(ATTACHMENT A)

Integrated Distributed Energy Resources (IDER) 2024 Avoided Cost Calculator (ACC) Staff Proposal

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1. Baseline Change from No New DER to IRP's Latest Adopted System Plan

1.1. Evaluation of the No New DER Scenario

California's Integrated Resource Planning (IRP) proceeding uses the RESOLVE resource planning model 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 California Public Utilities Commission (CPUC)'s IRP proceeding. RSP and PSP differ in a way that RSP is optimized without Load Serving Entities (LSEs)' plans as only a guide to meet state goals, whereas PSP is the system portfolio adopted after aggregating LSEs' proposed plans. The latest IRP adopted system plan to be used in ACC can be a RSP or PSP, depending on the concurrence of the ACC update year and the IRP cycle.

Both the RSP and the PSP include levels of future Distributed Energy Resources (DER) adoption based on the California Energy Commission (CEC)'s Integrated Energy Policy Report (IEPR) forecasts, as load modifiers to overall system demand. In 2020, the IRP modeling added a scenario known as "No New DER," for the purpose of informing the ACC. The No New DER scenario was introduced with the intention of evaluating the value of DER using a hypothetical alternative scenario with no future additions of DER to the system. For the 2020 and 2021 ACC, the No New DER scenario removed all load-reducing DER from the IRP's latest adopted system plan, which were in turn replaced by a least-cost combination of supply-side resources consistent with the state's greenhouse gas (GHG) goals. In the 2022 ACC, the No New DER scenario removed both load reducing and load increasing DER from the IRP plan and replaced these with least-cost supply-side resources.

When the No New DER scenario was first adopted, it was posited by some that a scenario without the forecasted DER included would better reflect the value of DER, because it would show what the avoided costs *would be* if DER were not available. It was thought that removing the load reducing DER and increasing total load would more accurately represent the value of DERs and result in higher avoided costs as the capacity expansion model would have to select generation resources further up the supply curve that were more expensive or had lower marginal Effective Load Carrying Capacity (ELCC) values. In practice, we found that by removing DER, the IRP modeling must select an alternative resource portfolio (with incremental non-DER resources). The impact of these additional non-DER resources changes marginal costs such that the system is in equilibrium and **does not necessarily result in higher hourly marginal supply costs across all components.** This occurs because with a large quantity of DER removed from the IRP plan, RESOLVE reoptimizes the portfolio to select an alternative resource mix with more utility-scale solar, wind and storage. The resulting portfolio has a very different mix from the IRP plan and can impact marginal GHG, generation capacity and energy avoided costs in different directions.

In addition to the system rebalancing dynamics mentioned above, using the results of the No New DER scenario to develop avoided costs has proven more resource intensive than anticipated and often led to some counter-intuitive results. For example, producing and validating hourly energy prices in SERVM, the production simulation model used in IRP, for the No New DER scenario requires the CPUC SERVM team to run a new portfolio, different from the IRP plan, for production costs simulation and perform a separate process to validate results. Furthermore, removing large amounts of DER creates a counterfactual scenario that cannot be benchmarked to historical market data or other production simulation models such as PLEXOS used by the CEC and California Independent System Operator (CAISO). The No New DER scenario is therefore resource intensive for both staff and stakeholders to produce and to validate results.

Lastly, it is difficult to group DER into one category for the No New DER scenario, given that DER includes a range of technology types with diverse performance characteristics. Load reducing DER like energy efficiency (EE), demand response (DR), and behind-the-meter (BTM) solar reduce load with fairly predictable impacts on total loads and load shapes. Load shifting DER like BTM energy storage and flexible loads are less predictable and have different impacts than load reducing DER. Load increasing DER such as transportation and building electrification have a different impact still. With increasing emphasis on load shifting DER and load increasing DER in resource planning, achieving the spirit of technology agnostic avoided costs is not feasible with a single No New DER scenario. Removing all types of DER produces mixed results with unpredictable and interactive effects that are not representative of any DER type. However, developing a single No New DER scenario that removes some types of DER but not others is also difficult to rationalize. And it would not be feasible to develop multiple No New DER scenarios for different DER types. **Hence, it is concluded that the No New DER scenario does not successfully achieve the goals of the Avoided Cost Calculator, which is to provide a single, technology-agnostic set of avoided costs to inform decision-making on DER investment, including investment in load decreasing DER, load shifting DER, and load increasing DER.**

1.2. Advantages of Switching from No New DER to IRP's Latest Adopted System Plan as the Baseline for ACC

Given the issues with using the No New DER scenario, staff proposes to switch to using the IRP's latest adopted system plan to set the baseline to develop marginal costs for the ACC. At the time of writing, the next adopted plan is assumed to be a Preferred System Plan (PSP), so this proposal often refers to PSP specifically, but it's not limited to PSP if RSP is adopted instead. This section outlines the reasons for this proposal. The IRP's adopted system plan reflects the most recent and most comprehensive view of California's plans to meet state clean energy goals and reliability needs. This portfolio provides the most coherent starting point for the derivation of avoided costs for several reasons.

First, the IRP's latest adopted system plan establishes a level playing field to evaluate all types of DER. The primary goal of the ACC is to inform decision-making on DER investment, including investment in load reducing, load shifting, and load increasing DER. Load reducing DER, such as EE and BTM Solar, has traditionally been the primary focus of the ACC, but as the state pursues economy-wide decarbonization goals, load increasing and load shifting DER, such as transportation and building electrification load, are becoming an increasing focus of DER policy and planning. To achieve the goal of evaluating all DER on a level playing field, the avoided costs should accurately calculate the marginal value of DER incremental to a planned portfolio based on the cost of resources that are being avoided. The RSP or PSP is the portfolio California is planning for and can serve as the baseline to evaluate any incremental change of any type of these resources to the planned portfolio and their respective value.

Second, the PSP also ensures that DER are evaluated under a framework that is consistent with the evaluation of supply-side resources in the IRP. When optimizing investment decisions in supply-side resources in the IRP, RESOLVE considers the marginal costs of building a resource relative to the portfolio that includes all resources (DER and non-DER) each year. In contrast, the No New DER scenario draws an arbitrary line for resource evaluation, which is inconsistent with how supply-side resources are evaluated. In the market, supply-side resources are valued and paid at market energy prices and capacity prices that also include all resources (DER and non-DER) on the system each year. For example, a utility-scale storage evaluation is conducted using price forecasts that include the future build-out of all storage. It is not evaluated using price forecasts from a "No New Storage" scenario. This concept applies to the evaluation of any other types of resources. Therefore, for DER to be evaluated on an equivalent basis, it is appropriate to evaluate them against the IRP's latest adopted system plan, instead of the No New DER portfolio. Also, the IRP's adopted system plan receives much more review and vetting by stakeholders for the purpose of creating and running cases in SERVM for IRP. It will provide a more stable baseline for the ACC and require less time and money to update ACC biennially.

Therefore, staff concludes and recommends that the IRP's latest adopted system plan is a better alternative to the No New DER scenario to develop a single and technology agnostic set of avoided costs to inform decision-making on DER investment that is consistent with the supply-side evaluation in the IRP.

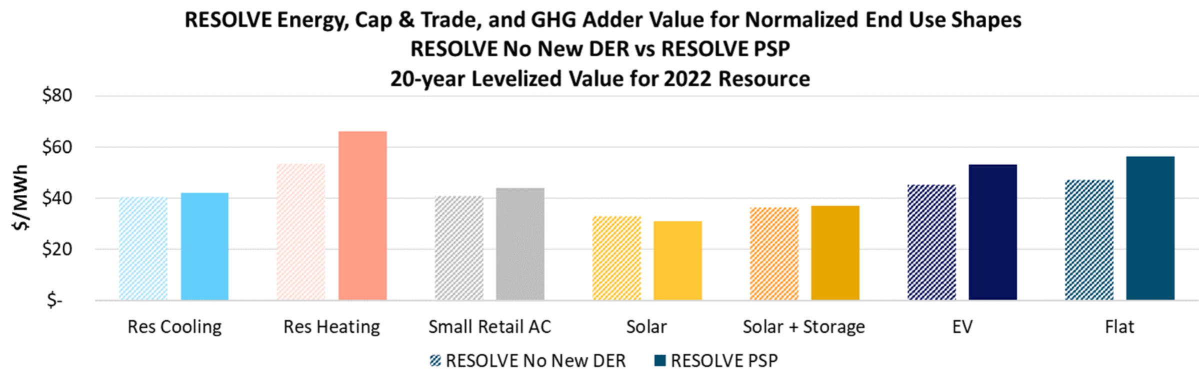
1.3. The Impact of Switching from No New DER to IRP's Latest Adopted System Plan

A comparison of the IRP's latest adopted system plan versus the No New DER scenario was performed to understand the expected direction and magnitude of change in the ACC resulting from a change to the baseline portfolio using results from 2022 ACC. By the time 2022 ACC was updated, the latest IRP adopted system plan was the 2021 PSP, and No New DER scenario was developed upon that plan. Due to the absence of immediately available SERVM energy price outputs of the 2021 PSP scenario, direct marginal energy prices from RESOLVE PSP scenario and RESOLVE No New DER scenario were used for this comparison exercise. Since RESOLVE is a capacity expansion model, the output "hourly energy costs $ per MWh" from RESOLVE includes energy, cap-and- trade, and GHG adder (the non-monetized carbon price beyond the cost of cap-and-trade allowances) values, but no generation capacity values. This comparison only considers these three limited price streams for the sake of simplicity and ease with which stakeholder can reproduce results.

Error! Reference source not found. Figure 1 shows a chart of simplified avoided costs for different end uses based on the hourly energy cost output from RESOLVE. These results show that the change of baseline from No New DER to the IRP's latest adopted system plan will have a relatively small impact on the avoided costs that are directly related to the RESOLVE capacity expansion modeling (e.g., energy, cap-and-trade, and GHG adder).

In addition, with the new proposed change to calculate generation capacity and GHG avoided costs in one framework (see Section 2: Integrated Calculation of Generation Capacity and GHG Avoided Costs) there is a corrective mechanism built in the ACC to calibrate the energy, generation capacity and GHG avoided costs against each other to ensure that total avoided costs related to RESOLVE will not be dramatically different with the baseline change.

Figure 1: The sum of RESOLVE energy, cap-and-trade, and GHG adder values for different end use load shapes comparing 20-year levelized values for a resource installed in 2022 for PSP and No New DER scenarios.



Staff Proposal Recommendation

To ensure that DER are evaluated in a consistent framework as supply-side resources, staff recommends switching from using the No New DER scenario to using IRP's latest adopted system plan as the baseline to develop a single and technology agnostic set of avoided costs to inform decision-making on DER investment.

2. Integrated Calculation of Generation Capacity and GHG Avoided Costs

The state of California's aggressive policy goals to transition to a decarbonized electricity system and the corresponding changes in the portfolio of generation resources that will meet customers' needs will have profound implications upon the system's avoided costs. For this cycle, staff proposes a methodology to determine generation capacity and greenhouse gas (GHG) avoided costs in a manner that is harmonized with energy avoided costs calculated from SERVM within a framework, thereby producing a set of avoided costs that values electricity that is directly tied to the portfolio of resources that will be needed to meet those goals.

2.1. Motivation

In the 2022 ACC, generation capacity and GHG avoided costs were determined via the following methods:

- The GHG avoided cost was derived directly from the 2035 "shadow price" on the carbon constraint in RESOLVE's No New DER scenario and escalated backward and forward based on the utility weighted average cost of capital (WACC)[1]; and
- The generation capacity avoided cost was calculated by applying a real economic carrying charge (RECC) methodology[2] to calculate the residual cost (less energy & ancillary service (AS) margins) for four-hour battery storage, the assumed marginal capacity resource.

These approaches reflected progressive efforts to integrate the ACC with the IRP proceeding, producing a set of avoided costs that was more closely aligned with the state's policy goals than in previous cycles. However, previous approaches also rely on several simplifications that offer potential for continued improvement:

1. The method used for the 2022 ACC treats GHG and generation capacity avoided costs as independent values, whereas the two are highly interdependent. Many of the supply-side resources that will support the state's decarbonization efforts provide both generation capacity and GHG value (including energy storage, the assumed marginal capacity resource) such that, all else equal, an increase in one should result in a decrease to the other. In other words, for a given resource portfolio selected to meet reliability and GHG targets, an increase in each resource's generation capacity contribution may result in a decrease in its GHG contribution.

[1] More details can be found in the 2022 Distributed Energy Resources Avoided Cost Calculator Documentation, Section 7.1 Electric Sector GHG Value, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/acc-models-latest-version/2022-acc-documentation-v1b-updated.pdf

[2] The RECC methodology compares the net present value cost of adding a resource in a specific year with the same resource one year later to derive a "carrying cost" for that resource. The application of the RECC methodology was an improvement upon the previously used "First-Year Net CONE" methodology used in previous iterations of the avoided costs. This improvement allowed the 2022 ACC to capture the effects of the future expected declines in storage costs upon present-day capacity value. This method is further described in the 2022 Distributed Energy Resources Avoided Cost Calculator Documentation, Section 8.1 Annual Generation Capacity Value, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/acc-models-latest-version/2022-acc-documentation-v1b-updated.pdf

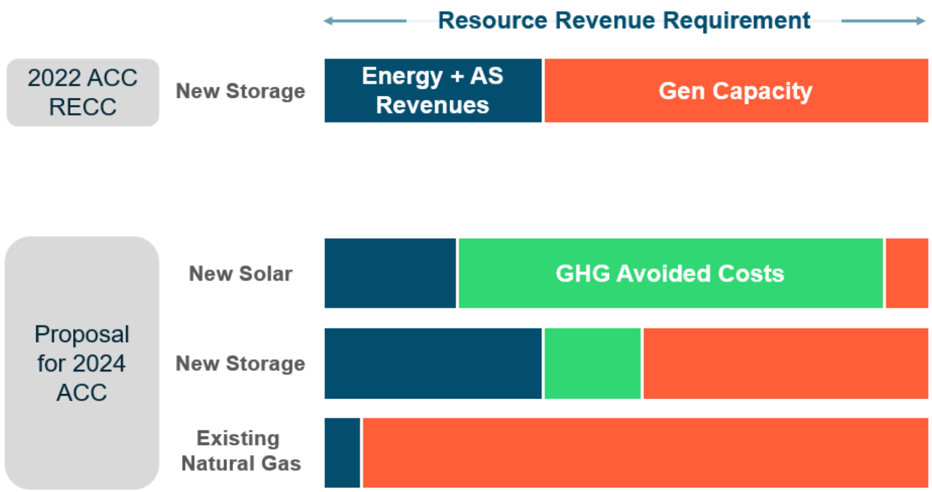
2. The RECC calculation used to calculate generation capacity avoided costs requires the specification of a single marginal resource, whereas it is possible that the marginal resource that provides capacity, GHG, or both values to the system may evolve over time.

While these specific shortcomings offer opportunity for improvement, several of the principles present in the 2022 ACC methods serve as the foundation for innovation. Most importantly, one of the natural outcomes of the RECC approach is that, when applied across a series of potential resource additions over many years, it produces a stream of values that exactly align with each added resource's costs on a net present value (NPV) basis. This axiomatic characteristic – that the "avoided costs" should reflect the costs of resources that can be avoided at the margin – is a feature of the RECC calculation and serves as the basis for the methodological improvements proposed in this cycle. **As the avoided costs reflect a set of explicit and implicit market signals that will drive investment in new resources needed to enable the transition to a reliable, decarbonized system, those signals should be sufficient to cover the costs of those resources.**

Staff proposes an approach that calculates both GHG and generation capacity avoided costs in an integrated manner using representative resource archetypes that reflect the portfolio developed in the IRP. The benefits of this proposed approach are threefold: First, it better aligns the ACC proceeding with IRP (RESOLVE + SERVM) modeling as the proposed approach integrates multiple fundamental values streams that govern resource portfolio in the IRP: generation capacity, GHG, energy and AS. Second, it creates a flexible, technology-agnostic approach to calculate avoided costs; in other words, generation capacity and GHG avoided costs can be determined jointly rather than independently in this new proposal. Finally, it allows for a derivation of avoided costs that are not tied to a single pre-specified resource, but rather to the portfolio of resources developed in the IRP.

Figure 2 compares the proposed methodology versus the 2022 ACC RECC method. The total length of each bar represents 100% NPV revenue requirement of each new resource. The goal of the proposed method is to derive avoided cost value streams for generation capacity and GHG, in addition to the energy avoided costs calculated from SERVM, that are sufficient to "make whole" each supply-side resource selected in the IRP portfolio; these values then represent the explicit and implicit signals that will encourage the investments needed to achieve the state's decarbonization goals. Compared to the 2022 ACC RECC method, the new proposal considers both generation capacity and GHG value streams for a given resource. Instead of using storage to calculate generation capacity avoided costs, multiple resources are considered to calculate avoided costs in the proposed approach.

Figure 2: Illustrative example of how GHG and generation capacity avoided cost should cover resource revenue requirement.



Due to the interactive effects of avoided costs, an optimization model is required to find the optimal set of avoided costs that can fully recover the costs of multiple resources while minimizing the total avoided costs borne by ratepayers. The proposed method involves a similar approach to how RESOLVE handles load additions or reductions on a marginal basis. When faced with a new load addition, RESOLVE utilizes an optimization process to determine the most cost-effective allocation of resources necessary to meet the system's requirements. RESOLVE evaluates the incremental load and identifies the resources that need to be built or allocated to fulfill this additional demand. The objective is to minimize the overall cost involved in meeting the load addition. Similarly, the proposed method adopts an optimization approach to address marginal load changes. It focuses on minimizing the total cost by optimizing different avoided cost streams to finance the resources selected by RESOLVE. This means identifying cost-saving opportunities and revenue streams that can help offset the expenses associated with deploying and maintaining the necessary resources. Both methods share the goal of achieving cost optimization by carefully considering the incremental load requirements and determining the most efficient allocation of resources. By utilizing optimization techniques, these methods strive to minimize the total cost involved while ensuring the system's needs are met effectively.

2.2. Proposed Approach

2.2.1. Overall Formulation

The proposed methodology for this update uses optimization to solve simultaneously for the avoided generation capacity and GHG costs across the 30-year time horizon of the avoided costs, seeking to identify the values that are sufficient to allow each resource to fully recover its costs while minimizing total costs to ratepayers. This principle can be expressed as the following equation, which applies as a constraint on a net present value basis to each resource archetype in each vintage:

$$\boldsymbol{AC}_{\boldsymbol{gen\ capacity}} \times Q_{ELCC} + \boldsymbol{AC}_{\boldsymbol{GHG}} \times Q_{GHG} + R_{energy} + R_{AS} \geq C$$

Table 1 defines each variable, its respective units, and the data source. The top two rows are decision variables; shaded rows are parameters for the optimization equation.

Table 1. Decision variable & parameter descriptions for updated GHG and generation capacity avoided cost calculation.

Decision Variable or Parameter	Description	Units	Source
$AC_{gen\ capacity}$	Generation Capacity Avoided Costs	\$/kW-year	To be Calculated
AC_{GHG}	GHG Avoided Costs	\$/tonne	To be Calculated
Q_{ELCC}	Deemed RA contribution	ELCC kW	RESOLVE output
Q_{GHG}	Marginal GHG impacts	tonne/kW-yr	Derived via SERVM energy prices
C	Resource Cost (Levelized Fixed Costs + Operations and Maintenance (O&M))	\$/kW-yr	RESOLVE output
R_{energy}	Net Energy Revenues (excluding embedded cap-and-trade prices)	\$/kW-yr	SERVM output
R_{AS}	AS Revenues	\$/kW-yr	SERVM output

The optimization aims to calculate **Generation Capacity Avoided Costs ($AC_{gen\ capacity}$)** and **GHG Avoided Costs (AC_{GHG})** every year based on other parameters listed in the table; the optimization minimizes total costs to ratepayers subject to the condition that each resource selected in the portfolio must be made whole of its resource cost. The GHG Avoided Costs calculated here include the cap-and-trade and GHG adder values in previous ACCs.

In addition to calculating avoided costs that minimize the total cost, we propose the following constraints to ensure resulting avoided costs are within appropriate range and do not fluctuate excessively year by year:

- Minimum generation capacity avoided costs should reflect the assumed ongoing fixed O&M cost of the existing gas fleet (see Section 2.2.3.4)
- Minimum GHG avoided costs should follow the cap-and-trade price forecast, similar to previous ACC cycles.
- Avoided costs should cover at least the first year of resource levelized costs minus energy and AS revenues.

2.2.2. Testing Proposed Approach with 2022 ACC Assumptions

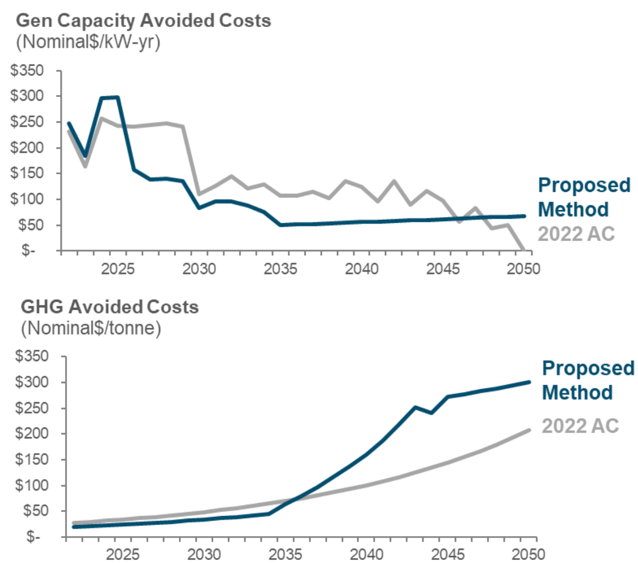
To provide an indication of how the change to the proposed approach will affect the ACC results, we tested this new calculation using the same inputs as 2022 ACC. **While this is a useful exercise to illustrate how the change in methods affects the ultimate results, the results of this testing should not be taken as an indication of the likely outcomes of the 2024 ACC**, as there are numerous other updates to inputs and assumptions (explained below) that will also cause differences in results.

For the purposes of this test, the optimization approach is applied to two resource archetypes using data from the 2021 No New DER RESOLVE portfolio developed in the 2019-2020 IRP Proceeding: utility-scale solar and four-hour battery storage. This approach requires marginal ELCC and levelized costs of resource archetypes as inputs to calculate avoided costs. Storage marginal ELCC and costs are the same as the inputs for the 2022 ACC generation capacity avoided costs, directly from the IRP No New DER RESOLVE portfolio, which sets the baseline for the 2022 ACC. The same methodology is also applied to retrieve marginal ELCC and costs of solar from the same portfolio. Energy and AS revenues and system marginal GHG emission rates are derived from the 2022 ACC SERVM prices without the cap-and-trade portion. The marginal GHG impact of each resource is calculated using the marginal emission rates derived from SERVM prices and the generation profile of the resource from the SERVM results.

Figure 3 compares generation capacity avoided costs and GHG avoided costs using the proposed method with the 2022 ACC. The new GHG avoided costs are directly comparable to the sum of the cap-and-trade and GHG adder in the 2022 ACC. Two primary changes in these results are noteworthy:

- Throughout much of the horizon, the proposed method produces a lower generation capacity avoided cost than the 2022 ACC method; this reflects the fact that the proposed method attributes GHG value to all resources (including battery storage) according to their GHG impact on the system, reducing the remaining residual cost that must be recovered through generation capacity. The avoided cost goes flat after 2035 due to a minimum floor set in Section 2.2.3.4.
- While the two methods produce similar GHG avoided costs through 2035, the proposed method produces higher GHG avoided costs in the long run; this is a better reflection of the long-run costs of achieving increasingly stringent decarbonization objectives over time than the escalation method used in the 2022 ACC.[3]

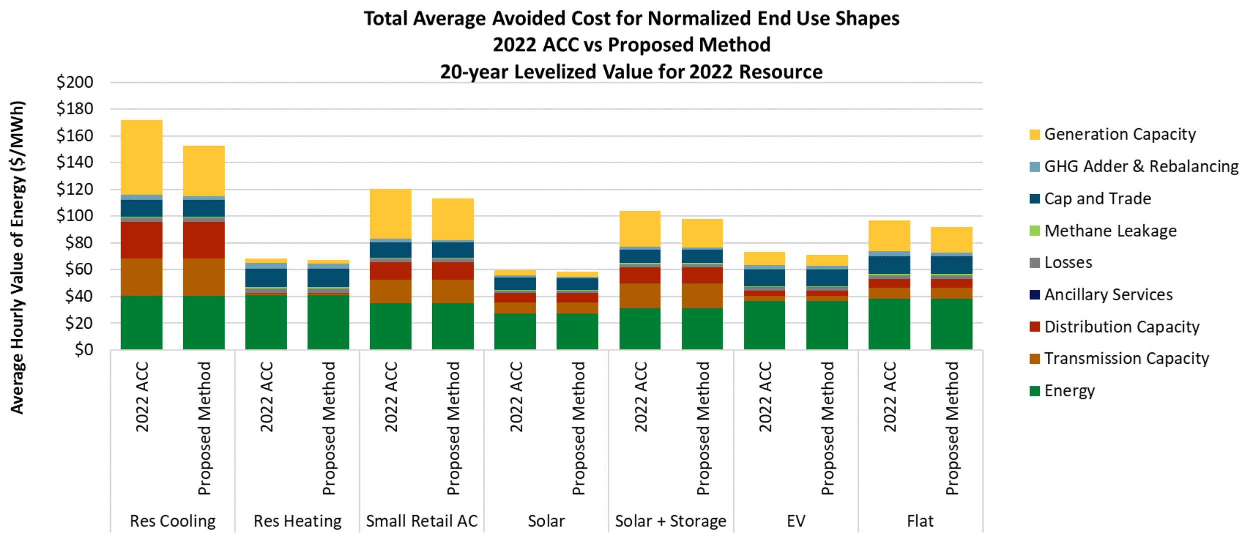
Figure 3: Generation capacity avoided costs and GHG avoided costs in 2022 ACC versus illustrative calculations using the same input data and the proposed method.



[3] The notch in the GHG avoided costs in 2045 is caused by the end effect treatment due to a lack of simulated data from SERVM beyond 2045. Refinement will be needed when producing results for the 2024 ACC.

Despite the changes in these value streams, the overall impact on the avoided costs attributed to normalized load shapes is relatively minor. Figure 4 compares levelized avoided costs for illustrative normalized load shapes from 2022 ACC and the proposed method. Although the proposed calculation changes the allocation of values between generation capacity and GHG avoided costs, the overall avoided costs are similar between the two approaches.

Figure 4: Total nominal levelized avoided costs ($nominal/MWh) for illustrative normalized load shapes from 2022 ACC versus illustrative calculation using the same input data and proposed method in PG&E CZ12.



It is important to note that these results are not meant to represent potential avoided costs in the 2024 ACC due to several factors:

- **IRA tax credits**: the 2022 IRA modifies and extends the current Production Tax Credit (PTC) and Investment Tax Credit (ITC) for renewable energy investments. These tax credits will be incorporated in the 2022-2023 IRP and likely have significant impact on resource costs.
- **New resource portfolio**: the 2024 ACC will be based on the 2022-2023 IRP portfolio. The new portfolio will be inherently different from the previous IRP portfolio, which is the basis of this test. Depending on the 2022-2023 IRP resource portfolio, we may choose a different set of representative resources, such as adding long-duration storage, to calculate avoided costs.
- **New baseline**: Staff proposes to change the baseline from No New DER to IRP's latest adopted system plan in the 2024 ACC (see Section 1: Baseline Change from No New DER to IRP's Latest Adopted System Plan). The new baseline may not change the magnitude of the total avoided costs too much, but it may impact SERVM prices and change the allocation between energy, generation capacity and GHG avoided costs.

2.2.3. Implementation Details

2.2.3.1. Determining Avoidable Resources from IRP Portfolios

As in the 2022 ACC update, the proposed approach would continue to use assumptions derived from CPUC IRP modeling (both RESOLVE and SERVM). This includes resource portfolios (to determine which resource types are selected and avoidable), resource cost assumptions, and energy and ancillary services (AS) revenues.

Given that the dominant resource additions from IRP modeling are utility solar and Li-ion batteries (making up the majority of the total procured MW, see Table 2 as an example), we propose focusing on capturing utility solar and Li-ion interactive portfolio value in this proposed approach. In addition, since the Renewable Portfolio Standards (RPS) was not a binding constraint in the 2021 IRP modeling, we will continue to focus on generation capacity and GHG avoided costs. Additionally, as part of deriving inputs from IRP modeling, we propose that resources that are specifically procured for the Mid-term Reliability procurement order (e.g., 1 GW of long-duration storage and 1 GW of firm zero-emitting resources) are not considered avoidable and therefore would not be considered in the analysis.

Table 2: 2021 IRP PSP Resource Additions.

	2025	2030	2035	2040	2045
Utility Solar	11.0	14.2	27.0	43.7	72.1
Li-ion	11.6	11.7	16.7	27.6	37.6
Wind	3.5	5.2	6.7	7.2	7.2
Firm zero-emitting (geothermal, biomass)	0.2	1.3	1.3	1.3	2.4
Other Storage	-	1.0	1.0	1.0	1.5
Gas	-	-	-	-	0.3

However, since the 2022 ACC update, significant changes in projected resource costs due to tax credits have the potential to significantly change IRP portfolio decisions in the next IRP cycle. At the time of this staff proposal, new IRP portfolios from the 2022-2023 IRP have not been published; however, the proposed methodology is flexible to different portfolios and resource costs and potentially capturing RPS avoided cost.

2.2.3.2. Calculating GHG Impacts of Resources

To derive GHG avoided costs, the marginal GHG impacts of each resource need to be accounted appropriately. To calculate resources' marginal GHG impact is to compare their emission rates with the system marginal emission rates. For zero-emitting and energy shifting resources, their GHG impacts are directly proportional to 1) resources' energy generation or consumption and 2) system marginal GHG emission rates. This implies that an additional MWh generated from a zero-emitting resource may offset a certain amount of emission occurred from the rest of generating resources. The GHG impacts of an emitting resource is the difference of emission rates between this resource and the system.

Figure 5 illustrates how to calculate GHG impacts of solar and storage on an example day:

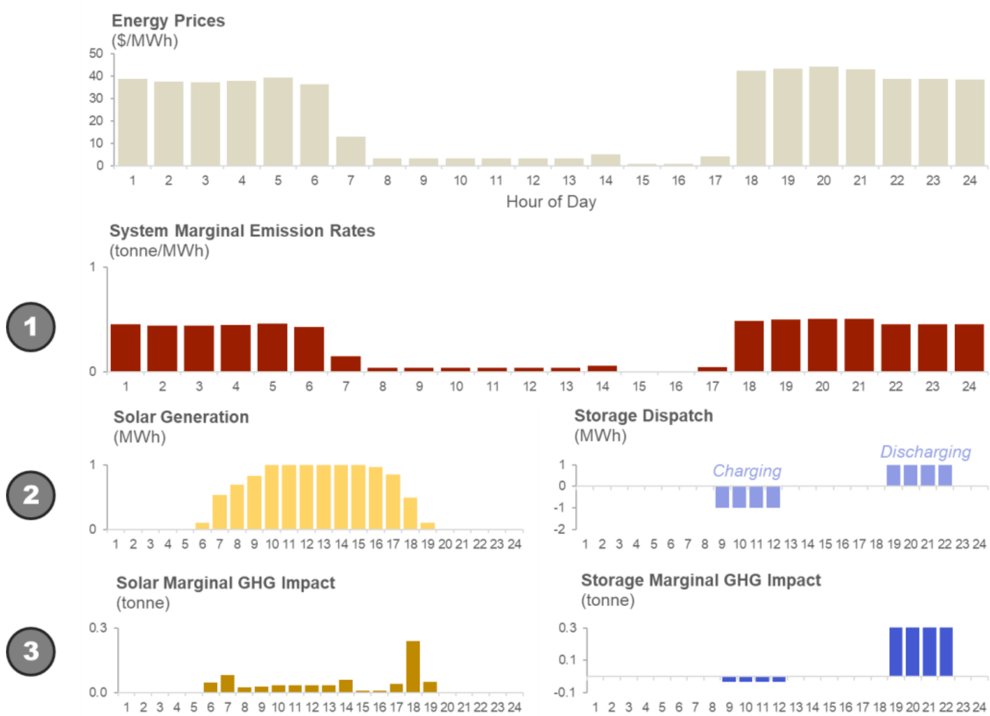
1. Calculate hourly system marginal emission rates (tonnes/MWh) from energy prices using an implied heat rate (IMHR) methodology. First, IMHR (MMBtu/MWh) is derived from energy

prices by excluding the impact of gas and carbon prices.[4] IMHR is then converted to system marginal emission rates by multiplying the carbon content of natural gas (tonnes/MMBtu).

2. Gather solar generation and storage dispatch profiles (MWh). Solar generation is always greater than or equal to zero. Storage dispatch is negative when storage is charging and positive when it is discharging.

3. The marginal GHG impact (tonnes) of each resource is equal to the system marginal emission rates multiplied by its corresponding generation profile. Positive GHG impacts represent that such resource is avoiding emissions. Negative GHG impacts represent causing emissions.

Figure 5. Illustrative calculations of the GHG impacts of solar and storage on an example day



As illustrated above, when solar produces energy and system marginal emission rates are above zero, solar has positive GHG impacts and will be valued accordingly by the GHG avoided costs. Storage consumes energy from 9 AM to 12 PM when system marginal emissions are above zero. It is therefore not avoiding any GHG emissions during these hours and will be penalized by the GHG avoided costs.

2.2.3.3. Energy and AS Revenues Tax Treatment

Since the proposed method is to derive avoided cost value streams for generation capacity and GHG that are sufficient to make whole the resource investment costs, it is noted that taxation is not placed upon the energy and AS revenues used in the calculation to calculate the missing money that need to be covered by generation capacity and GHG avoided costs. The levelized cost of a resource from the IRP reflects the total amount of revenue that a project would need to earn to enter the market, enough to

[4] More details can be found in the 2022 Distributed Energy Resources Avoided Cost Calculator Documentation, Section 5.1.1 Interpolating and Extrapolating SERVM Energy Prices Beyond SERVM Model Years, p.21,

cover its capital costs, O&M costs, return on investment, and the income taxes associated with that return. Therefore, the calculation only needs to determine how much additional generation capacity and GHG revenue a resource would need to earn beyond its pre-tax energy and AS revenues to cover its total resource costs.

2.2.3.4. Minimum Generation Capacity Avoided Cost

If existing gas stays online, generation capacity avoided cost should at least reflect the assumed ongoing fixed O&M cost of the existing gas fleet because gas will be on the margin to maintain reliability. This is $39/kW-year for existing Combustion Turbines for the 2022-2023 IRP PSP inputs and assumptions.[5]

2.2.3.5. Capturing Transmission Upgrade Costs due to Generation Additions

In the IRP, resource additions may require a transmission upgrade based on on-peak and off-peak transmission capability and costs data provided by CAISO.[6] These transmission upgrades reflect assumed technology-specific transmission impact factor. For example, CAISO reports that solar built in the SCE transmission area will have a 10.6% factor during the “highest system need” hours, so if a transmission upgrade is needed, 1 MW of solar built in that area will result in 0.16 MW of transmission upgrade costs above the solar resource’s costs alone. Staff will incorporate transmission upgrade costs as part of resource costs if RESOLVE in the next IRP cycle identifies transmission upgrades in conjunction with resource addition.

It is important to note that the transmission upgrade costs due to the generation additions described above are different from the Transmission Capacity Avoided Costs in the ACC Electric Model. The former is driven by resource build while the latter is driven by peak load change. The transmission upgrade costs do not include resource interconnection costs, which have been embedded in resource fixed cost.

2.2.3.6. End Effects

To calculate generation capacity and GHG avoided costs, the proposed method will use IRP resource costs up to the last modeling year of IRP, which is 2045 for the 2022-2023 IRP that will be used for 2024 ACC. After 2045, generation capacity and GHG avoided costs will be increased at a nominal inflation rate.

Staff Proposal Recommendation

To better align with the IRP, which plans for resources that support both system reliability and the state’s decarbonization efforts, staff recommends calculating generation capacity avoided costs and GHG avoided costs jointly rather than independently using representative resources selected in the IRP portfolio.

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[5] Inputs and Assumptions of 2022 IRP, Gas Fixed O&M Costs, slide 19 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/iamag09222022.pdf

[6] Inputs and Assumptions of 2022 IRP, Transmission Constraint Implementation, slides 83-86 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/iamag09222022.pdf

3. Allocation of Generation Capacity Value

3.1. Background

SERVM generates a preliminary dispatch schedule for all resources for each week of the year. The schedule optimizes for system operating costs while respecting all unit constraints and meeting load and operating reserve requirements. On days in which there is a projected shortfall of energy available to serve load, the preliminary battery commitment schedules charging and discharging to shave the net load peak such that the energy shortfall is spread equally across all battery discharge hours. If the net load is fully flattened, capacity shortfalls can extend into charging hours as well.

However, the preliminary commitment schedule for all resources is performed with some uncertainty on market purchases and generator performance, so some changes to the schedule are made closer to the prompt hour. Further, the final commitment heuristic in SERVM in real-time uses all capacity resources to meet load plus ancillary services regardless of potential energy exhaustion. Because all available resources will be dispatched as necessary to avoid loss of load for each sequential hour during the simulation, a typical loss of load profile for a summer day will show the battery storage resources exhaust their energy by hour ending 21 or 22. This results in a large amount of expected unserved energy (EUE) over 1-2 hours. A 12x24 matrix showing the typical distribution of EUE occurrence is shown in Figure 6 below, which utilizes the PSP portfolio from 2026, simulated across 5 levels of load forecast error and 23 weather years. The results show a high concentration of EUE in hour ending 22 in August and September.

Figure 6: Illustrative EUE % Occurrence with Original SERVM Dispatch.

Baseline

Month of Year

Hour of Day	1	2	3	4	5	6	7	8	9	10	11	12
1	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
7	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
8	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
9	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
10	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
11	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
12	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
13	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
14	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
15	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
16	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
17	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
18	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	1.1%	0.0%	0.0%	0.0%
19	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.1%	0.8%	12.0%	0.0%	0.0%	0.0%
20	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%	3.1%	0.2%	0.0%	0.0%	0.0%
21	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	17.0%	0.4%	0.0%	0.0%	0.0%
22	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.4%	44.9%	10.2%	0.0%	0.0%	0.0%
23	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%	0.4%	0.0%	0.0%	0.0%	0.0%
24	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

3.2. Updates for ACC Calibration

An alternative storage dispatch logic has been implemented to more accurately capture the reliability value that resources can provide by generating energy in non-loss-of-load hours if that preserved battery charge can be used to reduce loss of load in later hours. This approach was implemented by "spreading out" loss of load over all hours that are relevant from a marginal effective load carrying capability. To implement this approach, Astrapé has modified the way in which storage is discharged.

1. If a storage unit is scheduled to generate, it will generate at its scheduled value regardless of available thermal resources.
2. If a storage unit is scheduled to be offline, it will stay offline but will be available to provide spinning reserves.
3. If a storage unit is scheduled to charge, it will charge at its scheduled value unless there is no available generation to charge (due to a change in thermal resource availability)

See Figure 7 below for an illustration of the resulting 12x24 matrix of EUE occurrence utilizing the revised dispatch logic. The key difference between this chart and the prior chart is how EUE is spread across a longer duration of the net load peak period, primarily between hours ending 15 to 22 in August and September. This change provides reliability value to resources that can generate in early evening hours that previously may have not been receiving credit.

Figure 7: Illustrative EUE % Occurrence with Revised SERVM Dispatch.

Change Case

Month of Year

Hour of Day	1	2	3	4	5	6	7	8	9	10	11	12
1	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
7	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
8	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
9	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
10	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
11	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
12	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
13	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
14	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%
15	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%
16	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.5%	0.7%	0.0%	0.0%	0.0%
17	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.8%	1.3%	0.0%	0.0%	0.0%
18	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%	1.2%	6.6%	0.0%	0.0%	0.0%
19	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.6%	3.7%	28.9%	0.0%	0.0%	0.0%
20	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%	3.8%	8.0%	0.0%	0.0%	0.0%
21	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	3.1%	6.5%	0.0%	0.0%	0.0%
22	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	6.5%	15.0%	0.0%	0.0%	0.0%
23	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%	0.9%	1.7%	0.0%	0.0%	0.0%
24	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.5%	0.1%	0.0%	0.0%	0.0%

Because of the uncertainty in generator performance and market availability, the EUE with the revised storage logic is expected to be higher than the baseline logic which uses all available resources.

Staff Proposal Recommendation

Staff proposes to adopt the alternative storage dispatch logic in SERVM to more accurately capture the reliability value that resources can provide by generating energy in non-loss-of-load hours and preserving energy that can be used to reduce loss of load in later hours.

4. Calibrating and Benchmarking SERVM Prices

Prior to producing the energy and ancillary service (AS) price forecasts for use in the 2024 ACC update, staff proposes to benchmark the SERVM model outcomes produced for the 2023 PSP to actual CAISO market outcomes, as summarized in Table 3, and release results for review. While the PSP is a reliability modeling endeavor, it is indicative of the energy resources that will be in existence and operating at various times in the future. It is possible however that certain updates or fixes to model inputs will be needed to align the PSP portfolio and forecasted electric demand conditions to realistic market outcomes in terms of costs and dispatch patterns.

Staff will perform this benchmarking in several ways. Staff proposes to compare actual energy prices from 2022 and 2023 to a back-casted SERVM run meant to mirror those two years. Staff will compare hourly off-peak and on-peak energy prices each month of 2022 and 2023 to assess normal distribution and homogeneity of variance between actual CAISO market prices and the SERVM output.

Staff will analyze hourly dispatch patterns and implied heat rates each hour to ensure that the implied market heat rate each hour in the SERVM output conforms to the actual historical implied market heat rate of the CAISO market and produce charts illustrating the statistical variance in each hour. Staff will use these results to modify the portfolio of power generation resources in the PSP to match the corresponding mix used by CAISO in each month of the year being used for price calibration. In addition to calibrating the portfolio of resources, staff will ensure resources operate as seen in CAISO historical market outcomes. This may involve identifying input parameters in SERVM that may be contributing to the differences between SERVM results and the actual prices. Staff will assess whether to adjust these parameters to improve the accuracy of SERVM.

Table 3: Summary of proposed datasets and benchmarking.

	Proposed Dataset and Benchmarking Materials for Review
SERVM	Use of implied market heat rates instead of actual energy prices when comparing synthetic simulated 2022 and 2023 prices to actual historical 2022 and 2023 market prices, benchmarking the within-day volatility in heat rates, and comparison specifically comparing to months with similar hydrologic conditions to 2022 and 2023 (Same total hydro generation per month)
SERVM	Month-hour average heatmap of raw energy and ancillary service prices, compared with historical prices for a subset of years (12x24 heat map for both energy and AS)
SERVM	Monthly hours with zero or below-zero prices, benchmarked with near-term actuals.
SERVM	Summary of algorithmic changes made between 2022 and 2024 ACC
E3	Month-hour average heatmap of scarcity adjusted price results for a subset of years
E3	Price duration curve for scarcity adjusted implied heat rates, compared with historical heat rates for a subset of years
E3 & SERVM	IRP resource build by scenario, gas forecast, fossil plant heat rates, and renewable profiles

5. Refrigerant Calculator

ED staff proposes the Refrigerant Avoided Cost Calculator (RACC) adopt the modified version of the Deemed Refrigerant Avoided Cost Calculator (DRACC). Staff proposes that consideration of the Refrigerant Avoided Cost Calculator being transferred from this proceeding, R.22-11-013, to the Energy Efficiency Proceeding, R.13-11-005. Energy Efficiency is currently the primary user of the RACC and can make improvements and modifications more efficiently through the Database for Energy Efficiency Resources (DEER) Resolution in R.13-11-005. The next DEER Resolution will be issued in August 2024.

6. Gas GHG Adder

This Gas GHG adder will be used in the avoided cost calculator (ACC) to understand the value of avoiding GHG emissions, so we can determine the cost-effectiveness of ratepayer-funded gas customer programs. Before 2022, the ACC used the same GHG adder for both the electric and gas sectors, based on electric sector planning models used in the IRP proceeding. The rationale for using the same adder in both sectors was that (1) this allows for consistent evaluation of fuel substitution measures, and (2) there is no analogous GHG emissions target, or capacity expansion or other planning modeling, in the fossil gas sector. However, D.22-05-002, in the Integrated Distributed Energy Resources (IDER) proceeding (R.14-10-003), determined that using the electric GHG adder value to measure the cost of decarbonizing the gas sector is underestimating the value of building electrification, since it is very likely that the cost of reducing GHG emissions in the gas sector is higher than the cost of reducing GHG emissions in the electric sector. As a result, it was determined that it is in the interest of ratepayers to include a more accurate estimate of the costs of reducing gas sector GHG emissions.

D.22-05-002, in R.14-10-003, adopted an interim new gas GHG adder based on the cost of building electrification. However, this adder is only a very rough estimate of the likely value of reducing fossil gas sector GHG emissions. This ACC proceeding, R.22-11-013, or its successor proceeding, is the appropriate venue for developing a permanent gas GHG adder since the parties in this proceeding will likely have the necessary experience in the avoided cost calculator to provide the needed expertise. Staff proposes that the authority for the Gas GHG Adder updates existing within the ACC update processes and proceedings (the successor to R.22-11-013). ED staff proposes that the Commission oversee the development in the next 2026 ACC update cycle of an updated gas sector “GHG adder” that will measure the value of gas sector GHG emissions that can be avoided by distributed energy resources (DERs).

7. Minor Correction

7.1. Distribution PCAF of SCE CZ16

A stakeholder identified that the distribution PCAF used for SCE CZ16 does not add up to 100%. Staff will update and ensure all PCAFs in the “Distribution” tab of the Electric Model add up to 100% with updated data from utilities.

7.2. First and Last Year of the Gas Model

The Emissions Cost in the Gas Model (Row 32-35 of “User Dashboard) will not be updated dynamically if the user changes the first year and last year of the model and might lead to a mismatch of results with the years. This error only applies when the user changes the default setting for the first and last year.

Staff will update those functions correctly to ensure calculations are done correctly if the user changes the default inputs.

7.3. Gas Transportation Marginal Costs

The transportation marginal costs in the Gas Model (under tab “T&D”) were not updated in the past few cycles and the values for the year of 2024 and onward in the 2022 ACC model are interpolated based on outdated data. For the 2024 ACC, Staff will request the most recent data from utilities to provide data inputs to update the marginal costs for this section.

(END ATTACHMENT A)