2022 Distributed Energy Resources Avoided Cost Calculator Documentation

For the California Public Utilities Commission

August 12, 2022

Version 1b

Available at:
https://willdan.box.com/v/2022CPUCAvoidedCosts

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1 Introduction

This document describes the inputs, assumptions and methods used in the 2022 Distributed Energy Resources (DER) Avoided Cost Calculator (ACC). The DER ACC model, documentation and supporting files are available at:

- https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/energy-efficiency/idsm , and
- https://www.ethree.com/public_proceedings/energy-efficiency-calculator/, and
- https://willdan.box.com/v/2022CPUCAvoidedCosts

Decision (D.)19-05-019 in the Integrated Distributed Energy Resources (IDER) proceeding, R.14-10-003, initiated a process to implement major and minor updates to the Distributed Energy Resources (DER) Avoided Cost Calculator (ACC) in 2020. This process culminated in a Staff Proposal (ACC Staff Proposal) for the 2020 ACC update that was adopted in D.20-04-010. The 2020 ACC update implemented major changes in the CPUC's approach to estimating the avoided costs of distributed energy resources – most importantly, changes to align the ACC with the integrated resources and distribution planning processes. The 2022 ACC implements additional changes, as described below.

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 estimates 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.

Two additional uses of the ACC have been introduced in recent years. D.21-05-031 implemented the Total System Benefit (TSB) test for setting EE portfolio goals. The TSB uses avoided costs to represent the total present value lifecycle benefits of EE programs and will replace kWh, kW and therms as the primary goal for EE program portfolios. A December 13, 2021 proposed decision in the Net Energy Metering (NEM) successor tariff proceeding (R. 20-08-020) adopts the ACC as the basis for setting export compensation for behind-the-meter NEM PV.[2]

The ACC includes multiple components: an electric avoided cost calculator, a natural gas avoided cost calculator (including an avoided natural gas infrastructure calculator) and a refrigerant calculator. The ACC determines several types of avoided costs including avoided generation capacity, energy, ancillary services,

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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

2 A subsequent May 9, 2022 ruling reopened the evidentiary record and invited party comments on a limited basis to explore three elements of the proposed decision.

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 will be based on data and guidance from the distribution planning proceeding. The 2020 ACC was also updated to fully support evaluation of electrification measures that increase load, but may decrease total GHG emissions. This includes adopting a new avoided cost of high global warming potential (GWP) gases, which value the GHG impacts of distributed energy resources (DERs) on methane and refrigerant leakage.[3] The 2022 ACC adopts 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.

The ACC also provides hourly ancillary service prices 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. We also note that the ACC's hourly values has been used to determine the *increased* costs incurred by electrification programs that increase electric load. D.22-05-002 adopts the use of the ACC to determine increased, as well as decreased marginal costs. Table 1 summarizes the differences between the new methods adopted in the 2021 and 2022 ACCs.

[3] 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.

Table 1. Changes from 2021 and 2022 ACC Updates

Avoided Cost	2021 ACC	2022 ACC	Data Source
Generation Capacity	Battery Storage Cost of New Entry	Battery Storage Real Economic Carrying Charge (RECC)	RESOLVE input assumptions
Energy	RESOLVE and SERVM modeling	RESOLVE and SERVM modeling	SERVM outputs
Ancillary Services	RESOLVE and SERVM modeling	RESOLVE and SERVM modeling	SERVM outputs
GHG Value	Based on RESOLVE GHG shadow price and cap & trade	Based on RESOLVE GHG shadow price and cap & trade	RESOLVE outputs, cap & trade prices
GHG Emissions	SERVM short- run marginal emissions and RESOLVE long-run grid emissions intensity	SERVM short- run marginal emissions and RESOLVE long-run grid emissions intensity	RESOLVE and SERVM outputs, cap & trade prices, annual GHG electric sector goals
Transmission	From Distribution Planning	From Distribution Planning	GRC filings, IEPR forecasts, and historical utility cost and financial data
Distribution	From Distribution Planning	From Distribution Planning	GNA and DDOR data
High GWP gases	Methane & refrigerant leakage modeling	Methane & refrigerant leakage modeling	CARB data
Avoided Gas Infrastructure	NA	From utility filings	Utility data

1.1 Summary of Updates for 2022 ACC

The changes implemented for the 2022 major update cycle are listed below in Table 2. A summary comparison of avoided costs from the 2021 and 2022 ACC models are shown for PG&E, Climate Zone 12 (Sacramento) in the year 2030 in Figure 1 through Figure 4 (in nominal dollars in 2030). As explained further in the documentation below, the 2022 Avoided Costs are generally higher than 2021 in total values with a few major changes:

- Higher near-term capacity avoided costs, largely as the result of the low forecast of AS revenue from the SERVM model and the change from Net Cost of New Entry (Net CONE) approach to Real Economic Carrying Charge (RECC) approach. Net CONE only considers 1st year costs and revenues of a storage asset, but RECC considers the lifetime deferral value of the asset.

- Higher midday energy prices forecasted from SERVM around 2030 and declining GHG rebalancing values during the middle of the day due to low GHG shadow price.
- Higher near-term distribution avoided costs for PG&E and SDG&E due to increases in calculated counterfactual overload kW for both utilities.
- Higher transmission avoided costs for PG&E due to the November 2021 CPUC ruling replacing PG&E's calculated value with the value recommended by the Solar Energy Industries Association.
- Higher transmission avoided costs for SDG&E based on reduced demand forecasts and increased systemwide transmission project costs as determined by the utility.
- Lower GHG value from IRP RESOLVE modeling because the "No New DER" scenario removes both load reducing and load increasing DERs, and the 2020 CEC IEPR load forecasts include more electrification load.
- Natural gas avoided costs double as 2022 ACC adopts separate interim GHG value for the natural gas sector based on building electrification costs, rather than the electric sector GHG value, to reflect the higher costs to decarbonize the natural gas sector

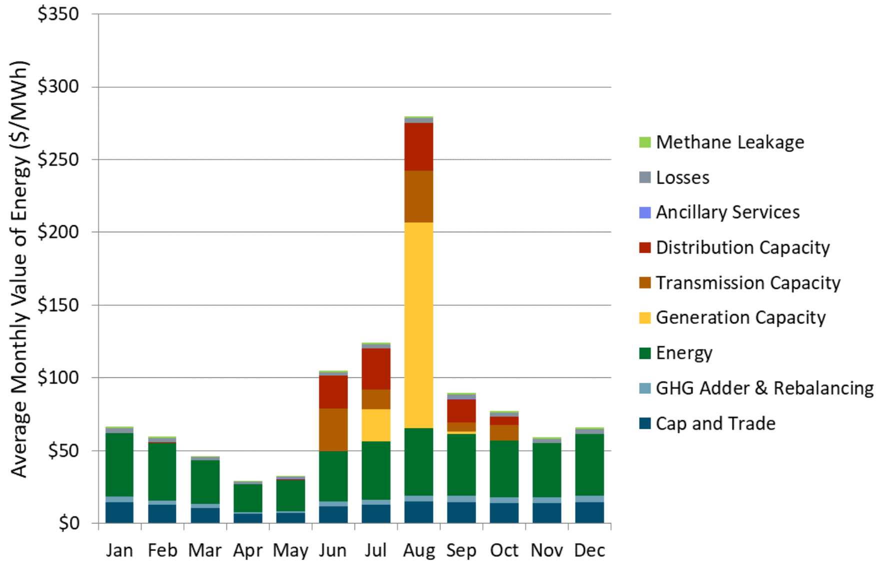
Table 2. Summary of 2022 ACC Update

Input	2022 Update	Data Source
No New DER Portfolio	Load and DER Forecasts	Final 2020 CEC IEPR Load Forecasts
	No New DER Portfolio	CPUC IRP RESOLVE Capacity Expansion Modeling
IRP Proceeding Inputs	Natural Gas Prices	CEC Power Plant Burner Tip Price Model, June 2020 Model
	Cost of Energy Storage	CPUC IRP RESOLVE Resource Costs and Build Inputs
	Weighted Average Cost of Capital	CPUC Authorized Rate of Return for 2021
SERVM Production Simulation	Updated SERVM Model from Astrapé	Run with No New DER Portfolio from CPUC IRP
Distribution Planning Inputs	No update	
Natural Gas Avoided Cost	CEC IEPR Natural Gas Prices	CEC Power Plant Burner Tip Price Model, June 2020 Model
	Transportation Rates Forecasts	CEC Power Plant Burner Tip Price Model, June 2020 Model
	GHG Adder	CEC GHG abatement cost for residential building electrification
Energy	Implied Marginal Heat Rate	Recalculated From SERVM Production Simulation based on CEC IEPR and CPUC ACC Natural Gas Prices
	Updated Scarcity Pricing Methodology	Benchmarked scarcity coefficient using historical 2021 SP15 DA energy prices
	Day Ahead Hourly Energy Prices	SERVM Production Simulation with Scarcity Pricing Adjustment
Ancillary Services	Real Time Energy and AS Prices	SERVM Production Simulation
	Avoided AS Procurement	Recalculated with SERVM Production Simulation Results
Generation Capacity	Generation Capacity	CPUC IRP RESOLVE Resource Costs and Build Inputs
GHG Value	GHG Value	CPUC IRP RESOLVE Capacity Expansion Modeling

Input	2022 Update	Data Source
	Cap and Trade Value	Final 2019 CEC IEPR
GHG Emissions	Updated Heat Rates from SERVM Modeling	Implied Market Heat Rates from CPUC SERVM Production Modeling
	Average Annual Grid GHG Emissions Intensity	CPUC IRP RESOLVE Capacity Expansion Modeling
Transmission	Update Transmission Allocation Factors	Transmission PCAFs calculated from 2021 CAISO load data for each utility
	Update Marginal Transmission Capacity Cost	IOU GRC Phase II filings and Loading Factor Inputs, Transmission Project Costs and Loading Factor inputs, and CEC IEPR
Distribution	Update Marginal Capacity Costs	IOU 2021 GNA and DDOR reports for near term, GRC filings for long term
High GWP gases	Updated GHG Adder	CPUC IRP RESOLVE Capacity Expansion Modeling

Figure 1. Average Monthly Avoided Costs (PG&E Climate Zone 12 in 2030)

2022 ACC



2021 ACC

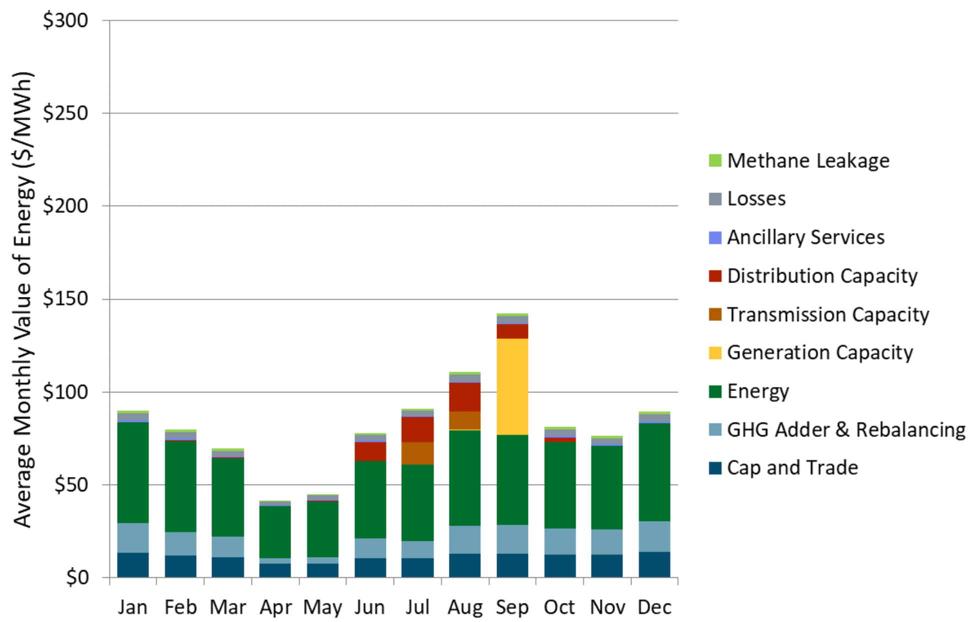
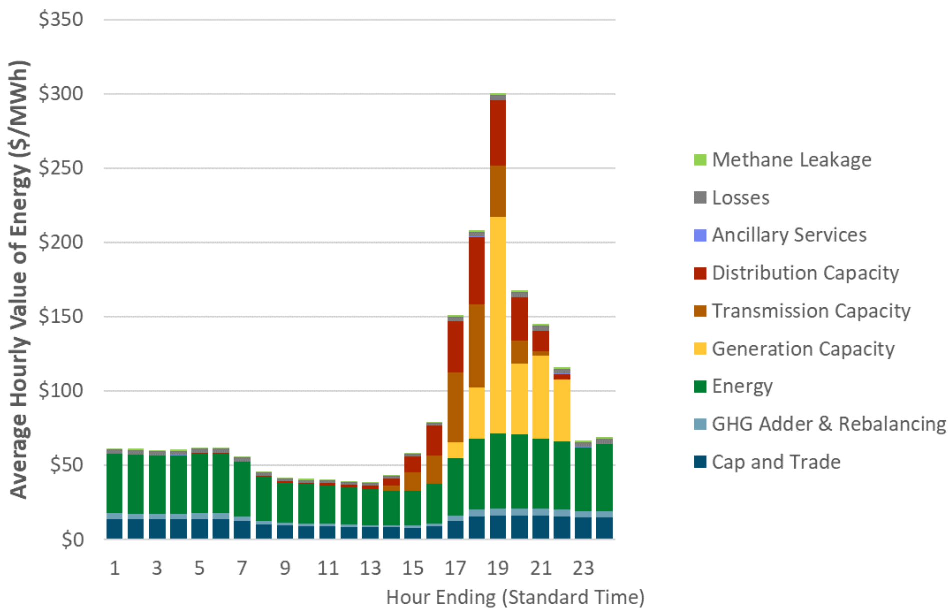


Figure 2. Average Hourly Avoided Costs (PG&E Climate Zone 12 in 2030)

2022 ACC



2021 ACC

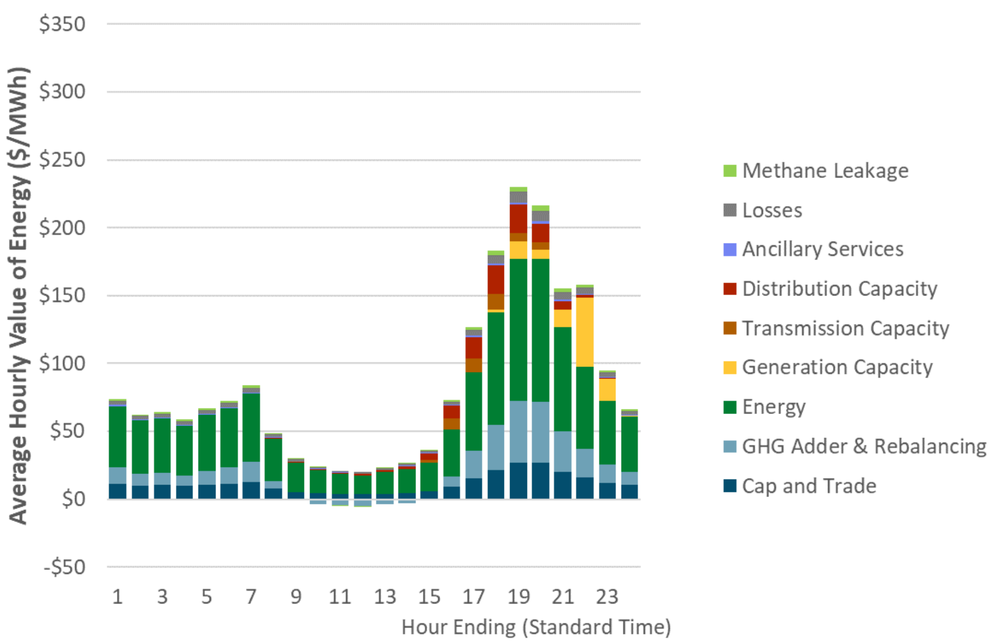
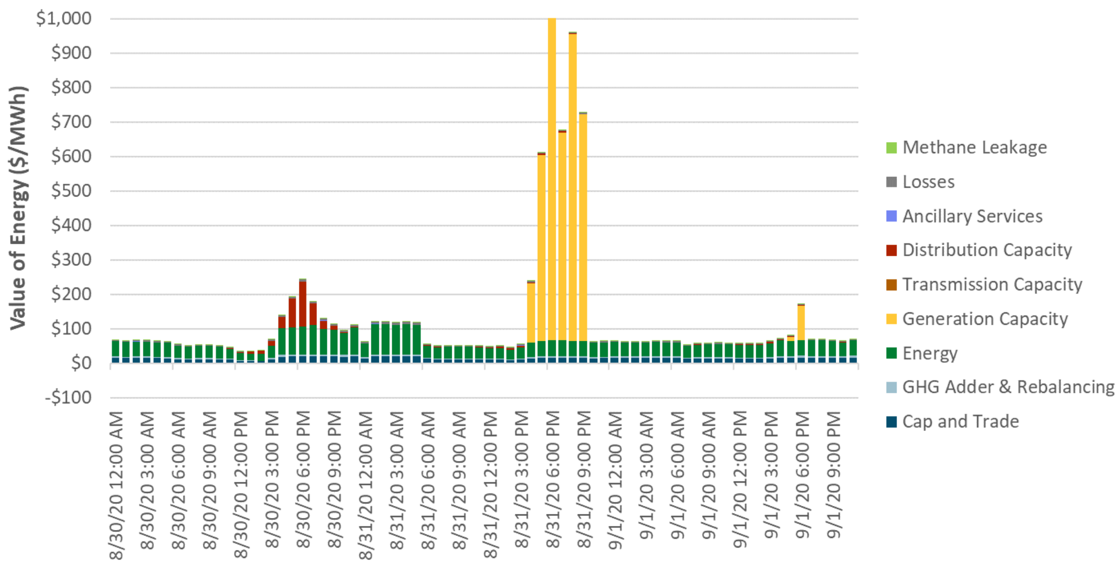
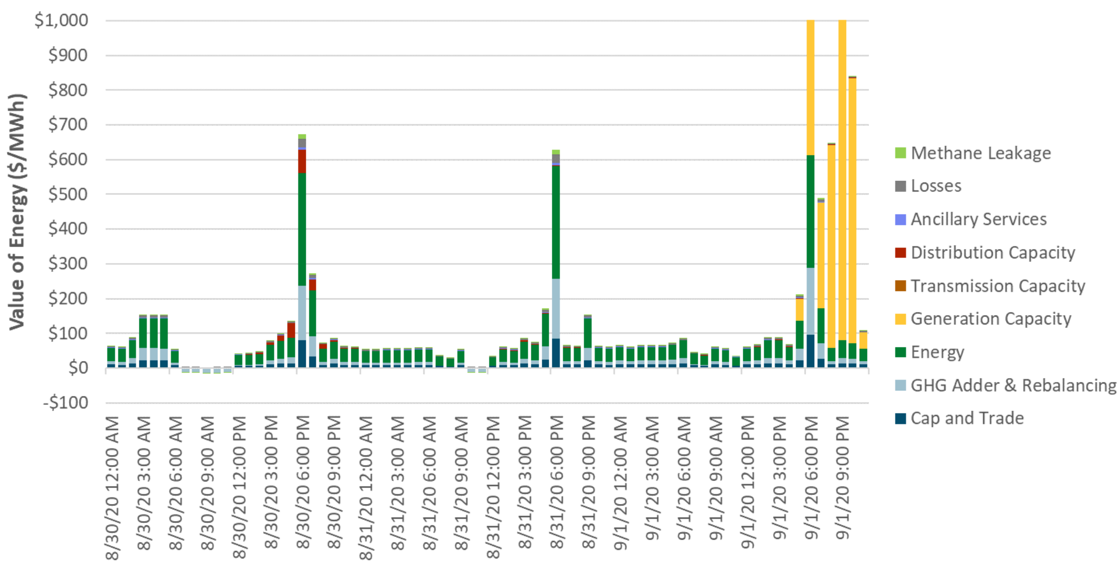


*Figure 3. Hourly Avoided Costs for Three Days Beginning August 30th (PG&E Climate Zone 12 in 2030)**

2022 ACC



2021 ACC

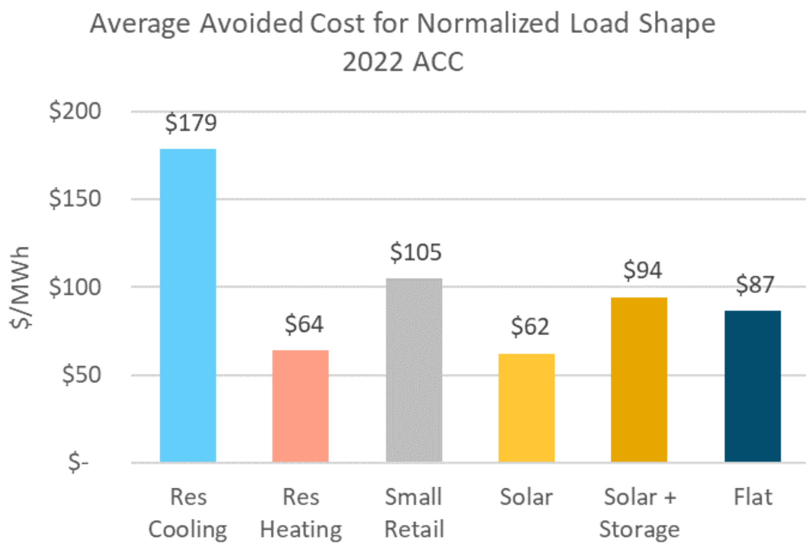


**Vertical axis is capped at $1,000/MWh. The high generation capacity hours shift from September in 2021 ACC (based on RECAP EUE results) to August in 2022 ACC (based on SERVM EUE results).*

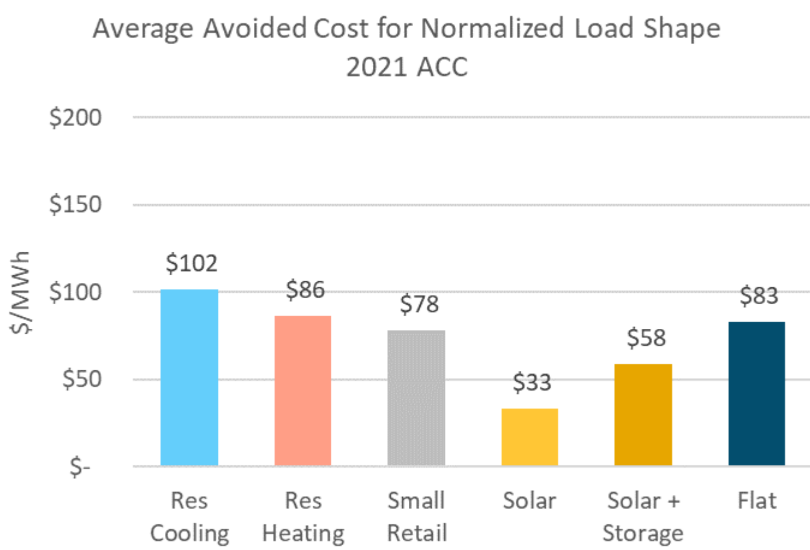
Annual average avoided costs from the 2022 ACC are shown for the single year of 2030 for selected end-use electric load shapes are shown Figure 4. The load shapes are end uses (not measure-specific impacts) for selected loads or generation (e.g., solar) types. "Flat" refers to use of a shape that has the same consumption in all hours to reflect a simple average avoided costs across all hours.

Figure 4. Average Annual Avoided Cost for Illustrative Normalized Load Shapes (PG&E Climate Zone 12 in 2030)

2022 ACC



2021 ACC



1.2 Flow Charts of Information Used in ACC

Figure 5 details the flow of data from IRP, Distribution Planning proceedings, and data sources such as the California Energy Commission (CEC) Integrate Energy Policy Report (IEPR), various California Air Resource Board (CARB) databases, and data from the California Independent System Operator (CAISO). Figure 6 shows the flow of inputs and calculations in the ACC.

Figure 5. Avoided Cost Process Overview

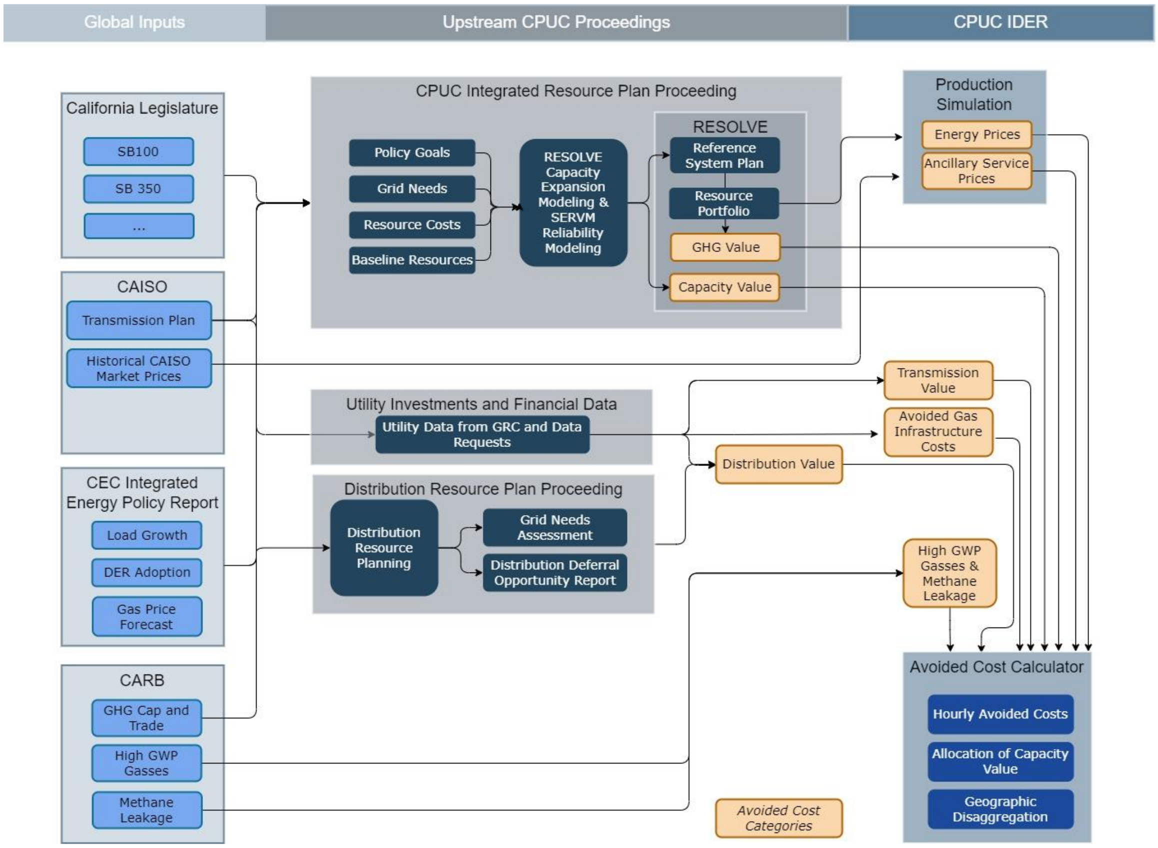
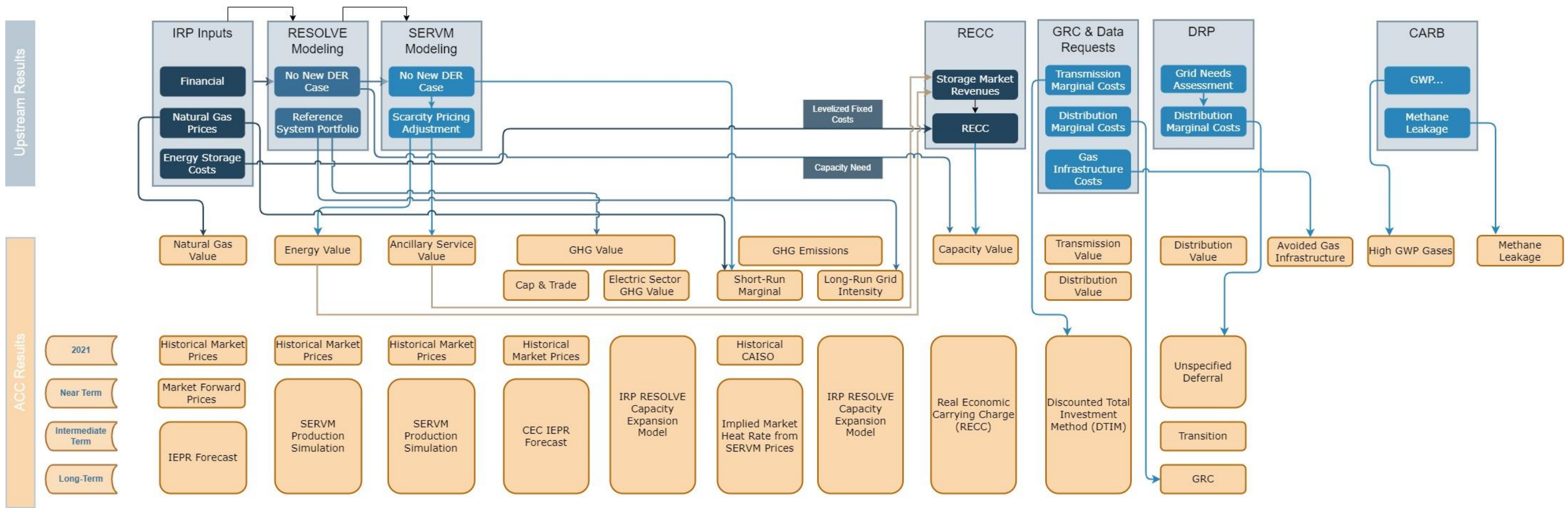


Figure 6. Avoided Cost Calculator Structure



2 Integrated Resource Planning Proceeding Inputs

Since 2020, the ACC has used inputs from the IRP proceeding.[4] 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.

California's IRP proceeding uses the RESOLVE resource planning model, which is a publicly available and vetted tool.[5] RESOLVE is a linear optimization model that co-optimizes investment and dispatch for a select number of days over a multi-year horizon to identify least-cost portfolios for meeting carbon emission reduction targets, renewables portfolio standard goals, reliability during peak demand events, and other system requirements. RESOLVE is used to create capacity expansion plans, including Reference System Plans (RSP) and Preferred System Plans (PSP), which identify supply-side resource build requirements and costs for the CPUC's IRP proceeding. Lastly, the final generation portfolio from RESOLVE is inputted into the SERVM model, a production simulation model provided by Astrapé Consulting, to generate wholesale electricity prices and access the reliability of the modeled generation portfolio.

The 2022 ACC relied upon the 2021 PSP Portfolio adopted in the IRP Proceeding. Over the last year, the IRP proceeding performed analyses with updated inputs and assumptions, including updated resource cost and build inputs and results from the Final 2020 CEC IEPR. The 2022 ACC uses the most recent available inputs and outputs from RESOLVE scenarios developed in 2019-2020 IRP Proceeding with these updates.

2.1 No New DER Scenario

The capacity expansion plans determined in the IRP proceeding include assumed levels of future DER adoption for most types of DERs. The forecasted DER levels are built-in as modifiers to overall system demand, and therefore impact the number and types of supply-side resources selected by RESOLVE. To better estimate the value that DERs can play in meeting demand, the IRP developed a sensitivity where DER adoption was projected to remain at the 2021 levels. This "No New DER" scenario assumes that no additional DERs are adopted post-2021 and demand response is discontinued, thus demonstrating a hypothetical counterfactual in which incremental DER adoption does not occur. In addition, the 2022 ACC uses an updated No New DER scenario that eliminates projected load increases due to fuel substitution/electrification. Removing both load increasing and load reducing DERs accounts for all types of DERs in the "No New DER" scenario. The No New DER scenario allows the IRP and ACC to explore the difference in supply-side costs in a situation where additional DERs are not adopted, and as a result, how much supply-side resources are necessary to meet overall demand. All other inputs are consistent with the

[4] See 2019-2020 IRP Events and Materials for source documents: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2019-20-irp-events-and-materials

[5] RESOLVE models, inputs and results are available at:
https://files.cpuc.ca.gov/energy/modeling/2021%20PSP%20NoNewDER%20RESOLVE%20Package.zip

latest resource portfolios modeled in the IRP Proceeding. Table 3 shows the changes in DER adoption to create the No New DER case, based on the DER adoption projected in the Final 2020 CEC IEPR.

The “No New DER” scenario keeps the amount of Behind-the-Meter solar installation would be adopted associated with building codes. Starting in 2020, since the 2019 California Building Standards went into effect, CEC stopped producing an Additional Achievable PV (AAPV) forecast. The installed PV capacity due to building codes from the 2020 IEPR was provided by CEC through a data request.

Table 3. DERs Removed in the “No New DER” Case

Load Increasing Electrification Removed

Electric Vehicles (GWh)	2021	2030	2040	2050
CEC 2020 IEPR - High Demand	3,758	14,668	32,420	49,316
No New DER	3,758	3,758	3,758	3,758
Other Transport Electrification (GWh)	**2021**	**2030**	**2040**	**2050**
CEC 2020 IEPR - Mid Demand	194	1,548	8,004	16,859
No New DER	194	194	194	194
Building Electrification (GWh)	**2021**	**2030**	**2040**	**2050**
None Through 2030	-	-	21,062	43,143
No New DER	-	-	-	-

Load Reducing DER Removed

Energy Efficiency (GWh)	2021	2030	2040	2050
CEC 2020 IEPR - Mid-Mid AAEE	1,988	10,229	21,701	34,829
No New DER	1,988	1,988	1,988	1,988
Behind-the-Meter PV (GWh)				
CEC 2020 IEPR - Mid PV + Mid-Mid AAPV	19,415	37,581	55,820	74,058
CEC 2020 IEPR - Mid-Mid AAPV	790	4,109	7,874	11,639
No New DER	19,415	23,524	27,289	31,054
Behind-the-Meter CHP (GWh)				
CEC 2020 IEPR	12,483	11,558	-	-
No New DER	12,483	11,558	-	-
Non-PV Non-CHP Self Generation (Includes Storage Losses) (GWh)				
CEC 2020 IEPR	281	256	396	537
No New DER	281	281	281	281
BTM PV Capacity (MW)				
CEC 2020 IEPR - Mid PV + Mid-Mid AAPV	11,481	21,706	32,151	42,596
CEC 2020 IEPR - Mid-Mid AAPV	451	2,345	4,494	6,643
No New DER	11,481	13,826	15,975	18,124
BTM Storage (MW)				
CEC 2020 IEPR	668	2,584	2,584	2,584
No New DER	668	668	668	668
Load Modifying Demand Response (MW)				
Load-Modifying Demand Response: 2020 Mid-Mid AAEE	(70)	(74)	-	-
No New DER	-	-	-	-
Shed DR (MW)				
Mid	1,617	1,617	1,617	1,617
No New DER	-	-	-	-

Loads - grossed up for T&D losses (GWh)	2021	2030	2040	2050
PSP Load	233,876	265,140	330,752	383,506
Load Impact of Removing Load Increasing Electrification *	-	(13,236)	(62,096)	(113,721)
Load Impact of Removing Load Reducing DER	-	8,867	21,400	35,720
**No New DER Load ** **	**233,876**	**260,936**	**290,222**	**305,671**

* Negative sign stands for decreased load impact; postive sign stands for increased load impact

** The load values reflect the calculation to derive the demand-side "Load" outputs in RESOVLE Results Viewer
"Load" outputs in RESOLVE Results Viewer does not reflect the impact of removing DERs (e.g. BTM PV)modeled as a supply-side resources in RESOLVE
DERs (e.g. BTM PV) modeled as a supply-side resources are removed on the supply side (under the resource type of "Customer Solar") in RESOLVE

2.2 IRP Data Used in the ACC

The IRP data used as inputs to the ACC includes basic planning inputs, such as utility Weighted Average Cost of Capital (WACC), the natural gas price forecast (which originally comes from the Integrated Energy Policy Report (IEPR)). The inputs are shown for the No New DER scenario described above.

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

2.3 SERVM Production Simulation

Since 2020, a production simulation model has been used to generate values for the energy, ancillary services, and emissions avoided cost components. California's electricity grid is rapidly evolving with the integration of renewable energy generation and energy storage, and wholesale electricity market price shapes depart from historical trends. Therefore, the Avoided Cost Calculator incorporates production simulation modeling for forecasted years. The CPUC performs extensive production simulation modeling as a part of the IRP modeling, providing a logical source of consistency between the IRP proceeding and the ACC. Since the 2020 ACC update, CPUC staff performs SERVM modeling using the No New DER case. SERVM is an 8760 hourly production simulation model provided by Astrapé Consulting that generates wholesale electricity prices based on the input system load and dispatch of the modeled generation portfolio.

Since the 2020 ACC update, Astrapé has updated algorithms used in SERVM and the CPUC staff and Astrapé performed benchmarking of SERVM model results to actual CAISO prices. CPUC staff performed new SERVM modeling with the No New DER portfolio provided by IRP RESOLVE modeling with the updated SERVM model for the 2022 ACC update. A comparison of 2021 and 2022 SERVM model results is presented in Appendix 14.1.

Model runs are performed for years 2022-2032 to reflect forecasted changes in system load and generation portfolio. In 2022 ACC, additional runs have been conducted for 2035, 2040 and 2045 to capture long-term price dynamics. This is an improvement over the straight-line inflation methodology used in prior ACCs. Each year assumes the CEC's new California Thermal Zone 2022 (CTZ22) typical meteorological year (TMY), shown in the table below.[6] As part of the IRP process, CPUC staff developed predictive models for system load shape and renewable generation profiles based on hourly weather conditions. To accurately model the effects of real weather data, CTZ22 selects specific full historical months, and references those historical months consistently across the state. For example, for the month of June, each climate zone will use local weather data from June 2013. Climate zone effects are then aggregated up to balancing authority and statewide levels.

Table 4. CTZ22 Historical Weather Months

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

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

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

3 Distribution Planning Proceeding Inputs

In June 2019, the Distribution Planning and IDER proceedings jointly issued an Amended Ruling "to determine how to estimate the value that results from using DER to defer transmission and distribution

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

(T&D) infrastructure".[7] The Ruling includes an Energy Division White Paper entitled *Staff Proposal on Avoided Cost and Locational Granularity of Transmission and Distribution Deferral Values* (T&D Staff White Paper) to estimate avoided T&D costs based on the forecast data provided in the IOU Grids Needs Assessment (GNA) and Distribution Deferral Opportunities Reports (DDOR). Utility GNA and DDOR reports filed in August 2021 are used to calculate near-term distribution avoided costs in the 2022 ACC update.

As first implemented in the 2020 ACC update, for the 2022 ACC we applied the T&D Staff White Paper methodology for calculating transmission and distribution values in this update. This methodology calculates specified and unspecified costs for both transmission and distribution.

Specified distribution deferral values are costs associated with distribution capacity projects that are currently being undertaken by each utility. Specified distribution deferral values are already estimated through the Distribution Investment Deferral Framework and therefore do not require further modeling to estimate or incorporate their values into the ACC.

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

4 Natural Gas Avoided Costs

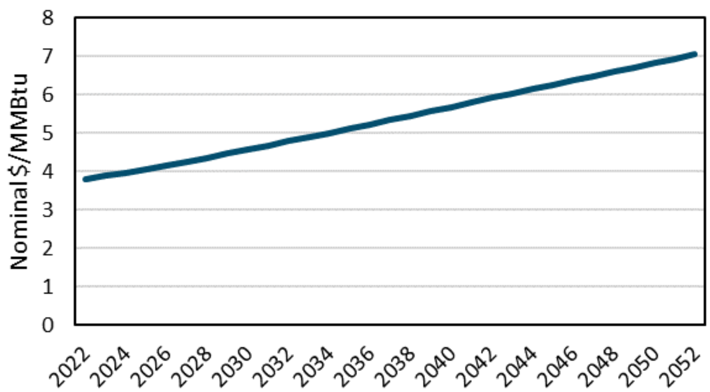
Natural gas ACC is developed to determine the benefits of programs which reduce direct natural gas consumption. In 2022 ACC, the Natural Gas ACC switched to CEC IEPR forecasts to develop avoided costs both for retail natural gas consumption and for electric generation, to be consistent with IRP. This is to ensure that demand-side resources and supply-side resources are evaluated using the same assumptions.

4.1 Continental Natural Gas Market

Natural gas delivered to California consumers is traded in an aggregate wholesale market that spans most of North America. Interstate natural gas pipelines transport the gas from the wellhead to wholesale market centers or "pricing hubs," where buyers include marketers, large retail customers, electric generators, and local distribution companies (LDCs) that purchase gas on behalf of small retail customers. The two pricing hubs most relevant for California are "PG&E Citygate" and "SoCal Border." The IEPR provides forecasts for the SoCal Border and PG&E Citygate up to 2035. The ACC translates the annual forecast values into monthly values using multipliers derived from the IEPR forecast and extrapolates values beyond 2035 (Figure 7). The EG natural gas avoided costs are then used as an input for the Electric ACC.

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

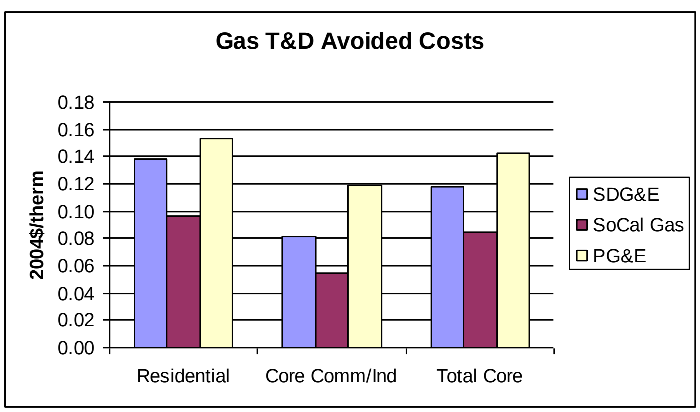
Figure 7. CA Gas Price Forecast ($Nominal)



4.2 Avoidable Marginal Distribution Costs for Core Customers

Avoided distribution costs reflect avoided or deferred upgrades to the distribution systems of each of the three investor-owned utilities in California. Unlike with electricity, hourly allocations are not necessary because of the ability of utilities to "pack the pipe," making use of the natural storage capacity of gas pipelines. Costs are allocated to winter peak months, however, to reflect the winter-peak driven capacity costs, especially for distribution pipe serving core customers. "Core" customers refer to the residential and small commercial customers that represent the majority of natural gas utility customers in California. The avoided costs in Figure 8 are from the Original 2005 Avoided Cost Report and have only been updated for inflation.

Figure 8. Natural Gas T&D Avoided Costs by Utility



4.3 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. 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 ACC. The CEC website has been updated with the 2021 model.[8] However, 2022 ACC still use the rates from the 2020 model, as shown in Table 5 below, to be consistent with the IRP model that uses the inputs from the 2020 model.

Table 5. Gas Transportation Charges for Electric Generators (2018$/MMBtu)

SoCalGas Backbone	SoCalGas TLS	PG&E Backbone (Redwood to On-System)	PG&E Backbone EG	PG&E Local Tranmission
$0.3598	$0.1084	$0.1717	-$0.0004	$1.0058

In the 2020 version of the CEC model, the Cap-and-Trade Cost Exemption Credit is subtracted, avoiding the double counting that occurred in the 2020 ACC. With the credit subtracted, the PG&E Backbone rate provided in the CEC model for Electric Generation is very slightly negative. This is due to annual balancing account adjustments with an unusually large credit.[9]

The 2022 ACC takes a simple average of transportation rates across PG&E Backbone, PG&E Local Transmission and SoCalGas. And the monthly gas prices are a simple average of PG&E Backbone, PG&E Local Transmission and SoCalGas burner tip prices. The methodology is consistent with IRP's methodology to calculate California state level natural gas prices for RESOLVE modeling.

4.4 Natural Gas GHG Value

The 2022 ACC adopts an 'interim' separate (and higher) GHG value for natural gas. This is to reflect that decarbonizing direct natural gas combustion in buildings through building electrification or use of renewable natural gas or other fuels is currently projected to be more expensive than avoiding GHG in electric generation. Assuming renewable natural gas supplies are likely to be targeted for otherwise hard-to-electrify applications, building electrification was found to be the best proxy for a marginal resource for decarbonizing natural gas, at least for this interim value.

In the 2022 ACC, the interim value is based on the $114/tonne GHG abatement cost for residential building electrification from the CEC report[10], escalated at utility WACC from 2020 to 2052 (Figure 9).[11]

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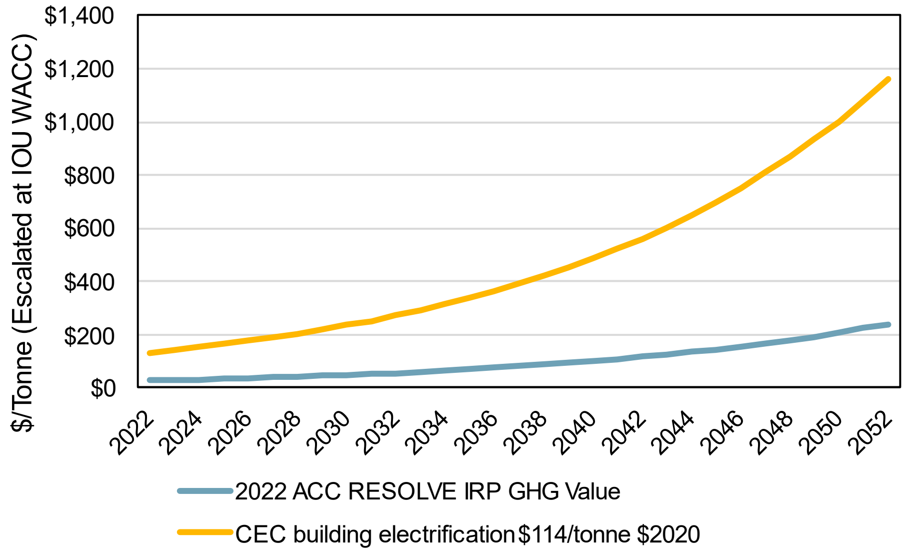
[8] CEC Power Plant Burner Tip Price Model, June 2020 Model, available at: https://www.energy.ca.gov/programs-and-topics/topics/energy-assessment/natural-gas-burner-tip-prices-california-and-western

[9] PG&E Advice Letter 4200-G, December 23, 2019. Available at: https://www.pge.com/tariffs/assets/pdf/adviceletter/GAS_4200-G.pdf

[10] California Building Decarbonization Assessment. 2021. Available at: https://www.energy.ca.gov/publications/2021/california-building-decarbonization-assessment. Figure 15, p. 56

[11] The CEC report calculates the $114/tonne GHG abatement cost using the total discounted net costs divided by cumulative avoided GHG emissions from 2020-2045. This is different than the methodology used to determine the electric GHG avoided costs calculated in RESOLVE, which is based on the annualized cost divided by total emissions

Figure 9. Natural Gas GHG vs Electric GHG Avoided Costs



5 Avoided Cost of Energy

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

Day-ahead (DA) hourly energy prices from SERVM are used for the energy component of the ACC to evaluate all types of DER.[12] SERVM results are also used to develop real-time (RT) energy prices. RT energy price is not a component of avoided costs in the ACC model. Rather, it offers inputs to estimate market revenues that could be earned by dispatchable DERs (e.g., demand response programs) participating in wholesale CAISO markets, which impact the cost-effectiveness of dispatchable DER programs.

5.1 Post-processing of SERVM Prices

SERVM is a production simulation model that represents a theorized and optimized view of the day-ahead energy market. Certain market dynamics are present in the historical prices but not in the SERVM simulation, such as high price volatility when the system is near full capacity. The ACC also requires additional price streams based on the SERVM simulation to capture a full spectrum of costs. Therefore,

each year. Given that this is an interim value, the alignment of methodology to calculate these two values will be addressed in future CPUC proceedings

[12] Note that for electrification measures that increase electric load, this value is a cost, not an 'avoided' cost.

several post-processing steps are applied to SERVM prices to better reflect historical market prices. The post processing steps are as follows:

1. Interpolating and extrapolating SERVM energy prices and implied marginal heat rates beyond SERVM model years.
2. Setting a price cap and floor for day-ahead energy prices.
3. Adjusting implied marginal heat rates and energy prices to capture system scarcity.
4. Deriving real-time prices.

5.1.1 Interpolating and Extrapolating SERVM Energy Prices and Implied Marginal Heat Rates Beyond SERVM Model Years

The scope of the ACC extends to 2052, while the SERVM model provides results in years 2022-2032, 2035, 2040 and 2045. Energy prices between two SERVM model years were linearly interpolated and prices beyond 2045 were extrapolated based on hourly implied marginal heat rates (IMHR). IMHR, as defined below, remains constant from 2045 onwards.

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

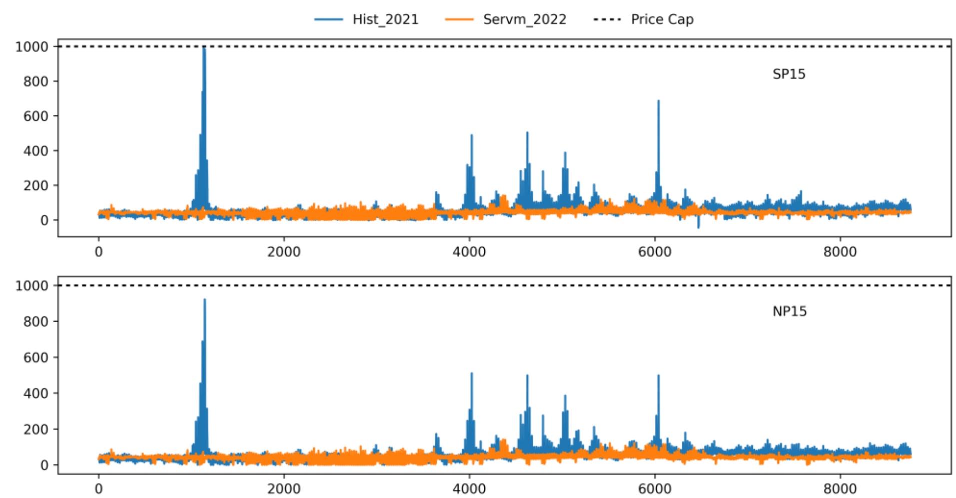
Where P_e is the energy price in \$/MWh, VOM_{CT} is the variable O&M of a CT generator in \$/MWh, P_g is the gas price in \$/MMBtu, P_c is the carbon price in \$/tonne and I_c is the carbon intensity in tonne-CO_2/MMBTU. IMHR is a simple but useful indicator of the marginal resource that is setting the hourly price. It is independent of the impact of evolving gas and carbon prices, which makes it a suitable anchor for extrapolating future energy price. Final hourly electricity market prices are calculated based on these heat rates, coupled with projections of fuel costs, power plant O&M costs and carbon prices. Scarcity adjusted implied heat rates are used to then derive energy prices without carbon (see Section 5.1.3). The carbon component of the final energy prices is calculated with capped implied heat rates that reflect the emission rates of the units on the margin. Fuel costs for final calculation of electricity generation prices are consistent with natural gas commodity prices discussed in Section 4.

5.1.2 Price Cap and Floor

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

Second, a price cap of $1000/MWh is also set on the energy price based on the maximum historical price in 2021. Figure 10 shows the historical prices in 2021 and raw SERVM prices in 2022.

Figure 10. Comparing Historical and SERVM Simulated Energy Prices, Showing Price Cap



5.1.3 Scarcity Adjustment

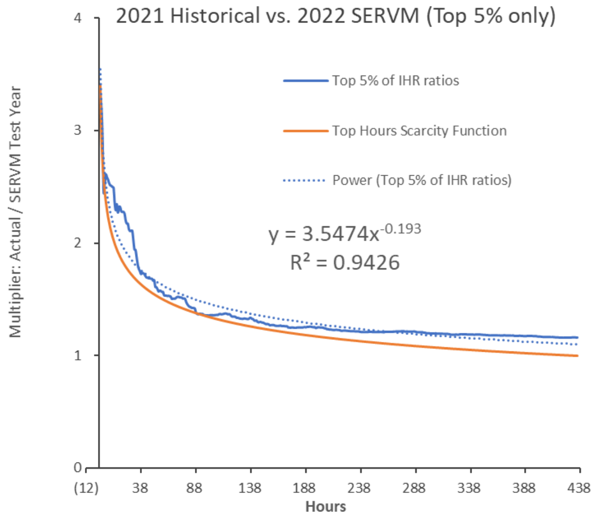
A scarcity scaling function is applied to SERVM results to better capture the non-ideal market conditions prominent in the highest hours when the system is operating near full capacity. Production simulation models are typically over-optimized or simplified, and unable to capture probabilistic real-world variables, such as contingency events, forecast errors, and market irrationality. Prices during these periods of scarcity when the system is strained are generally higher than predicted from fundamentals-based projections.

To adjust for scarcity, we first calculated hourly implied heat rates (IMHR) from SERVM 2022 DA energy prices and historical 2021 SP15 DA energy prices, respectively. The scaling is applied to the implied heat rates rather than directly to exclude impacts of changing gas price, carbon price, and other such variables across the time horizon. Using SP15 as a benchmark zone is because SP15 tends to experience more scarcity than NP15 and SP15 prices are generally higher than NP15 prices. We ranked SERVM 2022 IMHR and historical 2021 IMHR at a descending order and calculated the ratio between the two IMHRs (as shown in the blue solid line in Figure 11). The ratios of top 5% hours were plotted and fitted using a power trendline (the blue dash line in Figure 11) with a corresponding equation as the following:

$$y = ax^b$$

Where y is historical IMHR/SERVM IMHR, a and b are scarcity coefficients. The resulting function is the orange line in Figure 11.

Figure 11. Illustration of 2022 ACC scarcity adjustment



The scaling coefficient, 3.55, was applied to scaling SERVM IMHRs in the top 5% summer hot hours in all future years. The choice of 5% is based on internal benchmarks as well as the trade-off between capturing the scarcest IMHR and adjusting more IMHR. If more IMHR ratios were to be adjusted (i.e., include more hours to calculate scarcity coefficients), the resulting power trendline would not capture the highest IMHRs as it would be skewered towards tail hours.

The comparison between raw SERVM prices, scarcity adjusted SERVM prices and historical prices can be found in Figure 12 and Figure 13. Similar comparison for IMHR is shown in Figure 14.

Figure 12. Raw SERVM prices vs. Scarcity adjusted SERVM prices for Year 2020

Figure 13. Impact of scarcity adjustment on raw SERVM prices relative to historical data

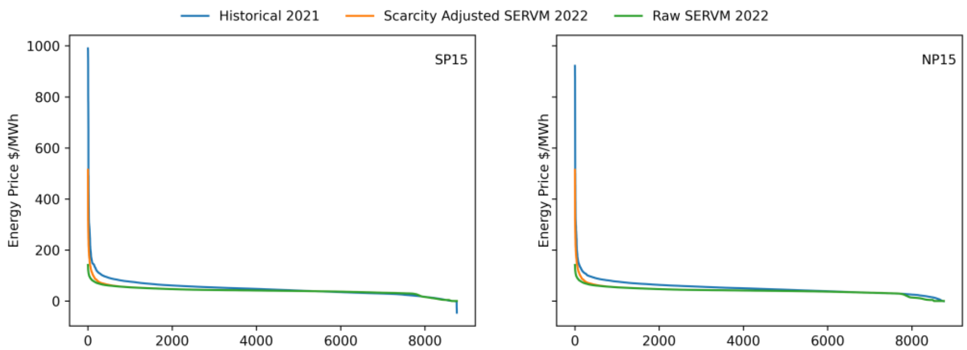
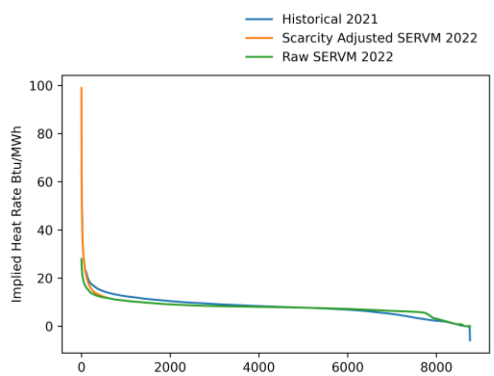


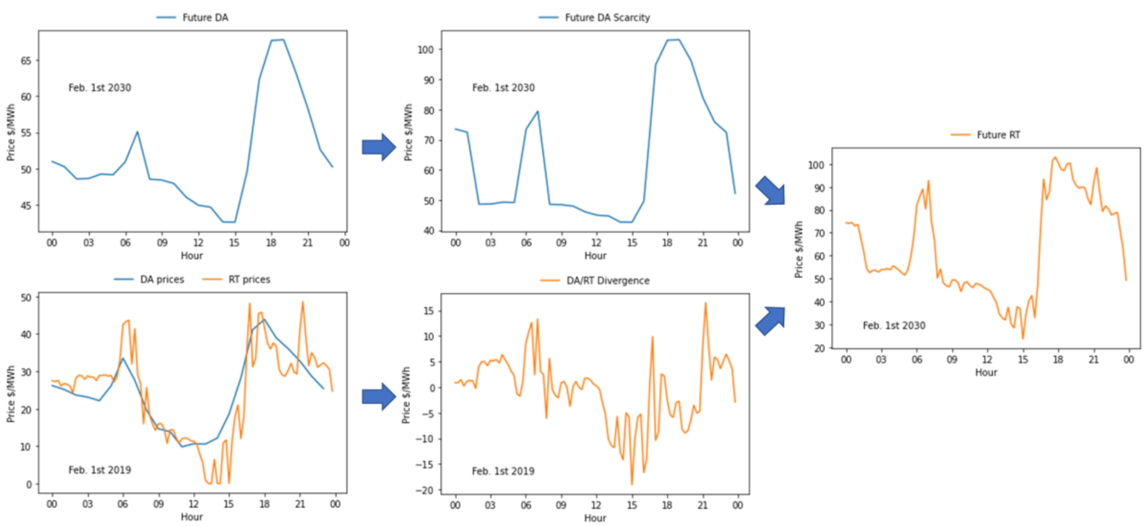
Figure 14. Impact of scarcity adjustment on raw SERVM IMHR relative to historical data – SP15



5.1.4 Real-time Prices

Real-time market (15-minute) prices are also developed based on the scarcity adjusted hourly prices. Real-time market prices are not a component of avoided costs in the ACC model, but they serve as additional information that can be used to evaluate additional energy revenue that could be earned by dispatchable DERs. The ACC uses the day-ahead (DA) and real-time (RT) price divergence in 2021 and superimposed this hourly divergence on top of simulated future day-ahead price to obtain synthetic real time prices. An overall diagram of the synthetic RT series can be seen in Figure 15.

Figure 15. Overall Methodology of Generating Future Real-time Prices



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

5.2 Energy Price Calendar Alignment

Users of the ACC generally calculate the impacts of a DER by multiplying the hourly avoided costs from the ACC by the hourly impact shape of their DER measure. Many DER impact shapes can vary significantly between weekdays and weekends/holidays because of different usage levels on non-workdays. It is therefore important that the weekends/holidays line up correctly in the impact shape and avoided cost data. The standard approach is to estimate impact shapes using a single defined calendar, regardless of what year's avoided costs are being used. To accommodate this, the avoided costs need to reflect the same chronology for all years. In the 2022 ACC update, all years reflect a 2020 calendar year (including the leap year day but excluding 12/31 the last day of the year to ensure continuous data). For the 2022 ACC, SERVM modeling has been adjusted to make the SERVM results align with the 2020 calendar year that starts on a Wednesday so that no further shifting is needed.

Following these steps, prices follow a trend of increased renewable generation and curtailment in the spring. In near-term years, peak prices occur in the summer evenings. In later years, peak prices continue to occur in summer system peak hours, but also move to the evenings and mornings of months that have limited renewable generation availability. The example results of the scarcity adjusted DA energy prices from SERVM for NP-15 are shown below in Figure 16 to Figure 18.

Figure 16. 2022 NP-15 Day Ahead Market Prices from SERVM

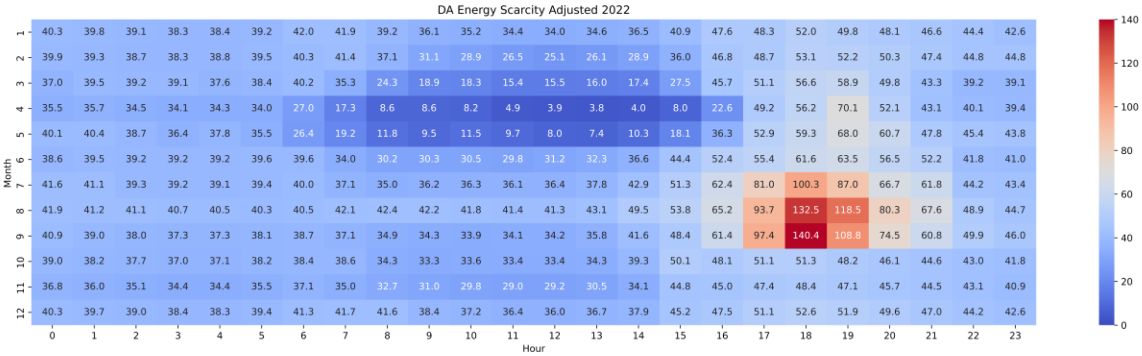


Figure 17. 2030 NP-15 Day Ahead Market Prices from SERVM

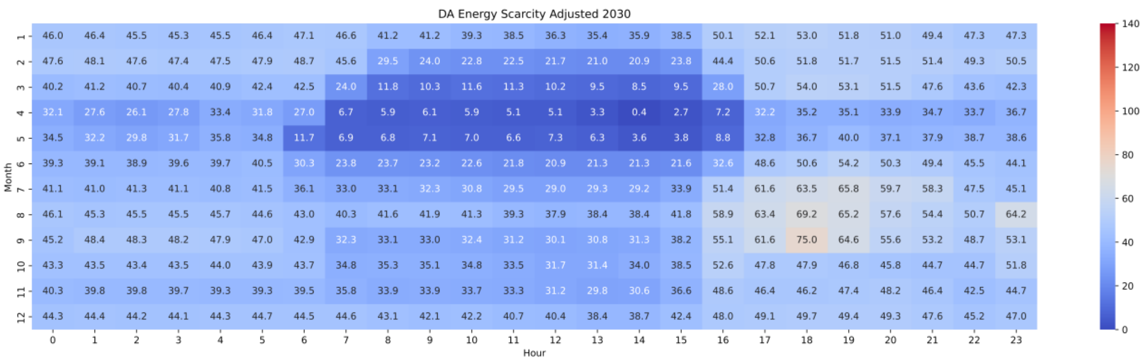
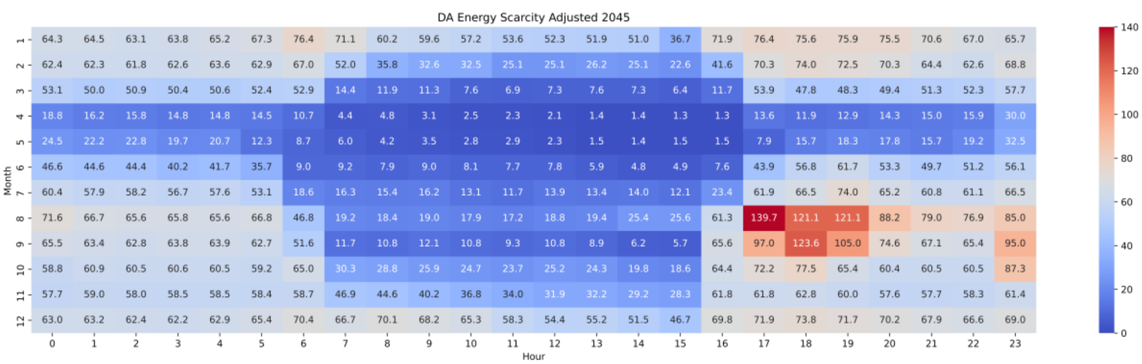


Figure 18. 2045 NP-15 Day Ahead Market Prices from SERVM



6 Ancillary Services

6.1 Avoided Ancillary Service Procurement

The CAISO procures ancillary services (AS) to maintain the reliability of the grid and competitiveness of energy markets. Common AS are 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.

The ACC provides two versions of AS costs. The first version was derived from SERVM's forecasted hourly spinning and regulation prices. We split regulation prices into reg up and down, as explained in Section 6.2. These hourly prices represent potential market revenues from dispatchable DERs participating in wholesale markets or providing AS-type services for the electric grid. These prices are used to calculate market revenues for energy storage for generation capacity values (Section 8) as well as estimate energy revenues of dispatchable DERs, such as demand response. Hourly spinning prices were used to calculate the second version of AS costs, which represent avoided AS a percentage of wholesale energy prices and is used as the Avoided Cost of Ancillary Services in the ACC model. The AS avoided cost does not include regulation reserves because DER programs are assumed to avoid spinning reserves only.

To calculate the avoided cost of AS, we took the averages of NP15 and SP15 scarcity adjusted DA prices and spinning prices from SERVM. We then calculated the ratio of annual average spinning prices to annual average SERVM energy prices and adjusted the ratio by 1.1% to reflect avoided AS as a percent of energy prices. The basis of the 1.1% adjustment is that AS are procured in the day-ahead CAISO market largely based on total load forecast for the following day. Reducing load generally reduces the amount of spin and non-spin AS that must be procured to operate the CAISO system. This load dependent AS procurement is approximately 1.1% of total wholesale energy costs, based on the latest CAISO Annual Report on Market Issues and Performance, currently for 2020. [13] The magnitude of frequency regulation services procured by the CAISO is independent of load and frequency regulation is therefore not included as an avoided cost for DER.

6.2 Splitting into Reg Up and Down

SERVM produces a single price for regulation, whereas the CAISO has separate markets for regulation up and regulation down. The single regulation price from SERVM was divided to separately represent regulation up and regulation down prices for CAISO.

To divide the price, a simple linear spline function is used to capture the relationship between historical regulation up fraction and historical IMHR. IMHR is once again used as the predictor here as in the scarcity

[13] CAISO, Ancillary Service Market, August 2020, Available at: https://www.caiso.com/Documents/Chapter4_AncillaryServiceMarkets.pdf

pricing adjustment of the previous chapter since it indicates the marginal generator and, consequently, whether the market is in surplus or shortage of resource.

Fitting a spline function over a full year of hourly historical 2021 data yielded a reasonable trend for the reg up fraction, which increases as IMHR goes up (Figure 19). This is expected, as an increasing IMHR indicates a shortage of resource and therefore an increase in price for upward regulation. As shown in Figure 20 to Figure 22, the resulting regulation up and down prices are flat especially in future years because regulation prices from SERVM are flat. These prices do not directly flow into the final ACC Model, but they have resulted in high near-term capacity avoided costs.

Figure 19. A. Linear spline functions to describe the historical relationship between reg up fraction and IMHR. B. Average hourly reg up and reg down price for 2020-2050. Highlighting diurnal trend.

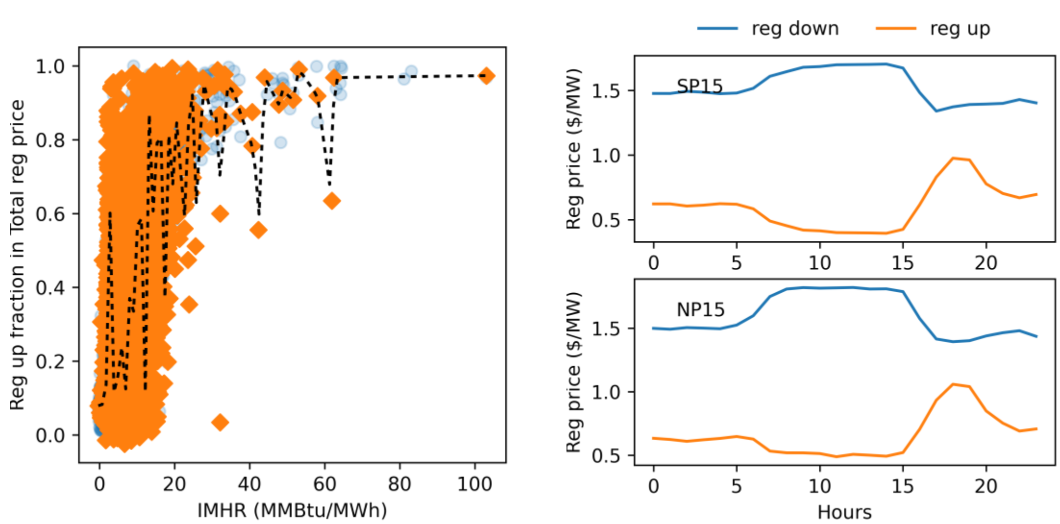


Figure 20. 2022 NP-15 Regulation Up Market Prices from SERVM and Heat Rate Predicted Splitting

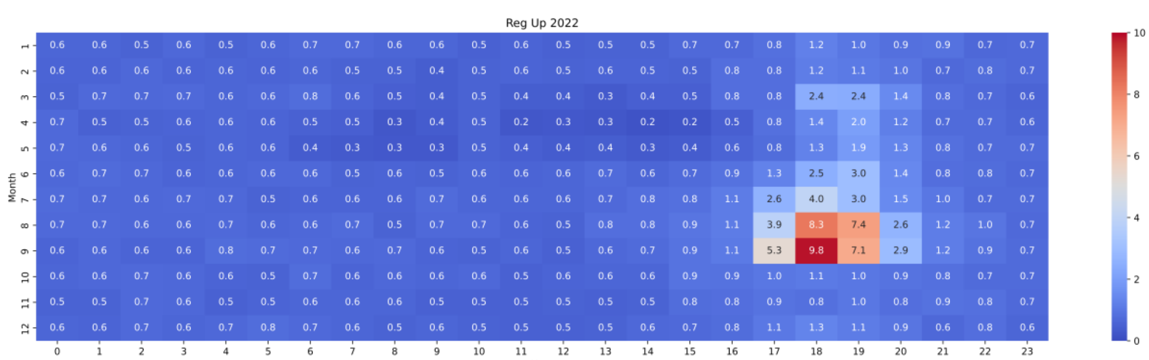


Figure 21. 2030 NP-15 Regulation Up Market Prices from SERVM and Heat Rate Predicted Splitting

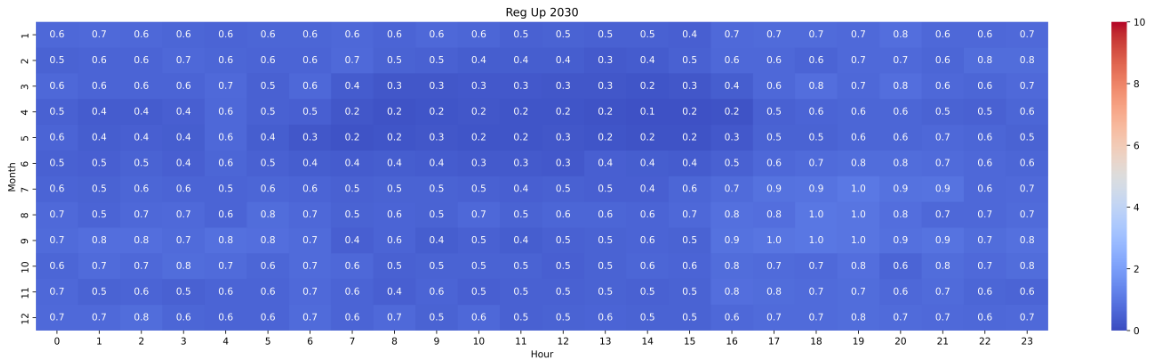


Figure 22. 2045 NP-15 Regulation Up Market Prices from SERVM and Heat Rate Predicted Splitting

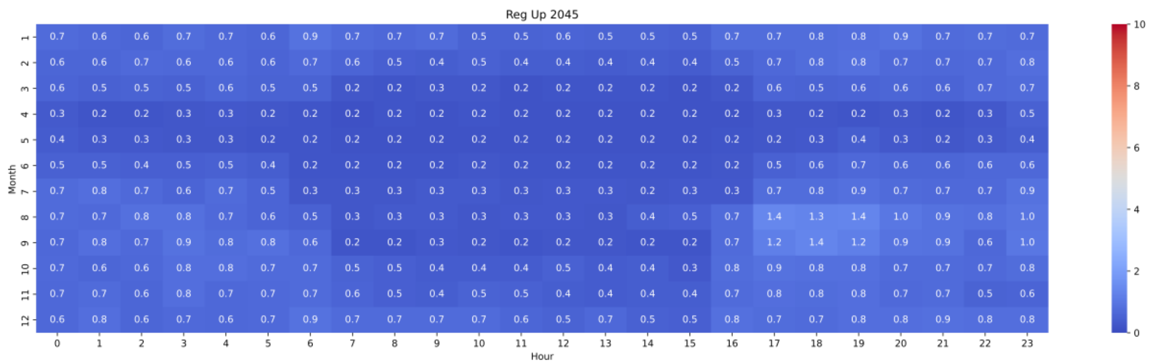


Figure 23. 2022 NP-15 Regulation down Market Prices from SERVM and Heat Rate Predicted Splitting

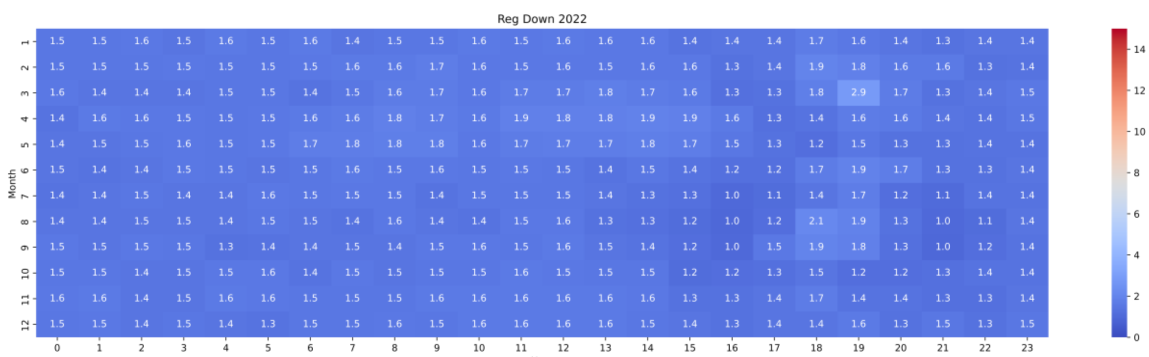


Figure 24. 2030 NP-15 Regulation down Market Prices from SERVM and Heat Rate Predicted Splitting

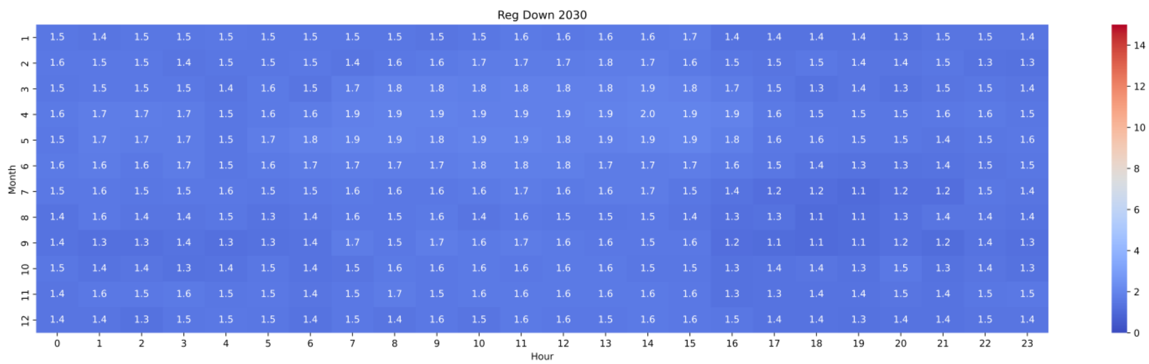
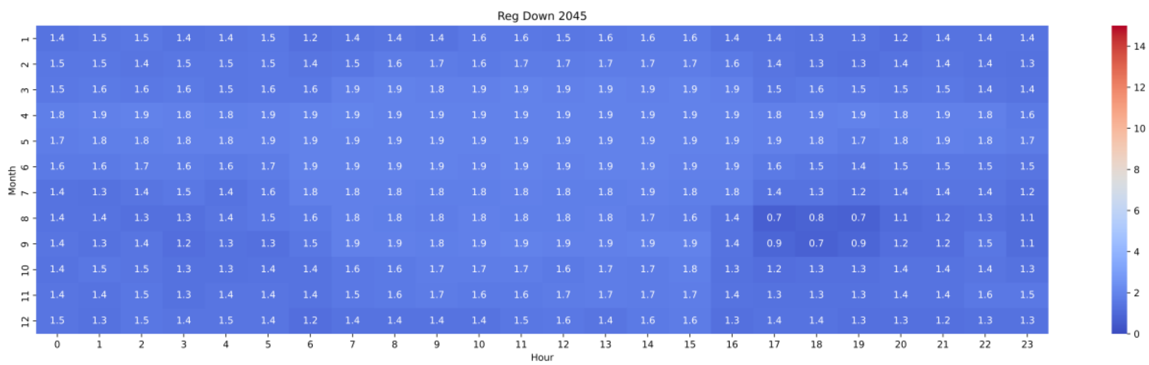


Figure 25. 2045 NP-15 Regulation down Market Prices from SERVM and Heat Rate Predicted Splitting



7 Avoided Cost of Greenhouse Gas Emissions

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

7.1 Electric Sector GHG Value

The 2020 ACC updated the valuation of GHG emissions to align with the IRP and California's GHG reduction goals. The value of GHG emissions is represented by the sum of two values: 1) the monetized carbon cap and trade allowance cost embedded in energy prices, and 2) the non-monetized carbon price beyond the cost of cap-and-trade allowances (represented by the "GHG Adder," as adopted by the CPUC).[14] The GHG Adder reflects the cost of further reducing carbon emissions from electricity supply, rather than the compliance cost represented by the cap-and-trade allowance price. The combination of adding the cap-and-trade price and the GHG Adder is the total GHG avoided cost component included in the 2022 ACC.

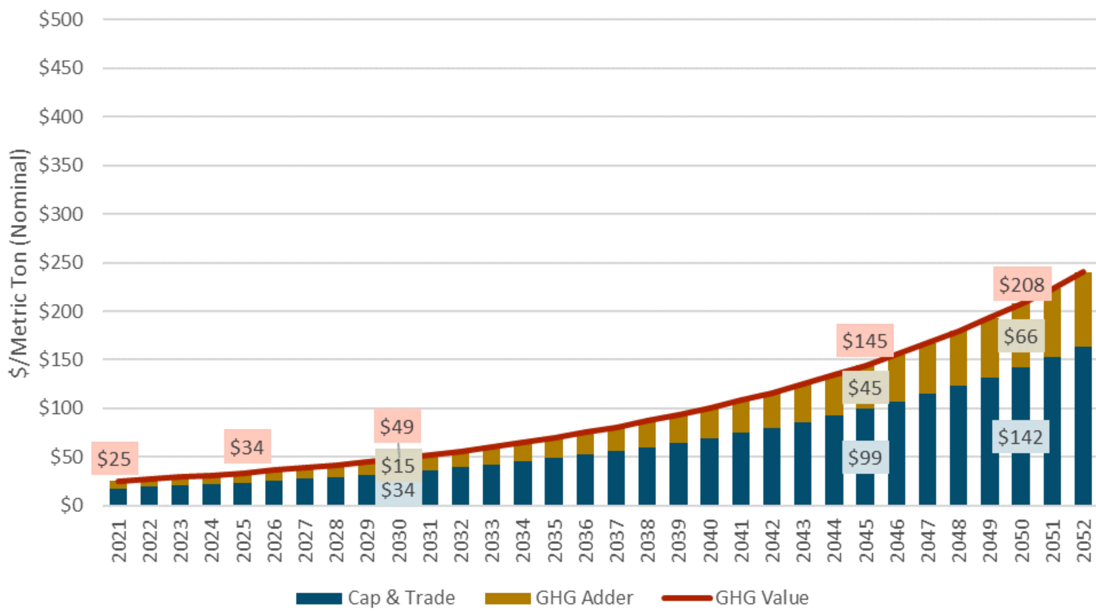
[14] D.18-02-018, Table 6. Note that in Table 6 of this IRP Decision, the term "GHG Adder" is used, inconsistent with the usage in IDER, to represent the combined value of the monetized cap and trade allowance price and the non-monetized residual value (rather than only the residual, non-monetized value).

The GHG values in the ACC are based on IRP RESOLVE outputs from the No New DER scenario. The key GHG cost value produced in the IRP is the shadow price of GHG emission reductions from RESOLVE. The GHG shadow prices represent the cost of reducing an additional unit of GHGs in each year. In the near-term, the GHG shadow price is fairly low, matching the cap-and-trade allowance prices. This is because renewable generation was procured prior to 2022 for reliability and to take advantage of the Federal Investment Tax Credit (ITC) before it steps down from 30% to 10%. The generation portfolio therefore exceeds the GHG targets for near term, resulting in a low GHG shadow price because emissions reductions are not the binding constraint in RESOLVE. However, in the long term, the RESOLVE GHG shadow price increases rapidly because the model must reduce GHGs in order to meet annual emissions targets for the electric sector. In other words, RESOLVE must procure additional clean energy resources in order to meet emissions targets, and this results in significant supply-side costs beyond the cap-and-trade allowance price. This means that emissions are more expensive in later years of the IRP as GHGs must be reduced significantly to meet the more stringent annual targets.

Figure 26 summarizes the GHG value that is based on the 2035 GHG shadow price from RESOLVE and discounted for 2021-2034 based on the utility weighted average cost of capital (WACC). This method is the same as what was used in the 2021 ACC but adjusted to start from 2035 due to zero “GHG Adder” value in 2030 (explained below). The method discounts the RESOLVE GHG shadow price in 2035 for 2020-2034 using the utility WACC, and scales up at the same rate for 2036 and beyond. This approach balances the goal of generating consistency with the IRP and RESOLVE.

This method using the RESOLVE 2035 GHG shadow price provides the total GHG avoided cost component for the calculator. The total GHG cost can still be split out as the cap-and-trade price and a “GHG Adder,” recalculated as the total avoided cost based on the method minus the IEPR mid-case cap and trade value. As discussed in the next section, both amounts that make up the total GHG avoided cost component are used to evaluate GHG emissions.

Figure 26: CO2 Cap & Trade and GHG Adder Price Series used in 2022 Avoided Cost Calculator



For the 2022 ACC, GHG value drops significantly compared to 2021 ACC (See Appendix 14.1.2) due to a number of factors. First, in 2022 the "No New DER" scenario removes both load reducing (such as behind-the-meter solar, storage or energy efficiency) and load increasing DER (such as building and transportation electrification). This significantly reduces load in 2030 compared to the 2021 ACC "No New DER" scenario. Second, the removal of both load-increasing and load-decreasing DER has impacted peak load and annual load such that the peak load is a stronger driver of resource build in the 2030 timeframe than the GHG constraint. That is why the "No New DER" scenario projects a much lower GHG shadow price than the PSP case for the 2022 ACC (Table 6).

Table 6. Comparison of the GHG value in PSP and No New DER case

No New DER	Unit	2022	2025	2030	2035	2040	2045
GHG Adder	$/tCO2	0	0	0	16	53	63
CARB Floor Carbon Price	$/tCO2	19	22	28	36	47	61
GHG Value	$/tCO2	19	22	28	52	100	123

PSP	Unit	2022	2025	2030	2035	2040	2045
GHG Adder	$/tCO2	0	0	38	94	101	269
CARB Floor Carbon Price	$/tCO2	19	22	28	36	47	61
GHG Value	$/tCO2	19	22	66	130	147	330

7.2 Electric Sector GHG Emissions

The ACC estimates GHG emissions levels and costs. Emissions levels and costs were based on changes in CO2 output of the marginal generating unit in each hour of each year. Prior to 2020, the total GHG avoided costs were considered to be the sum of the cap-and-trade compliance cost and the IDER GHG Adder, where the cap-and-trade portion represented the short-term cost to utilities of purchasing carbon allowances, and the GHG Adder portion represented the cost of procuring generation resources to meet California's GHG goals.

While this was a valid and appropriate estimation of the immediate or short-term impact of DER resources, this method did not account for how the DER would affect future emissions as the electricity system resources are rebalanced to reflect new overall levels of consumption. Quantifying GHG emissions based solely on the short-term marginal generation impact overstated lifecycle emissions on an increasingly decarbonized electric grid. Accounting for declining electric grid emissions intensity in the ACC is important to appropriately and consistently evaluate the GHG impacts of load-increasing electrification measures. The approach implemented for the ACC is similar in concept to the approach used for the fuel substitution test (D. 19-08-009), described in the Fuel Substitution Technical Guidance Version 1.1.[15] The CEC also uses a similar approach for the 2022 Title 24 TDV.[16]

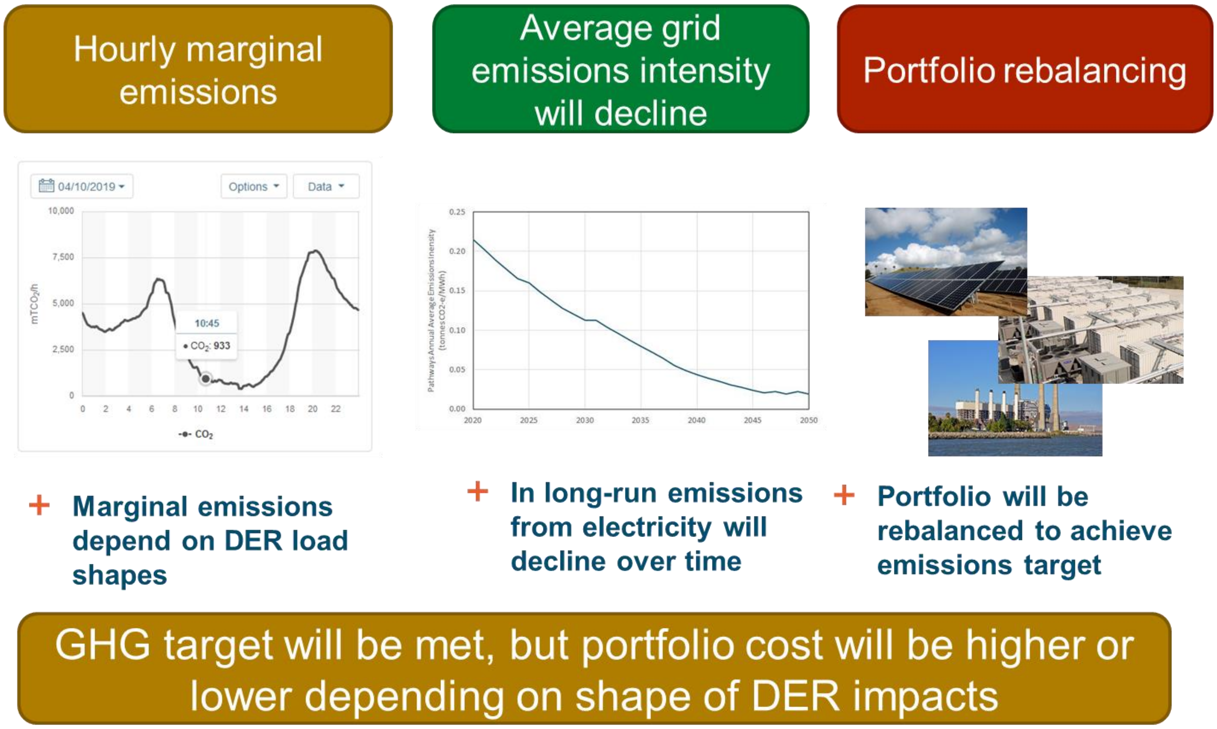
The 2022 ACC uses a two-step approach to estimate GHG emissions impacts from DER measures, similar to previous cycles:

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

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

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

Figure 27. GHG Emission Impact Estimation for DERs



7.2.1 Hourly Marginal GHG Emission Impact

For the 2022 ACC, SERVM production simulation of the No New DER case is used to calculate hourly marginal emissions. The hourly load shapes from DER will be multiplied by the hourly marginal emissions rates for each year to calculate hourly marginal emission impacts.

7.2.2 Average Annual Electric Grid GHG Emissions Intensity

The ACC estimates long-run GHG emission impacts. Given that California plans to meet the SB100 goal of 100% decarbonized electricity (as measured by retail sales) by 2045, average annual electric grid GHG emissions intensity can be calculated based on an assumed GHG reduction target aligned with the SB100 goal. The annual emissions intensity values derived from IRP are used to reflect the emissions attributed to load-modifying demand-side actions. RESOLVE capacity expansion modeling in the IRP determines the least-cost resource portfolio for meeting electricity sector GHG emission targets. The portfolio will achieve increasingly lower GHG emissions intensity over time.

Table 7 and

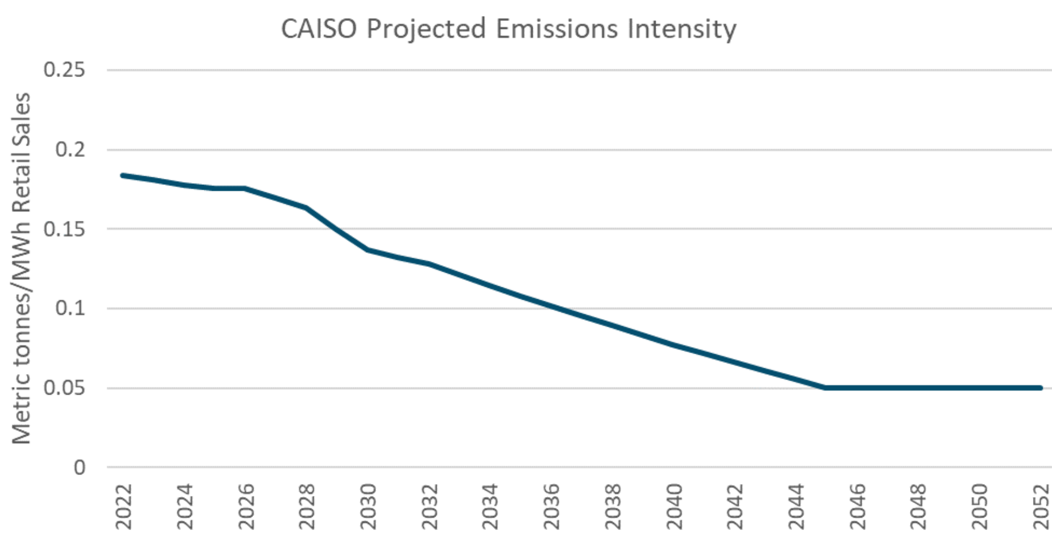
Figure 28 below depict the annual emissions intensity trajectory derived from the IRP RESOLVE modeling. Emissions intensity is calculated as tonnes of GHG per MWh of retail sales to be consistent with SB100 language that zero-carbon resources supply 100% of retail sales of electricity to end-use customers in 2030. The formula for calculating average intensity factors is shown here, for year *t*:

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

Table 7. 2021 IRP Preferred System Plan Results 38 MMT Case Load and Emissions

		2022	2025	2030	2035	2040	2045
Load	GWh	238,134	249,928	260,802	275,928	290,088	297,046
Retail sales	GWh	199,394	209,212	217,428	229,568	240,814	245,397
CAISO Emissions	MMtCO2/Yr	37	37	30	25	19	12
Grid Emissions Intensity	MMtCO2/MWh	0.18	0.18	0.14	0.11	0.08	0.05

Figure 28. CAISO Projected Emissions Intensity, 2022 IRP Preferred System Plan Results 38 MMT Case



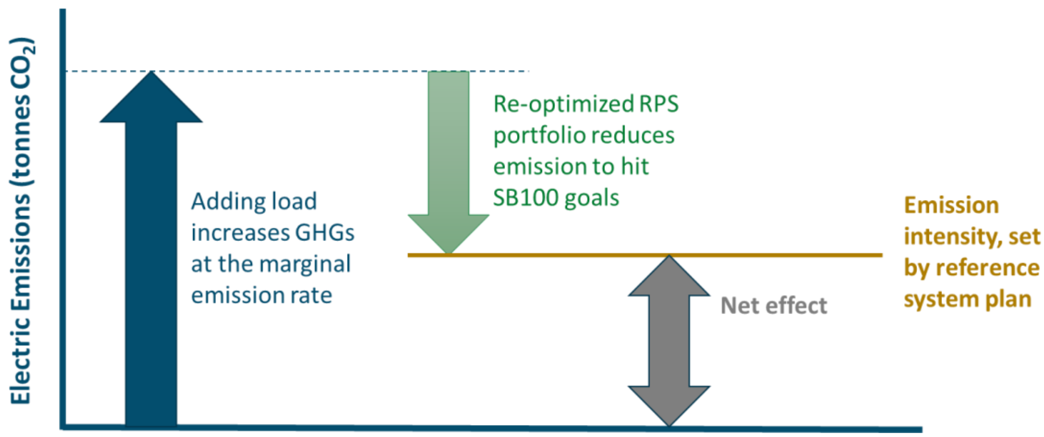
As the PSP provides retail sales and GHG emissions through 2030, a linear progression was assumed between these 2030 values and the 2045 SB100 goals to estimate emissions intensity at that end-year.

7.2.3 Portfolio Rebalancing GHG Emission Impacts

The ACC assumes that the supply-side portfolio will be rebalanced to achieve the emissions intensity target set in the IRP after accounting for changes in the DER portfolio. With this approach, the GHG emissions impact will reflects the energy sector emissions cost of achieving the required annual intensity target.

Figure 29 below provides an illustrative example of how portfolio rebalancing based on annual emissions intensity targets will be implemented.

Figure 29. Illustrative Long Run Emissions Calculation



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

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

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

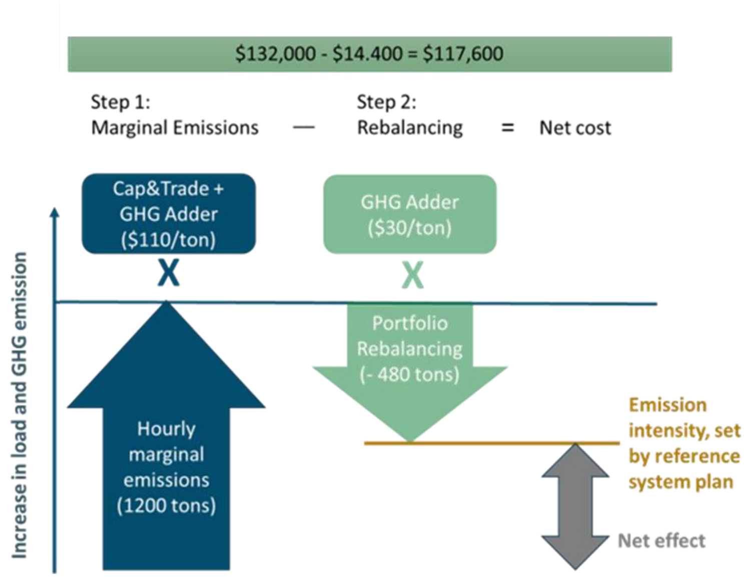
The following equations illustrate the GHG calculation used for the 2022 ACC. These equations reflect the value of the emissions attributable to a given measure or program in a year. Note that the first part of the 2022 ACC formula reflects the hourly marginal emissions valued at the total GHG avoided cost component. The new rebalancing component is indicated by the bold font in the second equation. The total GHG avoided cost component, using the methodology based on RESOLVE outputs described earlier in this documentation, is represented by the cap-and-trade value plus the GHG Adder.

$$
\begin{aligned}
&GHG\ Calculation_{2022\ ACC} \\
&\qquad = Load\ Shape\ (kWh)_h * Marginal\ Emissions\ (tCO_2e/kWh)_h \\
&\qquad * \ (Cap\&Trade + \ GHG\ Adder)(\$/tCO_2e)_y \\
&\qquad - \boldsymbol{Annual\ kWh * EmissionsIntensity_y * GHG\ Adder(\$/tCO_2e)_y}
\end{aligned}
$$

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

Figure 30 provides an illustrative example of approach based on the portfolio rebalancing calculation. This example illustrates increased emissions due to a load-building measure, but the inverse relationship would hold true for a measure which instead reduces load.

Figure 30. Current ACC GHG Valuation and Proposed Update (Illustrative Load Increase Example)



The figure shows that the rebalancing to meet the emission intensity target reduces the GHG-related costs for the load increase (e.g., building electrification). More details on the sample values used in the figure are presented in Appendix 14.2.

7.2.3.1 Rational for GHG Rebalancing Approach

The resource portfolio modeled in RESOLVE and in SERVM are developed to meet a maximum total GHG emissions for the electric sector (e.g., 30 million metric tons) given the retail electric load forecast by the CEC IEPR (used as an input in the CPUC IRP Proceeding). The constraint on the portfolio is the total allowable emissions to serve the retail load forecast and the average grid emissions intensity will decline over time to meet stricter GHG emission targets. SERVM modeling of that portfolio will also provide marginal hourly emissions. The *marginal* hourly emissions will also decline over time, but will tend to be higher than the *average* grid emissions as dispatchable fossil units will often be the marginal units kept online to provide operating reserves. The first step in the calculation of GHG avoided costs is based on the marginal emissions as calculated by SERVM.

The marginal emissions impact of adding or decreasing load provides only a partial picture. We must also consider how both the portfolio and the allowable GHG emissions target would adjust when load is added or removed on the margin. The clearest example is made by considering building and transportation electrification. These measures reduce GHG emissions overall, but add load to the electric system. If electrification load were added to an electric sector IRP portfolio, one would expect the allowable GHG emissions from the electric sector to increase proportionally, not to remain fixed at the original total emissions target.

The ACC is a simplified, static snapshot of the marginal costs for a given electric sector resource portfolio and a given GHG emissions target. The ACC requires a correspondingly simple and straightforward approach to reflect a proportional reallocation of allowable GHG emissions between the transportation, building and electric sectors with increased electrification load. The approach used in the ACC is to use the average grid emissions intensity for the modeled IRP portfolio to calculate a Step 2 portfolio rebalancing impact. The simplifying assumption is to assume the average grid intensity is a reasonable reflection of the electric sectors proportional responsibility for meeting California's total GHG emissions target. Thus, when considering incremental load growth from electrification, the allowable GHG emissions from the electric sector increases proportionally, and the allowable increase is the incremental load in kWh times the average grid emissions intensity in GHG/kWh.

7.2.3.2 Implementation of the GHG Portfolio Rebalancing in the ACC

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

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

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

8 Avoided Cost of Generation Capacity

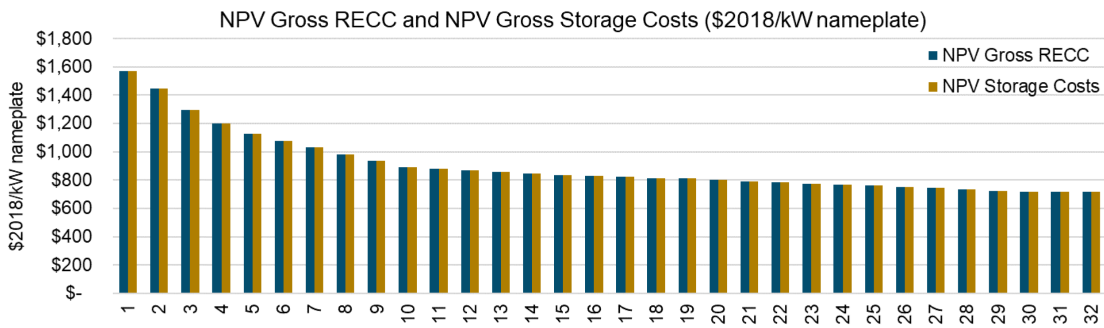
Generation capacity avoided costs are calculated based on the estimated value of a marginal generation capacity resource.

8.1 Annual Generation Capacity Value

Since the 2020 ACC, the proxy resource used for marginal generation capacity is assumed to be a battery storage resource, which replaced the gas combustion turbine previously used. In the 2022 ACC, a Real Economic Carrying Charge (RECC) approach has been implemented to calculate the deferral value of a new battery storage resource. The RECC approach takes the difference between the cost of investment in each year compared to an investment delayed by one year to obtain the annual avoided cost of the investment. This approach is different from the First-Year Net Cost of New Entry (CONE) approach used in 2020-2021 ACC iterations. The First-Year Net CONE approach is calculated using the levelized cost of a storage resource minus its first-year revenue and did not reflect the lifetime costs of a storage asset and its deferral value.

The calculation of the final RECC value that is used in the 2022 ACC can be broken down into several steps, as described in the following sections. A final "check" that the avoided cost of capacity is being computed correctly in each year is the comparison between the NPV of storage costs and the NPV of the avoided capacity costs (Figure 31). This demonstrates that the RECC value in the ACC correctly compensates resources such that their costs are exactly offset over the lifetime of the resource.

Figure 31. NPV Gross RECC vs NPV Gross Storage Costs



8.1.1 Calculate the annual fixed cost of storage by installation year, including replacement

The cost and configuration of the battery storage resource is taken from the IRP. The RESOLVE capacity expansion modeling in the IRP uses a battery storage resource with a 4-hour duration and a 20-year useful life (with augmentation costs) for a capacity resource.

The cost and performance assumptions as well as the financial pro-forma model from the IRP are used to calculate the levelized fixed costs of a battery over its expected useful life of 20 years which is assumed to remain constant in real dollars. A subset of the battery cost assumptions from the IRP are shown in Table 8, with the levelized costs by vintage show in Figure 32. Changes from the 2021 ACC include an interconnection charge which was added in the RESOLVE PSP modelling.[17]

Table 8. Subset of Battery Storage Resource Cost Assumptions from IRP

Resource			Utility-scale Battery - Li [Capacity] - No ITC	Utility-scale Battery - Li [Energy] - No ITC
Category for Cost Reductions	Resource Category		Battery Storage-Standalone	Battery Storage-Standalone
	Technology Type		Lithium ion (Grid) - Capacity	Lithium ion (Grid) - Energy
	Active Cost Trajectory Scenario		Mid	Mid
Performance Inputs		**Units**		
Plant Output	Installed Capacity	MW-ac	1	4
	Capacity Factor	%	15.0%	15.0%
	Degradation	%/yr	0.0%	0.0%
Plant Cost Inputs				
Capital Costs	Installed Cost, 2018	$/kW-ac	$97	$227
	Progress Multiplier	%	89%	89%
	Installed Cost, 2022	$/kW-ac	$87	$203
Interconnection Costs	Interconnection Cost	$/kW	$100	
Fixed O&M	Annual Fixed O&M, 2018 COD	$/kW-yr	$7.69	$0.00
	Progress Multiplier	%	100%	100%
	Annual Fixed O&M, 2022 COD	$/kW-yr	$7.69	$0.00
	Annual Escalation	%/yr	2.00%	2.00%
Warranty & Augmentation Costs	Annual Warranty Extension Cost	%	0.8%	0.8%
	Initial Warranty Length	yrs	2	2
	Annual Augmentation Cost	%	0.0%	1.2%

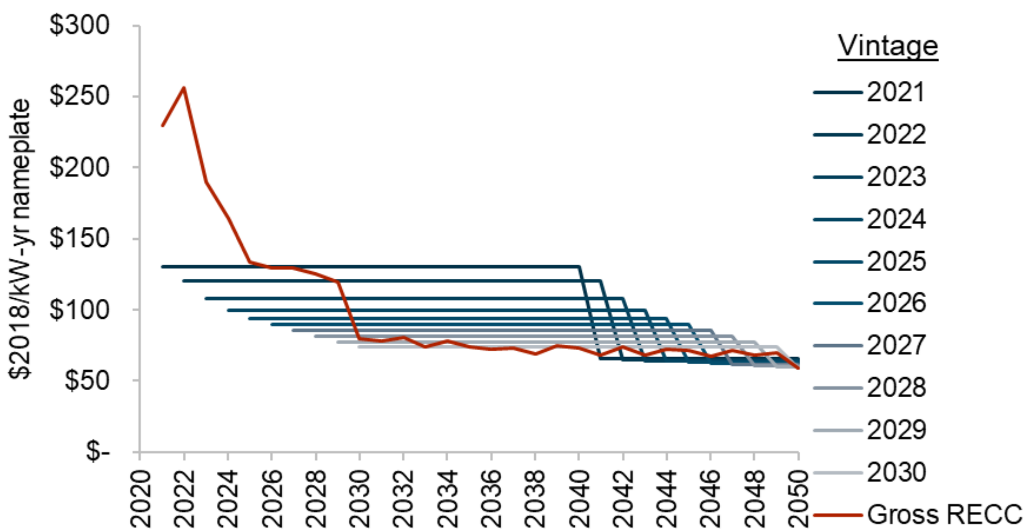
[17] See slide 114 of the RESOLVE Preferred System Plan (PSP) Modeling Results: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2020-irp-events-and-materials/psp-resolve-ruling-presentation.pdf.

8.1.2 Calculate the Gross Real Economic Carrying Charge (RECC)

The gross RECC calculates the one-year deferral of a storage investment by taking the difference between the net present value (NPV) of storage costs in one year versus the NPV of storage costs of the same resource installed a year later. The time period over which the RECC is calculated could theoretically be considered infinite because it is assumed that resources will be replaced at the end of their lifetime. In the 2022 ACC, storage costs are assumed to flatten beyond 2052, therefore the NPV of storage costs analysis is extended to 2072, to account for full deferral value of a storage investment including the deferral value of replacement.

One of the overarching objectives of the avoided costs is to harmonize assumptions with the CPUC's ongoing IRP proceeding. In the context of the avoided cost of capacity, this means relying on a consistent set of assumptions regarding the costs of the marginal capacity resource – namely, a long-term contract for energy storage. The assumed cost of such a long-term contract, which changes depending on the year of the installation, is calculated in the E3 Pro Forma[18], which uses a discounted cash flow methodology to calculate a cost-based contract price between a utility and a developer. Technical progress is reflected in the declining costs of each vintage of storage output by the pro forma (Figure 32).

Figure 32: Storage costs by vintage and gross RECC ($2018/nameplate kW-yr)



8.1.3 Calculate the Net RECC based on First-Year Revenues

A Net RECC value is calculated by subtracting first-year AS and energy revenues from the Gross RECC value calculated in the previous step. Only first-year revenues are needed for this calculation because in subsequent years, in a deferral framework, revenues will cancel each other out. Using net costs in the RECC calculation in the previous step will yield the same results.

[18] The E3 Pro Forma is a financial model that calculates the levelized costs of energy and capacity for a variety of energy generation and storage resources. It is used in the IRP proceeding.

The revenues that batteries earn in the energy and ancillary markets are calculated with optimal dispatch using the CEC Solar + Storage Model.[19] The prices for energy and ancillary services are derived from SERVM production simulation using resource portfolios from the No New DER case. These prices are used to calculate net market revenues for a new battery storage resource. A price floor of zero is also imposed.

8.1.4 Convert Net RECC to an Effective Capacity Value

With increasing penetrations of storage, the Effective Load Carrying Capacity (ELCC) of a 4-hour battery to provide generation capacity is diminished. This is reflected in the ACC by taking the ELCC from the IRP RESOLVE modeling and de-rating the capacity value of the 4-hour battery to obtain capacity value in $2018/effective kW-yr.

In the 2022 ACC, a correction has been made to use marginal ELCC instead of weighted average ELCC to evaluate new storage resources. New storage resources contribute capacity marginally to the system and should therefore be considered with a marginal ELCC, which is generally lower than the system average ELCC.

The deferral framework used to calculate the RECC is designed to compare the NPV cost of a resource addition with the addition of an *identical* resource in the second year. The idea that the two resources be identical is fundamental to this approach, the two resources provide the same capacity value to the system (i.e. a resource built last year is not intrinsically more or less valuable than an identical resource built this year). For this reason, ELCC is not considered in the first step to calculate the deferral value (section 8.1.1).

To address the cost of effective capacity in each year, the cost of effective capacity is determined by the marginal ELCC of storage in that year alone – which determines how many nameplate MW of storage would be needed to provide 1 MW of effective capacity in that year. The successive declines in marginal ELCC in surrounding years are not relevant to the cost of capacity in that year, as – whatever those declines may be – the deferred investment will provide the same marginal value to the grid under the deferral framework.

Finally, the capacity value is converted to nominal dollars based on the IRP inflation rate. The final net RECC value is plotted in Figure 33, along with the nominal value per nameplate capacity to demonstrate the impact of the ELCC.

8.1.5 Drivers of Changes from 2021 to 2022 Generation Capacity Avoided Costs

A summary of the storage costs, revenues, and resulting avoided capacity costs is shown in Table 9. The avoided cost of generation capacity is higher in the 2022 ACC compared with the 2021 version. This is driven by several factors:

1. The update to using marginal ELCC instead of weighted average ELCC reflects that new storage resources have lower value as they are added to the system compared to the average ELCC of existing resources. More storage therefore needs to be built to provide capacity, increasing capacity avoided costs.

[19] CEC Solar + Storage Model is an optimization model to evaluate the optimal dispatch and costs & benefits of DERs, available at: https://www.energy.ca.gov/programs-and-topics/programs/electric-program-investment-charge-epic-program/modeling-tool-maximize

2. The SERVM prices used to calculate energy and AS revenues have low AS prices compared to the SERVM prices used in the 2021 ACC, as well as compared to historical values.
3. The RECC methodology reflects the deferral value of a resource, taking into account the difference in net costs over the lifetime of the resource, instead of considering only the first year.

Figure 33. Net RECC per nameplate and effective capacity

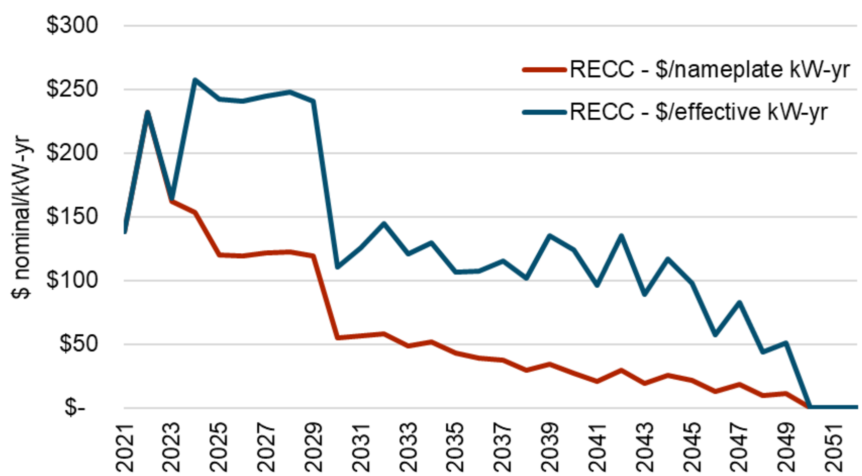


Table 9. Select Battery Storage Resource Capacity Avoided Costs Calculations from ACC

	2022	2025	2030	2035	2040
Fixed Costs					
Capacity ($2018/nameplate kW-yr)	$26	$23	$21	$21	$20
Energy x 4 ($2018/nameplate kW-yr)	$94	$71	$53	$49	$46
Total Levelized Fixed Costs ($2018/nameplate kW-yr)	$120.39	$93.58	$73.82	$69.49	$66.42
New Replacement Fixed Costs ($2018/nameplate kW-yr)	$65.24	$63.12	$59.42	$59.42	$59.42
ELCC Adjustment	100%	50%	50%	40%	22%
Revenues					
Net Energy Revenue ($nominal)	46,387	27,165	43,347	64,107	98,498
Regulation Down Revenues ($nominal)	6,281	9,103	9,122	7,765	7,020
Regulation Up Reveues ($nominal)	224	370	395	467	525
Spin Revenues ($nominal)	9,316	10,142	11,087	12,393	13,632
Total Revenues ($nominal)	**62,207**	**46,781**	**63,951**	**84,732**	**119,675**
Annual Charge (kWh)	1,424,854	1,406,231	1,411,024	1,418,991	1,424,677
Parasitic Losses (kWh)	230,524	231,316	230,020	229,566	230,881
Annual Discharge (kWh)	1,194,330	1,174,916	1,181,004	1,189,425	1,193,796
Round Trip Efficiency	84%	84%	84%	84%	84%
Energy Revenue/Annual Discharge ($nominal/MWh)	**$39**	$23	$37	$54	$83
Net Revenue					
Net Revenue ($nominal/nameplate kW-yr)	**$62**	**$47**	**$64**	**$85**	**$120**
After Tax Net Revenue ($nominal/nameplate kW-yr)	$45	$34	$46	$61	$86
After Tax Net Revenue ($2018/nameplate kW-yr)	$41	$29	$36	$44	$56
Avoided Capacity Costs					
RECC ($2018/effective kW-yr)	$ 215	$ 211	$ 87	$ 76	$ 80
RECC ($nominal/effective kW-yr)	$ 232	$ 242	$ 111	$ 107	$ 124

8.2 Hourly Allocation of Generation Capacity Value

The generation capacity values ($/kW-yr), after adjusting for temperature and losses, are allocated to the hours of the year with highest system capacity need using the SERVM model. Based on the electric demand and generation profiles used in the No New DER case, staff studied the No New DER case in SERVM to determine likely hours where Expected Unserved Energy (EUE) events would occur and in what magnitude. These results represent a system tuned to total Loss of Load Expectation (LOLE) of 0.1 (1 expected event in ten years), which is the industry standard. SERVM studied 100 probability-weighted cases using 20 weather years and 5 economic scenarios. The SERVM model determines the expected unserved energy (EUE) for each month/hour period in the year based on the No New DER RESOLVE case. It is expected that as solar and storage are installed on the grid, LOLE events gradually migrate to later in the evening. EUE will increasingly reflect risk at the “Net Load” peak, which is no longer the middle of the day when overall electric demand is highest. Instead, reliability risk will occur when solar and storage are largely expended for the day and demand is met with residual thermal capacity and imports.

A snapshot of these hourly EUE values in 2022 and 2030 are shown below in Figure 34 and Figure 35.

Figure 34. 2022 Expected Unserved Energy [MWh] from SERVM

Month\Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1																								
2																								
3																								
4																								
5																								
6																								
7																								
8																	0.02	0.48	3.50	0.03				
9																	0.15	74.18	83.26	2.71				
10																								
11																								
12																								

Figure 35. 2030 Expected Unserved Energy [MWh] from SERVM

Month\Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1																								
2																								
3																								
4																								
5																								
6																								
7																			23.75	6.31				
8																	7.38	23.04	72.84	25.78	38.09	28.19		
9																		0.25	2.05					
10																								
11																								
12																								

These month/hour EUE values were then allocated to days of the year using the CTZ22 temperature data and the 2020 calendar year for consistency with energy prices. A load-weighted daily maximum statewide temperature is calculated and all hours in days where the temperature exceeds a threshold receive the corresponding month/hour EUE value from SERVM. The temperature threshold was calculated as one standard deviation below the highest temperature. The resulting temperature threshold was 87 F and the 8760 hourly capacity allocation factors are shown below. The allocation factors between 2022 and 2030 were interpreted and allocation factors beyond 2030 are the same as 2030 (Figure 36 and Figure 37).

Figure 36. Generation Capacity Hourly Allocation Factors (2022)

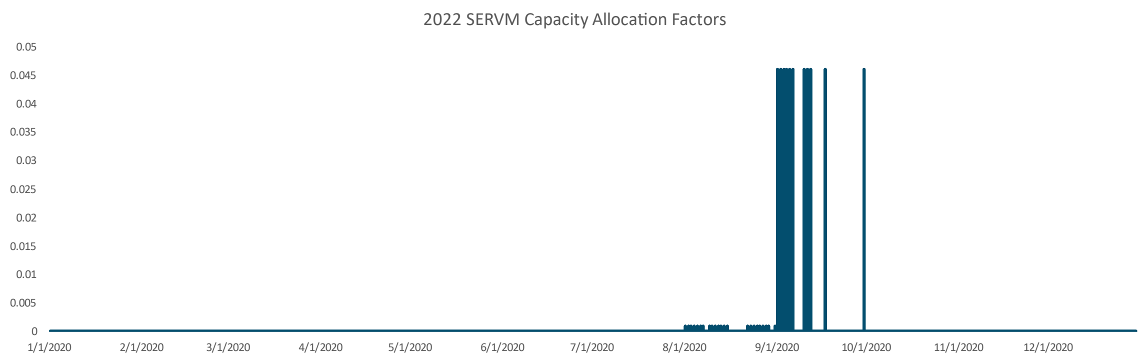
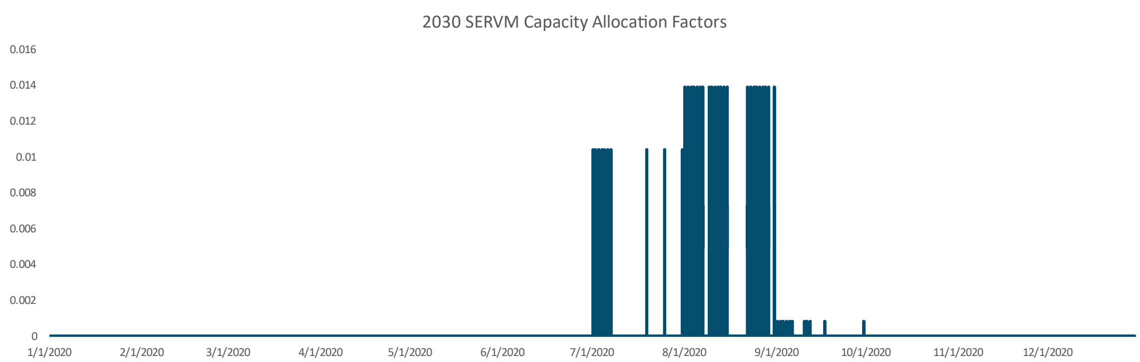


Figure 37. Generation Capacity Hourly Allocation Factors (2030)



9 Transmission Avoided Capacity Costs

9.1 Background

The 2022 ACC update uses the same general methodology as was used for the 2021 ACC to calculate transmission avoided costs for SCE and SDG&E. Changes made to improve consistency between utilities and incorporate updates to project data as provided by the utilities are noted in section 14.3. For PG&E, which previously had estimated transmission avoided costs in its GRC filings, the value used in the 2022 ACC update reflects the avoided cost proposed by the Solar Energy Industries Association and adopted by the CPUC in its D.21-11-016 ruling. Transmission avoided costs for SCE and SDG&E are calculated using the Discounted Total Investment Method (DTIM) for system-wide projects and Locational Net Benefits Analysis (LNBA) for individual large projects. Inputs are provided by each utility in response to individual data requests. The final values for all three utilities are listed in Table 10.

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

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

It should also be noted that the locations of the needs for demand reductions or distributed generation or storage will move over time as loadings on the utility systems evolve differently in different areas within the utility service territories. Thus, over the next ten years there could be a value to load reductions in area A, but not area B; but in years 10-20 the situation may flip, and area B could become the area with a need for load reductions, while area A no longer has a need. Given this locational and temporal uncertainty, the transmission avoided capacity costs are presented as a simple system average value for each utility. While this may underestimate the value of net load reductions in some areas and overestimate in other areas, we believe that this approach is superior to trying to forecast locational needs far into the future. Details on the calculation of the utility-specific transmission costs are included in Appendix 14.3.

Table 10. Long-Term Transmission Marginal Costs ($2021)

	PG&E	SCE	SDG&E
Transmission Capacity ($/kW-yr)	$52.54	$17.54	$152.47

9.2 Annual Transmission Marginal Capacity Costs

The transmission capacity marginal costs are escalated to nominal dollars using the annual inflation rates shown below. The inflation rates were provided by the utilities in their response to the Energy Division data request for the 2022 ACC update. Values for PG&E and SCE remained the same, while SDG&E noted that internal inflation or escalation rates may vary by project and provided annual transmission plant escalation rates as a reference. The value used herein is the simple average of the 2021 through 2026 values.

Table 11. Transmission Inflation Rates

PG&E	SCE	SDG&E
2.34%	2.33%	2.62%

The annual transmission capacity costs by utility are shown in Table 12.

Table 12. Annual Transmission Marginal Capacity Costs ($ Nominal)

Year	PG&E	SCE	SDG&E
2021	$52.45	$17.54	$152.47
2022	$53.68	$17.95	$156.46
2023	$54.93	$18.37	$160.56
2024	$56.22	$18.79	$164.77
2025	$57.53	$19.23	$169.09
2026	$58.88	$19.68	$173.52
2027	$60.26	$20.14	$178.06
2028	$61.67	$20.61	$182.73
2029	$63.11	$21.09	$187.52
2030	$64.59	$21.58	$192.43
2031	$66.10	$22.08	$197.47
2032	$67.65	$22.60	$202.65
2033	$69.23	$23.12	$207.95
2034	$70.85	$23.66	$213.40
2035	$72.51	$24.21	$218.99
2036	$74.20	$24.78	$224.73
2037	$75.94	$25.36	$230.62
2038	$77.72	$25.95	$236.66
2039	$79.54	$26.55	$242.86
2040	$81.40	$27.17	$249.23
2041	$83.30	$27.80	$255.76
2042	$85.25	$28.45	$262.46
2043	$87.25	$29.11	$269.33
2044	$89.29	$29.79	$276.39
2045	$91.38	$30.49	$283.63
2046	$93.51	$31.20	$291.06
2047	$95.70	$31.92	$298.69
2048	$97.94	$32.67	$306.51
2049	$100.23	$33.43	$314.54
2050	$102.58	$34.21	$322.78
2051	$104.98	$35.00	$331.24
2052	$107.44	$35.82	$339.92

9.3 Hourly Allocation of Transmission Avoided Capacity Costs

The annual capacity costs shown above are allocated to hours of the year to allow the ACC to reflect the time varying need for transmission capacity. The peak capacity allocation (PCAF) method used to estimate distribution allocation factors in the prior ACC has been applied to the IOU system level hourly loads to estimate the transmission hourly allocation factors. 2019 Historical system loads were taken from the CAISO Energy Management System dataset[20]. CAISO averaging methods during daylight savings hours were removed to generate a true 8760 hourly load profile, aligned with the CTZ22 weather year.

The PCAF method allocates capacity costs to the hours where each utility system is most likely to be constrained and require upgrades—the hours of highest load, with the additional constraint that the peak period contain between 20 and 250 hours for the year.

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

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

Where:

a is the utility,

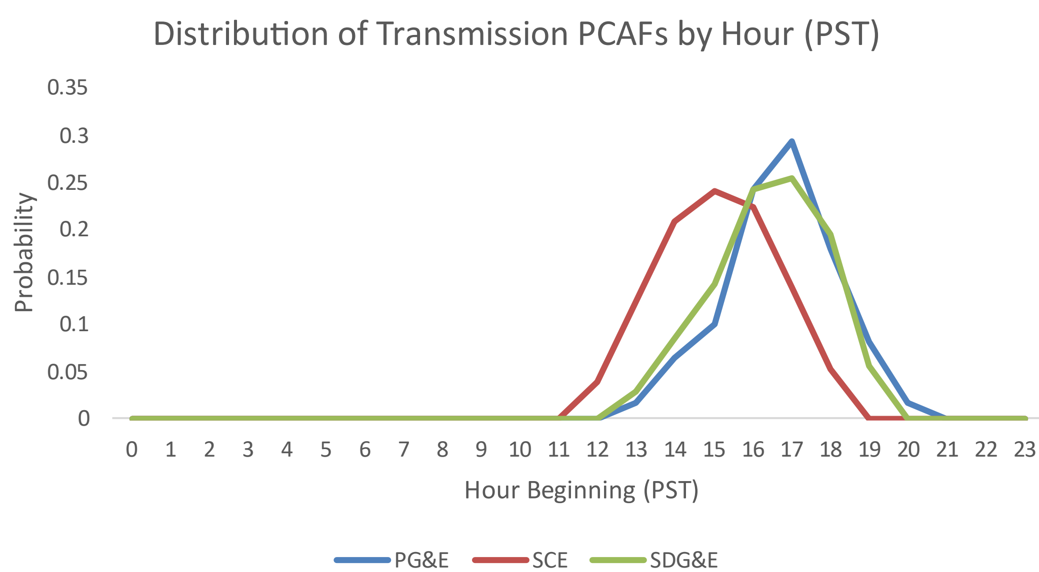
h is hour of the year,

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 20 and 250 hours with loads above the threshold.

We performed similar day and weather mapping as detailed in Section 10.5.1 to reallocate transmission PCAFs. The consultant aggregated climate zone temperature data to temperature profiles for each utility by taking the weighted average of temperature based on the load of each climate zone in each utility.

Figure 38. Transmission PCAF Allocators by IOU



10 Distribution Avoided Capacity Costs

The 2022 ACC update recalculates the avoided distribution capacity costs using similar methodology to the 2020 ACC update and with detailed 2021 GNA and DDOR information provided by each utility.

Distribution avoided costs represent the value of deferring or avoiding investments in distribution infrastructure through reductions in distribution peak capacity needs. The 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[21] defines two types of avoided costs, specified and unspecified, and proposes to leverage information from utility Distribution

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

Deferral Opportunity Report (DDOR) and Grid Needs Assessment (GNA) filings that contain detailed information about utility needs and investment plans. The avoided costs developed herein leverage information from those reports to estimate near term distribution marginal costs (for years 1 through 5 of the forecast) based on the recommendations in the T&D White Paper.

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

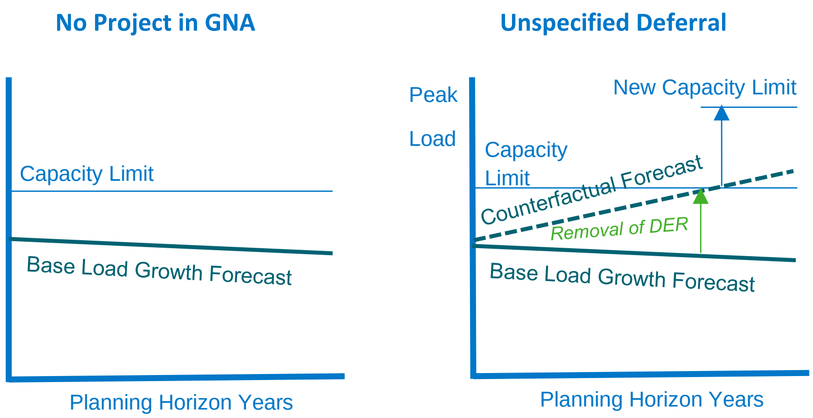
10.1 Near-term Distribution Marginal Costs from Distribution Planning

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

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

This is illustrated in Figure 39, 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 39. Project need from counterfactual forecast



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

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

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

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

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

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

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

Table 13. Near-Term Distribution Marginal Costs

	PG&E	SCE	SDG&E
Circuits only		$11.49	
B-Bank Substations		$11.93	
A-Bank Substations		$2.00	
Subtransmission		$1.33	
Total Distribution Capacity ($/kW-yr)	$22.70 ($2021)	$26.76 ($2021)	$4.36 ($2021)

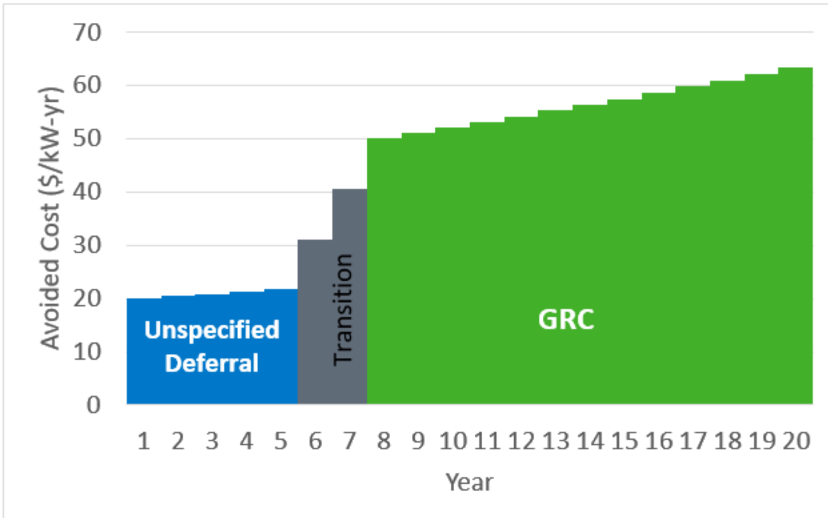
10.2 Use of Short-term and Long-term Avoided Distribution Costs

As stated in the T&D White Paper, "the impact of DERs to defer distribution upgrades accrue over the long term, while the GNA is limited to the forecast horizon that is necessary for distribution planning." The avoided costs estimates discussed above are based on DDOR and GNA filings that use a five-year planning

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

horizon. To extrapolate these estimates into long-term forecasts, the avoided costs in years 1-5 would be the unspecified deferral values held constant on a real dollar basis. Years 8 and beyond would be the GRC level held constant on a real dollar basis. Years 6 and 7 would linearly transition between the two end points of years 5 and 8. This method is depicted in the figure below.

Figure 40. Illustrative Distribution Avoided Cost Transition



10.3 Long-term GRC-based Marginal Costs

The California IOUs have used a wide variety of methods for estimating distribution marginal costs in their GRC filings.[24] The long-standing purpose of the marginal costs in a GRC filing is to guide the allocation of the utility revenue requirement to customer classes and the design of marginal cost-based rates. The GRC filing therefore provides a useful source for marginal costs that are estimated on regular three-year cycle. However, the GRC marginal costs might not be completely appropriate for use in DER cost effectiveness evaluations. They are not location-specific, and they are not necessarily avoidable costs. Therefore, Staff recommends that the GRC values be the source for long-run marginal costs, with the recognition that they may need to be modified for DER cost effectiveness and the ACC.

10.3.1 GRC Data Hierarchy

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

1. Values adopted for revenue allocation from most recently completed proceeding.
2. Values adopted for rate design purposes from most recently completed proceeding.

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

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

10.3.2 Distribution Marginal Costs from Most Recently Completed Proceedings

10.3.2.1 PG&E

PG&E provided updated marginal distribution capacity costs for the 2022 ACC, adopted in Decision 21-11-016.[25] Data is expressed in $/PCAF-kW-yr and $/FLT-kW-yr. PCAF (Peak Capacity Allocations Factors) 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 noncoincident measure of peak demand on the secondary equipment. To make the two marginal costs compatible, we convert the secondary costs from $/FLT-kW-yr to $/PCAF-kW-yr based on the ratio of FLT-kW to PCAF-kW in the division. The 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 14 shows the inputs and calculations for this process.

[25] 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

Table 14. Long-Term Distribution Capacity Costs for PG&E by Division (Base Year of 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

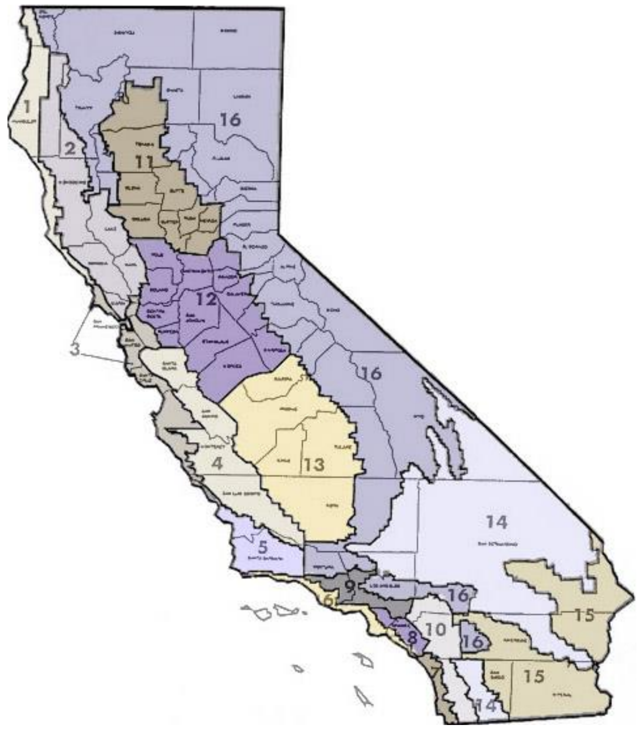
Columns A and B provided as updated values by PG&E for the 2022 ACC

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 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 15. Long-Term Distribution Capacity Costs for PG&E by Climate Zone (Base Year of 2021)

Climate Zone	Weighted Avg Capacity cost (F weighted by C) YR
1	**47.06**
2	**52.46**
3A	**50.32**
3B	**47.48**
4	**48.56**
5	**67.22**
11	**48.37**
12	**60.49**
13	**56.90**
16	**66.44**



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

10.3.2.2 SCE

SCE's long-term distribution marginal capacity costs have been updated from the prior ACC from the utility's 2021 GRC Phase II proceeding.[26] SCE did not develop marginal costs on a geographically disaggregated basis, but used a regression analysis of cumulative distribution capacity-related investments and cumulative peak loads, consistent with avoided distribution capacity costs that have been used for SCE in prior avoided cost updates. As noted in prior ACCs, SCE had developed marginal costs for three categories of distribution capacity investment: subtransmission, substations, and local distribution. In the 2021 GRC, these values were broken out into 4 components, with each substation and local circuit costs provided for each Distribution and Subtransmission. These are each provided in the table below, drawn from table I-11 in the 2021 GRC Phase II.

[26] Table I-11 of SCE 2021 GRC Phase II testimony

Table 16. Long-term Distribution Marginal Capacity Costs for SCE ($2021)

SCE Distribution Marginal Capacity Costs (2021$)		
	Substation	Circuit
Subtransmission ($/kW-yr)	$24.60	$16.40
Distribution ($/kW-yr)	$30.60	$109.40
Total ($/kW-yr)	$181.00	

10.3.2.3 SDG&E

SDG&E's long-term distribution marginal costs come from its 2019 GRC Phase II, which had not yet been adopted as of the prior ACC. These marginal costs are noted below.

Table 17. Long-term Distribution Capacity Costs for SDG&E[27]

	SDG&E Marginal Capacity Cost ($2019)
Substation ($/kW-yr)	$25.06
Local Distribution ($/kW-yr)	$57.63
Total	$82.69

10.4 Annual Distribution Capacity Costs

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

Table 18. Distribution Annual Escalation Rates

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

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

[27] "CH_5_WP#4 Marg Dist Demand Costs Rebuttal" - and from SDG&E 2019 GRC Phase II

Table 19. Annual Distribution Marginal Capacity Costs ($/kW-yr) (Nominal)

		PG&E										SCE	SDG&E
	Climate Zone:	CZ1	CZ2	CZ3A	CZ3B	CZ4	CZ5	CZ11	CZ12	CZ13	CZ16	All	All
2021	Historical	$22.70	$22.70	$22.70	$22.70	$22.70	$22.70	$22.70	$22.70	$22.70	$22.70	$26.76	$4.36
2022	Near Term	$23.27	$23.27	$23.27	$23.27	$23.27	$23.27	$23.27	$23.27	$23.27	$23.27	$27.38	$4.45
2023	Near Term	$23.85	$23.85	$23.85	$23.85	$23.85	$23.85	$23.85	$23.85	$23.85	$23.85	$28.02	$4.54
2024	Near Term	$24.45	$24.45	$24.45	$24.45	$24.45	$24.45	$24.45	$24.45	$24.45	$24.45	$28.67	$4.63
2025	Near Term	$25.06	$25.06	$25.06	$25.06	$25.06	$25.06	$25.06	$25.06	$25.06	$25.06	$29.34	$4.72
2026	Near Term	$25.68	$25.68	$25.68	$25.68	$25.68	$25.68	$25.68	$25.68	$25.68	$25.68	$30.03	$4.81
2027	Transition	$36.24	$38.43	$37.56	$36.41	$36.84	$44.42	$36.77	$41.69	$40.23	$44.11	$92.56	$36.81
2028	Transition	$46.79	$51.17	$49.44	$47.13	$48.01	$63.17	$47.85	$57.70	$54.78	$62.53	$155.09	$68.80
2029	Long Term	$57.34	$63.91	$61.32	$57.85	$59.17	$81.91	$58.93	$73.71	$69.33	$80.95	$217.62	$100.80
2030	Long Term	$58.78	$65.51	$62.85	$59.30	$60.65	$83.95	$60.40	$75.55	$71.06	$82.97	$222.69	$102.81
2031	Long Term	$60.24	$67.15	$64.42	$60.78	$62.16	$86.05	$61.91	$77.44	$72.84	$85.05	$227.88	$104.87
2032	Long Term	$61.75	$68.83	$66.03	$62.30	$63.72	$88.20	$63.46	$79.37	$74.66	$87.17	$233.19	$106.97
2033	Long Term	$63.29	$70.55	$67.68	$63.86	$65.31	$90.41	$65.05	$81.36	$76.53	$89.35	$238.62	$109.11
2034	Long Term	$64.88	$72.31	$69.37	$65.45	$66.94	$92.67	$66.67	$83.39	$78.44	$91.59	$244.18	$111.29
2035	Long Term	$66.50	$74.12	$71.11	$67.09	$68.61	$94.99	$68.34	$85.48	$80.40	$93.88	$249.87	$113.52
2036	Long Term	$68.16	$75.97	$72.88	$68.77	$70.33	$97.36	$70.05	$87.61	$82.41	$96.22	$255.70	$115.79
2037	Long Term	$69.87	$77.87	$74.71	$70.49	$72.09	$99.80	$71.80	$89.80	$84.47	$98.63	$261.65	$118.10
2038	Long Term	$71.61	$79.82	$76.57	$72.25	$73.89	$102.29	$73.60	$92.05	$86.58	$101.10	$267.75	$120.46
2039	Long Term	$73.40	$81.81	$78.49	$74.05	$75.74	$104.85	$75.44	$94.35	$88.75	$103.62	$273.99	$122.87
2040	Long Term	$75.24	$83.86	$80.45	$75.91	$77.63	$107.47	$77.32	$96.71	$90.96	$106.21	$280.37	$125.33
2041	Long Term	$77.12	$85.96	$82.46	$77.80	$79.57	$110.16	$79.26	$99.13	$93.24	$108.87	$286.90	$127.84
2042	Long Term	$79.05	$88.11	$84.52	$79.75	$81.56	$112.91	$81.24	$101.61	$95.57	$111.59	$293.59	$130.39
2043	Long Term	$81.02	$90.31	$86.64	$81.74	$83.60	$115.73	$83.27	$104.15	$97.96	$114.38	$300.43	$133.00
2044	Long Term	$83.05	$92.57	$88.80	$83.79	$85.69	$118.63	$85.35	$106.75	$100.41	$117.24	$307.43	$135.66
2045	Long Term	$85.12	$94.88	$91.02	$85.88	$87.83	$121.59	$87.48	$109.42	$102.92	$120.17	$314.59	$138.37
2046	Long Term	$87.25	$97.25	$93.30	$88.03	$90.03	$124.63	$89.67	$112.15	$105.49	$123.18	$321.92	$141.14
2047	Long Term	$89.43	$99.68	$95.63	$90.23	$92.28	$127.75	$91.91	$114.96	$108.13	$126.25	$329.42	$143.97
2048	Long Term	$91.67	$102.18	$98.02	$92.48	$94.59	$130.94	$94.21	$117.83	$110.83	$129.41	$337.10	$146.84
2049	Long Term	$93.96	$104.73	$100.47	$94.80	$96.95	$134.21	$96.56	$120.78	$113.60	$132.65	$344.95	$149.78
2050	Long Term	$96.31	$107.35	$102.98	$97.17	$99.37	$137.57	$98.98	$123.80	$116.44	$135.96	$352.99	$152.78
2051	Long Term	$98.72	$110.03	$105.56	$99.59	$101.86	$141.01	$101.45	$126.89	$119.35	$139.36	$361.22	$155.83
2052	Long Term	$101.19	$112.78	$108.20	$102.08	$104.40	$144.53	$103.99	$130.06	$122.34	$142.85	$369.63	$158.95

10.5 Allocation of Avoided Distribution Capacity Costs to Hours

The annual capacity costs shown above are allocated to hours of the year to allow the ACC to reflect the time varying need for distribution capacity. Earlier ACCs used the distribution hourly allocation factors based on regression estimates of distribution hourly loads. Those estimates reflected forecasts of net loads (load net of local PV production) for the present and future (2030). In this way, the allocation factors estimated an evolution in the timing of the peak capacity needs on the distribution system due to DER. With the change to estimating distribution capacity costs under the paradigm of no new incremental DER, this estimation of the timing of peak capacity needs in a future with more DER is no longer needed. Therefore, the distribution hourly allocation factors estimated for 2022 are used for all years 2022 through 2052 in the ACC.

In addition to holding the allocation factors fixed over the analysis period, this ACC update also utilizes historical utility data and GRC analyses for the allocation factors. Details by IOU are provided in Appendix 14.4.1.

10.5.1 Distribution Day and Weather Mapping

The distribution capacity hourly allocation factors described above reflect the particular years from which the historical data was obtained. The peak loads are therefore driven by weather conditions in those years – and that weather will not match the CTZ22 weather files used for the generation avoided cost modeling. To better align the distribution and generation costs, the distribution allocation factors are reordered to align with the weather in the CTZ22 files. Moreover, the hourly allocation factors are realigned so that the occurrence of weekends and holidays matches a 2020 calendar year (beginning with January 1 as a Wednesday. This remapping of allocation factors for weekends is particularly important for the evaluation of energy efficiency measures that vary by occupation schedules such as office HVAC.

For the 2022 ACC update, PG&E's PCAF values did not change from the previous ACC update. SCE provided new PLRFs based on forecasted load for 2024 but relied on historical data aligning most closely with the 2018 weather year. SDG&E does not generate PCAFs or PLRFs, and so provided distribution-level power flow data for each of its climate zones in the 2021 year. We calculated allocation factors following the methodology detailed in Appendix 14.4.1. IOUs provided 2018 temperature data from weather stations within the service territory, which were mapped to climate zones using the index provided by the *California Climate Zone Descriptions*[28] document published by the CEC. Data for climate zones 1, 5, and 16 were missing due to the size of the climate zones. Temperature Data for climate zone 2 was used to approximate climate zones 1 and 16, while data from climate zone 4 was used to approximate climate zone 5. These proxy climate zones were selected by choosing the climate zone with the most comparable amounts of heating and cooling degree days to the climate zone with missing data. The consultant obtained 2021 temperature data from National Center for Environmental Information for the following weather stations as a proxy of each climate zone.

Table 20. Weather stations corresponding to climate zones

Climate Zone	Weather Station
CZ 1	Arcata
CZ 2	Santa Rosa
CZ 3	Oakland
CZ 4	San Jose-Reid
CZ 5	Santa Maria
CZ 6	Torrance
CZ 7	San Diego-Lindbergh
CZ 8	Fullerton
CZ 9	Burbank-Glendale
CZ 10	Riverside
CZ 11	Red Bluff
CZ 12	Sacramento
CZ 13	Fresno
CZ 14	Palmdale
CZ 15	Palm Spring-Intl
CZ 16	Blue Canyon

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

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

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

11 Transmission and Distribution Loss Factors

11.1 T&D Capacity Loss Factors

The value of deferring transmission and distribution investments is adjusted for losses during the peak period using the factors shown in Table 21 and

Table 22. 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 2021 ACC.

Table 21. 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 22. Loss Factors for PG&E Transmission and Distribution Capacity

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

12 High GWP Gases

12.1 Introduction

This avoided cost component, introduced in 2020, measures the greenhouse gas (GHG) emissions from refrigerants and methane, two types of high Global Warming Potential (GWP) gases. High GWP gases are defined as GHGs that have a greater impact on global warming than CO_2. The GWP of a given gas is the ratio of its atmospheric effect on global warming to that of CO_2, so that the larger the GWP the more that a given gas contributes to the atmospheric greenhouse effect over a given time period. The GWP of a given gas may differ depending on the time period over which it is measured. For example, methane has a GWP of 72 over 20 years and a GWP of 25 over 100 years.[29] The 100-year GWP is used by CARB for emission inventory calculations and is provided as the default value with the 20-year GWP is provided as a sensitivity.[30]

[29] 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.

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

The impetus for this component was primarily the advent of DER programs designed to replace natural gas appliances with electric appliances, as a result of recent changes in state energy policy and new legislation.[31] These programs *decrease* GHG emissions due to their reduction in natural gas usage and associated methane leakage, but they simultaneously *increase* GHG emissions due to their increase in refrigerant use and electricity consumption. Therefore, these changes must be accounted for to accurately measure the GHG impact of these new programs. This avoided cost is used to value changes in methane leakage for a wide range of DERs, since DER programs are generally designed to decrease electricity consumption (which then results in a decrease in natural gas usage at power plants) or to decrease direct natural gas consumption in buildings.

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

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

12.2 Methane

12.2.1 Introduction and summary

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

Methane leakage occurs in all parts of the natural gas system – at production and storage facilities, in pipelines, at the meter, and behind the meter. The link between natural gas use (throughput) and methane leakage is not precisely known. Decreases in natural gas usage may result in decreased leakage at production facilities, since fewer new wells will be drilled over time in response to decreased demand (and

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

old wells may be taken out of service), but may not result in decreased leakage within pipelines or at storage facilities, at least in the short run, because many of those systems are kept at a constant pressure. However, in the long run, as parts of the natural gas distribution system are shut down as the result of building decarbonization efforts, methane leakage in the entire system will decrease.[32] Likewise, building decarbonization will eliminate leakage at the meter, and behind the meter, particularly when all natural gas appliances are removed from a building and the building's gas connection is shut off.

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.[33] Since California imports more than 90% of its natural gas, a national average, as opposed to a statewide estimate for methane leakage, is more appropriate for determining the lifecycle leakage of natural gas consumed in California. However, out-of-state methane leakage is not included in the CARB inventory, meaning that reducing this leakage does not count towards achieving California's GHG reduction goals. Thus, reduced out-of-state methane leakage is not strictly an avoided cost to California ratepayers, as defined by the current avoided cost framework. 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 the high GWP of methane. In this document, we primarily use leakage adders to quantify methane leakage as they are the most directly applicable to values.

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. We re-visited the inventory to develop separate estimates for upstream and behind-the-meter, so that methane leakage can be properly attributed to each category of natural gas use examined in the ACC. The resulting estimates are a leakage adder of 5.57% for upstream in-state methane leakage and a leakage adder of 3.78% for residential behind the meter leakage.

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

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

[33] 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 upstream leakage adder of 5.57% is most accurately described as an estimate of "long-run avoided methane leakage" for the natural gas system. With the exception of methane leakage at the individual appliance level, it is unclear if methane leakage in the natural gas system in California will change as a function of throughput,[34] unless portions of the gas distribution system are shut down due to coordinated electrification. However, in the long run, as the state transitions away from using natural gas in buildings, 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, we are "smoothing out" the stepwise function, and spreading the same total reduction in GHGs more evenly over time. This is similar to the way we currently treat avoided generation capacity in the ACC, where even a small change in peak energy usage is considered to have capacity value, even though only relatively large changes will actually avoid the construction of a new power plant.

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

12.2.2 Detailed Methodology for Methane Leakage Adders

The leakage adders in the 2022 ACC are calculated using CO2-equivalent emissions numbers from the 2017 GHG inventory published by the ARB.[35] The ARB inventory is a record of all GHG emissions occurring within the state borders of California, plus any out-of-state GHG emissions from electric generators supplying electricity to California.

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

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

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?"

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

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

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

methane leakage rate

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

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.[36]

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

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

produced. Burning a tonne of methane produces 2.74 tonnes of CO2. In order to determine the global warming impact of the leaked methane, we do not want to compare the effect of the leaked methane to that of one tonne of CO2, but rather to the 2.74 tonnes of CO2 we would have produced by burning it. So, we divide 25 by 2.74 to get 9.1. Hence, a tonne of methane leakage has 9.1 times the global warming impact if it is leaked compared to if it is burned.

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

Table 23. Leakage Adders in the ACC and their Corresponding Leakage Rates

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

12.3 Refrigerants

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

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

12.4 Use Cases

This 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.

The avoided costs of refrigerant usage (use case #3 below) are calculated separately from the ACC in the "Refrigerant Avoided Cost Calculator," which is available alongside the ACC on the CPUC website. This is a separate tool from the ACC because avoided costs of refrigerant leakage depend on program-specific characteristics such as device type and refrigerant charge. However, the standardized refrigerant leakage values (such as annual leakage rates) are also contained in the ACC itself, for reference.

It is important to note that the refrigerant cost calculator can be used not only for avoided costs, but also to calculate incurred costs, such as when a program results in the installation of a device containing refrigerants. It is crucial, however, to make sure that both the avoided and incurred costs are properly accounted for, in situations such as when a heat pump is substituting for an air conditioner. Both heat pumps and air conditioners contain refrigerants, so it is crucial to account for the refrigerant leakage from both devices when cost effectiveness is being examined.

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

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

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.

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-

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

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.

Use case #3: Changes in refrigerant usage or type – While this use case was developed primarily to estimate the GHG impact of building decarbonization, it also affects any existing EE measures that involve refrigeration or air conditioning, if those measures result in changes in equipment or refrigerant type, and therefore refrigerant leakage.

Note that this calculation applies to measures which result in changes to the *amount* of refrigerant, or the *type* of refrigerant, or both, since either change results in a change in the GHG emissions from refrigerant leakage.

12.4.1 Refrigerant Leakage Calculation by Measure Type

While the previous version of the ACC Refrigerant Calculator was designed to calculate the avoided or incurred cost due to refrigerant leakage from a single device, the 2022 ACC refrigerant calculator has been updated to calculate the avoided cost of refrigerant leakage for a measure type. With this update, the avoided cost associated with refrigerant leakage is calculated based on the leakage occurring given a particular measure compared to a counterfactual. Three types of measures are described below:

- Normal Replacement measure: the existing equipment is replaced with new equipment at the end of its effective useful life (EUL)
- Add-on Equipment measure: add-on equipment is installed alongside existing equipment and devices are retired at the end of their EULs
- Accelerated Replacement measure: the existing equipment is retired early (before the end of its EUL) and replaced with new equipment

12.4.1.1 Normal Replacement and Add-on Equipment Measures

The measure lifetime is defined as the life of the new device installed in the measure case. In the case of Normal Replacement and Add-on Equipment measures, the user must specify inputs for a new device that would be installed in the measure case, as well as the inputs for the new device that would have been installed in the counterfactual case. Device inputs include:

- Device type
- Device lifetime
- Device installation year
- Device refrigerant charge
- Refrigerant used (or a user-specified GWP for refrigerants that are not listed)

These inputs will impact the amount, timing, or GWP of refrigerant leakage, which will affect the associated costs. A description of the cost calculations for the refrigerant leakage associated with a device is given in more detail in Section 12.5 (see use case 3).

For Normal Replacement and Add-on equipment measures, inputs only need to be specified for newly installed devices because we assume that existing devices are the same between the measure and counterfactual (i.e., the refrigerant leakage from existing devices is exactly the same between the measure and counterfactual). Note that the previous version of the ACC Refrigerant Calculator output the incurred cost associated with refrigerant leakage from a single device, and no counterfactual device was specified. This would be analogous to choosing "Normal Replacement or Add-on Equipment" for the measure type, specifying inputs for a new device in the measure case, and selecting "None" for the counterfactual device in the updated 2022 version of the calculator. Selecting "None" for the counterfactual device would also be appropriate in the case where a heat pump was replacing a natural gas appliance that did not cause refrigerant leakage.

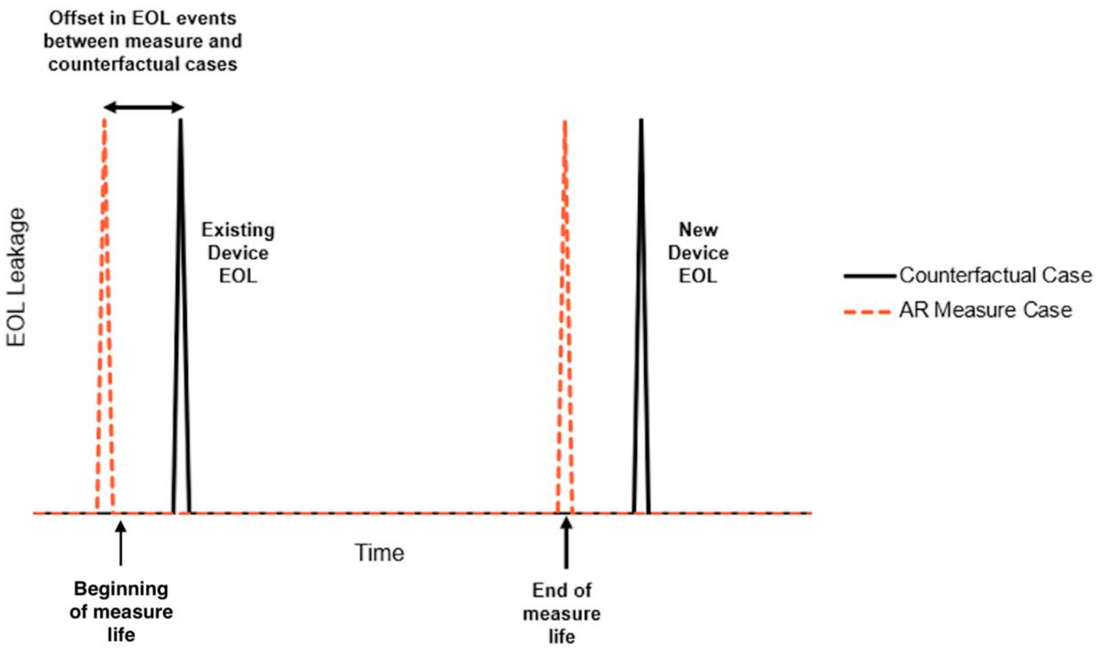
12.4.1.2 Accelerated Replacement Measures

In an Accelerated Replacement measure, an existing device is retired early and replaced with a new device. Typically, avoided costs for a measure would only consider costs occurring during the measure lifetime, However, accelerated replacement leads to two factors that necessitate a different approach to the avoided cost calculation:

1. **Due to the "spiky" nature of end-of-life leakage, the total change to refrigerant leakage resulting from an AR measure is not captured by only looking at events occurring within the measure lifetime.**

A large portion of the refrigerant leakage from a device comes from the end-of-life (EOL) leakage event, which occurs when a piece of equipment is retired or reaches the end of its EUL. In many cases, most of the refrigerant in a device may be leaked during the single EOL event upon device retirement. Hence, these events create large spikes in the leakage that must accounted for. However, there is an offset in these leakage event spikes between the measure case and the counterfactual baseline case (see Figure 41), which means that only looking at end-of-life leakage events occurring during the measure lifetime would not capture the full impact of the measure.

Figure 41. Illustration of end-of-life (EOL) leakage events for Accelerated Replacement measure case and counterfactual



** Note that there is an offset in the timing of the EOL leakage events, and the new device EOL occurs after the end of the measure life.*

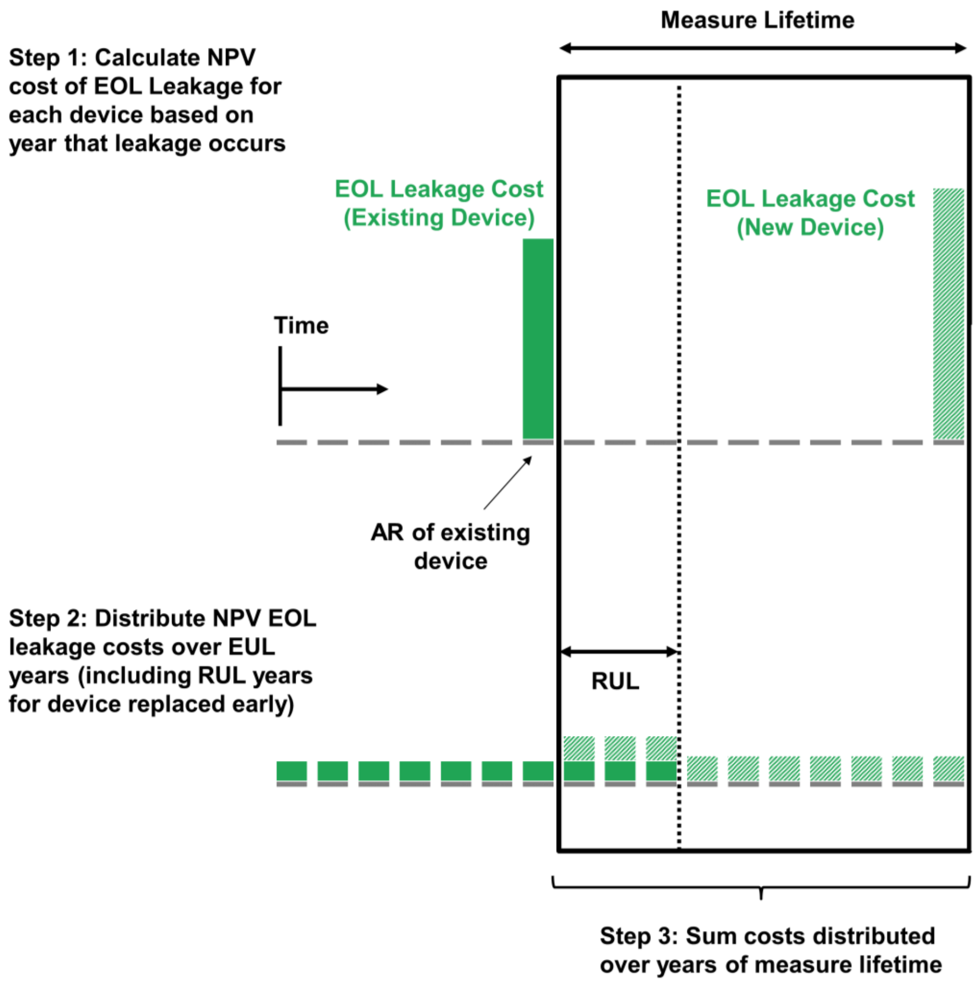
Considering only the leakage that occurs purely within the measure life would leave out the EOL event for the new device in the counterfactual case because it occurs after the end of the measure life as shown in Figure 41.

2. **Accelerated replacement of a device leads to more leakage overall than replacing a device at the end of its EUL.**

This point is clearly illustrated in considering the example of a device continually being replaced before the end of its EUL. For instance, consider a device with a typical EUL of 10 years. If it was replaced every 5 years instead of every 10 years, then double the leakage would occur assuming that all of the refrigerant is leaked upon retirement. This point illustrates the fact that Accelerated Replacement measures not only change the timing of end-of-life leakage events, but also the total leakage that occurs.

The above issues necessitated a framework for calculating the impact of Accelerated Replacement measures that allocates end-of-life refrigerant leakage to each year of a device's expected useful life, for purposes of accounting. In the updated Refrigerant Calculator, the EOL leakage cost for a device is evenly distributed over the years of the device's EUL, and then summed to the extent that these annualized costs occur during the relevant measure lifetime. Note that the timing of the EOL leakage is not assumed to change—rather, the avoided cost of EOL leakage is calculated for the year it actually occurs, and then allocated over each year of the device's EUL, for the purposes of attributing the EOL leakage to the measure in question. First, the NPV of the avoided cost due to end-of-life leakage from each device is calculated. Then, the NPV of avoided cost is evenly distributed over the years of the EUL of device, for purposes of attribution. Finally, the costs distributed over the measure lifetime years is summed to calculate avoided cost for the measure. A schematic of this accounting framework for Accelerated Replacement measures is shown in Figure 42.

Figure 42. Schematic of the framework for calculating avoided cost (shown for an Accelerated Replacement measure).



This approach solves both problems described above. In this proposed framework, the EOL leakage events for both the existing and new devices are accounted for despite the offset in timing between events in the measure and counterfactual cases. This approach also captures the cost of the extra leakage that occurs due to the accelerated replacement, which appears as EOL leakage distributed over the remaining useful life (RUL) of the device that was retired early, as shown in Figure 42.

Note that for an Accelerated Replacement measure, this framework requires the user to specify inputs for the existing device, as well as the new devices to be installed in both the measure and counterfactual cases. The Refrigerant Calculator assumes that the measure case and counterfactual case start with the same existing device and refrigerant specified by the user. For the measure case, the user must specify the year in which the new device will be installed, which will coincide with the early retirement of the existing device.

In the counterfactual case, it is assumed that the new device will be installed once the existing device is retired at the end of its EUL (i.e. the existing device will not be retired early).

12.5 Use Case Equations

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

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

This use case will apply to all DERs that result in changes in electricity usage. The new GHG value is the change in GHG emissions, multiplied by a percentage increase to account for methane leakage, and then multiplied by the 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.

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[38]. 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%[39].

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

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

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

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

3. Refrigerant leakage for device *i*

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

The cost of refrigerant leakage will be determined by multiplying the refrigerant leakage by the natural gas GHG value. This allows us to estimate either increased or decreased GHG costs for any situation where refrigerant charge (M_i), leakage $\left(q_{ann,i}\, t_i + q_{EOL,i}\left(1 - q_{ann,i} t_{EOL,i}\right)\right)$, or refrigerant GWP ($GWP_i$) has changed. Note that the natural gas GHG value is used instead of the electric model GHG adder because this use case applies primarily to building electrification measures.

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

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

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

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

= 40% + 85% (1 – 40%)

= 40% + 51%

= 91%

Value of refrigerant leakage =

$$-\ M_{\ i} * \left(q_{ann,i}\, t_i + q_{EOL,i}\left(1 - q_{ann,i} t_{EOL,i}\right)\right) * GWP_i * P_{GHGg}$$

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

The 2022 Refrigerant Calculator was updated such that refrigerant leakage is discounted at the mid-year rather than the end-of-year to be more consistent with continual leakage throughout a device's life. Note that in some cases, a measure may lead to an incurred cost due to refrigerant leakage rather than avoided cost. For instance, if a heat pump replaced a counterfactual natural gas appliance, the natural gas appliance would not have associated refrigerant leakage, and thus the avoided cost would be negative (e.g., there would be an incurred cost associated with the refrigerant leakage).

Table 24. Refrigerant Leakage Calculation Variables

Quantity	Abbr.	Units	Where?	Notes
Carbon intensity of grid in hour *h*	$CI_{grid,h}$	tonnes/kWh	ACC	
Change in electricity usage in hour *h,* device or program *i*	$\Delta E_{h,i}$	kWh	CE tool	Measure savings for EE; increased consumption for electrification; generation for solar, etc.
Upstream emissions adder	$\delta\%_{upstre}$	%	ACC	% change in GHG emissions to reflect change in methane leakage emissions
GHG electric adder	P_{GHGe}	$/tonne	ACC	Adopted in IDER Decision
Carbon intensity of natural gas	CI_{gas}	tonnes/BTU	ACC	Use standard # from EIA
Lifetime gas savings	ΔG_i	BTU	CE tool	Lifetime total gas savings for gas EE measures or gas usage for electrification of appliance *i*
Gas removal adder	$\delta\%_{BTM}$	%	ACC	Reflects additional avoided methane leakage when gas appliances are removed.
Natural gas GHG value	P_{GHGg}	$/tonne	ACC	Adopted in IDER Decision
Refrigerant charge	M_i	tonnes	CE tool	Refrigerant contained in device *i*.
Annual refrigerant leak rate	$q_{ann,i}$	%/year	ACC*	Typical leakage rate for appliance *i*
Lifetime	t_i	years	CE tool*	Expected useful lifetime of appliance *i*
End-of-life leak rate	$q_{EOL,i}$	%	ACC*	Leakage rate for appliance type *i* based on typical disposal practice
Number of years prior to end-of-life with no "top-off" refrigerant added to replace full charge	$t_{EOL,i},$	years	ACC*	Typical value for appliance type *i*. Important because devices generally do not have a full refrigerant charge at end-of-life.
Refrigerant GWP for installed device *i*	GWP_i	$\frac{tonnes\ CO2e}{tonne}$	ACC*	Global warming potential of refrigerant as compared with CO_2

*data for this variable will come from CARB

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

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

13 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[40], but will now apply to all distributed energy resource programs. This new avoided cost uses a similar method as in the Energy Efficiency proceeding and has been included in the 2022 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 in the ACC currently exclude costs borne by the customer, such as in-house infrastructure and plan reviews, although it is expected that these avoided costs will be included in the cost-effectiveness analyses done in individual resource proceeding.

Avoided cost estimates for natural gas distribution investments that are avoided by all-electric new construction is developed from GRC filings or other marginal cost filings. This information is on a separate tab within the Avoided Cost Calculator and will not be included in the hourly marginal avoided costs. It must be added separately to the benefits used in cost-effectiveness tests, and only for new construction projects, measures, and programs that have this benefit. The AGIC costs per unit are provided by utility through data requests and included in Appendix 14.6.

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

14 Appendix

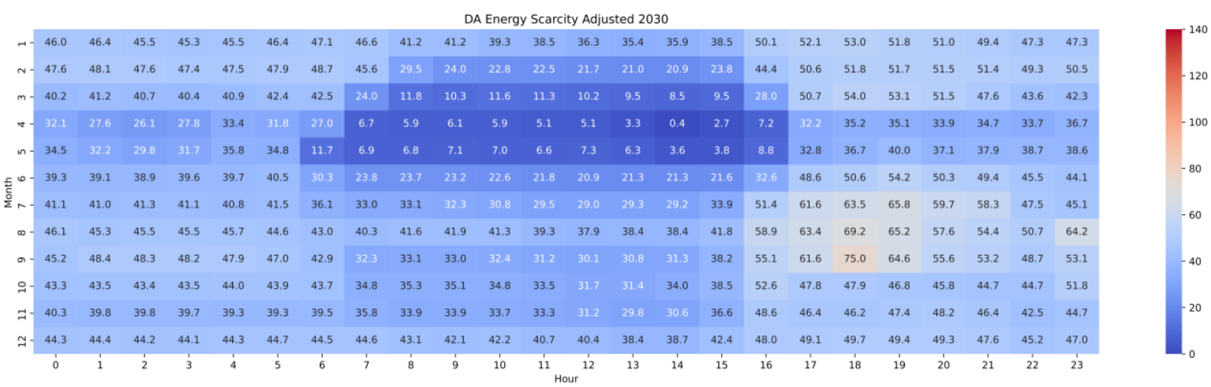
14.1 Comparison of 2021 ACC and 2022 ACC Inputs

14.1.1 SERVM Prices

2021 ACC: 2030 NP-15 Day Ahead Market Prices from SERVM

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	Avg
Jan	55	48	46	45	44	53	53	53	45	40	41	34	34	35	35	52	90	126	64	52	55	74	70	50	54
Feb	53	50	45	45	45	48	65	51	38	24	26	19	17	25	21	26	57	96	74	66	66	89	65	50	48
Mar	54	36	40	40	43	51	65	35	17	9	7	6	3	4	5	11	39	72	114	133	86	64	40	43	42
Apr	26	33	25	16	46	29	39	13	1	0	0	0	11	0	1	13	10	44	91	130	70	33	20	18	28
May	35	24	21	24	21	34	44	4	1	1	0	1	5	3	3	14	29	59	64	121	83	59	42	29	30
Jun	40	29	32	30	37	45	53	18	16	8	5	6	8	12	18	39	59	75	100	136	100	60	45	38	42
Jul	47	28	35	17	32	28	35	18	3	4	2	3	4	9	17	35	62	77	102	172	105	68	48	34	41
Aug	45	39	46	42	42	43	37	29	22	20	18	21	32	32	39	46	46	74	199	166	57	51	43	41	51
Sep	44	43	47	49	53	48	42	29	19	20	11	13	16	22	28	36	55	115	184	82	56	64	45	41	49
Oct	48	43	42	42	44	47	50	36	27	23	18	16	17	21	33	57	63	116	97	63	67	49	49	43	46
Nov	46	46	47	50	41	45	58	40	25	21	16	14	15	16	22	42	64	71	72	74	99	61	43	51	45
Dec	44	48	52	43	44	55	56	56	45	38	38	34	31	31	32	48	106	70	92	64	76	57	46	46	52
Avg	45	39	40	37	41	44	50	32	21	17	15	14	16	18	21	35	57	83	105	105	77	61	46	40	44

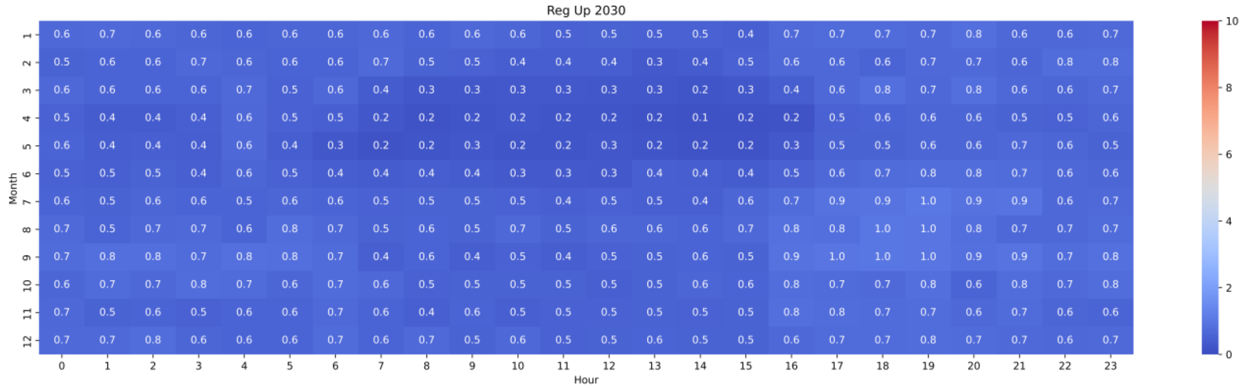
2022 ACC: 2030 NP-15 Day Ahead Market Prices from SERVM



2021 ACC: 2030 NP-15 Regulation Up Market Prices from SERVM

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	Avg
Jan	1.0	0.8	1.0	0.9	1.0	1.4	2.3	6.1	6.3	5.5	5.0	4.3	3.9	2.9	2.2	2.4	4.7	7.5	6.6	6.0	5.6	7.3	8.7	2.2	4.0
Feb	0.8	0.8	0.7	0.9	0.8	1.4	3.1	4.2	2.7	2.0	2.8	2.6	2.4	2.2	2.4	1.5	1.4	6.9	7.4	8.0	6.0	5.5	2.5	1.3	2.9
Mar	1.3	0.8	1.2	1.1	1.1	1.8	2.3	2.0	4.2	6.3	7.6	8.0	7.9	8.0	7.5	4.9	1.9	5.3	11.4	11.7	9.9	6.0	2.9	2.1	4.9
Apr	0.4	0.2	0.2	0.1	0.3	0.8	4.0	8.6	7.5	8.4	9.4	9.6	9.0	6.9	5.0	6.2	6.1	2.0	4.3	6.1	3.7	1.7	0.5	0.3	4.2
May	0.9	0.6	0.4	0.9	1.8	2.5	5.6	8.6	11.9	13.1	14.9	14.3	13.1	11.5	11.4	12.3	4.9	2.9	4.4	5.2	4.0	2.2	0.8	0.7	6.2
Jun	1.5	0.4	0.5	0.4	1.1	0.8	2.8	5.2	6.3	7.2	7.3	7.7	8.1	7.7	7.9	6.1	2.5	3.9	9.0	10.4	7.4	4.3	1.9	1.7	4.7
Jul	0.8	0.4	0.4	0.3	0.4	0.6	1.9	2.8	3.6	4.8	4.9	5.8	6.1	6.4	6.4	4.4	2.1	6.4	9.0	10.4	8.3	6.0	1.9	1.3	4.0
Aug	2.4	1.5	1.5	1.6	1.7	2.3	1.3	1.7	2.2	2.6	3.0	3.6	3.9	4.0	4.0	3.0	2.7	7.7	9.3	8.6	7.0	5.6	5.5	4.4	3.8
Sep	2.6	2.3	2.3	2.2	2.2	5.4	2.3	1.7	2.3	2.4	2.5	3.1	3.1	3.6	3.9	3.3	2.8	9.0	10.2	9.0	8.8	7.6	6.7	5.2	4.4
Oct	1.6	1.5	1.2	1.2	1.2	2.3	2.6	1.5	1.7	1.7	1.9	2.1	2.3	2.2	2.0	2.1	2.3	12.4	10.4	9.6	9.1	6.4	4.1	2.0	3.6
Nov	0.7	0.8	1.2	0.9	0.9	1.4	2.3	1.8	1.5	1.5	1.1	1.2	1.2	1.2	1.7	2.1	3.4	9.3	9.9	11.5	12.2	8.8	5.3	1.9	3.5
Dec	1.0	0.9	0.7	0.8	0.7	1.3	1.8	2.8	4.5	3.8	2.9	3.0	2.7	2.2	2.1	2.3	2.5	5.7	6.7	6.6	10.4	8.9	7.8	2.1	3.5
Avg	1.3	0.9	0.9	0.9	1.1	1.8	2.7	3.9	4.6	5.0	5.3	5.5	5.3	4.9	4.7	4.2	3.1	6.6	8.2	8.6	7.7	5.9	4.1	2.1	4.1

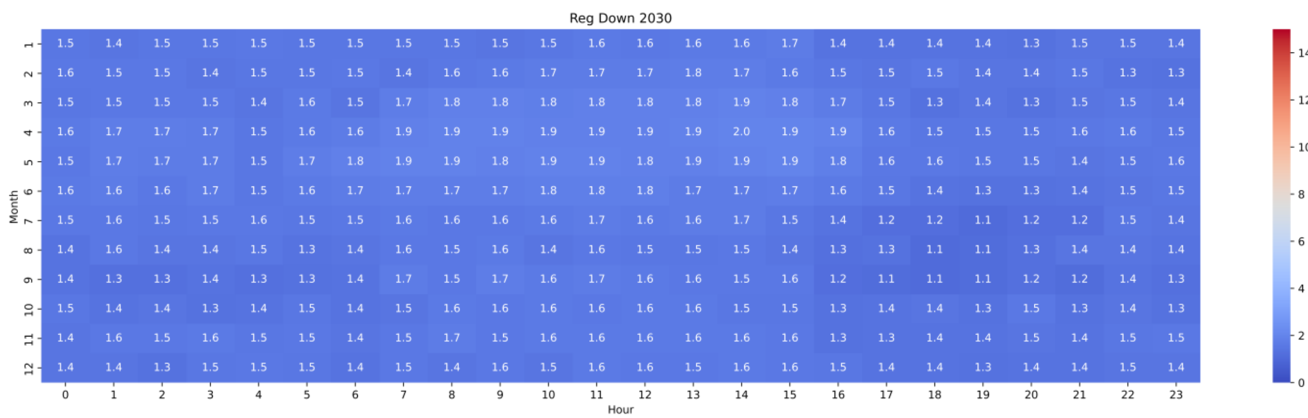
2022 ACC: 2030 NP-15 Regulation Up Market Prices from SERVM



2021 ACC: 2030 NP-15 Regulation Down Market Prices from SERVM

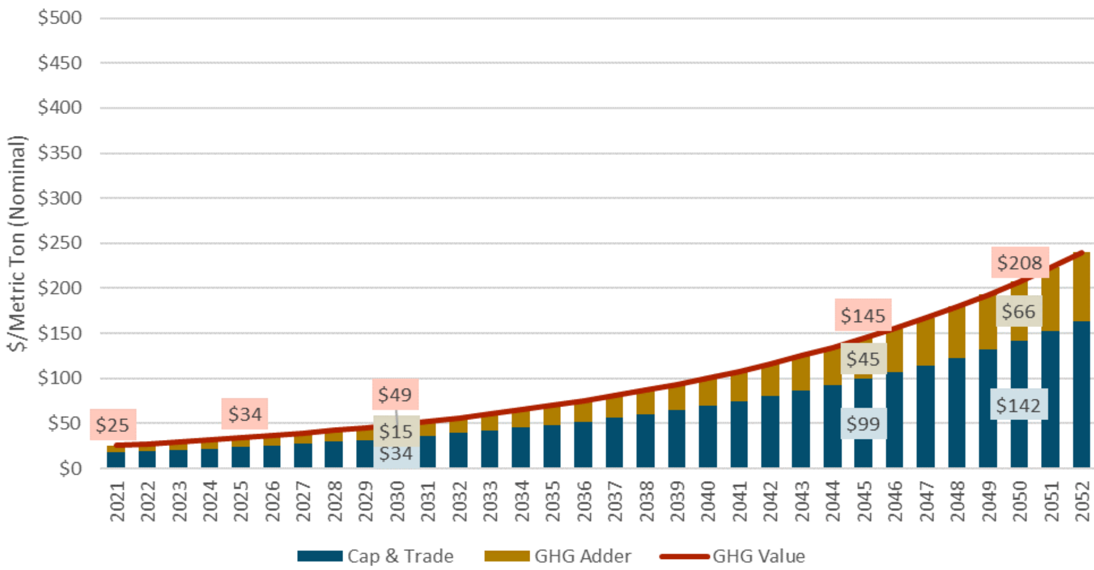
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	Avg
Jan	1.1	1.1	1.0	0.9	1.1	1.3	2.1	6.0	6.7	8.4	6.4	5.4	4.3	3.2	2.4	2.4	3.6	3.4	5.4	5.3	5.0	5.6	6.3	1.8	3.8
Feb	1.3	1.1	1.3	1.2	1.5	2.4	3.5	6.3	4.7	4.9	4.0	4.2	3.7	3.2	3.5	2.5	2.0	5.1	7.9	8.2	7.9	5.2	2.7	2.1	3.8
Mar	1.5	1.2	1.5	1.6	1.5	2.0	2.0	3.2	11.1	11.2	10.4	10.5	10.5	10.4	10.0	6.5	2.6	2.9	4.3	4.3	5.9	4.3	3.5	2.3	5.2
Apr	0.5	0.3	0.4	0.5	0.5	1.5	6.4	16.9	15.9	15.1	13.0	12.2	9.8	9.5	6.5	5.5	7.9	3.4	3.5	2.8	3.0	2.6	2.0	0.6	5.8
May	1.1	1.3	1.2	1.6	3.6	3.9	11.1	16.8	18.3	17.2	18.9	19.0	16.6	14.2	14.4	14.8	6.3	2.8	3.6	2.4	2.8	2.1	1.0	1.0	8.2
Jun	1.4	0.5	0.5	0.5	1.7	1.1	4.7	9.7	9.9	9.3	10.0	10.6	11.0	10.5	11.1	7.3	2.0	3.6	4.4	3.6	3.5	3.4	2.2	2.5	5.2
Jul	1.2	0.8	0.7	0.8	0.9	1.0	3.6	5.8	7.0	6.3	6.8	7.8	8.8	8.6	8.4	5.1	2.3	5.6	4.2	2.5	4.0	5.0	2.7	2.1	4.3
Aug	2.8	2.0	1.8	1.7	2.0	2.4	1.8	3.6	3.6	3.9	4.1	4.6	5.2	5.9	6.3	3.8	3.8	6.4	2.1	2.9	6.6	7.9	7.9	6.3	4.1
Sep	2.4	2.1	1.9	2.0	2.0	4.7	2.1	2.8	3.3	3.6	4.5	4.5	5.2	5.3	4.9	3.2	3.2	2.8	3.5	5.2	7.0	5.9	6.8	5.7	3.9
Oct	2.1	1.6	1.4	1.5	1.7	3.1	2.7	2.3	3.0	2.9	3.4	4.0	3.8	3.9	3.8	2.9	2.3	5.0	7.1	8.5	8.7	7.8	5.1	2.6	3.8
Nov	1.3	1.7	1.6	1.3	1.5	1.9	2.0	3.2	2.5	2.8	3.0	2.5	2.4	2.6	2.7	3.3	3.2	7.7	7.5	8.5	8.3	9.8	7.0	2.5	3.8
Dec	1.2	1.2	0.8	0.8	0.9	1.2	1.8	2.8	3.7	4.2	4.3	3.6	3.4	3.2	2.6	3.6	2.0	4.8	4.4	6.4	8.0	9.9	9.0	2.7	3.6
Avg	1.5	1.2	1.2	1.2	1.6	2.2	3.6	6.6	7.5	7.5	7.4	7.4	7.1	6.7	6.4	5.1	3.4	4.5	4.8	5.0	5.9	5.8	4.7	2.7	4.6

2022 ACC: 2030 NP-15 Regulation Down Market Prices from SERVM

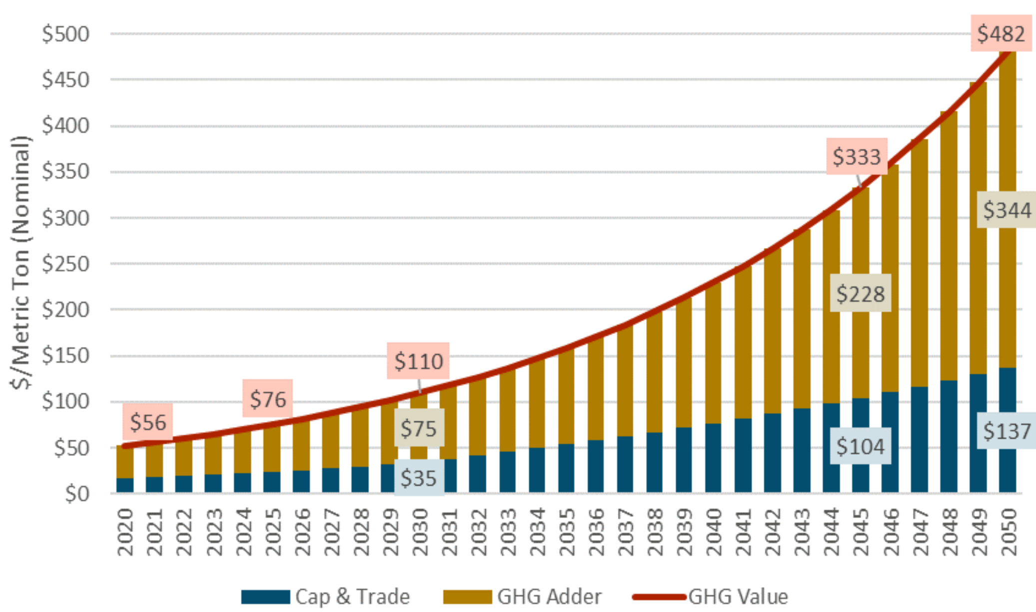


14.1.2 GHG Value

2022 ACC

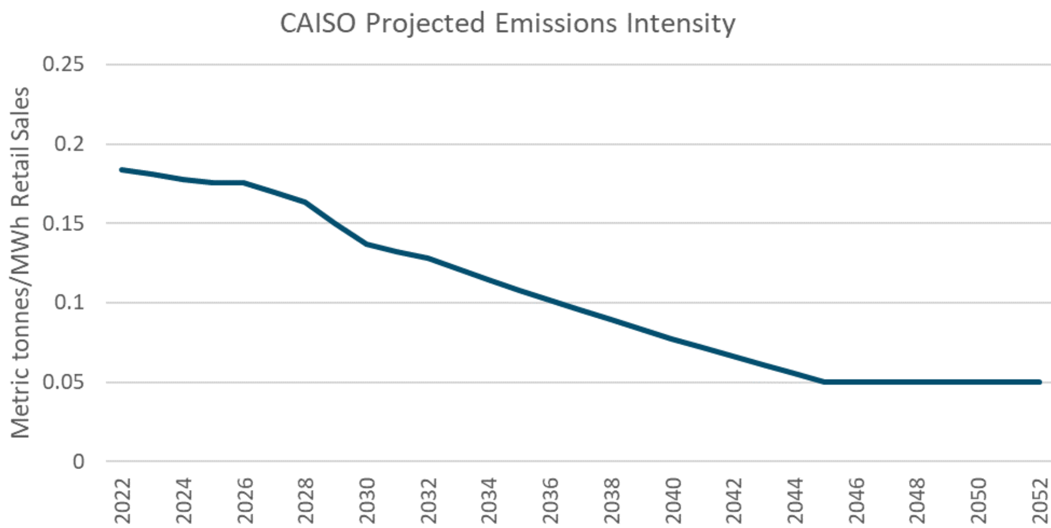


2021 ACC

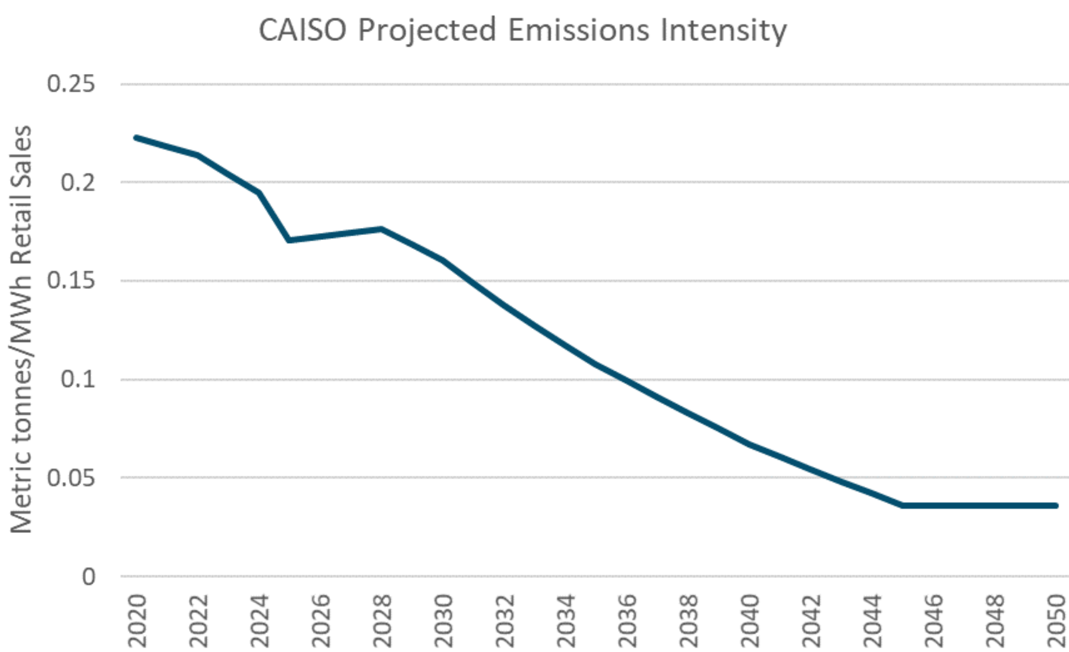


14.1.3 Emission Intensity

2022 ACC



2021 ACC



14.2 Example GHG Rebalancing Calculations

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

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

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

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

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

Table 25. GHG Cost: Unmanaged EV Charging Example

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

Space Heating Electrification Example: For the second measure, 3,000 MWh of commercial space heating load is added during the day, using 2,500 MWh of carbon free PV and 500 MWh of CCGT generation. Only

200 tons of hourly marginal GHG emissions are added, reducing the average grid intensity to 0.14 tons/MWh. This is below the annual target of 0.16 tons/MWh. To meet the 0.16 tons/MWh target emission intensity level, **480 tons** of increased emission would be allowed based on electrification load of 3000 MWh.

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

Table 26. GHG Cost: Commercial Space Heating Electrification Example

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

14.3 Utility-Specific Transmission Costs

14.3.1 PG&E

Recent ACCs have used transmission marginal capacity costs from PG&E's GRC proceedings. PG&E has estimated those values for ratemaking purposes using the Discounted Total Investment Method (DTIM). The DTIM calculates the unit cost of transmission capacity as the present value of peak demand driven transmission investments divided by the present value of the peak demand growth. This unit cost is then annualized using a Real Economic Carrying Charge (RECC) with adjustments for other ratepayer-borne costs, such as administrative and general costs (A&G) and operations and maintenance costs (O&M). This most recent calculation as performed by PG&E is provided in the table below, with a derived marginal transmission capacity cost of $12.02/kW-yr (in $2021).

However, in the California Public Utilities Commission 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).

Table 27. Derivation of PG&E Marginal Transmission Avoided Costs
(From PG&E 2020 GRC Ph II MTCC Model. Table Title retained from the PG&E model)

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

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

Notes:

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

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

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

14.3.2 SCE

SCE does not include estimates of transmission capacity costs in its GRC proceedings. We therefore calculate marginal transmission costs for SCE using information provided by SCE in response to Energy Division data requests. Determination of which transmission projects and costs to include is based on alignment with prior ACC's as well as the utility's judgement. SCE estimates approximately $187M in transmission investments for capacity needs through 2025. $165M of the costs are for a single project that serves less than 5% of SCE's load and is driven by 7MW per year of local load growth. The remaining $22M is for a secondary, smaller project driven by SCE system wide load growth. Given the different drivers of the projects (system load vs local load), we apply the DTIM to the system-wide project and the LNBA method to the large $165M project.

14.3.2.1 SCE DTIM Calculation for System Projects

The DTIM was previously applied to the SCE system-wide Big Creek and Sylmar projects, and in the 2022 ACC update is applied solely to the Sylmar project as the Big Creek project has been completed. This project is referred to as a system-wide project because SCE indicated that need is driven by SCE system peaks, rather than local peaks. The general PG&E process was applied to the SCE data, with some minor modifications for loading factors, and a large modification for the peak load forecast used. As in the prior ACC update, the forecast that SCE provided with its data response showed declining peak loads for the 2021 year and using those declining loads in the DTIM would result in negative values. To address this problem of individual years with negative load growth, we used the median peak load growth for SCE over the period 2021 through 2029 to represent the general system growth for SCE.

The SCE system-wide Sylmar project has a cumulative discounted investment cost of $18.23M over the five-year horizon, and the median growth forecast has a cumulative discounted growth of 809MW over the five-year analysis period. Combined with SCE's Annual MC factor, the resulting DTIM transmission marginal cost (without O&M) is $2.80 kW-yr for this systemwide projects.

Table 28. Derivation of SCE Marginal Transmission Avoided Costs for System Wide Projects (Without O&M)

PV of Investment ($M)	[1]	$18.23
PV of Load Growth (MW)	[2]	809
PV of Load Growth (kW)	[3]	808,985
Marginal Investment ($/MW)	[4]	$22,532
Marginal Investment ($/kW)	[5]	$22.53
Annual MC Factor	[6]	12.43%
O&M ($/kW-yr) (to be added later)	[7]	$0.0
Marginal Transmission Capacity Cost ($/kW-Yr)	[8]	$2.80

Notes:
[1] = The Discounted Project Cost of the Pardee Sylmar System-wide transmission project
[2] = The Cumulative Discounted Load Growth based on Median IEPR forecast without incremental DER
[3] = [2] x 1,000.
[4] = [1] * 10^6 / [2].
[5] = [1] * 10^6 / [3].
[6]: See Derivation of SCE Transmission Annual MC Factor
[7] = from Trans. O&M tab of "GRC 2-21 SCE-02 Dist. Streelight Workpapers"
[8] = [5] x [6] + [7].

Table 29. SCE Systemwide Transmission Project Costs and Load Forecasts

Year	Project Cost ($M) Pardee Sylmar (Systemwide)	SCE Forecast from IEPR SCE Forecast (MW)	Annual Peak Demand Growth (MW)	Median Growth (2021-2029)
		24,993		
2021	1	24941	(52)	192
2022	6	25175	234	192
2023	5	25388	213	192
2024	6	25571	183	192
2025	4	25695	124	192
2026	0	25839	143	192
2027	0	26088	249	192
2028	0	26281	193	192
2029	0	26473	192	192
NPV (2021 - 2025)	$18.23			809.0

Notes:

SCE Data request response: ED-SCE-ACC Transmission Cost 001 - 6.29.2022

IEPR Source Noted by SCE: IEPR CED Forecast 2021-2035 Baseline Forecast-Mid Demand Cast. Form 1.5 Extreme Temperature Peak Demand (MW) 1-in-10. Located at https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report/2021-1

IEPR Source for 2020 IEPR value: IEPR 2020-2030 Baseline Forecast-Mid Demand Cast. Form 1.5 Extreme Temperature Peak Demand (MW) 1-in-10. Located at https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2020-integrated-energy-policy-report-update-0

Real Discount Rate Used: 5.99%

Table 30. Derivation of SCE Transmission Annual MC Factor

Loaders & Financial Factors Inputs:			
Real Economic Carrying Charge (RECC)	[1]	10.11%	
Electric Transmission O&M ($/kW-yr)	[2]	$5.30	
A&G Payroll Loading Factor Transmission (Capital basis)	[3]	1.44%	
General Plant Loading Factor Transmission (Annual Capital basis)	[4]	7.30%	
Materials and Supplies Carrying Charge (Plant Based)	[5]		
Cash Working Capital Carrying Charge (Dist. O&M + A&G Based - Annualized)	[6]		
Franchise Fees & Uncollectibles Loading Factor RRQ Basis	[7]	1.12%	
MARGINAL INVESTMENT			
Marginal Investment	[8]	$100.00	
Annualized Marginal Investment	[9]	$10.110	[9] = [8] x [1].
MARGINAL EXPENSES			
O&M Expense (to be added directly, rather than included as a factor)	[10]		
A&G Expense	[11]	$1.44	[11] = [8] x [3].
General Plant	[12]	$0.74	[12] = [9] x [4]
Sub-total Marginal Expenses	[13]	$2.178	[13] = [11] + [12].
WORKING CAPITAL ALLOWANCE			
Materials and Supplies On-hand	[14]		
Cash Working Capital	[15]		
Sub-total Carrying Costs	[16]		[16] = [14] + [15].
Franchise Fees and Uncollectibles	[17]	$0.14	[17] = ([9] + [13] + [16]) x [7]
Marginal Cost	[18]	$12.43	[18] = [9] + [13] + [16] + [17]
Annual Marginal Cost Factor	[19]	12.43%	[19] = [18] / [8]

14.3.2.2 SCE Large Project Transmission Marginal Cost

The LNBA method was specifically developed in the DRP to estimate avoided capacity costs for individual projects.[41] The LNBA method calculates the value of deferring the original project and divides that value by the peak net load reduction needed to obtain that deferral. This deferral value per kW is then annualized over the planning period and adjusted for the additional cost factors such as taxes (in the present value revenue requirement factor) and A&G. O&M is added to the marginal costs after the system wide and individual large project marginal costs are combined in order to avoid double counting.

For the 2021 ACC update, it was determined that SCE's Alberhill project was relevant to the transmission avoided capacity cost and should be included following the LNBA method. This project is again included for the 2022 ACC update with the same data as was previously provided by the utility for the remainder of its anticipated project costs. For the SCE Alberhill project, we applied the LNBA method assuming a one-year deferral due to a 7MW reduction in area peak net loads. The deferral by one year of all investments in the multi-year capital plan results in a present value savings of $7.21M in direct costs, which translates to a value of $1,030.35 per kW of reduction ($7.21M deferral value / 7MW load growth).

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

Since the transmission capacity cost will apply to the entire SCE service territory, the next step is the calculate the equivalent avoided capacity cost for all of SCE. The paradigm we assume is that projects with this cost per kW of load growth would be required in the future in SCE's service territory. We cannot forecast where the projects would be needed, so we convert the project value into a uniform capacity value across the entire service territory. In this case, the project area represents 4.45% of SCE's peak loading, so the equivalent avoided cost is $9.44/kW-yr (the Total Project Marginal cost of $212.09 * 4.45%).

Table 31. SCE Derivation of Transmission Capacity Costs for Alberhill Project using the LNBA Method

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

	Year	Project Cost ($M)	Peak Demand Growth (MW)	1 Yr Deferral Value ($M)	Deferral Value ($/kW)		
6	2021	1	7	0.06	8.07		
7	2022	1	7	0.06	8.07		
8	2023	9	7	0.51	72.67		
9	2024	69	7	3.90	557.11		
10	2025	85	7	4.80	686.30		
11	2026		7	0.00	0.00		
12	2027		7	0.00	0.00		
13	2028		7	0.00	0.00		
14	2029		7	0.00	0.00		
15	NPV using Real Discount Rate			7.21	1030.35		
16	RECC (From Above) [5]					0.13	
17	Present Value Revenue Requirement Factor					1.461	
18	LNBA Value ($/kW-yr) [15] * [16] * [17]						$192.88
19							
20	A&G (1.44%)					1.44%	$2.78
21	General Plant (7.3%)					7.30%	$14.08
22	Franchise Fees (1.12% of all items above)					1.12%	$2.35
23							
24	Total Project Marginal Cost ($/kW-yr)						$212.09
25	Percent of system load						4.45%
26	**Project Marginal Cost spread across the system**						**$9.44**

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

Table 32. Total SCE Transmission Marginal Cost ($/kW-yr $2021)

	Marginal Cost ($/kW-yr)
System-wide projects	$2.80 / kW-yr
Alberhill project averaged over SCE system	$9.44 / kW-yr
Transmission O&M	$ 5.30 / kW-yr
Total	**$17.54 / kW-yr**

Transmission O&M is from SCE's 2021 GRC Workpapers.

14.3.3 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 transmission projects determined by SDG&E to be systemwide and potentially deferrable by DER. The derivation method for the Marginal Transmission Capacity Cost as displayed in Table 33 is the same as in the 2021 ACC update, but the input values to determine project costs ("PV of Investment") and forecasted load growth ("PV of Load Growth") have been updated. The calculation of the SDG&E Transmission Annual MC Factor remains the same as in the 2021 ACC, as the inputs were provided from the 2019 GRC, which is SDG&E's most recent GRC filing.

Table 33. Derivation of SDG&E Marginal Transmission Avoided Costs

PV of Investment ($M)	[1]	$186.29
PV of Load Growth (MW)	[2]	150
PV of Load Growth (kW)	[3]	149,918
Marginal Investment ($/MW)	[4]	$1,242,626
Marginal Investment ($/kW)	[5]	$1,242.63
Annual MC Factor	[6]	12.27%
	[7]	
Marginal Transmission Capacity Cost ($/kW-Yr)	[8]	$152.47

Notes:
[1] = The Cumulative Discounted Project Cost of SDG&E Transmission Projects
[2] = The Cumulative Discounted Load Growth based on Mid-Low 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]: For consistency with the prior ACC, O&M was not input in the DTIM calculation for SDG&E, though the value is included indirectly via the MC Factor
[8] = [5] x [6]

Table 34. Derivation of SDG&E Systemwide Transmission Project Costs and Load Forecasts

Discount rate	7.17%	2021 After Tax WACC Provided by SDG&E
Inflation	2.62%	
Real Discount Rate	4.43%	

Year	SDG&E XMSN Capital Expenditures ($M)	SDG&E Forecast from IEPR SDG&E Forecast (MW)	Annual Peak Demand Growth (MW)	Median Growth (2021-2029)
		4,578		
2021	52.68	4,547	(31)	29
2022	81.16	4,583	36	29
2023	0.00	4,600	17	29
2024	73.06	4,651	51	29
2025	0.00	4,682	31	29
2026	0.00	4,711	29	29
2027		4,753	42	29
2028		4,768	15	29
2029		4,795	27	29
NPV(2021-2026)	$186.29			149.92

Section 3 Standard Escalation Factors:
Escalation Factors Transmission Plant

Year	%
2021	2.90%
2022	6.45%
2023	3.64%
2024	1.54%
2025	0.59%
2026	0.63%
2027	1.12%
2028	1.55%
2029	1.89%
Average (2021-2026)	2.62%

- IEPR Values Drawn from CEU 2020 Managed Forecast -LSE and BA Mid Demand - Low AAEE Case. Form 1.5d (1-in-10): SDG&E TAC Area.
IEPR SDGE Used_CEDU 2020 Managed Forecast - LSE and BA Tables Mid Demand - Low AAEE Case.xlsx | Powered by Box

In the prior update, the SDG&E systemwide transmission load growth and investment calculation omitted one of the forecast years due to a negative load growth value. The use of this value would have resulted in undefined project costs under the DTIM method. In the 2022 update, this problem is instead addressed by taking the median growth over a 9-year forecast and applying it to each year within the time horizon. This aligns with the method used in both the 2021 and 2022 ACC updates for SCE and helps to address a concern that the shift in growth forecasts each year can lead to volatility in the final transmission value.

In SDG&E's data request response, forecasted capital expenditures for potentially DER-deferrable transmission projects were provided for the years 2021-2026. Because all relevant values were available for this time horizon, including corresponding load growth and escalation rates, all six years are incorporated in the calculation. Noting the anomaly when compared with the prior forecast, SDG&E explained that the high transmission capital costs represent an unusual concentration in expenditures due to pent up need. Further changes in the forecast when compared to the prior ACC inputs are due in part to the change in vintage of the forecast (the 2020 and 2021 ACC relied on a 2019 forecast whereas the 2022 ACC relies on a 2022 forecast) and several projects being included which were not yet solidified within the 5-year horizon as of 2019.

Table 35. Derivation of SDG&E Transmission Annual MC Factor

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

14.4 Derivation of Near-Term Distribution Marginal Capacity Costs

14.4.1 Unspecified Distribution Marginal Costs

Table 36 shows the calculation of the unspecified distribution marginal cost that is used for the near-term distribution marginal capacity costs. PG&E and SDG&E are shown as a single column, while SCE's costs are divided into circuits and substations separately. 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, which are derived from SCE's GRC Phase II Distribution Deferral Values and the Substation B-Bank values as noted below.

Table 36. Unspecified Distribution Deferral Costs by IOU

Line	Number of Overloads	PG&E	SCE-Substations (B-Bank)	SCE-Circuits	SDG&E	Notes:
1	Actual Overloads	347	44	102	9	[1]
2	Counterfactual Overloads	500	88	233	14	[2]
3	Percentage of Overloads addressed by Load Transfers	20%	20%	20%	9%	From 2021 ACC
	Overload Capacity					
4	Actual Overloads (kW)	955,369	255,450	328,150	12,533	[4]
5	Counterfactual Overloads (kW)	1,082,632	356,306	488,721	82,534	[5]
6	Deferrable Counterfactual Overloads (kW)	866,105	285,045	390,977	75,106	[6] = [5] x (100% - [3])
	Project & Planned Investment Costs					
7	Total Cost of Planned Investments in DDOR Filing ($)	$861,528,340	$314,794,356	$303,197,740	$4,740,000	[7]
8	Capacity Deficiency that Planned Investments Mitigate (kW)	1,066,790	258,340	496,060	8,709	[8]
9	Unit Cost of Deferred Distribution Upgrades ($/kW)	$807.59	$1,218.53	$611.21	$544.26	[9]* = [7] / [8]
	System Level Avoided Distribution Costs					
10	Deferrable Capital Investment	$699,457,621	$347,334,885	$238,969,645	$40,877,501	[10] = [9] x [6]
11	5 Year Total forecasted DER (kW)	2,591,211	3,502,414	3,134,911	1,068,061	[11]
12	Distribution Deferral Value ($/kW)	$269.93	$99.17	$76.23	$38.27	[12] = [10] / [11]
13	Marginal Cost Factor ('IOU Specific RECC')	8.41%	11.48%	11.48%	7.66%	[13]
14	Capacity Deferral Value ($/kW of DER installed-yr)	$22.70	$11.38	$8.75	$2.93	[14] = [12] * [13]
	O&M Distribution Costs					
15	O&M Deferral Value ($/kW-yr)		$6.74	$21.98	$20.26	[15]
16	O&M Deferral Value ($/kW of DER installed -yr)		$0.55	$2.74	$1.42	[16] = [15] * [6] / [11]
17	**Unspecified Marginal Cost ($/kW of DER installed-yr)**	**$22.70**	**$11.93**	**$11.49**	**$4.36**	[17] = [14] + [16]

Line		SCE Substations (A-Bank)	SCE Subtransmission	Notes
18	Distribution Deferral Value ($/kW-yr)	$24.60	$16.40	*From SCE 2021 GRC Phase II Table I-11
19	Deferrable Counterfactual Overloads (kW)*	285,045	285,045	* Using SCE Substation B-Bank Values [6]
20	5 Year Total forecasted DER (kW)	3,502,414	3,502,414	* Using SCE Substation B-Bank Values [11]
21	Unspecified Marginal Cost ($/kW of DER - yr)	**$2.00**	**$1.33**	[21] = [18] * [19] / [20]

Notes:

- [1] Number of circuits or areas in the utility Grid Needs Assessment (GNA) that have a deficiency or overload over the planning horizon (2021-2025) based on the utility planning forecast that includes peak load reductions due to DER. Note that while all utilities use a five year planning horizon, SDG&E only forecast projects for the first three years of the horizon (See [8] below).
- [2] See discussion below.
- [Omitted] Number of proposed projects deferred by Load Transfers or similar low-cost or no-cost solutions. This was only available for PG&E and SDG&E in the prior ACC update but currently results in a nonapplicable load transfer ratio due to changes in the data provided
- [3] Load transfer ratios are no longer calculable per the above omitted line but are important to recognize projects that would be deferred with low-cost or no-cost solutions. The values from the 2021 ACC are preserved, having been determined as a reasonable approximation in the analysis for SCE in that year.
- [4], [5] Sum of the maximum deficiency (kW) from 2021-2025 for each of the overloads identified in [1] and [2]
- [6-9] See discussion below,
- [11] Total forecasted DER was calculated by using the GNA and summing all DER adoption from 2021-2025 across all areas, including areas that were not overloaded. SDG&E's DER forecasts include estimates of coincident DER kW, rather than nameplate. This information was provided by SDG&E as a supplement to the information in the GNA and DDOR.
- [13] See 14.4.2 Derivation of Distribution Annual MC Factors.
- [15-16] O&M information is from data requests to the IOUs

Number of Overloads [Line 2]

As a part of the Grid Needs Assessment (GNA) each utility submitted a list of distribution areas with three key elements: a) Projected Load Forecasts (2021-2025) b) Projected DER adoption (2021-2025) and c) Facility Loading Limits. The counterfactual forecast takes the planning forecast and adds back, or removes, the load reduction from the DER. This results in higher cumulative loads. A circuit or area is considered overloaded if the projected load forecast in any year (2021-2025) exceeds the facility loading limit.

Deferrable Counterfactual Overloads [Line 6]

Multiplying the number of counterfactual overloads by one minus the low cost / no cost percentage, results in the number of counterfactual projects that could potentially be deferred by DER. Similarly, multiplying the amount of counterfactual overload kW (Line [5]) by one minus the low cost / no cost percentage, results in the amount of deferrable overload kW (Line [6]). This is the amount of load reduction that would be needed to defer the deferrable counterfactual projects.

Derivation of Unit Cost of Deferred Distribution Upgrades [Lines 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 August 2021 Grid Needs Assessment and DDOR reports provided by the utilities, with further detail on projects noted given in responses to a March 2022 Data Request from the Energy Division and its consultant.

Notes on significant changes to Unspecified Marginal Costs:

PG&E: The substantial change in the PG&E Unspecified Marginal Cost since the 2021 ACC update is tied to a 200% increase in both actual and counterfactual kW overloads. This increase is slightly mitigated in the final Unspecified Marginal Cost by a decrease in the per unit cost of PG&E's planned investments.

SDG&E: SDG&E's counterfactual overload kW tripled while actual overload kW remained fairly steady because many circuits increased to just below their 100% loading limit in the GNA-provided actual data and would have then exceeded it in the counterfactual scenario with no DER present. Similar to PG&E, this impact was partially counteracted by SDG&E's per kW cost of planned investments having reduced by half since the previous DDOR filing.

14.4.2 Derivation of Distribution Annual MC Factors

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

Table 37. PG&E Distribution Annual MC Factor

Annual Marginal Cost as a Percent of Marginal Investment

Loaders & Financial Factors Inputs:			
Real Economic Carrying Charge (RECC)	[1]	4.76%	
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 Bas	[4]	6.03%	
Materials and Supplies Carrying Charge (Plant Based)	[5]	0.88%	
Cash Working Capital Carrying Charge (Dist. O&M + A&G Based - Annualize	[6]	3.11%	
Franchise Fees & Uncollectibles Loading Factor RRQ Basis	[7]	1.0111	
MARGINAL INVESTMENT			
Marginal Investment	[8]	$100.00	
Annualized Marginal Investment	[9]	$4.76	[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]	$8.41	[18] = [9] + [13] + [16] + [17].
Annual Marginal Cost Factor	[19]	8.41%	[19] = [18] / [8].

Notes
[1] General RECC from 2021 PGE DDOR Appendix E LNBA
[2] E-Dist Primary Composite same as 2021 ACC from Table 1: Financial Factors from IntegeratedDistributedResourcesOIR_DR_ED_001-Q01Atch02.xlsm
[3] Distribution A&G from 2020 GRC Ph II Table 10-2 (Line 16)
[4] Distribution GPLF from 2020 GRC Ph II Table 10-2 (Line 17)
[5] M&S from 2020 GRC Ph II Table 10-2 (Line 18)
[6] CWC from 2020 GRC Ph II Table 10-2 (Line 19)
[7] FF&U Factor from 2020 GRC Ph II Table 10-2 (Line 20)

Table 38. SCE Distribution Annual MC Factor for Circuits

SCE MC Factor

Loaders & Financial Factor Inputs from the 2018 GRC

Loaders & Financial Factors Inputs:			
Real Economic Carrying Charge (RECC)	[1]	9.24%	
Electric Transmission O&M ($/kW-yr)	[2]	$21.98	
A&G Payroll Loading Factor Transmission (Capital basis)	[3]	1.44%	
General Plant Loading Factor Transmission (Annual Capital basis)	[4]	7.30%	
Materials and Supplies Carrying Charge (Plant Based)	[5]	n/a	
Cash Working Capital Carrying Charge (Dist. O&M + A&G Based - Annualized)	[6]	n/a	
Franchise Fees & Uncollectibles Loading Factor RRQ Basis	[7]	1.12%	
MARGINAL INVESTMENT			
Marginal Investment	[8]	$100.00	
Annualized Marginal Investment	[9]	$9.24	[9] = [8] x [1].
MARGINAL EXPENSES			
O&M Expense (not included as a factor by SCE for Dist)	[10]		[10] = not included in factors
A&G Expense	[11]	$1.44	[11] = [8] x [3].
General Plant	[12]	$0.67	[12] = [9] x [4].
Sub-total Marginal Expenses	[13]	$2.115	[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]	$0.13	[17] = ([9] + [13] + [16]) x [7].
Marginal Cost	[18]	$11.48	[18] = [9] + [13] + [16] + [17].
Annual Marginal Cost Factor	[19]	11.48%	[19] = [18] / [8].

Table 39. SCE Distribution Annual MC Factor for Substations

Loaders & Financial Factors Inputs:			
Real Economic Carrying Charge (RECC)	[1]	9.21%	
Electric Transmission O&M ($/kW-yr)	[2]	$21.98	
A&G Payroll Loading Factor Transmission (Capital basis)	[3]	1.44%	
General Plant Loading Factor Transmission (Annual Capital basis)	[4]	7.30%	
Materials and Supplies Carrying Charge (Plant Based)	[5]	n/a	
Cash Working Capital Carrying Charge (Dist. O&M + A&G Based - Annualized)	[6]	n/a	
Franchise Fees & Uncollectibles Loading Factor RRQ Basis	[7]	1.12%	
MARGINAL INVESTMENT			
Marginal Investment	[8]	$100.00	
Annualized Marginal Investment	[9]	$9.21	[9] = [8] x [1].
MARGINAL EXPENSES			
O&M Expense (not included as a factor by SCE for Dist)	[10]		[10] = not included in factors
A&G Expense	[11]	$1.44	[11] = [8] x [3].
General Plant	[12]	$0.67	[12] = [9] x [4].
Sub-total Marginal Expenses	[13]	$2.112	[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]	$0.13	[17] = ([9] + [13] + [16]) x [7].
Marginal Cost	[18]	$11.45	[18] = [9] + [13] + [16] + [17].
Annual Marginal Cost Factor	[19]	11.45%	[19] = [18] / [8].

Table 40. SDG&E Distribution Annual MC Factor

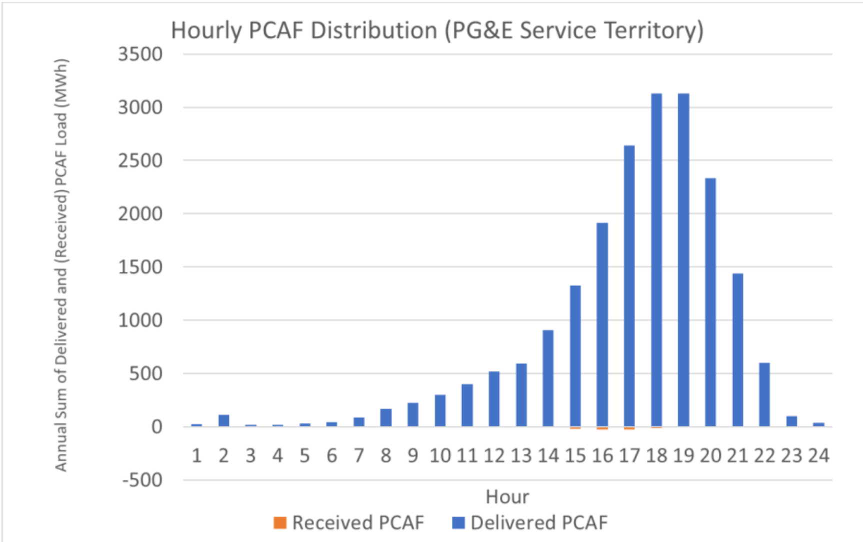
Loaders & Financial Factors Inputs:			
Real Economic Carrying Charge (RECC)	[1]	7.18%	
Electric Distribution O&M ($/kW-yr added later)	[2]	$20.54	
A&G Payroll Loading Factor Distribution (Annual Capital basis GPL)	[3]	1.72%	
General Plant Loading Factor Distribution (Annual Capital basis)	[4]	2.91%	
Materials and Supplies Carrying Charge (Plant Based)	[5]		
Cash Working Capital Carrying Charge (Capital Based)	[6]	1.99%	
Franchise Fees & Uncollectibles Loading Factor RRQ Basis	[7]		
MARGINAL INVESTMENT			
Marginal Investment	[8]	$414.07	
Annualized Marginal Investment	[9]	$29.73	[9] = [8] x [1].
MARGINAL EXPENSES			
O&M Expense	[10]		
A&G Expense	[11]	$0.54	[11] = [3] x ([9]+ [12] + [15])
General Plant	[12]	$0.87	[12] = [4] x [9]
Sub-total Marginal Expenses	[13]	$1.40	[13] = [10] + [11] + [12].
WORKING CAPITAL ALLOWANCE			
Materials and Supplies On-hand	[14]		
Cash Working Capital	[15]	$0.59	[15] = [9] x [6]
Sub-total Carrying Costs	[16]	$0.59	[16] = [14] + [15].
Franchise Fees and Uncollectibles	[17]	$0.00	
Marginal Cost	[18]	$31.72	[18] = [9] + [13] + [16] + [17]
Annual Marginal Cost Factor	[19]	7.66%	[19] = [18] / [8].

14.5 IOU Hourly PCAF Allocation by Climate Zone

14.5.1 PG&E PCAFs

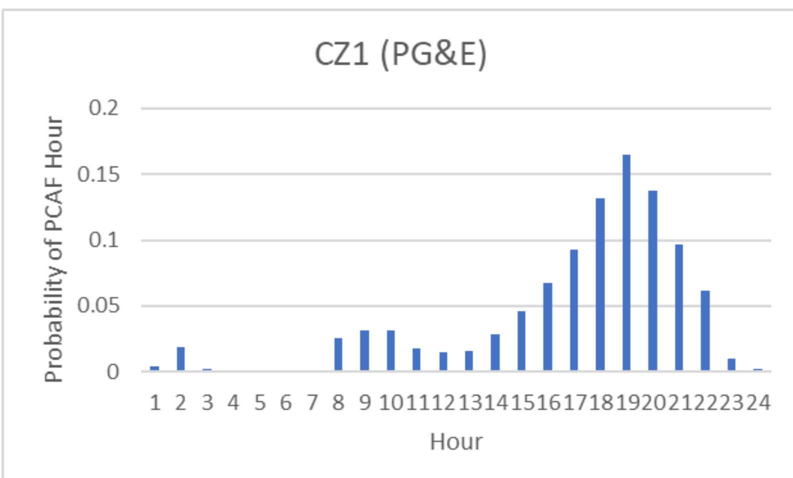
PG&E produces hourly peak capacity allocation factors (PCAFs) by distribution area for their GRC filing. In its 2020 GRC Phase II proceeding, PG&E presented a novel modification to its PCAF methodology wherein the need for capacity to accommodate exports is factored into the PCAF calculations. While this modification may have merit, it has not been incorporated into the ACC at this time because its impact is currently negligibly small. Figure 43 shows the PCAF associated with normal delivery of power from the grid to the customer, and the PCAF associated with exports. The export related PCAFs are barely visible in the hours 15-18.

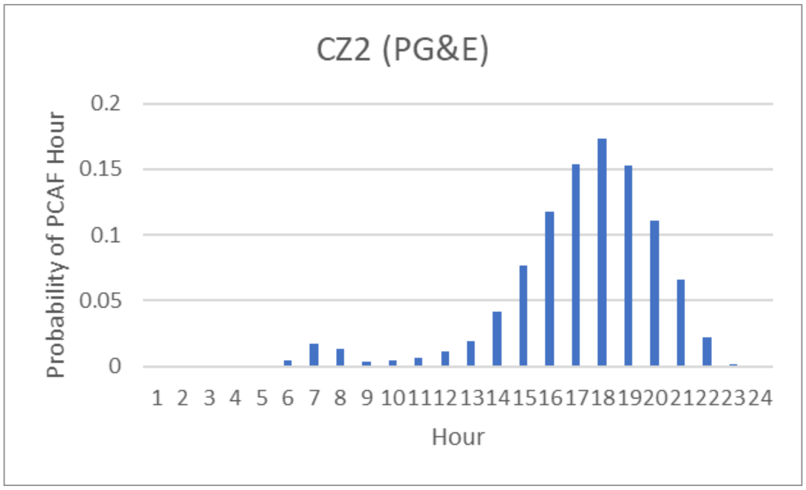
Figure 43. PG&E PCAF Distribution for all Areas by Hour of the Day (PST)

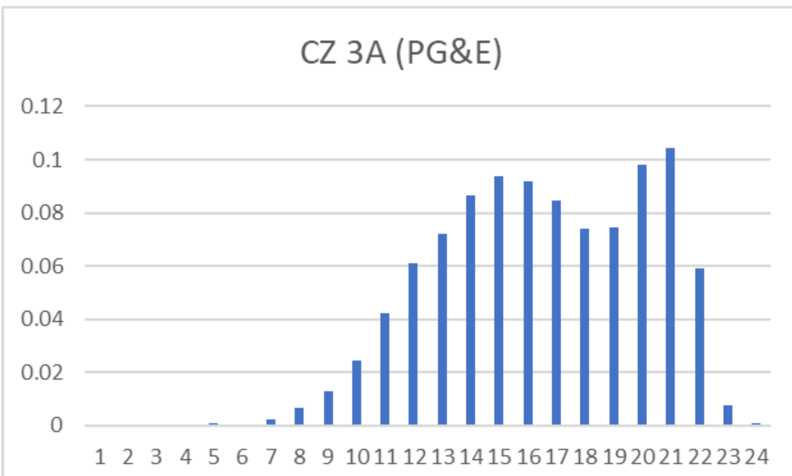


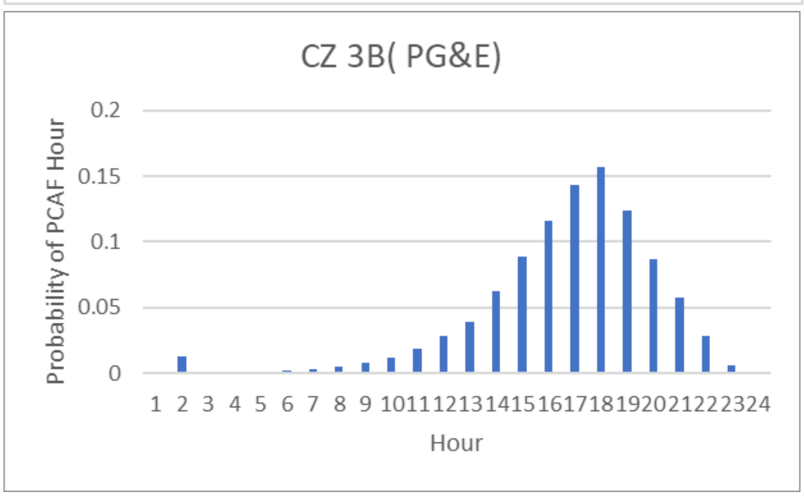
The PCAFs used in the ACC were provided by PG&E division and were the same data provided for the previous ACC, as this portion of the GRC Phase II proceeding has not been updated since the previous model. PG&E divisions were mapped to climate zones using the same methodology outlined in Table 14. If there was more than one division per climate zone, a weighted average of the PCAFs was taken.

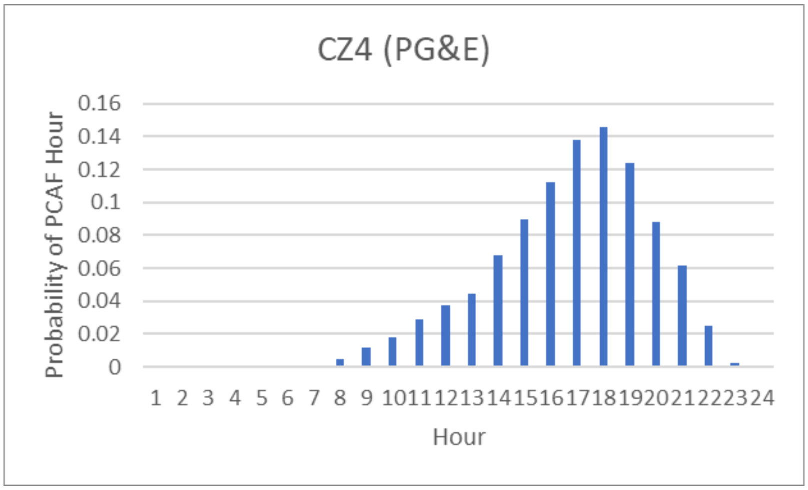
PG&E PCAFs by climate zones are shown below:

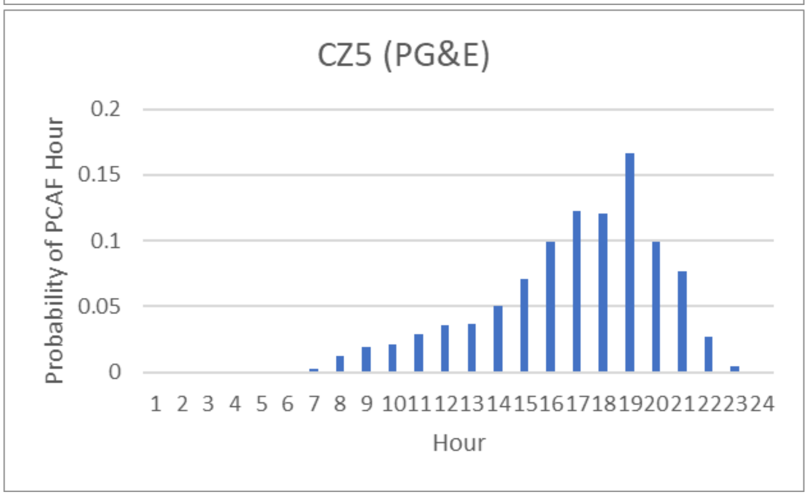


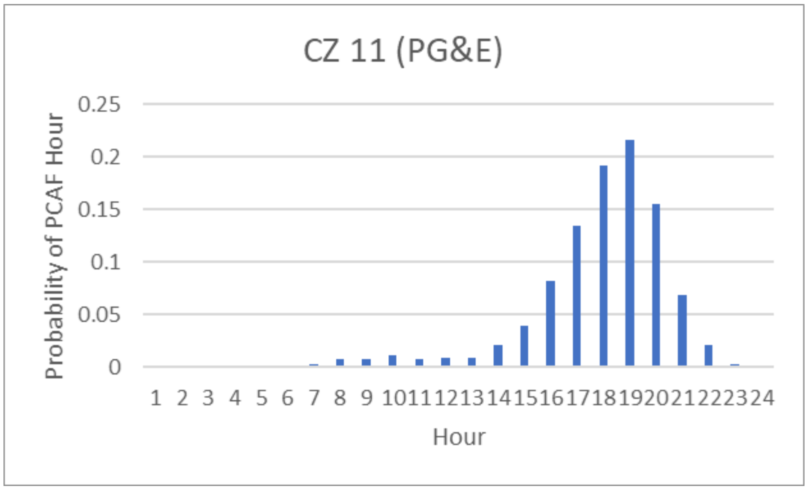

CZ2 (PG&E)
Probability of PCAF Hour
0.2
0.15
0.1
0.05
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

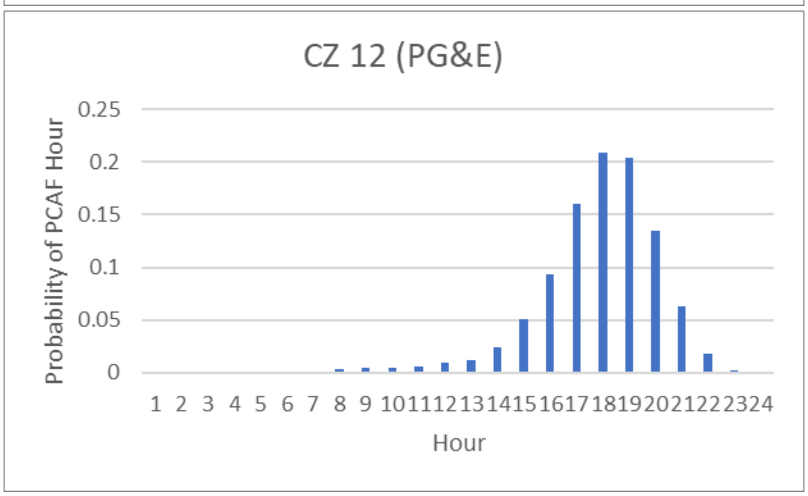

CZ 3A (PG&E)
0.12
0.1
0.08
0.06
0.04
0.02
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

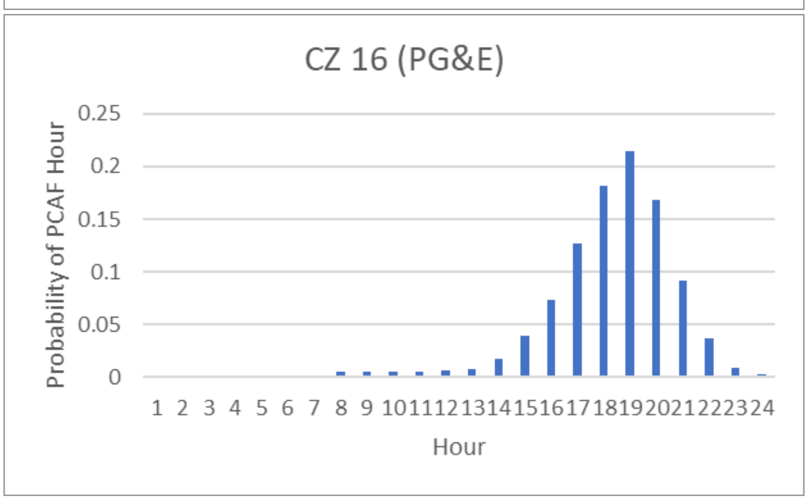

CZ 3B(PG&E)
Probability of PCAF Hour
0.2
0.15
0.1
0.05
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour


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


CZ5 (PG&E)
Probability of PCAF Hour
0.2
0.15
0.1
0.05
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour


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


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


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

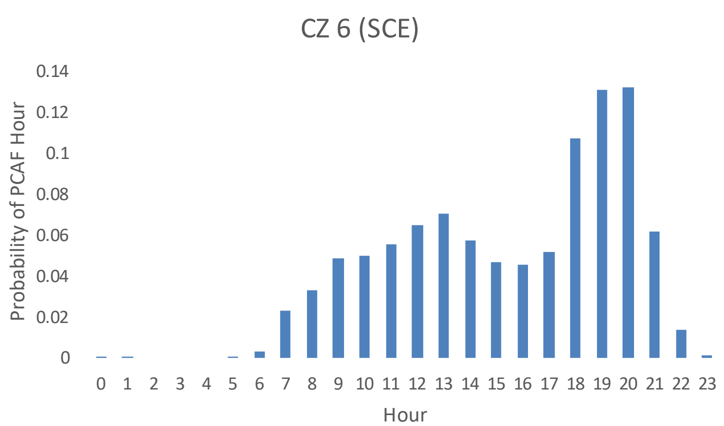
14.5.2 SCE Peak Load Risk Factors (PLRF)

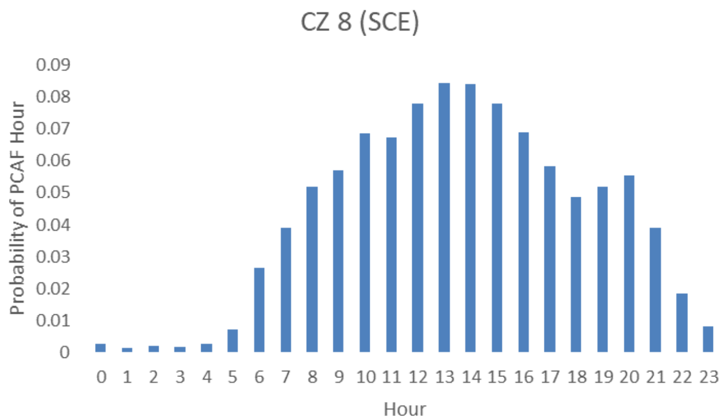
For SCE, the ACC utilizes the PLRF analysis completed by SCE in its 2021 GRC Phase II proceeding. According to SCE: "The PLRF methodology is a deterministic variant of the LOLE methodology used for generation capacity and uses the same conceptual framework of identifying hours of the year when expected load may result in an expected capacity constraint on the system. Since the distribution system is geographically disparate, the PLRF methodology is applied to each individual substation and circuit to take into account load diversity on the system."

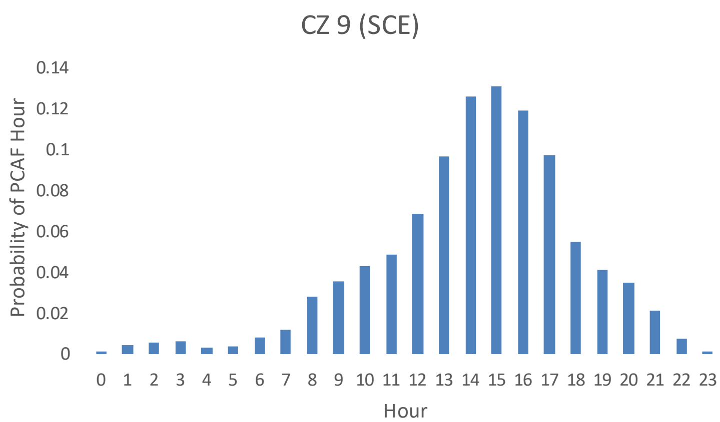
In the prior ACC, because the PLRF identifies the hours of peak capacity need for each substation and circuit, we aggregated these substations and circuits into climate zones and calculated the probability of peak capacity need for each hour. In this update, SCE has aggregated this data by climate zone and so the calculations will shift to selecting the peak hours as given within each climate zone. However, because the SCE-calculated PLRFs are still based on system wide peaks, the PLRFs values within each climate zone were then scaled up to sum to 100% within each climate zone. As 2024 is a leap year, the values for December 31st were removed before scaling the PLRFs for each climate zone. For Climate Zone 5, which showed no PLRF values in the 2024 forecast, the consultant calculated PCAF values following the same methodology used for SDG&E. For the 2022 ACC update, SCE's circuit-level loads and PLRF/PCAF values are used.

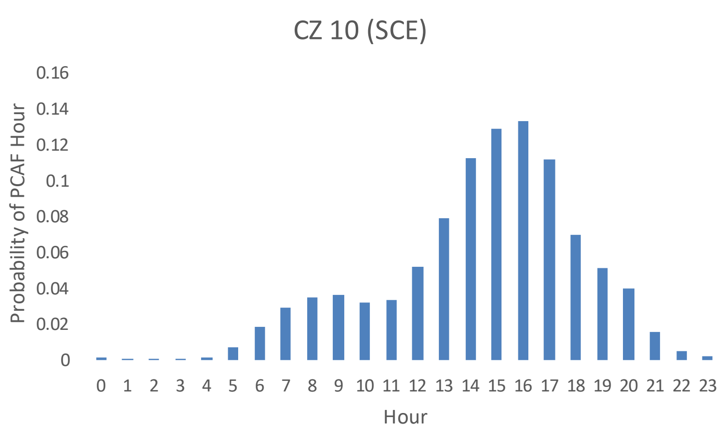
For its 2021 GRC, SCE provided an analysis forecasting future PLRFs for the 2024 calendar year. However, the consultant requires historical temperature data matching the PLRF year in order to align the PLRFs to a typical meteorological year. Per SCE's GRC filing and later confirmation via Energy Division data request, 2018 load data was referenced in creating the 2024 forecast and as such is considered to be the most appropriate reference year for aligning temperature data. The consultant has therefore aligned the PLRF and PCAF values as if the load and related temperature data were directly from the 2018 historical year.

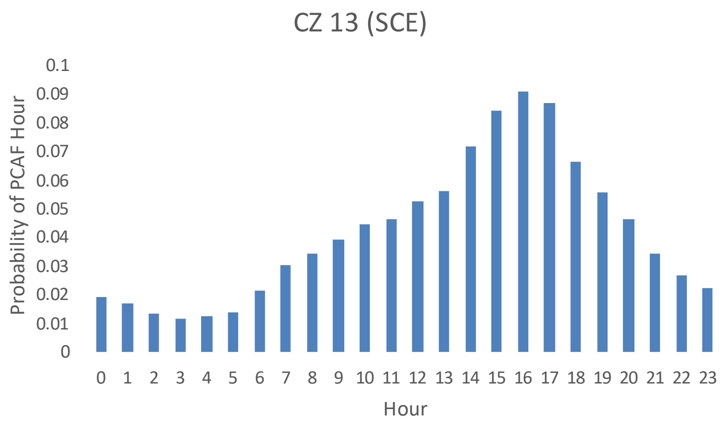
SCE PCAFs by climate zone are shown below.

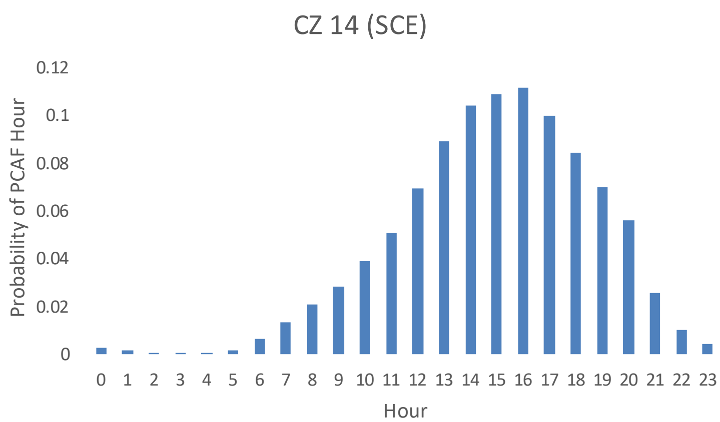


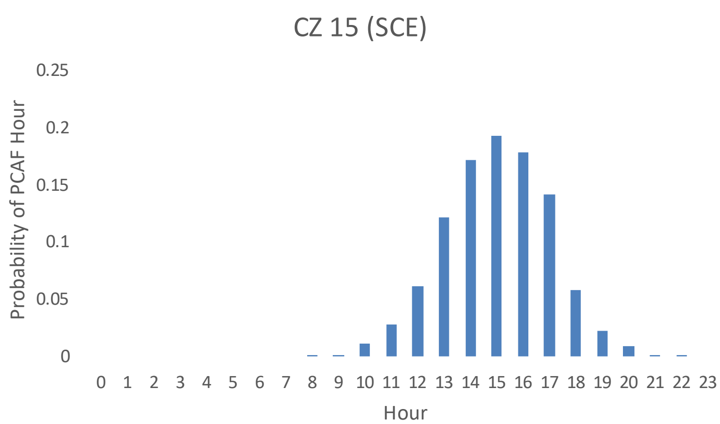

CZ 8 (SCE)
Probability of PCAF Hour
0.09
0.08
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour

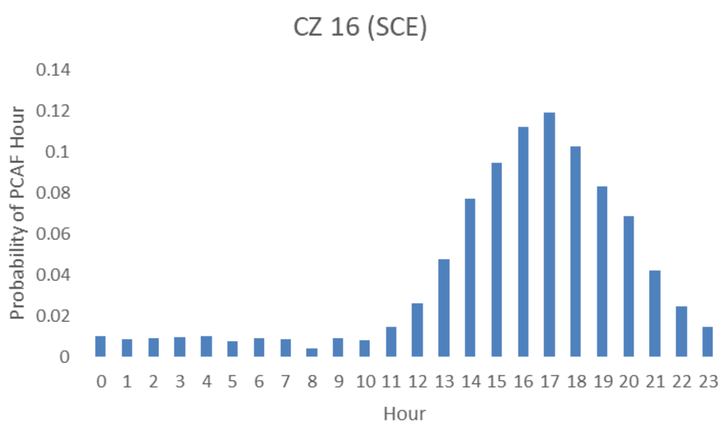

CZ 9 (SCE)
Probability of PCAF Hour
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour


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


CZ 13 (SCE)
Probability of PCAF Hour
0.1
0.09
0.08
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour


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


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

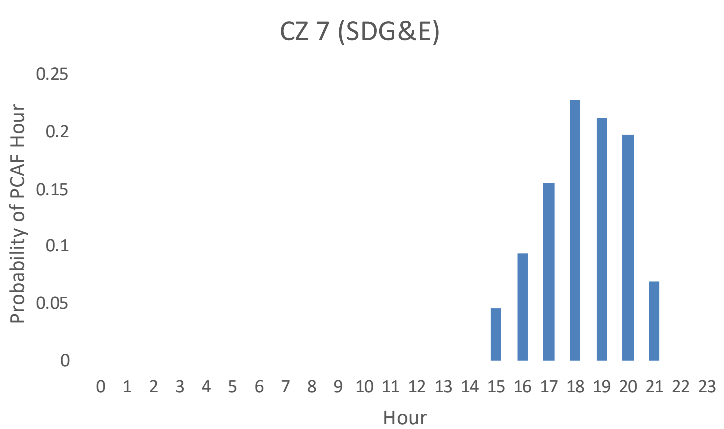


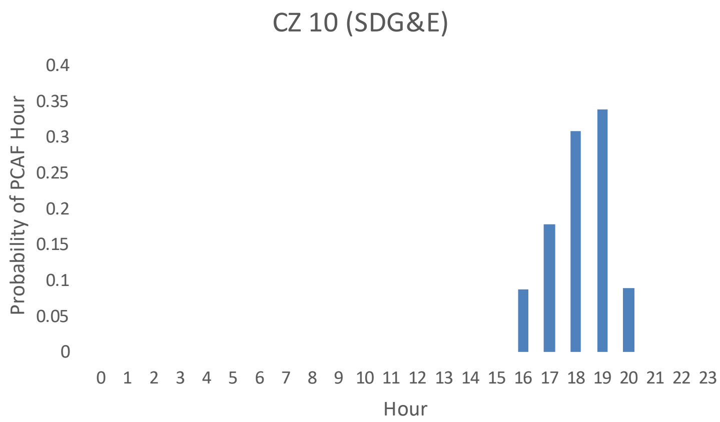
14.5.3 SDG&E PCAFs

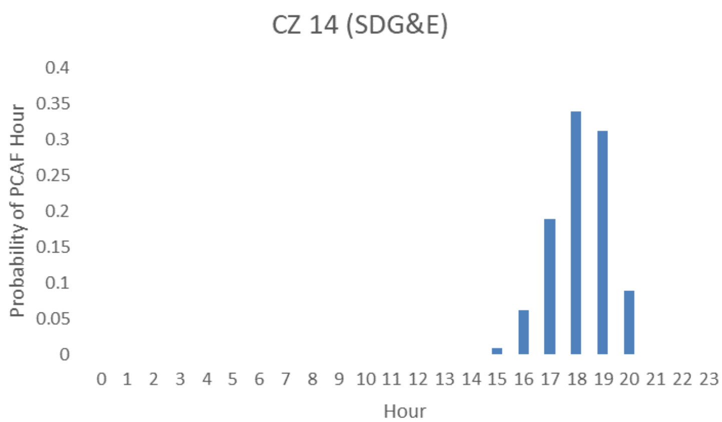
SDG&E does not produce PCAFs or PLRFs in its GRC proceedings. We therefore calculated PCAFs for the SDG&E climate zones using 2021 distribution-level power flow data provided by SDG&E and the PCAF methodology from the prior ACC. The allocation factors are derived with the formula below and the additional constraint that the peak period contain between 20 and 250 hours for the year.

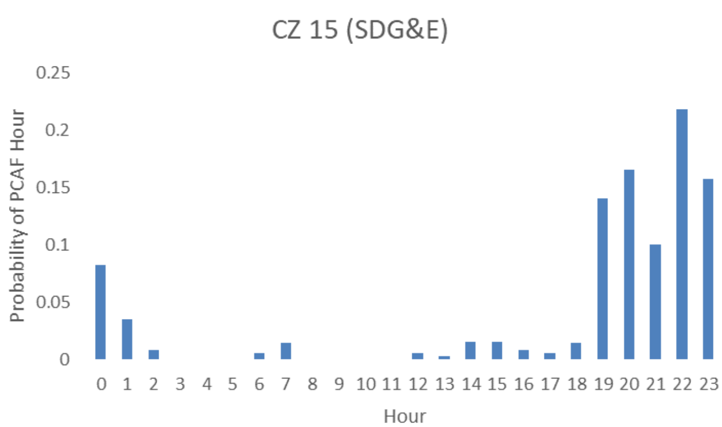
PCAF[a,h] = (Load[a,h] – Threshold[a]) / Sum of all positive (Load[a,h] – Threshold[a])

- Where:
    - a is the climate zone area,
    - h is hour of the year,
    - Load is the net distribution load, and
- Threshold is the area maximum demand less one standard deviation, or the closest value that satisfies the constraint of between 20 and 250 hours with loads above the threshold.
- SDG&E PCAFs by climate zones are shown below.









Note: The PCAFs for Climate Zone 15 show significant variation due to a much smaller total load present in SDG&E's territory within this zone. This results in small MW changes for certain hours having a greater proportional impact and more hours occurring in the peak period.

14.6 AGIC Data

14.6.1 PGE

	Existing Subdivision/ Development	New Greenfield Subdivision/ Development
Mainline Extension Includes: Material & Labor Excludes: Trenching, allowances to developer or customers	N/A It is assumed that new construction in an existing subdivision will not require a mainline extension.	<u>Single Family</u> $85/ft[(a)] <u>Multi-Family</u> $54/ft[(a)]
Service Extension (1" pipeline from mainline to meter) Includes: Materials & Labor, Trenching (developed for exciting and undeveloped for greenfield) Excludes: Allowances Credited to Customer or Developer	<u>Including Trenching</u> (Developed Area) $15,535 per service/building[(b)] <u>Excluding Trenching</u> $7,187 per service/building[(b)]	<u>Including Trenching</u> (Greenfield, Undeveloped) $3,330 per service/building[(b) (c)] <u>Excluding Trenching</u> $2,814 per service/building[(b)]
Meter (Including manifold outlet, where applicable)	<u>Residential Single Family</u> $658 per meter[(d)] <u>Residential Multi-Family</u> $752 per meter[(d) (e)] <u>Small/Medium Commercial</u> $1,309 per meter[(d) (e)] <u>Large Commercial</u> $11,714 per meter[(d) (e)]	<u>Residential Single Family</u> $590 per meter[(d)] <u>Residential Multi-Family</u> $752 per meter[(d) (e)] <u>Small/Medium Commercial</u> $1,309 per meter[(d) (e)] <u>Large Commercial</u> $11,714 per meter[(d) (e)]

(a) Per-foot averages are based on estimated costs taken from contracts that were issued to customers in 2021. These costs reflect labor and material, including engineering and administrative time allocated to the mainline extension. The costs do not reflect allowances.

(b) Averages are based on estimated costs taken from contracts that were issued to customers in 2021 (individual service sizes may vary). These costs reflect labor and material, including engineering and administrative time allocated to the service extension. The costs do not reflect allowances.

(c) Trenching for service extensions within greenfield subdivision projects is generally performed by the customer. PG&E estimates the value of service extension trenching within the franchised area or third-party property to collect the Income Tax Component of Contribution (ITCC). The customers' cost to perform service extension trenching on private property is not reflected in the estimate.

(d) Per-meter averages are based on estimated costs taken from contracts issued to customers in 2021. These costs reflect labor and material to install metering equipment, including manifolds where applicable. Engineering and administrative time for metering equipment is included in the Service Extension estimates. The costs do not reflect allowances

(e) For residential multi-family metering and non-residential metering, PG&E does not track or distinguish greenfield vs. existing developments.

14.6.2 SoCalGas

Table 1: SoCalGas Gas Infrastructure Cost Estimates		
	Existing Subdivision / Development	**New Greenfield Subdivision / Development**
Mainline Extension Includes: Material & Labor Excludes: Trenching, allowances to developer or customers	N/A It is assumed that new construction in an existing subdivision will not require a mainline extension.	Single Family $26.90/ft (2016 $) Multi-Family $26.90 /ft (2016 $)
Service Extension (1" pipeline from mainline to meter) Includes: Materials & Labor, Trenching (developed for exciting and undeveloped for greenfield) Excludes: Allowances Credited to Customer or Developer	Including Trenching (Developed Area) $1,567/building (2016 $) Excluding Trenching $1,567/building (2016 $)	Including Trenching (Greenfield, Undeveloped) $1,567/building (2016 $) Excluding Trenching $1,567/building (2016 $)
Meter (Including manifold outlet, where applicable)	Residential Single Family $209 per meter (2016 $) Residential Multi-Family $173 per meter (2016 $) Small/Medium Commercial $209 per meter (2016 $) Large Commercial $12,503 per meter (2016 $)	Residential Single Family $209 per meter (2016 $) Residential Multi-Family $173 per meter (2016 $) Small/Medium Commercial $209 per meter (2016 $) Large Commercial $12,503 per meter (2016 $)

Notes to Table 1:

1. SoCalGas is providing the best-available data from its 2020 TCAP filing (https://www.socalgas.com/regulatory/documents/a-18-07-024/workpapers/09_Chapter_9_Schmidt-Pines_Workpapers.pdf), providing data that correlate as closely as possible to the values requested by Energy Division.
2. SoCalGas does not track projects based on existing vs. greenfield development for its TCAP workpapers – numbers are provided for new construction as a bundled category.

14.6.3 SDGE

Table 2: SDG&E Gas Infrastructure Cost Estimates		
	Existing Subdivision / Development	New Greenfield Subdivision / Development
Mainline Extension Includes: Material & Labor Excludes: Trenching, allowances to developer or customers	N/A It is assumed that new construction in an existing subdivision will not require a mainline extension.	Single Family $38.69/ft (2021 $) Multi-Family $38.69 /ft (2021 $)
Service Extension (1" pipeline from mainline to meter) Includes: Materials & Labor, Trenching (developed for exciting and undeveloped for greenfield) Excludes: Allowances Credited to Customer or Developer	Including Trenching (Developed Area) $1,863/building (2020 $) Excluding Trenching $1,863/building (2020 $)	Including Trenching (Greenfield, Undeveloped) $1,863/building (2020 $) Excluding Trenching $1,863/building (2020 $)
Meter (Including manifold outlet, where applicable)	Residential Single Family $259 per meter (2020 $) Residential Multi-Family $259 per meter (2020 $) Small/Medium Commercial $259 per meter (2020 $) Large Commercial $7,411 per meter (2020 $)	Residential Single Family $259 per meter (2020 $) Residential Multi-Family $259 per meter (2020 $) Small/Medium Commercial $259 per meter (2020 $) Large Commercial $7,411 per meter (2020 $)

Notes to Table 2:

1. SDG&E is providing the best-available data from its 2020 TCAP filing (https://www.socalgas.com/regulatory/documents/a-18-07-024/workpapers/10_Chapter_10_Foster_Workpapers.pdf), providing data that correlate as closely as possible to the values requested by Energy Division. Mainline extension values were provided by SDG&E's Gas Engineering.

14.7 DER ACC Model Files

DER ACC model files are available at:

- https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/energy-efficiency/idsm , and
- https://www.ethree.com/public_proceedings/energy-efficiency-calculator/, and

- https://willdan.box.com/v/2022CPUCAvoidedCosts

File	Description
DER 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 Generation Capacity Avoided Costs	Calculation of system capacity value. Net Cost of New Entry for Energy Storage
ACC SERVM Prices	SERVM production simulation model results and scarcity pricing adjustments
ACC Refrigerant Calculator	Avoided costs and global warming potential for refrigerant gasses
Storage Dispatch Folder	Folder with .csv files of energy storage dispatch and revenue for each year 2020-2052
SERVM Modeling Folder	.csv files with SERVM modeling results for 2 weeks
Files Cited in ACC Folder	Copies of source files cites in DER ACC models

14.8 Revision Log

14.8.1 List of Major Updates for 2022 ACC v1a

General

- Updated the PG&E WACC from 7.81% to 7.34% (an adjustment made by PG&E in 2021)[42]
- Updated the inflation rate to 2% to be consistent with IRP

IRP No New DER

- Removed both load increasing and load reducing DERs to create the “No New DER” scenario

GHG

- Extrapolated GHG value based on 2035 GHG shadow price from RESOLVE

SERVM Prices and Implied Heat Rate

- Updated the SERVM prices forecast
- Capped implied heat rate in the electric model
- Used direct outputs from SERVM in years 2032, 2035, 2040 and 2045, and interpolated between SERVM years. The 2021 ACC did not have SERVM prices beyond 2030
- Adjusted scarcity scaling factors using 2021 historical energy prices instead of 2019 energy prices

[42] GAS_4275-G.pdf (pge.com)

- Made a small adjustment to fix an error in natural gas calculation in the draft ACC compared to the SERVM prices released in the 2022 ACC SERVM Modeling Release package. The impact on prices is very small, ranging from $0.1 - $1/MWh.

Generation

- Used Real Economic Carrying Charge (RECC) approach to calculate capacity avoided costs instead of Net CONE
- Corrected the usage of marginal ELCC, instead of weighted average ELCC, for capacity avoided costs, to be consistent with IRP
- Switched from RECAP to SERVM to generate EUE heatmap for capacity factor allocation

Transmission

- Calculated new transmission PCAFs based on 2021 CAISO load data for each utility
    - Remapped transmission PCAFs using 2021 weather data
- Updated Marginal Transmission Capacity Costs for PG&E based on the November 2021 CPUC decision

Distribution

- Updated Long Term Marginal Distribution Capacity Costs based on recent utility GRC filings
- Updated Near Term Marginal Distribution Capacity Costs using 2021 GNA and DDOR filings and additional forecasted project cost data provided by the utilities
- Updated distribution PCAFs for SCE and SDG&E

Refrigerant Calculator

- Discounted annual refrigerant leakage at the mid-year
- Updated calculation to allow for a user-specified GWP for refrigerants not listed in the provided database
- Accounted for the avoided cost of a measure type instead of a single device

Natural Gas ACC

- Switched to using IEPR natural gas forecasts for both near term and long term to be consistent with IRP
- Used residential building electrification costs as the basis for GHG value in the Natural Gas Avoided Costs Calculator
- Added Avoided Gas Infrastructure Costs (AGIC) as a new avoided cost component

14.8.2 List of Updates since the Draft 2022 ACC v1a Release

SERVM Prices and Implied Heat Rate

- In response to SEIA's comments, we corrected carbon costs in the "Prices with Scarcity" tab of the 2022 ACC SERVM Prices v1b.xlsx by using capped implied heat rate rather than scarcity adjusted implied heat rates to be consistent with the Electric Model. The draft calculator v1a calculated carbon costs using scarcity adjusted implied heat rates that caused the carbon costs to be too high during the scarcity adjusted hours. The correction was made to reflect a realistic view of the cap & trade carbon costs that plants will pay.

Generation

- In response to Joint IOUs' and CLECA's comments, we updated the presentation of the RECC calculation to make it easier to understand. This included netting out revenues from the storage costs after performing the RECC calculation. These changes did not affect the results (any changes that did affect results are summarized in the following bullets).
- In response to Joint IOUs' and CLECA's comments, we extended the timeframe of the RECC calculation to include the full lifecycle of the replacement resource, and we corrected an error for the replacement cost to differentiate the declining costs of 1st and 2nd replacement until the replacement costs flatten out. This fix aligns the NPV of storage costs with the NPV of capacity payments which is the intended outcome of the RECC calculation. Previously, the RECC calculation was performed over the lifecycle of the storage resource plus a single year of a replacement resource, which resulted in a small misalignment between the NPV of storage costs and NPV of capacity payments because it did not account for the full storage cost difference between resource of vintage X and the resource installed a year later. The replacement costs for the storage resource of vintage X are different than the replacement costs of the deferred storage resource of vintage X+1 due to expected cost declines. Using a longer timeframe, the storage costs are expected to flatten in real terms at the end of the timeframe. In addition, any small changes in cost are heavily discounted because they are far in the future and therefore have minimal impact on the calculated RECC value.
- In response to SEIA's comments, we updated storage revenues based on updated RESTORE modelling with new scarcity adjusted energy prices, as discussed in the "SERVM Prices and Implied Heat Rate" section above.

Transmission

- After receiving data from SCE and SDG&E, we updated Marginal Transmission Capacity Costs for SCE and SDG&E using inputs provided in additional data request responses. These responses included updated systemwide transmission project costs for both utilities as well as updated inflation and discount rates for SDG&E. SCE confirmed that their inflation and discount rates have not changed since the prior ACC update.
- After receiving data from SDG&E, we updated SDG&E Marginal Transmission Capacity Cost calculation to improve consistency with SCE method and address utility concerns around forecast volatility. We also noted that the SDG&E DTIM calculations performed for the 2021 ACC unintentionally omitted the Real Discount Rate in the present value formula, so this was corrected for the 2022 calculation.

Distribution

- After identifying an error, we updated PG&E Marginal Distribution Capacity Costs to note a lower total cost of PG&E's planned distribution investments and a resulting reduction in the calculated $/kW unit cost. The difference in the cost input was not due to new values being provided but rather due to a change in how PG&E presents its costs in the DDOR filings. This change was clarified by the utility just prior to the 2022 ACC workshop and so was not yet updated in the draft ACC model or documentation, but the corrected distribution value was presented at the workshop.

- After receiving data from SDG&E, we updated SDG&E's Distribution Annual Marginal Cost Factor using the most recent inputs as provided by the utility. In the draft calculation, SDG&E's marginal cost factor had not been updated, noting that the utility's most recent GRC was still the 2019 vintage. However, as the 2019 GRC had not yet been accepted as of the previous ACC update, several values in the 2021 ACC reflected the SDG&E 2016 GRC instead. The sum of these changes resulted in a $0.01 change in the near-term Marginal Distribution Capacity Cost.

Natural Gas ACC

- In response to SoCal Gas's comments, we revised the unit for the carbon cost from $/ton to $/tonne. The use of tonne instead of ton in the Natural Gas ACC is to ensure consistency with the Electric ACC and the Refrigerant Calculator.

Refrigerant Calculator

- In response to SoCal Gas's comments, we corrected the dollar year mistake from v1a by replacing the year '2022' with '2020' in the cost calculations that are supposed to reflect values in 2020$.
- In response to SoCal Gas's comments, we updated the GHG value to align with the GHG Value from Natural Gas ACC.