2020 SENATE BILL 695 REPORT

Report to the Governor and Legislature on Actions to Limit Utility Cost and Rate Increases Pursuant to Public Utilities Code Section 913.1

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California Public
Utilities Commission

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Executive Summary

The California Public Utilities Commission (CPUC) issues this 2020 Senate Bill (SB) 695 report pursuant to Public Utilities Code Section 913.1, which requires that the CPUC publish recommendations that can be undertaken over the succeeding 12 months to limit utility cost and rate increases consistent with the state's energy and environmental goals. California's Investor Owned Utilities (IOU) are also required by statute to study and report to the CPUC recommended measures to limit costs and rate increases.[1]

California continues to be a bellwether in the energy sector:

- In 2018, the state's per capita energy consumption was the fourth-lowest in the nation, due in part to its mild climate and its energy efficiency programs.[2]
- California ranked first in the nation in 2018 as a producer of electricity from solar, geothermal, and biomass resources and fourth in the nation in conventional hydroelectric power generation.[3]
- California has the most operating utility-scale battery storage capacity in the nation at over 200 MW, about twice as much as the installed capacity of the state with the next largest amount.[4]
- In 2019, nearly one-fourth of the nation's electric vehicle charging stations were in California.[5]

However, while California's IOUs continue to play a major role in many of these energy industry leading indicators, California's extensive efforts to increase energy efficiency and implement certain technologies have slowed growth in energy demand. Declining electricity consumption from energy efficiency, energy conservation, and customer generation of energy has the effect of raising electricity rates as fixed costs are spread over a smaller electric sales base. On the other hand, costs for various state-mandated programs intended to *increase* low-carbon electricity consumption, such as

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[1] *See* Public Utility Code §913.1(b): In preparing the report required by subdivision (a), the commission shall require electrical corporations with 1,000,000 or more retail customers in California, and gas corporations with 500,000 or more retail customers in California, to study and report on measures the corporation recommends be undertaken to limit costs and rate increases.

[2] *See* U.S. Energy Information Administration (EIA), California State Profile and Energy Estimates https://www.eia.gov/state/print.php?sid=CA (last updated January 16, 2020).

[3] *Ibid.*

[4] *See* EIA bar graph, "U.S. operating utility-scale battery storage by state (top 10, March 2019)" https://www.eia.gov/todayinenergy/detail.php?id=40072 .

[5] *See* U.S. Energy Information Administration (EIA), California State Profile and Energy Estimates.

funding electric vehicle infrastructure as a strategy for substantially reducing statewide greenhouse gas emissions, also may raise electricity rates. The cost implications and trade-offs of energy policy choices facing decision-makers, coupled with ongoing utility costs of providing Californians access to safe, reliable, clean, and affordable utility service and infrastructure, underscores the need for tools that forecast the rate impacts of both utility operational costs and policy choice costs.

Key highlights from this report include:

- Electric total System Average Rate (SAR) increases for PG&E and SCE have generally tracked inflation over the 2013- 2020 period. However, SDG&E's total SAR increased at a faster rate than inflation over this period.

- Historically, while California's electric Residential Average Rates (RAR) have been higher than in most of the nation, bills have been lower, as residential usage in California is low compared to most of the United States. However, low usage is showing diminishing returns as a mitigating factor and may no longer be enough to limit residential customer bill impacts. Further, the aggregated nature of average bill data can mask affordability concerns and requires analysis at a more geographically-granular level.

- Declining utility sales result in larger rate and bill increases as fixed costs are now spread over a smaller electric sales base.

- Analysis of electricity burden, or the ratio of a household's electricity bills to its reported income, is a starting point for assessing affordability, and work is in process to develop metrics that more comprehensively assess affordability to inform decision-makers.

- A Cost and Rate Tracking Tool for each large electric IOU is in the process of being developed for use by decision-makers to see the effect on residential class rates and bills of utility operational costs and legislative programs costs. Once fully developed, the tool will be capable of analyzing forecasted revenue requirements and resulting rate impacts at both the singular and cumulative pending proceedings levels.

- Estimated total wildfire mitigation costs as reflected in PG&E and SCE's 2020 Wildfire Mitigation Plans submitted pursuant to California Assembly Bill 1054 roughly translate to a 7 percent to 8 percent increase in residential rates for every $1 billion in corresponding revenue requirement not yet in rates. In 2020, the costs in these plans could result in up to a 7 percent bill increase for some customers.

1. Introduction

The Actions to Limit Utility Cost and Rate Increases report (SB 695 Report) has traditionally examined utility costs and resulting rate impacts at the total system level.[6] Starting with last year's 2019 SB 695 Report, more focus was placed on breaking down system-level costs to class-level costs in order to project 2019 residential class cost responsibility, and resulting rate and bill impacts, for certain legislative programs and utility wildfire mitigation plans. The 2020 SB 695 Report will continue to present these impacts for certain costs authorized for recovery during 2020, with an eye towards developing a framework for evaluating the potential costs of California's clean energy mandates, grid optimization, and safety needs.

Perhaps the greatest value in identifying and tracking essential legislative program cost information is in the increased transparency into the ramifications of the numerous decisions the CPUC makes annually that may affect the affordability of service. Concepts of affordability introduced in the 2018 and 2019 SB 695 Reports will be further explored in this year's report, with special emphasis on affordability as a geographic construct.[7]

Customers Pay Bills, not Rates

Electric Costs, System Average Rates, and Class Average Rates

Total system average rate (SAR), defined as an IOU's total authorized revenue requirement divided by total forecasted sales in kilowatt-hours (kWh), is a measurement of an IOU's cost to serve electricity to its customers:

$$\textbf{Total SAR} = \frac{\textbf{Total authorized revenue requirement (\$)}}{\textbf{Total forecasted sales (kWh)}}$$

Consideration of actions to limit utility costs begin with an examination of SAR as an annual trend indicator of all system costs. Historically, the total SAR of each of the three large electric investor owned utilities (IOUs), Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E), has generally tracked inflation. However, starting in 2013, the average annual change in SDG&E's total SAR began to outpace the inflationary rate.

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[6] Total system cost analysis is based on the total system revenue requirement, as opposed to on a bundled or unbundled customer revenue requirement basis. Bundled customers take generation, distribution, and transmission services. Unbundled customers take distribution and transmission service only.

[7] *See* Affordability Metrics Framework Staff Proposal R.18-07-006 dated January 24, 2020, wherein affordability is defined in terms of geographic areas at which income and certain household costs can be estimated.

While a good overall indicator of an IOU's total operating costs expected to be recouped in rates for all IOU customers (i.e. both bundled and unbundled customers), the total SAR is a high-level measure reflecting total **system costs** and does not directly convey **customer class costs** that result in rate and bill impacts for an IOU's bundled customers.[8] Annual trend analysis of **bundled residential average rate (RAR)** in particular provides a starting point for examining rates resulting from costs assigned to the bundled residential customer class, which receives all services -- generation, transmission, and distribution– bundled from an IOU.

Anecdotally, IOU customers are more likely to recall their monthly bill amount rather than the rate at which their electricity is served indicating that customers naturally think in terms of paying bills, not rates. A residential customer's total bill is largely driven by the volume of their usage, as reflected in the generation and delivery portions of their bill.[9] However, even though average residential usage in California is low compared to that of the United States, low usage is showing diminishing returns as a mitigating factor and may no longer be enough to limit residential customer bill impacts due to rising rates.

As low-carbon technologies are deployed in support of California's long-term climate goals, utility transportation electrification investment is an emerging area with potential impacts on residential customers' utility bills. Further analysis will be needed to better understand how households will be affected with increased electrification of transportation.

There is a prevailing view that the efforts to electrify transportation will result in much higher demand for electricity which could help reduce electric rates. However, most of the costs discussed in this report, including costs for transportation electrification, will likely show up in rates before any significant increased demand that could offset those costs. While it is hoped that investments in transportation electrification will have a net positive impact on rates, it is important to note that the time when authorized investments impact the revenue requirement and the increase in electric load from the investments are realized happen on different timelines. The current California Energy Commission (CEC) demand forecasts through 2030 include assumptions on the growth in demand due to transportation electrification suggesting that electric vehicle load could add as much as 20,000 GWh of demand statewide.[10] The same forecasts, however, also include assumption for the continued growth of customer-sited resources, with up to 45,000 GWh of behind-the-meter solar consumption and energy efficiency improvements cutting out more than 30,000 GWh of demand.[11]

Existing models and forecasting efforts, which do not yet capture the projected demand from electrifying medium and heavy-duty fleets, leave it unclear whether transportation electrification demand will result in downward pressure on rates over the next 10 years. Additional data from, and

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[8] Bundled customers pay for all retail and ancillary services.

[9] Usage (in kWh) multiplied by a rate factor equals the volume of electricity billed. Whereas the term "usage" is generally used in customer billings, the term "sales" is generally used when discussing SAR.

[10] Forecasts taken from the California Energy Commission's Transportation Energy Demand Forecast for the 2019 Integrated Energy Policy Report.

[11] Final 2019 Integrated Energy Policy Report including Errata, adopted by the CEC February 20, 2020.

evaluation of, current IOU programs may ultimately prove that increased electric load will result in downward pressure on rates, but more data collection alignment and analytical resources will be needed to measure the full impact of the state's transportation electrification goals on customer rates.

Improving cost containment in an increasingly competitive energy industry has no singular, one-size-fits-all solution: continually increasing electric utility revenue requirements, decreasing kWh sales, and expanding mandates all make cost control a challenging task. Electric total SAR increased from 2012 to 2020 on annual average of approximately:

- **PG&E:** 2 percent
- **SCE:** 1 percent
- **SDG&E:** 5 percent

Figure 1 shows the total SAR of each of the three large electric IOUs[12] along with a comparison of each IOU's inflation adjusted rates.[13]

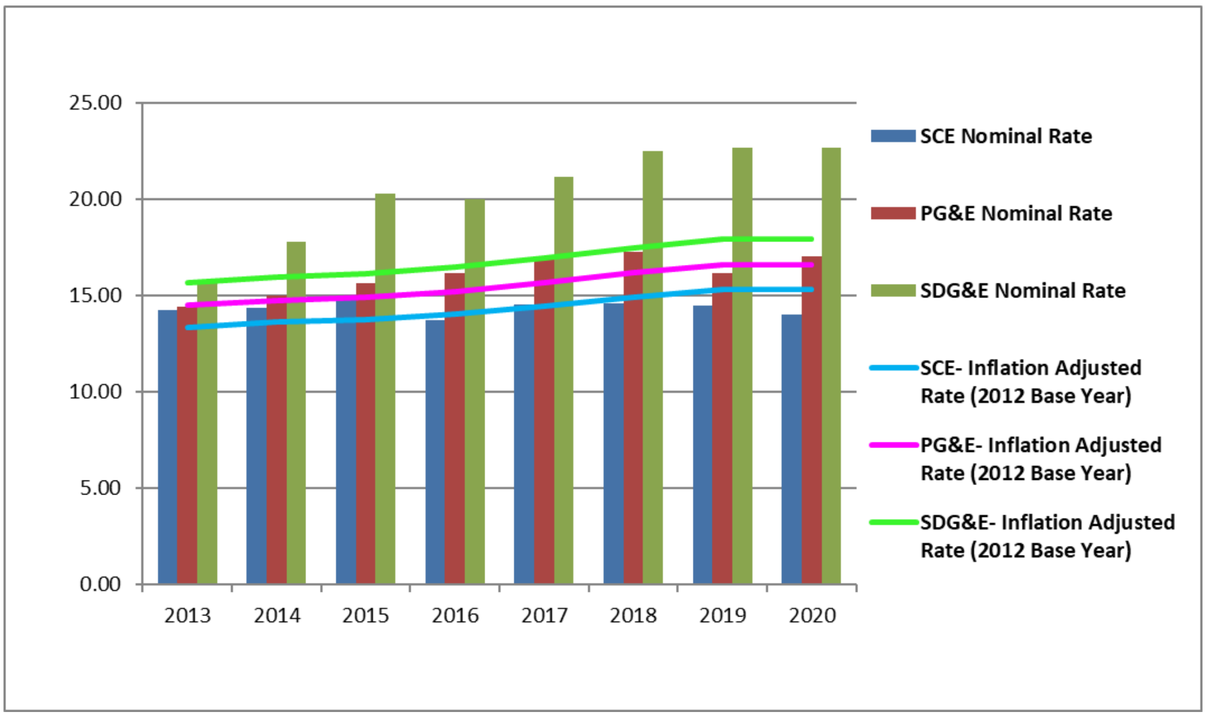

Figure 1: Total System Average Rate (¢/kWh), Nominal and Inflation-Adjusted, Rates in Effect January 1

[12] On January 1, 2020, SCE's electric total system average rate was 14.0¢/kWh, PG&E's was 17.1 ¢/kWh, and SDG&E's was 22.7 ¢/kWh. These figures are based on the January 1 authorized revenue requirement, including amortizations of balancing and/or memorandum accounts, and forecasted sales.

[13] Rates are tracked from the base year 2012 by applying the Consumer Price Index (CPI) to the previous year's SAR to show inflation-adjusted SAR. CPI reported by the U.S. Department of Labor, Bureau of Labor Statistics, West, All Items, All Urban Consumers (not seasonally adjusted). 2020 CPI data frozen at 2019 levels as 2020 data is not yet available.

While the average annual total SAR increases for PG&E and SCE have generally tracked inflation over this period,[14] SDG&E's average annual total SAR increase shows a sharper trajectory than the annual inflation rate. These average annual SAR increases, especially in the case of SDG&E, underscore the need for transparency between operating and infrastructure investment costs and the costs of policies and programs that keep California's grid green, safe, and reliable. SDG&E has a smaller customer base than the other two IOUs over which to spread those costs, reducing economies of scale for large investments. In addition, SDG&E has an increasing share of customers investing in roof-top solar. This high rate of photo-voltaic (PV) adoption affects the denominator of SDG&E's total SAR as customers appear to be consuming less electricity than they actually are. As a result, declining utility sales result in larger rate increases as fixed costs are now paid for by fewer customers.

Electric costs and rate trends for bundled customers are highlighted in this report. However, through electric delivery charges such as the distribution rate component, unbundled customers pay for costs described herein such as public purpose program (PPP) costs. In addition, through the Power Cost Indifference Adjustment (PCIA) charge, unbundled customers pay for commitments made by the IOUs for generation based on long-term forecasts of how much electricity their customers require. This means that some trends discussed in this report are the same for unbundled and bundled customers: as electric utility transmission and distribution revenue requirements increase and our legislative mandates expand, cost and rate control become more complicated and challenging for all customers.

Natural Gas Costs and Rates

Natural gas costs consist primarily of gas commodity costs and the expenses gas utilities incur in delivering the gas to customers for consumption. Natural gas rates are based on the costs (called a "revenue requirement") that the CPUC has authorized the gas utilities to recover from their customers. Procurement costs for residential (often referred to as "core") gas customers are recovered in utility gas procurement rates which are adjusted monthly and have fluctuated in recent years due to variations in the commodity price of gas.[15] Transportation rates recover pipeline transmission and distribution costs. Public Purpose Program costs such as energy efficiency are recovered through a separate rate.

For 2020, natural gas utility revenue requirements for PG&E decreased by 3 percent and increased for Southern California Gas (SoCalGas) and SDG&E by 9 percent and 18 percent, respectively.

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[14] SCE's total SAR began tracking slightly below inflation starting in 2016, and PG&E's total SAR has been tracking slightly above inflation since 2015.

[15] Large gas consumers such as industrial, refiners and electricity producers (called noncore customers) procure their own gas and pay the utilities for the delivery of the gas.

The principal reasons for the increases are from costs primarily associated with safety related programs, including new regulations, to maintain or enhance the safety of gas pipelines and storage facilities.

Vision and Organization of the Report

This report focuses on developing the necessary basics for generating information upon which recommendations may be made to limit California IOUs' increasing costs and rates. These basics include IOU forecasting of revenue requirements for several years based on approved rate-setting applications, rate-setting applications filed but not yet approved, and in some cases, estimated cost data presented in plans such as Wildfire Mitigation Plans[16] for which a rate-setting application may not yet have been filed. In addition, the report provides a deeper dive into selected bill impacts for bundled, full-service residential customers, with emphasis on the effect of these impacts on affordability for the residential customer class.

The overarching goals of this report are as follows:

- Provide an understanding of underlying program and policy drivers of rate trends in California.
- Illustrate how incremental bill impacts resulting from these programs may affect residential customers.
- Set forth a vision for how to improve analysis of policy mandates as a tool for decision makers in evaluating the impacts of proposed costs.

This report is organized as follows:

- **Section 2**: General historical trends in electric rates and overview of affordability and cost recovery
- **Section 3**: Legislative program budgets, including estimated residential customer class bill impacts of select programs
- **Section 4**: Actions taken by the CPUC in response to the COVID-19 pandemic
- **Section 5**: 2020 Wildfire Mitigation Plans submitted by the IOUs with an emphasis on plan costs and corresponding estimated residential customer class rate and bill impacts
- **Section 6**: Natural gas cost trends

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16 *See* SB 695 Report section "Wildfire Mitigation Plans."

Information provided by the IOUs to fulfill the requirements of Public Utilities Code Section 913.1(b)[17] is provided in Appendix A.

A Lexicon of Key Ratemaking Terms and Definitions

The following is a list of essential definitions used in this document and in the CPUC's rate-setting work in GRC Phase I, GRC Phase II proceedings, and other rate-setting proceedings:

- **Bundled Customers:** Customers who get all of their services -- generation, transmission, and distribution services -- from the Investor Owned Utilities.

- **Bundled System Average Rate (Bundled SAR):** Bundled authorized revenue requirement divided by bundled forecasted kilowatt-hour sales.

- **Bundled Residential Average Rate (Bundled RAR):** Bundled residential class authorized revenue requirement divided by bundled residential forecasted kilowatt-hour sales.

- **Coincident Demand Charge (CD):** A type of demand charge that is assessed on the customer's maximum demand in any 15-minute interval during the utility's peak time-of-use period. This is also known as peak-related demand charge.

- **Cost of Service Regulation (COSR):** A form of rate regulation where a regulated entity will be allowed to collect in rates its total cost of providing services plus a reasonable profit.

- **Demand Charge (DC):** A charge (in $/kW) based on a customer's highest moment of electricity usage in a month, other was known as his or her peak demand. For example, if for one 15 minute period during the month a customer's total demand was 100 kW and the demand charge was $1/kW, they would owe $100 on top of their volumetric charges. A demand charge is assessed on some customers on top of the volumetric charge for total energy usage and is intended to recover the fixed cost of serving that peak load.

- **Distributed Energy Resources (DER):** Distribution-connected generation resources, including energy efficiency, storage, electric vehicles, and demand response technologies.

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[17] Public Utilities Code Section 913.1(b) states, "In preparing the report required by subdivision (a), the commission shall require electrical corporations with 1,000,000 or more retail customers in California, and gas corporations with 500,000 or more retail customers in California, to study and report on measures the corporation recommends be undertaken to limit costs and rate increases."

- **Energy Burden:** Actual home energy costs as a percentage of household income.

- **Energy Resource Recovery Account (ERRA):** ERRA balancing accounts are evaluated in annual proceedings and track authorized versus actual utility energy procurement costs e.g. fuel and purchased power. ERRA costs are pass-through expenses; the utility receives no mark up or profit on these costs.

- **Fixed Charge (FC):** A charge assessed on customer bills to recover fixed costs.

- **General Rate Case (GRC):** A proceeding in which revenue requirements are approved based on the costs of operating and maintaining the utility system. GRCs are often "settled" based on overall agreement between advocacy groups and the utility, with the CPUC approving the settlement agreement if it is "reasonable in light of the whole record, consistent with the law, and in the public interest…"

- **Load Serving Entities (LSE):** A company or organization that supplies load (electricity) to customers. For CPUC-jurisdictional LSEs, these are defined as Investor-Owned Utilities (IOU), Community Choice Aggregators (CCA) and Direct Access (DA) suppliers.

- **Non-coincident Demand Charge (NCD):** Demand charge assessed on the customer's maximum demand in any 15-minute interval during the billing cycle irrespective of its impact on the utility's peak demand.

- **Non-Rate Base Expenses:** Costs that the utility collects from customers but does not place in rate base and for which it does not earn a profit. This includes pass-through costs for non-utility owned generation and fuel costs.

- **Non-Wires Alternatives (NWA):** Non-traditional solutions, such as DERs, which replace traditional transmission and distribution investments, such as poles, wires, and transformers.

- **Rate Base:** The book value, after depreciation, of the generation, distribution and transmission infrastructure assets owned and operated by the utility for which they may earn a profit. Other things being equal, a larger rate base results in higher net income for utilities.

- **Rate of Return (ROR) on Rate Base:** The cost of paying back utility debtholders with interest, plus the Return on Equity (ROE) to shareholders, as a weighted average of all types of capital.

- **Return on Equity (ROE):** Return to utility shareholders, or profit, and the most controversial component of the ROR formula.

- **Rate Design:** Designing rate schedules and further allocating revenues to individual customers within a customer class. Rate design is also used to promote conservation or other desired outcomes.

- **Revenue Requirement or Utility Costs:** Total operating costs, depreciation, and a reasonable profit, as recovered in rates.

- **Revenue Allocation:** Allocating total revenue requirement to individual customer classes (residential, commercial, agricultural, industrial) based on the utility's cost to serve that class.

- **Total Revenue Requirement:** Rate Base x Authorized Rate of Return + Expenses.

- **Total System Average Rate:** Total authorized revenue requirement divided by total forecasted kilowatt-hour sales.

- **Unbundled Customers**: Customers who take distribution and transmission service only, with generation service provided by a separate entity, usually a Community Choice Aggregator (CCA) or Direct Access (DA) service provider.

- **Utility Decoupling:** Decoupling refers to annual rate-making adjustments that ensure that utility earnings are separate and independent of actual kWh sales between rate cases, thus removing the disincentive for utilities to encourage energy conservation.

- **Utility Earnings (or Earning Per Share):** Earnings per share (EPS) represents the portion of a utility's earnings, net of taxes and preferred stock dividends, that is allocated to each share of common stock. The figure can be calculated by dividing net income earned quarterly by the total number of shares outstanding during the same term.

2. Rates and Cost Recovery

Trends in Electric System Average Rate

In cost of service regulation, the regulator determines the total amount of money that must be collected in rates for the utility to recover its reasonable and necessary costs plus earn a reasonable profit. The cost of service regulatory model aims to provide universal safe and reliable electricity while ensuring that monopoly service providers charge a fair price. Figure 2 presents a schematic of the process of how a utility's cost of service ultimately ends up in utility customer bills.

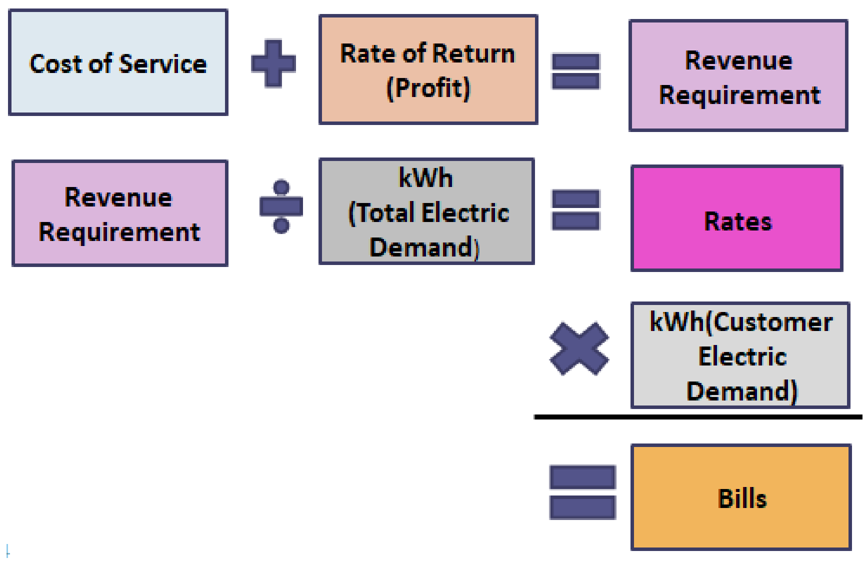

Figure 2: Process of How Utility Costs Result in Customer Bills

Once cost of service (including rate of return) is converted to revenue requirement,[18] a system average rate (SAR) may be obtained. Total SAR – an IOU's total authorized revenue requirement divided by total forecasted kWh sales -- is a metric used to measure an IOU's cost to serve energy to its customers. Consideration of actions to be taken to limit utility costs should begin with an examination of total SAR in order to see overall trends in an IOU's total costs expected to be recouped in customer rates. However, total SAR alone is not a good metric for determining whether energy bills are affordable.[19]

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[18] Conversion of costs includes converting capital costs and operations and maintenance (O&M) expenses. While O&M expenses convert to revenue requirement dollar-for-dollar, capital costs must be translated to capital-related expenses (e.g. depreciation, taxes and return on investment) in order to reflect revenue requirement.

[19] For additional discussion, *see* "Trends in Electric Residential Class Average Rate."

Historically, the total SAR of each of the three large electric IOUs have increased commensurately. However, starting in 2013,[20] SDG&E's total SAR started showing larger incremental increases than the total SARs of the other two large electric IOUs. Figure 3 shows the total SAR of each of the three large electric IOUs[21] along with a comparison of each IOU's inflation adjusted rates.[22] The comparison with theoretical inflation adjusted rates is useful as IOU rate data is stated in nominal values (i.e. actual rates in effect) and inflation-adjusted rates show what rates *would have been* if rates had tracked inflation. While the total SAR for PG&E and SCE has generally tracked their inflation-adjusted rate over the 2013 – 2020 period, SDG&E's total SAR markedly outpaces its inflation-adjusted rate over this period.[23]

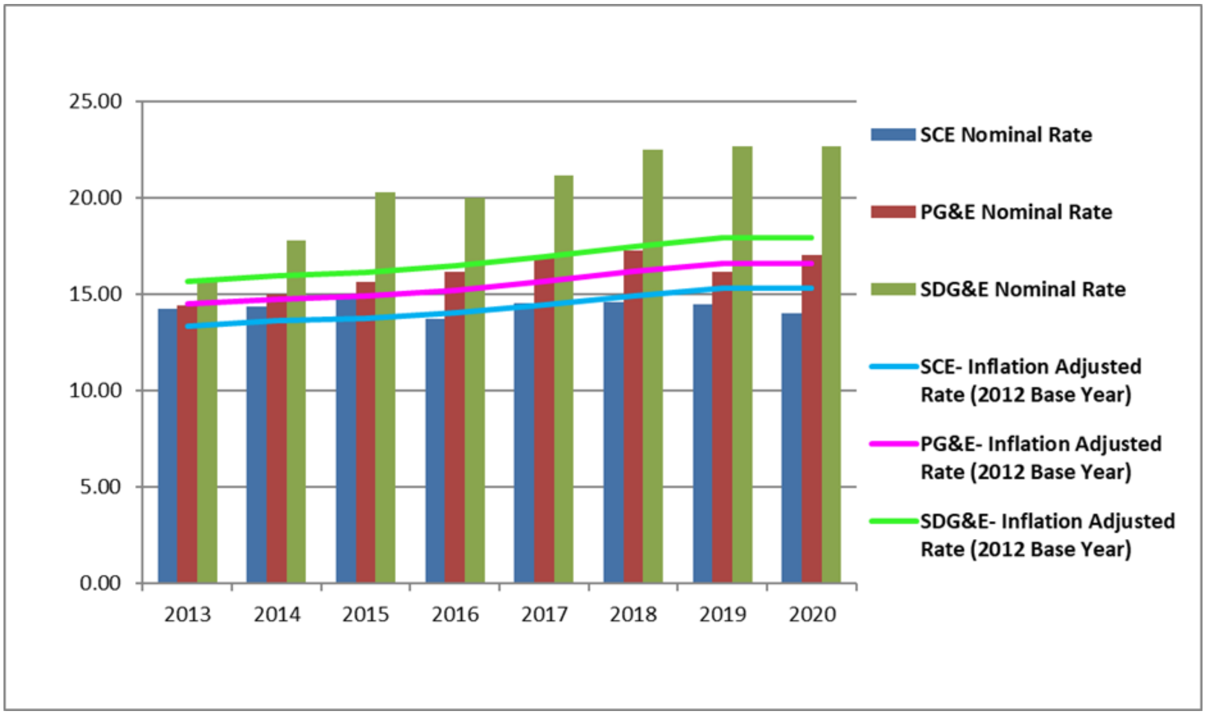

Figure 3: Total System Average Rate (¢/kWh), Nominal and Inflation-Adjusted, Rates in Effect January 1

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[20] Prior to 2013, the total SAR of each of the IOUs roughly tracked inflation, *see* the 2019 AB 67 Report (filed April 2020), available on the CPUC website (https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2020/2019%20AB%2067%20Report.pdf).

[21] On January 1, 2020, SCE's electric total system average rate was 14.0¢/kWh, PG&E's was 17.1 ¢/kWh, and SDG&E's was 22.7 ¢/kWh. These figures are based on the January 1 authorized revenue requirement, including amortizations of balancing and/or memorandum accounts, and forecasted sales.

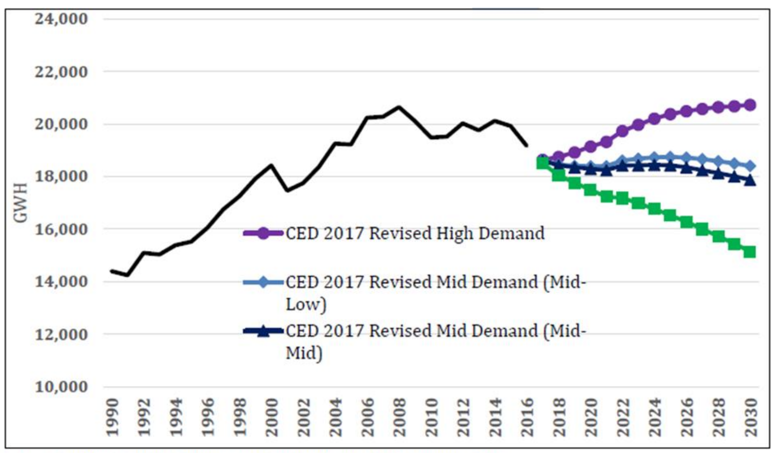
[22] Rates are tracked from the base year 2012 by applying the Consumer Price Index (CPI) to the previous year's SAR to show inflation-adjusted SAR. CPI reported by the U.S. Department of Labor, Bureau of Labor Statistics, West, All Items, All Urban Consumers (not seasonally adjusted). 2020 CPI data frozen at 2019 levels as 2020 data is not yet available.

[23] Electric total system average rates increased annually from 2013 to 2020 by approximately 1 percent for SCE, 2 percent for PG&E, and approximately 5 percent for SDG&E, compared to an average annual inflation rate of about 2 percent over the same period (base year 2012).

SDG&E Total SAR and Diminishing Sales

The variance in Figure 3 between SDG&E's inflation-adjusted SAR and its nominal SAR may be due to the effect of diminishing sales. SDG&E has an increasing share of customers investing in roof-top solar. This high rate of photo-voltaic (PV) adoption affects the denominator of SDG&E's total SAR as customers appear to be consuming less electricity than they actually are. As a result, declining utility sales result in larger rate increases as fixed costs are now paid for by fewer customers.

The prognosis for continued flat-to-declining sales is reflected in SDG&E's proposed 2020 - 2022 electric sales forecast[24] which is based on the California Energy Commission (CEC) report *California Energy Demand 2018 – 2030 Revised Forecast.*[25] SDG&E's proposed sales forecast through 2022 most closely resembles the forecast shown by the dark blue line in Figure 4 below.[26]



Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 4: SDG&E Historical and Projected Managed Sales

24 *See* A.19-03-002.

25 SDG&E's proposed 2020 – 2022 electric sales forecast uses the adjusted revised baseline electricity consumption mid-demand forecast. This proposal roughly coincides with the CEC managed sales forecasts showing flat mid-mid demand level (dark blue line). The CEC graph appears to omit the revised low demand (green line) from the legend.

26 *See* California Energy Commission (CEC) California Energy Demand 2018 – 2030 Revised Forecast (February 2018).

Trends in Electric Residential Class Average Rate

Allocation of revenue requirements across customer classes determines the rates ultimately paid by individual customers. Residential average rate (RAR) as shown in Figure 5 is determined in a similar manner as SAR in Figure 3, except that instead of using system-level (i.e. all) revenue requirement and system level forecasted sales, the revenue requirement is allocated to the residential class and residential class forecasted sales are used in the numerator and denominator, respectively. Residential tariffs are then designed to collect the revenue requirement reflected in the RAR.

Figure 5: Numerator and Denominator for Residential Average Rates Calculation

Bundled RAR

Bundled RAR is the rate resulting from the bundled residential customer class' share of the residential class revenue requirement and the bundled residential customer class' share of the residential class forecasted sales. Annual trend analysis of bundled RAR provides a starting point for examining rates resulting from costs assigned to the bundled residential customer class. Figure 6 shows the bundled RAR of each of the three large electric IOUs[27] along with a comparison of each IOU's inflation adjusted rates.[28]

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[27] On January 1, 2020, SCE's electric bundled residential average rate was 18.9¢/kWh, PG&E's was 22.6 ¢/kWh, and SDG&E's was 27.2 ¢/kWh. These figures are based on the January 1 authorized revenue requirement, including amortizations of balancing and/or memorandum accounts, and forecasted sales.

[28] Rates are tracked from the base year 2012 by applying the Consumer Price Index (CPI) to the previous year's RAR to show inflation-adjusted RAR. CPI reported by the U.S. Department of Labor, Bureau of Labor Statistics, West, All Items, All Urban Consumers (not seasonally adjusted). 2020 CPI data frozen at 2019 levels as 2020 data is not yet available.

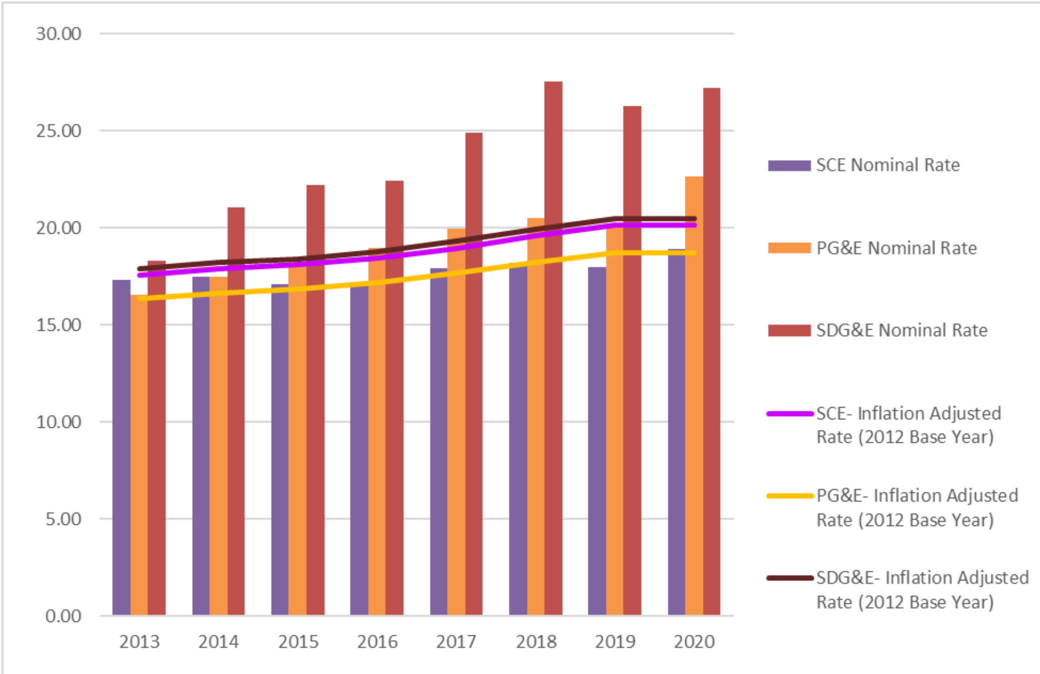

Figure 6: Bundled Residential Average Rate (¢/kWh), Nominal and Inflation-Adjusted, Rates in Effect January 1

The class average rate is generally higher than the SAR when the rate class in question contributes a higher proportion of revenue requirement relative to the system average and to other classes.[29] In addition, since bundled residential customers pay for generation service from the utility and unbundled residential customers pay for generation from another Load Serving Entity (LSE), bundled customer RAR will necessarily be higher than total RAR which reflects service to all residential customers.

In order to dive deeper into affordability issues for the bundled residential customer class, the impact of bundled RAR is converted to average bills for the bundled residential customer class. Figure 7 shows how class level rates determine customer bills:

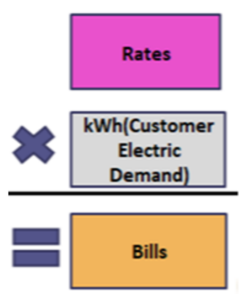

Figure 7: How Customer Class Rates Determine Customer Bills

[29] When comparing total SAR in Figure 2 to bundled RAR in Figure 6, the resulting rates are higher in all cases for bundled RAR than for total SAR.

Electricity **usage** (shown in kWh in Figure 7) is thus a major determinant in calculating bill impacts for bundled residential customers.[30]

Historically, the bundled RARs of the California IOUs have been higher than those of most United States IOUs. For 2018, the most recent year for which national-level data is available,[31] with respect to bundled residential average rate, PG&E ranked the 15th highest, SCE ranked the 31st highest, and SDG&E ranked the 9th highest out of approximately 200 total IOUs in the U.S. However, California IOU bundled residential customer bills have been lower than about half of those of all U.S. IOUs.[32] Using the same 2018 national-level data, with respect to bundled residential average monthly bills, PG&E ranked 94th highest, SCE ranked 136th highest, and SDG&E ranked 108th highest out of approximately 200 total IOUs nationally.

While relatively low average monthly usage of the average bundled residential customer of each of the three large California electric IOUs results in average monthly bills in roughly the bottom-half of those of all U.S. IOUs, the aggregated nature of average data can mask affordability concerns. First, monthly electric usage levels may vary within utility service territories depending on how those needs vary geographically. Further, electric utility bill affordability is fundamentally linked to some concept of household share-of-income,[33] which is necessarily based on geographically granular determinations of income.[34]

Electric Bill Affordability

A comparison of average monthly bills as a percentage of average monthly income is a next step in looking at electricity affordability. Average monthly bills along with average monthly household income express a ratio of a household's electricity bills to its reported income called electricity burden, as shown in the equation below:

$$\textbf{Electricity Burden} = \frac{\textbf{Average monthly electricity bill (\$)}}{\textbf{Average monthly household income (\$)}}$$

30 Other bill elements such as fixed charges and taxes are outside the scope of this analysis.

31 *See* U.S. Energy Information Administration (U.S. EIA), Annual 2018 Electricity Data by State and Utility (https://www.eia.gov/electricity/data.php). 2018 is the most recent year for which U.S. EIA data is available.

32 *Id.*

33 As monthly residential electric usage is billed at household level, residential monthly income should represent household-level data as well.

34 The IOUs are not required to gather customer household income data and when such data is needed for analyses, rely on public sources of income data such as U.S. Census Bureau data which varies across pre-defined geographic areas.

Tables 1, 2, and 3[35] show electricity burden for bundled residential customers calculated as shown in the above formula for the three large electric IOUs[36] by climate zone[37] and service territory based on 2019 recorded average usage data. The tables show the variability in electricity burden data at the finer spatial-scaled climate zone level than at overall service territory level.

PG&E 2019 Bundled Residential Customers											
	Electric Climate Zone										
All Bundled	Q	T	V	R	W	Y	Z	X	P	S	All
Average Monthly Bill ($)	91	67	109	122	118	100	68	101	132	123	**108**
Average Monthly Household Income ($)	7,747	6,334	4,066	4,521	4,812	4,602	5,233	8,502	4,623	5,724	**5,600**
Electricity Burden	**1.2%**	**1.1%**	**2.7%**	**2.7%**	**2.5%**	**2.2%**	**1.3%**	**1.2%**	**2.9%**	**2.1%**	**1.9%**

Climate zone key
Cool: T, V, Y, Z
Warm: X
Hot: R, S, W

Table 1: PG&E Electricity Burden, Average Bundled Residential Customers

SCE 2019 Bundled Residential Customers										
	Electric Climate Zone									
All Bundled	5	6	8	9	10	13	14	15	16	All
Average Monthly Bill ($)	102	75	77	85	95	100	85	120	84	**86**
Average Monthly Household Income ($)	7,888	6,443	5,593	5,727	5,298	3,997	4,183	5,289	4,918	**5,477**
Electricity Burden	**1.3%**	**1.2%**	**1.4%**	**1.5%**	**1.8%**	**2.5%**	**2.0%**	**2.3%**	**1.7%**	**1.6%**

Climate zone key
Cool: 6, 8, 16
Warm: 5, 9
Hot: 10 (Section 745),[38] 13, 14, 15

Table 2: SCE Electricity Burden, Average Bundled Residential Customers

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[35] *See* Appendix B for electricity burden further broken out by lower-income residential customers enrolled in the California Alternate Rates for Energy (CARE) program and residential customers not enrolled in the CARE program (Non-CARE).

[36] For income data: PG&E's analysis uses U.S. Census Bureau data that has been aggregated to approximate service territory composition; SCE's analysis uses third-party vendor Acxiom data, estimated by SCE's proprietary algorithm at SCE service account level; SDG&E's analysis uses U.S. Census Bureau data for which census tract data has been aggregated to climate zones. *See* each IOU's report in Appendix A for more methodology information.

[37] Climate zones, defined by each IOU in its Preliminary Statements, are drawn based on climactic variation and may also be referred to as baseline territories.

[38] Interpretation of Public Utilities Code Section 745 in D.16-09-016.

SDG&E 2019 Bundled Residential Customers					
	Electric Climate Zone				
All Bundled	**1**	**2**	**3**	**4**	**All**
Average Monthly Bill ($)	80	118	100	83	82
Average Monthly Household Income ($)	8,974	7,516	4,373	7,799	8,457
Electricity Burden	**0.9%**	**1.6%**	**2.3%**	**1.1%**	**1.0%**

Climate zone key
Cool: 1 (Coastal)
Warm: 4 (Inland)
Hot: 2 (Mountain), 3 (Desert)

Table 3: SDG&E Electricity Burden, Average Bundled Residential Customers

Electricity burden does not comprehensively define affordability, as it is only one of several possible metrics that can be used to measure electric bill affordability for bundled residential customers. While the electricity burden data reported in the above tables is based on total usage as reflected in monthly bills, affordability metrics can also be based on a quantity of essential usage.[39] For example, the CPUC is developing a framework and principles, as laid out in a rulemaking,[40] to assess the affordability impacts of utility rate requests and CPUC proceedings.[41] CPUC staff proposes that this framework use essential service utility charges alongside a household's income and other non-discretionary expenses such as housing costs in order to calculate an affordability ratio (AR) metric that could be used to inform the decision-making process.[42] Central to the determination of essential service utility charges is the concept of electric essential usage, which CPUC staff proposes be based on tier 1 baseline quantity for electric residential customers pending more robust determinations of essential usage by the large electric IOUs as part of CPUC-ordered essential use studies.[43]

As indicated in the above-referenced Affordability OIR Staff Proposal, a metric such as AR that takes into account several factors of the household budget, such as income and certain other types of expense in addition to utilities, more fully illustrates the notion that affordability is not just a function of household expenses but the ability to pay for those expenses.[44] This and other affordability metrics may be presented in future SB 695 Reports, as noted in the Staff Proposal:[45]

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[39] Total usage is comprised of essential usage and non-essential usage. Total usage can be affected by factors such as customer household composition and behavioral patterns, housing stock, appliance types, etc.

[40] *See* R.18-07-006: Order Instituting Rulemaking to Establish a Framework and Processes for Assessing the Affordability of Utility Service.

[41] *See* Affordability Metrics Framework Staff Proposal R.18-07-006 dated January 14, 2020 (Staff Proposal) (http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M325/K620/325620620.PDF).

[42] *Id.*, at 34 – 44. Other affordability metrics are proposed in the staff proposal as well.

[43] *Id.*, at 12 – 13.

[44] *Id.,* at 4.

[45] *Id.,* at 47.

> …[E]lectric and gas affordability metrics may eventually be presented in an existing report such as the Public Utilities Code Section 913.1 Annual Report to the Governor and Legislature *Actions to Limit Utility Cost and Rate Increases* (Senate Bill (SB) 695 Report)…

Tools for calculating the affordability metrics are being developed as part of the Affordability OIR and should be available to decision-makers at a future date.

Cost Recovery

Utilities file detailed descriptions of the costs of providing service (also referred to as "revenue requirements") and request authorization of these costs in various rate-making proceedings. Utilities may periodically also be directed by the CPUC to file applications pursuant to legislative mandates. For example, applications have been filed in the last several years for program investments and market structures to support wider deployment of zero-carbon and grid modernization, and as a result, substantial costs have been recently authorized in proceedings for transportation electrification and energy storage. In its authorization of an IOU's electric revenue requirement, the CPUC strives to provide electric utility customers safe, reliable utility service and infrastructure at just and reasonable rates, with a commitment to environmental enhancement and a healthy California economy.[46]

Cost Recovery by Rate Component

Electric IOU customers generally see customer bills organized by a generation rate and a delivery rate, with the delivery rate including all other non-generation rates including distribution, transmission, and the non-bypassable costs of public purpose programs that are paid by all customers who use the utility delivery system. The revenue that is collected from customer bills by rate component corresponds to the revenue requirement the IOUs are authorized to collect after cost recovery is approved in rate-making proceedings. The CPUC authorizes this cost recovery by one or more rate component corresponding to a functional area of utility operations (i.e. generation, distribution, etc.).

The **generation rate component** collects the revenue requirement corresponding to generation portfolio costs which include the cost of Utility Owned Generation (UOG), consisting of fuel, Operations and Maintenance (O&M) and capital-related costs associated with generation plants such

[46] More detailed descriptions of how General Rate Case (GRC) proceedings and Energy Resource Recovery Account (ERRA) proceedings authorize utility revenue requirements can be found in the 2019 AB 67 Report (filed April 2020), available on the CPUC website: (https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2020/2019%20AB%2067%20Report.pdf). All dollars are nominal i.e. not adjusted for inflation unless otherwise indicated.

as nuclear, gas, and hydro. IOUs also recover "purchased power costs" which represent the costs of electricity from third party generators. The incremental cost impact of renewable contracts to meet the Renewables Portfolio Standard (RPS) and greenhouse gas (GHG) costs will also be reflected in generation rates.

The **distribution rate component** collects the revenue requirement corresponding to distribution O&M and capital-related costs associated with distribution infrastructure. This rate component recovers the costs to distribute power to customers and includes power lines, poles, transformers, repair crews and emergency services, as well as certain wildfire mitigation costs related to grid reliability and safety. In addition, the CPUC has authorized the IOUs to recover funding related to specific public policy objectives such as transportation electrification and demand response through the distribution rate component.

The **transmission rate component** collects the revenue requirement associated with the bulk transmission lines owned by the utilities. The transmission rates are set by the Federal Energy Regulatory Commission (FERC). This rate component is comprised of four sub-components: 1) Base Transmission which recovers the O&M and capital-related costs associated with transmission assets under ISO operational control and subject to FERC's jurisdiction; 2) flow-through to customers of transmission revenues generated through wholesale customers' use of the transmission system; 3) Reliability Services costs related to contracts signed by the California Independent System Operator (CAISO) with certain generators needed to maintain system reliability; and 4) Transmission Access Charge which reflects the net contribution by IOU customers to the transmission revenue requirements of all participating transmission.

Other rate components are:

- Public Purpose Program (PPP),
- New System Generation (NSG),
- Nuclear Decommissioning (ND), and
- California Department of Water Resources (DWR) rate components.

The PPP rate component collects program funding authorized by the CPUC for Energy Efficiency, Low-Income programs, and other public policy programs. NSG charges recover the costs of "new generation" assets that the IOUs procure in order to maintain system reliability. Nuclear decommissioning costs are recovered separately in the ND rate component.[47]

The DWR Power and Bond Charge revenue requirements reflect costs that are outside of the IOUs' control recovered on behalf of the California Department of Water Resources. DWR Bonds were issued in 2003 to recover the costs incurred by the State of California to purchase power during the energy crisis. As of August 22, 2019, a $312 million balance remains outstanding on the DWR bonds

[47] The Competition Transition Charge (CTC) may also be shown as a rate component on tariff sheets. The CTC recovers above-market costs associated with power purchase contract obligations that resulted from electric industry restructuring pursuant to Public Utilities Code Section 367(a).

and is expected to be repaid by August of 2020. A new bond issuance (with a substantially equivalent bond charge) will be repaid through the Wildfire Fund non-bypassable charge pursuant to Assembly Bill (AB) 1054 (Holden, 2019). The new charge would support the participation of large electrical utilities in the Wildfire Fund.

The figures below for PGE, SCE, and SDG&E reflect the authorized revenue requirement by rate component on January 1 of each year.[48]

PG&E Revenue Requirement by Rate Component

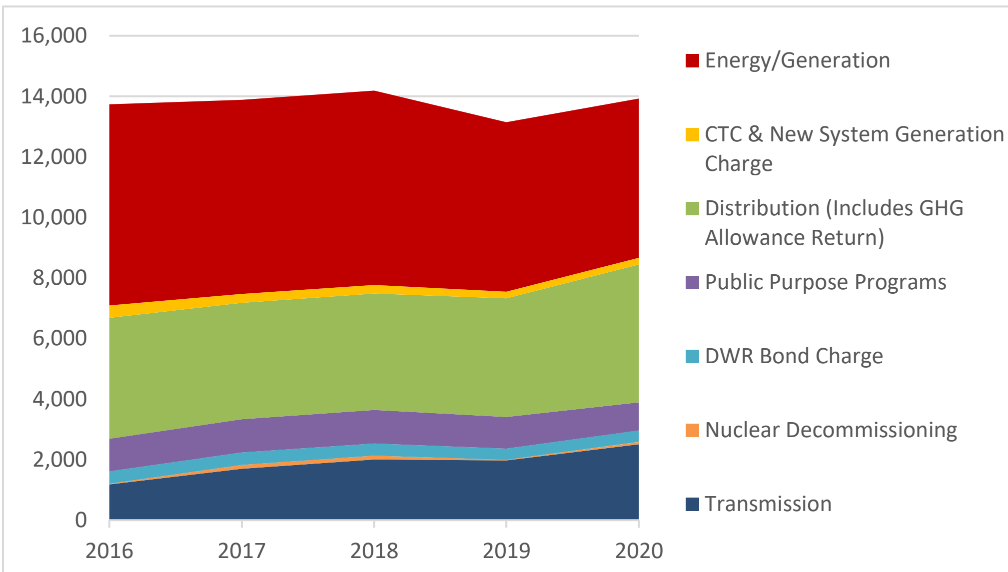

Figure 8: PG&E January 1 Revenue Requirement ($ millions) by Rate Component Category

PG&E's revenue requirement corresponding to costs recovered in its generation rate component has been decreasing since 2016, while costs recovered in the distribution rate component were generally constant over the period 2016 – 2019 but increased in 2020, and costs recovered in the transmission rate component have significantly increased over the 2016 - 2020 time period.

The 21 percent decline in PG&E's generation revenue requirement since 2016 reflects the reduction in PG&E's overall procurement costs due to the decrease in bundled load. The 16 percent increase in PG&E's distribution revenue requirement from 2019 to 2020 are GRC attrition, lower GHG

[48] All data is from 2016 – 2020 IOU responses to Energy Division SB 695 Report data requests. The 2020 Energy Resource Recovery Account (ERRA) applications for PG&E, SCE and SDG&E were pending authorization on January 1, 2020 and are not included.

revenue, higher Catastrophic Event Memorandum Account (CEMA) costs,[49] and higher balancing account under-collections.

Since 2016, PG&E's transmission revenue requirement has roughly doubled with the main cost driver being higher Transmission Owner (TO) revenue requirements due to substantial additions and replacements of PG&E's transmission system. Network transmission operation and maintenance expenses increased primarily due to increased inspection, maintenance, and repair work for the transmission facilities. Rising costs in general liability insurance have also contributed to transmission operation expense.

SCE Revenue Requirement by Rate Component

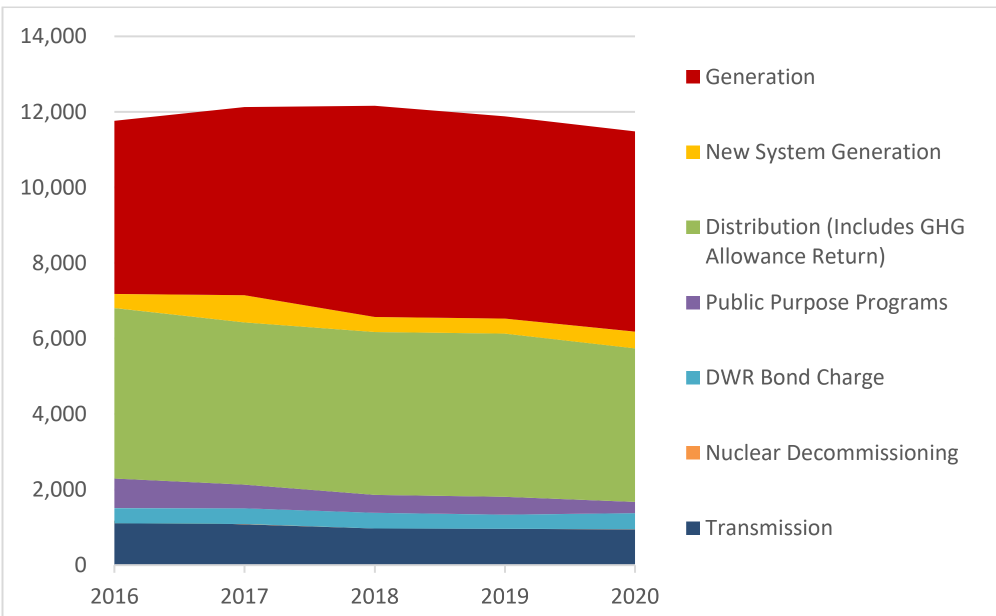

Figure 9: SCE January 1 Revenue Requirement ($ millions) by Rate Component Category

The revenue requirement corresponding to costs recovered in SCE's generation rate component has been generally rising since 2016, while costs recovered in the distribution and transmission rate components have been trending downward over the same time period.

SCE's generation revenue requirement has risen about 16 percent since 2016. Although the fuel and purchased power revenue requirement has been steadily decreasing over the period 2016 – 2020 due to the decrease in bundled load, the 2018 and 2019 generation costs increased to account for under

[49] CEMA cost recovery of approximately $370 million related to nine catastrophic events in 2016 and 2017 was authorized for 2020 collection through the distribution rate component.

collections by SCE in 2017. In 2018, a summer spike in natural gas prices due to unprecedented pipeline infrastructure outages and regulatory restrictions on usage of the Aliso Canyon storage fields, together with 2017 and 2018 gas prices generally exceeding forecasts, significantly impacted electric generation rates.[50] Over the last two years, SCE's generation revenue requirement has shown a slight decline from the 2018 high-point.

While SCE's distribution revenue requirement has decreased about 10 percent since 2016 and the transmission revenue requirement has decrease about 19 percent over the same period, both the distribution and transmission revenue requirements are expected to grow over the coming years as SCE responds to higher levels of wildfire risk. Further, distribution infrastructure costs may rise in connection with the need for a modernized grid that can monitor and control the two-way flow of power in the distribution system will be critical to maintaining, and hopefully enhancing the reliability and resiliency of the grid.

SDG&E Revenue Requirement by Rate Component[51]

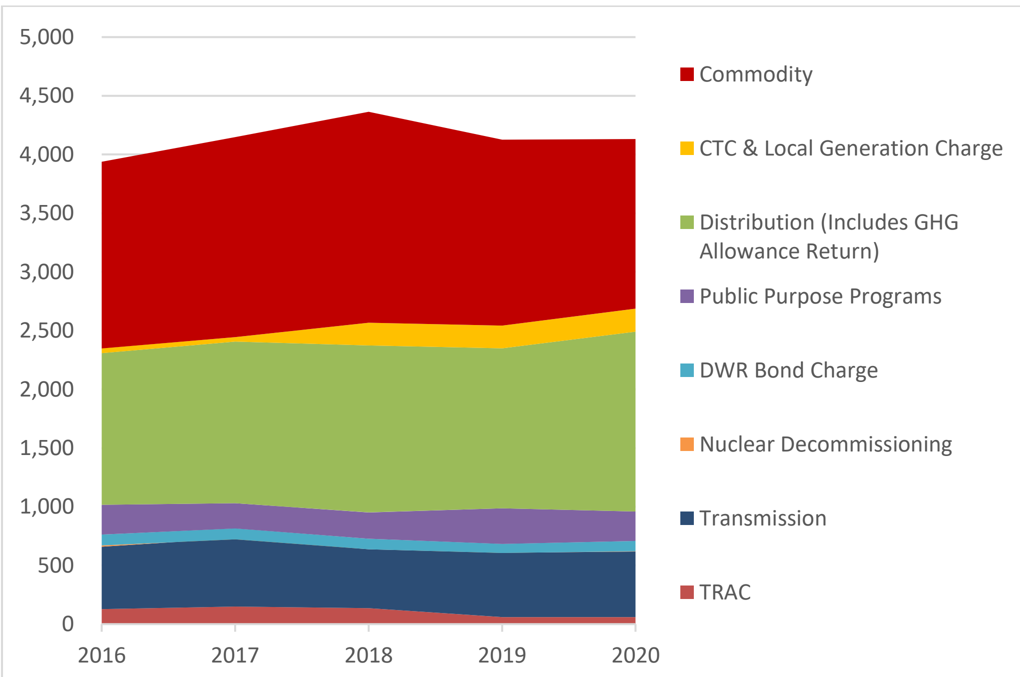

Figure 10: SDG&E January 1 Revenue Requirement ($ millions) by Rate Component Category

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[50] *See* D.19-01-045 (Decision Granting SCE's ERRA Trigger Application (A.)18-11-009) and SCE's AL 3954-E (Implementation of SCE's ERRA Trigger Application in compliance with D.19-01-045). In April 2019, the system average rate increased by 1.2 cents/kWh, and the residential average rate increased by 1.4 cents/kWh (based on 2019 ERRA forecast sales amounts.) as a result of the 2018 ERRA Trigger under-collection amount of $824.9 million.

[51] SDG&E's revenue requirement includes Total Rate Adjustment Component (TRAC), a charge which reflects the cost shift that resulted from capped residential tiered rates previously legislated under Assembly Bill 1X and Senate Bill 695. The TRAC revenue requirement reflects an under-collection due to a timing issue resulting from costs shifts not yet fully recovered.

SDG&E's revenue requirement corresponding to costs recovered in its generation rate component (called "commodity" rate component by SDG&E) rose from 2016 through 2018 and has been decreasing since then, while revenue requirement corresponding to costs recovered in the distribution and transmission rate components have been generally trending upward since 2016.

The primary drivers of the 12 percent decrease in SDG&E's commodity revenue requirement from 2018 to 2019 are the decommissioning of the San Onofre Nuclear Generating Station (SONGS) and expiring contracts for purchased power. The primary drivers of the 8 percent decrease in commodity revenue requirement from 2019 to 2020 are a decrease to amortization in the balancing accounts, a decrease in the 2019 GRC commodity revenue requirement, and refund due to the Tax Cut Job Act.

While SDG&E's transmission revenue requirement has increased slightly since 2016, the distribution revenue requirement has increased about 19 percent since 2016. Although SDG&E's distribution revenue requirement dipped slightly from 2018 to 2019, there was a 12 percent increase from 2019 to 2020, primarily from its most recent GRC outcome; on January 1, 2020, SDG&E implemented its 2019 General Rate Case Attrition Year 2020 which included updating its revenue requirement for its distribution rate component.

Cost Recovery by Proceeding

CPUC-jurisdictional revenue requirements corresponding to the regulated operations of IOUs are authorized in ratemaking proceedings known as General Rate Cases (GRCs) on a four-year cycle.[52] On an annual basis, these authorized revenue requirements may not be fully recouped or conversely collected in excess from customers, in which case a revenue requirement adjustment resulting from under- or over-collecting the authorized revenue requirement in a prior year is reflected in the consolidated January 1 revenue requirement.[53] GRC and related revenue adjustment accounts revenue requirements comprise a substantial portion of an IOU's total authorized revenue requirement.

The CPUC approves operating and maintenance (O&M) expenses and capital costs in each GRC proceeding. The IOUs earn a rate of return, or profit, only on capital expenditures (e.g. the value of utility-owned transmission and distribution assets), the total of which is referred to as rate base. Return on rate base is thus a component of an IOU's authorized revenue requirement and represents the profit the utility can return to shareholders.

In addition to GRC proceedings, Energy Resource Recovery Account (ERRA) proceedings take place annually to review each utility's fuel and power purchase forecast and other generation-related

[52] The CPUC may disallow recovery of an expenditure if it is determined to be unreasonably or imprudently incurred.

[53] These revenue adjustment accounts are known as balancing or memorandum accounts.

revenue requirements.[54] If the CPUC determines the power procurement costs subsequently incurred are reasonable, the IOU is authorized to pass the costs onto ratepayers as part of the revenue requirement.[55] The IOU does not earn a profit on these costs. Outside of GRC and ERRA proceedings, program budgets for public policy-related revenue requirements are periodically approved in specific proceedings. Lastly, the CPUC is required to allow recovery of all FERC-jurisdictional revenue requirements corresponding to transmission rate cases.

The January 1, 2020 revenue requirement for PG&E ($13.9 billion), SCE ($11.5 billion), and SDG&E ($4.1 billion) are shown by proceeding category in Figure 11.[56]

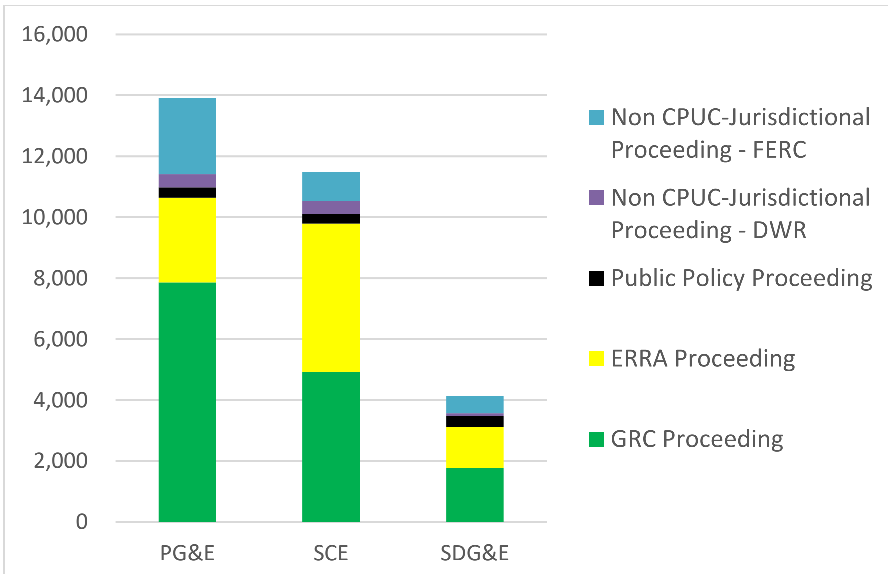

Figure 11: January 1, 2020 Revenue Requirement ($ millions) by Proceeding

For CPUC-jurisdictional proceedings, the combined ERRA and GRC proceedings comprise about 75 percent to 80 percent of each IOU's total revenue requirement, with public policy proceedings representing about 5 percent of the revenue requirement. Non CPUC-jurisdictional proceedings (DWR and FERC) comprise 15 to 20 percent of each IOU's total revenue requirement.

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[54] The ERRA is a power procurement balancing account required by Public Utilities Code § 454.5(d)(3). The general purpose of the ERRA is to provide recovery of energy procurement costs, including expenses associated with fuel and purchased power, utility retained generation, and California Independent System Operator (CAISO) related costs.

[55] These reasonableness reviews are done as part of applications filed by the IOUs in the year subsequent to the ERRA proceeding year.

[56] The total revenue requirement for each IOU is the same in this figure as in the previous figures showing revenue requirement by rate component. GRC Proceeding category captures all other Non-ERRA proceeding operating costs. Public Policy category includes all public purpose program and other public policy-related costs.

3. Legislative Programs: Present and Future Cost Implications

The Cost and Rate Tracking Tool

Forecasted Incremental Revenue Requirement and Projected Rate and Bill Impacts

As part of evaluating the impact on ratepayers of legislative program costs filed in **pending** cost recovery applications such as public policy programs, Energy Division staff has been working with the three large electric IOUs[57] to develop a Cost and Rate Tracking Tool that models forecasted incremental revenue requirements and resulting projected residential rate and bill impacts.[58] The IOU Cost and Rate Tracking Tools have been developed with the following assumptions:

- Forecasted incremental revenue requirements are classified at rate component level (i.e. Generation, Distribution, Public Purpose Program, etc.) to reflect the cost recovery mechanism.[59]
- Forecasted incremental revenue requirements corresponding to balancing account balances are held constant at current levels.
- Forecasted sales are based on authorized sales forecasts or on sales forecasts requested in pending applications, if available.
- Projected rate and bill impacts are based on forecasts and are for illustrative purposes only.[60]
- Projected bill impacts do not take into account any cost savings that may accrue to certain IOU cost categories or customers.[61]

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[57] Cost and Rate Tracking Tools have not been developed for the gas IOUs.

[58] PG&E, SCE, and SDG&E submit quarterly data responses to Energy Division that include the tracker tool workbook. At the time this report was published, SDG&E's tracker tool workbook included forecasted incremental revenue requirements but did not have rate and bill calculation functionality.

[59] For example, if cost recovery is proposed through the distribution rate component, rate and bill impacts will be calculated based on the revenue requirement collection through the distribution rate component. Authorized cost recovery mechanisms may include: 1) the rate component through which the cost will be recovered; 2) customer class responsibility for cost recovery; and 3) other terms or conditions.

[60] Projections are based on forward-looking estimates that are not historical facts and include forecasts and assumptions related to those forecasts.

[61] For example, energy efficiency programs show up as a cost under the public-purpose programs, however there should be a corresponding savings in other IOU cost categories and in overall bills due to reduced usage.

Once the Cost and Rate Tracking Tool for each IOU has been fully developed, Energy Division will make the tool available to CPUC decision-makers who wish to see the effect on residential class rates and bills of: 1) a single pending revenue requirement request or 2) the cumulative effect of two or more pending revenue requirement requests.

Estimated Bill Impacts for Selected Legislative Programs

For selected legislative programs in this report, estimated bill impacts at average bundled residential class level will be presented for 2020 authorized collections or program funding and for authorized incremental revenue requirements[62] corresponding to program costs estimated to be in rates in 2020.[63] These estimated bill impacts represent the approximate change in an average bundled residential customer's monthly bill[64] that will occur when the rates are implemented.

Renewable Portfolio Standard and Integrated Resource Planning

Background and Status

SB 1078 initiated the Renewable Portfolio Standard (RPS) in 2002 establishing targets for eligible renewable energy resources such as wind, solar photovoltaics (PV), hydroelectric, and biomass. The RPS targets have been legislatively adjusted several times their current values that now include a 60 percent eligible renewable target by 2030.[65] The overall contracted commitment in renewables by retail sellers in California has increased over time. California's three large IOUs collectively served 40 percent of their 2018 retail electricity sales with renewable power.

The CPUC sets cost-effectiveness policies and collects various renewables price data to understand cost trends and the impact of these costs on ratepayers. Figure 12 illustrates the average annual

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62 Program funding and authorized incremental revenue requirements are presented at system-level.

63 Rate impacts are not presented as estimated rate impacts are generally less than one-tenth of one cent ($0.001) for revenue requirements less than $50 million.

64 Estimated bill impacts are illustrative only, based on rates in effect January 1, 2020 unless otherwise indicated, and are estimated by rate component for cost recovery for PG&E and SCE. Bill impacts assume the following monthly usage for the average bundled residential customers: PG&E 435 kWh; SCE 547 kWh; and SDG&E 409 kWh. PG&E and SCE figures are based on a 2018 recorded usage of basic-service residential customers in all climate zones weighted by population and annualized for both the summer and winter seasons. SDG&E figure based on U.S. EIA Annual 2018 Electricity Data by State and Utility. Bill impacts for SDG&E are estimated without regard to rate component for cost recovery. Bill impacts calculated under this method may vary substantially from bill impacts calculated taking cost recovery rate component into consideration.

65 On September 10, 2018, SB 100 (de León, 2018) was signed into law, which accelerated the RPS requirement to 60 percent by December 31, 2030, with interim targets of 44 percent by December 31, 2024, and 52 percent by December 31, 2027 and sets a goal that all of the state's electricity to come from carbon-free resources by 2045.

contract prices in their year of execution for procuring RPS eligible projects with capacities greater than 3 MW in cents per kilowatt-hour (¢/kWh) for the three IOUs.[66, 67]

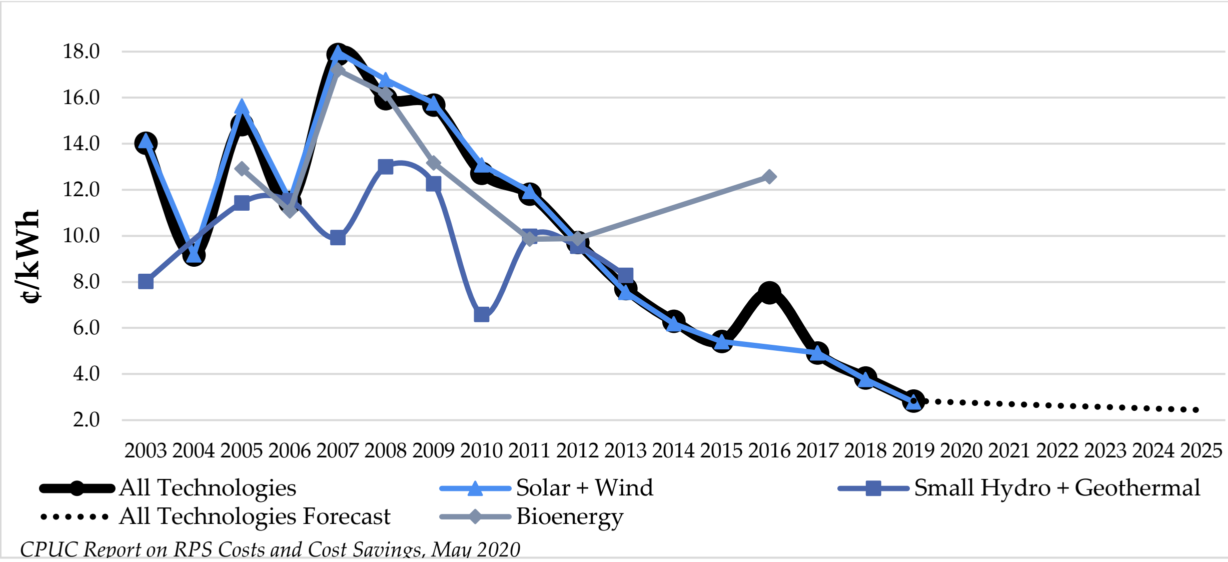

Figure 12: Average Annual RPS Contract Prices by Year of Execution, 2003 - 2025 (Real Dollars)

The IOUs use competitive procurement mechanisms and a least-cost, best-fit evaluation methodology to ensure procurement of renewable resources that provide the most value in their RPS Procurement Plans.

In 2019, RPS procurement expenditures accounted for less than 19 percent of the IOUs' total revenue requirements and are anticipated to decrease on a ¢/kWh basis slightly as the cost of new RPS projects are expected to decline over time. 44.9 percent of the IOUs' total generation was from RPS-eligible resources and expenditures on renewable generation was 42.4 percent of the IOUs' total generation costs. This shows that RPS expenditures as a percent of total generation costs are on par with non-renewables.

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66 Contract prices have been adjusted for inflation using the U.S. Bureau of Labor Statistics' Producer Price Index (PPI) for the Electric Power Generation, Transmission, and Distribution Industry.

67 *See* CPUC's *2020 Padilla Report, Costs and Cost Savings for the RPS Program* for more on historical renewable energy resource contract pricing.

SB 350 requires the CPUC to identify an optimal portfolio of resources to achieve California's long-term greenhouse gas (GHG) reduction goals at lowest costs while maintaining reliability and to create a process for all load-serving entities (LSE) to file individual integrated resource plans (IRP) with the CPUC. In February 2018, the CPUC adopted its first IRP Reference System Portfolio (RSP) of energy resources to meet a GHG planning target of 42 million metric tons (MMT) by 2030 for the electric sector, which identified a need to procure renewable resources beyond the 50 percent RPS target as part of a cost-effective portfolio. LSEs submitted integrated resource plans on August 1, 2018,[68] outlining their strategies for meeting their LSE-specific GHG planning targets while achieving the state's other policy goals. The Preferred System Portfolio (PSP) was adopted by the CPUC in 2019 and accounted for the aggregated IRP filings and associated policy actions needed to drive procurement and program activity across multiple supply and demand resources.

In March 2020, the CPUC adopted a new RSP and directed electricity providers to demonstrate how they would meet their share of the adopted 46 MMT target (which due to accounting changes is the same target as last cycle's 42 MMT target), as well as a deeper target of 38 MMT by 2030. Once the CPUC receives individual plans from LSEs later this year, the CPUC will compile and aggregate those portfolios in development of a PSP for this cycle of IRP.

Energy Storage Projects

Background and Status

In response to AB 2514 (Skinner, 2010), the CPUC established IOU energy storage targets of 1,325 MW to be procured by 2020 and operational by 2024. The energy storage must be procured within 3 grid domain sub-targets: behind the meter, distribution connected and transmission connected. The storage is required to be "cost-effective" which has been defined to include least-cost-best-fit (LCBF). What this means is the CPUC must procure storage that is cost reasonable. This means that sometimes the storage will increase ratepayer costs and sometimes save ratepayer costs. A future storage evaluation will help the CPUC verify how cost effective the storage procurement is as well as how well the storage is achieving state policy goals.

[68] *See* D.18-02-018.

In 2019, the CPUC approved over 211 MW of storage projects. The majority of this procurement happened in southern California and was driven by two needs: 1) to help address electrical system operational limitations resulting from reduced gas deliverability caused by the partial shutdown of the Aliso Canyon natural gas storage facility; and 2) to contribute to meeting long-term local capacity requirements (LCR) in the Moorpark sub-area of the Big Creek/Ventura local reliability area as defined by the CAISO. This portfolio of approved projects is expected to result in $3.5 million net positive savings for ratepayers. The CPUC approved other storage procurements to satisfy distribution deferral objectives where the storage may serve as a non-wire alternative (NWA) to a traditional distribution infrastructure investment. In one instance, the DER alternative was no more expensive then the deferred distribution asset would have been. In another instance, the DER alternative was $500,000 less expensive than the planned distribution investment.

Collectively, the three major IOUs have significantly exceeded the 1,325 MW target set in response to AB 2514. PG&E and SDG&E still need additional domain-specific procurement to meet the sub-targets. PG&E requires 39 MW in the customer domain. SDG&E needs 6 MW in the distribution domain.

Activities and Proceedings in the Upcoming 12-Months (May 1, 2020 – April 30, 2021)

Activities and proceedings that could result in additional energy storage procurement in this period and are expected to either save ratepayer costs, or at worst be cost neutral, include:

- IOU distribution deferral solicitations are underway or imminent in the Distributed Resource Planning (DRP) proceeding. If storage is procured as "non-wires alternatives" the cost is expected to be the same or less than the tradition infrastructure projects being deferred.
- The CPUC in the IRP proceeding has ordered the three IOUs to procure Resource Adequacy capacity to meet the state's System Reliability goals over the next three years through all-source RFOs. Each of the IOUs is evaluating storage and hybrid solar/storage projects as part of this process. The CPUC anticipates that many proposed procurements will be submitted as part of this process and that most will include energy storage projects and hybrid storage/solar projects. The costs are unknown until the time of contract execution. A first tranche of this procurement is expected to be submitted to the CPUC for approval by the 4th quarter of 2020. PG&E has issued an RFO to procure distributed resources that can provide microgrid services as part of their response to wildfire and resiliency concerns. Significant progress on this initiative is expected over the year.
- PG&E and SCE are each evaluating large energy storage procurement opportunities as environmentally preferred alternatives to planned distribution substation and transmission upgrade projects for reliability. If storage is procured as non-wires alternatives the cost is expected to be the same or less than the traditional infrastructure projects being deferred.

Longer-Term Trends (May 2021 and Beyond)

The latest models in the CPUC's Integrated Resource Planning process have called for up to 10,000 MWs of energy storage resources to come online by 2030. This comes in a landscape of continuing technological development and evolving market realities for IOUs and other California LSEs.

The CPUC will also launch the process to have an independent consultant conduct an evaluation of the programs and policies on energy storage in the state. The report produced by this consultant should help guide changes that may be needed to effectively plan for and procure energy storage resources as part of the State's clean energy future. The report findings could inform how the CPUC can maximize the value stacking benefits of energy storage which could improve the cost-effectiveness of energy storage and provide great value to ratepayers.

Self-Generation Incentive Program (SGIP)

Background and Status

The CPUC established the Self-Generation Incentive Program (SGIP) in 2001[69] in response to Assembly Bill (AB) 970 (Ducheny, 2000). AB 970 directed the CPUC to provide incentives for distributed generation resources to reduce peak energy demand. Since 2001, the Legislature has refined and extended SGIP several times.[70] Notably, SGIP is the longest running incentive program in the U.S. While incentivizing behind the meter, distributed generation technologies was once the main focus of SGIP, energy storage participation has grown significantly since 2016 and is now the main focus of SGIP.

In 2018, Senate Bill (SB) 700 (Wiener, 2018) was adopted by the legislature and signed into law,[71] authorizing the CPUC to extend annual ratepayer collections for SGIP from December 31, 2019 to December 31, 2024 by up to $166 million annually and to extend administration of the program from January 1, 2021 to January 1, 2026. SB 700 requires the CPUC to return to ratepayers any unallocated funds remaining as of January 1, 2026.

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69 *See* D.01-03-073.

70 AB 1685 (Leno, 2003), AB 2778 (Lieber, 2006), and SB 412 (Kehoe, 2009) collectively shifted SGIP's focus from peak demand reduction towards reducing criteria pollutants and greenhouse gas (GHG) emissions. SB 861 and AB 1478 authorized SGIP collections through 2019 and administration through 2020 and required a number of other changes. AB 1637 (Low, 2016) authorized the Commission to double annual collections through 2019 as compared to calendar year 2008.

71 Public Utilities Code § 379.6(a)(2).

In 2019, the CPUC adopted two important decisions that modified SGIP. The first decision,[72] modified the program to ensure that eligible SGIP energy storage systems reduce GHG emissions. The decision also required SGIP program administrators (PAs) to provide a digitally accessible final GHG signal that provides marginal GHG emissions factors in units of kilograms carbon dioxide per kilowatt hour (kg/kWh) and required customers with new residential storage projects to enroll in an approved time-varying rate if one is available. The second decision[73] modified SGIP equity budget program requirements and incentive levels to increase participation.

To help deal with critical needs resulting from wildfire risks in the state, it also established a new equity resiliency budget set-aside for vulnerable households located in Tier 2 and Tier 3 high fire threat districts, critical services facilities serving those districts, and customers located in those districts that participate in two low-income solar generation programs. It also establishes a $10 million budget for SGIP storage incentives to support pilot projects in eleven San Joaquin Valley disadvantaged communities[74] and a $4 million equity budget set-aside for heat pump water heater (HPWH) incentives.

Activities and Proceedings in the Upcoming 12-Months (May 1, 2020 – April 30, 2021)

In 2020, the CPUC authorized ratepayer collections of $166 million annually for the years 2020 to 2024 to fund SGIP consistent with the authorization established by SB 700. The decision[75] prioritizes allocation of 2020 to 2024 collections in accordance with AB 1144 (Friedman, 2019) and to benefit customers impacted by Public Safety Power Shutoff (PSPS) events or located in areas of extreme or elevated wildfire risk.[76] Table 4 shows SGIP authorized electric and gas ratepayer collections and estimated bill impacts.

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72 *See* D.19-08-001.

73 *See* D.19-09-027.

74 For more information on the San Joaquin Valley disadvantaged communities, *see* D.18-12-015.

75 *See* D.20-01-021.

76 The decision allocates the 2020 to 2024 incentive funds as follows: Energy storage technologies 88 percent and renewable generation technologies 12 percent. SGIP program administrators are to pause acceptance of incentive applications for renewable generation technologies using biogas sources that are already capturing methane until provided further guidance in a decision by the CPUC.

Program Administrator	Percent	Annual Collection ($ millions)	Total Collection 2020 - 2024 ($ millions)	Estimated Bundled Residential Customer Average Monthly Bill Impact ($)[77]
PG&E	44	$ 72	$ 360	$ 0.48
SCE	34	$ 56	$ 280	$ 0.42
SDG&E	13	$ 22	$ 110	$ 0.56
SoCalGas	9	$ 16	$ 80	Not Available
Total	**100**	**$166**	**$ 830**	

Table 4: SB 700 SGIP Authorized Ratepayer Collections and Bill Impacts

In 2020, the CPUC will take steps to implement SB 700's additional funding for the SGIP program. This will require review of numerous advice letter filings to update the SGIP Program Handbook that establishes the eligibility rules for applicants. One area of particular priority for CPUC staff in 2020 is ensuring that vulnerable customers who are eligible for the new equity resiliency budget can access those incentives and install energy storage prior to the 2020 fire season. This will require a concerted marketing, education, and outreach (ME&O) effort statewide that will span many different groups from the program administrators to local governments to community based organizations to battery storage project developers and beyond.

Also, in 2020, the Energy Division staff will hold a workshop to determine how to enable heat pump water heaters (HPWHs) to participate in the SGIP program. The CPUC is considering a workshop on directed biogas in the latter half of 2020 as well.

Transportation Electrification (TE) Programs

Background and Status

The CPUC and IOUs are responding to several legislative mandates and gubernatorial directives to support and accelerate widespread transportation electrification (TE).[78] SB 350 directed the CPUC to require the investor-owned utilities (IOUs) to submit applications for programs that leverage

[77] Estimated monthly bill impact is already in rates and is not incremental. This means customers will see no additional bill impact in 2020 for this program.

[78] SB 350 defined TE as any vehicle fueled by electricity generated outside of the vehicle, including light-duty vehicles, medium- and heavy-duty vehicles, off-road vehicles, and shipping vessels.

ratepayer funding to support EV adoption.[79] To date, the CPUC has authorized the IOUs to implement multiple TE programs to help meet California's zero-emission vehicle (ZEV) targets of 5 million ZEVs on the road by 2030, and 250,000 installed publicly available electric vehicle charging stations and 200 publicly available hydrogen fueling stations in the state by 2025.[80]

To date, the CPUC has authorized the IOUs to spend more than $1 billion to support the state's TE goals, and is considering applications for other large-scale investments:

- Out of ~$1.03 billion in authorized IOU funding to date, $265 million has been fully spent.
- Another $763 million (~70% of authorized funds) is still available for medium- and heavy-duty vehicles, including off-road vehicles (MD/HD).
- In addition, $804 million is pending in IOU TE program applications before the CPUC.

Activities and Proceedings in the Upcoming 12-Months (May 1, 2020 – April 30, 2021)

Over 2016-2019, the CPUC approved more than $1 billion in IOU ratepayer spending to support TE infrastructure programs.[81] The IOUs are in the process of installing the EV charging infrastructure and will continue to collect the corresponding revenue requirements through 2024,[82] as shown in Table 5.

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[79] Such as multi-unit dwellings (MUD), workplaces, destination centers, disadvantaged communities, and low/medium income residential communities.

[80] Executive Order (E.O.) B-48-18.

[81] *See* D.16-01-045 (SDG&E), D.16-01-023 (SCE), and D.16-12-065 (PG&E); D.18-01-024 (all three large IOUs); D.18-05-040 (all three large IOUs); D.18-09-034 (the three small/multi-jurisdictional IOUs), and D.19-08-026 (SDG&E).

[82] Program timelines are "soft" and may be continued until the budget is expended.

Category	Funding Time Frame	Approximate Approved Funding ($ millions)
Light Duty Vehicle (LDV) infrastructure*	2016-2022	$280
Medium-Heavy Duty Vehicle infrastructure	2018-2024	$705
Off-road infrastructure	2020-2022	$10.4
Public DC Fast Charging	2018-2024	$30.4
Education/Outreach	2018-2020	$2.3
Total	**2016-2024**	**$1,029**
***additional $804 million under consideration for LDV infrastructure**	*2020-2025*	*TBD*

Table 5: IOU TE Infrastructure Program Spending 2016-2024

In 2020, the CPUC is considering $803.6 million for two EV infrastructure proposals and one EV rate proposal that will potentially have cost recovery starting in 2021.[83] SCE has requested $760.1 million to expand the Charge Ready program to install EV charging infrastructure and provide rebates to support approximately 48,000 charging ports. SDG&E has requested $43.5 million to extend the Power Your Drive pilot for two years to install EV charging infrastructure and provide rebates to support the installation of approximately 2,000 charging ports.

Figure 13 illustrates the approved and proposed transportation electrification program budgets, and highlights that the majority of approved IOU funding is still available for customers to participate in the IOUs' medium- and heavy-duty vehicle programs, as depicted in blue. The funding associated with the pending applications described above is also illustrated in gold.

[83] As part of their applications, the IOUs estimated that these programs, if approved, would increase a typical residential ratepayer's monthly bill as follows: SCE (A.18-06-015) $0.84 and SDG&E (A.19-10-012) $0.46.

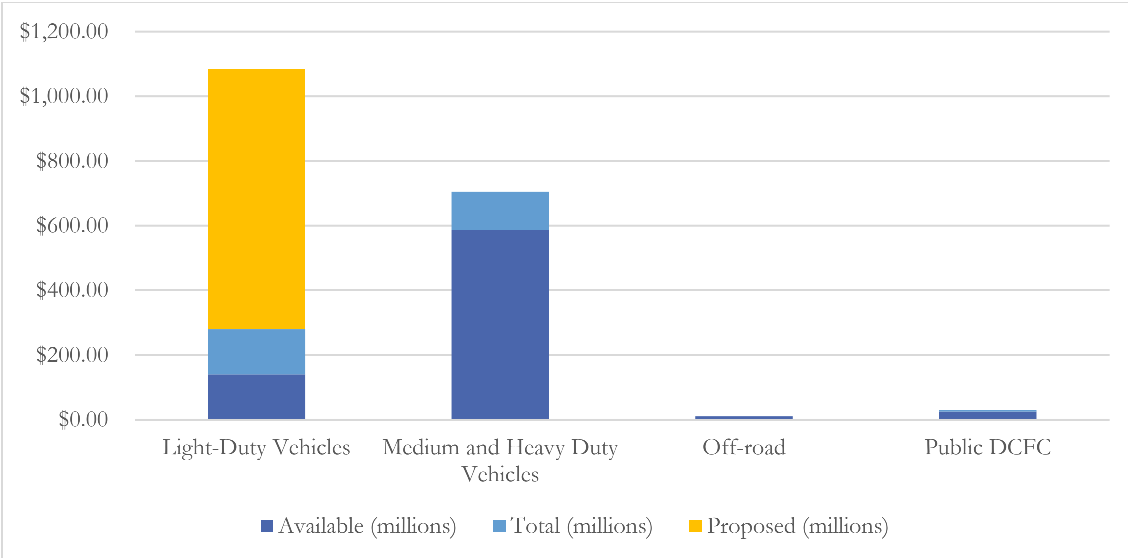

Figure 13: Transportation Electrification Total Budgets, Available Budgets, and Proposed Budgets by Sector

TE program authorized incremental revenue requirements to be implemented in rates in 2020 and resulting estimated bill impacts are shown in Table 6.

IOU	2020 TE Authorized System Incremental Revenue Requirement ($ millions)	2020 Estimated Bundled Residential Customer Average Monthly Bill Impact ($)
PG&E	$ 6.7	$ 0.05
SCE	$ 3.3	$ 0.03
SDG&E	$ 11.7	$ 0.35

Table 6: 2020 TE Program Authorized Incremental Revenue Requirement and Bill Impacts

Longer-Term Trends (May 2021 and Beyond)

SB 350 gave the CPUC a legislative mandate to ensure EV owners have charging options that are cleaner and at a lower costs than conventional fossil fuels.[84] The CPUC is also directed to explore a more targeted rate-design strategy for commercial EV customers and to deploy EV charging options in locations with existing grid capacity.[85] To meet these mandates, the CPUC is working with the IOUs to design electric rates that support grid beneficial EV charging habits, while preventing cost shifts to ratepayers who don't drive EVs.

In 2018, in an effort to address the need for a more focused process to guide utility investments in transportation electrification, the CPUC opened an Order Instituting Rulemaking (OIR)[86] to streamline the CPUC's efforts for future transportation electrification programs, tariffs, and policies.

The OIR also directed CPUC Energy Division (ED) staff to develop a transportation electrification framework (TEF) to, amongst other things, define the role of IOU ratepayer funding in meeting the states TE goals. The draft TEF was released in February 2020. Its primary recommendation is for the IOUs to file 10-year investment strategies identifying priority market segments where ratepayer funding would be most effective in promoting TE. In reviewing the proposals, the CPUC will examine pathways to encourage third-party investments and align the IOUs' investments with other state agencies, to lessen the rate impact of TE infrastructure investments on ratepayers.

One of the TEFs recommendations is to have the IOUs develop real-time, dynamic rates for all EV customers within the next five years to encourage vehicle charging at times that are beneficial to the grid. Similarly, each IOU program must now include vehicle-grid integration strategies that leverage vehicle batteries for demand response programs and other grid services.[87]

While the IOUs have requested ratepayer funds for their TE infrastructure programs, the expectation is that TE will likely lead to higher overall electricity demand, especially as medium- and heavy-duty fleets convert to EVs. The growing EV fleet presents an opportunity to enact dynamic grid management programs with the potential to drive down rates for all ratepayers.

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[84] Public Utilities Code 740.12 (a)(1)(H): "Deploying electric vehicle charging infrastructure should facilitate increased sales of electric vehicles by making charging easily accessible and should provide the opportunity to access electricity as a fuel that is cleaner and less costly than gasoline or other fossil fuels in public and private locations."

[85] Chapter 368 of the Statutes of 2018 created Pub. Util. Code §740.15, setting new requirements for the CPUC to support the development and deployment of new technologies and rate designs that promote grid integration.

[86] *See* R.18-12-006.

[87] Chapter 484 of the Statutes of 2019 created Pub. Util. Code §740.16, setting new requirements for the CPUC to adopt targets for the IOUs to deploy cost-effective vehicle-grid integration strategies by 2030.

Energy Efficiency (EE) Programs

Background and Status

The CPUC regulates ratepayer-funded[88] energy efficiency programs managed by energy efficiency program administrators (PA) including the investor owned utilities (IOU), community choice aggregators (CCA), and Regional Energy Networks (REN). The CPUC establishes energy savings goals, and energy efficiency PAs submit budgets for programs to achieve those goals.[89] Annual budgets are reviewed by Energy Division staff and collected in rates through the Public Purpose Program (PPP) revenue requirement. In order to ensure these funds are being used effectively, the CPUC evaluates all ratepayer-funded energy efficiency programs for cost-effectiveness and verifies energy savings.

In the 2018 program year, the approved energy efficiency program budget across energy efficiency PAs totaled $856 million, and final expenditures totaled $696 million. The 2018 reported program electricity savings were 3,088 gigawatt-hours, and natural gas savings were 81 million therms. For 2019, expenditures across energy efficiency PAs were $639 million, program electricity savings were 2,738 gigawatt-hours and natural gas savings were 84 million therms.

It is important to recognize that while energy efficiency programs have ratepayer costs, they also provide ratepayer benefits in the form of reduced energy consumption and, ultimately, lower customer bills. Generally speaking, as long as energy efficiency programs are cost effective, benefits to customers should be greater than the costs in rates (and greater than out-of-pocket costs paid by customers for higher-efficiency products, given the CPUC's use of the Total Resource Cost test in assessing energy efficiency portfolio cost effectiveness).

Activities and Proceedings in the Upcoming 12-Months (May 1, 2020 – April 30, 2021)

After the PAs filed their Annual Budget Advice Letters in September 2019, CPUC staff authorized $630 million in energy efficiency program spending for 2020.[90] If a utility is not able to contract for all forecasted energy efficiency programs in a given year, unexpended funding rolls over into the next year's budget request, and the tariffs used to collect these funds are reduced accordingly. For

[88] These funds are collected as a portion of the public purpose program rate component.

[89] In January 2017, program administrators submitted their initial 10-year forward business plans for energy efficiency. The business plans were reviewed and approved by the CPUC in 2018 via D.18-05-041.

[90] Annual Budget Advice Letters of PG&E, SCE, SoCalGas, and SDG&E, 2020. Other PAs are not included here.

2020, the collections needed for the total authorized budget of $630 million are reduced based on what was "unspent and uncommitted" from 2019.[91]

Table 7 shows 2020 energy efficiency program budgets, program funding, and estimated bill impacts.[92] Note that the energy efficiency programs will ultimately result in reduced electricity usage which lowers bills and reduces utility procurement costs. When these savings are calculated in the long term, bill impacts should be zero or result in a net savings.

Utility	2020 Total Budget[93] ($ millions)	2020 Public Purpose Program Funding[94] ($ millions)	Estimated Bundled Residential Customer Average Monthly Bill Impact[95] ($)
PG&E	$271.5	$258.2	$ 1.32
SCE	$168.0	$ 49.0	$ 0.36
SoCalGas	$109.0	$105.4	Not Available
SDG&E	$ 81.5	$ 60.5	$ 1.53
Total[96]	**$630.0**	**$473.0**	

Table 7: 2020 Energy Efficiency Program Budgets, Funding, and Bill Impacts

As shown in Table 7, all utilities had some amount of unspent/uncommitted funds that reduced the amount of public purpose funding requested for the 2020 program year. SCE's funding needs were significantly reduced by the amount of unspent/uncommitted funds from previous years.

91 "Unspent and uncommitted" from 2019 is projected to be $157 million, subjected to change upon receipt of final 2019 reports due in May 2020.

92 Columns may not sum due to rounding.

93 The 2020 IOU budgets are projected.

94 Includes collections from ratepayers for the calendar year minus any unspent/uncommitted funds from previous years

95 Estimated monthly bill impact reflects a reduced program funding level from previous level. This means customers will see a reduced bill impact in 2020 for this program, see Table 8 for this incremental bill impact.

96 Totals include Evaluation, Measurement & Verification funding, Regional Energy Network funding, and Community Choice Aggregator funding

Table 8 shows energy efficiency program authorized incremental revenue requirements to be implemented in rates in 2020 and resulting estimated bill impacts.

Utility	2020 EE Authorized System Incremental Revenue Requirement ($ millions)	2020 Estimated Bundled Residential Customer Average Monthly Bill Impact ($)
PG&E	($ 76.6)	($0.39)
SCE	($ 44.4)	($0.33)
SDG&E	($ 19.7)	($0.50)

Table 8: 2020 EE Program Authorized Incremental Revenue Requirement and Bill Impacts

Longer-Term Trends (May 2021 and Beyond)

The projected long-term energy efficiency budgets are described in business plan filings by each energy efficiency PA and forecast the spending necessary to meet the CPUC-established energy savings goals for the same period. The total of the PAs' projected budgets as filed in the business plans rises from $853,708,071 in 2020 to $880,169,403 in 2024.[97] The projected budget amounts trend slightly upwards as shown in Table 9, meeting the goal of increasing energy savings while keeping costs to ratepayers down.

	2020	2021	2022	2023	2024
PG&E	354,274,412	355,707,745	356,599,412	355,692,120	355,668,162
SCE	275,649,883	270,600,813	278,583,316	286,805,293	295,273,930
SoCalGas	104,064,000	106,195,000	108,356,000	110,548,000	112,771,000
SDG&E	119,719,776	119,719,776	119,719,776	116,456,311	116,456,311
Total	**853,708,071**	**852,223,334**	**863,258,504**	**869,501,724**	**880,169,403**

Table 9: Projected Energy Efficiency Program Budgets[98]

Several factors can affect the long-term projections contained in the PA business plan filings. The CPUC is currently updating its Energy Efficiency Potential Study, in collaboration with the California Energy Commission (CEC), which will help shape the goals for upcoming energy

[97] These are based on projected budgets. In some cases, these figures differ from approved budget amounts.
[98] Energy Efficiency Business Plans of PG&E, SCE, SoCalGas, and SDG&E.

efficiency programs. The results of the study will enable the CPUC and PAs to select the most promising options for cost effective energy savings in 2020 and beyond.

Second, energy efficiency PAs are now required to contract with third party implementers for a majority of their energy efficiency activities.[99] The rationale for third-party requirements is based on supporting innovation in program design, as well as the potential for cost savings through competitive solicitation of programs. In January 2018, the CPUC increased the required minimum percentage of third-party programs from 20 percent of total budgeted portfolio to at least 25 percent by the end of 2018, 40 percent by the end of 2020, and 60 percent by the end of 2022.[100] In November 2019, the CPUC granted an extension request for the 25 percent requirement to two separate dates: June 30th, 2020 (for SDG&E and PG&E), and September 30th, 2020 (for SoCalGas and SCE). The dates for the 40 percent and 60 percent requirements were not modified.

Third, the CPUC has recently put in place new requirements for IOUs to implement certain statewide energy efficiency programs.[101] Statewide programs are designed to deliver energy efficiency programs uniformly throughout the four major IOU service territories. 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. This can, in turn, reduce costs for ratepayers.

Fourth, in January 2020, the CPUC passed an updated Rulebook clarifying the use of normalized metered energy consumption (NMEC) approaches in measurement and verification (M&V) practices, as per AB 802 (Williams 2015).[102] NMEC may require upfront investment and longer reporting periods but has the potential to capture savings in a more streamlined and accurate way than currently used M&V practices. In the long term this approach may reduce program costs. NMEC can support pay-for-performance programs in which ratepayers only pay for energy efficiency savings that is documented by metered data.

Finally, in late-2019 the CPUC passed a new California market transformation framework intended to enable energy efficiency PAs and other program implementers to develop innovative methods to capture energy savings from emerging technologies, to remove barriers to energy savings, and to move new energy efficiency measures down the pathway toward adoption and eventually into code. The goal is to improve the cost effectiveness of energy savings through innovative new approaches and to find new ways to save energy.

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99 *See* http://www.cpuc.ca.gov/General.aspx?id=4460 .

100 *See* D.18-01-004.

101 *See* D.16-08-091, with later revisions in D.18-05-041.

102 *See* A.17-01-013 docket, Ruling on Certain Measurement and Verification Issues, filed January 31, 2019.

Demand Response (DR) Programs

Background and Status

Demand Response refers to the reduction or increase of electricity usage during some time 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 plants that would otherwise be necessary to meet peak demand or avoid curtailment of renewables during times of excess production.

Many DR resources are now bid into CAISO energy markets, enabling them to compete against generation bids and to be dispatched when and wherever needed by the CAISO. By competing against generation resources in these markets, DR resources may become more cost-competitive. Future DR programs will be designed to help integrate increasing amounts of renewable power onto the grid by shifting electric loads to periods of high renewable generation.

Activities and Proceedings in the Upcoming 12-Months (May 1, 2020 – April 30, 2021)

2018-2022 IOU Demand Response Portfolios: Overall, DR budgets have remained relatively flat because IOU portfolio budgets were frozen at 2017 levels.[103] In December 2017, the CPUC approved a 5-year budget for 2018-2022 of $1.16 billion for utility-operated DR programs[104] that will provide approximately 1,600 MWs of DR capacity by 2022.[105]

In 2018, the IOUs began operating from the budget approved in 2017.[106] The total budgets over the period 2018 - 2022 in DR Programs,[107] Pilots and Technology,[108] and Support for DR[109] are shown in Table 10 below.

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103 *See* D.16-09-056.

104 DR was bifurcated into Supply-Side and Load-Modifying DR programs in 2014 in D.14-03-026.

105 *See* D.17-12-003. Note that the 1,600 MWs includes IOU supply side DR programs and certain IOU load modifying programs like the Optional Binding Mandatory Curtailment program. It does not include MWs for time-differentiated pricing programs, which are approved in utility General Rate Cases, or Demand Response Auction Mechanism (DRAM), for which budgets were approved in D.17-10-017.

106 *See* D.17-12-003 as corrected in D.18-03-041.

107 DR Programs include Category 1: Supply Side Programs, and Category 2: Load Modifying Programs.

108 Pilots and Technology includes Category 3: Demand Response Auction Mechanism (DRAM) and Direct Participation Electric Rule 24/32, Category 4: Emerging and Enabling Technology programs, and Category 5: Pilots.

109 Support for DR includes Category 6: Marketing, Education, and Outreach (ME&O), and Category 7: Portfolio Support (includes EM&V, Systems Support, and Notifications).

IOU Demand Response Portfolio Budgets 2018 – 2022 ($ millions)				
Utility	DR Programs	Pilots and Technology	Support for DR	Total Budget
PG&E	$ 214.3	$ 49.8	$ 69.2	$ 333.3
SCE	$ 638.8	$ 60.7	$ 51.5	$ 751.0
SDG&E	$ 27.1	$ 28.1	$ 23.3	$ 78.5
Total	**$ 880.2**	**$ 138.6**	**$ 144.0**	**$1,162.8**

Table 10: IOU Demand Response Portfolio Total Budgets, 2018 - 2022

In addition to the DR portfolios managed by the IOUs, there have been significant developments for programs run by third-party DR providers including the Demand Response Auction Mechanism pilot.

The Demand Response Auction Mechanism (DRAM) Pilot: In 2014 the CPUC expressed an interest in implementing a competitive mechanism to procure DR resources as "supply-side" resources from non-IOU third parties to be bid into the CAISO market.[110] The competitive mechanism authorized by the CPUC is known as the Demand Response Auction Mechanism (DRAM). In 2016, the DRAM initiative was launched as a pilot to test "the feasibility of procuring [DR] Supply Resources for Resource Adequacy (RA) with third part[ies] … through an auction mechanism, and the ability of winning bidders to integrate their … DR [resources] into the [California Independent System Operator (CAISO)] markets."[111]

The Energy Division released its DRAM Evaluation Final Report on January 4, 2019, covering delivery years 2016 to 2018. The report found that the pilot results were mixed and recommended a continuation of the DRAM initiative conditioned on certain critical improvements. D.19-07-009 approved a four-year extension of the DRAM pilot for the 2020-2023 delivery years and adopted several measures to modify the design of DRAM to improve the performance of DRAM resources. For the most part, the same funding levels for annual Auction Mechanism solicitations budgets were maintained during the extension.[112] The annual budgets authorized for the DRAM pilot extension are shown in Table 11.

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[110] *See* D.14-12-024 Settlement at 69.

[111] *See* D.14-12-024 Settlement at 24.

[112] As funding levels from 2019 to 2020 are substantially the same, no bill impacts based on authorized incremental revenue requirement are presented.

Demand Response Auction Mechanism Budgets During the Extension: 2020 - 2023 Delivery Years ($ millions)						
Utility	2020 Budget (partial year)	2021 Budget	2022 Budget	2023 Budget	Evaluation by Independent Contractor	Total Budget 2020-2023
PG&E	$ 5.70	$ 6	$ 6	$ 6	$ 1.2	$ 24.90
SCE	$ 5.16	$ 6	$ 6	$ 6	$ 1.2	$ 24.36
SDG&E	$ 1.92	$ 2	$ 2	$ 2	$ 0.4	$ 8.32
TOTAL	**$ 12.78**	**$ 14**	**$ 14**	**$ 14**	**$ 2.8**	**$ 57.58**

Table 11: DR Auction Mechanism Program Budgets for 2020-2023 Delivery Years (4-year Pilot Extension)

CAISO Registrations and Meter Reprogramming: To support the DRAM and direct participation of third-party DR providers in the California Independent System Operator (CAISO) markets under Electric Rules 24 and 32,[113] the IOUs have requested funding to verify DR provider's registration of customers in the CAISO Demand Response Registration System (DRRS).[114] The IOUs have also requested funding to reprogram residential and small commercial customer meters from 60 to 15-minute intervals. All three IOUs are currently operating using existing funding approved through funding caps established in a formal proceeding and subsequent Resolutions.[115] This funding was also described in last year's SB 695 Report. In July 2019, after the last report, an additional

[113] Electric Rule 24 governs direct participation for PG&E and SCE. Electric Rule 32 governs direct participation for SDG&E.

[114] The funding for verification of DR provider's registration of their customers in the CAISO DRRS is also referred to as "CAISO registrations." The IOUs have requested funding to support a certain number of active registrations.

[115] D.16-06-008 and D.17-06-005 approved the funding caps of $10.39 million for PG&E, $3.2 million for SCE, and $4.9 million for SDG&E. The following Resolutions authorized funding for CAISO registrations and meter reprogramming under the cap, which were discussed in the 2019 SB 695 Report:

- Resolution E-4837 - PG&E - $1.914 million under the cap
- Resolution E-4935 - SCE - $3.2 million under the cap and $1.254 million fund shift
- Resolution E-4983 - PG&E - $0.89 million under the cap

Note that Resolution E-4914 approved $0.80 million in funding for SDG&E under the cap, but for click-through improvements not CAISO registrations or meter reprogramming. Funding for SCE meter reprogramming and CAISO registrations was also approved in the disposition of SCE Advice Letter 3553-E (November 2017) that approved the continued use of an existing budget of $3.523 million. SCE has also requested $1.5 million in funding as part of its Application 18-11-016 for meter reprogramming. In D.17-12-003, SDG&E received $2.98 million in authorized funding to support Rule 32 operations which includes staff to support meter reprogramming and CAISO registration verification.

$600,000 in funding for meter reprogramming and CAISO registrations was authorized for SDG&E to ensure SDG&E has sufficient funding for the meter reprogramming and CAISO registrations during the DRAM extension. Here, we assume that SDG&E will likely not need any funding until 2022. In October 2019, the CPUC approved funding under these cap of $ 0.89 million for PG&E.[116] PG&E expects the $0.89 million will be enough funding for meter reprogramming and CAISO registrations to last from 2020 through 2023 DRAM deliveries.[117] No additional funding has been approved for SCE since the last SB 695 report. The approximate annualized budgets are shown in Table 12.

CAISO Registration and Meter Reprogramming Budgets ($ millions)				
Utility	**2020**	**2021**	**2022**	**2023**
PG&E	$ 0.223	$ 0.223	$ 0.223	$ 0.223
SCE	$ 0.00	$ 0.00	$ 0.00	$ 0.00
SDG&E	$ 0.00	$ 0.00	$ 0.30	$ 0.30

Table 12: CAISO Registration and Meter Reprogramming Program Budgets

Demand response budgets and estimated bill impacts are summarized in Table 13.

[116] *See* Resolution E-4983.

[117] August 9, 2019 DRAM Working Group Report at A-27 to A-28.

Demand Response Average Budgets ($ millions)					
Utility	DR Portfolio Budgets (Five Year Average 2018 - 2022)	DR Auction Mechanism Budgets (Three Year Average 2021 – 2023)	CAISO Registration and Meter Reprogamming Budgets (Four Year Average 2020 – 2023)	Total Average Budget[118]	Estimated Bundled Residential Customer Average Monthly Bill Impact ($)[119]
PG&E	$ 66.7	$ 6.0	$ 0.2	$ 72.9	$ 0.49
SCE	$ 150.2	$ 6.0	$ 0.0	$ 156.2	$ 1.45
SDG&E	$ 15.7	$ 2.0	$ 0.2	$ 17.9	$ 0.45
TOTAL	**$232.6**	**$ 14.0**	**$ 0.4**	**$ 247.0**	

Table 13: Demand Response Average Budgets and Bill Impacts

Even though Table 13 shows a non-zero bill impact, DR programs have been shown to be generally cost-effective, leading to long-term bill savings for the ratepayers. Since more than 10 percent of California's grid capacity is used to support the peak demand for less than 0.5 percent of the hours each year, reduction of the peak demand through DR leads to cost savings for the ratepayers because of reduced buildout of the required generation capacity and deferred investment in T&D infrastructure.

Longer-Term Trends (May 2021 and Beyond)

The CPUC expects many of the activities currently in place to continue in the long term. As shown above, the IOU portfolio has been approved for 2018-2022. The DRAM pilot will continue until 2023[120] with continuous improvements through a staff-led refinement process.[121] The CPUC will determine whether to continue DRAM in the IOU 2023-2027 Portfolio Application proceeding which will be filed in November 2021[122] and be based in part on an evaluation by an independent

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118 DR portfolio budget capital costs comprising approximately 1 percent of the total budget are not included.

119 Estimated monthly bill impact is substantially already in rates as authorized budgets do not vary significantly from year to year. This means customers will see no substantive additional bill impact in 2020 for this program.

120 *See* D.19-07-009 at 31, approving solicitations in 2019 through 2022 for deliveries and budgets that will be spent in 2019 through 2024. For example, for the 2019 solicitation, funds will be spent in 2019 to run the Request For Offer (RFO), in 2020 for contracting and invoices for the 2020 deliveries, and in 2021 for invoices from fall and winter 2020 deliveries. Similarly, for the 2022 solicitation, funds will be spent in 2022 for the RFO, in 2023 for contracting and invoices for 2023 deliveries, and in 2024 for invoices from fall and winter 2023 deliveries.

121 *See* D.19-07-009 at 74.

122 *Id.*

consultant that will be published in 2021.[123] As discussed above, improvements to the click-through authorization process and meter and logger requirements could have cost implications as well.

Historically, DR proceedings have taken a cautious approach towards spending ratepayer funds. For example, DR has its own set of Cost-Effectiveness Protocols that must be used to determine whether the benefits of IOU DR programs exceed the cost. Further, Rule 24/32 funding was approved in phases, with Advice Letter approval of spending underneath a cap. The CPUC will likely continue this cautious approach to DR funding.

Income Qualified Assistance Programs

Background and Status

California Alternative Rates for Energy (CARE) and Family Electric Rate Assistance (FERA)

The California Alternate Rates for Energy (CARE) program is a low-income energy rate assistance program that provides a discount on energy rates to qualifying low-income households with incomes at or below 200 percent of the Federal Poverty Guideline. The CARE program currently provides a rate discount ranging from approximately 30 percent to 35 percent on electric bills and 20 percent on natural gas bills.

The Family Electric Rate Assistance (FERA) program provides families of three or more, whose household income slightly exceeds the CARE allowances, with an 18 percent discount on their electricity bill.[124] The income limits of the FERA program range from 200 percent to 250 percent of the Federal Poverty Guidelines. Public Utilities Code Section 739.1(f)(2) requires a single application form for CARE and FERA to enable applicants to apply for the appropriate assistance program based upon their level of income and economic need.

Energy Savings Assistance Program (ESA)

The Energy Savings Assistance (ESA) program provides no-cost home weatherization services, energy efficiency measures, and energy education to help eligible low-income households conserve

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[123] *Id.* at 78.

[124] In 2018, SB 1135 required the CPUC to continue the FERA program for the state's three largest electrical corporations, and required that effective January 1, 2019 the program discount be an 18 percent line-item discount applied to an eligible customer's bill calculated at the applicable rate for a monthly or other billing period.

energy, reduce energy costs, and improve health, comfort, and safety. Households with total annual incomes at or below 200 percent of federal poverty guidelines qualify for the ESA program.

The Energy Savings Assistance Common Area Measures Program (ESA CAM) launched in late 2018 and provides no-cost energy efficiency measures to the common areas or shared energy systems within a building or property of deed-restricted multifamily buildings that have a majority of tenants that are eligible low-income tenant households. At least 65 percent of tenant households must have total annual incomes at or below 200 percent of the federal poverty guidelines to qualify for the ESA CAM program. ESA CAM is not a part of the investor-owned utilities' total revenue requirement; the funding comes from previously unspent ESA funds allocated by Decision 16-11-022, as modified by Decision 17-12-009.

Activities and Proceedings in the Upcoming 12-Months (May 1, 2020 – April 30, 2021)

California Alternative Rates for Energy (CARE) and Family Electric Rate Assistance (FERA)

Approximately 4.5 million households were enrolled in the CARE program as of December 2019.[125] For the 2020 program year, the total budget for the CARE program[126] is approximately $1.3 billion as shown in Table 14.

125 For enrollment data, *see* December 2019 Monthly Low-Income Assistance Reports in A.14-11-007 docket. CARE expenditure data is also available in these monthly reports.

126 The CARE program budget was authorized in D.16.11-022 as modified by D.17-12-009.

	2020 CARE Budgets			
	Rate Discounts[127] ($ millions)	Administrative Expenses ($ millions)	Estimated Bundled Residential Customer Average Monthly Bill Impact ($)[128]	Total CARE Budget ($ millions)
PG&E	$ 599.1	$ 18.0	$ 0.09	$ 617.1
SCE	$ 492.1	$ 6.7	$ 0.05	$ 498.7
SDG&E	$ 74.6	$ 7.0	$ 0.18	$ 81.6
SoCalGas	$ 135.0	$ 10.1	Not Available	$ 145.1
Total[129]	$1,300.8	$ 41.8		$1,342.5

Table 14: 2020 CARE Program Budgets and Administrative Expenses Estimated Bill Impacts

Based on the most recent available data, as of December 2018, approximately 51,000 households were enrolled in the FERA program.[130] Actual 2019 FERA enrollment data will not be available until May 1, 2020.[131]

Energy Savings Assistance Program (ESA)

For the 2020 program year the total budget for the ESA program is approximately $596 million with an average household treatment goal of approximately 401,500 homes.[132] ESA budgets have

127 Rate discounts are cost allocations between residential Non-CARE and CARE customers.

128 Estimated monthly bill impact for administrative expense is already in rates and is not incremental. This means customers will see no additional bill impact in 2020 for administrative expense.

129 Table may not sum due to rounding.

130 *See* Annual Low-Income Assistance Reports in A.14-11-007 docket. FERA expenditures data is also available in these annual reports.

131 2020 FERA budget not presented. The IOUs have proposed that FERA budgets move from general rate case proceedings to the low-income proceeding.

132 The IOUs filed mid-cycle advice letters with updated ESA program budgets and household treatment goals: AL 3990-G/5329-E (PG&E), 3824-E (SCE), 5325-G (SoCalGas), and 3250-E/2688-G (SDG&E). For Households treated and ESA expenditures data, see December 2019 Monthly Low-Income Assistance Reports in A.14-11-007 docket. The IOUs will submit their annual reports on 2019 activity, including ESA CAM, on May 1, 2020.

increased significantly over the years, as new measures have been offered and it has become increasingly difficult and expensive to enlist hard-to-reach households. These changes have resulted in cost and rate impacts. The IOUs are on track to achieve the statutory goal to treat all willing and eligible low-income households by 2020 through ESA.[133] The authorized ESA budgets for 2020 and estimated bill impacts are shown in Table 15.

Utility	2020 ESA Authorized Budget ($ millions)	Estimated Bundled Residential Customer Average Monthly Bill Impact ($)[134]
PG&E	$243.1	$ 1.25
SCE	$ 85.3	$0. 63
SoCalGas	$231.9	Not Available
SDG&E	$ 35.5	$ 0.90
Total	**$595.8**	

Table 15: 2020 Energy Savings Assistance Program Budgets and Bill Impacts

Longer-Term Trends (May 2021 and Beyond)

In 2020 the CPUC is reviewing the IOUs' low-income budget applications in consolidated application proceeding A.19-11-003. The applications were filed in November 2019 and address program years 2021-2026. The IOUs propose approximately $8.5 billion for CARE (a $1.41 billion average annual spend), approximately $150 million (a $25 million average annual spend) to fund the FERA program, and approximately $2.59 billion for ESA (a $432 million average annual spend) from 2021-2026.

In the event that the CPUC does not reach a decision by November 16 of 2020, bridge funding was approved in D.19-06-022, pursuant to conforming advice letters from each utility, to allow the programs to continue with a reduced budget to ensure continuity of service in 2021.

133 *See* Public Utilities Code Section 382(e).

134 For 2020,the estimated monthly bill impact for SCE and SDG&E is already in rates and is not incremental. For PG&E, an approximate $58 million authorized incremental revenue requirement decrease results in an estimated bundled residential customer average monthly impact of ($ 0.30).

San Joaquin Valley (SJV) Pilots

Background and Status

On March 26, 2015, the CPUC opened a rulemaking to implement Public Utilities Code Section 783.5 (AB 2672). The CPUC was directed to analyze the economic feasibility of certain energy options including: (a) extending natural gas pipelines; (b) increasing existing program subsidies to residential customers; and (c) other alternatives that would increase access to affordable energy. The Phase I decision adopted the methodology for identification of communities meeting the statutory definition of a San Joaquin Valley Disadvantaged Community under Section 783.5. Phase II of the rulemaking adopted D.18-12-015 which approved $56 million in funding for 11 pilots with PG&E and SCE as the Pilot Administrators for electrification pilots and SoCalGas administering a natural gas pilot project in California City with limited gas pilots in Allensworth and Seville.

In 2019, efforts related to the SJV pilots consisted of planning and ramp up activities. Pilot administrators submitted implementations plans that contained program timelines, workforce development plans, and coordination methods that will be used to leverage existing program budgets. RFPs were run to select an entity to perform outreach and engagement tasks as well as a third-party pilot administrator. Workshops were held to discuss issues related to tenant protections and bill protections, with a final bill protection approach for pilot participants adopted in December 2019.

Activities and Proceedings in the Upcoming 12-Months (May 1, 2020 – April 30, 2021)

In 2020, implementation of the SJV pilots will begin in the 11 selected pilot communities. The entity selected to perform outreach, Self Help Enterprises (SHE), will begin engaging with potential participants via community meetings, door to door canvassing, and mailed solicitations. SHE will work with interested applicants to successfully guide them through the application and enrollment process. Pilot administrators will begin performing assessments of eligible households and will develop scopes of work for each individual household. Pilot participants will approve of final plans, after which pilot implementers will move forward with the installation of electrification and natural gas measures. Additionally, data gathering efforts in all of the 170 identified SJV disadvantaged communities will commence. The San Joaquin Valley pilot budgets are shown in Table 16.

	PG&E	SCE	SoCalGas
Program Timeline	Dec. 2018 - Dec. 2021	Dec. 2018 – Dec. 2021	Dec. 2018 – Dec. 2021
Budget	$35.5 million	$15.5 million	$5.5 million
Remaining Budget	$35.5 million (Dec. 2019)	$15.5 million (Dec. 2019)	$5.5 million (Dec. 2019)
Scope	1,218 electrification projects	449 electrification projects	224 natural gas line extensions

Table 16: San Joaquin Valley Pilot Budgets

Table 17 shows the San Joaquin Valley pilots authorized budget and resulting estimated bill impacts.

Utility	2020 SJV Pilots Authorized Budget($ millions)	2020 Projected Bundled Residential Customer Average Monthly Bill Impact ($)
PG&E	$ 35.5	$ 0.18
SCE	$ 15.5	$ 0.12
SDG&E	N/A	N/A

Table 17: : SJV Pilots Authorized Budget and Bill Impacts

4. COVID-19 Shelter-at-Home Executive Order

As Californians stay home in response to the Shelter-at-Home Executive Order issued in March 2020 due to the threat of COVD-19,[135] the IOUs are seeing shifts in daytime residential demand that are likely to lead to higher bills starting with the April billing cycle. In addition, mounting job losses exacerbate affordability concerns, as households face unprecedented and significant economic challenges.

135 *See* Executive Order N-33-20 dated March 19, 2020.

On March 19, 2020, PG&E, SCE, SDG&E, and SoCalGas each submitted advice letters (AL) to the CPUC regarding implementation of an emergency consumer protection plan for customers who are experiencing a financial crisis due to the COVID-19 pandemic, pursuant to Ordering Paragraph (OP) 1 of Decision (D.)19-07-015. The emergency consumer protection plans include provisions to:[136]

- Suspend service disconnections for non-payment.
- Waive security deposits and late fees.
- Implement flexible payment plan options.
- Provide additional support for low income and medical baseline customers.
- Freeze all CARE eligibility reviews.
- Establish customer qualification and communication plans.

The CPUC is taking action to ensure that sheltering in place does not become an added hardship for people who have lost their jobs or are otherwise suffering economically due to COVID-19. A summary of some of these actions include:

- Reducing residential and business energy bills over the coming months by utilizing the California Climate Credit.
- Suspending renewal requirements for key low-income programs, including California Alternative Rates for Energy (CARE) and Family Electric Rate Assistance (FERA).
- Temporarily modifying rates for high energy use customers to minimize the impacts of electricity bills in the summer.

The cost and rate implications of these actions are being carefully evaluated on an ongoing basis through continuous monitoring of IOU financial impacts resulting from uncollectibles resulting from customer account writeoffs (aging accounts receivables) and revenue undercollections across customer classes. Other costs resulting from increased CARE and FERA enrollment (increased subsidies), rate design changes, and related tools for shielding customers from the adverse billing impacts resulting from increased residential demand and economic fallout are also being tracked and estimated, and will be considered alongside longer term rate forecasting for managing IOU revenue shortfall.

[136] Not all provisions apply to all IOUs.

5. Wildfire Mitigation Plans

Senate Bill (SB) 901 (Dodd, 2018) and AB 1054 (Holden, 2019) require electric utilities to prepare and submit wildfire mitigation plans (WMP), which describe the level of wildfire risk in their service territories and how they intend to address those risks.[137] The WMPs cover a three-year period and the IOUs will need to submit new comprehensive plans at least once every three years with annual updates to the plans in between.

AB 1054 prohibits large electrical corporations from including in equity rate base their share of the first $5 billion spent statewide on fire risk mitigation capital expenditures in their approved WMPs. Of the $5 billion in capital expenditures total, PG&E's share is $3.21 billion, SCE's share is $1.575 billion, and SDG&E's share is $215 million. AB 1054 also provides that in place of earning an equity return on these investments, the investments may be debt-financed through securitization bonds.

This section of the SB 695 report summarizes the costs that the three large IOUs in California presented in their 2020 WMPs broken down into several activity areas.[138] It also discusses the portion of WMP costs estimated to not yet be in rates as well as presents a forecast of WMP-related incremental revenue requirement to be implemented in rates in 2020 for each IOU.

2020 WMP Total Costs

The IOUs presented tables showing capital expenditures and operations and maintenance (O&M) expenses in their 2020 WMPs.[139] Total costs shown in Table 18[140] are presented by WMP activity category in the year they are expected to be *incurred* regardless of whether they have been or will be approved by the CPUC for cost recovery.[141] The year that forecasted costs are expected to be *recovered* and reflected in rates will generally be later than the year costs are incurred due to the regulatory approval process.[142]

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137 In 2019, the IOUs filed their 2019 WMPs pursuant to SB 901. *See* each IOU's 2019 WMP at https://www.cpuc.ca.gov/2019wmp/ .

138 For more information on the specific activities included in each of these cost categories, *see* each IOU's 2020 WMP at https://www.cpuc.ca.gov/wildfiremitigationplans/ .

139 PG&E 2020 WMP Attachment 1 (Updated); SCE 2020 WMP Tables 1-31 Revision 2; SDG&E 2020 WMP Tables 1-31 Revised 03-02-2020. PG&E and SCE include FERC-jurisdictional costs in their WMPs, however SDG&E does not. In its WMP, SDG&E presents cost ranges, from which the midpoint of the range is used here.

140 Capital expenditures reflected in Table 18 may be subject to AB 1054 equity rate base exclusions.

141 Cost recovery may not be approved, or cost recovery may be approved in amounts substantially different than presented.

142 Forecasted costs presented are subject to change.

Activity Category ($ Nominal Millions)	2020			2021			2022		
	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
Risk Assessment and Mapping	0.0	0.0	1.4	0.0	0.0	1.8	0.0	0.0	10.7
Situational Awareness and Forecasting	48.3	25.6	11.3	48.5	30.0	6.8	43.2	34.6	6.2
Grid Design and System Hardening	1,696.9	1,088.4	266.0	1,656.5	986.6	284.0	1,749.1	1,087.3	302.6
Asset Management and Inspections	162.1	85.6	56.8	166.2	73.4	49.9	170.3	73.4	39.1
Vegetation Management and Inspections	857.1	200.6	62.3	881.3	187.3	62.3	906.3	195.2	62.3
Grid Operations and Protocols	253.0	91.7	25.1	263.0	53.6	29.3	271.7	53.1	14.9
Data Governance	88.2	11.7	0.3	49.6	18.0	0.3	39.3	9.1	0.3
Resource Allocation Methodology	0.0	78.5	12.0	0.0	31.3	6.1	0.0	23.5	7.6
Emergency Planning and Preparedness	36.9	23.5	8.9	37.9	24.1	4.4	38.8	24.7	4.4
Stakeholder Cooperation and Community Engagement	28.7	0.0	0.0	27.2	0.0	0.0	27.8	0.0	0.0
WMP 2020-2022	**3,171.3**	**1,605.6**	**444.1**	**3,130.3**	**1,404.3**	**445.0**	**3,246.6**	**1,500.9**	**448.1**

Table 18: WMP Total Costs Incurred or Forecasted to Be Incurred 2020 - 2022

Across the IOUs, the bulk of the expenditures fall into the categories of "grid design and system hardening" and "vegetation management and inspections," with the former being nearly three times as large as the latter over the three year period.

Grid design and system hardening includes replacing bare conductor with covered conductor, using fire resistant poles, undergrounding overhead lines, sectionalizing the distribution system to limit the number of customers who are affected by public safety power shutoff (PSPS) events, and installing microgrids. Vegetation management and inspections includes identifying trees and brush that pose a risk to electrical lines and addressing those risks through tree removal or pruning. Both of these activities require monitoring and maintenance of many miles of infrastructure, which is why the costs between IOUs scale in part with the number of infrastructure circuit miles in a utility service territory. Infrastructure cost drivers may also be related to the quantity and condition of grid components that must be monitored, upgraded, or replaced.[143] Other cost drivers may be associated with utility service territory characteristics such as High Fire-Threat District (HFTD) zone or tier designations,[144] classification of areas as urban, rural or wildland-urban interface (WUI) zones, and

[143] Actual unit installation and operation can be impacted by delays due to permitting, labor availability, and availability of equipment; number of installed units underlying cost forecasts is subject to change.

[144] HFTD areas were adopted by the CPUC in D.17-12-024.

number and location of customers. Higher costs may also be attributed to areas with increased wildfire ignition risks due to changes in fuel density and moisture.

Figure 14 shows HRFD tier areas within each large IOU's service territory.[145]

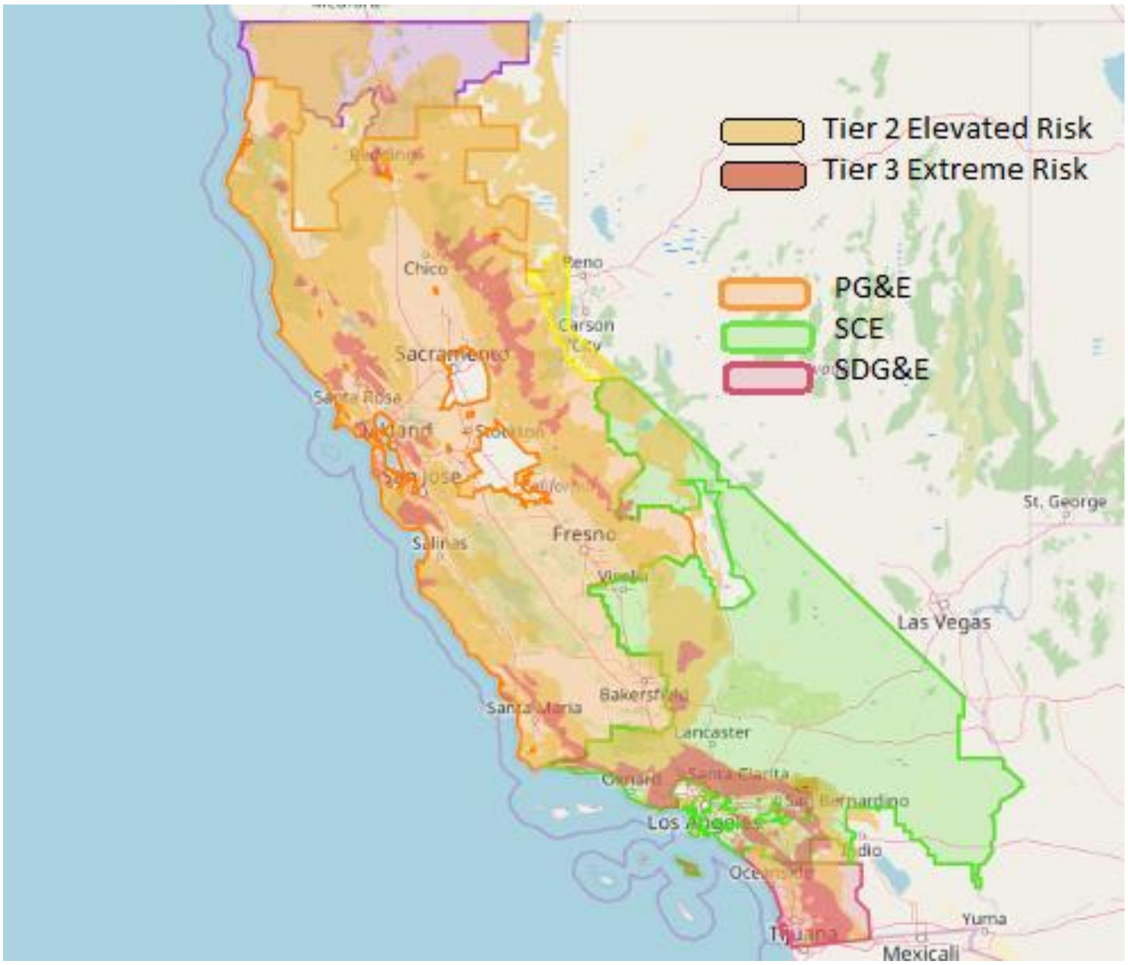

Figure 14: High Fire-Threat District Areas and IOU Service Territories

Over half of PG&E's service territory lies in HFTD areas. Approximately 5,500 circuit miles of overhead transmission and 25,500 circuit miles of overhead distribution infrastructure lie within these HFTDs. Many of these are long lines that serve low-density, non-urban customers and communities located within WUI zones who face an increased fire risk. CPUC-designated HFTD

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145 *See* https://ia.cpuc.ca.gov/firemap/ . Tier 2 fire threat areas depict areas where there is an elevated risk (including likelihood and potential impacts on people and property) from utility associated wildfires. Tier 3 fire threat areas depict areas where there is an extreme risk (including likelihood and potential impacts on people and property) from utility associated wildfires.

Tier 2 and Tier 3 areas comprise 27 percent of SCE's service territory,[146] within which are located approximately 2,000 circuit miles of overhead transmission and 2,400 circuit miles of overhead distribution infrastructure. In SDG&E's service territory, there are approximately 1,100 circuit miles of overhead transmission and 3,500 circuit miles of overhead distribution infrastructure.[147]

2020 WMP Cost Recovery

The 2020 – 2022 costs in the 2020 WMPs can be broadly categorized into three categories: (1) costs that are already in rates at the time the WMP is filed; (2) costs that are pending CPUC approval to be implemented in rates; and (3) costs for which an application seeking cost recovery has not yet been filed. Costs in categories (2) and (3) are referred to here as incremental costs that are not yet in rates. Estimated incremental costs that may eventually be implemented in rates, prior to any adjustments resulting from cost recovery proceedings,[148] are:

- PG&E: $9.5 billion
- SCE: $3.9 billion
- SDG&E: $599 million

Eventual recovery of costs included in the above figures is estimated to impact bundled average residential rates at the rate of approximately 7 percent to 8 percent for PG&E and SCE for every $1 billion in equivalent revenue requirement and approximately 3 percent for SDG&E for every $100 million in equivalent revenue requirement.

The IOUs are on different timelines for recovery of costs presented in their 2020 WMPs.[149] For costs in PG&E and SCE's 2020 WMPs not yet in the IOU's revenue requirement, **forecasted** incremental revenue requirement to be implemented in rates in 2020 and resulting estimated bill

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146 An additional 8 percent of SCE's service territory consists of various areas outside of the HFTDs considered by SCE to be at elevated risk of wildfires.

147 SDG&E does not quantify in its WMP the percentage of its service territory corresponding to HFTD areas.

148 Adjustments may include AB 1054 equity rate base exclusions applied as part of the cost recovery proceeding. Adjustments may also result from other modifications made to cost recovery sought as part of the cost recovery proceeding. Estimates are from PG&E 2020 WMP Attachment 1 (Updated); SCE 2020 WMP Tables 1-31 Revision 2; SDG&E 2020 WMP Tables 1-31 Revised 03-02-2020. PG&E and SCE include FERC-jurisdictional costs in their WMPs, however SDG&E does not. In its WMP, SDG&E presents cost ranges, from which the midpoint of the range is used here.

149 In addition to estimated costs for 2020 – 2022, the 2020 WMPs include updated data to reflect 2019 actual costs, as available, from the 2019 WMPs the IOUs submitted in February 2019. Costs incurred in 2019 may be reflected in incremental revenue requirements approved or pending approval in 2020. Costs incurred in 2019 and 2020 may also be forecasted for recovery in 2021 and beyond.

impacts are shown in Table 19.[150] **Authorized** incremental revenue requirement reflecting costs in SDG&E's 2020 WMP for 2020 rate implementation and resulting estimated bill impacts are also shown in Table 19:

IOU	2020 WMP System Incremental Revenue Requirement ($ millions)	Proceeding Number and Name	Status of Application or Rulemaking (Approved, Pending)	2020 Estimated Bundled Residential Rate Impact ($/kWh)	2020 Estimated Bundled Residential Customer Average Monthly Bill Impact ($)
PG&E	$1,000.7	(1) A.18-12-009 2020 GRC Phase I (Proposed Settlement Agreement) (2) A.20-02-003 Wildfire Mitigation and Catastrophic Events Interim Rates (3) R.19-09-009 Microgrids SB 1339 OIR	(1), (2), (3) Pending	0.0162	$8.21
SCE	$673.3	(1) A.18-09-002 Grid Safety and Resiliency Program (Proposed Settlement Agreement) (2) A.19-08-013 2021 GRC Phase I Track 2	(1), (2) Pending	0.0126	$6.54
SDG&E	$64.7	A.17-10-007 2019 GRC Phase I	Approved	0.0046	$1.88

Table 19: 2020 WMP Incremental Revenue Requirement and 2020 Rate and Bill Impacts

PG&E's 2020 WMP costs forecasted to be implemented in 2020 of $1.001 billion in incremental revenue requirement[151] is estimated to increase the bundled average residential rate by about 1.6 cents/kWh, or about 7 percent over rates in effect May 1, 2020,[152] and is estimated to increase the typical bundled residential customer's average monthly bill by $8.21, or by about a 7 percent increase.[153] A substantial part of PG&E's 2020 WMP costs forecasted to be implemented in 2020 will be reviewed for reasonableness during its 2020 GRC Phase I proceeding.[154] A large part of

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150 Forecasted incremental revenue requirements and projected rate and bill impacts were provided by the IOUs and are subject to change depending on regulatory outcomes. Forecasted incremental revenue requirement amounts and timing of the recovery of those amounts shown in Table 19 are presented for illustrative purposes only.

151 $1.001 billion is comprised of: $381 million in 2020 GRC Phase I (Proposed Settlement Agreement), $488 million in the Wildfire Mitigation and Catastrophic Events Interim Rates application, and $132 million in the SB 1339 Microgrids Order Instituting Rulemaking (OIR). Revenue requirements corresponding to capital expenditures subject to AB 1054 equity rate base exclusions are net of these exclusions.

152 PG&E used projected rates in effect 5/1/20 as the "before" rate for its projected rate impacts.

153 PG&E projects the typical bundled residential customer's average monthly bill will increase from an estimated $115.82 to $124.03.

154 The 2020 GRC Phase I Proposed Settlement Agreement includes a reduction to revenue requirement related to wildfire risk mitigation capital expenditures of $22 million in 2020 in accord with AB 1054.

PG&E's 2020 WMP-related projected 2020 rates implementation is also requested in its wildfire mitigation and catastrophic events interim rate relief application for amounts recorded through 2019 in various wildfire mitigation and catastrophic events memorandum accounts. A review for reasonableness of these costs will be requested at the time PG&E seeks formal recovery of these costs.

SCE's 2020 WMP costs forecasted to be implemented in 2020 of $673 million in incremental revenue requirement[155] is estimated to increase the bundled average residential rate by about 1.3 cents/kWh, or about 6 percent over rates in effect April 13, 2020,[156] and is estimated to increase the typical bundled residential customer's average monthly bill by $6.54, or by about a 6 percent increase.[157] A substantial part of SCE's 2020 WMP costs forecasted to be implemented in 2020 will be reviewed for reasonableness during its 2021 GRC Phase I Track 2 Request for Recovery of 2018-2019 Memorandum Account Balances. These costs are incremental to SCE's 2018 GRC-authorized revenues and are recorded in various wildfire mitigation memorandum accounts.[158]

SDG&E's 2020 WMP costs reflected in its 2019 GRC-authorized 2020 rates implementation of $65 million in incremental revenue requirement[159] increases the bundled average residential rate by about 0.5 cents/kWh, or about 2 percent higher than what rates would have otherwise been without wildfire mitigation related costs.[160] Implementing these costs into rates is estimated to increase a residential customer's average monthly bill by $1.88, or by about a 2 percent increase.[161] Fire risk mitigation work that is not otherwise covered in SDG&E's authorized revenue requirements or in an approved WMP is recorded in the Fire Risk Mitigation Memorandum Account (FRMMA). SDG&E has not filed for cost recovery of amounts recorded in its FRMMA; cost recovery for these amounts is expected beyond 2020.

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155 $673 million is comprised of: $500 million in 2021 GRC Phase I Track 2 (Motion filed for Interim Rate Recovery on March 12, 2020) and $173 million in Grid Safety and Resiliency Program (GSRP).

156 SCE used rates in effect 4/13/20 as the "before" rate for its projected rate impacts.

157 SCE projects the typical bundled residential customer's average monthly bill will increase from an estimated $111.46 to $118.00.

158 SCE filed on 3/12/2020 a Motion for Interim Rate Recovery seeking authority to recover a portion of 2021 GRC Phase I Track 2 costs in rates pending the review for reasonableness of these costs.

159 As part of D.19-09-051 approving SDG&E's 2019 GRC Phase I application, SDG&E was ordered to file a Tier 3 Advice Letter (AL) providing a detailed showing of the revenue requirement reduction resulting from the AB 1054 equity rate base exclusion. SDG&E's pending AL 3488-E and AL 3488-E-A were filed 12/30/2019 and 3/4/2020, respectively. In its ALs, SDG&E states that once the requested equity exclusion of $8.3 million in Post Teat Year 2020 is approved, SDG&E will implement the $8.3 million refund through rates.

160 SDG&E reflected in its rate impact the portion of the current rate in effect 2/1/2020 attributable to WMP-related costs.

161 Bill impacts were calculated using 409 kWh/month based on U.S. EIA Annual 2018 Electricity Data by State and Utility.

6. Natural Gas

Background and Status

The CPUC regulates the natural gas utility services of more than ten million customers served by PG&E, Southern California Gas (SoCalGas), SDG&E, and several smaller utilities.[162] Statute requires that the CPUC: 1) evaluate the reasonableness of rates and rate changes; 2) provide advice on core transport agent (CTA) rules[163] and certificates of public convenience; and 3) oversee the adoption of standards for bio-methane production. This mandate is reflected in ongoing activities in formal rate case, cost allocation, bio-methane pilot project and safety-oriented proceedings.

Natural gas utility costs are generally addressed in GRC proceedings and are composed of core procurement costs, gas system operations and customer service costs, and public purpose programs costs. Unlike the process for electric utilities, the CPUC does not set an annual authorized revenue requirement for natural gas utilities' procurement costs. Core gas procurement costs are recovered in utility gas procurement rates which are adjusted monthly resulting in monthly price changes in customer bills. By doing so, the impact of price variation affects current ratepayers as opposed to future ratepayers.[164] The figures below for PG&E, SoCalGas, and SDG&E reflect the revenue requirement by rate component forecast on January 1 of each year.[165]

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162 Public Utility Code §913.1(b) mandates that gas corporations with 500,000 or more retail customers in California study and report on measures the corporation recommends be undertaken to limit costs and rate increases. The large natural gas Investor-Owned Utilities (IOU) that are required by Public Utility Code §913.1(b) to submit Senate Bill (SB) 695 reports are PG&E, SoCalGas, and SDG&E.

163 Core Transport Agents (CTAs) procure gas for core customers such as residential and small commercial customers as an alternative to the utility. A CTA customer would not pay the utilities' procurement rate.

164 More detailed descriptions of how gas utility revenue requirements are determined can be found in the 2019 AB 67 Report (filed April 2020), available on the CPUC website (https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2020/2019%20AB%2067%20Report.pdf).

165 All data is from 2016 – 2020 IOU responses to Energy Division SB 695 Report data requests. Core procurement revenue requirement is an annual estimate and all other revenue requirements are authorized revenue requirements. For all IOUs, the core procurement revenue requirement estimate is lower in 2020 than in 2019 due to a forecasted decrease in the weighted average cost of gas in 2020.

PG&E Revenue Requirement by Rate Category

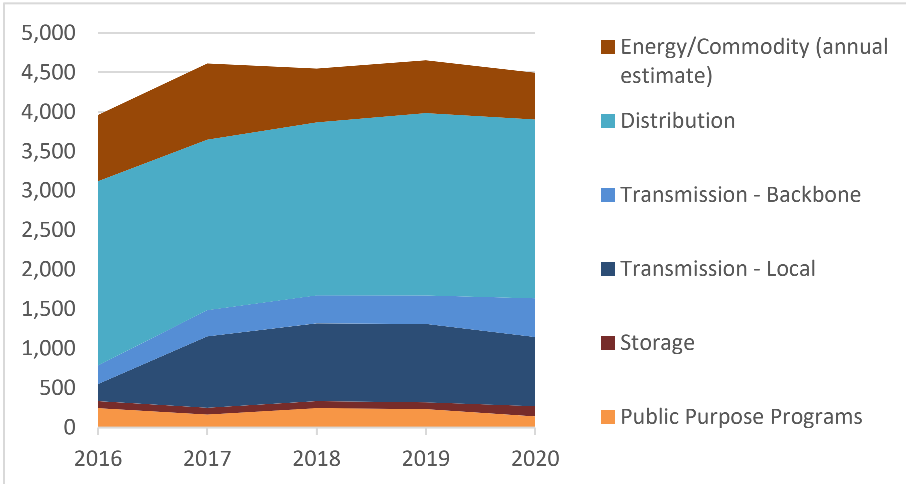

Figure 15: 2016 – 2020 PG&E January 1 Revenue Requirement, by Rate Category ($ millions)

PG&E's gas revenue requirement has increased by approximately 14 percent since 2016, with about a 3 percent decrease from 2019 to 2020, although backbone transmission increased about 37 percent from 2019 to 2020. The primary driver of this backbone increase is costs related to targeted investments that will strengthen and modernize PG&E's gas system.[166] The primary driver of the 12 percent decrease in local transmission costs is a significant decrease in the local transmission under-collection in rates.[167] Due to the timing of the 2015 Gas Transmission and Storage (GT&S) decision, there was approximately $189 million in rates related to the late implementation for local transmission. With the implementation of the 2019 GT&S decision, the local transmission under-collection decreased to $4.1 million. The primary drivers of the 50 percent increase in storage costs are increased costs for improving safety measures at all three PG&E gas storage facilities to reflect newly anticipated and more rigorous state laws and regulations.[168] The primary drivers of the 39 percent decrease in gas Public Purpose Program (PPP) funding are a decrease in the authorized Energy Savings Assistance Program (ESA) Funding and return of unspent Energy Efficiency and ESA funding.

166 *See* PG&E's 2019 Gas Transmission and Storage (GT&S) Decision (D.) 19-09-025.

167 *Id.*

168 *Id.*

SoCalGas Revenue Requirement by Rate Category

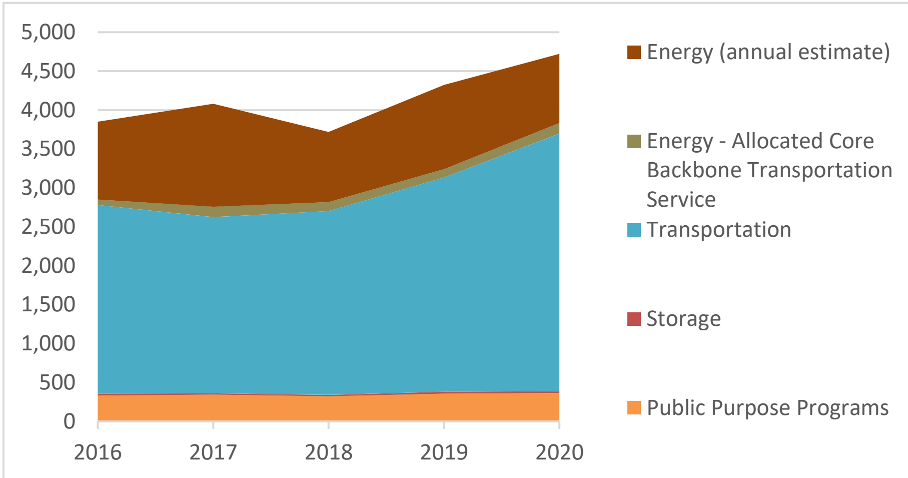

Figure 16: 2016 – 2020 SoCalGas January 1 Revenue Requirement, by Rate Category ($ millions)

Since 2016, SoCalGas's revenue requirement has increased by about 23 percent, with about a 9 percent increase from 2019 to 2020. The transportation costs, which include both transmission and distribution, comprise the largest portion of the 2019 – 2020 revenue requirement increase. The 2020 transportation revenue requirement increase is primarily due to the implementation of SoCalGas's 2019 General Rate Case (GRC) decision,[169] partially offset by an authorized decrease in the amortizations of the regulatory accounts. Transportation costs also include amounts from decisions on the utility's Pipeline Safety Enhancement Program (PSEP).

SDG&E Revenue Requirement by Rate Category

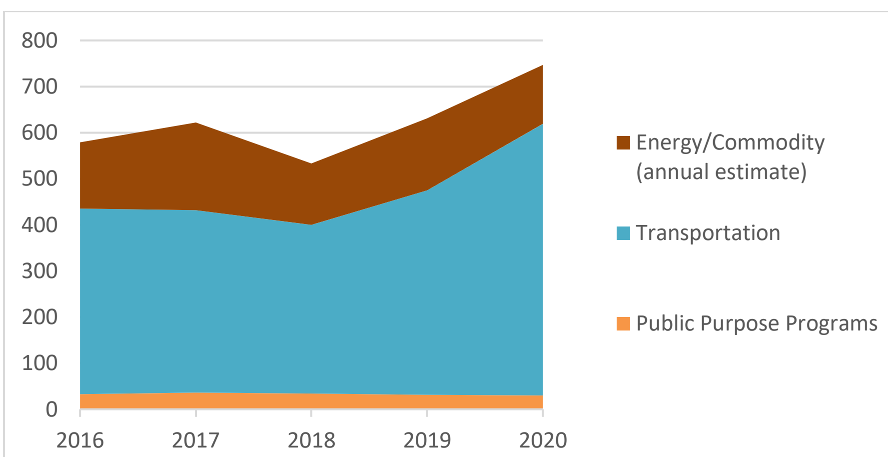

Figure 17: 2016 – 2020 SDG&E January 1 Revenue Requirement, by Rate Category ($ millions)

169 *See* D.19-09-051.

SDG&E's gas revenue requirement has increased by approximately 29 percent since 2016, with about an 18 percent increase from 2019 to 2020. Transportation costs comprise the largest proportion of the 2019 - 2020 revenue requirement increase. The 2020 increase in transportation revenue requirement is primarily due to the implementation of the General Rate Case (GRC) decision,[170] partially offset by a decrease in balancing accounts that are being amortized in 2020. Transportation costs also include amounts from decisions on the utility's Pipeline Safety Enhancement Program (PSEP).

Activities and Proceedings in the Upcoming 12-Months (May 1, 2020 – April 30, 2021)

PG&E 2020 General Rate Case (GRC)

PG&E submitted its 2020 General Rate Case (GRC) on December 13, 2018 in which it seeks approval of revenues for the period 2020-2022. PG&E is proposing a $1.058 billion increase over currently authorized spending for 2019. More than half of PG&E's proposed increase would be directly related to wildfire prevention, risk reduction, and additional safety enhancements. This proposal would increase a typical residential customer bill by 6.4 percent or $10.57 per month ($8.73 for electric service and $1.84 for gas service). A typical CARE customer would see an increase of about $7.01 a month ($5.54 for electric service and $1.47 gas service). PG&E's 2020 GRC includes investments to enhance gas and electric safety and reliability.

On December 20, 2019, PG&E submitted a 2020 GRC settlement agreement to the CPUC that is supported by various parties, including those representing customers, labor and safety. The settlement agreement also includes funding for electric and gas distribution safety and reliability and power generation. The settlement agreement would adopt most of PG&E's gas service proposal.

PG&E Test Year 2019 Gas Transmission and Storage Rate Case (Application for Rehearing)

In November 2017, PG&E filed an application[171] to set its revenue requirement and rates for the utility's gas transmission and storage (GT&S) system for 2019 through 2022. D.19-09-025 was issued in the proceeding and authorized a $1.33 billion GT&S revenue requirement for Test Year 2019 with increases in the subsequent rate case years. In October 2019, PG&E filed an Application for Rehearing (AFR) of D.19-09-025 wherein the utility is challenging the CPUC's disallowance of $304 million in capital expenditures for prior pipe replacements and reductions in forecasted costs for some transmission safety programs of $19.8 million. The AFR is currently pending.

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[170] *Id.*

[171] *See* A.17-11-009.

SoCalGas and SDG&E Application to Recover Costs for PSEP 2 (Application for Rehearing)

On September 2, 2016, Southern California Gas (SoCalGas) and San Diego Gas & Electric (SDG&E) filed an application[172] to recover recorded costs attributed to implementation of the Pipeline Safety Enhancement Program (PSEP) Phase II (D.14-06-007). On February 21, 2019, the CPUC approved the recovery of costs attributed to the implementation of the PSEP which includes 26 pipeline projects, 15 bundled valve projects and two methane sensing equipment pilot projects. Decision (D.)19-02-004 authorized SoCalGas and SDG&E to recover the balance of their recorded costs in the amount of $186,532,169. In April 2019, an Application for Rehearing (AFR) of D.19-02-004 was filed by the CPUC's Public Advocates Office disputing the authorization allowing SoCalGas to recover the costs of pressure testing transmission pipes installed between 1956 and 1970 which lacked a test record. The AFR is currently pending.

SoCalGas and SDG&E Application for Revenue Requirement associated with PSEP 4

On November 13, 2018, SoCalGas and SDG&E filed an application[173] for reasonableness review of PSEP costs for 44 pipeline projects and 39 bundled valve projects. SoCalGas and SDG&E state that they have spent approximately $854 million in capital expenditures and $86.7 million in Operations and Maintenance expenses, resulting in the associated revenue requirement of $188 million for SoCalGas and $23 million for SDG&E. The application is currently under preliminary evaluation by the CPUC.

SoCalGas and SDG&E Test Year 2019 General Rate Case (Petition for Modification)

On October 2, 2017, SoCalGas and SDG&E each filed an application[174] to set their revenue requirement and rates for the utilities' cost of providing gas and electric service for 2019 through 2021. For 2019, SoCalGas is requesting to increase the gas transportation and storage revenue requirement by $2.9 billion. SDG&E is requesting a total of $2.2 billion ($435 million for gas and $1.764 billion for electric) for costs in 2019. The CPUC decision approving the revenue requirements for 2019 through 2021 was issued in September 2019. However, pursuant to the Rate Case Plan decision[175] SoCalGas and SDG&E were ordered to file a petition for modification (PFM) of the 2019 GRC decision requesting to add 2022 and 2023 attrition years to transition from a three-year to a four-year GRC cycle. The PFM filing is currently pending.

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[172] *See* A.16-09-005.
[173] *See* A.18-11-010.
[174] *See* A.17-10-007 & A.17-10-008.
[175] *See* D.20-01-002.

SoCalGas and SDG&E Application to Revise Rates for Gas Services

On July 31, 2018, SoCalGas and SDG&E filed their Triennial Cost Allocation Proceeding (TCAP).[176] Cost allocation is the process of allocating the utilities' authorized revenue requirement to utility functions and customer classes, which include residential customers, small commercial and industrial customers, medium and large commercial and industrial customers, electric generators, and wholesale customers. The TCAP also addresses gas storage-related proposals and their impact on the reliability of the natural gas system. In this proceeding, SoCalGas and SDG&E also propose to update their baseline allowances per SB 711. Public Utilities Code Section 739 requires the CPUC to make efforts to minimize bill volatility for residential customers by modifying the length of baseline seasons or defining additional base seasons. SoCalGas' and SDG&E's current baseline allowances have been in effect since 2002. The application is currently under review with a decision expected in early 2020.

SoCalGas Gas Cost Incentive Mechanism Year 25

On June 14, 2019, SoCalGas submitted an application[177] seeking approval of a shareholder reward of $16,798,695 for its Gas Cost Incentive Mechanism (GCIM) gas procurement performance on behalf of core customers of Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) for the period April 1, 2018 through March 31, 2019 (Year 25). The purpose of the GCIM is to provide SoCalGas with a financial incentive to purchase and transport gas for core ratepayers at a cost that is equal to, or less than, prevailing market prices. The GCIM compares actual monthly purchased gas costs (commodity and transportation) to monthly benchmarks over the 12-month (April to March) period. D.20-02-007 was issued on February 11, 2020 approving SoCalGas' request. The rate impact is $.00432 per therm under the procurement rate. The total SoCalGas portion of annual GCIM saving will be amortized in rates.

OIR to Implement Dairy Biomethane Pilots

Pursuant to SB 1383 (Lara, 2016), the CPUC opened a rulemaking[178] to establish dairy bio-methane natural gas pipeline injection demonstration projects. In 2018, the CPUC along with the Air Resources Board and the Department of Food and Agriculture, put forth a pilot solicitation and selected six projects for construction. Contracts between utilities and developers of the six pilot projects have been signed and are under review at the CPUC. Construction on these projects should take approximately two years for interconnection to occur. Upon completion, the new dairy biomethane facilities will convert biogas from dairy digesters into renewable natural gas (RNG) for

[176] *See* A.18-07-024.
[177] *See* A.19-06-009.
[178] *See* R.17-06-015.

heating and transportation purposes and move California closer to its goal of reducing methane emissions by 40 percent from its 2013 levels by 2030. The pilots will undergo evaluation processes to determine GHG reduction levels and project goal attainment. Forecasted costs associated with the six pilot projects are estimated to be approximately $318 million.

OIR to Update Natural Gas Pipeline Injection Standards

In response to SB 840 (Budget 2016), a rulemaking[179] reopened in July 2018 to update natural gas pipeline injection standards based on the report published by the California Council on Science and Technology. The CPUC is currently evaluating whether to modify natural gas pipeline injection heating value and siloxane standards. Because gas utilities have different ways of managing their pipelines, for the purpose of streamlining and removing risk for renewable natural gas project developers, the CPUC is looking into the development of a standardized renewable natural gas interconnection tariff for the state. In addition, the CPUC is looking to investigate natural gas pipeline injection and storage standards for green hydrogen.

Decision to Implement a Biomethane Incentive Reservation System

On December 5, 2019, the CPUC issued D.19-12-009[180] that established an incentive reservation system for biomethane monetary incentive program adopted in D.15-06-029.[181] The biomethane monetary incentive program provides up to $3 million for non-dairy clusters and $5 million for dairy clusters that successfully interconnect with the natural gas pipeline system and operate by December 31, 2026. The incentive reservation program is currently available, and the Energy Division began accepting and evaluating reservation applications on February 3, 2020. Pursuant to Senate Bill SB 457 (Hueso, 2019), the pipeline interconnection incentives will be available until December 31, 2026, or until all available program funds are expended, whichever occurs first.

OIR to Identify Disadvantaged Communities in the San Joaquin Valley

On March 26, 2015, the CPUC opened a rulemaking[182] to implement Public Utilities Code Section 783.5 (AB 2672). The CPUC was directed to analyze the economic feasibility of certain energy options including: (a) extending natural gas pipelines; (b) increasing existing program subsidies to residential customers; and (c) other alternatives that would increase access to affordable energy. The Phase I decision adopted the methodology for identification of communities meeting the statutory definition of a San Joaquin Valley Disadvantaged Community under Section 783.5. Phase II of the rulemaking adopted D.18-12-015 which approved $56 million in funding for 11 pilots with PG&E

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179 *See* R.13-02-008.

180 *See* D.19-12-009.

181 *See* D.15-06-029.

182 *See* R.15-03-010.

and SCE as the Pilot Administrators for the electrification pilots and SoCalGas administering a natural gas pilot project in California City[183] with limited gas pilots in Allensworth and Seville. Under these pilot projects, homes that currently use propane or wood for space or water heating can opt for affordable natural gas service (through new line extensions), including new appliances and weatherization services. Legislative analysis of AB 2672 found that "for low income households, the use of natural gas or electricity can decrease utility costs, increase overall financial health, and provide a safer means of heating and cooling space and water." On December 19, 2019, participating utilities filed annual reports in compliance with the directives in D.18-12-015, to provide a status update on the pilot projects underway, which included information about community engagement and implementation efforts.

OIR to Evaluate Mobile Home Park Pilot Program and Adopt Programmatic Modifications

For this rulemaking[184], R.18-04-018, a Proposed Decision (PD) was issued for comment on February 24, 2020. This PD assesses the Mobilehome Park (MHP) Pilot program initially adopted in D.14-03-021 and extended by CPUC resolutions. Further, the PD approves a ten-year MHP Utility Conversion Program beginning in 2021 and concluding in 2030.

Please note that in the following, the costs and targets for conversion of mobilehome parks' master-metered service to utility service are aggregated for gas and electric conversions. The electric-only conversions are under the jurisdiction of State of California Housing and Community Development (HCD). The pilot program was designed and administered by the Safety and Enforcement Division's Gas Safety and Reliability Branch (GSRB). The pilot has been assessed as having met its goals. The total expenditures in 2014-18 were $612 Million and 25,000 spaces were converted to utility service. Apart from minor revisions, for the 2021-30 period as planned, the PD essentially retains the features of the pilot. Of the total of approximately 380,000 spaces in the 4,900 mobilehome parks in California the Utility Conversion program will aim for conversion of 50 percent of spaces by 2030 in the areas served by the large gas and electric utilities and 100 percent of spaces in the case of the smaller electric-only utilities. The estimated annual costs are $237 million for all the eight utilities in the program. The total costs will be over $2 billion, to be covered by ratepayers.

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183 SoCalGas is authorized to recover $5,641,100 for administering the gas pilot for California City.

184 *See* R.18-04-018.

SoCalGas Application to Sell Renewable Natural Gas

On February 2, 2019, SoCalGas and SDG&E filed a joint application[185] for authority to offer an opt-in renewable green gas tariff to customers and to collect costs through rates charged to program participants. In the proposed program, customers can voluntarily purchase all or a portion of their natural gas from renewable sources. Settlement discussions have been held, however an all-party settlement agreement on all issues raised in the application has not been reached. The application is currently under preliminary evaluation by the CPUC.

PG&E Application to Sell Line 306 to SoCalGas

On April 4, 2019, PG&E filed an application[186] for approval to sell local gas transmission pipeline Line 306 to SoCalGas. Line 306 spans approximately 70 miles from Kettleman to Morro Bay and was built in 1962 primarily to serve the Morro Bay Power Plant. The power plant was decommissioned in 2014 and the line, which traverses SoCalGas' service territory, still serves about 2,400 residential customers, a prison in Avenal and some small commercial customers. Prior to filing the application, PG&E and SoCalGas executed a sale agreement which would allow SoCalGas to serve customers currently using SoCalGas Line 44-1088. If SoCalGas is unable to purchase the line, the utility would need to replace Line 44-1088, at a cost of approximately $153 million. The agreed upon purchase price of Line 306 is $25 million resulting in an after-tax gain of about $15 million. In February 2020, a Proposed Decision was issued authorizing the sale of Line 306 finding that it would not be adverse to the public interest pursuant to Public Utilities Code Section 851.

OIR to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning

On January 16, 2020, the CPUC opened a rulemaking[187] to examine how events that have occurred since the existing gas reliability standards were passed require the CPUC to change the rules, processes, and regulations governing gas utilities. The scope of topics to be considered includes, but is not limited to, reliability standards, long-term contracting, regulatory accounting, reporting, and changes to system operator tools. There are three tracks of the proceeding. Track 1A will examine reliability standards for the gas transmission systems to determine, among other things, whether design changes are necessary to account for a warming climate and the service capacity of current and future gas system infrastructure. Track 1B will examine proposals for mitigating the negative impact that operational issues with gas transmission systems have on wholesale and local gas market prices and gas system and electric grid reliability. Track 2 will determine the regulatory solutions and

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185 *See* A.19-02-015.

186 *See* A.19-04-003.

187 *See* R.20-01-007.

planning strategy that the CPUC should implement to ensure that, as the demand for fossil natural gas declines, gas utilities maintain safe and reliable gas systems at just and reasonable rates, with minimal or no stranded costs.

SoCalGas/SDG&E Line 1600 Repairs and Replacement

A second phase to proceeding A.15-09-013 was recently approved that reviewed cost forecasts pertaining to the SoCalGas/SDG&E's Line 1600 Pipeline Safety Enhancement Plan (PSEP).[188] Under the approved plan, SoCalGas/SDG&E will replace segments of the line located in high consequence areas and hydrotest parts of the line located in non-high consequence areas. The project is estimated to cost $677 million, with $630 million anticipated to be capital expenditures and $47 million estimated to be operating expenses. Phase 2 of this proceeding will enable the CPUC to provide appropriate guidance regarding the reasonableness of the cost estimates, cost containment strategies, ratemaking and accounting treatment. D.20-02-024 did not grant cost recovery in this phase; however, reasonableness review of the cost forecasts established in this phase will occur in later GRCs.

188 *See* D.20-02-024.

7. Conclusion

Energy bill affordability considerations are at the forefront of the California IOUs' objectives of providing access to safe, reliable, and clean energy. As public policy-related costs resulting from legislative mandates aimed at achieving statewide policy goals are folded into IOU overall revenue requirements, the line between the costs of compliance with these mandates and basic operating costs begins to blur. While tools developed as part of the CPUC's affordability assessment and rate impact modeling efforts continue to evolve, a distinction between cost recovery in fulfillment of policy mandates versus operational cost recovery and rate requests should be maintained. Armed with information from these tools, energy industry leaders and stakeholders may better evaluate the potential costs of California's clean energy mandates, grid reliability requirements, and safety needs as part of understanding affordability tradeoffs to more effectively implement change.

8. Appendices

Appendix A

The following weblink to the CPUC's Energy Division Retail Rates webpage contains links to the reports submitted by PG&E, SCE, SDG&E, and SoCalGas, pursuant to Public Utilities Code Section 913.1: https://www.cpuc.ca.gov/General.aspx?id=6442465037

Appendix B

Electricity burden tables in Section 2 are broken out here by lower-income residential customers enrolled in the California Alternate Rates for Energy (CARE) program and residential customers not enrolled in the CARE program (Non-CARE) for each of the three large electric IOUs.

PG&E 2019 Bundled Residential Customers											
	Electric Climate Zone										
CARE	Q	T	V	R	W	Y	Z	X	P	S	All
Average Monthly Bill ($)	38	38	53	94	92	93	92	63	103	89	82
Average Monthly Household Income ($)	7,997	5,468	3,705	3,743	3,901	4,226	4,964	6,357	4,087	4,673	4,325
Electricity Burden	**0.5%**	**0.7%**	**1.4%**	**2.5%**	**2.4%**	**2.2%**	**1.9%**	**1.0%**	**2.5%**	**1.9%**	**1.9%**

Climate zone key
Cool: T, V, Y, Z
Warm: X
Hot: R, S, W

Table A-1: PG&E Electricity Burden, Average Bundled Residential Customers (CARE)

PG&E 2019 Bundled Residential Customers											
	Electric Climate Zone										
Non-CARE	Q	T	V	R	W	Y	Z	X	P	S	All
Average Monthly Bill ($)	97	76	140	146	142	101	67	111	144	139	121
Average Monthly Household Income ($)	7,721	6,598	4,199	5,136	5,690	4,685	5,241	8,909	4,828	6,220	6,252
Electricity Burden	**1.3%**	**1.2%**	**3.3%**	**2.8%**	**2.5%**	**2.2%**	**1.3%**	**1.2%**	**3.0%**	**2.2%**	**1.9%**

Climate zone key
Cool: T, V, Y, Z
Warm: X
Hot: R, S, W

Table A-2: PG&E Electricity Burden, Average Bundled Residential Customers (Non-CARE)

SCE 2019 Bundled Residential Customers										
	Electric Climate Zone									
CARE	**5**	**6**	**8**	**9**	**10**	**13**	**14**	**15**	**16**	**All**
Average Monthly Bill ($)	69	42	47	54	68	76	64	82	66	**59**
Average Monthly Household Income ($)	6,980	4,382	3,859	4,279	4,141	3,178	3,650	3,614	4,011	**3,972**
Electricity Burden	**1.0%**	**1.0%**	**1.2%**	**1.3%**	**1.6%**	**2.4%**	**1.8%**	**2.3%**	**1.6%**	**1.5%**

Climate zone key
Cool: 6, 8, 16
Warm: 5, 9
Hot: 10 (Section 745),[189] 13, 14, 15

Table A-3: SCE Electricity Burden, Average Bundled Residential Customers (CARE)

SCE 2019 Bundled Residential Customers										
	Electric Climate Zone									
Non-CARE	**5**	**6**	**8**	**9**	**10**	**13**	**14**	**15**	**16**	**All**
Average Monthly Bill ($)	104	81	87	96	108	119	99	133	88	**95**
Average Monthly Household Income ($)	7,945	6,812	6,183	6,250	5,824	4,637	4,522	5,817	5,086	**6,028**
Electricity Burden	**1.3%**	**1.2%**	**1.4%**	**1.5%**	**1.9%**	**2.6%**	**2.2%**	**2.3%**	**1.7%**	**1.6%**

Climate zone key
Cool: 6, 8, 16
Warm: 5, 9
Hot: 10 (Section 745),[190] 13, 14, 15

Table A-4: SCE Electricity Burden, Average Bundled Residential Customers (Non-CARE)

189 Interpretation of Public Utilities Code Section 745 in D.16-09-016.

190 Interpretation of Public Utilities Code Section 745 in D.16-09-016.

SDG&E 2019 Bundled Residential Customers					
	Electric Climate Zone				
CARE	**1**	**2**	**3**	**4**	**All**
Average Monthly Bill ($)	43	104	90	54	49
Average Monthly Household Income ($)	6,630	6,725	4,500	6,243	6,439
Electricity Burden	**0.6%**	**1.5%**	**2.0%**	**0.9%**	**0.8%**

Climate zone key
Cool: 1 (Coastal)
Warm: 4 (Inland)
Hot: 2 (Mountain), 3 (Desert)

Table A-5: SDG&E Electricity Burden, Average Bundled Residential Customers (CARE)

SDG&E 2019 Bundled Residential Customers					
	Electric Climate Zone				
Non-CARE	**1**	**2**	**3**	**4**	**All**
Average Monthly Bill ($)	88	121	102	92	90
Average Monthly Household Income ($)	9,510	7,650	4,342	8,301	8,994
Electricity Burden	**0.9%**	**1.6%**	**2.3%**	**1.1%**	**1.0%**

Climate zone key
Cool: 1 (Coastal)
Warm: 4 (Inland)
Hot: 2 (Mountain), 3 (Desert)

Table A-6: SDG&E Electricity Burden, Average Bundled Residential Customers (Non-CARE)