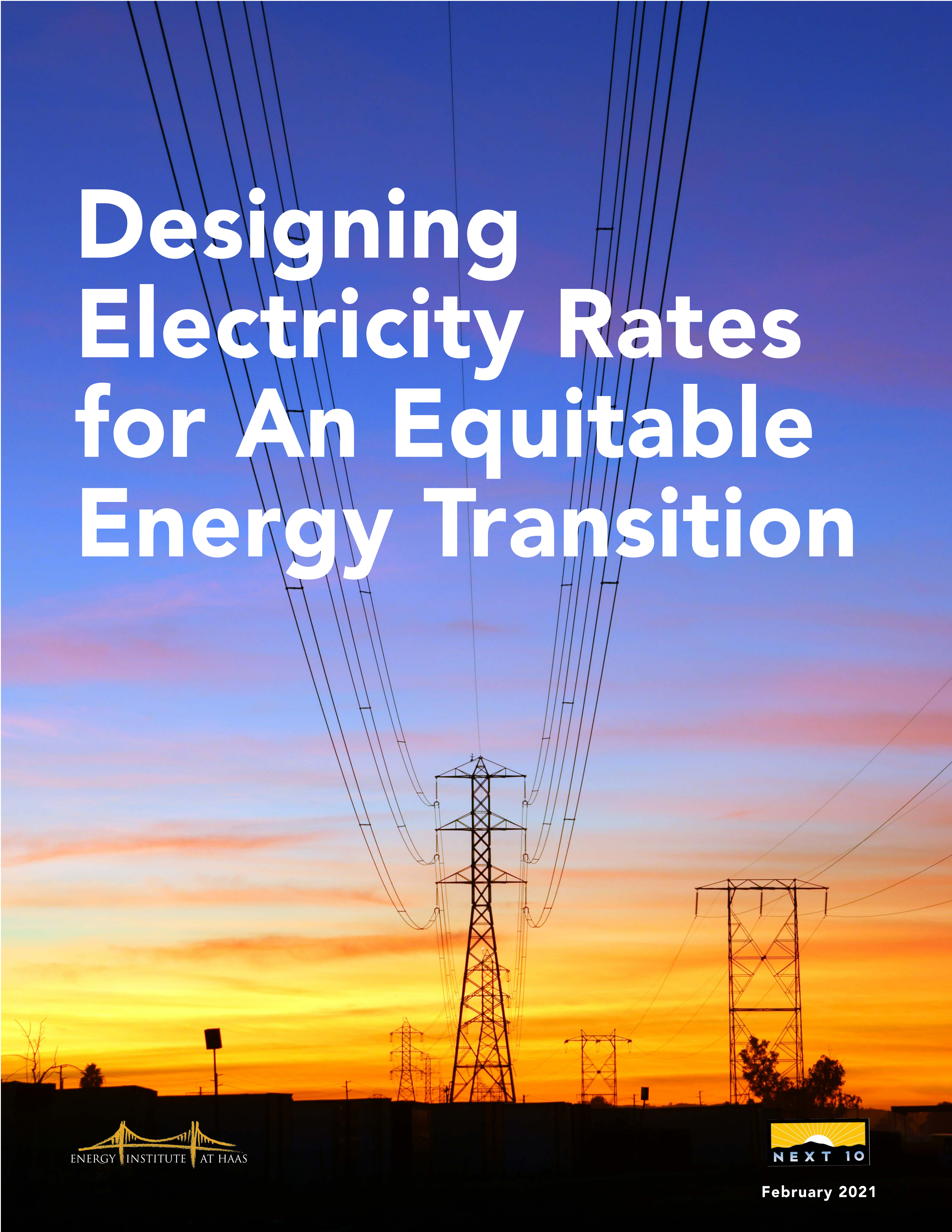
Designing Electricity Rates for An Equitable Energy Transition



ENERGY INSTITUTE AT HAAS

NEXT 10

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Next 10 is focused on innovation and the intersection between the economy, the environment, and quality of life issues for all Californians. We provide critical data to help inform the state's efforts to grow the economy and reduce greenhouse gas emissions. Next 10 was founded in 2003 by businessman and philanthropist F. Noel Perry.

The Energy Institute at UC Berkeley's Haas School of Business helps create a more economically and environmentally sustainable energy future through research, teaching and policy engagement.

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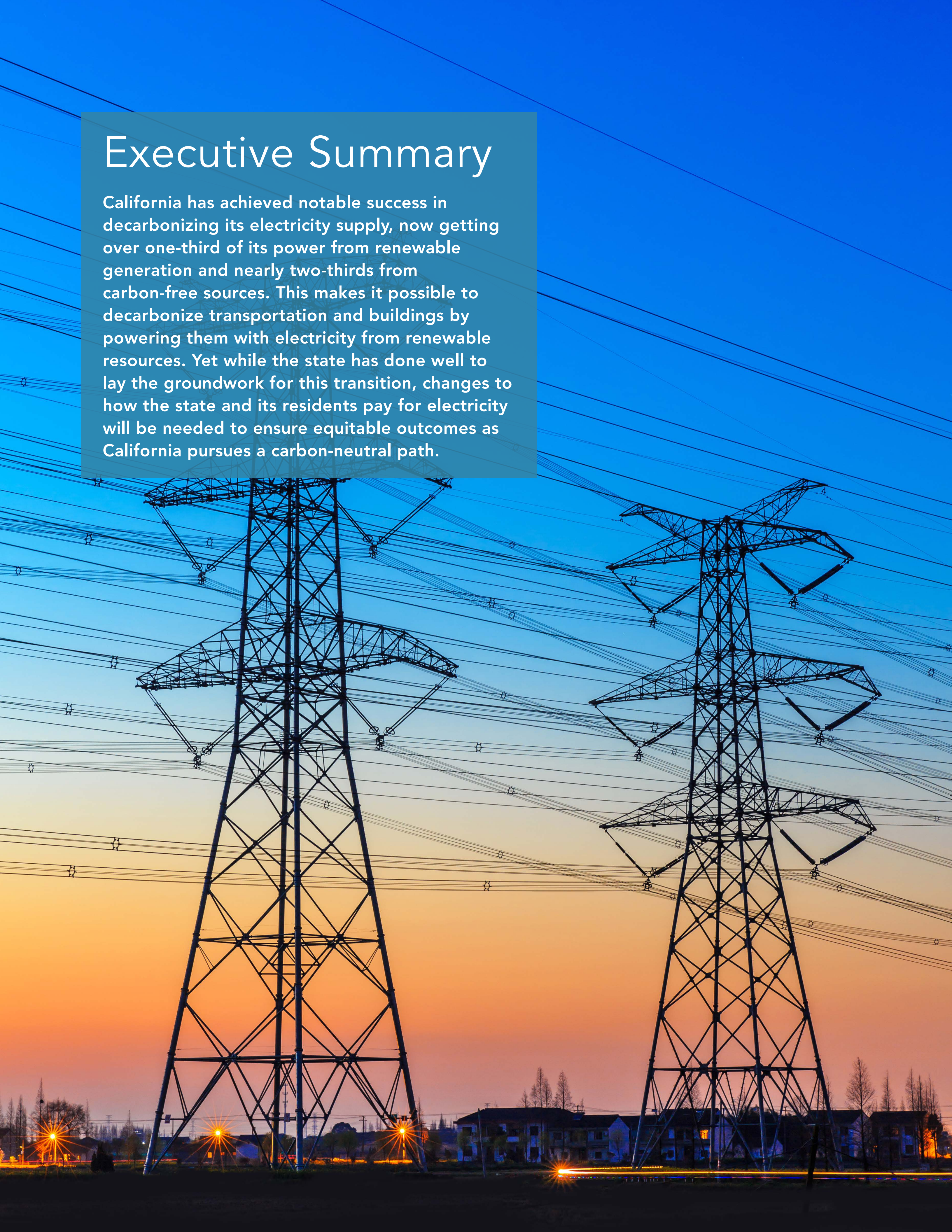
The Appendix can be found at https://www.next10.org/electricity-rates



Executive Summary

California has achieved notable success in decarbonizing its electricity supply, now getting over one-third of its power from renewable generation and nearly two-thirds from carbon-free sources. This makes it possible to decarbonize transportation and buildings by powering them with electricity from renewable resources. Yet while the state has done well to lay the groundwork for this transition, changes to how the state and its residents pay for electricity will be needed to ensure equitable outcomes as California pursues a carbon-neutral path.

Electricity prices in California are high and rising. This poses a heavy burden for many of the state's most economically vulnerable households. It is also a headwind in the state's efforts to combat climate change through electrifying transportation and buildings, which many see as critical steps to a low-carbon future.

The state's three large investor-owned electric utilities (IOUs) recover substantial fixed costs through increased per-kilowatt hour ("volumetric") prices. With nearly all fixed and sunk costs recovered through such volumetric prices, the price customers pay when they turn their lights on for an extra hour is now two to three times what it actually costs to provide that extra electricity—even when including the societal cost of pollution. This massive gap between retail price and marginal cost creates incentives that inefficiently discourage electricity consumption, even though greater electrification will reduce pollution and greenhouse gas emissions. Changing the way that electricity is paid for can address this issue.

This report takes stock of the current situation facing residential customers of California's large electricity IOUs and describes pricing reforms that could improve economic efficiency, facilitate decarbonization, and improve overall equity. The analysis includes several findings that are pertinent to ongoing conversations about affordability, decarbonization, rooftop solar, and wildfire mitigation, including:.

- **California IOUs' prices are high, by both historical and national standards.** A look at national data from the Federal Energy Regulatory Commission (FERC) shows that the average price of residential electricity in California's three large IOUs is out of line with the rest of the country. In the least expensive territory, Southern California Edison (SCE), residential prices per kilowatt hour are about 45 percent higher than the national average. Prices for Pacific Gas & Electric (PG&E) are about 80 percent higher, and prices in San Diego Gas & Electric (SDG&E) are roughly double the national average.
- **These high prices are two to three times the cost of producing additional electricity.** To reach this conclusion, this report analyzed the marginal cost of electricity—that is, the increase in cost incurred in order to deliver additional kilowatt-hours of electricity to an existing customer—and compared that cost to current rates. The authors found that the price of electricity ranged from double to triple the marginal cost in 2019. Even low-income customers who receive a subsidized rate paid prices well above marginal cost. The misalignment between price and cost creates problematic incentives.
- **High prices are driven in part by a shifting burden of fixed cost recovery.** Currently, 66 to 77 percent of the costs that California IOUs recover from ratepayers are associated with fixed costs of operation that do not change when a customer increases consumption. This includes much of the costs of generation, transmission and distribution of electricity, as well as subsidies for low-income household and public purpose programs, such as energy efficiency assistance. In addition, greater adoption of behind-the-meter (BTM) solar photovoltaic (PV) panels—which represented more than 15 percent of the residential electricity consumption across the PG&E, SCE, and SDG&E service territories in 2019—has disproportionately shifted cost recovery onto non-solar customers adopters.
- **Lower- and average-income households bear a greater burden.** These households are increasingly having to cover high fixed costs from a shrinking base as wealthier customers leave for rooftop solar. Higher-income households now consume only modestly more electricity than lower-income households.[1]
- **More equitable alternatives can be found and implemented.** The report authors detail a variety of potential approaches to ensure utility revenues can be kept stable without relying on the current regressive rate model as the state looks to increase electrification.

1 Borenstein (2017) finds that for customers in PG&E territory, households in the top 40% of income were more than twice as likely to install solar PV as households in the bottom 60%. Using a different statistical approach and data through 2016, Barbose et al (2018) find that the median income of California households installing solar PV was more than 40% above the median income of households overall. The next stage of the current research project will update analysis of this income gap. Borenstein available at: https://www.journals.uchicago.edu/doi/abs/10.1086/691978. Barbose et al available at: https://emp.lbl.gov/publications/income-trends-residential-pv-adopters

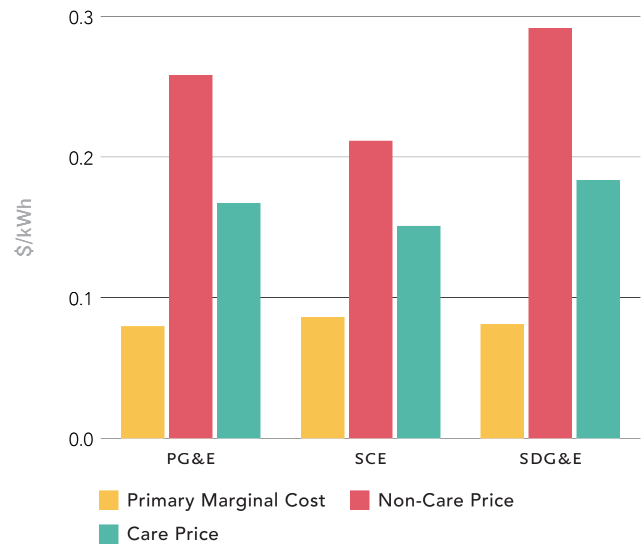
- **The report suggests the following alternatives for paying the cost of electricity in the state:**
  - » Tax revenue: Raising revenue from sales or income taxes would be much more progressive than the current system, ensuring that higher-income households pay a higher share of the costs.
  - » Income-based fixed charge: A more politically feasible option could be rate reform—moving utilities to an income-based fixed charge that would allow recovery of long-term capital costs, while ensuring all those who use the system contribute to it. To make a fixed charge equitable, it would be based on income. In this model, wealthier households would pay a higher monthly fee in line with their income.
    - · The report offers several ways to structure an income-based fixed charge, based on three criteria: set prices as close to cost as possible; recover the full system cost; and distribute the burden of cost recovery fairly.
- **Wildfire cost transparency.** Finally, the report identified the need for more transparent accounting of wildfire mitigation costs, as the authors could not obtain clear wildfire-related expenditure data. This is vital as wildfire mitigation costs are likely to be a major driver of price increases in the near future.[2]

More detail on these findings can be found below and in the body of the report.

Retail Prices Vs. Marginal Cost

The report's estimate of the marginal cost of electricity includes not only the cost of generating additional electricity, but also potential increases in costs for transmission and distribution capacity that scale with usage, as well as the potential need for additional generation capacity. The cost of greenhouse gas (GHG) emissions is also included, which is borne by society rather than the utilities to the extent that existing programs (e.g., cap and trade) only partially price this climate externality. There is no perfect way to calculate all of these costs with the available data, so a variety of alternatives is presented in the Appendix. In all cases, the marginal cost is vastly lower than current rates.

FIG ES-1 Residential Retail Prices Vs. Social Marginal Cost ($/kWh) for 2019



Note: Primary marginal cost estimates are weighted by IOU load. Average 2019 residential prices (CARE and non-CARE) are constructed using advice letters and rate schedules. PG&E sources: 5366-E-A/B; 5444-E; 5573-E; 5644-E. SCE sources: 67666-E: 67668-E. SDGE: 31811-E; 31501-E. Details on the methodology behind author calculations can be found in the Appendix.

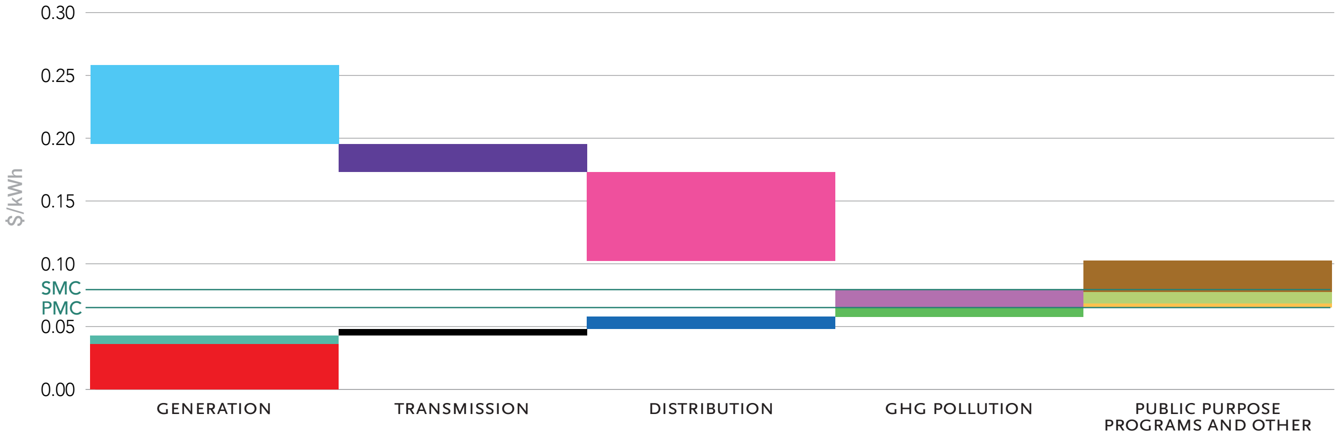
The authors' primary estimate of marginal cost for 2019 is shown in Figure ES-1, along with estimates of the average residential price of electricity for each IOU. The price of electricity is more than double the estimated marginal cost for SCE, and it is more than triple for PG&E and SDG&E. Over 25 percent of residential customers in California pay lower rates through the low-income program, California Alternative Rates for Energy (CARE), but report authors found that even CARE rates are substantially above marginal cost, as shown in the figure.

This finding is not a commentary on the appropriateness of overall costs. High total system costs in California may well be justified by conditions in the state. Rather, the implication of this finding is that by recovering total system costs through high volumetric prices, California's IOUs are now operating a pricing scheme that sends misleading signals about the true cost to society of consuming electricity. Pricing reform that aligns the volumetric price of energy with marginal cost would dramatically reduce prices, which has the potential to spur electrification of other sectors of the economy.

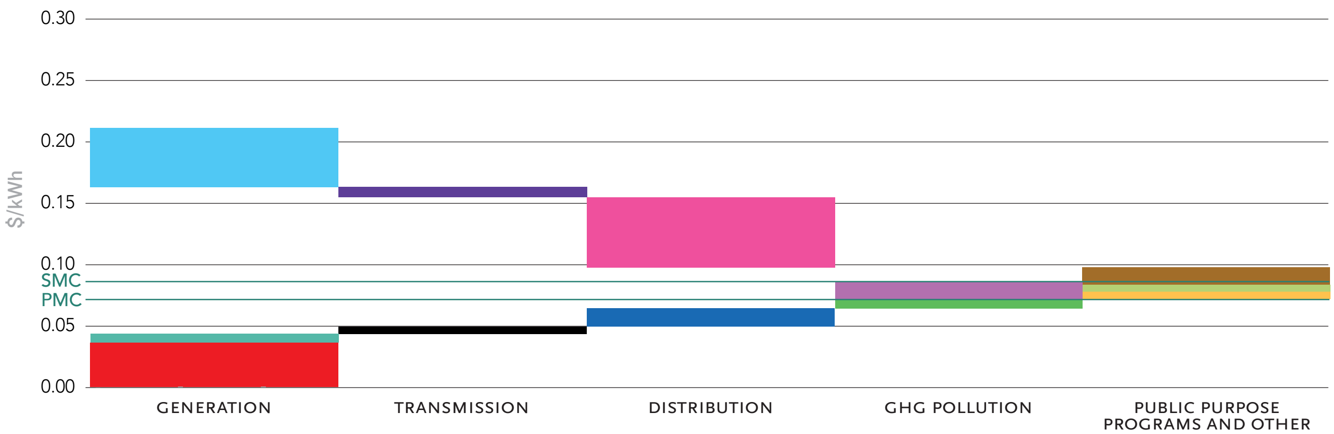
2 Balaraman, Kavya. "California IOUs plan to spend $11B on wildfire prevention in 2021 and 2022 after record-breaking fire season." Utility Dive. February 9, 2021. Available at: https://www.utilitydive.com/news/california-ious-plan-to-spend-11b-on-wildfire-prevention-in-2021-and-2022/594823/

FIG ES-2a-c Residential Price Decomposition ($/kWh) for 2019

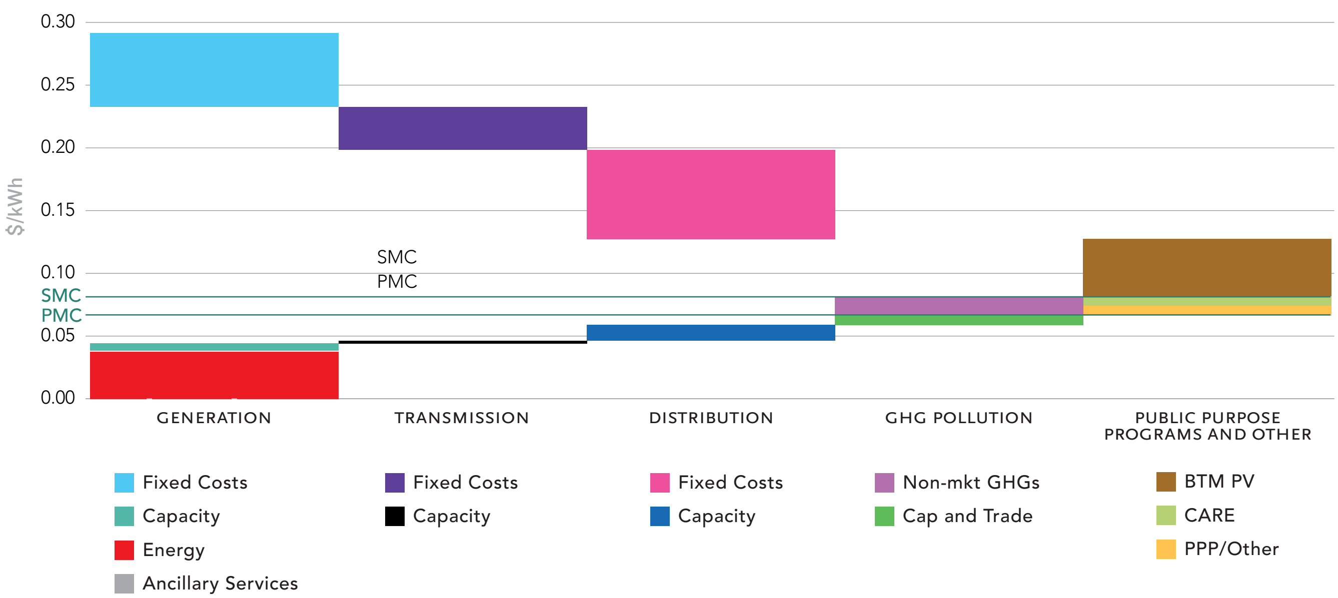
a. PG&E



b. SCE



c. SDG&E



Note: Details on data sources and methodology behind authors' calculations can be found in the Appendix.

Components of California Electricity Rates

The components of California's high electricity rates are unpacked in detail in this report and are summarized for each utility in Figure ES-2a-c, which breaks down the average volumetric price facing a residential customer on a standard rate. This figure decomposes costs into five main categories: generation, transmission, distribution, pollution and a residual category that combines public purpose programs and other costs. For generation, transmission and distribution, the costs are separated into the component that is part of marginal cost and the remaining costs that do not scale with usage. Details of each item's calculation is included in the report.

The marginal cost components are added up in the bottom staircase. Marginal cost is the combined height of the boxes representing the marginal costs of generation, transmission, distribution and greenhouse gas emissions that are associated with producing an additional unit of electricity. This is labeled here as the private marginal cost (PMC). Adding the unpriced portion of pollution damages resulting from electricity yields the social marginal cost (SMC). The other boxes represent additional system costs that do not scale with usage. These are all costs that are being recovered through high volumetric prices for standard rate customers, but they represent fixed costs that range from regular maintenance to wildfire mitigation to cross-subsidies for CARE customers and rooftop solar.

A few findings are apparent from the figure. First, the additional system costs are spread across several factors that, taken together, drive the high cost. In particular, costs associated with generation and distribution comprise a significant share of the cost recovery gap.

Second, as more and more households adopt behind-the-meter (BTM) solar photovoltaic (PV) panels, cost recovery is disproportionately shifted onto the bills of solar non-adopters. In 2019, the report authors estimate that behind the meter residential solar production supplied more than 15 percent of the residential electricity consumption across the PG&E, SCE, and SDG&E service territories. The fixed costs recovered via high volumetric electricity prices are shifted—not avoided—when a residential customer installs rooftop solar. In other words, as residential solar adoption increases, system costs are being recovered from a shrinking base.

An additional finding of the report's cost component analysis is that there is great need for a more transparent accounting of wildfire mitigation costs that could inform public debate. Despite going to considerable lengths in an attempt to delineate wildfire-related expenditures by separating them from other costs with publicly available data, it was not possible for the report authors to get clear numbers. In Figure ES-2-a-c, these costs are embedded primarily in transmission, distribution and other fixed costs. Wildfire mitigation costs are likely to be a major driver of price increases in the near future. Wildfire mitigation is a statewide priority that delivers benefits to households throughout all utility territories, regardless of the quantity of electricity they consume, suggesting that perhaps some associated costs should be borne by the state at large. Transparent and consistent data about associated costs is essential to inform decision-making about how to pay for wildfire mitigation.

Improving Equitable Pricing of Electricity

A key finding of the report's analysis is that the current system of recovering system costs through high volumetric prices is not only inefficient; it is also far less equitable than viable alternatives. It imposes a relatively large burden on lower- and average-income households while it recovers a shrinking fraction of system costs from higher-income households because of the diffusion of rooftop solar.

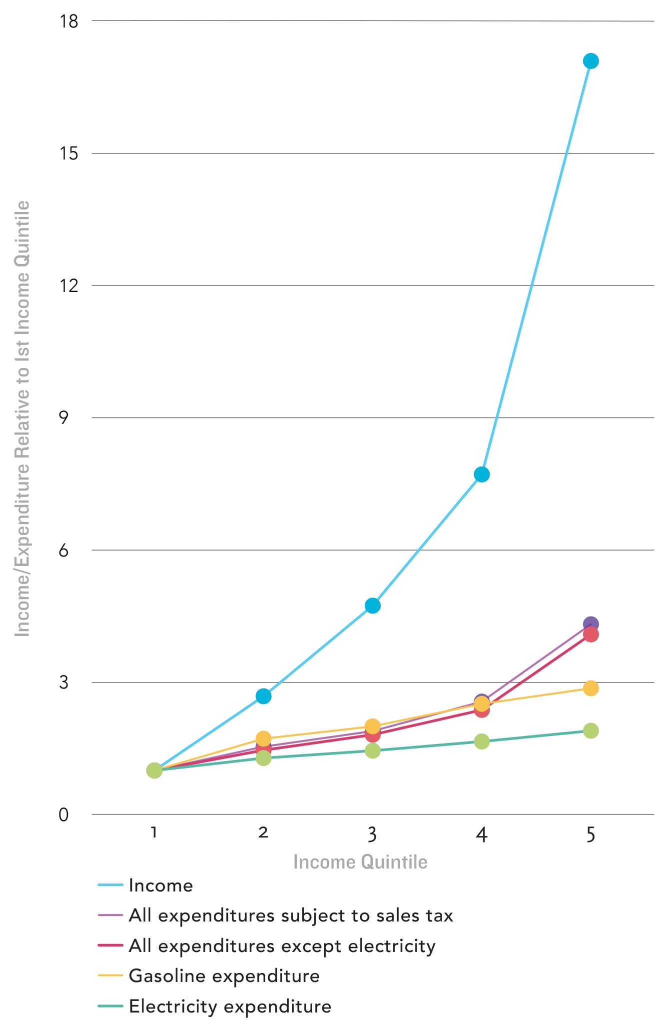
The authors are in the process of constructing a detailed assessment of how the burden of cost recovery is allocated across households in the current rate system, but that analysis involves customer billing data that was not obtained in time for this report. While a forthcoming Next 10-Energy Institute study will incorporate customer billing data, this initial report relied on survey data about household expenditures in California from the US Bureau of Labor Statistics, which are presented in Figure ES-3. Those data show that higher-income households spend only modestly more on electricity than lower-income households, a much smaller differential relative to differences in incomes or expenditures on most other goods, including even gasoline.

Alternative Funding Mechanisms to Ensure an Equitable Electrification Transition

To address these inefficiencies and ensure a more equitable path toward greater electrification, the state could potentially support some measures, such as public purpose programs or wildfire mitigation, directly through other tax revenue. Analysis of the survey data from the US Bureau of Labor Statistics (BLS) suggests that using revenue raised from sales or income taxes would be much more progressive than the current scheme of covering residual costs above marginal cost by increasing volumetric electricity prices. This is apparent in Figure ES-3, which shows that expenditures on goods subject to the sales tax rise much more steeply across the income distribution. Thus, raising electricity system revenue through the sales tax would recover far more of the costs from richer households than does the current scheme. The distribution of income rises even faster than do taxable expenditures—which means that paying for some system costs through additional revenue raised via the income tax in California would be even more progressive.

Recognizing potential political barriers to leveraging state revenue to pay for electricity system costs, the report also considered ways of reforming the electricity system that could align prices with marginal cost without imposing an additional burden on those least able to afford it. To that end, a final key finding is that an income-based fixed monthly connection charge could raise revenue to cover utility costs while maintaining a volumetric price that reflects marginal cost and improving equity outcomes. This fixed monthly charge would require income verification, but would ultimately help reduce volumetric rates while providing stable revenue to utilities. The report concludes by discussing the possible structure of an income-based fixed charge, including some possible rate structures, as well as some of the logistical and equity considerations and trade-offs that would need to be weighed in order to implement such a scheme.

FIG ES-3 Average Expenditures and Income per California Household by Income Quintile Relative to Lowest Quintile



Source: Authors' calculations of data from the Consumer Expenditure Survey in 2017-2018. Source data at https://www.bls.gov/cex/2017/research/income-ca.htm

1. Introduction

California has charted an ambitious course towards decarbonizing its economy. The state achieved its 2020 goal of reducing GHG emissions to 1990 levels four years early. Notably, almost all of these emissions reductions have been achieved in the electricity sector. At the same time, California has among the highest electricity prices in the continental U.S. These two facts create a tension: decarbonizing the economy most likely requires electrification of transportation and space and water heating, but high prices push against such a transition. High prices also have troubling implications for equity and affordability. If the costs of decarbonizing the power sector are recovered through higher electricity prices, this could impose a large economic burden on low-income households amidst an increasingly unequal economy. This report discusses the causes and consequences of California's high residential electricity prices, and it evaluates the merits of several potential remedies.

This study begins by asking why the residential electricity prices charged by California's investor-owned utilities (IOUs) are so high. First, the avoidable—or marginal—cost of providing additional kilowatt-hours (kWh) of electricity to a residential customer are identified. This is a necessary first step because, to the extent that high electricity prices actually reflect high incremental costs of generating and delivering electricity, high prices are economically efficient. If that is the case, then high prices are still problematic, but they can only be addressed in an economically- efficient manner by policies that lower marginal costs.

Instead, the authors find that residential electricity prices of California's IOUs are two to three times higher than social marginal costs (SMC), that is, marginal cost inclusive of environmental externalities. Marginal cost estimates from this study are consistent with prior work, such as analysis commissioned by the California Public Utilities Commission and other recent studies.[3] This conclusion is based on building an estimate of the social marginal cost of electricity that accounts for the direct cost of additional generation, the social cost of associated pollution, line losses from transporting the electricity, and appropriate capacity costs in generation, transmission and distribution that might change with demand. Section 3 provides a detailed discussion of the marginal cost estimates.

If a utility charges a retail electricity price equal to social marginal cost, this sends an economically-efficient price signal to consumers, but it would probably not collect enough revenue to cover all of the costs of the grid, as well as other priorities that are currently supported via volumetric (i.e., per-kWh) rates. The cost recovery gap is defined here as the difference between a utility's current revenue and the revenue it would collect if it instead charged the economically-efficient social marginal cost for the same quantity. This study estimates that gap and then decomposes it into a set of factors that increase the utilities' revenue requirements.

Broadly, these factors can be divided into three classes. One class includes costs that are currently funded through rates but are not required to serve current load. Energy efficiency programs are an example, as are funds that support new low-carbon technologies. A second class includes costs that are necessary for the maintenance of the grid but would not change if demand from current customers increased or decreased over a substantial range. An example is the maintenance of existing transmission lines. A third class includes cross-subsidies among rate payers. These include incentives for rooftop solar and rate discounts for low-income customers provided via the California Alternative Rates for Energy (CARE) Program.

The authors conclude that California's residential energy prices are high not because of any one factor, but because of the cumulative effect of many of these cost drivers. That said, some factors are larger than others. The role of energy efficiency programs and the Renewables Portfolio Standard (RPS) has waned in recent years, whereas the impact of rooftop solar subsidies is large and rapidly growing. The majority of the cost recovery gap is related to recovering fixed costs for the grid, which are projected to grow further as a result of wildfire mitigation and other factors. Details of the calculations for recent years are in Section 5.

Who bears the burden of fixed cost recovery under the current rate design? A detailed analysis of how costs are allocated across households requires utility billing data, which the authors of this report are in the process of acquiring, in anonymized form. For this initial report, however, the authors present preliminary analysis using the Consumer Expenditure Survey from the US Bureau of Labor Statistics. That analysis suggests that the current approach to cost recovery by increasing volumetric rates—essentially a volumetric tax—is quite regressive.

Unfortunately, the state budget is under considerable pressure, which makes it less likely that costs can be moved from electricity rates to the general fund. Therefore, this report explores an alternative that keeps cost recovery within electricity rates, but reduces regressivity. The starting point is to introduce a substantial fixed charge that would enable the utilities to lower volumetric prices towards avoidable cost. This would enhance economic efficiency and foster greater electrification, while keeping utility revenue stable.

3 Borenstein, S. and Bushnell, J. "Do Two Electricity Pricing Wrongs Make a Right? Cost Recovery, Externalities, and Efficiency." Energy Institute at Hass. July 2019. Available at: https://haas.berkeley.edu/wp-content/uploads/WP294.pdf. Detailed documentation of CPUC commissioned estimates of the avoided costs of distributed energy resources can be found at: https://www.ethree.com/public proceedings/energy-efficiency-calculator/

The primary objection to fixed charges is that they tend to be regressive. A move to uniform fixed charges that apply equally to all households would likely exacerbate the inequities in the current system. Instead, this report proposes a system of fixed charges that are based on a sliding scale of income, so that lower-income households pay a lower monthly connection fee. In terms of administration, it may not be advisable for the utilities themselves to determine the income of households, and so instead the authors propose that this system be implemented in coordination with the state's income tax authority, the Franchise Tax Board. Coordination between the utilities and the state could come in a variety of forms. Discussion of the strengths and weaknesses of several versions of this idea, as well as several potential rate structures, are in Section 7.

This report is a preliminary analysis in an ongoing research program. Going forward, the report authors plan to use anonymized customer billing records to characterize in much more detail the distributional burden of the current model of cost recovery and these alternatives. The potential impact of high volumetric rates on the goals of decarbonizing residential buildings and personal transportation will also be analyzed as part of a follow-on study to be released later this year.

2. California's Rates are Among the Highest in the Country

This report's analysis begins with an overview of California's residential retail prices. Figure 1 displays the average residential electricity price for the three California IOUs and a box-and-whiskers plot of the distribution of average residential electricity prices across US utilities, based on data from the Federal Energy Regulatory Commission (FERC). For each year, the solid horizontal line shows the national average (median) price (weighted across utilities by load), and the box traces the 25th to 75th percentiles. The lines (whiskers) extending from the box show the 5th and 95th percentiles. These data reveal that SDG&E and PG&E rates are now among the top few percentile of all residential rates in the country. SDG&E's rates are double the national median. SCE's rates are lower, but still about 45 percent above the national median.

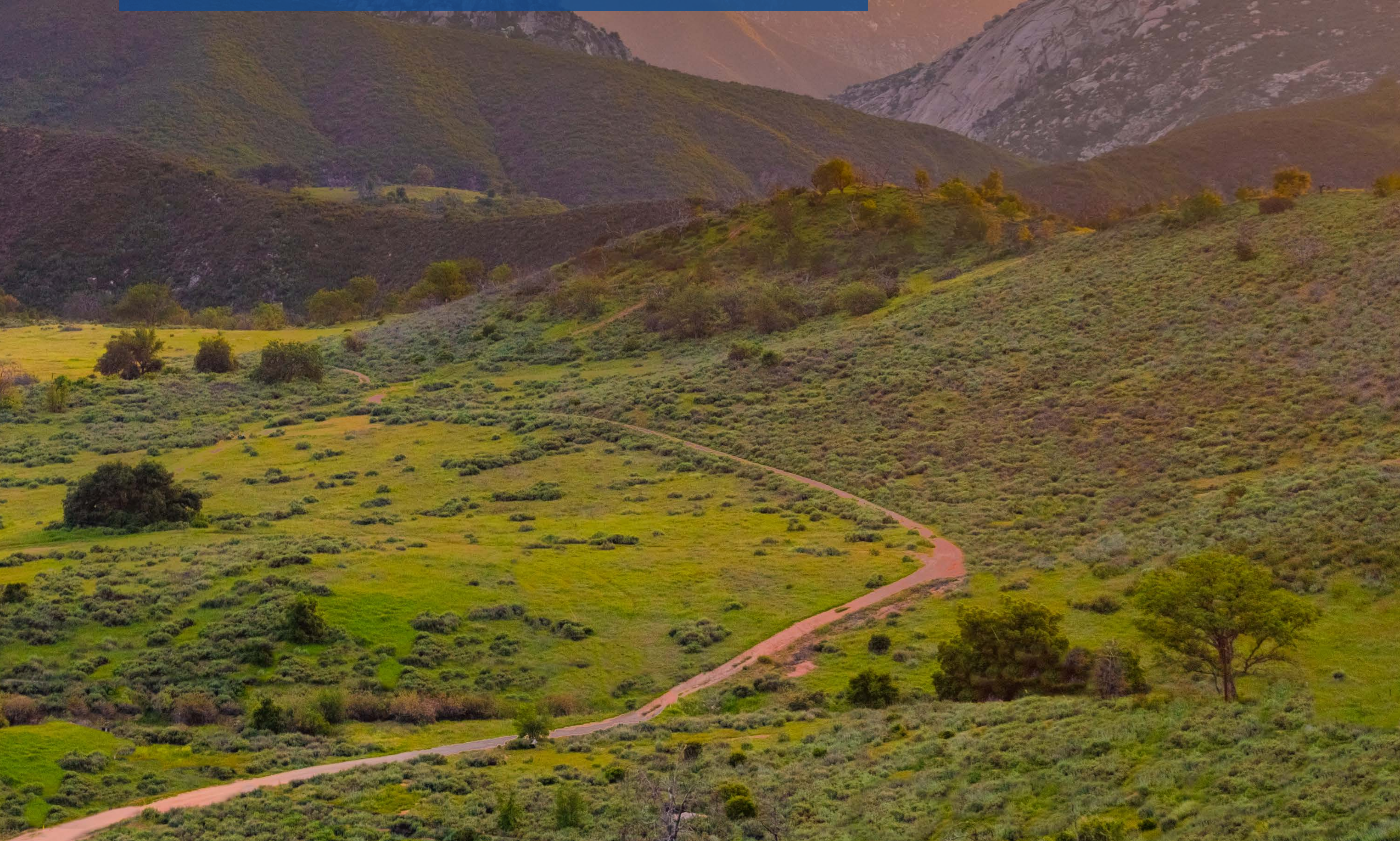
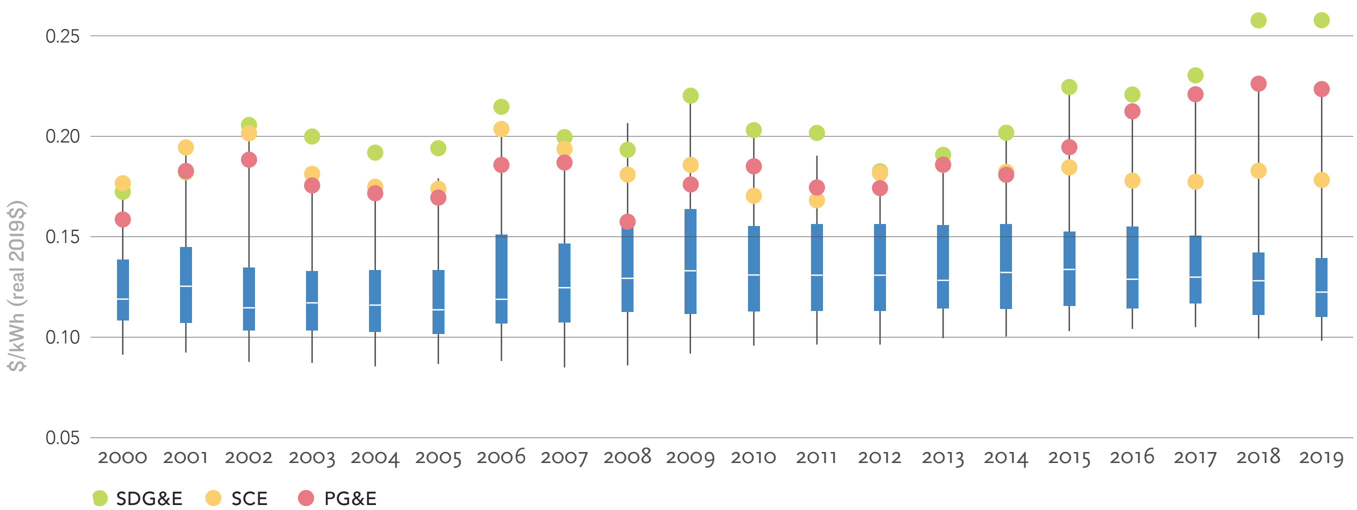


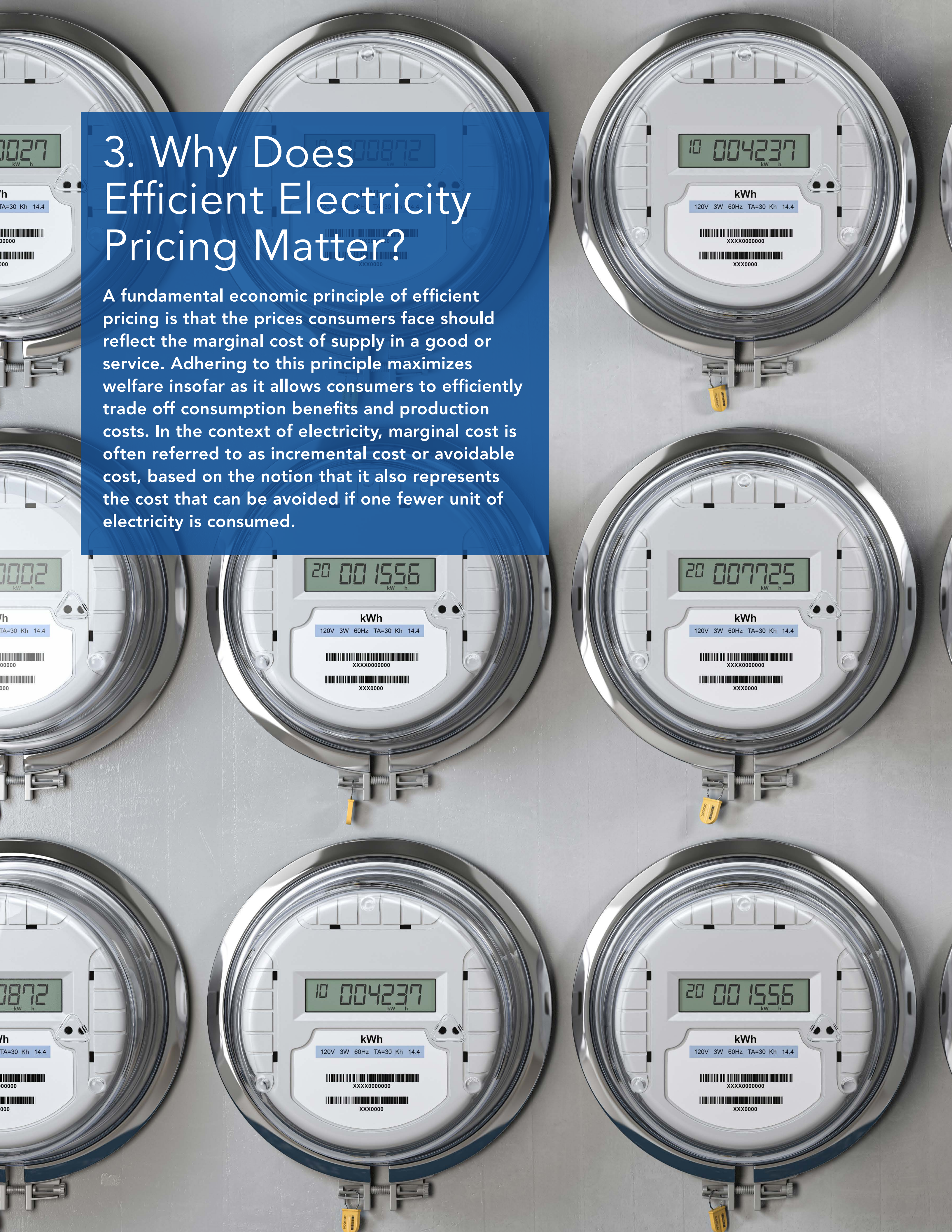
FIG 1 Average Residential Price ($/kWh) by Year for Major U.S. Utilities



Note: Observations are weighted by total annual consumption. The box represents the 25th, 50th, and 75th percentile. The whiskers represent the 5th, and 95th percentiles. Source: Data come from FERC Form 1.

Figure 1 presents the overall average residential rates, including those on low-income rates (CARE). In 2019, over a quarter of California IOU customers were enrolled in the CARE program.[4] When CARE customers are removed, average rates for non-CARE households are about 10 percent higher.

4 IOU annual reports on low income assistance programs indicate the share of residential customers that are presumptively eligible for CARE is in the range of 26-28%. All three utilities report very high (90-96%) CARE participation among eligible households.



3. Why Does Efficient Electricity Pricing Matter?

A fundamental economic principle of efficient pricing is that the prices consumers face should reflect the marginal cost of supply in a good or service. Adhering to this principle maximizes welfare insofar as it allows consumers to efficiently trade off consumption benefits and production costs. In the context of electricity, marginal cost is often referred to as incremental cost or avoidable cost, based on the notion that it also represents the cost that can be avoided if one fewer unit of electricity is consumed.

The concept of marginal cost depends on the time horizon being considered and the question being addressed. For example, at a moment in time when a system has excess power and is curtailing wind generation, the marginal cost of supply is effectively zero, because curtailing a little less wind power and instead delivering it to a customer would be virtually costless. But over the longer run, if wind generation would have to be expanded to meet a higher level of long-run demand, the marginal cost would include the cost of the wind turbine hardware. If additional demand in some hours of a year would require additional generation, transmission or distribution capacity, then the marginal cost of accommodating that additional demand would include the capacity investment cost that could otherwise be avoided or deferred. To the extent that there are many hours over the year in which the additional capacity may be utilized, then it is appropriate to allocate the cost of the additional capacity over those hours.

Societal, or social, marginal cost (SMC) includes not just costs borne by the producer, but also any external costs that are imposed in the production or consumption of the good. In the case of electricity production, the most notable externalities are the environmental impacts of pollution that are not fully reflected in electricity market prices. Explanation of how private marginal operating costs, private marginal capacity costs, and emissions-related external marginal costs were estimated is below and in the Appendix.

If the incremental, or "volumetric," price is set higher than SMC, then it will discourage usage of the good in some cases where it creates more value than it imposes costs. For instance, if a consumer would get $10 of value from consuming an additional unit of a good, and doing so would create an additional $5 in cost to the producer and an additional $2 in pollution externality costs, then this unit of consumption still creates $3 in net additional value ($10-$5-$2). However, if the volumetric price of the good is set, for instance, at $11, then the consumer will choose not to purchase it, because the price is greater than the value that the consumer would get.[5] That failure to purchase the good means that the $3 in value is lost. Such "deadweight loss" from under-consumption is avoided if the price of the good is set equal to its SMC—in this case $7.

Similarly, for the same good, if the price were set at $5, then it would encourage use of the good even in cases where it creates less value than the cost it imposes. In that case, for instance, if there were a customer who valued the good at $5.50, that person would buy the good, but this would lower value in the economy by $1.50, the difference between the customer's value of the good and the SMC of supplying it. Thus, this transaction would create $1.50 in deadweight loss from over-consumption.

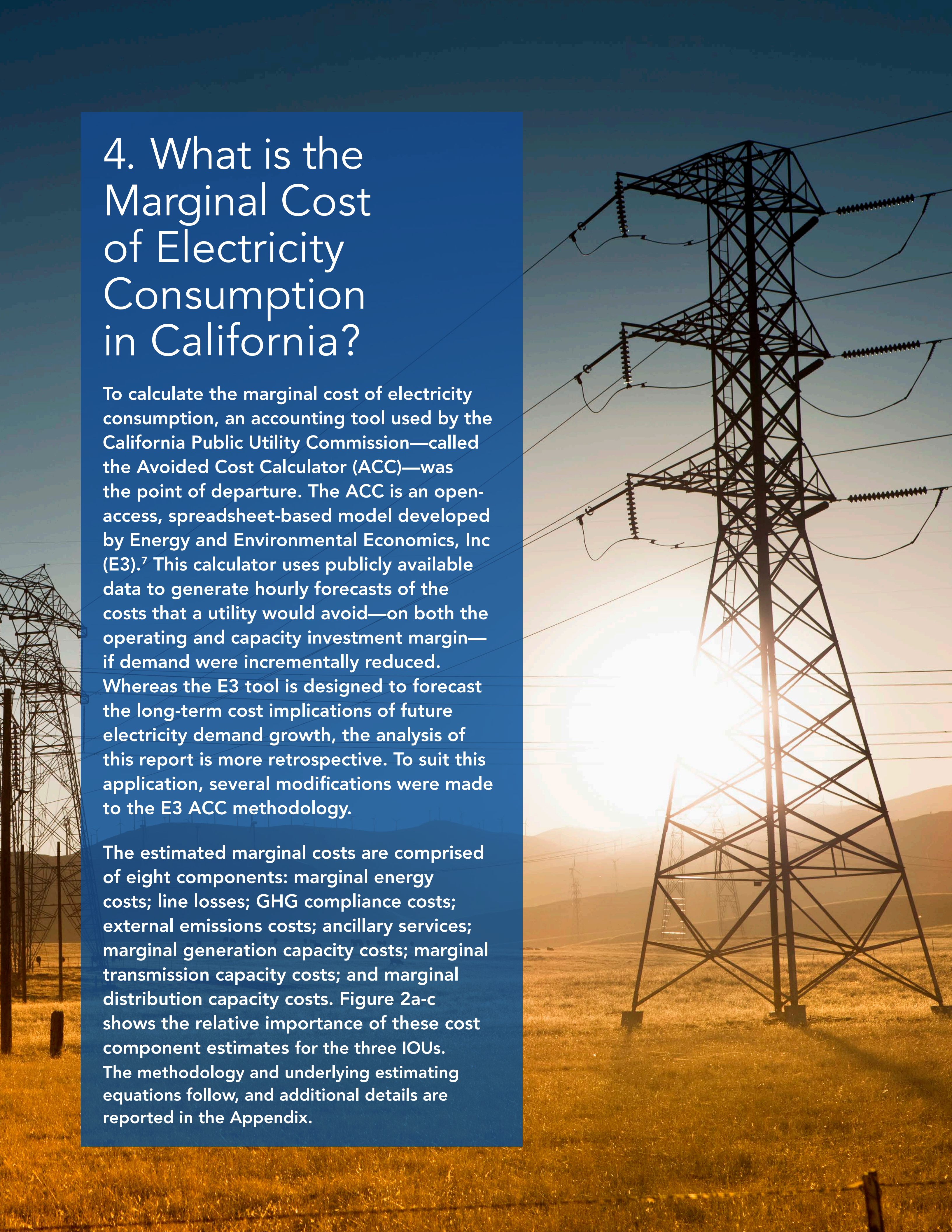
These hypothetical examples have very tangible applications in electricity pricing. Previous research suggests nearly all of California is pricing electricity well above its SMC, as is much of the Northeast, though to a somewhat lesser extent.[6] Many parts of the coal-reliant upper Midwest, however, are pricing well below their SMC, which is quite high due to the pollution from burning coal. In California, over-pricing electricity will inefficiently discourage some households from considering electrification of space heating, water heating, clothes drying, vehicle transportation and other services that can switch between energy sources. In regions that are underpricing electricity compared to SMC, there is too little incentive to adopt energy efficiency improvements that would maximize economic value creation.

One might ask whether this problem of over-pricing compared to SMC isn't ubiquitous in the economy, and why it should be more of a concern in electricity than elsewhere. It is true that many branded consumer goods are priced above their SMC, but that is less commonly the case with generic commodities, such as energy and

5 Note that a rational, well-informed consumer will make consumption decisions based on the incremental price, ignoring any costs to them that do not change with their consumption at that time. So, a fixed monthly charge would not affect their incremental (or "marginal") consumption decision. A demand charge on their peak consumption is non-marginal during most hours of the year, but could greatly increase the customer's expected incremental price if their consumption is nearly at their annual peak. There is some controversy about the extent to which electricity consumers act in a way that is as precisely rational as this discussion suggests. Ito 2014 finds that residential customers faced with increasing-block pricing seem to respond to the average price they face across the increasing- block price schedule rather than the marginal price. But recent work, such as Ito and Shuang 2020, suggests that customers don't make such errors when faced with a fixed charge. Ito and Shuang 2020 available at: https://www.nber.org/papers/w26853

6 Borenstein, S. and Bushnell, J. "Do Two Electricity Pricing Wrongs Make a Right? Cost Recovery, Externalities, and Efficiency." Energy Institute at Hass. July 2019. Available at: https://haas.berkeley.edu/wp-content/uploads/WP294.pdf

agricultural products. Furthermore, with many branded consumer goods—from new cars to airline tickets to groceries—price discrimination (charging different prices across customers even though the cost of supplying is the same) is a deeply ingrained part of the market. That discrimination is generally intended to pull in the customers with a lower value of the good while extracting high prices from those with a higher valuation. This practice exists to some extent in residential electricity pricing with prices that vary depending on the use of the electricity—such as special lower rates for EV charging. With the need for separate wiring, metering and billing, however, such market segmentation is costly and cumbersome. Moreover, it requires regulators to make price-setting decisions based not just on cost, but also on demand factors—a topic on which there is likely to be widely divergent views.

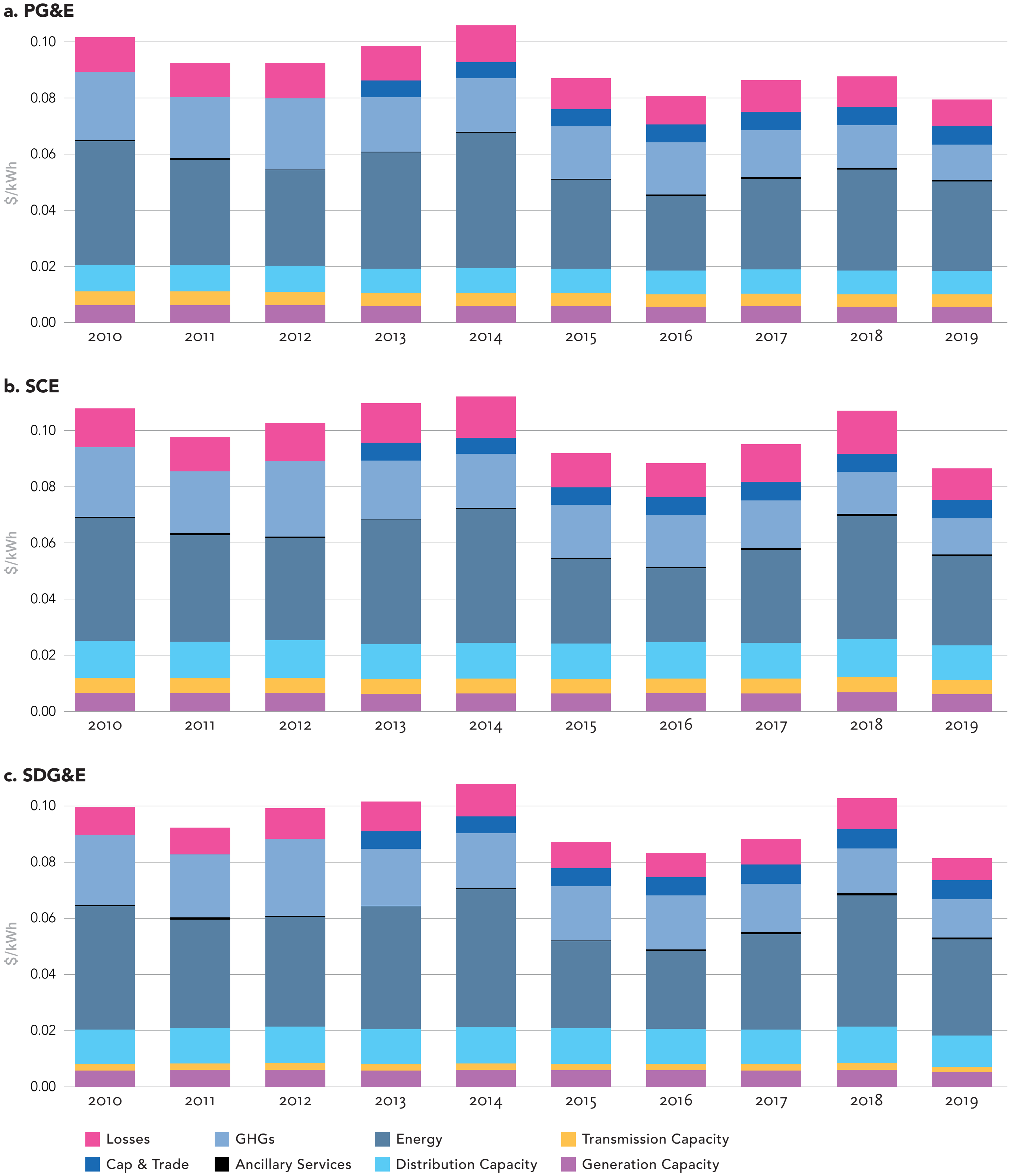


4. What is the Marginal Cost of Electricity Consumption in California?

To calculate the marginal cost of electricity consumption, an accounting tool used by the California Public Utility Commission—called the Avoided Cost Calculator (ACC)—was the point of departure. The ACC is an open-access, spreadsheet-based model developed by Energy and Environmental Economics, Inc (E3).[7] This calculator uses publicly available data to generate hourly forecasts of the costs that a utility would avoid—on both the operating and capacity investment margin—if demand were incrementally reduced. Whereas the E3 tool is designed to forecast the long-term cost implications of future electricity demand growth, the analysis of this report is more retrospective. To suit this application, several modifications were made to the E3 ACC methodology.

The estimated marginal costs are comprised of eight components: marginal energy costs; line losses; GHG compliance costs; external emissions costs; ancillary services; marginal generation capacity costs; marginal transmission capacity costs; and marginal distribution capacity costs. Figure 2a-c shows the relative importance of these cost component estimates for the three IOUs. The methodology and underlying estimating equations follow, and additional details are reported in the Appendix.

FIG 2a-c Annual Social Marginal Cost Estimates ($/kWh)



Notes: Marginal cost components are weighted by IOU load. See text for details on the construction of cost components. Additional details on data sources and methodology behind author calculations can be found in the Appendix.

4.1 Marginal Operating Costs

The first marginal cost component captures variable electricity generation costs by collecting hourly, day-ahead wholesale electricity prices for the default load aggregation points (DLAPS) associated with each of the three IOUs, respectively.[8] These locational marginal prices (LMPs) reflect not only the per-kWh fuel and variable operations and maintenance (O&M) costs at a given location, but also the costs of purchasing GHG permits to offset emissions, congestion related costs, and electricity losses due to long-distance transport.

The first task is to isolate the component of these prices that reflect the marginal cost of electricity generation. Using i to index the IOU territory and t to index hours of the year, the marginal energy cost MEC_{it} is defined as:

(1)

$$MEC_{it} = (LMP_{it} - \underbrace{\tau_t \cdot MOER_{it}}_{\text{GHG Costs}}) \underbrace{\left(\frac{1}{1 - LF_{it}}\right)}_{\text{Loss adjustment}}$$

Equation 1 subtracts the GHG compliance costs incurred by the marginal producer from the LMP. To estimate this per-kWh compliance cost, the prevailing GHG permit price, τ_t, is multiplied by the GHG emissions rate (measured in tons of CO2/kWh) of the marginal generator.[9] Assuming that the marginal unit is a natural gas plant, the marginal operating emissions rate ($MOER_{it}$) can be defined as:

(2)

$$\mathrm{MOER}_{it} = \mathrm{HeatRate}_{it} \cdot 0.05307,$$

where $HeatRate_{it}$ measures the fuel efficiency (in MMBtu/kWh) of electricity generation for the marginal producer in region i and hour t. Multiplying by the carbon intensity of natural gas (0.05307 metric tons/MMBtu) yields an estimate of the GHG intensity of electricity production.[10]

To estimate the marginal heat rate in Equation 2, it is further assumed that the LMP accurately reflects the variable operating costs of marginal producers (i.e., fuel costs plus non-fuel costs (NFC) of variable O&M and GHG compliance costs).[11] Invoking this assumption, the marginal heat rate is:

(3)

$$HeatRate_{it} = \frac{(LMP_{it} - NFC)}{(GasPrice_{it} + 0.05307 * \tau_t)}$$

When power is transferred from electricity producers to residential consumers, losses accrue due to physical resistance in the transmission and distribution system. Transmission losses are quite small (typically 1-2%) and are reflected in LMPs.[12] Losses on the lower-voltage distribution systems are substantially greater per kWh and increase with flow on the line.[13] These losses must be accounted for when estimating the marginal cost of serving residential customers. The Borenstein and Bushnell study cited above estimates average annual residential distribution losses at the distribution company level and then derive marginal losses from an engineering relationship. Equation 1 uses these marginal loss factors LF_{it} to scale variable operating costs. This

7 The Commission approved the first ACC in 2005 with Decision (D.) 05-04-24. Subsequent updates and reviews are available at https://www.ethree.com/public proceedings/energy-efficiency-calculator.

8 For each node, CAISO calculates a load distribution factor. These are used to construct load-weighted average prices for each utility. These data were downloaded from SNL Financial. This is a proprietary source of financial data and market intelligence that includes a convenient centralized database of publicly available LMP data.

9 To calibrate the GHG permit prices, we use quarterly GHG permit auction prices. These prices can be found at: https://ww2.arb.ca.gov/sites/default/files/2020-08/results_summary.pdf

10 This emission factor does not include emissions associated with the extraction and delivery of natural gas. These upstream emissions tend to be region-specific and are hard to estimate generically. Further details are available at: https://www.eia.gov/environment/emissions/co2_vol_mass.php

11 To calibrate variable O&M costs, we use the estimates provided in the E3 ACC. These costs are small (on the order of $0.6 per MWh). Natural gas prices are calibrated using IOU-specific volume-weighted average prices. For PG&E, monthly average prices are volume-weighted across northern California hubs. For SCE and SDG&E, prices are volume-weighted across Southern California hubs.

12 To be precise, one should account for transmission losses in deriving the heat rate of the marginal producer from LMPs. We do not make further adjustments, however, because transmission losses are so small and we have no data on variation in the transmission losses of the marginal producer.

13 Borenstein, S. and Bushnell, J. "Do Two Electricity Pricing Wrongs Make a Right? Cost Recovery, Externalities, and Efficiency." Energy Institute at Hass. July 2019. Available at: https://haas.berkeley.edu/wp-content/uploads/WP294.pdf

approximately accounts for the costs associated with distribution system losses.

In sum, Equations 1, 2, and 3 calibrate three cost components: marginal energy costs, GHG compliance costs, and distribution system losses. Figure 2a-c plots load-weighted annual average measures of these marginal cost components. Of these, marginal energy costs are the most economically significant, comprising 30 to 40 percent of social marginal costs. As of 2019, GHG compliance costs comprise seven to nine percent of private marginal costs. Estimated losses increase marginal costs by 10 to 12 percent.

4.2 Ancillary services

Ancillary services (AS) are procured day-ahead, largely on the basis of total load forecast. Reducing load will generally reduce the amount of ancillary services that must be procured to meet system operating protocols. To estimate this marginal cost, the average ancillary service costs reported annually by CAISO were utilized.[14] On a per-kWh basis, these AS costs are small. They are barely visible in Figure 2a-c.

4.3 GHG externality costs

From the inception of the California cap and trade market, in 2013, through 2019, GHG permit prices in quarterly allowance auctions ranged from $12-$17/metric ton.[15] These allowance prices fall below standard estimates of the social cost of carbon (SCC).[16] To account for GHG costs that are not captured by GHG permit prices, the authors define a residual GHG cost component:

(4)
$$GHG_{it} = (SCC - \tau_t) \cdot MOER_{it}$$

Primary cost estimates assume a SCC of $50/ton. Under this assumption, current GHG permit prices reflect up to 34 percent of the true social cost of GHG emissions. Figures 2a-c show how accounting for this GHG externality has an economically significant effect on our marginal cost estimates.

4.4 Marginal capacity costs

Thus far, this report has focused exclusively on the variable operating costs (private and social) associated with serving residential electricity demand. Next, the investment margin is considered. In principle, if peak demand for electricity in a utility service territory is reduced, some transmission projects, distribution system upgrades, and/or generation capacity investments could be deferred or avoided. In practice, the ability to defer these investments will depend on a number of factors, such as the location and timing of peak demand reductions.

Annualized cost impacts of incremental reductions in peak load on generation, distribution, and transmission capacity investments are discussed first—followed by an explanation of how these annualized costs are allocated across hours.

4.4.1 Marginal transmission capacity cost (MTCC):

The IOUs coordinate with the California Independent System Operator (CAISO) to plan transmission system investments. If peak load is reduced prior to a project implementation date, a planned transmission project that is driven by anticipated increases in demand—versus regulatory, safety, contractual, efficiency or other reasons—could be deferred.

The E3 ACC tool uses data from general rate cases, and data provided by the IOUs, to identify deferrable transmission investments. These utility-specific marginal capacity costs are measured in terms of dollars per kilowatt-year. The primary estimates of this report incorporate these E3 cost estimates directly. For each IOU, the reported deferrable transmission costs are averaged across the ten-year period considered. Some stakeholders have challenged the idea that any transmis-

14 These AS costs are taken from CAISO's Annual Report on Market Issues and Performance.

15 "California Cap-and-Trade Program: Summary of California-Quebec Joint Auction Settlement Prices." California Air Resources Board. November 2020. Available at: https://ww2.arb.ca.gov/sites/default/files/2020-08/results_summary.pdf

16 Following the 2016 Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis produced by the Interagency Working Group on Social Cost of Greenhouse Gases, we assume that the SCC is $50/ton. In the Appendix, we also consider a case with SCC equal to $100/ton.

sion investments are driven by load peak-load growth.[17] In the Appendix, alternative estimates which set MTCC component to zero are reported.

4.4.2 Marginal distribution capacity costs (MGCC):

The costs of operating, maintaining and replacing distribution equipment, once installed, are generally independent of electricity consumption levels. However, there are some types of distribution system investments that can be sensitive to rates of demand growth for a given set of customers. For example, distribution reinforcement investments provide capacity to meet demand growth on the existing system.

The E3 Avoided Cost Calculator leverages information reported in general rate cases to estimate the value of deferring or avoiding investments in distribution infrastructure through reductions in distribution peak capacity needs. These annualized costs, averaged across years, are used to construct this report's primary estimates of IOU-specific marginal distribution capacity costs. However, it should be noted that several stakeholders have challenged the idea that peak load reductions could defer distribution upgrades. Recognizing that these primary estimates may over-estimate distribution investment costs that are truly avoidable, the Appendix also reports marginal cost estimates that set the MDCC component to zero.

4.4.3 Marginal generation capacity costs (MGCC):

When peak demand is forecast to increase, or new generation capacity will be needed to replace retirements, the marginal generation cost captures the cost of procuring and operating new generation capacity (measured in terms of dollars per kilowatt-year). E3 ACC calculations use the levelized capital cost of a new simple cycle combustion turbine generating unit net of profits earned in energy and ancillary service markets to estimate marginal generation capacity costs.

In time periods when peak demand is not forecast to increase, the MGCC captures the going- forward fixed cost of operating existing generation resources net of energy gross margins earned in the energy and ancillary services markets. In GRC proceedings, reported costs capture the fixed O&M, insurance, and property tax costs incurred to keep marginal generation operating. Noting that peak load has been declining over time, the generation capacity costs assumed here are based on resource adequacy cost estimates. The primary marginal cost estimates assume an MGCC of \$30/kW-year.[18]

4.4.4 Hourly allocation of capacity costs:

To construct hourly marginal cost estimates, deferrable capacity costs must be allocated across hours of the year. Intuitively, these costs should be allocated to the hours when demand is likely to be highest. Historical load data is used to summarize systematic variation in hourly IOU load over the period of 2005 to 2019. The objective is to identify the hours in which electricity demand is likely to be highest, and then allocate capacity costs proportionally.

Hourly load is regressed in L $_{h,d,m,y}$ (where h is hour, d is day, m is month, and y is year) regressed on hour-of-day-by-month fixed effects, day-of-week fixed effects, and a set of holiday indicators:

(5)

$$L_{h,d,m,y} = \alpha_{h,d,m} + \lambda_d + \sum \delta_{hol} D_{j,y} + \varepsilon_{h,d,m,y}$$

The regression residual $_{h,d,m,y}$ captures variation in realized load that cannot be captured by our suite of fixed effects.

To predict hourly electricity demand in year y, Equation 5 is estimated using data from the five years prior. Hourly load is then estimated within the year and these hourly load estimates are ranked in descending order. Load in the 501st hour defines a threshold T_y. All hours with predicted load below this threshold receive a weight of zero. Non-zero allocation factors for hours that exceed

17 See for example, the Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning and Evaluation of Integrated Distributed Energy Resources. Rulemaking 14-10-003, April 24, 2020.

18 PG&E has calculated a Net Present Value (NPV) sum of the six years of MGCCs and then converted this NPV to a levelized value. PG&E used its after-tax Weighted Average Cost of Capital (WACC) of 7.0 percent. The estimated net costs of capacity: \$30.23/kW-year, \$29.62/kW-yr, \$28.53/kW-yr, \$27.63/kW-yr, \$27.70/kW-yr and \$27.42/kW-yr for 2017 through 2022, respectively.

this threshold are defined as:

Marginal capacity costs (for transmission, distribution, and generation) are allocated across hours of a year on the basis of these weights. Intuitively, for hours in the

(6)
$$w_{ty} = \frac{\hat{L}_{ty} - T_{y}}{\sum(\hat{L}_{ty} - T_{y})}$$

top 500 each year, marginal capacity costs are allocated in proportion to the difference between an hour's load and the threshold load level from the 501st hour. Thus, for instance, the 499th highest load hour would likely get almost no capacity costs allocation, because the load in that hour is probably nearly the same as the load in the 501st hour.

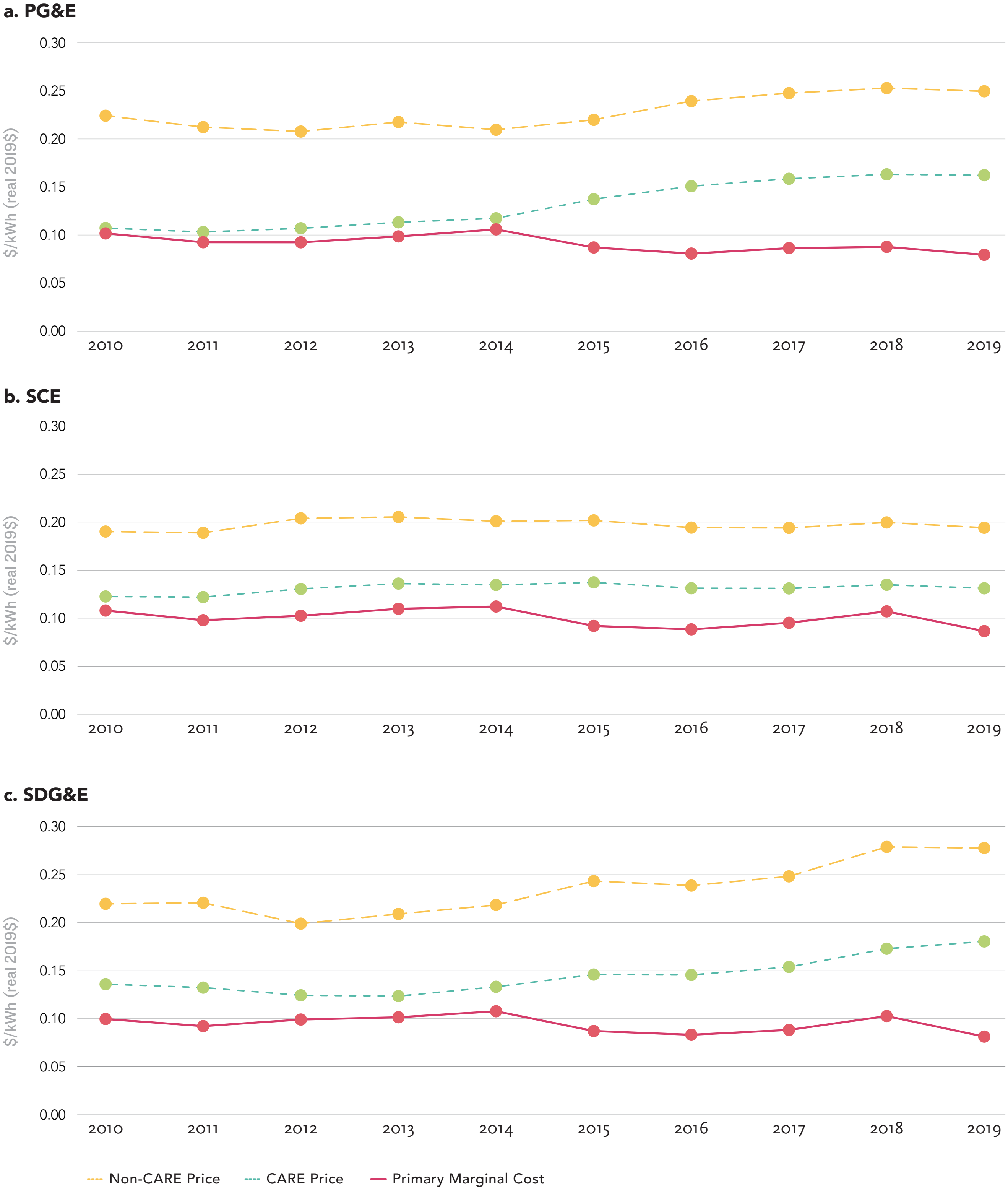
Figure 2a-c illustrates the magnitude of these marginal capacity cost components (expressed in terms of average cost per kWh) relative to other cost drivers. Distribution and transmission costs vary with the size of deferrable investments reported in general rate cases. Across all three utilities, the marginal distribution investment cost component is the largest of the capacity-related cost components.

4.5 The widening cost recovery gap

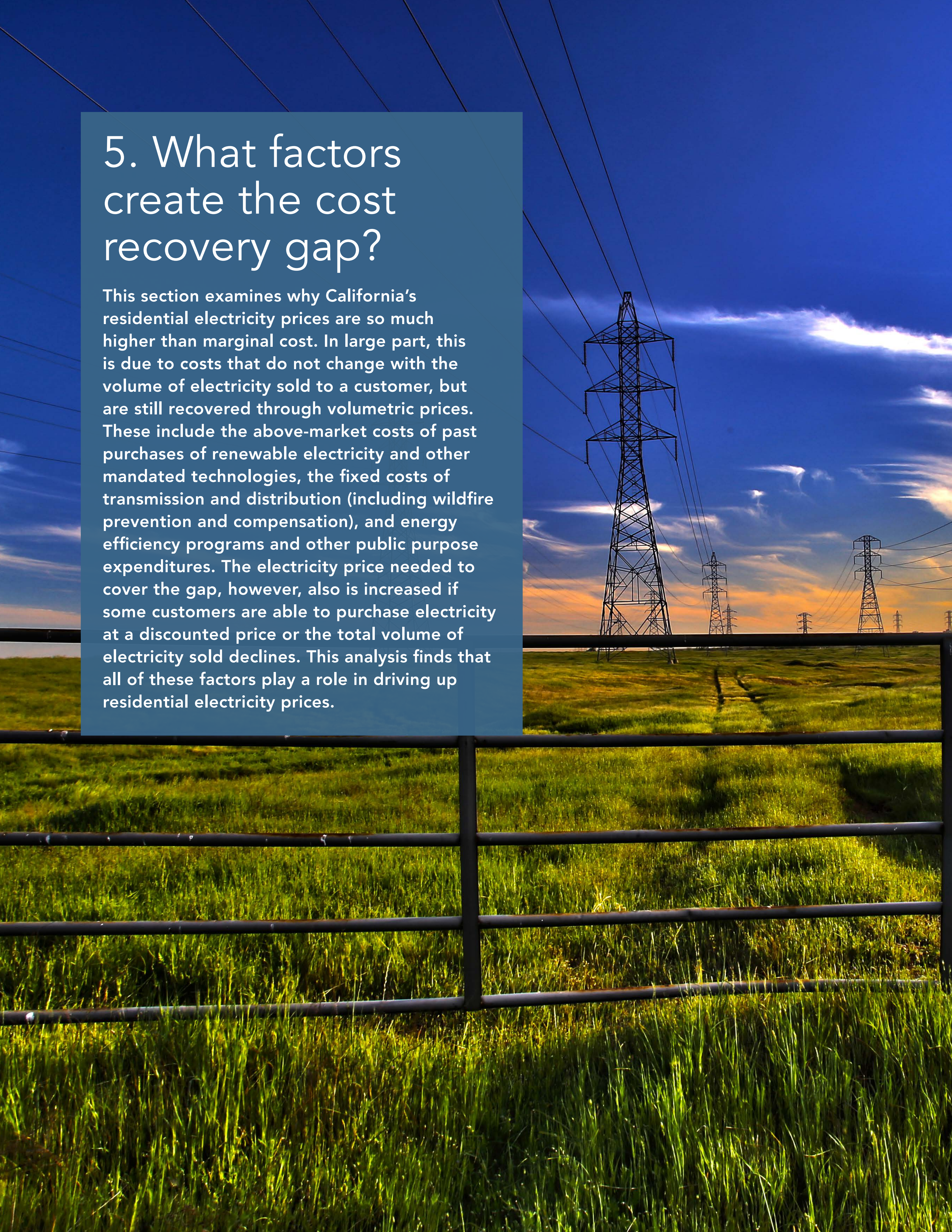
Figure 3a-c illustrates the significant gaps between social marginal cost and average retail prices for customers of all three utilities who are on not on a low-income rate. For PG&E and SDG&E, this gap has grown substantially over time. The SDG&E picture is particularly striking. In 2019, the average non-CARE retail price was more than three times the estimated social marginal cost. Note that the SMC captures not only the private marginal costs incurred by the utility, but also the full social cost of GHG emissions (evaluated at $50/ton CO2). For both SDG&E and PG&E, the gap between subsidized CARE rates and social marginal cost also has been widening over time.[19]

19 The retail price data for Figure 3a-c are created by taking the total residential revenue from FERC Form 1 and solving for the implied CARE and non-CARE prices based on the share of kWh sold to CARE customers and the average CARE discount. The resulting standard rate is 1 to 2 cents lower than the rates shown in Figure 4a-c, which is mostly due to the FERC form 1 data including the California Climate Credit while the bill component figures on which Figure 4a-c are based do not.

FIG 3a-c Retail Price Vs. Social Marginal Cost ($/kWh)



Source: Primary marginal cost estimates are authors' calculation explained in text, weighted across hours by IOU load. Average prices for bundled customers are from FERC form 1. CARE and non-CARE prices are derived using CARE and non-CARE kWh, CARE discounts, and participation sourced from CARE cost reports.



5. What factors create the cost recovery gap?

This section examines why California's residential electricity prices are so much higher than marginal cost. In large part, this is due to costs that do not change with the volume of electricity sold to a customer, but are still recovered through volumetric prices. These include the above-market costs of past purchases of renewable electricity and other mandated technologies, the fixed costs of transmission and distribution (including wildfire prevention and compensation), and energy efficiency programs and other public purpose expenditures. The electricity price needed to cover the gap, however, also is increased if some customers are able to purchase electricity at a discounted price or the total volume of electricity sold declines. This analysis finds that all of these factors play a role in driving up residential electricity prices.

Figure 4a-c illustrates both the components of social marginal cost (on the lower "staircase"), and the components of the gap between SMC and the average residential retail price for non-CARE customers (on the upper staircase). The left-most column presents the marginal costs associated with generation in the lower red box and the non-marginal costs associated with generation in the upper red box, and likewise in the other columns for transmission, distribution, greenhouse gas emissions, and a final column for public purpose programs and other expenses, virtually all of which are non-marginal.[20] The box heights in the lower staircase are load-weighted averages over time; both private and externality marginal costs can vary substantially hour to hour. The box heights on the upper staircase, however, are simply a total cost figure divided by quantity. These costs are not associated with supply in any particular hour.[21]

For the generation, transmission, and distribution columns, Figure 4a-c is constructed by starting from the residential bill components under the standard residential rate for each category. The cost is then decomposed between marginal cost (lower staircase) and residual cost recovery (upper staircase) by subtracting off the relevant marginal cost components shown in Figure 2a-c. The residual cost component is then adjusted further due to the existence of CARE and BTM solar, as described in the subsequent paragraphs. The pollution column shows the cap and trade liability for the marginal kWh and the additional externality cost above the emitter's cap and trade liability. Note that the cost of the additional externality is not borne by the producer, so is not part of the private marginal cost explained in this figure. Thus, the bottom of the next column begins at the top of the cap and trade box, not at the top of the non-market GHGs box. The pollution column is the end of the marginal cost components. Total private marginal cost is the top of the cap and trade box and total social marginal cost is the top of the non-market GHGs box. The costs represented in the right-hand column are not marginal in that they do not change with the consumption of the household paying the bill.

5.1 Generation

Figure 4a-c shows generation costs both as part of marginal cost on the lower staircase and as significant residual costs on the upper staircase. The energy costs, as explained above, are based on wholesale electricity prices, adjusted upward to reflect distribution line losses.

California's high electricity prices have occasionally been attributed to its aggressive adoption of renewable generation under the Renewables Portfolio Standard (RPS) program. In 2019, all electricity retail sellers had an annual target to serve at least 29 percent of their electric load with RPS-eligible resources. Under this RPS, utility-scale solar and wind generation capacity had reached almost 12,000 MW and 6,000 MW, respectively, by 2018.[22]

To the extent that qualifying renewable resources are more expensive, the RPS mandate will increase the cost of electricity generation. The CPUC tracks RPS and non-RPS procurement expenditures in terms of $/kWh and annual RPS revenue requirements.[23] RPS procurement costs have fallen at a rate of 13 percent per year between 2007 and 2019. In 2019, the average RPS energy contract price across all technology types was $28/MWh. As renewable energy technology costs have fallen, so has the above-market premium for renewable energy generation. The average difference in RPS versus non-RPS procurement costs reported by the large investor-owned utilities had dropped to $0.0028/kWh in 2019 (CPUC, 2020).

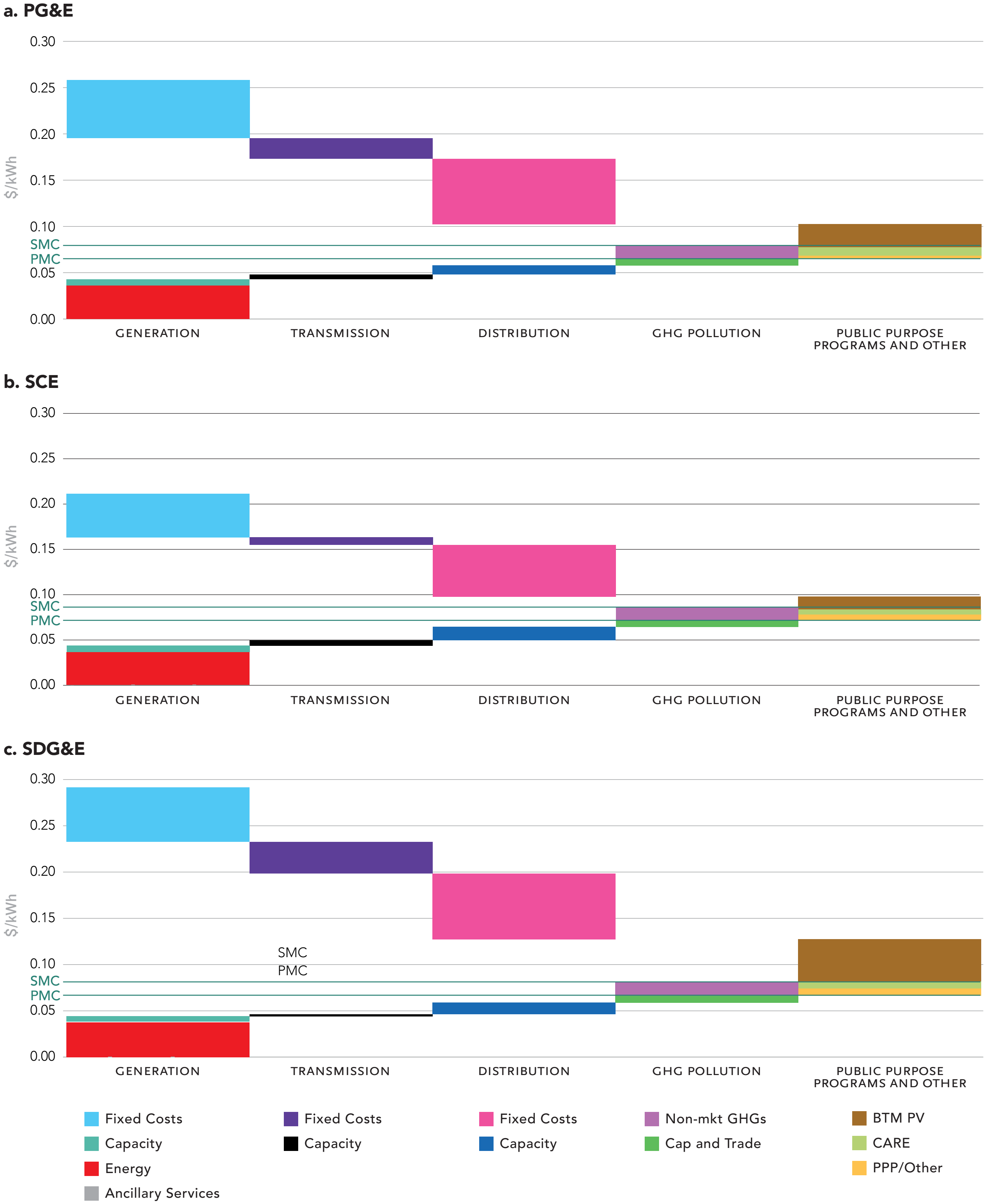
20 Figure 4a-c does not include costs of other pollutants that are associated with supplying electricity. In our continuing research, we are working to include costs of these pollutants. Borenstein and Bushnell, 2019, however, suggest that in California by far the largest negative air pollution externality associated with electricity supply is the emissions of greenhouse gases.

21 The CARE and BTM PV total costs are affected by the particular hours in which CARE customers and customers with BTM PV consume electricity, but are not associated with supply to most standard-rate customers.

22 2018 Total System Electric Generation. California Energy Commission. 2019. Available at: https://www.energy.ca.gov/ data-reports/energy-almanac/california-electricity-data/2019-total-system-electric-generation.

23 The CPUC is required to report annually to the state legislature on the progress of electricity retail sellers in meeting their RPS goals and substantive actions taken to achieve those goals. Two reports that are required annually have information on 1) RPS program costs and 2) progress and status of the RPS program. Past reports to the Legislature are available at: https://www.cpuc.ca.gov/RPS Reports Data.

FIG 4a-c Residential Price Decomposition ($/kWh) for 2019



Notes: Primary marginal cost estimates are weighted by IOU load. Average 2019 residential prices (CARE and non-CARE) are constructed using advice letters and rate schedules PG&E sources: 5366-E-A/B; 5444-E; 5573-E; 5644-E. SCE sources: 67666-E: 67668-E. SDGE: 31811-E; 31501-E. Details on the methodology behind author calculations can be found in the Appendix.

Dividing the utility-specific RPS revenue requirements by the corresponding RPS procurement cost (per kWh) yields an estimate of the quantity of electricity procured to comply with the RPS mandate. This quantity was then multiplied by the reported RPS cost premium to estimate the additional generation costs incurred to meet RPS obligations. Assuming that 40 percent of RPS compliance costs are recovered from residential customers, the impact of the RPS mandate on residential retail prices (in terms of $/kWh) can be estimated.[24] On a per kWh basis, these residential rate impacts of RPS compliance are small. In 2019, SDG&E paid no price premium for RPS-eligible procurement. The authors estimate average residential rate impacts per kWh of $0.006 and $0.0001 for PG&E and SCE, respectively. These cost differences for renewables comprise a very small part of the generation component of the upper staircase in Figure 4a-c. The large "Generation Fixed Costs" boxes for all three utilities represent contracts and utility-owned generation at costs well above 2019 market prices for all types of generation.

5.2 Transmission and distribution

For all three utilities, fixed costs of transmission and distribution (T&D) comprise more than half of the total fixed costs that are recovered in standard rates, before accounting for the cost shifts from CARE and behind-the-meter solar PV. These fixed costs include amortization and return on capital for investments in T&D. They also include all of the operation and maintenance expenditures for transmission and distribution that must be done to keep the lines in-service, including vegetation management. These are not rate-based capital investments, but they are nonetheless fixed costs in that they do not vary with the amount of electricity a household uses.

As mentioned earlier, while some amount of these costs are a result of wildfire risks and past damages, the report authors have not been able to access the data necessary to determine how much. Fixed cost due to wildfires include additional vegetation management, technology that monitors for wildfires near power lines, technology to detect line faults and shut off power before the line starts a fire, patrolling power lines during high fire risk periods, relocation of power lines, early replacement of lines and towers to reduce fire risk, and compensation for fire damage for which the CPUC determines ratepayers will contribute.

5.3 Energy efficiency and other public purpose programs

The lowest box in the right-hand column of Figure 4a-c represents all payments for public purpose programs except CARE. This includes energy efficiency programs, energy research and development programs, and subsidies for customer-sited batteries, among others.

5.4 Behind-the-meter solar PV

California's retail electricity pricing structure, together with the state's net energy metering (NEM) policy, have been important drivers of "behind the meter" solar PV (BTM PV) adoption. By 2018, 6,854 MW of distributed solar had been installed under the NEM program, 4,356 MW of which is residential.[25] This level of investment in distributed solar PV is significantly less than the utility-scale investments mandated under the RPS. However, the authors estimate that the retail rate implications of BTM PV investments have been much larger, as illustrated by Figure 5.

Residential customers with PV systems are credited at the retail electricity rate for every kWh of solar electricity they generate.[26] This effectively shifts the burden of fixed cost recovery onto customers that have not adopted BTM PV. As Figure 4a-c clearly shows, this confers a generous subsidy because residential rates significantly exceed social marginal cost (which includes, among other components, the estimated social cost of greenhouse gas emissions). Importantly, the growing gap between the retail rate and marginal cost reflects costs that are not

24 The CPUC is required to report annually to the state legislature on the progress of electricity retail sellers in meeting their RPS goals and substantive actions taken to achieve those goals. Two reports that are required annually have information on 1) RPS program costs and 2) progress and status of the RPS program. Past reports to the Legislature are available at: https://www.cpuc.ca.gov/RPS Reports Data.

25 California Distributed Generation Statistics. California Solar Initiative (CSI) Available at: https://www.californiadgstats.ca.gov/

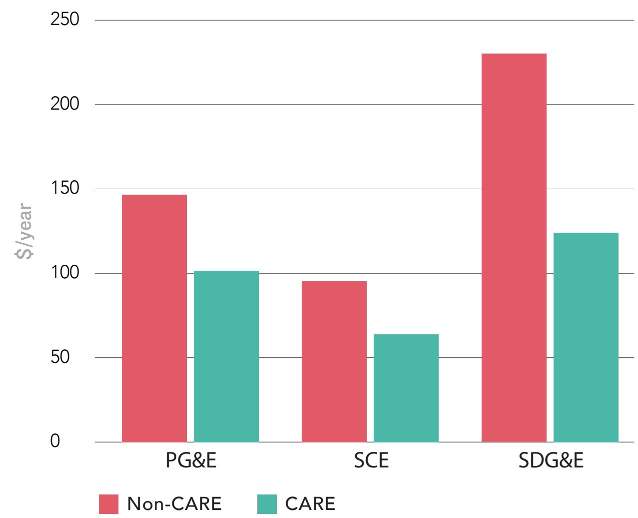
26 Under NEM2.0, which began in 2017, owners of rooftop solar now pay a small amount to cover their share of public purpose programs and a couple of other small charges, totaling about 2.5 cents per kWh.

avoided—only shifted—when a household adopts PV.

To assess the residential rate implications of this cost shift, the authors estimate what residential rates would have been absent investments in residential solar PV.[27] For each utility-year, the electricity generated by installed residential BTM PV was simulated and then this generation was added to the residential electricity sales actually observed. Next, an estimate of how much lower retail rates would have been had costs been spread across this broader base of residential electricity consumption was established. To streamline these calculations, the authors assume that PV systems are adopted by non-CARE customers and that residential electricity demand is perfectly inelastic.[28] The height of the box labeled "BTM PV" shows the implied retail price impact. These calculations serve as approximate estimates of the residential rate increase attributable to BTM PV incentives.[29]

To put these rate impacts in perspective, the implications for annual electricity expenditures were assessed. Absent household-level data, this analysis is limited in the extent that it can characterize the distribution of this cost shift across different types of households. However, it was possible to estimate average bill impacts for CARE and non-CARE households. Annual CARE reports estimate the average annual electricity consumption among non-CARE and CARE households, respectively. Assuming no change in the share of CARE costs borne by the residential sector, the number of CARE customers, and the CARE discount relative to the non-CARE rate, the average bill impacts of BTM PV incentives can be estimated. Figure 5 shows economically significant annual bill increases for both CARE and non-CARE customers. The impacts are particularly striking in SDG&E territory where residential PV generation accounted for more than 20 percent of residential consumption in 2019. Non-CARE and CARE rates increase by five cents and three cents, respectively. This translates into annual average bill increases of approximately $230 and $124 for non-CARE and CARE customers.

FIG 5 Household-Level Bill Impacts of BTM PV Incentives ($/year)



Notes: CARE and non-CARE rate impacts are authors' calculations. These assume that all PV systems are owned by non-CARE customers. Estimated annual average bill increases are based on average annual electricity purchases among CARE and non-CARE households. Further details on data sources and the methodology behind author calculations can be found in the Appendix.

5.5 CARE program for low-income customers

Between 25 and 30 percent of all residential electricity is sold to low-income customers at reduced rates, which by statute are 32.5 to 35 percent lower than the standard rates. The cost of this subsidy is borne by all other customers, both residential and non-residential.

The height of the CARE box in Figure 4a-c is constructed by calculating the difference between the rate that non-CARE customers pay and the rate that they would pay if there were no CARE program. If there were no CARE program, the standard rate would be somewhat lower than the top of the upper staircase because with additional customers on the standard rate, that rate would not need to be as high in order to cover the full revenue requirement from residential custom-

27 This is equivalent to assuming that the utility institutes a feed-in tariff policy in which all output from residential solar is compensated at the utility's marginal (i.e., avoided) cost.

28 Residential electricity demand is not perfectly inelastic. The simplifying assumption of perfectly inelastic demand will result in an under-estimation of the rate impacts of BTM-PV incentives. The assumption that all solar PV is adopted by non-CARE households is also strong. To the extent that solar PV is supplying CARE households, this assumption will over-state the rate impacts of BTM-PV incentives.

29 We assume that installation of behind the meter solar PV has no effect on the consumption of the household, either decreasing it due to greater environmental awareness or commitment to reducing pollution, or increasing it due to "moral licensing" of greater consumption or in response to actual lower opportunity cost of consumption under Net Energy Metering if solar panel output would otherwise exceed household consumption.

ers. That revenue requirement would change, however, because the transfer from non-residential to residential due to CARE—which occurs because the CARE subsidy is financed with an equal surcharge on all other kWh, including non-residential—would be eliminated. The counterfactual standard rate if there were no CARE program was calculated by solving simultaneously for the counterfactual standard rate and the new residential revenue requirement in the absence of CARE. Note that the height of the CARE box is not the full burden of the CARE program on other electricity prices. The majority of the CARE subsidy is covered through higher rates to non-residential customers.

6. Volumetric cost recovery is quite regressive

The current approach to raising revenues creates equity concerns because low-income consumers spend a larger share of income on energy consumption.[30] What other options does California have for raising revenue to achieve cost recovery for the electricity system and to support other worthy priorities? In principle, any source of revenue could be used to cover these, so an expansive view of the problem should consider all major sources of revenue to the state.

California tax revenue comes primarily from income and sales taxes, as summarized in Figure 6. Income tax revenue ($96.8 billion in fiscal year 2018-19) are more than double sales and use taxes ($41.1 billion in 2018-19) in the state. After those, a remaining 18 percent of revenue comes from taxes on corporations, motor vehicle excise taxes, and a collection of smaller sources. Property taxes are an important source of local revenue, but they play a small role at the state level.

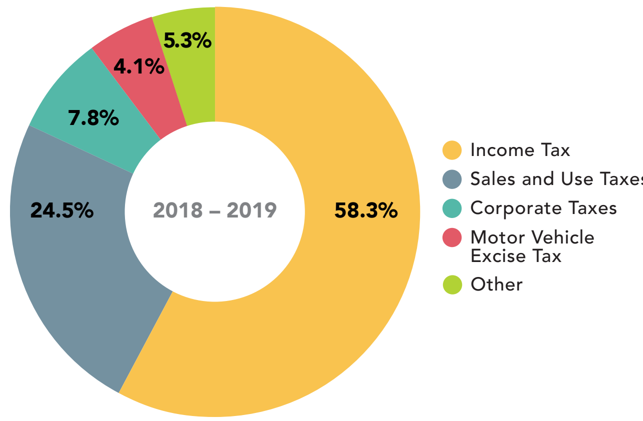
If California shifted some of the cost recovery from electricity rates towards income or sales taxes, what would be the impact on economic efficiency and distributional equity? On equity, a broad strokes answer to this question is provided by the Consumer Expenditure Survey from the US Bureau of Labor Statistics. The survey asks a random sample of U.S. households detailed questions about their expenditures.

Figure 7 plots data on expenditures by income quintile from the 2,469 California survey respondents in the 2017-2018 wave of the survey. Expenditures are normalized to the expenditure of the first quintile (e.g., a value of two implies that the group spends twice as much per household on that category as the lowest income quintile).

These data show that expenditures on electricity do indeed rise with income; the richest households spend almost twice as much as the quintile of households with the lowest income. But total household expenditures rise much more rapidly than electricity, with the richest households spending more than four times the amount of the poorest households on all types of consumption. This means that a tax on all expenditures would be substantially more progressive than a tax on electricity. Gasoline expenditures also rise much faster than electricity.

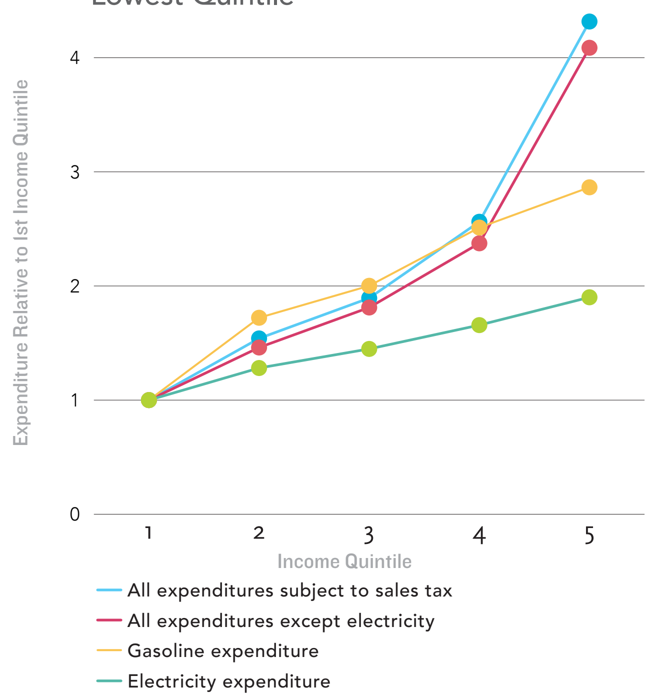
The sales and use taxes in California do not apply to all types of consumption. All of the consumption categories in the survey were coded for this report's analysis according to whether or not expenditures in that category would be predominantly subject to sales and use taxes. Figure 7 shows that relative expenditures of this subset of items tracks the overall level very closely. Thus, collecting

FIG 6 Sources of State Tax Revenue in 2018-19



Source: Authors' calculations of data from the State of California's Comprehensive Annual Financial Report For the Fiscal Year Ended June 30, 2019. Total tax revenue in FY 2018-19 was $168.3 billion.

FIG 7 Average Expenditures per California Household by Income Quintile Relative to Lowest Quintile



Source: Authors' calculations of data from the Consumer Expenditure Survey in 2017-2018. Source data at https://www.bls.gov/cex/2017/research/income-ca.htm

30 Thompson, A.L. "Protecting Low-Income Ratepayers as the Electricity System Evolves." Energy Law Journal, Volume 37, No. 2, p. 265. 2016. Available at: https://www.eba-net.org/felj/energy-law-journal-volume-37-no2-2016/

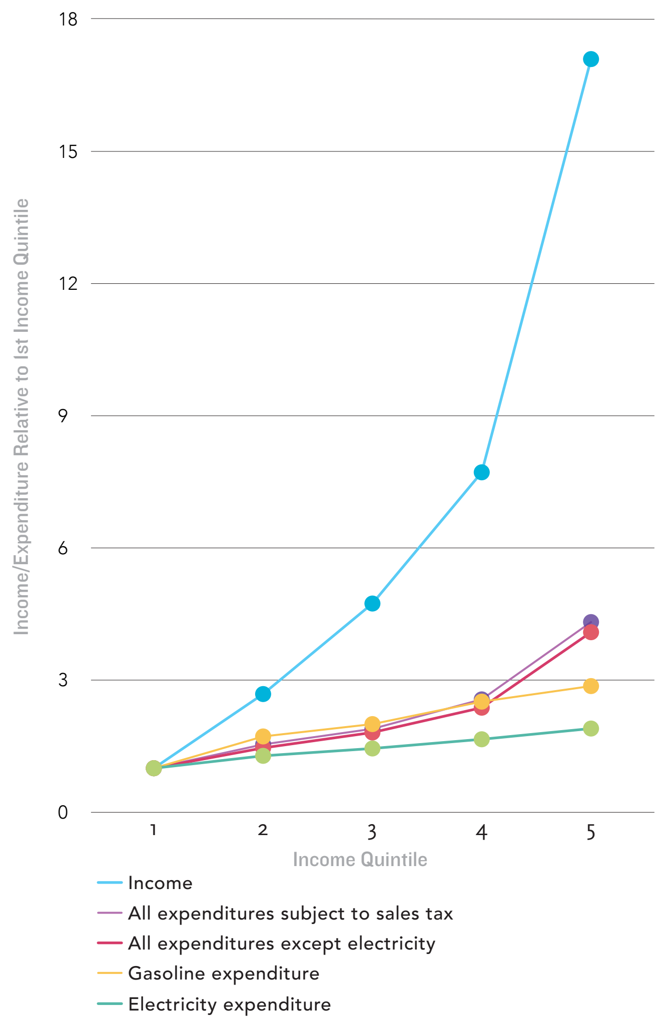
additional revenue from a sales tax also would be substantially more progressive than the current approach.

Collecting additional revenue from the income tax would be even more progressive. To see that, Figure 8 adds mean income within each quintile to the chart. According to the survey, the richest quintile of households have income more than 17 times that of the lowest quintile. As such, even a flat proportional tax on income would be vastly more progressive than the tax on electricity that we currently impose. California's progressive income tax implies an even steeper rise in income taxes paid as a function of income.

In terms of economic efficiency, reducing electricity prices would have the benefits described above in terms of reducing distortions caused by having prices well above marginal cost in the electricity sector. Still, it should be noted that raising revenue through income and sales taxes also creates distortions because these taxes lower the incentive to earn income. Economic theory suggests that the size of these distortions depends on the elasticity (i.e., how responsive is behavior to price) and the size of the pricing distortion squared. Because the pricing distortion for electricity is so large, the inefficiencies from an income or sales tax are likely to be far smaller than the distortions from raising the income or sales tax, but the authors are studying this important question in related ongoing research.

In short, there is good reason to believe that shifting some costs out of electricity rates and onto the general state budget could increase economic efficiency while also improving the overall equity of the system. There are, however, potential headwinds that make such a reform challenging. First is that this transition may face political opposition from those skeptical of adding any liabilities to the state budget. Second is that it does create winners and losers, not only within utility service territories (as will any rate reform), but also between utility territories, including the state's many municipal utilities. About 30 percent of California households are not customers of the three IOUs, and pricing implications differ even across those three. If system costs were funded through statewide revenue sources, it would effect a

FIG 8 Average Expenditures and Income per California Household by Income Quintile Relative to Lowest Quintile



Source: Authors' calculations of data from the Consumer Expenditure Survey in 2017-2018. Source data at https://www.bls.gov/cex/2017/research/income-ca.htm

transfer of resources from municipal customers to the IOUs and among the IOUs towards those with higher system costs.

If the goal is to better align customer prices with social marginal cost while still recovering total costs, the alternative to raising revenue elsewhere is to reform electricity rates, which avoids some of those potential objections. This approach is discussed next.

7. Fixed charges can be made more equitable

Fixed monthly charges have long played a role in residential electricity billing. They are very attractive on efficiency grounds, allowing the utility to cover a revenue gap with almost no risk of customer departure, while keeping volumetric prices close to marginal cost. They also have some appeal on fairness, based on the argument that everyone who uses the system should contribute to the infrastructure that supports it. But, fixed monthly charges that are the same for all residential customers are also highly regressive; they take a much larger share of household income or expenditures from lower-income households than from wealthy customers.

Fixed charges that vary with a household's income can retain much of the efficiency appeal of an undifferentiated fixed charge, while at the same time being more equitable. Still, implementation of such a tariff faces significant practical and administrative hurdles because of the need to verify income. And even if one decided to implement an income-based fixed charge, there are still many choices to be made because there are a multitude of possible ways to structure an income-based fixed charge, in terms of both the rate and the practical implementation. This section discusses the main options and obstacles in broad terms, and then sketches proposed rate structures as examples.

This report does not attempt to address all the relevant details here, which would inevitably be the subject of negotiation between utilities, customers, regulators, and other parties. Instead, the goal is to describe the core idea and identify the main conditions that would make it feasible to simultaneously improve the efficiency and equity of California's electricity rates via income-based fixed charges.

7.1 Core principles: efficiency, cost recovery, equity and feasibility

Roughly following Bonbright's principles, four principles should guide the design of an income-based fixed charge: efficiency, cost recovery, equity and feasibility.[31] In brief, a tariff should be designed that (1) sets volumetric prices as close to social marginal cost as possible, (2) recovers full system costs, (3) is fair in its allocation of burdens, and (4) respects administrative, legal and political limitations. Each of these criteria is discussed briefly next.

7.1.1 What is an efficient rate?

The core objective of this analysis is to propose a tariff that is more economically efficient. Roughly, this means a tariff with volumetric prices that are as close to social marginal cost as possible.

As discussed earlier, in many circumstances, when the price of a good equals its marginal cost (inclusive of externalities) the optimal (efficient) amount of that good will be produced and used, and it will be allocated among users so as to maximize its value. The analogous point for electricity is that its marginal price should be equal to social marginal cost.[32]

The ideal tariff thus charges social marginal cost per kWh, inclusive of generation costs, pollution impacts, and system costs that scale with usage. This applies the marginal, or avoidable, cost concept discussed extensively in Section 3. In addition, the volumetric rate should be time varying, as marginal costs vary across hours and days. The volumetric rate should also vary across space to the extent that transmission congestion implies different costs of delivering power to different locations within a utility's service territory. The additional complexities of time and location varying costs, which have been discussed extensively elsewhere, are not addressed in this analysis.[33]

CARE rates, increasing block pricing and climate zone baselines are instruments designed to alter the distributional outcomes of the current rate structures that charge prices well above avoidable cost. All of these features could be eliminated in a scheme that achieves equitable distribution through income-based fixed charges.[34]

Prices set at social marginal cost would encourage

31 Bonbright, J.C. "Principles of Public Utility Rates." Columbia University Press. 1961. Available at: https://www.degruyter.com/document/doi/10.7312/bonb92418/html. Available at: https://www.journals.uchicago.edu/doi/abs/10.1086/706793

32 Note, however, that it is not in fact ideal to price electricity exactly at its social marginal cost when the alternatives to electricity are themselves mispriced. To the extent that the price of natural gas and petroleum motor fuels differ from their social marginal cost—because, for example, producers and users do not have to pay the full cost of associated emissions (as well as congestion and accident costs for motor fuels) or fixed infrastructure cost recovery drives price for the alternative fuel above SMC—the optimal price for electricity may be somewhat below or above its social marginal cost. For a related analysis pertaining to the usage of electric vehicles, see Davis and Sallee (2020) cited in earlier footnotes. Here we focus simply on social marginal cost as a benchmark.

33 See for instance, Borenstein and Bushnell (2019) and Burger et al. (2020) in earlier footnotes.

34 Increasing-block pricing is also supported by some who believe that higher prices are appropriate in order to encourage conservation. However, by setting price equal to SMC, regulators encourage the efficient amount of conservation, because consumers face a price that reflects the full social cost of their consumption. Furthermore, Ito (2014) finds that increasing-block pricing does not reduce consumption overall compared to a price that does not change with quantity consumed, but yields the same average price across all customers. Climate zones are also partially intended to benefit households in hotter areas, but if income-based fixed charges were implemented, it is not clear why one would want to further benefit households in one area versus another. If redistribution to households in hotter areas were a policy goal, one could have lower fixed charges for households in those areas. Ito (2014) available at: https://www.aeaweb.org/articles?id=10.1257/aer.104.2.537

users to use electricity when their benefit from usage exceeds the cost to society of producing and delivering electricity and to make appropriate investments in energy efficiency and fuel switching. Thus, a rate reform that moves volumetric prices closer to social marginal cost will generate efficiency improvements.[35]

It is important to note that income-based fixed charges themselves could in principle induce inefficient behavior, because households may be deterred from earning more if their electricity bill rises with income. For example, if the fixed charges are a step function of income (what tax economists refer to as a notch in the tax schedule), then there could be an incentive to keep reported income below a critical cutoff. Similarly, if fixed charges are a smooth, rising function of income, they could have the same efficiency implications as an increase in the income tax rate, to the extent they are salient. Such responses would represent inefficient distortions in behavior. These might only be reporting distortions, but nevertheless, one should be attentive to perverse incentives that might be created by the fixed charge schedule because they erode efficiency (and, potentially, fairness).

Finally, there is another potential distortion from having fixed charges if some customers may disconnect from the grid to avoid the charge. Such a response would be potentially quite inefficient, but at this point there seems to be little risk of significant grid defection.[36]

7.1.2 What is a rate that achieves cost recovery?

An economically efficient volumetric price will recover some amount of revenue, but it will be substantially less than the total revenue requirement for California IOUs. The point of fixed charges is to recover the remaining costs without pushing volumetric prices above SMC.

This elides the more nuanced question of which costs ought to be recovered via electricity bills at all. As noted above, an appealing alternative is to simply recover some fixed costs via another revenue source, such as the income or sales tax. The discussion in this section is focused on establishing the relative merits of using different components of electricity bills to recover system costs. But whether some categories—like energy efficiency programs or wildfire mitigation—can nevertheless be moved out of electricity rates entirely should be an ongoing debate.

The possibility that utility costs are excessively high, whether because of mismanagement, poorly designed regulatory incentives, or ill-advised mandates is also not addressed in this analysis. Setting aside the question of whether costs can be reduced, the amount of revenue that must be recovered through charges to electricity customers is taken as given.

7.1.3 What is an equitable rate?

An income-based fixed charge can be made to have a wide range of possible structures that would distribute the burden of paying for the electricity system across households differently. What would make such a system equitable?

The component of the electricity system costs that does not change with level of household usage is effectively a public good among customers. Economists often use three distinct but related equity criteria to determine who should pay for a public good. One is the ability to pay principle: people with greater income or wealth should contribute more. A second is the benefits principle: those who benefit more from the public good should contribute more. A third is the responsibility principle: those who cause the need for the public good should contribute more.

Emphasizing the ability-to-pay principle naturally suggests income-based fixed charges as a means to make cost recovery relatively progressive. There is no universal agreement on how progressive revenue collection should be, but a useful benchmark is to consider what rates would be like if they were as progressive as other sources of state revenue that are used to fund public goods, namely the California income and sales taxes.

Another common understanding of fairness is based upon changes from the current status quo. Some may view a rate reform as unfair if it causes certain people to pay more. It is inevitable that a rate reform will cause some people to pay more and some less than under

35 With price set equal to SMC, optimal levels of energy efficiency might still not result if consumers are poorly informed about the efficiency of devices and the range of alternatives. It seems likely, however, that information provision or standards would be more effective for such specific cases than general increases in electricity prices.

36 Gorman, W., Callaway, D.S., and Jarvis, S. "Should I Stay or Should I Go? The Importance of Electricity Rate Design for Household Defection from the Power Grid." Applied Energy. Available at: https://www.sciencedirect.com/science/article/abs/pii/S0306261920300064

the current system, but it may be deemed important to ensure that certain groups of customers are not made worse off by a reform. To that end, the report explores rate designs firstly where households with the lowest income pay no more than they do today.

A final element is what economists sometimes call horizontal equity—which states that people who are similar in income should pay similar fees. Here, a potential threat to horizontal equity is if a rate structure has large, discrete jumps in fees at particular income cutoffs, then customers who are very similar in income may pay very different amounts.

7.1.4 What is a feasible rate?

Finally, implementation costs must be factored into analysis of alternative rate designs. This has several implications.

First, implementation of a rate may require new information to be collected or shared between institutions. The feasibility criterion requires that information sharing be permissible under the law and broadly acceptable among customers. It also requires that administrative costs of new information collection and processing be recognized and included in the analysis.

Second, it should not be overly burdensome on consumers. Consumers should be able to understand their rates and should have minimal additional burden imposed upon them.

Third, feasibility requires that the system be designed so that it is possible to collect credible income information about households. If the system is easily manipulated, then the principle of equity will be undermined.

The principle of feasibility imposes some real constraints on our proposed design, so we dis- cuss several key related issues in the next section before sketching out some hypothetical rates.

7.2 Administrative pathways towards an income-based fixed charge

In order to assess fixed charges that vary by income, there needs to be some marriage between utility billing data and information about income. There are several ways to achieve this. Four possibilities are outlined here, which range from one extreme that fully integrates utility billing with the state's income tax to another extreme that requires the utilities to conduct all of the income verification themselves. In between are a range of options that attempt to leverage the administrative strengths of state agencies for purposes of income verification, which are discussed third. The fourth approach explored levies fees at the community level rather than at the level of the individual in order to sidestep the challenge of verification.

Before detailing these, conceptual issues around the use of income as a primary measure are briefly discussed.

7.3 Measuring income

Like nearly all utility programs for the needy, this analysis focuses on current income as a measure of financial well-being. Economists have long recognized that this is not an ideal indicator. Lifetime income or wealth are likely to better indicate financial need of an individual or household. Unfortunately, data on such broader measures are even more difficult to access or estimate than measures of current income, so any feasible scheme is sure to rely on the less ideal, but commonly accepted, measure of current income.

A preferred measure of current income upon which to based fixed charges would account for all of the income earned by people who share the same utility account, but adjust charges in some way to account for the number of individuals served by an account, so as to better reflect the financial resources and financial needs of a household.

This presents some significant practical challenges. Because fixed charges would be higher when more sources of income are reported, customers might not have an incentive to accurately report all of the income-earning individuals associated with an account if asked. The system could be based by default on the income of the account holder (and spouse if married filing jointly), but inclusion of any other individuals in the household headcount would also require reporting of their income.

In the calculations below, households are sorted by household income, as reported to the Census Bureau, but no adjustment for household size is made. This gives a useful view of the income distribution, but it should be noted that full implementation might involve some scaling by household size and must grapple with the issue of adding up income when an account serves multiple adult earners.

7.3.1 Model 1: Revenue balancing with the Franchise Tax Board

From an information point of view, the best way to measure income is to use the income tax system. If an income-based fixed charge were fully integrated with California's state income tax, a scheme could proceed as follows.

Each utility would collect a fixed monthly charge from each account holder in each year. The utility would submit an information return to the tax filer and to the Franchise Tax Board stating two things: the total fixed charges paid by each account holder during the calendar year and the number of months that the account was active. The state's income tax form would include a calculation of the amount of utility cost recovery owed based on the account holder's income and the months of service. This would be similar to the documents filed for mortgage payments and myriad other tax provisions.[37]

If an account holder had been charged more than the amount they owed, then they would receive a credit. If they had paid too little already, then they would owe an additional payment. In either case, this payment would be rolled into the filer's state income tax reconciliation. The Franchise Tax Board (FTB) would then balance the account with each utility. This would act the same as any other fully refundable tax credit. If consumers did not wish to report any of this type of information to the utility, they could simply pay some default rate (which would presumably be high) and effectively opt out.

The great advantage of this system is that it assigns the logistical tasks to the institutions with the expertise and infrastructure to handle them best and imposes minimal additional burden on customers.

The Franchise Tax Board has all of the relevant information about income and already processes billions of information returns. The utilities are asked only to tally up one item from within a billing system that they are already operating. Customers need only provide a social security number, and they will need to add just one number on their tax return to claim a credit if they have overpaid. In addition, by operating directly through the tax system, it is easy to allow for fixed charges that are complex functions of income.

A simple approach is to collect the same high monthly fixed charge from all households, and then rebate overpayments as part of the tax return. But this would pose a significant burden on lower-income households. So, it seems important to give lower-income households, or perhaps all households, an option to make lower payments. This is very similar to employer withholding in the income tax system. It would be straightforward to develop a form that is analogous to the W-4 tax form through which account holders would make declarations about their income and household size, which would then be translated into a monthly payment amount. If that amount turns out to be too high or low, the difference would be reconciled on the return.

There are challenges associated with this approach. First, not all account holders file tax returns. Some method of accommodating such households without requiring them to process a full return just to claim their credit would be essential.

Second, there is an issue of underpayment and overpayment. Presumably, the FTB would just be a passthrough entity, not liable to the utility for a customer who doesn't pay and not having a claim on any overpayment from customers, or customer failure to claim a credit they are owed.

Third, there is a question of administrative cost. If the tax agency incurs costs on behalf of the utilities, it would presumably be necessary for the utilities to pay those costs out of their own revenue. So, some procedure for calculating those costs would be required.

Finally, perhaps the most important obstacle is that this approach uses the tax system to collect revenue for a private entity. This is quite rare, and it may raise a host of objections, legal and philosophical. This may be an insurmountable barrier. If so, then this scenario might be understood not as a likely outcome, but as a model against which to compare other schemes that try to leverage information sharing to enable an income-based fixed charge without involving the FTB in actual revenue collection or balancing.

37 It would be convenient for the utilities to file information returns based on the account holder's social security number (or taxpayer identification number), but if that poses privacy concerns, it would be straightforward for the tax agency to establish a personal identification key that maintains privacy.

7.3.2 Model 2: Opt-in verification only

The opposite extreme is for the utilities to be solely responsible for income verification, without the aid of the FTB or other state institutions.

Utilities would need to gather information about income from all account holders in order to sort them into the relevant categories. Account holders would have strong incentives to report lower income than the truth if it qualified them for substantial discounts. Thus, if utilities used the low cost option of simply asking customers to report their income, it seems likely that there would be substantial misreporting that would undermine the viability of the system.[38]

Instead, the utilities could require specific documentation of income. The obvious problem with that is that utilities would need a costly new administrative infrastructure for processing millions of financial documents. Likewise, customers would be burdened with significant hassle costs, as they would need to produce and share various documents with the utility. In addition, most ways of validating income would contain private information like social security numbers.

Utilities do not already have an infrastructure for verifying income, nor do they have any special expertise in such matters. Currently, CARE eligibility is determined by a self-declaration of the account holder. Auditing of these declarations is quite limited, and households face little or no penalty for declarations that they cannot substantiate. Thus, the administrative structures surrounding CARE seem to be a thin foundation for the more expansive system needed to execute an income-based fixed charge for all customers.

A system in which the utilities attempt to charge income-based fixed charges without direct cooperation from other state agencies seems seriously problematic. This leads to the next consideration: alternatives that do not rely on the tax system actually collecting revenue but do leverage information available in state institutions that can be shared with the utility.

7.3.3 Model 3: Information sharing without revenue collection

The prior two options represent extremes along a spectrum. In between are ways that the utilities and its customers could leverage the information available within state agencies in order to facilitate an income-based fixed charge. Here there are also a range of approaches.

Rather than actually collecting revenue, the FTB could simply report to the utilities the income associated with each account. This could be done on a rolling basis based on the prior year's tax return, or even prospectively based on withholding information.

A variant of this approach is to let consumers voluntarily send tax return documentation to the utilities for purposes of verification. But this involves greater hassle costs for customers, requires the sharing of personal information with the utilities, and requires the utilities to interpret and handle large volumes of documents.

Any version of information sharing that requires the utilities to handle, process and interpret a large flow of incoming documentation for its entire customer base is an inefficient use of institutional expertise. A more cost effective approach is to have the FTB produce a database that associates a fixed-charge rate with each account.[39]

The Franchise Tax Board does not have full income information for all account holders because not all people file an income tax return, and, if the analysis is based on a prior year's tax return, not all people will have paid taxes in the state in the prior year. Moreover, income changes over time, so it would be desirable to allow changes in income to impact rates more quickly than implied by a full year's delay based on the tax return cycle.

This suggests an enhanced version where the database provided to the utilities has information augmented by information returns held by the FTB and/or participation in other programs that screen households for eligibility based on income. That is, the database could identify house- holds as eligible for lower rates proactively based on participation in CalFresh, housing voucher programs, enrollment in unemployment or disability insurance, or other such programs. This could greatly improve the

38 CARE eligibility in the current regime is potentially subject to these same problems. It is not clear how many ineligible customers currently are on a CARE rate, but we conjecture that the incentives to misreport would be far more substantial if there was a salient change in the monthly charge associated with specific income thresholds, rather than the current rate discount.

39 Here it becomes useful if there are only a few distinct fixed charges. Then, revealing the rate class that is associated with each account divulges relatively less personal information.

accuracy of the scheme in real time, but it does clearly require a level of coordination across state agencies that may be costly.

Information sharing may also face legal barriers. This report's authors are not legal experts, but it seems likely that legal issues could be avoided if households had to opt-in to information sharing. They could be placed into the highest fixed charge tier unless they authorize the state to release information about which rate class they belong in. (The state does not need to release the information upon which that is based; it only needs to indicate the fixed-charge group.)

If revenue collection and balancing by the FTB is ruled out, the approach that likely yields the most efficient results by leveraging the relative expertise of different institutions is to have the utilities establish criteria for a specific set of rates, then have state agencies compile a database that assigns households to each rate based on tax information, supplemented by program participation to help incorporate non-filers, which the utilities use to assign a default rate. Customers who believe that this process puts them into the wrong group could appeal. Such an appeal might require some level of documentation. Presumably, these appeals would be adjudicated by the utilities or an independent consultant.

Note that many of the variants of this approach use the idea of defaulting customers into a higher fixed charge. If this option is considered a remedy for privacy concerns or hassle costs, then it is important to cap the fixed charges at a reasonable level, so that many customers actually belong in the highest rate class and if customers are wrongly put into that class, it need not be financially ruinous. This suggests the possibility that there might be several distinct default rates that vary by location.

7.3.4 Model 4: Presumptive charges by location

A fourth and final approach is quite different: the utilities could assign fixed charges based on the income of the relevant geographic community, such as a census block, block group or tract, based on survey or administrative data.

Households would be assigned a fixed-charge based on the income of the community they live in. This is meant as an imperfect proxy measure of the household's income (and possibly more reflective of lifetime income). Households who in fact have lower income that would qualify them for a lower fixed charge could have the option to present proof of eligibility that would drop them to a lower fee.

This version need involve state agencies only to the extent that they are used as a method of income verification by those who voluntarily choose to do so. But even that is not required; income can be measured with publicly available data from the Census Bureau.

The advantage of this approach is twofold. First, it greatly alleviates the need for household income verification. With relatively precise targeting and broader income classes for each fixed charge tier, it could well be the case that relatively few people would have an incentive to conduct verification. Second, it minimizes potential distortions to income earning. For households that stick with their default charge, there would be no consequence for earning more and thus no distortionary incentive. This would thus be a relatively efficient option, both in terms of economic incentives and administrative cost.

There are, however, two potential drawbacks. One is that such a scheme would be less equitable, as higher-income households that happen to live in lower-income neighborhoods would be getting lower charges than those with the same income who lived in a neighborhood with higher average incomes. If income verification is challenging, some who are eligible for a lower rate may not take it up.[40]

A second complication is that economic theory suggests that the person who benefits from a favorable rate might be the current landowner, rather than a renter or future buyer. The reason is that a fixed charge would essentially become an attribute of a home or apartment. If a landlord can offer an apartment that comes with a low monthly utility fee, they may be able to charge a higher rent. This would potentially mean that the benefits intended to go to lower income households in fact could flow to the people who sell them housing. Note that, where voluntary income verification is straightforward, this might be a benefit that the landlord could only extract value from if the renter has above average income for the neighborhood.

40 Census data that detail the income distribution within precise geographic areas could be used to study how much misclassification there would be for a given scheme. Much would depend on how much fixed charges vary (are there many different fixed charges, or only a few?) and how precise a geographic area could be used.

More broadly, the use of differentiated default rates can be integrated with some of the options described above. If a version with strong information sharing from the FTB, spatially differentiated default rates could be applied only to non-filers or those with missing information. Alternatively, spatially-differentiated default rates could serve as a base, but high-income earners identified by the FTB would be assigned a higher rate, whereas those with lower than (local) average income would have the option to provide documentation of eligibility for a lower rate.

7.4 Some example rate structures

This section describes a few possible rate structures that would feature income-based fixed charges. It is worth emphasizing again that there are many ways to construct a rate structure with income-based fixed charges in terms of the number of different rates, the incomes to which they apply, and the progressivity of the schedule. Here, a few simple possibilities are considered in order to illustrate the potential and to offer broad guidance on how high fixed charges might be.

In all of the scenarios, the authors propose that volumetric price be set at avoidable cost that is time- and location-specific. This will raise revenue that leaves a significant cost recovery gap.[41] To estimate the number of accounts at each level of income, data from the American Community Survey (ACS) that details counts of household income at the census block group level for sixteen distinct income categories was used. Block groups were assigned to each utility based on utility boundaries, providing a distribution of household incomes for each utility in 2019.[42]

The estimates in Section 5 suggest that in 2019, the cost recovery gap is $4.3 billion for PG&E, $3.0 billion for SCE, and $1.1 billion for SDG&E. Next, income-based fixed charge schedules that would recover those amounts of revenue are considered. According to FERC data, there are 4.8 million residential PG&E accounts, 4.3 million in SCE, and 1.3 million in SDG&E. This means that, on average, PG&E needs to recover almost $900 per household per year; SCE needs to recover around $700 per household per year; and SDG&E needs to recover around $850 per year. It is important to keep in mind that these are costs that the utilities already do recover. Currently they recover these costs via high volumetric prices. In the alternative discussed here, the total revenue collected is held constant, but these large sums are switched into fixed charges. It is of course possible to recover only some fraction of system costs via fixed charges, in which case volumetric prices would get closer to social marginal cost than they are currently, and fixed charges would be proportionally smaller.

For reference, the uniform fixed charge that would be required to fully eliminate the cost recovery gap if all account holders were charged the same monthly fee is first calculated. Assuming all accounts are active for 12 months, the monthly fixed charge would be $74.02 for PG&E customers, $58.80 for SCE customers, and $70.07 for SDG&E customers. In Figure 9, this is represented by the red horizontal line.

Note that in all of these calculations, it is assumed that a change in the rate structure does not impact the size of the cost recovery gap. This is consistent with the assumption that volumetric prices are exactly equal to social marginal cost in the reformed rate and pollution is fully priced. If so, then any change in consumption as a result of lower volumetric rates leads to a $1 increase in revenue for every $1 increase in total cost.[43]

Two income-based fixed charge schedules are considered here, one pegged to the progressivity of sales tax collections and the other to the income distribution in California, as determined by the data from the Consumer Expenditure Survey we analyzed in Section 6. Those data report sales taxes paid and income earned by household income quintile in California.

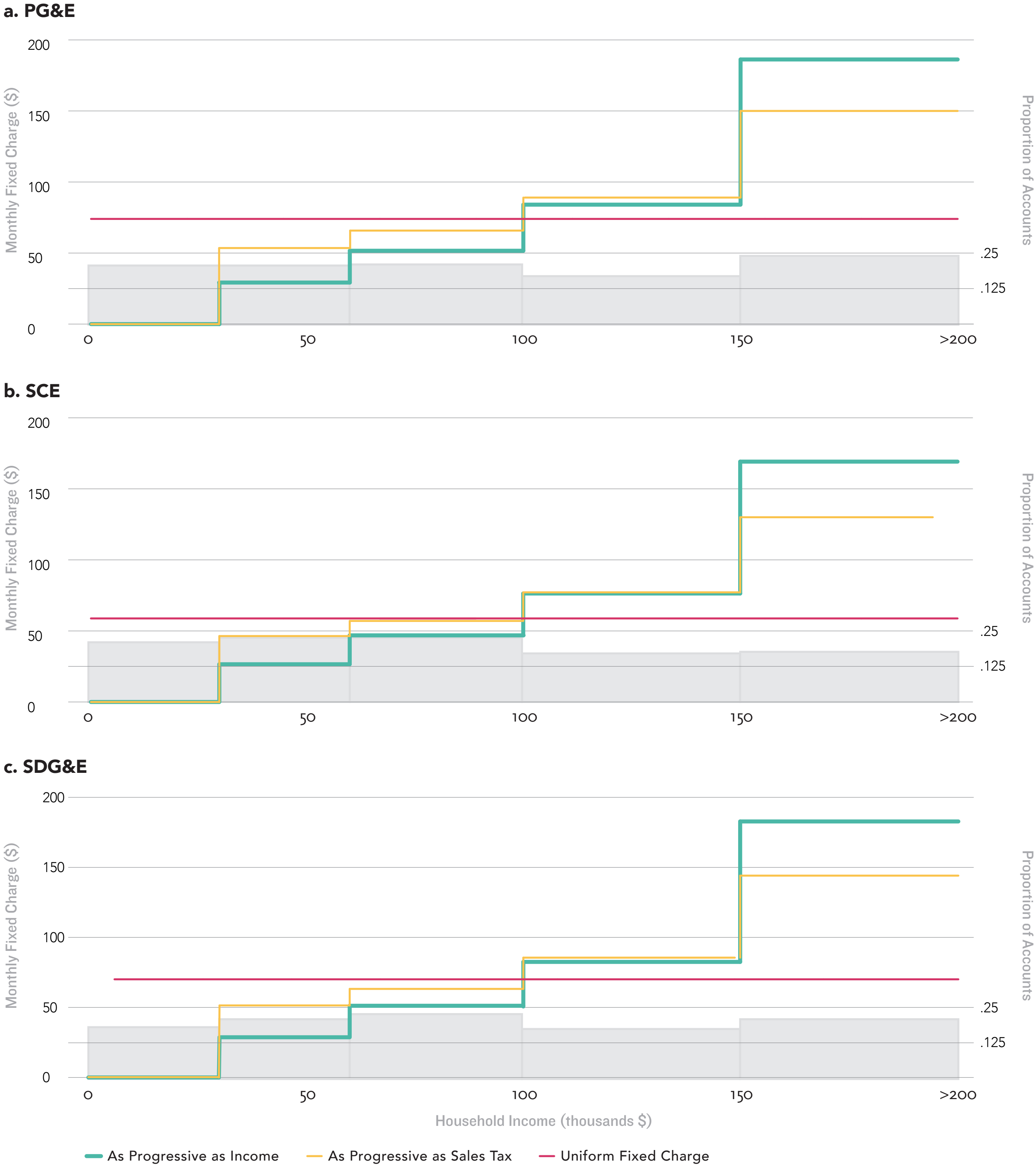
To develop example rate structures, the consumers were divided roughly into quintiles based on household

41 This discussion of alternatives to covering the cost recovery gap implicitly assumes no change in quantity demanded in response to alternative rate designs. However, this would have no impact on the analysis if price were set equal to private marginal cost. Setting price equal to social marginal cost instead implies that increases in quantity would have a small positive impact on utility revenues net of their private marginal cost, which would help to reduce the cost recovery gap.

42 The number of households assigned to each utility from the ACS differs slightly from the number of accounts reported in data from the FERC. We used a deflation factor to adjust the number of ACS households so that it matches the number of accounts reported in each utility service territory.

43 When pollution is priced below its social cost, as it is currently, this gap implies that utilities would recover a small amount of net revenue from an increase in consumption.

FIG 9a-c Example Income-Based Fixed Charge Schedules for 2019



Note: Each scheme depicted recovers the same amount of revenue. The gray histogram shows the proportion of accounts in each of the five pricing tiers in each service territory. Household distribution by income from the American Community Survey. Rates are authors' calculations based on cost recovery gap estimated in this study using proportional fees across quintiles as discussed in text. Full calculations available in the Appendix.

income. (They are not divided perfectly into quintiles because the ACS data reports only sixteen income categories.) It is then assumed that the lowest income quintile is assessed zero fixed charge.

Next, the authors ask what income-based fixed charge schedule would be consistent with a distribution of burdens across the richest four quintiles that is equal to the burden of raising the revenue through the sales tax. In practice, this means that, compared to a household in the second quintile, a household in the third (middle) quintile would pay 23 percent more, a household in the fourth quintile would pay 66 percent more, and a household in the fifth (richest) quintile would pay 180 percent (i.e., not quite three times) more. The state raises a substantial fraction of its revenue through a sales tax that has this same implied burden on its citizens. It is of course possible to dial up or dial down this progressivity, but pegging the progressivity of fixed charges to established sources of revenue provides a useful reference point.[44]

By construction, this schedule would raise revenue in a way that is roughly as progressive as the California sales tax. The implied rate structure for each utility is shown in the yellow lines in Figure 9. For PG&E, the monthly fixed charges would range from $54 for the second quintile up to $150 for the richest quintile (and zero for the lowest income quintile). In SCE, the implied schedule is slightly lower, with a range from $46 to $130 per month. For SDG&E customers, where even more revenue is needed per household, the proposed monthly fees range from $51 to $144.

An alternative is to peg the progressivity of the fixed-charge schedule to the progressivity of the income distribution. The survey data used as a reference point here reports taxable income, rather than state income tax paid. Thus, the tax progressivity is pegged to the income distribution (rather than the burden of the income tax), which is conceptually equivalent to pegging it to the progressivity of a flat income tax. This schedule is substantially more progressive. Again, it is assumed that the lowest-income quintile pays zero fixed charges. Relative to households in the second quintile, households in the third (middle) quintile will pay 77 percent more, households in the fourth quintile will pay 188 percent more (i.e., nearly three times as much), and the fifth (richest) quintile will nearly six-and-one-half times more.

Visually, this results in much steeper schedules, shown in blue in Figure 9. For PG&E, the second quintile would pay only $29 per month (as compared to $54 under the sales-tax motivated scheme), whereas the richest households would pay $186 (as compared to $150).

Again, the monthly charges are slightly lower for SCE customers, with fees ranging between $27 to $169. Monthly rates range between $27 and $169 for customers of SDG&E.

By design, this pricing schedule raises the same amount of revenue from consumers to cover fixed system costs. Overall, consumers would benefit because they would pay the same system costs but would face lower rates, which they could respond to by consuming more. However, any rate reform will create winners and losers. Compared to the current scheme of high volumetric prices, a pricing schedule with these income-based fixed charges would redistribute the burden of cost recovery both across income groups and within income groups depending on household consumption.

Among households in the same income category, those who consume more electricity will benefit more from the introduction of fixed charges. With the anonymized residential billing data requested from the three utilities, it is possible to fully characterize the number of winners and losers and the amount that they stand to gain or lose in each alternative rate reform.

It is thus easy to see how income-based fixed charges, even with a modest tilt to charges, can be much more progressive than the current scheme, in addition to being more efficient. A more comprehensive comparison of the implied change in cost recovery across higher and lower income households will be possible with the billing data we have requested.

There are many additional options that could make the schedule more progressive generally, or more generous to specific groups. For example, the lowest income households could have positive or negative fixed charges. Or, a larger or smaller fraction of households on the lower part of the income distribution could have zero fixed charges. In addition, the schedule need not involve large jumps at specific income thresholds. Fewer distinct categories may simplify the system, but a progressive schedule with few tiers will necessarily involve large price jumps, which can both create perverse incentives and may raise fairness concerns.

44 Note that we design rates for each utility separately, which means that the schedule depends in part on the distribution of income within the service territory. PG&E, for example, has a higher proportion of households in the highest income group.

8. Conclusion:
Rate reform can improve both efficiency and equity

High and rising retail electricity prices in California are fueling concerns about equity, affordability and the viability of the state's climate objectives. These high electricity prices are due not to high marginal costs of electricity supply, but rather to the reliance on high volumetric rates to recover system costs associated with transmission and distribution infrastructure, renewable energy subsidies, wildfire risk mitigation, and other factors. This way of recovering costs, which amounts to a tax on electricity consumption, is not only inefficient, it is also inequitable. Because annual electricity expenditure has only a modest correlation with income in California, taxing electricity consumption is quite regressive.

California's plans to electrify transportation and buildings as part of its path to decarbonization will require more investments in the electricity system. As long as the current rate structure remains in place, these investments threaten to exacerbate the inefficiencies and inequities described throughout the report.

This report has proposed some alternative approaches to cost recovery that could out-perform the status quo on both efficiency and equity grounds. These include an income-based fixed charge that could raise revenues in a more equitable way while maintaining an efficient volumetric price. Electricity rate reform will surely present challenges, both practical and political. But rate restructuring is essential to ensure that the California energy transition is both affordable and equitable. It is the authors' hope that this report can help build momentum towards a broader discussion about the best way to pay for electricity in the state.