**Avoided Cost Calculator**

The Avoided Cost Calculator (ACC) is used to determine the primary benefits of distributed energy resources and demand-side programs, such as NEM, across Commission proceedings.

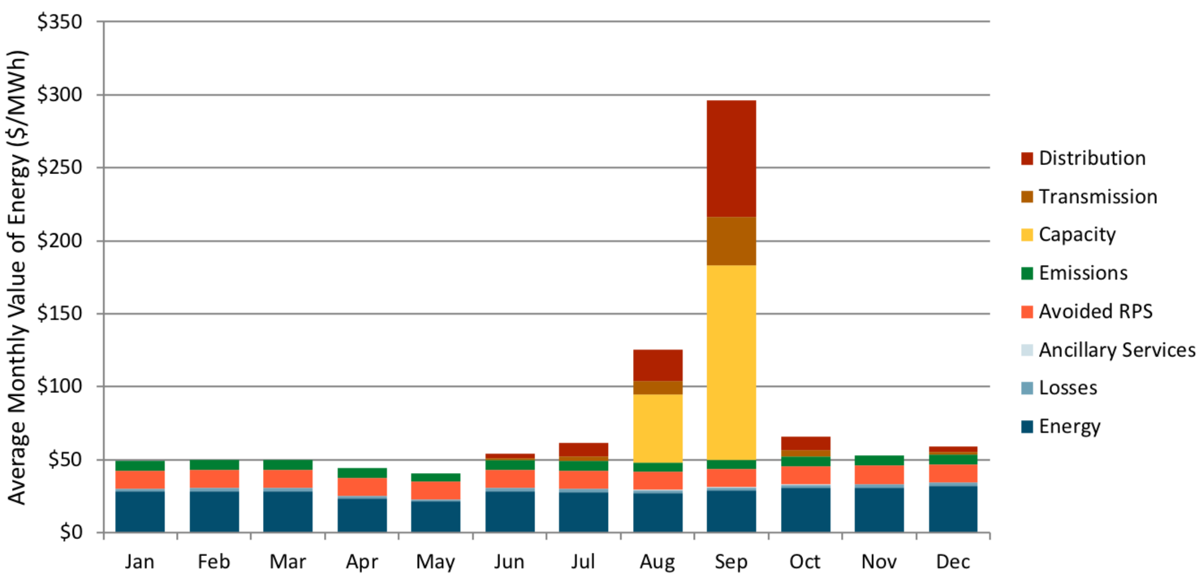
The Commission approved the first ACC in 2005 with Decision (D.) 05-04-24. It is designed to estimate the going-forward costs avoided by a DER investment that reduces forecast demand growth over a long (10-30 years) time frame. It is designed to provide ‘ a straightforward costing methodology that is implemented using a spreadsheet model and publicly available data, resulting in avoided cost estimates that are transparent and can be easily updated to reflect changes in major cost drivers.’

The output of the model is a set of hourly values over a 30-year time horizon that represents the marginal costs a utility would avoid in any given hour if a distributed energy resource reduced demand for energy during that hour. This emphasis on the reduction of future demand growth is not perfectly aligned with our application, as we are emphasizing a retrospective look at variable costs incurred to meet realized demand. Another complication is that the E3 ACC methodology/modeling changes year-to-year (especially wrt GHG costs) and there is a 5 year period over which the ACC was not updated. This will complicate the comparisons across years.

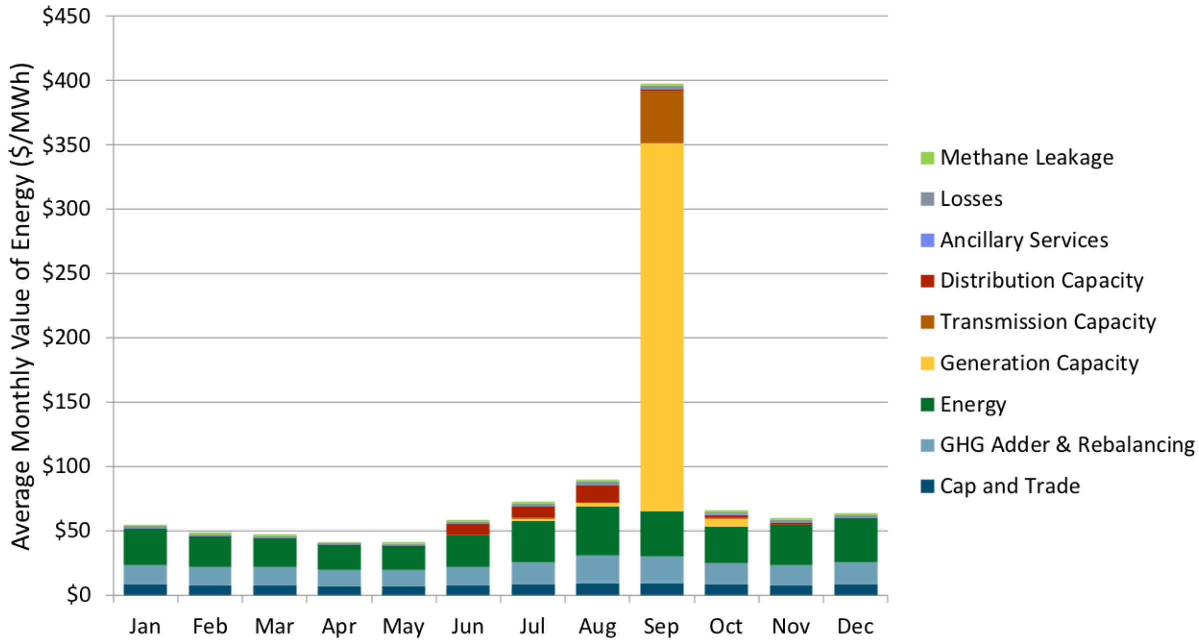
# 1 Definitions

The ACC calculates six types of avoided costs: generation capacity, energy, transmission and distribution capacity, ancillary services, renewable portfolio standard, and greenhouse gas emissions. The figures below show the relative importance of the key cost components (using 2016 and 2020 ACC calculators).

2016 E3 ACC 1 year time horizon



2020 E3 ACC 1 year time horizon




The primary cost components are summarized below:

## 1.1 Marginal Energy Cost (MEC)

The MEC is intended to reflect the cost of procuring electricity to meet one additional megawatt-hour (MWh) of load, measured in cents per kilowatt-hour. Because the IOUs meet residual needs by purchasing power in the CAISO day-ahead market, ISO wholesale energy price forecasts can be used to estimate the MEC. The E3 ACC generation energy costs are calculated hourly for 16 climate zones. The average energy cost in the near term is based on the OTC Global Holdings Forwards on-peak and off-peak market price forecasts for NP-15 and SP-15, averaged to calculate the system value. Hourly shape is derived from day-ahead LMPs at load-aggregation points in northern and southern California obtained from the California ISOs MRTU OASIS.

For the period after the available forward market prices, the method interpolates between the last available futures market price and the long-run energy market price. E3 has started to use production simulation models (PLEXOS, SERVM) versus ISO forecast prices to estimate this MEC component far into the future. Not so relevant for us if we work within the window where forecasts are available.

The E3 treatment of generation avoided costs was updated in 2016 to adjust for carbon prices in the electricity market price forecasts. The prior years E3 ACC does not account for this. The updated methodology starts with market prices that include CO2 costs, and decomposes the market price into an energy component and a CO2 component based on the 2015 IEPR CO2 prices and the inferred market heat rates.

I see two problems with using the E3 ACC to construct the energy cost comopnents:

- Over the 2010-2015 gap, the E3 ACC uses natural gas forecasts that diverge significantly from realized prices.

- Over 2012-2016, carbon prices are not removed.

For this reason, I propose we do the following:

$$MEC_{it} = (LMP_{it} - \tau_t \cdot MOER_t)(\frac{1}{1 - dL/dQ})$$

- Adjust for line losses. Use the $\alpha_{it}$ parameters from SMC2. These are differntiated by utility hour.
- Adjust for permit costs $\tau_t \cdot MOER_t$

GHG permit prices. We could use ICE prices, auction prices(?)

We also need hourly MOER estimates. E3 GHG impacts are based on hourly marginal emissions, calculated using an implied heat rate methodology that incorporates market price forecasts for electricity and natural gas, as well as gas generator operational characteristics. This process assumes that natural gas is the marginal fuel in all hours. The hourly emissions rate of the marginal generator is calculated based on the day-ahead market price curve (with the assumption that the price curve also includes the cost of CO2):

$$HeatRate_t = (LMP_t - VOM)/(GasPrice_t + EF * \tau_t)$$

Where:

- LMP is the hourly market price of energy.
- VOM is the variable OM cost for a natural gas plant. This is included in the E3 ACC documentation.
- GasPrice is the cost of natural gas delivered to an electric generator. We can get this from EIA? SNL?
- $\tau$ is the $/ton cost of CO2.
- EF is the emission factor for tons of CO2 per MMBTU of natural gas. E3 assumes 0.0585 tons/MMBtu.

The link between higher market prices and higher emissions rates is intuitive: higher market prices enable lower-efficiency generators to operate, resulting in increased rates of emissions at the margin. Of course, this relationship breaks when gas is not on the margin. For this reason, the avoided cost methodology bounds the maximum emissions rates based on the range of heat rates of gas turbine technologies ( 0 - 12,500 btu/kWh).

To cross-check can compare our numbers to those reported by E3 for the years we have.

## 1.2 GHG component

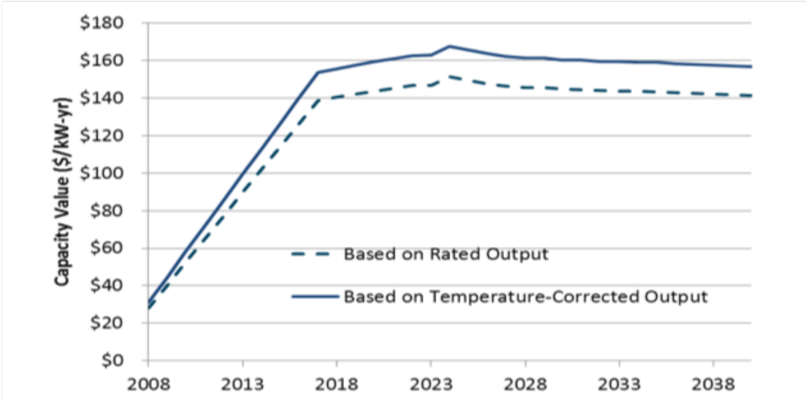
Conceptually, the E3 GHG cost is comprised of two components: the monetized allowance value embedded in the energy price and the non-monetized carbon price in excess of the allowance value. The 2020 ACC adds an additional 'rebalancing' step described below (one we do not want to take/adopt)

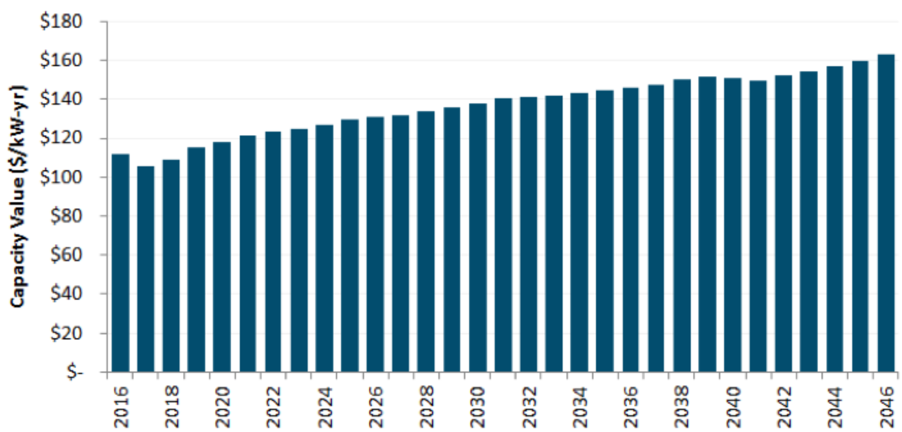
I think we should just use the MOERs we estimate in the prior step and multiply by the SCC.

Note that the E3 ACC also estimates marginal emissions rates for local pollution. We could add these in using EPA estimates of the costs per ton of NOx and SO2. These will be small.

## 1.3 Marginal Generation Capacity Costs (MGCC)

The MGCC captures the fixed cost of procuring and operating generation capacity to meet one additional megawatt of peak load. These are measured in terms of dollars per kilowatt-year. There are some important differences in how E3 ACC generation capacity costs are computed in 2010 versus 2016:




Some background and context:

- The resource balance year is defined as the year in which new forecasts predict new capacity will be needed; i.e., the year that generation resources are no longer balanced with load.
- In the 2010 ACC, the resource balance year was defined to be 2017. The 2008 resource adequacy value was estimated $28.07/kW. The graph above suggests that the ACC model interpolates between this 2008 RA value and the residual capacity value that kicks in at the resource balance year.
- The 2016 E3 ACC documentation refers to a May 3, 2016 Proposed Decision of Commissioner Florio in R. 14-10-003 has essentially set the Resource Balance Year to zero, which means E3 now uses the long-run capacity cost for all years. I cannot find this language in the Florio decision.
- After the resource balance year, the generation capacity cost is the levelized capital cost of a new simple cycle CT unit less the margin that the CT could earn from the energy and ancillary service markets. In 2016, this calculation updated to include carbon costs in both the bid prices for the CT and the market prices for energy.
- 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 CTs 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.

How to allocate these capacity costs across hours?

- In the 2010 E3 ACC, residual capacity value is allocated across the top 250 hours of CAISO system load, in inverse proportion to the gap between the system peak load plus operating reserves and the system loads for each of the 250 hours. Note that capacity value allocated across these 250 hours even if generation capacity constraints do not bind!
- In this manner, the highest load hour will receive the largest allocation of capacity value on a \$/kWh basis ( \$2,000/MWh). The 250th hour receives an allocation of \$400/MWh. Most of the capacity value falls in the summer on-peak period, though some falls in the summer and winter partial-peak periods as well.
- 2016 updated the approach to allocating residual capacity value uses the RECAP model that generates hourly, system wide expected unserved energy (EUE) values. The residual capacity values (\$/kW-yr), after adjusting for temperature, losses, and planning reserve margin, are then allocated to the hours of the year with highest system capacity need using the E3 RECAP model. Documentation does note the problem that arises when all hours have 0 EUE!
- GRCs take a similar weighting approach based on the likelihood that the electric system will be unable to serve customer demand in any given hour. There is always some likelihood, however small, that the system will be unable to serve demand due to insufficient availability of generation relative to the electricity demanded by customers. The risk of a generation shortage can be reduced by having more generation available than forecast peak demand (i.e., a reserve margin), but this additional generation capacity imposes costs on customers. Loss of Load Expectation (LOLE) is a measure that predicts the ability (or inability) to deliver energy to the load. An LOLE analysis can provide insight into the planning reserve margin required for each LSE in a region. The relative LOLE provides a method for allocating annualized capacity 22 value across hours in proportion to when the loss of load.

I propose we do the following:
**OPTION 1**: Use E3 ACC GCC off the shelf. I believe we can extract from the ACC the IOU specific capacity values in each ACC year. We can interpolate across the missing years between 2010 and 2016. We can then assign these values to years using the PCAF formula. That is, take the top 250 hours and estimate the following:

$$PCAF_h = (Peakload - Load_h)/\sum_h (Peak - Load_h)$$

We should double check that this comes pretty close to replicating the ACC hourly GCCs.
**OPTION 2**: RA approach?
Use the same PCAF weights to allocate a short run capacity cost of \$30/kW-yr.

- 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.

### 1.4 Marginal Transmission Capacity Costs (MTCC)

- On a regular basis, IOUs coordinate with the California Independent System Operator (CAISO) to plan transmission expansion upgrades (5 to 10 year time frame). If a given facility loading is reduced considerably prior to the implementation date, due to demand forecasts, then the implementation date of a planned transmission project may be deferred. Deferrable transmission projects are thus defined as 'demand-related' marginal transmission investments.
- If a project is deemed to be 'deferrable', this means that the project is driven by demand, and not by regulatory, safety, contractual, efficiency or other reasons.
- In the E3 ACC, marginal transmission capacity costs are based on these deferrable transmission projects. They represent the potential cost impacts on utility transmission investment from changes in peak loadings.
- As PGE is the only utility to file transmission-level costs in their general rate case, the ACC has included avoided future transmission costs for PGE but not for SCE or SDGE.
- Several stakeholders (e.g. Clean Coalition) argued successfully to extend this approach to other utilities in 2020.
- Other stakeholders offer a different view. For example, CLECA argues that most current and new transmission investment is not driven by load growth and is not marginal (cite CAISO e.g. 2016-2017 TPP at 102- 104).
- CERCLA submitted data requests to prove this point.
  - For SCE, only 2-4% of its forecast transmission system cap ex is load-growth related. The rest is for RPS, reliability, and grid operations needs. The result is low marginal transmission capacity costs.
  - For PGE, a response to a CLECA data request in its GRC Phase 2 shows a MTCC of \$3.93/kW- year.
  - For SCE, a response to a CLECA data request in its GRC Phase 2 shows a MTCC of \$21.40/kW- year
- These numbers are much smaller than E3 estimates. Data do not support claims that there are large marginal or avoidable transmission costs.

Upshot. \$0 is probably too small.

## 1.5 Marginal Distribution Capacity Costs (MDCC)

The Avoided Cost Calculator has a single avoided distribution value in each of the Southern California Edison Company (SCE) and San Diego Gas Electric Company (SDGE) territories based on the marginal cost of distribution from the general rate case. The Pacific Gas and Electric Company (PGE) avoided cost of distribution value is also based on the marginal cost of distribution from the general rate case and is further broken out by climate zone.

Unspecified distribution deferral avoided costs reflect the cost of distribution capacity projects that are likely to be needed in the future but are not specifically identified in current utility distribution planning.

- A detailed planning process uses uses peak load data and load growth forecasts to evaluate whether existing substation and feeder capacity is sufficient so that equipment is not overloaded and so that service-operating parameters (e.g., voltage limits and adequate reliability levels) are maintained under both normal, and emergency operating conditions.
- As a general rule, the costs of operating, maintaining and replacing distribution equipment, once installed, are independent of usage. Such costs associated with existing distribution equipment are properly considered fixed costs and excluded from marginal cost calculations.
- However, there are two types of 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.
- 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).

Many parties have amply documented why no value should be incorporated into the ACC for avoided distribution costs.

- Public Advocates Office recommends a zero value for unspecified avoided distribution costs 'because any non-zero value is likely to be uncertain and inaccurate; rather, a zero value for avoided distribution costs would align with the findings of the Distributed Resources Planning (DRP) Staff Paper on unspecified distribution deferral value.23'
- TURN argues that it is erroneous to assume that DERs could defer distribution upgrades which are intended to repair equipment or harden the grid to prevent utility-caused ignitions.
- CLECA argues that the use of GRC marginal costs for unspecified distribution benefits could lead to over-estimation of the true benefits.

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