



Actions to Limit Utility Cost and Rate Increases

Public Utilities Code Section 913.1 Report
to the Governor and Legislature



May 2016



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Introduction

This report is published in accordance with the mandate of Public Utilities Code Section 913.1¹, which requires the California Public Utilities Commission (CPUC) to publish a report with 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 913.1 also requires the CPUC to direct the investor owned utilities (IOUs or utilities) to report on measures that the IOUs recommend be taken to limit cost and rate increases, and those reports are attached to this document. The 2016 edition of the Section 913.1 report is hereby submitted by the CPUC to the Governor and Legislature.

To promote additional transparency and to underscore the CPUC's core values, the CPUC makes revisions to the report structure relative to previous annual reports, identifying new trends affecting electric utility costs, electricity sales, and rate increases, and presenting a few longer-term options for mitigating customer impacts. In addition, we identify actions for containing the costs of administering some of our highest priority programs and proceedings.

The purpose of the 2016 Report is to raise awareness of emerging, but not wholly unexpected trends in utility electricity sales and revenue requirement, and their relative impacts on retail rates and bills. Rather than recommending highly specific cost-cutting measures that should be determined in the General Rate Case (GRC) process or other formal rate-making proceedings, we instead focus on identifying some of the broader cost categories impacting the California Investor Owned Utilities' (IOUs or utilities) revenue requirement, while illustrating a few options for cost reduction (or sales growth) that the CPUC may wish to consider in future proceedings.

Over the past decade, California's Investor Owned Utilities' sales and revenue requirement have generally mirrored or paced each other in a gradual upward trend, engendering relative stability in their system average rates (calculated as total revenue requirement divided by total kWh sales). Indeed, system average rates also generally tracked inflation during this time. However, in recent years, sales have flattened out and/or gradually declined at different rates for each IOU while revenues have generally increased with few exceptions², in accordance with settlements approved in GRC and related ratemaking decisions.

This general trend upward in revenue requirement over the past decade is the result of a variety of factors, including but not limited to the replacement of aging utility infrastructure, compliance with legislative mandates such as the Renewable Portfolio Standard (RPS) and growth in program budgets and energy savings in energy efficiency. Thus, there are fewer kilowatt hours (kWh) electricity sales over which to spread an increasing authorized revenue requirement, which has

¹ This annual report was previously in compliance with PU Code section 748, but this changed to section 913.1 pursuant to a legislative report clean up bill, SB 697 (Hertzberg, 2015).

² For instance, SCE's revenue requirement has decreased from 2015-2016 for the first time in many years.

the effect of putting upward pressure on the system average rate, which in turn could adversely impact customer bills.

The flattening or declining trend in kWh sales is driven by market shifts resulting primarily from growth in the solar industry, increasing availability of demand side management (DSM) programs such as energy efficiency, and the incremental proliferation of retail choice. These developments point to the gradual erosion of IOU market power and the continued development of a more robust distributed energy resources (DER) market.

Many of the issues impacting electric utility costs, sales, and rate increases are structural and long-term, and therefore strategies to manage and contain retail rates and billing impacts cannot be limited to a 12-month period. Rather, they must be addressed in a more holistic fashion over a longer time horizon. The central objective of this report, therefore, is to stimulate a dialogue among decision-makers about the potential consumer impacts of these new market dynamics and some of the ratemaking and policy tools available to better manage retail rates and protect consumers in this more competitive and changing market environment. In the pages that follow, we outline several options for managing utility revenue requirement (or growing sales) while balancing the need for the utility to earn a reasonable shareholder return.

This report has four sections, organized as follows: (1) General and California-specific trends affecting utility costs and rates; (2) The key policy levers available to the CPUC and legislature to address these trends and the potential effects on rates; (3) CPUC program and proceeding areas, including those of natural gas utilities and costs, and the top two actions available in those areas to limit costs and rates in the next twelve months; and (4) The reports of the IOUs as directed by Section 913.1.

Recent Trends in Electric Utility Rates and Costs

System average electric rates are increasing in California. As noted in the April 2016 Assembly Bill (AB) 67 Report submitted to the legislature³, electric rates in California have increased by 3.4% per year since 2012, above the annual inflation rate of 2.0%. However, due to the large investments in DSM programs such as energy efficiency and demand response, customer bills have remained relatively flat. In essence, customers served by the large IOUs in California have high electricity rates but relatively low bills. In the sections that follow, we unpack some of the trends that contribute to this phenomenon.

Key Ratemaking Terms and Definitions

As we examine trends in utility costs and rates, it is essential to define some key ratemaking terms that will appear throughout this report, and their interrelationship:

- ✚ **Revenue Requirement** or *utility costs* are often used interchangeably and synonymously, and refer to the operating costs plus a reasonable profit that are recovered as revenues through electricity rates.
- ✚ **Ratebase** is the book value, after depreciation, of the generation, distribution and transmission infrastructure assets owned and operated by the utility. The utilities have the opportunity to earn a profit on assets contained in ratebase. Other things being equal, a larger ratebase results in higher net income for the utilities.
- ✚ **Authorized Rate of Return (ROR) on Ratebase** drives the utility's profitability, and represents the cost of paying back utility debt holders with interest, plus the Return on Equity (ROE) to shareholders.
- ✚ **Return on Equity (ROE)** is the return to utility shareholders, or profit, and is the most controversial component of the ROR formula.
- ✚ **Non-Ratebase Expenses** are costs upon which the utility must collect from its customers but does not put into ratebase and does not earn a Return on Equity.
- ✚ **Total Revenue Requirement** = Ratebase x Authorized Rate of Return + Expenses.
- ✚ **Retail Rates** are determined by dividing total revenue requirement by total kWh sales, and are subdivided by customer class.

³ The Electric and Gas Utility Cost Report submitted to the Legislature pursuant to PU Code §747 on April 1, 2016 contains many additional charts and graphs illustrating historical trends in ratebase, revenue requirement, return on equity and other concepts discussed here. A select few will be reproduced here.

Increasing Revenue Requirements and Ratebase

Over the past 10 years, the electric revenue requirement for PG&E has increased by 36%, SCE by 8% and SDG&E by 165%. These increases have been driven by a number of factors, including the costs of purchased power, the costs of fuel and increases in utility ratebase and investment, as evaluated in General Rate Cases (GRCs) and those in the Energy Resource Recovery Account (ERRA) proceedings. ERRA revenues represent the cost of purchased power and fuel costs and are passed through directly to customers once reviewed for reasonableness, while GRC revenues are those meant to recover the rest of a utility's costs related to operating and maintaining its system. We note that utilities are not eligible to earn a Return on Equity (ROE or profit) on revenues collected through the ERRA, so the relative increase in this category does not translate into profit for the IOU but rather is a straight pass through of costs.

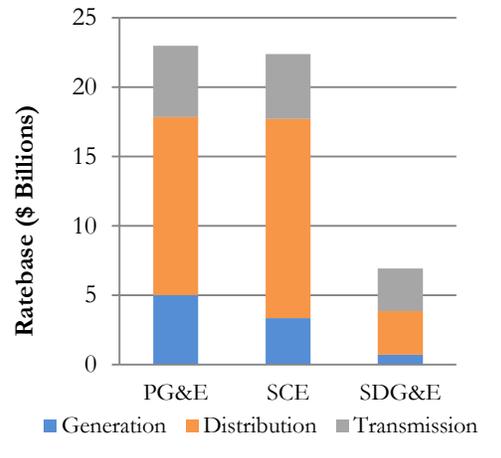
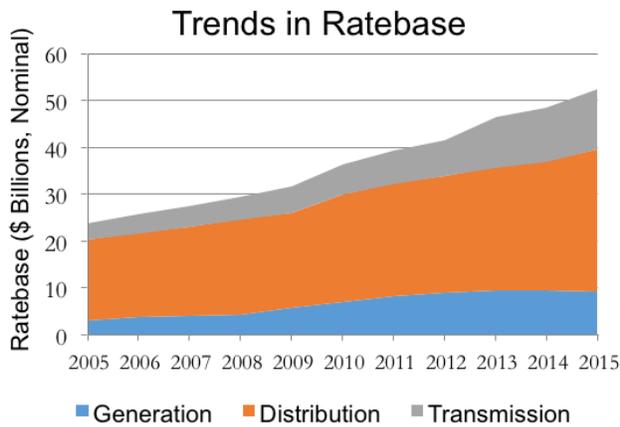
2015 Total Revenue Requirement (\$000)

Cost Category	PG&E	SCE	SDG&E
Generation/Energy Procurement Purchased Power	\$4,514,153	\$4,412,244	\$1,008,008
Utility Owned Generation	\$2,185,558	\$1,513,067	\$399,351
Distribution	\$4,399,854	\$4,350,777	\$1,138,103
Transmission	\$1,610,878	\$910,155	\$423,318
Demand Side Management and Public Purpose Programs	\$646,788	\$545,126	\$162,987
Bonds & Fees	\$673,170	\$485,956	\$131,756
Total 2015 Revenue Requirement*	\$13,730,664	\$12,198,048	\$3,578,637

* The total revenue requirements in the table do not include certain "other regulatory costs".

GRC revenue requirements have increased by 50% or more for all three IOUs in the past 10 years: 75% for SDG&E, 59% for PG&E and 50% for SCE. These increases were largely driven by a significant expansion in ratebase relative to total revenue requirement. Indeed, **SCE has increased its ratebase by 103%, PG&E by 72% and SDG&E by 61%**, which proportionately elevates the amount of earnings that the utilities receive based on their authorized rate of return (ROR). For instance, plant assets⁴ have increased by 60-65% over the past 8 years. As illustrated below, total California IOU ratebase has more than doubled over the decade from 2005 through 2015. Total ratebase per utility is the book value of transmission, distribution, and generation assets, less depreciation. The amortization of these assets over their useful lives, and their authorized ROR, is reflected in total annual revenue requirement.

⁴ Plant assets are actual capital spending; ratebase is authorized capital spending.



There are several reasons for the rapid rise in ratebase, including but not limited to costs associated with California’s Renewable Portfolio Standard (RPS) mandate, other than Power Purchase Agreements, which are a pass-through and are not added to ratebase, transmission and distribution (T&D) infrastructure upgrades, and smart meter investments. While California per capita energy use has remained relatively flat since the 1980’s, California’s population is expected to grow to over 48 million people by 2040.⁵ In order provide electric service to this burgeoning population, IOUs will be required to continue upgrading and replacing aging T&D infrastructure. In addition, new T&D infrastructure will likely be required to interconnect additional renewable resources to comply with Senate Bill 350 (De Leon, 2015), which mandates a 50% RPS by 2030.⁶

The Decline in Overall Electricity Sales in California

California’s electric utilities generally recover their costs by charging customers a rate per unit of energy consumed. Residential customers’ rates are based on units of energy consumed known as volumetric rates: these per kilowatt-hour (kWh) rates remain the primary way in which utilities charge customers and collect revenue. As explained in greater detail below, to account for energy efficiency savings, California has “decoupled” revenues from total electricity sales so that the utility remains neutral in selling a unit of electricity or a unit of energy efficiency. This decoupling mechanism saves ratepayers future investments in new generation assets, but it makes the relative rate per kWh higher as electricity sales decline with increased efficiency. In addition, commercial, industrial and agricultural customers are also charged a fee based on their maximum monthly demand through a “demand charge”.

Calculating the average residential rate entails dividing the utility’s revenue requirement for its residential customers by the number of energy units sold to those customers. Each year, utilities

⁵ Cook et. al. “The Future of Electricity Prices in California, Understanding Market Drivers and Forecasting Prices to 2040” Energy Efficiency Center, UC Davis, December 2013.

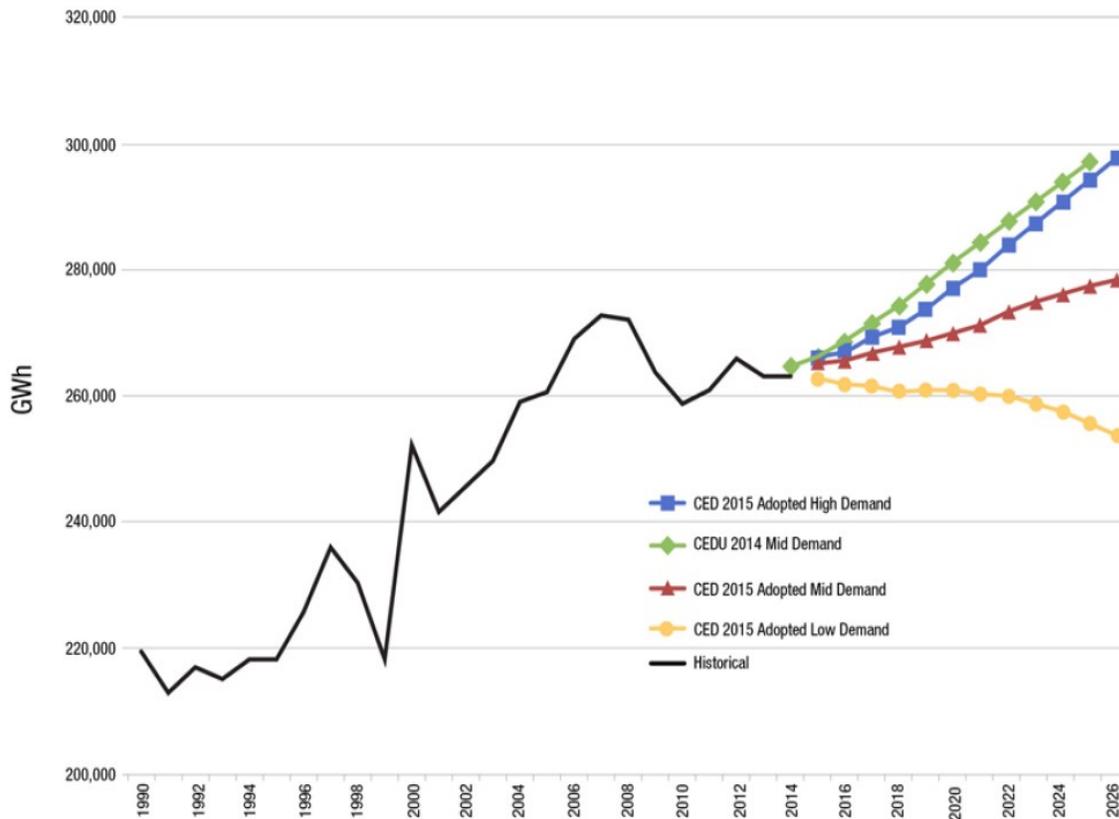
⁶ Bill Text, SB 350, Clean Energy and Pollution Reduction Act of 2015
https://leginfo.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350

forecast both their residential costs (revenue requirement) and sales to determine the rates that the utility will use for the year. For example, if at the end of 2016 a utility forecasts that its cost to serve residential customers in 2017 will be \$10 billion, and also estimates that it will sell 20 billion kWh of electricity to its residential customers in 2017, then the average rate for residential customers in 2017 will be approximately 20 cents/kWh.

Therefore, changes in either the cost forecast or the sales forecast can impact the actual rate that residential customers pay. Using the above example, if forecasted sales decline to 18 billion kWh while costs remain steady at \$5 billion then the average rate rises to 27.8 cents/kWh. If forecasted costs increase to \$5.2 billion while forecasted sales decline to 18 billion kWh then the average rate rises to 28.9 cents/kWh.

Historically, utilities could increase their forecasted costs while keeping their average rates steady by selling more kWh each year. In California, large population growth during the 20th century helped to power large growth in the amount of energy consumed. So long as the growth in the sales tracked the growth in costs then a utility's rates would stay fairly stable.

Historic Trends vs. Alternative Demand Forecast Scenarios in Electricity Sales



The 21st century and California’s climate change agenda brings with it new technologies, norms and policies that together contribute to an altogether different environment for utilities. They now face a situation where customers, policy-makers and technology providers all seek to reduce the amount of electricity sold per capita in California, with the exception of electric vehicle (EV) adoption. Numerous factors, many of which are cited in the California Energy Commission’s 2015 Integrated Energy Policy Report (IEPR), have contributed to sales decline, including the culmination of decades of energy efficiency improvements and rapid growth in rooftop solar. While community choice aggregation (CCA) has led to declining IOU sales, CCA customers must still pay for the delivery of electricity through transmission and distribution infrastructure.

Indeed, CCA growth has shown to be a modest factor relative to distributed generation and energy efficiency growth, with decreased sales of approximately 1%.⁷ However, as of March

⁷ This is an estimate based on existing market data.

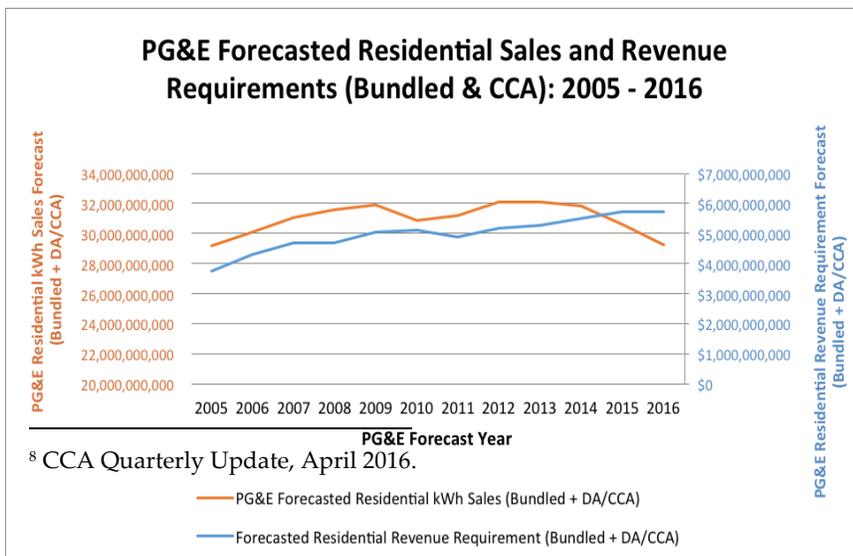
2016, more than 20 communities are pursuing CCA.⁸ Should these communities opt to depart bundled IOU electricity service, then the otherwise trivial impact of CCAs on IOU sales today would begin to increase. Since the IOUs recover most of the revenues from CCA customers through transmission and distribution components of the retail rate and nonbypassable charges (NBCs), revenue collection from these customers is not the chief concern, but rather gradual sales erosion. We note that the IOU still serves electric customers through the remaining non-generation assets. So while IOU electric sales may be declining because of CCA customers, the CPUC keeps the IOU indifferent in terms of non-generation related revenue requirement.

Concurrent with increases in revenue requirements, electric sales have been declining for all three utilities. PG&E has had a rather sharp sales decline of 4.4% in just the last year (from August 2014 through August 2015), while SCE has had a decline of 1.5%. SDG&E's sales have remained largely flat but are forecast to decline 0.6% in the next few years. Despite these modest numbers, larger percentage swings exist within classes. For example, SDG&E marked a 6% decline in residential class sales in 2015.

This report takes no position on this new environment for the utilities and only seeks to point out that, should this trend of declining sales and rising costs continue, volumetric rates for customers are bound to increase. This report aims to set in motion a process in which routine updates are provided to our decision-makers on sales and revenue forecasts, highlighting potential tools for mitigating their impact on rates in a retail market.

Decoupling Electricity Sales from Earnings

Lower sales and increasing revenues place pressures on ratepayers through increasing rates, and in some cases, potentially adverse billing impacts. In contrast, utility shareholders are insulated from sales fluctuations, as utility revenues are decoupled from sales in California, preventing changes in sales from impacting IOU earnings. Importantly, this policy has allowed California to keep electricity use per capita largely flat since the 1980s by removing the disincentive for utilities to encourage energy conservation, which has had measurable benefits for the environment. Other states that have not implemented decoupling or comparable mechanisms essentially require utilities to absorb sales declines and resulting revenue losses.



However, in a flat or consistently declining sales environment, rates will increase as IOU revenues have typically increased each year, and must be collected over fewer kWh sold. This is especially salient for lower-usage residential customers,

as restrictions on rate design following the electricity crisis and AB 1X (Keeley, 2001) were modified by SB 695 (Kehoe, 2009), and then lifted entirely by Assembly Bill 327 (Perea, 2013). Rate increases were largely absorbed by high usage customers in the years prior to AB 327's passage, but in a declining sales / increasing revenue requirement environment, these customers will be hit hardest by rate increases. For customers who are low-income and are subsidized by the California Alternative Rates for Energy (CARE) program, there may be a potentially larger impact as the CARE subsidy is capped, and low usage CARE customers may see bills rise if they do not reduce kWh consumed as the differentials between residential rate tiers is reduced through 2019.

Ratemaking & Policy Options for an Uncertain Future

Addressing the current cycle of increasing revenue requirements and declining sales requires a discussion of strategic, long term approaches to cost containment (or climate-friendly sales growth) for the IOUs. Removing the decoupling mechanism would conflict with the state's efforts to reduce energy usage; which is at odds with keeping rates and bills reasonably contained. The legislature has identified the electricity sector as having the potential for cost-effective ways to help decarbonize the California economy. This includes both conversion of natural gas assets and the transportation sector as a whole to electric assets. Increasing sales from EV adoption and charging is a potential strategy to mitigate rate increases through an important climate change strategy. However, increasing sales for other reasons would clearly run counter to California's climate goals.

Customer Impacts of Residential Rate Reform and Sales Decline

The CPUC's recent rate reform decision⁹ includes provisions for eliminating the distortions in the current tiered rate structure and setting a glidepath transition to a more cost-based rate design such as time-of-use (TOU) in order to better align usage with grid operational costs.¹⁰ As this transition to a more cost-based rate structure proceeds, some consumers will experience incremental rate and billing impacts which could be exacerbated by electricity sales decline and revenue requirement increases, should these trends continue. Residential rates are set to default to a TOU pricing structure in 2019. This will include peak periods when the cost and price of electricity are higher (i.e. the summer season, in late afternoon/early evening hours when air conditioning use is high) and off-peak periods when the cost and price of electricity are lower. This pricing scheme is intended to provide an incentive for shifting electricity usage to times of day when electricity supply is relatively cheaper.

Currently, residential TOU pilots are being deployed to assess the effectiveness of these rates as tools to modify energy usage and behavior, including permanently shifting load or conserving energy. While some customers may be unable to shift their usage to their advantage, other customers may shift usage to off-peak periods when energy prices are lower, resulting in lower bills. Some shifts may also be associated with conservation, resulting in a reduction in kWh sales for the utilities. More specifically, in bringing the IOUs' rates closer to cost, the upper tier rates will come down while lower tier rates gradually rise. Unfortunately, however, the combination of flat or declining kWh sales with increasing revenue requirement will again put upward pressure on retail rates, with twofold consequences for ratepayers: (1) partial erasure of the reductions in upper tier residential rates afforded by tier compression along the decision's prescribed glidepath for each utility, and (2) the compounding or exacerbation of rate increases

⁹ See Decision (D.)15-07-001.

¹⁰ For more information, see page 13, section entitled 'Rate Design'

and billing impacts on lower tier customers due to the combination of tier compression and kWh sales decline.

In light of these somewhat unpredictable forces and their potential impacts on bills, we must explore alternative management strategies to manage utility revenue requirement in proportion to kWh sales if we are to maintain an equitable rate structure for California ratepayers as the retail market develops and self-generation competition grows. We must also ensure that non-bypassable charges are fairly assessed on customers who do not purchase bundled electric service from IOUs, including CCA customers and Net Energy Metering (NEM) customers who consume only some of their energy from the transmission and distribution grid, and use the transmission grid to export solar energy. As a starting point, there are three broad areas that the CPUC can consider targeting for incremental reduction vis-à-vis the GRC and ERRRA proceeding process:

- Utility ROE and its impact on ROR
- Capital Spending
- Pass-through costs of purchased power and fuel

And a fourth option to consider:

- New policy initiatives to accelerate EV adoption and to increase kWh sales from EV charging.

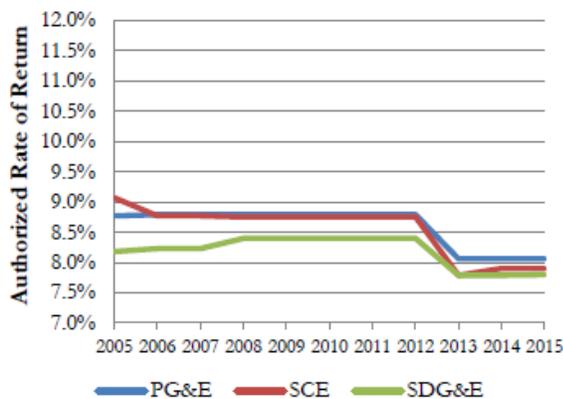
Utility Rate of Return

Through cost-of-service regulation, the utilities earn profits on their capital assets or ratebase¹¹. One chief concern with this type of regulation is that utilities are incentivized to over-invest in their infrastructure to increase their profits.

Two federal court decisions, *Bluefield Water Works & Improvement Co. vs Public Service Commission of West Virginia* (1923) 262 U.S. 679 and *Federal Power Commission vs. Hope Natural Gas Co.* (1944) 320 U.S. 591 help set the standard for determining the rate of return (ROR) for a utility. The *Bluefield* decision states:

[t]he return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties.

The *Hope* decision reinforces the *Bluefield* decision and emphasizes that the return to equity owners should be commensurate with returns available on alternate investments of comparable risks.



Currently California IOUs have relatively high authorized rates of return compared to other utilities across the country. In the most recent Cost of Capital decision¹², ROE was reduced from previous years, balanced against the risk of operating in California, and adjusted to facilitate capital infrastructure investment. Like ROE, ROR is determined in each IOUs' Cost of Capital proceeding, which is next slated to begin in 2017. CPUC Decision D.08-05-035 established a multi-year cost of capital mechanism (CCM) for the

utilities in which ROR is determined. The utilities have been required to file cost of capital applications every three years, although the CPUC has granted uncontested extension requests and has not conducted a full review since 2013. This time horizon extended after the 2012 round of applications.

¹¹ Capital assets or ratebase can include cash, [working capital](#), materials and supplies, deductions for accumulated provisions for [depreciation](#), contributions in aid of construction, customer advances for construction, accumulated deferred [income taxes](#), and accumulated deferred [investment tax credits](#).

¹² D.12-12-034

Note that this chart illustrates rate of return (ROR) authorized by the CPUC since 2006 for major energy utilities. ROR is the weighted average cost of debt, preferred and common stocks. The figure does not include ROR authorized by FERC for IOU transmission systems; it only includes ROR authorized by the CPUC for assets in ratebase, such as Utility Owned Generation (UOG) and distribution.

Return on Equity

Return on equity (ROE) refers to the amount of revenue a utility may collect from its ratepayers as profit. The component of rates comprised by ROE does not pay for new equipment or fuel; rather it represents the authorized return to IOU shareholders. ROE is a component of the IOUs' ROR on ratebase.

All privately-owned companies issue returns to shareholders. However, what distinguishes the regulated utilities is that a competitive market does not exist to benchmark their ROE. In the absence of a competitive market, regulators control the levels of ROE that utilities may earn. Conversely, in a competitive market a company will set its ROE at a level that profits its owners but also ensures it can direct funds toward things that might make the company more competitive and therefore more successful, such as research and development, expanding sales, providing excellent service, or providing benefits to employees.

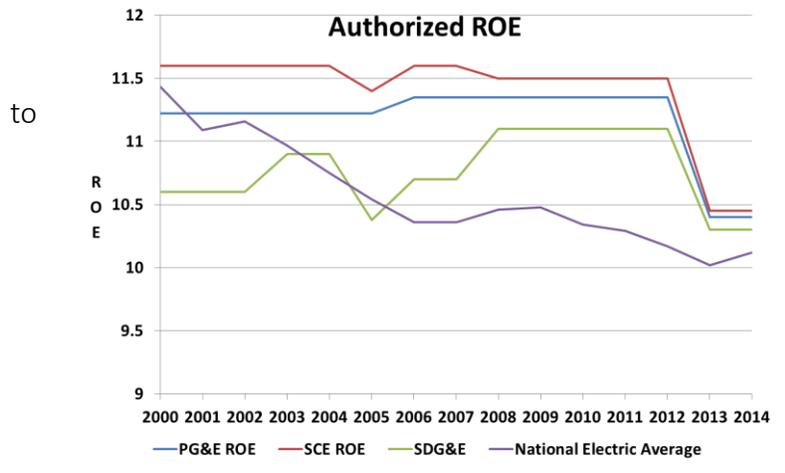
In a classic monopoly utility situation, there has historically been little threat of competition. Therefore, a utility can decide to give its shareholders as much of its maximum allowable return as to the benefit of its shareholders while, in the extreme case, potentially underinvesting in customer services.

In Cost of Capital proceedings, the CPUC determines the level of ROE that is adequate to enrich utility shareholders while ensuring that sufficient revenue is left to adequately invest in the services that must be provided to utility customers. A subcomponent of the utility's ROR on ratebase, adjustments to ROE can have a significant impact on total revenue requirement. While the market can establish the cost of debt, the CPUC also determines the appropriate equity to debt ratio for the utility and the proper mechanisms to finance debt, in order to best attract the needed capital for investing in infrastructure improvements.

In California and nationally, the recent trend has been a modest decline in ROE for electric and natural gas utilities. The table below shows the most recent ROE determinations for PG&E, SCE, SDG&E and SoCalGas, as of November 2015.

IOU	Current ROE (2013)	Previous ROE
PG&E	10.4%	11.35% (2007)
SCE	10.45%	11.5% (2009)
SDG&E	10.3%	10.7% (2008)
SoCalGas	10.1%	10.82% (2008)

Among the key factors in determining ROE are the utilities' credit ratings and an assessment of the market risks associated with operating in California. In the most recent Cost of Capital proceeding in 2012¹³, the CPUC decreased the ROE of California IOUs, bringing them closer to the national average, as demonstrated

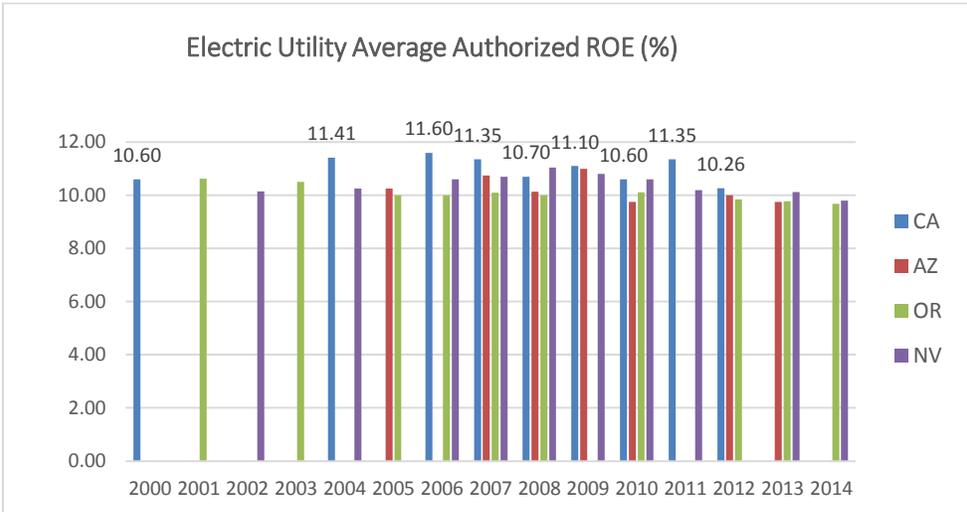


below. ROE was previously higher in California relative to national trends, which was predicated on the post-electricity crisis operating environment and credit ratings, which had dropped precipitously following the retail

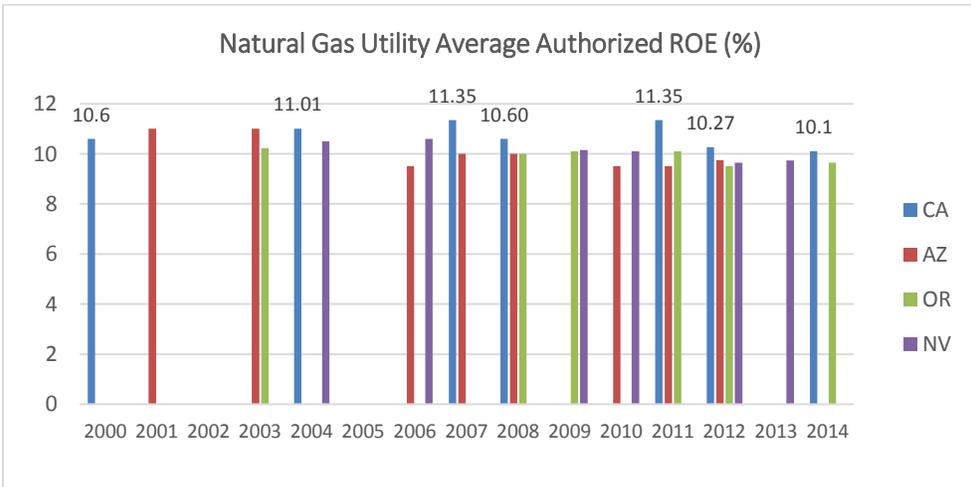
market failure, and in the case of PG&E, its bankruptcy filing. However, utility credit ratings have long since recovered, as has the retail electricity market, which is beginning to introduce some retail choice competition (within the limits prescribed by the legislature).

Similar trends are observable in California's adjacent neighbors (Oregon, Nevada and Arizona) suggesting that declining ROE is a regional as well as California trend. Nevertheless, California IOUs have enjoyed higher ROEs than IOUs in neighboring states for the last several years.

¹³ *Id.*



Source: Regulatory Research Associates



Source: Regulatory Research Associates

It is important to note that a higher ROE is not necessarily unjustified, as differences such as utility characteristics, regulatory risks, market environment, and other factors all matter in assessing an appropriate value.

Ratepayer Impacts of Reducing ROR and ROE

The following table illustrates the potential changes to revenue requirement of reducing both ROE and ROR by 10 basis points, or 0.1%, using the revenue and underlying data provided by the utilities in the most recent (2012) Cost of Capital decision.¹⁴

¹⁴ *Id.*

Utility	Change in Revenue Requirement From 10 basis points Change in ROE (in millions)	Change in Revenue Requirement From 10 basis points Change in ROR (in millions)
PG&E	17.00	32.69
SCE	16.80	35.00
SoCalGas	2.60	5.00
SDG&E	3.40	6.54

This illustrative example provides a frame of reference for Commissioners to understand how a change in ROE impacts revenue requirements. In the case of PG&E, for example, a 1% or 10 basis point reduction in ROE using 2012 data would result in an approximately \$170 million (\$17 million x 10) reduction in revenues. Also illustrated in the chart is the impact of a 1% or 10 basis point reduction in ROR, or \$327 million (\$32.7 million x 10) reduction in ROR. However, it is essential to note that any reductions in ROE would also reduce ROR to some extent, since ROE is a subcomponent of ROR – but this is not a one for one relationship.

It is also critically important to note that the cost of debt and the balance of debt to equity are the determinants of the ROR. Market forces partially impact the level of ROR and ROE set by the Commission. The Commission analyzes arguments about the amount of ROE necessary to attract capital for infrastructure investment. As an input to the ROR calculation, utility ROE is a critical lever for Commission management of revenue requirement. **Therefore, the Commission will evaluate the record in the 2017 Cost of Capital proceeding to determine whether downward adjustments in ROE are merited in light of the national average ROE and the investment climate in California. Should ROE be reduced revenue requirement savings could be achieved for ratepayers, but ROE must be sufficient to attract private capital to invest in California IOU infrastructure. The Commission will balance various issues that affect the appropriate ROE to support California IOU infrastructure investment, and compare California IOU ROE to the appropriate cohort to determine the proper ROE and debt to equity ratio.**

Capital Spending

Utilities earn profit by earning return on their capital assets contained in ratebase. If a rate of return decreases, the utility can only grow earnings by increasing ratebase. Other trends such as an increased focus on the distribution grid and safety may continue to increase capital spending.

Distribution Assets

Distribution has been the fastest growing segment of ratebase, and the rate of return on distribution assets for the three utilities has grown annually by approximately 4.3% since 2005.¹⁵ The distribution system is the largest component of the retail rate. It is the largest asset category of the IOUs and as such represents their main driver of earnings or profits. However, grid modernization efforts (smart meters/smart grid) and the ability of the grid to accept innovations such as electric vehicles and distributed energy resources (DER) such as solar and storage are affected by distribution upgrades and spending. **These innovations may also hold the key to reducing the need for future distribution upgrades. At the same time, unless the CPUC and the utilities are vigilant over costs, the movement toward increasing distributed generation could result in increased costs for ratepayers. The CPUC is actively considering new ways of containing costs for interconnecting distribution-level generation assets to help keep overall costs low and to ensure that upgrades to the distribution system are made systematically and purposefully.**

Investing in Safety

The renewed focus of the CPUC on safety including the new Safety Model Assessment Proceeding (S-MAP) and Risk Assessment Mitigation Phase (RAMP) components of the General Rate Case process may increase capital spending on infrastructure. These processes are designed to ensure that new investments in safety related infrastructure are cost-effective and risk-prioritized. Although safety and reduction of capital spending are sometimes at odds, there are often ways of accomplishing things which are both safer and cheaper, especially in the case of new technology. This process for administering general rate cases is intended to provide transparent justification for capital and expense requests. The goal is to develop clear and transparent risk assessment models, determine projects to mitigate risks, match spending requests in the GRC, and confirm that monies approved and spent demonstrate spending related safety impacts. The CPUC also needs to balance safety and system reliability with rates, which is at the core of our statutory mission in PU Code 451. However, much of California's infrastructure is aging, and the costs to maintain and upgrade such infrastructure,

¹⁵ The Electric and Gas Utility Cost Report submitted to the Legislature pursuant to PU Code §747 on April 1, 2016

including safety infrastructure may continue to increase in the near and medium term.

In R.13-11-006, the Order Instituting Rulemaking to Develop a Risk-Based Decision-Making Framework to Evaluate Safety and Reliability Improvements and Revise the General Rate Case Plan, the Commission embarked on course to account for prioritizing safety and reliability in the general rate case process. In December 2014, D.14-12-025 was issued and specified revisions to the General Rate Case plan that calls for utilizing risk based methodologies to identify infrastructure needs balanced by providing just and reasonable rates.

Moreover, there is an inherent link between system reliability and how we evaluate safety. According to a recent report by the CPUC's Policy and Planning Division, SDG&E's reliability performance remains excellent, while SCE and PG&E have steadily improved over the past 10 years and are nearing SDG&E's level of performance. This could suggest that the state of California infrastructure is better than anticipated, and therefore that additional major reliability-related investment may not be warranted at this juncture. This data will be evaluated during the SMAP and RAMP phases of the electric utilities GRC to prioritize the high safety-related needs for future infrastructure investment. **Increased coordination is necessary between the Commission's Energy Division and the Safety and Enforcement Division for the purposes of striking the right balance in authorizing reasonable and prudent safety investments without unnecessarily expanding IOU ratebase and profits at the expense of ratepayers.**

Transmission

Transmission revenue requirements have been trending up since 2003. These increases have been driven by California Independent System Operator (CAISO) reliability mandates and interconnection requests by renewable providers in compliance with the Renewable Portfolio Standards (RPS). This spending may increase to meet the renewable goals of Senate Bill 350. The appropriateness of transmission revenue requirement is decided in Federal Energy Regulatory Commission rate cases¹⁶. However, the CPUC is working with the CAISO to study the feasibility of meeting RPS targets with renewable resources that provide energy-only rather than those deemed to have full capacity deliverability status (FCDS).¹⁷

The transmission revenue requirements is spread among various customer classes, and included in the non-bypassable charges or bills of some unbundled customers such as CCAs. The CPUC's 2016 Decision exempted NEM customers from transmission charges, but stated that the CPUC will review the NEM decision in

¹⁶ See page 17, CPUC Advocacy for Reasonable Rates for Electric Transmission

¹⁷ See page 25, Transmission Costs

2019. We note that the ROE on transmission assets is generally established by FERC and is beyond the CPUC's control. **Nevertheless, if existing resources can be relied upon to address energy needs during peak demand periods, when FCDS resources would be utilized, this policy choice would limit transmission upgrades or the construction of new transmission lines to interconnect FCDS resources. Ultimately, the transmission revenue requirement required to meet California's renewables goals could then be reduced.**

Other Discretionary Spending

Other discretionary spending includes operation, maintenance and administrative expenses for utilities and includes all labor and non-labor expenses required to maintain utility systems and reliability. Through traditional cost-of-service regulation, this is typically the area where a utility would attempt to reduce its spending in order to earn a better return.

These costs are often highly influenced by events and the environment in which a utility operates. Examples include an increased cost of living in an area where many employees live or technology that makes operation of a large number of customer service offices unnecessary in areas where that technology is available and reliable. The new safety proceedings, S-MAP and RAMP, may also influence future costs for O&M.

For salaries, the utilities present a Total Compensation Study that examines how the salaries in different classifications (e.g. executives, management, or rank and file) compare to the labor market, and the CPUC incorporates these findings into its cost authorizations in the GRC process. The CPUC may wish to take a closer look at the impact of utility salaries, and in particular, executive compensation, on total utility revenue requirement in the next GRC cycle.

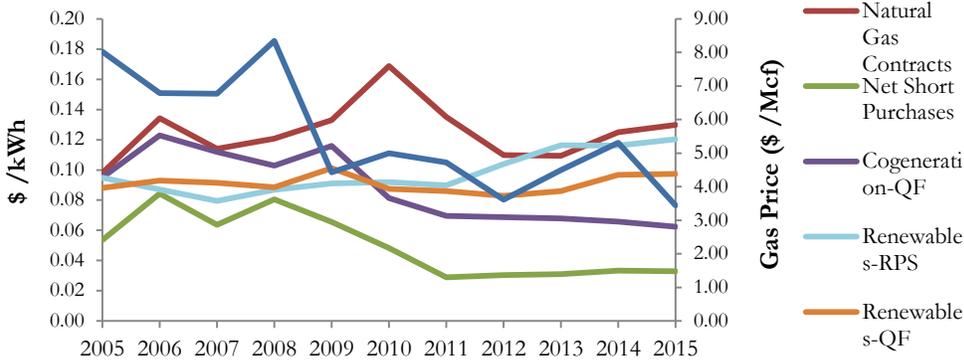
Regarding other items, the CPUC's Energy Division has in recent years tended to rely on the comments and analyses of intervenors in proceedings. In the future, the Energy Division intends to refocus its analyses of discretionary costs, developing metrics for reasonableness for different spending types. **The CPUC can reevaluate the optimal deployment of analytical and managerial resources for the purposes of maximizing support in the GRC process and adopting metrics for evaluating progress in managing costs in these and other areas that have yet to be identified.**

Pass-Through Costs of Fuel & Purchased Power

There are several categories of costs which are not directly determined by the utilities and are a major influence on rates. While the utilities have some discretion in their power purchase agreements, these costs are passed directly into rates without markup through separate proceedings such as ERRA and program-specific proceedings.

Power Procurement Costs

Although the average cost of purchased power has remained relatively stable over the last 10 years, the amount of power being purchased on the spot market has increased.



Reliability service, which is required to ensure adequate generation from the ISO, can be a major cost to the system. The new market based approach to backstop capacity can cost up to three times as much as power purchased through conventional procurement mechanisms. **This cost can be ameliorated with the careful consideration and coordination with the CAISO regarding the valuation and incorporation of additional, incremental demand response resources into the market.**

Public Purpose Programs and Other Legislative Mandates

Public purpose programs include demand side management and low-income programs required by the legislature and CPUC. Demand-side management programs including energy efficiency, demand response and customer generation currently account for roughly 4.5% of utility revenue requirements, while spending in this area has seen a 12% annual increase since 2005. Reduction in electricity demand, however, has kept customer’s bills amongst the lowest in the country. Although these programs do reduce costs for Californians by reducing the number of power plants required and avoiding the use of expensive peaking power plants, administration costs, among other costs, are still incurred by the utility. The CPUC has been involved in piloting and evaluating new financing, procurement, and administration methods to reduce the cost impacts of these programs.¹⁸ **The Commission should consider the use of annual targeted reductions to administrative cost savings in the GRC process, where feasible.**

¹⁸ See pages 23, Demand Response Auction Mechanism and 26, Energy Efficiency

Electric Vehicle Strategies to Increase Sales

Load growth due to transportation electrification is forecasted in the California Energy Commission's Integrated Energy Policy Report (IEPR).¹⁹ The IEPR estimates energy demand associated with four segments of electric transportation: 1) light duty electric vehicles, 2) buses, medium and heavy-duty trucks, 3) high-speed rail, and 4) port and other electrification. **Forecasted energy use in 2026 ranges from approximately 2,000 – 7,500 GWh.**

The two Mid Energy Demand cases include sensitivities that account for whether the high speed rail begins operation in 2022. In the case where high speed rail begins operation on schedule, the Mid Energy Demand Case approximates 6,500 GWh in 2026. Energy Division estimates that the transportation electrification goals defined for the Commission and the IOUs pursuant to Senate Bill 350 will entail additional demand.²⁰ The Air Resources Board's Mobile Source Strategy provides some insight to the scale of electric transportation necessary to meet near-term (2020-2030) regulations to comply with the Federal Clean Air Act. The measures suggest that the forecasts in the current IEPR may be conservative.²¹

The IOUs report load growth annually to the Commission, including measures like time of peak load.²² Since mid-2011, monthly peak demand for Plug-in Electric Vehicles (PEV) customers throughout the IOU service territories has steadily increased, with the relative rates of growth likely attributed to the charging power demands for Electric Vehicle (EV) types (battery or plug-in hybrid) that are popular within each service territory. In contrast, monthly peak demand for all residential customers has remained constant.²³

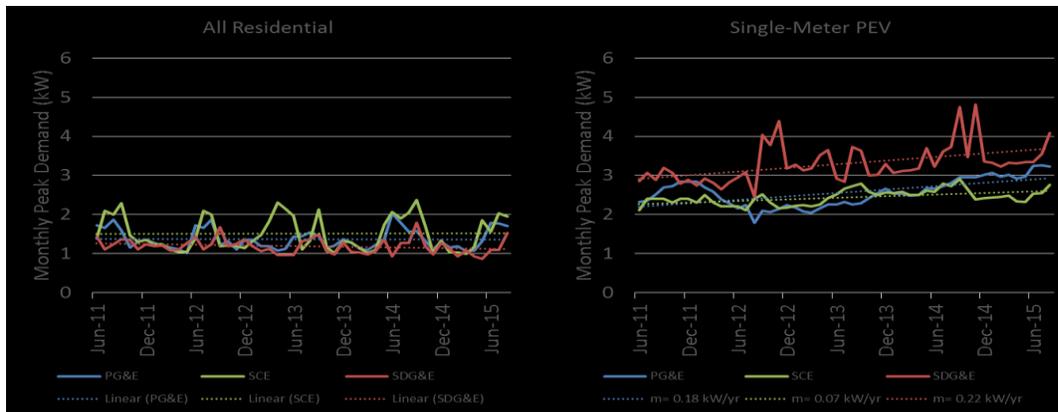
¹⁹ http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-01/TN210527_20160224T115023_2015_Integrated_Energy_Policy_Report_Small_Size_File.pdf page 116

²⁰ Public Utilities Code Sections 237.5, 701.1, 740.8, 740.12,

²¹ <http://www.arb.ca.gov/planning/sip/2016sip/2016mobsr.htm>

²² Load Research Reports filed with the Commission can be found at: <http://www.cpuc.ca.gov/General.aspx?id=5597>

²³ Please note that the monthly peaks for all residential customers generally occur in the evening (5 to 8 pm) while the EV customers' peak demand occurs between 12 and 2 am due to their enrollment with a Time-Of-Use rate.



Assuming that 7500 GWh of demand statewide for EV usage in 2026 is a best-case scenario in terms of the impact of charging on sales, it would appear that EV growth could mitigate a potentially significant portion of the IOU sales decline. This view is supported by analysis presented in the CEC’s 2015 Integrated Energy Progress Report, which indicates that **the mid case scenario for California electricity consumption in 2025 is projected to be 2.8% or 9,000 GWh lower than the 2014 mid case projection.**²⁴ If these projections are correct, approximately 80% of the projected sales decline could be offset by EV charging, but only under a best-case scenario. However, the relative impact of increased EV adoption will be balanced by the rate of growth in DG solar adoption, energy efficiency, and CCAs.

The CPUC is under statutory mandate to investigate policies that promote EV adoption, including pushing the rapid deployment of the required infrastructure to support EV growth in the light, medium and heavy duty EV market. EV adoption should also assist in grid management which may reduce future infrastructure related costs. The CPUC will be tasked with identifying policies and incentives including forward looking rate designs to accelerate the development of this market.

²⁴ 2015 Integrated Energy Policy Report, California Energy Commission, p.132.

CONTAINING COSTS IN PROGRAM-SPECIFIC PROCEEDINGS

Electric Utility Costs and Revenue Requirements

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.

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, 2016
(\$ Million)**

PG&E	SCE	SDG&E
\$13,735 ²⁵	\$11,763 ²⁶	\$3,841 ²⁷

The utilities file GRC applications every three or four years. CPUC GRC decisions 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.

In addition, 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 costs incurred during a prior annual period. The ERRA proceedings were established by the CPUC in 2002 pursuant to AB 57 (Wright, 2001), which required that the utilities receive timely recovery of electricity procurement costs.

²⁵ PG&E Advice Letter 4696-E-A, filed 12/30/15.

²⁶ SCE Advice Letter 3319-E, filed 12/23/15.

²⁷ SDG&E Advice Letter 2840-E, filed 12/29/15

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 2015 AB 67 Report (filed in April 2016), available on the CPUC website.²⁸

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.

2016 Authorized Electric General Rate Case Revenue Requirements (\$ Million)²⁹

Cost Category	PG&E	SCE	SDG&E
Operations and Maintenance	\$2,392	\$1,934	\$687
Depreciation	\$1,739	\$1,506	\$250
Return on Ratebase	\$1,355	\$1,389	\$258
Taxes	\$774	\$804	\$217
Total	\$6,261	\$5,635	\$1,412

PG&E 2017 GRC | A.15-09-001

In its application, PG&E requests to collect \$8.373 billion in revenues from its customers in 2017, of which \$2.170 billion is to recover costs of its operating its electricity generation facilities, \$4.376 billion is to recover costs of delivering electricity services (electric distribution), and \$1.827 billion to recover costs of delivering gas services (gas distribution), though our focus in this report is on

²⁸ Available online at:

http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Reports_and_White_Papers/AB67_Leg_Report_3-28.pdf

²⁹ Amounts shown include revenues adopted by the CPUC in the utilities' GRCs and additional revenues approved by the CPUC for inclusion in base revenues after the GRC decisions were issued.

electric costs. This request would increase PG&E's currently authorized revenues for 2017 by 5.8%. PG&E also requests to increase the total amount of revenues (gas distribution), electric generation, and electric distribution) by \$480 million, or 5.8%, in 2018 and by \$390 million, or 4.4%, in 2019. The Commission is currently reviewing the application. The Commission aims to issue a decision by the end of 2016 that will authorize the final amount of revenues PG&E can collect from its customers in 2017, 2018, and 2019.

SDG&E 2016 GRC | A.14-11-004

In this proceeding, SDG&E requests to collect \$1.895 billion in revenues from its customers in 2016, of which \$1.571 billion is to recover costs of its electricity services. This request would increase SDG&E's currently authorized revenues for 2016 by 1.2%³⁰. In September 2015, a settlement motion was filed to the Commission, by which all but two active parties in the proceeding reached a consensus on the amount of revenues SDG&E should be authorized to collect. The settling parties propose that the Commission authorizes SDG&E to collect \$1.710 billion in revenues from its customers, of which \$1.415 billion is to recover costs of its electricity business. The revenue amount proposed in the settlement would increase SDG&E's presently authorized revenues for 2016 by 1.2%. If the Commission were to adopt the settlement, the monthly bill of a typical SDG&E residential customer using 500 kWh of electricity per month would decrease by \$1.45 for gas services and would decrease by \$0.74 for electric services. The settlement motion also proposes that the Commission authorizes SDG&E to increase the amount of revenues it can collect from customers by 3.5% in both 2017 and 2018. The Commission is currently reviewing the Settlement and will issue a decision in 2016 to authorize the final amount of revenues SDG&E can collect for 2016, 2017 and 2018.

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

³⁰ The IOUs also include some gas expenses in their electric GRCs, though the bulk of gas costs are reviewed in separate gas transmission and storage cases.

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
\$4,827	\$3,783	\$1,224
Effective December 2015	Effective December 2015	Effective January 2015

PG&E's ERRA

In D.15-12-022, PG&E's ERRA revenue requirement of \$4,827 million was approved by the CPUC in PG&E's ERRA 2016 forecast proceeding. The CPUC expects that in June 2016 PG&E will file its ERRA application to request a fuel and purchased power revenue requirement for 2017.

SCE's ERRA

In D.15-12-011, the CPUC authorized SCE's ERRA revenue requirement of \$3.873 billion, \$1.008 billion lower than the 2014 revenue requirement. This amount also reflects a settlement to reflect energy crisis refunds, SONGS settlement refunds and 2013 SONGS costs.

SDG&E's ERRA

An SDG&E ERRA revenue requirement of \$1,288 million was approved by the CPUC in D.15-12-032. The CPUC expects that in April 2016 SDG&E will file its ERRA application to request a fuel and purchased power revenue requirement for 2016.

Natural Gas Rates and Costs

The CPUC has been examining natural gas utility costs to ensure that utility revenue requirements and rates for gas pipelines, storage, and customer services are reasonable in several major gas utility proceedings. CPUC staff, often in coordination with several other state agencies, has also been investigating the potential impact of the SoCalGas Aliso Canyon Gas Storage Field leak, and subsequent requirements that have been or may be imposed on the continued operation of the field.

To date, the CPUC staff's analysis has been focused on the impact on gas delivery and electric reliability if the Aliso Canyon field is unavailable or available only at reduced capacity. The staff has also been analyzing the amounts of costs that SoCalGas been authorized to recover from ratepayers for storage operations, how much it has spent, and how much it has requested for recovery in the 2016 GRC, including those amounts specifically related to Aliso Canyon.

In anticipation that the Aliso Canyon Field may be no longer available, or possibly only available at reduced capacity, in the future, the CPUC recently issued a decision that requires SoCalGas to track Aliso Canyon costs that are being recovered from ratepayers. It is possible that SoCalGas would later be required to refund such amounts back to ratepayers. In addition, the CPUC has been carefully considering whether the Aliso Canyon leak and storage safety will impact any of its current proceedings.

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, and includes significant increases for storage-related expenses and capital expenditures. The CPUC examined PG&E's proposal in 2014 and 2015, and heard alternative proposals from other parties, including the CPUC's Office of Ratepayer Advocates.

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. Thus, any change in PG&E's authorized revenue requirement may not become effective on January 1, 2015, but at a later date as decided in this proceeding.

Once the CPUC issues its initial decision in the proceeding, the CPUC will also need to then consider how to implement the requirements of D.15-04-024. In that decision, the CPUC ordered certain fines and penalties against PG&E in relation to the San Bruno pipeline explosion, its past transmission pipeline record-keeping practices, and its practices related to the safety classification of pipelines. One of the penalties ordered by the CPUC in that decision was that PG&E shareholders should pay for \$850 million in reasonable gas transmission pipeline and storage safety enhancements. Thus, once the Commission determines what reasonable gas transmission and pipeline safety enhancements should be made in its initial decision in this proceeding, the CPUC will then reduce those amounts by \$850 million in a second decision, setting forth the amounts that will be recoverable from ratepayers. The CPUC is expected to issue its initial decision in this proceeding in the spring or summer of 2016.

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

SoCalGas and SDG&E submitted their application for their 2016 Gas GRC in November 2014. The CPUC examined the utilities' request and heard alternative proposals from other parties in 2015. In September 2015, a number of parties in the proceeding proposed a major settlement to the CPUC on the amounts that SoCalGas and SDG&E should be authorized to recover from ratepayers.

If adopted, the settlement would result in roughly a 5.8% increase in SoCalGas' revenue requirement and a 0.3% increase in SDG&E's gas revenue requirement. The settlement also provides that the revenue requirement would be increased in 2017 and 2018 by 3.5% per year. The settlement authorizes over \$250 million in safety-related spending for transmission and distribution pipeline integrity management programs, as well as for a new safety-related Storage Integrity Management Program, as well as some costs specifically related to Aliso Canyon operations and safety. However, the amounts proposed in the settlement were all recommended prior to the Aliso Canyon leak. While some costs are included for safety for Aliso Canyon, the settlement includes no costs specifically related to remediation of the Aliso Canyon leak or to relocation of residents. The settlement does not resolve one major issue, benefits associated with a tax reduction due to a repairs deduction, so the CPUC will also need to determine the outcome of that issue in its decision.

Finally, it should be noted that the costs being considered for approval in the SoCalGas/SDG&E 2016 GRC do not include any costs being incurred by SoCalGas/SDG&E under its transmission pipeline Pipeline Safety Enhancement Plan. Those costs will be reviewed in separate reasonableness review proceedings. The CPUC is expected to issue its decision in this proceeding in the spring or summer of 2016.

Retail Rates

The CPUC regulates the pricing of electricity for all retail customers of the investor owned utilities, and authorizes rates and tariffs that provide affordable service and meet statewide policy goals while allowing the utilities to collect their authorized revenue requirement. Last July, the Commission issued Decision 15-07-001 in R.12-06-013, the Residential Rate Reform Rulemaking implementing key provisions of Assembly Bill 327 (Perea, 2013). The decision addressed ‘flattening’ of the tiered rate structure, a schedule and process for introducing default TOU rates, and a timeline and procedure for examining and considering whether fixed charges should be implemented. These changes are all intended to bring rates much closer to cost, and remove the distortions of price signals resulting from Assembly Bill 1X (2001) and the energy crisis. None of these provisions affect the amount of utility revenue requirement but change how revenues are collected, leading to increased rates for some and decreased rates for others. In addition, the implementation of TOU should provide customers the opportunity to shift some of their peak usage to off-peak times of day when it will be cheaper to do so, which could lead to incremental bill savings for some.

Residential Rate Reform Implementation

D. 15-07-001 established a ‘glide-path’ by which lower tier rates would gradually increase and upper tier rates would gradually decrease until 2018. In 2018, there will be two tiers with a 25% price differential. The decision also requires the utilities to file proposed default time-of-use rates in 2018 for possible implementation in 2019, within in the limits prescribed by PU Code section 745. In the next 12 months, the utilities will be collapsing tiers, gradually increasing lower tier rates and gradually decreasing upper tier rates in accordance with the glidepath. The utilities have also embarked on a pilot program to study time-of-use rates and recruiting tens of thousands of customers into the pilot program to determine the best structure for default 2019 TOU rates.

TOU Periods Rulemaking

In R. 15-12-12³¹, the Commission will develop a framework and methodology for identifying time-of-use periods. This proceeding will help align rates more closely with the cost of service and will examine load forecasting models created by the California ISO and the IOUs. High-cost (‘peak’) periods seem to be shifting later in the day due to increased levels of preferred resources such as solar. This potential late shift will affect bills for all customers as all commercial and industrial customers are currently on TOU rates and residential customers may default to them in 2019. These periods may also apply to time of delivery and other factors related to procurement and affect the price of purchased power. A decision is anticipated in this proceeding in 2016.

³¹ Order Instituting Rulemaking to Assess Peak Electricity Usage Patterns and Consider Appropriate Time Periods for Future Time-of-Use Rates and Energy Resource Contract Payments.

Water Energy Nexus Proceeding

In R.13-12-001, the Commission is examining the nexus between the embedded energy in water, and the embedded water in energy, as well as the use of communications technology to manage water and energy. The Commission will consider in Spring/Summer 2016 a proposal for “Matinee Pricing” pilots for commercial, industrial, and agricultural customers to shift their load to times when renewable and low-water using energy are abundant. These pilots are intended to create demand side strategies to balance renewable and other energy supply and demand. Such balance could reduce customer bills by decreasing the need to ramp down energy producers, and better align future energy resource needs.

The Water Energy Nexus Proceeding created a Cost Calculator to determine the embedded energy in water. This calculator can be used to evaluate the energy and GHG-saving potential of water-saving measures. In Spring/Summer 2016 the CPUC will consider pilots to require electric and gas IOUs to enter into agreements with water suppliers to “piggyback” on the energy “Smart meters” to improve information collection about water use. These pilots will test the ability to harness the Smart Meter network to save water, the embedded energy in water, and to reduce water leaks and thus waste of the embedded energy in water. The Water/Energy Nexus Proceeding will address other issues within its scope including the role of communications in managing water and energy and facilitating renewable power resource deployment.

PG&E 2017 GRC Phase II

D.15-07-001 allows the IOUs to request a fixed monthly charge, as permitted by AB 327, but only if certain conditions are met. One of the conditions is to develop a consistent methodology for calculating fixed costs and determine what categories of fixed costs will be included in a potential fixed charge. PG&E’s 2017 GRC Phase II, which will file in late June 2016, is where the utilities and stakeholders will present their methodologies for consideration by the Commission, which will decide whether, and to what extent, a fixed charge should be approved, on the basis of the proposed methodology.

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.

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 2015, 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 to examine 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 reduced by \$168.4 million³² by the FERC in the TO rate case proceedings during 2015. In 2016, the pending TO rate cases at FERC are for PG&E; SCE; SDG&E; NextEra Transmission West, LLC; 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.

Fifteen years later (and counting), a coalition of California Parties,³³ including the CPUC, continue litigating claims before 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

³² Revenue requirement reductions for the PG&E TO16 case were \$165.7 million (August, 2015); Mid-America Central California Transco case were \$0.36 million (May, 2015); and Duke American Transmission Company (DATC) case were \$2.3 million (April, 2015).

³³ 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).

Independent System Operator Corporation (CAISO), the Power Exchange (PX), and markets in the Pacific Northwest.

In 2015, the California Parties pursuing refunds continued to receive favorable decisions from both FERC and assigned Administrative Law Judges (ALJs), and continue to move forward towards obtaining recovery for refunds for ratepayers for sales made into short-term markets during the crisis. In addition the CPUC continues to actively prosecute claims against two remaining sellers – Shell Energy North America and Iberdrola Renewables – who negotiated long-term power contracts with the California Department of Water Resources (DWR) in the wake of the energy crisis. Hearings conducted before FERC in November and early December, 2015 went very well for the California Parties, and an initial decision on liability was recently issued in California’s favor in April, 2016.

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. While some of the settled claims resulted in significant monetary recovery for ratepayers, there are potentially more refunds as a result of ongoing litigation on the cases not settled. The CPUC continues to play an important role in all of these refund cases, including litigation and efforts to reach settlements.

Customer Generation

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

Net Energy Metering

NEM is a customer billing arrangement that provides full retail bill credits to customers with eligible generating facilities for the surplus electricity that their system exports to the grid. Under NEM, the customer's electric meter keeps track of how much electricity is consumed by the customer and how much excess electricity is generated by the system and sent back into the electric utility grid. Over a 12-month period, NEM customers currently only pay for the net amount of electricity used from the utility that is over-and-above the amount of electricity generated by their solar system (in addition to monthly customer transmission, distribution, and meter service charges they incur).

AB 327 directed the CPUC to adopt a NEM successor tariff for customers that receive NEM service after each IOU reaches its 5 percent NEM cap. As a result, on January 28, 2016, the CPUC adopted a NEM successor tariff in D.16-01-044. The Decision adopted a NEM successor tariff that largely continues the existing retail rate NEM billing structure, while making adjustments to align the costs between NEM customers and non-NEM customers.

Existing NEM customers will not be affected by the NEM successor tariff as they are grandfathered under the current NEM tariff provisions for 20 years from the date of interconnecting their NEM-eligible generating facility, unless they make significant system modifications or move their generating facility. Future customers taking service under the NEM Successor Tariff will continue the basic NEM bill structure of netting a customer's energy imports and exports over a 12-month period and receiving retail rate compensation for surplus energy exported to the grid, but the NEM successor tariff includes three major changes:

1. Customers will be responsible for paying an interconnection fee to interconnect their NEM-eligible generating facility
2. Customers must pay non-bypassable charges (NBCs) for each kWh of electricity they consume from the grid. Customers will not be able to net out NBCs using NEM bill credits. D.16-01-044 exempted NEM customers from transmission charges for the energy they consume, and those costs will be allocated to other customer classes.
3. Customers must receive service under an IOU's time-of-use retail rate schedule.

For each IOU, the NEM Successor Tariff will take effect either on July 1, 2017 or when each IOU reaches its statutorily mandated 5 percent NEM cap, whichever is earlier. Each IOU's progress

towards its NEM cap is being tracked on its NEM website.³⁴ D.16-01-044 stated that the CPUC will review the NEM Successor Tariff in 2019, as this allow analysis of the rate tier compression, transition to TOU pricing, and impact of the NEM Successor Tariff.

California Solar Initiative and Low-Income Solar Programs

Pursuant to SB 1, the California Solar Initiative (CSI) program was established by the CPUC in D.06-12-033. The CSI program is the solar rebate program for the IOUs that incentivizes adoption of customer-sited solar PV systems through financial rebates. The CSI program has a total budget of \$2.366 billion that sunsets in 2016 and a goal to install approximately 1,940 MW of new customer-sited solar generation capacity.

The Single Family Affordable Housing (SASH) and Multi Family Affordable Housing (MASH) programs are CSI sub-programs that were established in D.07-11-047 and D.08-10-036, respectively, and provide rebates for the installation of solar PV systems on low-income properties. The SASH program provides rebates for eligible low-income homeowners, while the MASH program provides rebates for eligible low-income multifamily housing. In January 2015, the Commission approved D.15-01-027, reauthorizing and extending both programs beyond 2016 with \$108 million of additional funding. The extended MASH and SASH programs will continue until all funds are exhausted or December 31, 2021, whichever occurs first. Additionally, when the CSI program sunsets at the end of 2016, any remaining unspent funds from the CSI general market program budget will be transferred over to the extended MASH and SASH programs' budget.³⁵ This rollover of CSI general market funding will reduce the total amount of money collected from ratepayers to fund the extended MASH and SASH programs.

In addition to the MASH and SASH programs, AB 693 (Eggman, 2015) created the new Multifamily Affordable Housing Solar Roofs Program, which will provide financial incentives for the installation of solar energy systems on qualified multifamily affordable housing properties. Specifically, it requires the CPUC to annually authorize \$100,000,000 or 10 percent, whichever is less, of the IOUs' Cap-and-Trade allowance revenues to create an incentive program for qualifying renewable energy systems. These allowance revenues must be appropriated between the fiscal year commencing July 1, 2016, and ending June 30, 2020, with the possibility of extending funding through June 30, 2026. The program would be funded for at least four years for a total of \$400 million, with the possibility of extending funding through 2026 for a total of \$1 billion. The bill requires the CPUC to begin authorizing incentive payments by June 30, 2017 and establishes a target of installing 300 MW of generating capacity on multifamily affordable housing properties by 2030. In D. 16-01-044, the Commission stated that it will address AB 693 in phase II of the NEM successor tariff proceeding (R.14-07-002).

³⁴ See: PG&E - <http://www.pge.com/en/mybusiness/save/solar/nemtracking/index.page>, SCE - <https://www.sce.com/wps/portal/home/residential/generating-your-own-power/net-energy-metering>, SDG&E - <http://www.sdge.com/clean-energy/net-energy-metering/overview-nem-cap>.

³⁵ Pub. Util. Code Section 2851(f)

Transportation Electrification

The CPUC, in coordination with other state agencies, develops policies to help achieve state transportation electrification and greenhouse gas emissions reduction goals. These policies aim to increase transportation electrification by:

- Coordinating the buildout of infrastructure to charge electric vehicles
- Establishing electric vehicle rates
- Utilizing Vehicle-Grid Integration technologies to use transportation energy as a resource that facilitates increased usage of renewable energy

The CPUC also oversees the electric and natural gas utilities' use of Low Carbon Fuel Standard credit revenue. The revenue generated from customers' use of alternative fuels (electricity and natural gas) is used to benefit drivers of alternative fuel vehicles, and promote further adoption of alternative fuel vehicles, without any ratepayer funding.

Additionally, the CPUC will implement Senate Bill 350 over the next several years to help meet long term greenhouse gas emissions reduction goals through increased transportation electrification. Senate Bill 350, the Clean Energy and Pollution Reduction Act of 2015, among other things, directs the CPUC to direct the electric utilities "to file applications for programs and investments to accelerate widespread transportation electrification to ... reduce emissions of greenhouse gases to 40 percent below 1990 levels by 2030 and to 80 percent below 1990 levels by 2050."

Electric Vehicle Infrastructure Pilots

Over the next 12 months, CPUC staff will oversee the implementation of electric utility pilots to install electric vehicle charging infrastructure. Through this oversight role, CPUC will help ensure that pilot implementation costs are reasonable and the programs benefit ratepayers.

Southern California Edison (SCE) Charge Ready Pilot Program

In January 2016, the CPUC authorized an SCE pilot program to incentivize the deployment of approximately 1,500 electric vehicle charging stations and conduct education and outreach in support of electric transportation.³⁶ SCE is authorized to spend \$22 million on implementation of Phase 1 of its Charge Ready and Market Education Programs under a settlement agreement among parties that was modified and approved by the CPUC. Ratepayers will fund the cost of all paneling, conduits, and wiring, up to the charging station itself. Edison will also provide charging station rebates to site owners to cover a pre-determined percentage of the charging system "base cost." The customer participant will own and operate the charging station and will be responsible for all related operating costs, including maintenance and electricity usage.

³⁶ Decision 16-01-023 in Application 14-10-014.

Over the next 12 months, CPUC staff will ensure appropriate program implementation, including establishing balancing accounts that cap the pilot-related expenditures that can be recovered from ratepayers. CPUC staff will work with other Charge Ready Advisory Board³⁷ members to ensure SCE uses an appropriate charging system “base cost” for purposes of determining the value of rebates provided to site owners.

San Diego Gas & Electric (SDG&E) Electric Vehicle-Grid Integration Pilot Program

In January 2016, the CPUC authorized an SDG&E pilot program to install and own 3,500 electric vehicle charging stations at 350 workplaces and multi-unit dwellings.³⁸ The four-year pilot authorization includes \$45 million in charging infrastructure, plus limited, reasonable operations and maintenance expenses to be considered in future General Rate Cases. The CPUC rejected a \$103 million proposal and a joint-party proposed settlement and instead approved a pilot program more consistent with goals to ensure ratepayer protection and competition, including increased reporting, a shorter pilot period, a smaller budget, and improved coordination with related clean energy programs. The CPUC’s Decision fully funds charging infrastructure installed in disadvantaged communities, and requires that 10 percent of installations be located in such communities. It also exempts low income customers from funding the pilot. The Decision further protects ratepayer interests by requiring a phased approach, a participation payment from site hosts outside of disadvantaged communities, leveraging of existing pilots, greater coordination with regional and national transportation-related initiatives, and increased reporting and oversight.

Over the next 12 months, CPUC staff will ensure appropriate program implementation, including establishing a memorandum account and balancing account that cap the pilot-related expenditures that can be recovered from ratepayers.

Pacific Gas and Electric (PG&E) Electric Vehicle Infrastructure Pilot Proposal

In February 2015, PG&E submitted an application for a pilot to deploy, own and maintain approximately 25,000 Level 2 electric vehicle charging stations and 100 DC Fast Chargers.³⁹ PG&E requested to recover actual costs up to \$653 million. Given the large request, the ALJ required PG&E to supplement its application with a proposal outlining a more phased approach to deployment. In response, PG&E provided a proposal for both 2,500 chargers and 7,500 chargers. The CPUC will continue considering PG&E’s supplemental proposal and examine the costs and benefits of the proposal before issuing a decision in mid-2016.

³⁷ The Advisory Board includes consumer advocates, environmentalists, electric vehicle drivers, the automotive industry, disadvantaged communities, labor, and electric vehicle charging partners. In the settlement agreement, SCE agreed not to take any material action regarding program design and implementation without consulting the Advisory Board.

³⁸ Decision 16-01-045 in Application 14-04-014.

³⁹ Application 15-02-009.

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. Demand Response is undergoing several changes that could ultimately impact utility costs and rates in the short and long-term. The two activities that could have significant potential impact are a.) integration of existing utility programs into CAISO markets, and b.) the Demand Response Auction Mechanism (DRAM) pilots.

Integration with CAISO Markets

In 2015, the Commission determined that most utility demand response (DR) programs must be integrated into the CAISO electricity markets by 2018, or they otherwise have no resource adequacy value. Until this past summer⁴⁰, utility DR programs were dispatched by the utility when the utility considered it appropriate to do so. Integration of DR into CAISO markets represents a significant change in several respects: DR will be dispatched if the resource wins an award in the CAISO market based on its bid prices; whereas utility DR programs that are not integrated are dispatched at the discretion of the utility, based on specific dispatch triggers in the program tariffs. . Integrated DR is more useful to the CAISO in addressing specific geographic needs. Most importantly, integrated DR is visible to the CAISO, is held to performance requirements in the CAISO market and is therefore considered more reliable. These changes overall make DR more useful to the electricity system, which is a better use of ratepayer funds that support these programs. While there are short-term costs associated with integrating DR programs (primarily infrastructure and operating costs), the potential long-term implications are significant: integrated DR enables demand response to compete against generation resources in the wholesale market. When a DR resource is dispatched, a higher-priced generation resource that otherwise would have been dispatched is avoided. Likewise, the CAISO can dispatch integrated DR for specific geographic needs that otherwise would be addressed with generation resources that are more expensive. Finally, by making DR more visible to the CAISO, DR can be more effectively integrated into long-term resource planning efforts which reduce the need for long-term investments in generation resources. That not only creates savings for ratepayers, but helps the Commission achieve its greenhouse gas reduction goals.

Demand Response Auction Mechanism (DRAM)

In 2015, the Commission approved a pilot to test a new capacity procurement strategy DR integrated into the market by third parties, outside of any utility DR program. The pilot, known as the Demand Response Auction Mechanism (DRAM), generated high interest as the utilities

⁴⁰ Southern California Edison integrated a large portion of its demand response portfolio into CAISO markets in the summer of 2015.

procured from the market almost double (40 MWs) the amount of MWs they were required to (22 MWs), for deliveries in 2016. The performance of the DRAM contract winners remains to be seen as deliveries of DR from the auction will not appear until June 2016. In the meantime, a second auction (for deliveries in 2017) was launched by the utilities in April of 2016. If the DRAM pilots demonstrate success in procuring reliable integrated DR, the Commission could determine that the DRAM should be expanded from a pilot into a full program. If that were to occur, ratepayer costs for DR programs could be reduced if DRAM is able to procure DR at lower costs than the utilities' costs to administer programs.

Renewables Portfolio Standard

Established in 2002 under Senate Bill 1078 (Sher), accelerated in 2006 under Senate Bill 107 (Simitian) and expanded in 2011 under Senate Bill 2 (1X) (Simitian), California's Renewables Portfolio Standard (RPS) is one of the most ambitious renewable energy standards in the country. The RPS program requires investor-owned utilities (IOUs), electric service providers (ESPs), publicly owned utilities (POUs), and community choice aggregators (CCAs) to increase retail sales from eligible renewable energy resources to 33% of total procurement by 2020. The CPUC and the CEC are jointly responsible for implementing the RPS program. Senate Bill 350 revises the current RPS target to obtain 50% of total retail electricity sales from renewable resources by December 31, 2030, with interim targets of 40% by December 31, 2024 and 45% by December 31, 2027. The CPUC will continue to implement efforts to minimize the cost associated with increased procurement of renewable energy through the measures discussed below.

IOUs' Bid Selection Criteria and RPS Procurement Standards of Review

In D.14-11-042 the CPUC adopted standards of review (SOR) for renewable power purchase agreements (PPA) that are submitted to the CPUC for approval. The SOR were adopted 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 adopting the standards of review, the CPUC has developed a standardized Renewable Net Short (RNS) method that more accurately depicts the RPS compliance positions of California's three major IOUs. The purpose of standardizing of the RNS methodology was 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 properly account the value 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.⁴¹ All three large IOUs have noted in their approved 2015 RPS Procurement Plans the intent to sell excess RPS generation if it is consistent with their

⁴¹ Renewables Portfolio Standard Quarterly Report to the Legislature, 4th Quarter 2015.

RPS position and provides value to ratepayers.⁴² The IOUs could lower total costs to ratepayers by selling any excess contracted renewable generation. As an aside, the CPUC has approved RPS sale contracts for SCE, PG&E, and SDG&E. We note that in general, all RPS contracts are “purchased power” contracts and the IOUs do not earn a rate of return on these electric sales.

Transmission Costs

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.

As noted earlier in this report, one important area of potential cost savings is in the avoided transmission investments that would be afforded by energy-only rather than full capacity delivery status (FCDS). If existing resources can be relied upon to address energy needs during peak periods, when FCDS resources would be utilized, this would therefore limit transmission upgrades or the construction of new transmission lines to interconnect FCDS resources. Ultimately, this could have a significant impact in reducing transmission revenue requirement required to meet California’s renewables goals.

⁴² D.14-11-042 approved the IOUs’ 2014 RPS Procurement Plans.

Energy Efficiency

The CPUC regulates ratepayer-funded energy efficiency programs managed by investor-owned utilities, other program administrators, and vendors. The programs are designed to overcome market barriers to adoption of high efficiency measures and to transform technology markets within California using ratepayer funds.

The CPUC oversees and approves the energy efficiency programs funded by charges established in: the Public Utilities Code Section 381 (Public Goods Charge); Public Utilities Code Section 890 – 900 (Gas Surcharge) and the Public Utilities Code Section 399.15 (b)/379.5. The current oversight of these activities is governed by Rulemaking R.13-11-005 at the CPUC. Last fall the Commission adopted decision D.15-10-028 which established goals for 2016 and beyond and a new administrative structure for ongoing review and approval of energy efficiency programs and initiatives called the “Rolling Portfolio”. This structure will allow for the ongoing improvement of the cost effectiveness of the energy efficiency portfolio and alignment with state policy goals.

Several new pieces of legislation including AB 802 focused on benchmarking and methods of estimating baseline conditions and measuring programs and activities based on metered performance may change the program activities in the upcoming year. SB350 which calls for the doubling of energy efficiency may have effects in the upcoming years for energy efficiency. The current proceeding schedule expects a business plan for energy efficiency from each program administrator in the fall of 2016. If budgets are significantly larger than historically requested, this may have a significant effect on rates.

Two strategies, which are both in fairly nascent phases, show potential for affecting costs of delivering energy efficiency in the upcoming years.

Statewide Financing Pilots

One of the goals of the statewide financing pilots is to eventually lead to a self-sustaining statewide program that does not rely on ratepayer funding. The 2012 Energy Efficiency Guidance decision (D. 12-05-015) recognized that cost can be a barrier to customers achieving deeper energy efficiency savings. To encourage uptake of deeper energy efficient measures, the decision adopted a financing path, to enable customers to afford measures that might not otherwise be attainable. The Decision also recognized that ratepayers’ ability to fund energy efficient savings is not infinite, and directed the utilities to propose pilots that would leverage ratepayer funds to bring in private capital. In D.13-09-044 the CPUC approved 7 finance pilots and authorized \$75.2 million of rate payer dollars to run the statewide pilots. Currently \$65.9 million of the authorized funds are allocated, and the CPUC will reconsider after the first residential pilot has been up and running for a year, whether or how to allocate the remainder of the budget. The ratepayer funds will be used as credit enhancements, to enable lenders to offer more attractive loans and leases to customers. Successful pilots could therefore benefit ratepayers, assuming that lenders are comfortable making loans for energy efficiency projects

without the need for a credit enhancement, and that customers are more interested in taking out a loan than receiving a rebate to participate in a program.

Additionally, in the 2012 Guidance Decision the CPUC directed the utilities to consider lowering incentives that were paid to customers that participating in the On- Bill Financing program. Currently one utility has proposed reducing its incentives. Another utility has proposed an alternative pathway for on bill financing which is currently being considered by Energy Division. If these changes occur, it could lead to a decrease in incentives that are paid to customers.

Expansion of Third Party Programs

Program administrators are required by the Commission to contract with third parties for at least 20% of the portfolio activities, and the Commission has consistently encouraged program administrators to “identify additional opportunities to enlist new third-party implemented programs through competitive solicitations.” (see D.12-05-015). Currently the majority of third party programs in the Commercial portfolio remained focused on hard-to-reach markets or regional needs. The IOUs seek competitive solicitations from contractors or program implementers to manage third party, direct install and local government programs that target hard-to-reach-sectors.

Energy Division staff hosted a workshop on March 24, 2015 to explore administrative models used in different states. The goal of the workshop was to consider the viability, benefits, and tradeoffs of changing the current program administrative model. Experts from Lawrence Berkeley National Lab presented a cross section of administrative models currently used in the country and including those with an expanded version of third party administration. Variations presented at the workshop included utilities as the main program administrators, a single non-profit administrator for all or just statewide initiatives, or a competitive procurement model as used in Hawaii and Vermont.

One of the most important considerations for changing the current model is whether third party administration would effectively drive down long-term costs as a result of competition for the ability to administer the programs. Also at question is whether it would result in lower administrative costs and more cost-effective programs or the overall portfolio. Additionally, there may be high upfront, short term transition costs to move transition to a third party implementation approach, with longer term savings for ratepayers.

No decision has been made by the Commission on changing the program administrator model.

Energy Savings Assistance Program

The CPUC administers the Energy Savings Assistance Program (ESA) to provide measures to low-income ratepayers to reduce energy hardships and increase their health, safety, and comfort. In Summer/Fall 2016, the CPUC will determine the ESA program design for the next three year

cycle. Measures that reduce kWh used can help low-income households reduce energy bills, or mitigate the impact of increased rates for lower tiers as a result of the rate reform proceeding. ESA is also considering measures to address the water-energy nexus in light of California's ongoing drought and Executive Orders to reduce water consumption and leaks.

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. Several procurement proceedings and the new load serving entity (LSE) capacity procurement program could affect rates in the near term. In addition, the CPUC administers the Long Term Procurement Plan proceeding (LTPP) that oversees IOUs' procurement plans and evaluates the need for new resources.

SCE Procurement in LA Basin

Pursuant to the 2012 LTPP Proceeding, SCE submitted an application for a total of 1,882.6 MW of procurement in the LA Basin (A.14-11-012). The application included a 500.6 MW of preferred and energy storage resources with online dates beginning in 2016 through 2021. Additionally, the application included 1,382.00 MW of conventional generation resources with online dates beginning in summer 2020. In D.15-11-041, the Commission approved the application with the exception of the 6 Demand Response contracts that relied upon fossil-fuel based backup generators. As a result, the total Preferred Resources approved was 430.6 MW.

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 Commission is scheduled to consider the Proposed Decision and Alternate Decisions in its meeting on May 12, 2016.

LSE Capacity Procurement (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 than system or local RA, rates could be affected. R.14-10-010 adopted local and flexible requirements for the 2016 year, and will adjust local and flexible requirements for the 2017 compliance year.

SDG&E Carlsbad Procurement (A. 14-07-009, D.15-05-051)

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 caused by the retirement of San Onofre Nuclear Generating Station (SONGS).

SDG&E submitted a 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 expected on-line date is March 16, 2018 and is expected to provide power for 20 years. The Commission Decision (D.15-05-051) approved the Carlsbad PPTA conditioned on the reduction of the capacity to 500 MW and the residual 100 MW must be preferred resources or energy storage.

CONCLUSION

Retail rates, such as those paid by all residential customers, are ultimately defined by a simple calculation – the revenue requirement of the utility divided by the electricity sales. In the 21st century, the former model of steady growth in energy sales is coming to a close, as new norms, policies and technologies continue to place downward pressure on sales. As a result, volumetric rates are bound to rise over time, which may lead to disproportionate bill impacts if all customers fail to reduce energy usage at exactly the same rate.

The IOUs are aware of this future, and therefore repeatedly propose reforms to rates such as fixed charges, demand charges, and minimum bills in order to ensure they can collect a fixed amount of revenue from a customer regardless of how much their total sales decline. This report takes no position on those proposals, however, it does seek to highlight that the Commission has many other options at its disposal to manage the other side of the rates equation – utility revenue requirement.

The impact on rates of declining sales can be ameliorated by making targeted reductions to utility revenue requirement, consistent with the decrease in utility sales. This report has sought to outline a few of the ways in which utility revenue requirements and retail rates may be managed going forward in the increasingly competitive market environment for controlling rates in the 21st century. Indeed, the CPUC has at its disposal a great number of options for limiting authorized utility revenue requirements that mitigate rate and billing impacts that can be prioritized before requiring customers to insulate the utilities from market competition through unavoidable fixed and demand charges. This 2016 report thus marks the beginning of a longer term dialogue with decision-makers about protecting consumers as increased energy efficiency, a robust DER market, and other market structure dynamics unfold in the decade to come.

UTILITY COMPLIANCE SUBMISSIONS

Public Utilities Code Section 913.1 mandates that the IOUs study and report on measures that they recommend be undertaken to limit costs and rate increases. These submissions include a list of each utility's proceedings before the Commission and their expected impact on rates, as well as descriptions of each utilities expected upcoming revenue requirements. 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 <http://www.cpuc.ca.gov/General.aspx?id=8324>.

PG&E's Recommendations

PG&E identifies the tiered rate structure as a major barrier to fair and equitable rates, contending that the changes made in the Residential Rate Reform Decision, D.15-07-001, may result in rate differentials that continue to have no cost basis. They support having a fixed monthly charge in residential rates that they believe will spread costs to customers in a more equitable way based on the fixed costs to serve them.

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. Continued high upper tier rates magnify the cost-shift when large users install solar systems. They assert that D.16-01-044 deferred any significant reforms of the cost-shifting associated with NEM.

In terms of managing cost components, PG&E notes that their 2014 GRC forecast included significant operational savings achieved through the implementation of SmartMeter technology which reduced forecasted costs. In PG&E's 2017 GRC, currently pending before the Commission contains significant safety and reliability investments which the company acknowledges need to be balanced with maintaining rates at a reasonable level.

PG&E's submission can be accessed at: <http://www.cpuc.ca.gov/General.aspx?id=11417>

SCE's Recommendations

In its 2015 GRC Phase II proceeding, Parties settled on a proposal that resulted in lower subsidization across and within rate classes, while also providing some measure of rate stability for those classes. SCE believes that recovering those costs equitably from customers ensures that those customers who are more costly to serve pay appropriately higher rates.

SCE also asserts that the state may have conflicting environmental policies which increase customer costs, time and resources, for example, the cost and delays of siting new renewable power to replace fossil fuel generation due to land use restrictions and the possibility of needing additional conventional resources to integrate those renewable projects, as well as potential struggles to license new gas generation due to emissions standards and lack of permits for particulate emissions. SCE recommends that the State pursue

a more coordinated effort to establish consistent and comprehensive goals and determine least cost and most efficient means to achieve those goals.

SCE's submission can be accessed at: <http://www.cpuc.ca.gov/General.aspx?id=11418>

SDG&E's Recommendations

SDG&E advocates the importance of establishing the 'right' rate design in light of the coming changes in the electric industry, including the move toward increasing amounts of distributed generation. SDG&E's vision of this future focuses on a more 'forward-thinking' rate design with cost-based rates and accurate price signals that truly reflect the cost of the variety of services (not necessarily the traditional 'full-service') that customers can receive from the utility.

SDG&E's major recommendations are that the CPUC and Legislature do cost analysis of state-mandated programs before adoption, and reduce cross subsidies between customers. They believe that AB327 made significant strides but that the NEM successor tariff decision chose to defer the question of cost-shift, which they assert is larger per customer than the CARE subsidy.

In addition, SDG&E has proposed in its 2016 GRC Phase II to update sales annually to better address regulatory balances and the impact of delayed regulatory decisions on rates.

SDG&E's submissions can be accessed at: <http://www.cpuc.ca.gov/General.aspx?id=11420>

and

<http://www.cpuc.ca.gov/General.aspx?id=11421>

SoCalGas' Recommendations

SoCalGas recommends that costs should be recovered in rates that reflect how those costs are incurred and proactively proposes changes to prevent intra-class subsidies. To that end, SoCalGas has proposed in its TCAP Phase 2 application, an increase to the monthly residential customer charge and a reduction in volumetric charges which they believe will decrease bill volatility and intra-class subsidies.

SoCalGas also asserts that key drivers or rates fall out of their control, including gas commodity prices, sales volumes, weather, natural disasters, permitting process delays and new environmental regulations. They recommend that the Commission consider the cost-effectiveness framework proposed in E, 15-01-008 to achieve the maximum feasible GHG reductions. Other recommendations include encouraging the installation of Combined Heat and Power (CHP) systems, consideration of fuel cell technology in emission reduction goals, and streamlining Commission reporting requirements.

SoCalGas' submission can be accessed at: <http://www.cpuc.ca.gov/General.aspx?id=11419>