# 2020 Distributed Energy Resources Avoided Cost Calculator Documentation

For the California Public Utilities Commission

May 1, 2020

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# 1 Introduction

Decision (D.)19-05-019 in the Integrated Distributed Energy Resources (IDER) proceeding, R.14-10-003, initiated a process to implement major and minor updates to the Avoided Cost Calculator (ACC) in 2020. This process culminated in a Staff Proposal (ACC Staff Proposal) for the 2020 ACC update that was adopted in D.20-04-010, issued April 24, 2020. The ACC determines the benefits of Distributed Energy Resources (DERs) such as energy efficiency and demand response. DER program cost-effectiveness analysis depends on the ACC to accurately determine the benefits they provide to the electric grid and natural gas system. The ACC determines several types of benefits including avoided generation capacity, energy, ancillary services, GHG emissions, and transmission and distribution capacity.

The 2020 ACC represents a major change in the CPUC's approach to estimating the avoided costs of distributed energy resources. The new ACC is closely aligned with the grid planning efforts of the Integrated Resource Planning (R. 16-02-007) and Distributed Resource Plan (R. 14-08-013) proceedings. The avoided costs will be based on data and analysis from Integrated Resource Planning (IRP) modeling, except for the avoided costs of transmission and distribution, which will be based on data and guidance from the Distributed Resources Plan (DRP) proceeding. The 2020 Avoided Cost Calculator also adopts a new avoided cost of high global warming potential (GWP) gases, which will value the greenhouse gas (GHG) impacts of distributed energy resources (DERs) on methane and refrigerant leakage. Table 1 summarizes the differences between the new methods adopted for the 2020 ACC and the prior 2019 ACC.

*Table 1. Changes from 2019 to 2020 ACC Update*

| Avoided Cost | 2019 ACC | 2020 ACC | Data Source |
|---|---|---|---|
| Generation Capacity | Combustion Turbine Cost of New Entry | Battery Storage Cost of New Entry | RESOLVE input assumptions |
| Energy | Energy futures and gas turbine modeling | RESOLVE and SERVM modeling | SERVM outputs |
| Ancillary Services | percentage of energy | RESOLVE and SERVM modeling | SERVM outputs |
| GHG Value | Based on RESOLVE GHG shadow price and cap & trade price | Based on RESOLVE GHG shadow price and cap & trade | RESOLVE outputs, cap & trade prices |
| GHG Emissions | Implied market-heat rate short-run marginal emissions | SERVM short- run marginal emissions and RESOLVE long-run grid emissions intensity | RESOLVE and SERVM outputs, cap & trade prices, annual GHG electric sector goals |
| Transmission | GRC marginal cost filings | From DRP guidance | GRC filings and historical utility cost and financial data |
| Distribution | GRC marginal cost filings | From DRP guidance | GNA data |
| High GWP gases | NA | Methane & refrigerant leakage modeling | CARB data |

Figure 1 details the flow of data from IRP, DRP, and data sources such as the California Energy Commission (CEC) Integrate Energy Policy Report (IEPR), various California Air Resource Board (CARB) databases, and data from the California Independent System Operator (CAISO). Figure 2 shows the flow of inputs and calculations in the ACC.

*Figure 1. Avoided Cost Process Overview*

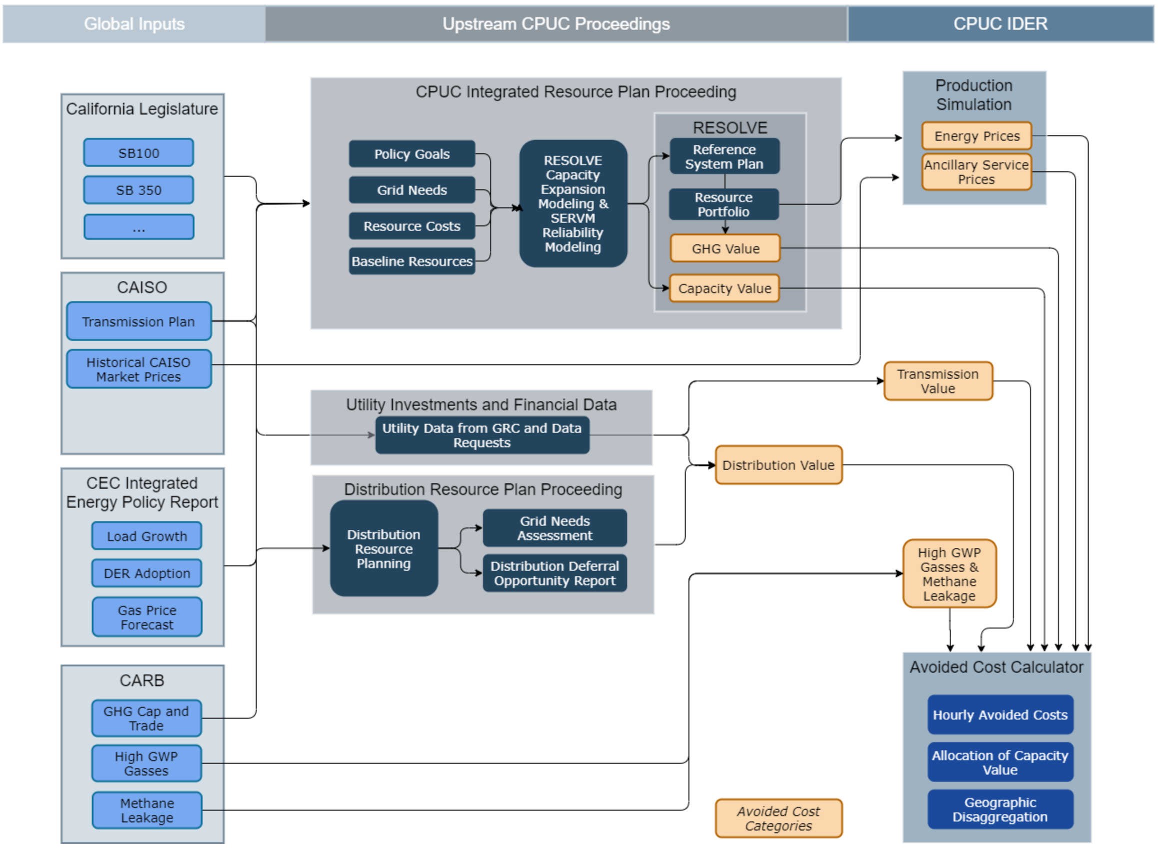
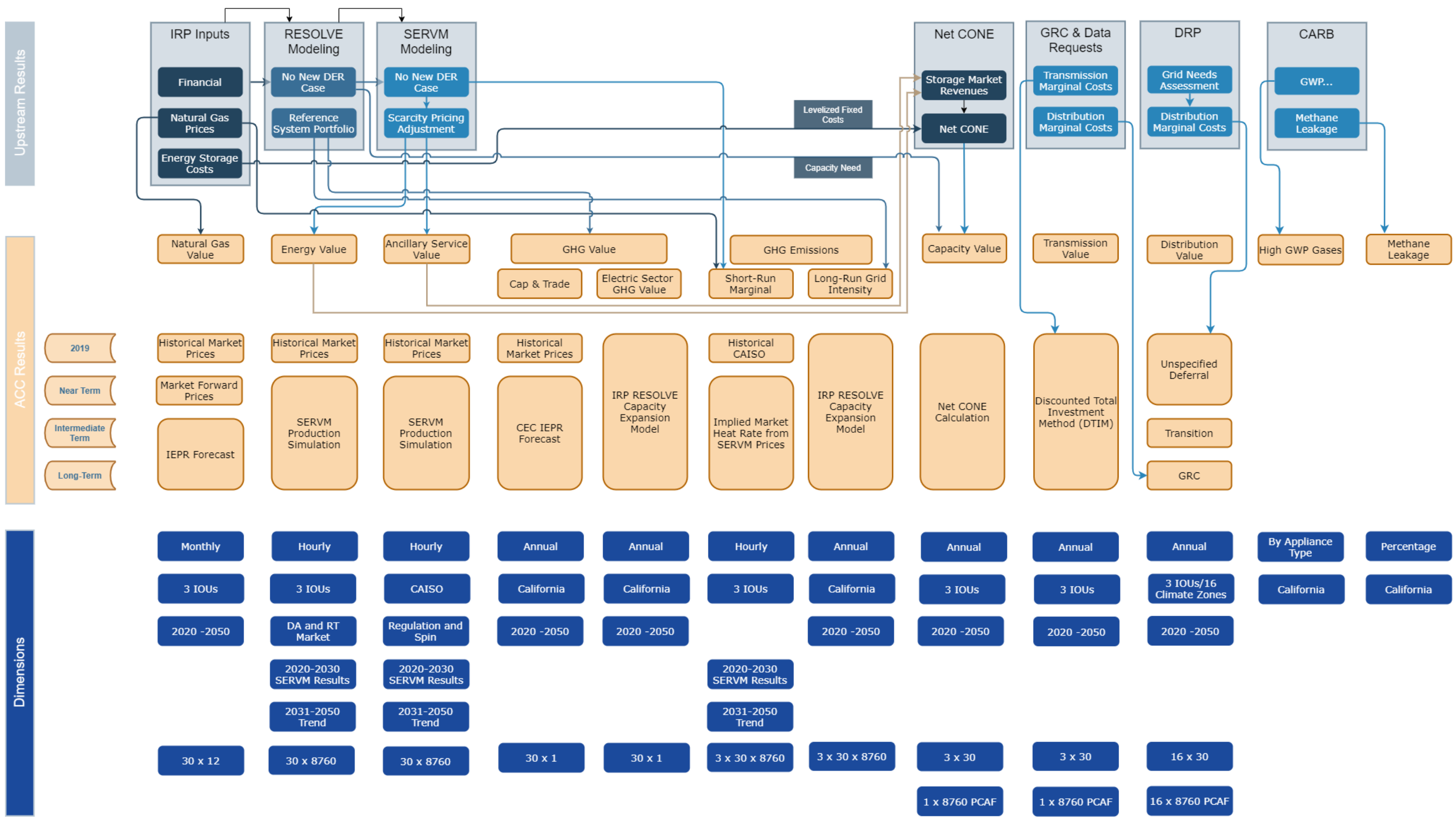


*Figure 2. Avoided Cost Calculator Structure*



# 2 Integrated Resource Planning Proceeding Inputs

Prior ACCs have relied on historic data and future projections from a number of sources. As described in the Staff Proposal, the 2020 ACC leverages inputs from California's IRP proceeding.[1] By coordinating with the state's IRP, the ACC will better align with supply-side planning and projected future energy prices. This approach ensures greater consistency between demand-side resources evaluated using the ACC and supply-side resources in IRP.

California's IRP proceeding uses E3's RESOLVE resource planning model, which is a publicly available and vetted tool.[2] RESOLVE is a linear optimization model that co-optimizes investment and dispatch for a select number of days over a multi-year horizon to identify least-cost portfolios for meeting carbon emission reduction targets, renewables portfolio standard goals, reliability during peak demand events, and other system requirements. RESOLVE is used to create the final Reference System Plan (RSP), which identifies supply-side resource build requirements and costs, for the CPUC's IRP proceeding.

The 2020 ACC uses inputs and outputs from the RESOLVE scenarios used for the 2019-2020 IRP. Future ACCs will be updated with the most recent IRP available.

## 2.1 No New DER Scenario

The IRP RSP includes assumed levels of future DER adoption. The forecast DER levels are built-in as modifiers to overall system demand, and therefore impact the amount of supply-side resources selected by RESOLVE. In order to better estimate the value that DERs can play in meeting demand, the IRP developed a sensitivity where DER adoption was projected to remain at 2018 levels. This "No New DER" scenario assumes that no additional DERs are adopted post-2018 and demand response is discontinued, thus demonstrating a hypothetical counterfactual in which incremental DER adoption does not occur. The No New DER scenario allows the IRP and ACC to explore the difference in supply-side costs in a situation where additional DERs are not adopted, and as a result, more supply-side resources are necessary to meet overall demand. All other inputs are consistent with the RSP. Table 2 shows the changes in DER adoption to create the No New DER case relative to the RSP.

[1] See 2019-2020 IRP Events and Materials for source documents: https://www.cpuc.ca.gov/General.aspx?id=6442459770

[2] RESOLVE models, inputs and results are available at: https://www.cpuc.ca.gov/General.aspx?id=6442464143

*Table 2. DERs Removed in the "No New DER" Case*

| CAISO Sales Forecast Buildup | | 2018 | 2020 | 2025 | 2030 |
|---|---|---|---|---|---|
| | **Energy Efficiency (GWh)** | | | | |
| | CEC 2018 IEPR - Mid Mid AAEE | 1,906 | 5,930 | 17,322 | 27,940 |
| | No New DER Case | 1,906 | 1,906 | 1,906 | 1,906 |
| | **Commited BTM PV** | | | | |
| | CEC 2018 IEPR - Mid PV + Mid-Mid AAPV | 12,439 | 16,797 | 25,446 | 32,466 |
| | No New DER Case | 12,439 | 12,439 | 12,439 | 12,439 |
| | **Additional Achievable BTM PV** | | | | |
| | CEC 2018 IEPR - Mid PV + Mid-Mid AAPV | - | 134 | 1,441 | 2,657 |
| | No New DER Case | - | - | - | - |
| | **Behind-the-Meter CHP (GWh)** | | | | |
| | CEC 2018 IEPR - Mid Demand | 13,594 | 13,637 | 13,648 | 13,595 |
| | No New DER Case | 13,594 | 13,594 | 13,594 | 13,594 |
| | **Non-PV Non-CHP Self Generation (includes storage losses) (GWh)** | | | | |
| | CEC 2018 IEPR - Mid Demand | 764 | 751 | 716 | 681 |
| | No New DER Case | 764 | 751 | 716 | 681 |

The 2020 ACC uses the No New DER scenario as the basis for its IRP inputs in the calculator. In the No New DER scenario, all IRP inputs are the same as the inputs in the final RSP, except for the amount of DER adoption.

## 2.2 "IRP Inputs" Tab

The IRP Inputs tab of the ACC contains all relevant inputs drawn from the IRP except for detailed battery cost and technology specifications that are shown separately on the "Battery Costs" tab. The IRP Inputs tab includes basic planning inputs, such as utility Weighted Average Cost of Capital (WACC) and discount rate used in the IRP proceeding. It also includes the natural gas price forecast, which is used in the IRP and originally comes from the state's Integrated Energy Policy Report (IEPR). The inputs are shown for the No New DER scenario, which is the same as the RSP except for the levels of DER adoption.

The IRP Inputs tab also shows the financial assumptions for new battery storage (utility-scale lithium-ion battery) installations. This includes the installed capacity and energy costs, levelized capacity and energy costs, and total levelized costs. These costs come from the Pro Forma model used in IRP modeling of generation resource costs. The IRP Inputs tab also includes the storage additions built in the No New DER scenario of RESOLVE. As discussed later in this documentation, the capacity avoided cost component is based on the Net CONE of battery storage, using the IRP cost assumptions and RESOLVE storage build.

## 2.3 SERVM Production Simulation

In this cycle of the ACC, a production simulation model is used to generate values for the energy, ancillary services, and emissions avoided cost components. In previous versions of the ACC, this was approached by projecting historical prices forward. As California's electricity grid is rapidly evolving with the integration of renewable energy generation and energy storage, wholesale electricity market price shapes may depart from historical trends. To better reflect these grid changes, this cycle of the Avoided Cost Calculator incorporates production simulation modeling for forecasted years. The CPUC already performs extensive production simulation modeling as a part of the IRP modeling, providing a logical source of consistency between the IRP proceeding and the ACC.

For the 2020 ACC, CPUC staff performed SERVM modeling using the No New DER case. SERVM is an 8760 hourly production simulation model, generating wholesale electricity prices based on the input system load and dispatch of the modeled generation portfolio. Model runs are performed for years 2020-2030, reflecting forecasted changes in system load and generation portfolio. Each year assumes the CEC's new California Thermal Zone 2022 (CTZ22) typical meteorological year (TMY), shown in the table below.[3] As part of the IRP process, CPUC staff developed predictive models for system load shape and renewable generation profiles based on hourly weather conditions. To accurately model the effects of real weather data, CTZ22 selects specific full historical months, and references those historical months consistently across the state. For example, for the month of June, each climate zone will use local weather data from June 2013. Climate zone effects are then aggregated up to balancing authority and statewide levels.

*Table 3. CTZ22 Historical Weather Months*

| CTZ Weather Year | |
|---|---|
| **Month** | **Year** |
| 1 | 2004 |
| 2 | 2008 |
| 3 | 2014 |
| 4 | 2011 |
| 5 | 2017 |
| 6 | 2013 |
| 7 | 2011 |
| 8 | 2008 |
| 9 | 2006 |
| 10 | 2012 |
| 11 | 2005 |
| 12 | 2004 |

To accurately model grid conditions, SERVM has representations of each balancing area in WECC. Since the ACC is focused on evaluating programs within IOU territories, SERVM outputs are taken from IOU balancing areas – PG&E Bay, PG&E Valley, SCE, and SDG&E. These results are aggregated up to NP-15 (PG&E Bay and Valley) and SP-15 (SCE and SDG&E) by taking load-weighted averages of hourly market price forecasts.

The SERVM modeling results are used as the basis for energy, ancillary services, and emissions avoided cost components, as discussed in more detail later in this documentation.

[3] See presentations from Oct 17, 2019 CEC Workshop and methodology reports (forthcoming) under Dockets #19-BSTD-03 and #19-BSTD-04: https://ww2.energy.ca.gov/title24/2022standards/prerulemaking/documents/

# 3 Distribution Resource Planning Proceeding Inputs

In June 2019, the ALJs in the DRP and IDER proceedings jointly issued an Amended Ruling "to determine how to estimate the value that results from using DER to defer transmission and distribution (T&D) infrastructure".[4] The Ruling includes an Energy Division White Paper entitled *Staff Proposal on Avoided Cost and Locational Granularity of Transmission and Distribution Deferral Values* (T&D Staff White Paper) to estimate avoided T&D costs based on the forecast data provided in the IOU Grids Needs Assessment (GNA) and Distribution Deferral Opportunities Reports (DDOR).

We apply the T&D Staff White Paper methodology for calculating transmission and distribution values in this update. This methodology calculates specified and unspecified costs for both transmission and distribution.

Specified distribution deferral values are already estimated through the DRP's Distribution Investment Deferral Framework and therefore do not require further modeling to estimate or incorporate their values into the ACC.

Unspecified distribution deferral values are costs that reflect the increased need for distribution capacity projects that are likely to occur in the future, but are not specifically identified in current utility distribution planning. Unspecified distribution deferral values are calculated using a system-average approach and a counterfactual forecast to determine the impact of DERs on load. Transmission avoided costs are developed from general rate case (GRC) data and data provided by the IOUs (Section 9). Distribution avoided costs are developed using information from the Distribution Deferral Opportunity Report and the Grid Needs Assessment, as filed in the DRP proceeding, supplemented with information acquired through data requests (Section 10)

# 4 Natural Gas Avoided Costs

Natural gas avoided costs are developed in a separate ACC for natural gas, which is used to determine the benefits of programs which reduce direct natural gas consumption. The Natural Gas ACC uses natural gas forward prices and CEC IEPR forecasts to develop avoided costs both for retail natural gas consumption and for electric generation (EG). The EG natural gas avoided costs are then used as an input for the Electricity ACC.

## 4.1 Continental Natural Gas Market

Natural gas delivered to California consumers is traded in an aggregate wholesale market that spans most of North America. Interstate natural gas pipelines transport the gas from the wellhead to wholesale market centers or "pricing hubs," where buyers include marketers, large retail customers, electric generators, and local distribution companies (LDCs) that purchase gas on behalf of small retail customers.

[4] ADMINISTRATIVE LAW JUDGE'S AMENDED RULING REQUESTING COMMENTS ON THE ENERGY DIVISION WHITE PAPER ON AVOIDED COSTS AND LOCATIONAL GRANULARITY OF TRANSMISSION AND DISTRIBUTION DEFERRAL VALUES, June 13, 2019.

Spot gas is traded in monthly and daily packages. Monthly deals are made during the last week of each month ("bid week") for delivery the following month. Daily trading is generally for delivery the following day. Spot gas trading is overwhelmingly bilateral, with buyers and sellers trading standard contracts by telephone or on electronic bulletin boards. The two pricing hubs most relevant for California are "PG&E Citygate" and "SoCal Border."

### 4.1.1 Futures Contracts

The CME Group offers trading in natural gas futures contracts. A natural gas futures contract is for 10,000 MMBtu delivered uniformly across a calendar month to Henry Hub. Prices are quoted in dollars per MMBtu. At any given time, 72 consecutive monthly contracts are open for trading, beginning with the next calendar month.

Natural gas futures trading is extremely liquid, especially in the early months, and the gas futures contract has become a closely watched barometer of market expectations for future price movements. Natural gas futures prices help discover the spot gas prices in a future delivery period via trading activities of futures buyers and sellers.

### 4.1.2 Basis Trading

The central and most liquid trading hub for natural gas is Henry Hub. Natural gas futures contracts typically trade out for 10 years at Henry Hub. Trading at other points is less active. Traders typically link prices at different locations through "basis differentials." A basis differential is the difference in the market value of natural gas at a given location and Henry Hub for the same month. Basis differentials respond to temporary events such as localized shortages or surpluses of natural gas supply or reductions in pipeline capacity. They can also vary over time with the introduction of new pipeline or storage capacity, changes in production costs at various locations, or permanent demand shifts.

Forward basis differentials are traded as financial derivatives known as "basis swaps." The holder of one side of a basis swap agrees to pay the counterparty the difference between the spot prices at the two specified locations at the designated time. The CME Group offers clearing services and calculates settlement prices for forward natural gas basis swaps contracts between Henry Hub and a number of pricing points, including the two California locations mentioned above: PG&E Citygate and SoCal Border. Forward basis swaps contracts are for 2,500 MMBtu, and are settled as the monthly bid week spot price (as defined by a particular price index such as *Natural Gas Intelligence*) minus the final settlement price of a Henry Hub futures contract for the corresponding month.[5] Trading for basis swaps do not trade as far out into the future as Henry Hub futures, typically only five years or less. Settlement prices are only calculated for those months in which traders hold open positions.

Forward prices for Henry Hub, PG&E Citygate and SoCal Border are obtained from the S&P Global Market Intelligence Platform.

[5] New York Mercantile Exchange, http://www.nymex.com/jsp/markets/ng_oth_pgbdes.jsp

## 4.2 Natural Gas Commodity Cost

In order to project natural gas commodity costs, the ACC divides the forecast time frame into three periods, defined by the availability of market data. This hybrid approach combines a market-based forecast for the near-term, when futures contracts are traded, and a model-based forecast for the long-term when there is no futures trading.

- **Market Period (2020-2024).** During this period, the average future contract prices from the S&P Global Market Intelligence are used for the Henry Hub along with forward prices for the SoCal Border and PG&E Citygate.[6] The average is over the year and is based on the 22 most recent trading day prices available at the time of update. For the months January through March in 2020, actual closing prices are used.[7]
- **Transition (2025-2027).** Three-year transition period that is the linear interpolation between the 2025 and 2029 price forecasts.
- **Model Period (2028 and beyond).** No futures contracts are traded for this period. Therefore, the ACC relies on forecasts of long-term natural gas prices. The 2019 ACC used the U.S. DOE EIA Annual Energy Outlook forecast for Henry Hub. For the 2020 ACC, the CEC IEPR natural gas price forecast will be used instead in order to be consistent with the natural gas prices used in the IRP proceeding. The IEPR provides forecasts for the SoCal Border and PG&E Citygate.

The ACC translates the annual forecast values into monthly values using multipliers derived from the IEPR forecast.

### 4.2.1 Avoidable Marginal Distribution Costs for Core Customers

Avoided distribution costs reflect avoided or deferred upgrades to the distribution systems of each of the three major LDCs in California. Unlike with electricity, hourly allocations are not necessary because of the ability of utilities to "pack the pipe," making use of the natural storage capacity of gas pipelines. Costs are allocated to winter peak months, however, to reflect the winter-peak driven capacity costs (especially for distribution pipe serving core customers). The avoided costs are from the Original 2005 Avoided Cost Report, and have only been updated for inflation.

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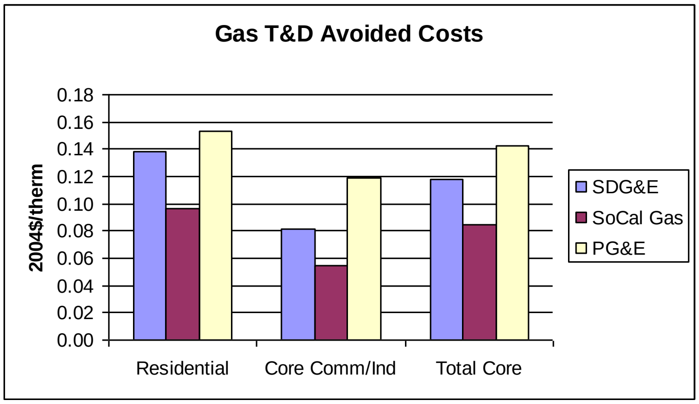
[6] S&P Global, Market Intelligence: Natural Gas Markets Forwards & Futures. West- West Coast Monthly Full Value Future/Forward as of 3/20/2020-04/20/2020

[7] S&P Global, Market Intelligence: Historical Commodity View Spot Natural Gas Index Monthly Average Price. Accessed 4/21/2020

*Figure 3. Natural Gas T&D Avoided Costs by Utility*




### 4.2.2 Transportation Charges for Electric Generators

Avoided natural gas costs for electric generators serve as inputs to electricity avoided costs. Electric generators in California purchase natural gas directly from the wholesale market, paying only transportation charges to LDCs. Because generators are not core customers, the appropriate measure of avoidable transportation charges is the applicable LDC tariff rate. The rates in Table 4 below are taken from the IEPR Power Plant Burner Tip Price Model.[8]

*Table 4. Gas Transportation Charges for Electric Generators ($/MMBtu)*

| SoCalGas Backbone | SoCalGas TLS | PG&E Backbone (Redwood to On-System) | PG&E Backbone EG |
|---|---|---|---|
| $0.3207 | $0.1831 | $0.1160 | $0.6798 |

# 5 Avoided Cost of Energy

The 2020 ACC has moved to using production simulation do develop energy values for the ACC. As explained earlier in this documentation, the CPUC IRP uses SERVM as a production simulation model and the ACC uses results from SERVM production simulation for energy avoided costs. Market prices reported directly from SERVM include the effects of carbon pricing from the cap and trade market. In post-processing the SERVM prices, the cap and trade value is backed out to provide an hourly energy only value for use in the ACC. The remaining energy value includes only fuel costs and power plant operating costs.

Day-ahead (DA) hourly energy prices from SERVM are used for energy component in the ACC to evaluate all types of DER. SERVM results are also used to develop real-time (RT) energy prices and prices for the ancillary services (AS) frequency regulation and spinning reserves. The RT energy and AS prices are used in

[8] CEC Power Plant Burner Tip Price Model, October 16, 2019, available at: https://ww2.energy.ca.gov/assessments/ng_burner_tip.html

two ways. The first is to calculate market revenues earned by battery storage for calculation of generation capacity value (Section 8). The second is to estimate market revenues that could be earned by dispatchable DER participating in wholesale CAISO markets. The RT energy and AS prices are not included in the standard ACC components for DER cost-effectiveness but are made available for use in other CPUC proceedings evaluating dispatchable DER (e.g. for energy storage in the Self-generation Incentive Program).

## 5.1 Post-processing of SERVM Prices

SERVM is a production simulation model that represents a theorized and optimized view of the day-ahead market. There are market dynamics that are present in the historical prices but not in the SERVM simulation. ACC also require additional price streams based on the SERVM simulation to capture a full spectrum of costs. Therefore, several post-processing steps are applied to SERVM prices to better reflect historical market prices.

### 5.1.1 Extrapolating SERVM Energy Prices Beyond 2030

While SERVM model runs are only produced through 2030, the scope of the ACC extends beyond this timeframe to 2050. To extrapolate energy price beyond 2030, a similar approach to previous ACC cycles is applied. Hourly implied marginal heat rates (IMHR) as defined below remains constant from 2030 onwards.

$$IMHR = \frac{P_e - VOM_{CT}}{P_g + P_c I_c}$$

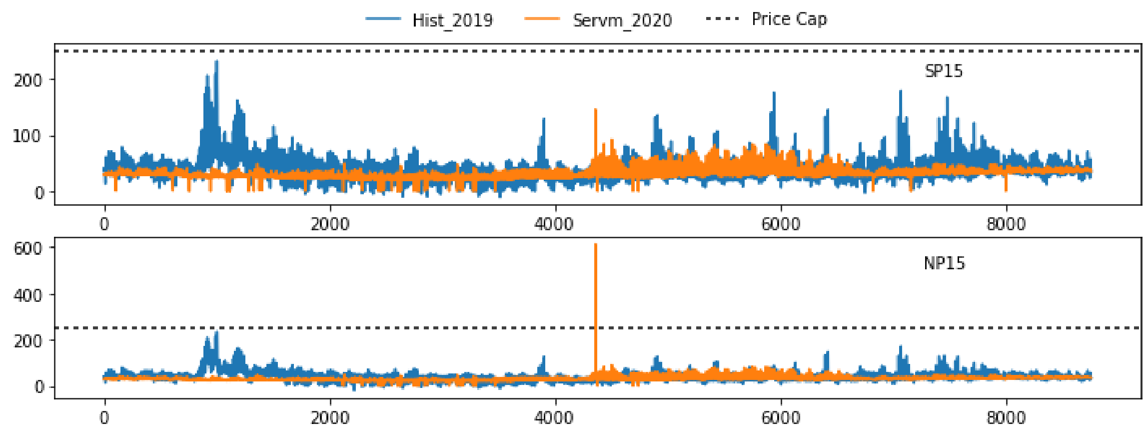
In which, $P_e$ is the energy price in \$/MWh, $VOM_{CT}$ is the variable O&M of a CT generator in \$/MWh, $P_g$ is the gas price in \$/MMBtu, $P_c$ is the carbon price in \$/tons and $I_c$ is the carbon intensity in tons-$CO_2$/MMBTU. IMHR is a simple but useful indicator of the marginal resource that is setting the hourly price. It is independent of the impact of evolving gas and carbon prices, which makes it a suitable anchor for extrapolating future energy price. Final hourly electricity market prices are calculated based on these heat rates, coupled with projections of fuel costs, power plant O&M costs and carbon prices. Fuel costs for final calculation of electricity generation prices are consistent with natural gas commodity prices discussed in Section 4.

### 5.1.2 Price Cap and Floor

First, a price floor of $0/MWh is set. Historical locational marginal prices in CASIO do fall below zero during hours of curtailment; this approach assumes that those negative prices are largely driven by Renewable Energy Credits from potentially curtailed renewable generation. In this cycle of the ACC, these negative prices are represented in the GHG Adder component – increasing load in those hours will reduce the costs of meeting electricity sector emissions targets. This reduction of costs is analogous to consuming more energy in negatively priced hours that are driven by curtailed renewables.

Secondly, a price cap of $250/MWh is also set on the energy price. SERVM prices could jump beyond $500/MWh in some most extreme hours, which lacks precedent in modern day CAISO market as shown in Figure 4 below.

*Figure 4. Comparing Historical and SERVM Simulated Energy Prices, Showing Price Cap*

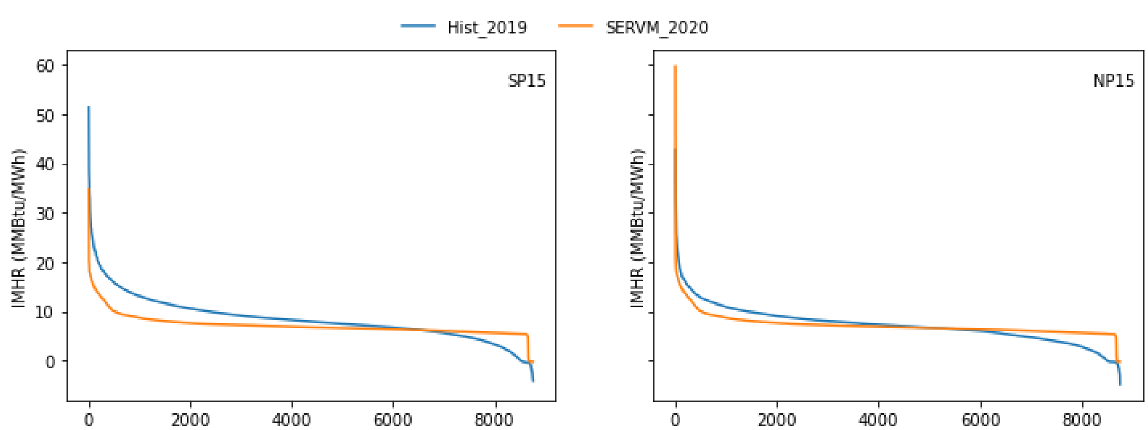



### 5.1.3 Scarcity Function

A scarcity scaling function is also applied to SERVM results to better capture the non-ideal market conditions prominent in the highest and lowest priced hours. Production simulation models are often unable to represent extreme hourly market prices, due to a lack of probabilistic real-world variables, such as contingency events, forecast errors and market irrationality.

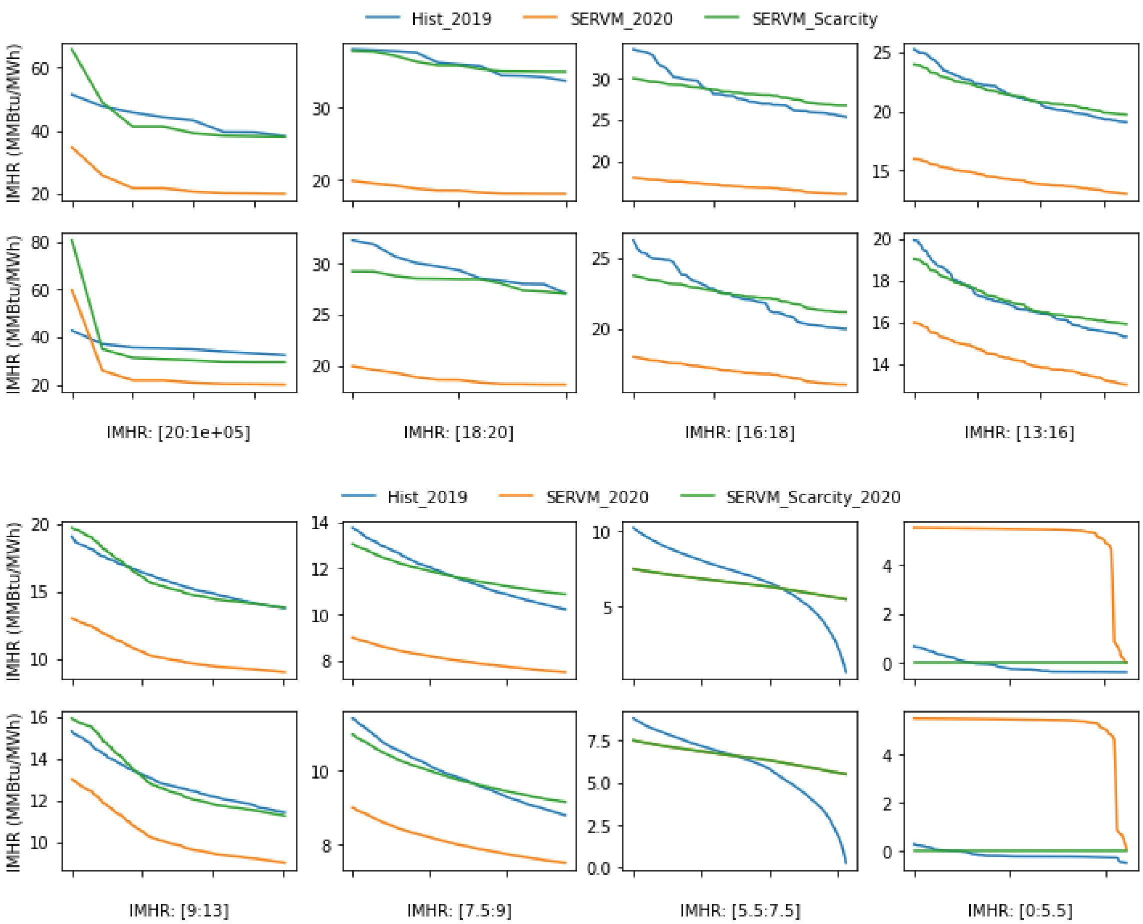
To apply the scarcity pricing algorithm, E3 compared the IMHR duration curve between a reference SERVM run in 2020 and a historical benchmark year in 2019. Once again, as IMHRs are proxies for marginal generators, for two consecutive years they should show a very similar duration curve. As shown in Figure 5 though, this is not the case especially in high and low-price region, which serves as the motivation for scarcity adjustment.

*Figure 5. Comparing the IMHR Duration Curves. Note the Discrepancy in High- and Low-price Region.*




IMHR along the duration curve are split into tranches. Adjustments are made to entire tranches rather than individual points to avoid over optimization and over-fitting the duration curve. The boundaries are determined such that there is a consistent relationship between the simulated and historical prices within each tranche. More granularity is given to the high price region. In each of the tranches, a scarcity scaling coefficient is developed with the aim to either minimize the difference between historical and scaled simulated price or reflect our understanding of the market fundamentals. After the scarcity coefficients are applied, we can see from Figure 6 that each tranche has significantly closed the gap between simulated and historical prices. Note: Labels for tranches below are in units of MMBtu/MWh; for example, IMHR 5.5:7.5 represents the range of implied marginal heat rate from 5,500 Btu/kWh to 7,500 Btu/kWh.

*Figure 6. Scarcity Adjustment within each IMHR Tranche*




The scarcity scaling factors for each zone and tranche is listed in Table 5. Notably, the scaling coefficients for IMHR between [0,5] are set to 0. This area is dominated by zero marginal cost renewable and possibly imported hydro, which is why we scaled the heat rate and consequently energy price to 0. For the high heat rate area, we need an upwards correction as the scarcity scalers are larger than one.

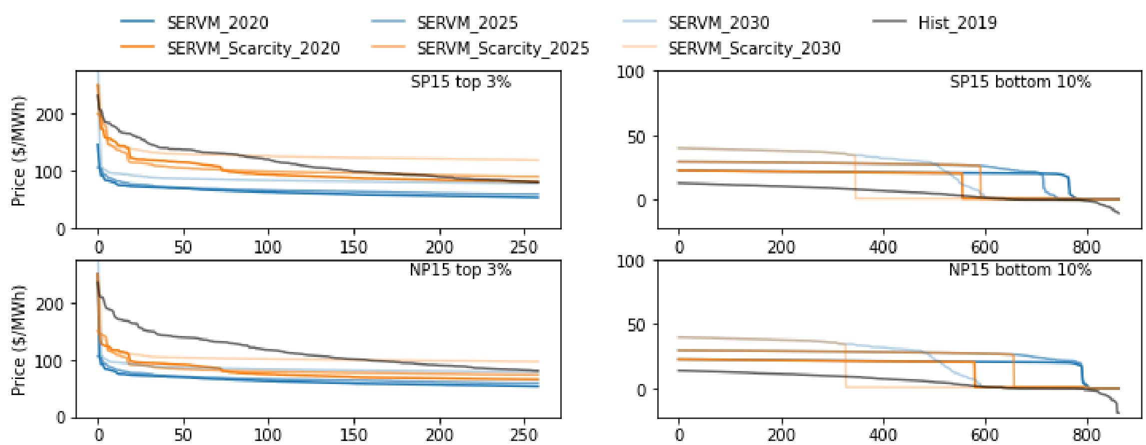
*Table 5. Scarcity Scaling Factors for each Zone and Tranche*

| IMHR Tranches, Lower Bound (MMBtu/MWh) | SP15 | NP15 |
|---|---|---|
| -9999.0 | 1 | 1 |
| 0.0 | 0 | 0 |

| | | |
|---|---|---|
| 5.5 | 1 | 1 |
| 7.5 | 1.45 | 1.22 |
| 9.0 | 1.53 | 1.25 |
| 13.0 | 1.5 | 1.19 |
| 16.0 | 1.67 | 1.32 |
| 18.0 | 1.93 | 1.57 |
| 20.0 | 1.89 | 1.35 |

This table of scarcity scaling factors developed from the benchmark years are then applied to all future SERVM simulated prices. The high- and low-price region for the year 2020, 2030 and 2040 after scarcity adjustment are shown in Figure 7. Overall, there are spikier extreme high prices and more zero and near zero price hours as suggested by the trend in 2019 historical prices.

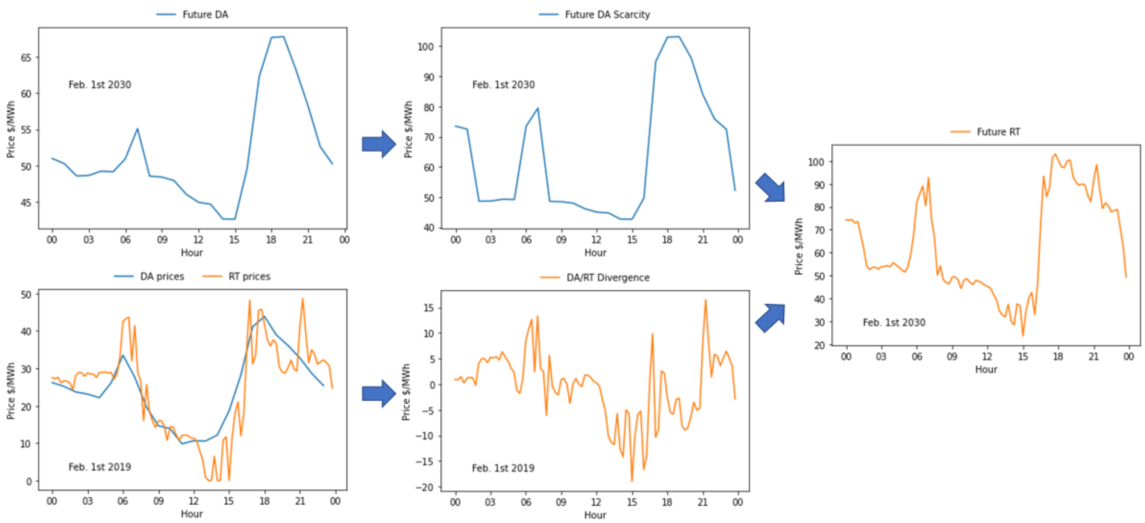
*Figure 7. Future Simulated Prices after Scarcity Adjustment, Highlighting High- and Low-price Region*




## 5.1.4 Real-time Prices

Real-time market (15-minute) prices are also developed based on the scarcity adjusted hourly prices, to serve as input to the energy price revenue stream. The ACC uses the day-ahead (DA) and real-time (RT) price divergence in 2019 and superimposed this hourly divergence on top of future simulated future day-ahead price to obtain synthetic real time prices. An overall diagram of the synthetic RT series can be seen in Figure 8.

*Figure 8. Overall Methodology of Generating Future Real-time Prices*




It is indeed unlikely that historical DA/RT divergence would repeat itself hour by hour in the future. However, ACC is not concerned with accurately calculating revenue for an individual hour, but rather representing cost mitigation over an extended and aggregated period. In this aspect, this methodology can capture aggregated annual DA/RT divergence. Inherent in this methodology is also the assumption that the annual DA/RT divergence would persist into the future. The current divergence is largely driven by stochastic events such as renewable/load forecast errors and unscheduled unit outage. This methodology essentially assumes that future storage installation would cancel out increase in net-load forecast error due to increasing renewable installation, and the total amount of uncertainty remains at the current manageable level.

## 5.2 Energy Price Calendar Alignment

Users of the ACC generally calculate the impacts of a DER by multiplying the hourly avoided costs from the ACC by the hourly impact shape of their DER measure. Many DER impact shapes can vary significantly between weekdays and weekends/holidays because of different usage levels on non-workdays. It is therefore important that the weekends/holidays line up correctly in the impact shape and avoided cost data. The standard approach is to estimate impact shapes using a single defined calendar, regardless of what year's avoided costs are being used. To accommodate this, the avoided costs need to reflect the same chronology for all years. For example, in the 2019 ACC, all years reflected a 2018 calendar year.

In this ACC, all years reflect a 2020 calendar year (excluding the leap year day). SERVM modeling, however, matches the calendar to the year being modeled. For example, 2020 starts on a Wednesday, while 2021 starts on a Friday. To accommodate the varying calendars in SERVM, the energy prices for years that do match the 2020 calendar (excluding the leap day), are shifted to align weekdays and weekends/holidays as if the year started on a Wednesday. The total annual energy prices of the original and shifted energy prices remain the same.

## 5.3 Energy Component Results

Following these steps, prices follow a trend of increased renewable generation and curtailment in the spring. In near-term years, peak prices occur in the summer evenings. In later years, peak prices continue to occur in summer system peak hours, but also move to the evenings and mornings of months that have limited renewable generation availability. The results of the scarcity adjusted DA energy prices from SERVM for NP-15 in 2020 and in 2030 are shown below in Figure 9 and Figure 10.

*Figure 9. 2020 NP-15 Day Ahead Market Prices from SERVM*

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | Avg. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jan | 26 | 25 | 25 | 25 | 26 | 26 | 28 | 30 | 29 | 27 | 26 | 26 | 25 | 26 | 26 | 26 | 29 | 36 | 40 | 38 | 35 | 36 | 30 | 27 | 29 |
| Feb | 23 | 23 | 23 | 23 | 23 | 24 | 27 | 28 | 24 | 22 | 21 | 20 | 20 | 19 | 21 | 22 | 24 | 32 | 36 | 34 | 31 | 29 | 27 | 26 | 25 |
| Mar | 20 | 20 | 21 | 21 | 21 | 23 | 24 | 22 | 20 | 19 | 19 | 19 | 19 | 19 | 19 | 21 | 23 | 30 | 34 | 34 | 33 | 27 | 26 | 24 | 23 |
| Apr | 16 | 15 | 15 | 18 | 17 | 20 | 20 | 18 | 15 | 17 | 17 | 16 | 17 | 15 | 15 | 18 | 24 | 25 | 30 | 33 | 30 | 24 | 21 | 20 | 20 |
| May | 14 | 15 | 14 | 13 | 15 | 16 | 14 | 9 | 13 | 15 | 18 | 18 | 17 | 15 | 16 | 20 | 24 | 27 | 31 | 33 | 32 | 25 | 22 | 18 | 19 |
| Jun | 21 | 19 | 20 | 18 | 18 | 21 | 19 | 19 | 20 | 21 | 21 | 22 | 22 | 23 | 24 | 27 | 30 | 36 | 39 | 41 | 39 | 29 | 24 | 23 | 25 |
| Jul | 22 | 22 | 22 | 22 | 22 | 22 | 21 | 21 | 22 | 23 | 23 | 23 | 24 | 24 | 26 | 33 | 38 | 69 | 62 | 61 | 58 | 53 | 26 | 23 | 32 |
| Aug | 26 | 25 | 25 | 25 | 26 | 26 | 26 | 26 | 26 | 26 | 27 | 28 | 30 | 31 | 36 | 42 | 48 | 62 | 72 | 71 | 64 | 52 | 35 | 28 | 37 |
| Sep | 26 | 26 | 25 | 25 | 26 | 27 | 27 | 25 | 25 | 25 | 25 | 26 | 26 | 28 | 32 | 37 | 41 | 55 | 66 | 63 | 52 | 50 | 33 | 29 | 34 |
| Oct | 25 | 25 | 25 | 25 | 25 | 26 | 28 | 26 | 25 | 25 | 25 | 26 | 26 | 27 | 28 | 33 | 39 | 42 | 43 | 40 | 36 | 33 | 28 | 26 | 30 |
| Nov | 29 | 29 | 29 | 28 | 29 | 29 | 30 | 30 | 29 | 29 | 28 | 28 | 28 | 28 | 29 | 32 | 40 | 46 | 46 | 42 | 38 | 38 | 33 | 32 | 32 |
| Dec | 32 | 31 | 31 | 31 | 31 | 32 | 34 | 36 | 34 | 33 | 32 | 32 | 32 | 31 | 32 | 33 | 40 | 45 | 45 | 44 | 44 | 43 | 35 | 32 | 35 |
| Avg. | 23 | 23 | 23 | 23 | 23 | 24 | 25 | 24 | 23 | 23 | 24 | 24 | 24 | 24 | 25 | 29 | 33 | 42 | 46 | 45 | 41 | 37 | 28 | 26 | 28 |

*Figure 10. 2030 NP-15 Day Ahead Market Prices from SERVM*

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | Avg. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jan | 66 | 68 | 63 | 63 | 65 | 68 | 78 | 93 | 89 | 87 | 82 | 77 | 74 | 68 | 64 | 66 | 83 | 102 | 105 | 103 | 100 | 92 | 87 | 73 | 80 |
| Feb | 66 | 68 | 67 | 65 | 66 | 70 | 79 | 84 | 64 | 57 | 55 | 54 | 53 | 53 | 52 | 56 | 67 | 89 | 95 | 93 | 88 | 82 | 74 | 72 | 69 |
| Mar | 59 | 52 | 60 | 60 | 63 | 66 | 67 | 51 | 40 | 39 | 37 | 38 | 36 | 37 | 31 | 35 | 61 | 70 | 82 | 83 | 83 | 75 | 67 | 67 | 57 |
| Apr | 44 | 45 | 46 | 46 | 47 | 56 | 51 | 20 | 10 | 10 | 12 | 13 | 10 | 6 | 3 | 5 | 26 | 67 | 71 | 70 | 66 | 61 | 54 | 52 | 37 |
| May | 50 | 50 | 50 | 51 | 56 | 55 | 41 | 20 | 23 | 24 | 26 | 27 | 26 | 21 | 14 | 20 | 47 | 70 | 76 | 82 | 75 | 68 | 61 | 58 | 45 |
| Jun | 53 | 50 | 51 | 51 | 56 | 51 | 41 | 39 | 41 | 44 | 45 | 46 | 48 | 45 | 43 | 51 | 71 | 75 | 85 | 88 | 81 | 72 | 63 | 60 | 56 |
| Jul | 48 | 49 | 48 | 48 | 49 | 48 | 41 | 40 | 42 | 46 | 46 | 43 | 40 | 35 | 35 | 52 | 62 | 98 | 96 | 93 | 89 | 87 | 63 | 58 | 56 |
| Aug | 64 | 61 | 62 | 63 | 65 | 67 | 57 | 49 | 51 | 51 | 52 | 53 | 57 | 58 | 65 | 79 | 88 | 108 | 104 | 103 | 98 | 96 | 86 | 81 | 72 |
| Sep | 65 | 65 | 65 | 65 | 66 | 74 | 63 | 46 | 46 | 46 | 46 | 47 | 48 | 51 | 55 | 66 | 74 | 94 | 93 | 92 | 90 | 87 | 81 | 76 | 67 |
| Oct | 62 | 63 | 62 | 62 | 63 | 69 | 68 | 53 | 51 | 49 | 49 | 51 | 51 | 52 | 56 | 67 | 86 | 91 | 91 | 90 | 87 | 81 | 73 | 67 | 66 |
| Nov | 61 | 62 | 61 | 60 | 60 | 62 | 65 | 61 | 52 | 51 | 51 | 50 | 50 | 51 | 51 | 58 | 72 | 88 | 88 | 87 | 87 | 83 | 76 | 68 | 65 |
| Dec | 68 | 66 | 65 | 64 | 65 | 66 | 70 | 74 | 75 | 73 | 69 | 66 | 65 | 64 | 63 | 68 | 76 | 96 | 97 | 96 | 94 | 92 | 88 | 74 | 75 |
| Avg. | 59 | 58 | 58 | 58 | 60 | 63 | 60 | 52 | 49 | 48 | 47 | 47 | 47 | 45 | 44 | 52 | 68 | 88 | 90 | 90 | 87 | 81 | 73 | 67 | 62 |

# 6 Ancillary Services

## 6.1 Avoided Ancillary Service Procurement

Ancillary services (AS) are procured in the day-ahead CAISO market largely on the basis of total load forecast for the following day. Reducing load generally reduces the amount of spin and non-spin AS that must be procured to operate the CAISO system. This load dependent AS procurement is approximately 0.9% of total wholesale energy costs, based on the latest CAISO Annual Report on Market Issues and Performance, currently for 2018.[9] Regulation services are excluded from this amount because their procurement is generally independent of load.

New for the 2020 ACC, SERVM production simulation is providing forecasted values for energy and for ancillary services. The 2020 ACC takes advantage of this information to adjust the avoided AS procurement costs going forward. The ACC calculates the ratio of spinning reserve to energy prices from 2020-2030 SERVM results and adjusts the 0.9% value from the 2018 CAISO report accordingly. The 0.9% is adjusted proportionally each year to reflect the AS as a percent of energy prices calculated from SERVM from 2021 to 2030 and then held constant through 2050.

## 6.2 Ancillary Service Market Revenues

New for the 2020 ACC, SERVM production simulation also provides prices to calculate potential market revenues from dispatchable DERs participating in wholesale markets or providing AS type services for the electric grid. These results are also used to calculate market revenues from energy storage for generation capacity value (Section 8). Real-time energy, frequency regulation and spinning reserve prices are produced from SERVM results. These follow a similar trend to energy prices, with low-cost hours corresponding with high solar generation and high cost hours corresponding with high system net load.

Ancillary Service market prices from SERVM are also only produced for each BA in WECC, for years 2020-2030. Similar to NP-15 and SP-15 energy prices, ancillary service prices for NP-15 and SP-15 are calculated as load-weighted averages of PG&E Bay and PG&E Valley (NP-15), and SCE and SDG&E (SP-15).

To extrapolate ancillary service prices beyond 2030, the 2030 normalized hourly price shape is held constant and multiplied by a projection of annual average price. Annual average prices are projected by taking the compound annual growth rate of the average hourly price for each AS price stream (Regulation and Spinning Reserves for NP-15 and SP-15). The equations for this extrapolation are as follows:

$$CAGR = \left(\frac{P_{avg,2030}}{P_{avg,2020}}\right)^{\frac{1}{(2030-2020)}} - 1$$

In which $CAGR$ is the calculated compound annual growth rate for a given AS price (regulation of spinning reserves) for a given zone (NP-15 or SP-15), $P_{avg,2030}$ and$P_{avg,2020}$ are the average hourly price for 2030 and 2020 for that price stream, respectively.

$$P_{\ avg,y} = P_{avg,2030} * (1 + CAGR)^{(y-2030)}$$

In which $P_{\ avg,y}$ is the projected average hourly price for projected year, $y$, a given AS price (regulation of spinning reserves) for a given zone (NP-15 or SP-15). And

$$P_{h,y} = P_{avg,y} * \left(\frac{P_{h,2030}}{P_{avg,2030}}\right)$$

[9] CAISO, 2018 Report on Market Issues and Performance, p. 141-142 and Figure 6.2. May 15, 2019. Available at: http://www.caiso.com/market/Pages/MarketMonitoring/AnnualQuarterlyReports/Default.aspx. Total cost of AS as a percentage of wholesale energy costs is 1.7%, and 53% of that is estimated to be spin and non-spin, resulting in 0.9%.

In which $P_{h,y}$ is the hourly market price for a given hour, $h$, in a given year, $y$, for a given AS price (regulation of spinning reserves) for a given zone (NP-15 or SP-15). SERVM produces a single price for frequency regulation, whereas the CAISO has separate markets for regulation up and regulation down. The single price from SERVM is divided in half to separately represent regulation up and regulation down prices for CAISO. The resulting NP-15 frequency regulation and spinning reserve prices from SERVM for 2020 and 2030 are shown in Figure 11 through Figure 14.

*Figure 11. 2020 NP-15 Regulation Up Market Prices from SERVM*

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | Avg. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jan | 0.5 | 0.4 | 0.4 | 0.4 | 0.4 | 0.6 | 0.9 | 1.1 | 1.1 | 0.9 | 0.8 | 0.7 | 0.6 | 0.6 | 0.6 | 0.7 | 1.2 | 1.3 | 1.6 | 1.5 | 1.2 | 1.9 | 1.2 | 0.8 | 0.9 |
| Feb | 0.5 | 0.5 | 0.4 | 0.4 | 0.4 | 0.7 | 1.2 | 1.3 | 0.9 | 0.6 | 0.5 | 0.4 | 0.4 | 0.4 | 0.4 | 0.5 | 0.9 | 1.3 | 1.5 | 1.3 | 1.2 | 1.2 | 0.9 | 0.6 | 0.8 |
| Mar | 0.4 | 0.2 | 0.3 | 0.3 | 0.5 | 0.8 | 1.1 | 0.8 | 0.6 | 0.5 | 0.4 | 0.4 | 0.5 | 0.5 | 0.4 | 0.6 | 1.0 | 1.2 | 1.3 | 1.5 | 1.3 | 1.1 | 1.0 | 0.7 | 0.7 |
| Apr | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.8 | 1.3 | 2.2 | 2.3 | 2.5 | 2.4 | 2.1 | 2.6 | 2.8 | 1.4 | 0.8 | 0.7 | 0.4 | 0.3 | 0.4 | 0.4 | 0.3 | 0.3 | 1.1 |
| May | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 | 0.8 | 1.2 | 1.6 | 1.9 | 2.1 | 2.2 | 2.3 | 2.2 | 2.1 | 0.9 | 0.8 | 0.7 | 0.4 | 0.5 | 0.4 | 0.4 | 0.4 | 0.3 | 1.0 |
| Jun | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.4 | 0.4 | 0.6 | 0.6 | 0.6 | 0.6 | 0.8 | 0.7 | 1.0 | 1.4 | 1.6 | 1.2 | 1.1 | 1.4 | 1.1 | 0.8 | 0.6 | 0.3 | 0.7 |
| Jul | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.3 | 0.3 | 0.3 | 0.5 | 0.5 | 0.6 | 0.6 | 1.0 | 1.6 | 1.4 | 9.0 | 5.0 | 4.3 | 3.7 | 3.0 | 0.6 | 0.2 | 1.4 |
| Aug | 0.6 | 0.4 | 0.4 | 0.6 | 0.6 | 0.7 | 0.6 | 0.6 | 0.7 | 0.8 | 0.8 | 0.9 | 1.2 | 1.2 | 1.5 | 2.0 | 2.5 | 5.1 | 7.0 | 7.1 | 5.8 | 2.5 | 1.4 | 0.8 | 1.9 |
| Sep | 0.5 | 0.4 | 0.4 | 0.4 | 0.5 | 0.7 | 0.7 | 0.6 | 0.6 | 0.6 | 0.6 | 0.7 | 0.9 | 1.0 | 1.3 | 1.5 | 1.4 | 3.6 | 6.1 | 5.6 | 3.4 | 3.4 | 1.1 | 0.8 | 1.5 |
| Oct | 0.4 | 0.3 | 0.3 | 0.3 | 0.4 | 0.7 | 0.9 | 0.7 | 0.6 | 0.6 | 0.6 | 0.5 | 0.7 | 0.7 | 0.9 | 1.2 | 1.2 | 1.4 | 1.4 | 1.3 | 1.1 | 0.9 | 0.8 | 0.6 | 0.8 |
| Nov | 0.4 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 | 0.7 | 0.7 | 0.4 | 0.4 | 0.4 | 0.3 | 0.3 | 0.3 | 0.4 | 0.9 | 1.1 | 1.2 | 1.3 | 1.1 | 1.0 | 1.4 | 0.9 | 0.7 | 0.6 |
| Dec | 0.5 | 0.5 | 0.4 | 0.4 | 0.4 | 0.5 | 0.6 | 0.7 | 0.7 | 0.6 | 0.6 | 0.6 | 0.5 | 0.5 | 0.6 | 0.7 | 0.9 | 1.1 | 1.2 | 0.9 | 0.7 | 1.1 | 0.6 | 0.6 | 0.7 |
| Avg. | 0.4 | 0.3 | 0.3 | 0.3 | 0.4 | 0.5 | 0.7 | 0.8 | 0.8 | 0.8 | 0.9 | 0.9 | 0.9 | 1.0 | 1.1 | 1.1 | 1.2 | 2.3 | 2.4 | 2.2 | 1.8 | 1.5 | 0.8 | 0.5 | 1.0 |

*Figure 12. 2030 NP-15 Regulation Up Market Prices from SERVM*

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | Avg. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jan | 1.0 | 1.0 | 1.0 | 1.0 | 1.1 | 1.4 | 2.3 | 6.3 | 6.8 | 7.3 | 6.0 | 5.1 | 4.3 | 3.2 | 2.4 | 2.5 | 4.3 | 5.7 | 6.3 | 5.9 | 5.5 | 6.7 | 7.8 | 2.1 | 4.0 |
| Feb | 1.1 | 1.0 | 1.0 | 1.1 | 1.2 | 2.0 | 3.5 | 5.6 | 4.0 | 3.7 | 3.7 | 3.7 | 3.3 | 2.9 | 3.2 | 2.1 | 1.8 | 6.4 | 8.1 | 8.4 | 7.2 | 5.5 | 2.7 | 1.6 | 3.5 |
| Mar | 1.5 | 1.1 | 1.4 | 1.4 | 1.4 | 1.9 | 2.2 | 2.7 | 7.9 | 9.1 | 9.3 | 9.6 | 9.6 | 9.5 | 9.0 | 5.9 | 2.4 | 4.3 | 8.4 | 8.7 | 8.5 | 5.7 | 3.4 | 2.5 | 5.3 |
| Apr | 0.5 | 0.3 | 0.3 | 0.3 | 0.4 | 1.3 | 5.5 | 13.1 | 12.0 | 12.1 | 11.5 | 11.2 | 9.6 | 8.4 | 5.9 | 6.1 | 7.3 | 2.7 | 3.9 | 4.5 | 3.3 | 2.1 | 1.2 | 0.5 | 5.2 |
| May | 0.9 | 1.0 | 0.8 | 1.1 | 2.7 | 3.3 | 8.5 | 12.7 | 15.2 | 15.2 | 17.1 | 16.8 | 15.0 | 12.8 | 13.0 | 14.2 | 5.9 | 3.0 | 4.2 | 4.0 | 3.6 | 2.3 | 1.0 | 0.9 | 7.3 |
| Jun | 1.6 | 0.5 | 0.6 | 0.7 | 1.6 | 0.9 | 4.2 | 8.7 | 9.3 | 9.5 | 9.8 | 10.4 | 10.8 | 10.3 | 10.6 | 7.0 | 2.2 | 3.6 | 7.0 | 7.1 | 5.5 | 3.9 | 2.0 | 2.2 | 5.4 |
| Jul | 1.0 | 0.6 | 0.6 | 0.6 | 0.6 | 0.7 | 2.8 | 4.4 | 5.5 | 5.8 | 6.1 | 7.0 | 7.7 | 7.8 | 7.7 | 5.0 | 2.5 | 6.4 | 6.9 | 6.9 | 6.4 | 5.7 | 2.2 | 1.7 | 4.3 |
| Aug | 2.6 | 1.7 | 1.7 | 1.7 | 1.9 | 2.4 | 1.6 | 2.8 | 3.0 | 3.4 | 3.7 | 4.3 | 4.8 | 5.2 | 5.4 | 3.5 | 3.3 | 7.4 | 5.7 | 5.7 | 7.0 | 7.2 | 7.1 | 5.5 | 4.1 |
| Sep | 2.8 | 2.3 | 2.2 | 2.2 | 2.2 | 5.1 | 2.3 | 2.4 | 3.0 | 3.2 | 3.7 | 4.0 | 4.4 | 4.7 | 4.7 | 3.4 | 3.1 | 6.2 | 7.3 | 7.6 | 8.4 | 7.3 | 7.0 | 5.5 | 4.4 |
| Oct | 1.9 | 1.7 | 1.4 | 1.4 | 1.5 | 3.2 | 2.7 | 2.0 | 2.4 | 2.4 | 2.7 | 3.1 | 3.1 | 3.2 | 3.0 | 2.7 | 2.5 | 9.0 | 9.0 | 9.4 | 9.2 | 7.2 | 5.0 | 2.7 | 3.8 |
| Nov | 1.2 | 1.3 | 1.5 | 1.2 | 1.3 | 1.7 | 2.3 | 2.4 | 2.1 | 2.2 | 2.1 | 2.0 | 1.9 | 2.0 | 2.3 | 2.8 | 3.4 | 9.0 | 9.2 | 10.3 | 10.7 | 9.5 | 6.2 | 2.2 | 3.8 |
| Dec | 1.1 | 1.1 | 0.8 | 0.8 | 0.8 | 1.3 | 1.9 | 3.1 | 4.2 | 4.1 | 3.7 | 3.4 | 3.2 | 2.8 | 2.4 | 3.0 | 2.4 | 5.5 | 5.9 | 6.9 | 9.7 | 9.9 | 8.7 | 2.6 | 3.7 |
| Avg. | 1.4 | 1.1 | 1.1 | 1.1 | 1.4 | 2.1 | 3.3 | 5.5 | 6.3 | 6.5 | 6.6 | 6.7 | 6.5 | 6.1 | 5.8 | 4.9 | 3.4 | 5.8 | 6.8 | 7.1 | 7.1 | 6.1 | 4.6 | 2.5 | 4.6 |

*Figure 13. 2020 NP-15 Spinning Reserve Prices from SERVM*

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | Avg. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jan | 0.5 | 0.4 | 0.4 | 0.4 | 0.4 | 0.6 | 0.9 | 1.1 | 1.1 | 0.9 | 0.8 | 0.7 | 0.6 | 0.6 | 0.6 | 0.7 | 1.2 | 1.3 | 1.6 | 1.5 | 1.2 | 1.9 | 1.2 | 0.8 | 0.9 |
| Feb | 0.5 | 0.5 | 0.4 | 0.4 | 0.4 | 0.7 | 1.2 | 1.3 | 0.9 | 0.6 | 0.5 | 0.4 | 0.4 | 0.4 | 0.4 | 0.5 | 0.9 | 1.3 | 1.5 | 1.3 | 1.2 | 1.2 | 0.9 | 0.6 | 0.8 |
| Mar | 0.4 | 0.2 | 0.3 | 0.3 | 0.5 | 0.8 | 1.1 | 0.8 | 0.6 | 0.5 | 0.4 | 0.4 | 0.5 | 0.5 | 0.4 | 0.6 | 1.0 | 1.2 | 1.3 | 1.5 | 1.3 | 1.1 | 1.0 | 0.7 | 0.7 |
| Apr | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.8 | 1.3 | 2.2 | 2.3 | 2.5 | 2.4 | 2.1 | 2.6 | 2.8 | 1.4 | 0.8 | 0.7 | 0.4 | 0.3 | 0.4 | 0.4 | 0.3 | 0.3 | 1.1 |
| May | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 | 0.8 | 1.2 | 1.6 | 1.9 | 2.1 | 2.2 | 2.3 | 2.2 | 2.1 | 0.9 | 0.8 | 0.7 | 0.4 | 0.5 | 0.4 | 0.4 | 0.4 | 0.3 | 1.0 |
| Jun | 0.2 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.4 | 0.4 | 0.6 | 0.6 | 0.6 | 0.6 | 0.8 | 0.7 | 1.0 | 1.4 | 1.6 | 1.2 | 1.1 | 1.4 | 1.1 | 0.8 | 0.6 | 0.3 | 0.7 |
| Jul | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.3 | 0.3 | 0.3 | 0.5 | 0.5 | 0.6 | 0.6 | 1.0 | 1.6 | 1.4 | 9.0 | 5.0 | 4.3 | 3.7 | 3.0 | 0.6 | 0.2 | 1.4 |
| Aug | 0.6 | 0.4 | 0.4 | 0.6 | 0.6 | 0.7 | 0.6 | 0.6 | 0.7 | 0.8 | 0.8 | 0.9 | 1.2 | 1.2 | 1.5 | 2.0 | 2.5 | 5.1 | 7.0 | 7.1 | 5.8 | 2.5 | 1.4 | 0.8 | 1.9 |
| Sep | 0.5 | 0.4 | 0.4 | 0.4 | 0.5 | 0.7 | 0.7 | 0.6 | 0.6 | 0.6 | 0.6 | 0.7 | 0.9 | 1.0 | 1.3 | 1.5 | 1.4 | 3.6 | 6.1 | 5.6 | 3.4 | 3.4 | 1.1 | 0.8 | 1.5 |
| Oct | 0.4 | 0.3 | 0.3 | 0.3 | 0.4 | 0.7 | 0.9 | 0.7 | 0.6 | 0.6 | 0.6 | 0.5 | 0.7 | 0.7 | 0.9 | 1.2 | 1.2 | 1.4 | 1.4 | 1.3 | 1.1 | 0.9 | 0.8 | 0.6 | 0.8 |
| Nov | 0.4 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 | 0.7 | 0.7 | 0.4 | 0.4 | 0.4 | 0.3 | 0.3 | 0.3 | 0.4 | 0.9 | 1.1 | 1.2 | 1.3 | 1.1 | 1.0 | 1.4 | 0.9 | 0.7 | 0.6 |
| Dec | 0.5 | 0.5 | 0.4 | 0.4 | 0.4 | 0.5 | 0.6 | 0.7 | 0.7 | 0.6 | 0.6 | 0.6 | 0.5 | 0.5 | 0.6 | 0.7 | 0.9 | 1.1 | 1.2 | 0.9 | 0.7 | 1.1 | 0.6 | 0.6 | 0.7 |
| Avg. | 0.4 | 0.3 | 0.3 | 0.3 | 0.4 | 0.5 | 0.7 | 0.8 | 0.8 | 0.8 | 0.9 | 0.9 | 0.9 | 1.0 | 1.1 | 1.1 | 1.2 | 2.3 | 2.4 | 2.2 | 1.8 | 1.5 | 0.8 | 0.5 | 1.0 |

*Figure 14. 2030 SP-15 Spinning Reserve Prices from SERVM*

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | Avg. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jan | 0.7 | 0.6 | 0.7 | 0.6 | 0.6 | 0.8 | 1.3 | 3.4 | 3.9 | 4.2 | 3.2 | 2.7 | 2.6 | 1.8 | 1.4 | 1.5 | 2.6 | 3.5 | 3.9 | 3.7 | 3.4 | 4.0 | 4.4 | 1.3 | 2.4 |
| Feb | 0.6 | 0.6 | 0.6 | 0.6 | 0.7 | 1.1 | 2.0 | 3.1 | 2.2 | 2.1 | 2.2 | 2.2 | 2.0 | 1.6 | 1.9 | 1.2 | 1.0 | 3.8 | 4.6 | 5.0 | 4.2 | 3.3 | 1.7 | 1.0 | 2.1 |
| Mar | 0.9 | 0.6 | 0.8 | 0.8 | 0.8 | 1.2 | 1.3 | 1.6 | 4.6 | 5.3 | 5.4 | 5.5 | 5.6 | 5.5 | 5.1 | 3.3 | 1.3 | 2.5 | 4.9 | 5.0 | 4.9 | 3.1 | 2.0 | 1.5 | 3.1 |
| Apr | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.8 | 3.2 | 7.6 | 7.0 | 7.2 | 6.7 | 6.6 | 5.8 | 5.0 | 3.5 | 3.5 | 4.2 | 1.6 | 2.3 | 2.7 | 1.8 | 1.1 | 0.5 | 0.2 | 3.0 |
| May | 0.5 | 0.6 | 0.4 | 0.7 | 1.6 | 2.0 | 4.8 | 7.3 | 8.8 | 8.9 | 9.8 | 9.7 | 8.8 | 7.6 | 7.3 | 8.2 | 3.6 | 1.7 | 2.3 | 2.2 | 2.0 | 1.4 | 0.5 | 0.5 | 4.2 |
| Jun | 0.9 | 0.2 | 0.4 | 0.4 | 0.9 | 0.5 | 2.5 | 5.1 | 5.6 | 5.4 | 5.8 | 6.2 | 6.4 | 6.1 | 6.2 | 4.1 | 1.3 | 2.0 | 4.0 | 4.1 | 3.1 | 2.3 | 1.1 | 1.2 | 3.2 |
| Jul | 0.5 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 | 1.6 | 2.6 | 3.2 | 3.4 | 3.5 | 4.2 | 4.4 | 4.5 | 4.4 | 2.9 | 1.4 | 3.5 | 3.9 | 3.8 | 3.5 | 2.9 | 1.1 | 0.8 | 2.4 |
| Aug | 1.5 | 1.0 | 0.9 | 1.0 | 1.2 | 1.4 | 0.9 | 1.6 | 1.7 | 2.0 | 2.1 | 2.4 | 2.7 | 3.1 | 3.1 | 1.9 | 2.1 | 4.3 | 3.3 | 3.4 | 4.2 | 4.1 | 4.1 | 3.1 | 2.4 |
| Sep | 1.6 | 1.3 | 1.2 | 1.3 | 1.3 | 2.9 | 1.3 | 1.4 | 1.6 | 1.8 | 2.2 | 2.2 | 2.5 | 2.8 | 2.7 | 1.9 | 1.8 | 3.6 | 4.2 | 4.5 | 5.0 | 4.2 | 4.0 | 3.1 | 2.5 |
| Oct | 1.1 | 0.9 | 0.7 | 0.8 | 0.8 | 1.9 | 1.7 | 1.2 | 1.4 | 1.4 | 1.5 | 1.8 | 1.9 | 1.9 | 1.8 | 1.6 | 1.6 | 5.2 | 5.3 | 5.6 | 5.6 | 4.3 | 2.9 | 1.4 | 2.3 |
| Nov | 0.7 | 0.8 | 0.9 | 0.8 | 0.8 | 1.1 | 1.4 | 1.5 | 1.3 | 1.4 | 1.3 | 1.2 | 1.1 | 1.2 | 1.4 | 1.8 | 2.0 | 5.0 | 5.1 | 5.8 | 6.2 | 5.7 | 3.7 | 1.5 | 2.2 |
| Dec | 0.5 | 0.7 | 0.5 | 0.5 | 0.5 | 0.8 | 1.1 | 1.7 | 2.3 | 2.3 | 2.0 | 1.8 | 1.8 | 1.5 | 1.3 | 1.7 | 1.4 | 3.2 | 3.3 | 4.2 | 5.6 | 5.6 | 5.1 | 1.3 | 2.1 |
| Avg. | 0.8 | 0.6 | 0.6 | 0.7 | 0.8 | 1.2 | 1.9 | 3.2 | 3.6 | 3.8 | 3.8 | 3.9 | 3.8 | 3.6 | 3.3 | 2.8 | 2.0 | 3.3 | 3.9 | 4.2 | 4.1 | 3.5 | 2.6 | 1.4 | 2.7 |

# 7 Avoided Cost of Greenhouse Gas Emissions

To determine the avoided costs of GHG emissions, it is necessary to determine both the *amount* and the *value* of GHG emissions from the electric grid.

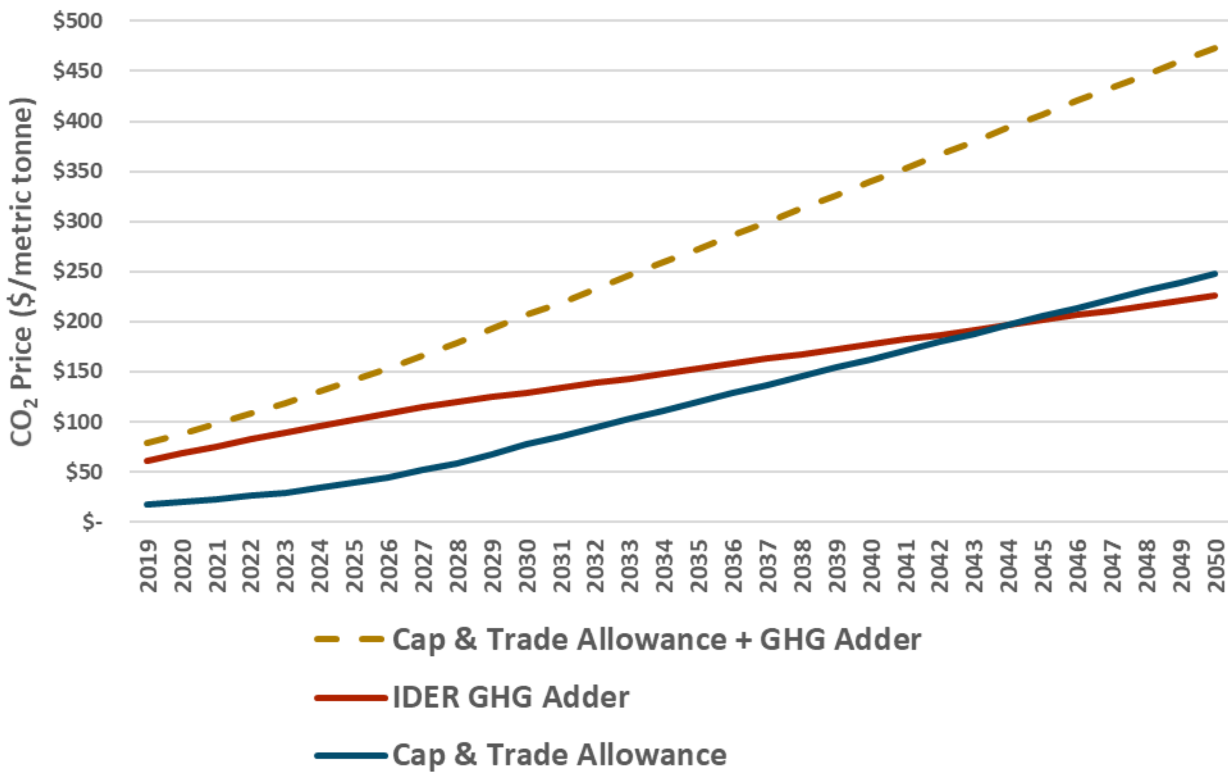
## 7.1 GHG Value

The 2020 ACC updates the valuation of GHG emissions to better align with the IRP and California's GHG reduction goals. In the 2019 ACC, the value of GHG emissions is represented by the sum of two values: 1) the monetized carbon cap and trade allowance cost embedded in energy prices, and 2) the non-monetized carbon price beyond the cost of cap and trade allowances (represented by the "GHG Adder," as adopted by the CPUC).[10] The GHG Adder reflects the cost of further reducing carbon emissions from electricity supply, rather than the compliance cost represented by the cap and trade allowance price. The combination of adding the cap and trade price and the GHG Adder is the total GHG avoided cost component included in the 2019 ACC.

Figure 15 below depicts the price forecasts for the cap and trade allowance price (solid blue line), the IDER GHG Adder (solid red line), and the allowance price plus the GHG Adder (dashed gold line) from the 2019 ACC v1b. The dashed gold line, representing the cap and trade allowance price plus the GHG Adder, is the final GHG avoided cost component in the 2019 ACC.

[10] D.18-02-018, Table 6. Note that in Table 6 of this IRP Decision, the term "GHG Adder" is used, inconsistent with the usage in IDER, to represent the combined value of the monetized cap and trade allowance price and the non-monetized residual value (rather than only the residual, non-monetized value).

*Figure 15. CO2 Cap & Trade and GHG Adder Price Series used in 2019 Avoided Cost Calculator*




For the 2020 ACC update, CPUC Energy Division staff (CPUC staff) and its consultants at E3 considered several different options for the GHG value. Because the ACC is updated to be more consistent with the IRP, CPUC staff decided to base the GHG values on IRP RESOLVE outputs from the No New DER scenario.

The key GHG cost value produced in the IRP is the shadow price of GHG emission reductions from RESOLVE. The GHG shadow prices represent the cost of reducing an additional unit of GHGs in each year. In the near-term, the GHG shadow price is fairly low, matching the cap and trade allowance prices. This is for a variety of reasons, but in part because renewable generation is procured prior to 2022 for reliability and to take advantage of the Federal Investment Tax Credit (ITC) before it steps down from 30% to 10%, rather than procuring renewables to support GHG goals. This results in a generation portfolio that exceeds the GHG targets for 2022 and 2026, resulting in a low GHG shadow price because emissions reductions are not the binding constraint in RESOLVE. However, after 2030 the RESOLVE GHG shadow price increases rapidly because the model must reduce GHGs in order to meet annual emissions targets for the electric sector. In other words, RESOLVE must procure additional clean energy resources in order to meet emissions targets, and this results in significant supply-side costs beyond the cap and trade allowance price. This means that emissions are more expensive in later years of the IRP as GHGs must be reduced significantly to meet the more stringent annual targets.

Figure 16 shows the different options that considered for updating the GHG value stream based on these RESOLVE values. CPUC staff started with the RESOLVE GHG shadow price as an option for the GHG avoided cost component (dotted blue line). As described above, the RESOLVE GHG shadow price is low in the near-term, which would result in much lower GHG avoided costs than in the 2019 ACC (dotted gold line) and would not accurately reflect the future cost of GHG emissions. Therefore, CPUC staff considered other options to better reflect future GHG avoided costs over the entire time horizon. The first option that CPUC staff considered (solid red line) was to take the 2030 GHG shadow price from RESOLVE and discount it for 2020-2029 based on the utility weighted average cost of capital (WACC). This option would better reflect the value of GHGs over the next ten years. This was the avoided cost stream originally recommended in the ACC Staff Proposal.

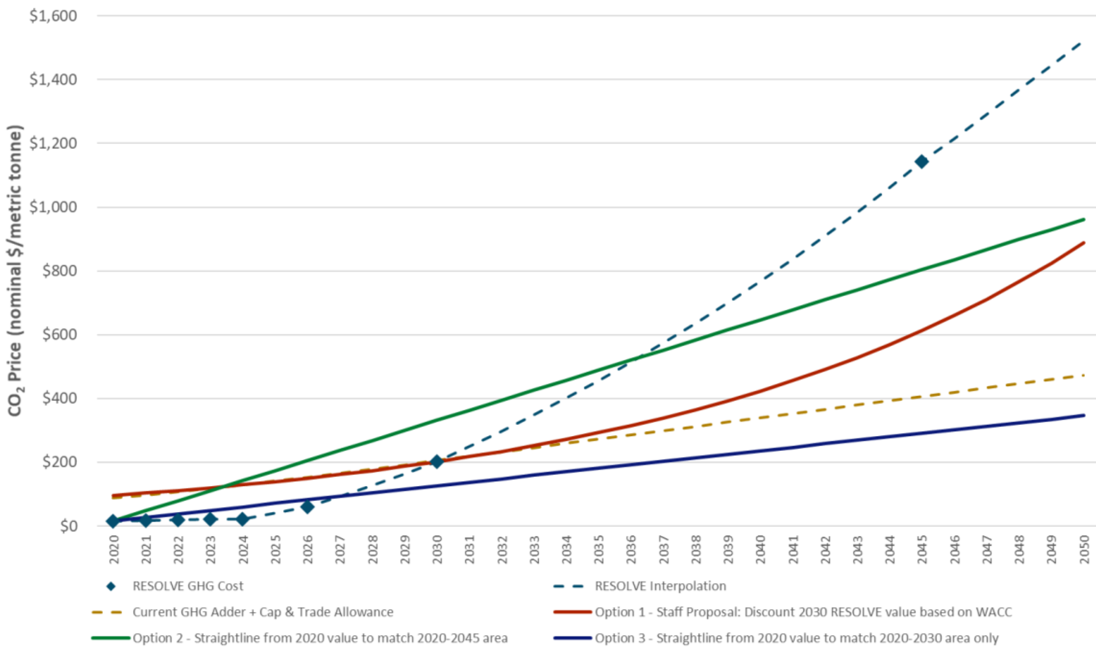
The second option that CPUC staff considered (solid green line) was to start with the RESOLVE GHG shadow price in 2020 and develop a straight-line trajectory for future years, where the area under the curve would match the RESOLVE shadow price area for all IRP years (2020-2045). Matching the area under the curve ensures that the total GHG value over time is equivalent. This method helps address the low prices in the near-term and makes the average GHG value equal the average RESOLVE shadow price during the IRP horizon. However, this option generates very high GHG values in the long-term, much larger than the values used in the 2019 ACC.

The third option that CPUC staff considered (solid purple line) was similar to the second option, except that the straight-line trajectory from the RESOLVE GHG shadow price in 2020 was developed to match the area under the RESOLVE shadow price curve for 2020-2030 only. The goal of this option was to remain consistent with the IRP by matching the 2020-2030 average shadow price value, but mitigate potentially large costs beyond 2030. However, this option produces GHG values that are low when compared with the 2019 ACC, and with RESOLVE shadow prices for 2030 and beyond. Use of this option would be inconsistent with D.20-04-010, which directed Staff to consider post-2030 values in development of the GHG adder.

Therefore, CPUC staff has decided to use the first option, discounting the RESOLVE GHG shadow price in 2030 for 2020-2029 using the utility WACC, and scaling up at the same rate for 2031 and beyond. This approach balances the goal of generating consistency with the IRP and RESOLVE with the objective of not deviating too drastically with the 2019 ACC values in the short-medium term.

This method using the RESOLVE 2030 GHG shadow price provides the total GHG avoided cost component for the calculator. The total GHG cost can still be split out as the cap and trade price and a “GHG Adder,” recalculated as the total avoided cost based on the new 2020 ACC method minus the IEPR mid-case cap and trade value. As discussed in the next section, both amounts that make up the total GHG avoided cost component are used to evaluate GHG emissions.

*Figure 16: The Options that CPUC Staff Considered for the GHG Avoided Cost Component*




## 7.2 GHG Emissions

GHG emissions levels and costs have been estimated in the ACC for years. Emissions levels and costs were based on changes in CO2 output of the marginal generating unit in each hour of each year. As described in the previous section, in previous ACCs the total GHG avoided costs were considered to be the sum of the cap and trade compliance cost and the IDER GHG Adder, where the cap and trade portion represented the short-term cost to utilities of purchasing carbon allowances, and the GHG Adder portion represented the cost of procuring generation resources to meet California's GHG goals. While this is a valid and appropriate estimation of the immediate or short-term impact of DER resources, the extant method did not account for how the DER would affect future emissions as the electricity system resources are rebalanced to reflect new overall levels of consumption. In other words, the extant method could over-estimate the cost of procuring future resources if the electricity sector emission targets were to change as electricity demand changed. This issue of rebalancing was not as much of a concern when the ACC's primary applications were for DERs that reduced grid electricity production. However, with the increased focus on electrification, the incremental resources to serve that new load will also have a larger impact on utility procurement costs, and those cost should be recognized in the GHG emission methodology.

In 2019 ACC, the emission levels in 2030 are assumed to be fixed. Therefore, any reduction in emissions due to reduced grid energy production from DERs reduces cap and trade costs because of lower natural gas consumption, as well as relaxing the need for emission-reducing technologies in the future, resulting in large GHG adder cost savings.

This paradigm of fixed emission levels, however, is not reasonable in a future with high electrification of buildings and transportation. It is highly unlikely that the electricity sector would be required to meet the existing emission forecast levels if electrification of buildings and transportation is to proceed. This would essentially require that those new loads be served with high cost zero GHG emitting resources, and ignore the large GHG savings that could be attained by the associated elimination of natural gas or liquid fuel usage. The approach is similar in concept to the approach used for the fuel substitution test (D. 19-08-009), described in the Fuel Substitution Technical Guidance Version 1.1.[11] The CEC also uses a similar approach for the 2022 Title 24 TDV.[12]

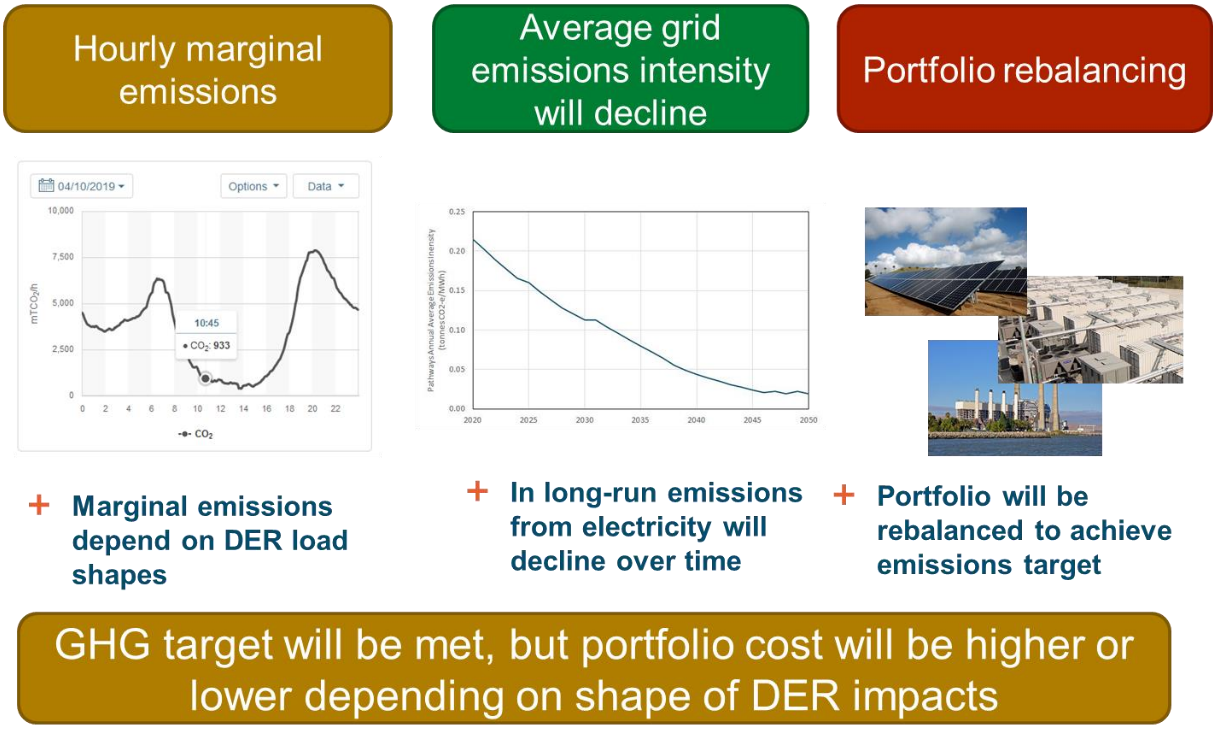
The 2020 ACC uses a two-step approach to estimate GHG emissions impacts from DER measures:

- **Step 1. Marginal Emissions:** Hourly marginal GHG emissions from DER will be estimated with hourly marginal emissions rates derived from SERVM production simulation. This is the same as was done in the 2019 ACC.
- **Step 2. Portfolio Rebalancing:** The rebalancing of emissions to meet annual electric grid GHG intensity targets from IRP. This step accounts for how the utility resource plan will adjust for added DER and be rebalanced to achieve the annual emissions intensity target. The average annual GHG emissions intensity target for the electricity sector will be estimated from RESOLVE capacity expansion modeling of the RSP.

[11] Fuel Substitution Technical Guidance for Energy Efficiency, V.1.1, October 31, 2019, Appendix A at Figure 1.

[12] Documentation is in development and will be published in the 2022 Energy Code Pre-Rulemaking Docket Log: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-BSTD-03

*Figure 17. GHG Emission Impact Estimation for DERs*




## 7.2.1 Hourly Marginal GHG Emission Impact

In the 2019 ACC, 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.[13] For the 2020 ACC update, SERVM production simulation of the No New DER case is used to calculate hourly marginal emissions. The hourly load shapes from DER will be multiplied by the hourly marginal emissions rates for each year to calculate hourly marginal emission impacts.

## 7.2.2 Average Annual Electric Grid GHG Emissions Intensity

A major methodological change for 2020 is to implement an estimate of long-run GHG emission impacts. Given that California plans to meet the SB100 goal of 100% decarbonized electricity (as measured by retail sales) by 2045, average annual electric grid GHG emissions intensity can be calculated based on an assumed GHG reduction target aligned with the SB100 goal.[14] The annual emissions intensity values derived from IRP

[13] See 2019 Avoided Cost Update Documentation available at: https://www.cpuc.ca.gov/General.aspx?id=5267

[14] A joint agency report process to assess an interpret SB 100 requirements is underway. Among the issues is an interpretation of how to define SB 100-eligible zero carbon resources. CPUC IRP inputs in the 2019 RSP modeling analysis were developed, of necessity, based on one possible interpretation of the SB100 goals. However, assumptions used for IRP modeling purposes by CPUC staff do not represent the Commission’s dispositive view on SB 100 interpretation.

are used to reflect the emissions attributed to load-modifying demand-side actions.[15] RESOLVE capacity expansion modeling in the IRP determines the least-cost resource portfolio for meeting electricity sector GHG emission targets. The RSP will achieve increasingly lower GHG emissions intensity over time.

Table 6 and Figure 18 below depict the annual emissions intensity trajectory derived from the 2017-2018 Reference System Plan. Note that the rebound in emissions intensity between 2022 and 2026 is due to the planned retirement of Diablo Canyon. Emissions intensity is calculated as tonnes of GHG per MWh of retail sales to be consistent with SB100 language that zero-carbon resources supply 100% of retail sales of electricity to end-use customers in 2030. The formula for calculating average intensity factors is shown here, for year $t$:

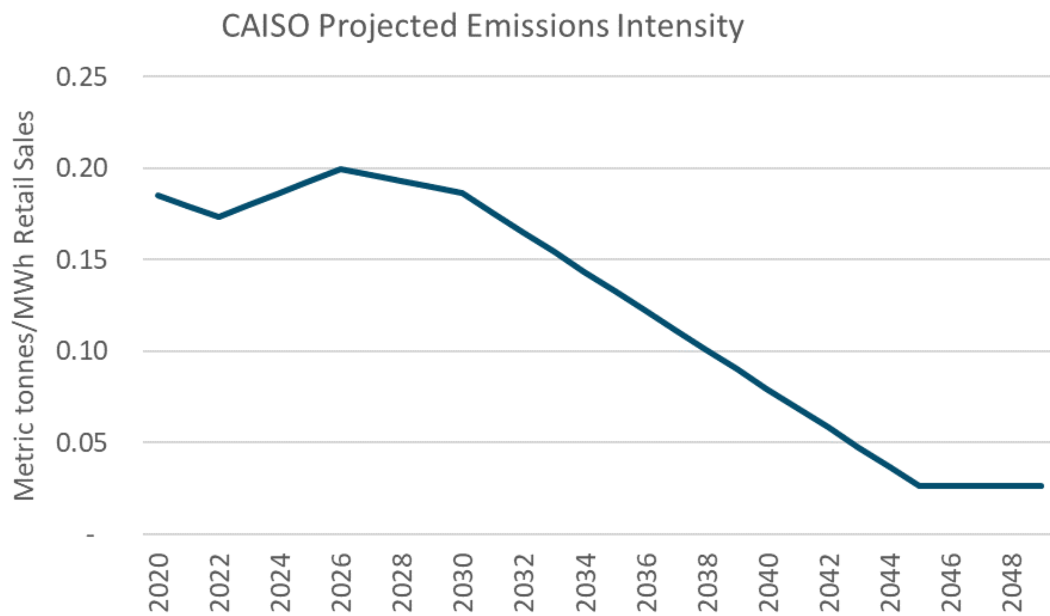
$$Emissions\ Intensity_t(\frac{tCO_2}{MWh}) = \frac{Total\ CAISO\ Emissions_t(tCO_2)}{Total\ Retails\ Sales_t\ (MWh)}$$

*Table 6. 2019 IRP Preliminary Results 46 MMT Case Load and Emissions*

| | | 2020 | 2022 | 2026 | 2030 | 2045 |
|---|---|---|---|---|---|---|
| Load | *GWh* | 242,188 | 247,401 | 253,790 | 257,010 | 382,590 |
| Retail sales | *GWh* | 207,479 | 208,055 | 207,224 | 203,413 | 294,207 |
| CAISO Emissions | *MMtCO2/Yr* | 43 | 38 | 41 | 38 | 12 |
| Intensity | *tCO2/MWh* | 0.21 | 0.18 | 0.20 | 0.19 | 0.04 |

[15] The 2017-18 Reference System Plan adopted an electric sector goal of 42 MMt $CO_2e$ by 2030, reflective of specific scenario assumptions. Energy Division's consultant E3 recommends using the implied annual emissions intensity – rather than the 42 MMt emissions goal itself or the updated 46 MMt goal in the proposed 2019-20 Reference System Plan – to reflect the electric sector target for that year.

*Figure 18. CAISO Projected Emissions Intensity, 2019 IRP Preliminary Results 46 MMT Case*




As the RSP provides retail sales and GHG emissions through 2030, a linear progression was assumed between these 2030 values and the 2045 SB100 goals to estimate emissions intensity at that end-year.[16]

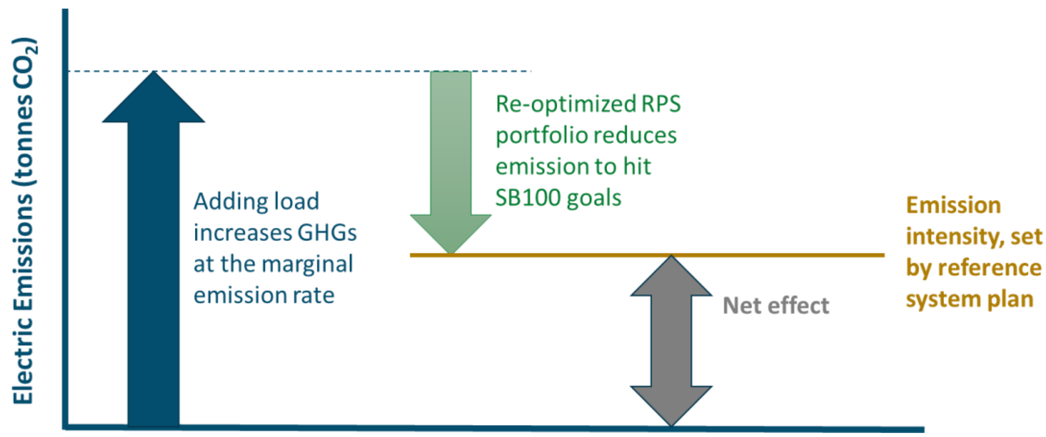
### 7.2.3 Portfolio Rebalancing GHG Emission Impacts

The 2020 ACC approach accounts for this supply-side response through a methodological shift based on declining average annual grid emissions intensity over time. The 2020 ACC assumes that the supply-side portfolio will be rebalanced to achieve the emissions intensity target set in the IRP after accounting for changes in the DER portfolio. With this approach, the GHG emissions impact will reflects the energy sector emissions cost of achieving the required annual intensity target.

Figure 19 below provides an illustrative example of how portfolio rebalancing based on annual emissions intensity targets will be implemented.

[16] To estimate the emissions intensity in 2045 it is assumed that SB100 goals will be met, requiring a minimum level of decarbonized generation equal to 100% of retail sales. With this assumption, up to approximately 7.25% of electric generation could be from natural gas generation (based on loss factor assumptions from the 2019 ACC v1b). Sector emissions in 2045 can be calculated using an assumption of the emissions intensity of a combined cycle gas turbine (with a heat rate of 7,000 Btu/kWh) and an assumed volume of fossil energy that could be used while still allowing the state to meet the SB100 target. The remaining energy on the system is assumed to have zero emissions.

*Figure 19. Illustrative Long Run Emissions Calculation*




This approach is most intuitively explained using electrification measures that increase load. The two steps described above are used:

1) the hourly marginal GHG emissions increases and
2) portfolio rebalancing to reach the long-run GHG emissions intensity target.

The first category of hourly marginal emissions will be valued at the total GHG avoided cost component– the sum of the cap and trade price and the GHG Adder, which reflects the annual economy wide cost of GHG emissions. The second category, the portfolio rebalancing, is valued at the GHG Adder only, which reflects the incremental costs associated with attaining GHG emission intensity targets.

The following equations illustrate the difference between the existing GHG calculation in the 2019 ACC and the proposed GHG calculation for the 2020 ACC. These equations reflect the value of the emissions attributable to a given measure or program in a year. Note that the first part of the 2020 ACC formula is the same as the 2019 ACC formula. The new rebalancing component is indicated by the bold font in the second equation. The total GHG avoided cost component, using the methodology based on RESOLVE outputs described earlier in this documentation, is represented by the cap and trade value plus the GHG Adder.

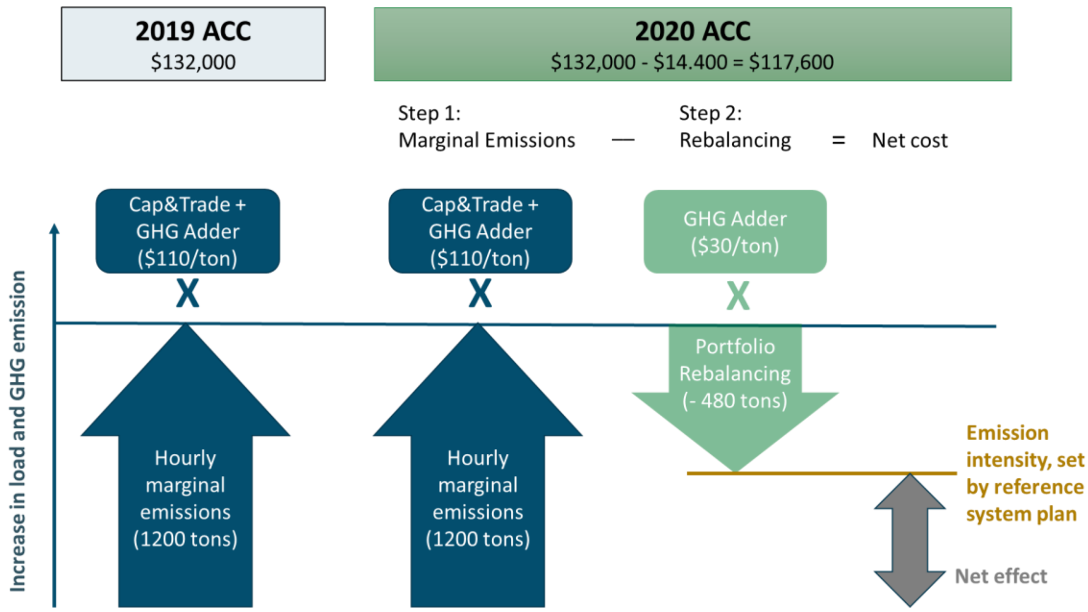
$$GHG\ Calculation_{2019\ ACC} = Load\ Shape\ (kWh)_h * Marginal\ Emissions\ (tCO_2e/kWh)_h * (Cap\&Trade + GHG\ Adder)(\$/tCO_2e)_y$$

$$GHG\ Calculation_{2020\ ACC} = Load\ Shape\ (kWh)_h * Marginal\ Emissions\ (tCO_2e/kWh)_h * (Cap\&Trade + GHG\ Adder)(\$/tCO_2e)_y - \boldsymbol{Annual\ kWh} * \boldsymbol{EmissionsIntensity_y} * \boldsymbol{GHG\ Adder}(\$/\boldsymbol{tCO_2e})_y$$

*Note, in the above equations h represents an hourly dimension, while y represents a yearly dimension.*

Figure 20 provides an illustrative example of the current ACC emissions valuation and the proposed update based on the portfolio rebalancing calculation. This example illustrates increased emissions due to a load-building measure, but the inverse relationship would hold true for a measure which instead reduces load.

*Figure 20. Current ACC GHG Valuation and Proposed Update (Illustrative Load Increase Example)*




The figure shows that the rebalancing to meet the emission intensity target reduces the GHG-related costs for the load increase (e.g.: building electrification). More details on the sample values used in the figure are presented below.

#### 7.2.3.1 Example GHG Rebalancing Calculations

This section presents example calculations for the GHG emissions impact and associated avoided costs. Using the methods described above, the examples add load to the electric grid and calculate the resulting increase in GHG emissions costs. To illustrate the combination of hourly marginal emissions and portfolio rebalancing impacts, we consider two electrification measures: 1) a commercial heat pump that adds air conditioning load in the middle of the day and 2) unmanaged residential EV charging that adds load in the evening. Each measure adds 3,000 MWh of electric load, but at different times of the day.

**Emissions Intensity:** Starting with a simple example, we begin with a supply portfolio of three resources: 1) a Combined Cycle Gas Turbine (CCGT) with an emissions rate of 0.40 tons/MWh, 2) Stand-alone utility scale PV and 3) PV integrated with long-duration energy storage that is able to avoid curtailment and deliver carbon free electricity in the evening. The IRP targets procurement of 10,000 MWh with 4,000 MWh of CCGT, 3,000 MWh of PV and 3,000 MWh of PV integrated storage. The resulting energy sector emissions are 1,600 tons with an average grid intensity of 0.16 tons/MWh.

**GHG Cost per Ton:** The cap and trade value is $80/ton and the IRP GHG value is $110/ton, making the GHG Adder $30/ton ($110-$80). In the two examples presented below, 3,000 MWh of load are added. To meet an intensity target of 0.16 tons/MWh with an addition of 3,000 MWh, only 480 tons of GHG may be added.

**Unmanaged EV Charging Example:** In this first example, 3,000 MWh of unmanaged residential EV charging load is added in the evening. No PV generation is available, and the new demand is met with an increase of 3,000 MWh of CCGT generation. However, this results in an hourly marginal emissions increase of **1,200 tons** of GHG that increases the grid emissions intensity to 0.22 tons/MWh. The resource portfolio must be rebalanced to reduce emissions by 720 in order to limit additional GHG emissions to only **480 tons** and achieve the annual target of 0.16 tons/MWh.

In the first step, the 1,200 tons of additional marginal GHG emissions are valued at the cap and trade value of $80/ton and the GHG Adder cost of $30/ton for a total cost of $132,000. This reflects the economy wide cost placed on GHG emissions. In the second step, we reflect the cost savings of rebalancing the supply portfolio to allow 480 tons of emissions in order to meet the electric sector intensity target of 0.16 tons/MWh. The rebalanced portfolio allowed emission increase of 480 tons is valued at the GHG adder value of $30/ton for a total cost reduction of $14,400. In total, of the allowable GHG emissions in step 1 ($132,000) and the portfolio rebalancing in step 2 (-$14,400) nets to $117,600. This equates to a cost of $98/ton for the 1,200 Tons of added marginal emissions and $39/MWh for the added 3,000 MWh of load.

*Table 7. GHG Cost: Unmanaged EV Charging Example*

| | | *A* | *B* | *C* | |
|---|---|---|---|---|---|
| | | GHG Cost ($/ton) | Emissions (tons CO2) | Cost ($) (A*B) | |
| 1 | Tons added | | 1,200 | | |
| 2 | Tons allowed by intensity target | | 480 | | *0.16t/MWH * L8* |
| | Marginal emissions impacts | | | | |
| 3 | Cap and Trade | $80.00 | 1,200 | $96,000 | |
| 4 | GHG Adder | $30.00 | 1,200 | $36,000 | |
| 5 | Total marginal emission cost | | | $132,000 | *L3 + L4* |
| | Rebalancing Impacts | | | | |
| 6 | GHG Adder | $30.00 | (480) | -$14,400 | |
| 7 | **Net GHG cost** | | | **$117,600** | *L5 + L6* |
| | | | | | |
| 8 | Usage added (MWh) | 3000 | | | |
| 9 | Net GHG cost per MWh | | | $39.20 | *L7/L8* |
| 10 | Net GHG Cost per ton of added marginal emissions | | | $98.00 | *L7/L1* |

**Space Heating Electrification Example:** For the second measure, 3,000 MWh of commercial space heating load is added during the day, using 2,500 MWh of carbon free PV and 500 MWh of CCGT generation. Only **200 tons** of hourly marginal GHG emissions are added, reducing the average grid intensity to 0.14 tons/MWh. This is below the annual target of 0.16 tons/MWh. To meet the 0.16 tons/MWh target emission intensity level, **480 tons** of increased emission would be allowed based on electrification load of 3000 MWh.

In step 1, the 200 tons of hourly marginal emissions are valued at the cap and trade price of $80/ton and the GHG Adder cost of $30/ton for a total cost of $22,000. In step 2, the portfolio is rebalanced to allow for an increase of 480 tons which are valued at the GHG Adder cost of $30/ton for a cost reduction of $14,400. In total the cooling load increases GHG costs by only $7,600. Dividing the $7,600 in GHG costs by the 200 tons of marginal GHG impacts results in a savings of $38/Ton. The reduced GHG costs divided by the 3,000 MWh of added load results in a GHG cost of $2.5/MWh.

*Table 8. GHG Cost: Commercial Space Heating Electrification Example*

| | | A | B | C | |
|---|---|---|---|---|---|
| | | GHG Cost ($/ton) | Emissions (tons CO2) | Cost ($) (A*B) | |
| 1 | Tons added | | 200 | | |
| 2 | Tons allowed by intensity target | | 480 | | *0.16t/MWH * L8* |
| | Marginal emissions impacts | | | | |
| 3 | Cap and Trade | $80.00 | 200 | $16,000 | |
| 4 | GHG Adder | $30.00 | 200 | $6,000 | |
| 5 | Total marginal emission cost | | | $22,000 | *L3 + L4* |
| | Rebalancing Impacts | | | | |
| 6 | GHG Adder | $30.00 | (480) | -$14,400 | |
| 7 | **Net GHG cost** | | | **$7,600** | *L5 + L6* |
| | | | | | |
| 8 | Usage added (MWh) | 3000 | | | |
| 9 | Net GHG cost per MWh | | | $2.53 | *L7/L8* |
| 10 | Net GHG Cost per ton of added marginal emissions | | | $38.00 | *L7/L1* |

#### 7.2.3.2 Implementation of the GHG Portfolio Rebalancing in the ACC

The rebalancing is based on annual average emission intensity levels described in section *7.2.2 Average Annual Electric Grid GHG Emissions Intensity.* It is calculated as:

Rebalancing $\text{Cost}_y$ ($/MWh) = - Emissions $\text{Intensity}_y$ (tonnes/MWh) * GHG Adder $\text{Cost}_y$ ($/tonne)

Within a year the rebalancing costs ($/MWh) are the same for all hours. Note that the rebalancing cost is presented as a negative value consistent with the presentation of avoided costs as positive benefits associated with load reductions. In the case of the rebalancing costs, a program that reduces load would incur a rebalancing disbenefit, that is, rebalancing would reduce the avoided cost benefits of the program. Conversely for a program that increases load, the rebalancing costs would reduce the net cost increases associated with the program.

# 8 Avoided Cost of Generation Capacity

## 8.1 Battery Storage Resource Net Cost of New Entry

The 2020 ACC adopts the approach recommended by the Joint Utilities in their prepared testimony[17] or calculating the Net Cost of New Entry (CONE) of a new battery storage resource. This approach is similar in concept to the approach used in prior ACC iterations, except that the proxy for new capacity is a battery storage resource instead of a gas combustion turbine. The cost and configuration of the battery storage resource is taken from the IRP. The RESOLVE capacity expansion modeling in the IRP uses a battery storage resource with a 4-hour duration and 20-year useful life (with augmentation costs) for a capacity resource. With increasing penetrations of solar, the Effective Load Carrying Capacity (ELCC) of a 4-hour battery to

[17] PACIFIC GAS AND ELECTRIC COMPANY, SAN DIEGO GAS & ELECTRIC COMPANY, AND SOUTHERN CALIFORNIA EDISON COMPANY (JOINT INVESTOR-OWNED UTILITIES) PROPOSED UPDATES TO THE AVOIDED COST CALCULATOR PREPARED TESTIMONY, submitted October 7, 2019 in R.14-10-003, p. 3-7.

provide generation capacity is diminished. This is reflected in the ACC by taking the ELCC from the IRP RESOVLE modeling and de-rating the capacity value of the 4-hour battery. The cost and performance assumptions as well as the financial pro-forma model from the IRP are used to calculate the levelized fixed costs of a battery over its expected useful life of 20 years. The revenues that batteries earn in the energy and ancillary markets are calculated with optimal dispatch using the CEC Solar + Storage Model and subtracted from the levelized fixed costs to calculate a Net CONE. The prices for energy and ancillary services are derived from SERVM production simulation using resource portfolios from the No New DER case. These prices are used to calculate net market revenues for a new battery storage resource.

*Table 9. Subset of Battery Storage Resource Cost Assumptions from IRP*

| Resource | | | Utility-scale Battery - Li [Capacity] - No ITC | Utility-scale Battery - Li [Energy] - No ITC | |
|---|---|---|---|---|---|
| **Category for Cost Reductions** | Resource Category | | Battery Storage-Standalone | Battery Storage-Standalone | |
| | Technology Type | | Lithium ion (Grid) - Capacity | Lithium ion (Grid) - Energy | |
| | Techno-Resource Group | | | | |
| | Active Cost Trajectory Scenario | | Mid | Mid | |
| **Performance Inputs** | | **Units** | | | |
| **Plant Output** | Installed Capacity | MW-ac | 1 | 4 | *4 hours duration* |
| | Capacity Factor | % | 15.0% | | |
| | Degradation | %/yr | 0.0% | | |
| **Plant Cost Inputs** | | | | | |
| **Capital Costs** | Installed Cost, 2016 | $/kW-ac | $226 | $313 | |
| | Progress Multiplier | % | 85% | 85% | |
| | Installed Cost, 2020 | $/kW-ac | $191 | $265 | *$/kWh Installed* |

*Table 10. Select Battery Storage Resource Net CONE Calculations from ACC*

| Fixed Costs ($2016) | 2020 | 2025 | 2030 | 2035 | 2040 |
|---|---|---|---|---|---|
| | | | | | |
| Capacity | $25 | $15 | $12 | $11 | $10 |
| Energy x 4 | $184 | $111 | $89 | $83 | $80 |
| Total Levelized Fixed Costs ($2016) | $209 | $126 | $101 | $94 | $90 |
| Total Levelized Fixed Costs Nominal | $227 | $151 | $133 | $137 | $145 |
| ELCC Adjustment | 100% | 94% | 88% | 71% | 53% |
| **ELCC Adjusted Nominal Fixed Costs** | **$227** | **$160** | **$151** | **$194** | **$271** |
| | | | | | |
| **Revenues** | | | | | |
| Net Energy Revenue ($) | 21,608 | 24,916 | 46,941 | 49,362 | 51,234 |
| Regulation Down Revenues ($) | 13,625 | 22,641 | 29,383 | 59,598 | 92,892 |
| Regulation Up Reveues ($) | 5,155 | 9,978 | 20,887 | 43,957 | 70,375 |
| Spin Revenues ($) | 3,753 | 5,975 | 9,899 | 14,210 | 17,834 |
| **Total Revenues ($)** | **44,141** | **63,511** | **107,110** | **167,127** | **232,335** |
| | | | | | |
| **Net Revenue ($/kW-Yr)** | **$44** | **$64** | **$107** | **$167** | **$232** |
| After Tax Net Revenue | $32 | $46 | $77 | $120 | $167 |
| **Net CONE** | **$195** | **$114** | **$74** | **$74** | **$104** |
| | | | | | |
| Annual Charge (kWh) | 1,269,401 | 1,171,809 | 1,172,144 | 1,072,227 | 1,003,830 |
| Annual Discharge (kWh) | 965,015 | 872,131 | 879,277 | 779,476 | 711,812 |
| | 76% | 74% | 75% | 73% | 71% |

## 8.2 Hourly Allocation of Generation Capacity Value

The generation capacity values ($/kW-yr), after adjusting for temperature, losses, and planning reserve margin, are allocated to the hours of the year with highest system capacity need using the E3 RECAP model. Using 63 years of historical load and generation data, the RECAP model determines the expected unserved energy (EUE) for each month/hour/day-type time period in the year based on the IRP.

Note that while a No New DER paradigm was used to develop the hourly energy price shape, it was not necessary to use that same case for the RECAP analysis. The RSP has a large amount of forecasted new distributed generation PV, and the No New DER scenario basically replaces that distributed generation with grid-sited PV. Since we use the RECAP analysis to determine the timing of the relative need for additional capacity, and that timing is basically unaffected by whether a generation resource is located at the customer site or on the grid, we can utilize the RECAP results based on the RSP for the ACC.

A snapshot of these hourly EUE values in 2020 is shown below

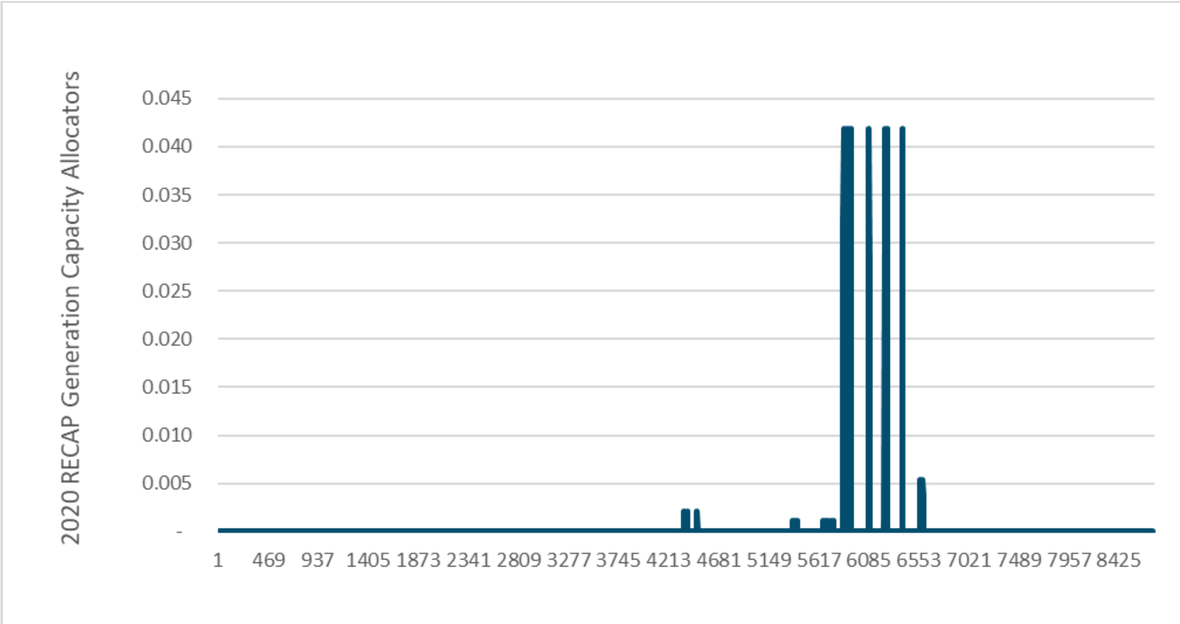
*Figure 21. Hourly Expected Unserved Energy from RECAP*

| base case, 2020 | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | jan | feb | mar | apr | may | jun | jul | aug | sep | oct | nov | dec |
| 1 | - | - | - | - | - | - | - | - | - | - | - | - |
| 2 | - | - | - | - | - | - | - | - | - | - | - | - |
| 3 | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | - | - | - | - | - | - | - | - | - | - | - | - |
| 5 | - | - | - | - | - | - | - | - | - | - | - | - |
| 6 | - | - | - | - | - | - | - | - | - | - | - | - |
| 7 | - | - | - | - | - | - | - | - | - | - | - | - |
| 8 | - | - | - | - | - | - | - | - | - | - | - | - |
| 9 | - | - | - | - | - | - | - | - | - | - | - | - |
| 10 | - | - | - | - | - | - | - | - | - | - | - | - |
| 11 | - | - | - | - | - | - | - | - | - | - | - | - |
| 12 | - | - | - | - | - | - | - | - | - | - | - | - |
| 13 | - | - | - | - | - | - | - | - | - | - | - | - |
| 14 | - | - | - | - | - | - | - | - | - | - | - | - |
| 15 | - | - | - | - | - | - | - | - | - | - | - | - |
| 16 | - | - | - | - | - | - | - | - | - | - | - | - |
| 17 | - | - | - | - | - | - | - | - | 2.71 | - | - | - |
| 18 | - | - | - | - | - | - | - | - | 83.96 | 3.14 | - | - |
| 19 | - | - | - | - | - | - | 1.78 | 2.69 | 107.24 | 2.12 | - | - |
| 20 | - | - | - | - | - | - | - | - | 69.15 | 0.30 | - | - |
| 21 | - | - | - | - | - | - | - | - | 37.73 | - | - | - |
| 22 | - | - | - | - | - | - | - | - | 8.37 | - | - | - |
| 23 | - | - | - | - | - | - | - | - | - | - | - | - |
| 24 | - | - | - | - | - | - | - | - | - | - | - | - |

These month/hour/day-type EUE values are then allocated to days of the year using the CTZ22 temperature data and the 2020 calendar year for consistency with energy prices. A load-weighted daily maximum statewide temperature is calculated and all hours in days where this value exceeds 90 degrees F receive the corresponding month/hour/day-type EUE value from RECAP.[18] The resulting 8760 hourly capacity allocators are shown below.

[18] In the 2019 update, the temperature threshold for the month of September was set to 85 degrees F (rather than 90), to account for the fact that only one non-workday in September 2018 – from which the underlying weather data is used – had an average temperature above 90 F (which is inconsistent with the September weather characterized in the RECAP assumptions).

*Figure 22. Generation Capacity Hourly Allocation Factors (2020)*




# 9 Transmission Avoided Capacity Costs

## 9.1 Background

Transmission avoided capacity costs represent the potential cost impacts on utility transmission investments from changes in peak loadings on the utility systems. The paradigm is that reductions in peak loadings via customer demand reductions, distributed generation, or storage could reduce the need for some transmission projects and allow for deferral or avoidance of those projects. The ability to defer or avoid transmission projects would depend on multiple factors, such as the ability to obtain sufficient dependable aggregate peak reductions in time to allow prudent deferral or avoidance of the project, as well as the location of those peak reductions in the correct areas within the system to provide the necessary reductions in network flows.

This avoided cost update does not look to evaluate whether any particular technology, measure, or installation could provide transmission avoided cost savings. Those determinations should be made in the proceedings in which these avoided costs are applied. The values developed herein represent the value provided IF the peak loading reductions can be obtained in the right amount, right location, and with the right dependability.

It should also be noted that the locations of the needs for demand reductions or distributed generation or storage will move over time as loadings on the utility systems evolve differently in different areas within the utility service territories. Thus, over the next ten years there could be a value to load reductions in area A, but not area B; but in years 10-20 the situation may flip, and area B could become the area with a need for load reductions, while area A no longer has a need. Given this locational and temporal uncertainty, the transmission avoided capacity costs are presented as a simple system average value for each utility. While this may underestimate the value of net load reductions in some areas and overestimate in other areas, we believe that this approach is superior to trying to forecast locational needs far into the future.

*Table 11. Long-Term Transmission Marginal Costs ($2020)*

| | PG&E | SCE | SDG&E |
|---|---|---|---|
| Transmission Capacity ($/kW-yr) | $11.75 | $28.82 | $14.44 |

*Note that the PG&E cost is derived for $2021. It has been converted to $2020 for consistency with the other values shown in the table.*

### 9.1.1 PG&E

Recent ACCs have used transmission marginal capacity costs from PG&E's GRC proceedings. PG&E has estimated those values for ratemaking purposes using the Discounted Total Investment Method (DTIM). The DTIM calculates the unit cost of transmission capacity as the present value of peak demand driven transmission investments divided by the present value of the peak demand growth. This unit cost is then annualized using a Real Economic Carrying Charge (RECC) with adjustments for other ratepayer-borne costs, such as administrative and general costs (A&G) and operations and maintenance costs (O&M). The DTIM has a long history of use for marginal cost estimation in California, and we continue its application for PG&E's avoided transmission capacity costs.

In response to a data request by the CPUC Energy Division in this proceeding, PG&E provided its forecast of peak demand driven transmission projects and its peak demand growth, along with its RECC and other financial factors that affect avoided costs (such as A&G and O&M). That data was originally developed by PG&E as part of their 2020 GRC Phase II Application.

PG&E is forecasting $229.8M in capacity-related transmission from 2020 through 2025. The forecasted load growth over that period is 2007 MW. Discounting at PG&E's real discount rate of 4.6%, these correspond to a discounted cumulative investment cost of $201.1M and discounted cumulative growth of 1793MW.[19] As shown in the table below, the investment costs and load growth result in an average unit cost of transmission investment of $115/kW. This is then multiplied the "Annual MC Factor" to derive the marginal transmission capacity cost of $12.02/kW-yr (in $2021).

[19] The casual reader may be troubled by the discounting of the load growth values for the DTIM approach. This discounting of both numerator (costs) and denominator (loads) is a counterintuitive but correct way to estimate average unit costs, and is well established for estimating marginal costs.

*Table 12. Derivation of PG&E Marginal Transmission Avoided Costs*
*(From PG&E 2020 GRC Ph II MTCC Model. Table Title retained from the PG&E model)*

**Table 3: Marginal Transmission Capacity Cost (2021 $) at 5-Year Time Horizon**

| [A] | | [B] |
|---|---|---|
| PV of Investment ($) | [1] | $206,142,713 |
| PV of Load Growth (MW) | [2] | 1,793 |
| PV of Load Growth (kW) | [3] | 1,793,203 |
| Marginal Investment ($/MW) | [4] | $114,958 |
| Marginal Investment ($/kW) | [5] | $115 |
| Annual MC Factor | [6] | 10.46% |
| Marginal Transmission Capacity Cost ($/MW-Yr) | [7] | $12,022 |
| Marginal Transmission Capacity Cost ($/kW-Yr) | [8] | $12.02 |

Notes:

[1] = The Cumulative Discounted Project Cost for the selected time horizon, multiplied by 10^6 from the CALC_DTIM PV Investments & Load tab.

[2] = The Cumulative Discounted Load Growth for the selected time horizon from the CALC_DTIM PV Investments & Load tab.

[3] = [2] x 1,000.
[4] = [1] / [2].
[5] = [1] / [3].
[6]: See CALC_Annual MC as % tab.
[7] = [4] x [6].
[8] = [5] x [6].

The PG&E Annual MC Factor annualizes the unit cost of transmission investment using a Real Economic Carrying Charge (RECC) and adds adjustments for O&M, A&G, General Plant, Working Capital, and Franchise Fees and Uncollectables. This is a well-established process for developing marginal capacity costs. The detailed derivation is shown below.

*Table 13. Derivation of PG&E Annual MC Factor (From PG&E 2020 GRC Ph II MTCC Model)*

| | | | |
|---|---|---|---|
| **Loaders & Financial Factors Inputs:** | | | |
| Real Economic Carrying Charge (RECC) | [1] | 6.56% | |
| Electric Transmission O&M Loading Factor (Capital Basis) | [2] | 2.77% | |
| A&G Payroll Loading Factor Transmission (Transmission O&M + A&G Basis) | [3] | 15.30% | |
| General Plant Loading Factor Transmission (Transmission O&M + A&G Basis) | [4] | 15.16% | |
| Materials and Supplies Carrying Charge (Plant Based) | [5] | 0.83% | |
| Cash Working Capital Carrying Charge (Dist. O&M + A&G Based - Annualized) | [6] | 2.44% | |
| Franchise Fees & Uncollectibles Loading Factor RRQ Basis | [7] | 1.0109 | |
| MARGINAL INVESTMENT | | | |
| Marginal Investment | [8] | $100.00 | |
| **Annualized Marginal Investment** | [9] | $6.56 | [9] = [8] x [1]. |
| MARGINAL EXPENSES | | | |
| O&M Expense | [10] | $2.77 | [10] = [8] x [2]. |
| A&G Expense | [11] | $0.42 | [11] = [10] x [3]. |
| General Plant | [12] | $0.48 | [12] = ([10] + [11]) x [4] |
| **Sub-total Marginal Expenses** | [13] | $3.68 | [13] = [10] + [11] + [12]. |
| WORKING CAPITAL ALLOWANCE | | | |
| Materials and Supplies On-hand | [14] | $0.03 | [14] = ([10] + [11]) x [5]. |
| Cash Working Capital | [15] | $0.08 | [15] = ([10] + [11]) x [6]. |
| **Sub-total Carrying Costs** | [16] | $0.10 | [16] = [14] + [15]. |
| **Franchise Fees and Uncollectibles** | [17] | $0.11 | [17] = ([9] + [13] + [16]) x ([7] - 1). |
| Marginal Cost | [18] | $10.46 | [18] = [9] + [13] + [16] + [17]. |
| **Annual Marginal Cost Factor** | [19] | 10.46% | [19] = [18] / [8]. |

Notes:
[1] to [8]: Inputs from Dashboard and IN_RECC and IN_Loaders tabs.

### 9.1.2 SCE

SCE does not include estimates of transmission capacity costs in its GRC proceedings. We therefore calculate marginal transmission costs for SCE using information provided by SCE in response to Energy Division data requests.

SCE indicates over $230M in transmission investments for capacity needs through 2025. $215M of the costs are for a single project that serves less than 5% of SCE's load and is driven by 7MW per year of local load growth. The remaining $15M is for smaller projects that are driven by SCE system wide load growth. Given the different drivers of the projects (system load vs local load), we apply the DTIM to the system-wide projects the LNBA method to the large $215M project.

#### 9.1.2.1 SCE DTIM Calculation for System Projects

The DTIM was applied to the SCE system-wide Big Creek and Sylmar projects. These projects are referred to as system-wide projects because SCE indicated that their need is driven by SCE system peaks, rather than local peaks. The general PG&E process was applied to the SCE data, with some minor modifications for loading factors, and a large modification for the peak load forecast used. Unlike the PG&E forecast, the forecast that SCE provided with its data response showed declining peak loads. Using those declining loads in the DTIM would result in negative values. We therefore replaced the SCE peak load forecast with the IEPR forecast net of incremental DER. To address the problem of some negative load growth years even with the IEPR forecast, we used the median peak load growth for SCE over the period 2020 through 2028 to represent the general system growth for SCE without DER.

The two SCE system-wide projects have a cumulative discounted investment cost of $17.68M, and the median growth forecast has a cumulative discounted growth of 382MW over the five-year analysis period. Combined with SCE's Annual MC factor, the resulting DTIM transmission marginal cost (without O&M) is $5.07kW-yr for these systemwide projects.

*Table 14. Derivation of SCE Marginal Transmission Avoided Costs for System Wide Projects (Without O&M)*

| | | |
|---|---|---|
| PV of Investment ($M) | [1] | $17.68 |
| PV of Load Growth (MW) | [2] | 382 |
| PV of Load Growth (kW) | [3] | 382,337 |
| Marginal Investment ($/MW) | [4] | $46,243 |
| Marginal Investment ($/kW) | [5] | $46.24 |
| Annual MC Factor | [6] | 10.96% |
| O&M ($/kW-yr) (to be added later) | [7] | $0.0 |
| Marginal Transmission Capacity Cost ($/kW-Yr) | [8] | $5.07 |

Notes:
[1] = The Cumulative Discounted Project Cost Big Creek and Pardee Sylmar projects
[2] = The Cumulative Discounted Load Growth based on Median IEPR forecast without incremental DER
[3] = [2] x 1,000.
[4] = [1] * 10^6 / [2].
[5] = [1] * 10^6 / [3].
[6]: See Derivation of SCE Transmission Annual MC Factor
[7] = from ED-SCE-001
[8] = [5] x [6] + [7].

*Table 15. SCE Systemwide Transmission Project Costs and Load Forecasts*

| | Project Cost ($M) | | | SCE Forecast | | IEPR without DER based forecast | | |
|---|---|---|---|---|---|---|---|---|
| Year | Big Creek | Pardee Sylmar | Total | Peak Demand (MW) | Peak Demand Growth (MW) | IEPR without DER Peak Load (MW) | Annual Peak Demand Growth (MW) | Median Growth (2020-2028) |
| | | | | 23825 | | 25,137 | | |
| 2020 | 5 | 0 | 5 | 23744 | -81 | 24,970 | (166) | 91 |
| 2021 | 0 | 0 | 0 | 23806 | 62 | 24,919 | (51) | 91 |
| 2022 | 0 | 6 | 6 | 23795 | -11 | 24,871 | (48) | 91 |
| 2023 | 0 | 10 | 10 | 23805 | 10 | 25,017 | 145 | 91 |
| 2024 | 0 | 0 | 0 | 23743 | -62 | 25,093 | 76 | 91 |
| 2025 | 0 | 0 | 0 | 23671 | -72 | 25,184 | 91 | 91 |
| 2026 | 0 | 0 | 0 | 23544 | -127 | 25,295 | 112 | 91 |
| 2027 | 0 | 0 | 0 | 23460 | -84 | 25,462 | 167 | 91 |
| 2028 | 0 | 0 | 0 | 23311 | -149 | 25,650 | 188 | 91 |
| NPV (2020 - 2024) | | | **$17.68** | | **(68.90)** | | | **382.34** |

Note:

IEPR Source: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-03

Real Discount Rate Used: 5.99%

*Table 16. Derivation of SCE Transmission Annual MC Factor*

| | | | |
|---|---|---|---|
| **Loaders & Financial Factors Inputs:** | | | |
| Real Economic Carrying Charge (RECC) | [1] | 9.11% | ED-SCE-001 |
| Electric Transmission O&M ($/kW-yr) | [2] | $6.70 | ED-SCE-001 |
| A&G Payroll Loading Factor Transmission ( Capital basis) | [3] | 1.10% | ED-SCE-001 |
| General Plant Loading Factor Transmission ( Annual Capital basis) | [4] | 6.90% | ED-SCE-001 |
| Materials and Supplies Carrying Charge (Plant Based) | [5] | | |
| Cash Working Capital Carrying Charge (Dist. O&M + A&G Based - Annualized) | [6] | | |
| Franchise Fees & Uncollectibles Loading Factor RRQ Basis | [7] | 1.12% | |
| MARGINAL INVESTMENT | | | |
| Marginal Investment | [8] | $100.00 | |
| **Annualized Marginal Investment** | [9] | $9.110 | [9] = [8] x [1]. |
| MARGINAL EXPENSES | | | |
| O&M Expense (to be added directly, rather than included as a factor) | [10] | | |
| A&G Expense | [11] | $1.10 | [11] = [8] x [3]. |
| General Plant | [12] | $0.63 | [12] = [9] x [4] |
| **Sub-total Marginal Expenses** | [13] | $1.729 | [13] = [11] + [12]. |
| WORKING CAPITAL ALLOWANCE | | | |
| Materials and Supplies On-hand | [14] | | |
| Cash Working Capital | [15] | | |
| **Sub-total Carrying Costs** | [16] | | [16] = [14] + [15]. |
| **Franchise Fees and Uncollectibles** | [17] | $0.12 | [17] = ([9] + [13] + [16]) x [7]. |
| Marginal Cost | [18] | $10.96 | [18] = [9] + [13] + [16] + [17]. |
| Annual Marginal Cost Factor | [19] | 10.96% | [19] = [18] / [8]. |

### 9.1.2.2 SCE Large Project Transmission Marginal Cost

The LNBA method was specifically developed in the DRP to estimate avoided capacity costs for individual projects.[20] The LNBA method calculates the value of deferring the original project and divides that value by the peak net load reduction needed to obtain that deferral. This deferral value per kW is then annualized over the planning period and adjusted for the additional cost factors such as taxes (in the present value revenue requirement factor) and A&G. O&M is added to the marginal costs after the system wide and Alberhill marginal costs are combined in order to avoid double counting

For the SCE Aberhill project, we applied the LNBA method assuming a one-year deferral due to a 7MW reduction in area peak net loads. The deferral by one year of all investments in the multi-year capital plan results in a present value savings of $12.15M in direct costs, which translates to a value of $1735.93 per kW of reduction ($12.15M deferral value / 7MW load growth).

Since the transmission capacity cost will apply to the entire SCE service territory, the next step is the calculate the equivalent avoided capacity cost for all of SCE. The paradigm we assume is that projects with this cost per kW of load growth would be required in the future in SCE's service territory. We cannot

[20] Details on the LNBA method can be found here: https://drpwg.org/sample-page/drp/ under *Joint IOU Demo B LNBA Tool.*

forecast where the projects would be needed, so we convert the project value into a uniform capacity value across the entire service territory. In this case, the project area represents 4.45% of SCE's peak loading, so the equivalent avoided cost is $16.75/kW-yr ($376.36 * 4.45%).

*Table 17. SCE Derivation of Transmission Capacity Costs for Alberhill Project using the LNBA Method*

| | | | |
|---|---|---|---|
| 1 | Discount Rate | 8.46% | |
| 2 | Inflation Rate | 2.33% | |
| 3 | Real Discount Rate | 5.99% | *(1+[1])/(1+[2]) - 1* |
| 4 | Planning Horizon (yrs) | 10 | |
| 5 | RECC | 12.81% | *([1]-[2])/(1+[1])*((1+[1])^[3]/((1+[1])^[3]-(1+[2])^[3]))* |

| | Year | Project Cost ($M) | Peak Demand Growth (MW) | 1 Yr Deferral Value ($M) | Deferral Value ($/kW) | | |
|---|---|---|---|---|---|---|---|
| 6 | 2020 | 50 | 7 | 2.83 | 403.70 | | |
| 7 | 2021 | 1 | 7 | 0.06 | 8.07 | | |
| 8 | 2022 | 1 | 7 | 0.06 | 8.07 | | |
| 9 | 2023 | 9 | 7 | 0.51 | 72.67 | | |
| 10 | 2024 | 69 | 7 | 3.90 | 557.11 | | |
| 11 | 2025 | 85 | 7 | 4.80 | 686.30 | | |
| 12 | 2026 | | 7 | 0.00 | 0.00 | | |
| 13 | 2027 | | 7 | 0.00 | 0.00 | | |
| 14 | 2028 | | 7 | 0.00 | 0.00 | | |
| 15 | NPV using Real Discount Rate | | | 12.15 | 1735.93 | | |
| 16 | RECC (From Above) [5] | | | | | 0.13 | |
| 17 | Present Value Revenue Requirement Factor (ED-SCE-001) | | | | | 1.549 | |
| 18 | LNBA Value ($/kW-yr) [15] * [16] * [17] | | | | | | $344.63 |
| 19 | | | | | | | |
| 20 | A&G (1.1%) | | | | | 1.10% | $3.79 |
| 21 | General Plant (6.9%) | | | | | 6.90% | $23.78 |
| 22 | Franchise Fees (1.1%% of all items above) | | | | | 1.12% | $4.17 |
| 23 | Plus O&M ($/kW-yr from ED-SCE-001) | | | | | | $6.70 |
| 24 | Total Project Marginal Cost ($/kW-yr) | | | | | | $383.06 |
| 25 | Percent of system load | | | | | | 4.45% |
| 26 | **Project Marginal Cost spread across the system** | | | | | | **$17.05** |

*Note that the RECC factor used herein is different from the RECC factor used in the DTIM method above. The DTIM RECC annualizes the full unit cost of the projects over the life of the project (50-60 years) and reflects the revenue requirement effects such as taxes that increase the cost of the project to ratepayers. This is equivalent to value of deferring the revenue requirement cost of the project and all of the project's future replacements by one year. This paradigm of the one-year replacement value is how the RECC was originally developed in the Electric Utility Rate Design Study Task Force 4 by NERA for EPRI (NP-22555). The LNBA method follows this same deferral concept, but directly calculates the value of deferring projects over each year over the planning horizon. Because the LNBA method sums the deferral value of projects over multiple years, a RECC is used to convert that multi-year value back to a $/kW-yr value needed for marginal costing. The RECC used for the LNBA method annualizes the total deferral value over the planning horizon (10 years) and does not include the Present Value Revenue Requirement Factor effects. For the LNBA, the RECC is utilized as a capital recovery factor that is constant in real dollars.*

*Table 18. Total SCE Transmission Marginal Cost ($/kW-yr $2020)*

| | Marginal Cost ($/kW-yr) |
|---|---|
| System-wide projects | $5.07 / kW-yr |
| Alberhill project averaged over SCE system | $16.75 / kW-yr |
| Transmission O&M | $ 6.70 / kW-yr |
| Total | **$28.52 / kW-yr** |

*Transmission O&M is from ED-SCE-001, and reflects SCE's 2018 GRC.*

### 9.1.3 SDG&E

SDG&E's response to the Energy Division data request indicated a preference for a regression-based estimation of marginal costs. Unfortunately, the provide system peak load data reflected a negative load growth trend. With that negative growth trend, the regression method resulted in a nonsensical negative marginal capacity cost for transmission.

To address the negative load growth problem, we again turn to the IEPR forecast. Combining the SDG&E Mid Low IEPR load forecast with SDG&E's forecasted capacity-driven projects allow us to derive transmission marginal costs via the DTIM approach. Using the IEPR forecast, we see increased peak load for all years except 2020.

*Table 19. SDG&E Transmission capital forecast and IEPR forecast without DER ($M and MW)*

| | | |
|---|---|---|
| Discount rate | 7.14% | Dec 2020 after-tax WACC |
| Inflation | 2.35% | |
| Real Discount Rate | 4.68% | |

| Year | SDG&E Capital Expenditures ($M) | IEPR without DER based forecast<br>IEPR without DER Peak Load (MW) | Annual Peak Demand Growth (MW) |
|---|---|---|---|
| | | 4,571 | |
| 2020 | 46.28 | 4,540 | (31) |
| 2021 | 9.78 | 4,579 | 38 |
| 2022 | 5.82 | 4,636 | 58 |
| 2023 | 4.96 | 4,695 | 58 |
| 2024 | 3.44 | 4,749 | 54 |
| 2025 | 0 | 4,800 | 50 |
| 2026 | 0 | 4,845 | 45 |
| 2027 | 0 | 4,892 | 47 |
| 2028 | 0 | 4,938 | 46 |
| NPV(2021-2024) | $21.85 | | 185.63 |

*Excludes projects deemed too large to be deferred (Sunrise Powerlink and South Orange County Reliability Enhancement)*

In applying the DTIM method, we use the period 2021 through 2024. Excluding 2020 avoids the problem introduced by the large negative load growth in that year of the IEPR forecast. In addition, $40.5M of the $46M 2020 investment cost is due to the last phase of a project that was commenced in 2012. Including that large project in the analysis without the ability to recognize the load growth that caused the need for the project would greatly skew the marginal cost results.

*Table 20. Derivation of SDG&E Marginal Transmission Avoided Costs*

| | | |
|---|---|---|
| PV of Investment ($M) | [1] | $21.85 |
| PV of Load Growth (MW) | [2] | 186 |
| PV of Load Growth (kW) | [3] | 185,629 |
| Marginal Investment ($/MW) | [4] | $117,706 |
| Marginal Investment ($/kW) | [5] | $117.71 |
| Annual MC Factor | [6] | 12.27% |
| Marginal Transmission Capacity Cost ($/kW-Yr) | [8] | $14.44 |

Notes:
[1] = The Cumulative Discounted Project Cost, excluding Sunrise and SOCRE
[2] = The Cumulative Discounted Load Growth based on Median IEPR forecast
[3] = [2] x 1,000.
[4] = [1] * 10^6 / [2].
[5] = [1] * 10^6 / [3].
[6]: See Derivation of SDG&E Transmission Annual MC Factor
[8] = [5] x [6]

*Table 21. Derivation of SDG&E Transmission Annual MC Factor*

| | | | |
|---|---|---|---|
| **Loaders & Financial Factors Inputs:** | | | |
| Real Economic Carrying Charge (RECC) | [1] | 7.07% | |
| Electric Transmission O&M (Capital basis) | [2] | $0.02 | |
| A&G Payroll Loading Factor Transmission ( Capital basis) | [3] | 0.88% | |
| General Plant Loading Factor Transmission ( Capital basis) | [4] | 2.77% | |
| Materials and Supplies Carrying Charge (Plant Based) | [5] | | |
| Cash Working Capital Carrying Charge (Capital Based) | [6] | 1.50% | |
| Franchise Fees & Uncollectibles Loading Factor RRQ Basis | [7] | | |
| MARGINAL INVESTMENT | | | |
| Marginal Investment | [8] | $100.00 | |
| **Annualized Marginal Investment** | [9] | $7.070 | [9] = [8] x [1]. |
| MARGINAL EXPENSES | | | |
| O&M Expense | [10] | $1.55 | [10] = [8] x [2]. |
| A&G Expense | [11] | $0.88 | [11] = [8] x [3]. |
| General Plant | [12] | $2.77 | [12] = [8] x [4]. |
| **Sub-total Marginal Expenses** | [13] | $5.200 | [13] = [10] + [11] + [12]. |
| WORKING CAPITAL ALLOWANCE | | | |
| Materials and Supplies On-hand | [14] | | |
| Cash Working Capital | [15] | $1.50 | [15] = [8] x [6] |
| **Sub-total Carrying Costs** | [16] | $1.500 | [16] = [14] + [15]. |
| **Franchise Fees and Uncollectibles** | [17] | | |
| Marginal Cost | [18] | $12.27 | [18] = [9] + [13] + [16] + [17]. |
| Annual Marginal Cost Factor | [19] | 12.27% | [19] = [18] / [8]. |

## 9.2 Annual Transmission Marginal Capacity Costs

The transmission capacity marginal costs are escalated to nominal dollars using the annual inflation rates shown below. The inflation rates were provided by the utilities in their response to the Energy Division data request. SDG&E provided an annual transmission inflation rates for 2010 through 2024. The value used herein is the simple average of the 2020 through 2024 values.

*Table 22. Transmission Inflation Rates*

| PG&E | SCE | SDG&E |
|---|---|---|
| 2.34% | 2.33% | 2.06% |

The annual capacity costs by climate zone and utility are shown below.

*Table 23. Annual Transmission Marginal Capacity Costs ($ Nominal)*

| Year | PG&E | SCE | SDG&E |
|---|---|---|---|
| 2020 | 11.75 | 28.52 | 14.44 |
| 2021 | 12.02 | 29.18 | 14.74 |
| 2022 | 12.30 | 29.86 | 15.04 |
| 2023 | 12.59 | 30.56 | 15.35 |
| 2024 | 12.89 | 31.27 | 15.67 |
| 2025 | 13.19 | 32.00 | 15.99 |
| 2026 | 13.50 | 32.74 | 16.32 |
| 2027 | 13.81 | 33.51 | 16.66 |
| 2028 | 14.13 | 34.29 | 17.00 |
| 2029 | 14.47 | 35.09 | 17.35 |
| 2030 | 14.80 | 35.90 | 17.71 |
| 2031 | 15.15 | 36.74 | 18.07 |
| 2032 | 15.51 | 37.60 | 18.45 |
| 2033 | 15.87 | 38.47 | 18.83 |
| 2034 | 16.24 | 39.37 | 19.21 |
| 2035 | 16.62 | 40.28 | 19.61 |
| 2036 | 17.01 | 41.22 | 20.01 |
| 2037 | 17.41 | 42.18 | 20.43 |
| 2038 | 17.81 | 43.17 | 20.85 |
| 2039 | 18.23 | 44.17 | 21.28 |
| 2040 | 18.66 | 45.20 | 21.71 |
| 2041 | 19.09 | 46.25 | 22.16 |
| 2042 | 19.54 | 47.33 | 22.62 |
| 2043 | 20.00 | 48.44 | 23.08 |
| 2044 | 20.47 | 49.56 | 23.56 |
| 2045 | 20.94 | 50.72 | 24.05 |
| 2046 | 21.43 | 51.90 | 24.54 |
| 2047 | 21.94 | 53.11 | 25.05 |
| 2048 | 22.45 | 54.35 | 25.56 |
| 2049 | 22.97 | 55.61 | 26.09 |
| 2050 | 23.51 | 56.91 | 26.63 |

## 9.3 Hourly Allocation of Transmission Avoided Capacity Costs

The annual capacity costs shown above are allocated to hours of the year to allow the ACC to reflect the time varying need for transmission capacity. The prior ACC used the distribution hourly allocation factors for transmission capacity costs. In this update, the generation capacity hourly allocation factors have been used. The generation capacity allocation factors are appropriate to use for transmission capacity costs because the transmission costs generally represent investments that are driven be system, rather than local needs.

# 10 Distribution Avoided Capacity Costs

Distribution avoided costs represent the value of deferring or avoiding investments in distribution infrastructure through reductions in distribution peak capacity needs. The DRP proceeding has developed considerable insight and data related to the impact of DERs on the distribution system. Specifically, the

Energy Division T&D White Paper attached to the DRP's June 13, 2019 ALJ Ruling[21] defines two types of avoided costs, specified and unspecified, and proposes to leverage information from utility Distribution Deferral Opportunity Report (DDOR) and Grid Needs Assessment (GNA) filings that contain detailed information about utility needs and investment plans. The avoided costs developed herein leverage information from those reports to estimate near term distribution marginal costs (for years 1 through 5 of the forecast) based on the recommendations in the T&D White Paper.

The distribution marginal costs then transition to GRC distribution marginal costs for the long-term values. Such GRC-sourced marginal costs have been a staple in the ACC in the past.

## 10.1 Near-term Distribution Marginal Costs from the DRP

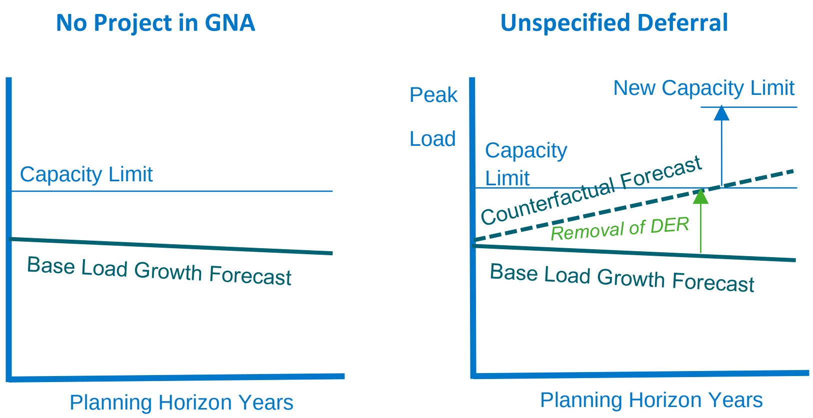
The utilities calculate distribution avoided costs as part of the annual DDOR process. These avoided costs are specific to a small number of utility capacity projects that could potentially be deferred via DER adoptions in the project areas. The DDOR avoided costs represent the value of deferring distribution investment projects through the addition of DER or other load reducing measures that are *above and beyond* the DER growth the utility expects to be adopted in the project area because of current DER policies, incentives, and programs. The T&D White Paper defines these DDOR costs as **"specified deferrals."**

The challenge is that these specified deferrals are not theoretically well-suited to determining the avoided distribution costs that could be provided by the DER that the utilities have embedded in their planning forecasts. The need for a capacity-driven distribution project is determined by the intersection of the capacity limit with the load growth forecast. In some cases, the load growth forecast may not intersect the capacity limit because of the expected peak load reductions from new embedded DER. However, if that new embedded DER were removed from the forecast, there could have been a need for a capacity project.

This is illustrated in Figure 23, where the chart on the left represents the GNA analysis for a circuit that shows no need for a capacity project within the five-year planning horizon. The chart on the right shows the effect of the removal of the new DER growth from the load forecast. The removal of the new embedded DER increases the loading on the equipment and results in higher deficiencies as well as the need for incremental projects over the five-year planning horizon (compared to the utility planning forecasts). The No New DER local load forecasts are referred to as the "counterfactual" forecasts in the T&D White Paper.

[21] ADMINISTRATIVE LAW JUDGE'S AMENDED RULING REQUESTING COMMENTS ON THE ENERGY DIVISION WHITE PAPER ON AVOIDED COSTS AND LOCATIONAL GRANULARITY OF TRANSMISSION AND DISTRIBUTION DEFERRAL VALUES, June 13, 2019

*Figure 23. Project need from counterfactual forecast*




The concern with how to estimate marginal costs under the No New DER paradigm, prompted the effort to quantify **"unspecified deferrals"** and the associated marginal distribution cost. For the ACC, the near-term marginal distribution capacity costs are the system average marginal costs under the counterfactual forecast for each utility. The marginal costs of the specified deferrals are not included in the ACC as the ACC modeling is done at the system and climate zone level, and the ACC would not currently accommodate the geographic specificity that would be necessary for the specified deferral cases. Instead, the marginal costs of specified deferrals should be applied with the already established DDIF process.

To calculate the marginal cost under the counterfactual forecast, we have implemented the method put forth in the T&D White Paper.[22]

1. **Calculate the counterfactual forecast from the GNA:** For each listed circuit, the counterfactual load can be derived by removing the circuit level DER forecast from the circuit level load.
2. **Identify potential new capacity projects under the counterfactual forecast:** All circuits that exceed the facility rating in any year of the counterfactual forecast. Note that in the T&D White Paper, this step also identified projects that would have occurred in the planning forecast, and separated those projects out from the calculations. We determined that this separation step was not needed in performing the final marginal cost calculations. The reason is that near-term distribution marginal costs derived herein will be applicable to all DER system wide. Therefore, the marginal costs should reflect a system-wide value. To be sure, DDIF can be used to target areas and recognize higher values in those project areas, but system-wide programs may also provide DER load reductions in those same areas independent of the DDIF.
3. **Estimate the percentage of distribution capacity overloads that lead to a deferred distribution upgrade:** Calculate a system level quantity for deferred distribution capacity by using a ratio between capacity overloads identified in the GNA to capacity overloads deferrable in the DDOR. The resulting percentage is a proxy for the percentage of distribution capacity upgrades that can be deferred by DER. Multiplying this percentage with the number of deferrable projects from Step 2 determines the subset of counterfactual capacity projects that could potentially be deferred via DER.

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[22] ADMINISTRATIVE LAW JUDGE'S AMENDED RULING REQUESTING COMMENTS ON THE ENERGY DIVISION WHITE PAPER ON AVOIDED COSTS AND LOCATIONAL GRANULARITY OF TRANSMISSION AND DISTRIBUTION DEFERRAL VALUES, June 2019, Attachment A, p. 11

4. **Calculate the average marginal cost of the deferred distribution upgrades:** The average DDOR marginal cost is the sum of the DDOR avoided distribution cost ($/kW-yr) for each project from the DDOR filing, multiplied by its total deficiency need over the planning horizon, and the sum then divided by the total deficiency need for all DDOR projects.
5. **Calculate system level avoided costs:** Multiply the average DDOR marginal cost found in step 4 by the total quantity of deferred capacity by DERs for each circuit. This product is then divided by the sum of forecasted level of DERs for all areas (not just DDOR areas) to obtain a single, system level distribution deferral value in $/kW-yr.

The method basically uses the utilities' GNA planned case to indicate the unit cost to add distribution capacity. A counterfactual forecast that adds back the load reductions of DER embedded in the utility planning cases is then used to calculate a counterfactual distribution capital plan. The counterfactual plan has the same system average distribution unit cost[23] as each IOU's plan, and is reduced if needed to reflect that not all forecasted overloads lead to a distribution project. In some cases, low or no cost solutions are available that would allow a circuit or area deficiency to be addressed without a meaningful capital project. The proportion of deficiencies that could be addressed in such a manner are removed from the counterfactual distribution plan.

This counterfactual plan is then converted into a system average marginal cost using standard GRC methods of applying a RECC annualization factor along with loaders or adders, such as A&G and O&M. Note that while only a fraction of the circuits and areas have need of a capital project even under the counterfactual forecast, the entire forecast amount of DER load reductions is used to calculate the system average marginal cost. This allows the near-term distribution marginal cost to reflect that only a fraction of DER installed in the next five years could contribute to deferring a distribution project over that same time period. However, as discussed later in this section, the distribution marginal capacity costs do increase toward long term marginal cost levels after year five, reflecting the potential value that could be provided by DER whose load reductions persist past year five.

*Table 24. Near-Term Distribution Marginal Costs ($2020)*

| | PG&E | SCE | SDG&E |
|---|---|---|---|
| Circuits only | | $12.24 | |
| B-Bank Substations | | $12.30 | |
| A-Bank Substations | | $3.07 | |
| Subtransmission | | $0.86 | |
| Total Distribution Capacity ($/kW-yr) | $14.49 | $28.47 | $2.16 |

## 10.1.1 Derivation of Near-Term Distribution Marginal Capacity Costs

### 10.1.1.1 Unspecified Distribution Marginal Costs

Table 25 shows the calculation of the unspecified distribution marginal cost that is used for the near-term distribution marginal capacity costs. PG&E and SDG&E are shown as a single column, while SCE's costs are

[23] Unit cost used here is the distribution capital cost per kW of circuit or area deficiency over the five year planning horizon.

divided into circuits and substations separately. In addition, there are subtransmission components to SCE's distribution marginal capacity costs, which are developed in the next section.

*Table 25. Unspecified Distribution Deferral Costs by IOU*

| Line | Number of Overloads | PG&E | SCE-Substations (B-Bank) | SCE-Circuits | SDG&E | Notes: |
|---|---|---|---|---|---|---|
| 1 | Actual Overloads | 224 | 35 | 226 | 11 | [1] |
| 2 | Counterfactual Overloads | 271 | 50 | 349 | 25 | [2] |
| 3 | Number of Proposed Projects | 180 | N/A | N/A | 10 | [3] |
| 4 | Percentage of Overloads addressed by Load Transfers | 20% | 20% | 20% | 9% | [4] = 100% - ([3]/[1]) |
| | **Overload Capacity** | | | | | |
| 5 | Actual Overloads (kW) | 289,880 | 269,140 | 634,702 | 10,039 | [5] |
| 6 | Counterfactual Overloads (kW) | 349,018 | 286,660 | 643,360 | 25,320 | [6] |
| 7 | Deferrable Counterfactual Overloads (kW) | 280,461 | 229,328 | 514,688 | 23,018 | [7] = [6] x (100% - [4]) |
| | **Project & Planned Investment Costs** | | | | | |
| 8 | Total Cost of Planned Investments in DDOR Filing ($) | $390,416,858 | $350,016,877 | $288,412,287 | $17,800,000 | [8] |
| 9 | Capacity Deficiency that Planned Investments Mitigate (kW) | 323,844 | 269,140 | 634,702 | 17,178 | [9] |
| 10 | Unit Cost of Deferred Distribution Upgrades ($/kW) | $1,205.57 | $1,300.50 | $454.41 | $1,036.21 | [10]* = [8] / [9] |
| | **System Level Avoided Distribution Costs** | | | | | |
| 11 | Deferrable Capital Investment | $338,114,662 | $298,241,326 | $233,877,317 | $23,851,370 | [11] = [10] x [7] |
| 12 | 5 Year Total forecasted DER (kW) | 2,285,003 | 2,911,430 | 3,113,110 | 625,460 | [12] |
| 13 | Distribution Deferral Value ($/kW) | $147.97 | $102.44 | $75.13 | $38.13 | [13] = [11] / [12] |
| 14 | IOU Specific RECC | 9.79% | 11.49% | 11.45% | 7.65% | [14] |
| 15 | Capacity Deferral Value ($/kW of DER installed-yr) | $14.49 | $11.77 | $8.60 | $2.92 | [15] = [13] * [14] |
| | **O&M Distribution Costs** | | | | | |
| 16 | O&M Deferral Value ($/kW-yr) | $0.00 | $6.74 | $21.98 | $20.26 | [16] |
| 17 | O&M Deferral Value ($/kW of DER installed -yr) | $0.00 | $0.53 | $3.63 | $0.75 | [17] = [16] * [7] / [12] |
| 18 | **Unspecified Marginal Cost ($/kW of DER installed-yr)** | **$14.49** | **$12.30** | **$12.24** | **$3.66** | [18] = [15] + [17] |

Table 25 Notes:

[1] Number of circuits or areas in the utility Grid Needs Assessment (GNA) that have a deficiency or overload over the planning horizon (2019-2023) based on the utility planning forecast that includes peak load reductions due to DER. Note that while all utilities use a five year planning horizon, SDG&E only forecast projects for the first three years of the horizon (See [8] below).

[2] See discussion below.

[3] See discussion below.

[5], [6] Sum of the maximum deficiency (kW) from 2019-2023 for each of the overloads identified in [1] and [2]

[8-10] See discussion below,

[12] Total forecasted DER was calculated by using the GNA and summing all DER adoption from 2019-2023 across all areas, including areas that were not overloaded. SDG&E's DER forecasts include estimates of coincident DER kW, rather than nameplate. This information was provided by SDG&E as a supplement to the information in the GNA and DDOR.

[15] See Table 26 through Table 29.

[16] O&M information is from data requests to the IOUs,

### *Number of Overloads [Line 2]*

As a part of the Grid Needs Assessment (GNA) each IOU submitted a list of distribution areas with three key elements: a) Projected Load Forecasts (2019-2023) b) Projected DER adoption (2019-2023) and c) Facility Loading Limits. The counterfactual forecast takes the planning forecast and adds back, or removes the load reduction from the DER. This results in higher cumulative loads. A circuit or area is considered overloaded (Table 25, Line [2]) if the projected load forecast in any year (2019-2023) exceeds the facility loading limit.

### *Percentage of Overloads Addressed by Load Transfers [Line 4]*

This is the percent of overloaded circuits or areas that can be addressed via low cost / no cost options. (Table 25, Line [3]) For PG&E, this is the total number of capacity-related "Candidate Deferral" projects provided in the PG&E DDOR divided by the overloaded circuits identified in Line 1 of the Table. For SDG&E, this is the number of demand-growth (capacity) related projects provided in the "Decision - GNA Contents" tab of the SDG&E DDOR divided by the overloaded circuits identified in Line 1. For SCE, see section 10.1.1.2 *Estimation of SCE Low Cost/ No Cost Project Percentage*

*Deferrable Counterfactual Overloads [Line 7]*

Multiplying the number of counterfactual overloads by one minus the low cost / no cost percentage, results in the number of counterfactual projects that could potentially be deferred by DER. Similarly, multiplying the amount of counterfactual overload kW (Line [6]) by one minus the low cost / no cost percentage, results in the amount of deferrable overload kW (Line [7]). This is the amount of load reduction that would be needed to defer the deferrable counterfactual projects.

*Derivation of Unit Cost of Deferred Distribution Upgrades [Lines 8-10]*

The average project cost per kW of deficiency in the planning case is used to estimate the cost of project upgrades under the counterfactual case. Project costs were only included if the project was proposed specifically to address a capacity overload. The sources for the project costs and associated grid needs are:

**PG&E:** The unit cost for each capacity-driven project in the "Planned Investments" of the DDOR was provided in a PG&E response to an E3 data request. Capacity needs are calculated by summing the "Grid Needs" which were provided for each project. PG&E provided a list of planned investments in the DDOR including a description of the type of distribution service required. The projects with a distribution service of "Capacity" were included in the total project cost and grid need calculation, while projects with a listed distribution service of "Reliability / Other" and "Voltage" were ignored.

**SCE:** Total project costs for sub-transmission, substation (A-Bank), substation (B-Bank) and circuits were provided by SCE in a March 2020 response to an E3 data request. Due to SCE's methodology, and the fact that the projects listed in the GNA were post-load transfer optimization, the total capacity needs are the same as those provided in [5].

**SDGE:** Total project costs and associated capacity needs from 2019-2021 were provided in the "Independent Professional Engineer SDG&E 2019 GNA-DDOR Report." Project costs are shown in Table 6-13, while Grid Needs are shown in Appendix A. Response 1 of Appendix A in the IPE Report states that SDG&E's 2019 distribution planning cycle did not identify any grid needs in 2022 or 2023. Thus, the listed project costs and associated grid needs are only applicable for a three-year time horizon.

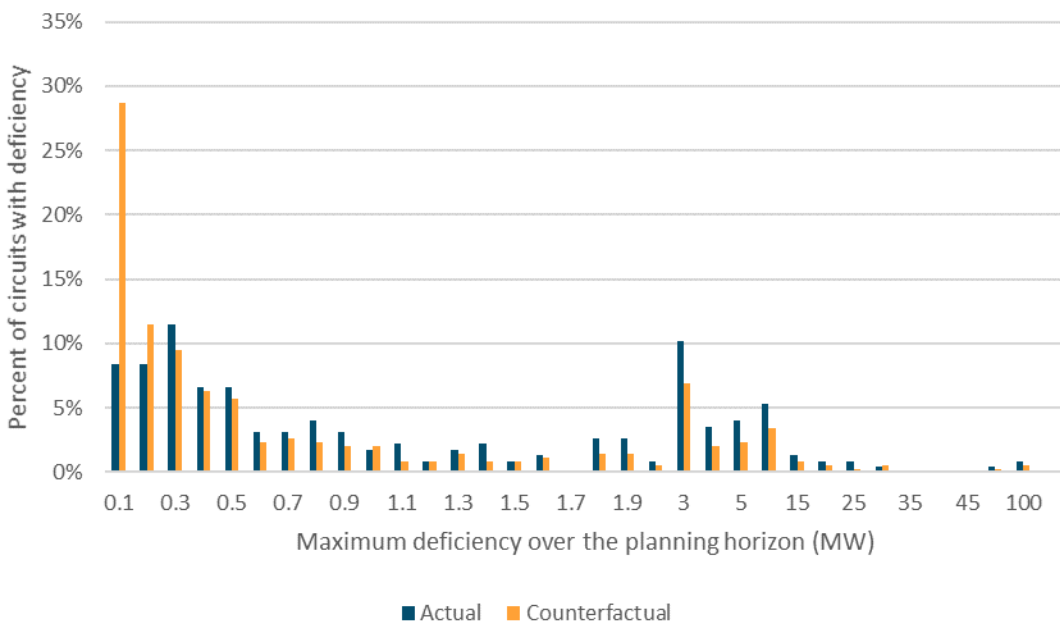
#### 10.1.1.2 Estimation of SCE Low Cost/ No Cost Project Percentage

A capital project is not always needed to address a capacity deficiency. In some cases, the utility can address the deficiency through low cost or no cost options such as reconfiguring the local distribution system through changes in switch settings. The percentage of overloads that can be addressed via low cost/ no cost options can be determined from the PG&E and SDG&E GNA and DDOR reports by comparing the deficiencies to the planned projects. This fraction of low cost / no cost solutions is then used to reduce the estimated deferrable capital investments under the counterfactual case.

For SCE, the low cost / no cost percentage cannot be calculated from their GNA or DDOR data because the SCE GNA reports reflect system conditions after their system has been reconfigured to remove the deficiencies addressed by low cost / no cost solutions. We expect that many deficiencies identified under the counterfactual case for SCE would have been addressable via low cost / no cost solutions, so we derived a low cost / no cost percentage for SCE based on the distribution of deficiencies for the projects identified by SCE in their GNA.

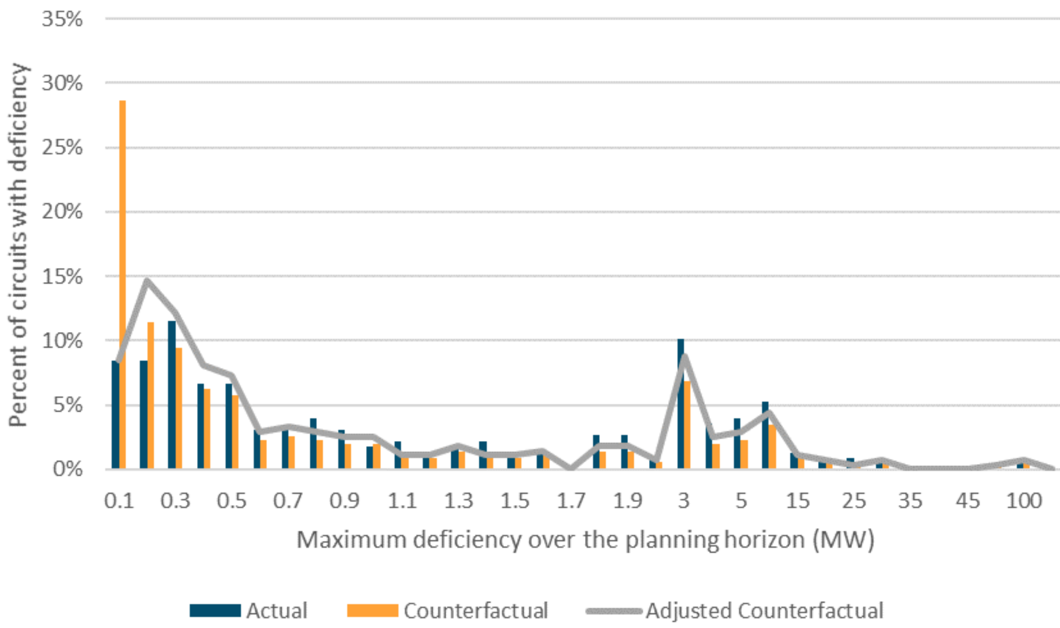
The assumption is that circuits or substations with small deficiency amounts would have a higher likelihood of being addressable via the low cost / no cost solutions. This is supported by Figure 24 that shows a far higher percentage of very low counterfactual deficiencies than the actual GNA deficiencies.

*Figure 24. Distribution of Actual and Counterfactual Deficiencies for SCE*



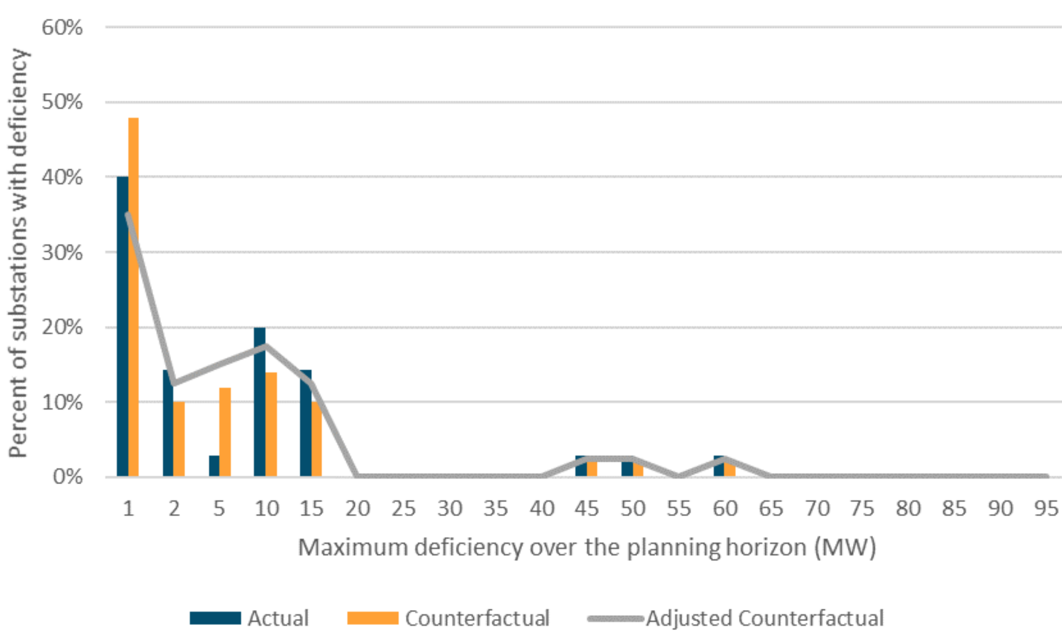

To correct for this overabundance of small deficiency projects, we remove the smallest deficiency counterfactual "projects" so that the distributions of actual and remaining counterfactual projects are similar. Figure 25 shows that removing the lowest 20th percentile of counterfactual deficiencies results in a deficiency distribution that is closer to the GNA actual data. The 20% value is also comparable to the los cost / no cost percentage of projects shown in the PG&E data.

*Figure 25. Distribution of SCE Circuit Adjusted Counterfactual Deficiencies (20% Removed)*




The same analysis process was used for SCE substations, and the 20th percentile was found to be a reasonable adjustment factor. The substation distributions are shown below.

*Figure 26. Distribution of SCE Substation Adjusted Counterfactual Deficiencies (20% Removed)*



### 10.1.1.3 Derivation of Distribution Annual MC Factors

As with Transmission, Annual MC Factors annualize the unit cost of capital investment using a RECC and adds adjustments for A&G, General Plant, Working Capital, and Franchise Fees and Uncollectables. PG&E also includes the cost of O&M in its RECC, whereas SCE and SDG&E provided O&M costs as a $/kW-yr cost separate from the RECC. The detailed derivations of the Annual MC Factors are shown below.

*Table 26. PG&E Distribution Annual MC Factor*

| | | | |
|---|---|---|---|
| **Loaders & Financial Factors Inputs:** | | | |
| Real Economic Carrying Charge (RECC) | [1] | 6.36% | |
| Electric Distribution O&M Loading Factor (Capital Basis) | [2] | 2.46% | |
| A&G Payroll Loading Factor Distribution (Distribution O&M + A&G Basis) | [3] | 24.17% | |
| General Plant Loading Factor Transmission (Transmission O&M + A&G Basis) | [4] | 5.53% | |
| Materials and Supplies Carrying Charge (Plant Based) | [5] | 0.83% | |
| Cash Working Capital Carrying Charge (Dist. O&M + A&G Based - Annualized) | [6] | 2.44% | |
| Franchise Fees & Uncollectibles Loading Factor RRQ Basis | [7] | 1.0109 | |
| MARGINAL INVESTMENT | | | |
| Marginal Investment | [8] | $100.00 | |
| **Annualized Marginal Investment** | [9] | $6.36 | [9] = [8] x [1]. |
| MARGINAL EXPENSES | | | |
| O&M Expense | [10] | $2.46 | [10] = [8] x [2]. |
| A&G Expense | [11] | $0.59 | [11] = [10] x [3]. |
| General Plant | [12] | $0.17 | [12] = ([10] + [11]) x [4] |
| **Sub-total Marginal Expenses** | [13] | $3.22 | [13] = [10] + [11] + [12]. |
| WORKING CAPITAL ALLOWANCE | | | |
| Materials and Supplies On-hand | [14] | $0.03 | [14] = ([10] + [11]) x [5]. |
| Cash Working Capital | [15] | $0.07 | [15] = ([10] + [11]) x [6]. |
| **Sub-total Carrying Costs** | [16] | $0.10 | [16] = [14] + [15]. |
| **Franchise Fees and Uncollectibles** | [17] | $0.11 | [17] = ([9] + [13] + [16]) x ([7] - 1). |
| Marginal Cost | [18] | $9.79 | [18] = [9] + [13] + [16] + [17]. |
| Annual Marginal Cost Factor | [19] | 9.79% | [19] = [18] / [8]. |

Notes:
[1] E-Dist Primary Composite from Table 1: Financial Factors from IntegeratedDistributedResourcesOIR_DR_ED_001-Q01Atch02.xlsm
[2] Overhead Secondary Line from Table 1: All Loaders Summary from IntegeratedDistributedResourcesOIR_DR_ED_001-Q01Atch03.xlsm
[3] Distribution A&G from Table 1: All Loaders Summary from IntegeratedDistributedResourcesOIR_DR_ED_001-Q01Atch03.xlsm
[4] Distribution GPLF from Table 1: All Loaders Summary from IntegeratedDistributedResourcesOIR_DR_ED_001-Q01Atch03.xlsm
[5] M&S from Table 1: All Loaders Summary from IntegeratedDistributedResourcesOIR_DR_ED_001-Q01Atch03.xlsm
[6] CWC from Table 1: All Loaders Summary from IntegeratedDistributedResourcesOIR_DR_ED_001-Q01Atch03.xlsm
[7] FF&U Factor from Table 1: All Loaders Summary from IntegeratedDistributedResourcesOIR_DR_ED_001-Q01Atch03.xlsm

*Table 27. SCE Distribution Annual MC Factor for Circuits*

| | | | |
|---|---|---|---|
| **Loaders & Financial Factors Inputs:** | | | |
| Real Economic Carrying Charge (RECC) | [1] | 9.25% | ED-SCE-003 follow up |
| Electric Transmission O&M ($/kW-yr) | [2] | $21.98 | ED-SCE-003 follow up |
| A&G Payroll Loading Factor Transmission ( Capital basis) | [3] | 1.44% | ED-SCE-003 follow up |
| General Plant Loading Factor Transmission ( Annual Capital basis) | [4] | 7.30% | ED-SCE-003 follow up |
| Materials and Supplies Carrying Charge (Plant Based) | [5] | | |
| Cash Working Capital Carrying Charge (Dist. O&M + A&G Based - Annualized) | [6] | | |
| Franchise Fees & Uncollectibles Loading Factor RRQ Basis | [7] | 1.12% | |
| MARGINAL INVESTMENT | | | |
| Marginal Investment | [8] | $100.00 | |
| **Annualized Marginal Investment** | [9] | $9.250 | [9] = [8] x [1]. |
| MARGINAL EXPENSES | | | |
| O&M Expense (to be added directly, rather than included as a factor) | [10] | | [10] = not included in factors |
| A&G Expense | [11] | $1.44 | [11] = [8] x [3]. |
| General Plant | [12] | $0.68 | [12] = [10] x [4]. |
| **Sub-total Marginal Expenses** | [13] | $2.115 | [13] = [10] + [11] + [12]. |
| WORKING CAPITAL ALLOWANCE | | | |
| Materials and Supplies On-hand | [14] | | |
| Cash Working Capital | [15] | | |
| **Sub-total Carrying Costs** | [16] | | |
| **Franchise Fees and Uncollectibles** | [17] | $0.13 | [17] = ([9] + [13] + [16]) x [7]. |
| Marginal Cost | [18] | $11.49 | [18] = [9] + [13] + [16] + [17]. |
| Annual Marginal Cost Factor | [19] | 11.49% | [19] = [18] / [8]. |

*Table 28. SCE Distribution Annual MC Factor for Substations*

| | | | |
|---|---|---|---|
| **Loaders & Financial Factors Inputs:** | | | |
| Real Economic Carrying Charge (RECC) | [1] | 9.21% | ED-SCE-003 follow up |
| Electric Transmission O&M ($/kW-yr) | [2] | $6.74 | ED-SCE-003 follow up |
| A&G Payroll Loading Factor Transmission ( Capital basis) | [3] | 1.44% | ED-SCE-003 follow up |
| General Plant Loading Factor Transmission ( Annual Capital basis) | [4] | 7.30% | ED-SCE-003 follow up |
| Materials and Supplies Carrying Charge (Plant Based) | [5] | | |
| Cash Working Capital Carrying Charge (Dist. O&M + A&G Based - Annualized) | [6] | | |
| Franchise Fees & Uncollectibles Loading Factor RRQ Basis | [7] | 1.12% | |
| MARGINAL INVESTMENT | | | |
| Marginal Investment | [8] | $100.00 | |
| **Annualized Marginal Investment** | [9] | $9.210 | [9] = [8] x [1]. |
| MARGINAL EXPENSES | | | |
| O&M Expense (to be added directly, rather than included as a factor) | [10] | | [10] not included in the factors. |
| A&G Expense | [11] | $1.44 | [11] = [8] x [3]. |
| General Plant | [12] | $0.67 | [12] = [10] x [4]. |
| **Sub-total Marginal Expenses** | [13] | $2.112 | [13] = [10] + [11] + [12]. |
| WORKING CAPITAL ALLOWANCE | | | |
| Materials and Supplies On-hand | [14] | | |
| Cash Working Capital | [15] | | |
| **Sub-total Carrying Costs** | [16] | | |
| **Franchise Fees and Uncollectibles** | [17] | $0.13 | [17] = ([9] + [13] + [16]) x [7]. |
| Marginal Cost | [18] | $11.45 | [18] = [9] + [13] + [16] + [17]. |
| Annual Marginal Cost Factor | [19] | 11.45% | [19] = [18] / [8]. |

*Table 29. SDG&E Distribution Annual MC Factor*

| | | | |
|---|---|---|---|
| **Loaders & Financial Factors Inputs:** | | | |
| Real Economic Carrying Charge (RECC) | [1] | 7.18% | |
| Electric Transmission O&M ($/kW-yr added later) | [2] | $20.26 | |
| A&G Payroll Loading Factor Transmission ( Annual Capital basis + GPL + CWC) | [3] | 2.10% | |
| General Plant Loading Factor Transmission ( Annual Capital basis) | [4] | 2.77% | |
| Materials and Supplies Carrying Charge (Plant Based) | [5] | | |
| Cash Working Capital Carrying Charge (Capital Based) | [6] | 1.50% | |
| Franchise Fees & Uncollectibles Loading Factor RRQ Basis | [7] | | |
| MARGINAL INVESTMENT | | | |
| Marginal Investment | [8] | $429.17 | |
| **Annualized Marginal Investment** | [9] | $30.83 | [9] = [8] x [1]. |
| MARGINAL EXPENSES | | | |
| O&M Expense | [10] | | [10] = [8] x [2]. |
| A&G Expense | [11] | $0.68 | [11] = [3] x ( [9]+ [12] + [15]) |
| General Plant | [12] | $0.85 | [12] = [4] x [9] |
| **Sub-total Marginal Expenses** | [13] | $1.530 | [13] = [10] + [11] + [12]. |
| WORKING CAPITAL ALLOWANCE | | | |
| Materials and Supplies On-hand | [14] | | |
| Cash Working Capital | [15] | $0.46 | [15] = [9] x [6] |
| **Sub-total Carrying Costs** | [16] | $0.462 | [16] = [14] + [15]. |
| **Franchise Fees and Uncollectibles** | [17] | $0.00 | |
| Marginal Cost | [18] | $32.82 | [18] = [9] + [13] + [16] + [17]. |
| Annual Marginal Cost Factor | [19] | 7.65% | [19] = [18] / [8]. |

#### 10.1.1.4 SCE Subtransmission and A-Banks Marginal Costs

The near-term distribution marginal costs for SCE are derived in three parts, Circuits, Substations, and Subtransmission. The marginal capacity costs for circuits and substations are derived using the T&D White Paper counterfactual process. Subtransmission, however, does not fit well with that paradigm because of the networked nature of system for addressing N-1 contingency events. In other words, the need for subtransmission projects cannot be determined simply by looking at the loadings on downstream circuits in the normal configuration. To address this gap, we include a fraction of SCE's long-term GRC-based subtransmission marginal capacity costs in the near-term costs. The fraction is the ratio of SCE Substation B-Bank counterfactual overloads to total DER reduction forecast over the five-year planning horizon (2019-2023). In this way, the subtransmission and A-bank marginal costs reflect an average expected avoided cost from systemwide DER deployment. This is the same treatment of the total DER reduction forecast used for the unspecified distribution marginal costs derived above.

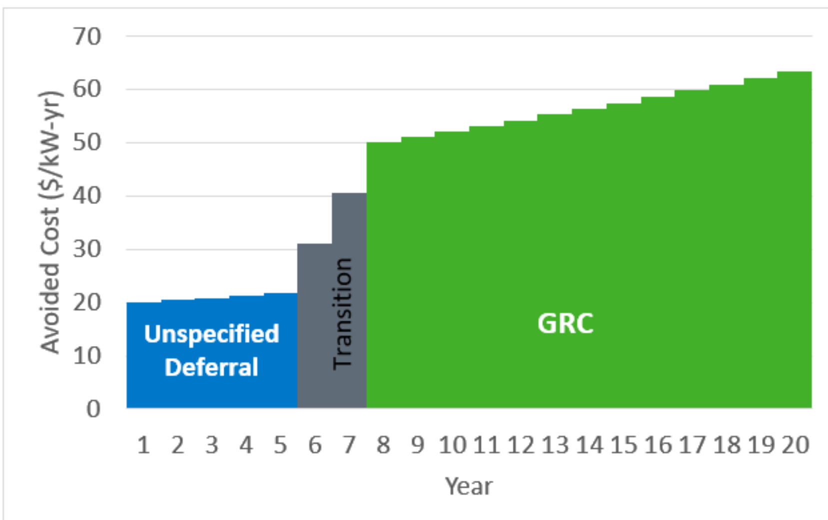
*Figure 27. SCE Subtransmission and A-Bank Distribution Deferral Value*

| Line | | SCE-Substations (A-Bank) | SCE Subtransmission | Notes |
|---|---|---|---|---|
| [1] | Distribution Deferral Value ($/kW-yr) | $ 31.17 | $ 8.77 | From SCE GRC |
| [2] | Deferrable Counterfactual Overloads (kW)* | 286,660 | 286,660 | * Using SCE Substation B-Bank Values |
| [3] | 5 Year Total forecasted DER (kW) | 2,911,430 | 2,911,430 | * Using SCE Substation B-Bank Values |
| [4] | Distribution Deferral Value ($/kW of DER - yr) | **$ 3.07** | **$ 0.86** | [4] = [1] * [2] / [3] |

## 10.2 Use of Short-term and Long-term Avoided Distribution Costs

As stated in the T&D White Paper, "the impact of DERs to defer distribution upgrades accrue over the long term, while the GNA is limited to the forecast horizon that is necessary for distribution planning." The avoided costs estimates discussed above are based on DDOR and GNA filings that use a five-year planning horizon. To extrapolate these estimates into long-term forecasts, the avoided costs in years 1-5 would be the unspecified deferral values held constant on a real dollar basis. Years 8 and beyond would be the GRC level held constant on a real dollar basis. Years 6 and 7 would linearly transition between the two end points of years 5 and 8. This method is depicted in the figure below.

*Figure 28. Illustrative Distribution Avoided Cost Transition*




## 10.3 Long-term GRC-based Marginal Costs

The California IOUs have used a wide variety of methods for estimating distribution marginal costs in their GRC filings.[24] The long-standing purpose of the marginal costs in a GRC filing is to guide the allocation of the utility revenue requirement to customer classes and the design of marginal-cost based rates. The GRC filing therefore provides a useful source for marginal costs that are estimated on regular three-year cycle. However, the GRC marginal costs might not be completely appropriate for use in DER cost effectiveness

[24] Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs, Prepared for the CPUC, October 2004, p. 102

evaluations. They are not location-specific, and they are not necessarily avoidable costs. Therefore, Staff recommends that the GRC values be the source for long-run marginal costs, with the recognition that they may need to be modified for DER cost effectiveness and the ACC.

Specifically, the long-term avoided costs use GRC total distribution capacity costs for all utilities and does not make a distinction between peak and grid distribution capacity. Energy Division's consultant E3 has examined SCE's proposed separation of peak and grid-related distribution marginal costs, and has concluded that it was not supported by sufficient estimation rigor. Use of the total distribution capacity cost as estimated by SCE's regression analysis of cumulative distribution capacity-related investments and cumulative peak loads is consistent with avoided distribution capacity costs that have been used for SCE in prior avoided cost updates.

Should SCE adequately revise its methods in a subsequent GRC proceeding, those revisions should be evaluated on their merits and not rejected based on the current findings herein.

### 10.3.1 GRC Data Hierarchy

In selecting data to use for the long term avoided costs, Staff used the following hierarchy of GRC Phase II data sources, presented in descending order of preference.

1. Values adopted for revenue allocation from most recently completed proceeding.
2. Values adopted for rate design purposes from most recently completed proceeding.
3. Values agreed to by majority of parties for revenue allocation in settlement agreement from most recently completed proceeding.
4. Values agreed to by majority of parties for rate design purposes in settlement agreement from most recently completed proceeding.
5. Utility-proposed values for revenue allocation from most recently completed proceeding.

### 10.3.2 Distribution Marginal Costs from Most Recently Completed Proceedings

#### 10.3.2.1 PG&E

PG&E marginal distribution capacity costs are from its settlement agreement in the utility's 2017 Phase II General Rate Case (GRC) proceeding. The attachment 1 of the settlement agreement[25] shows distribution marginal capacity costs by Operating Division and Planning Area.

For conversion of the capacity costs to Climate Zones, we use the Operating Division data shown in Settlement Table 4, and contained in the electronic workpaper file MCRev_GRC.xlsx. That marginal cost data is expressed in $/PCAF-kW-yr and $/FLT-kW-yr. The PCAF-KW are the coincident peak demands on the distribution system during the times of the peaks on the primary capacity equipment. The FLT-kW are the peaks on the final line transformers, and represent a more noncoincident measure of peak demand on the secondary equipment. To make the two marginal costs compatible, we convert the secondary costs from $/FLT-kW-yr to $/PCAF-kW-yr based on the ratio of FLT-kW to PCAF-kW in the division. The total distribution capacity cost by PG&E Operating Division is shown in column I of Table 30.

[25] GRC-2017-PhII_Plea_PGE_20171026_427910.pdf

*Table 30. Long-Term Distribution Capacity Costs for PG&E by Division (Base Year of 2017)*

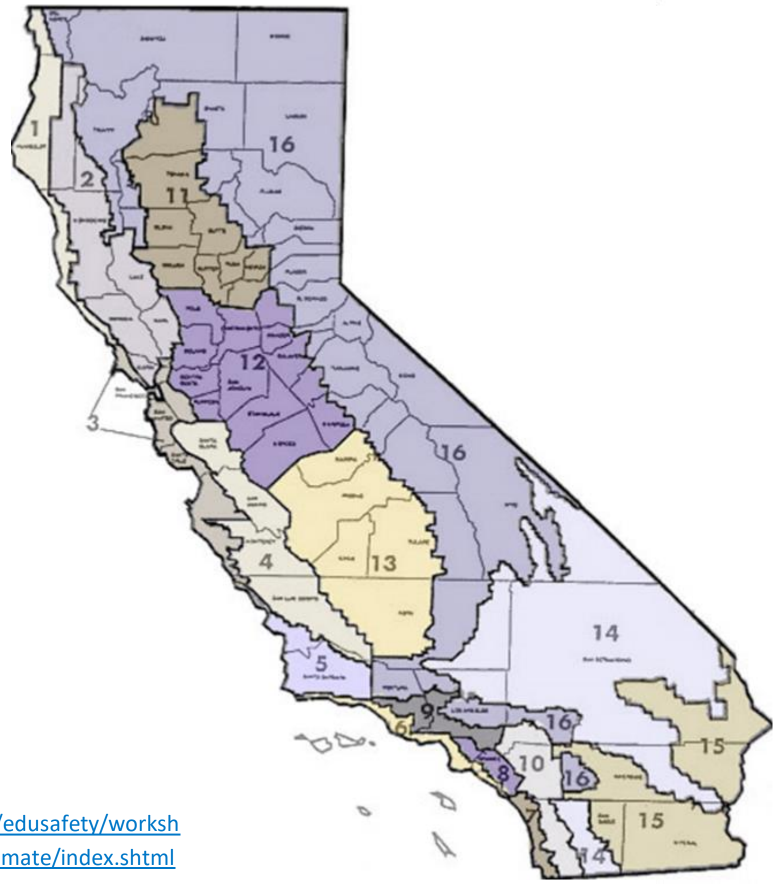
| A | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|
| Line No. | Division | Climate Zone | Primary Capacity $/PCAF-kW-yr /1/ | Secondary $/FLT-kW-yr /1/ | Total PCAF Loads (PCAF kW) /2/ | Total FLT Loads (FLT kW) /2/ | Secondary $/PCAF-kW-yr (E*G/F) | Total Distribution Capacity $/PCAF kW-yr (D+H) |
| 1 | Central Coast | 4 | $69.09 | $1.04 | 823,510 | 1,759,256 | 2.22 | $71.31 |
| 2 | De Anza | 4 | $35.65 | $1.01 | 741,675 | 1,234,311 | 1.68 | $37.33 |
| 3 | Diablo | 12 | $17.78 | $1.56 | 1,265,169 | 1,524,487 | 1.88 | $19.66 |
| 4 | East Bay | 3A | $19.99 | $0.88 | 627,862 | 1,338,170 | 1.88 | $21.87 |
| 5 | Fresno | 13 | $39.52 | $1.36 | 2,164,629 | 3,575,125 | 2.25 | $41.77 |
| 6 | Humboldt | 1 | $73.97 | $1.12 | 292,803 | 736,437 | 2.82 | $76.79 |
| 7 | Kern | 13 | $34.07 | $1.23 | 1,585,454 | 2,449,767 | 1.90 | $35.97 |
| 8 | Los Padres | 5 | $56.49 | $1.06 | 492,381 | 1,041,742 | 2.24 | $58.73 |
| 9 | Mission | 3B | $13.63 | $0.97 | 1,233,354 | 2,022,915 | 1.59 | $15.22 |
| 10 | North Bay | 2 | $29.42 | $1.75 | 647,540 | 1,283,383 | 3.47 | $32.89 |
| 11 | North Valley | 16 | $53.40 | $1.26 | 742,213 | 1,324,624 | 2.25 | $55.65 |
| 12 | Peninsula | 3A | $31.79 | $1.06 | 766,475 | 1,436,434 | 1.99 | $33.78 |
| 13 | Sacramento | 11 | $40.91 | $1.22 | 970,943 | 1,589,591 | 2.00 | $42.91 |
| 14 | San Francisco | 3A | $40.41 | $1.52 | 829,544 | 1,435,075 | 2.63 | $43.04 |
| 15 | San Jose | 4 | $40.12 | $1.16 | 1,369,868 | 2,130,431 | 1.80 | $41.92 |
| 16 | Sierra | 11 | $30.65 | $1.25 | 1,187,910 | 1,833,534 | 1.93 | $32.58 |
| 17 | Sonoma | 2 | $121.98 | $1.28 | 544,454 | 1,147,401 | 2.70 | $124.68 |
| 18 | Stockton | 12 | $33.36 | $1.34 | 1,207,506 | 2,114,747 | 2.35 | $35.71 |
| 19 | Yosemite | 13 | $60.18 | $1.56 | 1,090,280 | 2,098,437 | 3.00 | $63.18 |

/1/ From PG&E 2017 GRC Phase II, MCRev_GRC.xlsx. IN-Dist-Capacity MC tab
/2/ From PG&E 2017 GRC Phase II, MCRev_GRC.xlsx.OUT)PCAF-FLT Factors tab

Finally, the division-level avoided costs are converted into climate zone values. If a climate zone encompasses more than one Operating Division, then the weighted average value is calculated using the PCAF kW in each Operating Division. The PG&E long-term distribution marginal capacity costs by climate zone are summarized below. Climate Zone 3A is the western portion of the zone, comprised of San Francisco and neighboring cities in the Bay Area.

*Table 31. Long-Term Distribution Capacity Costs for PG&E by Climate Zone (Base Year of 2017)*

| J | K |
|---|---|
| Climate Zone | Wtd Avg Capacity Cost $/PCAF-kW-yr (Col I wtd by Col F) |
| 1 | $76.79 |
| 2 | $74.81 |
| 3A | $33.87 |
| 3B | $15.22 |
| 4 | $49.01 |
| 5 | $58.73 |
| 11 | $37.22 |
| 12 | $27.50 |
| 13 | $44.69 |
| 16 | $55.65 |




Climate zone map from: https://www.pge.com/myhome/edusafety/workshopstraining/pec/toolbox/arch/climate/index.shtml

### 10.3.2.2 SCE

SCE's long-term distribution marginal capacity costs are from is 2018 GRC Phase II proceeding.[26] SCE did not develop marginal costs on a geographically disaggregated basis, but used a regression analysis of cumulative distribution capacity-related investments and cumulative peak loads, consistent with avoided distribution capacity costs that have been used for SCE in prior avoided cost updates. SCE developed marginal costs for three categories of distribution capacity investment: subtransmission, substations, and local distribution.

[26] ERRATA, PHASE 2 OF 2018 GENERAL RATE CASE MARGINAL COST AND SALES FORECAST PROPOSALS, SCE-02A TABLE I-14 (SCE 2018 GRC PHASE II

*Table 32. Long-term Distribution Marginal Capacity Costs for SCE ($2018)*

| | SCE Distribution Marginal Capacity Costs (2018$) |
|---|---|
| Subtransmission ($/kW-yr) | $40.00 |
| Substation ($/kW-yr) | $25.00 |
| Local Distribution ($/kW-yr) | $102.90 |
| Total ($/kW-yr) | $167.90 |

In its 2018 GRC Phase II proceeding, SCE also proposes the functionalization of its distribution marginal capacity costs into a peak component and a grid component. SCE's rationale is that the peak refers to the capacity function to meet time-variant peak customer demand, whereas grid refers to the distribution system's function that enables the bi-directional transfer of energy to and from customers. (SCE-02A, p. 39).

With this functionalization, peak related costs are similar to how we previously viewed SCE distribution marginal costs, so they would continue to be included. There is a question, however, of whether grid-related capacity costs should be included in the forecast of SCE avoided distribution capacity costs.

The current avoided distribution capacity costs are consistent with the paradigm that power flows from generators connected to bulk transmission down to customers connected at lower voltages. With the reduction in demand at the customer meter, the need for distribution capacity expansion projects to deliver power from the grid to the customer meter are reduced, and future distribution costs decline. When power flows in the reverse direction (from the customer site onto the grid), however, reductions in demand at the meter could actually increase infrastructure costs as the reduction in customer gross usage results in higher net exports (reverse flow) and higher capacity needs to address those reserve flows.

That said, the method that SCE used to estimate distribution peak and grid capacity costs does not align with a bi-directional flow situation. SCE estimated the total distribution capacity costs using its long-standing NERA regression method. That method only looked at cumulative capacity investment and cumulative peak load. The approach is no different from how SCE estimated marginal distribution costs before its peak/grid distinction. There is no explicit reflection of reverse flow in the estimation of the marginal cost, which suggests that the entirety of the marginal cost should be included (peak plus grid), just as has been done in the past.

SCE makes an additional observation that the distribution system is evolving and that the grid-related equipment is serving more of a contingency and grid connectivity role. Again, while that may be true, the total distribution capacity costs (peak plus grid) that SCE derived do not present a functional relationship between contingency capacity or grid connectivity and distribution investment costs.

For these reasons, we are not making a distinction between peak and grid distribution capacity costs for SCE in this ACC update. We are including the total distribution capacity cost as estimated by SCE's regression analysis of cumulative distribution capacity-related investments and cumulative peak loads. This is consistent with avoided distribution capacity costs that have been used for SCE in prior ACCs.

#### 10.3.2.3 SDG&E

SDG&E's 2016 GRC Phase II does not have marginal costs adopted in the Decision, nor in the applicable Settlement Agreement. Accordingly, we use the marginal distribution costs filed by SDG&E in the Amended Testimony of William Saxe. The marginal costs are for 2016 per SDG&E testimony, pg. WGS-6. SDG&E currently has its 2019 GRC Phase II Application before the Commission (A.19-03-002), but that case has not been resolved as of the time of this writing.

*Table 33. Long-term Distribution Capacity Costs for SDG&E*[27]

| | SDG&E Marginal Capacity Cost ($2016) |
|---|---|
| Substation ($/kW-yr) | $22.05 |
| Local Distribution ($/kW-yr) | $77.97 |
| Total | $100.02 |

## 10.4 Annual Distribution Capacity Costs

As discussed in section *10.2 Use of Short-term and Long-term Avoided* Distribution Costs, the annual distribution marginal cost stream is a combination of near-term and long-term costs. The nominal marginal costs are shown below based on the IOU specific escalation rates shown below.

*Table 34. Distribution Annual Escalation Rates*

| | PG&E | SCE | SDG&E |
|---|---|---|---|
| Annual Distribution Escalation Rate (%/yr) | 2.5% | 2.33% | 2.0% |

*Escalation rates are from the IOU RECC factor derivations for distribution capital projects.*

[27] PREPARED DIRECT TESTIMONY OF WILLIAM G. SAXE ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY IN SUPPORT OF SECOND AMENDED APPLICATION CHAPTER 6, P. WGS-6 (SDG&E 2016 GRC)

*Table 35. Annual Distribution Marginal Capacity Costs ($/kW-yr) (Nominal)*

| | | PG&E | | | | | | | | | | SCE | SDG&E |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Climate Zone: | 1 | 2 | 3A | 3B | 4 | 5 | 11 | 12 | 13 | 16 | All | All |
| 2020 | Near Term | $45.36 | $45.36 | $45.36 | $45.36 | $45.36 | $45.36 | $45.36 | $45.36 | $45.36 | $45.36 | $26.09 | $3.39 |
| 2021 | Near Term | $46.49 | $46.49 | $46.49 | $46.49 | $46.49 | $46.49 | $46.49 | $46.49 | $46.49 | $46.49 | $26.70 | $3.45 |
| 2022 | Near Term | $47.65 | $47.65 | $47.65 | $47.65 | $47.65 | $47.65 | $47.65 | $47.65 | $47.65 | $47.65 | $27.32 | $3.52 |
| 2023 | Near Term | $48.84 | $48.84 | $48.84 | $48.84 | $48.84 | $48.84 | $48.84 | $48.84 | $48.84 | $48.84 | $27.96 | $3.59 |
| 2024 | Near Term | $50.06 | $50.06 | $50.06 | $50.06 | $50.06 | $50.06 | $50.06 | $50.06 | $50.06 | $50.06 | $28.61 | $3.67 |
| 2025 | Transition | $66.14 | $66.14 | $66.14 | $66.14 | $66.14 | $66.14 | $66.14 | $66.14 | $66.14 | $66.14 | $66.14 | $66.14 |
| 2026 | Transition | $82.22 | $81.38 | $63.90 | $55.95 | $70.36 | $74.51 | $65.34 | $61.19 | $68.52 | $73.20 | $125.46 | $106.37 |
| 2027 | Long Term | $98.29 | $95.77 | $43.36 | $19.48 | $62.74 | $75.18 | $47.65 | $35.20 | $57.21 | $71.24 | $206.57 | $124.36 |
| 2028 | Long Term | $100.75 | $98.16 | $44.44 | $19.97 | $64.30 | $77.06 | $48.84 | $36.08 | $58.64 | $73.02 | $211.39 | $126.85 |
| 2029 | Long Term | $103.27 | $100.62 | $45.55 | $20.47 | $65.91 | $78.99 | $50.06 | $36.98 | $60.11 | $74.84 | $216.31 | $129.39 |
| 2030 | Long Term | $105.85 | $103.13 | $46.69 | $20.98 | $67.56 | $80.96 | $51.31 | $37.90 | $61.61 | $76.71 | $221.35 | $131.97 |
| 2031 | Long Term | $108.50 | $105.71 | $47.86 | $21.51 | $69.25 | $82.99 | $52.60 | $38.85 | $63.15 | $78.63 | $226.51 | $134.61 |
| 2032 | Long Term | $111.21 | $108.35 | $49.05 | $22.04 | $70.98 | $85.06 | $53.91 | $39.82 | $64.73 | $80.60 | $231.79 | $137.31 |
| 2033 | Long Term | $113.99 | $111.06 | $50.28 | $22.60 | $72.75 | $87.19 | $55.26 | $40.82 | $66.35 | $82.61 | $237.19 | $140.05 |
| 2034 | Long Term | $116.84 | $113.84 | $51.54 | $23.16 | $74.57 | $89.37 | $56.64 | $41.84 | $68.00 | $84.68 | $242.72 | $142.85 |
| 2035 | Long Term | $119.76 | $116.68 | $52.82 | $23.74 | $76.44 | $91.60 | $58.06 | $42.88 | $69.70 | $86.79 | $248.37 | $145.71 |
| 2036 | Long Term | $122.76 | $119.60 | $54.14 | $24.33 | $78.35 | $93.89 | $59.51 | $43.96 | $71.45 | $88.96 | $254.16 | $148.62 |
| 2037 | Long Term | $125.82 | $122.59 | $55.50 | $24.94 | $80.31 | $96.24 | $61.00 | $45.06 | $73.23 | $91.19 | $260.08 | $151.60 |
| 2038 | Long Term | $128.97 | $125.66 | $56.89 | $25.56 | $82.31 | $98.65 | $62.52 | $46.18 | $75.06 | $93.47 | $266.14 | $154.63 |
| 2039 | Long Term | $132.19 | $128.80 | $58.31 | $26.20 | $84.37 | $101.11 | $64.08 | $47.34 | $76.94 | $95.80 | $272.34 | $157.72 |
| 2040 | Long Term | $135.50 | $132.02 | $59.77 | $26.86 | $86.48 | $103.64 | $65.69 | $48.52 | $78.86 | $98.20 | $278.69 | $160.88 |
| 2041 | Long Term | $138.89 | $135.32 | $61.26 | $27.53 | $88.64 | $106.23 | $67.33 | $49.73 | $80.84 | $100.65 | $285.18 | $164.09 |
| 2042 | Long Term | $142.36 | $138.70 | $62.79 | $28.22 | $90.86 | $108.89 | $69.01 | $50.98 | $82.86 | $103.17 | $291.82 | $167.38 |
| 2043 | Long Term | $145.92 | $142.17 | $64.36 | $28.92 | $93.13 | $111.61 | $70.74 | $52.25 | $84.93 | $105.75 | $298.62 | $170.72 |
| 2044 | Long Term | $149.57 | $145.72 | $65.97 | $29.65 | $95.46 | $114.40 | $72.51 | $53.56 | $87.05 | $108.39 | $305.58 | $174.14 |
| 2045 | Long Term | $153.30 | $149.37 | $67.62 | $30.39 | $97.85 | $117.26 | $74.32 | $54.90 | $89.23 | $111.10 | $312.70 | $177.62 |
| 2046 | Long Term | $157.14 | $153.10 | $69.31 | $31.15 | $100.29 | $120.19 | $76.18 | $56.27 | $91.46 | $113.88 | $319.99 | $181.17 |
| 2047 | Long Term | $161.07 | $156.93 | $71.04 | $31.93 | $102.80 | $123.20 | $78.08 | $57.68 | $93.74 | $116.73 | $327.44 | $184.80 |
| 2048 | Long Term | $165.09 | $160.85 | $72.82 | $32.73 | $105.37 | $126.28 | $80.03 | $59.12 | $96.09 | $119.65 | $335.07 | $188.49 |
| 2049 | Long Term | $169.22 | $164.87 | $74.64 | $33.54 | $108.00 | $129.43 | $82.03 | $60.59 | $98.49 | $122.64 | $342.88 | $192.26 |
| 2050 | Long Term | $173.45 | $168.99 | $76.50 | $34.38 | $110.70 | $132.67 | $84.08 | $62.11 | $100.95 | $125.70 | $350.87 | $196.11 |

## 10.5 Allocation of Avoided Distribution Capacity Costs to Hours

The annual capacity costs shown above are allocated to hours of the year to allow the ACC to reflect the time varying need for distribution capacity. The prior ACC used the distribution hourly allocation factors based on regression estimates of distribution hourly loads.[28] Those estimates reflected forecasts of net loads (load net of local PV production) for the present and future (2030). In this way, the allocation factors estimated an evolution in the timing of the peak capacity needs on the distribution system due to DER. With the change to estimating distribution capacity costs under the paradigm of no new incremental DER, this estimation of the timing of peak capacity needs in a future with more DER is no longer needed.

[28] While the updated allocation factors are superior to the prior values, they are not substitutes or replacements for the work that utilities are currently undertaking as part of the DRP proceeding. These allocation factors are simulations based on a limited number of 2010 circuit and substation load patterns. Actual loading for a specific local distribution area within a climate zone could vary significantly from the loading assumed herein. Moreover, the IOUs may develop alternate methods for determining the peak contribution of distributed energy resources.

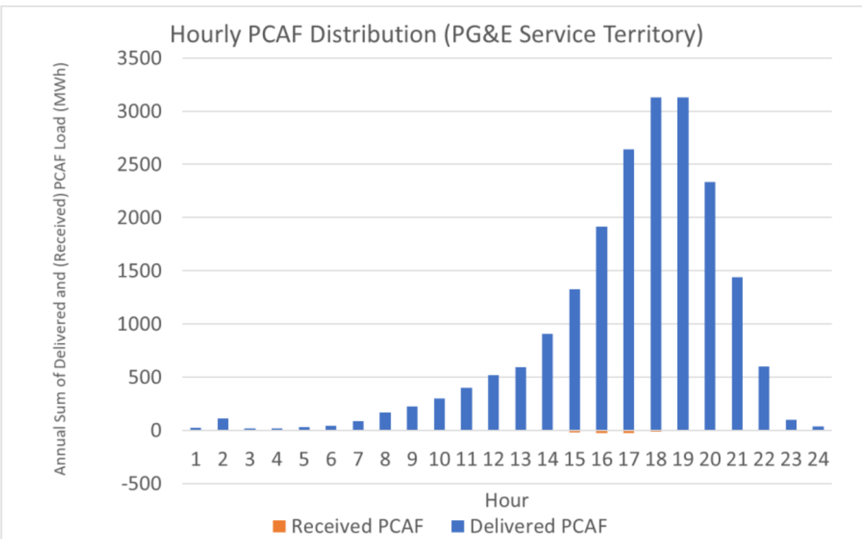
Therefore, the distribution hourly allocation factors estimated for 2020 are used for all years 2020 through 2050 in the ACC.

In addition to holding the allocation factors fixed over the analysis period, this ACC update also utilizes historical utility data and GRC analyses for the allocation factors. Details by IOU are provided blow.

### 10.5.1 PG&E PCAFs

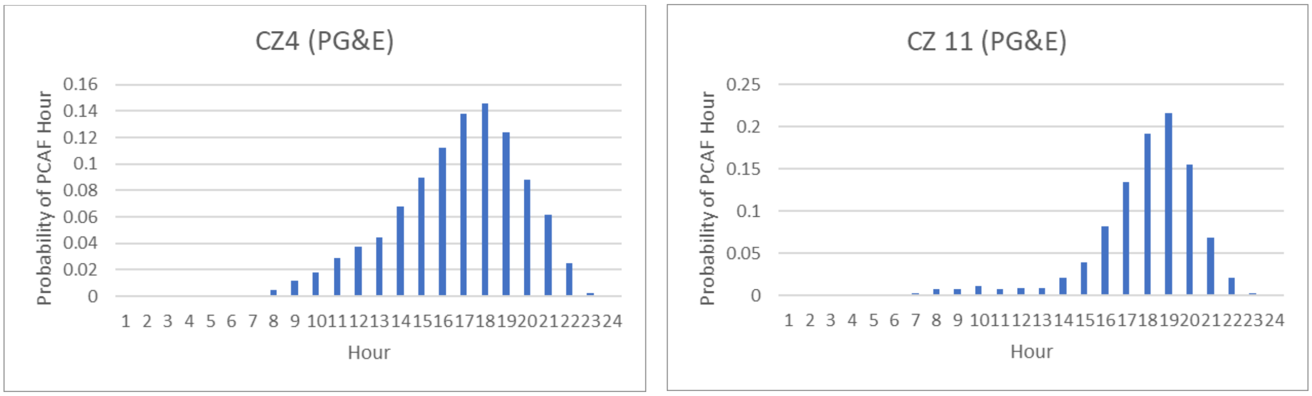
PG&E produces hourly peak capacity allocation factors (PCAFs) by distribution area for their GRC filing. In its 2020 GRC Phase II proceeding, PG&E presents a novel modification to its PCAF methodology wherein the need for capacity to accommodate exports is factored into the PCAF calculations. While this modification may have merit, it has not been incorporated into the ACC at this time because its impact is currently negligibly small. Figure 29 shows the PCAF associated with normal delivery of power from the grid to the customer, and the PCAF associated with exports. The export-related PCAFs are barely visible in the hours 15-18.

*Figure 29. PG&E PCAF Distribution for all Areas by Hour of the Day (PST)*




The PCAFs used in the ACC were provided by PG&E division. PG&E divisions were mapped to climate zones using the same methodology outlined in Table 30. If there was more than one division per climate zone, a weighted average of the PCAFs was taken. The appendix in section 0 contains figures for all IOU PCAFs by climate zone. Two climate zone results are shown below as examples.

*Figure 30. Example PG&E PCAF Distributions by Hour of Day (PST)*

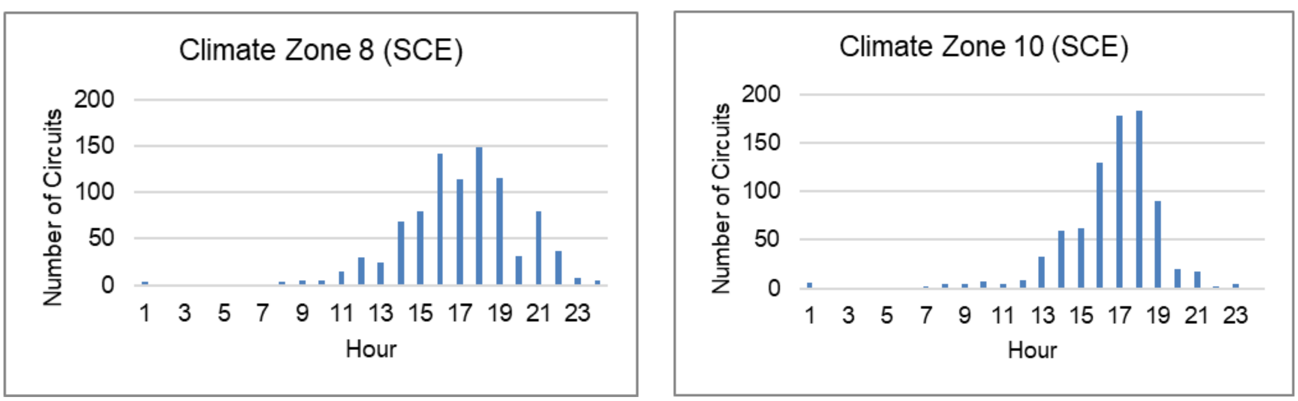



## 10.5.2 SCE Peak Load Risk Factors (PLRF)

For SCE, the ACC utilizes the PLRF analysis done by SCE in its 2018 GRC Phase II proceeding. According to SCE: "The PLRF methodology is a deterministic variant of the LOLE methodology used for generation capacity, and uses the same conceptual framework of identifying hours of the year when expected load may result in an expected capacity constraint on the system. Since the distribution system is geographically disparate, the PLRF methodology is applied to each individual substation and circuit to take into account load diversity on the system."

The PLRF identifies the hours of peak capacity need for each substation and circuit. To translate that to allocation factors by climate zone, we aggregated the substations and circuits into climate zones, and calculated the probability of peak capacity need for each hour based on the relative number of times each hour was the peak hour for a substation or circuit in the climate zone.

*Figure 31. Example SCE PLRF Distributions by Hour of the Day (PST)*




## 10.5.3 SDG&E PCAFs

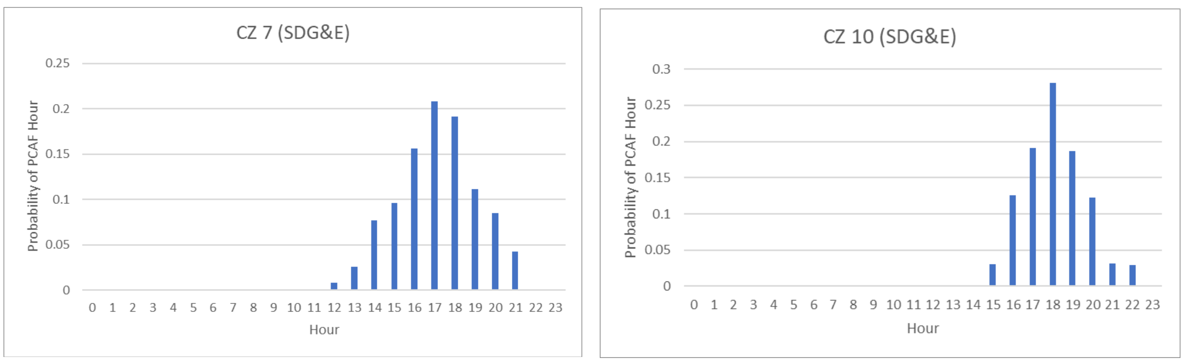
SDG&E does not produce PCAFs or PLRFs in its GRC proceedings. We therefore calculated PCAFs for the SDG&E climate zones using distribution-level power flow data provided by SDG&E and the PCAF methodology from the prior ACC. The allocation factors are derived with the formula below and the additional constraint that the peak period contain between 20 and 250 hours for the year.

PCAF[a,h] = (Load[a,h] – Threshold[a]) / Sum of all positive (Load[a,h] – Threshold[a])

Where:

- a is the climate zone area,
- h is hour of the year,
- Load is the net distribution load, and
- Threshold is the area maximum demand less one standard deviation, or the closest value that satisfies the constraint of between 20 and 250 hours with loads above the threshold.

*Figure 32. Example SDG&E Climate Zone PCAFs by Hour of the Day (PST)*




### 10.5.4 Distribution Day and Weather Mapping

The distribution capacity hourly allocation factors described above reflect the particular years from which the historical data was obtained. The peak loads are therefore driven by weather conditions in those years – and that weather will not match the CTZ22 weather files used for the generation avoided cost modeling. In order to better align the distribution and generation costs, the distribution allocation factors are reordered to align with the weather in the CTZ22 files. Moreover, the hourly allocation factors are realigned so that the occurrence of weekends and holidays matches a 2020 calendar year. This remapping of allocation factors for weekends is particularly important for the evaluation of energy efficiency measures that vary by occupation schedules such as office HVAC. Each IOU provided temperature data from weather stations within the service territory which were mapped to climate zones using the index provided by the *California Climate Zone Descriptions*[29] document published by the CEC. Data for climate zone 1, 5 and 16 were missing due to the size of the climate zones. Temperature Data for climate zone 2 was used to approximate climate zones 1 and 16, while data from climate zone 4 was used to approximate climate zone 5. These proxy climate zones were selected by choosing the climate zone with the most comparable amounts of heating and cooling degree days to the climate zone with missing data.

The CTZ22 weather data and calendar year 2020 are the master timeseries for the remapping.

[29] https://www.pge.com/includes/docs/pdfs/about/rates/rebateprogrameval/advisorygroup/climatezones.pdf

All timeseries data are assigned in 24-hour days to bins by workday/weekend-holiday, and season. Within each bin, the timeseries data is ranked by a temperature metric for each day. The temperature metric used by E3 for the PCAF is the mean temperature over the course of a day. The remapping then reorders the timeseries data by day within each bin by mapping temperature metric ranks for the master data and the weather data used in the utility analyses. For example, PCAFs for the summer weekday with the highest temperature metric (mean average temperature) will be remapped to the CTZ22 weekday with the highest ranked temperature metric. The second highest PCAF day would be mapped to the second highest base day, etc. If there are more source days in the bin than base year days, the lowest ranked source days would be discarded. If there are fewer source days in the bin than base year days, the lowest ranked source day would be replicated as needed. Given that PCAF and PLRF are concentrated in relatively few hours of the year, the effects of duplicating or discarding the lowest ranked days would likely have no impact.

The results of the remapping process is distribution hourly allocation factors that sum to the same total (basically 100%) for each climate zone, but better reflect the expected impact of CTZ22 weather and align all weekends and holidays with a 2020 calendar (each year starts on Wednesday).

# 11 Transmission and Distribution Loss Factors

## 11.1 T&D Capacity Loss Factors

The value of deferring transmission and distribution investments is adjusted for losses during the peak period using the factors shown in Table 36 and

Table 37. These factors are lower than the energy and generation capacity loss factors because they represent losses from secondary meter to only the distribution or transmission facilities.

*Table 36. Loss Factors for SCE and SDG&E Transmission and Distribution Capacity*

| | SCE | SDG&E |
|---|---|---|
| Distribution | 1.022 | 1.043 |
| Transmission | 1.054 | 1.071 |

*Table 37: Loss Factors for PG&E Transmission and Distribution Capacity*

| | Transmission | Distribution |
|---|---|---|
| Central Coast | 1.053 | 1.019 |
| De Anza | 1.050 | 1.019 |
| Diablo | 1.045 | 1.020 |
| East Bay | 1.042 | 1.020 |
| Fresno | 1.076 | 1.020 |
| Kern | 1.065 | 1.023 |
| Los Padres | 1.060 | 1.019 |
| Mission | 1.047 | 1.019 |
| North Bay | 1.053 | 1.019 |
| North Coast | 1.060 | 1.019 |
| North Valley | 1.073 | 1.021 |
| Peninsula | 1.050 | 1.019 |
| Sacramento | 1.052 | 1.019 |
| San Francisco | 1.045 | 1.020 |
| San Jose | 1.052 | 1.018 |
| Sierra | 1.054 | 1.020 |
| Stockton | 1.066 | 1.019 |
| Yosemite | 1.067 | 1.019 |

# 12 High GWP Gases

## 12.1 Introduction

This new avoided cost component measures the greenhouse gas (GHG) emissions from refrigerants and methane, two types of high Global Warming Potential (GWP) gases. High GWP gases are defined as GHGs that have a greater impact on global warming than $CO_2$. The GWP of a given gas is the ratio of its atmospheric effect on global warming to that of $CO_2$, so that the larger the GWP the more that a given gas contributes to the atmospheric greenhouse effect over a given time period. The GWP of a given gas may differ depending on the time period over which it is measured. For example, methane has a GWP of 72 over 20 years and a GWP of 25 over 100 years.[30]

The impetus for this new component is primarily the advent of DER programs designed to replace natural gas appliances with electric appliances, as a result of recent changes in state energy policy and new legislation.[31] These programs *decrease* GHG emissions due to their reduction in natural gas usage and

[30] The 100-year GWP is used the CARB inventory, documented here. The 20-year GWP is documented in IPCC materials, for example the technical documentation for the IPCC Fourth Assessment Report, p. 212.

[31] Such as SB1477 and AB3232, which implement statewide building decarbonization efforts.

associated methane leakage, but they simultaneously *increase* GHG emissions due to their increase in refrigerant use and electricity consumption. Therefore, these changes must be accounted for to accurately measure the GHG impact of these new programs. This new avoided cost will also be used to value changes in methane leakage for a wide range of DERs, since DER programs are generally designed to decrease electricity consumption (which then results in a decrease in natural gas usage at power plants) or to decrease direct natural gas consumption in buildings.

Methane leakage occurs within the natural gas system, so decreases in natural gas consumption can result in decreases in methane leakage, although the exact relationship between usage and leakage in different parts of the system is unclear. However, in the long run, large scale electrification will decrease methane leakage as large sections of the natural gas infrastructure are shut down. This new avoided cost component estimates this effect.

Most of the electric appliances that are expected to replace natural gas appliances due to the state's building decarbonization efforts use heat pumps, which contain refrigerants. This will result in an increase in refrigerant leakage. Since most refrigerants are potent GHGs – the most commonly used refrigerant has a 100-year GWP of more than 2000 – it is important to consider the impact of these devices on the state's GHG reduction goals. Hence, this new avoided cost will be used to measure the increase in GHG emissions from heat pump appliances. It will also be used for any future programs which focus on refrigerant replacement (i.e., replacing high GWP refrigerants with lower GWP refrigerants).

## 12.2 Methane

### 12.2.1 Introduction and summary

Natural gas is the primary fuel used in buildings both indirectly, for electricity generation, and directly, for space and water heating, cooking, and clothes drying. Natural gas consists mostly of methane. When methane is combusted, it produces $CO_2$, whereas if it leaks before it can be combusted it is not only wasted as a fuel but also has a disproportionately high impact on global warming, as compared to burning that same methane. Uncombusted methane has a 100-year GWP of 25, meaning it is 25 times more potent than CO2 as a greenhouse gas over a 100-year time horizon. Over a shorter time horizon, uncombusted methane is even more potent, which is why methane has a 20-year GWP of 72. The 100-year values are primarily what is discussed in this documentation, as this is what is used in the ARB GHG inventory, although the ACC includes the option to toggle between 100-year and 20-year GWPs. The 100-year value is the default value used in the ACC, with the 20-year value included for sensitivity analysis purposes.

Methane leakage occurs in all parts of the natural gas system – at production and storage facilities, in pipelines, at the meter, and behind the meter. The link between natural gas use (throughput) and methane leakage is not precisely known. Decreases in natural gas usage may result in decreased leakage at production facilities, since fewer new wells will be drilled over time in response to decreased demand (and old wells may be taken out of service), but may not result in decreased leakage within pipelines or at storage facilities, at least in the short run, because many of those systems are kept at a constant pressure. However, in the long run, as parts of the natural gas distribution system are shut down as the result of building decarbonization efforts, methane leakage in the entire system will decrease.[32] Likewise, building decarbonization will eliminate leakage at the meter, and behind the meter, particularly when all natural gas appliances are removed from a building and the building's gas connection is shut off.

The October 2019 IDER Staff Proposal presented two options for an avoided methane leakage rate: a national average estimate of 2.4% from a 2018 study and an in-state estimate of 0.7% implied by the CARB inventory.[33] Since California imports more than 90% of its natural gas, a national average, as opposed to a statewide estimate for methane leakage, is more appropriate for determining the lifecycle leakage of natural gas consumed in California. However, out-of-state methane leakage is not included in the CARB inventory, meaning that reducing this leakage does not count towards achieving California's GHG reduction goals. Thus, reduced out-of-state methane leakage is not strictly an avoided cost to California ratepayers, as defined by the current avoided cost framework. Hence, we now reject the proposal to use the national estimate. However, out-of-state methane leakage could, in theory, be incorporated as a societal cost, paired with a societal carbon price, in a future societal cost-effectiveness test.

The 0.7% estimate is a methane leakage *rate*, which is simply the percent of California natural gas consumption that is assumed to leak within the state. For incorporation into avoided costs, a leakage *rate* must be converted to a leakage *adder*—the % increase that methane leakage *adds* to the GHG intensity of natural gas. A 0.7% leakage rate is equivalent to a 6.4% leakage adder, due to the high GWP of methane. In this document, we primarily use leakage adders to quantify methane leakage as they are the most directly applicable to values. More information about leakage rates, leakage adders, and how they were derived can be found in the Appendix.

CPUC Energy Division staff and its consultant E3 coordinated with CARB to discuss the proposed 6.4% leakage adder (originally proposed as an equivalent 0.7% leakage rate) and determine if it is an appropriate value to use in the 2020 ACC. CARB informed us that the previous estimate of 6.4% included all sources of methane leakage in the state, including behind-the-meter leakage. We re-visited the inventory to develop separate estimates for upstream and behind-the-meter, so that methane leakage can be properly attributed to each category of natural gas use examined in the ACC. The resulting estimates are a leakage adder of 5.57% for upstream in-state methane leakage and a leakage adder of 3.78% for residential behind the meter leakage.

The leakage adder is the percent of $CO_{2e}$ emissions that will be added to gas emissions estimates in the ACC to account for methane leakage, which will be applied to all DERs. The residential behind-the-meter leakage adder will be applied only to DERs that reduce behind-the-meter natural gas combustion through removal of natural gas appliances.

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[32] As identified in the 2018 CARB/CPUC Joint Staff Report analyzing the California natural gas utilities' leakage abatement reports, leakage in the natural gas distribution system and at the meter represents the majority (roughly 70%) of in-state T&D leakage. Therefore, the majority of methane leakage in the T&D system could be avoided through large-scale building electrification that would allow a coordinated retirement of the gas distribution system.

[33] Note that the in-state 0.7% estimate is a rate of leakage occurring within state borders, expressed as a percentage of total natural gas consumption in the state, most of which is imported. Thus, the leakage rate for CA-produced natural gas alone would be much higher.

The upstream leakage adder of 5.57% is most accurately described as an estimate of "long-run avoided methane leakage" for the natural gas system. With the exception of methane leakage at the individual appliance level, it is unclear if methane leakage in the natural gas system in California will change as a function of throughput,[34] unless portions of the gas distribution system are shut down due to coordinated electrification. However, in the long run, as the state transitions away from using natural gas in buildings, all or most of the leakage in the natural gas system in the state could be avoided. Thus, it makes the most sense to attribute avoided methane leakage proportionally to each natural gas reduction, and each removed natural gas appliance, rather than only to the last building to electrify that enables part of the gas system to shut down. In other words, reducing natural gas usage will lead, in the long run, to reduced methane leakage that is likely to occur in a step-wise fashion, where large cumulative reductions in natural gas usage result in reductions in leakage that occur in relatively large "steps." By applying that large, long-run reduction to each BTU of natural gas reduction, we are "smoothing out" the step-wise function, and spreading the same total reduction in GHGs more evenly over time. This is similar to the way we currently treat avoided generation capacity in the ACC, where even a small change in peak energy usage is considered to have capacity value, even though only relatively large changes will actually avoid the construction of a new power plant.

[34] While decreased natural gas usage is likely to result in decreased methane leakage at production facilities, since less natural gas will be pumped, most of that leakage is not considered here because California imports almost all of its natural gas.

### 12.2.2 Detailed Methodology for Methane Leakage Adders

The leakage adders in the 2020 ACC are calculated using CO2-equivalent emissions numbers from the 2017 GHG inventory published by the ARB.[35] The ARB inventory is a record of all GHG emissions occurring within the state borders of California, plus any out-of-state GHG emissions from electric generators supplying electricity to California.

As mentioned in the preceding section, the methane leakage rate originally proposed in the IDER Staff Proposal was 0.7%, which corresponds to a 6.4% leakage adder (further explanation of the difference between these two quantities is below). After coordination with ARB, this estimate was refined to break out the residential behind-the-meter component of methane leakage, and divide this by residential consumption only, to arrive at the residential behind the meter leakage adder.

There are three categories of methane leakage that are included in the ARB inventory: 1) Oil & Gas Production and Processing, 2) Natural Gas Transmission and Distribution, and 3) Residential Behind-the-Meter (BTM). The methane leakage in categories 1) and 2) reflects the "upstream" methane leakage occurring within state boundaries, and is thus assumed to apply to all natural gas consumed in California. The CO2-equivalent methane leakage in these categories is divided by the CO2 emissions from all natural gas consumption in California, to arrive at the **upstream in-state methane leakage adder** of 5.57%. Note that the methane leakage emissions from production and processing of natural gas imported to California from out-of-state (representing about 90-95% of natural gas consumption in California) are not included in this estimate, so this 5.57% is significantly lower than it would otherwise be if these out-of-state emissions were included. These out-of-state emissions are not currently in the ARB inventory, which is why they are not currently included in this upstream emissions estimate. Also note that the CO2-equivalent methane leakage included in the ARB inventory is calculated using the 100-year GWP for methane. (The ACC includes the ability to toggle between 100-year and 20-year GWP, but this appendix focuses on the values calculated with the 100-year GWP.)

Similarly, the **residential behind-the-meter leakage adder** of 3.78% is calculated by dividing the CO2-equivalent methane leakage emissions in category 3) above by the CO2 emissions from residential natural gas consumption only. This second adder applies only to natural gas consumed in residential buildings, and is included as an avoided cost only for programs which remove a natural gas appliance from a building, since more efficient gas appliances such as tankless water heaters are not likely to reduce methane leakage.

These **methane leakage adders** are distinct from **methane leakage rates**, which were what was originally described in the Staff Proposal. Methane leakage rates reflect the percentage of unburned natural gas that is leaked across the lifecycle of natural gas consumption. Methane leakage adders reflect the impact of this leaked natural gas on the GHG intensity of natural gas, which is what is required for incorporating methane leakage into avoided cost calculations. A leakage adder is higher than its corresponding leakage rate due to the high GWP of methane. These two values are calculated in the following way:

- Methane leakage rate = $\frac{mass\ of\ natural\ gas\ leaked}{mass\ of\ natural\ gas\ consumed}$

[35] The 2017 ARB inventory (Economic Sector categorization) can be found here: https://ww3.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_by_sector_all_00-17.xlsx . This is the most recent version of the inventory.

- Answers the question: "What percent of my natural gas supply was leaked?"

+ Methane leakage adder = $\frac{CO2-equivalent\ emissions\ from\ leaked\ natural\ gas}{CO2\ emissions\ from\ burned\ natural\ gas}$
    - Answers the question: "How does this leaked methane increase the overall GHG emissions from natural gas consumption?"

At first glance, one might guess that the leakage adder is simply equal to the leakage rate times the GWP of methane, equal to 25 over a 100-year time horizon. However, this is not the case, because methane actually *gains mass when it is burned* due to being oxidized with oxygen-- each tonne of methane yields 2.74 tonnes of CO2 when it is burned. Thus, the conversion from a methane leakage rate to a methane leakage adder is done in the following way:

methane leakage rate | methane leakage adder

$$\frac{mass\ of\ methane\ leaked\ (tonnes\ CH4)}{mass\ of\ methane\ consumed\ (tonnes\ CH4)} \begin{matrix} \longrightarrow * \frac{25\ tonnes\ CO2eq}{tonne\ CH4\ leaked} \longrightarrow \\ = \\ \longrightarrow * \frac{2.74\ tonnes\ CO2}{tonne\ CH4\ burned} \longrightarrow \end{matrix} \frac{CO2eq\ emissions\ from\ leaked\ NG}{CO2\ emissions\ from\ burned\ NG}$$

**And therefore, because 25/2.74 = 9.1:**

$$methane\ leakage\ rate \quad * \quad 9.1 \quad = \quad methane\ leakage\ adder$$

Thus, the conversion factor between a methane leakage rate and a methane leakage adder is actually 9.1, not 25.[36]

Another way of looking at this is that on a tonne by tonne basis, methane does have 25 times the impact of CO2. In other words, releasing a tonne of methane to the atmosphere has 25 times the global warming impact of releasing a tonne of CO2 to the atmosphere (over 100 years). However, we are not comparing methane to CO2 on a tonne by tonne basis. Rather, we are comparing methane leakage to CO2 combustion. In other words, we are comparing tonnes of natural gas that we intended to combust but accidentally

[36] Note that this calculation assumes, for explanation purposes, that natural gas is 100% methane. In reality natural gas is about 95% methane, so the conversion factor of 9.1 would have to be modified slightly to account for this. However, since the ACC only relies on the leakage adders, which are calculated directly from the ARB inventory and do not require the conversion factor of 9.1, it is not necessary to account for this adjustment for the purposes of developing methane leakage estimates for the ACC. The explanation of the 9.1 conversion factor is included only to clarify the difference between leakage rates and leakage adders, since the Staff Proposal included a discussion of leakage rates only.

leaked instead with tonnes of natural gas that we are burning for fuel and thus producing CO2 as a byproduct.

For example, we start out with a tonne of methane. If we leak it, then (obviously) a tonne of methane will enter the atmosphere, which will have 25 times the global warming impact of a tonne of CO2. But, if we burn it, because of the different molecular mass of CH4 (methane) and CO2, more than 1 tonne of CO2 will be produced. Burning a tonne of methane produces 2.74 tonnes of CO2. In order to determine the global warming impact of the leaked methane, we do not want to compare the effect of the leaked methane to that of one tonne of CO2, but rather to the 2.74 tonnes of CO2 we would have produced by burning it. So, we divide 25 by 2.74 to get 9.1. Hence, a tonne of methane leakage has 9.1 times the global warming impact if it is leaked compared to if it is burned.

The final methane leakage adders, and their corresponding leakage rates, are included in the table below. Also included are the leakage adder values that correspond to a 20-year GWP for methane, which is calculated by multiplying the 100-year leakage adders by 2.88, the ratio between the 20-year and 100-year GWPs for methane (72 and 25, respectively). A toggle to switch between these two GWP calculations is included in the ACC; although the primary adopted value is the 100-year leakage adder (middle column).

*Table 38. Leakage Adders in the ACC and their Corresponding Leakage Rates*

| Leakage type | Leakage rate (% of natural gas consumption) | Leakage adder, 100-year GWP (% of CO2e emissions) | Leakage adder, 20-year GWP (% of CO2e emissions) |
|---|---|---|---|
| Upstream in-state methane leakage | 0.612% | 5.57% | 16.04% |
| Residential behind-the-meter methane leakage | 0.415% | 3.78% | 10.89% |

## 12.3 Refrigerants

Refrigerants are gases which can absorb and transfer heat. They have been used for many years in cooling systems such as refrigerators and air conditioners. They are also used in electric heat pumps, which are new, energy-efficient devices that supply electric space conditioning and water heating. As California pursues higher levels of building decarbonization, many more heat pumps will be purchased and used. All heat pumps use refrigerants, and most refrigerants used today are very strong greenhouse gases. The most common refrigerant, R410-A, has a 100-yr GWP of 2,088 – more than 2,000 times the global warming impact of $CO_2$.

Refrigerants only contribute to global warming when they leak, but leakage is inevitable, given current practices. Emissions from refrigerant leakage in all-electric buildings can be a significant portion of a building's lifecycle GHG emissions. Most refrigerant leakage occurs at an appliance's end of life, during the disposal process, although every appliance has some small amount of leakage that occurs during its useful lifetime. GHG emissions due to refrigerant leakage will be counted on a per-unit basis, rather than on a per-kWh basis.

## 12.4 Use Cases

This new avoided cost component has three different parts, or use cases, which will apply to different types of measures and affect different parts of the ACC. The use cases are described below, and details of the equations used to calculate them are discussed in the subsequent section:

**Use case #1: Changes in electricity usage** – This use case would likely affect all traditional electric DER programs, since they almost always result in decreases in electricity usage. All electric energy efficiency measures (by definition), most demand response programs (except possibly some load shift demand response), and most customer generation programs, result in decreases in electricity use.[37]

Decreases in GHG emissions from electricity usage depend partially on the hours of the day and year the electricity reductions occur. For this reason, the value of GHG emissions is based on both hourly electricity reductions and the GHG intensity of the electric grid for that hour. For example, the GHG intensity of the grid is zero during any hour where the marginal generating unit is a solar resource.

In previous versions of the electric ACC, the value of avoided GHG of any particular DER in a given hour was calculated to be the product of the electric GHG adder, the GHG intensity of the grid during that hour, and the change in electricity usage. That calculation will remain essentially the same[38], except that we add a term to reflect that reduced electricity usage results not only in reduced natural gas usage at the generator, but also reduced methane leakage in the natural gas system.

**Use case #2: Changes in gas usage** – This use case applies only to programs that change the amount of direct natural gas consumption in buildings. It would affect all traditional gas EE measures, as well as building decarbonization efforts that result in the removal of natural gas appliances.

In previous versions of the gas ACC, the value of avoided GHG of a gas EE measure was the reduced GHG emissions multiplied by the gas GHG adder, where the reduced GHG emissions are simply the lifetime decrease in natural gas consumption of the device (or program) multiplied by a constant which reflects the carbon intensity of natural gas. That calculation will remain essentially the same, except that we add two terms to reflect that reduced natural gas usage results in reduced upstream and behind-the-meter methane leakage. The upstream adder will be applied to all programs which directly reduce natural gas consumption, but the behind-the-meter adder will be applied only to programs that eliminate natural gas appliances from the building.

**Use case #3: Changes in refrigerant usage or type** – While this use case was developed primarily to estimate the GHG impact of building decarbonization, it would affect any existing EE measures that involve

[37] "Electricity use" in this sense refers only to utility-supplied electricity. A customer who generates their own electricity may increase or decrease their total usage, but their utility-supplied usage will decrease.

[38] This does not include any other changes made to the method of calculating GHG emissions, such as the use of both short- and long-run GHG emission calculations.

refrigeration or air conditioning, if those measures result in changes in equipment or refrigerant type, and therefore refrigerant leakage.

The calculations associated with this use case are new, and not reflected in any previous version of the ACC. Note that this calculation applies to measures which result in changes to the *amount* of refrigerant, or the *type* of refrigerant, or both, since either change results in a change in the GHG emissions from refrigerant leakage.

## 12.5 Use Case Equations

Details of the equation used to calculate each use case are shown below, and more information about each variable can be found in the table:

1. **Change in electricity usage for device *i***

This use case will apply to all DERs that result in changes in electricity usage. The new GHG value is the change in GHG emissions, multiplied by a percentage increase to account for methane leakage, and then multiplied by the GHG adder. The change in GHG emissions, in tonnes of $CO_{2e}$, is the hourly carbon intensity of the electric grid multiplied by the hourly change in electricity usage, summed over all hours. The percentage increase due to methane leakage is 100% + the upstream methane adder ($\delta\%_{upstream}$), or 105.57%. Note that except for the addition of the upstream methane adder, this calculation is the same in the current value of GHG.

$$\text{Value of change in electricity usage} = \Sigma_h\left(CI_{grid,h}\ \Delta E_{h,i}\right) * \left(100\% + \delta\%_{upstream}\right) * P_{GHGe}$$

$$(\$) = (\text{tonnes } CO_{2e}) \quad (\text{dimensionless}) \quad \left(\frac{\$}{tonne\ CO2e}\right)$$

2. **Change in gas usage for device *i***

This use case will apply to all DERs that result in changes in direct natural gas usage in a building. The new GHG value is the change in GHG emissions multiplied by a percentage increase to account for methane leakage, and then multiplied by the GHG adder. The first term in the equation below represents the change in GHG emissions, in tonnes of $CO_{2e}$, and it is equal to the carbon intensity of natural gas multiplied by the change in gas usage of a particular device (or program). The second term is the percentage increase due to methane leakage, which is 100% + the upstream methane adder ($\delta\%_{upstream}$) + the behind-the-meter adder ($\delta\%_{BTM}$). For programs that reduce natural gas consumption, but do not eliminate natural gas appliances from the building, the behind-the-meter adder is zero. Note that with the exception of addition of the terms $\delta\%_{upstream}$ and $\delta\%_{BTM}$ this calculation is the same as the current value of GHG for gas EE measures. Hence, for gas EE measures which reduce gas usage, the GHG value will be increased by 100% + the upstream methane adder, or 105.57%, as compared with the current GHG avoided cost[39]. For programs that eliminate natural gas appliances from the building, the current GHG value will be increased by 100% + the upstream methane adder + the behind-the-meter adder, or 100% +5.57% + 3.78% = 109.35%[40].

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[39] This does not take into account any changes to the value of $P_{GHGg}$, the gas GHG adder.

[40] This does not take into account any changes to the value of $P_{GHGg}$, the gas GHG adder.

Value of change in gas usage = $\left(CI_{gas}\ \Delta G_i\right) * \left(1 + \delta\%_{upstream} + \delta\%_{BTM}\right) * P_{GHGg}$

($) = (tonnes $CO_{2e}$) (dimensionless) ($\frac{\$}{tonne\ CO2e}$)

### 3. Change in refrigerant leakage for device *i*

This use case was developed primarily to calculate the increases in GHG impact due to refrigerant leakage when new heat pump devices are installed. This calculation can also determine changes in GHG impact when high GWP refrigerants are replaced with lower GWP refrigerants, or when a new device replaces an older one with a different refrigerant charge, leakage rate, or refrigerant.

The value of any change in refrigerant leakage will be determined by the difference between the "old" value for refrigerant leakage and the "new" value, multiplied by the electric GHG adder. This allows us to estimate either increased or decreased GHG for any situation where refrigerant charge ( $M_i$ ), leakage $\left(q_{ann,i}\ t_i + q_{EOL,i}\left(1 - q_{ann,i}t_{EOL,i}\right)\right)$ or refrigerant GWP ($GWP_i$) has changed.

In the cases where a heat pump replaces a natural gas appliance, the "old" values will be zero, since natural gas appliances have no refrigerant. As a result, the value will be negative, as is appropriate for an appliance which is *adding* GHG emissions.

In the cases where the refrigerant charge, leakage rate, and/or refrigerant GWP change (e.g., when a new heat pump replaces an old heat pump or a refrigerant is replaced) the inputs to the equation can distinguish between the "new" and "old" values of refrigerant charge, leakage rate or GWP. If one or two of those values do not change, then the "old" and "new" values are the same. For example, if a refrigerant with a GWP of 750 replaces a refrigerant with a GWP of 2088, then $GWP_{new}$ = 750 and $GWP_{old}$ = 2088, whereas all other quantities will remain the same (e.g., $M_{old}$ = $M_{new}$). Note that because $GWP_{old}$ is greater than $GWP_{new}$ and all other quantities are the same, the resulting value will be positive, as is appropriate when a low-GWP refrigerant replaces a high-GWP refrigerant. Note than when a new heat pump replaces more than one appliance (such as when a new heat pump HVAC system replaces both an air conditioner and an older heat pump), the calculation may be somewhat more complex, and may have to be done in a separate workpaper rather than a cost-effectiveness tool.

The term $(q_{ann,i}\ t_i + q_{EOL,i}\left(1 - q_{ann,i}t_{EOL}\right))$ represents the fraction of refrigerant charge that is leaked into the atmosphere over the device's life. It includes both the operational leakage that occurs through normal use, and the end-of-life leakage that occurs at disposal. The operational leakage is equal to the annual leakage rate ($q_{ann}$) multiplied by the device's expected useful lifetime (*t*). The end-of-life leakage depends on both the end-of-life leakage rate for each device ($q_{EOL}$ , which depends on the typical disposal practice for device type *i*) and on the extent to which refrigerant that is lost during the device's lifetime is replaced (i.e., "topped off").

For example, disposal practices for residential heat pump devices often do not follow regulations requiring refrigerant recycling, and instead the refrigerant is generally vented (i.e., completely leaked) before disposal. If this occurs in 85% of the units disposed, then, $q_{EOL,i}$ = 85% for these type of device. If the device is never topped off (as is typical for some residential devices) then $t_{EOL}$ = *t* – 20 years. If the annual leakage rate ($q_{ann}$) is 2%/year and the EUL (*t*) is 20 years then the total leakage is

$$q_{ann,i}\ t_i + q_{EOL,i}\left(1 - q_{ann,i}t_{EOL,i}\right)$$

= 2%/year * 20 years + 85% [1 – (2%/year * 20 years)]
= 40% + 85% (1 – 40%)
= 40% + 51%
= 91%

Value of change in refrigerant leakage =

$$M_{old,i} * \left(q_{ann,i}\, t_i + q_{EOL,i}\left(1 - q_{ann,i} t_{EOL,i}\right)\right)_{old} * GWP_{old,i} * P_{GHGe}$$

$$- M_{new,i} * \left(q_{ann,i}\, t_i + q_{EOL,i}\left(1 - q_{ann,i} t_{EOL,i}\right)\right)_{new} * GWP_{new,i} * P_{GHGe}$$

(tonnes) (dimensionless) $\left(\frac{tonnes\ CO2e}{tonne}\right)$ $\left(\frac{\$}{tonne\ CO2e}\right)$

*Table 39. Refrigerant Leakage Calculation Variables*

| Quantity | Abbr. | Units | Where? | Notes |
|---|---|---|---|---|
| Carbon intensity of grid in hour *h* | $CI_{grid,h}$ | tonnes/kWh | ACC | |
| Change in electricity usage in hour *h,* device or program *i* | $\Delta E_{h,i}$ | kWh | CE tool | Measure savings for EE; increased consumption for electrification; generation for solar, etc. |
| Upstream emissions adder | $\delta\%_{upstrea}$ | % | ACC | % change in GHG emissions to reflect change in methane leakage emissions |
| GHG electric adder | $P_{GHGe}$ | $/tonne | ACC | Adopted in IDER Decision |
| Carbon intensity of natural gas | $CI_{gas}$ | tonnes/BTU | ACC | Use standard # from EIA |
| Lifetime gas savings | $\Delta G_i$ | BTU | CE tool | Lifetime total gas savings for gas EE measures or gas usage for electrification of appliance *i* |
| Gas removal adder | $\delta\%_{BTM}$ | % | ACC | Reflects additional avoided methane leakage when gas appliances are removed. |
| GHG gas adder | $P_{GHGg}$ | $/tonne | ACC | Adopted in IDER Decision; currently equal to the GHG electric adder |
| Refrigerant charge | $M_i$ | tonnes | CE tool | Refrigerant contained in device *i*. |
| Annual refrigerant leak rate | $q_{ann,i}$ | %/year | ACC* | Typical leakage rate for appliance *i* |
| Lifetime | $t_i$ | years | CE tool* | Expected useful lifetime of appliance *i* |
| End-of-life leak rate | $q_{EOL,i}$ | % | ACC* | Leakage rate for appliance type *i* based on typical disposal practice |

| | | | | |
|---|---|---|---|---|
| Number of years prior to end-of-life with no "top-off" refrigerant added to replace full charge | $t_{EOL,i}$, | years | ACC* | Typical value for appliance type *i*. Important because devices generally do not have a full refrigerant charge at end-of-life. |
| Refrigerant GWP for installed device *i* | $GWP_i$ | $\frac{tonnes\ CO2e}{tonne}$ | ACC* | Global warming potential of refrigerant as compared with $CO_2$ |

*data for this variable will come from CARB

While traditional DERs will mostly fall under either of the first two use cases, EE fuel substitution measures and building decarbonization programs would likely fall under all three. For example, replacing a gas hot water heater with an electric heat pump hot water heater would increase GHG emissions related to the electric grid (case #1), decrease GHG emissions related to natural gas usage in the building (case #2), and increase refrigerant use (case #3).

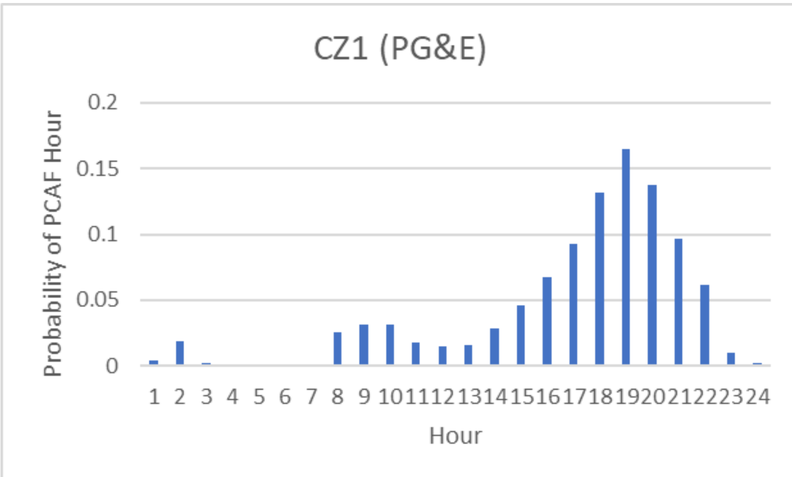
Estimating the total change in GHG emissions for building decarbonization requires this analysis because when switching from a mixed fuel to an all-electric home, GHG emissions related to natural gas decrease, but GHG emissions from refrigerants increase. Also, switching from a device that uses a high-GWP refrigerant to one that uses a low-GWP refrigerant decreases refrigerant emissions. These types of equipment changes represent a significant change in avoided cost that has not yet been quantified in the IDER framework. This avoided cost also applies to a number of similar situations, such as where the alternative technology is a standard air conditioner. Air conditioners are very similar to heat pumps, and often use the same (high-GWP) refrigerants.

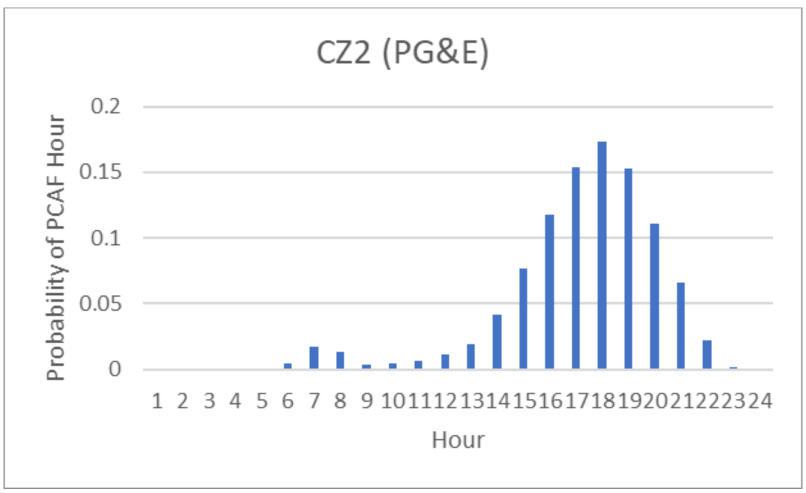
# Appendix A

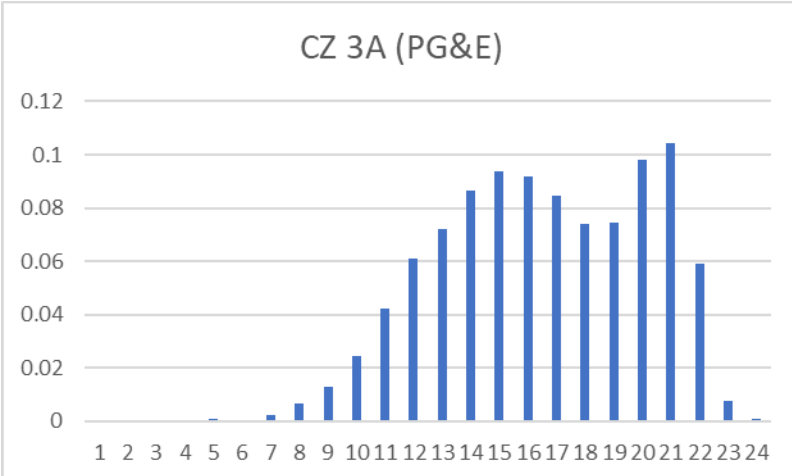
## IOU Hourly PCAF Allocation by Climate Zone

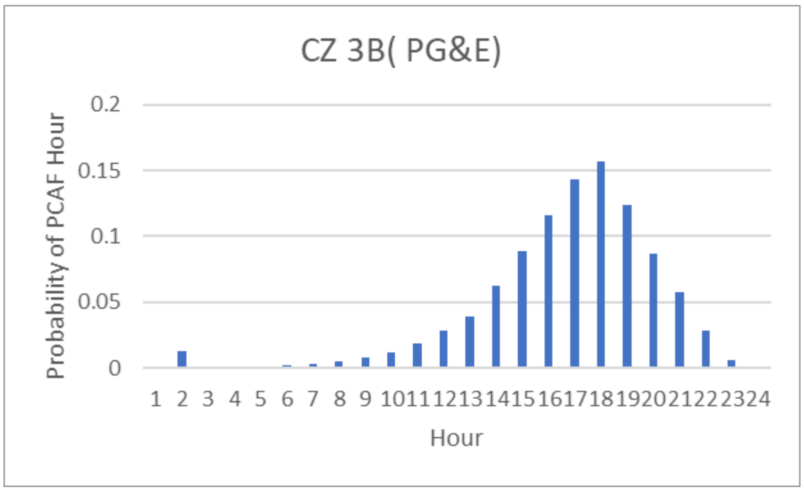
Note: all hours listed are PST (hour-ending)

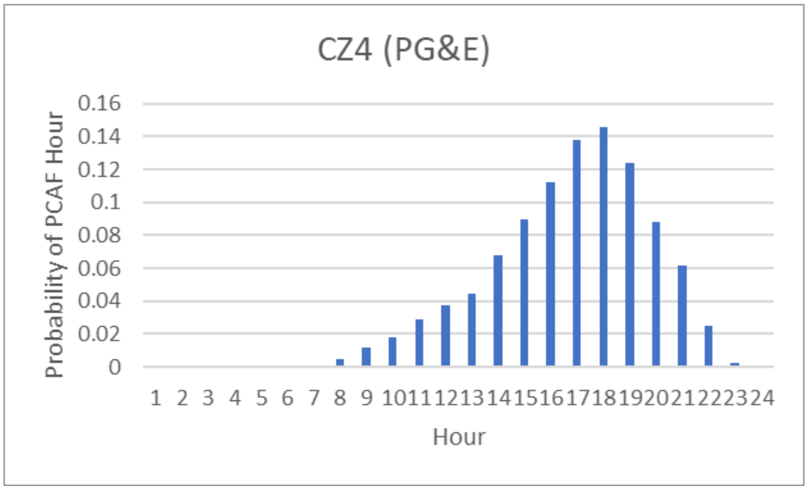
### PG&E

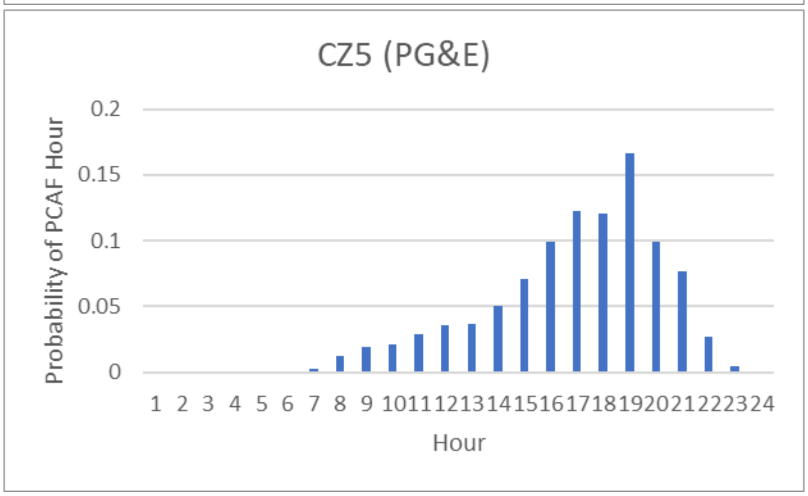



CZ 3A (PG&E)
0.12
0.1
0.08
0.06
0.04
0.02
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24


CZ 3B( PG&E)
Probability of PCAF Hour
0.2
0.15
0.1
0.05
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour


CZ4 (PG&E)
Probability of PCAF Hour
0.16
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour


CZ5 (PG&E)
Probability of PCAF Hour
0.2
0.15
0.1
0.05
0
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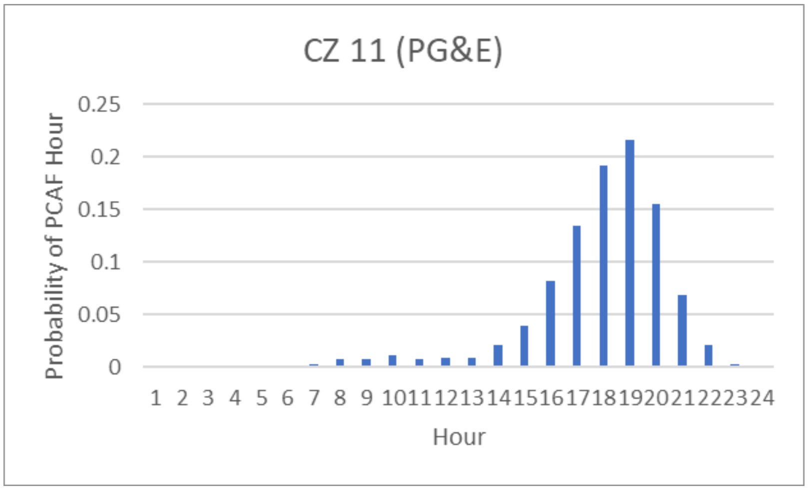
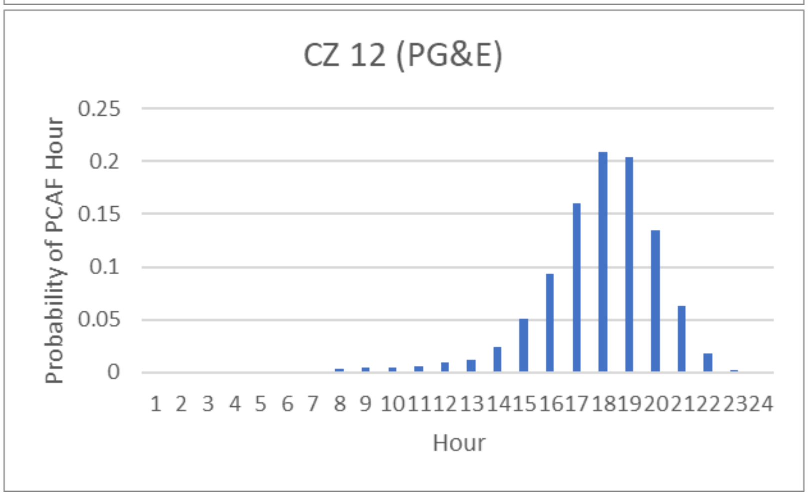
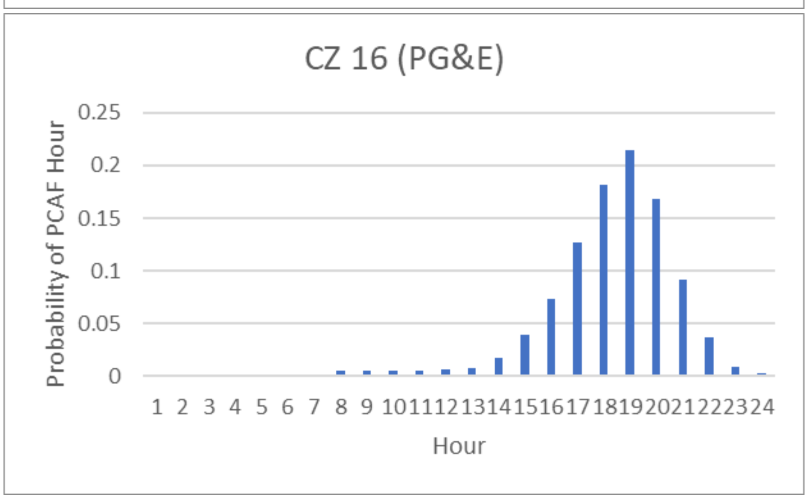
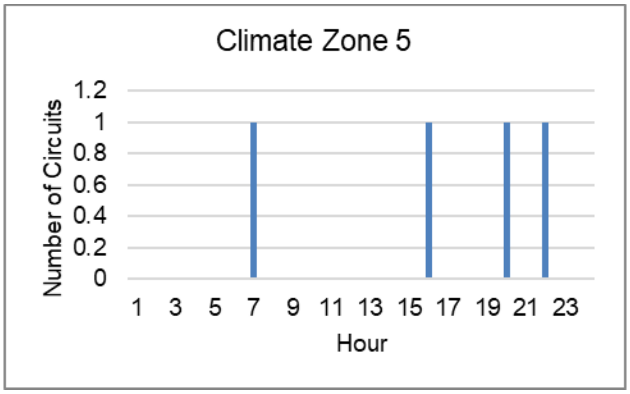
Hour

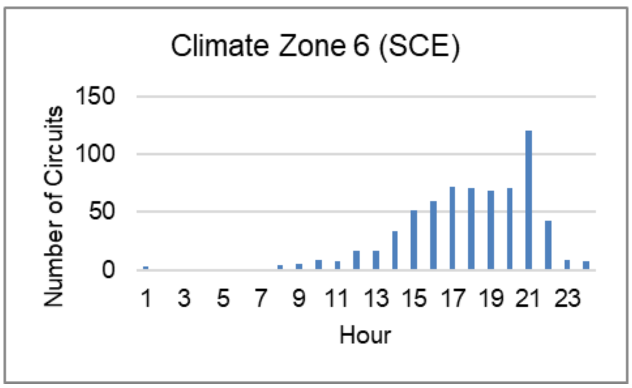

CZ 11 (PG&E)
Probability of PCAF Hour
0.25
0.2
0.15
0.1
0.05
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

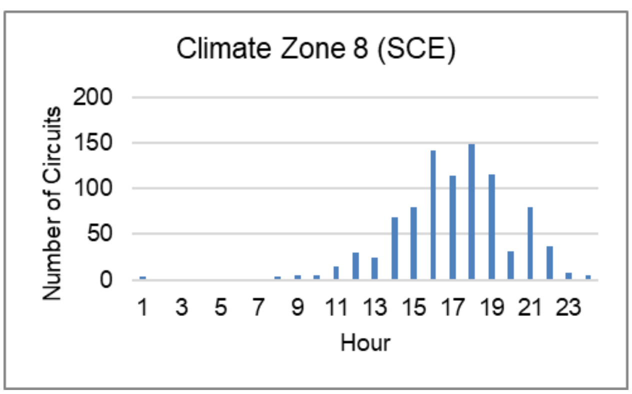

CZ 12 (PG&E)
Probability of PCAF Hour
0.25
0.2
0.15
0.1
0.05
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

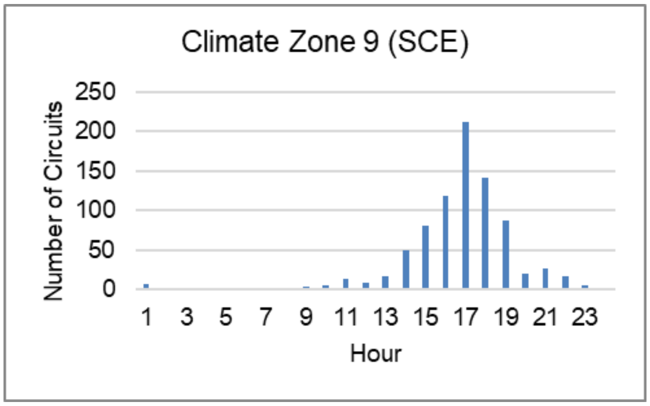

CZ 16 (PG&E)
Probability of PCAF Hour
0.25
0.2
0.15
0.1
0.05
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

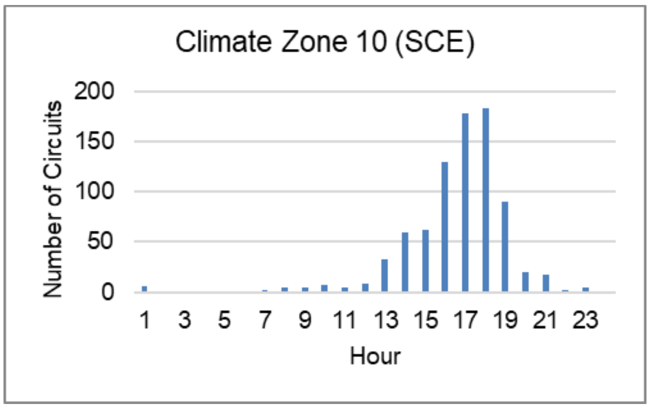
**SCE**

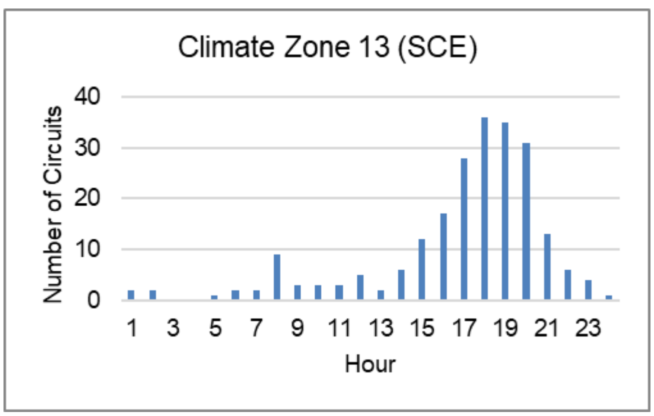

Climate Zone 5
Number of Circuits
1.2
1
0.8
0.6
0.4
0.2
0
1 3 5 7 9 11 13 15 17 19 21 23
Hour

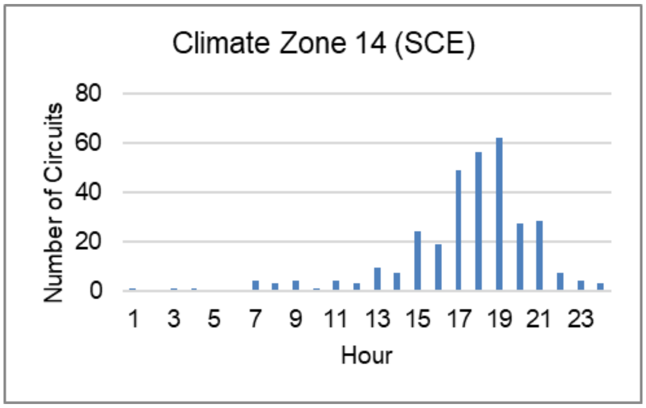

Climate Zone 6 (SCE)
Number of Circuits
150
100
50
0
1 3 5 7 9 11 13 15 17 19 21 23
Hour

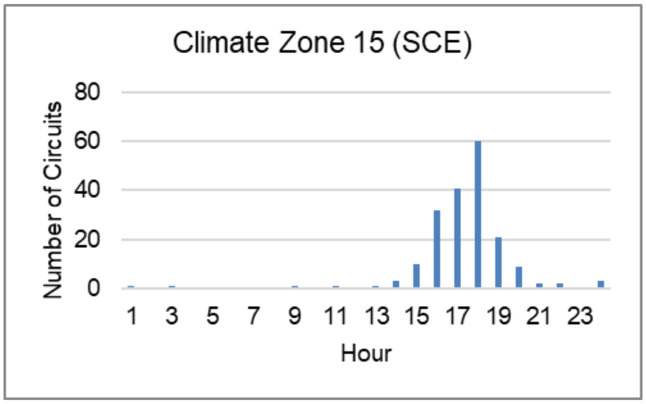

Climate Zone 8 (SCE)
Number of Circuits
200
150
100
50
0
1 3 5 7 9 11 13 15 17 19 21 23
Hour

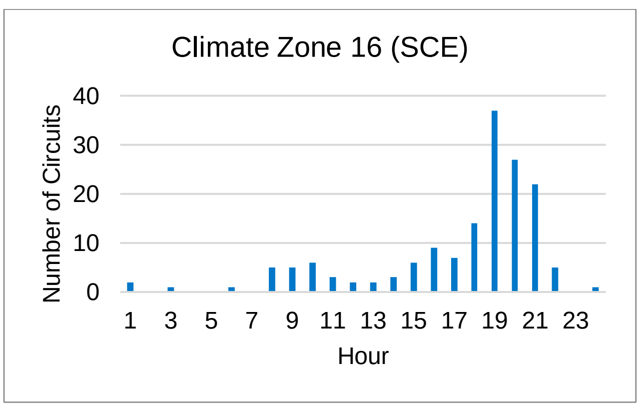

Climate Zone 9 (SCE)
Number of Circuits
250
200
150
100
50
0
1 3 5 7 9 11 13 15 17 19 21 23
Hour


Climate Zone 10 (SCE)
Number of Circuits
200
150
100
50
0
1 3 5 7 9 11 13 15 17 19 21 23
Hour

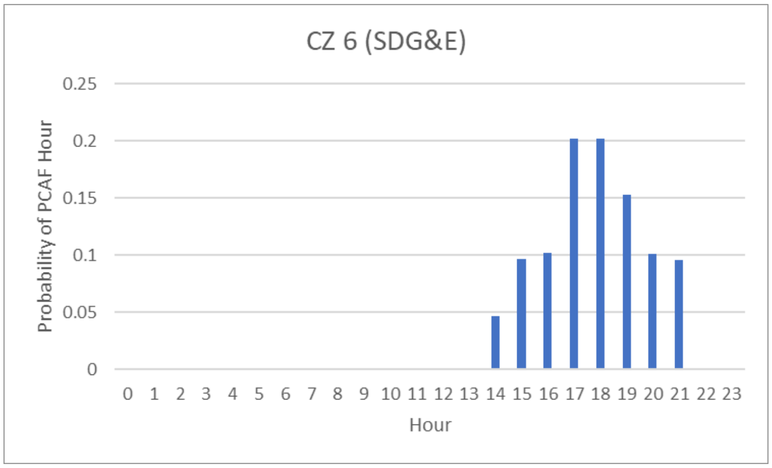

Climate Zone 13 (SCE)
Number of Circuits
40
30
20
10
0
1 3 5 7 9 11 13 15 17 19 21 23
Hour

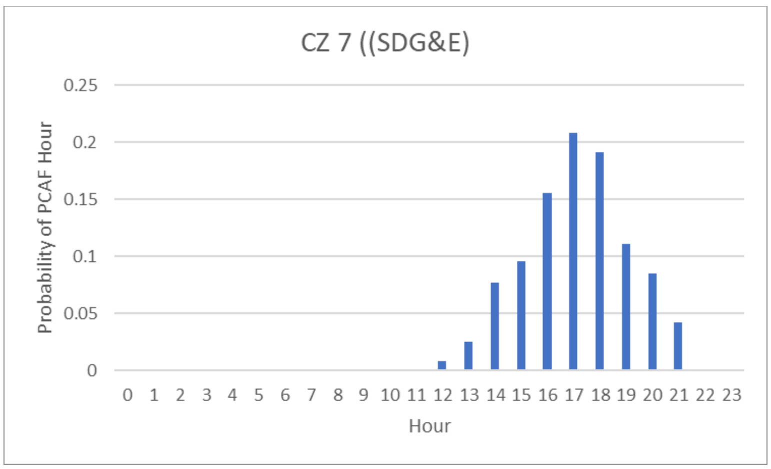

Climate Zone 14 (SCE)
Number of Circuits
0
20
40
60
80
1
3
5
7
9
11
13
15
17
19
21
23
Hour

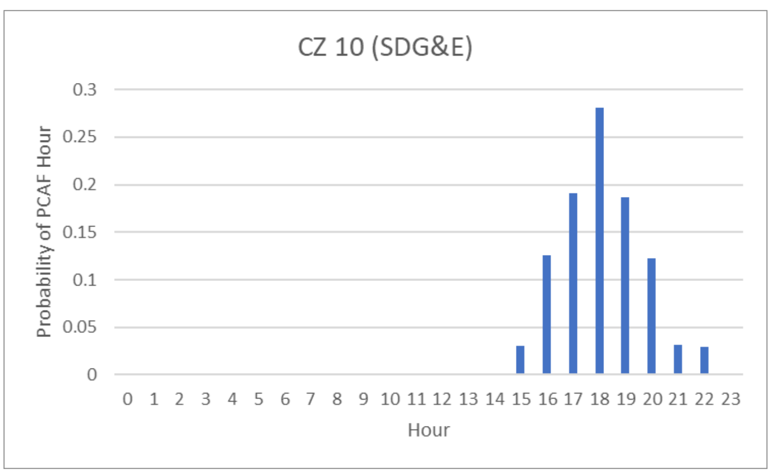

Climate Zone 15 (SCE)
Number of Circuits
0
20
40
60
80
1
3
5
7
9
11
13
15
17
19
21
23
Hour

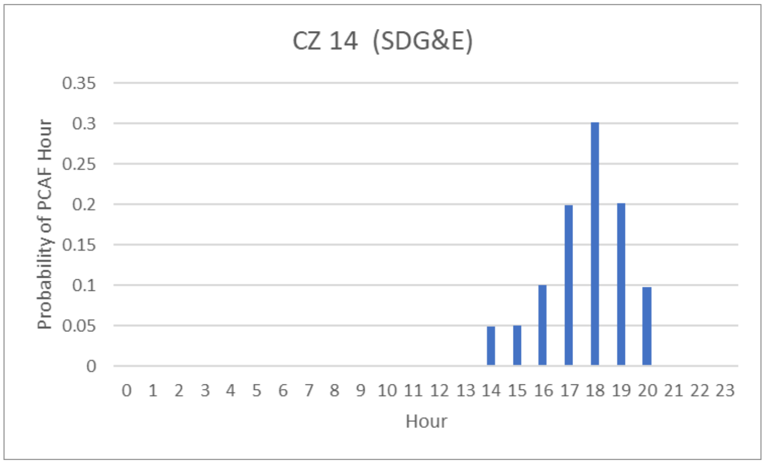

Climate Zone 16 (SCE)
Number of Circuits
0
10
20
30
40
1
3
5
7
9
11
13
15
17
19
21
23
Hour

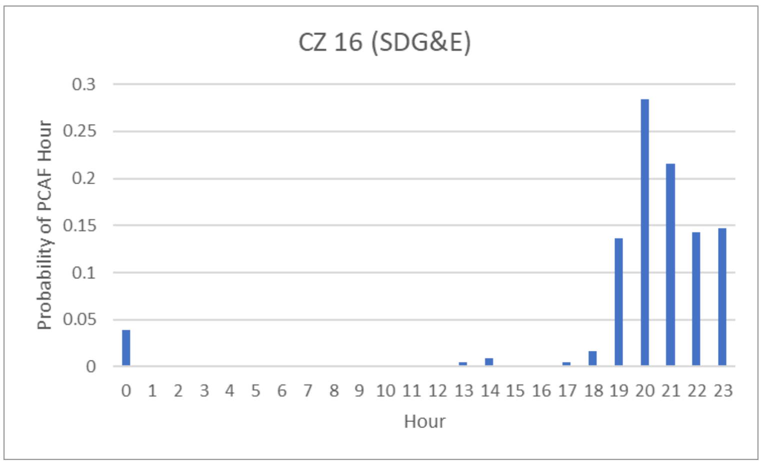
### SDG&E


CZ 6 (SDG&E)
Probability of PCAF Hour
0.25
0.2
0.15
0.1
0.05
0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour


CZ 7 ((SDG&E)
Probability of PCAF Hour
0.25
0.2
0.15
0.1
0.05
0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour


CZ 10 (SDG&E)
Probability of PCAF Hour
0.3
0.25
0.2
0.15
0.1
0.05
0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour


CZ 14 (SDG&E)
Probability of PCAF Hour
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour


CZ 16 (SDG&E)
Probability of PCAF Hour
0.3
0.25
0.2
0.15
0.1
0.05
0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour