Designing Electricity Rates for an Equitable Energy Transition
Online Appendix

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Abstract

This report examines the causes and distributional consequences of the high prices for residential electricity charged by California's investor-owned utilities (IOUs). It also considers reforms that would improve both the efficiency and equity of residential electricity pricing. We estimate avoidable (marginal) costs of electricity and demonstrate that IOU prices are two to three times higher than these cost estimates. California's electricity prices are high because nearly all fixed costs are recovered through volumetric prices, because of subsidies for low-income households and customers with rooftop solar, and because rates are used to fund objectives not directly related to the provision of electricity. Prices are set to rise further due to wildfire mitigation and other factors. High and rising prices undermine efforts to decarbonize transportation and buildings through electrification. Moreover, we show that the current rate structure is highly regressive, more so than other ways of raising revenue like a sales or income tax. We discuss the viability of alternative ways of recovering the costs of the electricity system that are more efficient and more equitable, with a focus on the creation of income-based monthly fixed charges on electricity bills.

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This document provides technical supporting information for the report titled *Designing Electricity Rates for an Equitable Energy Transition.* In the first section, we introduce alternative estimates of utility-specific marginal costs which incorporate different assumptions about avoided GHG-related damages and marginal transmission and distribution capacity costs. The final section introduces a repository of data sets and code which that we used to generate the figures and numbers in the paper. This repository is accessible at:https://github.com/marshallblundell/PfE.

1 Appendix 1: Alternative Marginal Cost Calculations

The marginal costs we estimate 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. In what follows, we summarize marginal cost estimates under a suite of alternative assumptions.

1.1 Alternative assumptions about the external GHG costs

The social cost of carbon (SCC) is an economic measure of the economic harm from climate change, expressed as the dollar value of the total damages from emitting one ton of carbon dioxide into the atmosphere. To construct our primary marginal cost estimates, we assume an SCC of $\$50$/ton. This is the median estimate (inflation adjusted) that is reported in 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. To account for GHG costs that are not captured by GHG permit prices, we define a residual GHG cost component:

$$GHG_{it} = (SCC - \tau_t) \cdot MOER_{it}. \tag{1}$$

The SCC is highly uncertain and sensitive to modeling assumptions. In our context, the true impact of a reduction in GHG emissions in the electricity sector is further complicated by the California's GHG cap. To assess the sensitivity of our marginal cost estimates to alternative SCC values, we consider two alternatives.

SCC alternative 1: $\$10/ton$**:** GHG emissions in California are subject to a state-wide cap on emissions. Over the time period we analyze, GHG permit prices have been close to the price floor. If this implies that the cap has been non-binding, reductions in electricity demand will cause a net reduction in GHG emissions.

If, instead, the GHG cap is binding, GHG reductions associated with reduced residential electricity consumption would be offset by increases in emissions from other capped sources. In

California, this ‘waterbed effect’ is somewhat more complicated given the extent of GHG permit banking and the potential for GHG leakage or reshuffling in the power sector. We therefore evaluate marginal social costs using a heavily discounted SCC ($\$10/ton$) to account for the fact that GHG emissions reductions in California’s electricity sector could be partially offset by increases elsewhere.

SCC alternative 2: $\$100/ton$**:** While the SCC value we use to construct our primary marginal cost estimates is the most vetted figure available, it does not include all of the economic impacts of climate change and is sensitive to modeling assumptions. The true costs of GHG emissions could be significantly higher. We therefore report marginal cost estimates that incorporate a higher SCC estimate of $\$100/ton$.

1.2 Alternative marginal transmission capacity cost (MTCC) values

In principle, if peak demand for electricity in a utility service territory is reduced, some transmission projects 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. Our primary marginal cost estimates use data from general rate cases, and data provided by the IOUs, to identify deferrable transmission investments. For each IOU we average these reported deferrable transmission costs across the ten year period we consider. Table 1 reports these marginal transmission capacity costs by year (in terms of $2019/kW-year).

This approach is consistent with a recent PUC decision (Decision 20-04-010) to use values from utility general rate cases to represent the avoided cost of transmission. However, some stakeholders challenge the idea that any new transmission investments are driven by load peak-load growth. For example, the Public Advocates Office submits there is no clear evidence showing that demand reductions can defer transmission costs. Both CLECA and Public Advocates Office argue that the Commission should adopt a zero value for avoided transmission costs.[1] We thus present alternative marginal cost estimates that assume marginal transmission capacity costs are zero.

Table 1: Marginal Capacity Cost Estimates ($2019 USD)

Capacity Cost	**PG&E**	**SCE**	**SDG&E**
Transmission ($/kW-year)	$29.11	$31.13	$ 13.74
Distribution ($/kW-year)	$ 54.46	$75.45	$77.62

[1]Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning and Evaluation of Integrated Distributed Energy Resources. Rulemaking 14-10-003, 4/24/2020.

1.3 Alternative marginal distribution capacity cost (MDCC) values:

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

Estimating or isolating those distribution investment costs that could be deferred if peak demand is incrementally reduced is challenging. The Commission recently approved a decision in R.14-08-01310 that adopts recommendations from the Energy Division's White Paper entitled "Staff Proposal on Avoided Cost and Locational Granularity of Transmission and Distribution Deferral Values". Our primary estimates use an approach that is consistent with the adopted approach. We average the deferrable distribution capacity costs reported in GRCs over the years 2010-2019. Table 1 reports these IOU-specific marginal distribution capacity costs in terms of $/kW-year.

Several stakeholders maintain that long-run distribution marginal costs are not avoidable. For example, ratepayer advocates at TURN maintain that it is erroneous to assume that distributed energy resources could defer the majority of distribution upgrades which are intended to repair equipment, replace aging equipment, or harden the grid to prevent utility-caused ignitions. The California Large Energy Consumers Association (CLECA) cautions that the use of general rate case marginal costs for unspecified distribution benefits could lead to over-estimation of the benefits of avoided distribution costs. In light of these concerns, we also construct marginal cost estimates that assume an MDCC of zero.

Appendix Figure 1 displays our primary social cost estimates (in red) and our alternative estimates by utility and year. We also report the E3 ACC estimates for reference in years when ACC calculators are available. Setting transmission and distribution marginal capacity costs to zero, and assuming that GHG reductions in the electricity sector are offset by GHG increases elsewhere in the economy, have similar impacts on our marginal cost estimates. Assuming a higher social cost per ton of GHG emissions avoided increases our estimates by approximately 25 percent.

2 Replication package

Code contained in the replication package can be used to build the data files and generate all figures in the paper. Visit https://github.com/marshallblundell/PfE and download the repository to begin. (Click the green code button, then select your choice of download method.) Appendix Table 2 summarizes the data files used to generate the figures and estimates.

Using these data files, open the R Project file "pfe_paper1_analysis_public.R" to set the working directory. This code assembles the data set and generates all Figures in the paper. The calculations for Figures 1-4 are all contained in the code. The calculations summarized in Section 5, which estimate the rate impacts of complying with the RPS policy and the rate impacts of BTM PV incentives are documented in detail in the spreadsheet titled RPS_BTM_PV_analysis_NEM2.0.xlsx.

The calculations in Sections 6 and 7 of the report are documented in the spreadsheet titled incomebasedfixedcharges_post.xlsx. One tab includes the data on state tax revenue used in the figure in Section 6. The other two tabs support the calculation of income-based fixed charges in Section 7. Calculations start in the tab labeled "Inputs," which takes initial data on the cost recovery gap, the number of households of each income in each service territory, and progressivity benchmarks and transforms those into a key multiplier. This is transformed into a series of possible income-based fixed charges that are shown in the tab labeled "Rates."

Table 2: Data Files

Name	**Description**
2010_Gaz_zcta_national	2010 Zip Code Centroids. We merge with zip code-leve PV installations and use latitude to impute tilt in BTM PV simulation. Zips change over time, and some are one centroid file and not others, so we use three files.
2018_Gaz_zcta_national	2018 Zip Code Centroids. We merge with zip code-leve PV installations and use latitude to impute tilt in BTM PV simulation.
advice_letters	Advice letters and tariffs sheets used to source 2019 CARE and non-CARE residential rates. We collected rates from the 2019 pdfs and recorded in rates_data.xlsx.
ancillary_services	Market conditions reports I use for ancillary servies costs. We collect cost as a percentage of energy cost and record in as_data.xlsx
avoided_cost_calculator	E3 avoided cost calculators. Used to compare our numbers. We also pull some information from these and store it in other datasets below.
California_Electric_Utility_Service_Areas-shp	Shapefile for CA IOU territories. Used to intersect ACS data with territories to get income distribution for each IOU.
care_reports	Annual reports on CARE and FERA. From the tables we collect avg. monthly CARE and non-CARE bills, and number of CARE customers.
Census	Sources of state tax revenue.
consumption_by_utility_year_sector	Annual consumption at the utility-year-sector level.
cpi	CPI-U used to adjust estimates for inflation.
ferc_form_1	FERC form 1 data retrieved from SNL. Used for box and whisker plots, counts of residential customers, and we use bundled residential rates in some of the plots.
gas_prices	Natural gas prices at CA hubs, retrieved from SNL. We use these to compute heat rate from wholesale prices.
lbnl_pv_data_public_tts	BTM PV installations by zip code. Used to simulate BTM PV production.
lmps	Wholesale prices at the IOU level. Used to compute marginal energy costs.
losses	Avgerage residential losses estimates by IOU, year. We use these to compute marginal losses.
permit_prices	CA cap and trade permit auction prices. Use these to compute marginal GHGs costs.
SalesTax	CEX data on spending by category by income quintile. Used to compare regressivity of recovering costs through electricity rates with other means.
SCE_Annual_Domestic_kWh_Borenstein.xlsx	Bundled sales net of BTM PV production for SCE. SCE submits gross (inclusive of BTM PV) to FERC so we use this to correct the FERC data.
snl_system_load_data	Hourly system load data for CA IOUs retrieved from SNL. Used to average 2019 rates that change over the year, also used to forecast load and allocate capacity costs on an hourly basis.
t_and_d_capacity_values	Transmission and distribution capacity values in $/kW-year. We take these out of the avoided cost calculators. Primary source is GRCs.
USzipcentroids	Zip Code Centroids. We merge with zip code-leve PV installations and use latitude to impute tilt in BTM PV simulation.
utility_cost_reports	AB67 utility cost reports. We source the care discount from these, which we use to compute CARE and non-CARE avg. residential rates.

Figure 1: Social Marginal Cost Estimates ($/kWh)

Source: Marginal cost estimates are authors' calculation explained in text, weighted across hours by IOU load.