# 2026 Distributed Energy Resources Avoided Cost Calculator Documentation

## For the California Public Utilities Commission

**September 2026**

*Version 1a*

Energy+Environmental Economics

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# Overview of the Avoided Cost Calculator

## 1. Introduction

This document describes the inputs, assumptions and methods used in the 2026 Distributed Energy Resources (DER) Avoided Cost Calculator (ACC). The DER ACC model, documentation and supporting files are available at:

- https://willdan.box.com/v/2026CPUC-ACC , and
- https://www.cpuc.ca.gov/dercosteffectiveness

### 1.1 Purpose of the ACC and Recent Developments

The ACC is used to determine the benefits of Distributed Energy Resources (DER), such as energy efficiency and demand response, for cost-effectiveness analyses. The ACC is the first part of the three-part cost-effectiveness process used by the CPUC to determine the costs and benefits of customer programs.[1] The ACC calculates hourly system-level costs of providing electric or gas service for 30 years, in $/kWh or $/therm. These hourly avoided costs are used with specific program data, such as hourly energy savings, to determine program benefits. Those benefits are then compared to program costs to determine cost-effectiveness.

The ACC both includes an electric avoided cost calculator and a natural gas avoided cost calculator, sometimes referred to as the ACC electric model and gas model, respectively. The ACC determines several types of avoided costs including avoided generation capacity, energy, ancillary services, greenhouse (GHG) emissions, high global warming potential gases, transmission and distribution capacity, and natural gas infrastructure.

Since 2020, the ACC has been closely aligned with the grid planning efforts of the Integrated Resource Planning (R. 16-02-007) and distribution planning proceedings. The avoided costs are based on data and analysis from Integrated Resource Planning (IRP) modeling, except for the avoided costs of transmission and distribution, which are based on data and guidance from utility transmission planning and distribution planning proceedings as well as supplemental general rate case inputs. The ACC also provides hourly ancillary service price forecasts from the SERVM reliability and production simulation model used in the IRP proceeding. Ancillary services are a potential benefit for dispatchable DER that can provide reserves in CAISO markets. This is different than the avoided ancillary service cost that estimates the value that DER provides to avoid procuring spinning reserves when load is reduced.

In 2020, the ACC was updated to fully support evaluation of electrification measures that increase load but may decrease total GHG emissions. This included adopting a new avoided cost of high

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[1] This three-part process is described in the "Cost-Effectiveness Brief Overview," available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/energy-efficiency/idsm

global warming potential (GWP) gases, which value the GHG impacts of distributed energy resources (DERs) on methane and refrigerant leakage.[2] The 2022 ACC adopted another new avoided cost – the avoided gas infrastructure cost (AGIC), which measures the value that new, all-electric construction provides in avoiding natural gas infrastructure. Decision D.22-05-002 formally adopted the use of the ACC to determine increased, as well as decreased marginal costs. This means that the ACC's hourly values have also been used to determine the *increased* costs of electricity incurred by electrification programs that add electric load. These increased costs incurred by electrification can also be paired with the decreased costs from the natural gas avoided cost calculator to determine the net cost impacts of fuel substitution measures that replace gas with electric usage.

The base ACC modeling reflects a total resource cost (TRC) perspective. In response to the Decision Adopting the Societal Cost Test mailed May 24, 2024 (R.22-11-013), the 2024 ACC added an option within both the Electric and Gas models to produce a Societal Cost Test (SCT) perspective of avoided costs. The SCT option, also included in the 2026 ACC update, implements a social cost of carbon (SCC), societal discount rate, national-average methane leakage adder, and air quality adder.

## 1.2 Summary of Updates for the 2026 ACC

Several methodological updates have been adopted in the 2026 ACC, subsequent to the July 31, 2026 Proposed Decision Adoption Changes to the Avoided Cost Calculator. These updates include:

- Adoption of a single electricity-based GHG value for both electricity and natural gas avoided cost models
- Removal of the GHG rebalancing component
- Simplified implementation of the integrated calculation for generation capacity and GHG costs
- Use of Loss of Load Hours (LOLH) for calculating generation capacity allocation factors
- Use of energy prices rather than temperature to allocate generation capacity value to specific days of the year
- Representation of reliability risk differences of weekdays versus weekends in generation capacity value allocation
- Use of load forecasts aligned with SERVM modeling to calculate transmission capacity allocation factors for future years
- Use of Discounted Total Investment Method approach to calculate marginal transmission costs for all electric utilities

Additional updates captured by the 2026 ACC include updates to inputs as well as methodological updates to supporting calculations to remedy inaccuracies in prior releases. These are described further in component-specific sections of the documentation.

[2] For electrification measures, the cost categories for delivering electricity for added load are not a benefit or 'avoided' cost, but an added cost. Reduced use of natural gas and GWP gases are avoided costs for electrification measures.

## 1.3 Overview of Inputs

Table 1-1-1 presents key inputs to the ACC and their sources for the 2026 ACC update.

***Table 1-1. Key ACC Inputs and Data Sources***

| Input | Element | Data Source |
|---|---|---|
| RESOLVE Portfolio | Load and DER Forecasts | 2024 CEC IEPR Planning Scenario |
| | Resource Portfolio | 2026-27 TPPCPUC IRP RESOLVE Capacity Expansion Modeling |
| | Cost of Solar & Energy Storage | 2023 CPUC IRP RESOLVE Resource Costs and Build Inputs |
| | Weighted Average Cost of Capital | CPUC Authorized Rate of Return for 2023 |
| SERVM Production Simulation | Updated SERVM Model | Run with TPP Portfolio from CPUC IRP |
| Natural Gas Avoided Cost | Natural Gas Commodity Prices | CEC IEPR Power Plant Burner Tip Price Forecast, 2023 Vintage |
| | Transportation Rates Forecasts and Avoided Gas Infrastructure Costs | Utility filings and data requests |
| Energy | Implied Marginal Heat Rate | Recalculated From SERVM Production Simulation based on CEC IEPR Natural Gas Price forecasts |
| | Day Ahead Hourly Energy Prices | SERVM Production Simulation |
| Ancillary Services | Avoided AS Procurement | Estimated based on CAISO 2025 Annual Report on Market Issues and Performance |
| Generation Capacity | Generation Capacity | Calculated with Integrated Calculation of Generation Capacity and GHG avoided costs model |
| GHG Value | GHG Adder | TPP RESOLVE GHG Shadow Prices |
| | Cap and Trade Value | CED 2022 Update Floor GHG Allowance Price Projections |

| Input | Element | Data Source |
|---|---|---|
| GHG Emissions | Marginal Emission Rates | Implied Market Heat Rates from CPUC SERVM Production Modeling |
| Transmission | Transmission Allocation Factors | Transmission PCAFs are calculated using 2025 CAISO hourly load data for each utility as well as SERVM forecasted loads for future years |
| | Marginal Transmission Capacity Cost | Utility GRC Phase II filings and Loading Factor Inputs, Transmission Project Costs and Loading Factor inputs, and CEC IEPR |
| Distribution | Marginal Distribution Allocation Factors | Distribution PCAFs provided by PG&E; PLRFs provided by SCE; PCAFs are calculated for SDG&E using utility distribution load data |
| | Marginal Distribution Capacity Costs | Utility 2025 GNA and DUPR reports for near term, GRC filings for long term and marginal cost factors |

## 1.4 Integrated Resource Planning Proceeding Inputs

Since 2020, the ACC has used inputs from the IRP proceeding. By coordinating with IRP, the ACC better aligns 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 evaluated in IRP.

### *1.4.1 IRP Planning Tools*

California's IRP proceeding uses several planning tools to develop and support long-term resource plans that meet the state's reliability needs and decarbonization objectives. These models are useful sources of inputs to the ACC process.

The primary model used in the IRP proceeding is RESOLVE, a long-term capacity expansion model developed and maintained by E3 that has been made publicly available and subjected to stakeholder scrutiny. RESOLVE is a long-term capacity expansion model that co-optimizes investment and dispatch decisions across a multi-year horizon to identify least-cost portfolios to meet carbon emission reduction targets, Renewables Portfolio Standards (RPS) and Clean Electricity Standard (CES) goals, system reliability needs, and other system requirements.

The IRP proceeding also utilizes SERVM, a system operation model that simulates system reliability and economic dispatch, for a range of supporting analyses. These include loss-of-load-probability studies that provide key inputs to the IRP proceeding and detailed simulations of portfolios developed in RESOLVE to generate wholesale electricity prices, assess the reliability of the portfolio, and identify periods of risk. SERVM is developed and maintained by PowerGEM Consulting.

### *1.4.2 2026-27 Transmission Planning Process*

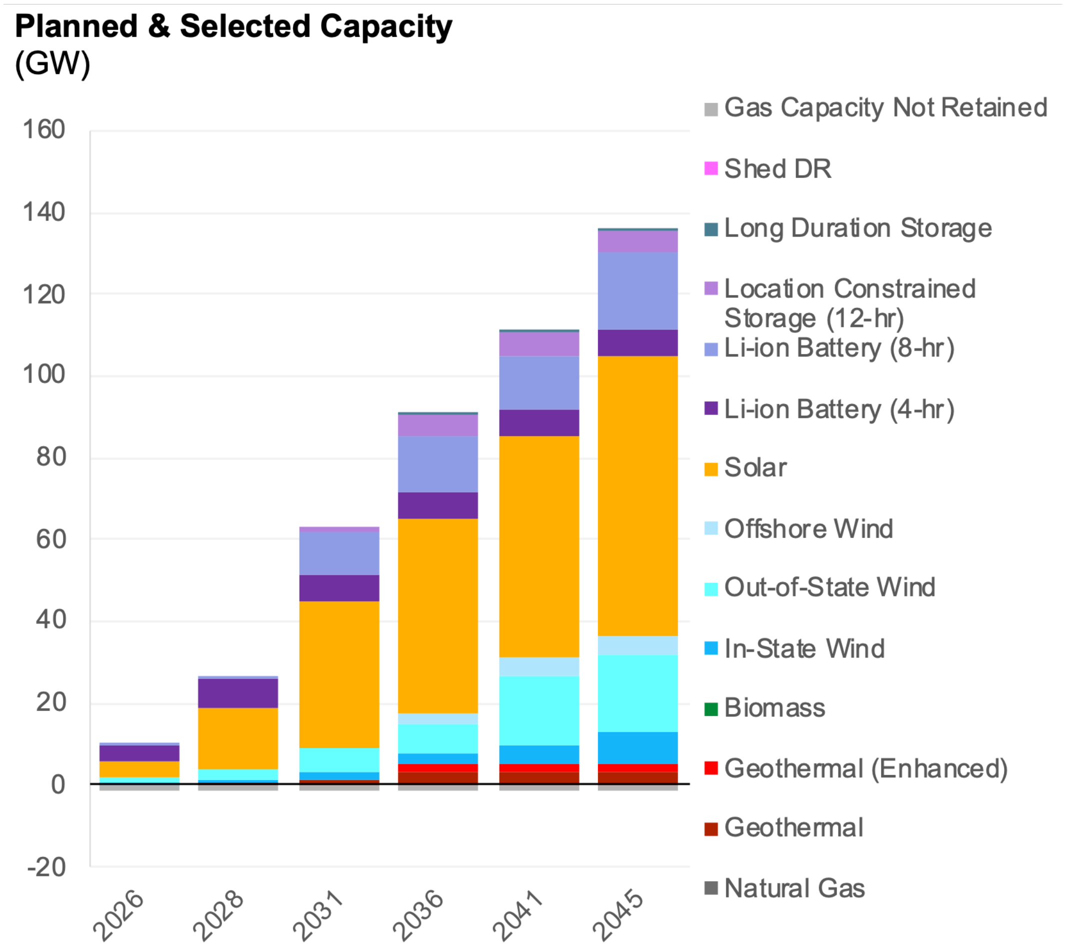
The 2026 ACC is based on IRP's latest system plan, the 2026-27 Tranmission Planning Process (TPP).[3] The 2026-27 TPP, adopted by the CPUC in D.26-02-057, was developed using RESOLVE and is designed to meet the state's reliability needs and aggressive decarbonization objectives. The TPP represents a portfolio of resources that:

- Aligns with the load forecast and future DER adoption levels produced in the CEC's 2024 Integrated Energy Policy Report (IEPR) planning scenario.
- Meets statewide electric-sector GHG planning targets of 25 million metric tons by 2035 and 8 million metric tons by 2045, as well as state clean energy policy requirements established by SB100.
- Includes resource additions identified by load-serving entities (LSEs) in plans they developed and submitted to the CPUC in the IRP proceeding.
- Includes a diverse mix of new generation technologies to meet these requirements, including solar, onshore wind across a broad geographic footprint, offshore wind, geothermal, energy storage resources with a range of durations, and demand response.

Figure 1-1, reproduced from a public workshop hosted in the IRP proceeding, shows the nameplate capacity of new resources included in this portfolio, which exceed 80 GW by 2035. By 2045, the PSP (Preferred System Plan) includes nearly 120 GW of new nameplate capacity; these result primarily from the continued additions of solar, storage and wind.

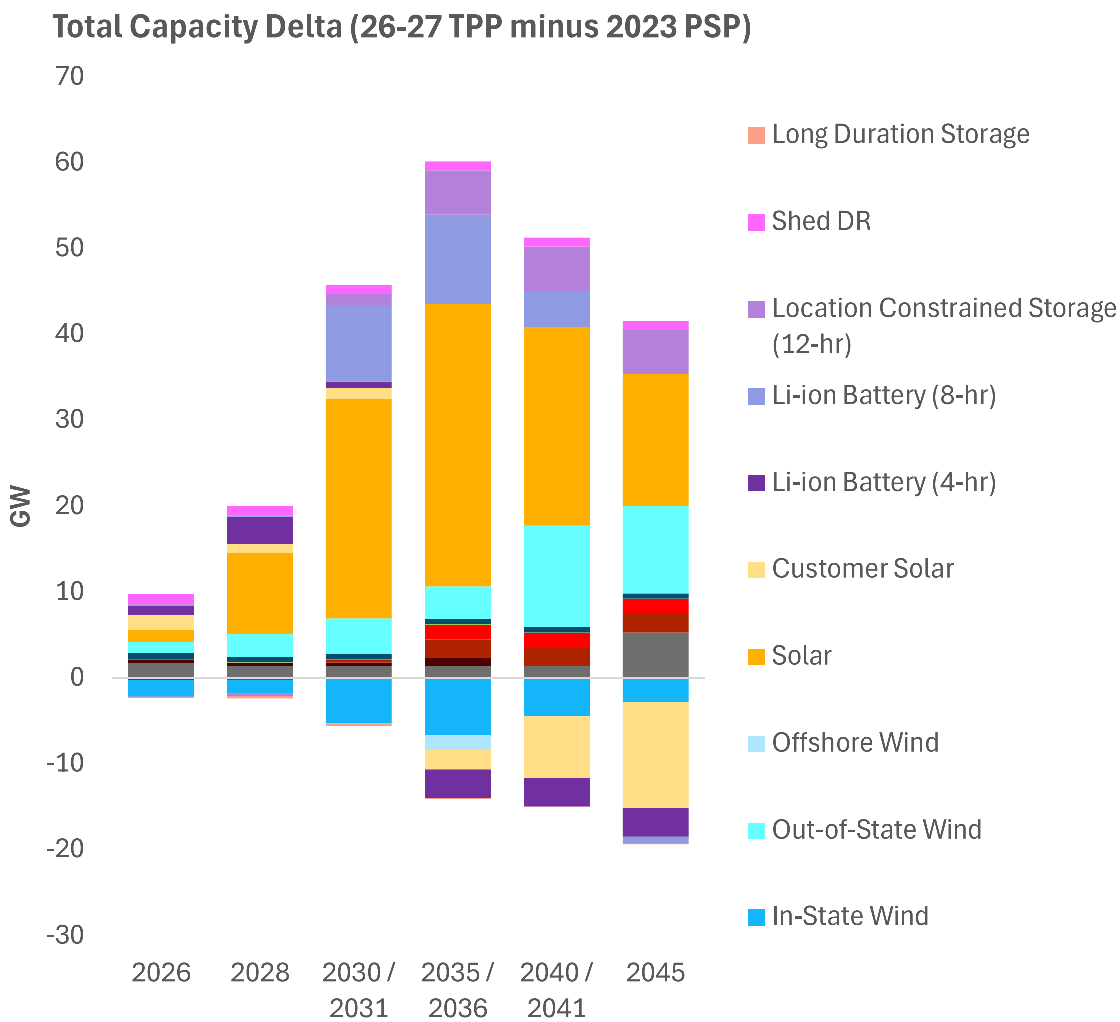
[3] Relevant information available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2024-27-irp-cycle-events-and-materials/assumptions-for-the-2026-2027-tpp

*Figure 1-1. TPP capacity additions*




The 2026 ACC is based on the portfolio developed for the 2026–2027 Transmission Planning Process (TPP), whereas the 2024 ACC relied on the 2023 PSP. As shown in Figure 1-2, relative to the 2023 PSP, the 26–27 TPP portfolio includes substantially greater quantities of new solar, battery storage, and wind capacity. These additions are driven primarily by the higher electricity demand forecast in the 2024 IEPR relative to the 2023 IEPR.

*Figure 1-2. Difference in total capacity between 26-27 TPP and 2023 PSP*




### *1.4.3 Linkages Between IRP and ACC Proceedings*

The TPP and associated inputs, assumptions, and results are used in multiple stages of the development of the ACC. Specifically:

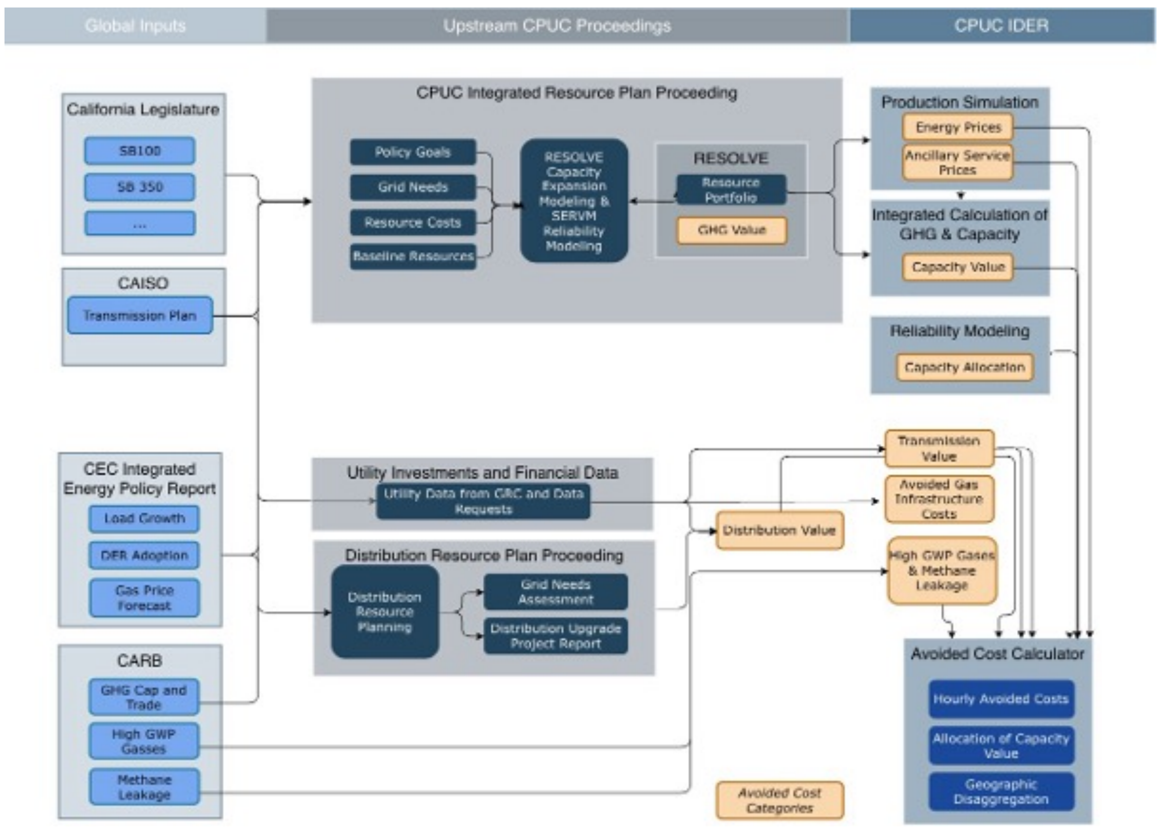
- General inputs and assumptions used in the ACC are aligned with the IRP proceeding where possible. Examples include the utility Weighted Average Cost of Capital (WACC) and the natural gas price forecast (originally a product of the CEC's IEPR).
- The PSP portfolio produced by RESOLVE is simulated in SERVM, an hourly production simulation model. The results of these simulations are used directly in both the development of the avoided costs of energy- and capacity- avoided costs and in the allocation of generation capacity value to specific hours of the year.
- A variety of outputs produced by both RESOLVE and SERVM—including the long-term cost of new solar and storage resources and their respective energy values, marginal capacity contributions, and marginal greenhouse gas impacts over time—are used in the Integrated

Calculation of GHG and Capacity Avoided Costs, which explicitly links the combined avoided costs of energy, generation capacity, and greenhouse gas emissions to the costs of the new resources needed to meet the state's reliability needs and decarbonization objectives.

## 1.5 Flowchart of Inputs to the 2026 ACC

Figure 1-3 details the flow of data from the IRP, Distribution Planning proceedings, and other such data sources 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 1-3. Avoided Cost Process Overview*




## 1.6 Illustrative ACC Results

The electric and natural gas avoided cost calculators produce annual and levelized results for each avoided cost component described in the following sections. Electric avoided cost results are produced with hourly granularity. Users can use the dashboard of each calculator to toggle through pre-set inputs and adjust certain parameters to understand how avoided costs differ by utility or in response to other factors. The following figures (A.1. , Figure 1-5, Figure 1-6, Figure 1-7, and

Figure 1-8) display a selection of results from the 2026 ACCs to illustrate key model outputs: average monthly avoided electric sector costs by driver, average hourly avoided electric sector costs by driver, average electric sector avoided costs for critical periods, total levelized electric sector avoided costs by month-hour of the year, and monthly gas system avoided costs by driver. Appendix A.1. provides graphical comparisons between the 2026 results and those from the 2024 ACC under the same parameter configuration as well as depictions of how this bears out for individual electricity end uses and fuel substitution measures.

***Figure 1-4. Electric Model Results: Average Monthly Avoided Costs (PG&E Climate Zone 12, 20-year levelized value of 2026 resource)***

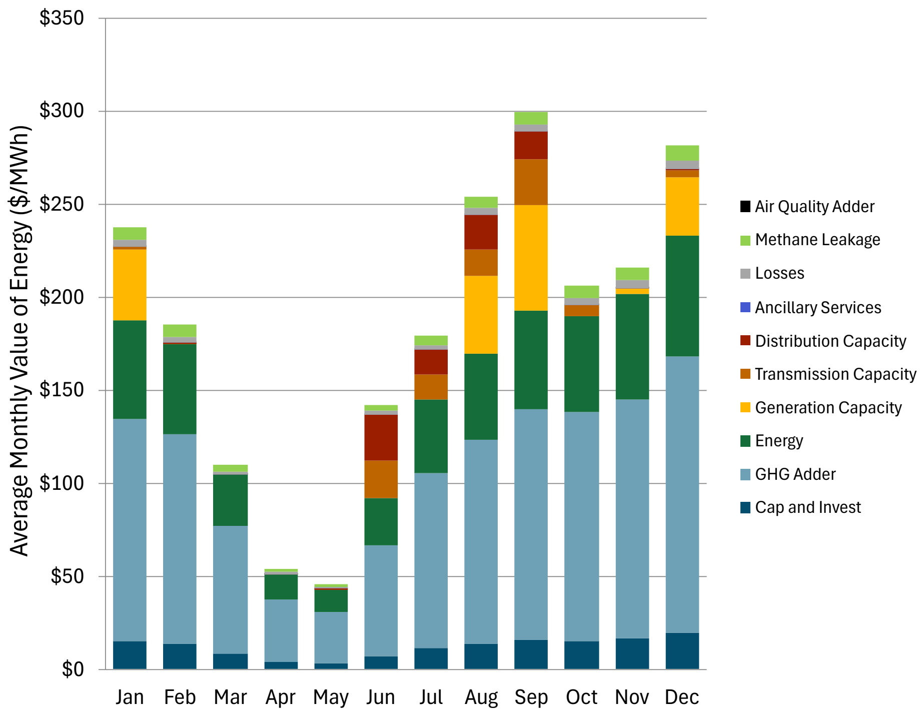


***Figure 1-5. Average Hourly Electric Avoided Costs (PG&E Climate Zone 12, 20-year levelized value of 2026 resource)***

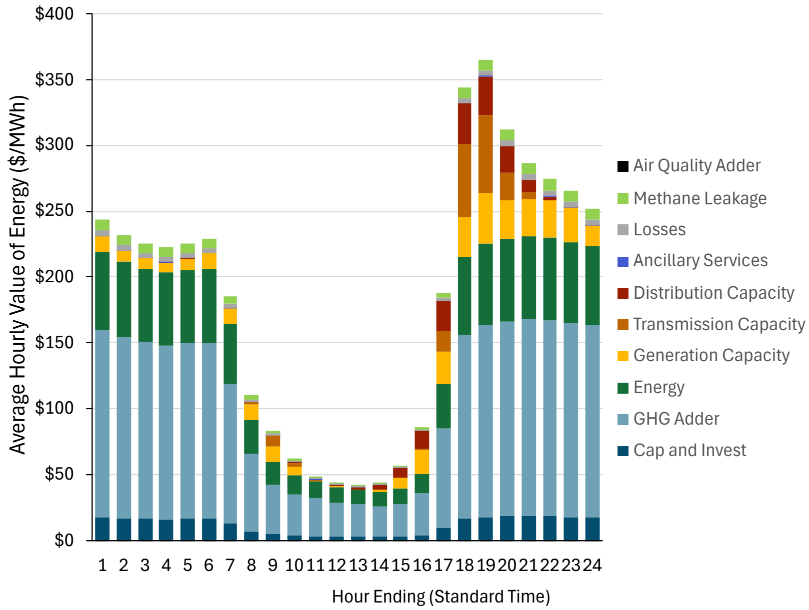
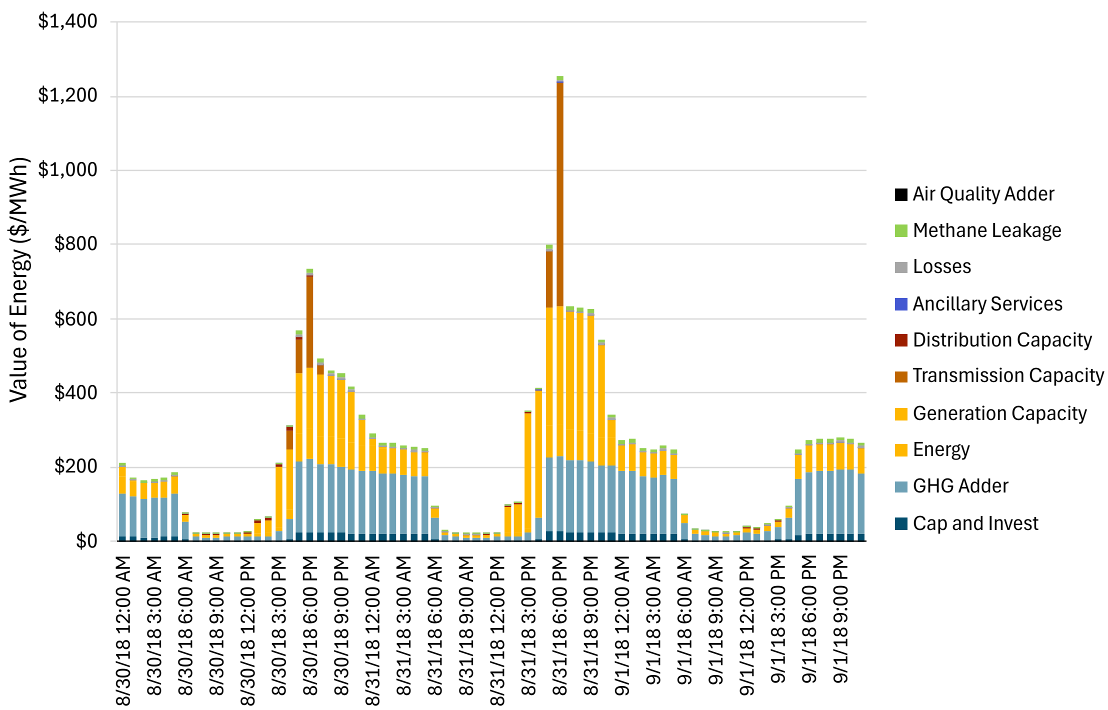



***Figure 1-6. Hourly Electric Avoided Costs for Three Days Beginning August 30th (PG&E Climate Zone 12, 20-year levelized value of 2026 resource)***[4]

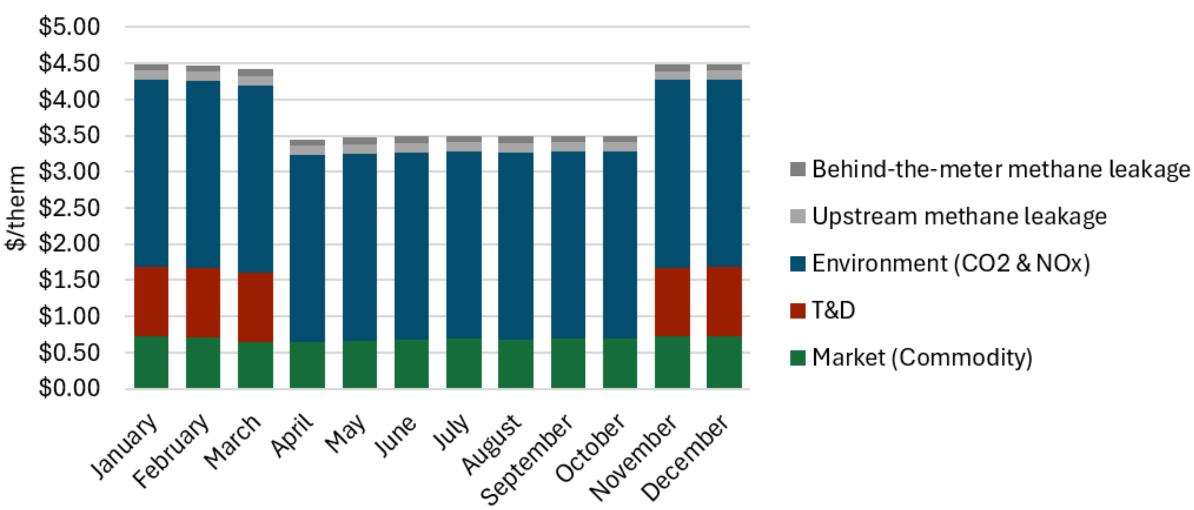



[4] Note that the 2026 ACC uses a 2018 calendar year. This impacts the alignment with the weather year and therefore the T&D allocation factors on each calendar day. High distribution costs in the 2026 ACC on the selected days illustrate how this variance can impact specific days.

### *Figure 1-7. Average Total Levelized Electric Avoided Cost Value by month and hour (PG&E Climate Zone 12, 20-year levelized value of 2026 resource)*

| 2026 ACC - Total Levelized Value ($/MWh) | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Hour \ Month | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| 0 | $ 314 | $ 278 | $ 187 | $ 109 | $ 90 | $ 170 | $ 241 | $ 295 | $ 308 | $ 288 | $ 292 | $ 326 |
| 1 | $ 308 | $ 270 | $ 177 | $ 102 | $ 85 | $ 158 | $ 230 | $ 264 | $ 285 | $ 280 | $ 284 | $ 319 |
| 2 | $ 304 | $ 266 | $ 172 | $ 98 | $ 80 | $ 151 | $ 221 | $ 256 | $ 275 | $ 277 | $ 279 | $ 313 |
| 3 | $ 303 | $ 263 | $ 171 | $ 93 | $ 74 | $ 143 | $ 214 | $ 254 | $ 274 | $ 276 | $ 277 | $ 312 |
| 4 | $ 310 | $ 266 | $ 169 | $ 87 | $ 71 | $ 142 | $ 215 | $ 259 | $ 284 | $ 283 | $ 284 | $ 319 |
| 5 | $ 327 | $ 279 | $ 180 | $ 86 | $ 64 | $ 120 | $ 186 | $ 247 | $ 291 | $ 295 | $ 299 | $ 350 |
| 6 | $ 343 | $ 289 | $ 161 | $ 39 | $ 10 | $ 33 | $ 89 | $ 130 | $ 180 | $ 260 | $ 304 | $ 364 |
| 7 | $ 293 | $ 179 | $ 50 | $ 11 | $ 6 | $ 21 | $ 52 | $ 62 | $ 91 | $ 84 | $ 169 | $ 285 |
| 8 | $ 191 | $ 82 | $ 24 | $ 5 | $ 4 | $ 19 | $ 47 | $ 56 | $ 82 | $ 69 | $ 121 | $ 274 |
| 9 | $ 91 | $ 51 | $ 20 | $ 6 | $ 2 | $ 17 | $ 43 | $ 52 | $ 78 | $ 60 | $ 91 | $ 229 |
| 10 | $ 68 | $ 44 | $ 16 | $ 3 | $ 2 | $ 17 | $ 41 | $ 50 | $ 75 | $ 57 | $ 76 | $ 150 |
| 11 | $ 61 | $ 37 | $ 14 | $ 2 | $ 2 | $ 18 | $ 39 | $ 49 | $ 73 | $ 52 | $ 69 | $ 130 |
| 12 | $ 51 | $ 35 | $ 14 | $ 2 | $ 2 | $ 22 | $ 42 | $ 53 | $ 78 | $ 51 | $ 63 | $ 111 |
| 13 | $ 41 | $ 31 | $ 13 | $ 2 | $ 3 | $ 32 | $ 48 | $ 80 | $ 85 | $ 54 | $ 60 | $ 97 |
| 14 | $ 42 | $ 28 | $ 14 | $ 2 | $ 3 | $ 48 | $ 59 | $ 97 | $ 170 | $ 59 | $ 69 | $ 102 |
| 15 | $ 54 | $ 36 | $ 18 | $ 1 | $ 3 | $ 77 | $ 79 | $ 212 | $ 250 | $ 73 | $ 95 | $ 135 |
| 16 | $ 171 | $ 72 | $ 24 | $ 3 | $ 5 | $ 136 | $ 147 | $ 316 | $ 476 | $ 247 | $ 290 | $ 353 |
| 17 | $ 333 | $ 279 | $ 142 | $ 54 | $ 51 | $ 378 | $ 414 | $ 608 | $ 794 | $ 391 | $ 299 | $ 347 |
| 18 | $ 329 | $ 282 | $ 175 | $ 80 | $ 73 | $ 472 | $ 467 | $ 675 | $ 808 | $ 332 | $ 301 | $ 345 |
| 19 | $ 327 | $ 283 | $ 180 | $ 93 | $ 92 | $ 394 | $ 370 | $ 503 | $ 526 | $ 298 | $ 301 | $ 344 |
| 20 | $ 324 | $ 282 | $ 186 | $ 107 | $ 101 | $ 279 | $ 294 | $ 432 | $ 462 | $ 299 | $ 299 | $ 340 |
| 21 | $ 321 | $ 277 | $ 186 | $ 109 | $ 102 | $ 211 | $ 274 | $ 404 | $ 441 | $ 297 | $ 298 | $ 337 |
| 22 | $ 315 | $ 275 | $ 186 | $ 115 | $ 100 | $ 191 | $ 263 | $ 377 | $ 418 | $ 294 | $ 291 | $ 330 |
| 23 | $ 312 | $ 274 | $ 188 | $ 117 | $ 97 | $ 184 | $ 258 | $ 327 | $ 333 | $ 294 | $ 289 | $ 325 |

### *Figure 1-8. Natural Gas Avoided Costs (PG&E Residential Furnace, Uncontrolled, 20-year levelized value for 2026 resource)*



# ACC Electric Model

## 2. Energy Avoided Costs

Energy avoided costs represent the marginal cost of generating an additional MWh to serve incremental load, or equivalently the generation cost avoided by reducing load by one MWh. Since 2020, the ACC has derived these values from SERVM, an hourly production simulation model, which produces day-ahead (DA) hourly energy prices for the latest IRP portfolio. These hourly prices reflect the marginal fuel and operating costs of the resource setting the price in each hour, given that hour's load and resource conditions.

### 2.1 Scope of SERVM Simulations

For the 2026 ACC, production cost modeling is based on the 2026–27 CPUC Transmission Planning Process (TPP) RESOLVE base case portfolio. SERVM model runs are performed for the years 2026–2041 and 2045 to reflect forecasted changes in system load and generation portfolio. In years for which a resource portfolio is not available from RESOLVE modeling, resource additions are linearly interpolated between the available RESOLVE years. In years for which SERVM results are not available, hourly energy prices are interpolated or extrapolated as described in Section 2.5.

SERVM includes representations of each balancing authority area within the Western Electricity Coordinating Council (WECC). Within the CAISO balancing authority area, the model resolves sub-areas corresponding to the PG&E, SCE, and SDG&E service territories. Because the ACC evaluates programs in IOU territories, SERVM outputs are taken from these three sub-areas and aggregated to NP-15 (PG&E) and SP-15 (SCE and SDG&E) using load-weighted averages of hourly market price forecasts.

Each simulation year assumes the CEC's California Thermal Zone 2025 (CTZ25) typical meteorological year (TMY), shown in Table 2-1. Rather than averaging weather across multiple years, the CTZ25 TMY is assembled by selecting one full historical month to represent each calendar month, and applying that same historical month consistently across all climate zones. For example, for the month of June, each climate zone uses its own local weather data from June 2016. The TMY construct preserves the observed intra-month correlation between temperature, load, and renewable output within each zone. It also ensures that the weather conditions modeled in any given hour are spatially consistent statewide. Zonal load shapes and renewable generation profiles are developed from the selected weather data and then aggregated to balancing authority and statewide levels.

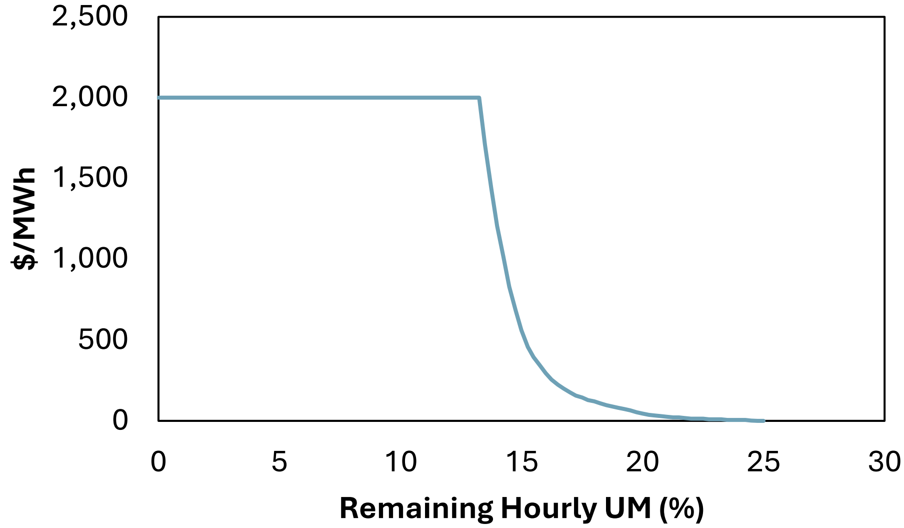
***Table 2-1. CTZ25 Historical Weather Months***

| CTZ Weather Year | |
|---|---|
| **Month** | **Year** |
| **1** | 2011 |
| **2** | 2008 |
| **3** | 2000 |
| **4** | 2018 |
| **5** | 2017 |
| **6** | 2016 |
| **7** | 2007 |
| **8** | 2005 |
| **9** | 2016 |
| **10** | 2012 |
| **11** | 2005 |
| **12** | 2004 |

SERVM production simulation included scarcity pricing directly in energy price outputs. Scarcity pricing represents non-ideal market conditions often present when the system is operating near full capacity. The scarcity pricing function in SERVM ties scarcity pricing adders to periods of low operating reserves and was calibrated using historical market price data.

The process to develop an endogenous scarcity adjustment in SERVM began with a generic exponentially decaying scarcity pricing function that was capped at the $2,000/MWh set by CAISO's Hard Energy Bid Cap. The x-axis of the scarcity pricing function is the total reserves available including demand response and other emergency resources. This curve was shifted right until the modeled and historical scarcity were in alignment. The modeled Operating Reserve Demand Curve (ORDC) is presented in Figure 2-1 below.

*Figure 2-1. Operating Reserve Demand Curve (ORDC) derived from historical CAISO scarcity*




## 2.2 Adjustments to SERVM Prices

A few post-processing adjustments are applied to the hourly energy prices produced by SERVM:

- A price floor of zero is applied such that there are no negative energy prices in the avoided costs. Negative pricing observed in wholesale markets today is largely reflective of the opportunity cost associated with curtailment of renewable resources and the corresponding loss of the renewable energy credit that can be used to comply with the state's RPS requirements. The ACC values resources (including renewables) based on their greenhouse gas reduction value (rather than their RPS compliance value), meaning that the value of the clean attribute they provide is reflected in the GHG avoided cost.
- A price cap of $1000/MWh is also applied based on the soft cap of $1000/MWh in the CAISO markets and the observation that historical prices in recent years rarely exceeded this value.
- Raw SERVM results embedded cap-and-invest costs associated with fossil fuel generation. Since ACC represents avoided energy and cap-and-invest prices separately, the cap-and-invest component is removed from the SERVM energy prices during the implied heat rate step.

## 2.3 Implied Marginal Heat Rates

Hourly energy price outputs from SERVM are used to derive hourly implied market heat rates (IMHR) for each hour simulated. IMHR is a simple but useful indicator of the marginal resource that determines the value of energy in each hour. It is independent of the impact of evolving gas and carbon prices, which makes it a suitable reference for interpolating and extrapolating future energy prices.

The derivation of IMHR values as an intermediate step serves several purposes in the ACC framework, each described in further detail in subsequent sections. First, they are used in the process of interpolating and extrapolating avoided costs to years for which explicit simulations were not conducted (described further below). Second, they are used to derive implied marginal emissions factors (tonnes/MWh) for each hour, which both serve as intermediate inputs into the Integrated Calculation of GHG and Capacity avoided costs and are used, in conjunction with the resulting GHG avoided cost ($/tonne) to determine the final hourly GHG avoided cost.

The IMHR in each hour is calculated as:

$$IMHR_i = \frac{P_{e,i} - VOM_{CC}}{P_{g,i} + P_{cap\_and\_invest} \times E_{g,i}}$$

Where $P_{e,i}$ is the energy price in hour *i* in $/MWh; $VOM_{CC}$ is the variable operations and maintenance (O&M) cost of a combined cycle generator in $/MWh; $P_g$ is the gas price in $/MMBtu; $P_{cap\_and\_invest}$ is the cap-and-invest prices assumed in SERVM modeling, in $/tonne; $E_{g,i}$ is the carbon content of natural gas, in tonne/MMBTU.

## 2.4 Marginal Emissions Factors

The IMHR can be translated directly to a marginal emissions factor that represents the quantity of greenhouse gas emissions avoided by a 1 MW reduction in load (or by 1 MW of additional generation) in each hour. While the marginal emissions factors do not directly impact the energy component of avoided costs, they are used in the process of determining both the annual and hourly GHG avoided costs (described in Section 4)

The conversion of IMHR to a marginal emissions factor is based on the carbon content of natural gas fuel (117 lb./MMBtu, or 0.053 metric tons per MMBtu). For instance, in an hour in which the IMHR is 7,000 Btu/kWh (a typical heat rate for a combined cycle natural gas plant), the marginal emissions factor would be 0.371 metric tons per MWh.

In the application of marginal emissions factors to determine GHG avoided costs, an upper bound corresponding to an IMHR of 12,500 Btu/kWh (0.663 metric tons per MWh) is applied. This is consistent with upper limits assumed in previous ACCs and is intended to reflect the fact that few natural gas units operational today have physical heat rates above this level.

## 2.5 Interpolation & Extrapolation

The scope of the ACC extends to 2055, while the SERVM model provides results in years 2026-2041 and 2045. Energy prices within intervening periods and beyond 2045 are interpolated and extrapolated, respectively, based on hourly IMHR values. Within the periods 2042-2044, the IMHR in each hour of the year is linearly interpolated. Beyond 2045, the IMHR is assumed to remain constant.

To determine the hourly avoided energy cost, the IMHR values are used in combination with the natural gas price forecast to calculate hourly energy prices in years for which SERVM simulations are not conducted:

$$P_{e,i} = IMHR_i \times P_g + VOM_{CC}$$

Fuel costs for final calculation of electricity generation prices are consistent with natural gas commodity prices discussed in the ACC gas model.

## 2.6 Summary of Results

The final energy avoided costs follow the expected trend of the effects of increased renewable generation and curtailment in the spring. Periods of high renewable production and low load in the spring show very low prices. **Error! Reference source not found.**2 to **Error! Reference source not found.**5 show the month-hour average energy avoided costs for SP-15 in 2026, 2030, 2035, and 2045. In near-term years, energy prices retain a conventional diurnal and seasonal shape, with high-price hours occurring in summer evenings and low-price hours limited to midday in the spring shoulder months.

Beginning in 2030, energy prices in the 2026 ACC are increasingly depressed, first in solar hours and subsequently across most spring hours. The duration curves show this as a growing separation between two pricing pattern: high price periods are driven by dispatchable thermal that sets the marginal price, and near-zero price periods in which curtailed renewables are on the margin. By 2045, more than 70% of hours are at or near zero due to significant penetration of renewable resources with little to no operating costs, and the April–May period is near zero in nearly all hours rather than in solar hours alone. Remaining high-price hours are concentrated in winter mornings and overnight periods, driven by demand from electric space and water heating as well as EV charging.

***Figure 2-2. Month-hour averages of 2026 SP15 Energy Avoided***

| | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jan | 58 | 58 | 58 | 58 | 59 | 65 | 68 | 60 | 39 | 29 | 25 | 21 | 19 | 14 | 18 | 26 | 60 | 73 | 72 | 70 | 69 | 66 | 63 | 60 |
| Feb | 62 | 61 | 61 | 62 | 65 | 70 | 75 | 62 | 35 | 32 | 24 | 20 | 18 | 16 | 14 | 15 | 44 | 77 | 76 | 73 | 73 | 69 | 66 | 64 |
| Mar | 51 | 50 | 50 | 50 | 51 | 54 | 52 | 22 | 10 | 9 | 7 | 5 | 5 | 5 | 6 | 6 | 12 | 52 | 58 | 59 | 60 | 58 | 54 | 52 |
| Apr | 50 | 48 | 48 | 48 | 50 | 49 | 24 | 5 | 1 | 2 | 0 | 0 | 1 | 0 | 1 | 0 | 2 | 46 | 55 | 58 | 58 | 58 | 53 | 51 |
| May | 51 | 50 | 49 | 47 | 49 | 47 | 9 | 4 | 3 | 1 | 2 | 2 | 2 | 1 | 1 | 1 | 10 | 43 | 53 | 58 | 59 | 59 | 55 | 52 |
| Jun | 56 | 55 | 54 | 53 | 53 | 53 | 30 | 27 | 26 | 23 | 21 | 20 | 23 | 25 | 27 | 29 | 46 | 71 | 70 | 69 | 68 | 67 | 63 | 59 |
| Jul | 63 | 61 | 60 | 60 | 62 | 58 | 49 | 45 | 43 | 41 | 41 | 38 | 43 | 47 | 50 | 53 | 66 | 83 | 81 | 77 | 75 | 75 | 71 | 67 |
| Aug | 67 | 65 | 65 | 64 | 67 | 67 | 55 | 50 | 46 | 44 | 44 | 46 | 49 | 52 | 56 | 61 | 79 | 84 | 83 | 77 | 75 | 74 | 70 | 68 |
| Sept | 68 | 66 | 65 | 67 | 70 | 72 | 59 | 49 | 47 | 44 | 43 | 42 | 46 | 47 | 54 | 55 | 74 | 86 | 80 | 77 | 76 | 76 | 71 | 70 |
| Oct | 61 | 60 | 59 | 59 | 62 | 68 | 63 | 45 | 44 | 40 | 37 | 35 | 35 | 38 | 41 | 47 | 71 | 72 | 71 | 72 | 71 | 69 | 65 | 63 |
| Nov | 59 | 58 | 58 | 58 | 60 | 63 | 66 | 48 | 44 | 39 | 36 | 35 | 32 | 33 | 34 | 43 | 69 | 72 | 72 | 71 | 70 | 67 | 63 | 61 |
| Dec | 61 | 60 | 60 | 60 | 62 | 69 | 72 | 61 | 54 | 50 | 46 | 44 | 43 | 41 | 43 | 51 | 76 | 75 | 74 | 74 | 73 | 71 | 66 | 64 |

### *Figure 2-3. Month-hour averages of 2030 SP15 Energy Avoided Costs*

| | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jan | 65 | 63 | 62 | 62 | 63 | 66 | 69 | 53 | 20 | 15 | 13 | 11 | 10 | 7 | 9 | 9 | 42 | 70 | 72 | 71 | 71 | 70 | 67 | 64 |
| Feb | 65 | 64 | 63 | 63 | 65 | 66 | 69 | 42 | 16 | 9 | 8 | 7 | 7 | 6 | 5 | 7 | 15 | 69 | 73 | 73 | 72 | 70 | 67 | 67 |
| Mar | 52 | 53 | 51 | 49 | 48 | 50 | 42 | 10 | 4 | 4 | 4 | 2 | 2 | 2 | 2 | 3 | 5 | 43 | 55 | 56 | 56 | 54 | 52 | 54 |
| Apr | 40 | 36 | 32 | 28 | 25 | 23 | 7 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 11 | 22 | 28 | 36 | 34 | 40 | 41 |
| May | 34 | 32 | 29 | 27 | 24 | 19 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 13 | 19 | 29 | 34 | 36 | 35 | 34 |
| Jun | 54 | 51 | 51 | 49 | 49 | 45 | 6 | 3 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 3 | 49 | 50 | 57 | 59 | 59 | 56 | 56 |
| Jul | 64 | 62 | 61 | 60 | 60 | 54 | 20 | 12 | 10 | 9 | 8 | 7 | 8 | 8 | 10 | 12 | 15 | 66 | 68 | 72 | 72 | 72 | 68 | 65 |
| Aug | 64 | 62 | 62 | 61 | 62 | 62 | 29 | 11 | 10 | 9 | 8 | 8 | 8 | 7 | 8 | 10 | 16 | 72 | 73 | 72 | 72 | 71 | 68 | 66 |
| Sept | 68 | 67 | 66 | 66 | 68 | 70 | 43 | 18 | 17 | 16 | 14 | 15 | 15 | 16 | 19 | 20 | 37 | 75 | 76 | 75 | 76 | 74 | 70 | 69 |
| Oct | 67 | 65 | 64 | 64 | 66 | 67 | 63 | 19 | 16 | 12 | 12 | 10 | 11 | 10 | 11 | 19 | 56 | 71 | 72 | 72 | 72 | 70 | 70 | 68 |
| Nov | 66 | 65 | 64 | 64 | 63 | 67 | 69 | 32 | 23 | 20 | 18 | 15 | 14 | 12 | 15 | 21 | 67 | 71 | 72 | 72 | 71 | 70 | 68 | 68 |
| Dec | 67 | 66 | 64 | 64 | 65 | 67 | 72 | 53 | 40 | 36 | 31 | 29 | 26 | 20 | 19 | 30 | 73 | 75 | 76 | 76 | 73 | 73 | 70 | 69 |

### *Figure 2-4. Month-hour averages of 2035 SP15 Energy Avoided Costs*

| | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jan | 73 | 70 | 69 | 68 | 66 | 72 | 76 | 58 | 21 | 7 | 5 | 4 | 4 | 5 | 4 | 7 | 31 | 72 | 74 | 76 | 75 | 75 | 73 | 71 |
| Feb | 69 | 65 | 64 | 63 | 63 | 64 | 71 | 31 | 12 | 8 | 6 | 4 | 4 | 3 | 3 | 4 | 8 | 60 | 68 | 68 | 68 | 68 | 67 | 66 |
| Mar | 34 | 29 | 26 | 28 | 27 | 29 | 21 | 6 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 4 | 16 | 24 | 27 | 30 | 31 | 33 | 32 |
| Apr | 7 | 8 | 7 | 6 | 5 | 3 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 4 | 4 | 6 | 7 | 8 | 8 |
| May | 4 | 4 | 4 | 3 | 2 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 3 | 4 | 4 | 4 | 6 | 5 |
| Jun | 24 | 20 | 20 | 15 | 18 | 10 | 2 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 13 | 17 | 22 | 26 | 27 | 25 | 27 |
| Jul | 49 | 46 | 44 | 40 | 39 | 33 | 9 | 5 | 4 | 4 | 3 | 2 | 2 | 2 | 2 | 3 | 6 | 37 | 45 | 51 | 56 | 56 | 54 | 54 |
| Aug | 65 | 63 | 62 | 61 | 61 | 52 | 18 | 4 | 3 | 1 | 2 | 1 | 1 | 1 | 2 | 4 | 9 | 57 | 70 | 72 | 72 | 72 | 71 | 70 |
| Sept | 70 | 67 | 65 | 65 | 67 | 66 | 33 | 14 | 12 | 14 | 12 | 11 | 12 | 11 | 14 | 16 | 27 | 64 | 74 | 74 | 74 | 73 | 71 | 70 |
| Oct | 70 | 68 | 68 | 67 | 68 | 70 | 60 | 8 | 6 | 4 | 4 | 3 | 3 | 4 | 4 | 7 | 51 | 72 | 72 | 73 | 73 | 71 | 73 | 74 |
| Nov | 73 | 69 | 68 | 66 | 66 | 69 | 72 | 38 | 19 | 13 | 11 | 10 | 11 | 9 | 12 | 16 | 69 | 71 | 73 | 73 | 73 | 73 | 71 | 72 |
| Dec | 82 | 79 | 78 | 76 | 78 | 80 | 84 | 59 | 43 | 33 | 30 | 26 | 20 | 17 | 18 | 28 | 86 | 88 | 87 | 86 | 84 | 84 | 81 | 80 |

### *Figure 2-5. Month-hour averages of 2045 SP15 Energy Avoided Costs*

| | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jan | 71 | 70 | 71 | 68 | 65 | 65 | 71 | 33 | 4 | 2 | 0 | 1 | 0 | 0 | 0 | 6 | 22 | 59 | 59 | 62 | 64 | 68 | 68 | 69 |
| Feb | 62 | 60 | 58 | 56 | 53 | 51 | 54 | 12 | 4 | 2 | 1 | 0 | 0 | 0 | 0 | 0 | 7 | 41 | 43 | 45 | 48 | 48 | 51 | 55 |
| Mar | 14 | 11 | 10 | 9 | 9 | 10 | 9 | 3 | 3 | 3 | 2 | 3 | 3 | 2 | 3 | 3 | 3 | 9 | 9 | 11 | 12 | 13 | 15 | 15 |
| Apr | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 |
| May | 2 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 2 |
| Jun | 8 | 6 | 5 | 3 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 3 | 5 | 8 | 11 | 10 | 11 |
| Jul | 25 | 24 | 23 | 24 | 22 | 16 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 4 | 13 | 21 | 23 | 23 | 27 | 31 | 32 |
| Aug | 32 | 27 | 26 | 25 | 24 | 19 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 22 | 32 | 32 | 33 | 32 | 40 | 39 |
| Sept | 62 | 63 | 60 | 59 | 60 | 59 | 19 | 10 | 5 | 4 | 6 | 4 | 3 | 6 | 8 | 9 | 31 | 60 | 64 | 64 | 62 | 63 | 63 | 64 |
| Oct | 62 | 56 | 52 | 52 | 49 | 48 | 26 | 3 | 0 | 0 | 3 | 0 | 0 | 3 | 3 | 2 | 25 | 50 | 53 | 53 | 56 | 57 | 60 | 63 |
| Nov | 77 | 76 | 77 | 73 | 72 | 73 | 74 | 13 | 9 | 4 | 3 | 2 | 3 | 3 | 4 | 10 | 69 | 69 | 71 | 71 | 72 | 73 | 73 | 74 |
| Dec | 98 | 96 | 92 | 91 | 91 | 92 | 94 | 41 | 24 | 15 | 15 | 14 | 14 | 12 | 15 | 20 | 86 | 83 | 83 | 85 | 84 | 86 | 88 | 89 |

# 3. Avoided Ancillary Services Costs

In the ACC, avoided ancillary service costs represent the ancillary service procurement that could be avoided through a reduction in load. The CAISO procures ancillary services (AS) to maintain the reliability of the grid and competitiveness of energy markets. Common AS products include regulation reserves, spinning reserves and non-spinning reserves. Regulation reserves are provided by generation resources that are running and synchronized with the grid and able to increase (reg up) or decrease (reg down) their output instantly. Spinning reserves are provided by generation resources that are running and capable of ramping up within 10 minutes and running for at least two hours. Non-spinning reserves are provided by resources that are available but not running.

Because the CAISO spinning and non-spinning reserve requirements are set as a function of forecast load, a reduction in load reduces the quantity of these products that must be procured to operate the system. Regulation reserves are excluded from the avoided ancillary service cost. The CAISO regulation requirement is determined from observed regulation needs in the corresponding periods of the prior year and prior month rather than from the level of load, so an incremental change in load does not produce a corresponding change in regulation procurement.

In prior ACC cycles, SERVM produced hourly ancillary service prices, which were reported as supplemental information. Avoided ancillary service costs were not derived from these hourly prices. They were estimated as a fixed percentage of hourly energy prices, consistent with the approach described below. Increasing storage penetration has produced a sustained decline in ancillary service prices, consistent with the AS saturation effect identified in the 2024 ACC, and the hourly price stream no longer provides meaningful additional information relative to its magnitude. Hourly ancillary service prices are therefore omitted from the 2026 ACC.

The percentage used to derive avoided ancillary service costs has been updated for the 2026 ACC. The CAISO *Annual Report on Market Issues and Performance* indicates that total ancillary service costs were approximately 1.1% of total wholesale energy costs in 2024.[5] Of this amount, the 2026 ACC assumes that half is associated with products that scale directly with load and is therefore avoidable by incremental DER resources, yielding 0.55%. This figure is then adjusted to reflect the continued decline in ancillary service prices, using the ratio of average spinning reserve prices to average energy prices as an indicator: this ratio was approximately 10% in 2024 and approximately 2% in 2025, implying a downward adjustment of one fifth. The resulting avoided ancillary service cost is approximately 0.12% of wholesale energy prices in 2025, and this percentage is held constant in all forecast years.

[5] CAISO, 2025 Annual Report on Market Issues and Performance, June 2026, Available at: https://www.caiso.com/documents/2025-annual-report-on-market-issues-and-performance.pdf

# 4. Integrated Calculation of GHG and Generation capacity avoided costs

## 4.1 Overview

Hourly GHG and generation capacity avoided costs in the ACC are developed in two steps. First, annual values are determined: GHG avoided costs (the GHG adders in the electric model) in $/tonne, and generation capacity avoided costs in $/kW-year. Second, each annual value is allocated to an hourly stream.

The determination of the annual values follows a single governing principle: for a marginal resource, the combined value of the energy, generation capacity, and GHG services it provides matches the total cost of that resource. Applying this principle in the 2026 ACC requires two determinations:

- The GHG adders in the electric model are set equal to the GHG constraint shadow price from the CPUC IRP RESOLVE modeling.
- The generation capacity avoided costs are calculated from the cost-recovery equation of a hybrid solar and lithium-ion battery storage resource.

Because the GHG adder is determined exogenously in the first step, generation capacity avoided cost is the only unknown remaining in the cost-recovery condition. A single linear equation per year is therefore sufficient to solve for it.

## 4.2 Annual Avoided GHG Costs

The CPUC's IRP proceeding uses long-term capacity expansion modeling (RESOLVE) to develop least-cost portfolios that meet the state's GHG reduction goals. The shadow price of the model's GHG constraint represents the marginal cost, expressed in dollars per metric ton, of achieving the modeled level of carbon reduction beyond the reductions already induced by the existing cap-and-invest program. Because the shadow price is incremental to the cap-and-invest program, it does not overlap with the avoided cap-and-invest price.

The GHG constraint shadow price implicitly reflects the total cost of the resources built on the margin to satisfy the GHG constraint net of the energy and capacity value those resources provide to the system. The shadow price therefore satisfies the same governing principle of the integrated calculation – the combined energy, GHG, and capacity value of a marginal resource equals its cost.

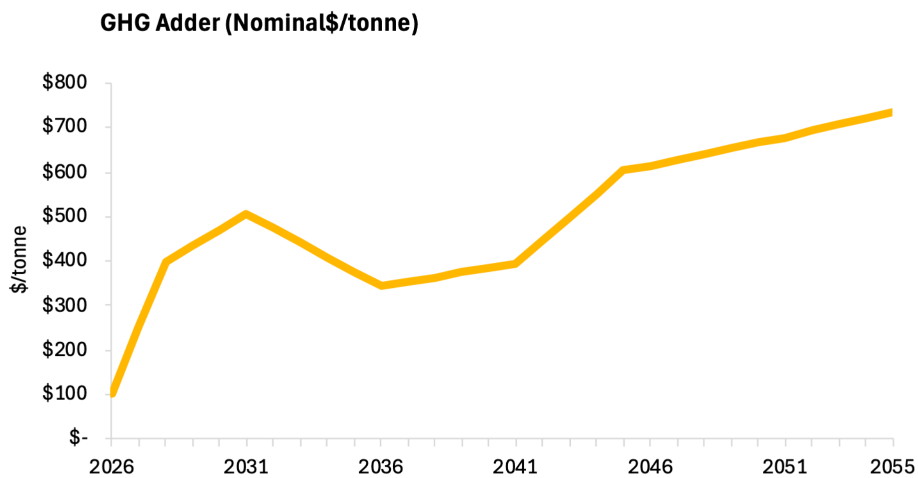
RESOLVE shadow prices were used as the GHG adders in earlier ACC cycles (e.g., the 2020 ACC). The 2022 ACC departed from that approach by solving for the GHG adder and the generation capacity avoided cost simultaneously within an optimization model. After weighing accuracy, transparency, and alignment with the IRP, the 2026 ACC returns to the shadow price approach.

RESOLVE shadow prices are reported in real 2024 dollars. For a given year n, staff converted them to nominal dollars using an assumed long-run inflation rate of 2%.

$$Nominal\ \$\ (n) = Real\ \$\ (n)\ \times\ (1 + 2\%)^{(n-2024)}$$

Since RESOLVE only modeled select years within the modeling horizon (2026-2045) of the 2026-27 TPP, the GHG shadow prices for interim years were calculated using linear interpolation and the GHG shadow prices after 2045 were based on a forward projection of the 2045 shadow price at a 2% inflation rate.

*Figure 4-1. GHG Adder, 2026 through 2055, nominal USD/tonnne*




## 4.3 Annual Avoided Generation Capacity Costs

As generation capacity avoided cost is the only unknown, only one linear equation is needed to solve it. The generation capacity avoided costs are calculated using a hybrid solar and li-ion battery storage resource. Both solar and Li-ion battery are selected economically throughout the IRP planning horizon (2026-2045), reflecting their respective long-term roles as scalable resources to meet the state's reliability and decarbonization goals.

### *4.3.1 Model Formulation*

Generation capacity avoided costs are calculated from a hybrid resource composed of utility-scale solar and lithium-ion battery storage. Both technologies are selected economically throughout the IRP planning horizon (2026–2045), reflecting their respective long-term roles as scalable resources for meeting the state's reliability and decarbonization goals. The hybrid is constructed by combining the two technologies in a ratio of 1MW of solar and 1MW of storage.

This formulation uses a single equation to directly calculate annual avoided costs for each year. For the hybrid resource, the relationship between resource costs and avoided costs is expressed as:

$$\boldsymbol{RECC\ (n) = R_{energy}(n) + AC_{GC}(n)\ \times Q_{ELCC}(n) + AC_{GHG}(n)\ \times Q_{GHG}(n)}$$

| Unknowns or Parameter | Description | Units | Source |
|---|---|---|---|

| | | | |
|---|---|---|---|
| $AC_{GC}$ | Generation Capacity Avoided Costs | \$/kW-year | To be Calculated |
| $AC_{GHG}$ | GHG Avoided Costs | \$/tonne | RESOLVE GHG shadow price plus Cap-and-Invest prices |
| $Q_{ELCC}$ | Deemed RA contribution | ELCC kW | RESOLVE output |
| $Q_{GHG}$ | Marginal GHG impacts | tonne/kW-yr. | Derived via SERVM energy prices |
| $RECC$ | Gross Economic Carrying Charge | \$/kW-yr. | RESOLVE output |
| $R_{energy}$ | Energy Revenues (excluding Cap-and-Invest prices) | \$/kW-yr. | Derived via SERVM energy prices |

The Gross Real Economic Carrying Charge (RECC) represents the annualized cost of deferring a marginal resource investment by one year. It is calculated as the difference between the NPV of total resource costs if the resource were installed in year *n* versus year *n + 1*. In essence, the RECC captures both the lifetime cost of the resource and the opportunity cost associated with delaying its installation by one year. The RECC concept has been used in the previous ACC cycles. The 2022 ACC used the RECC of a single representative resource, a four-hour lithium-ion battery, to determine generation capacity avoided costs.

### 4.3.2 Key Inputs and Assumptions

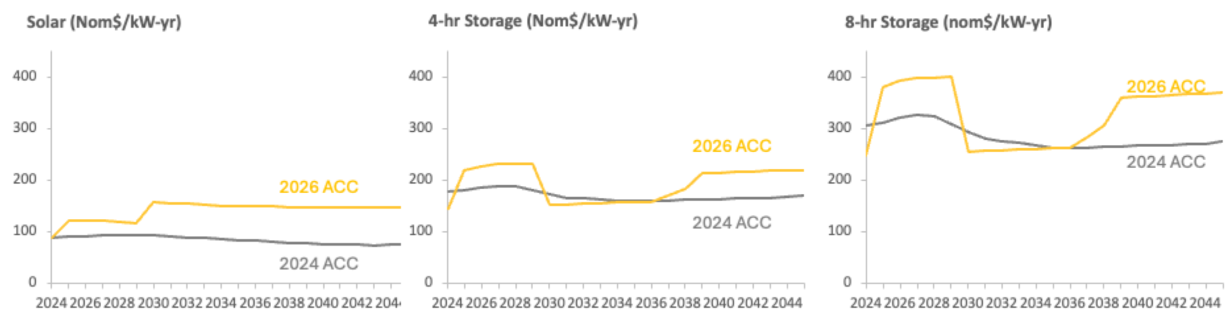
**Levelized fixed costs.** The levelized fixed costs used in the Integrated Calculation are consistent with the IRP. In the IRP, the costs of new resources are represented as a real levelized cost, intended to represent a stream of payments from a utility to a third-party developer under a long-term power purchase agreement escalating with inflation. The same methods and assumptions – including assumptions on the cost parameters for the resource, how it is financed, and how those costs are incurred by a utility – are used in the 2026 ACC. The levelized cost of resources in a specific year is calculated based on cost assumptions (capital cost, fixed operations and maintenance costs, warranty and augmentation costs) and financing parameters (costs of debt and equity, financing life, debt term, and debt-to-equity ratio).

New solar and storage costs have increased significantly since the 2024 ACC:

- Solar costs in the 2026–27 TPP assumptions are elevated in the near term due to tariffs, and increase again around 2030 as the supply of safe-harbored modules eligible for the production tax credit (PTC) is exhausted.
- Storage costs are also elevated in the near term due to tariffs, and increase again in the late 2030s with the expiration of the investment tax credit (ITC).

The final year of IRP resource costs is 2045. Resource costs for 2046 through 2055 are extrapolated following the cost trend observed over 2043–2045. Costs beyond 2055 are escalated at inflation. Figure 4-2 compares the difference in levelized cost results for solar, 4-hr storage, and 8-hr storage between the 2024 and 2026 ACC, from 2024 to 2050.

### *Figure 4-2. Levelized Costs for Solar, 4-hr Storage, and 8-hr Storage, 2024 to 2026*




**Energy revenues.** Energy revenues for both technologies are derived from SERVM energy prices. Solar energy revenues are calculated by multiplying the hourly solar generation profile from the SERVM resource portfolio by the hourly energy price in the corresponding year. Storage energy revenues are calculated from the “top-bottom-4" (TB4) or “top-bottom-8" (TB8) price spread in SERVM. The TB*N* spread is the difference between the average price of the *N* highest-priced hours and the average price of the *N* lowest-priced hours of each day. It approximates the gross arbitrage value available to a battery of *N*-hour duration operating with perfect foresight, and is applied net of round-trip efficiency losses. TB4 is applied to four-hour storage and TB8 to eight-hour storage.

Ancillary services revenues for storage are omitted in this cycle because ancillary services now represent a small and declining share of storage revenue. Energy revenues exclude the cap-and-invest price component of energy prices.

**Marginal GHG impact.** The marginal GHG impact of each representative resource is calculated using the same approach as energy revenues, substituting hourly marginal emission rates for hourly energy prices. The result represents the quantity of marginal greenhouse gas emissions displaced by each unit of generating capacity in each year. Multiplied by the GHG avoided cost ($/tonne), it yields the total annual GHG value provided by the resource.

**Resource Adequacy (RA) contribution.** Each resource’s contribution to the system’s capacity (or reliability) needs is characterized by its marginal ELCC, a direct output of RESOLVE in the CPUC IRP proceeding. Marginal ELCCs for solar resources are relatively low today due to the timing of the net peak in the early evening and remain at similar levels through the planning period. Marginal ELCCs for energy storage are relatively high today but decline as the penetration of storage in the portfolio increases.

The inputs to the Integrated Calculation model are summarized in Table 4-1 below.

## *Table 4-1. Summary of inputs for Integrated Calculation*

| | Generic Solar | | | | Generic 4-Hour Storage | | | | Generic 8-Hour Storage | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Fixed Costs by Vintage | Energy Revenues | Marginal GHG Impact | ELCC | Fixed Costs by Vintage | Energy Revenues | Marginal GHG Impact | ELCC | Fixed Costs by Vintage | Energy Revenues | Marginal GHG Impact | ELCC |
| | 2024$/kW-yr | 2024$/kW-yr | tonnes/MW-yr | % | 2024$/kW-yr | 2024$/kW-yr | tonnes/MW-yr | % | 2024$/kW-yr | 2024$/kW-yr | tonnes/MW-yr | % |
| 2026 | 118 | 80 | 592 | 4.5% | 218 | 56 | 437 | 35.3% | 377 | 89 | 693 | 56.8% |
| 2027 | 115 | 60 | 435 | 4.4% | 218 | 68 | 524 | 35.5% | 376 | 112 | 867 | 56.9% |
| 2028 | 111 | 50 | 364 | 4.3% | 214 | 74 | 567 | 35.7% | 369 | 125 | 964 | 57.0% |
| 2029 | 107 | 48 | 344 | 5.1% | 211 | 74 | 569 | 27.7% | 362 | 125 | 960 | 44.5% |
| 2030 | 139 | 25 | 180 | 5.9% | 136 | 70 | 534 | 19.7% | 227 | 123 | 934 | 31.9% |
| 2031 | 135 | 22 | 154 | 6.7% | 134 | 70 | 528 | 11.7% | 223 | 123 | 922 | 19.4% |
| 2032 | 131 | 20 | 140 | 6.8% | 132 | 69 | 513 | 11.1% | 220 | 119 | 888 | 18.6% |
| 2033 | 128 | 19 | 129 | 7.0% | 130 | 67 | 496 | 10.5% | 217 | 116 | 853 | 17.8% |
| 2034 | 124 | 18 | 123 | 7.1% | 128 | 70 | 512 | 10.0% | 213 | 120 | 881 | 17.1% |
| 2035 | 120 | 14 | 94 | 7.3% | 126 | 60 | 433 | 9.4% | 210 | 103 | 744 | 16.3% |
| 2036 | 118 | 14 | 95 | 7.4% | 125 | 59 | 425 | 8.8% | 207 | 101 | 726 | 15.5% |
| 2037 | 115 | 15 | 100 | 7.6% | 131 | 62 | 440 | 9.3% | 219 | 106 | 753 | 15.7% |
| 2038 | 112 | 16 | 102 | 7.8% | 139 | 63 | 442 | 9.8% | 232 | 108 | 758 | 15.9% |
| 2039 | 110 | 15 | 100 | 8.0% | 159 | 65 | 452 | 10.2% | 268 | 111 | 772 | 16.1% |
| 2040 | 107 | 13 | 86 | 8.2% | 156 | 61 | 423 | 10.7% | 264 | 106 | 730 | 16.3% |
| 2041 | 105 | 13 | 79 | 8.5% | 154 | 62 | 427 | 11.2% | 259 | 108 | 739 | 16.5% |
| 2042 | 103 | 11 | 66 | 7.9% | 152 | 58 | 395 | 10.7% | 255 | 101 | 681 | 16.0% |
| 2043 | 101 | 8 | 53 | 7.4% | 150 | 54 | 362 | 10.1% | 251 | 93 | 622 | 15.5% |
| 2044 | 98 | 6 | 40 | 6.9% | 147 | 50 | 330 | 9.6% | 247 | 85 | 564 | 15.0% |
| 2045 | 96 | 4 | 27 | 6.4% | 145 | 46 | 297 | 9.0% | 244 | 78 | 505 | 14.5% |

Other Assumptions:

- **Storage duration of the hybrid resource.** Generation capacity avoided costs are based on a solar + 4-hour storage hybrid through 2030 and a solar + 8-hour storage hybrid from 2031 onward. This follows the principle that the avoided capacity cost should reflect the cheapest new resource to provide capacity. With the current inputs, the avoided capacity cost derived from solar + 4-hour storage is lower than that derived from solar + 8-hour storage before 2031, and the relationship flips thereafter. The 2031 switch year is also consistent with the 2026–27 TPP portfolio, in which RESOLVE does not select a significant amount of 8-hour storage until 2031. As stakeholders have noted, the CPUC's Mid-Term Reliability (MTR) order likewise directs load-serving entities to procure 1,000 MW of 8-hour storage beginning in 2031.[6]
- **Price floor.** The floor of avoided capacity costs is set at $43/kW-yr (2024$). This value reflects the assumed ongoing fixed O&M cost of existing gas resources in the 2026-27 TPP inputs and assumptions.[7] The application of this floor is intended to ensure that the outputs of the Integrated Calculation also provide sufficient value to retain existing natural gas resources included in the TPP for their resource adequacy value.
- **Extrapolation beyond modeling years.** The last year for which SERVM and RESOLVE results are available is 2045, while the planning horizon for the 2026 ACC extends through 2055. Therefore, generation capacity avoided costs for 2046 through 2055 are held constant in real terms at the 2045 value and escalated at inflation.

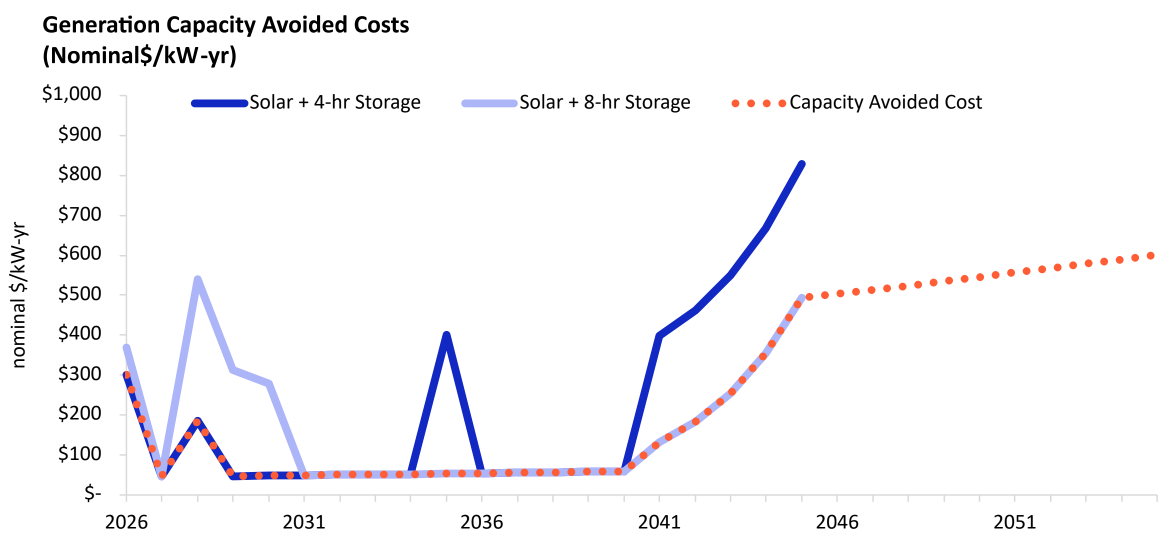
The resulting annual capacity avoided costs are shown in Figure 4-3.

[6] Comments of the Public Advocates Office on the Proposed Decision Adopting Updates to the Avoided Cost Calculator, R.22-11-013, p. 3.

[7] Consistent with 26-27 TPP gas O&M costs. Original source is CEC Estimated Cost of New Utility-Scale Generation in California. page B-25, https://www.energy.ca.gov/sites/default/files/2021-06/CEC-200-2019-005.pdf

- In the near term (2026–2028), elevated storage capital costs are not offset by the energy and GHG value of the marginal resource, leaving a large residual to be recovered through capacity value. Year-to-year variation over this period reflects the timing of tariff impacts on solar and storage costs.
- In the mid-term (2029–2040), the energy and GHG value of the marginal resource is sufficient on its own to recover its fixed costs. The calculated capacity value would fall to zero or below, and the price floor described above becomes binding. The capacity avoided cost in these years is set at the ongoing fixed O&M cost of existing gas resources.
- In the long-term (2041–2055), capacity value rises again. Increasing solar and storage penetration depresses energy prices as well as marginal ELCC. A larger share of the resource's fixed costs must be recovered through capacity value, and because avoided costs are denominated per kW of equivalent perfect capacity, the declining ELCC raises the resulting $/kW-yr value.

*Figure 4-3. Generation Capacity Avoided Costs*




## 4.4 Comparison between 2024 ACC and 2026 ACC

Figure 4-4 compares the GHG avoided costs (including GHG adders and avoided cap-and-invest prices) between the results from the 2024 ACC and those from the 2026 ACC. The GHG avoided cost from the 2026 ACC is higher than that from the 2024 ACC throughout the planning horizon. Although the methodology for determining the GHG adder changed between the two cycles, the primary driver of the increase is the rise in new resource costs reflected in the 2026–27 IRP TPP inputs and assumptions, which can be attributed to a combination of the impacts of federal tariffs, supply chain constraints, rising interest rates, and the expiration of federal tax credits. A comparison of RESOLVE GHG shadow prices across the two cycles, holding the methodology constant, shows an increase of similar direction and magnitude.

*Figure 4-4. Comparison of GHG Avoided Costs - 2024 ACC vs 2026 ACC*

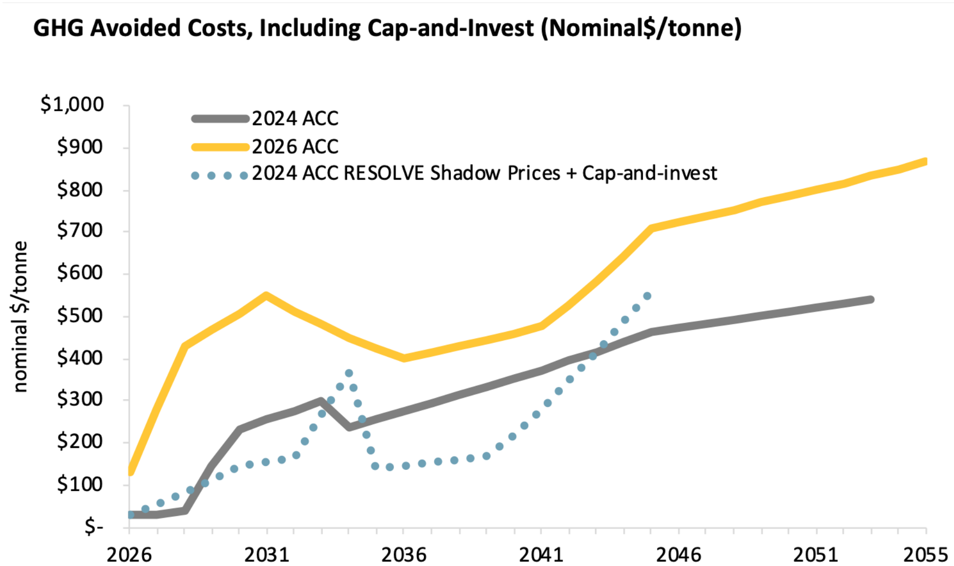
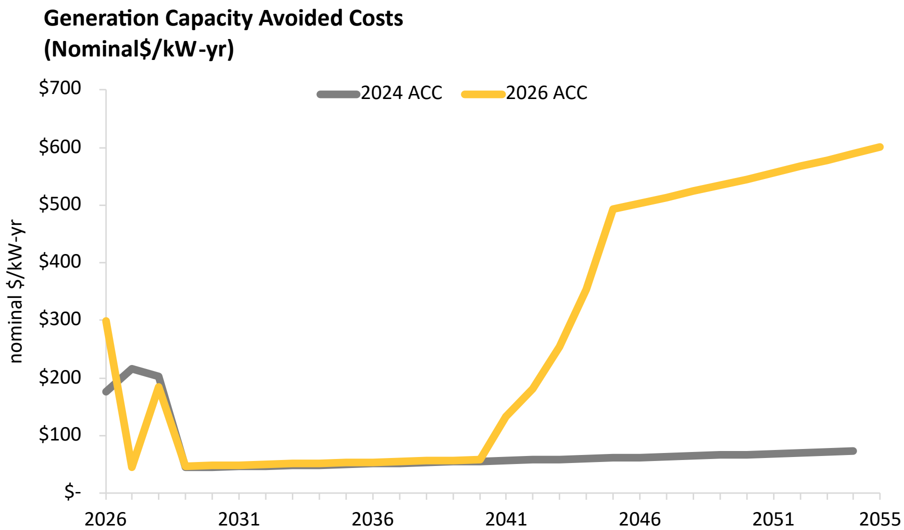



Figure 4-5 compares the generation capacity avoided costs between the 2024 ACC and the 2026 ACC. The two cycles produce similar values through 2041, after which the 2026 ACC values rise substantially above the 2024 ACC. This divergence is driven by increases in resource cost as well as the difference in methodology between the two cycles. The methodological difference is elucidated as follows:

The 2024 ACC represented solar and storage as standalone resources and solved for two value streams (i.e., GHG and generation capacity) simultaneously. By 2040, energy and GHG revenues alone were sufficient to cover the full cost of standalone storage. With no residual cost left for the capacity value stream to recover, the system of equations became under-determined in the later years. Therefore, the generation capacity avoided cost was set at the ongoing fixed O&M cost of existing gas resources as a proxy for the minimum value required to retain existing gas capacity.

In contrast, the 2026 ACC represents the marginal resource as a combined solar-and-storage hybrid, which continues to exhibit a revenue shortfall throughout the horizon and therefore requires capacity value to recover its costs. This revenue shortfall is driven by both higher resource costs assumed in the 2026 ACC as well as lower energy revenue with high renewable penetration. Because avoided costs are denominated per kW of equivalent perfect capacity, and marginal ELCCs low in the later years, even a modest shortfall translates into a high capacity value on a $/kW-year basis.

*Figure 4-5. Comparison of Generation Capacity Avoided Costs - 2024 ACC vs 2026 ACC*




## 4.5 Hourly allocation of generation capacity value

The annual generation capacity avoided costs ($/kW-yr) produced by the Integrated Calculation are allocated to hourly values when load reduction can help mitigate loss-of-load risks and provide reliability values. Staff used Loss of Load Hours (LOLH) as the basis for allocating the annual capacity value. Using LOLH reflects that load reduction during a loss-of-load event provides the same improvement to system reliability regardless of the size of that event.

There are two main steps to derive the hourly allocation. First, staff obtained month-hour averages of LOLH from SERVM. Second, staff allocated the month-hour LOLH to hourly values based on TMY energy prices.

To derive month-hour averages of LOLH, staff studied the 2026-27 TPP portfolio in SERVM to determine the timing and frequency of loss-of-load events. Reliability modelling results are based on simulations of a system tuned to a 1-day-in-10-years or 0.1 day/year Loss of Load Expectation (LOLE) standard, which is a common reliability standard in the electric utility industry. SERVM simulated 23 years of hydro variability with 23 weather years of weather variability (2000-2022), and 5 levels of demographic uncertainty in future years to total 2645 cases for each future year.

Month-hour average of LOLH reflects the average LOLH for a given year across all resource weather variability as well as demographic uncertainties. Similar to the 2024 ACC, the SERVM model used in the 2026 ACC incorporated storage dispatch logic that spread loss of load across all hours within the same day in which additional storage discharge could reduce Expected Unserved Energy (EUE). This storage dispatch approach spreads out LOLH that are driven by energy shortfalls but does not affect LOLH that are driven only by capacity shortfalls.

Notably, the current SERVM model's storage dispatch logic cannot spread loss of load across multiple days. As a result, LOLH spreading can get arbitrarily cut-off at midnight, even when there are storage discharge hours late at night of the preceding day or early in the morning of the following day. These cut-offs disproportionately affected 2036 and 2041, when LOLH was concentrated in winter mornings and there was little-to-no loss of load in the evening hours leading up to midnight. The normalized LOLH heatmaps based on SERVM EUE reports for 2036 and 2041 are shown in below, Figure 4-6 and Figure 4-7, respectively.

***Figure 4-6. 2036 Normalized Loss of Load Hours from SERVM Before Post-Processing***

| | Jan | Feb | Mar | Apr | May | June | July | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 5.32% | 0.08% | - | - | - | - | - | 2.59% | 0.37% | - | 0.63% | 0.09% |
| 2 | 5.31% | 0.08% | - | - | - | - | - | 0.48% | 0.10% | - | 0.63% | 0.09% |
| 3 | 5.16% | 0.09% | - | - | - | - | - | - | 0.06% | - | 0.62% | 0.02% |
| 4 | 5.11% | 0.14% | - | - | - | - | - | - | 0.05% | - | 0.56% | 0.03% |
| 5 | 5.53% | 0.14% | - | - | - | - | - | - | - | - | 0.62% | 0.06% |
| 6 | 6.56% | 0.20% | - | - | - | - | - | - | 0.01% | - | 0.66% | 0.08% |
| 7 | 7.18% | 0.20% | - | - | - | - | - | - | - | - | 0.68% | 0.13% |
| 8 | 7.39% | 0.20% | - | - | - | - | - | - | - | - | 0.68% | 0.22% |
| 9 | 7.25% | 0.20% | - | - | - | - | - | - | - | - | 0.68% | 0.15% |
| 10 | 2.97% | 0.10% | - | - | - | - | - | - | - | - | 0.57% | 0.09% |
| 11 | 0.06% | - | - | - | - | - | - | - | - | - | 0.15% | 0.04% |
| 12 | 0.01% | - | - | - | - | - | - | - | - | - | 0.01% | - |
| 13 | 0.05% | - | - | - | - | - | - | - | - | - | - | - |
| 14 | 0.05% | - | - | - | - | - | - | 1.12% | 0.01% | - | - | - |
| 15 | 0.05% | - | - | - | - | - | - | 1.74% | 0.02% | - | - | - |
| 16 | 0.06% | - | - | - | - | - | - | 2.26% | 0.19% | - | - | - |
| 17 | 0.10% | - | - | - | - | - | - | 2.39% | 0.60% | - | - | - |
| 18 | 0.10% | - | - | - | - | - | - | 2.39% | 0.57% | - | - | - |
| 19 | 0.03% | - | - | - | - | - | - | 2.43% | 2.47% | - | - | - |
| 20 | 0.06% | - | - | - | - | - | - | 2.39% | 0.20% | - | - | - |
| 21 | 0.02% | - | - | - | - | - | - | 2.36% | 0.20% | - | - | - |
| 22 | 0.01% | - | - | - | - | - | - | 2.36% | 0.20% | - | - | - |
| 23 | 0.01% | - | - | - | - | - | - | 2.36% | 0.20% | - | - | - |
| 24 | 0.01% | - | - | - | - | - | - | 2.36% | 0.20% | - | - | - |

***Figure 4-7. 2041 Normalized Loss of Load Hours from SERVM Before Post-Processing***

| | Jan | Feb | Mar | Apr | May | June | July | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 3.86% | - | - | - | - | - | - | 0.54% | 0.01% | - | 0.04% | 3.75% |
| 2 | 3.86% | - | - | - | - | - | - | 0.05% | - | - | 0.04% | 3.63% |
| 3 | 3.86% | - | - | - | - | - | - | - | 0.01% | - | 0.04% | 3.62% |
| 4 | 3.86% | - | - | - | - | - | - | - | - | - | - | 3.58% |
| 5 | 4.33% | - | - | - | - | - | - | - | 0.01% | - | 0.13% | 3.64% |
| 6 | 4.63% | - | - | - | - | - | - | - | - | - | 0.40% | 6.41% |
| 7 | 4.67% | - | - | - | - | - | - | - | - | - | 0.42% | 7.09% |
| 8 | 4.67% | - | - | - | - | - | - | - | - | - | 0.42% | 7.02% |
| 9 | 4.67% | - | - | - | - | - | - | - | - | - | 0.45% | 7.09% |
| 10 | 0.26% | - | - | - | - | - | - | - | - | - | 0.32% | 5.97% |
| 11 | - | - | - | - | - | - | - | - | - | - | - | 0.50% |
| 12 | - | - | - | - | - | - | - | - | - | - | 0.04% | - |
| 13 | - | - | - | - | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **14** | - | - | - | - | - | - | - | - | - | - | - | - |
| **15** | - | - | - | - | - | - | - | - | - | - | - | - |
| **16** | - | - | - | - | - | - | - | 0.45% | - | - | - | - |
| **17** | - | - | - | - | - | - | - | 0.50% | - | - | - | 0.02% |
| **18** | - | - | - | - | - | - | - | 0.50% | 0.25% | - | - | 0.02% |
| **19** | - | - | - | - | - | - | - | 0.53% | 1.28% | - | - | 0.02% |
| **20** | - | - | - | - | - | - | - | 0.51% | - | - | - | 0.02% |
| **21** | - | - | - | - | - | - | - | 0.50% | - | - | - | 0.01% |
| **22** | - | - | - | - | - | - | - | 0.50% | - | - | - | 0.01% |
| **23** | - | - | - | - | - | - | - | 0.50% | - | - | - | 0.01% |
| **24** | - | - | - | - | - | - | - | 0.50% | - | - | - | 0.02% |

SERVM dispatch reports for forty select cases with high winter morning LOLH—twenty each from 2036 and 2040—were post-processed to assess whether LOLH should be extended across multiple days. As a result of this analysis, the following modifications were made to the month-hour average LOLH values in 2036: January HE18-24 LOLH was set equal to January HE1 LOLH, January HE17 LOLH was set equal to half of January HE1 LOLH, November HE17-24 LOLH was set equal to November HE1 LOLH, and December HE17-24 LOLH was set equal to December HE1 LOLH. Similar modifications were made for 2041: January HE18-24 LOLH was set equal to January HE1 LOLH and December HE17-24 LOLH was set equal to December HE1 LOLH. These modifications resulted in a more even spread of LOLH across hours with storage discharge, which is consistent with original objective of the updates to the storage dispatch logic that began with the 2024 ACC.

The normalized LOLH values for 2027, 2031, 2036 and 2041 are shown in Figure 4-8 throughFigure 4-11 below.

### *Figure 4-8. 2027 Normalized Loss of Load Hours from SERVM*

| | Jan | Feb | Mar | Apr | May | June | July | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **1** | - | - | - | - | - | - | - | - | 0.04% | - | - | - |
| **2** | - | - | - | - | - | - | - | - | - | - | - | - |
| **3** | - | - | - | - | - | - | - | - | - | - | - | - |
| **4** | - | - | - | - | - | - | - | - | - | - | - | - |
| **5** | - | - | - | - | - | - | - | - | - | - | - | - |
| **6** | - | - | - | - | - | - | - | - | 0.04% | - | - | - |
| **7** | - | - | - | - | - | - | - | - | - | - | - | - |
| **8** | - | - | - | - | - | - | - | - | - | - | - | - |
| **9** | - | - | - | - | - | - | - | - | - | - | - | - |
| **10** | - | - | - | - | - | - | - | - | - | - | - | - |
| **11** | - | - | - | - | - | - | - | - | - | - | - | - |
| **12** | - | - | - | - | - | - | - | - | - | - | - | - |
| **13** | - | - | - | - | - | - | - | 0.07% | - | - | - | - |
| **14** | - | - | - | - | - | - | - | 1.06% | 0.20% | - | - | - |
| **15** | - | - | - | - | - | - | - | 1.35% | 3.23% | - | - | - |
| **16** | - | - | - | - | - | - | - | 3.72% | 5.92% | - | - | - |
| **17** | - | - | - | - | - | - | - | 3.75% | 7.77% | - | - | - |
| **18** | - | - | - | - | - | - | - | 3.75% | 8.23% | - | - | - |
| **19** | - | - | - | - | - | - | - | 3.76% | 10.32% | - | - | - |

| | Jan | Feb | Mar | Apr | May | June | July | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 20 | - | - | - | - | - | - | - | 3.75% | 7.77% | - | - | - |
| 21 | - | - | - | - | - | - | - | 3.75% | 7.77% | - | - | - |
| 22 | - | - | - | - | - | - | - | 3.75% | 7.77% | - | - | - |
| 23 | - | - | - | - | - | - | - | 3.42% | 6.99% | - | - | - |
| 24 | - | - | - | - | - | - | - | 0.13% | 1.71% | - | - | - |

### *Figure 4-9. 2031 Normalized Loss of Load Hours from SERVM*

| | Jan | Feb | Mar | Apr | May | June | July | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | - | - | - | - | - | - | - | 2.03% | 1.90% | - | 0.67% | - |
| 2 | - | - | - | - | - | - | - | 0.01% | 0.25% | - | 0.67% | - |
| 3 | - | - | - | - | - | - | - | - | - | - | 0.62% | - |
| 4 | - | - | - | - | - | - | - | - | - | - | 0.67% | - |
| 5 | 0.03% | - | - | - | - | - | - | - | - | - | 0.72% | - |
| 6 | 0.06% | - | - | - | - | - | - | - | 0.24% | - | 0.68% | - |
| 7 | 0.13% | - | - | - | - | - | - | - | - | - | 0.70% | - |
| 8 | 0.13% | - | - | - | - | - | - | - | - | - | 0.78% | - |
| 9 | 0.13% | - | - | - | - | - | - | - | - | - | 0.78% | - |
| 10 | 0.04% | - | - | - | - | - | - | - | - | - | 0.52% | - |
| 11 | - | - | - | - | - | - | - | - | - | - | 0.01% | - |
| 12 | - | - | - | - | - | - | - | - | - | - | - | - |
| 13 | - | - | - | - | - | - | - | 0.03% | - | - | - | - |
| 14 | - | - | - | - | - | - | - | 0.17% | 1.18% | - | - | - |
| 15 | - | - | - | - | - | - | - | 0.48% | 1.73% | - | - | - |
| 16 | - | - | - | - | - | - | - | 4.94% | 2.29% | - | - | - |
| 17 | - | - | - | - | - | - | - | 5.02% | 3.21% | - | - | - |
| 18 | - | - | - | - | - | - | - | 4.94% | 4.45% | - | - | - |
| 19 | - | - | - | - | - | - | - | 5.28% | 12.62% | - | - | - |
| 20 | - | - | - | - | - | - | - | 5.36% | 3.92% | - | - | - |
| 21 | - | - | - | - | - | - | - | 4.94% | 3.21% | - | - | - |
| 22 | - | - | - | - | - | - | - | 4.94% | 3.21% | - | - | - |
| 23 | - | - | - | - | - | - | - | 4.94% | 3.21% | - | - | - |
| 24 | - | - | - | - | - | - | - | 4.94% | 3.21% | - | - | - |

### *Figure 4-10. 2036 Normalized Loss of Load Hours from SERVM*

| | Jan | Feb | Mar | Apr | May | June | July | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 3.66% | 0.06% | - | - | - | - | - | 1.78% | 0.25% | - | 0.44% | 0.06% |
| 2 | 3.65% | 0.06% | - | - | - | - | - | 0.33% | 0.07% | - | 0.44% | 0.06% |
| 3 | 3.55% | 0.06% | - | - | - | - | - | - | 0.04% | - | 0.43% | 0.02% |
| 4 | 3.52% | 0.10% | - | - | - | - | - | - | 0.04% | - | 0.38% | 0.02% |
| 5 | 3.80% | 0.10% | - | - | - | - | - | - | - | - | 0.43% | 0.04% |
| 6 | 4.51% | 0.13% | - | - | - | - | - | - | 0.01% | - | 0.46% | 0.05% |
| 7 | 4.94% | 0.13% | - | - | - | - | - | - | - | - | 0.46% | 0.09% |
| 8 | 5.08% | 0.13% | - | - | - | - | - | - | - | - | 0.46% | 0.15% |
| 9 | 4.99% | 0.13% | - | - | - | - | - | - | - | - | 0.46% | 0.10% |
| 10 | 2.04% | 0.07% | - | - | - | - | - | - | - | - | 0.39% | 0.06% |
| 11 | 0.04% | - | - | - | - | - | - | - | - | - | 0.10% | 0.03% |
| 12 | 0.01% | - | - | - | - | - | - | - | - | - | 0.01% | - |
| 13 | 0.04% | - | - | - | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 14 | 0.04% | - | - | - | - | - | - | 0.77% | 0.01% | - | - | - |
| 15 | 0.04% | - | - | - | - | - | - | 1.20% | 0.02% | - | - | - |
| 16 | 0.04% | - | - | - | - | - | - | 1.55% | 0.13% | - | - | - |
| 17 | 1.83% | - | - | - | - | - | - | 1.64% | 0.41% | - | 0.44% | 0.06% |
| 18 | 3.66% | - | - | - | - | - | - | 1.64% | 0.39% | - | 0.44% | 0.06% |
| 19 | 3.66% | - | - | - | - | - | - | 1.67% | 1.70% | - | 0.44% | 0.06% |
| 20 | 3.66% | - | - | - | - | - | - | 1.64% | 0.14% | - | 0.44% | 0.06% |
| 21 | 3.66% | - | - | - | - | - | - | 1.63% | 0.14% | - | 0.44% | 0.06% |
| 22 | 3.66% | - | - | - | - | - | - | 1.63% | 0.14% | - | 0.44% | 0.06% |
| 23 | 3.66% | - | - | - | - | - | - | 1.63% | 0.14% | - | 0.44% | 0.06% |
| 24 | 3.66% | - | - | - | - | - | - | 1.63% | 0.14% | - | 0.44% | 0.06% |

### *Figure 4-11. 2041 Normalized Loss of Load Hours from SERVM*

| | Jan | Feb | Mar | Apr | May | June | July | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2.46% | - | - | - | - | - | - | 0.34% | 0.01% | - | 0.02% | 2.39% |
| 2 | 2.46% | - | - | - | - | - | - | 0.03% | - | - | 0.02% | 2.31% |
| 3 | 2.46% | - | - | - | - | - | - | - | 0.01% | - | 0.02% | 2.31% |
| 4 | 2.46% | - | - | - | - | - | - | - | - | - | - | 2.28% |
| 5 | 2.76% | - | - | - | - | - | - | - | 0.01% | - | 0.08% | 2.32% |
| 6 | 2.95% | - | - | - | - | - | - | - | - | - | 0.26% | 4.09% |
| 7 | 2.97% | - | - | - | - | - | - | - | - | - | 0.27% | 4.52% |
| 8 | 2.97% | - | - | - | - | - | - | - | - | - | 0.27% | 4.47% |
| 9 | 2.97% | - | - | - | - | - | - | - | - | - | 0.29% | 4.52% |
| 10 | 0.17% | - | - | - | - | - | - | - | - | - | 0.20% | 3.80% |
| 11 | - | - | - | - | - | - | - | - | - | - | - | 0.32% |
| 12 | - | - | - | - | - | - | - | - | - | - | 0.02% | - |
| 13 | - | - | - | - | - | - | - | - | - | - | - | - |
| 14 | - | - | - | - | - | - | - | - | - | - | - | - |
| 15 | - | - | - | - | - | - | - | - | - | - | - | - |
| 16 | - | - | - | - | - | - | - | 0.29% | - | - | - | - |
| 17 | - | - | - | - | - | - | - | 0.32% | - | - | - | 2.39% |
| 18 | 2.46% | - | - | - | - | - | - | 0.32% | 0.16% | - | - | 2.39% |
| 19 | 2.46% | - | - | - | - | - | - | 0.33% | 0.81% | - | - | 2.39% |
| 20 | 2.46% | - | - | - | - | - | - | 0.32% | - | - | - | 2.39% |
| 21 | 2.46% | - | - | - | - | - | - | 0.32% | - | - | - | 2.39% |
| 22 | 2.46% | - | - | - | - | - | - | 0.32% | - | - | - | 2.39% |
| 23 | 2.46% | - | - | - | - | - | - | 0.32% | - | - | - | 2.39% |
| 24 | 2.46% | - | - | - | - | - | - | 0.32% | - | - | - | 2.39% |

The month-hour averages of LOLH values were further allocated to specific days in each year to derive 8760 hourly values. This was done using a four-step process:

1. **Identify Number of Days per Year:** Staff determined that generation capacity value would be allocated to 18 days per year, representing the top 5% of days. In actual SERVM runs, the system is designed to achieve 0.1 LOLE per year, which means less than one day per year

experiences a loss-of-load event. Expanding the threshold to include more days spreads LOLH and reflects uncertainty in which specific days carry loss-of-load risk.

2. **Determine Number of Days per Month:** Staff used LOLE values to allocate the number of days with generation capacity value to each month. Using LOLE rather than LOLH to allocate days per month avoids biasing the allocation toward months with longer-duration loss-of-load events (i.e., more hours per event). The ratio between the month's total LOLE and the total LOLE for the year was used to allocate the days per year to days per month. For example, the total LOLE in 2027 was 0.009 and the total LOLE for September 2027 was 0.007 (0.007/0.009 ≈ 75%). For 18 days per year with capacity value, 14 days should be in September.
3. **Allocate to Months and Hours:** Staff used the normalized month-hour LOLH values to allocate generation capacity value to each month-hour. For example, the normalized LOLH for September hour 19 in 2027 is 10.1%, so 10.1% of the generation capacity value for 2027 should be allocated to September hour 19. However, this allocation could be spread across multiple days depending on the days per month. The allocation to days within a month is described in the next step.
4. **Identify Days within Month to allocate normalized LOLH:** Staff used SERVM energy prices to determine which specific days within a month would receive generation capacity value. All LOLH were allocated to weekdays, as SERVM results showed minimal reliability risk during weekends (Table 4-2). Days within each month were ranked by daily peak energy price, calculated as the average of the top 5 hours per day. The definition of a "day" is not necessarily the calendar period from hour 1 to hour 24. Instead, it is defined to capture the full span of loss-of-load hours. For example, for August 2041, LOLH appeared in hours 1–2 and hours 16–24. In SERVM results, a loss-of-load event begins at hour 16 on one day and extends to hour 2 on the following day. In such cases, a day is defined as the 24-hour window from hour 6 on one day to hour 5 on the next, so that the entire loss-of-load event falls within a single day. Days are then selected in descending order of peak energy price up to the required number of scarcity days per month. LOLH in each hour is allocated uniformly across all scarcity days.

***Table 4-2. % of LOLH in Weekdays vs Weekends***

| | Weekdays | Weekends |
|---|---|---|
| 2027 | 99.4% | 0.6% |
| 2031 | 96.9% | 3.1% |
| 2036 | 96.7% | 3.3% |
| 2041 | 99.4% | 0.6% |

### *4.5.1 Hourly allocation of GHG value*

In each hour, the annual GHG avoided cost is multiplied by a short-run marginal emissions factor (derived from SERVM as described in Section 2.4) to determine the hourly marginal GHG avoided costs. This represents the GHG value provided by a resource assuming a static emissions target for the electric sector. Because the marginal emissions factors are directly proportional to the price of energy, the hourly marginal GHG avoided costs exhibit the same general patterns throughout the year: across the horizon, hourly marginal GHG avoided costs tend to be lowest during daytime hours when the system is saturated with solar and highest during the evening and overnight periods when higher cost marginal resources must be operated to serve load.

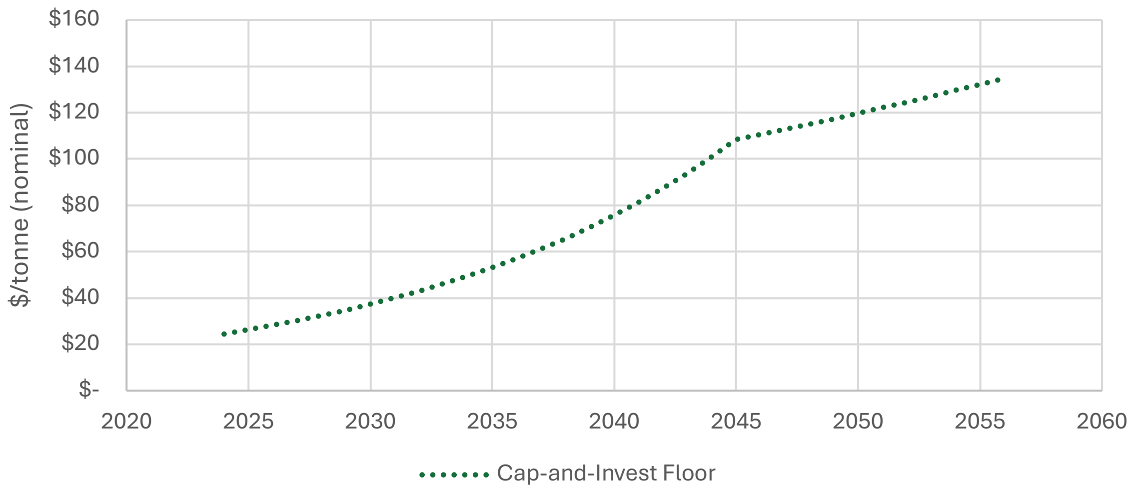
# 5. Avoided Cap-and-Invest Costs

California's Cap-and-Invest Program is one of the state’s key policies to reduce greenhouse gas (GHG) emissions and covers approximately 80 percent of statewide emissions.[8] The program is administered by the California Air Resources Board (CARB) pursuant to its authority under Assembly Bill 32, the California Global Warming Solutions Act of 2006, and was known as Cap-and-Trade prior to its renaming and extension under Assembly Bill 1207 in 2025. Compliance obligations under the program began in January 2013 and California linked its program with Québec’s in January 2014. Under the program’s market-based design, CARB sets a declining annual limit on emissions from covered sectors, issues a corresponding number of tradeable allowances (each equal to one metric ton of CO2-equivalent), and requires covered entities to surrender allowances sufficient to cover their annual emissions. Covered entities obtain allowances through free allocation, quarterly auction, or secondary-market trading. The program employs two principal cost-containment mechanisms to bound allowance prices within a predictable range: the Auction Reserve Price (i.e., Cap-and-Invest floor price), a minimum bid price below which allowances will not be sold at auction, and the Allowance Price Containment Reserve, a two-tiered mechanism under which CARB releases additional allowances into the market if prices rise to specified upper thresholds, currently set at $65.31 and $83.92 per allowance in 2026.[9] The Auction Reserve Price increases annually by 5 percent plus inflation, as measured by the Consumer Price Index, resulting in a 2026 floor of $27.94 per allowance.[10] Auction prices have traded at or near the floor price for the last two years.[11]

[8] California Air Resources Board, “FAQ Cap-and-Trade Program,” https://ww2.arb.ca.gov/resources/documents/faq-cap-and-trade-program.
[9] California Air Resources Board, “2026 Annual Allowance Price Containment Reserve Notice,” https://ww2.arb.ca.gov/sites/default/files/2025-12/nc-2026_reserve_sale_apcr_notice.pdf.
[10] California Air Resources Board, “2026 Annual Auction Reserve Price Notice,” https://ww2.arb.ca.gov/sites/default/files/2025-12/nc-2026_annual_reserve_price_notice_joint_auction.pdf.
[11] California Air Resources Board, “Summary of California-Quebec Joint Auction Settlement Prices and Results,” https://ww2.arb.ca.gov/sites/default/files/2020-08/results_summary.pdf.

In the 2026 ACC, the Cap-and-Invest floor price forecast is based on the "Low" trajectory from the California Energy Demand 2022 Update GHG Allowance Price Projections.[12]

***Figure 5-1. Cap-and-Invest Prices, 2024-2056***




## 6. Transmission Capacity Avoided Costs

Transmission capacity avoided costs reflect potential reductions in the total cost of investments required to meet peak loads on the transmission system. These avoided costs are calculated under the paradigm that by reducing peak loads, measures such as customer demand reduction, distributed generation, storage, or load flexibility may defer or avoid the need for certain transmission system investments.

The avoided cost calculator uses marginal transmission capacity costs as a proxy for avoided costs. The values developed herein represent the value which may be provided *if* the peak load reductions can be obtained in the right amount, with sufficient dependability, in transmission-constrained locations, and within the necessary timing windows while meeting any other operational needs of the system. The practical ability to defer or avoid transmission projects and realize avoided transmission costs depends on several additional factors, which the avoided cost calculator does not seek to address. For example, transmission system operators require the ability to obtain a sufficient magnitude of dependable aggregate peak reductions in the right locations on the transmission system and with sufficient advance notice to allow for prudent deferral or avoidance of a transmission infrastructure investment. This avoided cost calculation neither evaluates these elements, nor determines whether any particular technology, measure, or installation can provide

[12] California Public Utilities Commission, "2024-2026 Integrated Resource Planning Inputs & Assumptions," https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2024-2026-irp-cycle-events-and-materials/2025_inputs_and_assumptions_report_20260210.pdf.

transmission cost savings. Those determinations should be made in the proceedings in which the avoided costs are applied.

It should also be noted that transmission system needs and resulting transmission value will vary by location and may shift over time as system loads and other infrastructure concerns evolve differently in different areas of utility service territories. For example, over the next ten years Location A may face severe transmission capacity constraints and thus present a high potential value for reducing load, while Location B has little to no transmission capacity constraints and little value for load reductions. In the following 10 years that situation could reverse such that Location A no longer has need for load reductions and Location B could see greater benefit from such. Given this locational and temporal uncertainty, the transmission avoided capacity costs presented in the avoided cost calculator represent a simple average systemwide value for each utility. While this may underestimate the value of net load reductions in some areas and overestimate others, this provides a broadly applicable estimate of avoided costs without seeking to assign overly precise results to forecasts looking far into the future.

Transmission capacity avoided costs calculations for the 2026 ACC maintain the same general principles and approach as prescribed in the 2019 T&D whitepaper and applied in recent ACC cycles. Two methodological updates are made in this cycle which respectively seek to:

1) Bring the specific calculations used for determining SCE's marginal cost into closer alignment with the other utilities; and
2) Adjust hourly allocation of transmission value in future years to better reflect future system needs.

Other changes to the transmission values follow from updated utility data from recent transmission planning processes and GRC filings. For PG&E, the transmission avoided cost value remains unchanged from the 2022 and 2024 ACC cycles except for adjustments to account for inflation.[13]

## 6.1 Long-Term Transmission Marginal Costs

Transmission avoided costs are calculated on a $/kW-year basis according to the marginal cost of each utility's capacity-related transmission investments and the value of deferring those investments by a single year. In recent ACC cycles, two different methods for calculating this deferral value have been applied across utilities: the Discounted Total Investment Method (DTIM) and the Locational Net Benefits Analysis (LNBA) method. Both methods have the same general purpose and follow a similar set of steps, with some nuanced differences. The DTIM is well-suited for estimating systemwide average transmission avoided costs by aggregating the costs of multiple investments and the capacity needs served by those investments and then calculating the value of deferring these collective investments by a single year. The LNBA method, as the name suggests, calculates location or project-specific transmission avoided costs and looks at inputs for each project individually.

[13] Though marginal transmission costs for PG&E are normally calculated in its GRC filings and applied using a Discounted Total Investment Method, the most recently approved values remain those adopted by the CPUC in ruling D.21-11-016.

In the 2026 ACC, transmission avoided costs for all utilities are calculated using only the DTIM method.[14] This improves consistency in treatment across projects and utilities and also reduces some volatility for the transmission value related to the lumpiness of transmission investments and selection of which projects may be singled out.[15] Resulting avoided costs for each utility are presented in Table 6-1. Further detail on the transmission avoided cost inputs and calculations can be found in Appendix 0In previous ACC cycles, the DTIM has been applied across all three utilities while the LNBA method has also been applied on a limited basis for SCE alone. Because SCE has supplied broken-out costs for individual large projects alongside other systemwide transmission investments, the LNBA method was used to calculate costs separately for those large projects rather than treating them like the rest of the SCE investments and folding them into the DTIM. However, given that the avoided cost calculator has produced a single average transmission avoided cost value for each utility, the avoided costs determined from those LNBA calculations were then spread across the full system and added to the avoided costs for other systemwide investments calculated using the DTIM.

***Table 6-1. Transmission Avoided Costs (2025 $)***

| | PG&E | SCE | SDG&E |
|---|---|---|---|
| Transmission Capacity ($/kW-yr) | $53.98 | $22.03 | $62.74 |
| Change from 2024 ACC (%) | 0% | -58% | +33% |

Note that while SCE's avoided transmission values have decreased significantly from the 2024 ACC, this large decrease is not due to the change in methodology but rather stems from removing a single large transmission project from consideration per SCE's input that the project is not in fact capacity related and should not have previously been provided to the consultant for inclusion in the 2024 ACC. This update brings SCE's costs more in line with the values from the 2022 ACC, before the additional transmission project was included.

## 6.2 Annual Transmission Marginal Capacity Costs

The transmission capacity marginal costs are escalated to nominal dollars for future years in the modeling horizon using annual transmission escalation rates used by the utilities in their planning and provided in response to Energy Division data requests. The escalation rates applied in the 2026 ACC are provided in Table 6-2. The utilities have noted that escalation rates used in transmission planning may vary annually or by project based upon the forecast conducted during project planning. The values in the table are an average across years in the near-term transmission planning horizon.

[14] This applies to PG&E only in theory at the moment, given that values provided by the utility have yet to be updated since those adopted by the Commission in ruling D.21-11-016

[15] See discussion in the 2022 and 2024 ACC documentation and workshops regarding concerns around the lumpiness of transmission investments and modifications made to the DTIM in those cycles to help address this issue. Additional

***Table 6-2. Transmission Escalation Rates (Nominal %)***

| PG&E | SCE | SDG&E |
|---|---|---|
| 0.72% | 2.33% | 1.27% |

Table 6-3 provides the annual transmission capacity avoided costs resulting from this escalation.

***Table 6-3. Annual Transmission Marginal Capacity Costs ($ Nominal)***

| Annual Values by IOU ($/kW-yr) | | | |
|---|---|---|---|
| Year | PG&E | SCE | SDG&E |
| 2026 | *$54.37* | *$22.55* | *$63.54* |
| 2027 | *$54.76* | *$23.07* | *$64.34* |
| 2028 | *$55.15* | *$23.61* | *$65.16* |
| 2029 | *$55.55* | *$24.16* | *$65.98* |
| 2030 | *$55.95* | *$24.72* | *$66.82* |
| 2031 | *$56.35* | *$25.30* | *$67.66* |
| 2032 | *$56.76* | *$25.89* | *$68.52* |
| 2033 | *$57.17* | *$26.49* | *$69.39* |
| 2034 | *$57.58* | *$27.11* | *$70.27* |
| 2035 | *$57.99* | *$27.74* | *$71.16* |
| 2036 | *$58.41* | *$28.39* | *$72.06* |
| 2037 | *$58.83* | *$29.05* | *$72.97* |
| 2038 | *$59.25* | *$29.72* | *$73.90* |
| 2039 | *$59.68* | *$30.42* | *$74.83* |
| 2040 | *$60.11* | *$31.13* | *$75.78* |
| 2041 | *$60.54* | *$31.85* | *$76.74* |
| 2042 | *$60.98* | *$32.59* | *$77.71* |
| 2043 | *$61.42* | *$33.35* | *$78.70* |
| 2044 | *$61.86* | *$34.13* | *$79.69* |
| 2045 | *$62.30* | *$34.92* | *$80.70* |
| 2046 | *$62.75* | *$35.74* | *$81.73* |
| 2047 | *$63.21* | *$36.57* | *$82.76* |
| 2048 | *$63.66* | *$37.42* | *$83.81* |
| 2049 | *$64.12* | *$38.30* | *$84.87* |
| 2050 | *$64.58* | *$39.19* | *$85.95* |
| 2051 | *$65.05* | *$40.10* | *$87.03* |
| 2052 | *$65.51* | *$41.04* | *$88.14* |
| 2053 | *$65.99* | *$41.99* | *$89.25* |
| 2054 | *$66.46* | *$42.97* | *$90.38* |
| 2055 | *$66.94* | *$43.97* | *$91.53* |

## 6.3 Hourly Allocation of Transmission Capacity Avoided Costs

The annual capacity costs shown in Table 6-3 are allocated to individual hours of the year to reflect the time-varying need for transmission capacity. The peak capacity allocation (PCAF) method used to estimate distribution allocation factors in the prior ACC updates has been applied to the utility system-level hourly loads to estimate the transmission hourly allocation factors. The PCAF method allocates capacity costs to the hours of highest load (net of behind-the-meter generation) on each utility's system. These highest load hours are selected with the expectation that they are when transmission capacity constraints are likely to occur and trigger the need for further investment. The PCAF is calculated as:

$$\mathbf{PCAF}_{a,h} = \frac{(\mathbf{Load}_{a,h} - \mathbf{Threshold}_{a})}{\mathbf{Sum\ of\ all\ positive}\ (\mathbf{Load}_{a,h} - \mathbf{Threshold}_{a})}$$

*Where*:

a is the utility,

h is hour of the year,

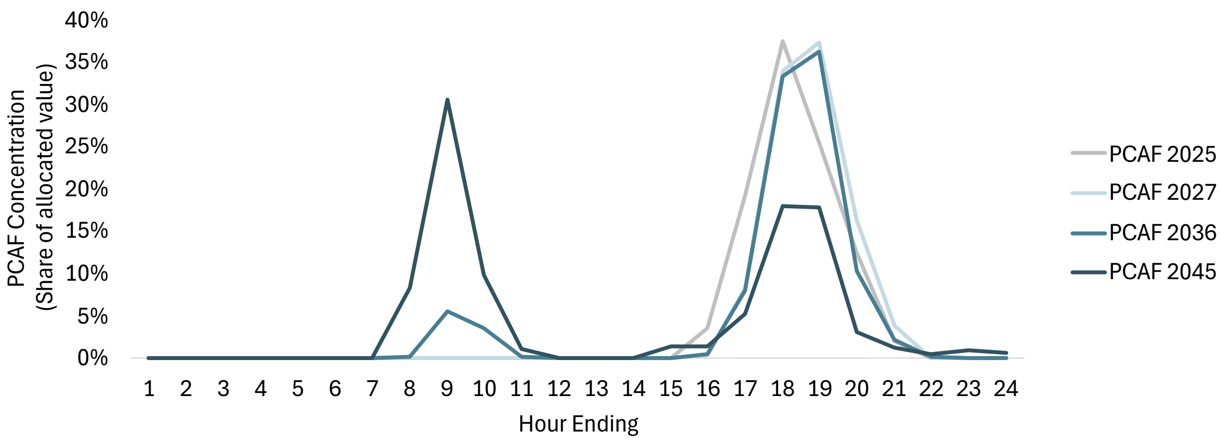
Load is the net utility load on the grid, and

Threshold is the utility maximum demand less one standard deviation, or the closest value that satisfies the constraint of between 100 and 250 hours with loads above the threshold.

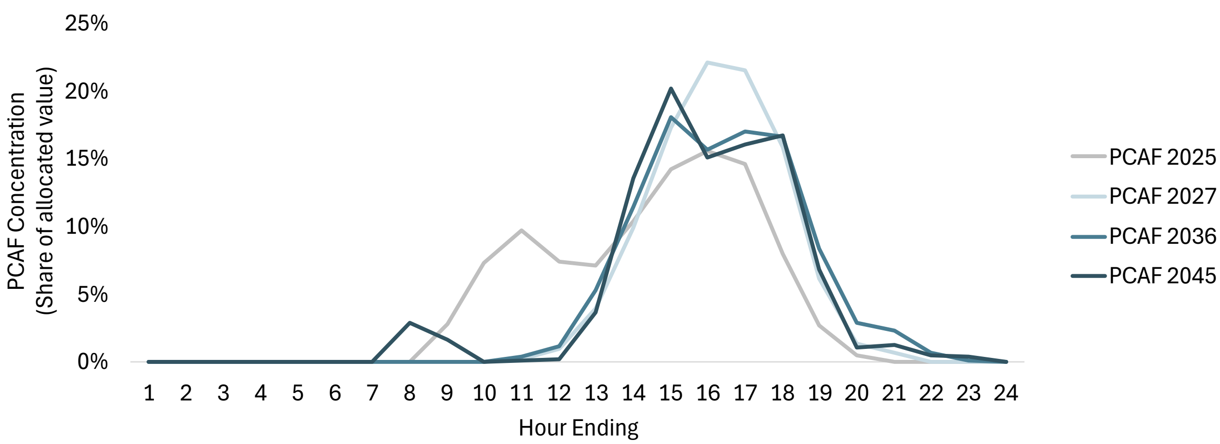
For the 2026 ACC, an additional modification has been made to have transmission hourly allocation factors change in future years to reflect the shifting timing of system needs. Consistent with prior ACCs, historical 2025 system loads from the CAISO Energy Management System dataset were used to set hourly allocation factors for the beginning of the modeling horizon (year 2026).[16] CAISO hourly loads were realigned to create an 8760 load profile matching the weather year of the 2026 ACC. Appendix A.5. provides further detail on how weather remapping is applied. New in the 2026 ACC, distinct PCAFs are calculated for 2027, 2031, 2036, 2041, and 2045. PCAFs from each listed year were also applied to the following intermediate years. These PCAFs are calculated based on, forecasted utility system loads (net of behind-the-meter generation) from the same SERVM modeling used in the ACC energy and integrated calculation. Because the SERVM load data is already aligned with the ACC weather year, no weather year adjustment is required for these future year PCAFs. The hourly allocation factors are multiplied by the annual transmission capacity marginal costs to determine the hourly transmission avoided costs within each year. Figure 6-1 through Figure 6-3 illustrate the shape of these PCAFs across utilities between 2025 and 2045.

[16] CAISO Historical EMS Load Data can be found here: http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx#Historical

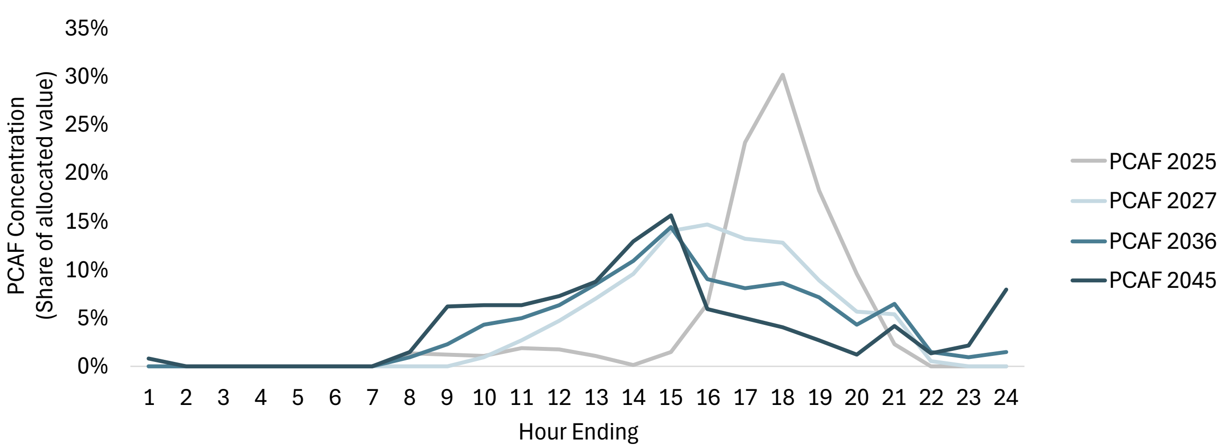
### *Figure 6-1. PG&E Transmission PCAFs Over Time*




### *Figure 6-2. SCE Transmission PCAFs Over Time*



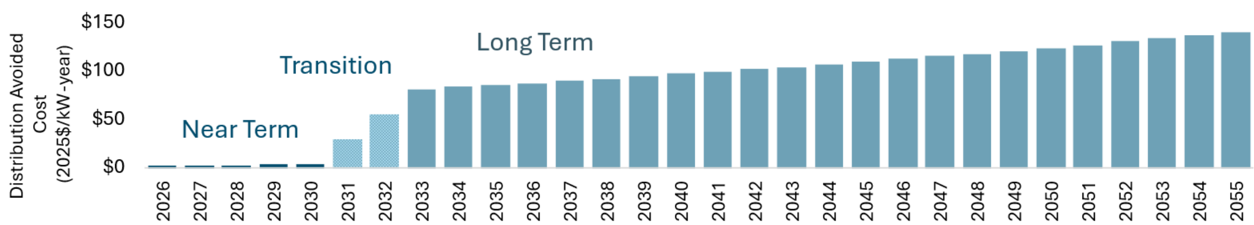

### *Figure 6-3. SDG&E Transmission PCAFs Over Time*



# 7. Distribution Capacity Avoided Costs

Distribution avoided costs follow the same paradigm as transmission avoided costs and represent the potential value of deferring or avoiding investments in electric distribution system infrastructure through reductions in distribution peak capacity needs. The Distribution Resources Plan (DRP) proceeding 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[17] defines two types of avoided costs, specified and unspecified, and proposed to leverage information from utility DDOR (now replaced with the Distribution Upgrade Project Report, or DUPR) and GNA filings that contain detailed information about utility needs and investment plans. The avoided cost calculator leverages information from those reports plus distribution cost escalation rates provided by the utilities to estimate near-term distribution marginal costs for unspecified deferral for years one through five of the forecast. Beginning in year eight, long-term distribution avoided costs are determined by the marginal distribution cost values adopted in utility GRC filings. Avoided cost values in years six and seven transition linearly between the two data sources. Figure 7-1 below illustrates this method at a high level.

***Figure 7-1. Distribution Avoided Cost Transition***




The 2026 ACC update recalculates the avoided distribution capacity costs using the above approach and the same methodology as the 2024 ACC update, with updated input data from utilities' GNA, DUPR, and GRC filings and responses to Energy Division data requests.

As with transmission avoided costs, the avoided cost calculator utilizes marginal distribution capacity costs as a proxy for the costs that could be avoided by DERs if certain planning and operating needs are met. It does not evaluate whether any particular measure is able to meet those conditions. Distribution avoided costs are assigned a further degree of locational granularity in the hourly allocation process by evaluating the timing of system needs at a climate zone level within each utility service territory and assigning hourly value according to that basis.

[17] 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

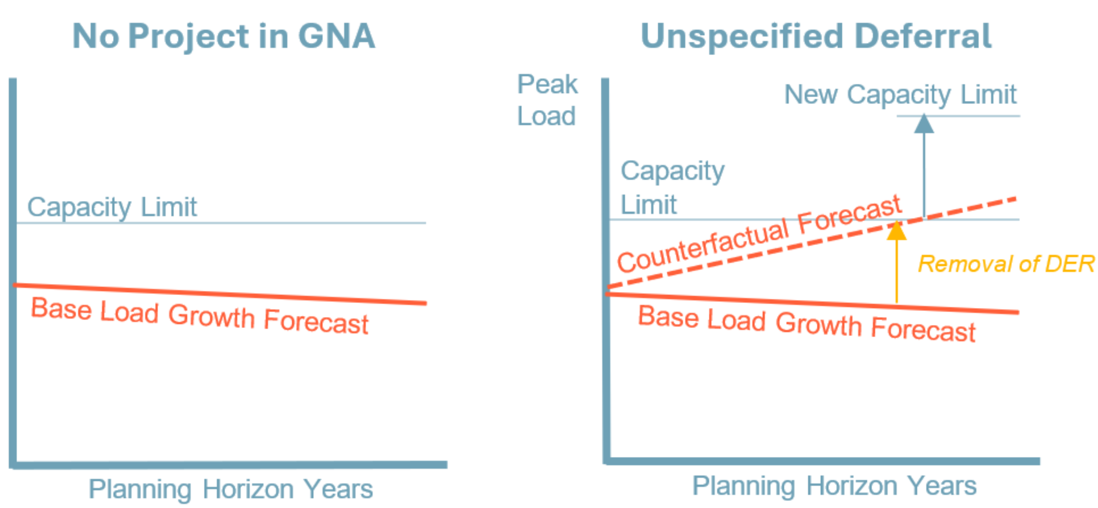
## 7.1 Near-term Distribution Marginal Costs from Distribution Planning

The utilities previously calculated distribution avoided costs as part of the annual DDOR process. These avoided costs were 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 represented 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 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 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. Instead, 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 DERs. 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 7-2, 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.

***Figure 7-2. Projected Need from Counterfactual Forecast***




The challenge with estimating 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 does not currently accommodate the geographic specificity required for 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, the consultant implemented the method put forth in the T&D White Paper:[18]

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:** Identify all circuits that exceed the facility rating in any year of the counterfactual forecast and determine the associated capacity of overload. In the T&D White Paper, this step also identifies projects that *would* have occurred in the planning forecast and excludes those projects from those considered DER-deferrable. This is done to focus on the marginal investment that DERs would defer or avoid, rather than the marginal investments that DERs may not be able to and are not expected to avoid. In prior ACC updates, this exclusion step was omitted in performing the final marginal cost calculations.
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 DUPR. 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.
4. **Calculate the average marginal cost of the deferred distribution upgrades:** The average DUPR marginal cost is the deficiency-weighted average of the DUPR avoided distribution costs for all avoided projects, i.e. the sum over all projects in the DUPR filing of: the DUPR avoided distribution cost ($/kW-yr.) for each project multiplied by the ratio of its total deficiency need over the planning horizon to the total deficiency need for all DDOR projects.
5. **Calculate system-level avoided costs:** Multiply the average DUPR 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 the forecasted level of DERs for all areas (not just DUPR areas) to obtain a single, system-level distribution deferral value in $/kW-yr.

This method essentially uses the utilities' GNA planned case to indicate the unit cost to add distribution capacity. A counterfactual forecast, which 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[19] as each utilities' 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

[18] 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

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

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 administrative & general (A&G) and O&M expenses. 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, 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 DERs with load reductions persisting past year five.

The 2024 ACC update refined the near-term distribution avoided cost methodology to separate out the differences in impacts at locations where DERs primarily increase load or decrease load ("load increasing DERs" vs load decreasing DERs"). While a single distribution avoided cost is still calculated by averaging these values, this refinement improves the suitability of the calculations for the present day situation where DERs can increase as well as decrease peak loads and mitigates the issue of artificially inflating avoided cost value at locations where DERs are effectively competing against each other to incur or avoid the need for distribution system investments. These changes are further detailed in the 2024 ACC documentation and have been maintained in the 2026 ACC.[20]

Two bug fixes were also applied in the 2026 ACC calculations. The first was to prevent unintentional double counting of DERs that show up multiple times in the DUPR data (for instance at both the feeder level and then again at the feeder bank level) in Step 5 of the calculation described above. The second was a minor fix to ensure that the deficiencies at each facility are calculated according to the rated capacity of the facility in each year, rather than the rated capacity at the beginning of the horizon.

Near term distribution avoided cost values based on the updated input data for 2026 are provided in Table 7-1. Further detail on calculations for the distribution avoided costs is provided in Appendix A.4.

***Table 7-1. Near-Term Avoided Distribution Costs (2025$)***

| | PG&E | SCE | SDG&E |
|---|---|---|---|
| Unspecified Distribution Capacity ($/kW-yr) | $2.76 | $1.21 | $2.53 |

[20] 2024 Distributed Energy Resources Avoided Cost Calculator Documentation. Energy and Environmental Economics, Prepared for the CPUC. October 2024. https://www.ethree.com/wp-content/uploads/2025/02/2024-ACC-Documentation-v1b_clean.pdf

## 7.2 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.[21] 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 an approximate three-year cycle. However, the GRC marginal costs might not be completely appropriate for use in DER cost effectiveness evaluations. As with the values calculated for near-term marginal costs, GRC marginal costs are not location-specific and can include cost categories that are not necessarily avoidable. 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. The most recent adopted values, escalated to 2025$, are presented in Table 7-2. The following subsections provide detail on the sources for these costs.

*Table 7-2. Long-term Distribution Marginal Costs*

| Utility | PG&E | SCE | SDG&E |
|---|---|---|---|
| Climate Zone | (simple Average) | All | All |
| Long Term Distribution Capacity Cost ($/kW-yr) | $ 60.19 | $ 210.38 | $ 94.47 |

### 7.2.1 GRC Data Hierarchy

In selecting data to use for the long term avoided costs, the ACC relies on 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.

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

### *7.2.2 Distribution Marginal Costs from Most Recently Completed Proceedings*

***PG&E***

PG&E confirmed that the marginal distribution capacity cost values from the 2022 ACC, adopted in Decision 21-11-016,[22] remain valid and the most appropriate data for use in the 2026 ACC update. Data is expressed in $/PCAF-kW-yr. and $/FLT-kW-yr. PCAFs are hourly allocation factors used by PG&E to calculate the relative need for distribution capacity across the year. The PCAF-KW are the PCAF-weighted coincident peak demands on primary capacity equipment. The FLT-kW are the peaks on the final line transformers and represent a more non-coincident measure of peak demand on the secondary equipment. To make the two marginal costs compatible, secondary costs are converted from $/FLT-kW-yr. to $/PCAF-kW-yr. based on the ratio of FLT-kW to PCAF-kW in the same utility division. The PCAF and FLT Loads used for converting secondary cost to $/PCAF-kW-yr and weighting climate zones come from PG&E's settlement agreement in the utility's 2017 Phase II General Rate Case (GRC) proceeding. These latter values and the source data were previously outlined in the 2021 ACC and are re-used for consistent weighting. Table 7-3 shows the inputs and calculations for this process.

***Table 7-3. PG&E Long-Term Distribution Capacity Costs by Division (Base Year 2021)***

| | | [A] | [B] | [C] | [D] | [E] | [F] |
|---|---|---|---|---|---|---|---|
| Division | Climate Zone | Primary Projects Total $/PCAF-KW-YR | Secondary Distribution $/FLT-KW-YR | Total PCAF Loads PCAF kW | Total FLT Loads FLT kW | Secondary Cost [B*D/C] $/PCAF-KW-YR | Total Distribution Capacity Cost [A+E] $/PCAF-KW-YR |
| CENTRAL COAST | 4 | $42.51 | $1.66 | 823,510 | 1,759,256 | $3.54 | $46.05 |
| DE ANZA | 4 | $44.84 | $2.20 | 741,675 | 1,234,311 | $3.66 | $48.51 |
| DIABLO | 12 | $69.63 | $2.68 | 1,265,169 | 1,524,487 | $3.22 | $72.85 |
| EAST BAY | 3A | $40.86 | $1.84 | 627,862 | 1,338,170 | $3.92 | $44.78 |
| FRESNO | 13 | $48.47 | $2.01 | 2,164,629 | 3,575,125 | $3.31 | $51.78 |
| HUMBOLDT | 1 | $43.54 | $1.40 | 292,803 | 736,437 | $3.53 | $47.06 |
| KERN | 13 | $51.00 | $2.20 | 1,585,454 | 2,449,767 | $3.40 | $54.40 |
| LOS PADRES | 5 | $63.38 | $1.82 | 492,381 | 1,041,742 | $3.85 | $67.22 |
| MISSION | 3B | $43.83 | $2.23 | 1,233,354 | 2,022,915 | $3.65 | $47.48 |
| NORTH BAY | 2 | $52.95 | $2.06 | 647,540 | 1,283,383 | $4.08 | $57.03 |
| NORTH VALLEY | 16 | $63.36 | $1.73 | 742,213 | 1,324,624 | $3.08 | $66.44 |
| PENINSULA | 3A | $48.18 | $2.02 | 766,475 | 1,436,434 | $3.78 | $51.96 |
| SACRAMENTO | 11 | $46.65 | $2.23 | 970,943 | 1,589,591 | $3.66 | $50.30 |
| SAN FRANCISCO | 3A | $48.93 | $2.36 | 829,544 | 1,435,075 | $4.08 | $53.01 |
| SAN JOSE | 4 | $46.29 | $2.45 | 1,369,868 | 2,130,431 | $3.81 | $50.10 |
| SIERRA | 11 | $43.89 | $1.88 | 1,187,910 | 1,833,534 | $2.90 | $46.79 |
| SONOMA | 2 | $43.15 | $1.84 | 544,454 | 1,147,401 | $3.87 | $47.01 |
| STOCKTON | 12 | $44.06 | $1.99 | 1,207,506 | 2,114,747 | $3.48 | $47.54 |
| YOSEMITE | 13 | $67.14 | $1.85 | 1,090,280 | 2,098,437 | $3.56 | $70.70 |

*Columns A and B provided as updated values by PG&E for the 2022 ACC*
*Columns C and D from PG&E 2017 GRC Phase II to maintain same climate zone weighting as the 2021 ACC*

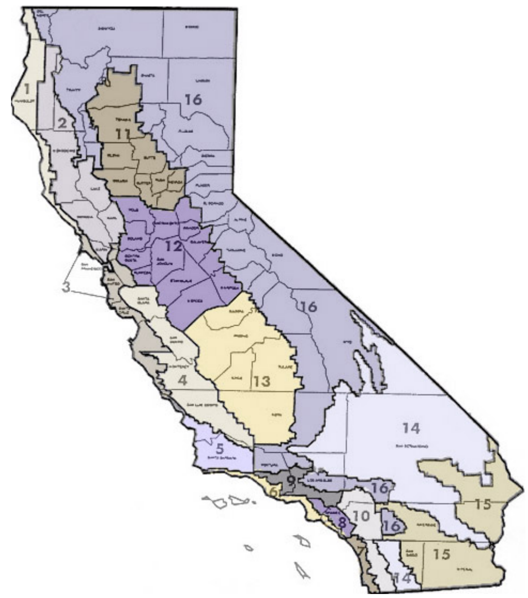
Finally, the division-level avoided costs are converted into climate zone values. If a climate zone encompasses more than one Operating Division, then the weighted average value is calculated using the 2017 PCAF kW in each Operating Division. The PG&E long-term distribution marginal

[22] DECISION ADOPTING MARGINAL COSTS, REVENUE ALLOCATION, AND RATE DESIGNS FOR PACIFIC GAS AND ELECTRIC https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M424/K378/424378035.PDF

capacity costs by climate zone are summarized below. Climate Zone 3A is the western portion of Climate Zone 3, comprised of San Francisco and neighboring cities in the Bay Area, while Climate Zone 3B represents the remainder of Climate Zone 3.

***Table 7-4. PG&E Distribution Marginal Capacity Costs by Climate Zone (2025$)***

| Dollar year | 2021 | 2025 |
|---|---|---|
| **Climate Zone** | **Weighted Avg Capacity Cost (Capacity cost weighted by PCAF loads)** | |
| | **$/PCAF-KW-YR** | **$/PCAF-KW-YR** |
| 1 | 47.06 | 51.95 |
| 2 | 52.46 | 57.90 |
| 3A | 50.32 | 55.55 |
| 3B | 47.48 | 52.41 |
| 4 | 48.56 | 53.60 |
| 5 | 67.22 | 74.20 |
| 11 | 48.37 | 53.39 |
| 12 | 60.49 | 66.77 |
| 13 | 56.90 | 62.81 |
| 16 | 66.44 | 73.34 |




### *SCE*

SCE's long-term distribution marginal capacity costs were most recently updated in the 2025 GRC Phase II proceeding. SCE develops marginal costs as four separate components, including substation and circuit costs at both the distribution and subtransmission level. These are combined for the total long-run distribution marginal capacity cost. These values and the total from the 2025 GRC are presented in Table 7-5.

***Table 7-5. SCE Distribution Marginal Capacity Costs by Component from the SCE 2025 GRC Phase II (2025$)***

| Cost Components | | |
|---|---|---|
| Substation ($/kW-yr) | Distribution | $25.27 |
| | Subtransmission | $45.50 |
| Circuit ($/kW-yr) | Distribution | $122.50 |
| | Subtransmission | $17.11 |
| **Total** | | **$210.38** |

### *SDG&E*

SDG&E's long-term distribution marginal capacity costs were most recently updated in SDG&E's 2024 GRC Phase II proceeding. SDG&E develops marginal costs at both the substation and local level, which are combined for the total long-run distribution marginal capacity cost. Table 7-6 presents SDG&E's values from the 2024 GRC as well as the values escalated to 2025$ according to SDG&E-provided distribution cost escalation rate.

***Table 7-6. SDG&E Distribution Marginal Capacity Costs from the SDG&E 2024 GRC Phase II (2024$ and 2025$)***

| Dollar year | 2024 | 2025 |
|---|---|---|
| **SDG&E Marginal Distribution Capacity Costs** | | |
| Feeders and Local Distribution Demand Costs ($/kW-yr) | $ 61.48 | $ 62.96 |
| Substation Distribution Demand Costs ($/kW-yr) | $ 30.76 | $ 31.50 |
| Total | $ 92.24 | $ 94.47 |

## 7.3 Annual Distribution Capacity Costs

The distribution capacity marginal costs are escalated to nominal dollars for future years in the modeling horizon using annual transmission escalation rates used by the utilities in their planning and provided in response to Energy Division data requests. The escalation rates applied in the 2026 ACC are provided in Table 7-7.

***Table 7-7. Distribution Escalation Rates***

| | PG&E | SCE | SDG&E |
|---|---|---|---|
| Annual Distribution Escalation Rate (%/yr) | 2.5% | 2.33% | 2.41% |

Table 7-8 provides the annual distribution capacity avoided costs resulting from this escalation.

### *Table 7-8. Annual Distribution Capacity Avoided Costs ($/kW-yr) (Nominal $)*

| Annual Values by IOU and Climate Zone ($/kW-yr) | | PG&E | | | | | | | | | | SCE | SDG&E |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Climate Zone: | CZ1 | CZ2 | CZ3A | CZ3B | CZ4 | CZ5 | CZ11 | CZ12 | CZ13 | CZ16 | All | All |
| 2026 | Near Term | $2.83 | $2.83 | $2.83 | $2.83 | $2.83 | $2.83 | $2.83 | $2.83 | $2.83 | $2.83 | $11.47 | $2.59 |
| 2027 | Near Term | $2.90 | $2.90 | $2.90 | $2.90 | $2.90 | $2.90 | $2.90 | $2.90 | $2.90 | $2.90 | $11.74 | $2.65 |
| 2028 | Near Term | $2.98 | $2.98 | $2.98 | $2.98 | $2.98 | $2.98 | $2.98 | $2.98 | $2.98 | $2.98 | $12.01 | $2.72 |
| 2029 | Near Term | $3.05 | $3.05 | $3.05 | $3.05 | $3.05 | $3.05 | $3.05 | $3.05 | $3.05 | $3.05 | $12.29 | $2.78 |
| 2030 | Near Term | $3.13 | $3.13 | $3.13 | $3.13 | $3.13 | $3.13 | $3.13 | $3.13 | $3.13 | $3.13 | $12.58 | $2.85 |
| 2031 | Transition | $23.18 | $25.60 | $24.64 | $23.37 | $23.85 | $32.22 | $23.77 | $29.20 | $27.59 | $31.87 | $92.70 | $40.01 |
| 2032 | Transition | $43.24 | $48.07 | $46.16 | $43.61 | $44.58 | $61.32 | $44.41 | $55.28 | $52.06 | $60.61 | $172.82 | $77.17 |
| 2033 | Long Term | $63.29 | $70.55 | $67.68 | $63.86 | $65.31 | $90.41 | $65.05 | $81.36 | $76.53 | $89.35 | $252.95 | $114.33 |
| 2034 | Long Term | $64.88 | $72.31 | $69.37 | $65.45 | $66.94 | $92.67 | $66.67 | $83.39 | $78.44 | $91.59 | $258.84 | $117.09 |
| 2035 | Long Term | $66.50 | $74.12 | $71.11 | $67.09 | $68.61 | $94.99 | $68.34 | $85.48 | $80.40 | $93.88 | $264.87 | $119.91 |
| 2036 | Long Term | $68.16 | $75.97 | $72.88 | $68.77 | $70.33 | $97.36 | $70.05 | $87.61 | $82.41 | $96.22 | $271.04 | $122.81 |
| 2037 | Long Term | $69.87 | $77.87 | $74.71 | $70.49 | $72.09 | $99.80 | $71.80 | $89.80 | $84.47 | $98.63 | $277.36 | $125.77 |
| 2038 | Long Term | $71.61 | $79.82 | $76.57 | $72.25 | $73.89 | $102.29 | $73.60 | $92.05 | $86.58 | $101.10 | $283.82 | $128.81 |
| 2039 | Long Term | $73.40 | $81.81 | $78.49 | $74.05 | $75.74 | $104.85 | $75.44 | $94.35 | $88.75 | $103.62 | $290.43 | $131.92 |
| 2040 | Long Term | $75.24 | $83.86 | $80.45 | $75.91 | $77.63 | $107.47 | $77.32 | $96.71 | $90.96 | $106.21 | $297.20 | $135.10 |
| 2041 | Long Term | $77.12 | $85.96 | $82.46 | $77.80 | $79.57 | $110.16 | $79.26 | $99.13 | $93.24 | $108.87 | $304.12 | $138.37 |
| 2042 | Long Term | $79.05 | $88.11 | $84.52 | $79.75 | $81.56 | $112.91 | $81.24 | $101.61 | $95.57 | $111.59 | $311.21 | $141.71 |
| 2043 | Long Term | $81.02 | $90.31 | $86.64 | $81.74 | $83.60 | $115.73 | $83.27 | $104.15 | $97.96 | $114.38 | $318.46 | $145.13 |
| 2044 | Long Term | $83.05 | $92.57 | $88.80 | $83.79 | $85.69 | $118.63 | $85.35 | $106.75 | $100.41 | $117.24 | $325.88 | $148.63 |
| 2045 | Long Term | $85.12 | $94.88 | $91.02 | $85.88 | $87.83 | $121.59 | $87.48 | $109.42 | $102.92 | $120.17 | $333.48 | $152.22 |
| 2046 | Long Term | $87.25 | $97.25 | $93.30 | $88.03 | $90.03 | $124.63 | $89.67 | $112.15 | $105.49 | $123.18 | $341.25 | $155.89 |
| 2047 | Long Term | $89.43 | $99.68 | $95.63 | $90.23 | $92.28 | $127.75 | $91.91 | $114.96 | $108.13 | $126.25 | $349.20 | $159.66 |
| 2048 | Long Term | $91.67 | $102.18 | $98.02 | $92.48 | $94.59 | $130.94 | $94.21 | $117.83 | $110.83 | $129.41 | $357.33 | $163.51 |
| 2049 | Long Term | $93.96 | $104.73 | $100.47 | $94.80 | $96.95 | $134.21 | $96.56 | $120.78 | $113.60 | $132.65 | $365.66 | $167.46 |
| 2050 | Long Term | $96.31 | $107.35 | $102.98 | $97.17 | $99.37 | $137.57 | $98.98 | $123.80 | $116.44 | $135.96 | $374.18 | $171.50 |
| 2051 | Long Term | $98.72 | $110.03 | $105.56 | $99.59 | $101.86 | $141.01 | $101.45 | $126.89 | $119.35 | $139.36 | $382.90 | $175.64 |
| 2052 | Long Term | $101.19 | $112.78 | $108.20 | $102.08 | $104.40 | $144.53 | $103.99 | $130.06 | $122.34 | $142.85 | $391.82 | $179.88 |
| 2053 | Long Term | $103.72 | $115.60 | $110.90 | $104.64 | $107.02 | $148.15 | $106.59 | $133.31 | $125.40 | $146.42 | $400.95 | $184.22 |
| 2054 | Long Term | $106.31 | $118.49 | $113.68 | $107.25 | $109.69 | $151.85 | $109.25 | $136.65 | $128.53 | $150.08 | $410.29 | $188.67 |
| 2055 | Long Term | $108.97 | $121.45 | $116.52 | $109.93 | $112.43 | $155.65 | $111.99 | $140.06 | $131.74 | $153.83 | $419.85 | $193.22 |

## 7.4 Hourly Allocation of Distribution Capacity Avoided Costs

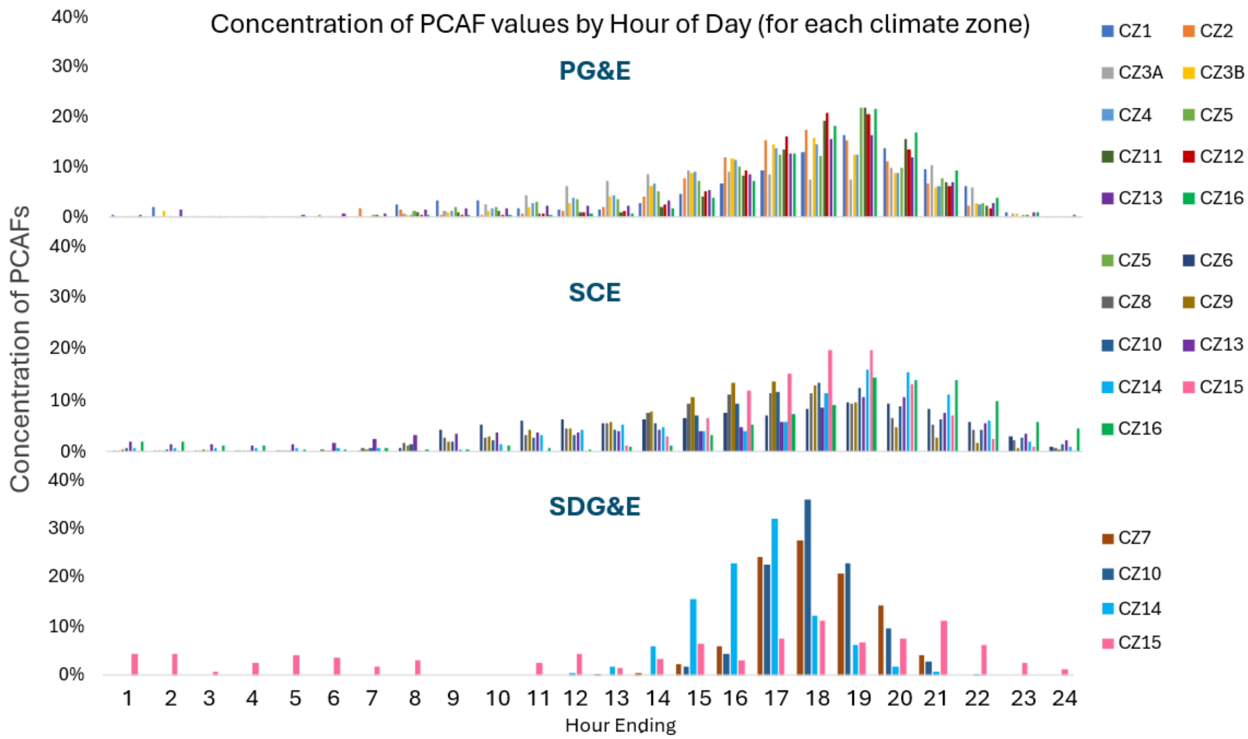
The annual distribution capacity costs are allocated to hours of the year to allow the ACC to reflect the time varying need for distribution capacity. For distribution avoided costs, these allocation factors are applied for each individual climate zone. As climate zone level forecasts for the distribution system loads were not available for the future years for all utilities, a single historical or representative year is used to calculate allocation factors for all years in the modeling horizon.

PG&E and SCE each calculate hourly allocation factors themselves in their GRC proceedings and planning processes, so these are applied for the ACC. PG&E uses a PCAF method similar to the one described in this document for transmission avoided costs, though PG&E includes net loads that exceed 80% of maximum demand and is performed at a circuit level before aggregating factors up to the division and climate zone level. PG&E's calculated PCAFs remain unchanged from the 2022 and 2024 ACCs, though the weather year remapping has been updated in the 2026 cycle based on clarification around the weather year reflected in PG&E's data. Appendix A.5. provides further detail on how weather remapping is applied for all utilities and climate zones.

SCE uses its own Peak Load Risk Factor (PLRF) method for hourly allocation. The PLRF method is similar in intent to the PCAF method but instead of simply using the maximum load to determine the threshold for peak hours, it looks at the load relative to the loading limit at each facility in order to more explicitly reflect the risk of overloads. SCE worked with Staff to provide updated PLRF values based on 2023 historical load data. SDG&E does not calculate PCAFs or the equivalent in its filings, so the consultant calculated PCAFs from the historical 2025 climate zone level load data provided by SDG&E.

Figure 7-3 below displays the resulting PCAF and PLRFs for each utility and climate zone by hour of day across the year.

***Figure 7-3. Distribution PCAF and PLRFs by Climate Zone***




## 8. Transmission and Distribution Loss Factors

The value of deferring transmission and distribution investments is adjusted for losses during the peak period using the factors shown in Table 8-1 and Table 8-2. These factors are lower than the energy and generation capacity loss factors because they represent losses only from the secondary meter to the distribution or transmission facilities. These values remain the same from the 2024 ACC.

***Table 8-1. 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 8-2. 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 |

# 9. Methane Leakage

## 9.1 Introduction and summary

The methane leakage avoided cost component is applied to both the electric and gas avoided cost models and measures the greenhouse gas emissions from methane. Methane is the primary component of natural gas, which is used in buildings both indirectly, for electricity generation, and directly, for space and water heating, cooking, and clothes drying. When methane is combusted, it produces $CO_2$. However, if methane leaks before it can be combusted it is not only wasted as a fuel but also has a disproportionately high impact on global warming compared to burning that same methane. Uncombusted methane has a 100-year Global Warming Potential (GWP) of 25, meaning it is 25 times more potent than CO2 as a greenhouse gas over a 100-year time horizon.[23] The GWP of a given gas may differ depending on the time period over which it is measured. Over a shorter time horizon, uncombusted methane is even more potent, with 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.[24] The 100-year value is the default value used in the ACC because it is what is used in the ARB GHG inventory, though the 20-year value is included for informational 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.[25] 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.

Two options were considered 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.[26] 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. Therefore, the ACC uses the in-state estimate of 0.7% implied by the CARB inventory. 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

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[23] See CARB Global Warming Potentials Table, available at: https://ww2.arb.ca.gov/ghg-gwps

[24] 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.

[25] 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.

[26] October 2019 IDER Staff Proposal. 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 high GWP of methane. In this document, the consultant primarily uses leakage adders to quantify methane leakage as they are the most directly applicable to values.

In 2020, CPUC Energy Division staff and its consultant 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. CARB informed us that the previous estimate of 6.4% included all sources of methane leakage in the state, including behind-the-meter leakage. The consultant 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.

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,[27] 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, most or all 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 stepwise 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, the stepwise function is "smoothed out", and spreading the same total reduction in GHGs more evenly over time. This is similar to the way the ACC currently treats avoided generation capacity, 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.

## 9.2 Detailed Methodology for Methane Leakage Adders

The leakage adders in the 2026 ACC are maintained from the 2022 and 2024 ACC cycles and are calculated using CO2-equivalent emissions numbers from the 2017 GHG inventory published by the ARB.[28] The ARB inventory is a record of all GHG emissions occurring within the state borders of

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[27] 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.

[28] 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.

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.

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 = $\frac{mass\ of\ natural\ gas\ leaked}{mass\ of\ natural\ gas\ consumed}$
  - 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:

$$\overbrace{\frac{mass\ of\ methane\ leaked\ (tonnes\ CH4)}{mass\ of\ methane\ consumed\ (tonnes\ CH4)}}^{\text{methane leakage rate}} \quad \begin{matrix} \rightarrow * \dfrac{25\ tonnes\ CO2eq}{tonne\ CH4\ leaked} \rightarrow \\ = \\ \rightarrow * \dfrac{2.74\ tonnes\ CO2}{tonne\ CH4\ burned} \rightarrow \end{matrix} \quad \overbrace{\frac{CO2eq\ emissions\ from\ leaked\ NG}{CO2\ emissions\ from\ burned\ NG}}^{\text{methane leakage adder}}$$

**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.[29]

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 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 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,

[29] 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.

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 9-1. 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% |

## 9.3 Use Cases

The methane 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.[30]

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.

The value of avoided GHG of any particular DER in a given hour is 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. Additionally, the GHG adder reflects 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.

[30] "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.

**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 affects all traditional gas EE measures, as well as building decarbonization efforts that result in the removal of natural gas appliances.

The value of avoided GHG of a gas EE measure is the reduced GHG emissions multiplied by the gas GHG value, 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. Additionally, two terms reflect that reduced natural gas usage results in reduced upstream and behind-the-meter methane leakage. The upstream adder is applied to all programs which directly reduce natural gas consumption, but the behind-the-meter adder is applied only to programs that eliminate natural gas appliances from the building.

## 9.4 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 electric model 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.

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

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

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 natural gas GHG value. 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[31]. 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%[32].

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

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

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

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

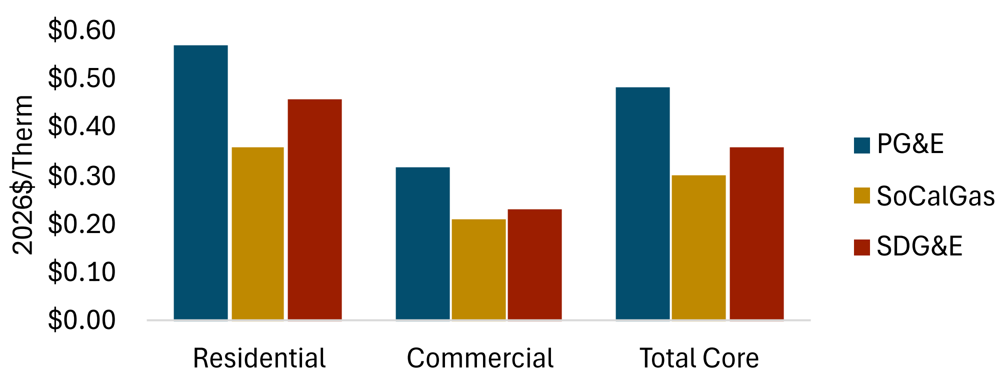
# ACC Gas Model

## 10. Natural Gas Avoided Costs

### 10.1 Avoided Gas Distribution Costs for Core Customers

Avoided natural gas distribution costs reflect avoided or deferred upgrades to the gas distribution systems for the three California IOUs. Unlike electricity, hourly cost allocations are not necessary because utilities can "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. "Core" customers refer to the residential and small commercial customers that represent the majority of natural gas utility customers in California. The avoided gas distribution costs, shown in Figure 10-1 were updated for the 2026 ACC with values provided by the IOUs.

*Figure 10-1. Natural Gas Distribution Costs Provided by Utilities*




### 10.2 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 transportation charges to Location Distribution Companies (LDCs). Because generators are not core customers, the appropriate measure of avoidable transportation charges is the applicable LDC tariff rate, which is reflected in the CEC IEPR Power Plant Burner Tip Price Model[33]. Thus, the CEC IEPR Power Plant Burner Tip Price Model is the source used for natural gas price forecast and transportation rates used in the electric model of the ACC. The 2026 ACC uses gas price forecasts

[33] Preliminary 2023 IEPR Electric Generation Price Model, available from the CEC's Natural Gas Electric Generation Prices for California and the Western United States website https://www.energy.ca.gov/programs-and-topics/topics/energy-assessment/natural-gas-electric-generation-prices-california-and

directly from the IRP PSP inputs, to ensure alignment with the IRP proceeding. These gas price forecasts take the average transportation rates across several hubs from the CEC IEPR forecasts.

### 10.3 Natural Gas GHG values

For the 2026 ACC, the avoided GHG value calculated for electricity is also used in the gas avoided cost model. In the 2022 and 2024 ACC cycles, a separate 'interim' GHG value for natural gas was calculated based on the cost of decarbonizing direct natural gas combustion in buildings. This use of a separate value reflected the expectation that decarbonization of direct combustion in buildings would be more expensive than decarbonization of electric generation. For the 2026 cycle, it was determined that the gas GHG avoided cost should again be aligned with the electric GHG values for each the total resource cost test and societal cost test perspectives. Unlike in 2024, the 2026 electric GHG value is generally higher over the study horizon than the alternative interim gas GHG value.

### 10.4 Avoided Natural Gas Infrastructure Costs (AGIC)

New construction of all-electric buildings avoid investment in new natural gas distribution infrastructure. This avoided cost was previously adopted for Energy Efficiency programs[34] and a similar method has been included in the ACC for use in cost-effectiveness evaluation of new construction building electrification projects and programs. The avoided gas infrastructure cost categories included in this calculation are mainline extensions, service extensions, and meters. The AGIC costs per unit are provided by utility through data requests and included in Appendix A.6. The AGIC costs in the ACC currently exclude costs borne by the customer, such as in-house infrastructure and plan reviews,[35] although it is expected that these avoided costs will be included in the cost-effectiveness analyses done in individual resource proceedings.

[34] Advice Letters 4386-G/6094-E and 4387-G/6095-E.

[35] This is responsible for the drop in PG&E greenfield service extension values, as data provided for 2026 reflects the observation that a large share of customers are performing their own trenching

# Appendix

## A.1. Comparison of 2024 ACC and 2026 ACC Results

***Figure 10-2. Average Monthly Avoided Costs (PG&E Climate Zone 12, 20-year levelized value of 2026 resource) - 2024 ACC***

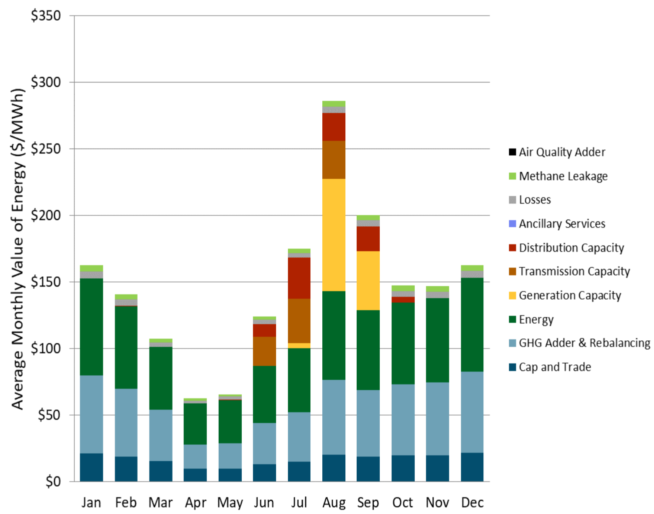



***Figure 10-3. Average Monthly Avoided Costs (PG&E Climate Zone 12, 20-year levelized value of 2026 resource) - 2026 ACC***

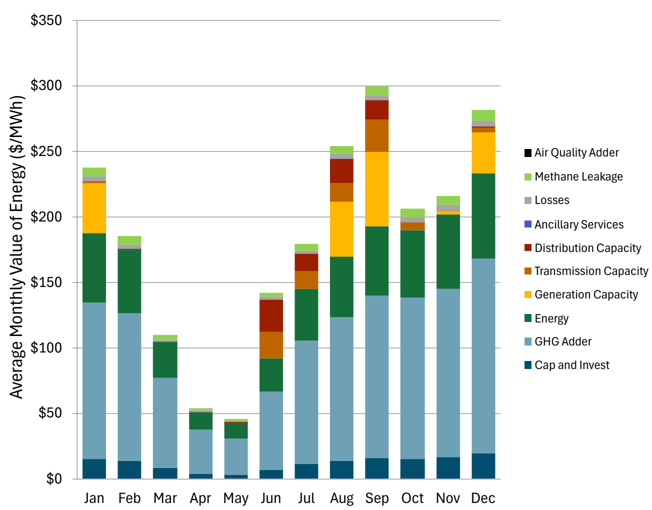


***Figure 10-4. Average Hourly Avoided Costs (PG&E Climate Zone 12, 20-year levelized value of 2026 resource) - 2024 ACC***

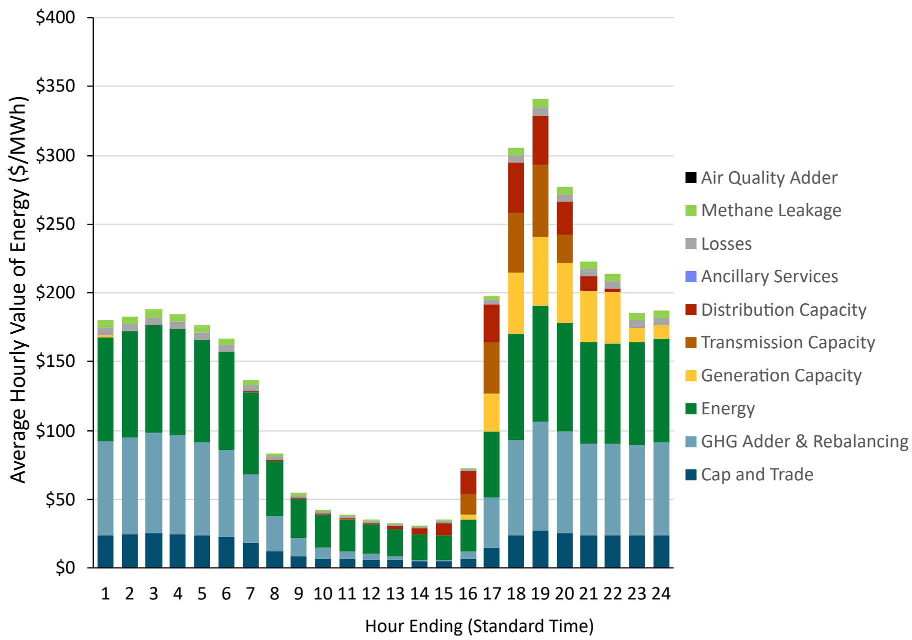



***Figure 10-5. Average Hourly Avoided Costs (PG&E Climate Zone 12, 20-year levelized value of 2026 resource) - 2026 ACC***

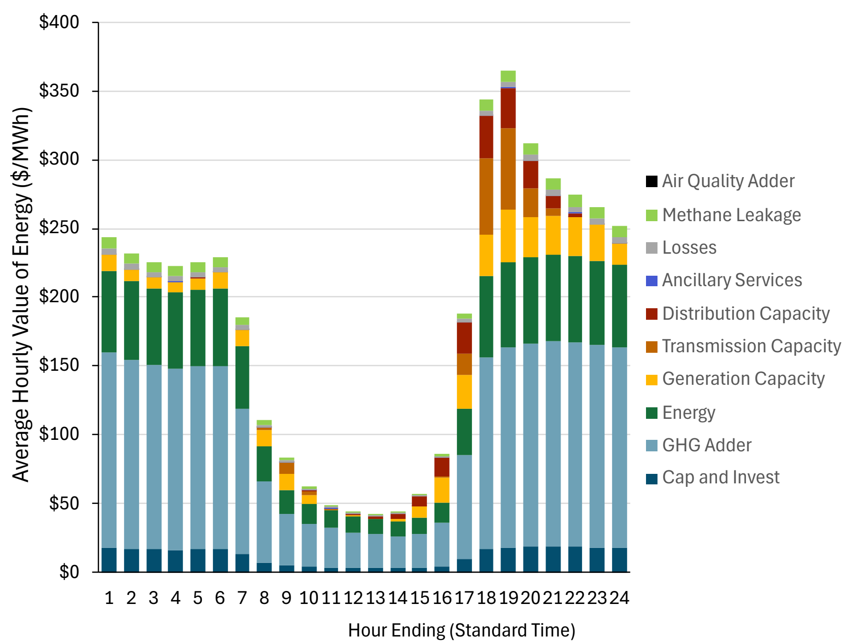



***Figure 10-6. Hourly Avoided Costs for Three Days Beginning August 30th (PG&E Climate Zone 12, 20-year levelized value of 2026 resource)* - 2024 ACC***

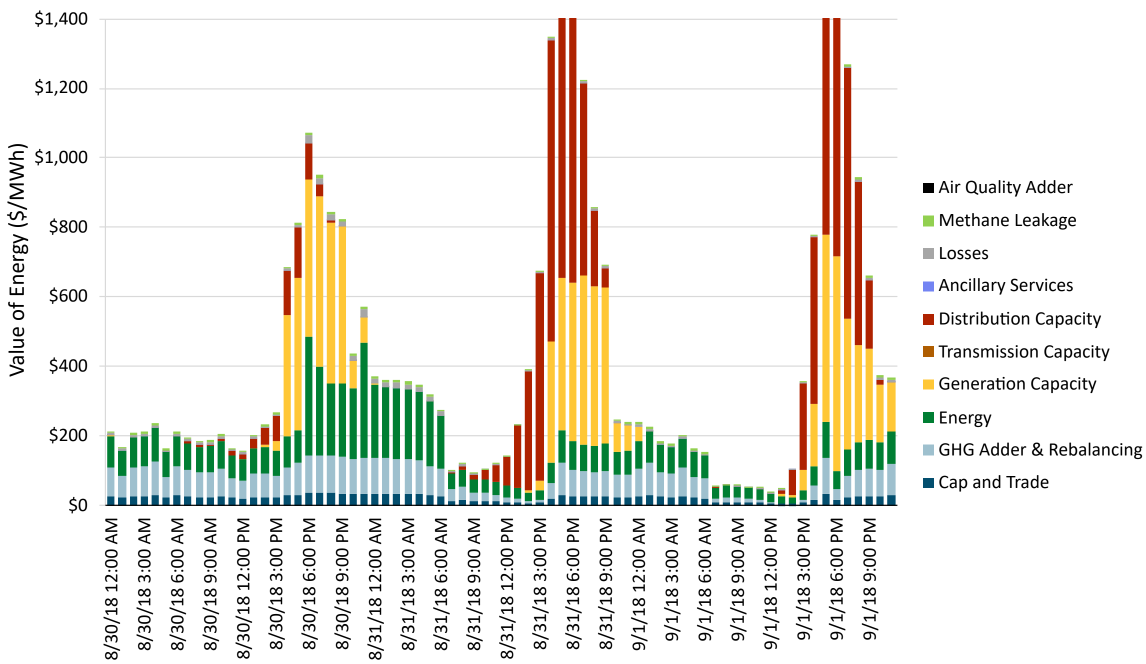
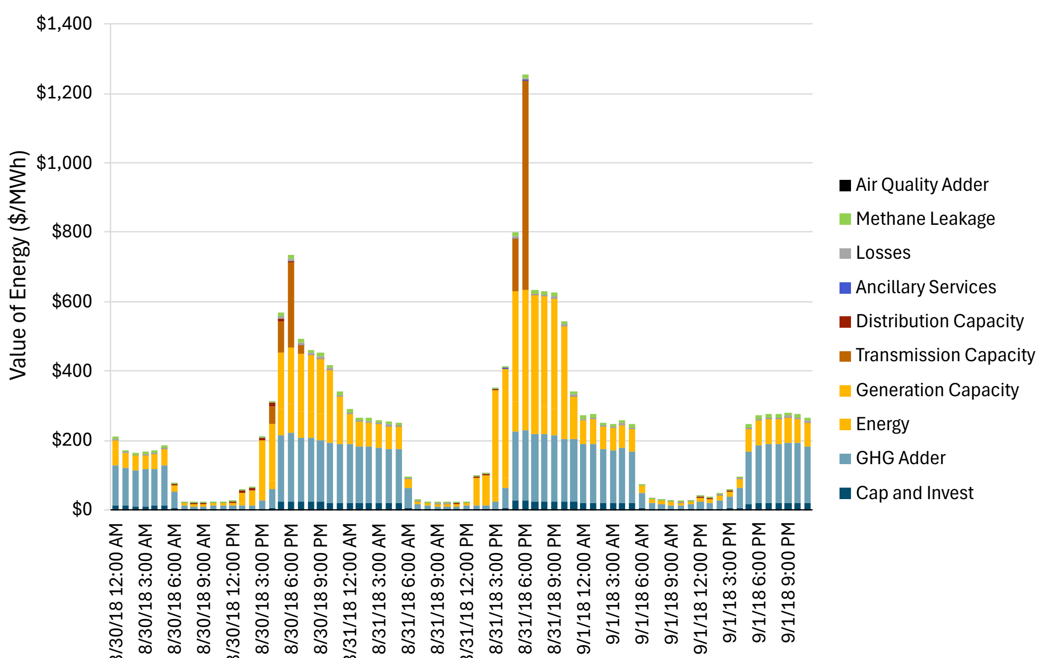



**Figure 10-7. Hourly Avoided Costs for Three Days Beginning August 30th (PG&E Climate Zone 12, 20-year levelized value of 2026 resource) - 2026 ACC**




* Vertical axis is capped at $1,400/MWh. 2024 ACC distribution value extends to over 1,300/MWh on August 31st, pushing the total levelized value to over the vertical axis cap. Also note that the 2024 ACC and 2026 ACC uses a 2018 calendar year. This impacts the alignment with the weather year and therefore the T&D allocation factors on each calendar day. High distribution costs in the 2024 ACC on the selected days illustrate how this variance can impact specific days though the 20-year levelized costs have not changed significantly.

### *Figure 10-8. Average Total Levelized Value by month and hour (PG&E Climate Zone 12, 20-year levelized value of 2026 resource) - 2024 ACC*

| 2024 ACC - Total Levelized Value ($/MWh) | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Hour \ Month | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| 0 | $ 223 | $ 203 | $ 165 | $ 101 | $ 120 | $ 143 | $ 161 | $ 211 | $ 215 | $ 195 | $ 202 | $ 218 |
| 1 | $ 213 | $ 200 | $ 170 | $ 112 | $ 132 | $ 154 | $ 175 | $ 215 | $ 207 | $ 200 | $ 200 | $ 218 |
| 2 | $ 217 | $ 209 | $ 175 | $ 135 | $ 137 | $ 168 | $ 176 | $ 222 | $ 199 | $ 203 | $ 199 | $ 215 |
| 3 | $ 215 | $ 216 | $ 180 | $ 125 | $ 121 | $ 150 | $ 168 | $ 224 | $ 199 | $ 207 | $ 202 | $ 212 |
| 4 | $ 217 | $ 215 | $ 174 | $ 104 | $ 90 | $ 141 | $ 158 | $ 211 | $ 195 | $ 200 | $ 203 | $ 211 |
| 5 | $ 219 | $ 206 | $ 158 | $ 82 | $ 70 | $ 122 | $ 145 | $ 200 | $ 188 | $ 190 | $ 210 | $ 215 |
| 6 | $ 224 | $ 191 | $ 133 | $ 42 | $ 23 | $ 45 | $ 93 | $ 159 | $ 151 | $ 161 | $ 196 | $ 219 |
| 7 | $ 191 | $ 152 | $ 64 | $ 10 | $ 0 | $ 18 | $ 46 | $ 78 | $ 75 | $ 91 | $ 122 | $ 159 |
| 8 | $ 136 | $ 62 | $ 23 | $ 1 | $ (1) | $ 18 | $ 38 | $ 80 | $ 58 | $ 60 | $ 65 | $ 112 |
| 9 | $ 81 | $ 40 | $ 13 | $ 1 | $ 0 | $ 20 | $ 41 | $ 73 | $ 53 | $ 52 | $ 51 | $ 77 |
| 10 | $ 73 | $ 38 | $ 11 | $ 3 | $ 2 | $ 20 | $ 39 | $ 73 | $ 46 | $ 47 | $ 44 | $ 65 |
| 11 | $ 58 | $ 30 | $ 8 | $ 3 | $ 4 | $ 20 | $ 39 | $ 71 | $ 41 | $ 46 | $ 40 | $ 59 |
| 12 | $ 53 | $ 28 | $ 7 | $ 1 | $ 2 | $ 20 | $ 37 | $ 68 | $ 35 | $ 42 | $ 39 | $ 56 |
| 13 | $ 46 | $ 26 | $ 5 | $ (8) | $ (5) | $ 20 | $ 39 | $ 73 | $ 36 | $ 41 | $ 36 | $ 54 |
| 14 | $ 42 | $ 34 | $ 2 | $ (11) | $ (7) | $ 24 | $ 51 | $ 88 | $ 52 | $ 45 | $ 37 | $ 54 |
| 15 | $ 69 | $ 31 | $ 7 | $ (12) | $ (6) | $ 97 | $ 150 | $ 193 | $ 111 | $ 68 | $ 73 | $ 86 |
| 16 | $ 187 | $ 93 | $ 46 | $ (11) | $ 2 | $ 194 | $ 359 | $ 569 | $ 272 | $ 210 | $ 216 | $ 224 |
| 17 | $ 218 | $ 234 | $ 201 | $ 80 | $ 85 | $ 294 | $ 521 | $ 830 | $ 526 | $ 238 | $ 205 | $ 219 |
| 18 | $ 187 | $ 189 | $ 212 | $ 202 | $ 205 | $ 411 | $ 635 | $ 890 | $ 527 | $ 226 | $ 189 | $ 201 |
| 19 | $ 190 | $ 184 | $ 189 | $ 168 | $ 184 | $ 283 | $ 404 | $ 693 | $ 422 | $ 211 | $ 190 | $ 198 |
| 20 | $ 191 | $ 191 | $ 172 | $ 103 | $ 111 | $ 169 | $ 221 | $ 568 | $ 348 | $ 196 | $ 193 | $ 204 |
| 21 | $ 206 | $ 201 | $ 156 | $ 90 | $ 105 | $ 161 | $ 179 | $ 538 | $ 315 | $ 204 | $ 200 | $ 206 |
| 22 | $ 217 | $ 199 | $ 155 | $ 89 | $ 102 | $ 144 | $ 157 | $ 267 | $ 273 | $ 206 | $ 207 | $ 209 |
| 23 | $ 229 | $ 208 | $ 156 | $ 92 | $ 105 | $ 144 | $ 163 | $ 269 | $ 261 | $ 201 | $ 202 | $ 218 |

### *Figure 10-9. Average Total Levelized Value by month and hour (PG&E Climate Zone 12, 20-year levelized value of 2026 resource) - 2026 ACC*

| 2026 ACC - Total Levelized Value ($/MWh) | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Hour \ Month | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| 0 | $ 325 | $ 278 | $ 187 | $ 109 | $ 89 | $ 169 | $ 241 | $ 297 | $ 309 | $ 288 | $ 292 | $ 337 |
| 1 | $ 319 | $ 270 | $ 177 | $ 101 | $ 84 | $ 158 | $ 230 | $ 264 | $ 285 | $ 280 | $ 284 | $ 329 |
| 2 | $ 315 | $ 265 | $ 172 | $ 97 | $ 79 | $ 150 | $ 221 | $ 256 | $ 275 | $ 278 | $ 279 | $ 323 |
| 3 | $ 314 | $ 263 | $ 170 | $ 92 | $ 73 | $ 142 | $ 214 | $ 254 | $ 274 | $ 276 | $ 277 | $ 322 |
| 4 | $ 322 | $ 266 | $ 169 | $ 87 | $ 70 | $ 141 | $ 215 | $ 258 | $ 284 | $ 283 | $ 284 | $ 329 |
| 5 | $ 341 | $ 279 | $ 179 | $ 85 | $ 63 | $ 119 | $ 186 | $ 247 | $ 291 | $ 295 | $ 300 | $ 369 |
| 6 | $ 356 | $ 289 | $ 161 | $ 38 | $ 9 | $ 32 | $ 88 | $ 130 | $ 179 | $ 260 | $ 305 | $ 385 |
| 7 | $ 306 | $ 178 | $ 49 | $ 10 | $ 5 | $ 20 | $ 51 | $ 61 | $ 90 | $ 83 | $ 170 | $ 304 |
| 8 | $ 204 | $ 81 | $ 22 | $ 4 | $ 2 | $ 18 | $ 46 | $ 55 | $ 81 | $ 68 | $ 121 | $ 294 |
| 9 | $ 91 | $ 50 | $ 19 | $ 5 | $ 1 | $ 15 | $ 42 | $ 51 | $ 77 | $ 59 | $ 91 | $ 245 |
| 10 | $ 67 | $ 43 | $ 15 | $ 1 | $ 1 | $ 16 | $ 40 | $ 49 | $ 74 | $ 56 | $ 75 | $ 151 |
| 11 | $ 60 | $ 36 | $ 13 | $ 1 | $ 1 | $ 17 | $ 38 | $ 48 | $ 72 | $ 51 | $ 68 | $ 129 |
| 12 | $ 50 | $ 34 | $ 12 | $ 1 | $ 1 | $ 21 | $ 41 | $ 52 | $ 77 | $ 50 | $ 62 | $ 110 |
| 13 | $ 40 | $ 30 | $ 12 | $ 1 | $ 1 | $ 31 | $ 47 | $ 79 | $ 84 | $ 53 | $ 59 | $ 96 |
| 14 | $ 41 | $ 27 | $ 13 | $ 1 | $ 2 | $ 47 | $ 58 | $ 97 | $ 173 | $ 58 | $ 68 | $ 101 |
| 15 | $ 53 | $ 35 | $ 17 | $ 0 | $ 2 | $ 76 | $ 79 | $ 218 | $ 255 | $ 72 | $ 95 | $ 134 |
| 16 | $ 171 | $ 71 | $ 23 | $ 1 | $ 4 | $ 135 | $ 146 | $ 321 | $ 483 | $ 247 | $ 290 | $ 364 |
| 17 | $ 344 | $ 279 | $ 141 | $ 53 | $ 50 | $ 377 | $ 413 | $ 615 | $ 803 | $ 391 | $ 299 | $ 358 |
| 18 | $ 340 | $ 282 | $ 174 | $ 79 | $ 72 | $ 472 | $ 466 | $ 681 | $ 824 | $ 332 | $ 301 | $ 356 |
| 19 | $ 338 | $ 283 | $ 180 | $ 92 | $ 91 | $ 394 | $ 370 | $ 509 | $ 534 | $ 298 | $ 301 | $ 355 |
| 20 | $ 335 | $ 282 | $ 185 | $ 106 | $ 100 | $ 278 | $ 294 | $ 438 | $ 470 | $ 299 | $ 299 | $ 351 |
| 21 | $ 332 | $ 277 | $ 185 | $ 108 | $ 101 | $ 210 | $ 274 | $ 410 | $ 449 | $ 297 | $ 298 | $ 348 |
| 22 | $ 327 | $ 275 | $ 186 | $ 115 | $ 100 | $ 190 | $ 263 | $ 383 | $ 425 | $ 294 | $ 291 | $ 341 |
| 23 | $ 323 | $ 274 | $ 188 | $ 117 | $ 96 | $ 184 | $ 258 | $ 330 | $ 335 | $ 294 | $ 289 | $ 336 |

### *Figure 10-10. Average Total Levelized Value by month and hour (PG&E Climate Zone 12, 20-year levelized value of 2026 resource) - Difference between 2024 ACC and 2026 ACC*

| 2026 ACC - 2024 ACC \| Total Levelized Value Difference between Vintages ($/MWh) | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Hour \ Month | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| 0 | $ 103 | $ 75 | $ 21 | $ 7 | $ (31) | $ 27 | $ 80 | $ 85 | $ 94 | $ 93 | $ 89 | $ 118 |
| 1 | $ 105 | $ 70 | $ 7 | $ (11) | $ (48) | $ 4 | $ 55 | $ 50 | $ 78 | $ 81 | $ 85 | $ 111 |
| 2 | $ 98 | $ 57 | $ (3) | $ (38) | $ (58) | $ (18) | $ 44 | $ 35 | $ 76 | $ 74 | $ 80 | $ 108 |
| 3 | $ 99 | $ 47 | $ (10) | $ (33) | $ (48) | $ (8) | $ 46 | $ 30 | $ 75 | $ 69 | $ 75 | $ 110 |
| 4 | $ 105 | $ 51 | $ (5) | $ (17) | $ (20) | $ 0 | $ 57 | $ 47 | $ 88 | $ 83 | $ 81 | $ 118 |
| 5 | $ 121 | $ 73 | $ 21 | $ 3 | $ (7) | $ (3) | $ 41 | $ 47 | $ 103 | $ 106 | $ 90 | $ 154 |
| 6 | $ 132 | $ 97 | $ 27 | $ (4) | $ (15) | $ (13) | $ (5) | $ (30) | $ 29 | $ 98 | $ 109 | $ 166 |
| 7 | $ 115 | $ 26 | $ (15) | $ (0) | $ 5 | $ 1 | $ 5 | $ (17) | $ 15 | $ (8) | $ 48 | $ 146 |
| 8 | $ 68 | $ 20 | $ (1) | $ 3 | $ 3 | $ (0) | $ 8 | $ (25) | $ 23 | $ 8 | $ 57 | $ 183 |
| 9 | $ 10 | $ 10 | $ 6 | $ 4 | $ 1 | $ (4) | $ 1 | $ (22) | $ 24 | $ 7 | $ 40 | $ 168 |
| 10 | $ (5) | $ 5 | $ 4 | $ (1) | $ (1) | $ (4) | $ 0 | $ (25) | $ 28 | $ 10 | $ 31 | $ 86 |
| 11 | $ 2 | $ 5 | $ 5 | $ (2) | $ (3) | $ (3) | $ (2) | $ (23) | $ 31 | $ 6 | $ 27 | $ 70 |
| 12 | $ (3) | $ 6 | $ 5 | $ (0) | $ (1) | $ 1 | $ 4 | $ (16) | $ 42 | $ 8 | $ 23 | $ 54 |
| 13 | $ (6) | $ 4 | $ 7 | $ 8 | $ 6 | $ 11 | $ 8 | $ 6 | $ 48 | $ 12 | $ 22 | $ 42 |
| 14 | $ (1) | $ (7) | $ 11 | $ 12 | $ 9 | $ 24 | $ 6 | $ 10 | $ 121 | $ 12 | $ 30 | $ 47 |
| 15 | $ (16) | $ 3 | $ 9 | $ 12 | $ 8 | $ (21) | $ (72) | $ 24 | $ 144 | $ 4 | $ 21 | $ 48 |
| 16 | $ (16) | $ (22) | $ (23) | $ 13 | $ 2 | $ (59) | $ (213) | $ (247) | $ 212 | $ 37 | $ 73 | $ 140 |
| 17 | $ 126 | $ 45 | $ (60) | $ (27) | $ (35) | $ 83 | $ (108) | $ (215) | $ 278 | $ 154 | $ 93 | $ 138 |
| 18 | $ 153 | $ 93 | $ (37) | $ (123) | $ (133) | $ 61 | $ (169) | $ (209) | $ 298 | $ 106 | $ 112 | $ 155 |
| 19 | $ 148 | $ 99 | $ (9) | $ (76) | $ (93) | $ 111 | $ (34) | $ (184) | $ 112 | $ 86 | $ 111 | $ 157 |
| 20 | $ 144 | $ 91 | $ 13 | $ 4 | $ (10) | $ 109 | $ 72 | $ (130) | $ 121 | $ 104 | $ 106 | $ 148 |
| 21 | $ 126 | $ 76 | $ 29 | $ 18 | $ (4) | $ 49 | $ 95 | $ (127) | $ 134 | $ 94 | $ 98 | $ 141 |
| 22 | $ 110 | $ 76 | $ 31 | $ 26 | $ (2) | $ 46 | $ 107 | $ 116 | $ 152 | $ 88 | $ 84 | $ 132 |
| 23 | $ 93 | $ 66 | $ 32 | $ 25 | $ (9) | $ 40 | $ 95 | $ 60 | $ 75 | $ 93 | $ 87 | $ 118 |

### *Figure 10-11. Average Annual Avoided or Increased Cost for Illustrative Normalized Load Shapes (PG&E Climate Zone 12, 20-year levelized value for 2024 resource)*

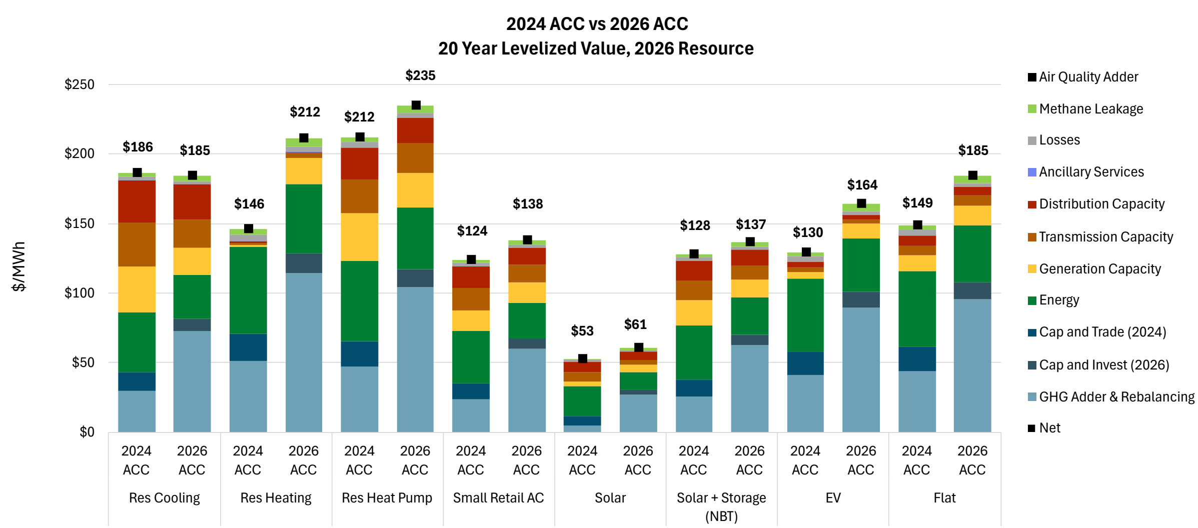



Figure 10-11 displays the avoided cost outputs on a 20-year levelized basis when applied to individual electricity end-use profiles. For DERs that reduce total electric load, including residential cooling (representing a heat pump replacing air conditioning), solar, and solar + storage, values represent avoided costs on a $/MWh unit basis. For end uses that increase electric load, these values represent increased costs. These values are based on normalized representative load shapes and so reflect the profile of electric usage or reduction rather than the expected magnitude of usage for each measure. The "Flat" End Use reflects a flat 1 MW load profile applied across the entire year.

As shown, outputs have increased both on a flat basis and for all individual end uses displayed except for residential cooling.

***Figure 10-12. Gas Avoided Cost Comparison (PG&E Residential Furnace, Uncontrolled, 20-year levelized value for 2026 resource)***

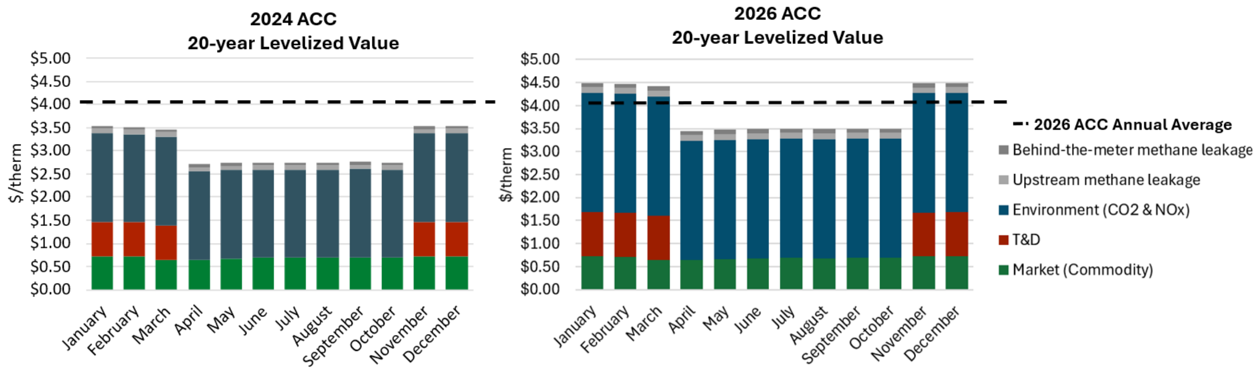



***Figure 10-13. Gas Avoided Costs and Electric Costs of Example HP HVAC and HPWH Combined Measure (PG&E Climate Zone 12, 20-year levelized value for 2024 resource, Uncontrolled Residential Gas Furnace)***

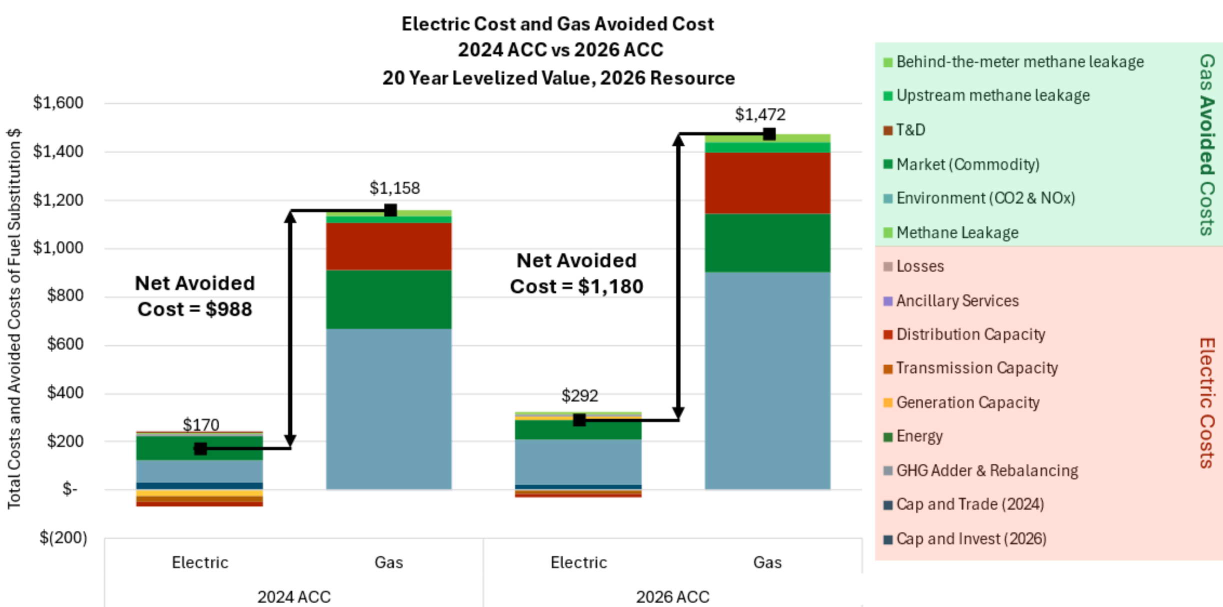



Figure 10-13 provides an example of the net avoided cost from fuel substitution using both the electric and gas avoided cost calculators from each 2024 and 2026. In this representative example of electric heating replacing a counterfactual gas resource, there are increased costs on the electric system but much higher avoided costs on the gas system, resulting in a net avoided cost across both systems combined.

## A.2. Comparison of 2024 ACC and 2026 ACC SERVM Prices

## A.3. Utility-Specific Transmission Costs

### *PG&E*

Transmission marginal capacity costs for PG&E typically come 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 most recent marginal transmission capacity cost was reported by PG&E to be $12.02/kW-yr (in 2021$).

However, in the CPUC Decision 21-11-016 published November 18, 2021, the Commission shifted to adopt the Solar Energy Industries Association's proposed marginal transmission capacity cost of $52.45 per kilowatt year (in 2021$). This value was used in the 2022 and 2024 ACC updates and is still in place (converted to $53.98 in 2025$) at the time of the 2026 ACC update.

### *SCE*

SCE does not include estimates of transmission capacity costs in its GRC proceedings. The consultant therefore calculates marginal transmission costs for SCE using information provided by SCE in response to Energy Division data requests. In prior ACCs, SCE projects were identified by the utility as being driven by either systemwide load growth ('systemwide projects') or local load growth ('individual large projects') and either the LNBA method or DTIM calculation were applied accordingly. Avoided cost values for the individual large projects were averaged across the system based on the share of load addressed and then summed with the systemwide project avoided costs to arrive at a total average avoided cost for SCE. For the 2026 ACC update, all major capacity-related projects are grouped before applying the DTIM calculation. This calculation and core inputs are provided in Table 10-1 through Table 10-3.

## *Table 10-1. SCE Project Costs and Load Forecast*

| Year | SCE Project Cost ($M) | | | | SCE Forecast from CEC | | |
|---|---|---|---|---|---|---|---|
| | Pardee Sylmar | New Serrano | Alberhill | Total | Forecast for SCE (MW) | Annual Peak Demand Growth (MW) | Median Growth (2025-2040) |
| | | | | | 24647 | | |
| 2025 | 2.108 | 26.546 | 4.73 | *33.384* | 25973 | *1,326* | *224* |
| 2026 | 1.5 | 35.324 | 9.65 | *46.474* | 26106 | *133* | *224* |
| 2027 | 1.5 | 12.253 | 73.369 | *87.122* | 26319 | *213* | *224* |
| 2028 | 1.5 | 10.533 | 53.492 | *65.525* | 26538 | *219* | *224* |
| 2029 | 0.579 | 17.754 | 13.326 | *31.659* | 26841 | *303* | *224* |
| 2030 | | | | | 27081 | *240* | *224* |
| 2031 | | | | | 27314 | *233* | *224* |
| 2032 | | | | | 27523 | *209* | *224* |
| 2033 | | | | | 27721 | *198* | *224* |
| 2034 | | | | | 28075 | *354* | *224* |
| 2035 | | | | | 28524 | *449* | *224* |
| 2036 | | | | | 28687 | *163* | *224* |
| 2037 | | | | | 28917 | *230* | *224* |
| 2038 | | | | | 29129 | *212* | *224* |
| 2039 | | | | | 29332 | *203* | *224* |
| 2040 | | | | | 29646 | *314* | *224* |
| NPV (2025 - 2029) | | | | *$228.28* | | | *972.5* |

| | |
|---|---|
| **Notes:** | SCE Data request response: ED-SCE-ACC Transmission-2026 - 4/1/2026 |
| *Source for 2024-2040 Demand* | CEC Demand Forecast 2024-2040 Baseline Forecast. Form 1.5 SCE Planning Area: Historical and Extreme Temperature Non-Coincident Peak Demand (MW). 2024 Data reflects Historical Net Peak, 2025-2040 data Located at https://efiling.energy.ca.gov/GetDocument.aspx?tn=260928 |
| Real Discount Rate Used: | *4.94%* |

## *Table 10-2. Derivation of SCE Transmission Marginal Cost Factor*

| **Marginal Transmission Cost Factor** | | | |
|---|---|---|---|
| 2026 MC Factor for Transmission | | | |
| **Loaders & Financial Factors Inputs:** | | | |
| Transmission Real Economic Carrying Charge (RECC) | [1] | 6.98% | *No update from 2024 value* |
| Electric Transmission O&M ($/kW-yr) | [2] | | *Applied later* |
| A&G Payroll Loading Factor Transmission ( Capital basis) | [3] | 0.87% | *No update from 2024 value* |
| General Plant Loading Factor Transmission ( Annual Capital basis) | [4] | 2.27% | *No update from 2024 value* |
| 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] | 2.36% | *No update from 2024 value* |
| MARGINAL INVESTMENT | | | |
| Marginal Investment | [8] | $100.00 | |
| **Annualized Marginal Investment** | [9] | *$6.980* | [9] = [8] x [1] |
| MARGINAL EXPENSES | | | |
| O&M Expense (to be added directly, rather than included as a factor) | [10] | | |
| A&G Expense | [11] | *$0.87* | [11] = [8] x [3] |
| General Plant | [12] | *$0.16* | [12] = [9] x [4] |
| **Sub-total Marginal Expenses** | [13] | *$1.028* | [13] = [10] + [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] | *$0.19* | [17] = ([9] + [13] + [16]) x [7] |
| Marginal Cost | [18] | *$8.20* | [18] = [9] + [13] + [16] + [17] |
| Annual Marginal Cost Factor | [19] | *8.20%* | [19] = [18] / [8] |

### *Table 10-3. Derivation of SCE Transmission Avoided Costs (DTIM)*

| | | |
|---|---|---|
| PV of Investment ($M) | [1] | *$228.28* |
| PV of Load Growth (MW) | [2] | *972* |
| PV of Load Growth (kW) | [3] | *972,455* |
| Marginal Investment ($/MW) | [4] | *$234,745* |
| Marginal Investment ($/kW) | [5] | *$234.74* |
| Annual MC Factor | [6] | *8.20%* |
| O&M ($/kW-yr) | [7] | $ 2.79 |
| Marginal Transmission Capacity Cost ($/kW-Yr) | [8] | *$22.03* |

Notes:

[1] = The Discounted Project Cost of the Pardee Sylmar + New Serrano System-wide transmission projects
[2] = The Cumulative Discounted Load Growth based on median growth from CEC Demand Forecast
[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 Utility Data Request Response
[8] = [5] x [6] + [7]

## *SDG&E*

Similar to SCE, SDG&E does not provide estimates of transmission capacity costs in its GRC proceedings. Therefore, the DTIM method is applied to capacity-related transmission projects provided by SDG&E. The application of the DTIM is similar between utilities except that the forecast used for SDG&E's planning horizon extends further into the future and O&M is included in the derivation of SDG&E's marginal cost factor and therefore is not applied again directly in the DTIM. SDG&E calculations are provided in Table 10-4 through Table 10-6.

### *Table 10-4. SDG&E Project Costs and Load Forecast*

| | | SDG&E Forecast from IEPR | | |
|---|---|---|---|---|
| Year | SDG&E XMSN Capital Expenditures ($M) | SDG&E Forecast (MW) | Annual Peak Demand Growth (MW) | Median Growth (2025-2044) |
| | | 4,647 | | |
| 2025 | 28.1 | 4,558 | *N/A* | *110* |
| 2026 | 52.0 | 4,569 | *11* | *110* |
| 2027 | 62.8 | 4,617 | *48* | *110* |
| 2028 | 77.6 | 4,727 | *110* | *110* |
| 2029 | 25.3 | 4,831 | *104* | *110* |
| 2030 | 24.5 | 4,938 | *107* | *110* |
| 2031 | | 5,045 | *108* | *110* |
| 2032 | | 5,147 | *101* | *110* |
| 2033 | | 5,247 | *100* | *110* |
| 2034 | | 5,341 | *95* | *110* |
| 2035 | | 5,467 | *126* | *110* |
| 2036 | | 5,538 | *71* | *110* |
| 2037 | | 5,749 | *211* | *110* |
| 2038 | | 5,945 | *196* | *110* |
| 2039 | | 6,135 | *190* | *110* |
| 2040 | | 6,329 | *194* | *110* |
| 2041 | | 6,474 | *145* | *110* |
| 2042 | | 6,621 | *146* | *110* |
| 2043 | | 6,756 | *136* | *110* |
| 2044 | | 6,886 | *130* | *110* |
| NPV(2025-2044) | *$216.41* | | | *522.90* |

**Notes:** SDG&E Response to 2.18.2026 Transmission Data Request

Transmission Capital Expenditures for 2026-2030 from SDG&E's TPR process data

Expenditures listed reflect planned projects that are expected to be completed but may be viewed as proxies for transmission that could potentially be deferred due to load reductions from incremental DER

IEPR source for 2025-2044 data: CED 2025-2050 Forecast - Local Reliability Scenario - LSE and BAA Tables. Form 1.5d (1-in-10): SDG&E TAC Area

IEPR source for 2024 data: Value for 2024 from CED 2024-2040 Forecast - Local Reliability Scenario - LSE and BAA Tables. Form 1.5d (1-in-10): SDG&E TAC Area. Accessible at https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2024-integrated-energy-policy-report-0

Real Discount Rate Used: *7.01%*

## Table 10-5. Derivation of SDG&E Transmission Marginal Cost Factor

| Marginal Transmission Cost Factor | | | |
|---|---|---|---|
| 2026 MC Factor for Transmission | | | |
| **Loaders & Financial Factors Inputs:** | | | |
| Real Economic Carrying Charge (RECC) | [1] | 8.32% | |
| Electric Transmission O&M Factor (%) (Capital Basis) | [2] | 1.44% | |
| A&G Payroll Loading Factor Transmission ( Capital basis) | [3] | 0.83% | |
| General Plant Loading Factor Transmission (Capital basis) | [4] | 3.07% | |
| Materials and Supplies Carrying Charge (Plant Based) | [5] | | |
| Cash Working Capital Carrying Charge (Dist. O&M + A&G Based - Annualize | [6] | 1.50% | |
| Franchise Fees & Uncollectibles Loading Factor RRQ Basis | [7] | | |
| MARGINAL INVESTMENT | | | |
| Marginal Investment | [8] | $100.00 | |
| **Annualized Marginal Investment** | [9] | *$8.320* | [9] = [8] x [1] |
| MARGINAL EXPENSES | | | |
| O&M Expense | [10] | *$1.44* | [10] = [8] x [2] |
| A&G Expense | [11] | *$0.83* | [11] = [8] x [3] |
| General Plant | [12] | *$3.07* | [12] = [8] x [4] |
| **Sub-total Marginal Expenses** | [13] | *$5.340* | [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] | *$1.50* | [16] = [14] + [15] |
| **Franchise Fees and Uncollectibles** | [17] | | |
| Marginal Cost | [18] | *$15.16* | [18] = [9] + [13] + [16] + [17] |
| Annual Marginal Cost Factor | [19] | *15.16%* | [19] = [18] / [8] |

## Table 10-6. Derivation of SDG&E Transmission Avoided Costs (DTIM)

| | | |
|---|---|---|
| PV of Investment ($M) | [1] | *$216.41* |
| PV of Load Growth (MW) | [2] | *522.90* |
| PV of Load Growth (kW) | [3] | *522,903* |
| Marginal Investment ($/MW) | [4] | *$413,871* |
| Marginal Investment ($/kW) | [5] | *$413.87* |
| Annual MC Factor | [6] | *15.16%* |
| | [7] | |
| Marginal Transmission Capacity Cost ($/kW-Yr) | [8] | *$62.74* |

Notes:
[1] = Cumulative discounted cost of SDG&E transmission projects potentially deferrable by DERs
[2] = Cumulative discounted load growth based on Local Reliability 1-in-10 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
[7]: Consistent with prior ACCs, O&M was not input in the DTIM calculation for SDG&E and is instead included indirectly via the MC Factor
[8] = [5] x [6]

## A.4. Derivation of Near-Term Distribution Capacity Avoided Costs

### Unspecified Distribution Marginal Costs

Table 10-7 shows the calculation of the unspecified distribution marginal cost that is used for the near-term distribution marginal capacity costs. Columns showing calculations for each of the load increasing and load decreasing DERs are provided for each utility. SCE's costs are further divided, as costs are provided separately for each facility type. The final SCE Total Distribution Capacity value is achieved by summing the circuit and B-Bank substation values with distribution deferral values for the A-Bank and subtransmission facilities.

***Table 10-7. Unspecified Near Term Distribution Deferral Values by Utility***

| | | PG&E | | SCE-Substations (B-Bank) | | SCE-Circuits | | SDG&E | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Line | Number of Overloads | Load Decreasing DERs | Load Increasing DERs | Load Decreasing DERs | Load Increasing DERs | Load Decreasing DERs | Load Increasing DERs | Load Decreasing DERs | Load Increasing DERs | Notes: |
| 1 | Actual Overloads | 394 | 394 | 144 | 144 | 477 | 477 | 12 | 12 | [1] |
| 2 | Counterfactual Overloads | 1264 | 367 | 180 | 119 | 722 | 0 | 23 | 12 | [2] |
| 3 | Percentage of Overloads that can be Deferred by Load Transfers | 20% | 20% | 20% | 20% | 20% | 20% | 9% | 9% | From 2021 ACC |
| | **Overload Capacity** | | | | | | | | | |
| 4 | Actual Overloads (kW) | 1,180,970 | 1,180,970 | 1,812,025 | 1,812,025 | 1,055,215 | 1,055,215 | 15,255 | 15,255 | [4] |
| 5 | Counterfactual Overloads (kW) | 3,911,058 | 1,057,599 | 2,136,797 | 1,320,549 | 1,274,208 | 906,713 | 21,983 | 13,811 | [5] |
| 5b | Estimated Overload Capacity Deferred by DERs (Includes Load Transfers) (kW) | 2,730,088 | -123,371 | 324,771 | -491,476 | 218,993 | -148,503 | 6,729 | -1,444 | [5] - [4] |
| 6 | Estimated Overload Capacity Deferred by DER - Excluding Load Transfers (kW) | 2,184,070 | -98,697 | 259,817 | -393,181 | 175,194 | -118,802 | 6,123 | -1,314 | [6] = [5b] x (100% - [3]) |
| | **Project & Planned Investment Costs** | | | | | | | | | |
| 7 | Total Cost of Planned Investments in DUPR Filing ($) | $259,869,081 | $259,869,081 | $1,928,327,347 | $1,928,327,347 | $1,928,327,347 | $1,928,327,347 | $70,528,437 | $70,528,437 | [7] |
| 8 | Capacity Deficiency that Planned Investments Mitigate (kW) | $763,120 | $763,120 | $4,230,590 | $4,230,590 | $4,230,590 | $4,230,590 | $13,645 | $13,645 | [8] |
| 9 | Unit Cost of Deferred Distribution Upgrades ($/kW) | $340.53 | $340.53 | $455.81 | $455.81 | $455.81 | $455.81 | $5,168.97 | $5,168.97 | [9]* = [7] / [8] |
| | **System Level Avoided Distribution Costs** | | | | | | | | | |
| 10 | DER-Deferrable Capital Investment ($) | $743,751,999 | -$33,609,703 | $118,426,146 | -$179,214,119 | $79,854,584 | -$54,150,675 | $31,650,839 | -$6,791,839 | [10] = [9] x [6] |
| 11 | Total Load Reduction from DER forecasted across all facilities, 2025-2029 (kW) | 12,663,314 | -4,577,865 | 4,030,840 | -6,307,415 | 4,030,840 | -6,307,415 | 594,652 | -1,309,952 | [11] |
| 12 | Unspecified Distribution Deferral Value ($/kW of DER installed) | $58.73 | $7.34 | $29.38 | $28.41 | $19.81 | $8.59 | $53.23 | $5.18 | [12] = [10] / [11] |
| 13 | Marginal Distribution Cost Factor ('IOU Specific RECC') (%) | 8.36% | 8.36% | 10.39% | 10.39% | 10.39% | 10.39% | 7.93% | 7.93% | [13] |
| 14 | Capacity Deferral Value ($/kW of DER installed-yr) | $4.91 | $0.61 | $3.05 | $2.95 | $2.06 | $0.89 | $4.22 | $0.41 | [14] = [12] * [13] |
| | **O&M Distribution Costs** | | | | | | | | | |
| 15 | O&M Deferral Value ($/kW-yr) | | | $29.23 | $29.23 | $29.23 | $29.23 | $37.68 | $37.68 | [15] |
| 16 | O&M Deferral Value ($/kW of DER installed -yr) | | | $1.88 | $1.82 | $1.27 | $0.55 | $0.39 | $0.04 | [16] = [15] * [6] / [11] |
| 17 | Unspecified Marginal Cost ($/kW of DER installed-yr) | $4.91 | $0.61 | $4.94 | $4.77 | $3.33 | $1.44 | $4.61 | $0.45 | [17] = [14] + [16] |

| | | SCE Substations (A-Bank) | | SCE Subtransmission | | |
|---|---|---|---|---|---|---|
| | | Load Decreasing DERs | Load Increasing DERs | Load Decreasing DERs | Load Increasing DERs | Notes |
| 18 | Distribution Deferral Value ($/kW-yr) | $45.50 | $45.50 | $17.11 | $17.11 | *From SCE 2025 GRC Phase II Table I-11 |
| 19 | Estimated Overload Capacity Deferred by DER - Excluding Load Transfers (kW) | 259,817 | -393,181 | 259,817 | -393,181 | * Using SCE Substation B-Bank Values [6] |
| 20 | Total Load Reduction from DER Forecasted Across Distribution System, 2025-2029 (kW) | 4,030,840 | -6,307,415 | 4,030,840 | -6,307,415 | * Using SCE Substation B-Bank Values [11] |
| 21 | Unspecified Marginal Cost ($/kW of DER installed-yr) | $2.93 | $2.84 | $1.10 | $1.07 | [21] = [18] * [19] / [20] |
| | | | | $8.45 | | |

| | SCE Total Distribution System | | |
|---|---|---|---|
| | Load Decreasing DERs | Load Increasing DERs | Notes |
| Unspecified Marginal Cost ( $/kW of DER installed-yr) | $12.30 | $10.12 | Sum of all SCE unspecified marginal costs [17] + [21] for each category |

| | | PG&E | SCE | SDG&E | Notes |
|---|---|---|---|---|---|
| 22 | Average Unspecified Marginal Cost ($/kW of DER installed-yr) | $2.76 | $11.21 | $2.53 | Average of values for load decreasing and load increasing DERs for each utility |

Notes:

[1] Number of circuits or areas in the utility Grid Needs Assessment (GNA) that have a deficiency or overload over the planning horizon (2025-2029) based on the utility planning forecast that includes peak load reductions due to DER.

[2] Number of overloads expected to occur in a counterfactual scenario. As a part of the Grid Needs Assessment (GNA) each utility submitted a list of distribution areas with three key elements: a) Projected Load Forecasts (2025-2029) b) Projected DER adoption (2025-2029) and c) Facility Loading Limits.
The counterfactual forecast takes the planning forecast and adds back, or removes, the load reduction or load increase on each circuit that results from the projected DER reduction. A circuit or area is considered overloaded if the projected load forecast in any year (2025-2029) exceeds the facility loading limit.

[3] Share of proposed projects that could be deferred by load transfers or similar low-cost or no-cost solutions, labeled collectively as the load transfer ratio. This was only able to be calculated or estimated using earlier GNA + DDOR methodology for PG&E and SDG&E. The PG&E value had also been determined as a reasonable approximation for SCE. These values are preserved from the 2020 and 2021 ACC updates. In response to a data request from the Energy Division, the utilities each indicated that they do not currently have any recommendations for a better approach to estimate this input.

[4], [5] Sum of the maximum deficiency (kW) from 2025-2029 for each of the overloads identified in [1] and [2]

[5b] Overload capacity estimated to be deferred by DERs in the planning forecast (Counterfactual overloads minus actual overloads)

[6] Overload capacity estimated to be deferred by DERs in the planning forecast, multiplied by one minus the load transfer ratio in order to exclude overloads that would otherwise be expected to be avoided by load transfers or other low-cost or no-cost solutions.

[7-9] 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 project costs and associated grid needs are collected from the 2025 Grid Needs Assessment and DUPR reports provided by the utilities, with further detail on projects noted provided in responses to Data Requests from the Energy Division and its consultant.

[11] Total forecasted DER was calculated by using the GNA and summing all DER adoption from 2025-2029 across all areas, including areas that were not overloaded.

[13] See following section on derivation of distribution marginal cost factors

[15-16] O&M information is from data requests to the IOUs

### *Derivation of Distribution Marginal Cost Factors*

Distribution marginal cost factors annualize the unit cost of capital investment using RECCs provided by each utility and add adjustments for A&G, General Plant, Working Capital, and Franchise Fees and Uncollectables. PG&E also includes the cost of O&M in its marginal cost factor, whereas SCE and SDG&E provide O&M costs separately. In response to data requests for the 2026 ACC, PG&E noted that annual deferral value is no longer calculated in the DIDF process. The only value updated at this time for PG&E is its distribution RECC, while remaining inputs have not been updated in the utility's GRC process since the 2024 ACC update cycle.

The detailed derivations of each utility's marginal cost factors are shown in the following tables.

### *Table 10-8. PG&E Distribution Annual Marginal Cost Factor*

| Loaders & Financial Factors Inputs: | | 2026 ACC Values | |
|---|---|---|---|
| Real Economic Carrying Charge (RECC) | [1] | 4.71% | |
| Electric Distribution O&M Loading Factor (Capital Basis) | [2] | 2.46% | |
| A&G Payroll Loading Factor Distribution (Distribution O&M + A&G Basis) | [3] | 31.63% | |
| General Plant Loading Factor Transmission (Transmission O&M + A&G Basis) | [4] | 6.03% | |
| Materials and Supplies Carrying Charge (Plant Based) | [5] | 0.88% | |
| Cash Working Capital Carrying Charge (Dist. O&M + A&G Based - Annualized) | [6] | 3.11% | |
| Franchise Fees & Uncollectibles Loading Factor RRQ Basis | [7] | 1.0111 | |
| MARGINAL INVESTMENT | | | |
| Marginal Investment | [8] | $100.00 | |
| **Annualized Marginal Investment** | [9] | $4.71 | [9] = [8] x [1] |
| MARGINAL EXPENSES | | | |
| O&M Expense | [10] | $2.46 | [10] = [8] x [2] |
| A&G Expense | [11] | $0.78 | [11] = [10] x [3] |
| General Plant | [12] | $0.20 | [12] = ([10] + [11]) x [4] |
| **Sub-total Marginal Expenses** | [13] | $3.43 | [13] = [10] + [11] + [12] |
| WORKING CAPITAL ALLOWANCE | | | |
| Materials and Supplies On-hand | [14] | $0.03 | [14] = ([10] + [11]) x [5] |
| Cash Working Capital | [15] | $0.10 | [15] = ([10] + [11]) x [6] |
| **Sub-total Carrying Costs** | [16] | $0.13 | [16] = [14] + [15] |
| **Franchise Fees and Uncollectibles** | [17] | $0.09 | [17] = ([9] + [13] + [16]) x ([7] - 1) |
| Marginal Cost | [18] | $8.36 | [18] = [9] + [13] + [16] + [17] |
| Annual Marginal Cost Factor | [19] | 8.36% | [19] = [18] / [8] |

Notes
[1] General RECC from 2023 PG&E DUPR Appendix E: LNBA Planned Investments - General Inputs
[2] E-Dist Primary Composite same as 2022 and 2021 ACC updates. From Table 1: Financial Factors provided in PG&E Response to OIR
[3] Distribution A&G from 2020 GRC Phase II Table 10-2 (Line 16)
[4] Distribution GPLF from 2020 GRC Phase II Table 10-2 (Line 17)
[5] M&S from 2020 GRC Phase II Table 10-2 (Line 18)
[6] CWC from 2020 GRC Phase II Table 10-2 (Line 19)
[7] FF&U from 2020 GRC Phase II Table 10-2 (Line 20)
[8] $100 is used to represent a small marginal level of investment in the system and for simplicity in illustrating factors
*PG&E confirmed that values 2-7 have not changed since the 2022 ACC Update*

### Table 10-9. SCE Distribution Annual Marginal Cost Factor

| Loaders & Financial Factors Inputs: | | | |
|---|---|---|---|
| Real Economic Carrying Charge (RECC) | [1] | 8.59% | |
| Electric Distribution O&M ($/kW-yr) | [2] | | |
| A&G Payroll Loading Factor (Capital basis) | [3] | 1.13% | |
| General Plant Loading Factor (Annual Capital basis) | [4] | 6.39% | |
| 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 | |
| **Annualized Marginal Investment** | [9] | *$8.59* | [9] = [8] x [1] |
| MARGINAL EXPENSES | | | |
| O&M Expense (to be added directly, rather than included as a factor) | [10] | | [10] = included separately, not included in factors for SCE |
| A&G Expense | [11] | *$1.13* | [11] = [8] x [3] |
| General Plant | [12] | *$0.55* | [12] = [9] x [4] |
| **Sub-total Marginal Expenses** | [13] | *$1.679* | [13] = [10] + [11] + [12] |
| WORKING CAPITAL ALLOWANCE | | | |
| Materials and Supplies On-hand (currently not used) | [14] | | |
| Cash Working Capital (currently not used) | [15] | | |
| **Sub-total Carrying Costs** | [16] | | |
| **Franchise Fees and Uncollectibles** | [17] | *$0.12* | [17] = ([9] + [13] + [16]) x [7] |
| Marginal Cost | [18] | *$10.39* | [18] = [9] + [13] + [16] + [17] |
| Annual Marginal Cost Factor | [19] | *10.39%* | [19] = [18] / [8] |

### Table 10-10. SDG&E Distribution Annual Marginal Cost Factor

| Loaders & Financial Factors Inputs: | | | |
|---|---|---|---|
| Real Economic Carrying Charge (RECC) | [1] | 7.42% | |
| Electric Distribution O&M ($/kW-yr added later) | [2] | | |
| A&G Payroll Loading Factor Distribution ( Annual Capital basis GPL) | [3] | 1.53% | |
| General Plant Loading Factor Distribution ( Annual Capital basis) | [4] | 3.07% | |
| Materials and Supplies Carrying Charge (Plant Based) | [5] | | |
| Cash Working Capital Carrying Charge (Capital Based) | [6] | 2.14% | |
| Franchise Fees & Uncollectibles Loading Factor RRQ Basis | [7] | | |
| MARGINAL INVESTMENT | | | |
| Marginal Investment | [8] | $100.00 | |
| **Annualized Marginal Investment** | [9] | *$7.42* | [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 (added separately) |
| A&G Expense | [11] | *$0.12* | [11] = [3] x ( [9] + [12] + [15]) |
| General Plant | [12] | *$0.23* | [12] = [4] x [9] |
| **Sub-total Marginal Expenses** | [13] | *$0.35* | [13] = [10] + [11] + [12] |
| WORKING CAPITAL ALLOWANCE | | | |
| Materials and Supplies On-hand | [14] | | |
| Cash Working Capital | [15] | *$0.16* | [15] = [9] x [6] |
| **Sub-total Carrying Costs** | [16] | *$0.16* | [16] = [14] + [15] |
| **Franchise Fees and Uncollectibles** | [17] | | |
| Marginal Cost | [18] | *$7.93* | [18] = [9] + [13] + [16] + [17] |
| Annual Marginal Cost Factor | [19] | *7.93%* | [19] = [18] / [8] |

## A.5. Weather Year Remapping for Distribution and Transmission

Both transmission capacity hourly allocation factors for historical load years and distribution capacity hourly allocation factors are remapped from the original weather year to match the typical meteorological year (TMY) weather files used for the avoided cost modeling. The motivation for this weather year remapping is the fact that temperature is a strongly correlated variable with load, so using hourly load allocation factors across different years, when hourly weather patterns are different, does not produce meaningful results. The hourly distribution allocation factors are therefore reordered such that the corresponding dry bulb temperature from their native year match with the dry bulb temperature of a particular hour in the TMY. This reordering also takes into account the occurrence of weekends and holidays, as well as daylight-savings time, to match a 2018 calendar year. This remapping of allocation factors for weekends vs. workdays is particularly important for the evaluation of DERs and energy efficiency measures that vary according to occupation schedules such as commercial office HVAC.

Remapping relies on dry bulb temperature data from the National Oceanic and Atmospheric Administration database for weather stations within each California climate zone, as listed in Table 10-11.[36] Because weather data for climate zone 6 had significant data quality issues and missing values, temperature data for climate zone 9 was used to approximate climate zone 6. This proxy climate zone was selected both based on geographic proximity and the observed alignment of heating and cooling days between climate zones 9 and 6.

***Table 10-11. Climate Zones and Representative Weather Stations***

| Climate Zone: Weather Station | WBAN |
|---|---|
| CZ 1: Arcata | 24283 |
| CZ 2: Santa Rosa | 23213 |
| CZ 3: Oakland | 23230 |
| CZ 4: San Jose | 23293 |
| CZ 5: Santa Maria | 23273 |
| CZ 6: Torrance | 3174 |
| CZ 7: San Diego-Lindbergh | 23188 |
| CZ 8: Santa Ana | 93184 |
| CZ 9: Burbank-Glendale | 23152 |
| CZ10: Riverside | 3171 |
| CZ11: Oroville | 93210 |
| CZ12: Sacramento | 93225 |
| CZ13: Fresno | 93193 |
| CZ14: Palmdale | 23182 |
| CZ15: Palm Spring-Intl | 93138 |
| CZ16: Blue Canyon | 23225 |

The remapping process takes two year's weather data as inputs: the weather data of the native year of the PCAF data,[37] and the weather data of the TMY. First, for each of the two input years, the hourly 8760 dry bulb temperature data is aggregated into a daily granularity by assigning each day's

[36] https://www.ncei.noaa.gov/access/search/data-search/local-climatological-data-v2

[37] For the distribution PCAFs, the native weather years are as follows: PGE: 2017, SDG&E: 2025, SCE: 2025. For the transmission PCAFs, the native weather years for all utilities is 2025.

temperature the dry bulb temperature at midnight. The resulting daily timeseries data are then assigned bins parametrized by the combination of workday/weekend-holiday classification and month. Within each bin, the daily timeseries data is rank-ordered by the drybulb temperature metric for each day. At the end of this process, there are two daily-granularity temperature series, each bucketed by month- and weekend/weekday classification.

The next step in the remapping process entails matching each day from the PCAF-native year to the TMY day within the same month-weekend/weekday bucket. 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 (midnight temperature) will be remapped to the TMY 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.[38] In the case that the number of days between the PCAF-native and TMY datasets are the same, the remapping is bijective so that all PCAF-native days have a 1:1 mapping to a TMY day. The daily data is then expanded to hourly by assigning all hours within the same day to the corresponding TMY hour of the mapped-to day to recover a full 8760 mapping.

The final step in the remapping process is the reordering of the PCAF data using the remapping derived from the daily temperature data described above. This results in distribution hourly allocation factors that sum to the same total of 100% for each climate zone but better reflect the expected impact of TMY weather and align all weekends and holidays with a 2018 calendar year.

[38] 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.

## A.6. AGIC Data

### *Table 10-12. Avoided Gas Infrastructure Cost Inputs from Gas Model*

*PG&E inputs reflect projects from 2021-2025. 2023 dollar year is used as a simple midpoint from the dataset*

| | PG&E | SoCalGas | SDG&E |
|---|---|---|---|
| *Input Dollar Year* | 2023 | 2025 | 2025 |

**Mainline Extension ($/ft)**

| Subdivision | Building Type | PG&E | SoCalGas | SDG&E |
|---|---|---|---|---|
| New Greenfield | Residential Single Family | $ 23.00 | $ 31.00 | $ 95.00 |
| New Greenfield | Residential Multi-Family | $ 24.00 | $ 31.00 | $ 95.00 |
| New Greenfield | Small/Medium Commercial | $ 50.00 | $ 31.00 | $ 95.00 |
| New Greenfield | Large Commercial | $ 50.00 | $ 31.00 | $ 95.00 |

**Service Extension ($/service or building)**

** Excluding trenching costs*

| Subdivision | PG&E | SoCalGas | SDG&E |
|---|---|---|---|
| Existing | $ 3,786.00 | $ 10,159.00 | $ 5,390.00 |
| New Greenfield | $ 78.00 | $ 10,159.00 | $ 5,390.00 |

**Meter ($/meter)**

| Subdivision | Building Type | PG&E | SoCalGas | SDG&E |
|---|---|---|---|---|
| Existing | Residential Single Family | $ - | $ 656.00 | $ 325.00 |
| Existing | Residential Multi-Family | $ 58.00 | $ 656.00 | $ 325.00 |
| Existing | Small/Medium Commercial | $ 1,267.00 | $ 553.00 | $ 325.00 |
| Existing | Large Commercial | $ 1,267.00 | $ 16,309.00 | $ 9,229.00 |
| New Greenfield | Residential Single Family | $ 582.00 | $ 656.00 | $ 325.00 |
| New Greenfield | Residential Multi-Family | $ 511.00 | $ 656.00 | $ 325.00 |
| New Greenfield | Small/Medium Commercial | $ 851.00 | $ 553.00 | $ 325.00 |
| New Greenfield | Large Commercial | $ 851.00 | $ 16,309.00 | $ 9,229.00 |

*Project costs provided by SoCalGas and SDG&E are bundled for existing and greenfield development*

### *Table 10-13. PG&E Avoided Gas Infrastructure Cost Input Assumptions*

| |
|---|
| **Mainline Extension**<br>Includes: Material & Labor<br>Excludes: Trenching, allowances to developer or customers |
| **Service Extension**<br>(1" pipeline from mainline to meter)<br>Includes: Materials & Labor, Trenching (developed for exciting and undeveloped for greenfield)<br>Excludes: Allowances Credited to Customer or Developer |
| **Meter**<br>(Including manifold outlet, where applicable) |

(Values from PG&E data request are included in Table 10-12 above.

### *Table 10-14. SoCalGas Avoided Gas Infrastructure Cost Data Request Inputs*

**Table 1: SoCalGas Gas Infrastructure Cost Estimates**

| | **Existing Subdivision / Development** | **New Greenfield Subdivision / Development** |
|---|---|---|
| **Mainline Extension**<br><br>Includes: Material & Labor<br><br>Excludes: Trenching, allowances to developer or customers | N/A<br><br>It is assumed that new construction in an existing subdivision will not require a mainline extension. | Single Family<br>$31/ft (2025 $)<br><br>Multi-Family<br>$31/ft (2025$) |
| **Service Extension**<br>(varies not to exceed 3" pipeline from mainline to meter)<br><br>Includes: Materials & Labor, Trenching (developed for exciting and undeveloped for greenfield)<br><br>Excludes: Allowances Credited to Customer or Developer | Including Trenching<br>(Developed Area)<br>$10,159/building (2025 $)<br><br>Excluding Trenching<br>$10,159/building (2025 $) | Including Trenching<br>(Greenfield, Undeveloped)<br>$10,159/building (2025 $)<br><br>Excluding Trenching<br>$10,159 building (2025 $) |
| **Meter**<br>(Including manifold outlet, where applicable) | Residential Single Family<br>$656 per meter (2025$)<br><br>Residential Multi-Family<br>$656 per meter (2025 $)<br><br>Small/Medium Commercial<br>$553 per meter (2025 $)<br><br>Large Commercial<br>$16,309 per meter (2025 $) | Residential Single Family<br>$656 per meter (2025 $)<br><br>Residential Multi-Family<br>$656 per meter 2025 $)<br><br>Small/Medium Commercial<br>$553 per meter (2025 $)<br><br>Large Commercial<br>$16,309 per meter (2025 $) |

Notes to Table 1:

1. SoCalGas does not track projects based on existing vs. greenfield development– numbers are provided for new construction as a bundled category.
1. For mainline extensions, 6" and under plastic pipe are typical to serve residential areas and was used as the basis for the costs above. Mainline extension values were provided by SoCalGas' Gas Distribution and overheads were added.
2. For services, SoCalGas does not track costs separately for services including or excluding trenching and therefore provide the same values for both requested here.

Typical residential service lines are ½" diameter. Larger single-family, multi-family buildings and commercial customers sometimes require larger diameter services, depending on the loads being served. To be responsive to the data requested above, we are providing data based on costs per foot which varies but does not exceed 3".

3. For meter costs, SoCalGas is providing the costs of the meter set assembly (MSA), including the meter and pressure regulator as well as labor and non-labor costs for installation.
4. The most common meter size for single family and individually metered multi-family residential is a size 3. Installation and regulator costs are frequently shared for multi-family residential and are therefore lower on a unit cost basis than single family.
5. The most common meter across Small/Medium Commercial customers is a size 1.
6. The most common meter installed for Large Commercial customers (is a size 10.

***Table 10-15. SDG&E Avoided Gas Infrastructure Cost Data Request Inputs***

**Table 2: SDG&E Gas Infrastructure Cost Estimates**

| | Existing Subdivision / Development | New Greenfield Subdivision / Development |
|---|---|---|
| **Mainline Extension**<br><br>Includes: Material & Labor<br><br>Excludes: Trenching, allowances to developer or customers | N/A<br><br>It is assumed that new construction in an existing subdivision will not require a mainline extension. | Single Family<br>$95/ft (2025 $)<br><br>Multi-Family<br>$95 /ft (2025 $) |
| **Service Extension**<br>(1" pipeline from mainline to meter)<br><br>Includes: Materials & Labor, Trenching (developed for exciting and undeveloped for greenfield)<br><br>Excludes: Allowances Credited to Customer or Developer | Including Trenching<br>(Developed Area)<br>$16,188/building (2025 $)<br><br>Excluding Trenching<br>$5,390/building (2025 $) | Including Trenching<br>(Greenfield, Undeveloped)<br>$16,188/building (2025 $)<br><br>Excluding Trenching<br>$5,390/building (2025 $) |
| **Meter**<br>(Including manifold outlet, where applicable) | Residential Single Family<br>$325 per meter (2025 $)<br><br>Residential Multi-Family<br>$325 per meter (2025 $)<br><br>Small/Medium Commercial<br>$325 per meter (2025 $)<br><br>Large Commercial<br>$9,229 per meter (2025 $) | Residential Single Family<br>$325 per meter (2025 $)<br><br>Residential Multi-Family<br>$325 per meter (2025 $)<br><br>Small/Medium Commercial<br>$325 per meter (2025 $)<br><br>Large Commercial<br>$9,229 per meter (2025 $) |

Notes to Table 2:

1. Mainline extension values were provided by SDG&E's Gas Engineering.
2. For mainline extensions, 2" Plastic pipe is typical to serve residential areas and was used as the basis for the costs above.
3. Typical residential service lines are ½" diameter. Larger single-family, multi-family buildings and commercial customers sometimes require larger diameter services, depending on the loads being served. To be responsive to the data requested above, we are providing data based on costs to extend a 1" plastic service to a single-family residential customer site.
4. For meter costs, SDG&E is providing the costs of the meter set assembly (MSA), including the meter and pressure regulator as well as labor and non-labor costs for installation.
5. The most common meter type for single family and individually metered multi-family residential is a type 250.
6. The most common meter type across Small/Medium Commercial customers is a type 250.
7. The most common meter type installed for Large Commercial customers is a type 11M.

## A.7. DER ACC Model Files

The DER ACC model, documentation and supporting files are available at:

- https://www.cpuc.ca.gov/dercosteffectiveness , and
- https://willdan.box.com/v/2026CPUC-ACC

| File | Description |
|---|---|
| CPUC 2026 ACC Documentation | This document. PDF summary of DER ACC inputs, assumptions and methods |
| ACC Electric Model | 8,760 hourly Avoided Costs for electricity |
| ACC Gas Model | Avoided costs for natural gas |
| ACC SERVM Prices | SERVM production simulation model results and scarcity pricing adjustments |
| ACC Integrated Calculation Inputs | Inputs for the Integrated Calculation of GHG and generation capacity avoided costs |
| ACC CPUC Integrated Calculation Model | Integrated Calculation Model zip file with pre-loaded inputs and results for TRC and SCT |

## A.8. Revision Log

**Core updates for 2026 ACC v1a.**

General – Electric ACC

- Used IRP 26-27 TPP portfolio to develop avoided costs
- Updated utility WACCs
- Updated treatment of Cap-and-Invest for SCT to ensure it is included when appropriate based on user selection

GHG

- Updated methodology for GHG adders
- Removal of GHG rebalancing component

SERVM Prices and Implied Heat Rate

- Updated the SERVM prices forecast

Generation

- Updated Integrated Calculation methodology to derive annual generation capacity avoided costs
- Updated capacity allocation factors based on SERVM LOLH modeling and post-processing of SERVM dispatch reports to capture effects of multi-day discharging

Transmission

- Updated Marginal Transmission Capacity Costs for SCE and SDG&E based on IEPR load forecasts and utility transmission planning data
- Updated Transmission PCAFs using 2025 historical hourly loads and SERVM future load forecasts

Distribution

- Updated Long Term Marginal Distribution Capacity Costs based on most recent utility GRC Phase II filings
- Updated Near Term Marginal Distribution Capacity Costs using 2025 GNA and DUPR filings and accompanying project cost inputs provided by the utilities
- Updated PG&E Distribution PCAFs and SCE Distribution PLRFs based on utility-provided values. Calculated SDG&E Distribution PCAFs based on utility loads
    - Updated weather-year remapping for each utility

Natural Gas ACC

- Updated utility WACCs
- Updated gas GHG cost input to use electric model GHG cost
- Updated AGIC values based on utility data request responses
- Updated transportation costs based on utility data request responses
- No update to gas commodity costs (2023 forecast remains most recent)