Docket	:	A.24-09-014
Exhibit Number	:	
Commissioner	:	Alice Reynolds
Admin. Law Judge	:	Nilgun Atamturk/
	:	Rajan Mutialu
Public Advocates	:	Nathan Chau/
Project Mgr.	:	James Ka Ho Lau
Witnesses	:	Nathan Chau

PUBLIC ADVOCATES OFFICE
CALIFORNIA PUBLIC UTILITIES COMMISSION

PREPARED TESTIMONY ON MARGINAL GENERATION CAPACITY COSTS IN PACIFIC GAS & ELECTRIC COMPANY'S 2023 GENERAL RATE CASE PHASE 2

San Francisco, California
July 23, 2025

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TABLE OF CONTENTS

Pages

CHAPTER 2 – MARGINAL GENERATION CAPACITY COSTS

(Witness: Nathan Chau)

I. SUMMARY AND RECOMMENDATIONS

This chapter presents the Public Advocates Office at the California Public Utilities Commission's (Cal Advocates) recommendations pertaining to Pacific Gas & Electric Company's (PG&E) marginal generation capacity costs (MGCC). Marginal generation capacity costs (MGCC) represent the cost of marginal generation resources required to meet a one kilowatt (kW) increase in coincident peak demand and are expressed in dollars per kilowatt-year ($/kW-year).[1] MGCC are important because they are used to inform the allocation of class-level generation revenue requirements and electricity rates for each customer class. PG&E multiplies its proposed MGCC by each customer class's coincident peak demand to allocate each class's marginal generation capacity cost revenue.[2]

PG&E calculates its proposed MGCC using a modified version of the Net Cost of New Entry (NetCONE) method adopted by the Commission in PG&E's prior General Rate Case Phase II (GRC II) proceeding[3] and the 2021 Avoided Cost Calculator (ACC).[4] From this methodology, PG&E assumes that the marginal resource is a standalone 4-hour lithium-ion (Li-Ion) battery. PG&E then calculates annual generation capacity costs (AGCCs) over 6 years (2024-2029)[5] as the going-forward fixed costs of the battery net of energy arbitrage revenues, divided by an effective load carrying capacity (ELCC)[6]

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[1] Application (A.)24-09-014, *Pacific Gas and Electric Company 2023 General Rate Case Phase II Errata to September 30, 2024 Prepared Testimony Exhibit (PG&E-2) Cost of Service Studies* (PG&E-2), April 18, 2025, at "Chapter 1: Introduction to Cost of Service Analysis Proposals" (Chapter 1), at 1-10.

[2] PG&E-2, "Chapter 3: Energy Generation and Capacity Cost of Service" (Chapter 3), at 3-5.

[3] PG&E-2, "Chapter 2: Marginal Generation Coats" (Chapter 2), at 2-3 to 2-5.

[4] PG&E-2, Chapter 2, at 2-3.

[5] PG&E-2, Chapter 2, at 2-30.

[6] PG&E-2, Chapter 2, at 2-8, 2-3, (PG&E states that 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

percentage. PG&E then levelizes those AGCCs into a single MGCC value[7] with adjustments for line losses for transmission, primary distribution, and secondary distribution voltage levels.

PG&E's AGCC calculations produce overstated MGCC values in two ways. First, PG&E incorrectly applies a solar capacity factor ratio which artificially deflates its annual ELCC values and inflates its proposed MGCC values. Second, PG&E calculates battery revenues using its proposed marginal energy costs (MECs), which PG&E calculates using an inflated renewable curtailment price floor. Consequently, PG&E underestimates battery revenues which increases AGCC and MGCC values.

The Commission should therefore adopt Cal Advocate's proposed MGCC of $43.12/kW-year, which applies the following adjustments to PG&E's method:

- A higher ELCC value resulting from removing PG&E's solar capacity factor ratio and;
- Higher battery revenues resulting from using Cal Advocates' proposed MEC values.[8]

Table 2-1 compares PG&E's and Cal Advocates' proposals:

Table 2-1: Comparison of Cal Advocates' and PG&E's Proposed Capacity Factor, Renewable Curtailment Floor, and MGCC Values

Proposed Value	PG&E	Cal Advocates
Behind the Meter Solar Capacity Factor Adjustment	65%	100%
ELCC Range from 2024-2029	81-51%	84-65%
Renewable Curtailment Floor for MECs ($)	($31.37)	($54.56)
2024-2029 Battery Revenue Total ($ million)	$1.08	$1.26
MGCC ($/kW-yr)	$79.50	$43.23

contribute to meeting peak demand and ensuring grid reliability.").

[7] PG&E-2, Chapter 2, at 2-30.

[8] See Cal Advocates Prepared Opening Testimony, Chapter 1.

II. DISCUSSION OF RECOMMENDATIONS

A. The Commission Should Continue to Use a Standalone 4-Hour Lithium-Ion Battery as the Proxy Resource for Estimating MGCC.

PG&E's use of a 4-hour standalone Li-Ion battery as the proxy resource is appropriate because it is the most readily available and economically viable generation resource in line with California's clean energy goals. PG&E asserts that based on the Commission's recent decisions and the results from the 2022-2023 Integrated Resource Plan (IRP) cycle, "it is unlikely that new natural gas generation would be built in California in the future."[9] Standalone batteries also comprise 66% of the expected cumulative procurement under contract to Commission-jurisdictional load-serving entities (LSEs) through the end of 2026.[10] Standalone 4-hour batteries represent the majority of currently operating grid-scale battery resources[11] due to their cost-effectiveness compared to other battery resources.[12] The timing of when long-duration storage resources become lower-cost compared to 4-hour batteries is "highly uncertain and sensitive to ELCC or capacity credit modeling assumptions."[13] Until long-duration storage becomes financially viable at scale, 4-hour batteries can help meet the need for longer-duration. They can be configured to discharge for longer than 4 hours at a portion of their total capacity.[14] Therefore, the Commission should adopt PG&E's use of a 4-

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[9] PG&E-2, Chapter 2, at 2-24 – 2-25.

[10] See Appendix B, Attachment 2-B (California Public Utilities Commission (CPUC) and California Energy Commission (CEC), *Joint Agency Reliability Planning Assessment: Senate Bill (SB) 846 Fourth Quarterly Report*, December 2023, at 7-8 (excerpt), available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/joint-reliability-planning-assessment-sb-846-fourth-quarterly-report.pdf).

[11] See Appendix B, Attachment 2-C (Lumen Energy Strategy, *California Public Utilities Commission Energy Storage Procurement Study* (CPUC 2023 Storage Procurement Study), May 31, 2023, at 24, 72 (excerpt), available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/energy-storage/2023-05-31_lumen_energy-storage-procurement-study-report.pdf).

[12] See Appendix B, Attachment 2-C (CPUC 2023 Storage Procurement Study, at 24).

[13] See Appendix B, Attachment 2-C (CPUC 2023 Storage Procurement Study, at 74-76).

[14] See Appendix B, Attachment 2-C (CPUC 2023 Storage Procurement Study, at 75-76).

hour standalone Li-Ion battery as the proxy marginal resource for estimating MGCC because it represents the lowest-cost, most readily available generation resource.

B. The Commission Should Reject PG&E's Behind-the-Meter (BTM) Solar Capacity Factor.

1. PG&E's ELCC Method and Solar Capacity Factor

A resource's ELCC captures its reliability contribution relative to a hypothetical "perfect capacity" resource, and is expressed in percentage terms (with 100% representing perfect capacity).[15] PG&E applies an ELCC within its NetCONE calculation with the stated goal "to account for the fact that batteries will not contribute 100% to the reliability of capacity resources."[16] PG&E divides each annual AGCC value by a corresponding annual ELCC percentage derived from the IRP.[17] This approach is similar to how ELCC is applied in MGCC calculations of the 2022 and 2024 Avoided Cost Calculator (ACC) methodologies.[18] PG&E applies an ELCC percentage, which spreads the net costs of a four-hour Li-Ion battery over a subset of the battery's capacity, rather than its total nameplate capacity. Thereby, PG&E increases its proposed MGCCs, which it presents in $/kW-year terms. Mathematically, the AGCCs are increased by dividing a percentage value less than 100%.

PG&E derives annual ELCC values for 2024-2029 using inputs from the 2022-2023 IRP.[19] The IRP projects marginal ELCC for various 4-hour storage capacity levels as a function of installed solar capacity. According to the IRP Inputs and Assumptions, the reliability contribution of batteries at increasing capacity levels is contingent upon

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[15] See Appendix B, Attachment 2-D (Energy Division, *Final Inputs & Assumptions: 2022-2023 Integrated Resource Plan* (IRP Inputs & Assumptions), CPUC, October 2023, at 142-144 (excerpt), available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/inputs-assumptions-2022-2023_final_document_10052023.pdf).

[16] See Appendix B, Attachment 2-E (PG&E Response to Cal Advocates Data Request No. 004, Question 17, at 1).

[17] PG&E-2, Chapter 2, at 2-28 and 2-29.

[18] PG&E-2, Chapter 2, at 2-8, fn. 9.

[19] PG&E-2, Chapter 2, at 2-28 and 2-29.

commensurate increases in solar capacity.[20] The reliability contribution of battery increases when there is more solar resources available for them to charge from during the lowest-cost midday hours.[21] To capture these interactive effects between battery and solar capacity levels, the IRP uses ELCC studies from the Strategic Energy Risk Valuation Model (SERVM) to produce a solar-plus-storage ELCC "surface."[22] The surface maps of the combined solar-plus-storage portfolio ELCC percentages across various levels of solar and battery storage additions beyond the 2030 updated Preferred System Plan (PSP) portfolio.[23] Figure 2-1 presents the marginal battery ELCC values from the solar-plus-storage surface.

Figure 2-1: Incremental Battery Storage ELCC Across the IRP ELCC Surface[24]

Calculated Incremental Storage ELCC %

Solar Nameplate Capacity (GW)

4-Hour Battery Namplate 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%

[20] See Appendix B, Attachment 2-D (IRP Inputs & Assumptions, at 154, 156 – 157).

[21] See Appendix B, Attachment 2-D (IRP Inputs & Assumptions, at 154, 156 – 157).

[22] See Appendix B, Attachment 2-D (IRP Inputs & Assumptions, at 154 – 155).

[23] See Appendix B, Attachment 2-D (IRP Inputs & Assumptions, at 154 – 155).

[24] See Appendix B, Attachment 2-D (IRP Inputs & Assumptions, at 157).

PG&E uses the IRP's forecasted solar and battery capacity levels for 2024-2029[25] (under the IRP's 25 million metric tons (MMT) emissions scenario)[26] to extract ELCCs for each year from the table above.[27]

PG&E includes both capacity types in its forecasted total solar capacity levels because the solar axis of the ELCC surface includes both behind-the-meter (BTM) and grid-scale solar[28] However, PG&E reduces the capacity of BTM solar by applying a capacity factor ratio, while it inputs the nameplate capacity of grid-scale solar. PG&E calculates the ratio by dividing the capacity factor[29] of BTM solar by that of grid-scale solar (both derived from the IRP), producing a value of 65%. It then multiplies the forecasted nameplate capacity of BTM solar for each year by this percentage, and inputs the resulting values into its total solar capacity forecasts that it uses to derive annual ELCC values.[30] PG&E contends that it is necessary to apply this capacity factor ratio "to account for the lower capacity factor associated with BTM solar as opposed to grid-scale

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[25] See workpaper titled "GRC_2023_PhII_WP_PGE_20241018_Ex02Ch02_MEC_MGCC_PUB," October 23, 2024 (2023 GRC II MEC & MGCC Workpaper), "IRP Inputs" tab.

[26] The IRP's 25 MMT case represents a scenario achieving 25 million metric tons (MMT) of carbon dioxide equivalent emissions by 2035.

[27] See Appendix B, Attachment 2-E (PG&E Response to Cal Advocates Data Request No. 004, Question 18, at 1 (PG&E interpolates or estimates ELCC values between the percentages listed in the IRP Inputs & Assumptions table, based upon the forecasted solar and storage capacity levels under the IRP's 25 MMT scenario for 2024-2029)).

[28] See Appendix B, Attachment 2-D (IRP Inputs & Assumptions, at 150).

[29] See Appendix B, Attachment 2-F (National Renewable Energy Laboratory (NREL), *2020 Annual Technology Baseline*: "*Utility Scale PV: Methodology - Capacity Factor Definition*" (NREL ATB PV Capacity Factor Definition), 2020, available at https://atb-archive.nrel.gov/electricity/2020/index.php?t=su, ("A capacity factor represents the expected annual average energy production divided by the annual energy production, assuming the plant operates at rated capacity for every hour of the year. It is intended to represent a long-term average over the lifetime of the plant; it does not represent interannual variation in energy production. Future year estimates represent the estimated annual average capacity factor over the technical lifetime of a new plant installed in a given year.")).

[30] 2023 GRC II MEC & MGCC Workpaper, Tab "IRP Inputs", cells E19:M:19; See Appendix B, Attachment 2-7 (PG&E Response to Cal Advocates' Data Request 007, Question 8, at 1 (PG&E "[scales] the BTM solar by a factor (< 1), equal to the ratio of their capacity factors, and add the resulting capacity to the grid scale solar to calculate the total solar capacity. This is then used to find the ELCC from the ELCC surface derived from Inputs and Assumptions of CAISO Integrated Resource Plan (IRP) 2022-2023.")).

solar… Assuming that grid-scale solar and BTM solar are equal when they have different capacity factors would be an incorrect assumption."[31]

2. PG&E's BTM Solar Capacity Factor Runs Counter to IRP Methodology and Results in Artificially Low ELCC and High MGCC Values.

PG&E's application of a capacity factor ratio runs counter to how IRP methodology considers capacity factors. The IRP Inputs & Assumptions clearly states that users of the ELCC surface should look up ELCC values using the forecasted nameplate capacity of solar resources, including BTM solar.[32] The IRP solar-plus-storage surface already accounts for the relatively lower capacity factors of the future California Independent System Operator (CAISO) -wide portfolio of solar resources in the multivariate equation used to produce the ELCC surface. As stated in the IRP Inputs & Assumptions:

> 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.[33]

Thus, the IRP already embeds a capacity factor ratio into the solar axis of the solar-storage ELCC surface. Due to this, PG&E's application of a similar ratio to BTM solar is duplicative and inappropriate.

PG&E's application of a solar capacity factor leads to artificially low ELCCs. PG&E unnecessarily applies a solar capacity factor ratio with a value less than 1 to BTM solar. PG&E is therefore undercounting the annual projected BTM solar capacity levels that it uses to calculate annual ELCC values. PG&E undercounting BTM solar reduces its ELCC values, because it results in lower forecasted solar capacity growth relative to

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[31] See Appendix B, Attachment 2-G (PG&E Response to Cal Advocates Data Request No. 007, Question 8, at 1).

[32] See Appendix B, Attachment 2-D (IRP Inputs & Assumptions, at 156-157).

[33] See Appendix B, Attachment 2-D (IRP Inputs & Assumptions, at 156-157).

the forecasted growth of battery storage capacity. Table 2-2 provides a comparison of the BTM solar capacity forecasts and ELCC values with and without PG&E's capacity factor ratio applied. ELCCs values for each year are raised by removing PG&E's solar capacity factor ratio and results in a more gradual decline of ELCCs from 2024-2029.

Table 2-2: Forecasted Solar Capacity & ELCC Values with and without PG&E's Solar Capacity Factor (SCF) Ratio, 2024-2029[34]

		2024	2025	2026	2027	2028	2029
Solar Capacity (GW)	**PG&E's Proposed Values**	32.88	36.60	38.34	--	42.94	--
	Without SCF Ratio	38.76	42.94	45.04	--	50.63	--
ELCC	**PG&E's Proposed Values**	81%	79%	51%	52%	51%	51%
	Without SCF Ratio	84%	84%	74%	72%	71%	65%

PG&E's application of a solar capacity factor ratio also results in an artificially inflated MGCC. Under the NetCONE method, PG&E calculates AGCCs by dividing the cost of batteries net of revenues by the ELCC.[35] As shown in Table 2-3, the resulting impact of removing PG&E's solar capacity factor ratio is a decrease of the MGCC from $79.50/KW-year to $63.26/kW-year.[36]

[34] The IRP does not forecast resource capacity levels for the years 2027 and 2029. PG&E interpolates ELCC values for those years (averaging between the 2026 and 2028 ELCC values for 2027, and between the 2028 and 2030 levels for 2029). Cal Advocates applies the same method in determining its ELCC values.

[35] ELCCs range between values of 0 and 1. Therefore the closer such values are to 0, the higher the resulting AGCC will be.

[36] Holding all other variables constant. This value is provided for illustrative purposes only and does not represent Cal Advocates' proposed AGCC or MGCC values. The workpaper in which Cal Advocates calculated this illustrative value is available upon request. See Appendix B, Attachment 2-I.

Table 2-3: AGCCs and MGCC with and without PG&E Solar Capacity Factor Ratio[37]

		2024	2025	2026	2027	2028	2029
AGCC ($/kW-yr)	**With SCF Ratio**	$61.35	$62.62	$97.89	$100.06	$86.44	$73.78
	Without SCF Ratio	$59.31	$59.03	$68.17	$71.59	$63.55	$58.48
MGCC ($/kW-yr)	**With SCF Ratio**	**$79.50**					
	Without SCF Ratio	**$63.26**					

C. Cal Advocates' Proposed MECs Are More Accurate for Computing Battery Revenue Values And MGCC.

In PG&E's previous GRC II, PG&E used an internal avoided cost model to calculate battery revenues as a function of arbitrage and ancillary services.[38] In this GRC II, PG&E uses an "internal storage perfect foresight model" that calculates battery revenue solely as a function of arbitrage revenues.[39] The model uses PG&E's proposed MECs as hourly price forecasts and models revenues assuming that a 4-hour Li-Ion battery will charge during the four hours with the lowest MECs of the day and discharge during the four hours with the highest MECs.[40] In its MEC calculations, PG&E accounts for renewable curtailment by using the negative 2024 Forecasted Renewable Portfolio

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[37] The workpaper in which Cal Advocates calculated this illustrative value is available upon request. See Appendix B, Attachment 2-I.

[38] See Appendix B, Attachment 2-J (A.19-11-019, *Pacific Gas and Electric Company 2020 General Rate Case Phase II Prepared Testimony Cost of* Service *PG&E-2* (2020 GRC II Testimony), November 22, 2019, at "Chapter 2: Marginal Generation Costs" (Chapter 2), at 2-42 – 2-47).

[39] PG&E-2, Chapter 2, at 2-26 and 2-27.

[40] PG&E-2, Chapter 2, at 2-26 and 2-27.

Standard (RPS) Adder value (-$31.73)[41] as a renewable curtailment price floor.[42] As Cal Advocates argues in Chapter 1, the 2024 Final RPS Adder value (-$54.56)[43] provides a more accurate price floor. The Final RPS Adder aligns better with observed curtailment prices for 2024 and is calculated using transaction data that is more recent and temporally aligned with the 2024 test year.[44]

The 2024 Final RPS Adder produces lower off-peak and super-off-peak MEC estimates. These resulting MECs increase battery revenues (by lowering the costs of charging during the off-peak hours)[45] which in turn reduces AGCCs as illustrated in Table 2-4.[46]

Table 2-4: Comparison of Battery Revenues and AGCCs calculated using the 2024 Forecast and Final RPS Adder Values as a Renewable Curtailment Price Floor

Output	MEC Type	2024	2025	2026	2027	2028	2029
Battery Revenues (in thousands ($))	2024 Forecast RPS Adder	172	180	187	192	198	202
	2024 Final RPS Adder	190	199	207	214	220	226
AGCCs ($/kW-year)	2024 Forecast RPS Adder	61	63	98	100	68	74
	2024 Final RPS Adder	46	45	69	70	55	40

[41] See Appendix B, Attachment 2-J (Energy Division*, Market Price Benchmark Calculations 2024 REVISED* (Revised 2024 Market Price Benchmark Calculations), CPUC, November 5, 2024, at 1, available from https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/community-choice-aggregation-and-direct-access/2024-market-price-benchmarks-revised-20241105.pdf).

[42] PG&E-2, Chapter 2, at 2-14.

[43] See Appendix B, Attachment 2-J (Revised 2024 Market Price Benchmark Calculations, at 1).

[44] See Cal Advocates Prepared Opening Testimony, Chapter 1.

[45] See Appendix B, Attachment 2-E (PG&E Response to Cal Advocates Data Request No. 004, Question 3(c), at 2).

[46] PG&E recalculated battery revenues under various RPS adder values in its response to data request Cal Advocates-007, Question 5. See Appendix B, Attachment 2-A.

D. The Commission Should Adopt Cal Advocates' MGCC Modifications.

Cal Advocates calculates MGCC using PG&E's NetCONE methodology with two changes: the calculation does not apply a solar capacity factor ratio and also uses battery revenues calculated based on Cal Advocates' proposed MECs. These MEC values are produced using PG&E's MEC model, but with a renewable curtailment price floor equal to the negative value of the 2024 Final RPS Adder Value. These modifications produce a lower and more accurate MGCC value of $43.23. Table 2-5 compares Cal Advocates' and PG&E's proposed AGCC and MGCC values.

Table 2-5: Cal Advocates' and PG&E's Proposed AGCC and MGCC Values ($/kW-yr)

<table>
<tr><th>Output</th><th>Proposed By</th><th>2024</th><th>2025</th><th>2026</th><th>2027</th><th>2028</th><th>2029</th></tr>
<tr><td rowspan="3"><u>AGCC</u></td><td>PG&E</td><td>$61.35</td><td>$62.62</td><td>$97.89</td><td>$100.06</td><td>$86.44</td><td>$73.78</td></tr>
<tr><td>Cal Advocates</td><td>$44.13</td><td>$42.60</td><td>$48.22</td><td>$49.98</td><td>$40.36</td><td>$31.95</td></tr>
<tr><td>% Difference</td><td>-28%</td><td>-32%</td><td>-51%</td><td>-50%</td><td>-53%</td><td>-57%</td></tr>
<tr><td rowspan="3"><u>MGCC</u></td><td>PG&E</td><td colspan="6">$79.50</td></tr>
<tr><td>Cal Advocates</td><td colspan="6">$43.23</td></tr>
<tr><td>% Difference</td><td colspan="6">-46%</td></tr>
</table>

Cal Advocates' proposed MGCC value corrects for the deficiencies in PG&E's MGCC calculations. Specifically, PG&E's proposed MGCC value is inaccurate and inflated due to PG&E's application of a solar capacity factor ratio in its ELCC calculation, and underestimated battery revenues. Cal Advocates produces a more accurate MGCC compared to PG&E by recalculation of MGCC without a solar capacity factor and battery revenues based on more accurate MECs. Therefore, the Commission should reject PG&E's proposed MGCC value and adopt Cal Advocates' proposal.

III. CONCLUSION

The Commission should adopt PG&E's use of a standalone 4-hour Li-Ion battery as the most cost-effective marginal resource, and Cal Advocates' proposed MGCC value, which corrects for deficiencies in PG&E's approach. Cal Advocates' removed PG&E's solar capacity factor from its ELCC calculations. This method produces an ELCC that better reflects how IRP methodology already considers capacity factors and in turn provides a more accurate MGCC value. The use of MECs that are better aligned with observed 2024 curtailment prices and REC transactions to calculate battery revenues also produces a more accurate MGCC. For these reasons, the Commission should adopt Cal Advocates' recommendations.

LIST OF ATTACHMENTS FOR CHAPTER 2
(See Appendix B)

#	Attachment	Description
1	2-A	PG&E Response to Cal Advocates Data Request 7, Question 5 with Screen Shot of Attachment
2	2-B	California Public Utilities Commission (CPUC) and California Energy Commission (CEC) Senate Bill (SB) 846 Fourth Quarterly Report: Joint Agency Reliability Planning Assessment, pages 7-8.
3	2-C	California Public Utilities Commission 2023 Energy Storage Procurement Study, pages 24, 72, 74-76.
4	2-D	CPUC Energy Division, Final Inputs & Assumptions: 2022-2023 Integrated Resource Plan, pages 142-144, 150, 154-157
5	2-E	A.24-09-014 General Rate Case Phase II Application PG&E Response to Cal Advocates' Data Request 004, Questions 3(c), 17, and 18.
6	2-F	National Renewable Energy Laboratory 2020 Annual Technology Baseline, "Utility Scale PV: Methodology Capacity Factor Definition."
7	2-G	A.24-09-014 General Rate Case Phase II Application PG&E Response to Cal Advocates' Data Request 007, Question 8.
8	2-H	Cal Advocates Workpaper to Demonstrate Impact of Solar Capacity Factor on MGCC using Illustrative Values. Available by email upon request.
9	2-I	A.19-11-019 Pacific Gas and Electric Company 2020 General Rate Case Phase II Prepared Testimony Cost of Service PG&E-2, "Chapter 2: Marginal Generation Costs" pages 2-42 – 2-47.
10	2-J	CPUC Energy Division Market Price Benchmark Calculations 2024 REVISED.

APPENDIX A

Qualifications of Witness

QUALIFICATIONS AND PREPARED TESTIMONY OF NATHAN CHAU

Q.1 Please state your name and address.

A.1 My name is Nathan Chau and my business address is 505 Van Ness Avenue, San Francisco, California.

Q.2 By whom are you employed and what is your job title?

A.2 I work in the Electricity Pricing and Customer Programs Branch of Cal Advocates as a Regulatory Analyst.

Q.3 Please describe your educational and professional experience.

A.3 I hold a Bachelor of Science degree in Applied Economics from the University of the Pacific. My degree included coursework in finance, economics, and econometrics that I find relevant to this case. Since joining the Commission in April 2015, I have actively participated in a number of rate cases such as SDG&E's General Rate Case Phase II (A.23-01-008), PG&E's General Rate Case Phase II (A.16-06-013), the Time-of-Use Order Instituting Rulemaking (R.15-12-012), the Application on SB 350 Transportation Electrification Proposals (A.17-01-021) and the Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs (R.20-08-020). I also worked as project coordinator and witness in PG&E's General Rate Case Phase II (A.19-11-019).

Q.4 What is your area of responsibility in this proceeding?

A.4 I am project coordinator and author for Chapters 2 and 5 on MGCC and Revenue Allocation in Cal Advocates' Prepared Testimony in this proceeding.

Q.5 Does that complete your prepared testimony?

A.5 Yes, it does.

APPENDIX B

SUPPORTING MATERIALS

LIST OF ATTACHMENTS FOR CHAPTER 2

#	Attachment	Description
1	2-A	PG&E Response to Cal Advocates Data Request 7, Question 5 with Screen Shot of Attachment
2	2-B	California Public Utilities Commission (CPUC) and California Energy Commission (CEC) Senate Bill (SB) 846 Fourth Quarterly Report: Joint Agency Reliability Planning Assessment, pages 7-8.
3	2-C	California Public Utilities Commission 2023 Energy Storage Procurement Study, pages 24, 72, 74-76.
4	2-D	CPUC Energy Division, Final Inputs & Assumptions: 2022-2023 Integrated Resource Plan, pages 142-144, 150, 154-157
5	2-E	A.24-09-014 General Rate Case Phase II Application PG&E Response to Cal Advocates' Data Request 004, Questions 3(c), 17, and 18.
6	2-F	National Renewable Energy Laboratory 2020 Annual Technology Baseline, "Utility Scale PV: Methodology Capacity Factor Definition."
7	2-G	A.24-09-014 General Rate Case Phase II Application PG&E Response to Cal Advocates' Data Request 007, Question 8.
8	2-H	Cal Advocates Workpaper to Demonstrate Impact of Solar Capacity Factor on MGCC using Illustrative Values. Available by email upon request.
9	2-I	A.19-11-019 Pacific Gas and Electric Company 2020 General Rate Case Phase II Prepared Testimony Cost of Service PG&E-2, "Chapter 2: Marginal Generation Costs" pages 2-42 – 2-47.
10	2-J	CPUC Energy Division Market Price Benchmark Calculations 2024 REVISED.

Attachment 2-A

PG&E Response to Cal Advocates Data Request 7, Question 5 with Screen Shot of Attachment

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

PG&E Data Request No.:	CalAdvocates_007-Q005
PG&E File Name:	GRC-2023-PhII_DR_CalAdvocates_007-Q005
Request Date:	December 30, 2024
Requester DR No.:	CAL ADVOCATES-007
Requesting Party:	Public Advocates Office
Requester:	Kimiko Akiya/Nathan Chau/James Lau/Sarah Meyerhoff
Date Sent:	April 16, 2025
PG&E Witness(es):	Eshan Singh – Engineering, Planning and Strategy

SUBJECT: MARGINAL ENERGY COSTS AND MARGINAL GENERATION CAPACITY COSTS

QUESTION 005

Please provide annual battery revenues for northern and southern California (presented as "NPRevenue" and "SPRevenue" in PG&E's workpapers)[1] for 2024, 2025, 2026, 2027, 2028, 2029 and 2030 calculated using MECs that assume:

a. A curtailment price floor of -$54.56, equal to the negative value of the 2024 RPS final value.[2]

b. A curtailment price floor of -$71.24, equal to the negative value of the 2025 Forecast RPS value.[3]

c. A curtailment price floor that starts at -$54.56 for 2024,[4] then decreases to the following levels: -$75.08 in 2025, -$103.32 in 2026, -$142.17 in 2027, -$195.65 in 2028, -$269.23 in 2029, and -$370.48 in 2030.

ANSWER 005

See attachment *"GRC_2023_PhII_DR_CalAdvocates_007-Q005ATCH01.xlsx"* for the results asked in this data request. The Tab: EnergyRevenue has the revenue for each of the above cases. The total revenue is calculated based on 80% of SP and 20% of PGE DLAP revenue.

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1 See workpaper titled "GRC_2023_PhII_WP_PGE_20241018_Ex02Ch02_MEC_MGCC_CONF_2," (TY2023 GRC2 MEC & MGCC Workpaper V2), Tab "MGCC Calculation", cells V3:AG4.

2 Revised 2024 Market Price Benchmark Calculations.

3 Revised 2024 Market Price Benchmark Calculations.

4 Revised 2024 Market Price Benchmark Calculations.

		2024	2025	2026	2027	2028	2029	2030
REC $31.73	REC	$ 31.73	$ 31.73	$ 31.73	$ 31.73	$ 31.73	$ 31.73	$ 31.73
	NP	$ 156,570.15	$ 163,739.80	$ 169,650.11	$ 174,678.27	$ 179,654.83	$ 184,024.09	$ 187,855.38
	SP	$ 176,335.85	$ 184,361.65	$ 190,855.72	$ 196,637.76	$ 202,068.99	$ 206,694.60	$ 210,508.26
	Total	$ 172,382.71	$ 180,237.28	$ 186,614.60	$ 192,245.86	$ 197,586.16	$ 202,160.50	$ 205,977.68
	MGCC	$ 79.50	$ 77.27	$ 74.18	$ 63.10	$ 50.50	$ 39.51	$ 29.75
REC $54.56	REC	$ 54.56	$ 54.56	$ 54.56	$ 54.56	$ 54.56	$ 54.56	$ 54.56
	NP	$ 164,160.39	$ 171,937.04	$ 178,406.22	$ 183,977.27	$ 189,441.08	$ 194,196.66	$ 198,227.58
	SP	$ 196,574.04	$ 206,217.19	$ 214,228.99	$ 221,467.50	$ 228,199.59	$ 233,892.91	$ 238,254.93
	Total	$ 190,091.31	$ 199,361.16	$ 207,064.43	$ 213,969.45	$ 220,447.89	$ 225,953.66	$ 230,249.46
	MGCC	$ 54.11	$ 48.52	$ 42.47	$ 30.92	$ 18.40	$ 8.14	$ 0.22
REC $71.24	REC	$ 71.24	$ 71.24	$ 71.24	$ 71.24	$ 71.24	$ 71.24	$ 71.24
	NP	$ 169,718.40	$ 177,936.76	$ 184,816.25	$ 190,781.44	$ 196,598.70	$ 201,636.23	$ 205,811.46
	SP	$ 211,416.06	$ 222,247.95	$ 231,378.48	$ 239,690.30	$ 247,381.67	$ 253,864.13	$ 258,638.19
	Total	$ 203,076.53	$ 213,385.71	$ 222,066.04	$ 229,908.53	$ 237,225.08	$ 243,418.55	$ 248,072.85
	MGCC	$ 35.48	$ 30.83	$ 26.21	$ 17.92	$ 9.14	$ 3.10	$ -
REC Varying 370.48 after 2030	REC	$ 54.56	$ 75.08	$ 103.32	$ 142.17	$ 195.65	$ 269.23	$ 370.48
	NP	$ 254,803.93	$ 272,440.77	$ 289,257.21	$ 305,476.91	$ 321,402.46	$ 335,469.17	$ 345,667.92
	SP	$ 436,165.84	$ 471,922.67	$ 507,414.51	$ 542,626.55	$ 576,908.62	$ 607,593.76	$ 628,495.49
	Total	$ 399,893.46	$ 432,026.29	$ 463,783.05	$ 495,196.63	$ 525,807.39	$ 553,168.84	$ 571,929.98
	MGCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
REC Varying 31.73 after 2030	REC	$ 54.56	$ 75.08	$ 103.32	$ 142.17	$ 195.65	$ 269.23	$ 370.48
	NP	$ 176,073.42	$ 184,433.28	$ 191,296.24	$ 196,833.57	$ 201,339.57	$ 203,291.93	$ 200,508.61
	SP	$ 227,199.85	$ 238,329.33	$ 247,314.94	$ 254,463.52	$ 258,691.61	$ 257,033.31	$ 243,595.85
	Total	$ 216,974.56	$ 227,550.12	$ 236,111.20	$ 242,937.53	$ 247,221.20	$ 246,285.04	$ 234,978.40
	MGCC	$ 21.80	$ 18.76	$ 20.58	$ 20.28	$ 19.46	$ 20.70	$ 22.68

Attachment 2-B

California Public Utilities Commission (CPUC) and California Energy Commission (CEC) Senate Bill (SB) 846 Fourth Quarterly Report: Joint Agency Reliability Planning Assessment, pages 7-8.

These projects represent close to 15,000 MW of new nameplate capacity. The CPUC posts this information on its Tracking Energy Development (TED) Task Force website.

The volume of new projects that LSEs are reporting as under contract continues to increase through 2026 as LSEs sign new contracts. LSEs and counterparties frequently adjust the on-line date for projects due to continual contracting refinements. The CPUC receives updates about new resources under development across the 40+ CPUC jurisdictional LSEs and for the dozens of counterparties. There are over 300 contracts represented within this data for hundreds of resources under development by over 80 counterparties. As such, the data in Tables 3 and 4 are subject to change frequently. Changes reported in Tables 3 and 4, relative to prior versions, reflect best available information on when projects will reach on-line status, which will change regularly until projects are confirmed to be on-line, at which point they are tracked via Table 1. Most projects facing changes in on-line dates have simply been delayed to future quarters but are expected to come on-line in the future.

Table 3: Expected Cumulative New September NQC (MW) by Resource Type, Based on LSE-Contract Data for 2023 and 2024

Resource Type	2023 Q1	2023 Q2	2023 Q3	2023 Q4	2024 Q1	2024 Q2	2024 Q3	2024 Q4
Solar	7	26	101	150	182	318	321	331
Battery	654	810	1,302	1,825	2,504	5,199	5,528	5,538
Paired /Hybrid	395	473	638	1,280	1,446	1,847	1,856	2,324
Wind	-	14	14	14	14	14	14	14
Geothermal	21	21	21	21	21	74	74	92
Biomass /Biogas	-	-	-	3	22	22	22	25
Total	1,076	1,344	2,076	3,293	4,188	7,474	7,814	8,324

Source: CPUC staff, data as of August 2023

Table 4: Expected Cumulative New September NQC (MW) by Resource Type, Based on LSE-Contract Data for 2025 and 2026

Resource Type	2025 Q1	2025 Q2	2025 Q3	2025 Q4	2026 Q1	2026 Q2	2026 Q3	2026 Q4
Solar	441	459	459	459	462	462	462	462
Battery	5,972	6,743	6,743	6,743	6,865	7,221	7,221	7,221
Paired /Hybrid	2,498	2,815	2,929	2,993	3,001	3,061	3,061	3,061
Wind	14	31	31	31	31	60	60	60
Geothermal	93	122	143	144	160	195	195	200
Biomass /Biogas	25	28	28	28	28	28	28	28
Total	9,043	10,198	10,333	10,398	10,546	11,026	11,026	11,030

Source: CPUC staff, data as of August 2023

The project development volume in Tables 3 and 4 will occur throughout the State of California in 2023 to 2026. The data show that 34 different counties will have some amount of new clean energy projects, including 12 counties that were not included in Table 2 as they did not have any development in the past four years.

Some of the counties that have seen substantial development, such as Kern, Riverside, and San Bernardino counties, are expected to continue to have large amounts of clean energy development (over 1,000 MW Nameplate per county) in the years ahead. In addition, there is projected to be over 1,000 MW nameplate capacity development in Fresno, Tulare, and San Diego counties. Additionally, there is projected to be over 200 MW of new nameplate capacity being developed in Imperial, Los Angeles, Monterey, San Joaquin, Solano, and Stanislaus counties.

Tracking Project Development

Trends in Resource Development

Since the August 2023 third quarterly report was released, the CPUC continues to see the same major themes in new resource development: high levels of LSE contracting for new resources and challenges to bringing resources on-line in the immediate term. Broadly, CPUC-jurisdictional LSEs continue to report new contracts for their compliance with IRP orders, leading to an overall increase in new megawatts expected to come on-line in the midterm horizon of 2023-2028. Information on the IRP's procurement track is available at the CPUC's website: IRP Procurement Track.

The CPUC has received two Petitions for Modification (PFMs) to D.21-06-035 (the "Mid-Term Reliability" Decision). Both these PFMs assert a difficult procurement environment LSEs are

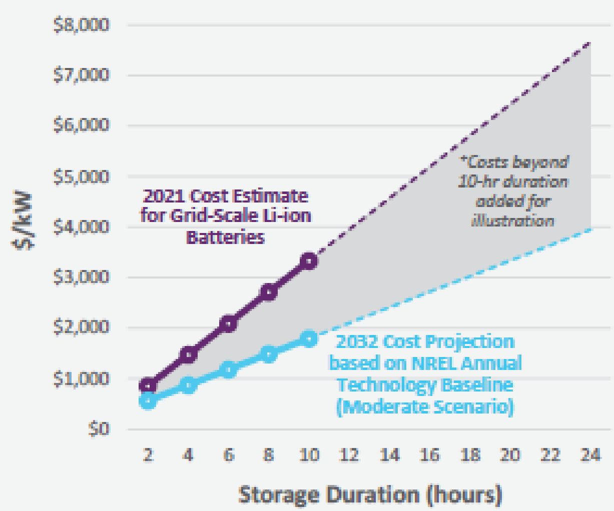
Attachment 2-C

California Public Utilities Commission 2023 Energy Storage Procurement Study, pages 24, 72, 74-76.

Most grid-scale battery energy storage systems historically procured in California are configured for 4-hour duration, which means they can continuously discharge up to 4 hours at full capacity. This is a result of the high initial value of 4-hour storage in addressing current system reliability needs. Lithium-ion batteries currently dominate the market due to their favorable economics for providing short-duration capacity.

Going forward, as California continues to decarbonize its electric system by deploying more clean energy resources, system flexibility needs and the role of storage will evolve and longer duration storage systems will be needed. Batteries are highly modular and there are no technical barriers to configuring them with longer durations above 4 hours. But a very large share of batteries' installed cost is from energy-related costs (e.g., battery pack), which increases with duration. For example, a 4-hour transmission-connected battery currently costs around $1,500/kW (Figure 17). A battery with 8-hour duration is estimated to cost around $2,700/kW, which is 1.8 times the cost of a 4-hour battery with the same nameplate MW.

The cost-effectiveness of long-duration energy storage depends partly on how fast the future storage needs and value will evolve over time (see Attachment B) and partly on cost trajectory of lithium-ion batteries and emerging long-duration storage technologies. For the near-term, when system needs can still be met by intraday energy time shift (up to 10 hours), lithium-ion batteries will likely stay cost competitive and set the price to beat. For example, in early 2022, two separate long-duration storage procurement efforts by a group of California CCAs both resulted in contracts with 8-hour lithium-ion battery projects. When multiday, multiweek, or seasonal storage is needed in the future as the state approaches to 100% clean energy goal, storage technologies with high power-related costs and low energy-related costs such as compressed air or hydrogen storage can become more competitive as they can scale up their durations with little incremental cost.



- Batteries are highly modular; there are no technical barriers to configuring them with longer durations
- But lithium-ion batteries have relatively high energy-related capex, which increases linearly with duration
- This cost structure makes it difficult to deploy lithium-ion batteries cost effectively at longer durations above a certain level

Figure 17: Impact of adding duration on installed cost of grid-scale battery projects.

As the California's grid transformation continues, new challenges are emerging to create fair and efficient RA capacity market signals to properly capture the contribution of energy storage towards meeting future resource adequacy needs within a rapidly changing mix of resources in the system.

These challenges include how to characterize the inevitable (but highly uncertain) decline in storage capacity credits due to saturation effects and how to differentiate signals for resources with longer duration.

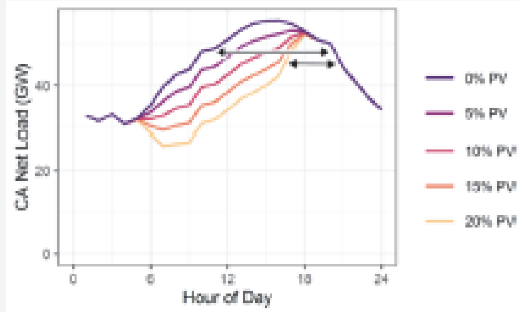


Figure 49: Effect of solar on net peak duration (Blair et al. 2022)

New and existing energy storage face decreasing and uncertain marginal capacity credits. In 2014, the CPUC established RA program eligibility requirements for energy storage and supply-side demand response (D. 14-06-050). The requirements include "the ability to operate for at least four consecutive hours at maximum power output (PmaxRA), and to do so over three consecutive days," also known as the "4-hour rule." As such, most of the grid-scale battery storage operating on the system is 4-hour duration storage. Customer installations tend to be shorter duration: about 2 hours on average, mainly because most of the initial SGIP funds declined after the first 2 hours of duration.

While this simple approach can be considered sufficiently close in capturing the capacity value of the first wave of energy storage resources towards system reliability, longstanding concerns about expected decline in capacity contributions of energy-limited resources at high penetration rates and portfolio interactions among load, renewables, and storage led to implementation of stochastic approaches to estimate effective load carrying capability (ELCC) of resources. There are two complex interactions that needs to be considered: (1) increased solar buildout shifts net peak to evening periods and compresses the need to fewer hours, and (2) increased storage penetration flattens net load extending the need to longer durations.

Recognizing these complex dynamic interactions in the system, CPUC's IRP studies are currently updated with a multivariable "ELCC surface" developed based on ELCC studies to characterize portfolio ELCC levels as a function of solar PV and battery storage (see IRP's Modeling Advisory Group webinar in April 2022). Utilizing a similar ELCC study, in October 2021, CPUC published incremental ELCC values to be used for compliance with the Mid-Term Reliability Procurement order, which required LSEs to procure 11,500 MW of net qualifying capacity by 2026. ELCCs for the first 8,000 MW of this requirement by 2023–2024 are finalized. ELCC values for the remaining 3,500 MW in 2025–2026 are also finalized for contracts executed by November 30, 2022. Contracts executed after then will use updated ELCCs for 2025–2026.

To adapt to the rapidly changing energy landscape in California, CPUC's Resource Adequacy (RA) program, which focuses on near-term needs, is also refining its RA accounting and compliance framework. After an extended stakeholder process and several proposals, the CPUC selected a stakeholder proposal (called "slice-of-day") to refine the current RA framework. The proposed approach divides the days into 24 hourly slices and creates RA requirements varying by month. This is intended to account for the fact that California's system reliability needs are no longer confined to "gross peak" while also attempting to balance complexity, administrative burden, and transactability. Counting for storage resources will consider daily resource capabilities and efficiency losses, and LSEs will need to show capacity to meet storage charging needs. Many implementation details still need to be figured out and final implementation is expected in 2025 under the schedule adopted in CPUC's decision D. 22-06-050 issued in June 2022.

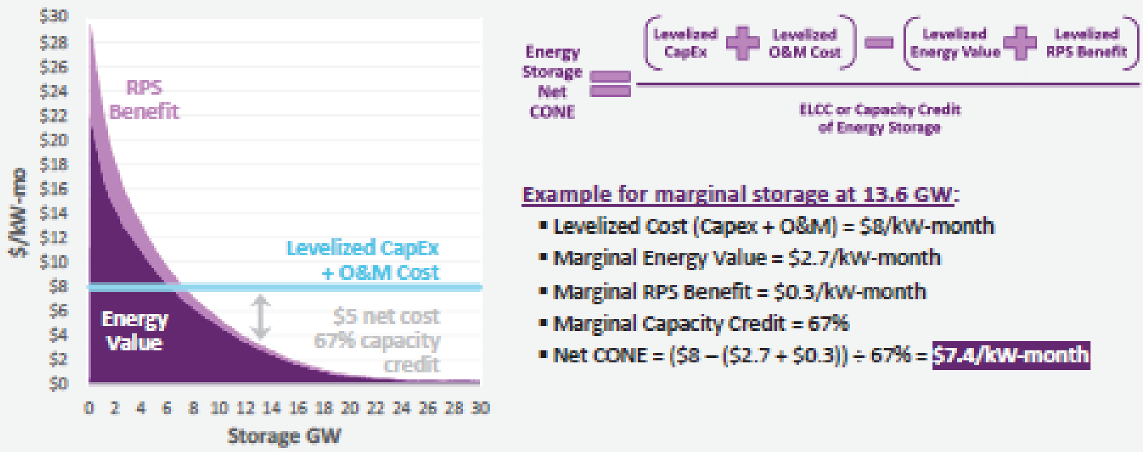


Figure 51: Calculation of marginal net cost of new entry (net CONE) for energy storage.

Needs for long(er) duration energy storage are uncertain and sensitive to the characteristics of the grid's resource portfolio. When will the California system need energy time shift over longer durations? The question of when the state will need energy storage to charge and discharge over longer timeframes is an important one because: (a) the transition will likely happen very soon, and (b) under-procurement of longer duration storage can have system reliability implications, or it may inadvertently require over-procurement of shorter duration storage at higher cost.

For clarification, in this section, we discuss longer timeframes that still fall within the "short duration" category: up to 10-hour duration energy storage used primarily for intraday energy time shift. Long durations with multi-day, weekly, monthly, or even seasonal energy storage will inevitably be needed when the state approaches its 100% clean energy goal by 2045.

As the recent IRP procurements show, energy storage in California will play an increasingly important role to help the state maintain reliability while transitioning to a clean energy future. However, meeting the state's goals with 4-hour storage alone is not economically plausible as declining marginal capacity credits and other value streams will raise capacity payments needed to support further development. At a certain point, storage systems with longer duration will likely offer lower cost solutions to address incremental RA capacity. Exact timing of this transition is uncertain and highly sensitive to relative ELCC or marginal capacity credit curves for storage at different duration levels.

Figure 52 shows our estimated net CONE of storage resources in a 2032 system with high renewables. We assumed 4-hour energy storage development drives overall storage penetration and calculated net CONE based on marginal resources added with durations ranging from 4 hours to 10 hours.

Net CONE is zero for the initial deployment because energy and RPS value in 2032 would have been sufficient to recover costs if penetration remained low.

Overall, 4-hour storage is more cost effective initially (as expected) but the gap with longer duration storage configurations closes as more storage is installed. We see crossover points after capacity credit of 4-hour storage drops significantly at around 12 GW. But the difference remains relatively low until storage penetration levels reach 25 GW or more.

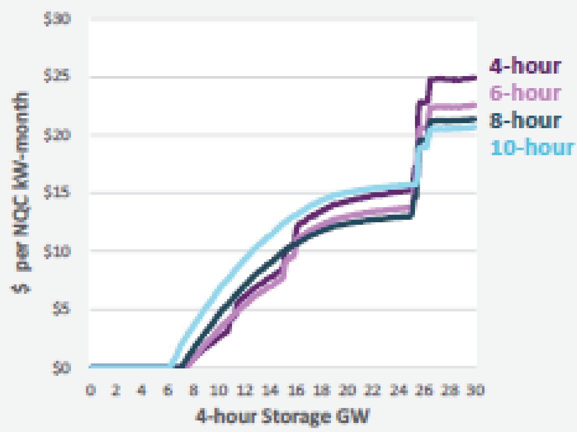


Figure 52: Estimated 2032 net CONE of storage by duration (in 2022 $)

*Net CONE values estimated for marginal additions with different durations in a system where bulk of the storage portfolio has 4-hour duration.

These results suggest the path for cost-effective longer-duration storage (up to 8–10 hours) is in sight, but exact timing and magnitude of the need is highly uncertain and sensitive to ELCC or capacity credit modeling assumptions. As described earlier, the IRP and RA program is going through several reforms to adapt to the rapidly changing energy landscape in California. But implementation is not yet fully tested, and more stakeholder input and transparency are needed to understand key differences in modeling assumptions and results across durations to make sure they signal the need for long-duration storage when the need arises.

The differences were less important in the beginning as 4+ hour storage got high ELCC regardless, but this will change quickly as we approach the tipping point discussed previously. Both absolute and relative ELCC levels matter:

- Overestimating marginal ELCC leads to under-procurement, with increased exposure to reliability events
- Underestimating marginal ELCC leads to over-procurement, with cost implications
- Not sufficiently capturing delta across duration levels may fail to signal need for long duration

Incremental ELCC values for the CPUC's mid-term reliability procurement show little difference between the ELCC estimates of 4- and 8-hour batteries: 74.2% vs. 82.2% in 2025 and 69.0% vs. 78.2% in 2026. Future updates to ELCC values deserve extra attention and stakeholder input before getting finalized. If the difference is indeed small, it needs to be sufficiently explained and illustrated why that is. **With less than 10% delta in ELCC values, it is highly unlikely any 8-hour storage will be developed economically, beyond the 1,000 MW carve-out.**

This is important because if capacity contribution of long-duration storage is inadvertently understated in ELCC estimates, it may lead to higher costs for ratepayers. For example, Figure 52 above shows longer duration storage can enter the market at $3–$5 per kW-month below the price point for 4-hour storage at higher penetration if ELCC of 4-hour storage drops rapidly but ELCC of longer duration storage remains high. In that scenario, procurement of each 1,000 MW of NQC from 4-hour storage costs $36–$60 million per year more, relative to procuring the same NQC from storage with higher duration. Understating ELCC of long-duration storage also results in over-procurement of resources to meet the 1,000 MW carve-out. Figure 52 above shows estimated net CONE of 8-hour storage at around $$10/kW-month if its ELCC stays high (above 95%) when installed storage approaches 15 GW in the system. An ELCC of 80% instead of 95% would require approximately 200 MW more storage capacity at an incremental cost of over $20 million per year.

Energy storage modularity can provide real option value for adding duration when needed. **There are inherent uncertainties with future RA capacity needs and resource contributions, even with "perfect" analysis. Procurement efforts may have to pivot quickly and adjust target portfolios based on unexpected changes and new information. Battery storage systems and site designs are highly modular and adding duration at existing sites can have a streamlined interconnection process that can be completed more quickly and at a lower cost. In our review of the actual grid-scale installations, we see that some of the developers are already taking advantage of this modularity in their market participation and development strategies by building the MW capacity first and increasing duration later when the need arises.**

Creating a "real option" to add more duration to battery projects at the initial design and procurement phase could support a timely and cost-effective transition for longer duration. There is an extrinsic value associated with such an option because when to economically transition from current 4-hour systems to longer configurations is highly uncertain. If utility and other LSE's energy storage system designs or contracts with third parties, for example, included options to expand duration in an expedited manner, it would give them the right, but not the obligation, to deploy longer-duration storage capabilities quickly and hedge against potential price surges and/or lead-time constraints.

Reflection of future climate trends and extremes in the state's resource planning and ELCC models is becoming essential. **As previously described in Chapter 1 (Market Evolution), CAISO, CPUC, and CEC's joint investigation of the mid-August 2020 system emergency events and power outages in California confirmed that one of top contributing factors was the climate change-induced extreme heat wave across the western U.S. and recommended an updated, broader range of climate scenarios to be considered in future planning studies, along with increased coordination among the agencies to prepare for contingencies.**

Understanding and incorporating the effects of climate change on frequency and magnitude of extreme events, and electric supply and demand is an area of active research and development. For example, even though the state agencies' Final Root Cause Analysis showed that mid-August 2020 events were driven by a 1-in-30 year weather event, based on 35 years of historical data, it is not clear how frequently the system will experience similar events going forward. Demand forecasts and supply availability assumptions used in resource planning rely on historical weather variants and do not yet fully consider that the normal levels and variability of weather events have been changing historically and will continue to change in the future, potentially at a faster pace.

Through the EPIC program, the CEC has launched several studies designed to break down institutional barriers and accelerate innovations and uptake of new climate projection data and weather extremes throughout the state's resource planning activities. One effort in particular, awarded under the solicitation GFO-21-302 and launched in 2022, aims to build a resilience planning framework and re-parameterize the state's planning model inputs and assumptions in order to capture key climate-related uncertainties and risks to future electricity supply and delivery.

Attachment 2-D

CPUC Energy Division, Final Inputs & Assumptions: 2022-2023 Integrated Resource Plan, pages 142-144, 150, 154-157

7. Resource Adequacy Requirements

7.1 System Resource Adequacy

To ensure that the optimized resource portfolio is sufficient to meet resource adequacy[157] needs throughout the year, IRP planning models (both RESOLVE and SERVM) perform assessments to ensure that total available generation capacity (measured in effective load carrying capability, i.e., ELCC) plus available imports in each year meets or exceeds a reserve margin above the annual 1-in-2 gross peak demand. IRP modeling is designed to ensure that the CAISO system would not be expected to endure more than one loss of load event in ten years, satisfying the Commission's 1-day-in-10-year loss of load expectation (LOLE) reliability standard used in the IRP proceeding.

SERVM is utilized for resource adequacy and reliability studies. A study is performed to measure the amount of perfect capacity required to meet the 0.1 LOLE reliability standard in the CAISO system. The required level of perfect capacity (or perfect capacity equivalent) is a measure of the system's Total Reliability Need (TRN). Portfolios selected in RESOLVE's capacity expansion module are constrained to meet or exceed the TRN calculated in SERVM. RESOLVE calculates TRN endogenously via a comparison of median gross peak demand and an input PRM percentage based on the SERVM study.

7.1.1 Setting the Total Reliability Need and the Associated Planning Reserve Margins

The TRN is the total effective capacity needed to reach a system's probabilistic reliability standard. Historically, via the Resource Adequacy program and prior IRP cycles, the CPUC has used installed capacity (ICAP) based accreditation methods, which count firm capacity resources (gas, nuclear, etc.) at their installed capacity and count non-firm resources (hydro, solar, wind, etc.) using either heuristics or their ELCC. This method does not explicitly quantify the impact of firm plant forced outages in the reliability need determination, indirectly increasing the reserve margin required to account for the risk of those outages. However, this can create an un-level playing field between resources, whereby thermal resources are accredited at a value higher than their actual reliability contribution (i.e., their ELCC), while non-firm resources – including new carbon-reducing resources – are accredited at their ELCC.

Two key improvements were made for this IRP cycle:

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[157] Resource adequacy is referred to here in a broad sense, rather than with specific reference to the CPUC RA program.

First, the planning reserve margin is now calculated from the total reliability need, as derived from SERVM model simulations using the most recent data.[158] Staff believes this is an improvement over the PRM values used in past IRP cycles because it is tied to the fundamental weather, load, and operating reserve drivers that create reliability risk in SERVM's loss of load probability modeling, using the most recent data available on past historical weather conditions. While past cycles have used a PRM higher than 15%, this is the first cycle to directly use a "target PRM" derived from SERVM analysis consistent with the 1-day-in-10-year LOLE standard.

Second, the reliability need definition is now defined in total ELCC MW, i.e., total perfect capacity equivalent MW, using "PCAP" accounting instead of the ICAP accounting used in previous cycles. This puts all resources on a level playing field within RESOLVE's economic optimization as it requires that all resources are counted at their ELCC. It also provides a more durable reliability need determination across the planning horizon, because the PCAP total reliability need (and therefore the PCAP PRM) is not dependent on the resource portfolio, but instead on load shapes, load variability, and operating reserve requirements. This PCAP PRM is lower than the ICAP PRM used in previous IRP cycles, because no resources are accredited higher than their PCAP equivalent. The PCAP PRM is measured above the gross system peak, i.e., the IEPR managed peak before BTM PV peak reduction. A PRM measured at the gross (higher) peak is a lower percentage than a PRM measured at the managed (lower) peak because the same total reliability need MW can be obtained with a lower percentage margin when multiplied by a higher (gross) peak.

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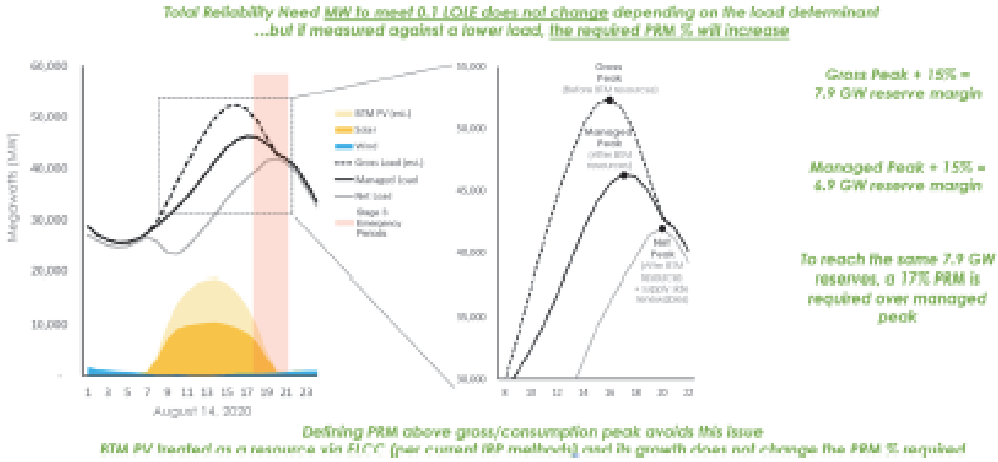
[158] RESOLVE originally used a 15% ICAP PRM, based on modeling in the early-mid 2000's that led to the 15% PRM assumption used for many years in LTPP and the RA program. In the 2019-2021 IRP cycle, RESOLVE used an adder above 15% to account for calibration with SERVM results and then used a 22.5% ICAP PRM to reflect the assumptions used in the MTR procurement order. The most recent RESOLVE runs (i.e., the 23-24 TPP) used a PCAP PRM consistent with the current methodology, albeit an earlier PCAP PRM calculations based on the 2021 IEPR.

Figure 27. Gross vs. Managed vs. Net Peak and the impact on PRM %



A "perfect capacity" generator is a theoretical concept, representing a firm generator that has no outages, fuel constraints, or other availability limitations. Since no resource provides perfect capacity, as shown in Figure 28, the perfect capacity concept is simply a useful metric for which to measure all resources on a level playing field. ELCC studies are performed to calculate the perfect capacity equivalent MW, i.e., the ELCC for each resource.

Figure 28. Comparing Variable, Use-limited, and Firm Capacity to "Perfect" Capacity

The TRN measures the necessary accredited capacity to meet a target reliability standard. When all resources are counted at their ELCC, the total reliability need for the CAISO system can be expressed as the total ELCC MW required to maintain a 0.1 days/year loss of load expectation reliability standard. For example, the results of the most recent SERVM simulations on the 2026 CAISO system are shown in Figure 29 below; these were updated in 2023 to use the 2022 IEPR load forecast.[159] They indicate that, in 2026, 61.7 ELCC GW are necessary to

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[159] See the July 2022 IRP MAG webinar for details of the PRM study design and prior results. Results shown here are updated using the 2022 IEPR. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-

144

7.1.2 Adjusting Total Reliability Need to Reflect CPUC Procurement Orders

To ensure the RESOLVE portfolio reflects the procurement ordered by recent Commission IRP Mid-Term Reliability (MTR) procurement orders (D.21-06-035 and D.23-02-040), a modification is made to RESOLVE's reliability need. An adjustment to reliability constraints is necessary to ensure RESOLVE builds enough new capacity to meet the cumulative 15.5 GW NQC from the MTR orders.

The total ELCC MW from the cumulative MTR order amounts is calculated as a minimum total ELCC MW of new zero-emission resources RESOLVE must cumulatively build in each respective year. Additionally, RESOLVE must comply with the 2028 MTR requirement for Long Lead-Time resources for 1 GW of firm zero-carbon resources and 1 GW of long duration storage (8-hour duration or greater). Resources are counted toward this requirement based on ELCCs calculated by the MTR Incremental ELCC Study.[160] For resource types not addressed by the Study, RA program NQCs are used. For years in which the total MTR ELCC MW requirement is higher than the PCAP PRM requirement, RESOLVE will build additional capacity to comply with the MTR procurement order.

7.1.3 Approach to Calculating Resource ELCCs

With all resources counted at their ELCC, an approach was necessary to account for interactive effects amongst resources. This requires calculating each resource type's ELCCs in a sequence so that the interactive effects between different resource types present on the system are properly accounted for and not over-counted. For instance, if all resources were studied via their "last-in" ELCC, i.e., wherein each resource's ELCC is calculated in the presence of all other resources in the portfolio, then the interactive effects of the portfolio would be counted in each resource's ELCC, and hence the true interactive effects of the portfolio would be over-counted when summing the ELCCs of all resources in RESOLVE. Instead of treating all resources as "first-in" or "last-in", resource ELCCs were calculated in sequence (first-in, second-in, third-in, etc.) starting with existing resources and then moving on to candidate resource options. The following approach was taken:

+ Existing firm[161] resource ELCCs were developed as "first-in" ELCCs for the firm resource fleet

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[160] [20230210_irp_e3_astrape_updated_incremental_elcc_study.pdf (ca.gov)]

[161] "Firm" resources are those that can generally operate on demand without any significant use limitations, though they are still subject to unplanned forced outages.

- Candidate biomass and geothermal resources receive the "first-in" ELCCs derived from the existing firm resource fleet
- Existing hydro ELCCs were calculated as "second-in" ELCCs
- Existing pumped hydro storage ELCCs were calculated as "third-in" ELCCs
- Existing demand response resources were calculated as "fourth-in" ELCCs
- Solar, battery storage, and wind resources, as well as other candidate resource options, were then calculated on top of the existing resource fleet
  - Wind ELCCs were calculated as three stand-alone curves for in-state, out-of-state, and offshore wind using the 2030 portfolio from the 38 MMT 2021 PSP portfolio (updated with the 2021 IEPR), including the level of solar and storage selected
  - Solar and 4-hour duration battery storage ELCCs were calculated as a two-dimensional ELCC "surface" to capture interactive effects between the two resources, using the 2030 portfolio from the 38 MMT 2021 PSP portfolio (updated with the 2021 IEPR), including the level of wind selected
  - Candidate demand response resources are accounted for on the storage dimension of the solar + storage surface; the nameplate capacities of demand response resources are derated when being counted on the surface to reflect their reliability value relative to 4-hour battery storage
  - Candidate pumped hydro storage and long-duration storage resources are accounted for on the storage dimension of the solar + storage surface; the nameplate capacities of these resources are increased by a scalar multiplier when counted on the surface to reflect the increased reliability value of longer duration storage resources relative to 4-hour storage

By sequencing the ELCC calculations in this way, interactive effects between the existing resources and new resources (e.g., between existing DR and new battery storage) are allocated to the new candidate resources. This is appropriate for RESOLVE, since nearly all the existing resources remain throughout the planning horizon, while RESOLVE makes economically optimal decisions for adding candidate resources using their marginal incremental capacity value on top of the existing resource fleet.

Figure 32 below summarizes the new methods for capacity contributions compared to those used in the last IRP cycle.

Figure 32. Reliability Planning Changes for the 2022-2023 IRP Cycle

	Prior Approach: 2021 Preferred System Plan (PSP)	Current Approach: 2022-23 IRP Cycle
Planning Reserve Margin	**22.5% installed capacity based (ICAP)** PRM above managed peak	**~12-16% perfect capacity based (PCAP)** PRM over gross peak
Wind	ELCC (solar/wind ELCC surface)	ELCC (in-state, OOS, offshore wind curves)
Solar PV		ELCC (solar/storage surface)
BTM PV	ELCC (solar/wind ELCC surface), after increasing need by IEPR peak shift	
Battery Storage	ELCC curve (Battery only)	
Long Duration Storage	Installed capacity (NQC)	ELCC (model new long duration storage on storage dimension of solar/storage surface, w/ up-rate multiplier)
Demand Response (Load Shed)	DR program capacity (NQC) for new + existing	ELCC (model new DR on storage dimension of solar/storage surface, w/ de-rate multiplier)
Hydro		
Bio/Geo/Nuclear	Installed capacity (NQC)	ELCC
Fossil (CT/peaker, CCGT, CHP, coal)		
BTM Storage	Load modifier via IEPR assumptions	Load modifier via IEPR assumptions

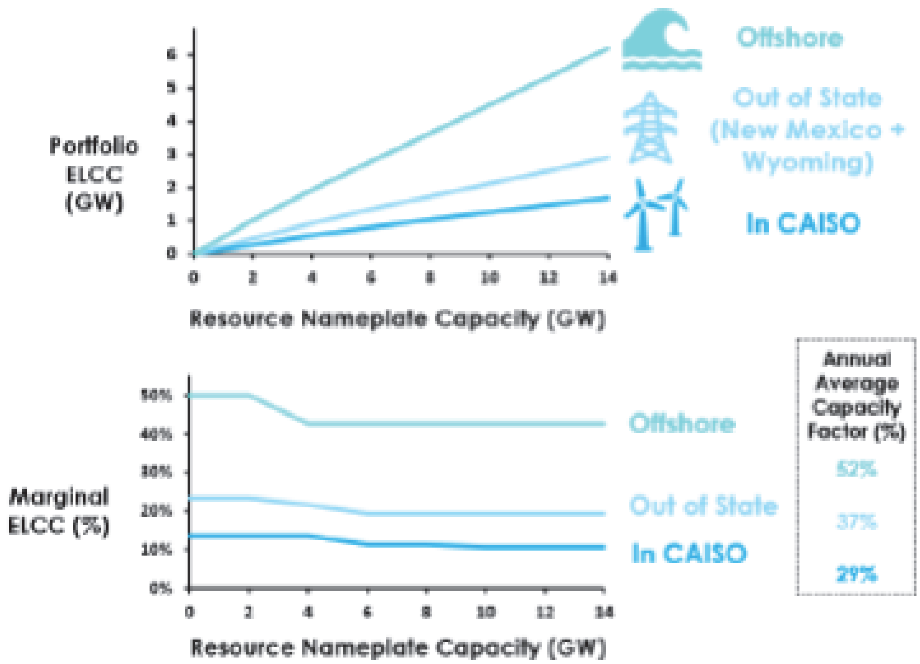
Note that all resources are now counted at ELCC except for BTM storage. This resource is modeled as a load modifier based on the IEPR's hourly charging and discharging shapes. This is because the IEPR's shapes generally show low capacity value for the BTM storage discharge, hence modeling it as a supply side battery resource would overstate its value relative to the IEPR. Future IRP cycles will continue to review IEPR BTM storage shapes and consider whether and how to incorporate BTM storage value as a resource counted at ELCC (such as using a de-rate factor relative to other battery storage). The ELCC values of all modeled resources can be found in the "*PRM and MTR*" tab of the RESOLVE Scenario Tool

7.1.4 Firm Resource Contributions (Gas, CHP, Coal, Nuclear, Biomass/gas, Geothermal)

The contribution of firm capacity resources was developed by calculating in SERVM the "first-in" ELCC of the entire firm resource fleet: gas, CHP, coal, nuclear, biomass/gas, and geothermal resources. This was done using 2030 CAISO loads and resources. This firm fleet ELCC MW was then allocated across each firm fleet resource category based on the relative EFORd[162] outage rates. In unforced capacity (UCAP) accounting used in some eastern RTO resource adequacy programs, UCAP MW is based on nameplate capacity * (1 – EFORd). However, the ELCC de-rate is higher than the EFORd value, because the EFORd value is an average outage rate value whereas in LOLP modeling a distribution of outages for the firm fleet are considered in a Monte

[162] Equivalent Forced Outage Rate demand (EFORd) is a SERVM output characterizing class average forced outage rates during operating hours using generator performance data.

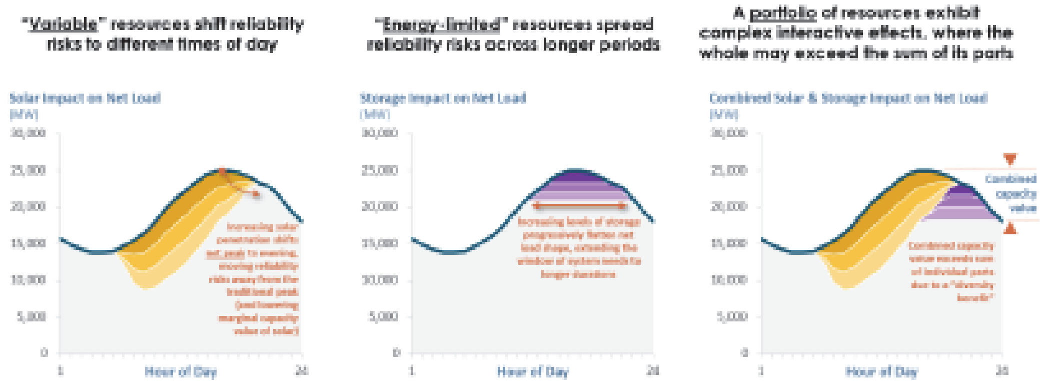
Figure 35. Wind ELCC Curves



7.1.9 Solar and Battery Storage

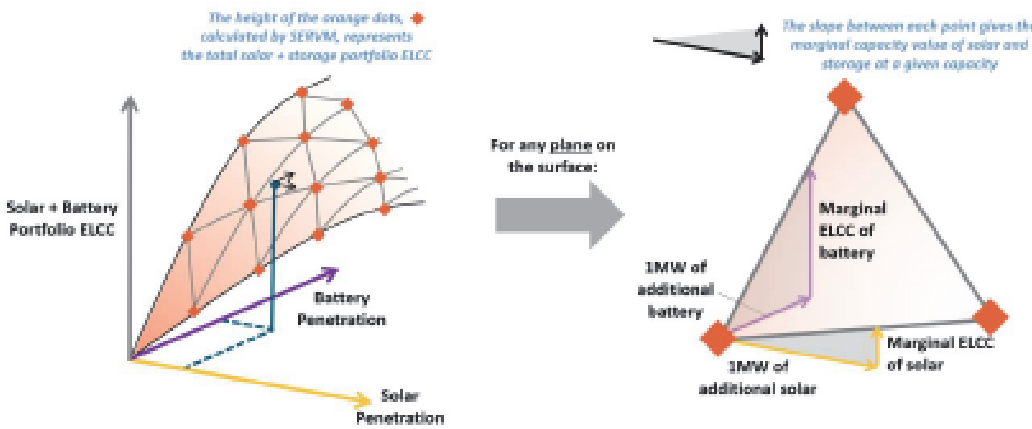
For this IRP cycle, the wind and solar two-dimensional ELCC surface is replaced by a solar and 4-hr battery storage ELCC surface. This change recognizes that, going forward for the CAISO, solar and battery storage resources have the most important interactive effects that should be captured in long-term capacity expansion studies. This synergistic interactive effect is illustrated in Figure 36 below. Solar and battery storage additions to the CAISO are very large in past RESOLVE studies. Solar shifts and narrows the net peak into the evening hours and provides mid-day charging energy for new batteries. Batteries shift and extend the net peak back into the mid-day solar hours.

Figure 36. Solar and Storage Interactive Effects (illustrative)



To capture these interactive effects, an ELCC surface was generated using SERVM ELCC studies that analyzed the portfolio ELCC of various levels of solar and battery storage additions on top of the 2030 updated PSP portfolio. A schematic of the surface is shown in Figure 37 below. Solar penetration is one dimension, 4-hr battery storage penetration is another dimension, and the combined portfolio ELCC is the third dimension of the surface. Since the entire surface cannot practically be mapped, specific points are sampled and the marginal ELCC between the points is calculated, as shown on the right side of the figure.

Figure 37. Solar and Storage ELCC Surface Schematic



Each facet i on the surface is a multivariate linear equation of the form $f_i(PV,STR) = a_iPV + b_iSTR + c_i$, where $f_i(PV,STR)$ is the total ELCC MW provided by solar and battery storage and PV and STR represent the MW capacity of solar and battery storage, respectively. Because of the declining marginal ELCC of solar and battery storage (and the corresponding convexity of this surface), the cumulative ELCC for any penetration of solar and battery storage can be evaluated as the minimum of all linear equations: $F(PV,STR) = \min[f_i(PV,STR)]$.

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 %

Solar Nameplate Capacity (GW)

4-Hour Battery 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%	5%	5%	5%	5%	5%	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	15%	8%	8%	4%	5%	5%	5%	5%	5%	5%	5%	2%	2%	2%	2%
20	25%	25%	21%	9%	6%	4%	4%	4%	4%	4%	8%	8%	8%	8%	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.

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[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 %

Solar Nameplate Capacity (GW)

4-Hour Battery Namplate 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

Attachment 2-E

A.24-09-014 General Rate Case Phase II Application PG&E Response to Cal Advocates' Data Request 004, Questions 3(c), 17, and 18.

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

PG&E Data Request No.:	CalAdvocates_004-Q003
PG&E File Name:	GRC-2023-PhII_DR_CalAdvocates_004-Q003
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

Renewable Curtailment

QUESTION 003

Please provide a narrative description of how PG&E's modeling of renewable curtailment in this General Rate Case Phase 2 (GRC2) proceeding (A.24-09-014) differs from that of its Test Year (TY) 2020 GRC2 (A.19-11-019).

a. Please describe why PG&E does not include soft and hard price floors as it did in its modeling of renewable curtailment within its TY2020 GRC2 MEC calculations.[1]

b. Please identify the metrics demonstrating why PG&E's new method for modeling renewable curtailment is an improvement on the method employed in the last its TY 2020 GRC2.

c. Please describe the impact of PG&E's renewable curtailment methodology on its final MEC values.

    i. How would PG&E's MEC values differ if PG&E did not include renewable curtailment?

    ii. How would PG&E's MEC values differ if PG&E applied its TY2020 GRC2 methodology for accounting for renewable curtailment?

1 A.19-11-019, *Pacific Gas and Electric Company 2020 General Rate Case Phase II Prepared Testimony Cost of* Service PG&E-2 (TY2020 Testimony), November 22, 2019, "Chapter 2: Marginal Generation Costs" (Chapter 2), at p. 2- 27.

ANSWER 003

a. PGE has improved upon the modeling methodology used in previous 2020 GRC II, by employing a linearly decreasing power price. This means that PG&E does not need to have soft and hard floor prices for its renewable curtailment. The current methodology better reflect the market operations, as seen in the answer to Q 001 Section b.

b. A simple metric showcasing the improvements made is the coefficient of correlation, over the historic day-ahead prices. Even with increased dynamics in the market, such as deeper duck belly with increased solar generation mid-day, significant battery introduction that is starting to impact day-ahead prices, frequent congestion along major transmission pathways, and negative prices occurring often in mid-day, not only in southern, but northern California, the model has improved the R^2 from previous GRC II, from 75% to 80%. This represents a significant improvement. Moreover, PG&E also validated the model this time over 2024 day-ahead prices and found an impressive R^2 of 75% over the un-trained period. Only recently, negative prices have been observed in northern California, an occurrence that might have broken the previous model. The current methodology not only models negative prices, it also shows significantly high specificity in negative prices. PG&E tracked the specificity (a metric designed to evaluate how well a model is handling negative prices = $\frac{True\ Negative}{True\ Negative + False\ Positive}$). Specificity using 2020 GRC II model over the same historical period of 2019-2023 would have been 18%, as opposed to 34% with the new model.

c.

i. How would PG&E's MEC values differ if PG&E did not include renewable curtailment?

If PG&E had not included renewable curtailment, it would be less reflective of the reality, and the resulting MECs would be >= 0 at all times. This would essentially result in a higher average MEC for all time-periods.

ii. How would PG&E's MEC values differ if PG&E applied its TY2020 GRC2 methodology for accounting for renewable curtailment?

PG&E did not have a renewable curtailment methodology per se in TY2020 GRC2, instead it relied on the value of ANL to predict the MEC directly (as opposed to ANL informing the PMC as stated above). This meant that for some hours, one could have ANL that is negative, but the MEC not negative, depending on the fitted coefficient of the 3-degree polynomial used between ANL and MEC. The current method works similar to how markets operate. Once the ANL reaches zero, and the export limits are reached, it curtails the excess generation, forcing negative prices. Hence, instead of a mathematical forcing, PG&E is relying on market fundamentals to inform curtailment occurrences in each region.

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

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Requester DR No.:	CAL ADVOCATES-004
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Date Sent:	December 13, 2024
PG&E Witness(es):	Eshan Singh

SUBJECT: MARGINAL ENERGY COSTS AND MARGINAL GENERATION CAPACITY COSTS

ELCC

QUESTION 017

Please clarify whether PG&E incorporated ELCC into its TY2020 GRC2 calculations. If so, please describe how PG&E's use of ELCC in its current GRC2 calculations differs from that of its TY 2020 GRC2 calculations. If not, please describe PG&E's reasoning for incorporating ELCC in this proceeding.

ANSWER 017

ELCC was not used in TY2020 GRC2 calculations. PG&E is using ELCC in the current GRC II, to account for the fact that batteries will not\ contribute 100% to the reliability of capacity resources, more so as there are more batteries discharging in future. The relationship between the ELCC values shown in the workpaper (and IRP chart referred in to in Exhibit (PG&E-2), Ch. 2, Figure 2-14) can be understood as follows: In small capacity, each new battery installed contributes fully to the grid reliability and provides capacity during peak hours. As the battery installation increases beyond a certain value, not all batteries can contribute fully to capacity requirements. This could be driven by the limited charging availability, or simply the peak capacity requirements. If, however, solar installations are also increased in tandem, it results in more charge (batteries usually charge during low-cost hours which coincides with high solar generation) and hence, greater availability for discharging during peak hours. This results in a decreasing ELCC with increasing Battery Nameplate Capacity and increasing ELCC with increasing solar installation, as observed in tab 'IRP Inputs'.

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

PG&E Data Request No.:	CalAdvocates_004-Q018
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Request Date:	December 2, 2024
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Date Sent:	December 13, 2024
PG&E Witness(es):	Eshan Singh

SUBJECT: MARGINAL ENERGY COSTS AND MARGINAL GENERATION CAPACITY COSTS

ELCC

QUESTION 018

PG&E projects that ELCC will decrease from 79% to 51% between 2025-2026, based on IRP projections of solar and battery adoption over those years. [1] Please describe why the ELCC drops sharply over these years, particularly relative to other years in the forecast period.[2]

ANSWER 018

The ELCC projections (including the decrease from 79% to 51% between 2025 – 2026) are a direct result of the IRP's indication on how ELCC varies with both the battery capacity and solar installation, along with what the forecasted installation. Considering that PG&E relies on IRP for deciding the ELCC value, PG&E increased the resolution of the Figure 39 from IRP PSP to extract accurate ELCC values.[3] The ELCC value comes from the lookup table in tab 'IRP Inputs'. For the solar generation, PG&E calculates the total solar installation at grid scale capacity factor (row 19 on tab 'IRP Inputs'). For battery installation, PG&E calculates the total storage (short and long term). With both values calculated, PG&E extracts the ELCC from the table. The forecasted solar,

1 TY2023 GRC2 MEC & MGCC Workpaper, "MGCC Calculation" tab, cells F23:G23.

2 Across the other years in the 6-year forecast period, the ELCC changes 1-2% year-over-year.

3 CPUC, Inputs & Assumptions, 2022-2023 Integrated Resources Planning (IRP), October 2023, <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/inputs-assumptions-2022-2023_final_document_10052023.pdf> (as of December 12, 2024).

battery values from RESOLVE are available for few years, so PG&E interpolates the years in between.

Attachment 2-F

National Renewable Energy Laboratory 2020 Annual Technology Baseline, "Utility Scale PV: Methodology Capacity Factor Definition."

Capacity Factor

Definition: The capacity factor represents the expected annual average energy production divided by the annual energy production, assuming the plant operates at rated capacity for every hour of the year. It is intended to represent a long-term average over the lifetime of the plant; it does not represent interannual variation in energy production. Future year estimates represent the estimated annual average capacity factor over the technical lifetime of a new plant installed in a given year.

PV system inverters, which convert DC energy/power to AC energy/power, have AC capacity ratings; therefore, the capacity of a PV system is rated in MW_{AC}, or the aggregation of all inverters' rated capacities, or MW_{DC}, or the aggregation of all modules' rated capacities. Other technologies' capacity factors are represented exclusively in AC units; however, in previous years of the ATB, PV pricing is represented in $/kW_{DC}$. In the 2020 ATB, we represent utility-scale PV (though not commercial PV or residential PV) in $/KW_{AC}$; for this reason, values in this year's report are not directly comparable to previous years of the ATB without adjusting previous versions from W_{DC} to W_{AC}.

The capacity factor is influenced by the hourly solar profile, technology (e.g., thin-film or crystalline silicon), the bifaciality of the module, axis type (i.e., none, one, or two), shading, expected downtime, and inverter losses to transform from DC to AC power. The DC-to-AC ratio is a design choice that influences the capacity factor. PV plant capacity factor incorporates an assumed degradation rate of 0.7%/yr (Feldman et al. Forthcoming) in the annual average calculation. R&D could increase energy yield through bifaciality, better soil removal, improved cell temperature, lower system losses, O&M practices that improve uptime, and lower degradation rates of PV plant capacity factor; future projections assume energy yield gains of 0% to 27% depending on the location and scenario.

Attachment 2-G

A.24-09-014 General Rate Case Phase II Application PG&E Response to Cal Advocates' Data Request 007, Question 8.

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

PG&E Data Request No.:	CalAdvocates_007-Q008
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Requester:	Kimiko Akiya/Nathan Chau/James Lau/Sarah Meyerhoff
Date Sent:	January 30, 2025
PG&E Witness(es):	Eshan Singh – Engineering, Planning and Strategy

SUBJECT: MARGINAL ENERGY COSTS AND MARGINAL GENERATION CAPACITY COSTS

QUESTION 008

As part of its calculation of electric load carrying capacity (ELCC), PG&E calculates future grid-scale solar capacity (denoted as "Total solar@Gridscale CF" in its workpapers) by multiplying forecasted behind-the-meter (BTM) solar capacity by a ratio of the respective capacity factors of grid-scale and BTM solar (before summing this product with the total grid-scale solar capacity).[1] Please describe PG&E's rationale for applying the abovementioned ratio to BTM solar capacity within this calculation.

ANSWER 008

PG&E used this ratio to BTM solar capacity within the above calculation because it normalizes the grid and BTM solar capacity. Normalizing the grid and BTM solar capacity is needed to account for the lower capacity factor associated with BTM solar as opposed to grid-scale solar. The calculation of ELCC requires total solar capacity: BTM solar and grid-scale solar. Therefore, assuming that grid-scale solar and BTM solar are equal when they have different capacity factors would be an incorrect assumption. To address this, we scale the BTM solar by a factor (< 1), equal to the ratio of their capacity factors, and add the resulting capacity to the grid scale solar to calculate the total solar capacity. This is then used to find the ELCC from the ELCC surface derived from Inputs and Assumptions of CAISO Integrated Resource Plan (IRP) 2022-2023.[2]

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1 TY2023 GRC2 MEC & MGCC Workpaper V2, Tab "IRP Inputs", cells E19:M:19.

2 "Input and Assumptions: CAISO Integrated Resource Planning (IRP) 2022-2023", p. 157, Figure 39 (Oct. 2023). Available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/inputs-assumptions-2022-2023_final_document_10052023.pdf (last accessed Jan. 29, 2025).

Attachment 2-H
Cal Advocates Workpaper to Demonstrate Impact of Solar Capacity Factor on MGCC using Illustrative Values. Available by email upon request.

		2024	2025	2026	2027	2028	2029
Solar Capacity (GW)	**PG&E's Proposed Values**	32.88	36.60	38.34	--	42.94	--
	Without CF Ratio	38.76	42.94	45.04	--	50.63	--
ELCC	**PG&E's Proposed Values**	81%	79%	51%	52%	51%	51%
	Without CF Ratio	84%	84%	74%	72%	71%	65%

Attachment 2-I

A.19-11-019 Pacific Gas and Electric Company 2020 General Rate Case Phase II Prepared Testimony Cost of Service PG&E-2, "Chapter 2: Marginal Generation Costs" pages 2-42 – 2-47.

costs) only when the average electric energy price over a block of hours is higher than the total variable costs over those hours.[56] The EGM for each year was derived by taking the expected values of net energy market revenues during the year. Because thermal resources obtain a very small portion of their revenues from providing A/S, the EGM for thermal resources was based only on energy revenues.

b) Energy Storage

In contrast, ES resources (i.e., FTM batteries) currently obtain most of their revenue from providing A/S, with some additional revenue from "energy arbitrage" (charging during low price periods and discharging during high price periods).[57] Thus, estimating the EGM for ES resources must use different methodologies and models than for thermal resources.

First, a forecast of A/S prices must be developed that aligns hour-by-hour with the MEC forecasts. Then the ES operation is modeled using two "operating regimes:" (1) assuming that the ES operates only for energy arbitrage; and (2) assuming that the ES can sell up to its entire capacity in the A/S market, modeled as co-optimizing revenue from the Energy and A/S markets (just as the CAISO co-optimizes Energy and A/S costs

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56 In the 2017 GRC analysis, PG&E used two blocks: an on-peak block from 4 p.m. to Midnight and an off-peak block from Midnight to the following day's 4 p.m. The current analysis uses three blocks, with an on-peak block from 5 p.m. to 11 p.m.; an overnight block from 11 p.m. to 7 a.m.; and a mid-day block from 7 a.m. to 5 p.m. PG&E assumes that a CCGT would only incur a startup in a day if net revenues exceeded costs (including startup costs) in the on-peak block; and would then stay on during the overnight block if energy revenues in that block exceeded costs (this time without a startup cost). Likewise, the units could also stay on during the mid-day block if energy revenues exceeded costs; the latter situation occurred very rarely.

57 This can be seen from the pattern of battery charge/discharge in the CAISO's Daily Outlook page at http://www.caiso.com/TodaysOutlook/Pages/supply.aspx. While they sometimes follow price trends, batteries are mostly responding to a regulation signal.

in the DA and RTMs).[58] Finally, PG&E estimates the EGM as a WAVG of the above scenarios, with the weight on the full A/S regime declining over time as more ES is deployed in the CAISO. These steps are described in turn below.

i) Ancillary Services Price Forecasts

The A/S price forecast was developed using a new PG&E model calibrated from CAISO Day-Ahead Energy and Ancillary Service prices from 2010 through June 2019. The model for Reg Up derives from the observation that Reg Up prices tend to follow energy prices at high heat rates (because the opportunity cost for providing Reg Up is essentially the amount that a generator can earn in the energy market by increasing its output, which is zero at low heat rates but tracks energy prices above a thermal generator's marginal heat rate). Specifically, for Reg Up, the A/S prices are modeled as:

$$P_{RU}^{t} = \text{Max}(0, \text{RU\_Adder} + \begin{cases} \text{RU\_Mult1}*\text{MEC}^{t} & \text{If } \text{EMHR}^{t} < \text{RU\_Thresh} \\ \text{RU\_Mult1}*(\text{MEC@RU\_Thresh}) + \text{RU\_Mult2}*(\text{MEC}^{t} - \text{MEC@RU\_Thresh}) & \text{Otherwise} \end{cases})$$

where

P_{RU}^{t} equals the Reg Up price in hour t,

MEC^{t} equals the DA Energy Price in hour t,

$EMHR^{t}$ is the Effective Market Heat Rate corresponding to MEC^{t},

RU_Adder is the modeled Reg Up price when P_E equals zero,

RU_Mult1 < RU_Mult2 are slopes of a piecewise linear curve of P_{RU} vs. MEC,

58 CAISO has five types of A/S: Regulation Up, (Reg Up); Regulation Down (Reg Down); Spin; Non-Spin; and Regulation Energy Management (REM). However, only the first three types of A/S were modeled—revenues from Non-Spin are negligible for batteries in the CAISO, since Non-Spin prices are always less than Spin prices while batteries can always provide as much Spin as Non-Spin (having zero start-up times); and the CAISO has limited need for REM so batteries already online or projected to be online by 2021 will likely saturate the REM market, leaving the other A/S products as marginal.

RU_Thresh is the EMHR threshold above which the slope increases, and

MEC@RU_Thresh is the DA Energy Price corresponding to EMHR = RU_Thresh.

The coefficients for this model were calibrated separately for the years: (1) 2010 and 2012-2015, and (2) 2011 and 2016 – June 2019, with an objective function that minimized the weighted MAE[59] while matching average prices during each set of years. The first set of years represent periods in which A/S prices were low relative to energy prices (due to dry or average hydro conditions, and relatively low renewable generation), while the second set of prices represent periods of high A/S prices relative to energy prices (due to wet hydro conditions and/or high renewable generation).[60]

This model captures 69 percent of the variability in Reg Up prices, i.e., its R-squared coefficient is 0.69.

For Reg Down, prices are highest when energy prices are *low*, because the opportunity cost for providing Reg Down is the amount a generator can earn by *reducing* its output. This leads to the following model for Reg Down prices (where coefficients were again calibrated separately for the years 2010 and 2012-2015, and 2011 and 2016 – June 2019):

$$P_{RD}^{t} = \text{Max}(0, \text{RD\_Adder} + \begin{cases} \text{RD\_Mult1} \cdot \text{GasGHG}^{t} \cdot (\text{RD\_Thresh} - \text{EMHR}^{t}) & \text{If } \text{EMHR}^{t} > \text{RD\_Thresh} \\ \text{RD\_Mult2} \cdot \text{GasGHG}^{t} \cdot (\text{RD\_Thresh} - \text{EMHR}^{t})) & \text{Otherwise} \end{cases}$$

[59] The weighted MAE used the same weights as the MEC model (i.e., greater for later years).

[60] Large hydro is an excellent source of A/S (which is why the coefficient h in the MEC model is greater than one, reflecting hydro's large "bang for the buck"). However, during wet years, hydro generators often run close to maximum capacity to avoid spilling, reducing their ability to provide both upward and downward A/S. The need for A/S generally increases with (non-dispatchable) renewable penetration, as the CAISO must then balance a system with greater uncontrolled variability.

where

P_{RD}^{t} equals the Reg Down price in hour t,

GasGHGt equals the combined gas and GHG Price in hour t,

EMHRt is the Effective Market Heat Rate in hour t,

RD_Adder is the modeled Reg Down price when EMHRt equals RD_Thresh,

RD_Mult1 < RD_Mult2 are slopes of a piecewise linear curve of PRD vs. EMHR, and

RD_Thresh is the EMHR threshold above which the slope decreases.

This model captures 29 percent of the variability in Reg Down prices, i.e., its R-squared coefficient is 0.29.

Finally, the model for Spin prices considers that the correlation between Spin and Reg Up prices is extremely high (0.957 over the period May 2010 through June 2019). Thus, the Spin model is defined in terms of the Reg Up price, as follows:

$$P_{SP}^{t} = \begin{cases} \text{Max(0, SP\_Mult1* } P_{RU}^{t} & \text{If } P_{RU}^{t} < \text{SP\_Thresh} \\ \text{SP\_Mult1*(SP\_Thresh) +} & \text{Otherwise} \\ \text{SP\_Mult2*(} P_{RU}^{t} - \text{SP\_Thresh))} & \end{cases}$$

where

P_{SP}^{t} equals the Spin price in hour t,

SP_Mult1 < SP_Mult2 are slopes of a piecewise linear curve of P_{SP} vs. P_{RU}, and

SP_Thresh is the EMHR threshold above which the slope increases, and

This model captures 76% of the variability in Spin prices, i.e., its R-squared coefficient is 0.76.

To develop forecast scenarios of Reg Up, Reg Down and Spin prices, the formulae specified above were evaluated using as inputs the energy prices (MEC) and EMHR from each weather scenario, developing Reg Up forecasts first so that they could be used for the Spin price forecast.

ii) Modeling Energy Storage Operations and EGM

To estimate annual EGM for a four-hour battery, MECs and A/S price forecasts were input to EPRI's public domain

StorageVET tool (Version 1.0).[61] This Valuation Estimating Tool (VET) co-optimizes energy and A/S revenues from DA and optionally RT energy markets given prices in those markets and input characteristics of the ES device. While the tool can calculate overall financial results based on tax structure, debt/equity and other parameters, in this case StorageVET provided annual revenues and variable costs, and those data were input to PG&E's MGCC model to maintain consistency with prior GRC practice. Due to run-time constraints, the EGM could only be calculated for one of the 2005-2014 weather year scenarios. PG&E chose 2013 as the most representative weather year based on a combination of matching the average annual peak and matching the forecasted average hourly EMHR.

Three operating regimes were modeled: (1) Full A/S operations (offering Reg Up and Down, and Spin as well as Energy Arbitrage) with upper and lower State of Charge (SOC) bounds of 75 percent and 25 percent; (2) Spin and Energy Arbitrage, with upper and lower SOC bounds of 95 percent and 5 percent; and (3) Energy Arbitrage only, with upper and lower SOC bounds of 95 percent and 5 percent. The reason that modeled SOC bounds are tighter when modeling regulation is that the actual amount of charge/discharge in each hour is unknown when providing regulation, so the forecasted or "expected" SOC for the ES device must be kept close to its mid-range to avoid getting outside the 0 to 100 percent operational limits in practice. Operations are much more predictable when the ES is only offering spin and/or energy arbitrage, so the modeled SOC limits can be wider for those operating modes. Estimated annual EGM turned out to be higher in

61 Documentation and login instructions available at https://www.storagevet.com/documentation/.

Full A/S mode than Spin plus Energy and Energy-only modes for all forecast years; while battery degradation, though greater in Full A/S mode, was still small enough in either mode not to require battery augmentation during the assumed ten-year life.

While A/S price model coefficients were estimated from both "Low A/S" years (2010 and 2012-2015) and "High A/S" years (2011 and 2016 – June 2019), only the "Low A/S" model was used in the EGM calculations. The reason is that by 2021, approximately 1,550 MW of four-hour FTM ES is expected to be installed within CAISO, rising to over 1,800 MW by 2023 (see Figure 2-13, from the June 17, 2019 CPUC Presentation to the IRP Modeling Advisory Group on 2019-2020 IRP Modeling Assumptions).[62] This Figure shows the "baseline" assumptions (i,e,, the amount that is expected to be built irrespective of model outputs); PG&E believes that ES build will continue after 2024, so the baseline quantities (blue bars) represent a minimum that is likely to be exceeded significantly by 2030.

62 Slide 29 of the Webinar Presentation, available at https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/IRP_MAG_20190617_CoreInputs.pdf. Note that the 2020 value includes approximately 570 MW of ES procured by PG&E in response to Resolution E-4949; the majority of that ES has expected online date of December 2020, so its first full year of operation would be 2021.

Attachment 2-J

CPUC Energy Division Market Price Benchmark Calculations 2024 REVISED.

Market Price Benchmark Calculations 2024 REVISED

November 5, 2024

This document provides revised Market Price Benchmarks (MPB) for the Power Charge Indifference Adjustment Forecast and True Up issued on October 4, 2024, to correct errors and omissions, which are briefly explained below.

For informational purposes, ED included the 2024 MPB for comparison.

Table 1. 2024 Final Market Price Benchmarks Used in PCIA Calculations

		2023 Final Market Price Benchmarks			2024 Final Market Price Benchmarks		
		PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
RA Adder	System RA	$14.37			~~$28.65~~ $26.26		
	Local RA	$8.38	$7.79	$9.77	$12.22	~~$10.26~~ $10.24	~~$17.21~~ $16.44
	Flexible RA	$7.82			~~$12.89~~ $12.76		
RPS Adder		$30.30			~~$65.63~~ $54.56		

Table 2. 2025 Forecast Market Price Benchmarks

		2024 Forecast Market Price Benchmarks			2025 Forecast Market Price Benchmarks		
		PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
Energy Index	On-Peak	$72.88	$68.30	$68.30	$55.02	$41.54	$41.54
	Off-Peak	$65.77	$62.59	$62.59	$53.18	$47.84	$47.84
RA Adder	System RA	$15.23			~~$42.54~~ $40.31		
	Local RA	$9.52	$8.81	$8.60	$13.29	~~$11.10~~ $11.23	$9.99
	Flexible RA	$9.12			~~$14.16~~ $16.97		
RPS Adder		$31.73			~~$67.06~~ $71.24		

The differences are explained briefly below:

- ED staff identified one submission that was omitted due to naming convention issues. This resulted in changes to some of the local values for SDG&E and SCE.
- ED staff identified some transactions that were misidentified as resource specific imports when they were unspecified imports and visa versa. ED staff excludes unspecified import

transactions from the system MPB because CPUC rules require unspecified RA resources to be specified in $/kWh. These corrections resulted in changes to the system MPBs

- ED staff initially calculated the flexible RA MPB using the price multiplied by the flexible RA capacity, rather than the system RA capacity, but here calculated the flexible RA MPB as the price multiplied by the system RA capacity. This lowered the price for the 2024 flexible MPB because of lower priced contracts with more system capacity than flexible capacity and this raised the forecast price because of higher priced contracts with flexible capacity greater than system capacity.