced the energy efficiency revenue requirements for the three year period relative to recent years.

2013-2015 EE Portfolio Implementation

The IOUs' 2013-2015 program budgets and portfolios address rate impacts and control costs in a number of ways. These are the highlights:

- Scale Up and Leverage Energy Efficiency Finance: The utilities are continuing the popular and successful On Bill Finance program for non-residential customers while at the same time piloting a number of statewide and local finance models that leverage private capital through a variety of financial institutions. These pilots offered by the IOUs and local governments (through Regional Energy Networks, or RENS) are intended to broaden the reach and affordability of energy efficiency measures and retrofits for commercial and residential customers. Finance programs reduce rate impacts of energy efficiency programs because some of the finance dollars used to pay for efficiency measures replace program funds that would otherwise have needed to come from rates.
- Cost Caps: In 2009, the CPUC imposed a 10% hard cap on administrative costs in order to control utility personnel and overhead costs associated with energy efficiency. The CPUC cost cap remains in place for the 2013-2015 program cycle, having reduced the IOUs' overall budget request by $167

[19] Public Utilities Code Sec. 454.5(b)(9)(C).
[20] The term "avoided costs" refers to the marginal cost avoided when a resulting decrease in demand for electric or gas services defers or avoids generation from existing or new utility supply-side investments or energy purchases in the market.
[21] The energy efficiency avoided cost calculator was adopted in D.05-04-024, and updated in D.06-06-063, D.09-09-047, and D.12-05-015.

million, and limits costs by setting additional targets to reduce "direct implementation" costs as well as review of this cost category.

Interagency Coordination Regarding Energy Efficiency Impacts on Grid Planning

The CPUC, the California Energy Commission (CEC) and California Independent System Operator (CAISO) have increased their inter-agency cooperation in order to more effectively follow the "loading order," which prioritizes demand-side resources over new fossil fuel generation in generation and transmission planning. This requires properly accounting for the impacts that energy efficiency programs have on load reduction and reflecting this in determinations of need for new electric infrastructure. In 2014:

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

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

Post-2014 Portfolio Planning Proceeding

In October 2014, the CPUC issued D.14-10-046, which appended a third year (2015) to the 2013-2014 program cycle and established portfolios and funding for this third year (2015 is also serving as "year zero" of the rolling portfolio, as 2015 programs and funding will be left in place until the earlier of either CPUC direction to revise programs and funding or the year 2025). Phase II of the proceeding (R.13-11-005) is underway in 2015 and will examine a number of issues, including more detailed guidance on the transition to a rolling portfolio and an improved understanding of balancing accounts and the use of unspent funds in subsequent program years. These reviews will continue to ensure that the energy efficiency programs deliver the maximum level of energy savings for the lowest cost.

Audits and Evaluation

The CPUC's Division of Water and Audits performs financial, management and regulatory compliance audits of the utilities' energy efficiency portfolios. All issues identified in the audits are then addressed by CPUC staff and the utilities by modifying program activities and reporting requirements, as needed. The CPUC's Energy Division also relies on the audit results to help inform the utilities' energy efficiency incentive award calculations.

In addition, the CPUC's 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. The evaluation work that covered the 2010-2012 program cycle concluded in 2014 and determined that the IOUs' energy efficiency program portfolio for the three-year period was cost-effective, with every dollar invested returning $1.04 in energy savings. The Energy Division and the IOUs are currently in the process of evaluating programs in the 2013-2015 program cycle. The Energy Division will work with the utilities to incorporate findings from these audits and evaluations into improving the 2013-2015 portfolio implementation and planning the post-2015 program design.

Demand Response

Demand response (DR) is a reduction or shift in electricity consumption by customers in response to either economic or reliability signals. Demand Response programs and tariffs help to reduce peak electricity consumption and manage demand. DR is at the top of the CPUC's "loading order," next to energy efficiency. The IOUs operate a suite of DR programs and have contracts with third-party DR providers (also known as aggregators) who offer DR incentives to end-users. In total, the IOUs have approximately 1,900 MW of DR[22], approximately the capacity of four large power plants.

Activities and Proceedings in the next 12 months

Continue Progress on the Bidding of DR into Wholesale 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 continue their efforts to bid their own DR resources in wholesale markets (SCE is anticipated to bid the majority of its DR portfolio in summer 2015). In March, the CPUC approved funding for utility technology platforms and business processes that enable bidding of DR into wholesale energy markets by third party demand response providers and large end-use customers starting in 2016.

Procurement of Additional DR in Southern California

By the end of 2015, the CPUC is anticipated to issue a decision on SCE's competitive solicitation to address long-term, local area capacity requirements in Southern California (retirement of the San Onofre Nuclear Generating Station and other power plants). The solicitations include additional demand response resources.

Demand Response Rulemaking: Continue the Push for Improved DR

The CPUC's DR Rulemaking (R.13-09-011) is focused on enhancing the role of DR in meeting the state's resource planning needs and operational requirements. Over the next 12 months, the CPUC will be focused on developing policies and guidance that will further shape two categories of DR so that they will be able to meet future needs of the grid: 1) supply resource DR (bid into ISO markets), and 2) load-modifying DR.

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.

DR Potential Study

The CPUC is expected to launch a DR 'potential study' in the spring of 2015 that will inventory different types of DR that can serve future grid needs (flexible capacity, for example) and then determine the amount of potential for those types of DR. The purpose of this study is to inform the development of DR policy goals for 2018 and beyond.

[22] This is an ex ante estimate for summer 2015.

Launch Demand Response Auction Mechanism Pilot (DRAM)

The CPUC is expected to authorize the launch of a DRAM pilot by the fall of 2015. The DRAM is intended to test a competitive auction mechanism as a new way to procuring DR capacity from third party providers. The DRAM may prove to be a more efficient means of procuring DR, as well as an effective way to increase broader participation by third party DR providers.

Customer-Sited Distributed Generation

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

The Single-Family Affordable Solar Homes (SASH) and Multifamily Affordable Solar Housing (MASH) programs provide rebates for the installation of solar PV systems on low-income properties. The SASH program provides rebates for eligible low-income home owners, while the MASH program provides rebates for eligible low-income multifamily housing. The SASH program was initially established in November 2007 in D.07-11-047 as part of the CSI Program. The MASH program was initially established in in October 2008 in D.08-10-036. Both programs were reauthorized and extended in January 2015 in D.15-01-027.

Activities and Proceedings in the next 12 months

SGIP

In late 2014, the CPUC authorized annual collections for SGIP from 2015 through 2019 pursuant to the program extension required by SB 861 (Committee on Budget and Fiscal Review, 2014). SGIP will continue to be funded at $83 million per year. The CPUC will spend 2015 conducting a program review of SGIP to incorporate the mandates of SB 861 and to consider other program modifications to further the core goals of the program, which include greenhouse gas emissions reduction and grid reliability. The CPUC expects that any program changes resulting from this review will be put into effect by January 1, 2016.[23]

CSI

Due to robust participation, most of the CSI installation rebates are no longer available, and the program's capacity goals are on track to be surpassed. The CSI program administrators have filed a motion to allow for an accelerated payment schedule for the performance-based incentive (PBI) payments, which would save the program a significant amount of administrative costs if, for example, PBI payments were to be spread over 24 months instead of 60 months. If approved, such a change would continue to reward higher performing systems with higher rebates, while passing administrative cost savings back to ratepayers.

MASH and SASH

On January 29, 2015, the CPUC adopted D.15-01-027, implementing AB 217 (Bradford, 2013), which extended the MASH and SASH programs until 2021, authorized an additional $108 million in program funding, and set a capacity goal of 50 MW of solar PV installed at low-income customer housing across both programs. The Decision also implemented new energy efficiency and job training requirements. In the coming year, the CPUC will be overseeing the implementation and roll out of the newly reauthorized programs.

[23] Pursuant to SB 861, the CPUC must update one aspect of the program, the factor for avoided greenhouse gas emissions, on or before July 1, 2015.

NEM – Implementing AB 327 (Perea, 2013)

Implementation of AB 327 provisions related to NEM is expected to have significant impacts on rates. Specifically, the extent to which non-NEM customers bear the costs of NEM will be subject to CPUC review. In passing AB 327, the Legislature granted the CPUC 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 CPUC to balance the ratepayer costs of the program with the need to maintain a growing and sustainable distributed generation industry.

California Alternate Rates for Energy (CARE) Program

The California Alternate Rates for Energy (CARE) is a low-income energy rate assistance program instituted in 1989 authorizing a discount on energy rates to households with incomes at or below 200% of the Federal Poverty Guidelines (FPG)[24]. Efforts are currently underway to implement AB 327, which became effective on January 1, 2014. AB 327 mandates that the CARE discount be adjusted to 30-35%. In the meantime, the existing structure of the 20% discount remains in effect.

For program year 2014, the CPUC approved a cumulative IOU CARE budget of approximately $1.28 billion[25], funded by ratepayers through the Public Purpose Program (PPP) Charge.

Activities and Proceedings in the next 12 months

On November 18, 2014 the four large IOUs submitted their applications for the 2015-2017 program cycle, requesting approval for a three year budget and certain modifications to the program. These applications include proposals for CARE subsidy and administrative funding, marketing, outreach and enrollment practices, among other program and policy changes. The CPUC is in the process of reviewing the applications, taking into consideration input from all stakeholders, and plans to issue a decision authorizing new budgets and program modifications sometime in the 4th quarter of 2015.

Efforts are also underway to implement AB 327, which will affect future CARE revenue requirements and/or rates. Specifically, PU Code section 739.1 requires that the average effective electric 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. The law also requires that effective excesses in existing discounts, greater than 35 percent, be reduced by a reasonable amount on an annual basis. Finally, PU Code section 382 mandates a Low Income Needs Assessment (LINA) study every 3 years which is funded with ratepayer dollars. The last LINA study was completed in 2013, requiring the next LINA study to be completed by the end of 2016. The preliminary scope of this study is under review and may address energy savings potential, energy insecurity and burden, barriers to program participation, and a review of program measures and their benefits. The final scope and budget authorization for this study will be addressed in an upcoming decision.

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[24] 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% to 20% and changed the income eligibility criteria from 150% of Federal Poverty Guidelines to 175% of Federal Poverty Guidelines.

[25] As approved in D.14-08-030.

Energy Savings Assistance (ESA) Program

The Energy Savings Assistance (ESA) program began in the 1980s as a direct install assistance program provided by the electric and gas utilities in California, and was formally adopted by the legislature in 1990 through PU Code Section 2790.

Eligible participants include those living in single-family, multi-family, and mobile homes with household incomes at or below 200% of the Federal Poverty Guidelines (FPG). The program provides weatherization measures and services including 1) Appliances: refrigerators, microwaves, clothes washers, 2) Water Conservation: water heater blankets, pipe insulation, low flow shower heads, 3) Enclosure: insulation, air/envelope sealing, weather stripping), 4) HVAC: furnace repairs/replacements, air conditioning, infiltration, 5) Lighting, 6) Energy Education, and 7) Other miscellaneous measures such as smart strips and pool pumps.

Each IOU's portfolio of measures is evaluated for cost-effectiveness during the budget application process in an effort to determine which measures should be introduced, continued or retired from the program. Beginning in 2015, the IOUs applied two new cost-effectiveness tests, the Energy Savings Assistance Cost-Effectiveness Test (ESACET) and the Total Resource Cost (TRC) test in an effort to increase the accuracy and transparency of the cost-effectiveness framework, and in turn, enable the CPUC to improve upon the bundle of measures offered in the program.

For program year 2014, the CPUC approved a cumulative IOU ESA program budget of approximately $390 million[26], funded by ratepayers through the Public Purpose Program (PPP) Charge.

Activities and Proceedings in the next 12 months

New Program Cycle

On November 18, 2014 the four large IOUs submitted their applications for the 2015-2017 program cycle, requesting approval for a three year budget and certain modifications to the ESA program. These applications include proposals for measure funding, administrative funding, new measure offerings to include additional water saving measures, enhanced marketing, outreach and enrollment practices, among other program and policy changes.

The IOUs have also proposed a budget and scope for the next Low Income Needs Assessment (LINA) study to be completed by the end of 2016. The preliminary scope of this study may address energy savings potential, energy insecurity and burden, barriers to program participation, and a review of program measures and their benefits. The CPUC is in the process of reviewing the applications, taking into consideration input from all stakeholders, and plans to issue a decision authorizing new budgets and program modifications sometime in the 4th quarter of 2015. The final scope and budget authorization for the LINA study will also be addressed in this decision.

In the meantime, the CPUC has authorized a bridge funding period for program year 2015 based on the authorized 2014 budget levels, and existing program rules. The IOUs are directed to continue to work towards delivering greater benefits to the low-income population through increased program efficiencies and collaborations efforts. This includes making improvements to better serving the multifamily sector, an

[26] As approved in D.14-08-030.

ongoing review of the overall cost effectiveness of the program, and a focus on best practices and enhancements to the existing ESA program delivery model.

Cap & Trade Program Implementation

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 participate in the California Air Resources Board's (ARB's) Greenhouse Gas (GHG) Cap-and-Trade Program, which became effective January 1, 2012.[27] The Cap-and-Trade Program requires covered entities, including electric and natural gas utilities regulated by the CPUC, to surrender allowances and offsets[28] equal to their annual GHG emissions. Electric utilities became regulated under Cap-and-Trade beginning January 1, 2013, and natural gas utilities became regulated as of January 1, 2015.

Activities and Proceedings in the next 12 months

Cap & Trade and Customer Impacts

CPUC proceeding R.14-03-003 is to determine, among other things, how natural gas utilities should use proceeds that they receive from selling Cap-and-Trade allowances that they hold on behalf of ratepayers. The current procedural schedule anticipates a decision on this issue in mid-2015.

Cap & Trade and Utility Costs

In 2015, the five regulated electric IOUs (PG&E, SCE, SDG&E, PacifiCorp and Liberty Utilities) will collectively introduce approximately $879 million in GHG costs into rates, and they will also return $1.1 billion in allowance proceeds to customers. Of all the allowance proceeds returned to electric customers in 2015, approximately 5% will be returned to "emissions-intensive and trade-exposed" (EITE) customers, 7% will be returned to small business customers, and 88% will be returned to residential customers.

Summary of the Electric IOUs' Forecast GHG Costs and Uses of Allowance Proceeds in 2015 ($ Million)

Total GHG Costs to be Recovered in 2015 Rates[29]	**$879**
GHG Allowance Proceeds to be Returned to Customers in 2015	
EITE Customer Return	($60)
Small Business Volumetric Return	($75)
Residential Volumetric Return	($400)
Revenue Distributed for the Climate Credit	($577)
Total Proceeds Returned	**($1,113)**

[27] The proceeding number is R.11-03-012.
[28] Covered entities can use offsets for up to 8% of their compliance obligation.
[29] GHG costs generally include forecast 2015 costs as reconciled with recorded 2013 and 2014 costs, plus the remaining 2013 costs to be amortized in 2015 rates. PacifiCorp and Liberty Utilities' GHG costs must be reported in aggregate, since these forecasts are confidential and cannot be disclosed by utility.

Electric IOUs' 2015 Residential Climate Credit

Utility	Semi-Annual Credit Amount ($ per household)
PG&E	$24.76
Liberty Utilities	$35.01
SCE	$29.00
Pacific Power	$141.03
SDG&E	$23.99[30]

In 2015, natural gas utilities will also incur costs to comply with ARB's Cap-and-Trade Program. CPUC D.14-12-040 granted the natural gas utilities authority to begin purchasing compliance instruments – allowances and offsets – to comply with Cap-and-Trade, but it required the utilities to defer including these costs in gas rates until the CPUC resolves a number of policy and implementation issues related to how these costs should be reflected in rates, how allowance revenue should be used, and how to ensure that large natural gas customers that are already covered under Cap-and-Trade are not double-charged for their pollution through their gas rates. Similar information about natural gas utilities' forecasted GHG costs and allowance revenue will become available as the CPUC completes this proceeding (R.14-03-003).

CPUC Advocacy for Reasonable Rates for Electric Transmission

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.

Activities and Proceedings in the next 12 months

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 2014, 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 fundamental objectives of the CPUC's advocacy role in FERC proceedings is of ensuring safety, prudence, 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

[30] SDG&E's 2015 Climate Credit is pending approval before the CPUC in A.14-04-018. This amount listed in this table has not been authorized by the CPUC.

reduced by $157.8 million[31] by the FERC in the TO rate case proceedings during 2014. Looking forward to 2015 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 2015, the pending TO rate cases at FERC are for PG&E; SCE; SDG&E; Mid-America Central California Transco, LLC; Duke American Transmission Company (DATC) Path 15; and other transmission companies.

Future Refunds to CA Ratepayers from the Energy Crisis

The Energy Crisis of 2000-2001 was a catastrophe for California, with record high prices for electricity and natural gas, combined with widespread disruptions in service to customers. The economic burden on California was enormous, and is still being paid off by utility customers through the Bond Charges assessed on all electricity users through 2022.

Fourteen years later and counting a coalition of California Parties,[32] which includes the CPUC, continue litigating claims before the Federal Energy Regulatory Commission (FERC) in order to secure refunds of excessive charges, plus interest, that were extracted by wholesale sellers into short-term spot markets run by the California Independent System Operator Corporation (CAISO), the Power Exchange (PX) as well as those markets in the Pacific Northwest. Claims remain pending against fifteen sellers. FERC divided claims for refunds in the short-term markets into three time periods, which are pending in separate litigation tracks: The Summer Period, constituting May 1, 2000 – October 1, 2000 that involved sales to CAISO/PX; the Refund Period, constituting October 2, 2000 – June 20, 2001 that also involved sales to the CAISO/PX; and the CERS Period, constituting January 18, 2001 – June 20, 2001, which overlaps in time with the Refund Period but only involves sales to the California Energy Resource Scheduling division ("CERS") of the California Department of Water Resources ("CDWR").

In 2014, the California Parties pursuing refunds received two favorable FERC decisions. In the CERS Period docket (EL01-10), an Initial Decision finding that Shell Energy North America and other sellers engaged in tariff violations in the spring of 2001 through sales to CERS, including false exports and other conduct constituting bad faith. FERC has not yet ruled on the Initial Decision but it is a significant favorable development. In the Summer Period docket (EL00-95), FERC issued Opinion 536 on November 10, 2014 that affirmed findings in the initial decision that Shell and other sellers engaged in tariff violations during the Summer Period and adopted the California Parties' proposed methodology to calculate damages.

In addition to seeking refunds on short-term transactions, the CPUC and other parties are pursuing claims against sellers who negotiated long-term power contracts with the California Department of Water Resources (DWR) in the wake of the energy crisis. Two sellers remain in this case: Shell Energy North America and Iberdrola Renewables. FERC issued an order on remand in November, 2014 establishing further procedures and setting a hearing date on the California Parties' claims on overcharges in long term contracts signed with DWR during the crisis, which exceed $1.8 billion. The CPUC is developing testimony (due in May, 2015) and preparing for hearings to commence at FERC in November, 2015.

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31 Revenue requirement reductions for the PG&E TO15 case were $32.4 million (November, 2014), for the SDG&E TO4 Cycle 1 (March, 2014) case $117.4 million, and for the Trans Bay Cable TO2 (November, 2014) case were $8.0 million.

32 The California Parties include: The California Attorney General (AG), the California Department of Water Resources (CDWR), Pacific Gas & Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E).

Despite favorable developments and the trial date for the long term contract claims, the cases will likely continue to be litigated for several more years before all appeals are exhausted and FERC could order refunds to flow. To date, no money has flowed back to ratepayers except as the result of settlement negotiations. The CPUC continues to play an important role in all of these refund cases, including litigation and efforts to reach settlements.

GAS UTILITY RATES AND COSTS

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

- **Procurement Rate**: recovers the cost of procurement of the natural gas itself,
- **Transportation Rate**: recovers the cost of the utility to deliver natural gas and provide various customer services, and
- **Gas Public Purpose Program surcharge**: 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 do not pay a procurement rate to the utility. In addition, electric generation customers are exempt from the gas PPP surcharge.

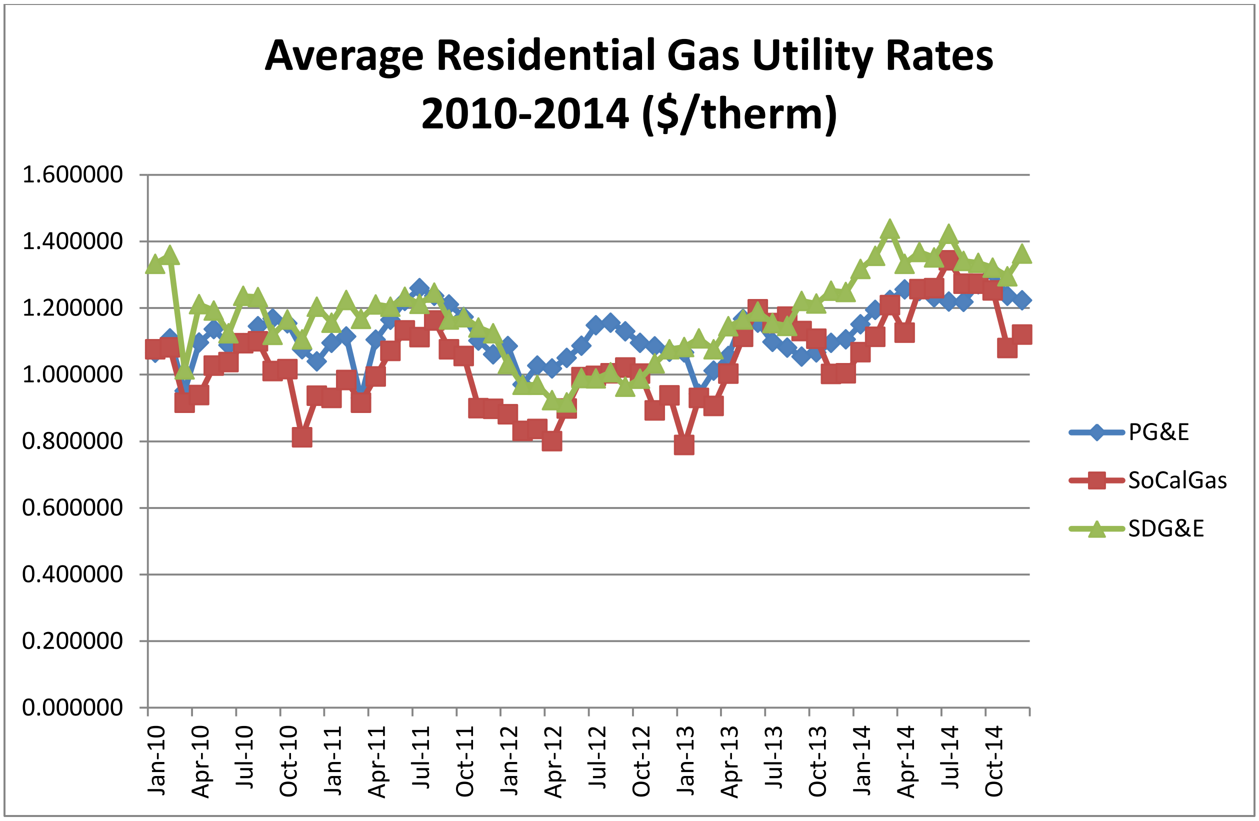
Some utility storage capacity is allocated to core customers along with the associated costs. But, storage costs are unbundled from noncore rates, and storage is an optional service for them.

Due to relatively low natural gas prices, gas utility customers continued to experience fairly stable natural gas costs in 2014. Total utility gas costs were actually slightly lower in 2014 than in 2010. 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.

CPUC-authorized gas utility costs related to the delivery and storage of natural gas and to the provision of customer services rose significantly in recent years. Gas utility operational costs rose by 35% for PG&E and by 26% for SoCalGas since 2010, and additional increases are being requested, as discussed below.

Total residential natural gas rates on average were fairly stable in the 2010-2014 time period, as shown in the following graph. But, residential gas rates did go up in 2014 compared to 2013, due to: 1) a slight overall increase in procurement costs, due to high gas prices experienced in the first half of 2014, and 2) increases in the transportation 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 remain low in the coming 12 months.

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



Approved gas PPP costs only increased by 5% during the 2010 to 2014 time period.

CPUC Actions to Limit Utility Cost and Rate Increases

As gas utility safety-related costs continue to escalate, the CPUC will be facing a significant challenge to maintain natural gas utility transportation rates at reasonable levels in the coming year. In addition, as discussed below, the major natural gas utilities have continued to propose large incremental pipeline safety costs in addition to other operational costs. If approved by the CPUC, these additional costs would further increase the utilities' transportation rates in 2015 and future years.

Gas Utility Operational Costs and Rates

During the next 12 months, in order to ensure that utility revenue requirements and rates for 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 2015.

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, as 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 ($299 million) 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 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 examined the updated PSEP in 2014, and issued a decision in November 2014. That decision approved a settlement among various parties that reduced PG&E's PSEP revenue requirement by $76 million.

In R.11-02-019, the CPUC has also been considering modifications to its General Order (GO) 112-E. Gas utilities have asserted that implementation of the proposed new requirements in a revised GO, i.e. GO 112-F, will require significant new expenditures, and have requested that the CPUC authorize balancing accounts so that new costs should be recoverable from ratepayers. The CPUC expects to issue a decision on this GO shortly.

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. The CPUC issued its decision in the TCAP in June 2014. With regard to cost allocation and rates, the CPUC authorized a rate increase of 4.6 cents per them for SoCalGas residential customers and an increase of 2.9 cents per therm for SDG&E gas residential customers.

As noted above, the CPUC examined the first phase of SoCalGas and SDG&E gas safety implementation plans in the TCAP, in 2012 and 2013. With regard to the SoCalGas/SDG&E gas safety implementation plan, in 2014 the CPUC approved the SoCalGas/SDG&E plan, but found that there was not an adequate basis to determine a forecast of reasonable costs to implement the plan. Instead, the CPUC required the utilities to submit future applications to request recovery of actual PSEP costs. (As noted below, SoCalGas submitted A.14-12-016 to request recovery of some of the PSEP costs incurred.) In addition, the CPUC found that SoCalGas/SDG&E shareholders should bear some of the costs of the plan's implementation.

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

In PG&Es 2014 General Rate Case (GRC) Application (A.12-11-009), PG&E sought CPUC approval for an increase in gas distribution revenue requirement of $446 million (34%) in 2014 relative to then-authorized amounts for 2014, and by additional amounts in 2015 and 2016. PG&E indicated that the primary reason for this increased spending was to improve gas distribution pipeline safety. The CPUC examined PG&E's

request in 2013, and issued a decision in August 2014. The CPUC adopted a revenue requirement increase of $264 million for PG&E's gas distribution department, a 20% increase.

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. The CPUC considered PG&E's proposal in 2013 and 2014 and expects to issue a decision in the spring or early summer of 2015.

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 associated with these assets 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 has been examining PG&E's proposal in 2014 and will continue its review in 2015. Hearings were conducted in February and March 2015. The CPUC expects to issue a decision in this proceeding in 2015.

Due to the necessity to examine whether PG&E violated CPUC rules related to communications with the CPUC, this proceeding was delayed by about 5 months. In a November 2014 decision, the CPUC fined PG&E $1.05 million, but also found that PG&E shareholders shall cover a significant portion of the revenues that would normally have been collected from ratepayers during the 5-month delay caused by PG&E's actions.

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 2015.

SoCalGas/SDG&E 2016 GRC (A.14-11-003/A.14-11-004)

SoCalGas and SDG&E submitted their application for their 2016 GRC in November 2014. SoCalGas states in its application that it is requesting an increase in their revenue requirement of $256 million over 2015, an increase of 12%. SDG&E states that their request would result in a $4 million decrease in revenue requirement, a 0.9% decrease. The CPUC will be considering the utilities' requests in 2015.

SoCalGas PSEP Memo Account Recovery (A.14-12-016)

As noted above, the CPUC determined in its decision A.11-11-002 that SoCalGas/SDG&E need to submit applications to recover reasonable PSEP costs. In December 2014, SoCalGas/SDG&E submitted their first such application, seeking to recover costs recorded in their PSEP Memo Account through June 12, 2014. The expenditures amount to $9.7 million in capital and $48.4 million in operation and maintenance expense. If approved, these costs would result in a 0.3 cents per therm (0.4%) rate increase for SoCalGas residential customers and a 0.2 cents per therm rate increase (0.2%) for SDG&E gas customers.

SoCalGas/SDG&E TCAP (A.14-12-017)
In the most recent SoCalGas/SDG&E TCAP application, submitted in December 2014, SoCalGas and SDG&E make some new proposals related to allocations of storage assets and to balancing rules. The utilities' proposals result in a 0.06 cents per therm rate increase (0.1%) for SoCalGas residential customers and a 0.3 cents per therm rate increase (0.3%) for SDG&E residential gas customers.

Gas Leak Rulemaking (R.15-01-008)
SB 1371 requires the CPUC to adopt rules and procedures to minimize natural gas leakage from CPUC-regulated natural gas pipelines. R.15-01-008 was initiated by the CPUC to implement SB 1371 in January 2015. It is possible that the rules and procedures adopted in R.15-01-008 will lead to additional revenue requirement increases for natural gas utilities. At this time, it is not clear which proceeding will address any need for such revenue requirement increases.

Gas Public Purpose Programs (PPPs)

In 2014, the costs of the gas related PPPs for the major gas utilities was about $582 million. The costs associated with the natural gas PPPs has been fairly stable since 2010, increasing by only 5%.

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.

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
- Allows utilities to engage in efficient natural gas hedging practices

For example, in 2013 and 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.

CPUC Advocacy for California Natural Gas Interests at FERC

The CPUC represents California gas interests at FERC Gas proceedings. In the last few years, CPUC intervention at FERC has been primarily on interstate pipeline general rate cases. Interstate pipelines are regulated by 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 a Transwestern Pipeline FERC proceeding, RP15-23. The rate case may result in a significant increase in Transwestern transportation rates to California. In addition, the GTN Pipeline may submit a general rate case request at FERC in 2015.

SUMMARY OF UTILITY PROPOSALS

Public Utilities Code Section 748 mandates that the IOUs study and report on measures that they recommend be undertaken to limit costs and rate increases. The IOUs duly responded to the CPUC's request for this year's report, and their recommendations are summarized below. Their full reports can be accessed on the CPUC website at the hyperlinks listed.

PG&E's Recommendations

PG&E generally recommends that the current tier-based rate structure for residential electricity be reformed to allow for a more accurate relationship between rates and the cost of service. CPUC proceeding R.12-06-013 is currently considering this potential reform.

PG&E also argues that some of the fixed costs of its service are being shifted from NEM customers to non-NEM customers, and that this has a consequent impact on rates. CPUC proceeding R.14-07-002 is considering this issue and the potential responses to it.

PG&E further recommends that the Legislature and CPUC periodically review mandates with respect to renewable energy and GHG emissions "to ensure that they appropriately balance the social or customer benefits with the overall cost to customers."

PG&E notes that while some drivers of costs are beyond its control, PG&E claims that in its latest GRC proceeding it demonstrated administrative and cost efficiencies that led to ratepayer benefits.

PG&E's full report can be found at: http://www.cpuc.ca.gov/NR/rdonlyres/78B33B18-273D-4D4B-8BCA-B36B0B28577F/0/PGE2015SB695Report.pdf.

SCE's Recommendations

SCE recommends that the state pursue greater coordination of its environmental and energy objectives to ensure that they are efficiently implemented. It also argues that markets should be called upon to procure specific technologies, rather than mandating that those technologies be adopted in certain ways.

SCE generally recommends that the state relax some of the timing and content requirements of its environmental policies to result in what it argues will be lower costs.

SCE's full report can be found at: http://www.cpuc.ca.gov/NR/rdonlyres/E076B165-8D96-4CD4-BDDC-76E9F8FD149B/0/SCE2015SB695Report.pdf.

SDG&E's Recommendations

SDG&E recommends that "some of the mechanics of how customers pay for electric service must change… to match the changes occurring in how utility services are provided." Like PG&E, SDG&E points to the retail rate reform proceeding and the NEM proceeding as areas where they believe rate policies could be improved.

SDG&E further recommends transparency in the incentives customers receive and in the incentives that other customers finance to further the state's goals, effective customer education to ensure that customers understand the services they receive, simple bills to ensure that customers understand the services they are paying for, and competitive choices to ensure that customers are making economically efficient decisions.

SDG&E's full report can be found at: http://www.cpuc.ca.gov/NR/rdonlyres/2453ED8C-FC37-454A-923F-9D750BD2C4A5/0/SDGE2015SB695ReportPartI.pdf and http://www.cpuc.ca.gov/NR/rdonlyres/00815577-D653-4182-A6F9-7B4C655A03EC/0/SDGE2015SB695ReportPartII.pdf.

SoCalGas' Recommendations

SoCalGas generally recommends that the state:

- Support policies and programs that encourage the installation of combined heat and power (CHP) systems
- Promote the use of fuel cell technology at the residential level
- Give flexibility to utilities in their energy efficiency and greenhouse gas programs in order to allow utilities to respond quickly to customer and market demands
- 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
- Ensure only qualified customers are participating in the CARE program
- Review mandated reporting requirements to make sure they are useful and non-duplicative.

SoCalGas' full report can be found at: http://www.cpuc.ca.gov/NR/rdonlyres/4CEDAF9E-B035-4C15-BC05-CDA76C0F14A0/0/SoCalGas2015SB695Report.pdf.