



Actions to Limit Utility Costs and Rates

Public Utilities Code Section 913.1 Annual Report to the Governor and Legislature



CALIFORNIA PUBLIC UTILITIES COMMISSION

ENERGY DIVISION

MAY 2017



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Table of Contents

1. Introduction 3

2. The Basic Outlook: Rising Electric Rates in California 5

 2.1 A Brief Lexicon of Key Ratemaking Terms and Definitions 5

 2.2 Overall Trends in Rates in California 6

3. The Ongoing Evolution of the Rate Structure 6

 3.1 The State of Residential Rate Reform Implementation 6

Tiered Rate Collapse: Nearing the End State Rate..... 7

TOU Opt-In Pilots: 2016 Summer Results and Protecting Vulnerable Customers..... 7

TOU Default Pilots – Testing the Transition and Evaluating Customer Insights..... 8

New TOU Periods and Optimizing Grid Resources..... 8

 3.2 General Rate Case Phase II Considerations 8

SDG&E GRC Phase II – Pending Decision (A.16-06-013) 8

PG&E GRC Phase II 9

4. Containing Costs in Program-Specific Proceedings 10

 While cost containment efforts are a common feature of numerous proceedings at the Commission, we focus on a handful here: 10

 4.1 Electric Vehicles 11

State Mandates and Strategies to Increase Transportation Electrification..... 11

IOU Transportation Electrification Programs and Investments 12

 4.2 Integrated Resource Planning 14

 4.3 Energy Efficiency 16

Statewide Approach to Program Implementation..... 17

Expansion of Third Party Programs 17

AB 802 and Existing Conditions Baselines..... 17

 4.4 Demand Response 18

 4.5 Electric Utility Costs and Revenue Requirements 18

 4.6 Electricity General Rate Case Phase I 19

PG&E 2017 GRC | A.15-09-001 — Filed Sept. 1, 2015; Effective Jan. 1, 2017..... 20

SCE 2018 GRC | A.16-09-001 — Filed Sept. 1, 2016; Effective Jan. 1, 2018..... 20

<i>SDG&E 2016 GRC / A.14-11-004 — Filed Nov. 14, 2014; Effective Jan. 1, 2016</i>	21
4.7 Electric Fuel and Purchased Power Costs	21
<i>ERRA Proceedings</i>	22
4.8 Evaluating Costs in Natural Gas	22
<i>PG&E Gas Transmission and Storage (A.13-12-012)</i>	22
<i>SoCalGas/SDG&E General Rate Case (A.14-11-003/A.14-11-004)</i>	22
5. Conclusions	23
Appendix: IOU Summaries	24

1. Introduction

This report is published in accordance with Public Utilities Code Section 913.1, 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.

The CPUC continues to make strategic changes to the report structure, shifting focus to identify long term macro trends affecting electric utility costs, electricity sales, and rate increases, and short term opportunities for our decision-makers to mitigate potentially deleterious customer impacts. As in the 2016 report, we identify priority actions in 2017 for containing the costs of administering some of our most important programs and proceedings. We acknowledge that while trends in rates emerge gradually over a longer time horizon, the short run opportunities for the CPUC's strategic management of rate and billing impacts can change by the year.

Cost Containment in an Increasingly Competitive Energy Industry

The purpose of the 2017 Report is to evaluate ongoing but not wholly unexpected trends in utility electricity sales and revenue requirement, and their relative impacts on retail rates and bills for our customers, taking both a long term view of the system level impacts as well as an evaluation of opportunities in 2017 for our decision-makers to make informed policy choices in the short run to mitigate consumer impacts. However, rather than presenting an exhaustive list of specific cost-cutting measures that should be determined in the General Rate Case (GRC) process or other formal rate-making proceedings, we instead identify some of the broader cost categories impacting the Investor Owned Utilities' (IOUs' or utilities') revenue requirement and earnings, while illustrating a few options for cost reduction (or sales growth) that the CPUC may wish to consider in future proceedings.

Historically, the IOUs' sales and revenue requirement have generally mirrored or paced each other in a gradual, predictable upward trend, engendering relative stability in their system average rates (SARs, calculated as total revenue requirement divided by total kWh sales). Indeed, system average rates also generally tracked inflation until 2012. However, in recent years, sales have flattened out or gradually declined while revenues requirements have generally increased with few exceptions.

Short Term Versus Long Term Outlook

The flattening or declining trend in kWh sales is driven by a changing economy, growth in the customer (so called “behind-the-meter”) solar industry, increasing availability of demand side management (DSM) programs such as energy efficiency, and the incremental proliferation of retail choice. These developments may point to the gradual erosion of IOU market share and the continued development of a more robust distributed energy resources (DER) market in the longer term. In the short term they result in fewer kilowatt hours (kWhs) of electricity sales over which to spread an increasing revenue requirement, which has the effect of putting upward pressure on system average rates.

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. 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 addition to this Introduction, this report has four sections, organized as follows: (2) Trends in electric rates and customer impacts; (3) The key policy levers available to the CPUC and legislature to address these trends and the potential effects on rates; (4) 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 (5) Conclusions. Summaries of the IOUs’ report required by Section 913.1, as well as links to the full reports, are provided in an Appendix.

2. The Basic Outlook: Rising Electric Rates in California

2.1 A Brief Lexicon of Key Ratemaking Terms and Definitions

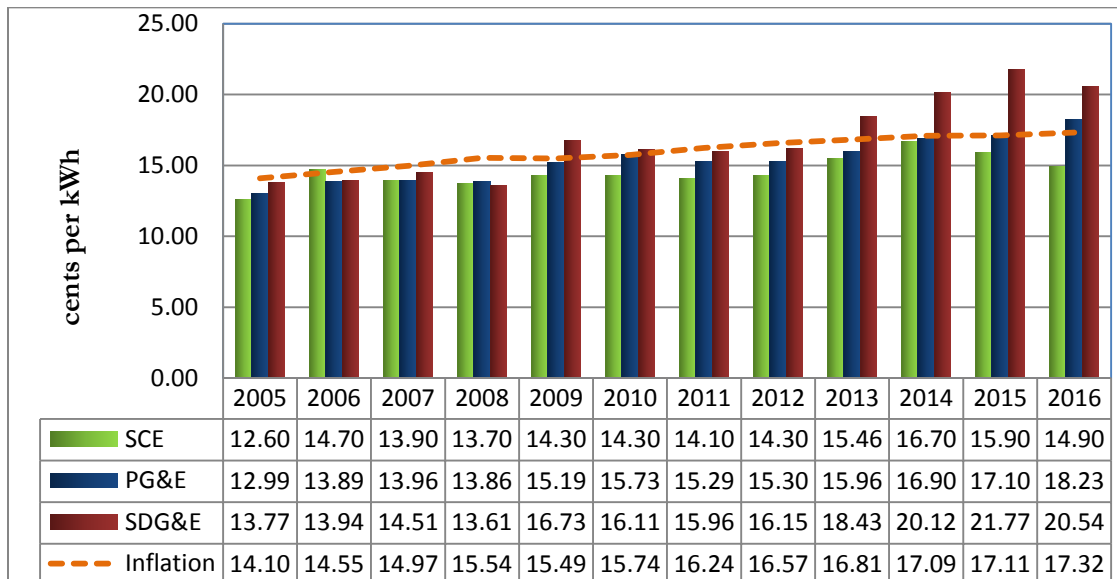
The following is a list of essential definitions used in this document and in the Commission's ratesetting work in GRC Phase I and GRC Phase II:

- ✦ **Revenue Requirement or *utility costs*** are used interchangeably and synonymously, and refer to the operating costs, depreciation, and 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.
- ✦ **Rate of Return (ROR) on Ratebase** 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 profit.
- ✦ **Total Revenue Requirement** = Ratebase x Authorized Rate of Return + Expenses.
- ✦ **Retail Rates** are determined by dividing total revenue requirement by total kWh sales (system average rate), and are further subdivided by customer class.
- ✦ **Fixed Charge (FC):** A charge assessed on customer bills to recover fixed costs caused by each customer.
- ✦ **Demand Charge (DC):** A non-coincident demand ("NCD") charge (in \$/kW) is assessed on the customer's maximum demand in any 15-minute interval during the billing cycle. A peak-related (or coincident) demand charge ("CD charge") is assessed on the customer's maximum demand in any 15-minute interval during the peak TOU period.
- ✦ **Utility Earnings (or Earnings Per Share)¹:** Earnings per share (EPS) represents the portion of a company's earnings, net of taxes and preferred stock dividends, that is allocated to each share of common stock. The figure can be calculated simply by dividing net income earned quarterly by the total number of shares outstanding during the same term.

¹ PG&E Corporation is adjusting 2017 guidance for projected GAAP earnings in the range of \$3.48 to \$3.77 per share, which includes forecasts for the revenue adjustment authorized in the 2015 GT&S rate case, pipeline-related costs, legal and regulatory expenses, penalties imposed by the CPUC, as well as other items

2.2 Overall Trends in Rates in California

In recent years system Average Rates (SARs) have broken the historic trend of roughly tracking inflation and have instead increased faster than inflation. As noted in the April 2016 Assembly Bill (AB) 67 Report submitted to the legislature², electric rates in California have increased by 3.44% per year since 2012, above the annual inflation rate of 1.3%. However, due to the large investments in DSM programs such as energy efficiency, behind-the-meter solar, and demand response, average customer bills have remained relatively flat. We expect continued expansion of these programs will lead to savings by the utilities, reduced revenue requirements and lower bills in the long run, as compared to a system that was built without these resources. The chart below provides an overview of the SAR trends from 2005.



3. The Ongoing Evolution of the Rate Structure

3.1 The State of Residential Rate Reform Implementation

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. In July 2015, 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).

² The Electric and Gas Utility Cost Report submitted to the Legislature pursuant to PU Code §913.1 in April 2017 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.

The Rate Reform 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 the cost of providing service. None of these rate reforms affect the utility’s total revenue requirement and instead change how revenue requirement is allocated and collected among utility customers, leading to increased rates for some and decreased rates for others. In addition, the implementation of TOU should provide customers the incentives to shift some of their peak usage to off-peak times of day when it will be cheaper to do so, which should result in a more efficient grid and lower bills, on average, in the long run.

Tiered Rate Collapse: Nearing the End State Rate

In D. 15-07-001, the Commission implemented a tiered rate glidepath process for utilities beginning in 2015 in which lower tier rates gradually increase and upper tier rates gradually decrease until 2018. These prescribed steps bring the IOUs closer to a cost based rate structure, where customer bills more accurately reflect the cost of providing them service, and the ability to move customers onto TOU rates. Before the rate reform decision, there were up to 5 tiers with the spread between the tiers generally as high as 300% or more (meaning the customers were paying up to 3 times as much for electric usage in the top tier as they were for tier 1 usage).³ Presently, there are two tiers, and the price differential between these tiers is narrowing toward 25% by 2018. The utilities are then required to file proposed default time-of-use (TOU) rates in 2018 for implementation in 2019, within the limits prescribed by PU Code section 745.

TOU Opt-In Pilots: 2016 Summer Results and Protecting Vulnerable Customers

In 2016, utilities launched opt-in TOU pilot programs to evaluate the performance various TOU rate options. The pilots included of nearly 60,000 customers. a. Some of the initial findings around participant load shift, billing impacts, and customer surveys, have been encouraging, as follows:

In 2016, the utilities launched opt-in TOU pilot studies to evaluate customers’ response to a

- Load reductions during peak hours generally range from 4-6%, or from 0.04-0.06 kW
- Most PG&E and SCE customers experienced higher summer bills on the TOU rate than they would have on the tiered rate, but some were able to mitigate some of the increase through changes in behavior.
- SDG&E customers’ summer bills were comparable whether on the TOU rate or on the tiered rate.
- Customers on TOU rates engaged in load shifting behavior much more frequently than customers on tiered rates.

³ In January 2010, PG&E briefly had 5 tiers with the baseline rate at approximately 11.8 cents/kWh and Tier 5 at 47.3 cents/kWh, for a 400% spread between the tiers. This spread has decreased substantially between 2010 and 2017, with 5 tiers collapsing to 2 plus the super-user surcharge.

- Satisfaction ratings were comparable between customers on TOU rates and tiered rates.
- Low-income customers had lower levels of understanding of peak hours than non-low-income customers.
- Less than 3% of customers opted-out of any of the rates tested.
- No strong indications that any particular rate or rates are preferable to others, which suggests the value in giving customers more than one TOU rate option.
- Lower levels of understanding amongst the low-income population suggest a need to identify more effective ways to communicate with low-income customers.

TOU Default Pilots – Testing the Transition and Evaluating Customer Insights

The utilities will collectively default approximately 770,000 customers onto TOU rates in spring 2018. This “soft launch” will ensure that the utilities’ IT systems, business processes and customer service centers are prepared for the full rollout of default TOU in 2019. Each utility will test a variety of marketing, education and outreach materials in order to determine the most effective ways of communicating customers’ rate choices and the most effective ways of motivating customers to take action in changing energy behaviors.

New TOU Periods and Optimizing Grid Resources

In R. 15-12-12⁴, the Commission developed 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 are shifting later in the day due to increased levels of solar generation. If adopted, this shift will affect bills for all commercial and industrial customers, which are currently on TOU rates, and would also affect residential customers if the Commission adopts TOU rates for residential customers in the future. These periods may also apply to time of delivery and other factors related to procurement and affect the price of purchased power. Energy Division is reviewing new base TOU periods for each utility in 2017.

3.2 General Rate Case Phase II Considerations

The utilities total revenue requirement is decided in the several Commission proceedings. How that revenue requirement is allocated and collected between customers is generally determined in the General Rate Case (GRC) Phase II proceeding.

SDG&E GRC Phase II – Pending Decision (A.16-06-013)

Due to increased DG solar penetration, the peak period has gradually shifted to later in the day. As a result, SDG&E has proposed a shift to its peak TOU period from the current 11:00 am to 6:00 pm to 4:00 pm to 9:00 pm.; however, certain parties oppose SDG&E’s proposal, and prefer

⁴ 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.

an earlier 2:00 pm start to the peak period. In addition, consistent with the GRC phase II process historically, parties proposed a variety of marginal costs and revenue allocations, and a settlement agreement is pending in this proceeding.

Among significant non-residential rate design issues, SDG&E has proposed changes to its demand charge structure that could have implications for some customers in terms of billing impacts and the value proposition of DER investments.⁵ In addition, San Diego public schools have requested discounted rates, and have reached an agreement with SDG&E (which other parties oppose). There is also a pending settlement between SDG&E and agricultural parties. Finally, a commercial electric vehicle (shuttle bus) fleet operator is seeking relief from demand charges (which the Commission has granted, in other venues to commercial electric bus operators.

Residential rate design is being addressed separately in R.12-06-013.

PG&E GRC Phase II

Due to the complexity of the changing nature of retail rates, the PG&E GRC Phase II has been broken into two tracks phase which will allow some decisions to be fast tracked to Commission decisions in the summer of 2017.

Fixed Charge Phase

The Residential Rate Reform decision (D.15-07-001) allows the IOUs to request a fixed monthly charge, as permitted by AB 327, but only after developing a consistent methodology for calculating fixed costs and determining which cost categories will be included in a potential fixed charge. As such, in the PG&E GRC phase II, all three utilities were directed to present their fixed charge methodologies for consideration by the Commission, which will decide whether a fixed charge should later be approved, on the basis of the proposed methodology. The two proposals being debated on record are as follows:

- (1) The IOUs have proposed that fixed costs include all costs except marginal energy and capacity costs; and
- (2) The Joint Parties (ORA, TURN, and SEIA) have proposed that only ongoing costs of customer services should be eligible for inclusion in fixed charges.

A decision in this phase is expected early summer 2017.

⁵ More specifically, SDG&E proposes a greater use of “non-coincident” demand charges (not necessarily related to peak hours or dependent on time) in its distribution rates for medium and large commercial customers. In addition, SDG&E also proposes greater use of coincident (peak-related) demand charges in its generation rates for these customers.

Non-Fixed Cost Phase (Marginal cost, Revenue Allocation, Rate Design)

Traditionally the core of the second phase of our GRC proceedings, proposed marginal costs and revenue allocation issues are often settled by parties. However, there are non-residential rate design issues involving demand charges and competing sets of storage rate proposals that may need to be litigated. This proceeding enables the Commission to take another step toward facilitating the transition to default residential TOU rates and grid optimization through an evaluation of the following:

- Reasonableness of marginal costs, revenue allocation, and rate design proposals;
- Feasibility and reasonableness of proposed Direct Access (DA) and Community Choice Aggregation (CCA) fee structures;
- Reasonableness of TOU hours and 4 month summer season proposals.

4. Containing Costs in Program-Specific Proceedings

While cost containment efforts are a common feature of numerous proceedings at the Commission, we focus on a handful here:

- **Electric Vehicles (EV):** The implementation of SB 350 and progress toward widespread transportation electrification will incrementally reduce GHG emissions while increasing electricity sales, which in turn could partially offset sales reductions resulting from the proliferation of distributed energy resources (DERs).
- **Integrated Resources Planning (IRP):** SB 350 requires the CPUC to take a more holistic approach to resource planning to ensure California meets its GHG reduction goals at the lowest possible cost while maintain grid reliability. The CPUC will meet this requirement through an new Integrated Resource Planning process. As the IRP umbrella proceeding moves forward, it presents a key opportunity for ensuring the cost-effectiveness of utility proposals for long term resource needs by promoting prudent investments over a reasonable time horizon.
- **Energy Efficiency:** After reviewing the 2013-2015 program cycle results and implementing the “Rolling Portfolio” administrative structure, we examine new opportunities for achieving greater cost-effectiveness in energy efficiency as we meet SB 350 goals.
- **Demand Response (DR):** In 2017, the Commission has an opportunity to assess the proposed utility DR five-year program budgets and anticipated benefits, as well as to evaluate the results of the Demand Response Auction Mechanism (DRAM) pilot to determine whether the DRAM is more cost-effective than utility-operated DR programs.

- **Energy Resource Recovery Account (ERRA):** ERRA forecasting and recovery proceedings are continuous annual opportunities to evaluate the pass-through costs and rate impacts of utility fuels and purchased power, approximately half of the utilities’ revenue requirements.
- **GRCs:** The three-year GRC cycle is staggered for our three utilities, and therefore each year presents an opportunity to take a closer look at proposed revenue requirements and keep them contained in this era of declining sales so as to keep rates in check.
- **Gas Cost Proceedings:** As 2016 gas cost decisions for SoCalGas and PG&E get implemented in 2017, the CPUC will be able to begin reviewing the effectiveness of infrastructure and safety spending.

4.1 Electric Vehicles

State Mandates and Strategies to Increase Transportation Electrification

Senate Bill 350 (DeLeon, 2015)⁶ established a goal of accelerating statewide transportation electrification, which will lead to more deployment of electric vehicles. The CPUC is developing policies to support customers that adopt electric vehicles and is collaborating with other state agencies to ensure the utilities’ programs aimed at accelerating transportation electrification also effectively reduce emissions and petroleum dependence.

Transportation electrification will not only help California meet its goals to reduce greenhouse gas emissions and criteria pollutants, but will also increase electric utilities’ load and potentially offset declining energy sales. Growth in EV deployment will lead to higher overall demand, which will enable better management of rates and energy supply and demand imbalances reflected in the “duck curve”, with opportunities for improved load management through additional demand response and storage. However, the favorable impacts of increased sales on rates will depend heavily on the incremental increase in revenue requirement needed to fund EV infrastructure, as discussed in more detail below.

The investor-owned utilities annually report load growth to the CPUC, with a specific focus on demand stemming from increased EV deployment.⁷ The IOUs have been piloting time-of-use rate options targeted specifically to EV customers in order to encourage charging in off-peak hours. The utilities also suggest that the distribution system will need to be upgraded to account for instances when the entire potential EV charging demand occurs during peak load⁸.

The Commission’s policies focus on three main objectives:

⁶ SB 350 was later codified into law within Public Utilities Code Section 740.12

⁷ Load Research Reports filed with the Commission can be found at: <http://www.cpuc.ca.gov/zev/>

⁸ Joint IOU 5th Electric Vehicle Load Research Report filed 12/30/2016

- Coordinating the buildout of electric vehicle charging infrastructure;
- Establishing electric vehicle rates;
- Utilizing vehicle-to-grid integration technologies that allow electric vehicles to serve as a grid resource that facilitates increased renewable energy usage, especially during periods of overgeneration, to mitigate duck curve imbalances including the steepness of the evening ramp toward the peak.

IOU Transportation Electrification Programs and Investments

The CPUC reviews, approves and oversees implementation of pilot programs and investments developed by the three electric IOUs aimed advancing transportation electrification.

In 2016, the CPUC approved three IOU pilot programs focused on installing electric vehicle charging infrastructure. Since the costs of these programs are recovered in rates, it is the Commission’s responsibility to ensure the implementation costs are reasonable and that the programs benefit ratepayers. The three utilities’ programs will deploy charging infrastructure at public sites, such as workplaces and in multi-family dwellings, as follows:

	SDG&E 'Power Your Drive'⁹	SCE 'Charge Ready'¹⁰	PG&E 'EV Charge Network'¹¹
Status	Approved Jan 2016	Approved Jan 2016	Approved Dec 2016
Scope	3,500 charging stations	1,500 charging stations	7,500 charging stations
Budget	\$45M	\$22M	\$130M
Markets	multifamily, workplace	multifamily, workplace, public	multifamily, workplace
Disadvantaged Communities	≥10% charging stations in disadvantaged communities	≥10% charging stations in disadvantaged communities	≥15% charging stations in disadvantaged communities
Charger Ownership	IOU	Site host	Site host. IOU ownership allowed only in MUD or disadvantaged community up to 35%
Cost to host	Participant Payment	Rebate	Participant Payment or Rebate
Rates	VGI rate to driver or host	TOU rate to host	TOU rate to driver or host

The three electric IOUs also in January 2017 filed applications for transportation electrification programs with a combined budget of more than \$1 billion.¹² The IOUs have proposed to

⁹ www.sdge.com/clean-energy/electric-vehicles/poweryourdrive

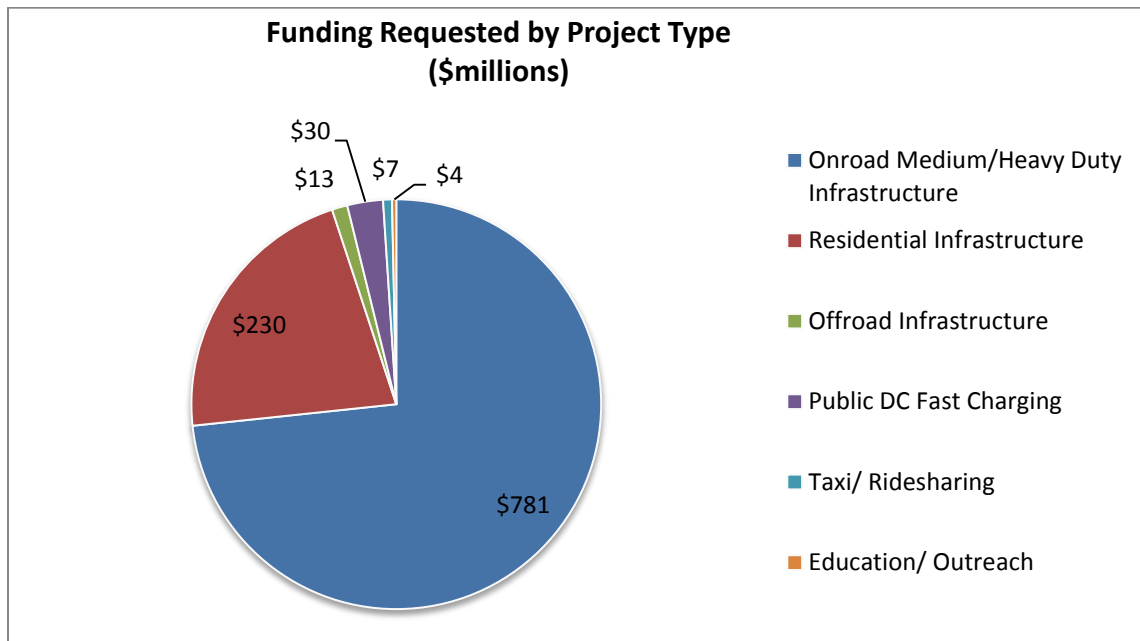
¹⁰ on.sce.com/chargeready

¹¹ pge.com/evcharge

¹² The utilities’ applications and testimony can be found at <http://www.cpuc.ca.gov/sb350te/>

recover the majority of those costs through distribution rates. The bulk of the revenue requested in the applications would go towards infrastructure projects as detailed in the graph below.

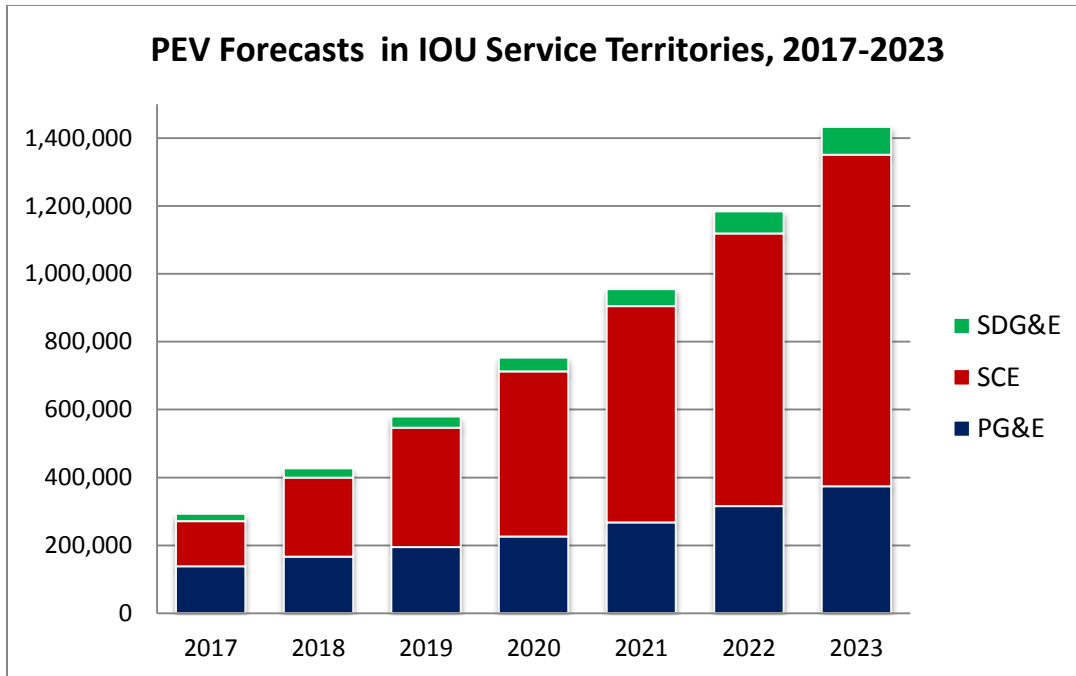
While these EV programs will increase sales, their resulting combined revenue requirement increase in excess of \$1 billion will to some extent reduce or cancel out the beneficial rate impacts of electrification, depending on the rate of EV adoption. This implicit tradeoff between kWh sales and revenue requirement highlights the critical importance of maximizing the cost effectiveness of these programs in an effort to keep rates in check.



The proposals include infrastructure programs to support electric vehicles as they are increasingly adopted across all market sectors, and new rate designs that account for EV customers’ different energy demands.

Customers with EVs can find themselves in a higher rate tier or, in the case of commercial customers, facing significant demand charges, due to the energy demand related to charging their vehicle(s). The IOUs have proposed rates aimed at addressing these issues in an effort to encourage more customers to adopt electric vehicles.

The utilities were directed to propose smaller, less controversial projects that could be processed on an expedited schedule. The proposals for these priority review projects span a variety of sectors. The proposed priority review projects are highlighted in blue in the graphic below, and the CPUC expects to issue a decision on the proposed priority review projects in the fall of 2017. The larger, standard review proposals will go through a more typical review process and the CPUC intends to issue a decision on them before the end of 2018.



In summary, the CPUC is weighing the full costs and benefits associated with IOU investments in EV infrastructure and designing policies to ensure the investments are in the benefit of ratepayers. As the CPUC reviews these applications, it is examining how the proposals would affect rates and which customers would benefit from the implementation of the projects. In this process, the Commission is working with other state agencies to evaluate the environmental and economic benefits of the proposals and ensure that they equitably benefit ratepayers. It is also a priority for the CPUC to approve well-crafted rates that properly incentivize charging during off-peak hours to help stabilize the distribution system and integrate the increasing amount of renewable energy available in the state.

4.2 Integrated Resource Planning

Historically, the Commission has used the Long Term Procurement Planning proceedings to address the overall long-term need for new system, local, and flexible resources to ensure reliability. Pursuant to SB 350, Long Term Procurement Planning is transitioning to an Integrated Resource Planning (IRP) framework, which places more emphasis on optimizing resources based on GHG emission reductions, reliability, and cost.

The IRP framework will implement a resource planning process that will ensure that load serving entities (LSEs) meet planning targets that allow the electricity sector to contribute to California’s economy-wide greenhouse gas emissions reductions goals in a reliable and cost-effective manner.

Specifically, statute (PU Code Sections 454.51 and 454.52) requires the Commission’s IRP process to identify a diverse and balanced portfolio of resources to ensure a reliable electricity supply that provides optimal integration of renewables while:

- ✚ Meeting the GHG emissions reduction targets established by ARB;
- ✚ Having a portfolio that relies upon zero carbon-emitting resources to the maximum extent reasonable;
- ✚ Procuring at least 50% eligible renewable energy resources by 2030;
- ✚ Serving customers at just and reasonable rates;
- ✚ Minimizing impacts on ratepayers' bills;
- ✚ Ensuring system and local reliability;
- ✚ Minimizing GHG and air pollutant emissions with early priority on disadvantaged communities; and
- ✚ Strengthening the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities.

Through the IRP framework, the Commission has an opportunity to identify optimal resource solutions that might not otherwise be found, and to guide resource investment decisions across all types of LSEs and resource programs. IRP will also allow the Commission to examine multiple, heretofore largely separate resource planning processes as a whole and identify the optimal mix of energy resources across the state needed for achieving its policy goals in a least-cost manner.

The IRP proceeding's primary goal in 2017 is to establish the essential groundwork and structure for IRP, and to move through the entire process once (**Error! Reference source not found.**). The lessons learned from IRP 2017 will be incorporated into a revised, multi-year IRP process, beginning in 2018 or 2019 and likely operating over a two-year cycle.

Key Steps for CPUC IRP 2017 Process Alignment	
1.	CARB develops the 2030 Target Scoping Plan Update and defines GHG reduction ranges for the electric sector, which inform IRP planning.
2.	CPUC generates "Reference System Plan" modeled and optimized over the combined LSE service territories, which will guide overarching investment, resource acquisition, and programmatic decisions to reach the state's policy goals.
3.	CPUC develops specific guidance for LSE filing requirements (e.g., contents, data format, other criteria), and procurement guidelines.
4.	LSEs develop individual IRPs, selecting one preferred portfolio of resources.
5.	CPUC reviews all LSE IRPs and aggregates them into a single "Preferred System Plan," which replaces the Reference Plan in the subsequent IRP cycle.
6.	If applicable, CPUC authorizes any necessary procurement or investment to meet the requirements of the Preferred Plan.

IRP staff recently issued a proposal on the high-level components of the proposed CPUC IRP analytical framework that will be used to identify the preferred portfolio of resources for meeting the state's goals. It will include staff recommendations for the first round of IRP (IRP 2017) and ask for comments from parties on these recommendations. This issuance of the staff proposal will lead to a final CPUC Decision adopting guidance for IRP 2017 later this year. .

In order to identify the optimal portfolio of resources that meets state goals through reasonable rates and with minimal impact on ratepayers' bills, staff will quantify the cost impacts on the electric sector of different resource portfolios under a variety of possible future scenarios.

This analysis will be done by quantifying the impacts of different scenarios (e.g. higher levels of ZEV adoption) on total cost and average rates over the IRP planning horizon. It is expected that the IRP will develop projections of the average system rate and will analyze the impacts of the optimal portfolio on the average system rate.

4.3 Energy Efficiency

The CPUC regulates ratepayer-funded energy efficiency programs managed by the 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.

Several pieces of energy efficiency-focused legislation were introduced in 2015 and are currently being implemented through Commission direction and ratepayer-funded programs. SB 350, which calls for the doubling of energy efficiency, may impact the size and scope of programs and budgets. 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. In support of these changes, AB 1330 was passed in September 2016, requiring the Commission to ensure sufficient funding is available to achieve these state efficiency targets.

The current oversight of these efficiency activities is governed by Rulemaking R.13-11-005 at the CPUC. In fall of 2015, the Commission established efficiency goals for 2016 and beyond, as well as a new administrative structure for ongoing review and approval of energy efficiency programs 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. The Commission provided further guidance on the Rolling Portfolio structure in Decision 16-08-019, setting expectations for program administrators on their initial program and budget filings.

In January 2017, program administrators submitted their initial Rolling Portfolio filings, called business plans, in accordance with the Rolling Portfolio review and approval structure. While the business plans are currently being reviewed by the Commission and are pending approval, the plans are required to reflect the legislative directions and goals mentioned above.

Statewide Approach to Program Implementation

The Commission requires IOUs to implement certain energy efficiency programs as statewide programs. Statewide programs are designed to be delivered uniformly throughout the four Investor-owned utility service territories. The reasoning behind such requirements is to take advantage of opportunities where customer or market actors for certain programs do not vary significantly across the state. Administering these programs on a statewide basis is intended to reduce transaction costs for administrators and implementers by allowing uniform incentive structures and reduction of administrative burden across IOU service territories. A list of the subprograms required to be administered statewide was decided upon in the Commission's August 2016 energy efficiency decision. These statewide programs will be implemented once the business plans are approved.

Expansion of Third Party Programs

Program administrators are required by the Commission to contract with third parties for a portion of their energy efficiency portfolio activities. The rationale for third-party requirements has primarily been based on supporting innovation in program design, as well as the potential for cost savings through competition.

In August 2016 (D. 16-08-019), the Commission increased the required minimum percentage of third-party programs to 60 percent of total budgeted portfolio. Program administrators must transition to 60 percent of third-party designed and delivered programs by the end of 2020. The previous requirement for third-party programs was 20 percent. Previously, these third party programs focused on hard-to-reach markets or regional needs. However, as trends in related proceedings move toward all-resource solicitations and the Commission continues to pursue program delivery cost savings and program design innovation, increasing the third-party requirements offered a logical strategy to achieve these goals.

While there may be high upfront transition costs associated with a third party implementation approach, longer term savings for ratepayers would be expected as third party administration would effectively drive down long-term costs through competition. More specifically, the transition to a majority of third-party programs is expected to lower administrative costs and present more cost-effective programs and portfolios.

AB 802 and Existing Conditions Baselines

Baseline policy is the set of methodologies that exist in order to set a hypothetical level of consumption (the baseline) as a point of comparison to measure energy savings. With the passage of AB 802, the Legislature required the Commission to alter default assumptions in this baseline determination. Implementing this new baseline policy will have cascade effects through various energy efficiency approaches and calculations, including program design and incentive payment structures. As discussed in D.16-08-019, the baseline policy adopted by the commission is designed to enable additional energy efficiency savings to be achieved with potentially new program efforts.

New programs and new incentive structures may alter the necessary costs of achieving energy efficiency goals. It remains to be seen how this change in baseline policy will affect costs moving forward. In D. 16-08-019, the Commission states that it should address concerns about prudent expenditures of ratepayer funds on energy efficiency in light of the new default baseline policy and will continue to study the impact of this baseline policy through a sponsored study.

4.4 Demand Response

Demand Response (DR) refers to the reduction of electricity usage during peak periods (or shifting of usage to another time period), in response to a price signal, financial incentive, environmental condition or a reliability signal. DR programs save ratepayers money by reducing the need to build power plants or avoiding the use of older, less efficient power plants that would otherwise be necessary to meet peak demand. The reduction in peak demand also lowers the price of wholesale energy and, in turn, retail rates. DR resources to be bid into CAISO energy markets, enabling them to compete against generation bids and to be dispatched when and wherever needed by the CAISO. Future demand response programs will be designed to help integrate increasing amounts of renewable power onto the grid, lowering the cost to ratepayer of California's increasing renewable portfolio.

Between April 2017 and April 2018, the CPUC will be undertaking two DR activities that will have implications for future utility costs and rates:

First, by the end of 2017, the CPUC is expected to issue a decision on utility-operated DR programs that have a proposed budget of \$622.5 million budget for 5 years (2018-2022). These programs are expected to provide 1,617 MWs of DR capacity. The costs of the programs would be recovered from ratepayers through retail electricity rates and would need to demonstrate that they are cost-effective per established CPUC rules and protocols. Preliminary analysis indicates that the utilities' proposed budgets for 2018-2022 DR programs may be less than prior year budgets on an annual spend basis.

Secondly, the CPUC will also be evaluating the DRAM pilot to determine if it should transition to a primary means by which future DR resources are procured. The DRAM is a capacity auction where third-party DR providers are awarded contracts for DR capacity that they provide to the utilities. The DRAM may be a more cost-effective method of securing DR capacity than utility-operated DR portfolios. The evaluation of the DRAM will be completed by mid-2018.

4.5 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 profit 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, 2017 (\$ Million)		
PG&E	SCE	SDG&E
\$13,888 ¹³	\$12,131 ¹⁴	\$4,149 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 purpose 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.¹⁶

4.6 Electricity General Rate Case Phase I

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.

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 2017 authorized by the CPUC in recent GRCs for the three major utilities are listed below.

¹³ PG&E Advice Letter 4902-E-B, filed 12/30/16.

¹⁴ SCE AL 3515-E-A, filed 12/21/16.

¹⁵ SDG&E Advice Letter 3028-E, filed 12/29/16.

¹⁶ 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

2017 Authorized Electric General Rate Case Revenue Requirements (\$ Million)¹⁷			
Cost Category	PG&E	SCE	SDG&E
Operations & 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 — Filed Sept. 1, 2015; Effective Jan. 1, 2017

In this application, for which a decision is pending, PG&E has requested to collect \$8.373 billion in revenues for GRC-related costs 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 is to recover costs of delivering gas services (gas distribution), although our focus in this report is on 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 April 2017 that will authorize the final amount of revenues PG&E can collect from its customers in 2017, 2018, and 2019.

PG&E estimates that the impact for electric residential customers not covered by the California Alternate Rates for Energy (CARE) program using 500 kilowatt-hours will be an increase of approximately 3.20%, or about \$2.86 per month.

SCE 2018 GRC / A.16-09-001 — Filed Sept. 1, 2016; Effective Jan. 1, 2018

In its application, SCE requests approval to increase authorized base rates by 5.5 percent total (\$313 million), effective January 1, 2018, over currently authorized rates. This increase, if adopted, would result in a GRC-related revenue requirement of \$5.885 billion per year. The costs will be reflected in distribution, generation, and new system generation (peakers) rates. The application also forecasts sales reductions.

¹⁷ 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.

SCE estimates that the impact of this General Rate Case application would increase bundled residential rates (over June 1, 2016 rates) by just over 3%, or an increase of 0.58 cents per kilowatt hour.

SDG&E 2016 GRC / A.14-11-004 — Filed Nov. 14, 2014; Effective Jan. 1, 2016

The Commission approved Decision (D.) 16-06-054, in June 2016, addressing the general rate case (GRC) applications of SDG&E and Southern California Gas Company (SoCalGas)¹⁸. The decision adopted a 2016 GRC-related revenue requirement of \$1.811 billion for SDG&E’s combined operations (\$1.5 billion for its electric operations, and \$310 million for its gas operations). The adopted revenue requirement for SDG&E is \$104 million lower than what SDG&E had requested in its updated testimony. The adopted base margin 2016 revenue requirement represents a \$50 million increase over SDG&E’s previously authorized base margin revenue requirement of \$1.721 billion.

The impact on a typical electric residential customer of SDG&E (using, for example, 500 kilowatt hours of electricity usage per month), is a 1.8% increase, or about \$1.86 per month.

4.7 Electric Fuel and Purchased Power Costs

In addition, PG&E, SCE, and SDG&E file ERRA forecast applications annually to recover fuel and purchased power costs expected during the next calendar year. 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. Each utility also files an annual ERRA compliance application to address actual costs incurred during the previous calendar year.

Because 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.

Annual Electric Revenue Requirements for ERRA Costs		
(\$ Million)		
PG&E	SCE	SDG&E
\$3,952	\$4,485	\$1,357
Effective December 2015	Effective December 2015	Effective December 2016

¹⁸ 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.

ERRA Proceedings

- **PG&E:** In D.16-12-038, PG&E's 2017 ERRA revenue requirement of \$3.952 billion was approved by the CPUC in PG&E's ERRA 2017 forecast proceeding. The CPUC expects that in June 2017 PG&E will file its ERRA application to request a fuel and purchased power revenue requirement for 2018.
- **SCE:** In D.16-12-054, the CPUC authorized SCE's 2017 ERRA revenue requirement of \$4.485 billion, \$799.7 million lower than the 2016 revenue requirement. The CPUC expects that in May 2017 SCE will file its ERRA application to request a fuel and purchased power revenue requirement for 2018.
- **SDG&E:** An SDG&E 2017 ERRA revenue requirement of \$1.357 billion was approved by the CPUC in D.16-12-053. The CPUC expects that in April 2017 SDG&E will file its ERRA application to request a fuel and purchased power revenue requirement for 2018.

4.8 Evaluating Costs in Natural Gas

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

In June 2016 the Commission approved D.16-06-056, which funded new natural gas transmission and storage projects to mitigate safety risks from gas infrastructure. The safety mitigations included the hydrotesting program adopted from the Pipeline Safety Enhancement Plan and expanding the infrastructure replacement program included in the Transmission Integrity Management Program. In the subsequent Commission decision, D.16-12-010, the Commission partially mitigated this increase for PG&E residential customers by requiring that the utility's shareholders fund various safety-related projects, as recompense for the San Bruno gas pipeline explosion.

SoCalGas/SDG&E General Rate Case (A.14-11-003/A.14-11-004)

D.16-06-054, for the SoCalGas/SDG&E Gas GRC, the estimated impact to an average SoCalGas gas customer using 37 therms per month was an increase of about 3.4% in the monthly bill. The estimated impact to an average SDG&E gas customer using 26 therms per month was a 0.6% decrease in the monthly gas bill.

While D.16-08-003 allowed SoCalGas to recover costs associated with the Pipeline Safety Enhancement Plan, the Commission did deny Sempra's application for the proposed North-South gas pipeline project in 2016. This proposed gas pipeline would have cost over \$600 million dollars, but was rejected by the Commission in favor of exploring cheaper proposals for reliability objectives put forth by other companies.

The decision provided SoCalGas and SDG&E with the necessary funds to operate its natural gas transmission, distribution, and storage systems safely and reliably at reasonable rates. These funds also ensure sufficient monies to cover federal requirements for inspection and integrity of its gas transmission and distribution pipelines. In addition, the GRC provided SoCalGas with funds to engage in a proactive storage integrity management program for gas storage facilities to protect against another gas storage leak event; however, SoCalGas was ordered to separate out the costs related to the Aliso Canyon leak in its next GRC to ensure that none of those costs are reflected in the 2019 revenue requirement.

5. Conclusions

Given the size of California utility revenue requirements, legislative program mandates, safety needs, and operational requirements, as well as the increasingly competitive distribution marketplace, managing costs and rates is more challenging than ever. The long term trends of rising revenue requirement and decreasing kWh sales is leading to unforeseen rate increases, which turns the spotlight toward our energy efficiency, demand response, and electric vehicle programs, as well as our cyclical ratesetting processes for short term opportunities to mitigate customer billing impacts. There are four key takeaways from this year's report that should offer global direction to the CPUC in its management of the critical cost proceedings before it in 2017:

- (1) Rates have risen faster than inflation for the past five years, and are placing increasing pressure on our energy efficiency and demand response programs to be increasingly effective in order to contain customer billing impacts in the long run;
- (2) While EV programs and policies are a key opportunity to partially offset kWh sales reductions due to DER penetration, we should temper our expectations in accordance with the forecasts contained herein;
- (3) The CPUC's approach to IRP will be crucial for managing prudent resource portfolio costs and potential cost efficiencies over a reasonable time horizon.
- (4) The CPUC may need to re-examine its approach to its mammoth GRC, ERRA, and Gas Cost proceedings with an eye toward improved strategic management of revenue requirement if it wants to keep rates and bills manageable in the long run.

Appendix: IOU Summaries

Public Utilities Code Section 9.13.1 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 utility's expected upcoming revenue requirements. The IOUs responded to the CPUC's request for this year's report and their recommendations are summarized below.

Along with this report, each of the IOU submissions can be accessed via the CPUC website at: <http://www.cpuc.ca.gov/General.aspx?id=6442453555>.

Southern California Edison's Recommendations:

SCE views equitable and cost-based rates as those that send the correct price signals to customers, prevent uneconomic decisions regarding energy usage, and ensure that those customers who are more costly to serve pay appropriately higher rates. In its 2015 GRC Phase II proceeding, Parties settled on a proposal that resulted in lower transfer of costs across and within classes, while also providing a measure of rate stability for those classes.

SCE contends that conflicting environmental policies are increasing costs and more coordination between policies is necessary to mitigate cost increases. Additionally, SCE argues that grid reliability should be considered from the start in environmental policy development, rather than as a secondary consideration. SCE's recommendations focus on allowing flexibility in market solutions to meet policy goals, including allowing out of state resources, if they are lower cost, and limiting technology-based targets.

Pacific Gas & Electric's Recommendations:

PG&E identified two major barriers to achieving fair and equitable rates: the tiered rate structure for residential rates and the cost-shift associated with customer-owned generation. PG&E contends changes made in the Residential Rate Reform Decision, D. 15-07011, may result in rate differentials that continue to have no cost basis. According to PG&E, efforts to reduce the gap between top and bottom tier rates are hampered by a cap on Tier 1 rate increases and the introduction of "super user" surcharges. PG&E argues that these two actions present a barrier to implementing rate reform. PG&E supports 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 identifies cost-shift from customer-owned generation as the second major challenge to fair rates. According to PG&E, the increasing adoption of solar PV coupled with the NEM tariff continues to shift fixed costs associated with accessing the grid to non-NEM customers. Continued high upper tier rates magnify the cost-shift when large users install solar systems.

PG&E notes various actions they have taken to mitigate cost and rate increases, including increasing field productivity in their transmission and distribution operations and re-evaluating the need for certain transmission capacity projects that may no longer be necessary. PG&E also lists using new technologies, for addressing gas leaks and Smart Meter technology, as important in achieving cost savings throughout their operations.

Southern California Gas Company:

SoCalGas' overall rate policy is to base rates on costs incurred while providing safe and reliable gas service and to change rates to avoid intra-class subsidies. SCG manages costs through participation in interstate pipeline rate cases and operational efficiencies.

SoCalGas recommends that the Commission address unamortized balances in the Greenhouse Gas balancing accounts in order to limit rate impacts of catching up on those costs. They also reiterate their recommendations to consider the cost-effectiveness framework proposed in R. 15-01-008 to achieve the maximum feasible GHG reductions, as well as their support for the installation of Combined Heat and Power systems, the consideration of fuel cell technology for emissions reductions, and the streamlining of Commission reporting requirements.

San Diego Gas & Electric Recommendations:

SDG&E argues that cost-based rate design will be increasingly important as technology advances, even though it may increase complexity of rate design. SDG&E sees cost-causation based rate design as critical to ensuring usage matches grid conditions and that customers received the proper price signals incentivizing behavior that minimizes system and local capacity needs.

SDG&E recommends that the costs associated with clean energy goals are paid for equitably and in a way that limits the ability for customer to bypass paying for their fair share of programs. SDG&E sees this being achieved by continuing the efforts towards a cost-based rate structure and transparent incentives, as well as recovering a portion of residential costs through fixed charges.