Application A.24-09-014
Exhibit No. CLECA-01

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company to Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U39E)	**Application 24-09-014** **(Filed September 30, 2024)**

Direct Testimony of

Sam Harper

on behalf of

California Large Energy Consumers Association

March 9, 2026

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CONTENTS

1. Executive Summary....1

2. Introduction....2

Summary of Recommendations....5

CLECA Members Operations and Interests....8

CLECA Member Electric Rate Affordability and Impacts of Proposals....9

Marginal Cost Basis for Revenue Allocation and Rate Design....13

3. Marginal Energy Costs (MEC)....15

PG&E's Proposed MEC....15

Transparency Concerns with PG&E Proprietary MALARD Model....17

Cal Advocates' Proposed Marginal Energy Costs....20

CLECA's Proposed Marginal Energy Costs....23

Renewable Energy Certificate (REC) Adder....24

4. Marginal Generation Capacity Costs....33

PG&E's Proposed MGCC....33

PG&E's Battery Optimization Assumes Excessive Battery Cycling....34

PG&E's Four-Hour Battery is Not Adequate to Meet system capacity needs during peak periods....45

CLECA Recommends an Eight-Hour Battery as the Proxy Resource....51

PG&E's Battery Revenue Price Assumptions are Flawed....55

Cal Advocates' Proposed Removal of the BTM Solar Capacity Factor Adjustment Is Unsupported and should be rejected....62

5. Marginal Distribution Capacity Costs (MDCC)....66

The Commission Should Reject PG&E's Proposal to Recover ALL Vegetation Management (VM) Costs Through the EQUAL PERCENT MARGINAL COST (EPMC) Scalar....66

6. Marginal Customer Access Costs (MCAC) 70

CLECA Supports PG&E's Proposed Replacement Cost New Less Depreciation (RCNLD) Method for Calculating the MCAC 70

7. Revenue Allocation and rate design 72

CLECA Supports PG&E's proposal for collection of wildfire costs 72

CLECA Supports PG&E's Economic Development Rate Program with Recommended Enhancements 73

CLECA Supports progress toward Cost-of-Service Rates while Mitigating potential Rate Shocks 79

8. Conclusion 82

1. EXECUTIVE SUMMARY

Industrial PG&E customer electric rates are currently 300% of average rates in neighboring states, which makes it difficult for companies to stay in California and remain competitive. These companies provide essential jobs and contributions to the California economy, supplying critical goods and services essential to the well-being of all Californians, including materials for critical infrastructure, medical grade hospitals, and food storage and distribution. California is rightly concerned about the climate change impact of emissions leakage when energy-intensive industries can no longer compete locally causing the state to import critical materials from outside California that are made with less stringent regulations, dirtier electricity, and shipped over longer distances with higher transportation emissions. Affordable electric rates are critical for these industries.

Adhering to sound marginal cost rate making principles is important to send proper price signals and avoid cross-subsidies, as well as to encourage efficient customer investment and consumption of energy. CLECA proposes in this testimony adoption of cost allocation and rate design based on a proxy resource that is adequate to serve reliability needs into the future, with industry standard dispatch, and with reasonable energy cost assumptions based on sound marginal cost causation principles. In contrast, we strongly oppose the use of outlier Renewable Energy Certificate (REC) price energy adders and energy price floors based on calculations that are not fit for purpose, faulty adjustments to resource costs, and we identify issues with distribution related Vegetation Management (VM) cost allocation. Finally, we support moving rates to reflect cost of service with reasonable collars to avoid rate shock, and we support PG&E's proposed collection of wildfire costs consistent Commission precedent, and suggest

enhancements to the Economic Development Rate (EDR) to ensure it continues to be effective at attracting and retaining businesses.

2. INTRODUCTION

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Sam Harper. My business address is Harper Advisory LLC, 9002 Six Pines Drive, Shenandoah, TX 77380.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of energy markets and policy.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A Please see Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the California Large Energy Consumers Association (CLECA). CLECA is an organization of large, high-load factor industrial customers of PG&E and SCE. The members are in the cement, steel, industrial gas, medical gas, pipeline, beverage, cold storage, and minerals processing industries, and share the fact that electricity costs comprise a significant portion of their costs of production.[1]

[1] CLECA member companies produce goods essential for daily life, including critical infrastructure, oxygen for hospitals, and food distribution. CLECA members represent the steel, cement, industrial and medical gas, beverage, minerals processing, cold storage, and pipeline transportation industries. Their aggregate electric demand is about 500 Megawatts, which is equivalent to the electricity consumption of approximately 470,000 average California households. CLECA members are large, high load factor and high voltage industrial electric customers in California for whom the price of electricity is essential to their competitiveness and for whom the reliability of electricity service is critically important. For both reasons, CLECA member companies have participated for decades in the Base Interruptible Program (BIP), providing reliability demand response to the grid

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A Pacific Gas & Electric (PG&E) filed its General Rate Case Phase 2 application on September 30, 2024, to update electric marginal costs and the associated cost of service, revise interclass revenue allocation, and modify rate designs for each customer class. PG&E discovered errors in its testimony and filed corrected testimony first on October 29th, 2025 and then again on January 23rd, 2026. This testimony responds to Issues 1 to 3 in the March 21, 2025 Assigned Commissioner's Scoping Memo and Ruling that address whether PG&E's proposed marginal costs, cost of service, revenue allocation, and rate designs are reasonable.[2]

On February 6th, 2026, the Public Advocates Office (Cal Advocates) submitted Errata testimony reflecting revisions to its July 23rd, 2025 opening testimony. This testimony also responds to statements and proposals made by the Cal Advocates in its Errata testimony.

Q HOW IS YOUR TESTIMONY ORGANIZED?

A My testimony is organized as follows. Following this introduction and a summary of our recommendations, I describe CLECA's members, their operations and interests, and the impacts that PG&E's proposals would have on their electric rate affordability and competitiveness, and potential for investments in electrification and decarbonization projects that would increase electricity consumption that rely on affordable industrial rates. I then address the marginal cost basis for revenue allocation and rate design, which provides the analytical foundation for the sections that follow. I address each major marginal cost component in turn.

in times of need. Some members are bundled customers, others are Direct Access (DA) customers, and some are served by Community Choice Aggregators (CCAs); several members have onsite renewable generation.

[2] Assigned Commissioner's Scoping Memo and Ruling, March 21, 2025 at 2.

First, I address Marginal Energy Costs (MEC), including PG&E's proposed MECs and CLECA's concerns with the transparency of PG&E's proprietary hybrid production-regression model (termed 'MALARD model'), my evaluation of Cal Advocates' proposed MECs, and CLECA's own MEC recommendations, including CLECA's position on both PG&E's and Cal Advocates' proposed Renewable Energy Certificate (REC) adder that I believe produces outlier results that are not fit for purpose in this rate proceeding.

Second, I address Marginal Generation Capacity Costs (MGCC), including criticisms of PG&E's excessive battery cycling assumptions, the inadequacy of PG&E's proposed four-hour battery as a proxy resource to cover peak reliability hours, and flaws in PG&E's battery revenue price assumptions. I also address Cal Advocates' proposed removal of the behind-the-meter solar capacity factor adjustment, which is unsupported and produces unreasonable results. I recommend an eight-hour battery as the appropriate proxy resource, and propose reasonable adjustments to the battery revenue calculations.

Third, I address Marginal Distribution Capacity Costs (MDCC), where CLECA opposes PG&E's proposal to recover all vegetation management (VM) costs through the Equal Percent Marginal Cost (EPMC) scalar.

Fourth, I address Marginal Customer Access Costs (MCAC), where CLECA supports PG&E's proposed RCNLD method.

I then turn to revenue allocation and rate design, addressing PG&E's proposed collection of wildfire hardening costs, PG&E's Economic Development Rate program, which CLECA supports with recommended enhancements, and PG&E's proposal to move toward cost-of-service rates while mitigating potential rate shock.

SUMMARY OF RECOMMENDATIONS

Q PROVIDE A SUMMARY OF YOUR POSITIONS IN THIS TESTIMONY.

A CLECA takes the following positions:

1. Marginal Energy Cost (MEC)

Table 2-1: CLECA's Proposed MEC[3]

CAISO - NP15 | 2024

		Voltage Level		
Line No.	TOU Rate Period	Transmission	Primary Distribution	Secondary Distribution
1	Summer Peak	6.684	6.810	7.147
2	Summer Partial-Peak	3.943	4.017	4.216
3	Summer Off-Peak	3.076	3.134	3.289
4	Winter Peak	5.456	5.559	5.834
5	Winter Off-Peak	4.367	4.449	4.669
6	Spring Super Off-Peak	0.741	0.754	0.792
7	Bundled Load-Weighted Annual Average	4.474		

The MECs should be based on the 2024 CAISO actuals rather than the proprietary MALARD model, as PG&E proposes. There is no need to rely on a complicated proprietary model with disputed input assumptions and significant transparency concerns when the actual market data is readily available and not in dispute.

CLECA recommends rejecting the REC Adder because it is fundamentally an embedded cost. However, if a REC Adder is adopted, it should be applied on a marginal cost basis as closely as possible. This means the REC Adder should be applied to specific hours when renewables are at the margin; the REC Adder

[3] CLECA Workpaper 1 available by email upon request. Illustrative tables are based on estimates; where they differ from the written testimony, the written recommendations prevail.

should not be applied as an embedded cost as a percentage of all energy. The REC Adder price should be based on current trading prices that are aligned with historical norms, not outlier results from the Power Charge Indifference Adjustment (PCIA) Market Price Benchmark (MPB). The PCIA MPB is a limited regulatory mechanism that currently reflects outlier results, and the PCIA MPB is based on historical contract costs (an embedded cost principle) for a narrow subset of REC transactions.[4] If a REC Adder is applied at all, the Commission should adopt CLECA's proposal to apply it only to specific hours when renewables are at the margin, and CLECA's proposed REC price of $15/MWh which reflects current market prices.

2. Marginal Generation Capacity Cost (MGCC)

Table 2-2: CLECA's Proposed MGCC[5]

	2024	2025	2026	2027	2028	2029
AGCC	$238.41	$246.84	$307.32	$399.09	$396.29	$390.09
MGCC	**$322.11**					

The MGCC should be based on an 8-hour proxy resource battery adequate to cover peak hours for reliability into the future with corresponding higher Effective Load Carrying Capacity (ELCC) values from the Avoided Cost Calculator (ACC). The battery should be constrained to one full throughput cycle per day. The revenues the battery earns should be based on NP-15 MEC prices where all

[4] Based on "bundled, short-term (under ten years), index-plus6, Portfolio Content Category 1 (PCC-1) transactions" https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/community-choice-aggregation-and-direct-access/calculation-of-the-market-price-benchmarks-2024-2025.pdf p. 2.

[5] CLECA Workpaper 10 available by email upon request. Illustrative tables are based on estimates; where they differ from the written testimony, the written recommendations prevail.

of PG&E's customers are located, and based on reasonable MECs with a price floor based on a $15/MWh REC price reflecting historical norms and current trading prices, not outlier results of the PCIA MPB which is not fit for purpose in this rate case. The out-years energy price escalator should be modified to reflect compressed intraday price variability consistent with expanded battery buildout as the primary capacity resource.

3. Marginal Distribution Capacity Cost (MDCC)

CLECA opposes recovery of the entirety of Distribution VM costs through the Equal Percent Marginal Cost (EPMC) scalar. The proportion of VM costs caused by new distribution circuit infrastructure should be allocated through the MDCC, rather than spread through the EPMC scalar.

4. Marginal Customer Cost (MCC)

CLECA supports PG&E's proposed Replacement Cost New Less Depreciation (RCNLD) method to collect Marginal Customer Access Costs (MCAC).

5. Revenue Allocation and Rate Design

Table 2-3: CLECA's Proposed Revenue Allocation[6] [7]

Class	Distribution Revenue		Delivery (excl. Dist)		Bundled Generation		PCIA		Total	
Res	$ 4,393,924,603	44.82%	$ 1,615,248,235	33.54%	$ 2,058,672,312	49.40%	236,412,491	38.54%	8,304,257,640	42.80%
SL&P	$ 1,567,198,082	15.99%	$ 531,149,549	11.03%	$ 383,321,683	9.20%	69,528,949	11.34%	2,551,198,262	13.15%
ML&P	$ 943,362,871	9.62%	$ 589,735,090	12.24%	$ 313,883,776	7.53%	72,869,464	11.88%	1,919,851,200	9.90%
B19	$ 1,132,007,564	11.55%	$ 802,539,463	16.66%	$ 398,112,291	9.55%	103,715,866	16.91%	2,436,375,184	12.56%
Stlt	$ 36,209,791	0.37%	$ 12,223,326	0.25%	$ 6,433,034	0.15%	1,888,972	0.31%	56,755,123	0.29%
Stby	$ 32,556,002	0.33%	$ 20,693,253	0.43%	$ 36,467,503	0.88%	3,037,021	0.50%	92,753,779	0.48%
AG	$ 987,533,176	10.07%	$ 372,008,057	7.72%	$ 529,162,735	12.70%	40,059,333	6.53%	1,928,763,300	9.94%
B20T	$ 87,283,882	0.89%	$ 331,316,915	6.88%	$ 223,447,921	5.36%	33,798,522	5.51%	675,847,239	3.48%
B20P	$ 422,936,711	4.31%	$ 375,211,305	7.79%	$ 174,461,854	4.19%	38,938,602	6.35%	1,011,548,473	5.21%
B20S	$ 132,210,507	1.35%	$ 115,006,411	2.39%	$ 28,104,203	0.67%	11,723,721	1.91%	287,044,842	1.48%
BEV	$ 68,711,939	0.70%	$ 51,093,801	1.06%	$ 15,077,911	0.36%	1,394,090	0.23%	136,277,741	0.70%
System	$ 9,803,935,127	100.00%	$ 4,816,225,405	100.00%	$ 4,167,145,223	100.00%	613,367,028	100.00%	19,400,672,784	100.00%

[6] CLECA Adapted RARD Model Workpapers available by email upon request. Tables are illustrative; where they differ from the written testimony, the written recommendations prevail.

[7] Excludes CLECA's proposal for Distribution Vegetation Management allocation.

CLECA supports PG&E's proposed collection of wildfire hardening costs and PG&E's proposal to move toward cost-of-service rates while mitigating potential rate shock. We also support PG&E's EDR program and provide recommended enhancements to ensure the program continues to be effective at attracting and retaining businesses.

CLECA MEMBERS OPERATIONS AND INTERESTS

Q WHO ARE CLECA MEMBERS?

A CLECA members are large industrial and manufacturing customers with facilities served by PG&E[8] that rely upon safe, reliable, clean, and affordable electricity. CLECA member companies provide goods and services essential to the daily life and well-being of all Californians, including materials for critical infrastructure, medical grade oxygen for hospitals, and cold storage for food distribution.

Q WHAT ARE THE INTERESTS OF CLECA MEMBERS IN THIS CASE?

A The price of electricity is critically important to CLECA member companies and greatly impacts their operations' competitiveness. Most of the CLECA member company operations are highly trade exposed and compete with operations in western states, across the US, and internationally. Energy costs are a significant driver of these energy intensive operations' ability to compete and impact their ability to maintain or expand operations within the state.

The ability for CLECA members to compete is important to achieve the economic and environmental policy goals of the state of California. These companies comprise a meaningful

[8] CLECA members are also customers of other Investor Owned Utilities (IOUs) and Public Owned Utilities (POUs), with facilities throughout California.

portion of the California economy across numerous sectors and provide family sustaining jobs throughout the state. Importantly, the critical materials supplied by CLECA members are energy intensive to produce and heavy to transport. Producing these materials in-state reduces emissions overall compared to production out of state with less stringent environment regulations, longer transportation distances and less clean electricity. When these critical operations are no longer able to compete, in part due to electricity prices, production is shifted out of state and overall emissions increase.[9]

Further, many CLECA members have set individual environmental targets that involve electrifying portions of their operations, adopting carbon capture technology, or other technologies that involve consuming significantly more electricity to run their highly energy intensive processes.[10] The ability to invest and execute in these environmental strategies depends directly on the price of electricity.[11]

CLECA MEMBER ELECTRIC RATE AFFORDABILITY AND IMPACTS OF PROPOSALS

Q WHAT IS THE CURRENT STATE OF INDUSTRIAL SECTOR ELECTRIC RATE AFFORDABILITY?

A California's electric rates for industrial sector customers are dramatically higher than industrial sector rates of neighboring western states. This gap has grown dramatically in recent years, in particular for PG&E industrial customers. PG&E now holds the dubious distinction of having the highest industrial rates amongst the large investor-owned utilities in California, and industrial rates over 300% of neighboring western states – See Figure 1. Many of the CLECA

[9] *CPUC, California Industry Assistance: What is the purpose of the California Industry Assistance Credit? California Industry Assistance [website accessed 3/9/2026]*
[10] CLECA Workpaper 4 available by email upon request.
[11] California Air Resources Board (CARB) Appendix C – Standardized Regulatory Impact Assessment (SRIA), p. 11.

members' California facilities compete with operations located in neighboring states; lower electric rates in other states provide a strong competitive advantage to energy-intensive operations out of state, and put tremendous competitive pressure on operations looking to remain, expand, or electrify in California.

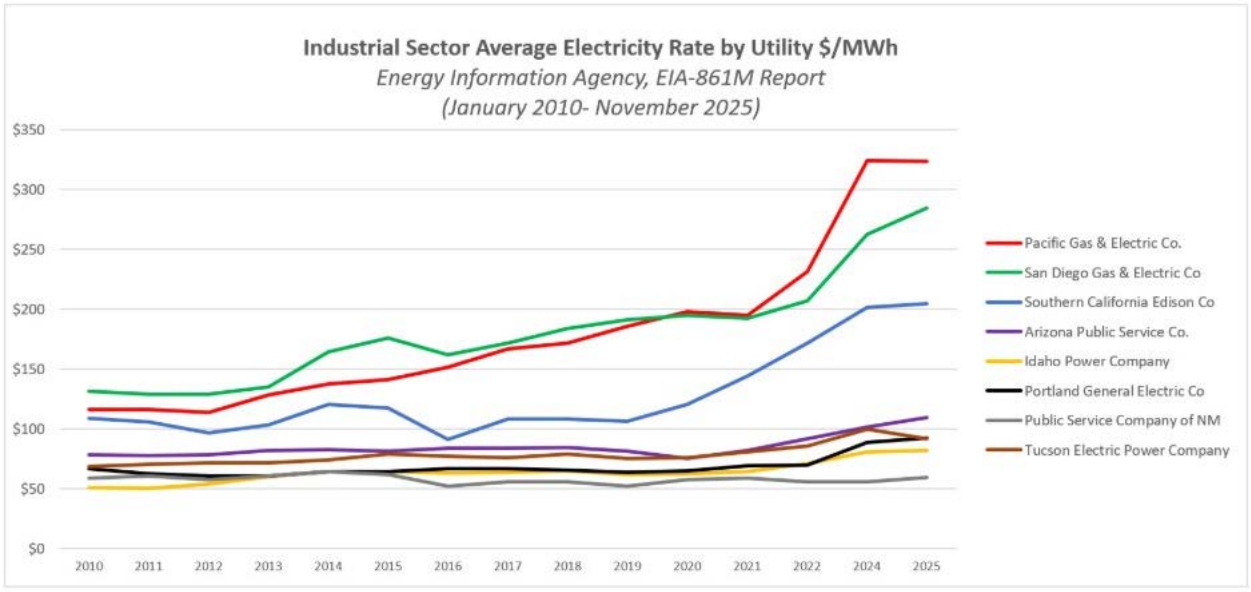
A recent example of the impact of policy on California Industry is the recently announced closure of the Anheuser-Busch's Fairfield Brewery in the Bay Area.[12] This plant had been operating since 1976 and had 475 full-time employees. The company announced it would be shifting production to other U.S. facilities and would be offering employment to the affected staff in other U.S. facilities. The City Mayor lamented this closure in a statement mentioning high energy prices specifically:

> Fairfield and other Solano cities have lost major businesses because California is a hostile business environment… We have the most expensive gas, energy, grocery prices, and housing.[13]

This economic and emissions leakage from California is and should be of serious and urgent concern. The Commission must move to address this problem by adhering to cost causation principles and avoiding cross-subsidies. California needs real goods from physical materials produced in industrial facilities. The question is whether those facilities will provide California jobs and contribute to California's environmental goals, or simply import the goods for other states.[14]

[12] https://www.mercurynews.com/2025/12/12/anheuser-busch-to-close-fairfield-brewery-2/.
[13] *Ibid.*
[14] CARB, Staff Report – Initial Statement of Reasons (ISOR), p. 70 "The costs of some decarbonization options continue to be greater than allowance prices, contributing to an increased leakage risk for the manufacturing sector."

Figure 2-1: Industrial Sector Average Electricity Rate by Utility ($/MWh) [15]



Q WHAT WOULD BE THE IMPACTS OF PG&E AND CAL ADVOCATES' PROPOSALS ON CLECA MEMBERS?

A PG&E makes several proposals that inappropriately allocate costs to large energy consumers based on an inadequate 4-hour battery proxy resource to meet peak hour reliability needs with excessive cycling and flawed marginal energy cost assumptions; and inappropriate allocation of distribution VM costs.

In its testimony, Cal Advocates makes numerous proposals that would make the cost allocation deviate sharply from a cost-of-service basis, including applying unsupported adjustments to proxy resource ELCC and outlier REC Adder calculations.

The Commission should reject these proposals that deviate from sound cost causation principles and artificially push cost responsibility onto industrial rates. Driving up the level of

[15] Source: Energy Information Agency (EIA), EIA-861M Monthly Electric Power Industry Report, Monthly sales to ultimate customers by state and utility for all sectors (Industrial columns) January 2010 - November 2025.

industrial rates is inappropriate and counterproductive to California's economic and climate policy goals.

Industrial customers like CLECA members are unable to simply pass along the electricity costs proposed by PG&E and Cal Advocates because they compete in regional, national and international markets. The PG&E and Cal Advocates proposals would exacerbate the impact of already high electricity rates and further undermine the viability of industrial businesses in California. Cal Advocates' proposal would undercut the State's climate goals, because keeping the production of cement, steel, minerals, industrial gases, beverages, and provision of cold food storage in California enables their manufacturing where the energy is cleaner, regulations are more robust, and avoids additional emissions associated with transportation from out-of-state facilities. California is rightly concerned about greenhouse gas (GHG) leakage in the electric energy sector and GHG leakage from critical industries moving outside California as part of implementing its climate change policy; this concern warrants recognition in the rate making process.

Departing from proper marginal cost-based ratemaking to incorporate subsidies and inaccurate price signals creates economic distortions. The importance of accurate price signals becomes ever greater as more options emerge for customers to manage their energy consumption pattern or install their own distributed energy resources (DERs). The decision of an individual customer to electrify its industrial operation, charge an electric vehicle (EV) at a particular time, invest in onsite solar or batteries, run the air conditioning on a particular day, or continue to operate a business or expand operations in California are all influenced by the electricity price signal.

When rates exceed the actual cost of providing energy at a specific location and time, customers are economically incentivized to reduce energy consumption in ways that are inefficient. This behavior decreases their contribution to fixed costs, which in turn drives up rates for everyone else. On the other hand, when rates are set below the actual cost, customers are encouraged to use more energy than is economically efficient, increasing overall system costs. These additional costs must then be recovered from other customers through cross-subsidies. Over time, this creates a vicious cycle: the burden of cross-subsidies raises rates for those paying them, further incentivizing those customers to find alternatives and bypass the utility system altogether.

MARGINAL COST BASIS FOR REVENUE ALLOCATION AND RATE DESIGN

Q WHAT IS MARGINAL COST AND WHY IS IT IMPORTANT?

A A marginal cost is the incremental cost of providing service in response to an increment of demand for that service. As noted by PG&E, the Commission has long used marginal cost to establish the cost to serve different classes of customers.[16] The majority of marginal costs involve fixed forward commitments paid for by all relevant ratepayers, though in practice some cost components — like demand at peak — are more readily fungible across customers than others, like customer connection costs.

[16] PG&E-2 at 1-1.

Q WHY DOES THE COMMISSION USE MARGINAL COST FOR REVENUE ALLOCATION?

A The Commission has been using marginal cost in revenue allocation since the late 1970's[17], and more recently reaffirming that marginal cost pricing sends proper price signals that result in more efficient consumption decisions by ratepayers:

> The use of marginal costs is consistent with an economic approach to ratemaking that seeks to impose the greatest utility rates on those customers that impose the greatest costs on the utility at the margin (i.e., the greatest costs imposed by requiring an additional unit of a given utility service). In this way, those customers that impose the greatest marginal costs have the most incentive to reduce their usage and demand, which in turn should drive down the utility's marginal expenses most efficiently. This reduction in utility expenses ultimately benefits all utility customers through lower overall rates.[18]

California is unusual in using marginal costs for revenue allocation, as many states instead use embedded cost techniques[19] — though many jurisdictions, including California, have long used marginal costs for rate design purposes. My testimony in this proceeding is based on what I believe is the closest adherence to the marginal cost policies the Commission has pursued during this extended period.

Q ARE THERE LIMITATIONS TO USING MARGINAL COSTS FOR REVENUE ALLOCATION?

A Yes. Marginal costs do not equal average or embedded costs; the sum of marginal costs is generally either significantly greater or significantly smaller than the revenue requirement to be recovered from the several customer classes. As a result, the marginal cost revenues (i.e.,

[17] D.18-08-013 at 12: "…in the late 1970's the Commission began changing the basis of revenue allocation and rate design from the previous embedded cost approach to an approach based on marginal costs."
[18] D.21-11-016 at 6.
[19] The National Association of Regulatory Utility Commissioners (NARUC) Desk Reference Manual – Ratemaking Fundamentals and Principles section (3. Ratemaking Fundamentals and Principles - NARUC) specifies in its Cost Allocation methodology that marginal cost is only "sometimes considered".

indicated marginal costs multiplied by class billing determinants) must be scaled up or down to reconcile with and collect the actual revenue requirement. Not only are the marginal cost revenues scaled, but individual rate elements are also scaled by the same factor. This raises some concern about the accuracy of the price signal being sent when marginal costs require such scaling.

3. MARGINAL ENERGY COSTS (MEC)

PG&E'S PROPOSED MEC

Q WHAT ARE PG&E'S PROPOSED MECS FOR THE RATE CASE CYCLE?

A PG&E proposes the following MECs for Test Year (TY) 2024, shown in Table 3-1, below:

Table 3-1: PG&E's Proposed MEC's[20]

TABLE 2-3
MEC BY TOU PERIODS
AND VOLTAGE LEVEL AVERAGED OVER YEAR 2024
(¢/kWh)

Line No.	TOU Rate Period	Voltage Level		
		Transmission	Primary Distribution	Secondary Distribution
1	Summer Peak	8.244	8.399	8.815
2	Summer Partial-Peak	6.938	7.069	7.419
3	Summer Off-Peak	6.103	6.218	6.526
4	Winter Peak	7.654	7.798	8.184
5	Winter Off-Peak	5.592	5.697	5.979
6	Spring Super Off-Peak	1.549	1.578	1.656
7	Bundled Load-Weighted Annual Average	6.436		

Q WHAT IS THE BASIS FOR PG&E'S PROPOSED MECS?

A PG&E's proposed hourly MECs are generated by a forecast of CAISO Day-ahead hourly prices for PG&E's DLAP. As PG&E explains:

> To meet its residual needs, PG&E buys residual energy from the day-ahead and real time-markets operated by the CAISO. The CAISO economically dispatches resources that are bid into the

[20] PG&E-2 at 2-10.

> market. Because PG&E meets its residual needs by purchasing power in the CAISO day-ahead market, a forecast of day-ahead market prices provides the most relevant estimate of PG&E's future MECs. PG&E calculates the MEC by forecasting hourly prices for years 2024 to 2055, using historical day-ahead prices at PG&E Default Load Aggregation Points (DLAP).[21]

PG&E's forecasts are generated through an in-house, regression-based model housed in MATLAB[8], primarily relying on publicly available data and the 2022-2023 IRP. PG&E claims that this model improves upon the prior MEC methodology by building into it the (1) effects of congestion or the transmission limits due to the flow of electricity along Path 26 and the (2) impact of renewable curtailment on MECs through setting a price floor based off of Energy Division's 2024 Forecast Renewable Portfolio Standard (RPS) adder.[22] For this application, PG&E generates hourly forecast MECs for years 2024-2035 (for the out-years beyond 2035, time period based escalation rates are applied) in three scenarios accounting for variability in inputs: Dry Year, Wet Year, and Normal Year. The average of these outputs makes up PG&E's proposal. These changes altogether, according to PG&E, make up for a more aligned and accurate forecast of MECs.[23]

Q DOES PG&E'S APPROACH PRODUCE REASONABLE HOURLY PRICES?

A No. As seen in Table 3-2 below, for 2024, PG&E's MECs vastly exceed the observed CAISO Day-ahead PG&E DLAP (NP-15) prices, by an average of 43.9%. These results are grossly inappropriate for ratemaking, especially given the superior alternative available in this GRC – using actual 2024 prices for 2024 prices.

[21] PG&E-2 at 2-11.
[22] GRCII_MGCC_MEC_CLECA_Presentation (presented to CLECA via Meet-and-Confer).
[23] PG&E-2 at 2-7: "This new in-house, proprietary model more accurately replicates historical day-ahead prices in northern California region, compared to the one used in the 2020 GRC II."

Table 3-2: PG&E vs. CAISO NP-15 DLAP Day-ahead[24]

TOU Period	CAISO 2024 NP-15	PG&E Errata II	Difference
Summer Peak	6.684	8.244	23.3%
Summer Partial-Peak	3.943	6.938	76.0%
Summer Off-Peak	3.076	6.103	98.4%
Winter Peak	5.456	7.654	40.3%
Winter Off-Peak	4.367	5.592	28.1%
Spring Super-Off-Peak	0.741	1.549	109.2%
Bundled Load-Weighted Annual Average	4.474	6.436	43.9%

TRANSPARENCY CONCERNS WITH PG&E PROPRIETARY MALARD MODEL

Q WHAT IS THE MALARD MODEL?

A MALARD — Marginal Analysis of Loads and Resources for Dispatch — is a proprietary MATLAB-based model that PG&E developed in-house to calculate marginal energy costs for this proceeding.[25] It replaces the Excel-based regression model PG&E used in its 2020 GRC Phase II. The 2020 model used a cubic polynomial regression relating adjusted net load to an effective market heat rate. MALARD upgrades this to a multiple linear regression incorporating additional predictor variables — daily gas prices at PG&E CityGate and SoCal CityGate, GHG allowance prices, adjusted net load, and gas fleet characteristics.[26] MALARD also adds iterative modeling of congestion impacts and renewable curtailment adjustments that were not present in PG&E's prior approach.

[24] CLECA Workpaper 1 available by email upon request.
[25] PG&E Response to Cal Advocates Data Request No. 004, Question 1(a), at 2.
[26] PG&E-2 at 2-13.

Q ARE THERE TRANSPARENCY CONCERNS WITH PG&E'S PROPRIETARY MALARD MODEL?

A Yes, and they are significant. MALARD is a proprietary model built in a commercial software environment (MATLAB). PG&E did not make the underlying model code available to intervenors. No intervenor can independently validate the model, which is a clear and fundamental due process deficiency. PG&E's proposed marginal energy costs directly determine how billions of dollars in generation costs are allocated amongst customers. The Commission should not adopt rate allocation or design derived from a model that no intervenor has been able to independently verify.

Q IS THIS LACK OF TRANSPARENCY JUSTIFIED BY THE MODEL'S PERFORMANCE?

A No. As Cal Advocates documents, the R-squared improvement from PG&E's 2020 Excel-based regression model to the MALARD model is approximately 2 percentage points — from roughly 75 percent to roughly 77 percent.[27] A 2 percentage point gain in explanatory power does not justify replacing a transparent, workpaper-driven model with a proprietary black box that no other party can run.

Moreover, transparent alternatives exist. Both SCE and SDG&E use PLEXOS — an industry-standard, commercially available production cost model — to calculate MECs in their most recent GRC Phase II proceedings.[28] PG&E declined to use PLEXOS, claiming it is "computationally expensive" and requires "a very long lead time to set up and test."[29] No

[27] Cal Advocates at 1-12.
[28] Cal Advocates at 1-13.
[29] Cal Advocates 1-Appendix B, Attachment 1-E. PG&E Response to Cal Advocates Data Request No. 015, Question 3(b) at 2.

matter the model platform: Excel, PLEXOS, MATLAB or any other alternative, it is imperative that the underlying model code and logic be made available to stakeholders.

Q DOES CAL ADVOCATES IDENTIFY SIMILAR TRANSPARENCY CONCERNS?

A Yes. Cal Advocates devotes an entire section of its MEC testimony to the transparency and replicability deficiencies of PG&E's MALARD model.[30] Cal Advocates documents that it was unable to independently validate PG&E's MEC results despite extensive data requests, and characterizes PG&E's approach as a departure from the historically transparent, workpaper-driven methodology used in prior GRC Phase II proceedings. CLECA shares these concerns.

Cal Advocates recommends that, for future GRC's, PG&E either adopt an industry-standard production cost model such as PLEXOS or make its MATLAB model and all supporting code fully accessible to intervenors.[31] For this proceeding, Cal Advocates recommends the Commission require PG&E to provide an Excel-based tool that can validate MEC outputs, so that the MEC results underlying PG&E's proposed rates can be verified before the Commission adopts them[32].

Q HOW DOES CLECA PROPOSE TO ADDRESS THESE TRANSPARENCY CONCERNS?

A For the TY 2024 MEC values, CLECA recommends using actual day-ahead CAISO prices, which are more accurate and transparent than any model could be.

Regarding the other applications in this proceeding (2030 MEC values used in time-of-use (TOU) analysis, 2025-2055 MEC values used in EGM projection), CLECA concurs with Cal

[30] Cal Advocates at 1-10: "C. PG&E's Choice to Build its MEC Model in MATLAB Raises Transparency and Replicability Concerns".
[31] Cal Advocates at 1-19.
[32] Cal Advocates at 1-21.

Advocates that PG&E should be required to provide intervenors with an Excel-based tool that can validate MEC outputs, so that the MEC results underlying PG&E's proposed rates can be verified before the Commission adopts them.

For future GRC Phase II proceedings, CLECA concurs with Cal Advocates in recommending that the Commission direct PG&E to adopt PLEXOS or a comparable industry-standard, commercially available production cost model with transparent code and logic for MEC calculations, consistent with the practice of both SCE and SDG&E.

A model that no intervenor can run is a model that no intervenor can challenge — and a model that no intervenor can challenge should not be the basis for setting rates.

CAL ADVOCATES' PROPOSED MARGINAL ENERGY COSTS

Q WHAT ALTERNATIVE APPROACH DOES CAL ADVOCATES PROPOSE FOR CALCULATING MECS?

A Despite its extensive critique of the MALARD model's transparency deficiencies, Cal Advocates does not propose an independent MEC methodology. Instead, Cal Advocates continues to rely on PG&E's proprietary MALARD model, adjusting a single input: the renewable curtailment price floor.[33] Cal Advocates replaces PG&E's 2024 Forecast RPS Adder of $31.73 per MWh with the 2024 Final RPS Adder of $54.56 per MWh, which lowers the price floor from negative $31.73 to negative $54.56 per MWh. All other MALARD inputs, methodology, and code remain unchanged.

[33] Cal Advocates at 1-3 footnote 13: "Cal Advocates calculates its proposed MEC values by TOU period by inputting PG&E's modeled hourly MECs calculated using the 2024 Final RPS Adder into PG&E's calculations of the average MEC for the TOU periods weighted by hourly bundled load."

Q WHAT ARE CAL ADVOCATES' PROPOSED MECS?

A Cal Advocates' proposed MECs are substantially similar to PG&E's. The annual bundled load-weighted average is 6.428 cents per kWh under Cal Advocates' approach, compared to 6.436 cents per kWh under PG&E's — a difference of negative 0.12 percent.[34] The differences are concentrated in off-peak periods: Spring Super Off-Peak decreases by 14.36 percent, while peak and on-peak periods are essentially unchanged.

Table 3-3: Comparison of Cal Advocates' and PG&E's Proposed 2024 MEC Values (¢/kWh) at the Transmission Level[35]

TOU Period	PG&E Errata II	Cal Advocates	Difference
Summer Peak	8.244	8.244	0.00%
Summer Partial-Peak	6.938	6.938	0.00%
Summer Off-Peak	6.103	6.096	-0.13%
Winter Peak	7.654	7.654	0.00%
Winter Off-Peak	5.592	5.577	-0.26%
Spring Super Off-Peak	1.549	1.326	-14.36%
Bundled Load-Weighted Annual Average	**6.436**	**6.428**	-0.12%

The near-identical results are unsurprising. Cal Advocates changed only the price floor, which affects only those modeled hours with high curtailment. Both parties' MECs are outputs of the same proprietary model that, as discussed above, no intervenor has been able to independently verify.

[34] Cal Advocates at 1-3 (Table 1-1).
[35] *Ibid.*

Q DOES CAL ADVOCATES' APPROACH PRODUCE REASONABLE HOURLY PRICES?

A No. Actual 2024 CAISO day-ahead prices at the NP-15 trading hub averaged $45 per MWh for the year.[36] Both PG&E's and Cal Advocates' modeled MECs average approximately $64 per MWh — about 44 percent higher than the wholesale prices actually observed at PG&E's pricing region during the test year, as shown in Table 3-4.

Table 3-4: PG&E and Cal Advocates' Proposed MEC's vs Actual CAISO ($/MWh)[37]

TOU Period	CAISO 2024 NP-15	PG&E Errata II	Difference	Cal Advocates	Difference
Summer Peak	6.684	8.244	23.3%	8.244	23.3%
Summer Partial-Peak	3.943	6.938	76.0%	6.938	76.0%
Summer Off-Peak	3.076	6.103	98.4%	6.096	98.2%
Winter Peak	5.456	7.654	40.3%	7.654	40.3%
Winter Off-Peak	4.367	5.592	28.1%	5.577	27.7%
Spring Super-Off-Peak	0.741	1.549	109.2%	1.326	79.1%
Bundled Load-Weighted Annual Average	4.474	6.436	43.9%	6.428	43.7%

The divergence is particularly pronounced in the Spring Super-Off Peak and Summer Off-Peak periods in which PG&E and Cal Advocates forecast prices 77% - 107% higher than CAISO actual prices. These periods are critical for rate design to signal to consumers to use more energy, when marginal costs (and marginal emissions) are particularly low. And yet both PG&E and Cal Advocates overstate these costs sending an inadequate price signal. Both parties are modeling price behavior that simply did not occur in the test year.

[36] CLECA Workpaper 1 available by email upon request.
[37] CLECA Workpaper 1 available by email upon request.

CLECA'S PROPOSED MARGINAL ENERGY COSTS

Q WHAT ALTERNATIVE APPROACH DOES CLECA PROPOSE FOR CALCULATING MARGINAL ENERGY COSTS?

A CLECA proposes actual CAISO NP-15 day-ahead prices as the basis for marginal energy costs in this proceeding. TY 2024 is now in the past, and actual wholesale market prices for the entire calendar year are available from the CAISO Open Access Same-Time Information System.[38] There is no need to rely on a complicated proprietary model with disputed input assumptions and significant transparency concerns when the actual market data is readily available and not in dispute.

PG&E describes MALARD's purpose as producing a model that "more accurately replicates historical day ahead prices in [the] northern California region."[39] PG&E also states that it "validated this model against the actual energy prices from January until June 2024."[40] The stated purpose of replicating day ahead prices and the act of validating against those day ahead prices demonstrates that PG&E regards the actual day ahead prices as more authoritative than the model's output. CLECA agrees — actual prices are more accurate than any model. Thus, rather than attempting to "forecast" 2024 CAISO NP-15 prices as MECs, CLECA recommends using the *actual* 2024 CAISO NP-15 prices as MECs.

[38] There are five hours during 2024 that have a price of zero in OASIS most likely due to missing data. For our calculations, in place of each hour's missing price, we used the corresponding price from the following week with the same weekday and hour. This is in CLECA Workpaper 1 available by email upon request.
[39] PG&E-2 at 2-7.
[40] PG&E-2 at 2-16.

Q WHAT ARE CLECA'S PROPOSED MARGINAL ENERGY COSTS?

A CLECA proposes the following MECs by TOU period (also shown in *Summary of Recommendations portion* of this testimony), based on aggregating actual CAISO NP-15 day-ahead prices for calendar year 2024 without adjustment:

Table 3-5: CLECA's Proposed MEC's by TOU for 2024 (cents/kWh) [41]

CAISO - NP15 | 2024

Line No.	TOU Rate Period	Voltage Level		
		Transmission	Primary Distribution	Secondary Distribution
1	Summer Peak	6.684	6.810	7.147
2	Summer Partial-Peak	3.943	4.017	4.216
3	Summer Off-Peak	3.076	3.134	3.289
4	Winter Peak	5.456	5.559	5.834
5	Winter Off-Peak	4.367	4.449	4.669
6	Spring Super Off-Peak	0.741	0.754	0.792
7	Bundled Load-Weighted Annual Average	4.474		

These values are load-weighted averages of the hourly CAISO NP-15 day-ahead prices observed during 2024, classified into TOU periods as defined in PG&E's testimony.[42]

RENEWABLE ENERGY CERTIFICATE (REC) ADDER

Q WHAT DO PG&E AND CAL ADVOCATES PROPOSE FOR THE REC ADDER?

A Both PG&E and Cal Advocates propose to add a REC Adder to the MECs before computing the Generation Marginal Energy Cost Revenue (GMECR). The REC Adder is intended to represent the cost associated with the RPS program. Both parties derive their REC Adder from the PCIA MPB multiplied by the 44 percent RPS compliance requirement in 2024.[43] PG&E

[41] CLECA Workpaper 1 available by email upon request. Illustrative tables are based on estimates; where they differ from the written testimony, the written recommendations prevail.
[42] PG&E-2 at 3-7.
[43] Cal Advocates at 1-9.

uses the 2024 *Forecast* RPS Adder of $31.73 per MWh, producing a REC Adder of $13.96 per MWh. Cal Advocates uses the 2024 *Final* RPS Adder of $54.56 per MWh, producing a REC Adder of $24.01 per MWh.[44]

Notably, PG&E does not mention the REC Adder in its testimony. They state:

> The GMECR for a bundled customer class is calculated by multiplying the hourly MEC by the corresponding hourly load of that bundled customer class.[45]

Whereas Cal Advocates states:

> PG&E then adds this [REC Adder] value to each hourly MEC value, and multiplies these hourly sums by hourly load for each customer class, to calculate each class's generation marginal energy cost revenue (GMECR).[46]

Thus, PG&E's MEC-to-GMECR "equation" is missing a step and its testimony is missing descriptions of the methodology and assumptions embedded in the REC Adder. This lack of transparency is itself a concern — an adder that materially increases generation marginal energy cost revenues warrants explicit discussion and justification in testimony.

Q DOES COMMISSION PRECEDENT REQUIRE THE REC ADDER?

A No. The current REC Adder methodology was established in D.21-11-016, which ordered a REC value and REC Adder approach based on the PCIA MPB "to be applied during this [TY 2020] GRC cycle."[47] However, the Commission expressly contemplated revision, stating, "This REC value and REC adder methodology may be revisited in PG&E's next GRC Phase 2

[44] PG&E-2, Chapter 3, workpaper model, "IN_REC" tab. The REC Adder mechanism is not discussed in PG&E's testimony text.
[45] PG&E-2 at 3-6.
[46] Cal Advocates at 1-9.
[47] D.21-11-016, at 41.

proceeding."[48] Thus, CLECA appropriately proposes to revisit both the methodology and value of the REC Adder.

Q IS THE PROPOSED REC ADDER CONSISTENT WITH MARGINAL COST PRINCIPLES?

A No. The REC Adder is fundamentally an embedded cost concept that is inappropriate to apply to hourly marginal energy costs. RPS resources are typically procured under long-term power purchase agreements with bundled energy and renewable attributes. In fact, most of these contracts are long-term per the RPS program requirement that 65% of procurement must be derived from contract durations of at least ten years.[49] The costs of these resources are historical contract costs — embedded costs — that are inextricable with the underlying portfolio of procured energy, not marginal costs.

Q WHAT IS WRONG WITH APPLYING A REC ADDER ACROSS ALL ENERGY USAGE?

A The REC Adder mechanism takes a single REC price, multiplies it by a fixed percentage of all energy, and spreads the resulting cost across all hours regardless of what resource was actually at the margin in each hour. This is conceptually identical to embedded energy production cost ratemaking, in which the fuel and operating costs of a particular generation type are built into rates without regard to what resource was actually at the margin in each particular hour. Applying a flat adder to a percentage of all MWh is fundamentally an embedded cost approach, not a marginal cost approach.

[48] D.21-11-016, at 41.
[49] CPUC, 60% RPS Procurement Rules: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/rps/rps-compliance-rules-and-process/60-percent-rps-procurement-rules.

This embedded cost approach also distorts TOU price signals by spreading the adder uniformly across all hours rather than considering the hours where renewable generation is actually at the margin. The result is a loss of accuracy in TOU prices — undermining one of the core purposes of marginal cost ratemaking.

Q DOES APPLYING AN EMBEDDED COST ADDER TO MARGINAL ENERGY COSTS PRODUCE REASONABLE RESULTS?

A No. The unreasonable results confirm the problem. With 2024 CAISO NP-15 prices as the MEC basis, adding PG&E's REC Adder of $13.96 per MWh increases GMECR by 31%. Cal Advocates' adder of $24.01 per MWh increases GMECR by 54%.[50] The resulting conclusion of adopting these results – that the State's renewable energy compliance mandate increases wholesale energy costs by 31%-54% – is not reasonable.

Mixing an hourly MEC with an embedded, historical contract cost derived REC adder predictably produces distorted results. An MEC for a given hour—particularly when a natural gas unit is on the margin—already reflects the full short-run marginal cost of the marginal generator: fuel, variable O&M, carbon compliance costs, and any other incremental operating expenses associated with the highest-cost unit dispatched in that interval. By definition, marginal cost constructs used for resource dispatch and marginal rate design isolate the cost of the last unit needed to serve load. They intentionally exclude the lower-cost inframarginal resources that were operating in that same hour. Superimposing an embedded REC cost onto the marginal gas unit therefore double-counts and materially overstates the true cost of serving load in that hour. The REC purchase cost cannot be incurred from the marginal gas generator; it

[50] Percentages derived by dividing the proposed REC Adder by CLECA's proposed average MEC of $44.74/MWh.

is associated with renewable generation that did not set the marginal clearing price in that hour.

To incorporate REC costs to hours in which a renewable resource was not at the margin in a manner that is internally coherent, one would have to assume that 44% of the hourly energy is procured bundled from a renewable resource capable of producing a REC at its own lower marginal energy cost, with the remaining 56% supplied by the marginal resource.

That implies a blended cost construct. But this proportional allocation is fundamentally inconsistent with marginal energy cost ratemaking. Marginal pricing does not reflect a weighted average of resource types; it reflects the cost of the single marginal unit setting price in that hour. This tension exposes the flaw in the proposed methodology. One cannot simultaneously rely on a pure marginal cost construct for energy and then layer on an embedded, portfolio-based REC adder without violating the internal logic of marginal cost rate design.

Q IS THE PCIA MARKET PRICE BENCHMARK AN APPROPRIATE BASIS FOR THE REC PRICE?

A No. The PCIA calculation is "intended to equalize cost sharing between departing load and bundled load"[51] — in other words, it relates to the embedded generation costs of the incumbent utilities and other load serving entities required to report transactions to the Commission. The PCIA calculation is designed to determine whether there are potential stranded costs in the utility's generation costs. It is not an hourly calculation, nor is it a marginal calculation. Thus these embedded costs are inappropriate for hourly marginal cost ratemaking.

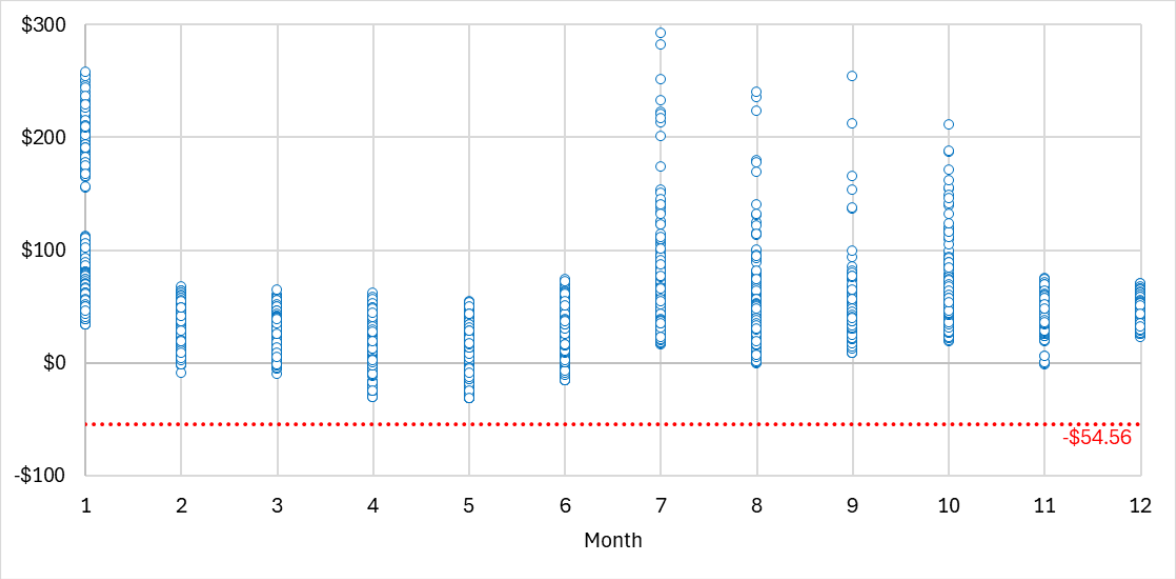
[51] D.18-10-019, slip op. at 3.

The PCIA MPB RPS Adder methodology further compounds the problem. The benchmarking process examines a cross-section of RPS contracts taken from the benchmarking year and compares it to the utilities' historical contracted costs.[52] The MPB's sample of RPS contracts is restricted to "bundled, short-term (under ten-years), index-plus, Portfolio Content Category 1 (PCC-1) transactions."[53] This excludes fixed-price PPAs with bundled RECs, and PCC-2 and PCC-3 transactions, and most notably, bundled contracts ten years or longer, which must comprise a majority of RPS portfolios. Applying an RPS Adder derived from this narrow subset to all marginal energy costs is entirely inappropriate for ratemaking.

Cal Advocates argues that the Final RPS Adder "better captures market dynamics and observed curtailment in 2024" and "produces lower spring off-peak MEC values . . . reflecting lower negative pricing during curtailment hours."[54] Indeed, the proposed floor price is significantly lower than what was observed in the market. As seen in Figure 3-1 below, PG&E's territory NP-15 market prices throughout 2024 did not approach Cal Advocates' floor of -$54.56. This underscores the disconnect between Cal Advocates' proposal and reality.

[52] D.19-10-001, slip op. at 13–14.
[53] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/community-choice-aggregation-and-direct-access/calculation-of-the-market-price-benchmarks-2024-2025.pdf p. 2.
[54] Cal Advocates at 1-9.

Figure 3-1: CAISO Hourly Day-ahead Prices vs. Cal Advocates' Floor ($/MWh)[55]



Finally, both proposed benchmarks are from a historical contract date range that include transactions significantly prior to the Test Year (2024) and also **exclude** significant transaction periods occurring within the Test Year as shown in Table 3-6.

Table 3-6: PCIA Benchmark RPS Adders and Contract Date Ranges

Party	PCIA Benchmark RPS Adder	Contract Date Range[56]
PG&E	2024 Forecast	Sep 2022 – Aug 2023
Cal Advocates	2024 Final	Dec 2022 – Aug 2024

Q ARE PG&E'S AND CAL ADVOCATES PROPOSALS A DEPARTURE FROM HISTORICAL NORMS?

A Yes. These proposed MPB prices are not only distorted by artifacts of the MPB methodology, but they are also clear outliers from historical MPB values. The historical MPB-derived REC price prior to 2023 ranged between $12.63 and $17.35 per MWh, as shown in Cal Advocates Testimony and reproduced here in Table 3-7.

[55] CLECA Workpaper 6 available by email upon request. Each point represents a CAISO NP-15 day-ahead hourly price during that month.
[56] Cal Advocates footnote 24 at 1-5.

Table 3-7: Forecast and Final RPS Adders from 2019 to 2025 (PCIA Market Price Benchmark Studies) ($/MWh)[57]

Year	Forecast RPS Adder		Final RPS Adder	
	Value	*Annual Change*	*Value*	*Annual Change*
2019	--	--	$16.44	--
2020	$17.35	--	$15.10	-8%
2021	$14.49	-16%	$14.23	-6%
2022	$13.56	-6%	$13.24	-7%
2023	$12.63	-7%	$30.30	129%
2024	$31.73	151%	$54.56	80%
2025	$71.24	125%	--	--

The 2024 values used by both PG&E and Cal Advocates represent a historically extreme spike driven by short-term market forces that has already abated, as current PCC1 market prices are trading below $14.[58] Cal Advocates mistakes this spike for a sustained upward trend, pointing to the 2025 Forecast values as further confirmation[59] — but those values reflect the same MPB transaction window (Sep 2023 - Aug 2024) and thus the same non-representative subset of REC transactions.

Moreover, because Load Serving Entities (LSEs) can use PCC1, PCC2, and PCC3 RECs to meet RPS compliance obligations, the weighted average compliance cost is substantially lower than the PCC1-only price the MPB reflects. Table 3-8 below shows the components and weighted average compliance cost for RPS compliant procurement based on recent trading prices.[60]

[57] Cal Advocates Table 1-2, at 1-8.
[58] CLECA Workpaper 8 available by email upon request. Based on Karbone, Inc. CAISO Weekly Forward Curves, REC pricing data for Compliance Year 2026, year-to-date through February 23, 2026 (subscription platform; data on file with CLECA).
[59] Cal Advocates at 1-7: "Forecast Adder values have more than doubled each year from 2023 to 2025".
[60] CLECA Workpaper 8 available by email upon request. Based on Karbone, Inc. CAISO Weekly Forward Curves, REC pricing data for Compliance Year 2026, year-to-date through February 23, 2026 (subscription platform; data on file with CLECA).

Table 3-8: Weighted Average RPS Compliance Portfolio Cost ($/MWh)

Type	Mid Price	Compliance Share[61]	Share x Price
PCC1	13.73	75%	10.30
PCC2	10.24	15%	1.54
PCC3	3.78	10%	0.38
		Weighted Avg =	12.22

Q WHAT DOES CLECA RECOMMEND?

A CLECA's primary recommendation is to eliminate the REC Adder entirely. Applying embedded costs is antithetical to marginal cost ratemaking. It distorts price signals between classes and distorts TOU rate differentials by spreading a fixed cost across all hours. The CAISO day-ahead prices that CLECA proposes as MECs already reflect renewable generation that set marginal clearing prices — there is no need to layer an embedded cost adder on top.

If, however, contrary to CLECA's primary recommendation, the Commission decides to include a REC Adder, two modifications to a REC Adder must be made to conform to marginal cost principles. First, rather than applying a fixed adder to a percentage of all energy, the REC Adder should be applied only to those hours in which a REC-eligible generator is at the margin. This respects marginal cost principles by applying the adder in the hours where renewable generation is actually the marginal resource, rather than spreading it across all hours.

Second, the REC price should reflect actual market conditions rather than a PCIA MPB derived outlier result. Based on current weighted average trading prices for PCC1, PCC2, and PCC3 RECs, CLECA proposes a REC price of $15 per MWh, applied only during hours where renewable generation is the marginal resource. This approach is based on observable market

[61] Cal. Code Regs. Tit. 20, § 3204 - RPS Procurement Requirements (c)(3) specifies 75% minimum PCC1 and 10% maximum PCC3. Since PCC3 is lowest-cost and PCC1 is highest-cost, the lowest-cost compliant portfolio would have 75/15/10 allocation among PCC1/2/3.

data and respects marginal cost principles to a further extent than the PG&E and Cal Advocates proposals.

4. MARGINAL GENERATION CAPACITY COSTS

PG&E'S PROPOSED MGCC

Q WHAT IS PG&E'S PROPOSED MGCC FOR THE RATE CASE CYCLE?

A PG&E proposes the following MGCC for the 2023-26 rate case cycle is shown below:

Table 4-1: PG&E's Proposed MGCC[62]

PG&E Proposal: Marginal Generation Capacity Cost

	2024	2025	2026	2027	2028	2029
AGCC	$65.03	$ 66.92	$ 105.41	$ 108.45	$ 95.75	$ 84.40
MGCC	$86.51					

Q WHAT IS THE BASIS FOR PG&E'S PROPOSED MGCC?

A PG&E's MGCC is based on the Net Cost of New Entry (Net CONE) methodology, which calculates the annualized cost of building a new generation resource to meet incremental capacity needs, net of the revenues that resource would earn in the energy market. Matching its 2020 GRC Phase II methodology adopted in D.21-11-016, PG&E assumes that the marginal generation resource is a front-of-the-meter, four-hour lithium-ion battery energy storage system.

PG&E derives the battery's capital cost and Fixed O&M assumptions from the CPUC's 2022-2023 IRP Preferred System Plan inputs, which in turn rely on cost projections from the National Renewable Energy Laboratory (NREL). Using these inputs along with financial

[62] PG&E-2 at 2-30.

assumptions including a 20-year asset lifetime, PG&E calculates a levelized annual gross CONE for the battery. PG&E then estimates the battery's Energy Gross Margin (EGM) — the net revenue from energy market arbitrage — using a perfect-foresight battery optimization model that dispatches the battery against forecasted hourly prices. The forecasted hourly prices are determined from PG&E's proprietary MALARD forecast model. Battery revenues are weighted 80 percent to SP15 and 20 percent to the PG&E DLAP region. These revenues are then levelized over the 20-year battery lifetime. PG&E calculates the net cost for each year by subtracting the levelized EGM from the levelized gross CONE.

The net cost for each year is then divided by the battery's ELCC to produce an Annual Generation Capacity Cost (AGCC) for each year from 2024 through 2029. The ELCC values are interpolated from a solar and storage ELCC function in the CPUC's 2022-2023 IRP. The resulting ELCC values drop from 81 percent in 2024 to 51 percent by 2026 (thus AGCCs tend to increase from 2024). Finally, from this series of AGCC's, PG&E produces a levelized MGCC for each year using the 6-year period starting in that year and an after-tax weighted average cost of capital of 7.18 percent.

PG&E'S BATTERY OPTIMIZATION ASSUMES EXCESSIVE BATTERY CYCLING

Q HOW DOES PG&E'S MGCC INCORRECTLY RELY ON EXCESSIVE BATTERY CYCLING?

A PG&E's MGCC analysis relies on a battery optimization model that dispatches the battery more intensively than PG&E's own cost assumptions and its explicit testimony support. The resulting mismatch materially and wrongly overstates the dispatch availability and economic performance of the resource.

> PG&E acknowledges that its optimization model does not explicitly model battery degradation. Instead, it relies on NREL-based cost assumptions incorporated into the IRP framework[63]. PG&E further explains: Costs in IRP 2022-2023, indicate that a higher Fixed O&M cost may be needed if the battery is operating at a much higher rate of cycling than one cycle per day.

Indeed, the referenced NREL paper specifies that its Fixed O&M cost is "consistent with providing approximately one cycle per day."[64]

However, PG&E's dispatch results show significantly more intensive use than one cycle per day. As seen in Table 4-2, the battery was discharged an average of 6.8 to 8.6 hours per day over the years 2024-2035 in SP, and 6.3 to 8.2 hours per day over those years in NP. For a 4-hour battery, a cycling rate of one cycle per day would limit discharge to 4 hours per day. Thus, the implied cycling rates are 1.58 to 2.15, or 58% to 115% higher than the IRP one-cycle-per-day rate that PG&E cites for its cost basis.

Table 4-2: Average Daily Charge & Discharge (hours) of MGCC resource (4-hour battery)[65]

Line No.	Year	SP		NP	
		Charge	Discharge	Charge	Discharge
1	2024	6.9	6.9	6.5	6.5
2	2025	6.8	6.8	6.3	6.3
3	2026	7.1	7.1	6.6	6.7
4	2027	7.0	7.0	6.5	6.5
5	2028	7.4	7.4	6.9	6.9
6	2029	7.9	7.9	7.5	7.5
7	2030	8.4	8.4	8.1	8.1
8	2031	8.3	8.3	7.8	7.8
9	2032	8.4	8.4	8.0	8.0
10	2033	8.6	8.6	8.2	8.2
11	2034	8.5	8.5	8.2	8.2
12	2035	8.2	8.2	7.9	7.9

Despite this, PG&E contends that the battery cycle count entailed in this dispatch is "very close to 1."

[63] PG&E Response to CLECA_013-Q001.
[64] Cost Projections for Utility-Scale Battery Storage: 2023 Update p. 7.
[65] GRC-2023-PhII_DR_CLECA_015-Q003.

Q WHY DOES PG&E'S REPORTED CYCLE COUNT DIFFER FROM THE CYCLE COUNT IMPLIED BY ITS OWN DISPATCH DATA?

A Through data requests, it was revealed that this discrepancy is due to PG&E's reliance upon the following novel definition of "battery cycle":

> A battery cycle counts only if the battery is fully charged and then some hours later fully discharged. If a battery is partially charged and then partially discharged, that is not considered a battery cycle. A battery may be partially charged then partially discharged multiple times per day and this activity would not be considered a battery cycle unless the battery was fully charged and subsequently fully discharged.[66]

Q AS OPPOSED TO PG&E'S PROPOSED NOVEL DEFINITION, WHAT IS A MORE REASONABLE DEFINITION OF "BATTERY CYCLE"?

A A battery cycle is commonly defined as each time the discharged throughput energy (MWh) equals the energy capacity (MWh) of the battery. This view is summarized in *The BESS Book: A Cell to Grid Guide to Utility-scale Battery Energy Storage Systems*:[67]

> By dividing the discharged energy by the initial capacity of the battery being measured, the throughput can be expressed in cycles.[68]

The BESS Book further states that "The most common battery warranties allow for one cycle per day,"[69] reinforcing the notion that this definition of cycle limit is industry standard and the basis for NREL's (and therefore PG&E's) fixed operating and maintenance cost estimate.

[66] GRC-2023-PhII_DR_CLECA_015-Q001 p 2.
[67] Authored by Drew Lebowitz, P.E., Principal and Managing Director at PowerSwitch, an energy storage advisory firm in Portland, OR; Sean Duffy, Project Design Engineer specializing in utility connection at Akaysha Energy; and Swetha Sundaram, Director of Energy Storage Project Design at RWE Clean Energy. Published in 2024, the book covers the fundamentals of utility-scale lithium-ion battery systems. Positive reviews by several industry professionals are shown at thebessbook.com ("Reviews").
[68] D. Lebowitz et al., The BESS Book: A Cell-to-Grid Guide to Utility-Scale Battery Energy Storage Systems (2024), § 3.9.
[69] *Ibid.*

Q WHAT OTHER SUPPORT IS THERE FOR THIS DEFINITION?

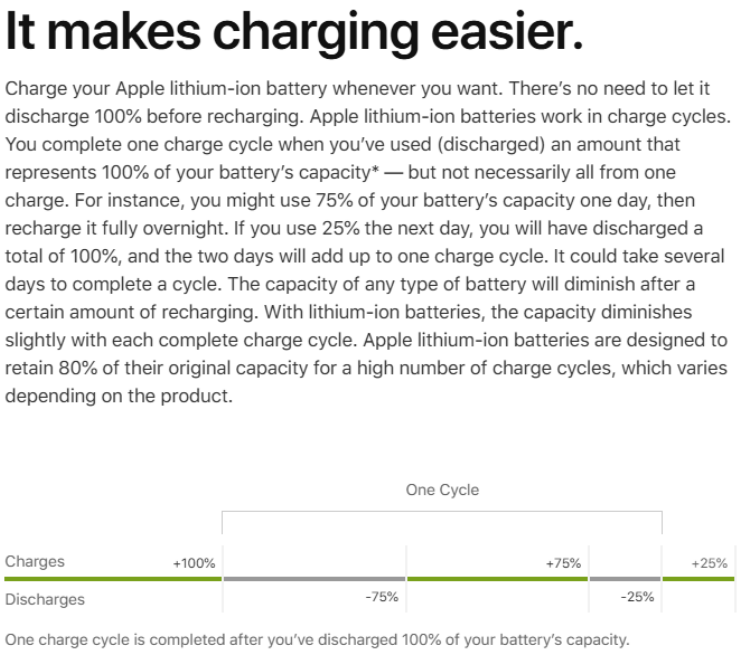
A This common definition of battery cycle has also been invoked by the NREL directly. In an NREL article on EV batteries filed within 6 months of the NREL study used for PG&E's cost basis,[70] a battery degradation model is put forth which includes cycle-based degradation.[71] The cycle-based term has a coefficient for "Equivalent Full Cycles", with that term being defined by the following:

> For example, the 4-hour storage capacity of batteries that together deliver a maximum of 0.25 GW until depletion will be 1 GWh… The short-term storage capacity and power capacity are defined based on a typical 1-time equivalent full charging/discharge cycle per day (amounting to 4 hours of cumulative maximum discharge power per day).[72]

This same definition of battery cycle is also used in small-scale consumer Lithium-ion batteries: Apple, Inc explains it clearly on its website (Figure 4-1). While this is a different application than utility-scale battery storage, the throughput-based definition of a cycle is industry standard across lithium-ion battery contexts.

[70] https://docs.nrel.gov/docs/fy23osti/82683.pdf.
[71] *Ibid p. 7.*
[72] *Ibid p. 3.*

Figure 4-1: Apple, Inc.'s definition of "charge cycle" for lithium-ion batteries[73]



Q IS PG&E'S NOVEL DEFINITION REASONABLE?

A No. PG&E's use of its novel definition is unreasonable because it deviates from the basis of PG&E's cost estimate, and because it assumes that the significant partial usage has *no effect* on cycle count and thus no effect on degradation or operating cost. Consider the following example, shown in Table 4-3, below:[74]

[73] Batteries - Why Lithium-ion? - Apple.
[74] PG&E Response to CLECA_015-Q001.

Table 4-3: Example PG&E Dispatch from DR 15-Q001

Hour	State of Charge %	Charge Position	Charge MWh		Discharge MWh
1	0%	0			
2	25%	1	1.17		
3	50%	2	1.17		
4	75%	3	1.17		
5	100%	4	1.17		
6	75%	3			1
7	50%	2			1
8	75%	3	1.17		
9	50%	2			1
10	25%	1			1
11	50%	2	1.17		
12	75%	3	1.17		

Hour	State of Charge %	Charge Position	Charge MWh	Discharge MWh
13	50%	2		1
14	25%	1		1
15	50%	2	1.17	
16	75%	3	1.17	
17	50%	2		1
18	25%	1		1
19	50%	2	1.17	
20	75%	3	1.17	
21	50%	2		1
22	25%	1		1
23	50%	2	1.17	
24	25%	1		1
	Sum		**14.04**	**11**

This example shows the PG&E MGCC battery following a hypothetical day's dispatch, where its State-of-Charge (SoC) – the ratio of the energy currently stored in a battery to its usable energy capacity, typically expressed as a percentage – goes from 0% to 100%, then 75%, then oscillates between 75% and 25% for the rest of the day. The total discharge of this 4 MWh battery is 11 MWh, constituting 2.75 cycles by the common definition (11 MWh discharged / 4 MWh storage capacity). But under PG&E's novel definition, since the battery never returned to 0% SoC, this dispatch would constitute **zero cycles**, as confirmed by PG&E.[75]

Consider that this battery could follow this dispatch pattern for day 1. Then, on day 2, it could follow an almost-identical dispatch – but starting at 25% (rather than 0%) and skipping the charge in hour 1. Thus, on day 2, the same amount of discharging would have occurred: 11

[75] PG&E Response to CLECA_015-Q001 Answer 001-c, Example No. 3.

MWh or 2.75 cycles. And yet, by PG&E's definition, since the battery never fully discharges, day 2's dispatch would also constitute zero PG&E cycles.

This same dispatch pattern can repeat indefinitely from Day 2 onward, as shown in Table 4-4. The battery would average 2.75 cycles per day, well beyond the most common warranty[76] – and yet by PG&E's definition, this battery would never accumulate a single cycle.

Table 4-4: Indefinite Dispatch with Zero PG&E Cycles

	Day 1	Day 2	Day 3	….
Start SoC	0%	25%	25%	25%
End SoC	25%	25%	25%	25%
MWh Discharged	11	11	11	11
Cycles	2.75	2.75	2.75	2.75
PG&E Cycles	0	0	0	0

Q HAS PG&E OFFERED A SECONDARY DEFINITION OF CYCLE?

A Yes. In response to CLECA Data Requests regarding excessive cycling, PG&E offered a secondary definition for battery cycle, the "Depth-of-Discharge method" – but this definition also lacks support in the literature PG&E cites, is not supported in PG&E testimony, and continues to result in excessive cycling materially higher than one cycle per day.

This method, presented at a Meet and Confer held on July 14, 2025 and expanded upon in PG&E's response to a follow-up Data Request,[77] computes the number of "cycles" based on a weighted sum of the battery's discharges:

> The battery degradation weight of the full discharge from 100% charged to fully discharged was set at 1, the weight of a medium partial discharges (from 100% to 25%, 75% or 50% to zero, 100% to 50%, 75% to 25%) were weighted as 0.3, and the shallow partial

[76] D. Lebowitz et al., The BESS Book: A Cell-to-Grid Guide to Utility-Scale Battery Energy Storage Systems (2024), § 3.9: "The most common battery warranties allow for one cycle per day".
[77] PG&E Response to CLECA_015-Q002.

discharges (from 100% to 75%, 75% to 50%, 50% to 25%,and 25% to zero) were weighted as 0.1. [78]

For example, a battery going from 100% to 25% SoC, by the common definition, will have completed 1.00 – 0.25 = 0.75 cycles. But based on PG&E's Depth-of-Discharge definition, that would constitute only 0.3 cycles, since it is classified by PG&E as a "medium partial discharge," weighted at 0.3. PG&E reports that when they apply this method to their battery's simulated dispatch, the average "cycling" rate is approximately 1.20 cycles per day over the 2024-2055 evaluation period.[79] Even under this alternative definition, cycles are 20% higher than once per day, materially higher than industry standard and PG&E's cost basis assumptions.

Q WHERE DID PG&E FIND THIS DEPTH-OF-DISCHARGE CYCLE DEFINITION?

A As support for this second novel definition of battery cycle, PG&E says they "based the weights on industry studies … that battery lifetime degradation of Li-Ion batteries increases exponentially with increase in depth of discharge."[80] However, neither of the cited studies mention this new cycle definition PG&E has adopted.[81,82]

[78] PG&E Response to CLECA_015-Q002, Answer 002, c.
[79] Ibid.
[80] PG&E Response to CLECA_015-Q002, Answer 002, c.
[81] First study cited: Battery University | BU-808: How to Prolong Lithium-based Batteries describes how Depth-of-discharge can *impact* a battery's cycle count but does not define a cycle based on depth-of-discharge.
[82] Second study cited: *Xu, B., Oudalov, A., Ulbig, A., Andersson, G. and Kirschen, D.S., 2016. Modeling of lithium-ion battery degradation for cell life assessment. IEEE transactions on smart grid, 9(2), pp.1131-1140*. Measures the degradation from each "cycle" – with each cycle being either a full-cycle or a half-cycle (full-cycle is an excursion from a lower SoC to a higher SoC, then back to the lower SoC. Half-cycle is half of this "round-trip"). This definition of a cycle is independent of Depth-of-discharge, thus different than what PG&E proposes. Study not attached herein as subscription is required to view.

Q DOES DISPATCH OF 6+ HOURS FOR THE 4-HOUR BATTERY CONTRADICT PG&E'S WRITTEN TESTIMONY?

A Yes. In addition to violating PG&E's cost basis assumptions, this excessive dispatch also contradicts PG&E's written testimony, which states:

> To estimate annual [Energy Gross Margin] for a 4-hour battery, MECs were input to an internal storage perfect-foresight model. Based on day-ahead (forecasted) prices, the model calculates the net revenue. The calculated net revenue is the revenue from **discharging a 4-hr battery during 4 highest-cost hours**, minus the cost of charging in lowest-cost hours. [83]

PG&E affirms in testimony that the 4-hour battery would discharge 4 hours per day – directly contradicting PG&E's unconstrained model which results in 6+ hours per day of discharge (see Table 4-2 above).

The unconstrained dispatch cannot be reconciled with PG&E's own described methodology or cost basis. Correcting it is necessary to make PG&E's model and testimony internally consistent.

Q WHAT ADJUSTMENT TO THE PG&E BATTERY OPTIMIZATION MODEL DOES CLECA PROPOSE TO ADDRESS THIS EXCESSIVE CYCLING?

A CLECA proposes to impose a battery discharge limit of one cycle per day. This is appropriate because it is consistent with NREL's specification of a one cycle per day average and the most appropriate definition of a daily cycle (total discharge per day / battery storage capacity).

Q HOW, TECHNICALLY, DOES CLECA RECOMMEND TO CONSTRAIN BATTERY DISPATCH?

A CLECA proposes to modify the current model's algorithm as follows:

[83] PG&E-02 p. 2-26 (emphasis added).

1. Track the number of discharge steps (hours of discharge) taken in the current day
2. Once the number of steps reaches the battery capacity (i.e. 4 hours of discharge for a 4-hour battery), disallow any further discharge until the current day ends

The proposed modification to PG&E's VBA code, implementing this change, is detailed in CLECA Workpaper 5[84].

Q WHAT IS THE IMPACT OF THIS PROPOSED CONSTRAINT ON THE BATTERY'S AVERAGE DAILY CYCLE RATE?

A Table 4-5 shows the cycle count for each year, both before (unconstrained) and after (constrained) this cycle limit is implemented. This constraint brings average cycle count for each year below 1, ranging from 0.99 to 1.00 cycles per day.

Table 4-5: Cycles per Day: Unconstrained (PG&E) and Constrained (CLECA)[85]

	Unconstrained		Constrained	
Year	SP15	NP15	SP15	NP15
2024	1.71	1.61	0.99	0.99
2025	1.69	1.58	0.99	0.99
2026	1.77	1.66	1.00	0.99
2027	1.75	1.63	1.00	1.00
2028	1.85	1.73	1.00	1.00
2029	1.99	1.88	1.00	1.00
2030	2.10	2.03	1.00	1.00
2031	2.07	1.95	1.00	1.00
2032	2.11	2.01	1.00	1.00
2033	2.15	2.05	1.00	1.00
2034	2.12	2.06	1.00	1.00
2035	2.04	1.96	1.00	1.00

[84] Available by email upon request.
[85] CLECA Workpaper 7 available by email upon request. Cycles per day = Annual discharge (MWh) / Battery capacity (MWh) / days per year.

Q WHY IS THIS PROPOSAL THE MOST APPROPRIATE WAY TO ADDRESS EXCESSIVE DISPATCH?

A CLECA’s proposed modification simply limits the battery's dispatch to bring it in line with the battery's cost basis. PG&E's unconstrained dispatch is clearly excessive — as shown above, it is excessive by over 50% on the industry standard throughput cycle definition basis. PG&E may contend that it is only excessive by 20%, according to its Depth-of-Discharge concept. Either way, PG&E's model dispatches the battery beyond what its cost inputs contemplate.

The alternative to constraining dispatch would be to leave dispatch unconstrained and instead increase the battery cost assumptions to account for the additional degradation and augmentation that more intensive cycling would require. But that approach would necessitate modifying the IRP cost assumptions that PG&E itself selected as its cost basis — introducing additional contested assumptions around degradation rates, augmentation costs, and battery replacement timing that are outside the scope of this proceeding and unsupported by PG&E's existing workpapers. CLECA's approach avoids this complexity entirely: rather than debate the extent of the excess and derive a corresponding cost adder, our proposal simply aligns dispatch with the cost basis PG&E has already adopted. This is the most methodologically straight-forward correction available, requiring no assumptions beyond the cost basis PG&E has already adopted.

PG&E'S FOUR-HOUR BATTERY IS NOT ADEQUATE TO MEET SYSTEM CAPACITY NEEDS DURING PEAK PERIODS

Q CAN PG&E'S PROPOSED FOUR-HOUR BATTERY SUSTAIN OUTPUT THROUGHOUT THE COMMISSION-ADOPTED PEAK PERIOD?

A No. The Commission has adopted a five-hour peak period, from 4:00 PM to 9:00 PM, for PG&E's retail TOU rate schedules.[86] PG&E itself reaffirms this peak period in the current proceeding, proposing to retain the 4:00 PM to 9:00 PM peak definition based on a goodness-of-fit analysis of marginal generation and distribution costs.[87]

A four-hour lithium-ion battery operating at its full rated capacity in kilowatts (kW) will exhaust its stored energy in kilowatt-hours (kWh) after four hours of continuous discharge. A battery that begins discharging at 4:00 PM will be fully depleted by 8:00 PM—one hour before the peak period ends. A marginal capacity resource used to benchmark the cost of capacity should, at minimum, be capable of sustaining full output throughout the period for which that capacity is valued. The four-hour battery does not satisfy that requirement.

Q IS THE FOUR-HOUR BATTERY CAPABLE OF DISPATCHING THROUGHOUT THE CAISO'S RESOURCE ADEQUACY AVAILABILITY ASSESSMENT HOURS?

A No. The CAISO's Availability Assessment Hours (AAH) process identifies the hours of greatest system reliability need and establishes the window during which RA resources must be available under the CAISO's Resource Availability Incentive Mechanism, pursuant to CAISO Tariff Section 40.9.[88] The CAISO derives these hours from an annual technical study of the top five percent of load hours within each month using actual system load data.

[86] D.17-08-030 at p. 24; D.21-11-016 (maintaining 4:00 PM to 9:00 PM peak period for PG&E's 2020 GRC Phase II).
[87] PG&E-2, p. 10-13 ("the Peak period for both summer and winter should remain at 4 p.m. – 9 p.m. at this time").
[88] CAISO Fifth Replacement FERC Electric Tariff, Section 40.9.

The Final 2026 Availability Assessment Hours establish measurement windows of 4:00 PM to 9:00 PM for summer months (June through October) and 5:00 PM to 10:00 PM for non-summer months (November through May).[89] In both seasons, the AAH window spans five hours. A four-hour battery cannot dispatch throughout the entire window in either season.

Q DOES THE COMMISSION'S RESOURCE ADEQUACY SLICE OF DAY FRAMEWORK BEAR ON THE REQUIRED DURATION OF THE MARGINAL CAPACITY RESOURCE?

A Yes. In D.22-06-050, the Commission adopted the Resource Adequacy (RA) Slice-of-Day (SOD) framework, which requires load-serving entities to demonstrate RA compliance on an hourly basis across the full 24-hour day rather than only at a single monthly peak hour.[90] D.23-04-010 subsequently adopted implementation details, including resource counting rules for energy-limited resources.[91] Under this framework, resources counted toward RA must be capable of delivering their qualifying capacity during each hour for which they are shown.

For a storage resource shown during all five hours of the summer peak window from 4:00 PM through 9:00 PM, the SOD energy sufficiency test requires the resource to hold at least five hours of full-capacity energy at the start of the peak window.[92] A four-hour battery holds only four hours of energy at full charge and therefore cannot pass the energy sufficiency test for the five-hour peak window. The SOD compliance framework's requirement that storage resources carry sufficient energy to serve all hours during the peak window they are supplying should be applied to the MGCC proxy resource selection.

[89] D.25-06-048 at pp. 13-15.
[90] D.22-06-050 (adopting 24-hour SOD framework); D.24-06-004; D.24-12-003.
[91] D.23-04-010 at p. 41 (storage resource counting under SOD framework).
[92] Id.

Q DOES PG&E'S BATTERY DISPATCH MODEL RAISE ADDITIONAL CONCERNS ABOUT THE FOUR-HOUR BATTERY'S ABILITY TO DELIVER DURING THE PEAK WINDOW?

A Yes. PG&E's description of its Energy Gross Margin ("EGM") model in testimony and its model outputs both indicate that the battery is not guaranteed to enter the peak window fully charged. The EGM model makes no explicit provision for peak hours as it only seeks to discharge during the highest-priced hours, whether they are peak or not[93]. Thus, if prices are elevated at any time before the 4:00 – 9:00 PM peak relative to the prices during that window, the model will call for the battery to discharge before the window, leaving the battery partially drained to start the peak period.[94]

PG&E's model results corroborate this, as shown in Table 4-6. Over the simulation period, the battery was frequently beginning the Peak Window at less than full charge: it was fully charged at the beginning of the peak period only 58% of the time in NP15 and 35% of the time in SP15. A four-hour battery that begins the 4:00 PM peak window partially depleted will exhaust its remaining capacity even earlier than 8:00 PM, compounding the duration-mismatch problem identified above.

Table 4-6: Frequency of State-of-Charge (SoC) Levels at Beginning of Peak Hours[95]

SoC %	*0*	*25%*	*50%*	*75%*	*100%*
NP15	0%	3%	13%	26%	58%
SP15	8%	8%	23%	26%	35%

[93] PG&E-02 p. 2-26: "discharging a 4-hr battery during 4 highest-cost hours".
[94] Also evident in the algorithm / model supplied by PG&E in response to DR-008; The algorithm is agnostic to TOU.
[95] CLECA Workpaper 7 available by email upon request.

Q WHAT DOES DATA FROM THE IRP PROCEEDING SHOW ABOUT THE DURATION OF THE SYSTEM PEAK CAPACITY NEED?

A Data from the IRP proceeding indicates that the system's peak capacity need extends beyond four hours. The 2022–2023 IRP Inputs and Assumptions document—the same IRP cycle from which PG&E draws its battery cost inputs for this proceeding—shows that after approximately 10–20 GW of battery storage is added to the system, the net peak extends in duration such that four-hour battery resources have insufficient energy to discharge across the full peak, reducing their incremental capacity value.[96] This is reflected in the sharp decline in the four-hour battery's ELCC from 79 percent in 2025 to 51 percent in 2026 in PG&E's own MGCC calculation.

The Commission subsequently adopted the 2023 Preferred System Plan in D.24-02-047, endorsing deployment levels that place battery penetration well into the range where four-hour resources face significant ELCC degradation.[97] This IRP data corroborates the conclusion that a four-hour battery is increasingly inadequate as a proxy for the marginal capacity resource.

Q DOES PG&E'S TESTIMONY ADDRESS THE MISMATCH BETWEEN THE FOUR-HOUR BATTERY AND THE FIVE-HOUR PEAK PERIOD?

A No. PG&E's testimony does not acknowledge, analyze, or attempt to justify the mismatch between the four-hour discharge capacity of its proposed proxy resource and the

[96] 2022–2023 IRP Inputs & Assumptions, Oct. 2023, at p. 156. CLECA raised this concern at the protest stage of this proceeding. See CLECA Protest to A.24-09-014 (Nov. 4, 2024) at p. 4.
[97] D.24-02-047 (Decision Adopting 2023 Preferred System Plan and Related Matters) Table 4 at page 69.

five-hour duration of the Commission-adopted peak period.[98] PG&E presents the four-hour battery as a continuation of the framework established in D.21-11-016 without addressing whether that duration remains appropriate given the Commission's five-hour peak period, the CAISO AAH, the Commission's RA SOD energy sufficiency requirements, or the IRP data indicating a longer underlying peak duration requirement.

Q WHAT IS PG&E'S PEAK CAPACITY ALLOCATION FACTOR METHODOLOGY?

A The Peak Capacity Allocation Factor ("PCAF") is the mechanism PG&E uses to allocate the annual MGCC among customer classes for generation revenue allocation. The PCAF method concentrates cost allocation on the hours of highest system stress—the hours during which the adjusted net load ("ANL") is greatest—on the correct basis that those are the hours that drive capacity procurement costs.[99]

Under the methodology adopted in D.21-11-016, PCAF hours are the hours during which the ANL equals or exceeds 80 percent of the annual maximum hourly ANL.[100] Because this threshold is defined relative to the peak, the number of qualifying hours varies from year to year depending on the shape of the load duration curve—a steeper curve produces fewer PCAF hours. In this proceeding, PG&E proposes to replace the 80 percent threshold with a 95th percentile ANL threshold, which selects the top 5 percent of all hours in the year, yielding a

[98] PG&E-2 at 2-25 through 2-31 (Section F.2). PG&E's testimony does not address the relationship between the four-hour battery and the Commission's five-hour peak period, the CAISO SOD energy sufficiency requirements, or the IRP data on peak duration.

[99] PG&E-2 at 3-12 through 3-14; D.21-11-016, p. 168, Ordering Paragraph 12 (adopting PCAF methodology). The PCAF weight formula assigns each PCAF hour *i* a weight equal to $(ANL_i - T) / \Sigma(ANL_i - T)$ for all PCAF hours, where T is the PCAF threshold. Non-PCAF hours receive zero weight.

[100] PG&E-2 at 3-12.

fixed 438 PCAF hours per year.[101] PG&E contends this produces more stable year-over-year revenue allocation results.[102]

Q DOES CLECA'S ANALYSIS OF PG&E'S PCAF WORKPAPER DATA REVEAL INFORMATION RELEVANT TO THE BATTERY DURATION QUESTION?

A Yes. CLECA has reviewed the hourly ANL data underlying PG&E's PCAF calculation.[103] That review reveals a pattern that directly corroborates the concern about the adequacy of a four-hour battery as the proxy capacity resource: On a significant number of days that include any PCAF hours, the system is in a high-ANL condition for more than four hours.

Specifically, CLECA's analysis of the Chapter 3 ANL workpaper data shows the following distribution of PCAF hours per day:

Table 4-7: Distribution of PCAF Hours Per Day[104]

Number of PCAF Hours in Day	Number of Days	Freq
4 or fewer PCAF hours	72	64%
More than 4 PCAF Hours	34	30%
More than 8 hours	7	6%

Of the days that contain at least one PCAF hour, 34 days—approximately 30 percent—contain more than four PCAF hours. On those days, the system is experiencing peak-level ANL conditions for a duration that a four-hour battery cannot fully serve. CLECA's analysis further identifies multiple days in the dataset with eight or more PCAF hours, indicating that on the

[101] PG&E-2 at 3-13 through 3-14 (Section E.4, proposing 95th percentile ANL threshold modification). PG&E-2 p. 3-13, fn. 16 ("This 438 PCAF hours number is calculated by multiplying the total number of hours in a year (generally 8760) times 5 percent. In leap years, PCAF hours number is 440.").
[102] PG&E-2 at 3-13 through 3-14 and fn. 17 (reporting that the 95th percentile method produced an average generation revenue allocation standard deviation of 1.19 percent versus 1.60 percent for the 80 percent of max ANL method during the 2017–2023 period).
[103] CLECA_Workpaper_02_ PCAF Days.
[104] *Ibid.*

most extreme peak days, the system's elevated-ANL condition persists for at least twice the duration of PG&E's proposed proxy resource.

This finding is internally inconsistent with PG&E's own framework. PG&E's PCAF methodology identifies the hours of greatest system capacity stress—the hours that drive capacity procurement costs. A marginal capacity resource that is exhausted midway through a day's PCAF window cannot adequately represent the cost of serving peak capacity demand on that day. PG&E cannot simultaneously argue that PCAF hours correctly identify the period of peak capacity cost and that a resource incapable of serving the full duration of those hours on a significant amount of peak days is an appropriate cost benchmark. The Commission should not adopt a methodology whose cost basis and revenue allocation are in such conflict.

CLECA RECOMMENDS AN EIGHT-HOUR BATTERY AS THE PROXY RESOURCE

Q WHAT DOES CLECA RECOMMEND AS THE PROXY RESOURCE FOR CALCULATING THE MGCC?

A CLECA recommends that the Commission direct PG&E to remodel its MGCC using an eight-hour lithium-ion battery as the proxy resource. As demonstrated above, PG&E's proposed four-hour battery cannot sustain output throughout the Commission's five-hour peak period, cannot pass the Commission's SOD energy sufficiency test for that window, and is inconsistent with PG&E's own PCAF data showing that peak capacity conditions exceed four hours on the majority of peak days. An eight-hour battery addresses each of these deficiencies.

Q WHY DOES CLECA RECOMMEND AN EIGHT-HOUR BATTERY RATHER THAN A FIVE-HOUR OR SIX-HOUR BATTERY?

A A five-hour battery satisfies the Commission's five-hour peak period only under ideal conditions—fully charged at 4:00 PM, discharged at constant full output, with no outages and

no pre-peak cycling. Utility-scale lithium-ion batteries do not operate under ideal conditions. Depth-of-discharge limitations, temperature derating, planned and unplanned outages, and round-trip efficiency losses over battery life all can reduce effective discharge duration below the nameplate rating. PG&E's battery dispatch model includes frequent pre-peak cycling to capture price spikes as previously shown and does not discount battery capacity for planned and unplanned outages.[105] An eight-hour battery provides the margin needed to ensure full-capacity delivery across all five peak hours under realistic operating conditions.

Beyond the operating margin, several independent lines of evidence support an eight-hour resource. The CAISO's Final 2026 Availability Assessment Hours show that the top five percent of maximum load hours regularly span more than five hours per day, with peak loads over eight hours in four of five summer months.[106]

Figure 4-2: 2026 Forecast Frequency of Top 5% of Load Hours[107]

	Hour	15	16	17	18	19	20	21	22	23	Season	Recommendation
MONTH	Jan				8	19	9	1			Winter	HE18-HE22
	Feb				1	18	14				Winter	HE18-HE22
	Mar					4	17	11	5		Spring	HE18-HE22
	Apr				2	4	8	13	7	2	Spring	HE18-HE22
	May					4	10	13	10		Spring	HE18-HE22
	Jun		2	3	5	7	8	6	4	1	summer	HE17-HE21
	Jul	1	3	4	8	8	7	4	2		summer	HE17-HE21
	Aug		2	6	9	12	6	2			summer	HE17-HE21
	Sep	2	4	5	7	7	5	4	2		summer	HE17-HE21
	Oct	1	3	4	7	9	7	4	2		summer	HE18-HE22
	Nov		2	4	14	11	4	1			Winter	HE18-HE22
	Dec				14	14	9				Winter	HE18-HE22

The Commission's RA SOD framework requires resource adequacy across all 24 hours and requires storage resources to demonstrate energy sufficiency across all hours for which

[105] GRC-2023-PhII_DR_CLECA_013-Q001 at 2: "No, the model does not assume any amount of forced outage rate for the battery."
[106] See CAISO, Final 2026 Availability Assessment Hours, at p. 5 (showing top 5% load hours by month and season), available at: https://stakeholdercenter.caiso.com/InitiativeDocuments/Final-Availability-Assessment-Hours-2026.pdf.
[107] https://stakeholdercenter.caiso.com/InitiativeDocuments/Final-Availability-Assessment-Hours-2026.pdf page 5.

they are shown—an eight-hour battery is a substantially more realistic resource to satisfy that requirement than a four-hour or five-hour battery.[108]

The direction of California's resource planning further supports this recommendation. IRP data from the 2022–2023 cycle shows that as battery penetration increases, the net peak extends in duration beyond what four-hour resources can serve, and the Commission's adoption of the 2023 Preferred System Plan endorses deployment levels well into the range where four-hour battery ELCCs decline sharply.[109] A marginal resource proxy should reflect the type of resource that Commission planning processes are driving the market to build in the future that substantially meets system reliability needs, not a resource whose capacity value is rapidly eroding.[110]

Further, in its recent Decision Requiring 2029–2032 Electric Resource Procurement and Transmitting Portfolios for 2026-2027 Transmission Planning Process, the Commission required LSEs to procure 6,000 MW of new net qualifying capacity with online dates starting in 2029 and going through 2032.[111] In adopting this requirement, the Commission specified that at least one-quarter of each LSE's total procurement obligation must come from long-duration storage resources—defined as resources able to discharge for at least eight hours—and/or clean firm resources with capacity factors of at least 80 percent.[112] Batteries with less than eight hours of capacity would not meet this Commission requirement.

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[108] D.24-06-004 (Decision Adopting Slice of Day Resource Adequacy Framework, June 26, 2024); D.24-12-003 (Decision Addressing Slice of Day Implementation Issues, December 12, 2024).
[109] 2022–2023 IRP Inputs & Assumptions, Oct. 2023, at p. 156; D.24-02-047 (Decision Adopting 2023 Preferred System Plan and Related Matters).
[110] See *Supra* Table 4-8 for Effective Load Carrying Capacity (ELCC) of a 4-hour battery on CAISO based on 2023 Preferred System plan, dropping from over 80% in 2024 to under 60% by 2028.
[111] D. 26-02-057 for R. 25-06-019 issued 3/5/2026 at 2.
[112] *Ibid.*

Finally, as demonstrated in CLECA's analysis of PG&E's PCAF workpaper data, peak capacity conditions as identified by PG&E's own revenue allocation methodology exceed four hours on approximately 60 percent of peak days; moreover, there are multiple days exhibiting eight or more PCAF hours. An eight-hour battery is the minimum duration resource capable of serving the full range of peak conditions reflected in PG&E's own data.

Q DOES PG&E'S OWN MARGINAL ENERGY COST TESTIMONY SUPPORT AN EIGHT-HOUR BATTERY AS THE PROXY RESOURCE?

A Yes. PG&E's MEC analysis in PG&E-2, Chapter 2 independently corroborates that the economically relevant dispatch window for batteries aligns with an eight-hour resource.

PG&E's long-term price escalation profile defines an eight-hour "evening peak" spanning Hour Ending 17 through Hour Ending 24—that is, 4:00 PM to midnight. PG&E assumes batteries will be needed increasingly during this during this eight-hour window.[113]

PG&E's MEC dispatch model projections further support this. PG&E states that while batteries contribute toward meeting the evening peak load in 2024, by 2030 "significant overnight and morning peak management" will come from batteries.[114] Figures 2-5 through 2-10 show substantial growth in battery discharge during HE 21 through HE 6 across all seasons from 2024 to 2030—extending well beyond even the eight-hour evening peak window.[115] A proxy resource should be capable of dispatching across the full window that PG&E's own

[113] PG&E-2 at 2-14 (long-term MEC escalation profile defining "Evening peak hours: HE 17-24" with prices assumed to increase at 2 percent annually for years beyond 2035).
[114] PG&E-2, Chapter 2, p. 2-17 ("Batteries contribute towards meeting the evening peak load in 2024 (Figures 2-5, 2-7, and 2-9). As their capacity increases, by 2030, we observe significant overnight and morning peak management coming from batteries."); see also Figures 2-5 through 2-10 (showing growth in battery discharge during HE 21–6 from 2024 to 2030 across all seasons).
[115] *Ibid.*

analysis identifies as most valuable — not just a fraction of it. An eight-hour battery is the minimum duration consistent with PG&E's projected 8+ hour evening window.

Q WHAT ADJUSTMENTS TO PGE'S MGCC DO YOU RECOMMEND TO ACCOMMODATE AN 8-HOUR BATTERY?

A First, in PG&E's Battery Revenue Model (Storage Perfect Foresight Model) we change the input from a 4-Hour, 4 MWh proxy resource to an 8-hour, 8MWh proxy resource.

Second, in the MGCC Calculation found in PG&E's workpapers we change the input for the proxy resource cost (capacity and energy) from a 4-Hour Li-ion Battery Storage to its 8-hour Li-ion Battery Storage equivalent.[116]

Finally, for the ELCC input in the same workpaper, we replace the 4-hour battery ELCC with the 8-hour battery ELCC profile published in the 2024 Avoided Cost Calculator (ACC) tool.[117]

PG&E'S BATTERY REVENUE PRICE ASSUMPTIONS ARE FLAWED

Q HOW DOES PG&E CALCULATE THE ENERGY GROSS MARGIN USED TO OFFSET THE COST OF ITS PROXY BATTERY RESOURCE IN THE MGCC CALCULATION?

A PG&E calculates its proxy battery's EGM by modeling battery revenues using a weighted average of forecasted prices from two CAISO pricing locations: 80 percent of revenues are assumed to come from the SP15 region, which covers Southern California Edison's (SCE) service

[116] CLECA Workpaper 3 available by email upon request.

[117] 2024 Distributed Energy Resources Avoided Cost Calculator v1b, prepared by E3 for the CPUC. File: 2024 ACC Integrated Calculation Inputs v1b.xlsx, Summary Tab. The Commission adopted the 2024 ACC in D.24-08-007 and Resolution E-5328. The ACC is the Commission's primary tool for valuing distributed energy resources and is used across multiple proceedings, including the net energy metering successor tariff (D.22-12-056), demand response cost-effectiveness evaluation (D.20-04-010), and Self-Generation Incentive Program valuations. The ELCC profiles in the ACC are derived from Astrapé Consulting's SERVM model, the same capacity valuation model used in the Commission's Integrated Resource Planning proceeding (R.20-05-003).

territory, located south of Path 26, and only 20 percent from PG&E's own DLAP located north of Path 26. PG&E attempts to justify this weighting by pointing to survey data showing that roughly 80 percent of recently deployed utility-scale battery storage in California is physically located in the SP15 region.[118]

Q IS THE PG&E ASSUMPTION OF 80/20 SP15/PG&E REVENUE WEIGHTING APPROPRIATE?

A The purpose of the MGCC is to estimate the cost net of expected revenues of the marginal capacity resource that PG&E would procure to serve its own customers. PG&E's proxy resource is a hypothetical battery to meet the needs of PG&E's load. By definition, that resource should be sited where PG&E's load is located. PG&E's customers are located entirely north of Path 26 — in PG&E's own service territory. This is not a contested point. In data request GRC-2023-PhII_DR_CLECA_011-Q004, CLECA asked:

> "Please state in terms of load (MWs) the portion of PG&E customers that are located north and the portion of PG&E customers that are located south of Path 26."

PG&E responded:

> "PG&E does not serve any load south of Path 26."[119]

Accordingly, there is no basis for assuming that PG&E's proxy resource earns 80 percent of its revenues by locating south of Path 26 at SP15 prices. Placing the proxy resource in SCE's service territory — solely because batteries have recently been built there in large numbers — confuses where the industry has chosen to invest with where PG&E's marginal resource must actually be located to serve PG&E's load. The proxy resource revenues should reflect the prices

[118] PG&E-2 at 2-27.
[119] Response to Data Request CLECA_011-Q004.

the proxy resource would actually earn when sited in PG&E's service territory to serve PG&E's customers.

Q DOES THE SAME LOGIC APPLY TO ANY BATTERY SITED OUTSIDE OF PG&E SERVICE TERRITORY?

A Yes. The flaw in PG&E's reasoning is not limited to SP15. If the relevant criterion were simply where batteries happen to be deployed in large numbers, one could just as easily argue that PG&E's proxy resource should be placed in Nevada, Washington, or another jurisdiction with import capacity into PG&E's service territory. That reasoning is flawed for any jurisdiction outside of PG&E's service territory; the proxy resource exists to represent the cost of capacity built to serve PG&E customers, not capacity built elsewhere that may or may not be available to PG&E when capacity is most constrained.

Q DOES PG&E APPLY SIMILAR LOGIC TO ITS MEC?

A No. PG&E uses exclusively the PG&E DLAP for its MEC calculation. We believe this treatment is appropriate and should be applied to MGCC revenues consistently. We recommend that the Commission direct PG&E to recalculate its EGM using 100 percent PG&E DLAP prices.

Q ARE THERE OTHER FLAWS IN PG&E'S BATTERY REVENUE PRICE ASSUMPTIONS?

A Yes. The forecasted prices used to generate proxy resource battery revenues are calculated using PG&E's MALARD model and out-year price escalations which forecast MEC hourly energy prices for years 2024 through 2055.[120]

[120] PG&E-2, at 2-12 to 2-14.

As discussed in the MEC section of this testimony, CLECA recommends actual 2024 CAISO prices for the test year MEC because actual prices are available and superior to any model forecast. For battery revenue projections, however, actual prices exist only for the test year — the EGM calculation requires a price forecast extending through 2055. In the absence of a transparent alternative model, CLECA accepts the use of MALARD's forecasted prices for this purpose, subject to the corrections described below regarding the price floor and out-year escalator assumptions.

The reasonableness of the MEC forecast depends critically on the accuracy of its underlying assumptions. PG&E's model is complicated and lacks adequate transparency as previously explained. Multiple, opaque layered inputs all conspire to produce the ultimate forecast MECs. We have concerns about the reasonableness of many of the inputs used to derive the MECs. However, we focus on the two assumptions described below: (1) the renewable curtailment model with a price floor tied to REC prices; and (2) the escalator assumptions for specific time periods used in the out-years beyond 2035.

Q IS PG&E'S FLOOR PRICE ASSUMPTION REASONABLE?

A No. PG&E assumes that the marginal energy price declines linearly as export capacity is exhausted and is ultimately floored at the negative of the prevailing REC price. PG&E proposes a price floor of -$31.73/MWh, derived from the 2024 Forecast MPB. [121]

We find this floor value unreasonable on two grounds. First, the MPB-derived REC price is not an appropriate proxy floor price. The PCIA MPB is designed to serve an embedded cost

[121] PG&E-2 at 2-14.

based regulatory accounting function to estimate the market value compared to historic contract cost by utilities on behalf of bundled customers. It is not fit for purpose to represent the current market value for RECs as previously explained in the MEC and REC Adder sections of this testimony, and produces outlier results counter to established historical trends and current trading prices.

Second, current REC market trading data indicates that REC prices have moderated substantially from elevated post-pandemic levels and have returned to historical norms. Recent PCC1 prices as reported by Karbone, Inc.,[122] are below $14/MWh for compliance year 2026.[123] Even if the Commission were to find that PG&E's proposed PCIA MPB historical contract costs derived REC Adder is appropriate for the 2024 TY, such highly elevated outlier REC prices are not a reasonable assumption for a curtailment floor prices going forward when the market has already returned to historical norms.

Q IS CAL ADVOCATES' PROPOSED FLOOR PRICE ASSUMPTION REASONABLE?

A No. Cal Advocates recommends a floor price of -$54.56/MWh based on a more recent MPB price that includes the same not fit for purpose challenges and exacerbates the outlier results even further. Cal Advocates mistakes what is clearly an outlier REC value for a secular trend; indeed, this purported trend has already reversed.

[122] Karbone, Inc. is an established broker having served 5000 clients since 2008 and consistently one of the most awarded brokers for California by Environmental Finance Market Rankings (Environmental Market Rankings 2025: Environmental Finance).

[123] CLECA Workpaper 8 available by email upon request. Based on Karbone, Inc. CAISO Weekly Forward Curves, REC pricing data for Compliance Year 2026, year-to-date through February 23, 2026 (subscription platform; data on file with CLECA).

Using either PG&E or Cal Advocates' PCIA MPB-derived value as the floor in a production cost model produces a price signal that is disconnected from actual market conditions and produces unreasonable outlier results during renewable curtailment hours, which in turn distort the estimated battery revenues and therefore the Net CONE and MGCC.

Q WHAT FLOOR PRICE DOES CLECA PROPOSE?

A CLECA proposes a floor of -$15/MWh which more accurately reflects the current market environment (current prices below $14/MWh[124]) and is aligned with historical norms (Historical PCIA in Table 3-7), thus providing a more reasonable basis for the MEC curtailment price floor.

Q ARE PG&E'S OUT-YEAR ESCALATOR ASSUMPTIONS REASONABLE?

A No. PG&E uses the outputs of the MALARD model in 2035 and escalates prices through 2055. PG&E describes their escalation methodology as follows[125, 126]:

> For years beyond 2035, an escalation rate of 2 percent is employed for MEC calculations. For example, for the evening peak hours (HE 17-24), prices between Monday through Saturday are assumed to increase at the long-term inflation rate of 2 percent each 12 months, in parallel across the hours. During the morning hours (HE 1-8), the hourly prices are assumed to increase at half of the inflation rate. Finally, mid-day prices are held constant at a nominal term from 2036 to 2055.

PG&E's approach creates ever widening prices between the midday hours and late evening hours. However, that assumption is exactly the reverse to what would be expected with batteries as the default capacity resource in the decades to come. Meeting the growing

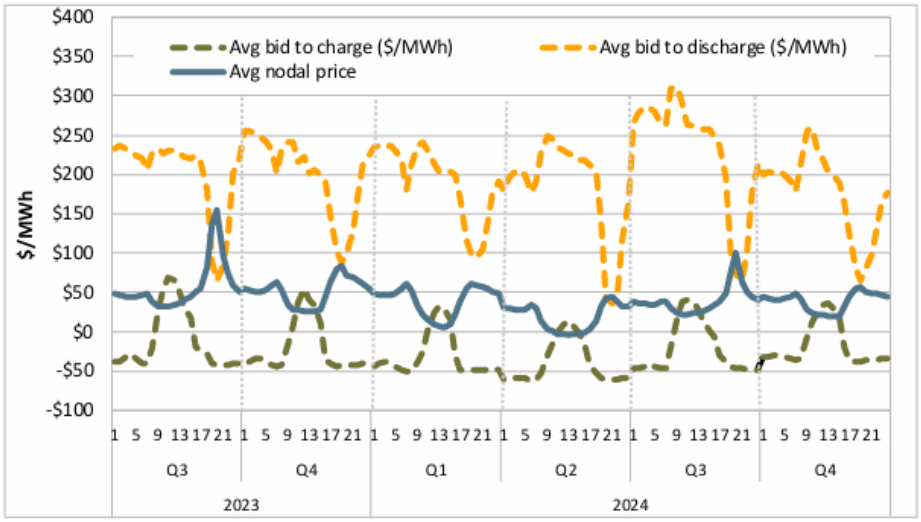
[124] CLECA Workpaper 8 available by email upon request. Based on Karbone, Inc. CAISO Weekly Forward Curves, REC pricing data for Compliance Year 2026, year-to-date through February 23, 2026 (subscription platform; propriety data utilized by CLECA to produce provided aggregate results).
[125] PG&E-2 at 2-14.
[126] Sundays and Holidays have 1% escalation during the morning hours and 0% the rest of the day, per "Out Year Forecast" PG&E presented at Meet & Confer.

capacity needs of California load with batteries is starkly different than the historical reality of capacity resources largely comprised of natural gas peaker plants.

Batteries installed on the system for capacity needs will operate substantially differently than natural gas peaker plants. Batteries require charging which will typically be done during midday which creates upward pressure on midday prices. Once installed, batteries also have lower marginal dispatch costs than natural gas plants and are expected to be cycled daily compared to natural gas peaker plants that sit idle unless the energy price justifies their operation.[127] Batteries are expected to dispatch more often, typically once per day, compared to natural gas peakers. This extra energy provided to the grid will typically occur during late evening hours when prices are expected to be highest.

This tendency to charge mid-day and discharge in evenings is illustrated in Figure 4-3 below, from the CAISO's 2024 Special Report on Battery Storage.

Figure 4-3: Hourly Average Real-time Battery Bids and Nodal Prices (by quarter)[128]



[127] U.S. GAO Report 24-106145: Electricity: Information on Peak Demand Power Plants, May 2024: Figure 1 (p 1) shows average annual peaker dispatch by hour based on EPA data; dispatch is less than 10% of capacity even during peak hours. https://www.gao.gov/assets/gao-24-106145.pdf.

[128] CAISO's 2024 Special Report on Battery Storage Figure 2.5.

As shown in Figure 4-3, above, batteries bid most aggressively for charging (Avg bid to charge) between HE 9 and 17, and bid most aggressively for discharging (Avg bid to discharge) during evening hours (after HE 17). Replacing gas peakers with batteries means increasing the representation of this bidding behavior in the market, which will tend to cause intraday price compression compared to the historical system with natural gas peaker plants as the primary capacity resource.

Q WHAT OUT-YEAR ESCALATOR ASSUMPTIONS DOES CLECA RECOMMEND?

A CLECA recommends a 2% escalator for the midday hours (HE 9-16) and a 1% escalator for evening hours (HE 17-24). These assumptions will lead to a gradual compression of intraday prices as more batteries are installed as the primary capacity resource.

CAL ADVOCATES' PROPOSED REMOVAL OF THE BTM SOLAR CAPACITY FACTOR ADJUSTMENT IS UNSUPPORTED AND SHOULD BE REJECTED

Q WHAT ADJUSTMENT TO PG&E'S ELCC METHODOLOGY DOES CAL ADVOCATES PROPOSE?

A Cal Advocates recommends that PG&E remove the solar capacity factor ("SCF") ratio used to scale behind-the-meter ("BTM") solar capacity before entering the IRP ELCC surface. In PG&E's MGCC workpaper, this ratio converts BTM solar from nameplate MW to grid-scale-equivalent MW by multiplying by the ratio of BTM to grid-scale capacity factors (approximately 0.65). Cal Advocates characterizes this as "double counting," arguing that the ELCC surface "already accounts for the relatively lower capacity factors of the future solar fleet."[129] Removing the SCF ratio increases the total solar input to the ELCC surface by approximately 6 to 10 GW depending on the year, which produces higher ELCC values and a lower MGCC. Cal Advocates'

[129] Cal Advocates Chapter 2, at 24.

analysis shows that this change reduces PG&E's proposed MGCC from $86.51/kW-year to $68.75/kW-year.[130]

Q IS CAL ADVOCATES CORRECT THAT PG&E'S BTM SOLAR SCALING CONSTITUTES DOUBLE COUNTING?

A No. Cal Advocates' argument reflects a misunderstanding of the relationship between the IRP ELCC surface and the inputs used to query it. The 2022-2023 IRP Final Inputs and Assumptions document explains that the ELCC surface was constructed by scaling each solar resource's nameplate MW by the ratio of its capacity factor to a reference capacity factor, then running reliability simulations across a range of total (scaled) solar and battery levels.[131] This means the surface's solar axis is denominated in capacity-factor-adjusted MW — not raw nameplate MW.

When PG&E applies the BTM capacity factor to BTM capacity, it is not applying an additional modeling adjustment on top of the surface. Rather, it is converting its inputs into the units the surface requires. BTM solar must be scaled down because its capacity factor (~0.20) is substantially lower than the grid-scale reference (~0.31)[132], meaning each BTM nameplate MW produces less energy and has less impact on system reliability than a grid-scale MW.

Cal Advocates' proposal to remove this conversion and enter raw BTM nameplate MW into the surface amounts to querying the surface in the wrong units. The capacity factor scaling is not applied twice — it is embedded once in the surface's construction and matched once in PG&E's input preparation. Removing the input-side conversion does not avoid double counting;

[130] Cal Advocates Chapter 2, Table 2-3.
[131] 2022-2023 IRP Final Inputs and Assumptions, at 157.
[132] PG&E Exhibit 2 Workpaper: GRC_2023_PhII_WP_PGE_20251029_Ex02Ch02_MEC_MGCC_CONF, MGCC Input tab Cells E17:M18.

it introduces a unit mismatch that systematically overstates the solar penetration level, thus inflating the resulting ELCC and deflating the MGCC.

Q WHAT IS THE QUANTITATIVE IMPACT OF CAL ADVOCATES' PROPOSED CHANGE ON THE ELCC VALUES USED IN THE MGCC?

A The impact is substantial and grows over time as BTM solar penetration increases. Table 4-8 compares the total solar input and resulting ELCC values with and without the SCF ratio, using data from PG&E's MGCC workpaper:

Table 4-8: Total Solar Input and ELCC Values With and Without SCF Ratio[133]

Year	With SCF (GW)	Without SCF (GW)	Difference (GW)	ELCC With SCF	ELCC Without SCF
2024	32.88	38.76	5.88	81%	84%
2025	36.60	42.94	6.34	79%	84%
2026	38.34	45.04	6.71	51%	74%
2028	42.94	50.63	7.68	52%	71%
2030	49.90	58.16	8.27	50%	58%

As shown, the overstated solar input produces ELCC values that diverge increasingly from PG&E's values in later years, when BTM solar growth is most significant. The results proposed by Cal Advocates are simply not reasonable and not adequately supported. In fact, the ACC produces values for a 4-hour battery that are much more aligned with PG&E's proposal than Cal Advocates' proposal.

Q DOES THE COMMISSION'S AVOIDED COST CALCULATOR ALIGN WITH CAL ADVOCATES' ELCC VALUES?

A No. The Commission's ACC independently calculates ELCC values for a four-hour battery that are far more consistent with PG&E's results than with Cal Advocates' results. The ACC is

[133] CLECA Workpaper 9 available by email upon request.

the Commission-adopted tool for valuing distributed energy resources, developed by E3 under Commission direction and relied upon across multiple proceedings including the net energy metering successor tariff, demand response cost-effectiveness, and Self-Generation Incentive Program valuations.[134] Table 4-9, below, compares the ACC's four-hour battery ELCC with the values produced by PG&E's and Cal Advocates' methods for the years used in the MGCC calculation:

Table 4-9: ACC ELCC vs. PG&E and Cal Advocates Proposals[135]

	4-Hour ELCC		
	ACC	**PG&E**	**Cal Advocates**
2024	79%	81%	84%
2025	79%	79%	84%
2026	66%	51%	74%
2027	52%	52%	72%
2028	48%	52%	71%
2029	45%	51%	65%
Levelized[136]	**63.1%**	**62.5%**	**75.7%**

The ACC's ELCC values are much closer to PG&E's ELCC results. PG&E's method results in the same percentage or slightly higher in all but one year, with levelized average over the relevant period within one percentage point. Cal Advocates' method, by contrast, produces ELCC results dramatically higher—by 2029 44% higher than the ACC results, and 20% higher on a levelized basis.[137]

[134] The Commission adopted the 2024 Avoided Cost Calculator (ACC) in D.24-08-007 and Resolution E-5328. The ACC is used to value distributed energy resources in multiple proceedings, including the net energy metering successor tariff (R.20-08-020, D.22-12-056), demand response cost-effectiveness evaluation (D.20-04-010), and Self-Generation Incentive Program valuations.
[135] CLECA Workpaper 9 available by email upon request.
[136] Levelized using 7.18 percent nominal cost of capital, consistent with PG&E's MGCC calculation.
[137] 2029 Cal Advocates ELCC of 65% minus ACC ELCC of 45% = 20% divided by 45% ACC = 44% higher ELCC.

The close alignment between the ACC and PG&E's results is significant because the ACC represents the Commission's own independently derived assessment of battery ELCCs, based on the same underlying IRP ELCC method, developed through a separate proceeding and analytical framework. The fact that the ACC and PG&E converge on similar ELCCs, while Cal Advocates' method diverges, strongly suggests that it is Cal Advocates' method — not PG&E's — that produces anomalous results.

Q WHAT IS CLECA'S RECOMMENDATION?

A The Commission should reject Cal Advocates' recommendation to remove the BTM solar capacity factor ratio from PG&E's MGCC calculation. PG&E's approach is consistent with the IRP methodology that underlies the ELCC surface, and Cal Advocates has not demonstrated otherwise. Removing the ratio introduces a unit mismatch that artificially inflates ELCC values and depresses the MGCC below its cost-based level.

5. MARGINAL DISTRIBUTION CAPACITY COSTS (MDCC)

THE COMMISSION SHOULD REJECT PG&E'S PROPOSAL TO RECOVER ALL VEGETATION MANAGEMENT (VM) COSTS THROUGH THE EQUAL PERCENT MARGINAL COST (EPMC) SCALAR

Q WHAT DOES PG&E PROPOSE REGARDING THE ALLOCATION OF VEGETATION MANAGEMENT COSTS?

A PG&E proposes to entirely remove vegetation management (VM) expenses from the operations and maintenance loading factors historically used to calculate MDCCs.[138] Since the 2020 GRC Phase 2, when the loading factors approach was last adopted, annual VM expenses

[138] PG&E-2 at 6-9.

have grown from approximately $200 million to over $1.2 billion,[139] inflating the distribution line O&M loading factor and increasing MDCC by approximately 45 percent. PG&E and Cal Advocates propose to recover the removed VM costs through the EPMC scalar.[140]

Q WHAT IS THE EPMC SCALAR?

A The EPMC scalar bridges the gap between marginal cost revenues and the utility's total revenue requirement. Because marginal costs never equal the revenue requirement, the EPMC method applies a uniform multiplier to each class's marginal cost revenue so that every class bears a proportionate share of the residual. The key feature of the EPMC scalar is that it allocates costs that are not tied to marginal costs — costs for which no better allocator exists than each class's overall marginal cost share.

Q WHY SHOULD THE COMMISSION REJECT PG&E'S PROPOSAL TO RECOVER VM COSTS ENTIRELY THROUGH THE EPMC SCALAR?

A Because marginal VM costs are indeed incurred when new distribution circuit infrastructure is built, and the EPMC scalar severs that important cost causation link. PG&E's addition of a new distribution circuit is likely to incur marginal VM costs. Similarly, upgrades to an existing circuit may in some cases involve larger setbacks or new line routing that require new VM costs. PG&E acknowledges that building an entirely new distribution line may incur new VM cost but questions whether the VM costs necessarily scale proportionally to the distribution capital investment and whether new distribution lines incur new VM costs ubiquitously.[141] Whether marginal VM cost is exactly proportional to capital cost or applies in

[139] PG&E-2 at 9-10.
[140] Cal Advocates at 4-10.
[141] PG&E-2, Chapter 6, at 6-10.

each and every case does not nullify that a new distribution line will generally incur new VM costs.

The EPMC scalar is appropriately applied to costs that bear no marginal relationship to any specific cost component. That is not the case here. Cal Advocates characterizes VM expenses as "fixed system costs" that "benefit all customers equally by reducing wildfire risk and preventing system outages."[142] But as the Commission has decided, "Rates should be based on cost causation,"[143] and some portion of VM costs are marginal costs caused by new or upgraded distribution lines.

Q DOES CLECA ACKNOWLEDGE THAT VM COSTS DO NOT PERFECTLY SCALE WITH DISTRIBUTION CAPITAL INVESTMENT?

A Yes. Not every dollar of distribution capital investment produces a proportional increment of VM cost. Adding capacity to an existing distribution line — larger conductor, additional line transformers — may not increase VM costs at all.[144] On this point, CLECA, PG&E, and Cal Advocates agree, and it is the reason the loading factor approach is imperfect.

But PG&E's response to that imperfection is to abandon cost causation altogether. Rather than propose a better marginal allocator that more precisely captures the relationship between distribution infrastructure and VM costs, PG&E proposes to dump these costs into the EPMC residual — the mechanism specifically designed for costs with no marginal cost basis. That is not an improvement; it replaces an imperfect marginal cost signal with no marginal cost signal at all.

[142] Cal Advocates Chapter 4, at 4-10 to 4-11.
[143] Decision 23-04-040 Electric Rate Design Principle 3.
[144] PG&E-2, Chapter 6, at 6-9 to 6-10.

Q WHAT DOES CLECA RECOMMEND?

A The Commission should reject PG&E's proposal and retain a proportion of VM cost that is associated with distribution capacity additions in the O&M loading factors. The previously approved loading factor approach imperfectly captures VM cost causation, but it does allocate these costs appropriately through circuit MDCC to the customer classes that actually use distribution circuit infrastructure. PG&E's concern that the acknowledged marginal VM cost that may occur for new distribution lines cannot be accurately reflected in the MDCC does not follow then that **all** VM costs are non-marginal.[145]

CLECA recommends PG&E provide an assessment of the marginal VM costs associated with distribution capacity upgrades along with underlying data for stakeholders to review, with a resulting proportion of VM costs to apply through the loading factor and the remainder recovered through the EPMC. This approach is consistent with general marginal cost rate making where the identified marginal cost of serving incremental load is assigned by cost causation with the remainder to EPMC. It is uncommon for the marginal costs to match 0% or 100% of revenue requirement. In the absence of such an updated cost causation-based approach, no party to this proceeding has proposed a superior marginal cost allocator for VM costs to the historic loading factor approach. Until one is developed, the previously approved loading factor approach is the most reasonable available — it preserves the link between VM costs and distribution circuits, and it is consistent with prior Commission-approved treatment.

[145] PG&E-2, Chapter 6, at 6-11.

6. MARGINAL CUSTOMER ACCESS COSTS (MCAC)

CLECA SUPPORTS PG&E'S PROPOSED REPLACEMENT COST NEW LESS DEPRECIATION (RCNLD) METHOD FOR CALCULATING THE MCAC

Q WHAT METHOD SHOULD THE COMMISSION ADOPT FOR CALCULATING MCAC?

A CLECA supports PG&E's use of the RCNLD method for calculating MCAC, and recommends the Commission reject Cal Advocates' proposed New Customer Only (NCO) method.[146]

Q WHAT IS THE DIFFERENCE BETWEEN THE TWO METHODS?

A Both methods estimate the cost of the equipment that connects a customer to the utility system — the transformer, service drop, and meter. The difference is in how each method treats that equipment at existing customer premises. The RCNLD method values existing connection equipment at its depreciated replacement cost — applying a depreciation factor based on the average age of the equipment to the current cost of a new installation — and then calculates an annualized rental cost for that equipment as a weighted average across new and existing customers in each class. The NCO method assigns a marginal cost only to equipment installed for physically new connections during the test year, assigning a marginal cost of zero to all existing equipment. It then divides the cost of those new connections across all customers in the class.

[146] Cal Advocates at 3-2.

Q WHY DOES CLECA SUPPORT THE RCNLD METHOD?

A Because existing customer access equipment has a marginal cost. The service this equipment provides to one customer is service it cannot simultaneously provide to another. This is true regardless of when the equipment was installed or for whom. The RCNLD method captures this by measuring what it costs, in economic terms, to provide one customer with access for one year. The NCO method does not.

Q CAL ADVOCATES STATES THAT THE NCO METHOD DOES NOT TREAT EXISTING CUSTOMER ACCESS EQUIPMENT AS VALUELESS. IS THAT CONSISTENT WITH THE NCO METHOD'S TREATMENT OF THAT EQUIPMENT?

A No. Cal Advocates acknowledges that existing connection equipment has "utility (or intrinsic value)" to the customer it serves.[147] But Cal Advocates then asserts that "there is no marginal cost associated with the connection equipment's utility."[148] This latter assertion cannot be true so long as the equipment could serve an alternative use – for example, by the equipment relocating or by another customer taking the current customer's place.

Consider the analogy to rental property. The building provides value to the current tenant. That building – though it cannot be easily moved – has an alternative use in that it could be rented to another tenant. As such, the marginal cost of renting to the current tenant is the opportunity cost of not renting to other tenants. The landlord doesn't ignore this marginal cost just because it's not a cash expense – a rational landlord still charges rent based on the value of the property, and does not rent the property for free just because the cost of constructing the building was already "sunk".

[147] Cal Advocates at 3-8.
[148] *Ibid.*

Customer access equipment works the same way. The transformer, service drop, and meter at an existing premises provide ongoing service; the next customer to occupy that premises will receive that service at no new immediate capital outlay but not at no marginal cost.

Q IS THE NCO METHOD CONSISTENT WITH MARGINAL COST PRINCIPLES?

A No. A marginal cost is the cost of providing one additional unit of service — here, one customer-year of access. Under the NCO method, the numerator is the capital cost of connecting only new customers added during the test year, while the denominator is all customers in the class. The resulting per-customer value, applied to a single customer, does not recover the cost of actually providing that customer with access. A calculation that cannot recover its own unit cost is not producing a marginal cost — it is producing an average allocation of new hookup expenditures across the existing customer base.

7. REVENUE ALLOCATION AND RATE DESIGN

CLECA SUPPORTS PG&E'S PROPOSAL FOR COLLECTION OF WILDFIRE COSTS

Q DOES CLECA SUPPORT PG&E'S PROPOSED COLLECTION OF WILDFIRE HARDENING CHARGE COSTS?

A Yes. We observe that wildfire hardening costs are fundamentally distribution-related costs, incurred to protect and harden PG&E's distribution infrastructure. Strictly speaking, a cost-causation analysis would support allocating these costs consistent with how other distribution costs are allocated. However, PG&E does not propose to change the existing allocation methodology for the Wildfire Hardening Charge, which continues to follow the special wildfire, catastrophic events, and hazardous substance allocator adopted by the

Commission in D.21-11-016 and held for the duration of the associated bonds.[149] With respect to rate design, PG&E proposes to continue the treatment established by D.23-11-005, recovering the Wildfire Hardening Fixed Recovery Charge through fixed customer and demand charges rather than volumetric energy charges, and reasonably proposes caps on customer charges for transmission-voltage customers on Schedule B-20-T in the interest of bill stability. We support that approach as a reasonable implementation. Departing from allocation and rate design methodologies established by Commission decision and embedded in bond financing structures would be inappropriate in this proceeding, and we therefore do not recommend any modifications to PG&E's Wildfire Hardening Charge proposals at this time

CLECA SUPPORTS PG&E'S ECONOMIC DEVELOPMENT RATE PROGRAM WITH RECOMMENDED ENHANCEMENTS

Q WHAT IS THE ECONOMIC DEVELOPMENT RATE?

A The Economic Development Rate ("EDR") is an electric rate discount program authorized under Public Utilities Code Section 740.4(a), which requires the Commission to authorize public utilities to engage in programs to encourage economic development.[150] PG&E's EDR program offers qualified businesses a discounted electric rate to attract new businesses to California, retain businesses considering leaving the state, and support the expansion of existing operations.[151] The program uses a three-tiered discount structure based on local unemployment rates, with greater discounts available in areas with higher unemployment.

[149] PG&E-3 at 2-5: Table 2-3 provides a summary of the current allocation methods for other functional revenues that PG&E is not proposing to adjust in this proceeding (Wildfire Hardening Charge listed as item 8 in the table).
[150] Pub. Util. Code § 740.4(a).
[151] PG&E-3 at 8-1.

Q WHAT IS PG&E'S PROPOSAL FOR THE EDR IN THIS PROCEEDING?

A PG&E proposes to continue its existing EDR program structure with the three rate reduction tiers adopted in its 2020 GRC Phase 2: 12 percent (Standard Tier), 18 percent (Mid-Enhanced Tier), and 20 percent (Enhanced Tier).[152] The primary change PG&E proposes is to increase the program cap from 150 MW to 200 MW, reflecting the shift to a four-year rate case cycle. PG&E notes that it has been on pace to exhaust its 150 MW cap before receiving a decision in this proceeding, as occurred in the prior cycle when the cap was exhausted in 2021.[153] PG&E also proposes minor updates to the generation and distribution allocation factors for the rate reduction, and proposes to maintain the separate 5 MW cap for small businesses. The five-year contract term for individual EDR customers would remain unchanged.

Q DOES CLECA SUPPORT CONTINUATION OF THE EDR PROGRAM?

A Yes. CLECA strongly supports continuation and expansion of the EDR program. As discussed earlier in this testimony, PG&E industrial rates now exceed 300 percent of the average industrial rates in neighboring western states, and this gap has grown dramatically in recent years.[154] The consequences of this rate disparity are not hypothetical. The recently announced closure of Anheuser-Busch's Fairfield Brewery — a facility that had operated since 1976 and employed 475 full-time workers — is a stark illustration of the economic and emissions leakage that California faces when businesses can no longer compete here.

The EDR program is a critical tool for counteracting these pressures. PG&E's own data demonstrates the program's effectiveness: since 2014, 144 projects have signed EDR contracts,

[152] PG&E-3 at 8-4.
[153] PG&E-3 at 8-1.
[154] See discussion of CLECA member operations and rate affordability in Section 2, supra.

creating or retaining approximately 21,000 jobs and generating over $184 million in annual recurring revenue that benefits all ratepayers through contribution to margin.[155] CLECA supports PG&E's proposed increase of the program cap from 150 MW to 200 MW, and supports a higher cap of 300 MW as explained below.

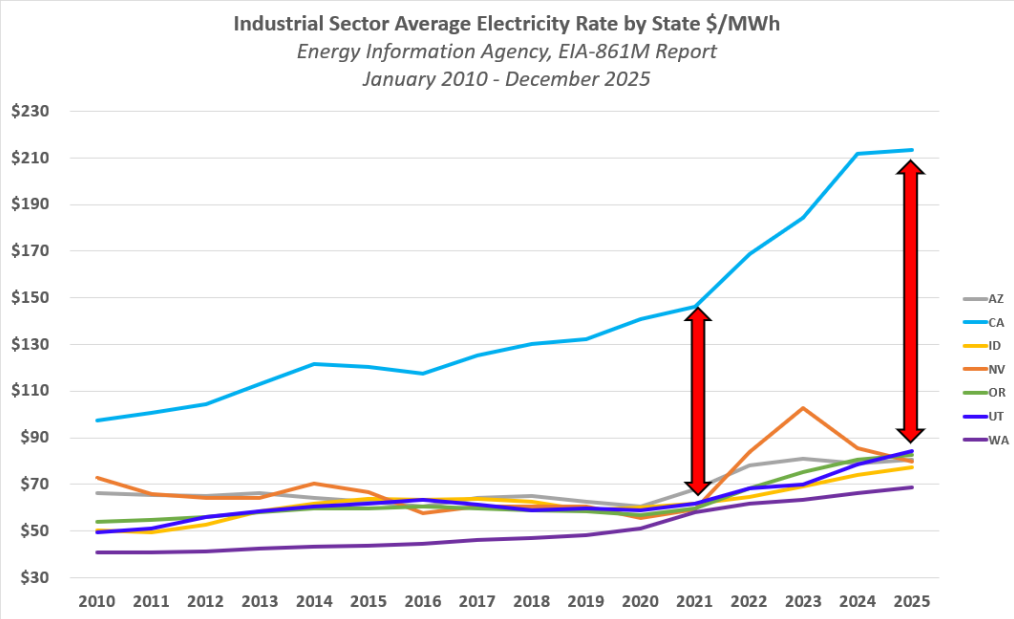
Q IS THE CURRENT EDR DISCOUNT SUFFICIENT TO ADDRESS CALIFORNIA'S COMPETITIVENESS CHALLENGES?

A Not always. While the EDR program is valuable and necessary, the current discount levels do not fully overcome California's cost disadvantage. PG&E's 2022 survey of EDR applicants provides a telling example: one customer that was approved for the EDR ultimately decided not to locate in California, citing high commercial, wage, and labor costs.[156]

The rate gap between California and neighboring states has also grown since the last GRC, as shown in Figure 71.

[155] PG&E-3 at 8-5.
[156] PG&E-3 at 8-8.

Figure 7-1: Rate Gap Between CA and Neighboring States[157]



When industrial rates are over 300 percent of those in neighboring states, a 12 to 20 percent reduction — while helpful —still leaves California facilities at a significant cost disadvantage. The rate differential has only grown since the current tier structure was established, yet PG&E proposes no increase in the discount percentages. CLECA urges the Commission to consider whether deeper discounts or additional program enhancements are warranted in light of the continued deterioration of California's economic competitiveness.

Q WHAT DOES CLECA RECOMMEND REGARDING THE EDR CONTRACT TERM?

A CLECA recommends that the EDR contract term be extended to at least ten years. While CLECA appreciates PG&E's commitment to continuing the EDR program, a five-year term is insufficient for the capital planning and reinvestment decisions that the EDR program is designed to influence. Major industrial operations considering whether to locate, expand, or

[157] U.S. Energy Information Administration Historical State Data, EIA-861M Monthly Electric Power Industry Report (released: 2/24/2026).

remain in California are evaluating investments in capital equipment with multi-decade useful lives. A longer term of rate certainty would better align with these industrial capital planning horizons and would strengthen California's competitiveness in attracting and retaining these investments.

This is especially important for attraction and expansion projects, where a company is deciding among competing states for a new facility. As PG&E's testimony documents, the program has been successful at attracting facilities that might otherwise have located in Nevada or other lower-cost states.[158] Retention projects similarly would benefit as the unfortunate decision to close a facility often aligns with the need for major capital upgrades which also require long term investment horizon. A ten-year commitment would make the state's incentive package materially more competitive and provide the certainty that businesses need to commit to California for the long term.

Q WHAT DOES CLECA RECOMMEND REGARDING THE RATE TIERS?

A CLECA supports PG&E's use of a tiered discount structure that aligns the depth of the discount to the vulnerability of the recipient and the benefit to the state. In addition to considering the economic needs of geographic areas, CLECA recommends that the Commission adopt the Emissions-Intensive and Trade-Exposed (EITE) designation as a qualification for the Enhanced Tier discount, regardless of local unemployment rates.

[158] PG&E-3 "EDR Successes: Customers Choosing PG&E Service Territory" at 8-15.

The Commission has identified EITE customers as those entities in industrial sectors that qualify for Industry Assistance under CARB's Cap-and-Trade Regulation.[159] These industries face both high energy costs and intense competition from producers in jurisdictions without comparable climate policies, meaning they cannot pass through increased electricity costs to their customers. These are precisely the businesses most at risk of relocating out of state — the customers the EDR program is designed to retain.

Using the EITE designation as an Enhanced Tier qualification would provide an objective, administrable criterion grounded in an existing state regulatory framework, rather than relying solely on geographic unemployment rates that may not capture the competitive pressures most relevant to industrial retention. Recognizing the EITE designation in the EDR tier structure would align the Commission's rate design objectives with the state's broader emissions leakage prevention policies and ensure that the more competitive rates achieved through the EDR reach the businesses that need them most.

Q DOES CLECA SUPPORT PG&E'S PROPOSED INCREASE TO THE PROGRAM CAP?

A CLECA supports PG&E's proposal to increase the program cap from 150 MW to 200 MW, and recommends a further increase to at least 300 MW. PG&E's own experience demonstrates why a larger cap is warranted: the 150 MW cap was exhausted in 2021, before the end of the prior rate case cycle,[160] preventing PG&E from enrolling additional qualifying businesses during a period when California's competitiveness challenges were only intensifying. A 200 MW cap

[159] CPUC D.14-12-037, p. 4 (adopting the definition from D.12-12-033, which construes "emissions-intensive and trade-exposed" under Pub. Util. Code § 748.5 to mean entities in industrial sectors eligible for Industry Assistance under CARB's Cap-and-Trade Regulation, listed by NAICS code in Cal. Code Regs., tit. 17, § 95870 *et seq.*).
[160] PG&E-3 at 8-9.

risks the same outcome over a four-year cycle, particularly as California's rate disadvantage continues to grow and demand for the program increases accordingly.

CLECA's view is that, in principle, no qualifying customer should be excluded from the EDR program. If a business meets the program's eligibility criteria and the EDR is a material factor in its decision to locate, expand, or remain in California, turning that business away undermines the very purpose of Public Utilities Code Section 740.4. Every qualifying customer that is denied an EDR contract represents a potential loss of jobs, economic activity, tax revenue, and contribution to system costs — costs that are then borne by remaining ratepayers.

CLECA recognizes, however, that the Commission and PG&E have legitimate needs to plan and budget for the revenue impact of EDR discounts. A cap of at least 300 MW would better balance those administrative needs against the growing demand for the program, while reducing the likelihood that qualifying businesses are turned away during the rate case cycle.

Q DOES CLECA HAVE OTHER RECOMMENDATIONS REGARDING THE EDR PROGRAM?

A Yes. CLECA stresses the importance of program continuity across GRC cycles. Uncertainty about whether the EDR program will be available as a new rate case cycle approaches can significantly delay or derail a project. PG&E's proposal to continue the program until December 31, 2027, or until a decision is rendered in Phase 2 of PG&E's 2027 GRC, whichever is later, is a reasonable approach and CLECA supports clear language ensuring that there is no gap in program availability for investment planning purposes.

CLECA SUPPORTS PROGRESS TOWARD COST-OF-SERVICE RATES WHILE MITIGATING

POTENTIAL RATE SHOCKS

Q WHAT IS CLECA'S POSITION ON PG&E'S PROPOSED REVENUE ALLOCATION TRANSITION AND CAL ADVOCATES' PROPOSED RATE COLLARS?

A CLECA supports PG&E's proposal to transition toward full cost-of-service revenue allocation. PG&E proposes to move one-quarter of the way to full cost each year over four years, with a cap limiting the total bundled rate change for any class to 8 percent — roughly 1.9 percent per year on a compounded basis.[161] For classes that are far from their cost of service, this means the transition will not be completed in a single four-year cycle; PG&E has indicated it plans to revisit marginal costs and revenue allocations in the 2027 GRC Phase 2 with the intent to continue the transition.[162]

As the Commission recognized in the previous Phase 2 decision:

> As a matter of basic fairness, customer classes that are less expensive to serve should enjoy the benefit of that status, and those that cost more should see that reflected in their rates.[163]

And, as put forth in the introduction of this testimony, marginal cost-based rate signals provide an important economic signal for energy consumption and investment.[164]

PG&E's glidepath with the 8 percent cap strikes a reasonable balance between making meaningful progress toward cost-based rates and providing rate stability.

[161] PG&E-3 at 2-12.
[162] *Ibid.*
[163] D.21-11-016, p. 162, Conclusion of Law 2.
[164] *See supra, "2. Introduction: Marginal Cost Basis for Revenue Allocation and Rate Design".*

Q WHY DOES CLECA OPPOSE CAL ADVOCATES' PROPOSED 3 PERCENT COLLAR?

A Cal Advocates proposes a 3 percent collar on total bundled average rates and a 6 percent collar on distribution average rates.[165] CLECA acknowledges Cal Advocates' concerns about affordability, and notes that all customer classes have legitimate affordability concerns, but opposes adoption of the overly restrictive collars Cal Advocates proposes.

A collar both caps rate increases and floors rate decreases. While CLECA agrees that transition mechanisms are appropriate to mitigate rate shock, the collar Cal Advocates proposes is problematic for two reasons.

First, the 3 percent cap component is unnecessarily restrictive given that PG&E's 8 percent cap over 4 years already provides meaningful protection against rate shock. Under PG&E's proposal, no class would see a bundled rate increase of more than about 1.9 percent per year on a compounded basis. Cal Advocates' 3 percent cap over the full four-year period — roughly 0.75 percent per year — would make only marginal progress toward cost-of-service rates, extending the period over which some classes subsidize others well beyond what is necessary.

Second, the floor component of the collar would limit rate *decreases* to 3 percent. Under PG&E's full-cost allocation, several customer classes — including Medium and Large Light and Power, Schedule B-19, and Streetlighting — are currently paying significantly more than their cost of service. For example, PG&E's analysis shows Streetlighting rates would decrease by over 20 percent under a full-cost allocation.[166] Cal Advocates' collar would cap that

[165] Cal Advocates at 5-8.
[166] PG&E-3 Table 2-4 at 2-12.

relief at just 3 percent over four years — meaning these customers would continue to overpay for years beyond what cost-of-service principles justify.

Q WHAT DOES CLECA RECOMMEND?

A CLECA recommends the Commission adopt PG&E's proposed four-year glidepath with an 8 percent cap on total bundled rate changes. This approach balances the competing objectives of making meaningful progress toward cost-of-service rates and providing reasonable rate stability during the transition. CLECA notes that, in principle, the goal should be to reach full cost-of-service allocation as expeditiously as practicable. Caps and collars, while sometimes necessary as a transitional tool, by definition prolong departures from cost-based rates. The Commission should be cautious about adopting transition mechanisms that are more restrictive than necessary, as inaccurate price signals delay the efficient grid utilization the Commission's own rate design principles are designed to promote.[167]

8. CONCLUSION

Q WAS THIS MATERIAL PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A Yes, it was.

Q INSOFAR AS THIS MATERIAL IS FACTUAL IN NATURE, DO YOU BELIEVE IT TO BE CORRECT?

A Yes, I do.

[167] See D.23-04-040 Principles iii. "Rates should be based on cost causation" and viii. "Rates should avoid cross-subsidies that do not transparently and appropriately support explicit state policy goals".

Q INSOFAR AS THIS MATERIAL IS IN THE NATURE OF PROFESSIONAL OPINION OR JUDGMENT, DOES IT REPRESENT YOUR BEST PROFESSIONAL OPINION OR JUDGEMENT?

A Yes, it does.

Q DO YOU ADOPT THIS TESTIMONY AS YOUR SWORN TESTIMONY IN THESE CONSOLIDATED PROCEEDINGS?

A Yes

Q DOES THIS CONCLUDE YOUR TESTIMONY?

A Yes.

APPENDIX A

QUALIFICATIONS OF SAM HARPER

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Sam Harper. My business address is Harper Advisory LLC, 9002 Six Pines Drive, Shenandoah, TX 77380.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am a consultant in the field of energy markets and policy. I am employed by Harper Advisory LLC.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A I have extensive experience in energy procurement, utility regulation, ISO/RTO governance, renewable energy development, and demand response. I have direct experience with commercial energy arrangements, demand response, and the stakeholder processes in PJM, MISO, ERCOT, CAISO, IESO, CENACE, and various unorganized markets. In my current role as a consultant, I advise organizations that engage across the energy supply chain, including large energy consumers for whom energy is a significant percentage of their cost of production.

Prior to consulting, I was the Director of Energy of North American operations for Gerdau, a major steel producer with significant energy requirements and active demand response participation. From 2013-2022, I held a variety of positions for Gerdau, which included Regional Energy Manager and Assistant Vice President of Operations for Gerdau's subsidiary load serving entity. My responsibilities included demand response operations, RTO/ISO stakeholder process, utility regulatory intervention, commercial energy contract negotiations,

commodity risk management, and renewable energy development. Before that, I was employed from 2008-2013 by ArcelorMittal, a global steel producer, ending my tenure as the Sourcing Manager of Electricity for US Operations. During that time, I created and managed a load serving entity and curtailment service provider in the PJM territory.

I was elected in 2025 to represent the Commercial and Industrial (C&I) customer sector on the Regional Organization for Western Energy (ROWE) Nominating Committee to seat its first independent board. I was elected each year from 2016 through 2021 to the Board of Directors of the Electric Reliability Council of Texas (ERCOT). I served on the Human Resources and Governance Committee throughout my tenure, and in 2021 was elected Vice-Chair. I served during the Storm Uri reliability crisis in February 2021 and its aftermath. From 2017-2020 I served on the Advisory Board for the Renewable Development Fund of Minnesota.

I earned a Bachelor of Science degree in Business Administration from the University of Illinois at Urbana-Champaign in 2008, graduating with Honors.

CERTIFICATION

I, the undersigned, hereby certify, pursuant to Rule 13.7(e) of the Rules of Practice and Procedure of the CPUC, under penalty of perjury under the laws of the State of California, that the foregoing is true and correct to the best of my knowledge, and that this Certification was executed on this 9th day of March at Tervuren, Belgium.



By: _____
Name: Sam Harper
Title: Consultant to the California Large Energy Consumers Association

APPENDIX B

Data Request Attachments

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response

PG&E Data Request No.:	CalAdvocates_004-Q001
PG&E File Name:	GRC-2023-PhII_DR_CalAdvocates_004-Q001
Request Date:	December 2, 2024
Requester DR No.:	CAL ADVOCATES-004
Requesting Party:	Public Advocates Office
Requester:	Kimiko Akiya/Nathan Chau/James Lau/Sarah Meyerhoff
Date Sent:	December 13, 2024
PG&E Witness(es):	Eshan Singh

SUBJECT: MARGINAL ENERGY COSTS AND MARGINAL GENERATION CAPACITY COSTS

Marginal Energy Costs (MEC) Calculations

Documentation of MEC Calculations

QUESTION 001

Please provide an updated version of the Excel-based workpaper[1] which includes the additional documentation requested below. For each item, please make sure files include all formulas and that formulas are intact such that all relevant inputs are properly linked so any value change applied to the inputs are carried through to the results. Please also ensure that this version of the workpaper includes the additional documentation on Marginal Generation Capacity Costs (MGCC) calculations as requested in questions 12, 13, 14, and 15.

a. Full documentation of the regression formula used to calibrate historic MECs and forecast future MECs.

b. Full documentation of PG&E's modeling of renewable curtailment.

c. Full documentation of PG&E's congestion modeling.

ANSWER 001

Attachment GRC_2023_PhII_WP_PGE_20241018_Ex02Ch02_MEC_MGCC_CONF_2.xlsx to this response contains CONFIDENTIAL information described in the Declaration Supporting Confidential Designation dated December 13, 2024.

1 See workpaper titled "GRC_2023_PhII_WP_PGE_20241018_Ex02Ch02_MEC_MGCC_CONF," (TY2023 GRC2 MEC & MGCC Workpaper).

Please see the attached file:
GRC_2023_PhII_WP_PGE_20241018_Ex02Ch02_MEC_MGCC_CONF_2.xlsx. This workbook has been updated to ensure that the sources are either listed or hyperlinked.

The hourly MECs are an output from PG&E's internal MALARD model, built in MATLAB. The model is complex and cannot be put in an excel format to allow for direct manipulation of inputs and retrieval of outputs. PG&E is providing detailed explanation for the model below.

a. The regression formula used to calibrate the historic MECs and forecast MECs are based on a few predictor variables. The variables used for regression model are:

- Proxy Marginal Cost (PMC)-marginal cost for proxy marginal plant of the hour
- High Threshold of Net Load (NL_Threshold_High)
- Three-hour Ramp of Net Load (NL_3HrRampUp)
- Top 6 hours of the day (TopNLHr_1 to TopNLHr_6)
- Top 3 hours of the morning (MorningTopNLHr_1 to MorningTopNLHr_3)
- Gas Price Spreads for different locations (Basis2Min, BasisLocalNorCal, BasisLocalSoCal)

The regression is multi-variate linear regression model in shifted log form (to handle negative prices smoothly),

$$\log\left(MEC(h) + C\right) = \log\left(\mathrm{PMC(h)} + \mathrm{C}\right) + \sum_{i=1}^{n} A_i x_i\,(h)$$

Where C is a constant used to shift the prices so that MEC+C is nonnegative, h is the hour and n is the number of predictor variables besides PMC, x's are the variables and A's are the coefficients.

Note that the coefficient for $\log\left(\mathrm{PMC(h)} + \mathrm{C}\right)$ is set to 1 in the above equation. This is because MEC or marginal energy cost at hour h is, by definition, the cost of next MW in the margin, which is provided by the plant at the margin and hence marginal plant for that hour. $\mathrm{PMC(h)}$ is derived based on the load in hour h that needs to be met by the gas fleet available at hour h accounting for all other resources in the region of interest, plant capacities and marginal cost ranking given gas/GHG prices and marginal heat rates (answer to question part b will address the cases when net load is low hence gas plants might not be needed and/or there is curtailment).

PG&E's approach is a simplified (hence proxy) version that mimics how the market actually operates. Other things being equal, factors such as gas/GHG prices and plant heat rate changes that impact PMC are expected to affect MEC similarly, that is why PG&E imposes the constraint that the coefficient for PMC variable is 1. The coefficients PG&E got after regressing over data from 01 Jan 2019 to 31 Dec 2023, are provided below:

Optimized coefficients for various inputs considered.

Constant	0.012487063
PMC	1 (forced)
NL_Threshold_High	1.22084E-08
NL_3HrRampUp	3.34202E-06
TopNLHr_1	0.089335166
TopNLHr_2	0.081811278
TopNLHr_3	0.070171128
TopNLHr_4	0.059443566
TopNLHr_5	0.046207677
TopNLHr_6	0.034168479
MorningTopNLHr_1	0.029732082
MorningTopNLHr_2	0.027139146
MorningTopNLHr_3	0.01428485
Basis2Min	0.033336657
BasisLocalNorCal $LB(d,1)$	-0.076405823
BasisLocalSoCal $LB(d,2)$	-0.062694795

Where NL_Threshold_High refers to the square of the portion of CAISO Net Load being higher than threshold value (top 1 percentile). NL_3HrRampUp refers to the difference in CAISO NL over 3 hours duration, TopNLHr reflects six top CAISO net load hours. Similarly, MorningTopNLHR refers to top CAISO NL hours during HE 1 to HE 9. Basis2Min refers to the log difference between the locational gas price (PG&E Citygate for Northern California or SoCal Citygate for Southern California) and the minimum of PG&E Citygate and SoCal Citygate natural gas prices. $LB(d,i)$ is the local gas basis on day d for location i. i=1 for NorCal and i=2 for SoCal.

For Northern California, PG&E uses the log difference between PG&E Citygate and Malin gas prices. For Southern California, PG&E uses the log differences of SoCal Citygate and SoCal Topock prices.

b. PG&E does not have a separate renewable curtailment model. It is simply reflected in the PMC calculation (PMC is the price of the gas plant on the margins, when serving the net load after other resources have been subtracted).

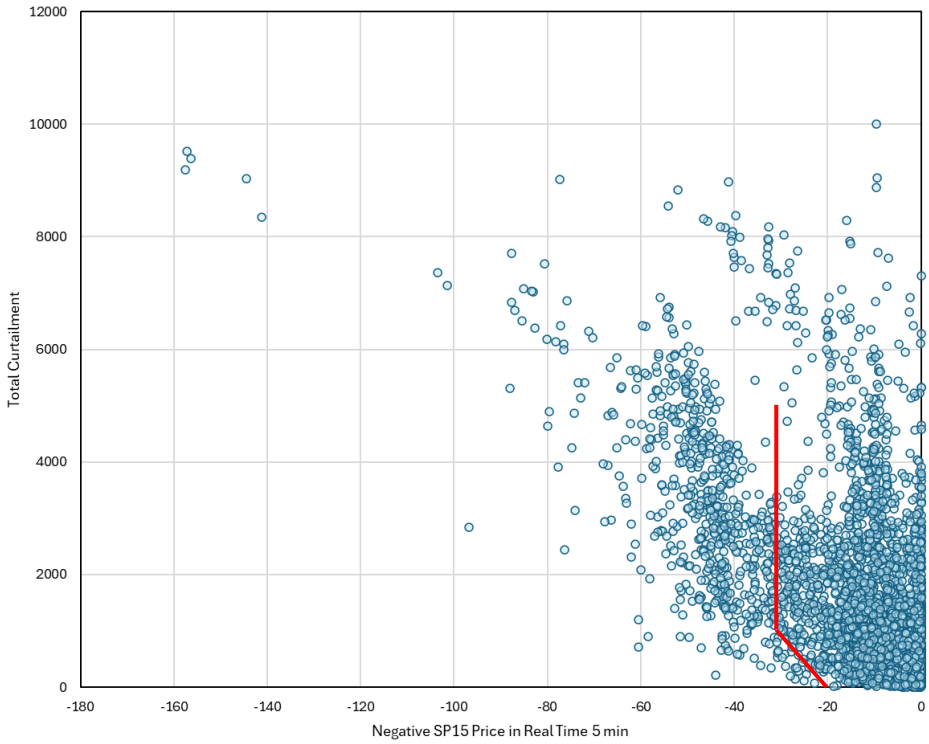
In historical data, CAISO releases aggregated actual curtailment numbers (recently separated out local and system curtailment for wind and solar technology type), though not for Day Ahead market or in more granular details that one can use to pinpoint price impacts at individual locational marginal price level. In forecasting, PG&E assumes that once net load reaches a value that exports cannot absorb the excess generation anymore (i.e. export limit is reached), excess generation requires curtailing and may result in negative prices. There is a floor to this negative price (equal to a fixed value of market price benchmark for Renewable Energy Credit (REC) = $31.73 for all years).

Renewable generators or the beneficiaries of the marginal energy has a tradeoff for the curtailment decision when price is negative: generate and get the credit

from the REC or pay the market to take the energy. They are indifferent if the REC price is equal to negative price in absolute value. In Day Ahead market, we expect that they behave rationally and negative price is truncated at the negative REC in the worst case because at that price level they would exercise the option to curtail. Real time market factors can cause deviation but those are out of scope. Also, PG&E does not observe that energy prices (especially for hubs like NP15, SP15 or the corresponding DLAPs) drop to negative REC immediately when curtailment level is relatively low, potentially due to local constraints and hence local curtailment (as opposed to systemwide curtailment). As a first approximation, PG&E assumes that negative price grows linearly with curtailment level up to a level and floors at negative REC. More specifically, from zero curtailment to 1000MW of curtailed generation, the price decreases linearly from 0 to -$31.73. There are two decisions made here, one is the choice of linear relationship between prices and negative net load, and the other is the MW threshold and floor price. These are based on recent observations in day-ahead and real-time markets. For example, in the scatter plot below using the lowest 5 minute real time price in an hour vs. hourly curtailment using data from 4/1/2022 to 6/30/2024, one can see the negative prices in SP15 grew with total curtailment (total in the sense that it is local plus system curtailments, note that these are actual curtailment numbers and real time prices since we do not have Day Ahead curtailment data). While not perfect, a linear relationship, as argued above, is a first approximation and does a reasonable job in capturing the observations in the scatter plot. With regards to 1000MW threshold, it was chosen as a compromise. While 1000MW may not seem high for recent actual curtailment, it is a reasonable choice for the Day-Ahead market that we strive to capture given that it is equivalent to two sizeable solar plants (500MW each) simultaneously curtailing their total output which is likely to coincide with systemwide curtailment events. Please also refer to answer to question 4a for evidence of price reaching minimum when ANL reach -5000MW based on 2019-2023 historical data in the Day Ahead market. With export limit at around 4000 MW, this implies the 1000 MW curtailment threshold.

Negative prices and curtailment are still active areas for future studies and their impacts will likely comingle with other factors and assumptions. PG&E will reserve further discussion for future.

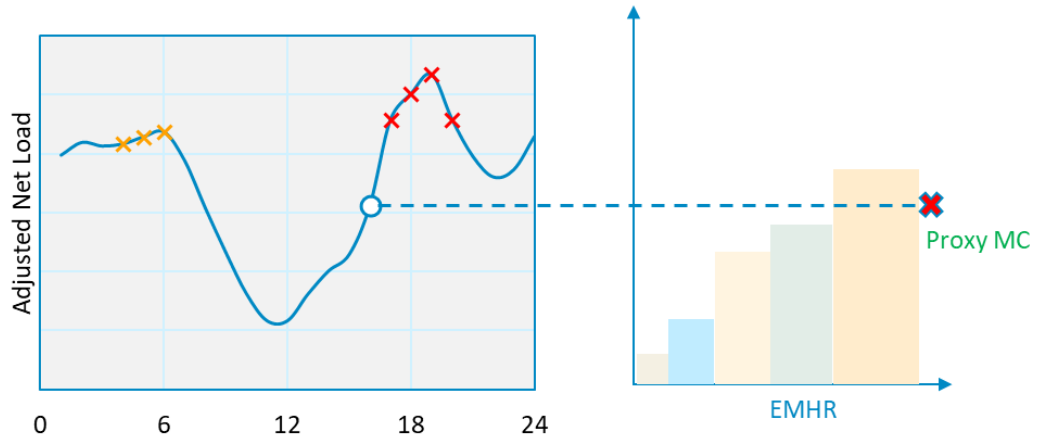
The last assumption is related to the floor price. PG&E explored other prices (including varying prices with each year, as the REC prices in 2024 seemed exaggerated, and may subside with time). PG&E decided to proceed with publicly available price. While the price may seem high initially (MPB prices were mostly less than 20$ in yesteryears), PG&E believes that as we get closer to renewable targets, it will become exceedingly difficult to meet the remaining pledges (law of diminishing returns). PG&E believes that renewable credits will be worth more in those times. Hence a flat price of $31.73 seems justified in our opinion.



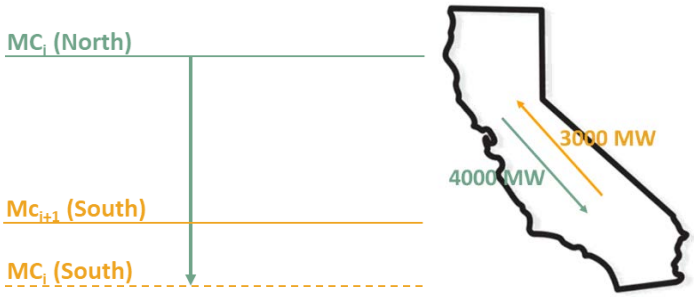
c. With 2023 GRC II, PG&E is incorporating congestion modeling in its MEC estimation for the first time. PG&E believes this has enabled better replication of market reality. PG&E models the congestion along Path 26, a major transmission pathway between northern and southern California.

As described earlier, the model uses the regression of predictor variables on day-ahead prices over a historical period (2019-2023). PMC is calculated as follows:

For each hour, the adjusted net load is calculated as the load, net of other resources which displace thermal generation (such as nuclear, hydro, solar, wind biomass etc. and inclusive of storage dispatch). For the example shown below, HE16 has ANL shown by hollow marker. All operational thermal plants in that hour are arranged in increasing order of heat rate (from most efficient to least efficient), and dispatched in that order, until the ANL is met. The plant which meets the ANL is the marginal plant and the price from it (i.e. heat rate x Gas GHG price) is the PMC.



PMC is the most important predictor (coefficient of 1) of the final MEC. PG&E calculates the PMC for different regions (PGE DLAP and SP15, for instance), based on the thermal plants online in the region. For that, PG&E creates a thermal plant list, with the maximum MW, heat rate, must run flag and region. Must-run plants are dispatched first, irrespective of the heat rate. The remaining plants in the northern and southern California are dispatched in increasing order of heat rate, contributing their MW to the ANL. The PMC is therefore calculated for each region this manner. If there is a disparity in PMC observed for northern and southern California, the ANL between the two regions are modified accordingly (a maximum of 3000MW can flow from south to north and 4000MW vice versa, in accordance with the transmission limits along path 26). Once the transmission limit is reached, PMC cannot be changed any more. If flowing the MW for the maximum allowed from one region to other results in reversing the direction of the price spread between them, PG&E concluded there is no congestion and we calculate the PMC on a CAISO-wide basis (i.e. all plants are available for dispatch as needed for the total ANL for north + south California).



The final PMC calculated from the above exercise is either:

- PMC(PGE DLAP)>PMC(SP15), and 3000MW South to North transmission limit is reached.
- PMC(SP15)>PMC(PGE DLAP), and 4000MW North to South transmission limit is reached.
- PMC(PGE DLAP)=PMC(SP15), when transmission is less than the transmission limits.

In historical day-ahead prices, one often sees disparity between prices in northern and southern California, owing to congestion. It is often the case that the most efficient thermal plant cannot be dispatched because the transmission

limits are reached. PG&E's approach allows modeling such circumstances, as evident in the close replication of historical day-ahead prices.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase II
Application 24-09-014
Data Response

PG&E Data Request No.:	CalAdvocates_004-Q002
PG&E File Name:	GRC-2023-PhII_DR_CalAdvocates_004-Q002
Request Date:	December 2, 2024
Requester DR No.:	CAL ADVOCATES-004
Requesting Party:	Public Advocates Office
Requester:	Kimiko Akiya/Nathan Chau/James Lau/Sarah Meyerhoff
Date Sent:	December 13, 2024
PG&E Witness(es):	Eshan Singh

SUBJECT: MARGINAL ENERGY COSTS AND MARGINAL GENERATION CAPACITY COSTS

Marginal Energy Costs (MEC) Calculations

Documentation of MEC Calculations

QUESTION 002

For each predictor variable used to calibrate PG&E's MEC model, please identify the source and clarify whether the predictor variable reflects California Independent System Operator (CAISO)-wide data or data limited to the default load aggregation point (DLAP) level. These variables include but are not limited adjusted net load (which is used to calculate the marginal proxy price),[1] greenhouse gas (GHG) prices, and gas fleet characteristics.[2]

ANSWER 002

The predictor variables used to calibrate the MEC model are often not direct, but indirectly derived from prices and loads. The list of the predictor variables used for calibrating and forecasting is already provided in the answer to Question 001. These are based on Citygate Gas prices for Northern and Southern California, and CAISO's forecasted (or actual generation as proxy) generation and load. The regional (north and south) fraction of load and generation is also based on CAISO's recommendation. While CAISO provides annual forecasts for load and generation, these are converted into hourly profiles based on RESOLVE. Essentially, PG&E chooses typical day-profiles for each load/generation resource, and extends those over each day of the year. Once the

1 *Pacific Gas and Electric Company 2023 General Rate Case Phase II Prepared Testimony Exhibit PG&E-2 Cost of Service Studies* (PG&E-2), "Chapter 2: Marginal Generation Costs" (Chapter 2) at pp. 2-9 – 2-10.

2 PG&E-2, Chapter 2 at p. 2-10.

ANL is calculated, the other predictor variables, which depend on ANL can be calculated. For example, the peak load hours in the day, or in the morning, the loads with greater than threshold load, etc.

The table below provides the list of all inputs:

Primary Input	Source	Derivative Input used in model	Derivative Input calculations
Gas Prices	Natural Gas Intelligence (NGI) Daily Index for PGE Citygate, PGE Malin, SoCal Topock, Platts (S&P) Daily Price for SoCal Citygate	Basis2Min BasisLocalNorCal BasisLocalSoCal	For North California power price regression, Basis2Min = log(PGE Citygate price)-log(Min(PGE Citygate price, SoCal Citygate price), For Southern California: Basis2Min = log(SoCal Citygate price)-log(Min(PGE Citygate price, SoCal Citygate price); BasisLocalNorCal =log(PGE Citygate price/PGE Malin price) BasisLocalSoCal= Log(SoCal Citygate price/SoCal Topock price)
GHG Prices	CAISO GHG Allowance Price		Convert from $/Metric Ton to $/MMBTU using multiplier of 0.053
Load Forecasts	DA load forecast from CAISO for CA ISO-TAC, PGE-TAC	Use nonPGE system load for Southern California to catch residual loads	Southern California load = CAISO load - PGE Load
Generation Forecasts for Wind and Solar	Use CAISO Actual Wind and Solar	Use sum of NP and ZP for Northern California Wind and	

	generation as Proxy for Day Ahead generation for NP, SP and ZP	Solar, use SP for Southern California Wind and Solar	
Large Hydro Input	CAISO Actual Hydro Generation	Split into North California and Southern California Hydro assume 2:1 ratio	Northern California Hydro = 2/3 * CAISO hydro Southern California Hydro = CAISO hydro /3
Battery MW Dispatch	CAISO Actual Battery Charging and Discharging	Northern and Southern CA battery dispatch	Northern CA battery dispatch = CAISO battery dispatch * 0.2 Southern CA battery dispatch = CAISO battery dispatch * 0.8
Import	CAISO Actual Import	Northern and Southern CA Import	Northern CA Import =CAISO Import * 0.2 Southern CA Import = CAISO Import * 0.8
RPS other than Wind and Solar	CAISO	Northern and Southern CA other RPS	Northern CA Other RPS = CA Other RPS * 0.4 Southern CA Other RPS = CA Other RPS * 0.6
Diablo Nuclear Dispatch	CAISO Day Ahead Award	No change	No change

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase Ph II
Application 24-09-014
Data Response

PG&E Data Request No.:	CLECA_013-Q001
PG&E File Name:	GRC-2023-PhII_DR_CLECA_013-Q001
Request Date:	June 20, 2025
Requester DR No.:	013
Requesting Party:	California Large Energy Consumers Association
Requester:	Cathy Yap
Date Sent:	July 7, 2025
PG&E Witness(es):	Eshan Singh – Engineering, Planning and Strategy

QUESTION 001

Regarding the Battery Optimization model provided to CLECA in response to CLECA-08:

a. Does the model take into account increased battery degradation and its associated cost for those days where the model would have the battery cycle more than one time per day?

b. If yes, please describe in detail how the model takes the increased degradation into account in the battery cost.

c. Does the model limit the range of battery discharge or does the model allow the battery to discharge fully (to 100%) in each battery cycle?

d. If the model limits the range of discharge, please state the range across which the battery is allowed to operate.

e. Does the model assume any amount of forced outage rate for the battery?

f. If so, please state the assumed forced outage rate.

g If PG&E assumes that the battery runs with no outages across its life, please provide the basis for making such an assumption.

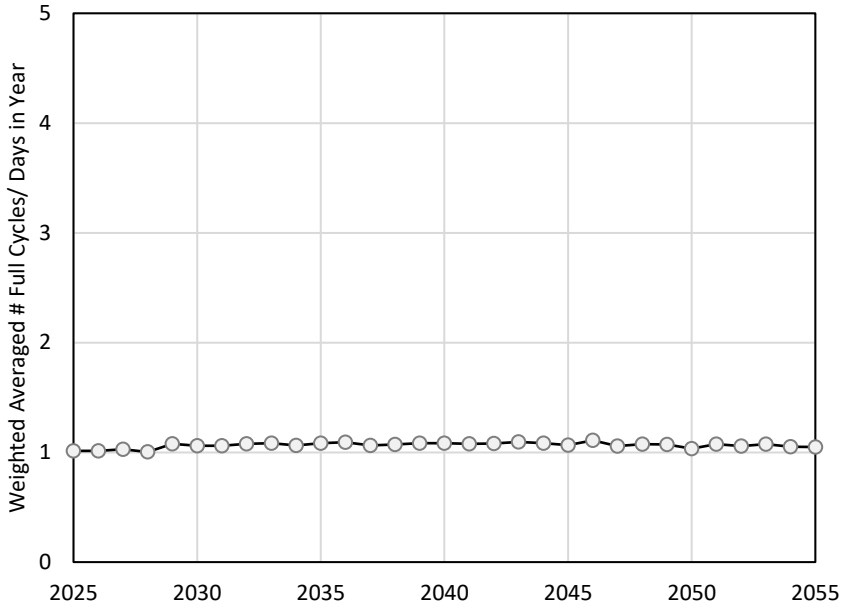
ANSWER 001

a. No. The model does not explicitly consider battery degradation. The National Renewable Energy Laboratory's (NREL) Cost Projections for Utility-Scale Battery Storage: 2023 Update (NREL ATB 2023 Report)[1], which forms the basis for Fixed Costs in IRP 2022-2023, indicate that a higher Fixed O&M cost may be needed if the battery is operating at a much higher rate of cycling than one cycle per day. Battery

[1] Cole, Wesley and Akash Karmakar, Cost Projections for Utility-Scale Battery Storage: 2023 Update (June 2023), pp. 7 – 8, <https://docs.nrel.gov/docs/fy23osti/85332.pdf> (as of July 2, 2025).

cycling used in our model does not warrant such an increase in Fixed O&M, as the analysis below suggests.

We assessed the battery usage on a yearly basis. The number of full cycles in North and South were weighed by 20:80 and then divided by the number of days in each year. We get a ratio very close to 1, for all years in the study. Considering the low deviation from the assumed battery cycling in the IRP 2022-2023, we did not make any changes to the IRP derived costs.



b. N/A.

c. We do not set a limit to the discharge for our analysis. This is consistent with the assumptions made by NREL 2023 Report, in which the IRP costs are based, i.e. one fully charged and discharged profile per day.

d. N/A

e. No, the model does not assume any amount of forced outage rate for the battery.

f. N/A

g. Because of the modular nature of the batteries, PG&E assumes that an outage on a small subset of the capacity will not impact on the total operational capacity significantly.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase Ph II
Application 24-09-014
Data Response

PG&E Data Request No.:	CLECA_015-Q001
PG&E File Name:	GRC-2023-PhII_DR_CLECA_015-Q001
Request Date:	July 17, 2025
Requester DR No.:	015
Requesting Party:	California Large Energy Consumers Association
Requester:	Cathy Yap
Date Sent:	July 31, 2025
PG&E Witness(es):	Eshan Singh – Engineering, Planning and Strategy

Regarding the Meet and Confer held on July 14, 2025, to further discuss PG&E's response to CLECA-13, Q.1, CLECA sets forth the following questions:

QUESTION 001

CLECA understands PG&E to state in its answer to CLECA Q.13.1(a), second paragraph, that its determination of the number of daily battery cycles is based on the following definition of the term "battery cycle": A battery cycle counts only if the battery is fully charged and then some hours later fully discharged. If a battery is partially charged and then partially discharged, that is not considered a battery cycle. A battery maybe partially charged then partially discharged multiple times per day and this activity would not be considered a battery cycle unless the battery was fully charged and subsequently fully discharged.

a) If the statement set forth above at Q.15.1. correctly characterizes PG&E's definition of "battery cycle", please confirm that it does. If the statement set forth above at Q.15.1. does not correctly characterize PG&E's definition of "battery cycle", please make corrections as necessary to ensure that it correctly characterizes PG&E's definition of "battery cycle" while ensuring that PG&E explains how partial charging and partial discharging fit into its definition.

b) Please provide a mathematical derivation of the full cycle count in the response to Q.13.1 (a), second paragraph, using the convention that battery step 0 is fully discharged, step 1 corresponds to 25% charged, step 2 corresponds to 50% charged, step 3 corresponds to 75% charged, and step 4 corresponds to fully charged. PG&E's response may focus on a single year in providing the detailed derivation.

c) Using the five examples for battery charging and discharging during a 24-hour period that are included in CLECA-15, Attachment 1, for each example, please state the number of cycles produced by the full cycle count methodology described in response to Q.15.1.2.

ANSWER 001

a) Yes, the statement correctly characterizes the PG&E's definition of "Battery cycle": A battery cycle counts only if the battery is fully charged and then some hours later fully discharged. If a battery is partially charged and then partially discharged, that is not considered a battery cycle. A battery may be partially charged then partially discharged multiple times per day and this activity would not be considered a battery cycle unless the battery was fully charged and subsequently fully discharged.

b) Please find the calculation of cycle count done in Matlab. These calculations are yearly.
We start with variable 'a' is a matrix with columns: [year, hour, SoC]
The SoC has values 0,1,2,3,4 corresponding to 0%, 25%, 50%, 75% and 100%:
years = unique(a(:,1));

```
cycle_counts = zeros(length(years),2); %Column 1: Year, Column 2: Cycle Count
for i = 1:length(years)
    year = years(i);
    soc_values = a(a(:,1) == year,3); % Extract SoC values for the year
    cycles = 0; % Initialize cycle tracking
    in_cycle = false;
    reached_4 = false;
    for j = 1:length(soc_values)
        soc = soc_values(j);
        if soc == 0
            if in_cycle && reached_4
                cycles = cycles + 1;
            end
            in_cycle = true;
            reached_4 = false;
        elseif soc == 4
            reached_4 = true;
        end
    end
    cycle_counts(i,:) =[year,cycles];
end
```

c) The number of cycles for the five examples in *"GRC-2023-PhII_DR_CLECA_015-Q001Atch01.xlsx" are* provided below:

Example	Cycle Count
Example No. 1	1

Example No. 2	1
Example No. 3	0
Example No. 4	0
Example No. 5	0

PG&E notes that each of the five examples above represents one 24-hour window whereas PG&E does cycle counts over an entire year. As shown in the attachment, a 24-hour window has partial cycles which are not counted. PG&E's method of using an entire year avoids partial cycles at the end of a 24-hr window. Therefore, the above example yields fewer cycles compared to PG&E's yearly methodology.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase Ph II
Application 24-09-014
Data Response

PG&E Data Request No.:	CLECA_015-Q002
PG&E File Name:	GRC-2023-PhII_DR_CLECA_015-Q002
Request Date:	July 17, 2025
Requester DR No.:	015
Requesting Party:	California Large Energy Consumers Association
Requester:	Cathy Yap
Date Sent:	July 31, 2025
PG&E Witness(es):	Eshan Singh – Engineering, Planning and Strategy

Regarding the Meet and Confer held on July 14, 2025, to further discuss PG&E's response to CLECA-13, Q.1, CLECA sets forth the following questions:

QUESTION 002

As part of the Meet and Confer discussion, PG&E's experts provided a secondary explanation for battery cycling characterized as the "Depth of Discharge" analysis. In this discussion, the battery degradation weight of the full discharge from 100% charged to fully discharged was set at 1, the weight of a partial discharge from 75% or 50% to zero was weighted as 0.3, and the partial discharge from 25% to zero was weighted as 0.1.

a) If this is a correct characterization of the "Depth of Discharge" analysis that PG&E presented during the Meet and Confer discussion, please state that it is correct. If Q.15.3 is not a correct characterization of the "Depth of Discharge" analysis, please correct the description so PG&E agrees that it is correct.

b) How does the Depth of Discharge Analysis factor into PG&E's characterization and calculation of a "battery cycle" as was used in its response to CLECA-13, Q.13.1(a)?

c) What assumptions have been made in developing the battery degradation weights associated with partial discharge? Please provide the citations to any sources or documentation that PG&E has relied upon in developing its battery degradation factors.

d) What cycle count does the PG&E Depth of Discharge Analysis produce for the five examples included in CLECA-15, Attachment 1?

e) Regarding the graph presented in response to CLECA-13, Q.13.1(a), how many cycles per day would show for each year in the study if the PG&E Depth of Discharge Analysis were used to determine battery cycles?

ANSWER 002

a) No, the following statement is not a correct characterization: "In this discussion, the battery degradation weight of the full discharge from 100% charged to fully discharged was set at 1, the weight of a partial discharge from 75% or 50% to zero was weighted as 0.3, and the partial discharge from 25% to zero was weighted as 0.1."

More specifically, there are multiple ways that a battery can undergo medium and shallow discharge, beyond the three suggested in the statement (75% or 50% to zero, and 25% to zero). The various ways to achieve medium/shallow discharge considered in our calculations is given below:

Depth of Discharge	Weight	Examples
100 (deep)	1	100 to 0
75 (medium)	0.3	100 to 25, 75 to 0
50 (medium)	0.3	100 to 50, 75 to 25, 50 to 0
25 (shallow)	0.1	100 to 75, 75 to 50, 50 to 25, 25 to 0

Based on the above table, we can revise the previously incorrect statement as follows:

The battery degradation weight of the full discharge from 100% charged to fully discharged was set at 1, the weight of a medium partial discharges (from 100% to 25%, 75% or 50% to zero, 100% to 50%, 75% to 25%) were weighted as 0.3, and the shallow partial discharges (from 100% to 75%, 75% to 50%, 50% to 25%,and 25% to zero) were weighted as 0.1.

b) The depth of discharge analysis was not used in the response to CLECA-13. The full cycle method showed 1.08 cycles per day (8% higher), while the depth of discharge method showed 1.20 cycles per day (20% higher). PG&E prepared the depth of discharge analysis in preparation for the July 14, 2025 meet and confer.

c) PG&E based the weights on industry studies cited below that battery lifetime degradation of Li-Ion batteries increases exponentially with increase in depth of discharge. To account for the exponential increase, the medium DoD were given a weight lower than their proportional value (0.75 and 0.5 would be proportional, so PG&E chose 0.3). Similarly for shallow DoD, PG&E gave 0.1 weight rather than proportional 0.25 weight. Table 2 and Figure 6 in the article from Battery University[1] gives the relationship between cycle life and depth of discharge. The values are shown below normalized by lifetime at 100% DoD. Similar data is also available in

[1] BU-808: How to Prolong Lithium-based Batteries - Battery University

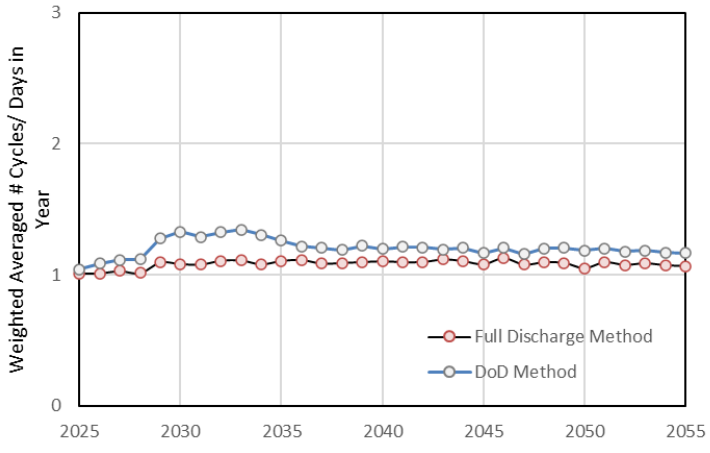
Figure 3c of IEEE research article[2]. While the application for the batteries and the time period might be different than what was used in PG&E's testimony, a similar battery chemistry suggests that the behavior of battery degradation should be similar.

Depth of Discharge	Lifetime (Rel to 100% DoD)	Weight (1/Rel. Lifetime)
100	1	1
80	1.5	0.67
60	2.5	0.4
40	5	0.2
20	15	0.067

d) The number of cycles for the examples in CLECA-15 Attachment 1 as per the DoD methodology are shown in table below:

Example	No. of Cycles
Example 1	1
Example 2	=0.3 x 5 + 0.1 x 1 = 1.6
Example 3	=0.3 x 5 + 0.1 x 1 = 1.6
Example 4	=0.3 x 6 = 1.8
Example 5	=0.3 x 5 = 1.5

e) The cycle counts for both the DoD and full discharge (shown previously in response to CLECA-013) methods are shown below. As previously mentioned, we do not calculate these values on a daily basis.



The numerical values are provided in Table below.

[2] Xu, B., Oudalov, A., Ulbig, A., Andersson, G. and Kirschen, D.S., 2016. Modeling of lithium-ion battery degradation for cell life assessment. *IEEE transactions on smart grid*, *9*(2), pp.1131-1140.

Year	Full Discharge	DoD Method
2024	1.01	1.07
2025	1.01	1.04
2026	1.01	1.09
2027	1.03	1.11
2028	1.01	1.12
2029	1.09	1.28
2030	1.08	1.33
2031	1.08	1.29
2032	1.11	1.33
2033	1.11	1.34
2034	1.08	1.30
2035	1.11	1.26
2036	1.11	1.22
2037	1.09	1.21
2038	1.09	1.19
2039	1.10	1.22
2040	1.10	1.20
2041	1.10	1.21
2042	1.10	1.21
2043	1.12	1.19
2044	1.10	1.20
2045	1.08	1.17
2046	1.13	1.20
2047	1.08	1.16
2048	1.10	1.20
2049	1.09	1.21
2050	1.05	1.19
2051	1.10	1.20
2052	1.08	1.18
2053	1.09	1.19
2054	1.07	1.17
2055	1.07	1.17

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase Ph II
Application 24-09-014
Data Response

PG&E Data Request No.:	CLECA_015-Q003
PG&E File Name:	GRC-2023-PhII_DR_CLECA_015-Q003
Request Date:	July 17, 2025
Requester DR No.:	015
Requesting Party:	California Large Energy Consumers Association
Requester:	Cathy Yap
Date Sent:	July 31, 2025
PG&E Witness(es):	Eshan Singh – Engineering, Planning and Strategy

Regarding the Meet and Confer held on July 14, 2025, to further discuss PG&E's response to CLECA-13, Q.1, CLECA sets forth the following questions:

QUESTION 003

Using the data relied upon in PG&E's battery optimization model study, for each year in the study, please provide the average number of hours per day spent discharging the battery and the average number of hours per day charging the battery.

ANSWER 003

Line No.	Year	SP		NP	
		Charge	Discharge	Charge	Discharge
1	2024	6.9	6.9	6.5	6.5
2	2025	6.8	6.8	6.3	6.3
3	2026	7.1	7.1	6.6	6.7
4	2027	7.0	7.0	6.5	6.5
5	2028	7.4	7.4	6.9	6.9
6	2029	7.9	7.9	7.5	7.5
7	2030	8.4	8.4	8.1	8.1
8	2031	8.3	8.3	7.8	7.8
9	2032	8.4	8.4	8.0	8.0
10	2033	8.6	8.6	8.2	8.2
11	2034	8.5	8.5	8.2	8.2
12	2035	8.2	8.2	7.9	7.9

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase Ph II
Application 24-09-014
Data Response

PG&E Data Request No.:	CLECA_011-Q004
PG&E File Name:	GRC-2023-PhII_DR_CLECA_011-Q004
Request Date:	June 20, 2025
Requester DR No.:	011
Requesting Party:	California Large Energy Consumers Association
Requester:	Cathy Yap
Date Sent:	July 7, 2025
PG&E Witness(es):	Eshan Singh – Engineering, Planning and Strategy

PG&E provided documentation to CLECA on 4/28/2025 about PG&E's proprietary MALARD model used for the calculation of MECs. In the section on Congestion, PG&E states: "We then allow the energy to flow from lower cost area to higher cost area to change the marginal costs subject to the directional constraints for Path 26 (4000 MW North to South and 3000 MW from South to North)."

QUESTION 004

Please state in terms of load (MWs) the portion of PG&E customers that are located north and the portion of PG&E customers that are located south of Path 26.

ANSWER 004

PG&E does not serve any load south of Path 26.

APPENDIX C

Meet & Confer Attachments

2023 GRC II Marginal Generation Cost Overview

April 28, 2025

Presenters:
Eshan SINGH
S. J. Liu
Osman Sezgen

Marginal Generation Cost = MEC + MGCC

The current methodology improves the methodology adopted in 2020 GRC II, also improving the model performance.

Line No.	Cost (2024)	Proposed Value	Using Methodology Adopted in Decision (D.) 21-11-016	Changes
1	MEC – bundled	6.276 c/kWh	While we use the adopted underlying regression-based approach based on ANL, for the 2023 GRC II we have implemented enhancement to our MEC model and updated modelling assumptions to reflect more recent information. A summary of these changes is included in the next column.	PG&E recommends the following improvements: (1) additional input data for the regression calculation, to include historical import as well as Energy Storage (ES) from Preferred System Plan (PSP); (2) Inclusion of the impacts of congestion on prices in northern and southern California, by modeling congestion along Path 26;[a] These improvements increase alignment of model driven energy prices when compared to historical prices and therefore improve forecast accuracy. In addition, PG&E uses updated inputs based on the CPUC 2022-23 IRP.
2	MGCC – 6-yr levelized	79.50 $/kW-year	A Net Cost-of-New-Entry (NetCONE) methodology was used to develop the MGCCs adopted in 2020 GRC Phase II. The Commission has since adopted its own version of NetCONE in its 2021 Avoided Cost Calculator (ACC). For 2023 GRC II, PG&E uses the NetCONE methodology from the 2021 ACC with some improvements, as summarized in the next column.	PG&E's recommends the following improvements to the 2021 ACC: (1) Modify the treatment of Effective Load Carrying Capacity (ELCC)[b] to better reflect true NetCONE; and (2) Use updated cost forecasts based on 2022-23 IRP.

(a) Path 26 is a crucial transmission path in California's power grid, a set of three 500 kilovolt (kV) power lines primarily located in Los Angeles County and extending into Kern and Ventura counties. It is part of the Western Electricity Coordinating Council's (WECC) links of electrical intertie paths in the western United States.

(b) ELCC quantifies the amount of "perfect" capacity that an intermittent resource can provide, effectively translating the variable output of these resources into a more stable and reliable capacity value. This helps in assessing how much these resources can contribute to meeting peak demand and ensuring grid reliability.

Regression-based calculation of Marginal Energy Costs

The regression formula used to calibrate the coefficients based on historical MECs data. The same coefficients with forecasted predictor variables are used to forecast MECs.

The predictor variables used for regression model are:

- Proxy Marginal Cost (PMC)
- High Threshold of Net Load (NL_Threshold_High)
- Three-hour Ramp of Net Load (NL_3HrRampUp)
- Top 6 hours of the day (TopNLHr_1 to TopNLHr_6)
- Top 3 hours of the morning (MorningTopNLHr_1 to MorningTopNLHr_3)
- Gas Price Spreads for different locations (Basis2Min, BasisLocalNorCal, BasisLocalSoCal)

$$\log(MEC(h) + C) = \log(\mathrm{PMC(h)} + \mathrm{C}) + \sum_{i=1}^{n} A_i x_i\,(h)$$

Regression is performed over a period of 2019-2023

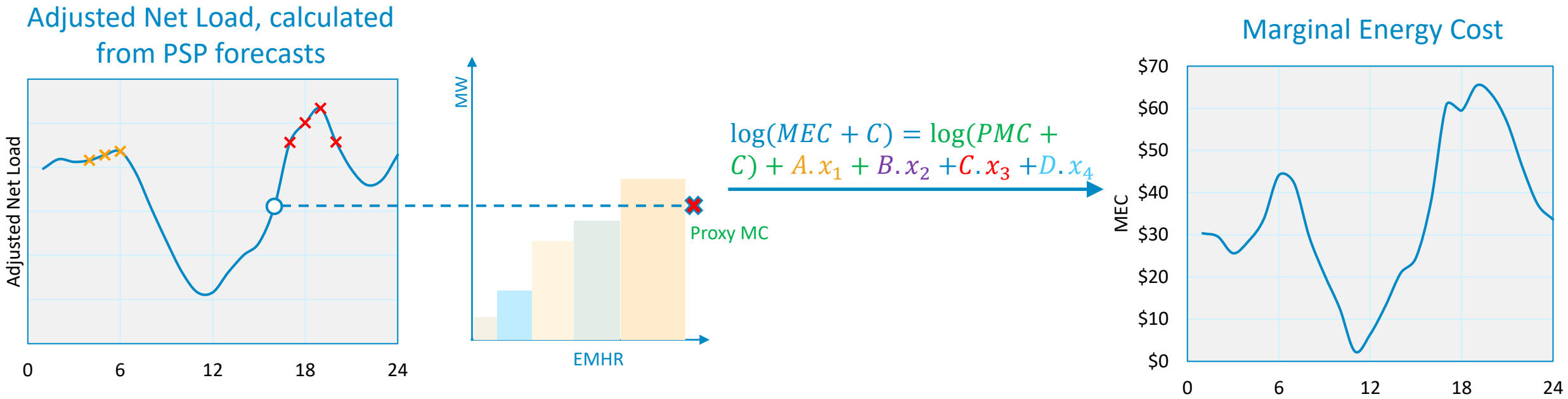
Constant	
PMC	Explained later
NL_Threshold_High	$max(NL - NL_H, 0)^2$, where NL_H = Top 1 %ile NL
NL_3HrRampUp	$max(NL_h - NL_{h-3}, 0)$
TopNLHr_1	Top 6 NL hours during 24-hours
TopNLHr_2	
TopNLHr_3	
TopNLHr_4	
TopNLHr_5	
TopNLHr_6	
MorningTopNLHr_1	Top 3 NL hours between HE3 to HE9
MorningTopNLHr_2	
MorningTopNLHr_3	
Basis2Min	$log\left(\frac{GasGHG_i}{\min(GasGHG)}\right)$
BasisLocalNorCal $LB(d,1)$	$log\left(\frac{GasGHG_{PGE_CG}}{GasGHG_{PGE_Malin}}\right)$
BasisLocalSoCal $LB(d,2)$	$log\left(\frac{GasGHG_{SoCal_CG}}{GasGHG_{SoCal_Topock}}\right)$

Inputs to MALARD model

Primary Input	Source	Derivative Input used in model	Derivative Input calculations
Gas Prices	Natural Gas Intelligence (NGI) Daily Index for PGE Citygate, PGE Malin, SoCal Topock, Platts (S&P) Daily Price for SoCal Citygate	Basis2Min BasisLocalNorCal BasisLocalSoCal	For North California power price regression, Basis2Min = log(PGE Citygate price)-log(min(PGE Citygate price, SoCal Citygate price), For Southern California: Basis2Min = log(SoCal Citygate price)-log(Min(PGE Citygate price, SoCal Citygate price); BasisLocalNorCal =log(PGE Citygate price/PGE Malin price) BasisLocalSoCal= Log(SoCal Citygate price/SoCal Topock price)
GHG Prices	CAISO GHG Allowance Price		Convert from $/Metric Ton to $/MMBTU using multiplier of 0.053
Load Forecasts	DA load forecast from CAISO for CA ISO-TAC, PGE-TAC	Use non-PGE system load for Southern California to catch residual loads	Southern California load = CAISO load -PGE Load
Generation Forecasts for Wind and Solar	Use CAISO Actual Wind and Solar generation as Proxy for Day Ahead generation for NP, SP and ZP	Use sum of NP and ZP for Northern California Wind and Solar, use SP for Southern California Wind and Solar	
Large Hydro Input	CAISO Actual Hydro Generation	Split into North California and Southern California Hydro assume 2:1 ratio	Northern California Hydro = 2/3 * CAISO hydro Southern California Hydro = 1/3 * CAISO hydro
Battery MW Dispatch	CAISO Actual Battery Charging and Discharging	Northern and Southern CA battery dispatch	Northern CA battery dispatch = CAISO battery dispatch * 0.2 Southern CA battery dispatch = CAISO battery dispatch * 0.8
Import	CAISO Actual Import	Northern and Southern CA Import	Northern CA Import =CAISO Import * 0.2 Southern CA Import = CAISO Import * 0.8
RPS other than Wind and Solar	CAISO	Northern and Southern CA other RPS	Northern CA Other RPS = CA Other RPS * 0.4 Southern CA Other RPS = CA Other RPS * 0.6
Diablo Nuclear Dispatch	CAISO Day Ahead Award	No change	No change

Proxy Marginal Cost Calculation

Similar to 2020 GRC II, 2023 GRC II used a regression model based on Adjusted Net Load that explains >80% variability in historic costs.



- Adjusted Net Load in each hour is supplied by gas resources starting from lowest EMHR (Effective Market Heat Rate), resulting in a Proxy Marginal Cost (MC).
- Final Marginal Energy Cost is a function of Proxy MC and other predictor variables.

Features of MALARD

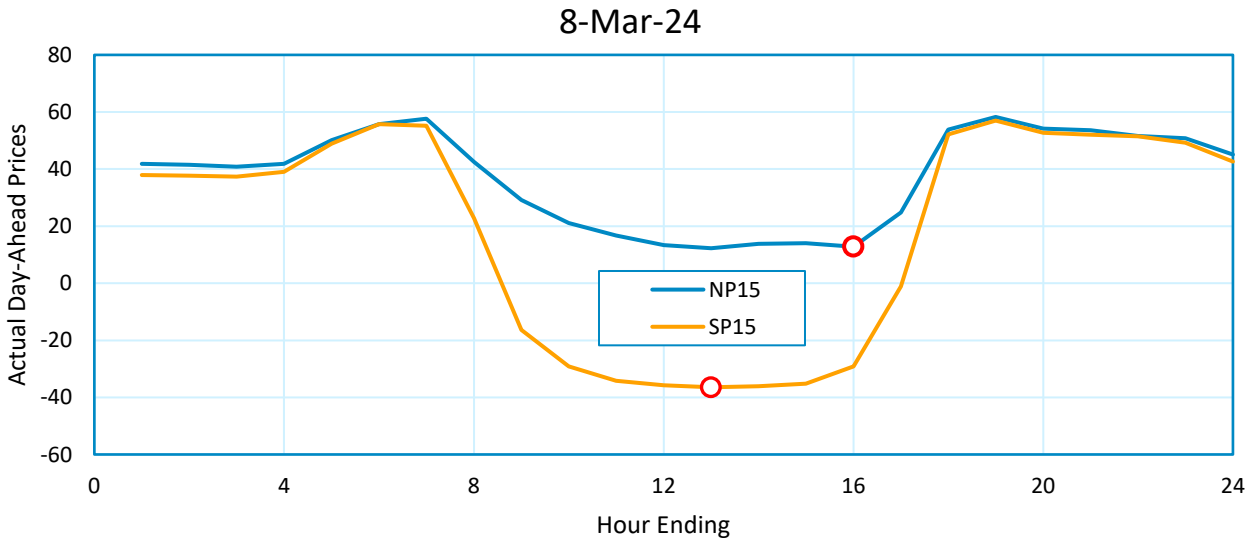
Modeling improvements result in price differentials between PGE DLAP and SP15 and improvements in the accuracy of MEC.

PG&E's internal price forecasting model has been improved significantly for GRC II.

- Hydro and Import proxies replaced by actual values
- Congestion in Path 26 is modeled
- Renewable Curtailment is modeled

Modeling Congestion along Path 26

- We observe greater price disparity between north and south California.
- This price disparity can be attributed to congestion along transmission pathways.

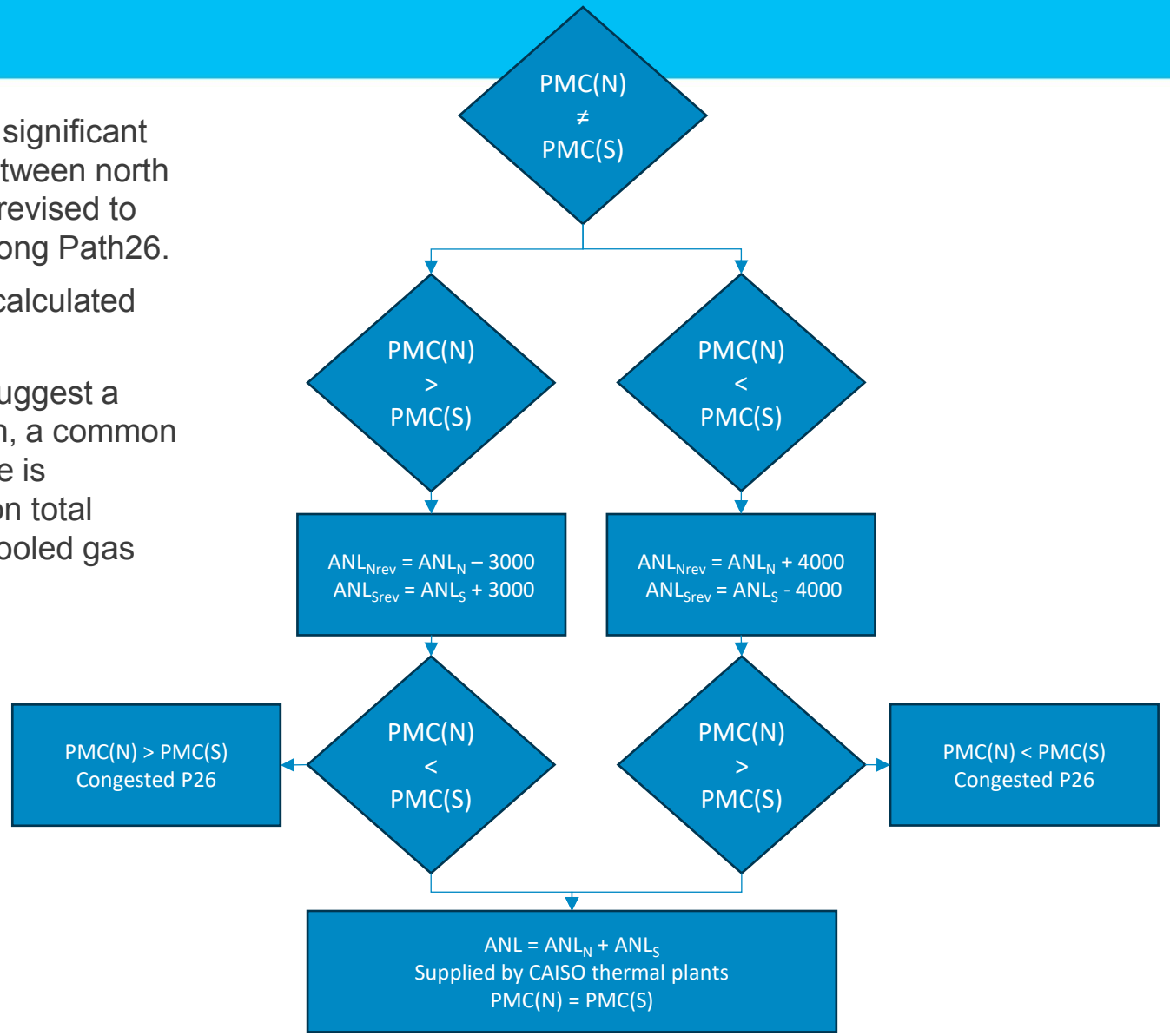


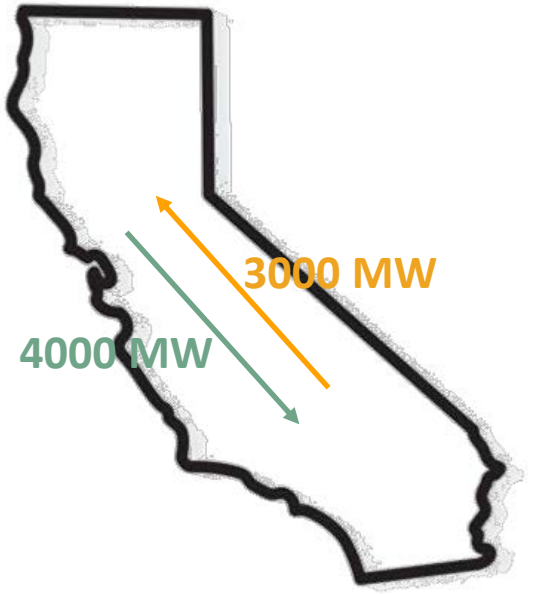
MINIMUM DAY-AHEAD PRICES IN PG&E DLAP (LEFT) AND SP15 (RIGHT) FOR JAN-JUL 2024, IN $/MWh

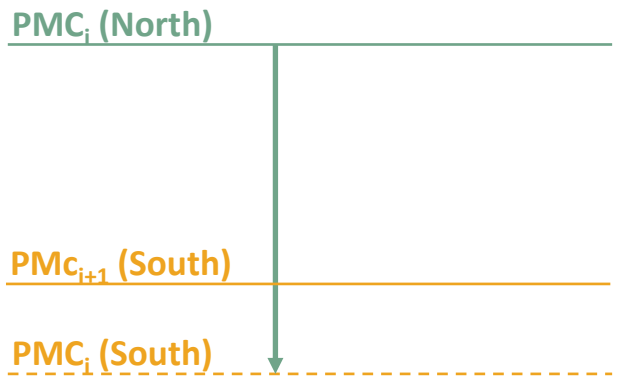
PGEMin	1	2	3	4	5	6	7	SPMin	1	2	3	4	5	6	7
1	34	37	30	1	-2	-16	27	1	22	37	-15	-32	-24	-26	22
2	41	28	24	0	2	-8	29	2	22	10	-12	-44	-11	-39	25
3	42	37	26	9	8	-1	32	3	27	-1	-45	-46	-8	-17	18
4	43	40	26	36	24	5	26	4	10	24	-35	-37	-3	-11	19
5	52	44	29	24	-19	9	31	5	24	43	-27	-35	-31	-21	30
6	61	42	30	12	-7	14	23	6	8	41	-7	-66	-16	9	24
7	54	38	19	18	-17	9	20	7	13	8	-30	-67	-26	5	16
8	73	36	12	10	-9	-1	31	8	30	-1	-36	-28	-17	-9	31
9	53	38	4	0	1	-11	31	9	21	4	-35	-39	-15	-20	33
10	65	23	8	12	19	10	36	10	23	-12	-23	-31	-13	1	37
11	65	27	20	7	10	10	33	11	33	-18	-35	-23	-22	6	34
12	78	31	-4	5	-7	12	38	12	22	0	-22	-30	-25	8	37
13	169	29	0	22	13	11	29	13	43	0	-40	-13	-8	12	29
14	155	40	-5	2	20	5	28	14	31	-7	-34	-23	-2	3	22
15	167	35	7	-1	15	-7	30	15	95	-13	0	-36	-3	-13	29
16	202	39	-2	-8	10	-16	31	16	60	-3	-16	-31	-18	-29	31
17	69	35	5	3	-4	-9	30	17	19	-10	-47	-32	-17	-14	27
18	49	34	3	5	-32	6	31	18	8	-19	-12	-16	-32	3	31
19	55	31	3	-9	-32	0	32	19	43	31	-19	-33	-51	-5	32
20	45	33	0	-7	-10	8	28	20	36	32	-38	-56	-26	2	28
21	41	24	8	-21	-13	16	28	21	37	-4	-47	-33	-19	13	24
22	49	15	4	0	-10	17	33	22	49	-8	-20	-18	-25	14	30
23	39	17	-10	-2	-10	20	38	23	22	-2	-20	-22	-28	16	37
24	49	0	-5	-2	-24	26	37	24	39	-6	-35	-30	-26	27	36
25	37	-9	0	2	-31	32	36	25	17	-11	-44	-32	-48	32	36
26	41	21	-3	-7	-31	26	33	26	15	18	-45	-16	-39	25	33
27	40	10	14	-31	-5	23	22	27	2	-31	-28	-49	-33	20	17
28	34	2	4	-25	1	22	16	28	3	-21	-36	-41	-20	19	6
29	35	8	23	-12	-13	17	25	29	10	-23	-38	-20	-18	15	21
30	34		4	-2	16	15	18	30	4		-5	-16	-3	10	15
31	38		-1		13		26	31	25		-23		-5		25

Path 26 transmission limits modeled in 2023 GRC II

- When we observe significant price difference between north and south, ANL is revised to account for flow along Path26.
- The prices are re-calculated with revised ANL.
- If the new prices suggest a change of direction, a common (CAISO-wide) price is calculated based on total CAISO ANL and pooled gas fleet.



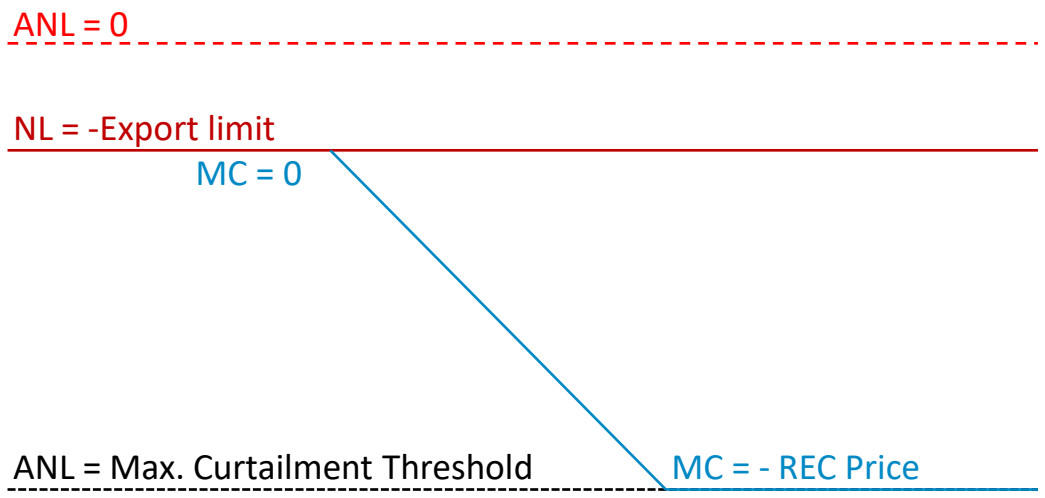


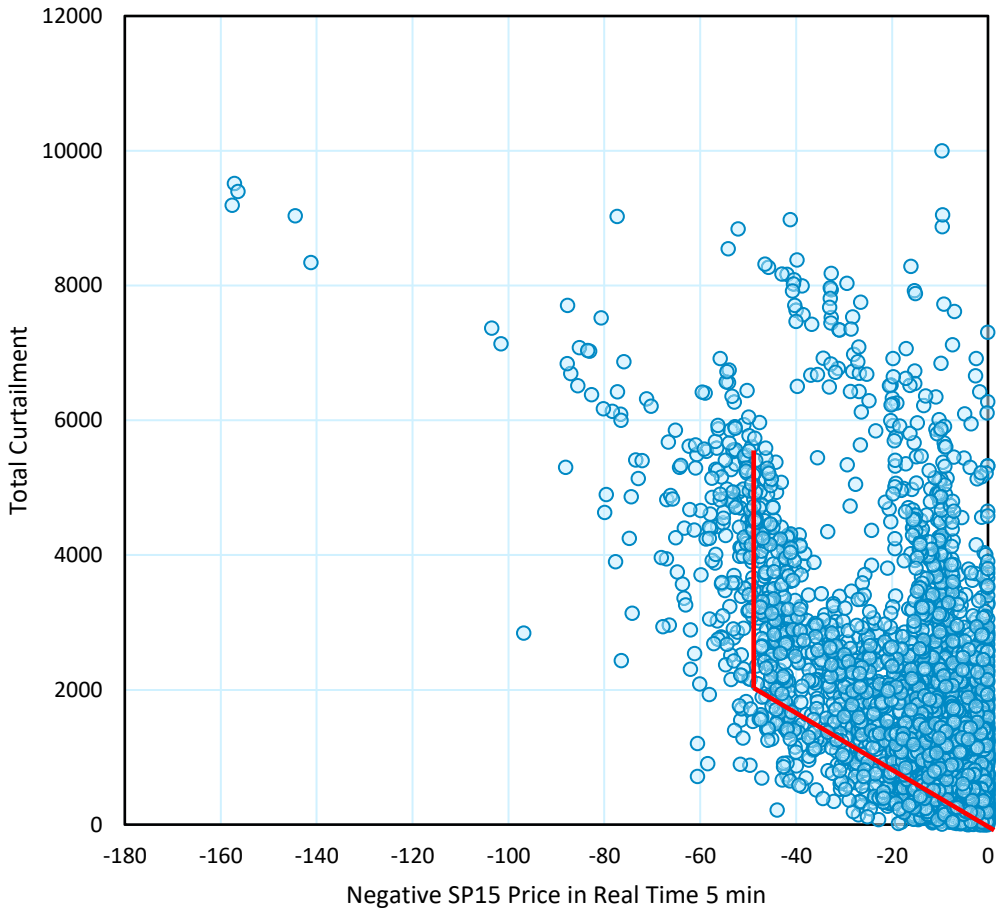


For discussion purposes only.

Modeling Curtailment

- We observe negative prices more frequently now.
- The ratio of negative prices between NP and SP are taken from observed minimum value in 2024 = 38%
- When ANL reaches 0, and cannot be absorbed by exports, prices go negative linearly up to –REC prices.





The model outputs hourly MECs

The hourly MECs are:

- Reported as bundled load-weighted MEC over six TOU periods
- Input for calculating the Energy revenue using a perfect foresight battery revenue model.

Marginal Energy Cost (MEC)

PGE presents bundled average MEC for six TOU periods and Annual average.

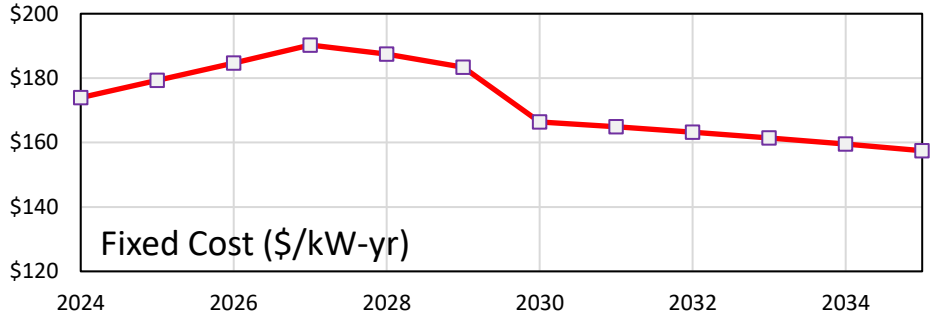
TABLE 2-3
MEC BY TOU PERIODS
AND VOLTAGE LEVEL AVERAGED OVER YEAR 2024
(¢/KWH)

Line No.	TOU Rate Period	Voltage Level		
		Transmission	Primary Distribution	Secondary Distribution
1	Summer Peak	8.244	8.399	8.815
2	Summer Partial-Peak	6.938	7.069	7.419
3	Summer Off-Peak	6.103	6.218	6.526
4	Winter Peak	7.654	7.798	8. 184
5	Winter Off-Peak	5.294	5.394	5.661
6	Spring Super Off-Peak	1.549	1.578	1.656
7	Bundled Load-Weighted Annual Average	6.276		

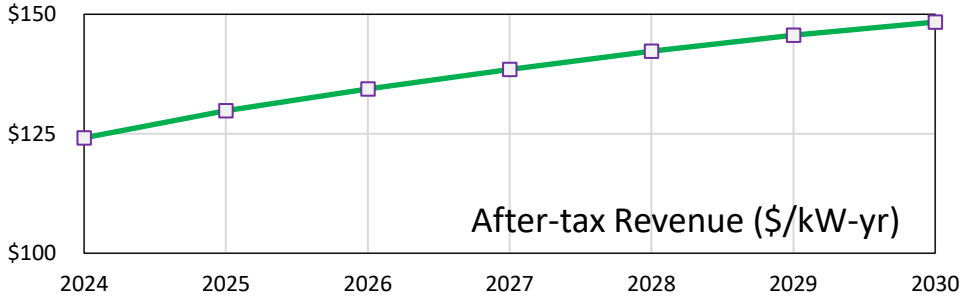
Generation: Marginal Generation Capacity Cost

MGCC methodology is based on ACC 2021 NetCONE methodology, albeit with a few improvements.

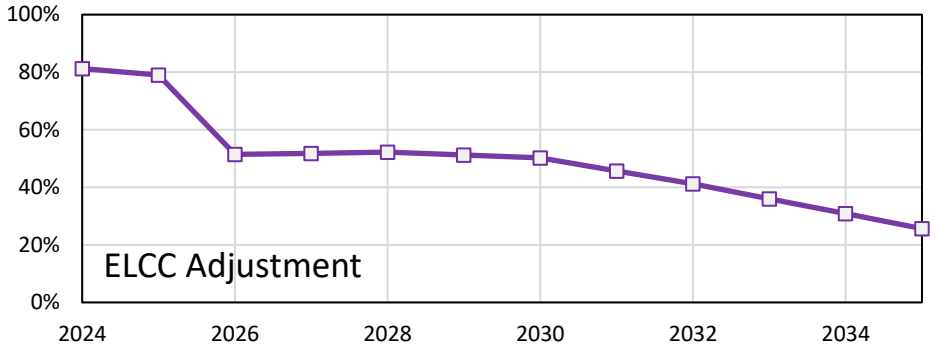
- PG&E's marginal capacity resource:
  - Standalone 4-hr Lithium-Ion Battery
  - 80% in South and 20% in Northern California region
- Cost taken from 2022-23 IRP PSP



- Revenue from internal perfect foresight model:



- ELCC taken from 2022-23 IRP PSP, Fig. 39



Annual Generation Capacity Cost

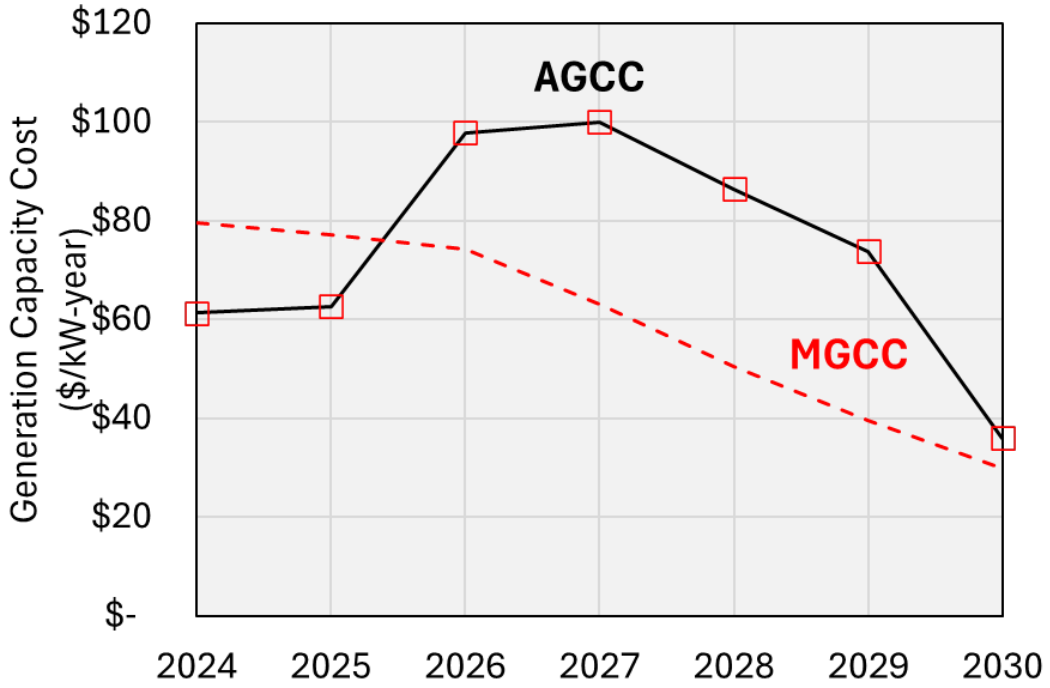
$$AGCC = \frac{Cost - Revenue}{ELCC\ (\%)}$$

Generation: Marginal Generation Capacity Cost

For calculating MGCC, AGCC Levelized over 6-years with discount factor of 7.18%.

Annual Generation Capacity Cost

$$AGCC = \frac{Cost - Revenue}{ELCC\ (\%)}$$



Generation: Marginal Generation Capacity Cost

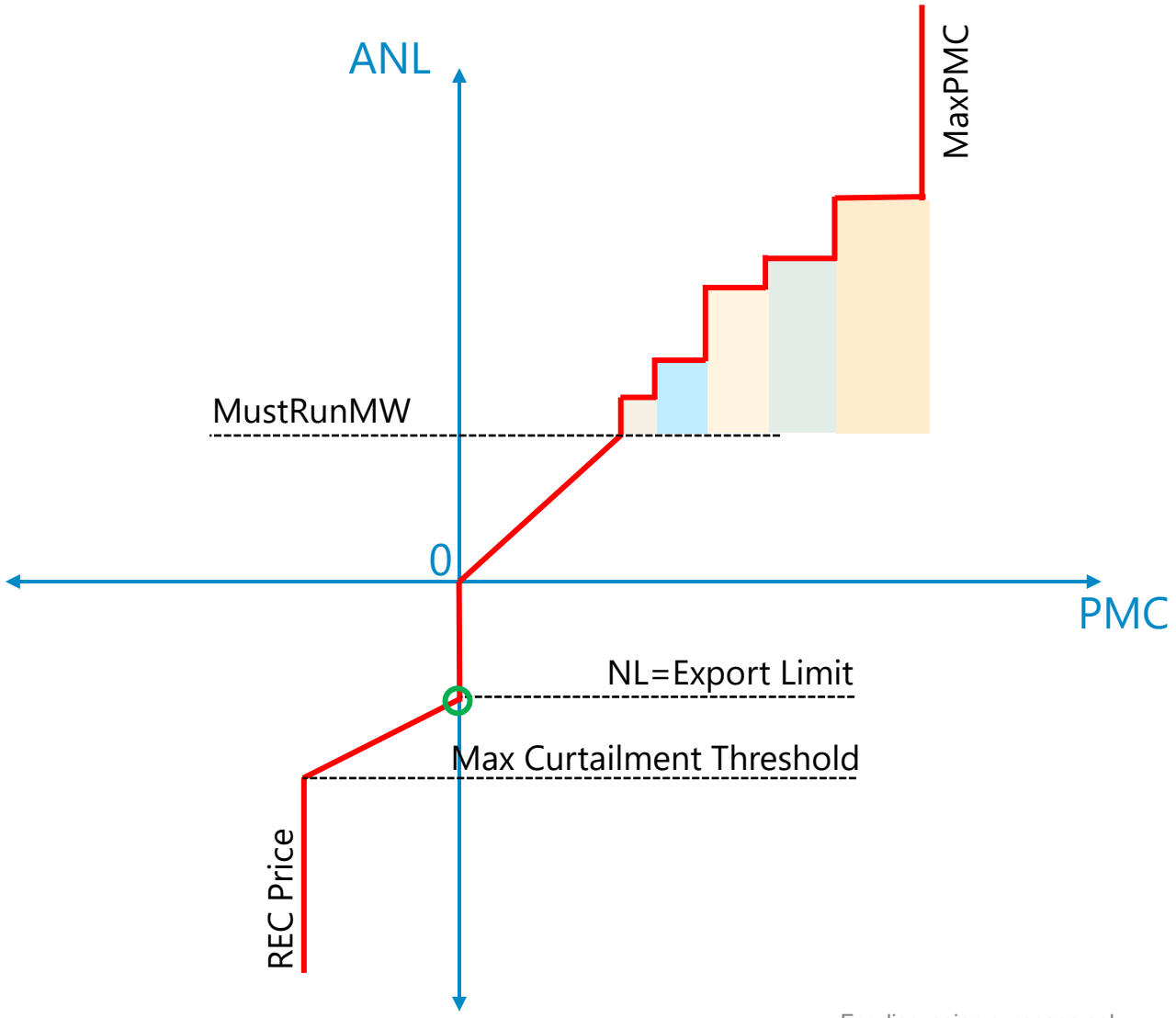
TABLE 2-4
LEVELIZED MGCC BY VOLTAGE LEVEL FOR 2024-2029
($/KW-YEAR)

Line No.	Period	Voltage Level		
		Transmission	Primary Distribution	Secondary Distribution
1	2024-2029 Levelized Cost	$79.50	$81.83	$84.28

MGCC is based on six-year levelized cost from 2024 to 2029 with WACC of 7.18%

Schematics of PMC calculations

(For illustrative purpose only, does not signify quantitative values of ANL or PMC)



- Curtailment = NL (for NL < Export Limit)
  Export Limit based on max. Export each year.
  Curtailment Threshold = -1000 MW over the Export limit, below which PMC is fixed at – REC price

  This schematic is for calculating the PMC for a given region (for e.g. PGE DLAP or SP15).

  If there is a difference in PMC between PGE DLAP and SP15, they undergo a shift, allowed by Path 26 transmission.

  The final PMC is based on the calculations after transmission between north and south are considered.

Methodology for Escalation of MEC beyond 2036.

The price forecast for out-years (beyond 2035) is based on an escalation of Gas-GHG prices. Here we explain the methodology with an example of the first two days in the year 2036.

2035 is the last year for the model to run and selected as the base year (on which the further year's MEC will be based).

For a given month, we categorize a given day based on whether it is Mon-Sat or if it is a Sunday/Holiday; the latter is treated as off-peak hours (i.e. smaller increment is applied).

Forecast for 1/1/2036:

1/1/2036 is a holiday and should be treated accordingly. First, we look at all Sunday/Holiday days in January of 2035. A random selection is made among all the available options. An increment is applied only to the Hour Ending (HE) 1 to HE 8, equal to:

*Increment (mo,yr, HE1-8) = 0.5 x (GasGHGPrice(mo,yr)*HR(mo,2035) – MEC(mo,2035))*.

The remaining hours are copied as is, and no increment is applied.

Forecast for 1/2/2036:

1/2/2036 is Tuesday. In this case, we randomly select a day from the same day-type in January of 2035 (i.e. non-Holiday Monday to Saturday). Once the selection is made, and copied to MECs for 1/2/2036, an increment is applied on these. This increment varies by the hour:

For HE 17 – HE 24, the increment is calculated as:

*Increment (mo,yr, Mon-Sat, HE17-24) = GasGHGPrice(mo,yr)*HR(mo,2035) – MEC(mo,2035)*

The GasGHG prices (sum of Gas Prices and the associated GHG prices) escalate each year at 2%. The increment is a constant averaged value for each month.

For HE 1 – HE 8, the increment is calculated as:

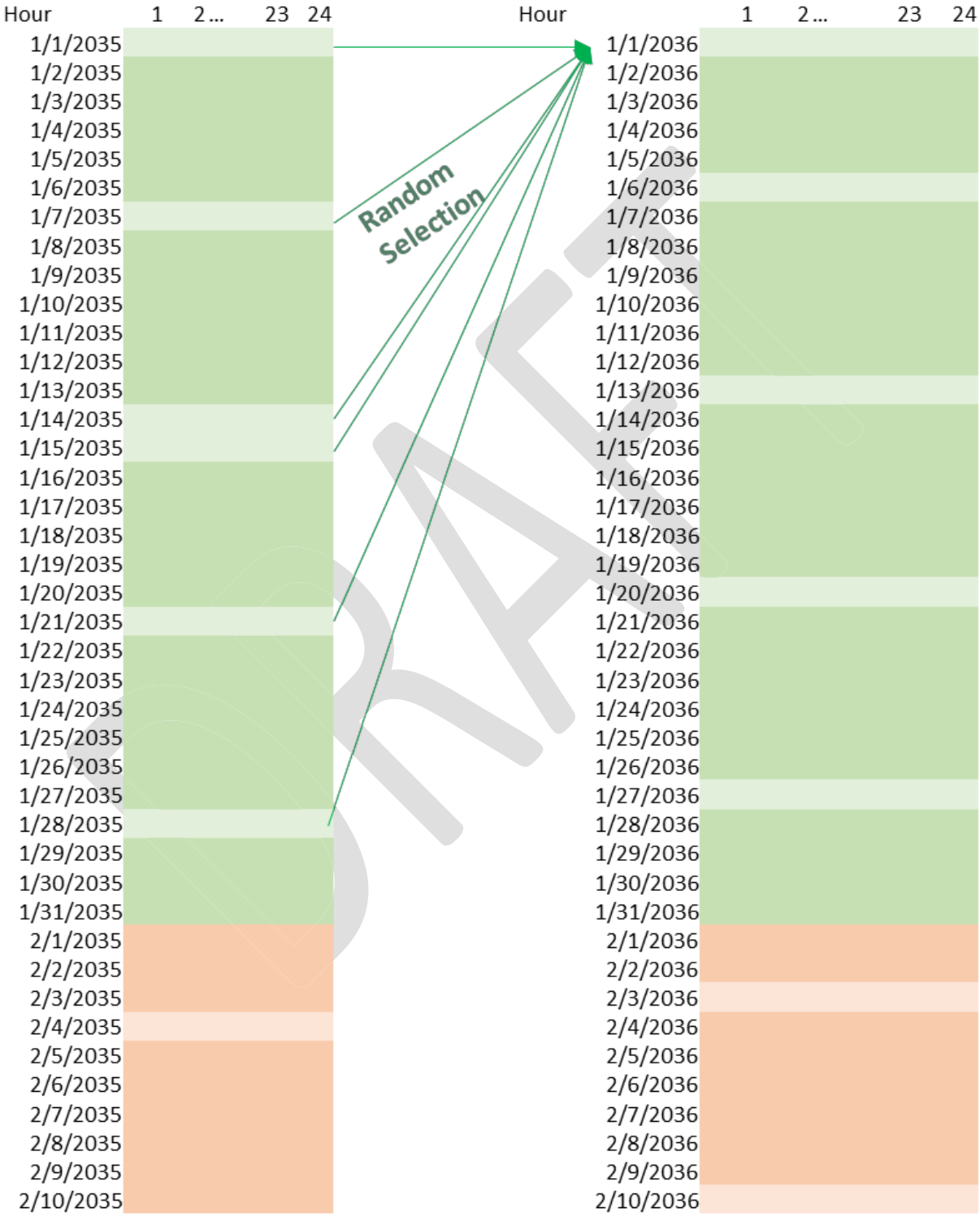
*Increment (mo,yr, HE1-8) = 0.5 x(GasGHGPrice(mo,yr)*HR(mo,2035) – MEC(mo,2035))*

For HE 9 – HE 16 (super off-peak hour), there is zero increment.

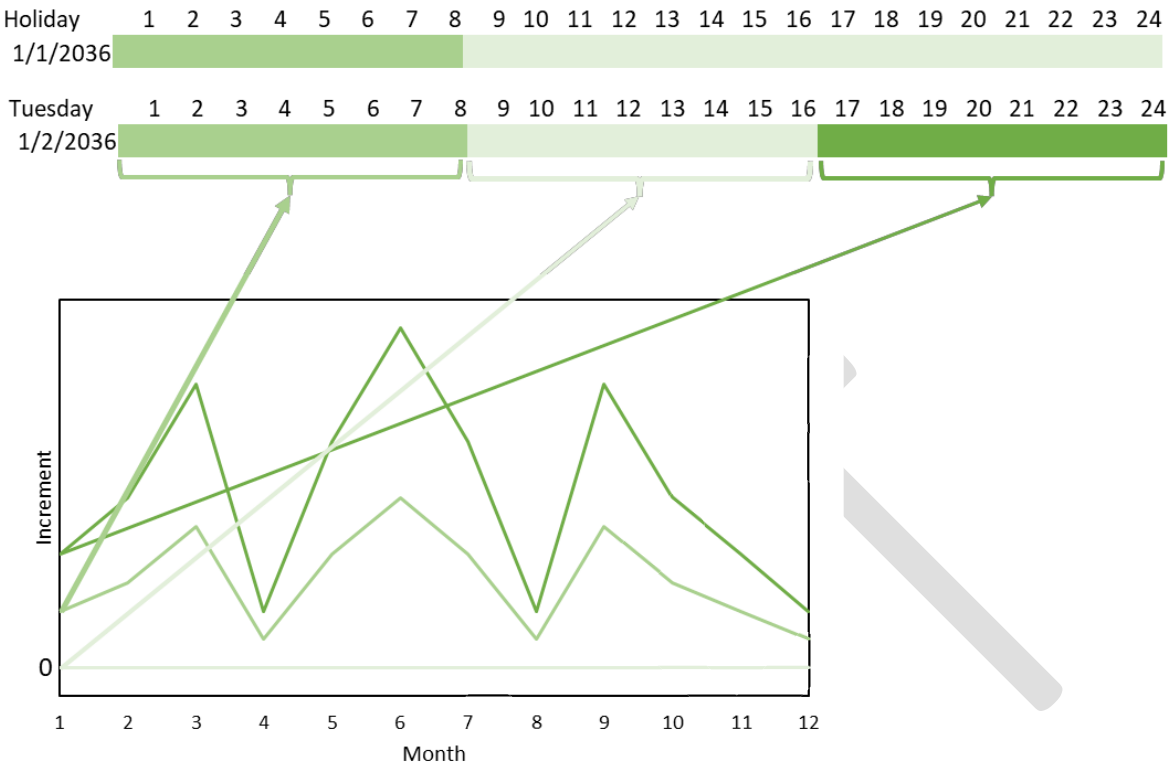
A schematic of the above methodology is provided in the figures below:
January month is shaded in Green, with light Green showing Sunday/Holiday, and darker shade for Mon-Sat (non-Holiday days). For 1/1/2036, (light green) for all 24 hours, the prices come from one of the randomly selected light green days in 2035. Similarly, 1/2/2036, a randomly selected day from all the dark green days forms the base-day.

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Thereafter an increment is applied to the base-day MEC for dark-green days. This increment (a fixed value for the month of January) is applied differently based on the time of day.



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Holiday
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
1/1/2036
Tuesday
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
1/2/2036
Increment
0
1 2 3 4 5 6 7 8 9 10 11 12
Month

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APPENDIX D

External and Other Attachments

California Industry Assistance

CALIFORNIA INDUSTRY ASSISTANCE

What is the California Industry Assistance Credit?

The California Industry Assistance Credit is an annual credit for eligible industrial facilities that are customers of the investor-owned electric utilities. The CPUC created this credit program, calculates the credit amount, and oversees the utilities' distribution of the credits to their customers.

The credit is part of California's greenhouse gas reduction program. It is designed to reward businesses that have taken early action to reduce their energy use and greenhouse gas emissions, and to help prevent emissions increases.

This webpage provides informational updates, background, and responses to Frequently Asked Questions (FAQs). For formal and complete information, refer to the specific policies, rules, and formulas that were developed in December 2014 in CPUC Decision (D.)14-12-037 as modified by D.15-08-006, D.16-07-007, and D.21-08-026.

What is the purpose of the California Industry Assistance Credit?

The credit is part of California's greenhouse gas reduction program. The CPUC created the California Industry Assistance Credit as part of its implementation of California's Cap-and-Trade Program to help ensure that emissions leakage does not occur. Emissions leakage occurs when emissions decrease within California but increase outside of California as a result of the Cap-and-Trade Program. Emissions leakage could occur if a production facility moved out of California to a jurisdiction without a Cap-and-Trade Program or other climate goals. This credit protects eligible industrial sectors against emissions leakage by compensating them for a portion of the GHG emission costs associated with the electricity they buy.

Additionally, the California Industry Assistance Credit incentivizes energy and GHG reductions. It is designed to reward businesses that have taken early action to reduce their energy use and greenhouse gas emissions, and to help prevent emissions increases. The amount of the credit is determined by the CPUC for each facility using emissions-efficiency benchmarks that provide an incentive to make products in California in the most energy-efficient way possible.

Who is eligible for Industry Assistance?

One of the basic eligibility requirements is that facilities need to be operating in an industry that is "emissions-intensive and trade-exposed" (EITE). Businesses in EITE industrial sectors face a higher risk of emissions leakage. That is why they are eligible to receive this credit. Any size business can receive the credit.

Another basic requirement is that facilities must be current customers of one of California's investor-owned electric utilities: PG&E, SCE, SDG&E, Liberty Utilities (CalPeco Electric), Bear Valley Electric Service, or Pacific Power (PacifiCorp).

There are two ways the CPUC identifies eligible EITE facilities:

- **Facilities that are eligible because they report to CARB.**
  Eligible EITE facilities that report to CARB (California Air Resources Board) under its Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (MRR) are eligible for CPUC's Industry Assistance Credit. The CPUC and CARB work together to identify these facilities, and the CPUC works with the utilities to deliver the credit.
- **Facilities that must submit an eligibility claim**.
  Eligible EITE facilities that do not report to CARB under its MRR, but that operate in the same eligible EITE sectors, can submit a claim (called an attestation form) to verify their eligibility.

If your facility reports to CARB under MRR you do not need to submit an eligibility claim, although your utility will contact you to identify which service account the credit should be applied to. You can contact your utility to find out more about your eligibility status.

If you think you're eligible, but you don't already report to CARB under MRR, read the instructions below about the attestation process.

Attestation Process for Eligible EITE Facilities with Emissions below 10,000 MTCO2e/year

If you believe your facility is eligible to receive California Industry Assistance and you do not already report to CARB under its Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (MRR), you must complete an eligibility claim, or attestation form, to receive California Industry Assistance. The main purpose of the attestation process is to show that your facility operates in an eligible industry. The annual schedule for attestation is below.

California Industry Assistance Schedule from Resolution E-4716

Date	Action
September 30	Attestation form submission deadline
November 30	Utilities complete review and verification of attestation forms and provide eligible facility data to Energy Division
January 31	Energy Division calculates credit due to each eligible facility (identified by September 30 of the previous year) and provides information to utilities
April 1	Utilities begin issuing California Industry Assistance as a bill credit to eligible facilities

Attestation Forms

When the attestation period is open, attestation forms are available from your respective utility using the following links:

- Pacific Gas and Electric Company (PG&E)
- Southern California Edison Company (SCE)
- San Diego Gas & Electric Company (SDG&E)

Customers of Liberty Utilities (CalPeco Electric), Pacific Power (PacifiCorp), and Bear Valley Electric Service should contact their utility directly if they believe they are eligible for California Industry Assistance.

The attestation process is completed at the facility level, where facility is defined in CARB's Cap-and-Trade Regulation Section 95802(144)(A) as ". . . physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties…" If a business has multiple eligible facilities, it must complete a separate attestation for each facility.

All attestation forms are subject to a random audit to ensure program integrity.

If you would like to see a sample attestation form before your IOU portal opens to see what types of information you may need to gather, an example is in Appendix B of Resolution E-4716 available here.

Attestation Timing

Facilities have the opportunity to attest to their eligibility before September 30 each year. If the facility is eligible, it will receive the credit the next year. If eligible facilities that have received the credit wish to continue receiving California Industry assistance, the facility must re-attest before the start of each compliance period (typically every three years).

CARB Compliance Periods

January 1 - December 31 of the years

1st	2nd	3rd	4th	5th	6th	7th
2013-2014	2015-2017	2018-2020	2021-2023	2024-2026	2027-2029	2030-2032

Credit Timing and Size

Eligible industrial facilities will receive the California Industry Assistance Credit once per year, either on their electricity bill or as a credit from their utility. Normal credit distribution occurs each year in April. The credit is expected to continue through April 2030, although this may change.

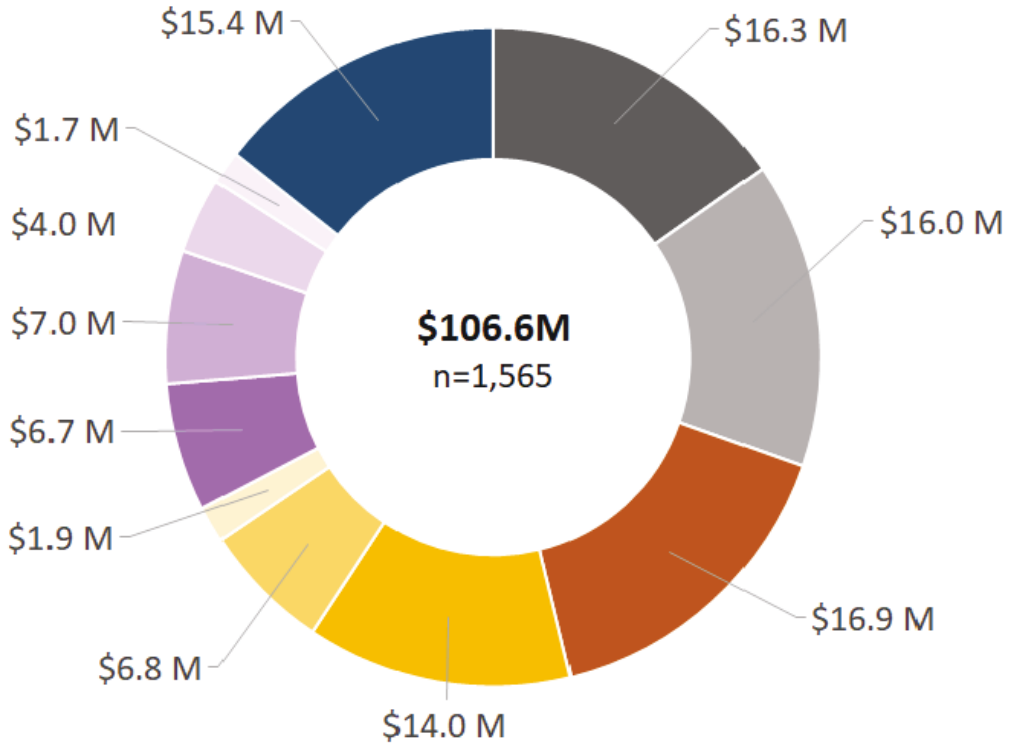
The amount of the credit is determined through the use of emissions efficiency benchmarks, which rewards businesses that have taken early action to reduce GHG emissions. This approach will also ensure that, in the future, these industries have a strong incentive to produce products in California in the most GHG-efficient way possible.

The amount of the credit is calculated for each facility by the CPUC. Utilities do not calculate the credit; they only deliver it on the CPUC's behalf. Credits are calculated using confidential business information which the CPUC protects from disclosure. For more information about how credits are calculated, see Appendix A of D.16-07-007. Updates some formulas and to the Dollar Conversion Factor and GHG Intensity Factor were made in D.21-08-026.

2025 CA Industry Assistance by Sector

To protect confidentiality, each wedge represents multiple facilities and covers multiple NAICS codes. The number of facilities is indicated by the "n=" number in the legend. NAICS codes included in each wedge are adapted from the California Air Resources Board (CARB) reporting available here.





Fossil Fuels & Energy

- Petroleum Refining and Hydrogen Production; n= 53
- Crude Petroleum and Natural Gas Extraction; n= 152

Cement & Building Materials

- Cement, Lime, Gypsum, and Clay Product Manufacturing; n= 47

Food Production

- Other Food Manufacturing; n= 697
- Dairy Product Manufacturing; n= 41
- Fruit and Vegetable Canning; n= 18

Metal/Glass/Paper/Chemicals

- Metal Processing and Manufacturing; n= 210
- Chemical, Biological, and Pharmaceutical Manufacturing; n= 106
- Glass Manufacturing; n= 18
- Paper Manufacturing; n= 17

Other Industrial Facilities

■ Miscellaneous Industrial Facilities; n= 206

	2023		2024		2025	
	Assistance ($)	Number (n)	Assistance ($)	Number (n)	Assistance ($)	Number (n)
Petroleum Refining and Hydrogen Production	$25.1 M	65	$22.9 M	51	$16.3 M	53
Crude Petroleum and Natural Gas Extraction	$13.6 M	68	$15.8M	159	$16.0 M	152
Cement, Lime, Gypsum, and Clay Product Manufacturing	$17.4 M	36	$17.4 M	40	$16.9 M	47
Other Food Manufacturing	$9.7 M	866	$8.1 M	425	$14.0 M	697
Dairy Product Manufacturing	$6.7 M	53	$6.1 M	34	$6.8 M	41
Fruit and Vegetable Canning	$1.2 M	23	$1.1 M	20	$1.9 M	18
Metal Processing and Manufacturing	$7.1 M	142	$6.4 M	156	$6.7 M	210
Chemical, Biological, and Pharmaceutical Manufacturing	$3.9 M	55	$4.2 M	58	$7.0 M	106
Glass Manufacturing	$4.3 M	9	$4.1 M	11	$4.0 M	18
Paper Manufacturing	$1.5 M	11	$1.7 M	16	$1.7 M	17
Miscellaneous Industrial Facilities	$12.8 M	186	$13.8 M	178	$15.4 M	206
	$103.4 M	1,514	$101.6 M	1,148	$106.6 M	1,565

CA Industry Assistance by Utility

	2022	2023	2024	2025
	Assistance ($)	Assistance ($)	Assistance ($)	Assistance ($)
PG&E	$35.1 M	$44.3 M	$41.7 M	$47.1 M
SCE	$40.1 M	$58.3 M	$57.5 M	$56.1 M
SDG&E	$0.5 M	$0.7 M	$2.5 M	$3.4 M
	$75.7 M	$103.4 M	$101.6 M	$106.6M

**Note: Customers of Bear Valley Electric Service, Liberty Utilities, and Pacific Power are eligible for CA Industry Assistance. However, currently no facilities served by these IOUs have been identified or attested. Please contact industry.assistance@cpuc.ca.gov if you are customer of one of these utilities and would like additional information.*

Additional information on historic total CA Industry Assistance can be found here.

Factors Used to Calculate CA Industry Assistance

Dollar Conversion Factor

The Dollar Conversion Factor is an estimate used when calculating CA Industry Assistance to convert a ton of GHG-equivalent emissions into $USD. Per D.21-08-026, the Dollar Conversion Factor is defined as the average of CAISO's daily Greenhouse Gas Allowance Index Price for the preceding year plus eight percent. Per D.21-08-026, Energy Division posts this number online:

Year	Dollar Conversion Factor ($/MT of CO_2e)
2017	$14.57
2018	$15.31
2019	$17.27
2020	$17.17
2021	$23.15
2022	$25.00
2023	$31.83
2024	$36.79
2025	$41.14
2026	$32.28

Based on data from http://oasis.caiso.com/mrioasis/logon.do
Prices>Index Prices>Greenhouse Gas Index Prices

Emissions Intensity Factor

The Emissions Intensity Factor is an estimate used when calculating CA Industry Assistance of the emissions associated with a megawatt hour of electricity. Per D.21-08-026, Energy Division posts this number online:

	PG&E	SCE	SDG&E	Offsite CHP	Unspecified
Pre-2022	0.291	0.379	0.379	0.431	0.379
2022	0.188	0.278	0.308	0.431	0.379
2023	0.181	0.270	0.300	0.431	0.379
2024	0.178	0.262	0.292	0.431	0.379
2025	0.227	0.254	0.284	0.431	0.379
2026	0.243	0.250	0.280	0.431	0.379

Numbers in $MTCO_2e/MWh$

Cap Adjustment Factor

This factor is specified in the CARB Cap-and-Trade regulation and accounts for annual decline in the total number of allowances issued.:

Year	Cap Adjustment Factor
	NAICS Codes 324199 (coke

	Most NAICS Codes	calcining only), 325311, 327310, and 327410
2022	0.783	0.892
2023	0.749	0.875
2024	0.715	0.858
2025	0.681	0.841
2026	0.647	0.824

From Table 9-2 of the CARB Cap-and-Trade Regulation

Contact

While you can always contact the CPUC if you have concerns or questions, we suggest you try your utility first. That is because your utility can directly access your individual records, tell you whether you're receiving the credit, and correct any errors directly.

If you have questions about CA Industry Assistance, email industry.assistance@cpuc.ca.gov.

California Industry Assistance FAQs

Who is eligible for Industry Assistance?

Entities that primarily operate in industrial sectors that qualify for California Industry Assistance under CARB's Cap-and-Trade Regulation, regardless of the amount of emissions produced, are eligible for California Industry Assistance. A facility is eligible if its principal source of revenue comes from a product, activity, or service that is eligible.

Eligible industries are listed by 2007 North American Industry Classification System (NAICS) Code in Table 8-1 of CARB's Regulation. See the current list of EITE-eligible NAICS codes here.

Facilities must be customers of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), Liberty Utilities (CalPeco Electric) LLC, Pacific Power (PacifiCorp), or Bear Valley Electric Service.

When do I receive my California Industry Assistance?

Most facilities will receive their credit in April each year.

How much assistance will I receive?

The CPUC Energy Division will calculate the level of California Industry Assistance for each eligible facility. The amount of the credit is determined through the use of emissions efficiency benchmarks, which reward businesses that have taken early action to reduce GHG emissions. This approach will also ensure that, in the future, these industries have a strong incentive to produce products in California in the most greenhouse gas-efficient way possible.

If your facility is not a covered entity in the Cap-and-Trade Program, you will receive a credit amount that is based on a benchmark of your historical electricity use.

If your facility is a covered entity, you will receive assistance either based on a benchmark of your historical electricity use or based on the efficiency and level of your production.

To learn more about how the CPUC calculates your credit, please read D.16-07-007 and review the formulas in Appendix A of this decision. Updates to some formulas and to the Dollar Conversion Factor and GHG Intensity Factor were made in D.21-08-026.

Will I get a bill credit or check?

By default, eligible facilities will receive California Industry Assistance as an electricity bill credit.

Only covered entities under the Cap-and-Trade Program may request a check instead of a bill credit. If you're eligible to request a check, your utility will contact you.

All customers receiving California Industry Assistance have the option to "cash out" any remaining bill credit by requesting a check from the utility, if their credit amount exceeds their total bill amount.

What is the attestation process?

The attestation process applies to industrial facilities that want to demonstrate that they are eligible to receive California Industry Assistance. These facilities do not report to CARB under MRR and must sign an attestation form to demonstrate to the CPUC that they primarily operate in an industrial sector that qualifies for California Industry Assistance.

What is a facility?

For the purposes of the California Industry Assistance Credit, a facility is described in CARB's Cap-and-Trade Regulation as "any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas…"

For the full definition please refer to Section 95802(a)(144) of the Cap-and-Trade Regulation.

Appendix C

Standardized Regulatory Impact Assessment, Department of Finance Comment Letter, and CARB Responses

Proposed Amendments to the Cap-and-Trade Regulation

CARB staff is also considering a new form of industrial allocation to minimize emissions leakage and incentivize GHG emissions abatement actions in hard to abate sectors, such as electrification of natural-gas-fueled industrial processes or procuring low-carbon energy. This industrial incentive allocation provides allowances to support GHG emission reductions while keeping efficient industrial production in California, and aligns with the industrial decarbonization strategy outlined in the 2022 Scoping Plan Update, which showed that:

- Where technically or commercially feasible, cost barriers limit needed widespread electrification of industrial processes; and
- Limited supplies of certain replacement fuels like biomethane or low-carbon hydrogen should be prioritized for sectors where direct electrification may not be feasible.

Updates to Utility Allocation, Consignment, and Revenue Spending Requirements

CARB staff is proposing to update 2025-2030 allowance allocation for Electrical Distribution Utilities (EDUs) to reflect the 60% Renewable Portfolio Standard (RPS) in 2030 pursuant to SB 100 (De Leon, Chapter 312, Statutes of 2018) RPS procurement targets and newly available data from the California Energy Commission's 2022 Integrated Energy Policy Report (CARB 2023e). EDU allowance allocation is designed to address the anticipated Program cost burden for each utility. Since EDU allowance allocation is set in advance,[9] individual utilities may be over- or under-allocated depending on how the actual electricity load or generation mix matches projections. More recent data and policy evolution shows that changes to 2025-2030 EDU allocation are needed to more accurately reflect the expected Cap-and-Trade Program cost burden in coming years.

Staff are also proposing to require EDUs that are publicly owned utilities (POUs) to consign all their allocated allowances to auction and spend the resulting proceeds on projects that benefit ratepayers. Currently, POUs can choose whether to consign their allocated allowances to auction or to use some or all allocated allowances directly for Program compliance. Staff used the historic proportions of allocated allowances used by POUs for Program compliance or for auction consignment to project the changes in future proceeds and compliance costs associated with full consignment.

Replenish the Voluntary Renewable Electricity Allowance Reserve

CARB staff is proposing to place a total of approximately 5.5 million additional allowances from 2025-2030 annual budgets into the Voluntary Renewable Electricity (VRE) Reserve account. The VRE Program recognizes investments in renewable electricity generation beyond what is required by the RPS, supporting the transition of the electricity sector to 100% zero-carbon generation by 2045, as mandated by SB 100. Adding allowances to the VRE Reserve account is essential to continue the VRE Program, as allowances currently available in the VRE Reserve account are projected to be exhausted in the next few years.

[9] Current 2021-2030 EDU allowance allocation is listed in Table 9-4 of the Regulation.

BUSINESS > ECONOMY • News

Anheuser-Busch to close Bay Area brewery, a loss of 475 jobs



(Chris Riley/The Reporter)

The Anheuser-Busch Budweiser Brewery in Fairfield has made the announcement that it will close down the Fairfield plant in early 2026. (Chris Riley/The Reporter)

By **ROBIN MILLER** | Vacaville Reporter
PUBLISHED: December 12, 2025 at 6:46 AM PST

Anheuser-Busch will shut down its Fairfield brewery in early 2026, city officials confirmed Thursday, marking the loss of one of the community's largest employers and dealing what leaders say will be a major economic blow.

Mayor Catherine Moy announced the closure in a social media post, calling the news "horrible" and "devastating." She said City Manager David Gassaway notified her Thursday morning after receiving confirmation from the company.

RELATED: **Bay Area gains jobs in September as California suffers losses**

In a message to the City Council, Gassaway wrote that Anheuser-Busch plans to close three facilities nationwide, including Fairfield's, and that all employees will be offered jobs at other company locations across the country. A specific closure date has not yet been set, beyond "early 2026," he said.

The Fairfield brewery first opened its doors in 1976. Anheuser-Busch (the original U.S. company) was sold to Belgian brewer InBev in 2008, forming Anheuser-Busch InBev (AB InBev), the world's largest brewer, but AB InBev still operates the Anheuser-Busch brand, selling off some smaller brands while also acquiring new ones to grow its portfolio. The Fairfield site as of 2024 was brewing more than 20 of Anheuser-Busch's brands.

Gassaway warned of significant local impacts, including the loss of jobs and reduced revenue for the city's water utility. He added that the specialized nature of the brewery will make it challenging to find a new user for the site, though the city is already seeking to connect with the company's real estate team to explore reuse options.

"To be clear, I don't think that will be an easy task given the large and highly specialized nature of the facility," he wrote to the mayor and council. "I hope I'm wrong though."

Moy said the city is mobilizing immediately to support affected workers and search for potential buyers for the plant.

Skip Ad

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“It’s shocking,” she said of the announcement. “I remember when that plant first opened. It was a big deal and it has been a big part of Fairfield.”

The plant employs hundreds of people and Moy said the news coming just before Christmas shows a “heartlessness” she cannot stand.

She said she spoke with company officials early Thursday and they indicated it would close in the first part of February but had no real explanation of why the plant has been targeted for closure.

“There has been no reason for why and we didn’t know anything about this. It hit us from out of nowhere this morning,” she said.

A spokesperson did not give specifics for why the Fairfield site was closed but issued a formal statement saying, “Over the last five years we have taken steps to update and modernize our U.S. manufacturing operations, investing nearly $2 billion in our 100 facilities across the country; after conducting a thorough review, we have decided to sell our Newark, NJ facility to the Goodman Group and to close our facilities in Fairfield, CA and Merrimack, NH in early 2026; we will be shifting production from these three facilities to our other U.S. facilities and these changes will enable us to invest even more in our remaining operations and in our portfolio of growing, industry-leading brands.”

The statement said the company “will support the approximately 475 full-time employees currently working at these three facilities by offering all of them a full-time role elsewhere in our U.S. operations.”

Moy noted that the closure is the third large facility to announce its departure in Solano County. “Benicia is losing a refinery,” she said, referring to the announced closure of the Valero refinery. “We lost Copart, a huge company, and now Budweiser.”

And she put the blame squarely on state government.

“Fairfield and other Solano cities have lost major businesses because California is a hostile business environment,” she wrote on social media. “A one-party super majority is like a dictator … We have the most expensive gas, energy, grocery prices, and housing. We also have the highest unemployment, one of the lowest in literacy rates with our youth. And our Legislature keeps eating away at your rights to make policy at the city level. It’s so sad and maddening.”

She said now the city is turning its focus to the impacts locally.

“Now we must help our people and look closer at impacts to Fairfield,” Moy wrote in her post. She said on the phone that the city will work with local employment advisors to help impacted employees.

The Fairfield brewery has long been a major industrial presence in Solano County, and its closure shocked residents, many of whom pointed out that the company had invested more funding in the site as recently as 2024 – when it announced a $7 million investment in the Fairfield brewery for capital infrastructure projects that support ongoing improvements at the facility, including updates to the brewery’s roofing, equipment overhauls, new lighting, and other structural repairs.

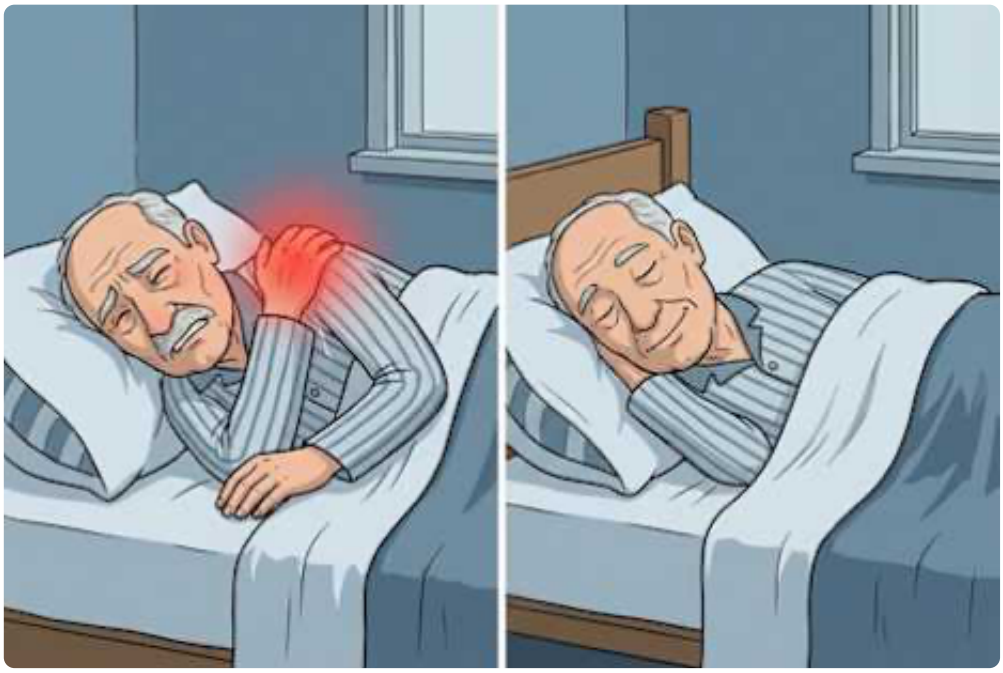
“These investments in our Fairfield brewery strengthen capabilities across our entire business to ensure our northern California facility continues to brew the great-tasting, high-quality products that have satisfied drinkers for generations,” said Brendan Whitworth, CEO of Anheuser-Busch said at the time.

Wayne Senalik, who retired from Anheuser Busch after working at the Fairfield site for more than 34 years, including 11 as the plant manager said Thursday he is “saddened” by the announcement.

“I think it is a sad time for the community,” he said. “It was a good company but once they sold, there were a lot of changes and I know the capacity of the brewing was way down from when we were there.”

Around the Web

REVCONTENT



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RejuvaCare

California Air Resources Board

Public Hearing to Consider the Proposed Amendments to the Regulation for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms

Staff Report: Initial Statement of Reasons

Date of Release: January 20, 2026
Scheduled for Consideration: May 28, 2026

used the best-in-class approach and set the benchmark at the most efficient facility. Electricity efficiency benchmarks are added in a new column in Table 9-1 of the Regulation.

5. Manufacturing Decarbonization Incentive Allocation

Pursuant to the requirements of AB 1207 direction that the Program minimize emissions leakage risk and support the state's climate targets, the Proposed Amendments include a Manufacturing Decarbonization Incentive Allocation (Incentive Allocation) designed to both minimize emissions leakage risk and support decarbonization of California's manufacturing industry. California's manufacturing industry includes a diverse range of facilities, including cement plants, glass manufacturers, paper manufacturers, mining operations, metal processors, and food processors, among others. Combustion of fossil gas, other gaseous fossil fuels, and solid fossil fuels provide energy to meet three broad industry needs: electricity, steam, and process heat.

Decarbonizing manufacturers depends on displacing fossil fuel use with a mix of electrification, solar thermal heat, biomethane, low- or zero-carbon hydrogen, and other low-carbon fuels to provide energy for heat and reduce combustion emissions and reduction of process emissions through alternative materials and sequestration. The costs of some decarbonization options continue to be greater than allowance prices, contributing to an increased leakage risk for the manufacturing sector (CARB 2024f). To minimize this leakage risk, the Proposed Amendments include an allowance allocation mechanism for covered manufacturing facilities that incentivizes on-site decarbonization actions from 2027 through 2038. This allocation provision will incentivize a set of GHG emissions reduction strategies that can achieve GHG emissions reduction at facilities thereby decreasing compliance costs and reducing a facility's emissions leakage risk.

These Proposed Amendments align with the industrial strategies contained in the 2022 Scoping Plan Update (CARB 2022a) to achieve deep emissions reductions in this sector. The 12-year period for the Incentive Allocation aligns with newly proposed compliance periods, and is expected to result in substantial GHG emissions reduction, create a long-term market signal for the development and deployment of new technologies, and provide support for manufacturing facilities that lost federal funding opportunities such as those previously available under the Inflation Reduction Act.[29] The Proposed Amendments would provide annual allocation for eligible facilities and decarbonization strategies with a specified end date to provide certainty to industry and to reflect expected long-term reductions in abatement costs. This incentive allocation mechanism is also reflective of Board direction to prioritize policy discussions related to the transition of biomethane into hard-to-decarbonize sectors (CARB 2023d).

[29] The 2019 Bipartisan Infrastructure Law and 2022 Inflation Reduction Act included large investments to decarbonize the manufacturing industry. These investments have largely been canceled by the current federal government.

Resources

About The NARUC Desk Reference Manual
1. History of Utility Regulation and Regulatory Agencies
3. Ratemaking Fundamentals and Principles
4. Rules, Proceedings and Process
5. Ethics and Conflict of Interest

3. Ratemaking Fundamentals and Principles

Ratemaking is the foundation of utility regulation. Commissioners will learn the fundamentals

3.1 Just and Reasonable Rates and Affordability

One key mission for state PUCs is setting just and reasonable rates for ratepayers. Rate affor design.

- Cost Allocation and Revenue Requirement
  - Cost allocation is one of the major steps in the traditional regulatory process t are primarily determining how to equitably divide a set amount of costs, typica among several broadly defined classes of ratepayers. The predominant impact group of customers pays for which costs. In many cases, this is the share of cc customers and industrial customers.[33]

- Revenue Requirement Determination
  - The basic formula for Revenue Requirement Determination can be expressed RR =ra (RB) + O&M + D + T
    where:
    RR = total test year (annualized) revenue requirements from rates
    ra= authorized (not guaranteed) rate of return to compensate debt holders ar
    RB = rate base (original cost of invested utility plant in service net of accumul construct
    O&M= operation & maintenance expenses, including administrative & general
    D = depreciation and amortization expense
    T = taxes other than income and income tax expense
    Rates generally reflect RR divided by billing determinants,[34] such as sales.
    Alternatively, for regulated utilities, the Revenue Requirement = Net Income (

- Other Accounting Terms frequently used in RR determination rate case:
  - **Contributions in Aid of Construction (CIAC)**. CIAC is a nonrefundable donat individuals, governmental agencies or others for construction or property-ad excluded from the rate base on which the utility may earn an approved return
  - **Allowance for Funds Used During Construction (AFUDC)**. AFUDC is a non- interest costs of debt and the required return on preferred and equity funds u included in the CWIP accounts and income. This portion of the carrying value utility company\'s rate base and is recovered through depreciation in rates.
  - **Construction Work In Progress (CWIP).** CWIP is a plant under construction some or all assets under construction into the rate base (CWIP) as they are cc
    - Recoverable costs generally include used and useful plant in service and p expenses.[37] Sometimes the state commission sets budget ceilings for cap such a ceiling is exceeded, utilities\' excessive spending will not be allowe the commission\'s prior decisions.

- Cost allocation includes three steps: (1) Functionalization; (2) Classification, and (3)
  - *Functionalization*: In the case of vertically integrated utility, costs can be relate

billing and customer service. To classify the cost items to each function is calle
choice state, the utility functions are limited to distribution, billing, and custom

- *Classification:* The next step after functionalization is classification. The costs c
demand-related (kW) or customer-related (such as billing and metering).
- *Allocation:* The third step is allocation. The detailed cost categories can be attr
residential, commercial, or industrial. Subclasses exist for each category. For e
commercial and large commercial classes.
    - In cost allocation, two principles are generally followed: (a) Fairness of the
    costs of service among the different consumers and (b) Avoidance of "un
    - In the rate case, the utilities generally submit a class cost of service study
    each customer class, from functionalization, classification, to allocation.
    - After finishing the class cost of service study, the utility can work on the
    customer classes are inter-class rate design and the determination of ho
    charge and demand charge is intra-class rate design.
    - Thus, the revenue requirement determines the size of the pie, while the
    revenue is allocated to which class – or determining the slicing of the pie
    - Obviously, the utility generally pays more attention to size of the pie rath
    groups of customers will be affected by both the size of the pie and the p
    requirement), assigned to the class. Given it is a zero-sum game, it is diffi
    customers interests. For example, if one assigns 30 percent to residentia
    the remaining costs need to be shouldered by industrial class – 30 perce
    costs for remaining classes will be less.
    - In such rate design, people also pay attention to the following guidelines:
        - (a) Cost causation and cost averaging will be considered.
        - (b) Marginal cost pricing sometimes was considered but is used less
        - (c) Matching benefits with costs.
        - (d) Gradualism. Keep rate stability for customer groups rather than c
        - (e) Rates should not be discriminatory.
        - (f) Rates should be designed based on accurate revenue requiremer
        resubmitted.
        - (g) Rate design should also consider efficiency and equity. Fully alloc
        efficient and equitable.
        - (h) Socialized costs. In many cases, the socialized costs (such as low-
        kWh (or volumetric rates). Another example is the System Benefit C
        management programs such as energy efficiency and demand respo
    - There are many ways to slice the pie in rate design and cost plus non-cos
    - Ideally, if there is no subsidy, then each class should earn a rate of return
    However, from various considerations, some classes could be subsidized.
    subsidized by commercial and industrial customers. When subsidy exists,
    Some classes will be earning more, and some classes will be earning less
    with negative rate return implies that the cost of the class exceeds the re

[33.] Electric Cost Allocation for a New Era A Manual by Jim Lazar, Paul Chernick and William Marcus. RAP, January 2

[34.] For customer charge, billing determinants would be total number of customers times 12. For demand charge, th
for kWh charge, the billing determinants would be annual kWh by the class.

[35.] Notes from IPU, Annual Regulatory Studies Program, CAMP NARUC, August 2021 by Ken Rose.

[36.] https://financialaccounting.com/freebook.html

[37.] Notes from CAMP NARUC, August 2021.

[38.] Ibid. at 27.

3.2. Variable Costs, Fixed Costs and Customer Charge

There are three basic rate components:

- Customer charge: monthly charge that generally does not vary with respect to any usag charge include billing, metering, and customer service.
- Volumetric energy charges: prices based on kWh usage during the billing period.
- Demand charges: prices based on metrics of kW or kilovolt-ampere (kVA) power draw c options allow for a wide range of variations based on season, time of day and type of de from season to season or month to month. Both demand charges and energy charges r over a period of time. Even though demand charges are typically denominated in kWs a demand charges are actually imposed on consumption within short windows, often the the billing period.[39]

[39.] Ibid. at 30.

3.3. Key Issues for a Rate Case

- Rate Case generally requires both technical and legal staff's joint efforts in the Commiss
- Commission's Accounting Staff will look into utility's revenue requirement determinatio and final tariff (rates) determination.
- Some states have a legislative mandate for rate case length, and some do not.
- One of the most controversial finance/accounting issues is Rate of Return determinatio of debt and equity for the Company.
- Obviously, the Company generally prefers higher rate of return and the ratepayer group therefore one of the most controversial issues in rate case.
- Most rate cases involve formal litigation, testimony, rebuttal testimony and cross examir about state Commission's decision, they could submit a "reconsideration" filing after the on reconsideration is still not satisfactory, the party could seek court decisions against t
- Sometimes Settlement is reached for rate case. Settlement generally reduces litigation

3.4. Different Types of Rates - Policy Initiatives

- Time of Use Rates (TOU rates)
  - Rates vary with time of the day. TOU rates can have two or three rating periods – TOU rates are designed to stimulate more consumption in the off-peak period. For reduce peak impact. Electric dish washers can be run during off-peak period to rec

- Dynamic Pricing
  - Dynamic pricing is designed to link retail and wholesale price signals so that consur caused by extreme weather or high peak demand. Customers with advanced meter program options (Critical Peak Pricing (CPP), Critical Peak Rebate (CPR) or Hourly reduced due to behavior change by customers. Customers will receive day-ahead r they anticipate extreme weather the next day and are expected reduction in dema can earn additional rebates under CPR program and also contribute to reduced sys

- Income based rates
  - o Low-income customers may receive different rates (lower rates) or receive credit decided by state PUCs. For example, D.C. has the low-income customer class who their bill. D.C. also has a senior and disabled citizen's class who receive $7.50 mont

- Net Metering rates
  - Net metering customers have on site solar panels or DG facilities which allow then import, they would need to pay full retail rates but if they export, they would be ge could be generation rate only, or full retail rates (including generation, transmissior different net metering rates for such programs.

- Declining Block Rates and Increasing Block Rates
  - Declining block rates – Some states have set their rates by blocks of consumption. block", e.g., first 400 kWh of consumption.
  - The subsequent block could have higher or lower block rates. If it is lower, it encou encourages conservation. This type of rate structure is called Increasing block rate

[40.] In PJM, Maryland and Delaware have adopted CPR and customers received rebates during summer for reduced c

3.5 Alternative Form of Regulation[41] (AFOR)

- Some State Commissions have switched to Alternative Forms of Regulation rather than the AFOR: (A) protects consumers; (B) ensures the quality, availability, and reliability of r of the public, including shareholders of the utility, then the regulators may choose AFO types of AFOR generally include the following categories:
  - *Multi-Year Rate Plan:* MRPs are a price mechanism that sets a utility's base rates ar 12-month period. MRPs specify rates beyond the rate effective year of a rate case forecasts for allowable rate changes over the duration of the plan. For example, ins when conditions change, an MRP may forecast what these conditions are and adju
  - *Performance-Based Regulation Plan ("PBR").*PBR is an approach to regulation des compared to traditional regulation by tying growth in revenues or rates to a metric an opportunity for greater profits by constraining costs rather than increasing sale mechanisms (e.g., multi-year rate plans, revenue decoupling) and/or performance i mechanisms, benchmarking, earnings sharing mechanisms).
  - *Formula Rates:* Formula rates allow utilities to make prospective annual adjustment With formula rate regulation, utilities can make prospective rate adjustments based rate case. Generally, the formula rate is primarily centered on a utility's allowed rate formula rates spans multiple years and rates may change annually based on project case. Therefore, the formula is set to allow the utility the opportunity to earn a RO acts as a cap/limitation on the amount that rates can change year-over-year in orc
  - *A Fully Forecasted Test Year (FFTY):* A FFTY is a ratemaking tool that allows utilitie sales and revenue of a hypothetical future 12-month period that will help to impro FFTY is the first year of the rate effective period that follows a base rate case.[43]
  - *Surcharges and Riders:* See section below.

[41.] See DCPSC website, www.dcpsc.org, Order No. 20273.

[42.] See NRRI, Report No. 16-08 October 2016, Multiyear Rate Plans and the Public Interest by Ken Costello.

[43.] DCPSC Order No. 20273 at 10 and 11.

3.6. Riders, Trackers and Decoupling Mechanism

- Defining Riders, Trackers, and Decoupling Mechanisms
  - Riders, trackers, and decoupling mechanisms allow a utility to recover its actual cos case. Decoupling mechanisms allow utilities to separate profits from total sales to e the utility earns no more or less than its revenue requirement.[44]

- List of States that have Water-Related Riders[45]
  - Will include a list of states with DSICs/QIPs, CWIPs, or CapEx riders and those wit revenue stabilization riders.

- Distinguished from Ratemaking
  - Trackers, riders, and decoupling are unique methods of cost recovery because they general rate case. Riders are for single volatile and variable costs/items and have no

- Purpose & Policy
  - Riders, trackers, and decoupling mechanisms all function as means through which

more certainty and less risk to investors.

- Procedure, Reconciliation, True-Ups
  - Procedural Mechanisms & Considerations
    1. Riders, trackers, and decoupling mechanisms are either created statutorily throu
    state utility commission action.
  - Considerations for Regulators
    2. When making decisions related to the implementation of riders and trackers, re
    confirm whether:
    a) A utility's costs were incurred prudently and,
    b) If the need exists for infrastructure of the specific size or type requested.
  - The True-Up
    3. The annual reconciliation, or "true-up" mechanism reconciles amounts collectec
    determinants) with the actual, prudently incurred recoverable costs during each ye
    up is generally due to the difference between actual cost recovered vs. projected c
  - Deadline for action
    4. Rider filings often do not have statutory deadlines for commission action, but th
    year.

- Benefits and Limitations of Riders
  - Policy
    5. The implementation of riders can cause rates to increase gradually annually, help
    from a sudden increase in rates after a formal rate case. They can also reduce regu
    more lengthy formal rate cases.
  - Perceived Benefits and Limitations
    6. Surcharges can effectively guarantee recovery of variable utility costs. However,
    reduce the utility's incentives to control costs and encourage utilities to spend mor
  - o Actual Benefits and Limitations
    7. In a traditional rate case, regulators can only investigate whether these costs we
    whether the project expenditures became used and useful.
    8. However, surcharges allow regulated utilities to make necessary infrastructure ir
    systems to improve the quality of service to customers. Infrastructure related surcl
    utilities more timely cost recovery for reliability related capital expenditures. Penns
    – DSIC – is one good example.

[44.] https://www.moenergy.org/publications/energy-perspectives/summer-2015/decoupling-faqs/

[45.] https://brattlefiles.blob.core.windows.net/files/7485_alternative_regulation_and_ratemaking_approaches_for_wat

[46.] https://www.puc.pa.gov/general/consumer_ed/pdf/DSIC_FS.pdf

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60% RPS Procurement Rules

The California RPS Program was established in 2002 by Senate Bill (SB) 1078 (Sher, 2002) with initial requirement that 20 percent of electricity retail sales must be served by renewable resources by 2017. The program was accelerated in 2006 under SB 107 (Simitian, 2006) which required that the 20 percent mandate be met by 2010. In April 2011, SB 2 (1X) (Simitian, 2011) increased the mandate to 33 percent RPS by 2020. In 2015, SB 350 (de León, 2015) mandated a 50 percent RPS by December 31, 2030. SB 350 also includes interim annual RPS targets with multi-year compliance periods and requires that 65 percent of RPS procurement must be derived from long-term contracts of 10 or more years. In 2018, SB 100 (de León, 2018) increased the RPS to 60 percent by 2030 and established a goal for 100 percent of the State's electricity to come from renewable and carbon-free resources by 2045.

RELATED PROGRAMS

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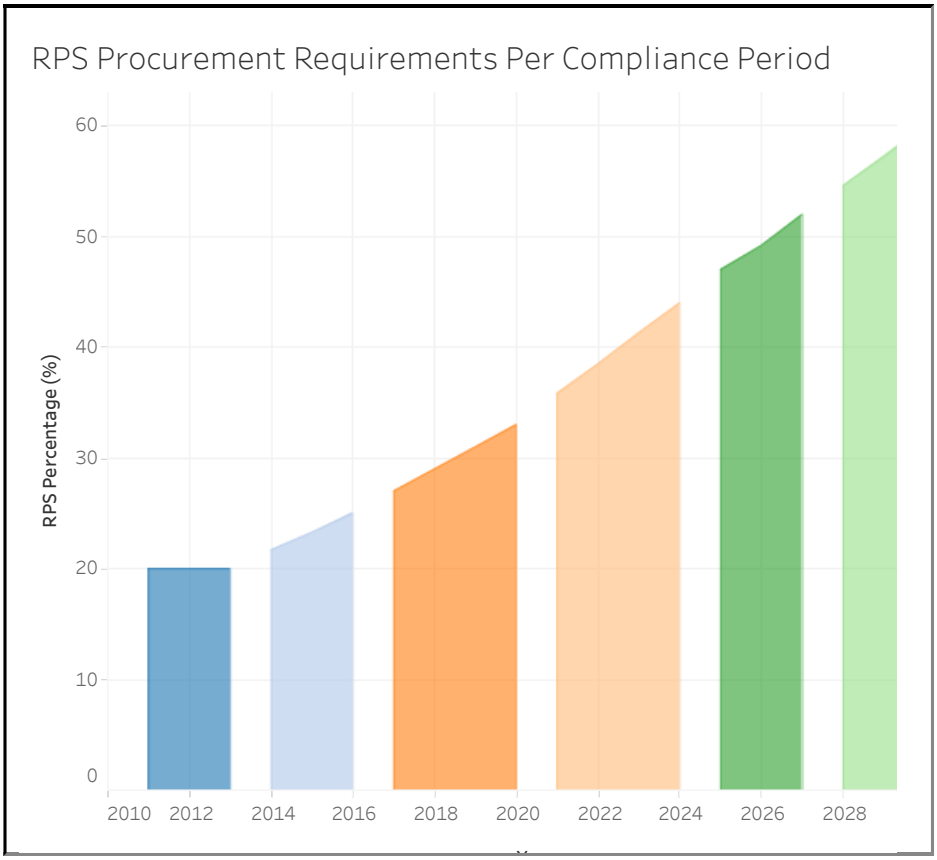
The Role of the CPUC

The CPUC is responsible for establishing RPS requirements for retail sellers (investor-owned) utilities, community choice aggregators, and electric service providers). The CPUC determines compliance based on each retail seller's procured renewable energy credits (RECs), as verified by the California Energy Commission (CEC). Lastly, the CPUC is responsible for establishing RPS enforcement procedures and imposing non-compliance penalties for retail sellers.

60% RPS Procurement Requirement

Compliance with California's RPS program is determined by the amount of renewable energy credits (RECs) retired for compliance within multi-year compliance periods. In Decision (D.) 11-12-020, the Commission implemented the new RPS procurement quantities established in Pub. Util. Code § 399.15(b), for all retail sellers (investor-owned utilities, community choice aggregators, and electric service providers). Compliance with California's RPS program will be determined by the amount of renewable energy credits (RECs) retired for compliance within the multi-year compliance periods. The methodology for calculating RPS procurement requirements through 2030 applies a linear trend between the compliance period targets defined in SB 100 (40% by December 31, 2024; 52%

by December 31, 2027 and 60% by December 31, 2030). In all later three-year compliance periods, retail sellers must procure at least 60% of their retail sales from RPS-eligible resources.



60% RPS Portfolio Content Categories

DEFINITION OF THREE PORTFOLIO CONTENT CATEGORIES

Renewable generation facilities may be located anywhere within the WECC region and sell energy and /or renewable energy credits (RECs) to a California retail seller of electricity to meet its RPS obligation, provided the facility meets all RPS-eligibility criteria established by the California Energy Commission (CEC). The CEC's RPS Eligibility Guidebook is available here.

California's RPS program defines all renewable procurement acquired from contracts executed after June 1, 2010 into three portfolio content categories, (PCC). In D.11-12-052, the CPUC implemented the new portfolio content categories established in Public Utilities Code § 399.16 (b), pursuant to SB 2 (1X) and continued in SB 350.

Refer to D.11-12-052 and D.16-12-040 for complete rules governing the classification of RPS procurement. The determination of whether RECs fall into Category 1, 2 or 3 for the purposes of compliance with RPS program will be made at the end of each compliance period.

- Category 1: Renewable energy and renewable energy credits (RECs) from the

facilities with a first point of interconnection within a California Balancing Authority (CBA), or facilities that schedule electricity into a CBA on a hourly or sub-hourly basis.

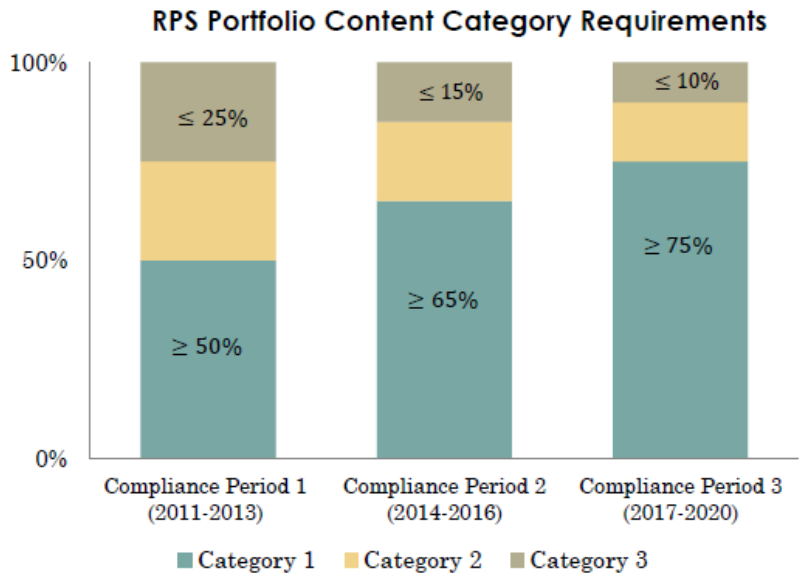
- Category 2: Renewable energy and RECs with incremental electricity, and/or substitute energy, from outside a CBA. Generally, Category 2 RECs are generated from out-of-state renewable facilities and require a Substitute Energy Agreement that details the simultaneous purchase of energy and RECs from a RPS eligible facility.

- Category 3: RECs that do not include the physical delivery of the energy that generated the REC. Generally, Category 3 RECs are associated with the sale and purchase of the RECs themselves, not the energy.

PORTFOLIO BALANCE REQUIREMENTS

In addition to complying with RPS procurement requirements and PCC classifications, most retail sellers have specific requirements for the balance or mix of procurement from contracts that are executed after June 1, 2010. Specifically, these retail sellers must procure a minimum level of Category 1 RECs, which increases over the initial three multi-year compliance periods. There is a maximum limit on the amount of Category 3 procurement that may be used in each compliance period, which decreases over the same time frame.

The figure below depicts the PCC limits and how they adjust across the compliance periods until 2020, at which point they remain at those limits for each successive compliance period.



Calculation of the Market Price Benchmarks for the Power Charge Indifference Adjustment Forecast and True Up

October 2, 2024

Pursuant to Decision (D.) 22-01-023, Energy Division issues the following values for the Power Charge Indifference Adjustment (PCIA) Forecast and True Up, which the investor-owned utilities (IOU) will use for their 2025 Energy Resource Recovery Account (ERRA) Forecast Updates in early October, 2024. The PCIA calculations incorporate Market Price Benchmarks (MPB) – the Energy Index, Renewable Portfolio Standard (RPS) Adder, and Resource Adequacy (RA) Adder – as defined by D.18-10-019 and revised by D.19-10-001, D.22-01-023 and D.23-06-006. D.22-01-023 directed Energy Division to calculate and distribute these values by the first business day in October each year and D.23-06-006 directed Energy Division to calculate and distribute a Greenhouse Gas-Free (GHG-Free) forecast MPB.

The reported GHG-Free values do not meet the 1,000 GWh threshold set by D.23-06-006[1] to set an MPB. As such, the MPB for GHG-Free resources is $0 per MWh.

There has been an unforeseen delay to the release of the RA MPB.

Table 1. 2024 Market Price Benchmarks Used in PCIA Calculations

2024 Final Market Price Benchmarks				
		PG&E	SCE	SDG&E
RA Adder	System RA	Not available		
	Local RA	Not available	Not available	Not available
	Flexible RA	Not available		
RPS Adder		$65.63		

Table 2. 2025 Forecast Market Price Benchmarks

2025 Forecast Market Price Benchmarks				
		PG&E	SCE	SDG&E
	On-Peak	$55.02	$41.54	$41.54

Energy Index	Off-Peak	$53.18	$47.84	$47.84
RA Adder	System RA	Not available		
	Local RA	Not available	Not available	Not available
	Flexible RA	Not available		
RPS Adder		$67.06		

Market Price Benchmarks

The PCIA calculation was established in D.11-12-018 and has most recently been refined in D.23-06-006. The PCIA is the amount by which the IOU is indifferent to the energy power costs after load departs from bundled service and is equivalent to an IOU's total PCIA- eligible portfolio costs less the portfolio's market value in a given year. Market value is defined in D.19-10-001 as "the estimated financial value, measured in dollars, that is attributed to an IOU portfolio of energy resources for the purpose of calculating the Power Charge Indifference Adjustment for a given year."[2] D.19-10-001 defines MPBs as "estimates of the value per unit (not total portfolio value) associated with three principal sources of value in IOU portfolios (energy, resource adequacy, and renewable energy)."[3] MPBs are multiplied by the relevant portfolio volume as part of the overall calculation of market value. The forecasted adders are mechanisms that aim to reduce uncertainty of the indifference amount, and the true up adders are mechanisms that aim to align realized market revenues with forecasted values.

Energy Index

Energy Index is the MPB that reflects the estimated market value of each unit of energy in an IOU's PCIA-eligible portfolio, in dollars per megawatt hour ($/MWh). The Energy Index was previously referred to as the "Brown Power Index."[4]

The Energy Index above was calculated using Platts-ICE Forward Curve-Electricity market data. Energy Division received a Platts on-peak and off-peak forward price for each month of 2024 and each electrical zone (NP15 and SP15), as calculated on each individual non-holiday weekday from September 1, 2024 through September 30, 2024 (inclusive). Using this data, Energy Division calculated a 2024 monthly average price for each peak period and each electrical zone, thereby arriving at the values in Table 1 above. The IOUs will use weighted averages of these values in the October Updates to their 2025 ERRA Forecast Applications.

RPS Adder

The RPS Adder is the MPB that reflects the estimated value (incremental to the Energy Index) of each unit of RPS-eligible energy that is attributable to the fact of that eligibility, in dollars per megawatt hour ($/MWh). Both the forecast and the final adders are based on bundled, short-term (under ten years), index-plus[6], Portfolio Content Category 1 (PCC-1)[7] transactions.

- **The Forecast RPS Adder** was calculated using the volume-weighted average of all eligible IOU, CCA, and ESP market transactions executed from September 2023 through August 2024, with delivery in 2025.
- **The Final RPS Adder** was calculated using the volume-weighted average of all eligible IOU, CCA, and ESP market transactions executed from December 2022 through August 2024, with delivery in 2024.



Cost Projections for Utility-Scale Battery Storage: 2023 Update

Wesley Cole and Akash Karmakar

National Renewable Energy Laboratory

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
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Contract No. DE-AC36-08GO28308

Technical Report
NREL/TP-6A40-85332
June 2023

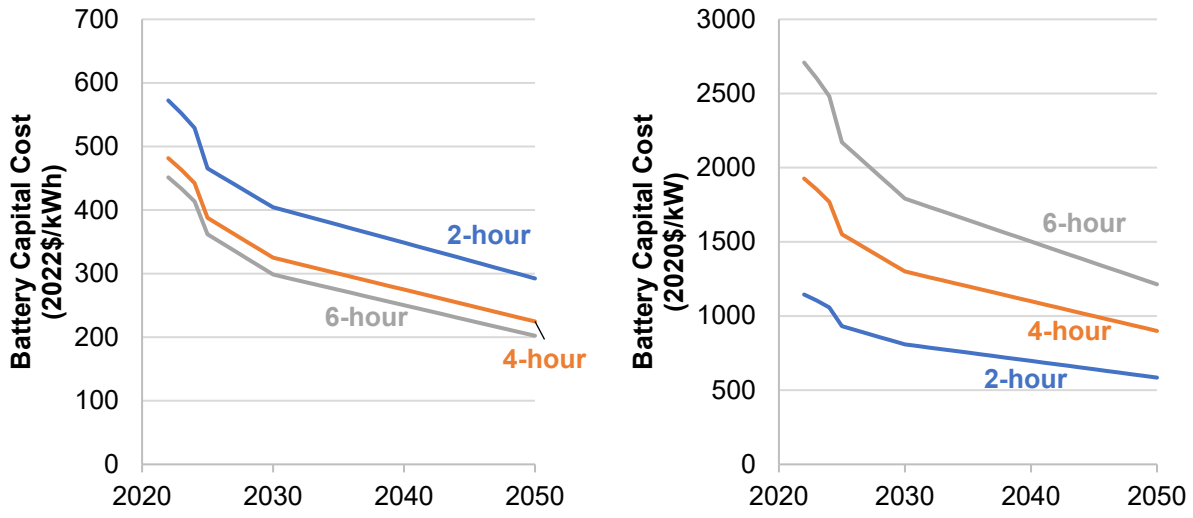


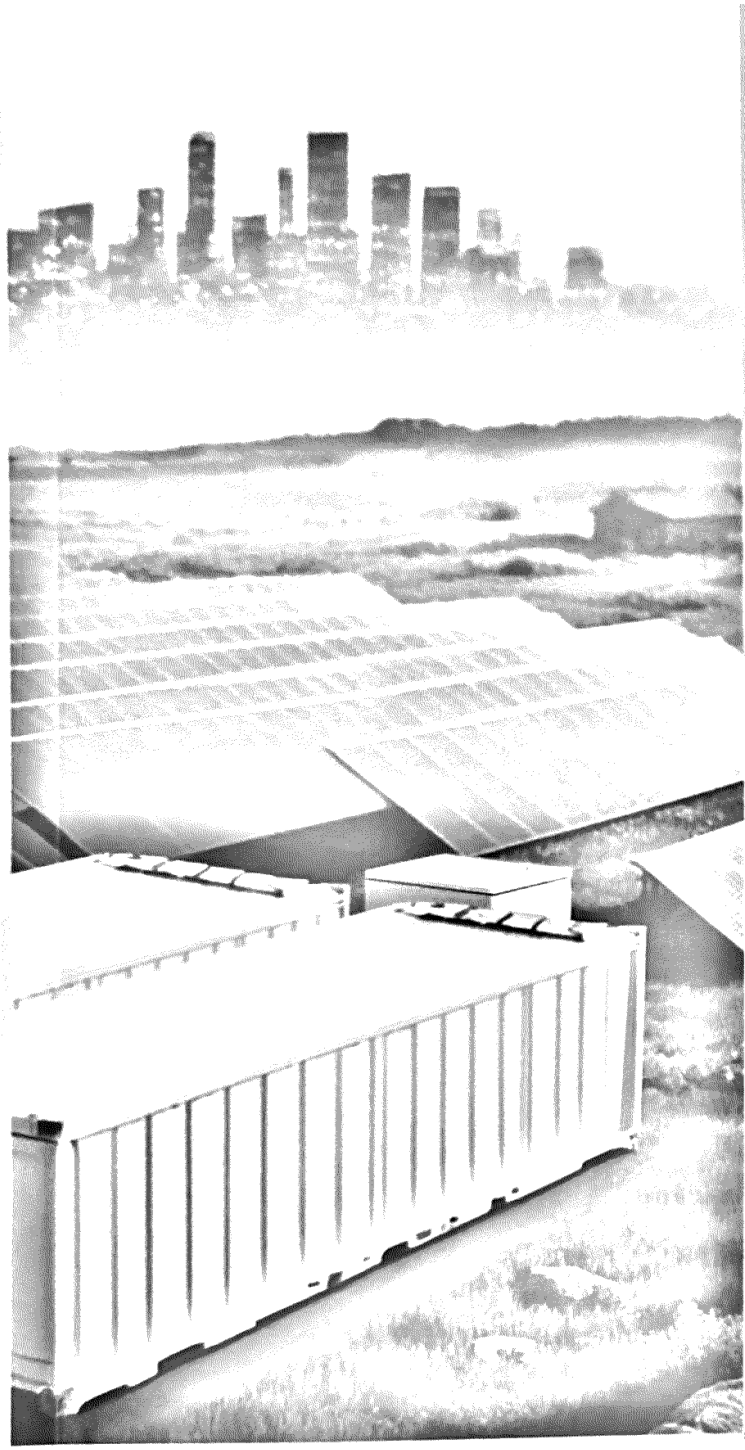
Figure 5. Cost projections for 2-, 4-, and 6-hour duration batteries using the mid cost projection.
Left shows the values in $/kWh, while right shows the costs in $/kW.

To fully specify the cost and performance of a battery storage system for capacity expansion modeling tools, additional parameters besides the capital costs are needed. Figure 6 shows the range of variable operations and maintenance (VOM), fixed operations and maintenance (FOM), lifetime, and round-trip efficiency[1] assumptions from the publications surveyed. The rightmost point in the figure shows the value that we have selected to represent our 4-hour battery system. The VOM is often taken to be zero or near zero, and we have adopted zero for the VOM. This VOM is defined to coincide with an assumed one cycle per day and a given calendar lifetime. The three publications showing non-zero, but still small, VOM values indicate that there is not consensus that the VOM should be zero.

We have allocated all operating costs (at the one-cycle-per-day level) to the FOM. By putting the operations and maintenance costs in the FOM rather than the VOM we in essence assume that battery performance has been guaranteed over the lifetime, such that operating the battery does not incur any costs to the battery operator. The FOM has a much broader range of values. One of the primary differences in the level of FOM was whether augmentation or performance maintenance were included in the cost. Lower FOM numbers typically include only simple maintenance while higher FOM numbers include some capacity additions or replacements to address degradation. We have adopted a FOM value from the high end and assume that the FOM cost will counteract degradation such that the system will be able to perform at rated capacity throughout its lifetime.[2] The FOM value selected is 2.5% of the $/kW capacity cost for a 4-hour battery. We assume that this FOM is consistent with providing approximately one cycle per day.

[1] Round-trip efficiency is defined as the system efficiency through a charge/discharge cycle. For example, it would include losses associated with cooling systems or battery control equipment.
[2] The Brattle publication (Newell et al. 2022) performs a detailed analysis of the operations and maintenance costs needed to keep the battery at rated capacity throughout its lifetime, and their reported cost is well-aligned with the value we have chosen. However, Brattle also assumed a lower storage cost than what we assume here, but has a similar total FOM cost, so based on their analysis an even higher FOM value for our projection might be justified.

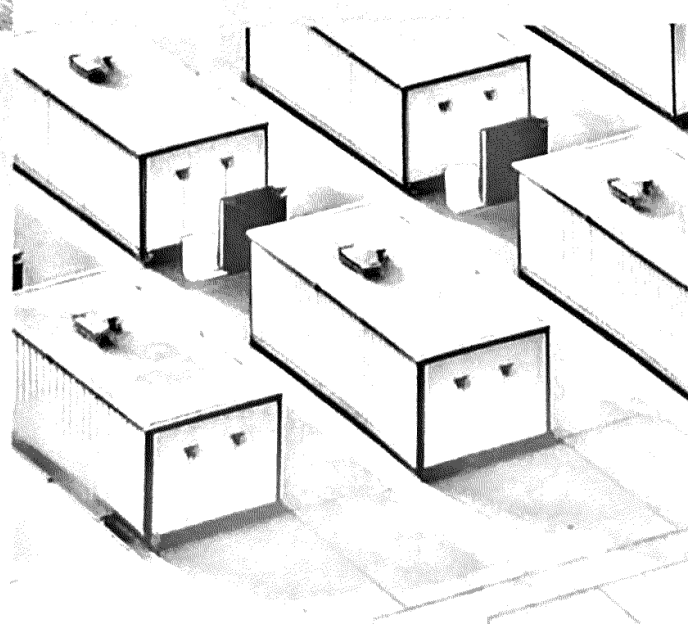
This report is available at no cost from the National Renewable Energy Laboratory at www.nrel.gov/publications.



the BESS BOOK

A Cell to Grid Guide to Utility-scale Battery Energy Storage Systems

Drew Lebowitz, P.E.
Swetha Sundaram
Sean Daly



The most common way to measure throughput is by measuring the output energy of the battery and determining how many equivalent charge-and-discharge cycles have been used. In practice this is most often done by metering the output of the battery and measuring how much energy (kWh or MWh) passes through it. This can be done on the cell, module, rack, or unit level. By dividing the discharged energy by the initial capacity of the battery being measured, the throughput can be expressed in **cycles** (sometimes referred to as turnovers).

For example, if a 375 Ah BOL battery cell (1.2 kWh at 3.2 V nominal voltage) has its output measured over the course of one year, and it is observed to have discharged 252 kWh over this time, it could be said to have been used for 210 cycles over the course of the year. The most common battery warranties allow for one cycle per day, which is described more fully in Section 9.5 on battery warranties and guarantees.

A large BESS facility can be measured in the same way. For example, if a 150 MWh BESS meters its discharge at the point of interconnection (usually at a high-voltage transformer) and is seen to discharge at 10 MW for 4 hours in the morning, then at 60 MW in the early afternoon for 1 hour, and then at 22.5 MW for 2 hours in the evening. The net energy discharged would be (note that only real power [MW] is discussed here to simplify the example):

$$\textit{Net discharged energy} = 10\,MW \times 4\,hr + 60\,MW \times 1\,hr + 22.5\,MW \times 2hrs$$

$$\textit{Net discharged energy} = 40\,MWh + 60\,MWh + 45\,MW = 145\,MWh$$

Since the system has discharged 145 MWh over the course of the day, it could be said to have discharged 0.97 cycles that day. Note that some warranties allow for individual days of higher cycling provid-ing the annual average doesn't exceed 1 cycle per day. As a battery degrades, often the capacity degradation can affect the size of the cycle which is measured.

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ISBN: 979-8-218-44798-4

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Illustrations by Sidra Aslam unless otherwise noted.
Cover design by Casey Ramsey, with contributions from Dall-E 3
Book interior and e-book design by Amit Dey.

First edition.

nature communications

Article

https://doi.org/10.1038/s41467-022-35393-0

Electric vehicle batteries alone could satisfy short-term grid storage demand by as early as 2030

Received: 7 April 2022

Accepted: 30 November 2022

Published online: 17 January 2023

Check for updates

Chengjian Xu[1] ✉, Paul Behrens[1], Paul Gasper[2], Kandler Smith[2], Mingming Hu[1], Arnold Tukker[1,3] & Bernhard Steubing[1]

The energy transition will require a rapid deployment of renewable energy (RE) and electric vehicles (EVs) where other transit modes are unavailable. EV batteries could complement RE generation by providing short-term grid services. However, estimating the market opportunity requires an understanding of many socio-technical parameters and constraints. We quantify the global EV battery capacity available for grid storage using an integrated model incorporating future EV battery deployment, battery degradation, and market participation. We include both in-use and end-of-vehicle-life use phases and find a technical capacity of 32–62 terawatt-hours by 2050. Low participation rates of 12%–43% are needed to provide short-term grid storage demand globally. Participation rates fall below 10% if half of EV batteries at end-of-vehicle-life are used as stationary storage. Short-term grid storage demand could be met as early as 2030 across most regions. Our estimates are generally conservative and offer a lower bound of future opportunities.

Electrification and the rapid deployment of renewable energy (RE) generation are both critical for a low-carbon energy transition[1,2]. They also address many other environmental issues, including air pollution. However, the variability of critical RE technologies, wind and solar, combined with increasing electrification may present a challenge to grid stability and security of supply[1,2]. There are several supply-side options for addressing these concerns: energy storage, firm electricity generators (such as nuclear or geothermal generators), long-distance electricity transmission, over-building of RE (resulting in curtailment in periods of lower demand), and power-to-gas[3] (in approximate ascending order of today's estimated cost). Demand-side management is also vital in shifting and flattening peak demand[4]. Given rapid cost-declines, battery storage is one of the major options for energy storage and can be used in various grid-related applications to improve grid performance. Cost declines in batteries have been the major driver for electric vehicle (EV) cost reductions. Given that many batteries will be produced for light-duty transport these could offer a low-cost and materially-efficient approach for short-term electricity grid storage requirements[5].

EV batteries can be used while in the vehicle via vehicle-to-grid approaches, or after the end of vehicle life (EoL) (when they are removed and used separately to the chassis in stationary storage). "Smart" vehicle-to-grid charging can facilitate dynamic EV charging and load shifting grid services. EVs can also be used to store electricity and deliver it back to the grid at peak times[6]. These opportunities rely on standards and market arrangements that allow for dynamic energy-pricing and the ability of owners to benefit from the value to the grid. Value to the grid can include deferred or avoided capital expenditure on additional stationary storage, power electronic infrastructure, transmission build-out, and more[6]. When the remaining battery capacity drops to between 70-80% of the original capacity, batteries generally become unsuitable for use in EVs[7]. However, these batteries at vehicle EoL (hereafter termed retired batteries) may still have years of useful life in less demanding stationary energy storage applications and represent substantial value to the grid[8].

The utilisation of EV batteries could improve the flexibility of supply while reducing the capital costs and material-related emissions associated with additional storage and power-electronic

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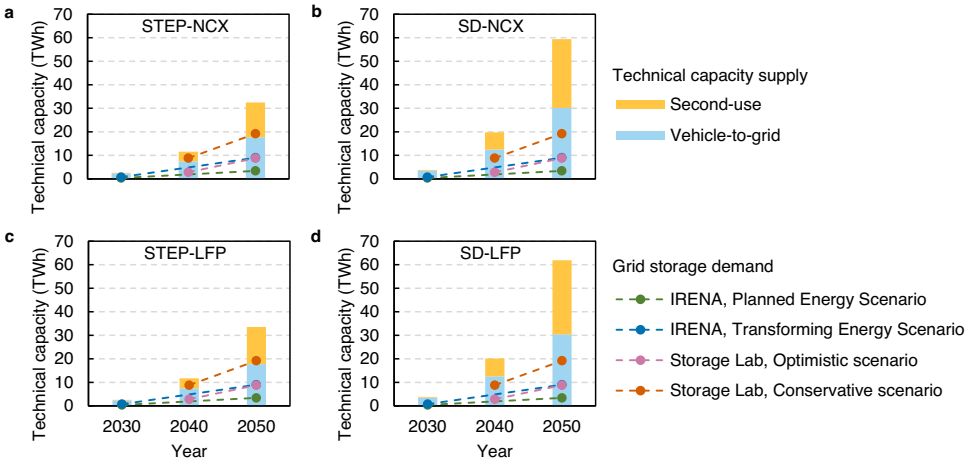


Fig. 2 | Total technical capacity for EV batteries and comparison to grid storage demand. a STEP-NCX scenario. **b** SD-NCX scenario. **c** STEP-LFP scenario. **d** SD-LFP scenario (see details in Supplementary Table 1). IRENA = International Renewable Energy Agency.

For example, the 4-hour storage capacity of batteries that together deliver a maximum of 0.25 GW until depletion will be 1 gigawatt hour[19] (GWh). The short-term storage capacity and power capacity are defined based on a typical 1-time equivalent full charging/discharge cycle per day (amounting to 4 hours of cumulative maximum discharge power per day). This 4-hour threshold is chosen as it is required by some jurisdictions such as the California Public Utilities Commission and New York Independent System Operator[20], energy system analysts anticipate this threshold as the most important to markets[21], and is often the length of time used in the literature[22].

We compare our results against storage requirements reported in the IRENA (International Renewable Energy Agency) Planned Energy and Transforming Energy Scenarios (with a warming of "likely 2.5 °C" and "well below 2 °C" in the second half of this century, respectively)[2], along with two Storage Lab scenarios (Conservative and Optimistic)[23]. Both Storage Lab scenarios result in a warming of "well below 2 °C" by 2100, but differ in the role for grid storage please see Supplementary Table 1 for more). These scenarios report short-term grid storage demands of 3.4, 9, 8.8, and 19.2 terawatt hours (TWh) for the IRENA Planned Energy, IRENA Transforming Energy, Storage Lab Conservative, and Storage Lab Optimistic scenarios, respectively. When assuming a 4-hour storage period for this capacity, this results in power demand of 850-4800 GW, or, 2500 GW when assuming an average storage capacity demand of 10 TWh.

Results

Total technical capacity

We define technical capacity as the total cumulative available EV battery capacity in use and in second use at a specific time while considering battery degradation and the capacity needed to meet driving demand. Globally, the SD scenario sees a total technical capacity twice that of the STEP scenario due to the larger fleet size (see Supplementary Fig. 8 and Note 1). Globally, the LFP scenario sees a slightly higher cumulative capacity than the NCX scenario, due to different battery market shares and the lower degradation of LFP across most countries/regions (see Supplementary Data 1 for a full comparison). Compared to the SD-NCX scenario, The SD-LFP scenario sees 2.6 TWh of higher technical capacity for China, EU, US, and RoW by 2050 compared to the SD-NCX and a 0.05 TWh lower technical capacity for India (see Supplementary Note 2). These capacity differences are small compared to the total technical capacity. As shown in Fig. 2, the SD-LFP scenario has a technical capacity 48% higher by 2030 and 91% higher than the STEP-NCX scenario by 2050 (3.8 TWh and 2.6 TWh in 2030 and 32 TWh and 62 TWh in 2050, respectively).

Under all scenarios, cumulative vehicle-to-grid and second-use capacity will grow dramatically, by a factor of 13–16 between 2030 and 2050. Putting this cumulative technical capacity into perspective against future demand for grid storage we find that our estimated growth is expected to increase as fast or even faster than short-term grid storage capacity demand in several projections[2,23] (Fig. 2). Technical vehicle-to-grid capacity or second-use capacity are each, on their own, sufficient to meet the short-term grid storage capacity demand of 3.4-19.2 TWh by 2050. This is also true on a regional basis where technical EV capacity meets regional grid storage capacity demand (see Supplementary Fig. 9).

Vehicle-to-grid opportunities and limitations

Examining the vehicle-to-grid opportunity alone, we find that 21%-26% of the global theoretical battery capacity (i.e., on-board EV battery capacity of the entire EV fleet without considering battery degradation) could be available for vehicle-to-grid services by 2050 (Fig. 3a). The most important limiting factor is the battery capacity required to meet consumer driving demands[24,25]. Driving demand can limit the available capacity by 57%-63%. PHEVs, which make up around 11% of the theoretical capacity in 2050, are not considered for vehicle-to-grid as they have a low storage potential due to low capacities. On average, just 5% of the theoretical capacity is lost due to battery degradation by 2050. These losses vary between 7% in India and 4% in RoW due to differences in regional factors such as use conditions and temperature (for full regional results see Supplementary Fig. 10). Overall, taking these factors into account yields an estimated technical vehicle-to-grid capacity of 18-30 TWh by 2050 (see Fig. 3).

However, there are other factors that may limit real-world available storage capacity, primarily the vehicle-to-grid participation rate. Not all EV consumers will necessarily participate in the market and the participation rate is defined as the percentage of the technical vehicle to grid capacity connected to the grid, as shown in Fig. 3b. Participation rates of 38% and 20% are required to satisfy short-term storage demands of 10 TWh in 2050 (for STEP-NCX and SD-NCX scenarios, respectively). In practice, it is likely that EVs with high battery capacities and low degradation will be used for providing vehicle-to-grid services since these will provide the highest revenue for EV owners[26] (the full battery capacity distributions by 2050 across countries/regions are available in Supplementary Figs. 11–15).

Impacts of deploying second-use batteries in stationary storage

Over time EV batteries degrade to the point they cannot be used to power vehicles[27], generally when the battery's relative State of Health

(speed versus time) based on the standard US combined driving cycle (i.e., 55% city driving and 45% highway driving, see details in Supplementary Figs. 5 and 6, and Supplementary Note 1).

Charging behavior may be affected by charging infrastructure, amongst others, on-board EV charger, consumer preferences. We assume an immediate and slow home charging at constant charging power to full charge for all EV sizes and types because home charging is the major charging way (see Supplementary Data 1). We assume the home charging power as 1.92, 6.6, 22, and 1.92 kW for small, mid-size, large BEV, and PHEV, respectively[59]. We assume that due to high costs and limited utility no consumers will install higher power charging infrastructure at home. We further anticipate the charging behaviors in terms of changing frequency by comparing the various DDDs in multiples of the EV range. As driving intensity increases, the higher charging frequency is assumed for 5 DDD classes (1x every four days, 1x every three days, 1x every two days, 1x each day, and 2x every day respectively). For example, if the DDD of mid-size BEV (with a 312 km EV range) increases from 75 km to 625 km, and the battery needs to be charged more frequently from 1 time per four days to 2 times per day.

We calculate battery SoC under three EV states: driving, charging, and parked. For the battery SoC during driving, we use FASTSim model[59], Future Automotive Systems Technology Simulator developed by National Renewable Energy Laboratory (NREL), to calculate EV battery SoC second-by-second. The model inputs include the EV driving cycle, EV configurations, and battery performance parameters (specific energy and battery capacity). We select one representative EV model from the FASTSim model[59] for each EV size and type as EV configuration (Supplementary Table 2), and NCM622 as a representative chemistry for all EV types; because it was found that EV configurations and battery performance parameters (such as specific energy) had small effects on the resulting battery SoC simulations. For battery SoC during charging, we assume the battery SoC increases linearly under a constant charging power with a 90% charging efficiency[60]. If an EV is parked, the SoC of the battery is slowly decreasing due to losses caused by battery self-discharging. A typical self-discharging rate of 5% per month is assumed for lithium-ion battery[61]. Self-discharging occurs due to parasitic chemical reactions that consume active lithium and form electrochemically inactive species while lithium-ion batteries are at rest. These parasitic reactions both reduce the SoC of the cell, and also reduce the total amount of lithium available for cycling. The impact of self-discharge on the SoH of NCM and LFP batteries is captured in the battery degradation model we use. Note that for the sake of battery safety, a portion of battery capacity is unusable (15% for BEVs and 30% for PHEVs based on the BatPac model[62]), therefore we assume the usable SoC range as 5%-90% for BEV battery and 15%-85% for PHEV battery.

The battery temperature depends on the heat generation from chemical reactions inside batteries, amongst others, ambient temperature and environment (such as solar power radiation), battery management system (air or liquid cooling system to control battery temperature). The temperature can also vary from cell to cell, module to module, and component to component in the battery pack. The modelling of battery temperature is complicated and out of scope of this study. Here we use city ambient temperature to represent battery temperature, which is then used to calculate battery degradation. The main justification for this simplification is that the degradation for most consumer vehicles is dominated by calendar aging effects, as light-duty vehicles are only driven for a relatively small fraction of time throughout their life. For higher vehicle utilisation, neglecting battery pack thermal management in the degradation model will generally result in worse battery lifetimes, leading to a conservative estimate of electric vehicle lifetime. As such our modelling suggests a conservative lower bound of the potential for EV batteries to supply short-term storage facilities. Here, we use monthly average temperature of total 159 cities to capture the effects of geographic and temporal temperature variance on battery degradation. The temperature data is collected from[63–66], can be found in Supplementary Data 1.

Battery degradation model

Battery degradation is crucially important for determining EV battery capacity both in use and for second-life applications, but there are still many open research questions surrounding the importance of EV driving habits, charging behavior, and battery chemistries on capacity development[67]. Degradation model approaches include physics-based degradation models[68] as well as machine learning models[69,70] though there is no agreed-upon best practice[71]. Here, to balance the complexity and accuracy of the battery degradation model, we develop a semiempirical battery degradation model based on method from[16]. The model considers both calendar life and cycle life aging (Eq. (1)), assuming a square-root dependence on time for calendar life (degradation rates depend on temperature and SoC, see Eq. (2)) and a linear dependence on energy throughput for cycle life (degradation rates depend on temperature, Depth-of-Discharge (DoD), and Current rate (C_{rate}) see Eq. (3)).

$$q = 1 - q_{\mathrm{Loss,Calendar}} - q_{\mathrm{Loss,Cycling}} \tag{1}$$

$$q_{\mathrm{Loss,Calendar}} = k_{Cal} \cdot \exp\left(\frac{-E_a}{\mathbf{R}T}\left(\frac{1}{T} - \frac{1}{\mathbf{T_{ref}}}\right)\right) \cdot \exp\left(\frac{\alpha \mathbf{F}}{\mathbf{R}}\left(\frac{U_a}{T} - \frac{U_{a,ref}}{\mathbf{T_{ref}}}\right)\right) \cdot \sqrt{t} \tag{2}$$

$$q_{Loss,Cycling} = k_{Cyc} \cdot (A \cdot DOD + B) \cdot (C \cdot C_{rate} + D) \cdot (G \cdot (T - \mathbf{T_{ref}})^2 + H) \cdot EFC \tag{3}$$

where q is the relative battery degradation, $q_{\mathrm{Loss,\ Calendar}}$ is the relative calendar life degradation, $q_{\mathrm{Loss,\ Cycling}}$ is the relative cycling life degradation, T is temperature, t is time (unit: days), EFC is equivalent full cycles. Note R is the universal gas constant (8.3144598 J mol^{-1} K^{-1}), T_{ref} is the reference temperature (298.15 K), F is Faraday constant (96485 C mol^{-1}), k_{Cal} (unit: $days^{0.5}$), E_a (unit: J mol^{-1} K^{-1}), and α (no unit) are fitting parameters for calendar life degradation, and k_{Cyc} (unit: EFC^{-1}). A, B, C, D, G, and H (no units) are fitting parameters for cycling life degradation. The value of the anode-to-reference potential, U_a (unit: V), is calculated from the storage SoC using the Eqs. (4) and (5)[72].

$$\begin{aligned} U_a(x_a) = {} & 0.6379 + 0.5416 \cdot \exp(-305.5309 \cdot x_a) + 0.044 \cdot \tanh\left(-\frac{x_a - 0.1958}{0.1088}\right) \\ & - 0.1978 \cdot \tanh\left(\frac{x_a - 1.0571}{0.0854}\right) - 0.6875 \cdot \tanh\left(\frac{x_a + 0.0117}{0.0529}\right) \\ & - 0.0175 \cdot \tanh\left(\frac{x_a - 0.5692}{0.0875}\right) \end{aligned} \tag{4}$$

where x_a, which represents the lithiation fraction of the graphite, is a simple linear function of the SoC:[73]

$$x_a(SOC) = x_{a,0} + SOC \cdot (x_{a,100} - x_{a,0}) \tag{5}$$

where $x_{a,\,0}$ is the lithiation fraction of the graphite at 0% SoC and $x_{a,\,100}$ is the lithiation fraction of the graphite at 100% SoC. $x_{a,\,0}$ equals to 0.0085, and $x_{a,\,100}$ equals to 0.78.

To obtain these fitting parameters, we collect publicly available battery degradation data, including calendar life aging and cycle life aging, for NCM[16] and LFP[14,15,17] chemistry. These data sets represent state-of-the-art lifetime performance for each chemistry; the LFP cells shown reach between 5000 and 8000 equivalent full cycles before reaching 80% remaining capacity, 4000-5000 equivalent full cycles

for NCM cells. This experimental data was then fit with the semi-empirical model Eqs. (1), (2), and (3) using a non-linear least squares solver in MATLAB. The NCM model has no C_{rate} dependence, due to lack of data in the aging data set, so the parameters C and D are simply set at 0 and 1. We first fit the calendar fade data with the time-dependent portion of the model ($q_{Loss,\ Calendar}$, parameters k_{Cal}, E_a, and α); the parameter α is bounded between -1 and 1, with other parameters unbounded. The parameters for the cycling fade (A, B, C, and D) are optimized on the cycling aging data. For both LFP and NCM, the raw cycling fade data was processed prior to optimizing a model based on expert judgement. For LFP, only cells with linear fade trajectories and data for at least 5000 EFCs were used for model optimization. For NCM, only data after 200 EFC at T > 5 °C and data at q < 0.85 at T < 5 °C was used for the optimization of the NCM cycling model parameters. The optimized parameters for the LFP and NCM degradation models are shown in Supplementary Table 3. Fitting results are shown in Supplementary Fig. 33 and degradation rates are shown in Supplementary Fig. 34.

Note that we assume NCA battery has the same degradation patterns as NCM battery due to a lack of state-of-the-art open-source data for NCA batteries. Besides cell chemistry, capacity degradation characteristics vary with cell design, manufacturing process, and proprietary additives[67,74], which is out of scope of this study. We use cell degradation patterns to represent battery pack degradation without consideration of cell-to-cell and module-module differences.

For simulation of the degradation under the EV driving loads (battery SoC evolution over time) and during dynamic temperature changes, the degradation model is reformulated to solve for the degradation occurring during consecutive timesteps[15]. We choose a timestep of 1 day for making SoH updates and update the SoC time-series for each day by the current SoH. At each timestep, the temperature is the average temperature during the simulation month at city from different countries/regions. Average SoC, DoD, C_{rate}, and the number of EFCs is extracted from the SoC timeseries. Average SoC refers to the time-averaged value of SoC. DoD is the difference between the maximum and minimum values of SoC. C_{rate} is calculated using the absolute change of SoC per second, and then taking the average of all C_{rates} greater than 0 during the entire timeseries. The number of EFCs is calculated by summing the changes to SoC over the timeseries. Dependence of the expected degradation rate on current SoH is incorporated by calculating a 'virtual time'[15]. The virtual time is found by inverting the calendar degradation equation to solve for time:

$$t_{virtual} = \left(q_{Current}/k_{Cal} \cdot \exp\left(\frac{-E_a}{\mathbf{R}T} \cdot \left(\frac{1}{T} - \frac{1}{\mathbf{T_{ref}}}\right)\right) \cdot \exp\left(\frac{\alpha \mathbf{F}}{\mathbf{R}} \cdot \left(\frac{U_a}{T} - \frac{U_{a,ref}}{\mathbf{T_{ref}}}\right)\right)\right)^2 \quad (6)$$

The degradation change Δq during any given timestep Δt is then calculated by the following equation:

$$\Delta q = \left(k_{\mathrm{Cal}} \cdot \exp\left(\frac{-E_a}{\mathbf{R}T} \cdot \left(\frac{1}{T} - \frac{1}{\mathbf{T_{ref}}}\right)\right) \cdot \exp\left(\frac{\alpha \mathbf{F}}{\mathbf{R}} \cdot \left(\frac{U_a}{T} - \frac{U_{a,ref}}{\mathbf{T_{ref}}}\right)\right)/2 \cdot \sqrt{t_{virtual} + \Delta t}\right) \cdot \Delta t + k_{Cyc} \cdot (A \cdot DOD + B) \cdot (C \cdot C_{rate} + D) \cdot (G \cdot (T - \mathbf{T_{ref}})^2 + H) \cdot \Delta EFC \quad (7)$$

For cycling fade, the virtual EFC does not need to be calculated, as the degradation rate is constant with respect to the change of EFC during any given timestep. This reformulation of the degradation model captures the path-dependent degradation observed in real-world battery use. See Supplementary Note 2 for modelled battery degradation for NCM and LFP.

Available capacity from EV batteries

Vehicle EoL does not necessarily correspond to battery EoL. With technological improvements in battery reliability and durability, many batteries in EoL vehicles may still have years of useful life at the end of vehicle end of life. Vehicle battery EoL is usually as defined the time at which remaining battery capacity is between 70 and 80% of the original capacity[7]. We assume an EV lifespan distribution, used in our previous work[27], to account for EoL of EV. In our modelling approach, the vehicle lifespan distribution determines when batteries are not used in EVs any more (i.e., retired batteries). Retired batteries may have quite different capacity under different use conditions. When vehicles reach EoL due to consumer choices or other issues before the battery pack reaches 70% relative capacity, retired batteries will still have over 70% relative SoH and are assumed to be used in a second-life application. When battery pack reaches 70% relative SoH before a vehicle reaches its EoL, we assume that batteries may be still be used in EVs for low distances-driving. Retired batteries from such vehicles will have lower than 70% relative SoH and are assumed to be recycled rather than for a second-use. We assume any battery with a relative SoH lower than 60% is recycled and removed from potential grid storage capacity[75]. However, even batteries with a relative SoH of 60–70% have a limited economic value and can have relatively high safety risks. (methods)[32].

We define technical vehicle-to-grid capacity as the availability of EV battery stock capacity for vehicle-to-grid application, considering the capacity reserved for EV driving, the capacity of PHEVs that will not participate in vehicle-to-grid due to low capacity, and capacity fade due to battery degradation. We further define the actual vehicle-to-grid capacity as the availability of technical vehicle-to-grid capacity for the grid under different consumer participation rates in the vehicle-to-grid business. Results focus on investigating under which participation rate can actual vehicle-to-grid capacity meet grid storage demand.

The technical second-use capacity is defined as the retired batteries capacity that can be repurposed (i.e., retired batteries with over 70% relative SoH). We further investigate actual second-use capacity under different utilisation rates (i.e., not all retired batteries will be deployed in second-use). The results are intended to determine the required utilisation rate for the second-use battery to meet grid storage demand.

We investigate the real-world capacity as a function of both vehicle-to-grid participation rate and second-use utilisation rates. We further analyze the market participation rates and utilisation rates that are required to meet short-term grid storage demand globally.

Impact of battery capacity assumptions

The model is highly influenced by the battery capacity per vehicle. Therefore, we conduct a sensitivity analysis of battery capacity per vehicle by assuming all BEVs are small BEVs equipped with a battery with a capacity of 33 kWh. This assumption is based on three arguments: first, small BEVs could provide most of the daily driving demand for consumers, even though they have a lower driving range than large BEVs equipped with a high-capacity battery. Second, the development of widespread EV charging infrastructure, including fast charging technology, could help to overcome the range anxiety of small BEV owners. Third, the increasing use of small BEVs would reduce demand for batteries and materials, along with lowering embodied GHG emissions of those batteries.

Data availability

The datasets, including EV fleet size by country, EV sales share by cities, and battery chemistry share, are all deposited in an Excel file (https://doi.org/10.6084/m9.figshare.21542472.v1). These raw data are used for the dynamic battery stock model for quantifying future battery flows. Please see the dynamic battery stock model from this link (https://doi.org/10.6084/m9.figshare.13042001.v4). City ambient temperature and

Why Lithium-ion?

Compared with traditional battery technology, lithium-ion batteries charge faster, last longer, and have a higher power density for more battery life in a lighter package. When you know a little about how they work, they can work that much better for you.

It charges fast for convenience and slow for longevity.

Your Apple lithium-ion battery uses fast charging to quickly reach 80% of its capacity, then switches to slower trickle charging. The amount of time it takes to reach that first 80% will vary depending on your settings and which device you're charging. Software may limit charging above 80% when the recommended battery temperatures are exceeded. This combined process not only lets you get out and about sooner, it also extends the lifespan of your battery.



Stage 1: Fast Charge
Gives you more power more quickly.

Stage 2: Trickle Charge
Eases the electrical current to extend battery lifespan.

It makes charging easier.

Charge your Apple lithium-ion battery whenever you want. There's no need to let it discharge 100% before recharging. Apple lithium-ion batteries work in charge cycles. You complete one charge cycle when you've used (discharged) an amount that represents 100% of your battery's capacity* — but not necessarily all from one charge. For instance, you might use 75% of your battery's capacity one day, then recharge it fully overnight. If you use 25% the next day, you will have discharged a total of 100%, and the two days will add up to one charge cycle. It could take several days to complete a cycle. The capacity of any type of battery will diminish after a certain amount of recharging. With lithium-ion batteries, the capacity diminishes slightly with each complete charge cycle. Apple lithium-ion batteries are designed to retain 80% of their original capacity for a high number of charge cycles, which varies depending on the product.



One charge cycle is completed after you've discharged 100% of your battery's capacity.

* A complete charge cycle is normalized between 80% and 100% of original capacity to account for expected diminishing battery capacity over time.

BATTERY UNIVERSITY

BU-808: How to Prolong Lithium-based Batteries

Battery research is focusing on lithium chemistries so much that one could imagine that the battery future lies solely in lithium. There are good reasons to be optimistic as lithium-ion is, in many ways, superior to other chemistries. Applications are growing and are encroaching into markets that previously were solidly held by lead acid, such as standby and load leveling. Many satellites are also powered by Li-ion.

Lithium-ion has not yet fully matured and is still improving. Notable advancements have been made in longevity and safety while the capacity is increasing incrementally. Today, Li-ion meets the expectations of most consumer devices but applications for the EV need further development before this power source will become the accepted norm. BU-104c: The Octagon Battery – What makes a Battery a Battery, describes the stringent requirements a battery must meet.

As battery care-giver, you have choices in how to prolong battery life. Each battery system has unique needs in terms of charging speed, depth of discharge, loading and exposure to adverse temperature. Check what causes capacity loss, how does rising internal resistance affect performance, what does elevated self-discharge do and how low can a battery be discharged? You may also be interested in the fundamentals of battery testing.

- BU-415: How to Charge and When to Charge?
- BU-706: Summary of Do's and Don'ts

What Causes Lithium-ion to Age?

The lithium-ion battery works on ion movement between the positive and negative

electrodes. In theory such a mechanism should work forever, but cycling, elevated temperature and aging decrease the performance over time. Manufacturers take a conservative approach and specify the life of Li-ion in most consumer products as being between 300 and 500 discharge/charge cycles.

In 2020, small wearable batteries deliver about 300 cycles whereas modern smartphones have a cycle life requirement is 800 cycles and more. The largest advancements are made in EV batteries with talk about the one-million-mile battery representing 5,000 cycles.

Evaluating battery life on counting cycles is not conclusive because a discharge may vary in depth and there are no clearly defined standards of what constitutes a cycle(See BU-501: Basics About Discharging). In lieu of cycle count, some device manufacturers suggest battery replacement on a date stamp, but this method does not take usage into account. A battery may fail within the allotted time due to heavy use or unfavorable temperature conditions; however, most packs last considerably longer than what the stamp indicates.

The performance of a battery is measured in capacity, a leading health indicator. Internal resistance and self-discharge also play roles, but these are less significant in predicting the end of battery life with modern Li-ion.

Figure 1 illustrates the capacity drop of 11 Li-polymer batteries that have been cycled at a Cadex laboratory. The 1,500mAh pouch cells for mobile phones were first charged at a current of 1,500mA (1C) to 4.20V/cell and then allowed to saturate to 0.05C (75mA) as part of the full charge saturation. The batteries were then discharged at 1,500mA to 3.0V/cell, and the cycle was repeated. The expected capacity loss of Li-ion batteries was uniform over the delivered 250 cycles and the batteries performed as expected.

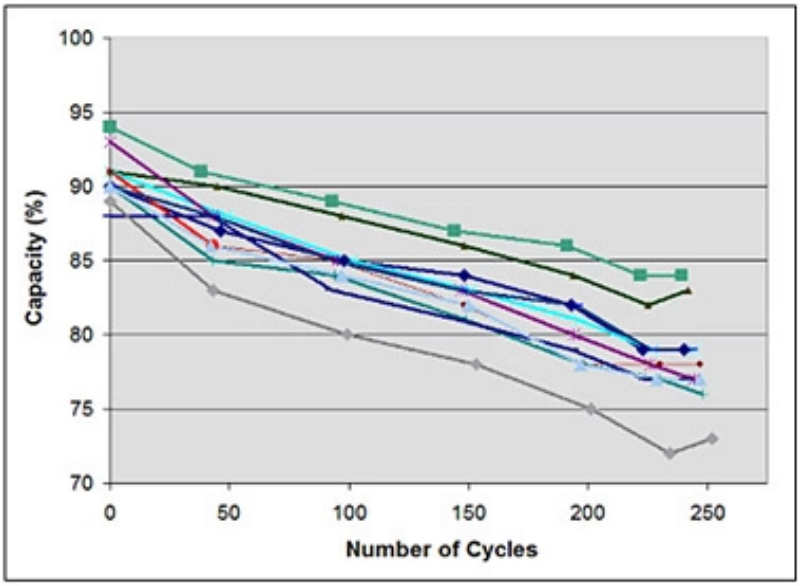


Figure 1: Capacity drop as part of cycling [1]

Eleven new Li-ion were tested on a Cadex C7400 battery analyzer. All packs started at a capacity of 88–94% and decreased to 73–84% after 250 full discharge cycles. The 1500mAh pouch packs are used in mobile phones.

Although a battery should deliver 100 percent capacity during the first year of service, it is common to see lower than specified capacities, and shelf life may contribute to this loss. In addition, manufacturers tend to overrate their batteries, knowing that very few users will do spot-checks and complain if low. Not having to match single cells in mobile phones and tablets, as is required in multi-cell packs, opens the floodgates for a much broader performance acceptance. Cells with lower capacities may slip through cracks without the consumer knowing.

Similar to a mechanical device that wears out faster with heavy use, the depth of discharge (DoD) determines the cycle count of the battery. The smaller the discharge (low DoD), the longer the battery will last. If at all possible, avoid full discharges and charge the battery more often between uses. Partial discharge on Li-ion is fine. There is no memory and the battery does not need periodic full discharge cycles to prolong life. The exception may be a periodic calibration of the fuel gauge on a smart battery or intelligent device(See BU-603: How to Calibrate a “Smart” Battery)

The following tables indicate stress related capacity losses on cobalt-based lithium-ion. The voltages of lithium iron phosphate and lithium titanate are lower and do not apply to the voltage references given.

Note: **Tables 2, 3 and 4** indicate general aging trends of common cobalt-based Li-ion batteries on depth-of-discharge, temperature and charge levels, Table 6 further looks at capacity loss when operating within given and discharge bandwidths. The tables do not address ultra-fast charging and high load discharges that will shorten battery life. No all batteries behave the same.

Table 2 estimates the number of discharge/charge cycles Li-ion can deliver at various DoD levels before the battery capacity drops to 70 percent. DoD constitutes a full charge followed by a discharge to the indicated state-of-charge (SoC) level in the table.

Depth of Discharge	Discharge cycles	
	NMC	$LiPO_4$
100% DoD	~300	~600
80% DoD	~400	~900
60% DoD	~600	~1,500
40% DoD	~1,000	~3,000
20% DoD	~2,000	~9,000
10% DoD	~6,000	~15,000

Table 2: Cycle life as a function ofdepth of discharge*

A partial discharge reduces stress and prolongs battery life, so does a partial charge. Elevated temperature and high currents also affect cycle life.

Lithium-ion suffers from stress when exposed to heat, so does keeping a cell at a high charge voltage. A battery dwelling above 30°C (86°F) is considered *elevated temperature* and for most Li-ion a voltage above 4.10V/cell is deemed as *high voltage*. Exposing the battery to high temperature and dwelling in a full state-of-charge for an extended time can be more stressful than cycling. **Table 3** demonstrates capacity loss as a function of temperature and SoC.

TEMPERATURE	40% CHARGE	100% CHARGE
0°C	98% (after 1 year)	94% (after 1 year)
25°C	96% (after 1 year)	80% (after 1 year)
40°C	85% (after 1 year)	65% (after 1 year)
60°C	75% (after 1 year)	60% (after 3 months)

Table 3: Estimated recoverable capacity when storing Li-ion for one year at various temperatures
Elevated temperature hastens permanent capacity loss. Not all Li-ion systems behave the same.

Most Li-ions charge to 4.20V/cell, and every reduction in peak charge voltage of 0.10V/cell is said to double the cycle life. For example, a lithium-ion cell charged to 4.20V/cell typically delivers 300–500 cycles. If charged to only 4.10V/cell, the life can be prolonged to 600–1,000 cycles; 4.0V/cell should deliver 1,200–2,000 and 3.90V/cell should provide 2,400–4,000 cycles.

On the negative side, a lower peak charge voltage reduces the capacity the battery stores. As a simple guideline, every 70mV reduction in charge voltage lowers the overall capacity by 10 percent. Applying the peak charge voltage on a subsequent charge will restore the full capacity.

In terms of longevity, the optimal charge voltage is 3.92V/cell. Battery experts believe that this threshold eliminates all voltage-related stresses; going lower may not gain further benefits but induce other symptoms(See BU-808b: What causes Li-ion to die?) **Table 4** summarizes the capacity as a function of charge levels. (All values are estimated; Energy Cells with higher voltage thresholds may deviate.)

CHARGE LEVEL* (V/CELL)	DISCHARGE CYCLES	AVAILABLE STORED ENERGY **
[4.30]	[150–250]	[110–115%]
4.25	200–350	105–110%
4.20	**300–500**	**100%**
4.13	400–700	90%
4.06	600–1,000	81%
4.00	850–1,500	73%
3.92	1,200–2,000	65%
3.85	2,400–4,000	60%

Table 4: Discharge cycles and capacity as a function of charge voltage limit

Every 0.10V drop below 4.20V/cell doubles the cycle but holds less capacity. Raising the voltage above 4.20V/cell would shorten the life. The readings reflect regular Li-ion charging to 4.20V/cell.

Guideline: Every 70mV drop in charge voltage lowers the usable capacity by about 10%.
Note: Partial charging negates the benefit of Li-ion in terms of high specific energy.

***** *Similar life cycles apply for batteries with different voltage levels on full charge.*
****** *Based on a new battery with 100% capacity when charged to the full voltage.*

Experiment: *Chalmers University of Technology, Sweden, reports that using a reduced charge level of 50% SOC increases the lifetime expectancy of the vehicle Li-ion battery by 44–130%.*

Most chargers for mobile phones, laptops, tablets and digital cameras charge Li-ion to 4.20V/cell. This allows maximum capacity, because the consumer wants nothing less

than optimal runtime. Industry, on the other hand, is more concerned about longevity and may choose lower voltage thresholds. Satellites and electric vehicles are such examples.

For safety reasons, many lithium-ions cannot exceed 4.20V/cell. (Some NMC are the exception.) While a higher voltage boosts capacity, exceeding the voltage shortens service life and compromises safety. **Figure 5** demonstrates cycle count as a function of charge voltage. At 4.35V, the cycle count of a regular Li-ion is cut in half.

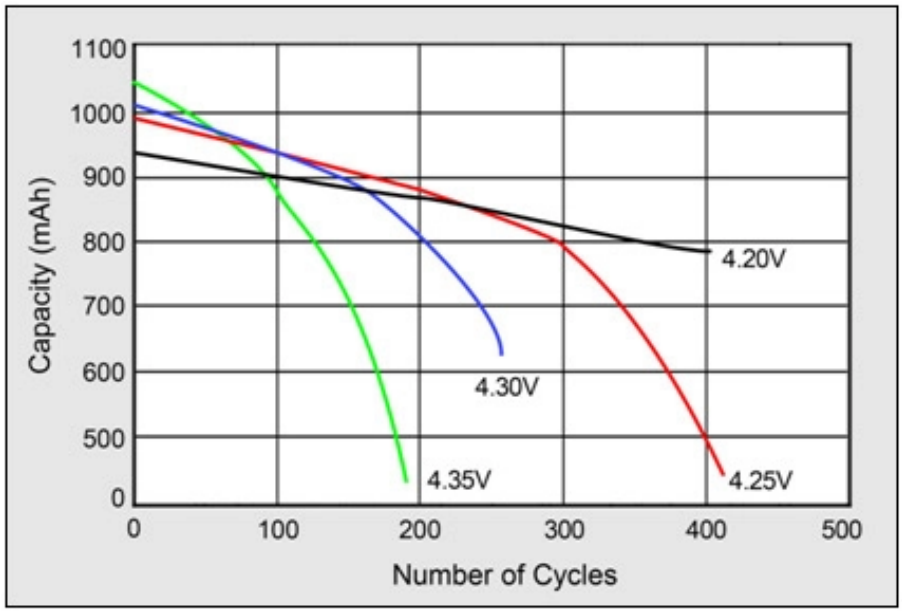


Figure 5: Effects on cycle life at elevated charge voltages [2]
Higher charge voltages boost capacity but lowers cycle life and compromises safety.

Besides selecting the best-suited voltage thresholds for a given application, a regular Li-ion should not remain at the high-voltage ceiling of 4.20V/cell for an extended time. The Li-ion charger turns off the charge current and the battery voltage reverts to a more natural level. This is like relaxing the muscles after a strenuous exercise(See BU-409: Charging Lithium-ion)

Figure 6 illustrates dynamic stress tests (DST) reflecting capacity loss when cycling Li-ion at various charge and discharge bandwidths. The largest capacity loss occurs when discharging a fully charged Li-ion to 25 percent SoC (black); the loss would be higher if fully discharged. Cycling between 85 and 25 percent (green) provides a longer service life than charging to 100 percent and discharging to 50 percent (dark blue). The smallest capacity loss is attained by charging Li-ion to 75 percent and discharging to 65 percent.

This, however, does not fully utilize the battery. High voltages and exposure to elevated temperature is said to degrade the battery quicker than cycling under normal condition. (Nissan Leaf case)

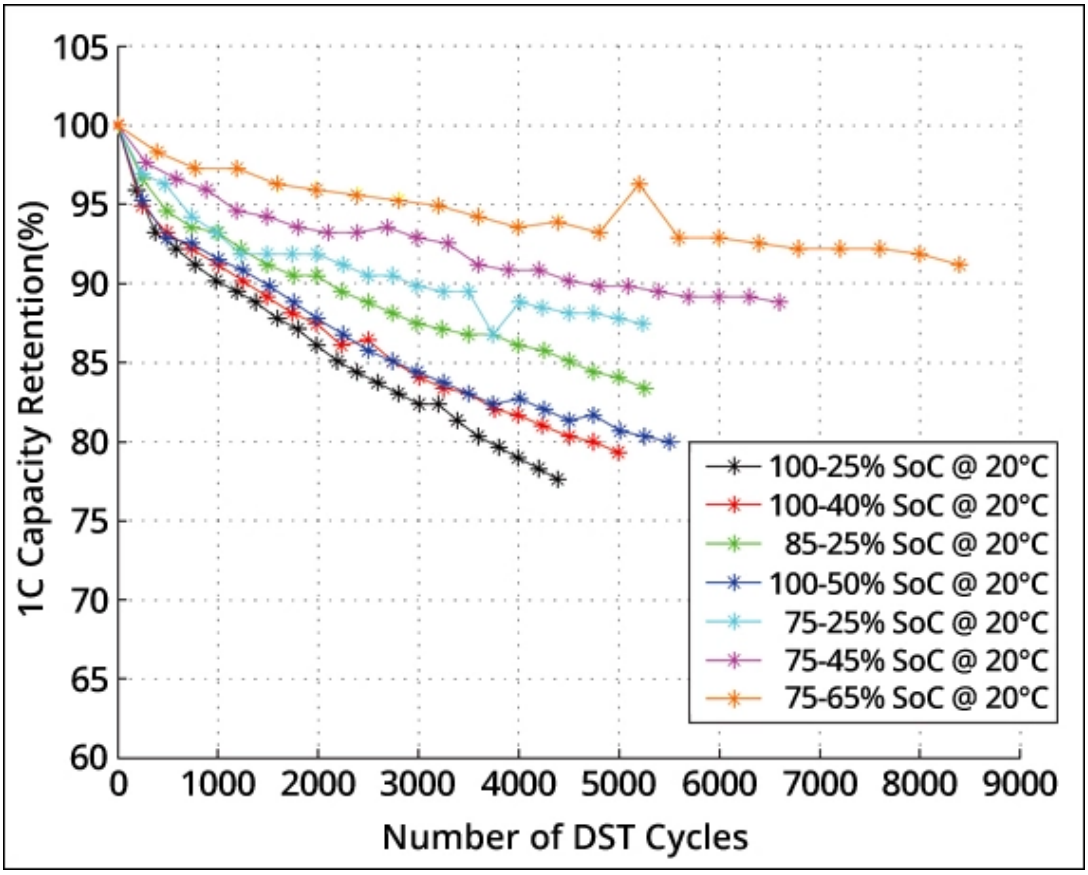


Figure 6: Capacity loss as a function of charge and discharge bandwidth* [3]
Charging and discharging Li-ion only partially prolongs battery life but reduces utilization.

- **Case 1:** 75–65% SoC offers longest cycle life but delivers only 90,000 energy units (EU). Utilizes 10% of battery.
- **Case 2:** 75–25% SoC has 3,000 cycles (to 90% capacity) and delivers 150,000 EU. Utilizes 50% of battery. (EV battery, new.)
- **Case 3:** 85–25% SoC has 2,000 cycles. Delivers 120,000 EU. Uses 60% of battery.
- **Case 4:** 100–25% SoC; long runtime with 75% use of battery. Has short life. (Mobile phone, drone, etc.)

****** Discrepancies exist between **Table 2** and **Figure 6** on cycle count. No clear explanations are available other than assuming differences in battery quality and test methods. Variances between low-cost consumer and durable industrial grades may also play a role. Capacity retention will decline more rapidly at elevated temperatures than at 20°C.*

Only a full cycle provides the specified energy of a battery. With a modern Energy Cell, this is about 250Wh/kg, but the cycle life will be compromised. All being linear, the life-prolonging mid-range of 85-25 percent reduces the energy to 60 percent and this equates to moderating the specific energy density from 250Wh/kg to 150Wh/kg. Mobile phones are consumer goods that utilize the full energy of a battery. Industrial devices, such as the EV, typically limit the charge to 85% and discharge to 25%, or 60 percent energy usability, to prolong battery life(See Why Mobile Phone Batteries do not last as long as an EV Battery)

Increasing the cycle depth also raises the internal resistance of the Li-ion cell. **Figure 7** illustrates a sharp rise at a cycle depth of 61 percent measured with the DC resistance method(See also BU-802a: How does Rising Internal Resistance affect Performance?) The resistance increase is permanent.

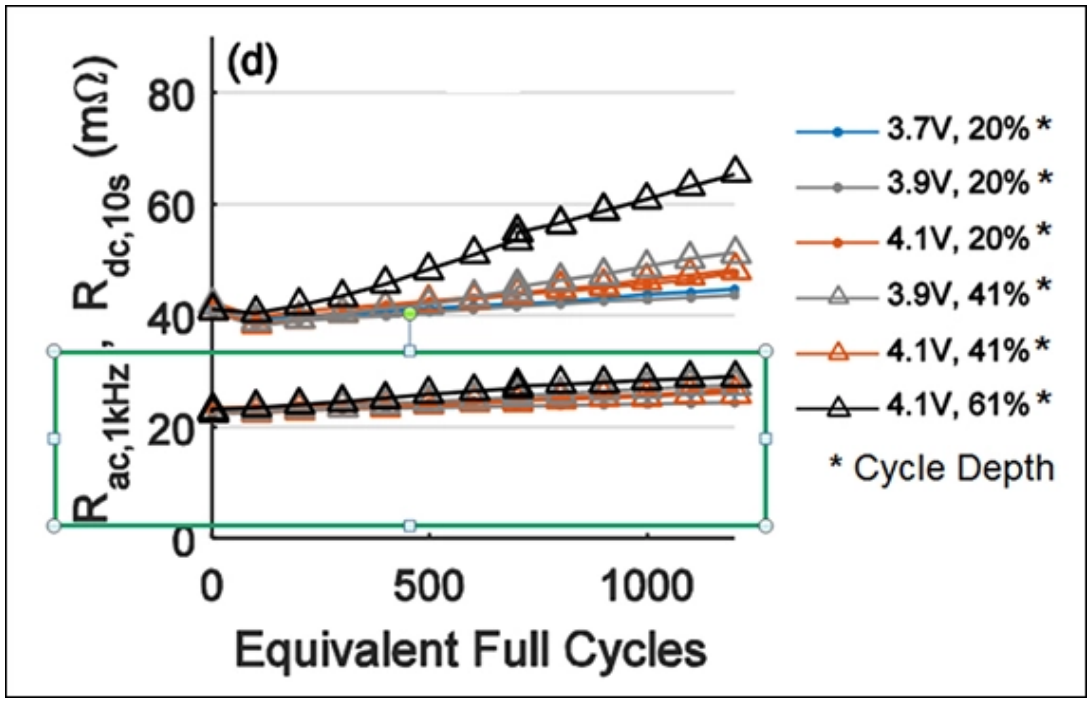


Figure 7: Sharp rise in internal resistance by increasing cycle depth of Li-ion [4]

Note: DC method delivers different internal resistance readings than with the AC method (green frame). For best results, use the DC method to calculate loading.

Figure 8 extrapolates the data from **Figure 6** to expand the predicted cycle life of Li-ion by using an extrapolation program that assumes linear decay of battery capacity with progressive cycling. If this were true, then a Li-ion battery cycled within 75%–25% SoC (blue) would fade to 74% capacity after 14,000 cycles. If this battery were charged to

85% with same depth-of-discharge (green), the capacity would drop to 64% at 14,000 cycles, and with a 100% charge with same DoD (black), the capacity would drop to 48%. For unknown reasons, real-life expectancy tends to be lower than in simulated modeling(See BU-208: Cycling Performance)

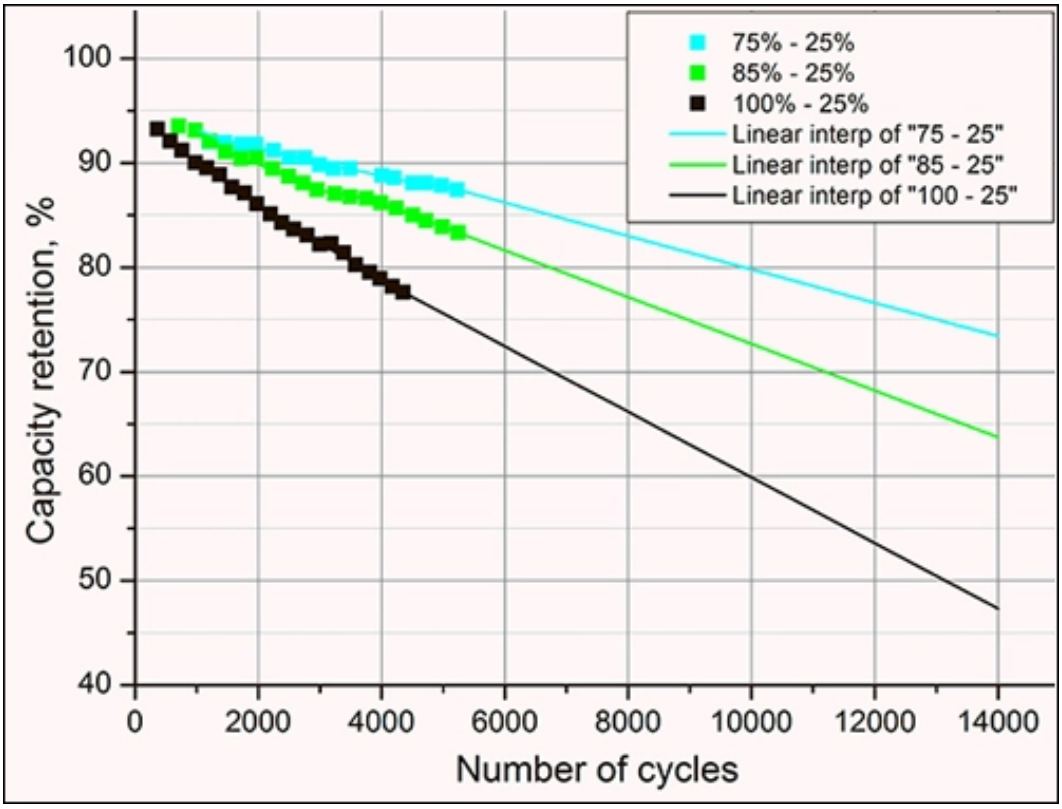


Figure 8: Predictive modeling of battery life by extrapolation [5]

Li-ion batteries are charged to three different SoC levels and the cycle life modelled. Limiting the charge range prolongs battery life but decreases energy delivered. This reflects in increased weight and higher initial cost.

Battery manufacturers often specify the cycle life of a battery with an 80 DoD. This is practical because batteries should retain some reserve before charge under normal use(See BU-501: Basics about Discharging, "What Constitutes a Discharge Cycle") The cycle count on DST (dynamic stress test) differs with battery type, charge time, loading protocol and operating temperature. Lab tests often get numbers that are not attainable in the field.

What Can the User Do?

Environmental conditions, not cycling alone, govern the longevity of lithium-ion

batteries. The worst situation is keeping a fully charged battery at elevated temperatures. Battery packs do not die suddenly, but the runtime gradually shortens as the capacity fades.

Lower charge voltages prolong battery life and electric vehicles and satellites take advantage of this. Similar provisions could also be made for consumer devices, but these are seldom offered; planned obsolescence takes care of this.

A laptop battery could be prolonged by lowering the charge voltage when connected to the AC grid. To make this feature user-friendly, a device should feature a “Long Life” mode that keeps the battery at 4.05V/cell and offers a SoC of about 80 percent. One hour before traveling, the user requests the “Full Capacity” mode to bring the charge to 4.20V/cell.

The question is asked, “Should I disconnect my laptop from the power grid when not in use?” Under normal circumstances this should not be necessary because charging stops when the Li-ion battery is full. A topping charge is only applied when the battery voltage drops to a certain level. Most users do not remove the AC power, and this practice is safe.

Modern laptops run cooler than older models and reported fires are fewer. Always keep the airflow unobstructed when running electric devices with air-cooling on a bed or pillow. A cool laptop extends battery life and safeguards the internal components. Energy Cells, which most consumer products have, should be charged at 1C or less. Avoid so-called ultra-fast chargers that claim to fully charge Li-ion in less than one hour.

References

[1] Courtesy of Cadex

[2] Source: Choi et al. (2002)

[3] B. Xu, A. Oudalov, A. Ulbig, G. Andersson and D. Kirschen, "Modeling of Lithium-Ion Battery Degradation for Cell Life Assessment," June 2016. [Online]. Available: https://www.researchgate.net/publication/303890624_Modeling_of_Lithium-Ion_Battery_Degradation_for_Cell_Life_Assessment.

[4] Source: Technische Universität München (TUM)

[5] With permission to use. Interpolation/extrapolation by OriginLab.

Last Updated: 11-Oct-2023

Inputs & Assumptions

2022-2023 Integrated Resource Planning (IRP)

October 2023



California Public
Utilities Commission

Figure 38 and Figure 39 below shows the marginal ELCCs of solar and storage on the ELCC surface at various penetrations of solar and storage MW in 2030.[165] At ~30 GW of solar penetration (combined utility scale and BTM PV), solar has low incremental value when battery storage is low (e.g. ~3-8% ELCC going from 30 to 40 GW of solar). However, when battery storage is added, the incremental solar ELCC rises as mid-day solar energy becomes increasingly important for ensuring batteries remain sufficiently charged to address the evening net peak.

Figure 38. Incremental Solar ELCC % across the ELCC Surface

Calculated Incremental Solar ELCC %

4-Hour Battery Namplate Capacity (GW) \ Solar Nameplate Capacity (GW)	30	35	40	45	50	55	60	65	70	75	80	85	90	95	100
0	5%	3%	3%	3%	3%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
5	6%	3%	3%	3%	3%	3%	3%	2%	2%	2%	2%	2%	2%	2%	2%
10	6%	5%	3%	3%	3%	3%	3%	3%	3%	2%	2%	2%	2%	2%	2%
15	13%	8%	8%	4%	3%	3%	3%	3%	3%	3%	3%	2%	2%	2%	2%
20	25%	25%	21%	9%	6%	4%	4%	4%	4%	4%	3%	3%	3%	3%	2%
25	25%	21%	21%	21%	16%	9%	8%	4%	4%	4%	4%	4%	1%	1%	1%
30	25%	21%	21%	21%	19%	19%	10%	9%	4%	1%	1%	1%	1%	1%	1%
35	25%	21%	21%	21%	19%	19%	17%	14%	10%	4%	1%	1%	1%	1%	1%
40	25%	21%	21%	21%	19%	19%	17%	14%	14%	14%	14%	4%	1%	1%	1%
45	25%	21%	21%	21%	19%	19%	17%	17%	14%	14%	14%	14%	14%	1%	1%
50	25%	21%	21%	21%	19%	19%	17%	17%	17%	14%	14%	14%	14%	14%	14%

At low penetration, incremental battery storage ELCCs remain high and are not sensitive to the level of solar on the system. However, after adding ~10-20 GW of battery storage to the system, the net peak extends its duration such that 4-hr battery resources have insufficient energy to discharge, reducing their incremental value. Incremental batteries may also struggle to charge as the net load during the charging hours has increased such that there may be insufficient charging energy. At this point, the ability for battery storage to provide significant additional ELCC depends on adding solar together with batteries. RESOLVE will now consider these dynamics endogenously in its portfolio optimization.

[165] The surface is scaled with the peak load of the system to account for the impact of load growth on capacity value saturation.

Figure 39. Incremental Battery Storage ELCC % across the ELCC Surface

Calculated Incremental Storage ELCC %

4-Hour Battery Namplate Capacity (GW) \ Solar Nameplate Capacity (GW)	30	35	40	45	50	55	60	65	70	75	80	85	90	95	100
0	90%	92%	92%	92%	92%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
5	90%	92%	92%	92%	92%	92%	92%	95%	95%	95%	95%	95%	95%	95%	95%
10	90%	90%	92%	92%	92%	92%	92%	92%	92%	95%	95%	95%	95%	95%	95%
15	70%	79%	79%	87%	90%	90%	91%	92%	92%	92%	92%	95%	95%	95%	95%
20	33%	33%	33%	65%	70%	75%	81%	84%	84%	84%	90%	90%	92%	92%	95%
25	33%	33%	33%	33%	37%	44%	45%	52%	52%	52%	52%	52%	52%	52%	52%
30	27%	27%	27%	27%	27%	27%	28%	30%	32%	36%	36%	36%	36%	36%	36%
35	17%	17%	17%	17%	17%	17%	17%	17%	28%	32%	36%	36%	36%	36%	36%
40	9%	9%	9%	9%	9%	9%	9%	11%	11%	12%	12%	32%	36%	36%	36%
45	9%	9%	9%	9%	9%	9%	9%	9%	11%	11%	11%	11%	12%	36%	36%
50	9%	9%	9%	9%	9%	9%	9%	9%	9%	11%	11%	11%	11%	11%	12%

To reflect the dynamic that a solar resource's reliability contribution will typically scale with capacity factor, the capacity (in MW) of individual solar resources used in the multivariate linear equations is scaled by the ratio of each solar resource's capacity factor to that of the solar resource capacity factor used in the SERVM ELCC simulations. The capacity (in MW) of storage resources used in the multivariate linear equation is the 4-hour duration equivalent, calculated for each individual storage resource as storage resource capacity [MW] * MIN(1, duration [h] / 4 h).

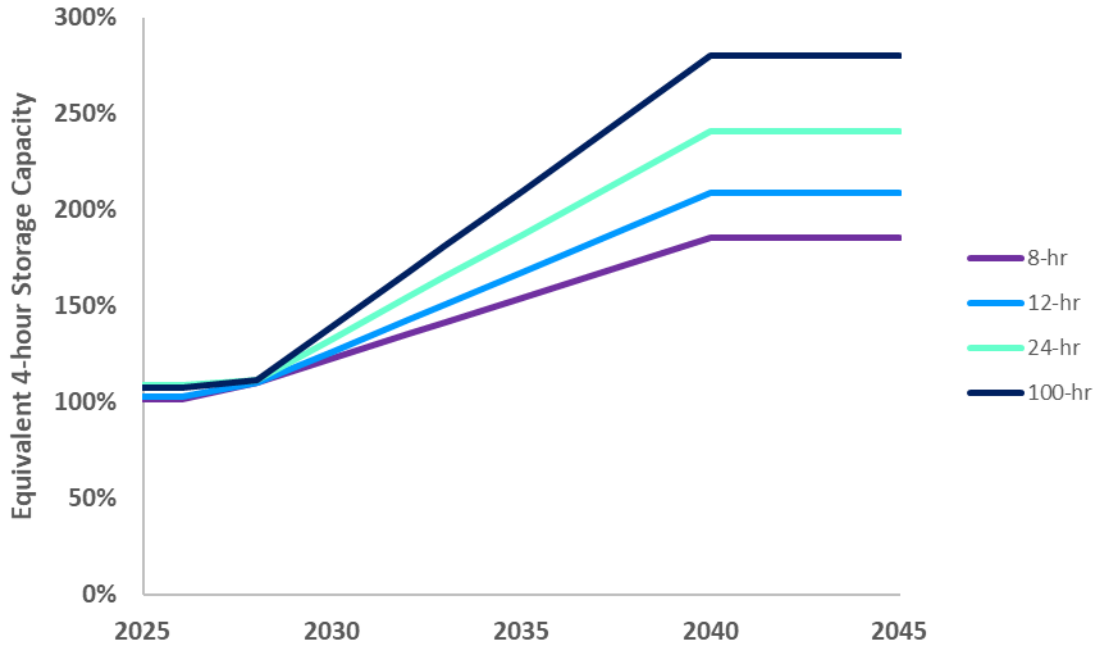
7.1.10 Candidate Long-Duration Storage

Candidate long-duration energy storage (LDES) resources are accounted for on the storage dimension of the solar + storage ELCC surface. The nameplate capacities of candidate long (8+ hour) duration storage resources counted on the surface are multiplied by scalar factors (> 1) to reflect the greater reliability contribution of longer duration storage resources relative to the 4-hour duration battery storage resource represented by the ELCC surface. The multipliers were calculated by estimating the ratio of LDES marginal ELCC to 4-hour storage marginal ELCC at various penetrations of solar and 4-hour storage on the solar + storage surface. This ratio provides an “exchange rate” of reliability value between storage resources of different durations. The key assumption underlying this methodology was that the solar + storage surface would have approximately the same shape or form regardless of the duration of the storage resource represented by the surface, with the main difference being that longer duration storage resources’ ELCCs decline more slowly with increasing storage penetration. The

multipliers used to model long-duration storage ELCC in RESOLVE vary by year based on the expected level of 4-hour storage penetration on the CAISO system in each year. The multiplier values for 8-hour, 12-hour, 24-hour, and 100-hour duration storage resources are shown below. These long-duration storage resources represent, respectively, 8-hour lithium-ion battery storage, 12-hour pumped hydro storage, 24-hour compressed air energy storage, and 100-hour iron-air battery storage.

Candidate pumped hydro storage is modeled on the solar + storage ELCC surface as a 12-hr resource, with the respective multiplier.

Figure 40. Nameplate Multipliers for Long-Duration Storage ELCC Accounting on Solar + Storage Surface



7.1.11 Candidate Demand Response

Candidate shed demand response resources are modeled on the storage dimension of the solar + storage ELCC surface. This enables RESOLVE to capture the antagonistic interactive effect between use- and duration- limited demand response with energy and duration limited battery storage resources. Marginal ELCCs were calculated for additional demand response at various points on the solar and storage surface corresponding to the installed capacity in the 38MMT updated PSP portfolio. These marginal ELCCs were compared to the 4-hr battery storage marginal ELCCs at that point on the surface and a de-rate factor was calculated. For example, if battery storage provides an 80% marginal ELCC and demand response provides a 60% marginal ELCC, then the 4-hr battery equivalent de-rate factor is 60%/80% = 75%. Figure 41 below shows the demand response de-rate factor used for each year.



Availability assessment hours

Hong Zhou
Lead Market Development Analyst, Short-Term Forecasting

May 13, 2025

The ISO proposes Winter and Spring Season Alignment for AAH

2024 actual frequency of top 5% of load hours

	Hour	8	15	16	17	18	19	20	21	22	23	Season
MONTH	Jan	4				9	13	7	4			Winter
	Feb					6	14	10	3			Winter
	Mar	1				2	6	15	13			Spring
	Apr	1					2	10	16	7		Spring
	May					1	4	11	13	7	1	Spring
	Jun		1	2	2	6	8	8	6	3		summer
	Jul			2	4	8	10	8	5			summer
	Aug			1	4	7	17	6	2			summer
	Sep		2	4	6	7	7	6	3	1		summer
	Oct		1	5	8	8	8	6	1			summer
	Nov					16	13	5	2			Winter
	Dec	1			2	10	10	9	4	1		Winter

2026 forecast frequency of top 5% of load hours

	Hour	15	16	17	18	19	20	21	22	23	Season	Recommendation
MONTH	Jan				8	19	9	1			Winter	HE18-HE22
	Feb				1	18	14				Winter	HE18-HE22
	Mar					4	17	11	5		Spring	HE18-HE22
	Apr				2	4	8	13	7	2	Spring	HE18-HE22
	May					4	10	13	10		Spring	HE18-HE22
	Jun		2	3	5	7	8	6	4	1	summer	HE17-HE21
	Jul	1	3	4	8	8	7	4	2		summer	HE17-HE21
	Aug		2	6	9	12	6	2			summer	HE17-HE21
	Sep	2	4	5	7	7	5	4	2		summer	HE17-HE21
	Oct	1	3	4	7	9	7	4	2		summer	HE18-HE22
	Nov		2	4	14	11	4	1			Winter	HE18-HE22
	Dec				14	14	9				Winter	HE18-HE22

- Winter Months shift to HE 18-22
- Monitoring HE 8 values within top 5% of load hours

Looking further into top 10% of the hours to monitor HE 8, HE 17, and HE 22

2024 actual frequency of top 10% of load hours

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
Jan																								
Feb								3	1	1							2	9	19	17	12	3		
Mar								5	1									4	9	24	22	9		
Apr								2	2	1									7	21	22	17		
May																		2	10	19	23	16	4	
Jun														1	2	2	6	11	13	14	12	10	1	
Jul															2	6	8	15	15	13	10	5		
Aug																4	6	18	21	19	4	2		
Sep	2	1	1	3	2	1	1	6	5	1	1	1	4	7	6	10	9	9	9	8	7	7	6	1
Oct	1	2	2			4	3	1	3	2	3	2	1	3	7	10	12	11	11	10	9	7	5	2
Nov	8	1			1	7	1	3	2		3	1	2	1	2	1	8	18	19	16	8	2	1	3
Dec	3	1				2	4	9	4	3	1	2	3	2	2	3	5	17	16	12	9	5	4	4

2026 forecast frequency of top 10% of load hours

Hour	1	2	3	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan						3										19	22	19	10	1		
Feb						3										9	20	19	16			
Mar																	12	22	20	16	4	
Apr															1	2	5	18	22	18	5	1
May																3	10	17	20	20	4	
Jun													2	3	5	8	11	13	13	11	5	1
Jul												1	2	5	8	12	14	13	11	7	1	
Aug													1	6	11	16	16	14	8	2		
Sep	5	1	1	2	4	4	4	2	1	1		3	5	9	11	13	13	11	8	5	2	3
Oct	4	4	2		12	1		4		1	1	2	4	5	7	13	15	15	9	6	4	2
Nov	2	1		16			1	5		1			3	4	8	21	20	17	4		3	2
Dec	9			8	1				7				6		4	21	21	16	12	3	2	1

- During Fall and Early winter you observe more scattered top 10% of load.
- AAH currently is a 5 hour continuous time period; will need to monitor changes to this area due to duel peaking starting to be highlighted in results.

Environmental Finance

Environmental Market Rankings 2025

Market remains optimistic after another turbulent year

Environmental markets service providers navigated political uncertainty in 2024, impacting prices and trading, writes Rob Langston

Policy uncertainty and the politicisation of environmental challenges had a significant impact on prices during 2024, according to the winners of Environmental Market Rankings.

While many countries, particularly in the Asia-Pacific region, have pushed forward with their own compliance carbon markets, partly in response to the EU's Carbon Border Adjustment Mechanism (CBAM), while legal challenges in the US stalled progress in North America.

Meanwhile, ongoing speculation about the convergence of the UK and EU emissions trading systems (ETS) have stoked prices in two of the most established markets.

Nevertheless, market participants – who are no strangers to such volatility and uncertainty – saw signs for optimism, as progress continues on several fronts and hope for more stability around pricing as interim decarbonisation targets approach.

Categories

Compliance Carbon Markets

Green Certificates

Meanwhile, demand for green certificates is set to be boosted by technology giants' growing thirst for renewable and low-carbon energy to help fuel the boom in AI.

This could help sustain voluntary markets, even as regulated markets brace for headwinds from President Donald Trump's assault on renewables, they argue.

Once again, the Environmental Market Rankings received hundreds of votes from market participants highlighting the companies providing the best services in the compliance carbon markets and green certificates.

Netherlands-based STX Group topped the leaderboard in this year's rankings, after being named as top provider in 14 categories for both markets, a significant increase on the nine it won in 2023-2024 rankings. (See table below). It was named top provider in seven compliance carbon markets categories, including three won by STX Group company Vertis Environmental Finance. It also emerged as readers' favourite in seven of the green certificates categories.



Slipping slightly from last year's showing, US-based Karbone topped seven categories, down from the nine it won in 2023-2024. Four of its awards came from the North American compliance carbon markets, while picking up three in the green certificates.

Anew Climate completed the top-three providers from this year's awards, winning six categories spread equally across compliance and green certificates. This year's haul matches its showing last year.

Rounding out the top-five providers, were ClearBlue Markets and ICE with three awards each.

COMPLIANCE CARBON MARKETS		
EU EMISSIONS TRADING SYSTEM		
Category	Winner	Runner up
Best broker, options & futures	Evolution Markets	Vertis
Best trading company, options & futures	Vertis	CFP Energy
Best broker, OTC/spot	Vertis	Evolution Markets
Best trading company, OTC/spot	CFP Energy	Vertis
Best advisory/consultancy	ClearBlue Markets	Redshaw Advisors
Best exchange/clearing house	ICE	
UK EMISSIONS TRADING SYSTEM		
Category	Winner	Runner-up
Best broker, OTC/spot	Vertis	Redshaw Advisors
Best trading company, OTC/spot	CFP Energy	Vertis
Best advisory/consultancy	Redshaw Advisors	ClearBlue
NORTH AMERICAN MARKETS (California)		
Category	Winner	Runner-up

Best broker, options & futures	Karbone	Evolution Markets
Best trading company, options & futures	STX Group	Anew
Best broker, OTC/spot	Karbone	STX Group, Anew
Best trading company, OTC/spot	STX Group	Anew, Karbone
Best project developer	Anew	ClearBlue
Best advisory/consultancy	ClearBlue Markets	Karbone, Anew
NORTH AMERICAN MARKETS (RGGI)		
Category	Winner	Runner-up
Best broker	Karbone	Evolution Markets
Best trading company	Anew	STX Group
NORTH AMERICAN MARKETS (All - includes Canada and Mexico)		
Category	Winner	Runner-up
Best broker	Karbone	Evolution Markets
Best trading company	STX Group	Anew
Best advisory/consultancy	ClearBlue Markets	STX Group
Best verification company	First Environment	
Best project developer	Anew	ClearBlue
APAC MARKETS		
Category	Winner	Runner-up
Best broker	CORE Markets	STX Group

Best trading company	STX Group	3Degrees
Best advisory/consultancy	Kanaka Management Services	CORE Markets
Best verification company	EPIC Sustainability Services	
Best project developer	Kanaka Management Services	STX Group

In compliance carbon markets, one of the big winners in the EU and UK ETS categories was Vertis Environmental Finance, an STX Group company, which topped the rankings in three different categories, up from one last year. It was named Best trading company, options & futures and Best broker, OTC/spot for the EU ETS and Best broker, OTC/spot for the UK ETS.

CFP Energy was named Best trading company, OTC/spot for both the EU ETS and UK ETS, and was a runner-up in the Best trading company, options & futures for the EU market.

Evolution Markets was named Best broker, options & futures in the EU carbon markets, but was unable to equal last year's haul of three awards.

ClearBlue Markets was voted Best advisory/consultancy in the EU ETS and was runner-up for the UK. It was also named Best advisory/consultancy for California and North America markets overall.

Karbone was one of the standout winners in the North American markets taking four awards Best broker, options & futures and Best broker OTC/spot in California, and was also named Best broker for RGGI and North American markets overall (including Canada and Mexico). It was also named runner-up in several categories.

Another multiple winner was Anew Climate, which won three awards, including Best project developer in California and North American markets overall, and Best trading company for RGGI. It was runner-up in several other categories.

STX Group topped the polls as Best trading company, options & futures and Best trading company, OTC/spot in California, while also being named Best trading company for North American markets overall.

Elsewhere, ClearBlue Markets was voted Best advisory/consultancy for California and North American markets overall. It was also a runner-up in several categories.

Meanwhile, First Environment was chosen as North American markets Best verification company returning to the rankings after last winning the top spot in 2022.

In Asia-Pacific, there was a return to the rankings by Kanaka Management Services, which last featured in 2022. It topped two categories in this year's rankings after being voted Best advisory/consultancy and Best project developer.

Both CORE Markets and EPIC Sustainability Services retained their positions as Best broker and Best verification company respectively. STX Group topped the poll as the region's Best trading company and was a runner-up in several other categories.

GREEN CERTIFICATES		
ENERGY ATTRIBUTE CERTIFICATES - EUROPE		
Category	Winner	Runner-up
Best broker	STX Group	Redshaw Advisors
Best trading company	STX Group	CFP Energy
Best advisory	STX Group	Redshaw Advisors, Karbone
Best exchange/clearing house	ICE	
ENERGY ATTRIBUTE CERTIFICATES - NORTH AMERICA		
Category	Winner	Runner-up
Best broker	Karbone	STX Group

Best trading company	STX Group	Anew
Best advisory	Anew	Karbone
Best exchange/clearing house	ICE	
ENERGY ATTRIBUTE CERTIFICATES - APAC		
Category	Winner	Runner-up
Best broker	CORE Markets	STX Group
Best trading company	STX Group	
RENEWABLE IDENTIFICATION NUMBERS MARKET		
Category	Winner	Runner-up
Best broker	Karbone	STX Group
Best trading company	STX Group	Anew
Best advisory/consultancy	Anew	Karbone
Best verification company	EcoEngineers	
RENEWABLE NATURAL GAS MARKET		
Category	Winner	Runner-up
Best broker	Karbone	
Best trading company	STX Group	Anew
Best advisory/consultancy	Anew	STX Group
Best verification company	Weaver	

STX Group also had a strong showing in the Renewable Energy Certificates rankings, as it was voted the best provider in seven categories.

It dominated the European market, winning three out of four categories, including Best broker, Best trading company and Best advisory. It was also named Best trading company in North America and APAC, and in the Renewable Identification Numbers and renewable natural gas markets. It was also named a runner-up in several other categories.

Karbone three categories in this year's certificates rankings, including Best broker for North America, and in the Renewable Identification Numbers and renewable natural gas markets.

Anew Climate topped the rankings as Best advisory in North America and Best advisory/consultancy in the Renewable Identification Numbers and renewable natural gas markets.

ICE was named Best exchange/clearing house for Europe and North America, while EcoEngineers and Weaver were readers' Best verification company for the Renewable Identification Numbers and renewable natural gas markets respectively.

Environmental Finance would like to congratulate to all this year's winners and runners-up.

How the rankings were conducted

Companies were emailed in November 2024 and asked to nominate the leading traders, brokers, and service providers in the markets covering carbon emissions and green certificates, via an online survey.

They were asked to vote only in those categories in which they had direct experience and to make their judgements based on efficiency and speed of transaction; reliability; innovation; quality of information and services provided; and influence on the market, not just the volume of transactions handled.

Around 1,000 completed responses were received. Only one vote per company

site was allowed and those firms that nominated themselves had their votes disregarded.

U.S. Government Accountability Office

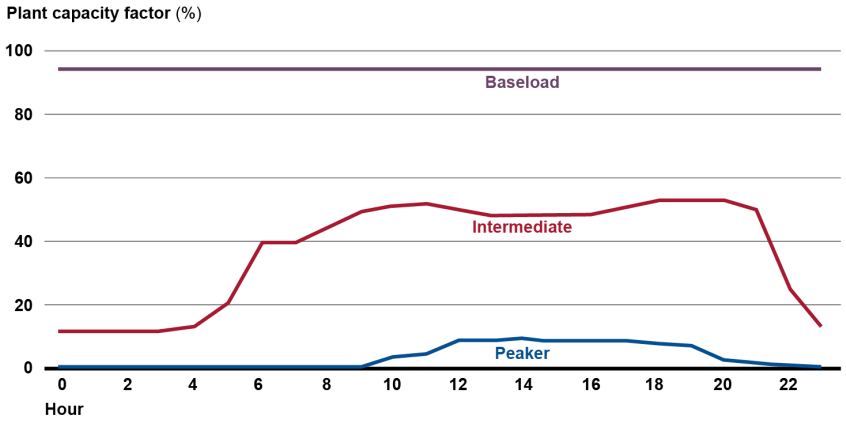
Electricity: Information on Peak Demand Power Plants

GAO-24-106145
Q&A Report to Congressional Requesters
May 21, 2024

Why This Matters

Peaker power plants are part of the U.S. energy infrastructure and help meet peak electricity demand. Peak demand generally occurs at times during the day when cooling and heating needs are generally the highest among households. Peakers are used to supplement other types of power plants, such as baseload plants, which run consistently throughout the day and night, and intermediate plants, which run mostly during the day and less at night (see fig. 1).

Figure 1: Illustrative Example of Annual Average Hourly Capacity Factors, by Plant Type



Source: GAO Analysis of Environmental Protection Agency data. | GAO-24-106145

Note: A plant's capacity factor is the percent of energy it produced of the total energy it could have produced during a certain time frame if it operated continuously at full power.

Peakers may be less efficient than other types of plants—such as intermediate and baseload plants—because they undergo frequent startups using comparatively large amounts of fuel. Further, environmental advocates and some congressional leaders have expressed concerns that peakers may also negatively affect the air quality in communities—which may be historically disadvantaged or disproportionately low income—around the plants.

We were asked to examine pollution from peakers across the nation. We are providing information on the number and locations of peakers in the U.S.; the proximity of peakers to disproportionately low-income, and historically disadvantaged racial or ethnic populations; the extent to which they emit pollutants and how these pollutants affect the health of people exposed; alternatives for replacing them; and potential challenges of replacing them.

Key Takeaways

- Historically disadvantaged racial or ethnic communities tend to be closer to peakers.





2024 Special Report on Battery Storage

May 29, 2025

Prepared by: Department of Market Monitoring

California Independent System Operator

2.4 Energy bids and prices

With the ISO's non-generator resource model, batteries submit a single energy bid curve, which reflects both willingness to charge and discharge. Battery resources do not submit energy price bids solely based on the actual costs of providing energy. Rather, they also consider the *opportunity costs* of discharging or charging in one particular part of the day. For example, discharging energy during low-demand hours may preclude batteries from discharging during high-demand hours. The difference in market prices between low-demand and high-demand hours can represent an opportunity cost of discharging in lower priced hours.

Batteries participating in the resource adequacy (RA) program are subject to must-offer obligations, meaning they are required to bid their entire upward RA capacity into the market. These resources tend to manage opportunity cost through their bid prices, rather than by limiting the quantity of their bids. For example, to avoid being dispatched when market prices are low, batteries may submit bid prices to discharge that greatly exceed the prices they paid to charge, especially in earlier hours of the day. Conversely, batteries may submit excessively low downward energy bids to avoid charging in certain hours.[8]

Figure 2.4 and Figure 2.5 show average energy bids of battery resources compared to average nodal prices by quarter in both the day-ahead and real-time markets, respectively.[9] As shown in Figure 2.4, the spread of average energy bids remained high throughout 2024 in the day-ahead market. Average bid prices to charge were $81 lower and bids to discharge were $230 higher than the nodal price, with an average bid price spread of $312. In comparison, the average bid price spread was $235 in 2023.

Figure 2.5 shows average real-time bids of battery resources for the portion of a resource's dispatch range that is available to the real-time market (i.e., operating range that is not covered by real-time self-schedules or day-ahead ancillary service awards held in real-time). The average price spread in battery bids in the real-time market increased from $202/MWh in 2023 to $223/MWh in 2024.

In both the real-time and day-ahead markets, batteries expressed their highest willingness to charge in the afternoon during peak solar production hours, when nodal prices are lowest on average. Batteries submitted their lowest discharging bids for peak demand hours, when their opportunity cost for discharging is lowest.

[8] Currently, only batteries with flexible resource adequacy capacity are subject to must-offer requirements on their downward capacity (i.e., to charge).

[9] Both bids and nodal prices are weighted average values, weighted by the bid quantity at each price and location.

Figure 2.4 Hourly average day-ahead bids and nodal prices (by quarter)

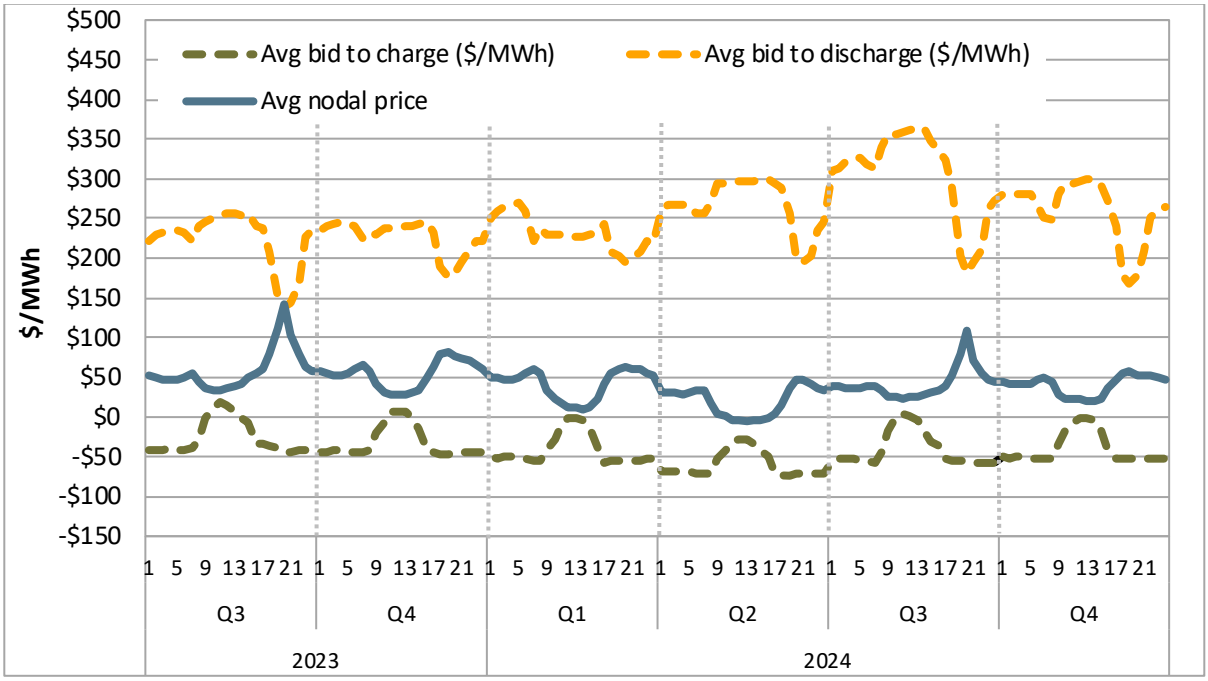


Figure 2.5 Hourly average real-time battery bids and nodal prices (by quarter)

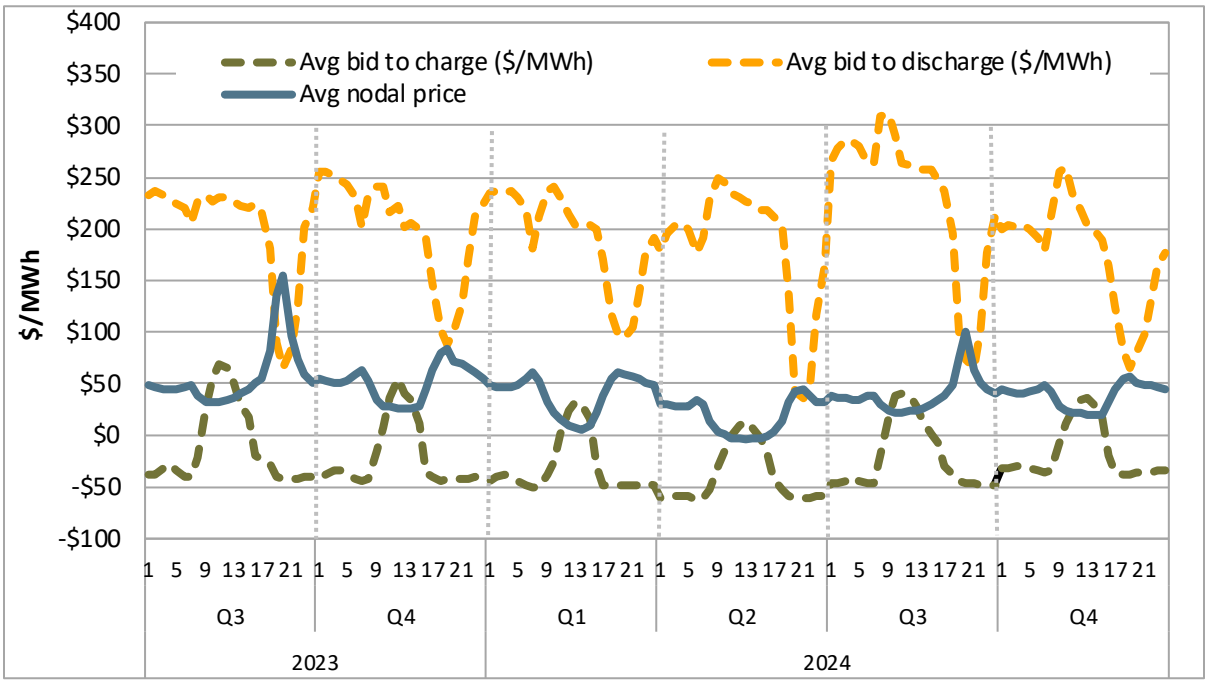


Figure 2.6 shows the average of batteries' submitted 15-minute market bids by price range in each hour in Q3 2024. Though some battery capacity was bid-in at the $1,000/MWh price cap throughout the day, most capacity was bid in at lower than $100, on average.