An accounting tool used by the California Public Utilities Commission serves as our point of departure for the estimation of the avoidable costs of electricity. [1] The Avoided Cost Calculator (ACC) is a spreadsheet-based model developed by Energy and Environmental Economics, Inc (E3). It uses publicly available data to generate hourly forecasts of the marginal costs that a utility would avoid if demand were incrementally reduced.

The E3 ACC tool is designed to forecast the long-term cost implications of future electricity demand growth in California. In contrast, our analysis is more retrospective. We aim to estimate how costs would have been impacted if realized electricity demand had been incrementally lower. To suit our application, we make several methodological modifications and refinements to the E3 approach. But we adopt the basic accounting structure which decomposes avoided costs per kWh into eight components: marginal energy costs; losses; GHG-related costs; ancillary services; marginal generation capacity costs; marginal transmission capacity costs; marginal distribution capacity costs. Figures X-Y show the relative importance of these estimated cost components, both across time and and across IOUs.

In what follows, we provide a conceptual overview of our methodology and underlying estimating equations. Additional details are reported in Appendix X.

0.1 Marginal Electricity Operating Costs

We use [XXX placeholder for specific refXXX] wholesale electricity prices to estimate marginal operating costs. In California, hourly locational marginal prices (LMPs) reflect not only the per kWh fuel and operations costs at a given location in time and space, but also the costs of purchasing GHG permits to offset emissions, congestion-related costs, and electricity losses due to long-distance transport. [PLACEHOLDER FOR THE DA LMP PRODUCT - ARE THESE DIFFERENTIATED BY IOU? AND IF YES, HOW ARE PRICES AGGREGATED WITHIN IOU TERRITORY?]

For accounting purposes, we decompose observed hourly wholesale electricity prices into marginal energy costs, GHG-related compliance costs, and losses. Let i index the IOU territory. Let t denote hour. The marginal energy cost MEC_{it} is defined as:

$$MEC_{it} = (LMP_{it} - \underbrace{\tau_t \cdot MOER_{it}}_{\text{GHG costs}})\underbrace{(\frac{1}{1 - dL/dQ})}_{\text{Loss adjustment}} \tag{1}$$

To isolate the marginal cost of electricity generation, Equation 1 subtracts the per kWh GHG compliance costs incurred by the marginal producer from the LMP. This compliance cost is given by the product of the prevailing GHG permit price τ and the GHG emissions rate (measured in tons of CO_2/kWh) of the marginal generator.[2] If we assume that the marginal unit is a natural gas plant, the marginal operating emissions rate ($MOER_t$) can be defined as:

$$MOER_{it} = HeatRate_{it} \cdot 0.0585, \tag{2}$$

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 (0.0585 tons/MMBtu) yields an estimate of the GHG intensity of electricity production.

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

[2] We use quarterly GHG permit auction prices to calibrate τ. These prices can be found at: $https://ww2.arb.ca.gov/sites/default/files/2020-08/results_summary.pdf$.

XXX THIS GHG FACTOR SEEMS OFF? WE SHOULD BE USING METRIC TONS TO BE CONSISTENT WITH THE PERMIT PRICE? SHOULD THIS BE 0.0530703 XXX?
To estimate the marginal heat rate in Equation 2, we further assume that the LMP accurately reflects the variable operating costs of marginal producers (i.e.fuel costs, non-fuel costs, and GHG compliance costs). Rearranging this equilibrium condition, we can define the marginal heat rate as:
XXX THIS SEEMS NOT QUITE RIGHT/INTERNALLY INCONSISTENT GIVEN OUR LOSS ADJUSTMENT? XXX

$$HeatRate_{it} = (LMP_{it} - NFC)/(GasPrice_{it} + 0.0585 * \tau_t)$$

XXX WHAT DO WE ASSUME ABOUT THE NON FUEL PRICE PER KWH? WHERE DOES THIS COME FROM? AND WHERE DO WE GET OUR REGIONAL GAS PRICES?
In addition to variable operating costs, hourly electricity prices reflect the incremental cost of losses due to physical resistance as power is moved across the transmission network that connects producers to consumers.
[XXXSUMMARIZE SEVERIN'S LOSS FACTOR AND HOW WE USE IT TO IMPUTE MEC AND GHG COSTS FROM LMP XXX].
Taken together, Equations 1, 2, and 0.1 are used to estimate three avoided cost components: marginal energy costs, GHG compliance costs, and losses. Figures Xa-c plot unweighted annual average measures of these avoidable cost estimates by utility. Marginal energy costs are the largest of these cost components, comprising 30-40 percent of avoided costs over the time period we consider. As of 2019, GHG compliance costs comprise 18 percent of variable operating costs. Estimated losses increase avoidable costs by a 10-12 percent.

0.2 GHG externality costs

The monetized allowance value in 1 captures only a fraction of the total social cost of GHG emissions. Over the time period we consider, GHG permit prices in quarterly allowance auctions ranged from $12-$17/metric ton.[3] These allowance prices fall well below standard estimates of the social cost of carbon (SCC). To account for these external GHG costs, we define a residual GHG cost component:

$$GHG_{it} = (SCC - \tau t) \cdot MOER_{it}$$

Our preferred ACC estimates use a conservative SCC of

$$50/ton$$

. Figures X-Y show how this residual GHG cost component is economically significant.

0.3 Marginal Capacity Costs

Marginal capacity costs represent the potential cost impacts on generation, distribution, and transmission investments from reductions in peak load. In principle, if peak demand for electricity 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 multiple factors, such as the location and timing of peak demand reductions.
We estimate three types of marginal capacity costs:

[3] $https://ww2.arb.ca.gov/sites/default/files/2020-08/results_summary.pdf$.

Marginal Transmission Capacity Costs: The IOUs coordinate with the California Independent System Operator to plan transmission system investments and upgrades. If peak load is considerably reduced prior to the implementation date, a planned transmission project that is driven by demand – versus regulatory, safety, contractual, efficiency or other reasons – could be deferrable.
The E3 ACC tool tracks transmission projects that utilities have classified as deferrable. These represent the potential cost impacts on utility transmission investment from changes in peak load. Our preferred ACC estimates use the deferrable transmission investments reported in the E3 ACC data. Notably, stakeholders have challenged the idea that any new transmission investment is driven by load load growth (cite CAISO e.g. 2016-2017 TPP at 102- 104). We therefore report alternative estimates which set marginal transmission capacity costs at zero.
Marginal Distribution Capacity Costs: The costs of operating, maintaining and replacing distribution equipment, once installed, are generally independent of usage and should therefore be treated as fixed costs. However, there are two types of distribution system investments that are made to meet demand growth: (1) Distribution reinforcement investments provide capacity to meet demand growth on the existing system and (2) distribution investments for primary line extensions provide access and the associated capacity for new demand due to the addition of new customers.
The E3 Avoided Cost Calculator uses estimates of marginal distribution investment costs reported general rate cases. Here again, some stakeholders have challenged the idea that peak load reductions could defer distribution upgrades. Our preferred estimates use E3 costs, recognizing that these may over-estimate costs that are truly avoidable.
Marginal generation capacity costs: In years when demand is forecast to increase, the marginal generation cost captures the cost of procuring and operating new generation capacity to meet an incremental increase in peak load (measured in terms of dollars per kilowatt-year). In forward-looking E3 ACC calculations, marginal generation capacity costs are estimated using the levelized capital cost of a new simple cycle CT unit less the profits that the CT could earn from the energy and ancillary service markets.
In the 2016 GRC, PGE estimated the short-run cost of capacity as the going-forward fixed cost of the existing generation resource net of energy gross margins it earns from the spot energy market over the period 2017-2022. They assumed an existing combined cycle gas turbine (CCGT) plant as the marginal unit. The going-forward fixed cost consists of fixed OM, insurance and property tax. Insurance and property tax are estimated based on the capital costs.

To calculate levelized MGCC, PGE first calculated a Net Present Value (NPV) sum of the six years of MGCCs and then converted this NPV to a levelized value. PGE 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 represents the cost of an existing CCGTs fixed costs above and beyond what it could earn in the energy market. These are much closer to the resource adequacy value that E3 estimated at $28.07/kW.

To determine the long-run value of capacity, the avoided cost model performs an hourly dispatch of a new CT to determine energy market net revenues. The CT's net margin is calculated assuming that the unit dispatches at full capacity in each hour that the real-time price exceeds its operating cost (the sum of fuel costs and variable OM) plus a bid adder of 10%. In each hour that it operates, the unit earns the difference between the market price and its operating costs.

The market revenues earned in the energy and AS markets are subtracted from the fixed and variable costs of operating a CT to determine the residual capacity value. One thing to note is that E3 natural gas price forecasts are on the high side. This will drive up wholesale price forecasts and thus reduce residual capacity value.

In 2020, to create greater alignment with IRP, the generation capacity value will now use a new 4-hour battery storage resource as a proxy.

Primary distribution marginal costs are reported in dollars per PCAF-kilowatt (kW) per year and primary distribution for new business and secondary distribution marginal costs are shown in dollars per FLT-kW per year.

In the ACC, these marginal costs are allocated across hours using distribution Peak Capacity Allocation Factors (PCAF).

Not only is no clear record evidence available that DERs are capable of deferring transmission costs, DERs may increase congestion problems in certain areas