2026 Avoided Cost Calculator (ACC) Staff Proposal Workshop

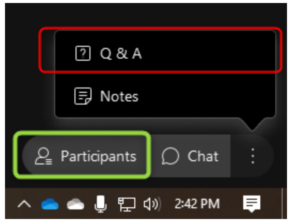
April 29, 2026

California Public Utilities Commission

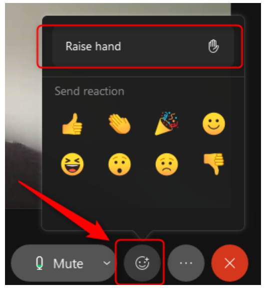
General Information

- **Please use the "raise hand" function if you want ask a question verbally and we will unmute you.**
- **Please use the Q&A function to ask questions.**
  - This leaves the chat free for general announcements
- **This workshop will be recorded and the recording and the slides will be made available.**

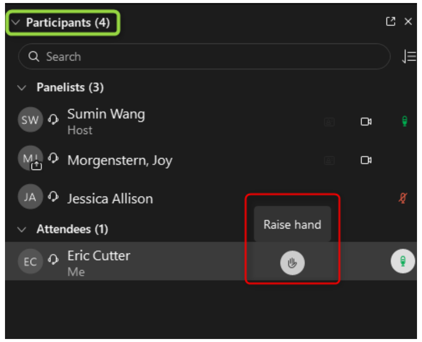
Q&A Panel
Lower-Right



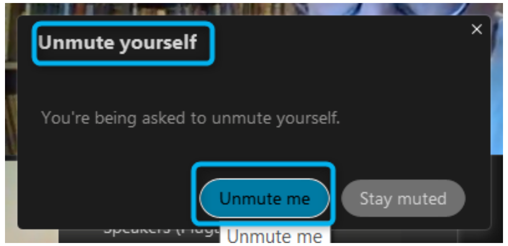
Raise Hand
Lower-Middle



Participants Panel
Upper-Right



Unmute
A host will unmute you – *then you must click button to unmute yourself*



Agenda

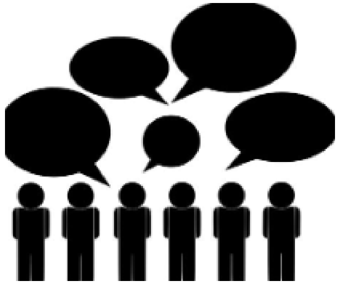
Topic	Presenter	Duration
Opening Remarks and Workshop Agenda	CPUC staff	10:00 — 10:15 AM
GHG Avoided Costs	E3	10:15 — 10:35 AM
Integrated Calculation of Generation Capacity and GHG Avoided Costs	E3	10:35 — 10:55 AM
Break		10:55 — 11:05 AM
Hourly Allocation of Generation Capacity Value	E3	11:05 — 11:25 AM
Hourly Allocation of Transmission Capacity Value	E3	11:25 — 11:35 AM
Next Steps & Close	CPUC staff	11:35 — 11:45 AM

Opening Remarks

Energy Division

California Public Utilities Commission

General Ground Rules



- This is a safe space for a discussion:
  - Today, we are going over the Staff Proposal and addressing questions. We're tackling topics, not people
- Maintaining our purpose: The focus of today is on what is being proposed in the 2026 ACC Staff Proposal
  - Subject matter outside of these topics will be redirected back to the key topics
  - Material on the Transmission and Distribution Study can be found on the DER Cost-Effectiveness Webpage and was covered in the 22 August 2025 Webinar
- Matters outside the scope of R.22-11-013 Track 1 may not be discussed at this workshop

2026 ACC Proposal Workshop

April 29, 2026

Energy+Environmental Economics

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Contents

Refinement of GHG avoided costs

Energy+Environmental Economics

Summary of Proposed Changes for 2026 ACC

1. **Refinement of GHG avoided costs**
   a) Apply a single value to GHG emission reductions
   b) Remove the GHG Rebalancing component
   c) Cap total GHG value at the societal cost of carbon
2. **Refinement of integrated calculation of generation capacity and GHG avoided costs**
3. **Refinement of hourly allocation of generation capacity value**
   a) Use LOLH rather than EUE for capacity allocation factors
   b) Use energy prices (rather than temperature) to assign days with high generation capacity value
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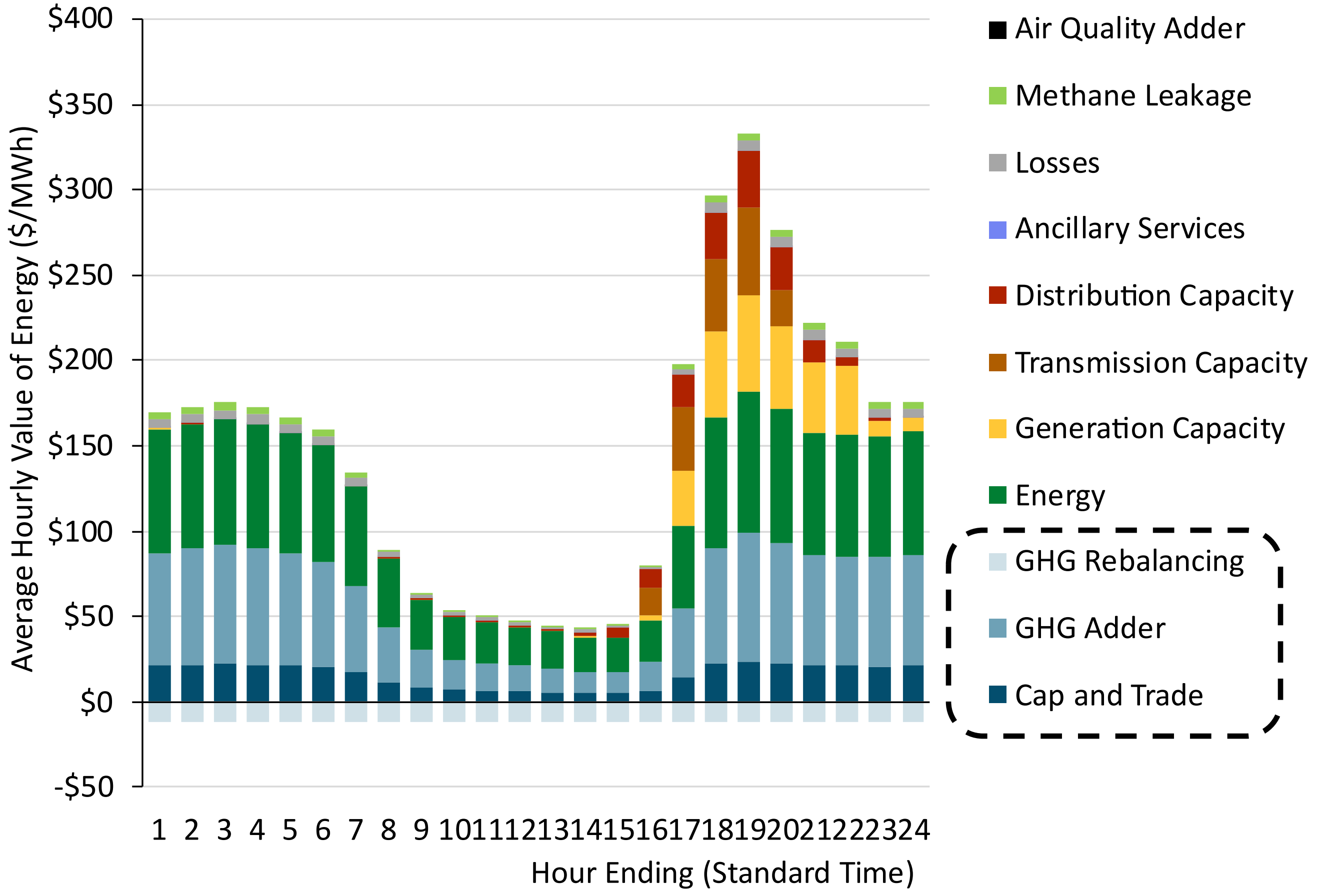
4. **Calculate transmission capacity allocation factors using forecast load instead of historical**

GHG value in the 2024 ACC

+ **The GHG value in the current electric model has three components:**
  - Cap-and-Trade: represents the price forecast for California's Cap-and-Invest program
  - GHG Adder: represents the additional costs needed beyond the Cap-and-Invest program to meet the electric sector GHG target.
  - GHG Rebalancing: represents an assumed change to the electric sector GHG target due to changes in load or distributed generation.
+ **The GHG value in the current gas model is a separate, "interim" value**
  - Based on a 2021 CEC report on the GHG abatement cost in buildings



** GHG Adder and GHG Rebalancing are usually shown combined into a single value*

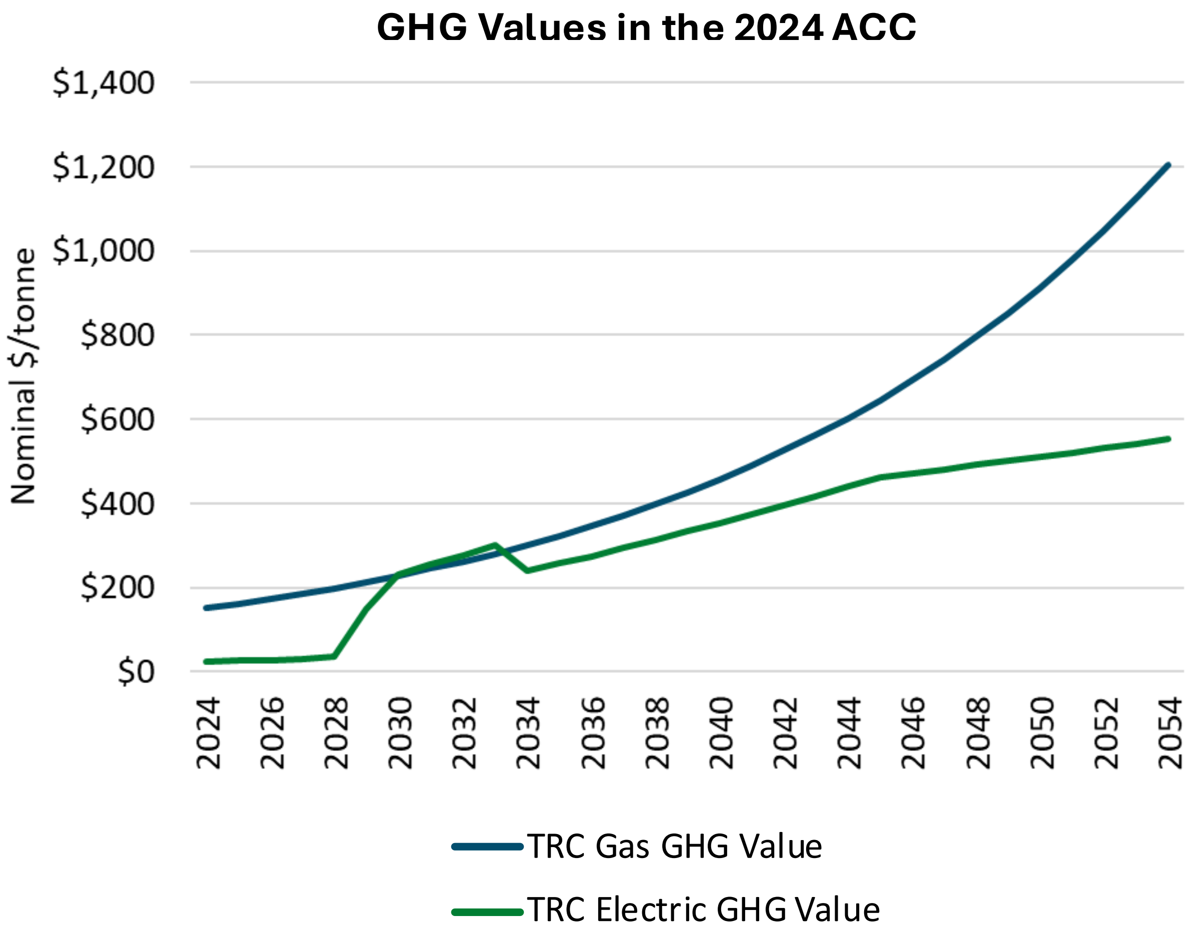
Background on marginal GHG value in California

+ **There is no framework in California for determining a single, marginal GHG abatement cost across sectors (electric, gas, transportation)**
  - Sector-specific targets and programs to achieve those targets are defined instead
+ **The CPUC establishes an electric-sector GHG cap, consistent with the CARB scoping plan**
  - IRP modelling determines the most cost-effective way to meet the electric sector cap. This modeling results in a well-defined electric-sector marginal GHG abatement cost
  - Other sectors do not have similarly robust modelling

The electric-sector GHG abatement cost is the most accurate estimate we have on the cost to reduce emissions within the state

Apply a single value to GHG emission reductions

- Apply the **electric-sector GHG value** to all GHG reductions in the ACC model (gas and electric)
- This value is **aligned with the marginal GHG value in the IRP**
  - IRP is the state's most robust and transparent modeling process that analyzes the cost to meet specified GHG reduction goals.
- Better reflects the state's objective of achieving net zero by 2045 **across all sectors**
- Provides a **consistent price signal for DER investment** by treating GHG reductions as equally valuable regardless of whether they occur in the electric or gas sector

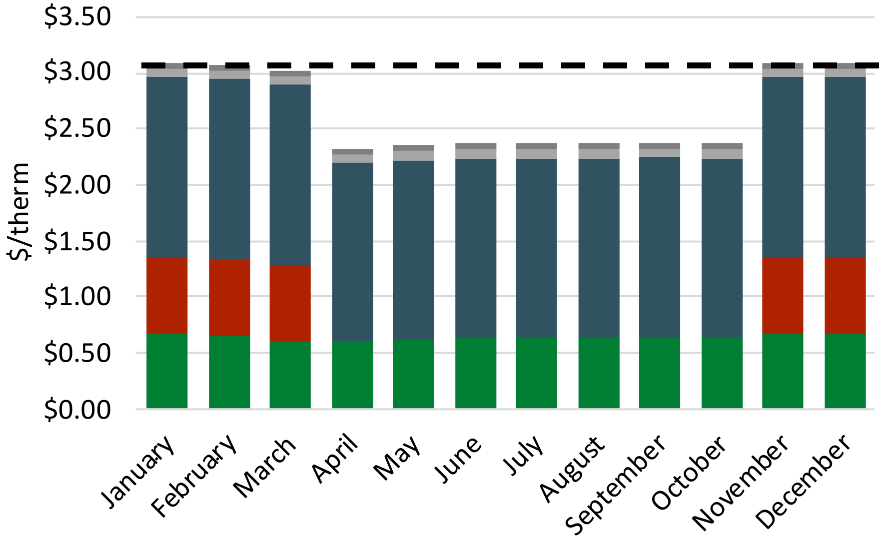


Impact of using Electric Model GHG value in Gas Model

2024 ACC

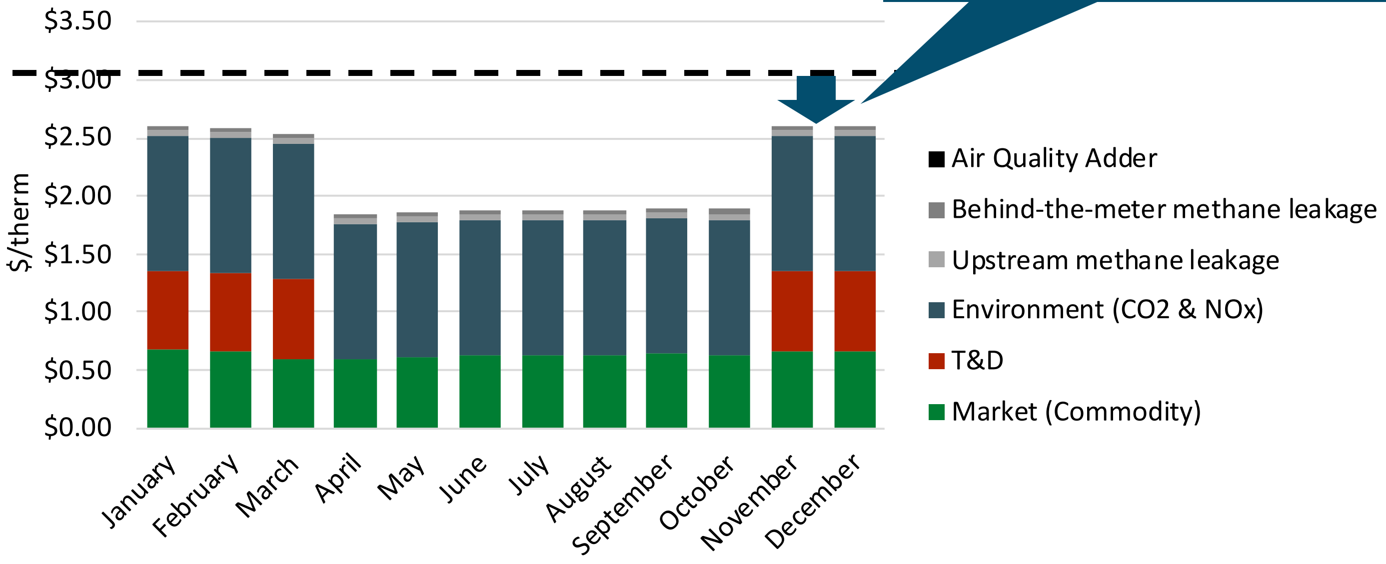
GHG value reduced by
$84/tonne CO2*

2024 ACC
20-year Levelized Value



2024 ACC with Electric Model GHG Value
20-year Levelized Value

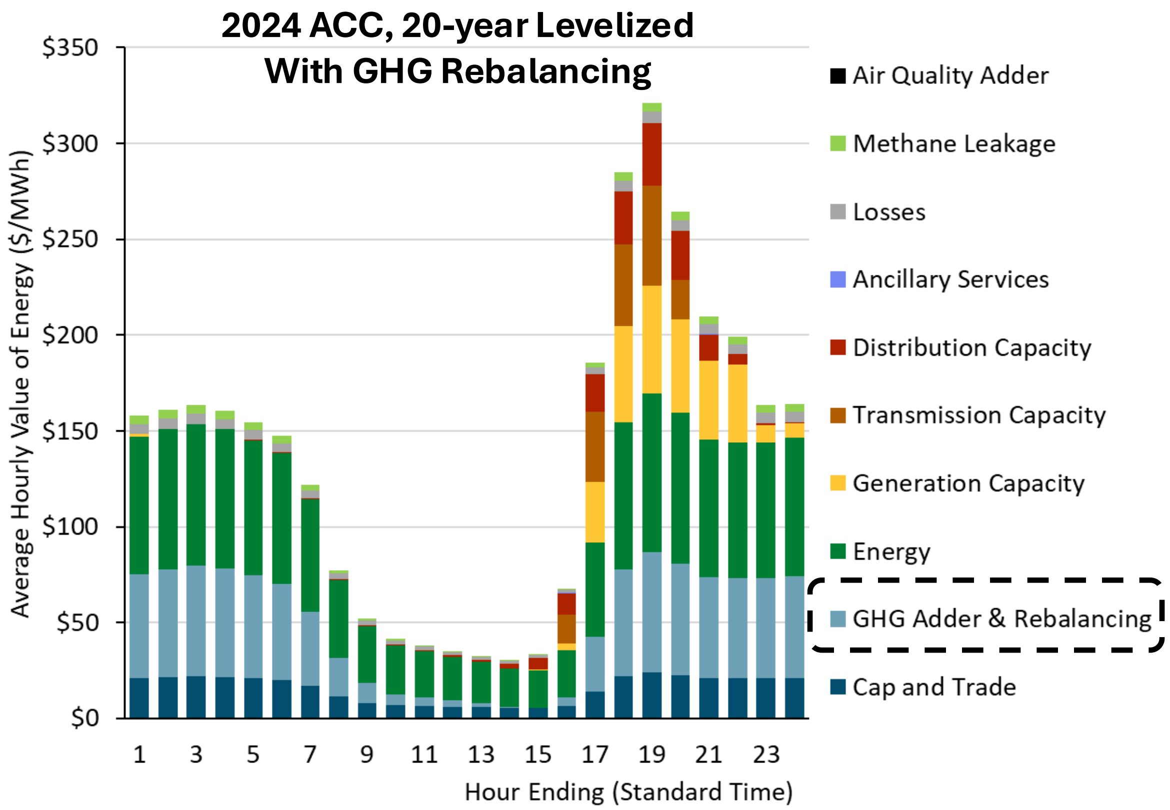
*Gas avoided costs reduced by **$0.49/therm****

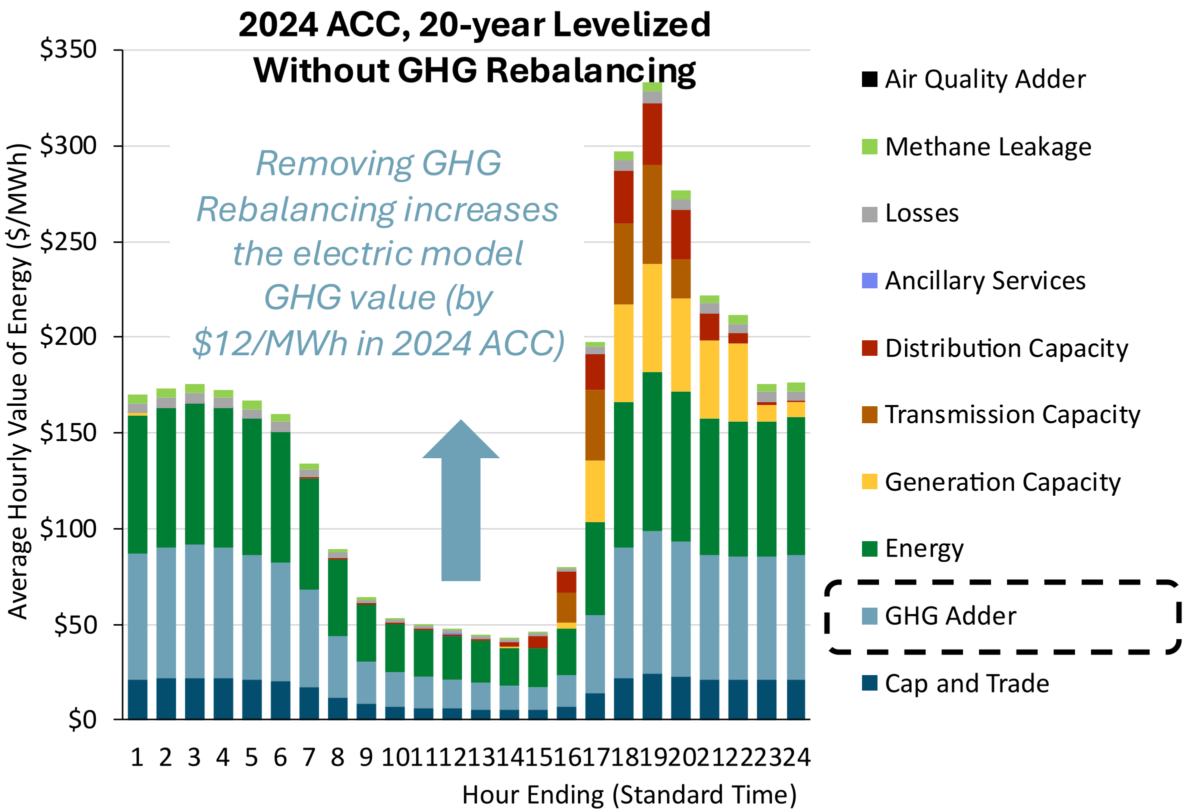


**20-year levelized value for 2024 resource*

Remove the GHG Rebalancing component

- With a single GHG value across electric and gas models (proposed change #1), there is no longer a need for a separate adjustment to reflect cross-sector (gas to electric) transfers
- Aligns the GHG value in the ACC with the marginal GHG value calculated in the IRP



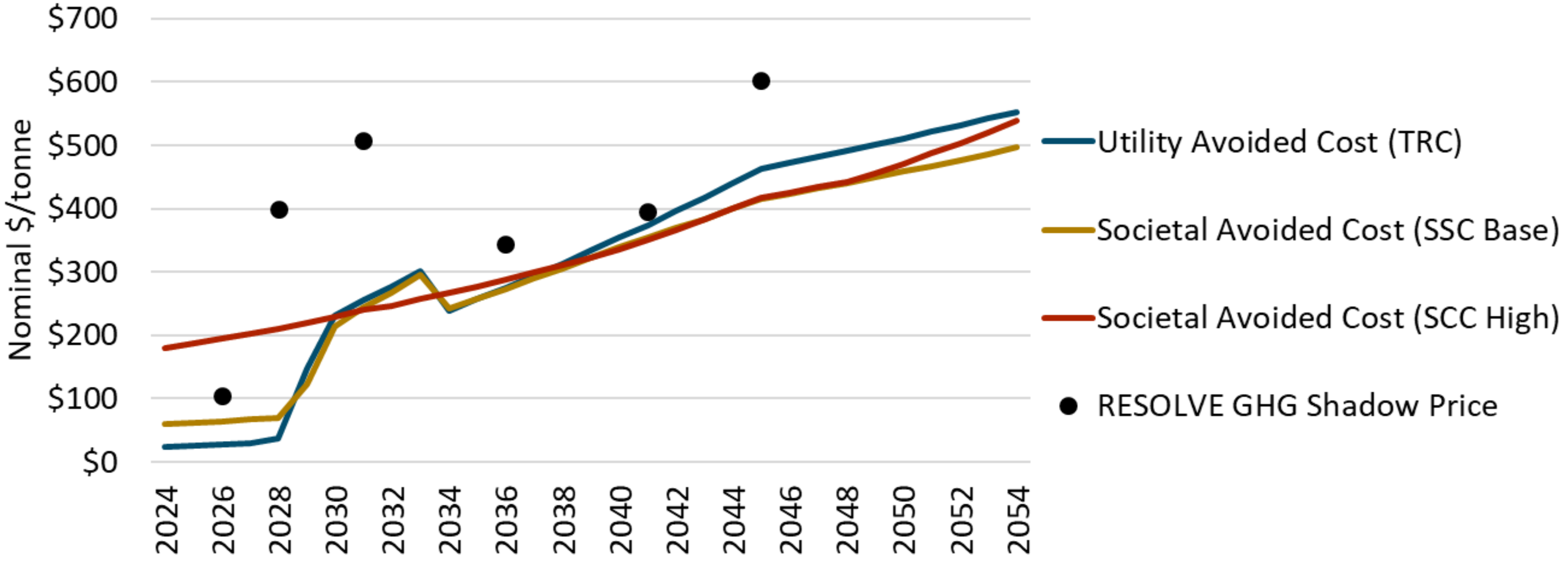


Proposed refinement of GHG value #3

Cap total GHG value at the "high" societal cost of carbon

+ **Implementing a cap on the total GHG value would provide a safeguard for ratepayers against a GHG value that exceeds the value that emissions reductions provide to society**
  - In the long term, GHG targets should be adjusted if they result in a marginal GHG value that too high for ratepayers to bear or reductions in other sectors can be more cost-effectively achieved
  - In the interim, implementing a cap would ensure that between IRP and ACC cycles, an excessively high GHG value is not being used to determine long-term DER investments.

GHG Values in the 2024 ACC with 26-27 TPP RESOLVE GHG Shadow Price



Updates to integrated calculation of GHG and Generation Capacity avoided costs

Energy+Environmental Economics

Summary of Proposed Changes for 2026 ACC

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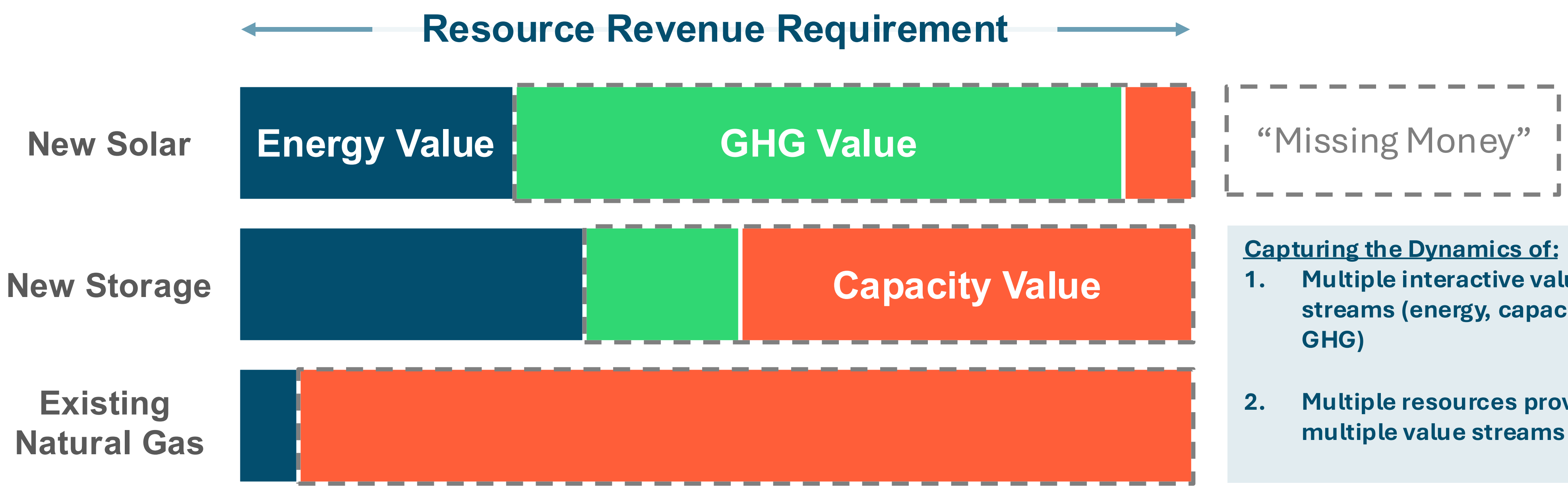
GHG and generation capacity avoided costs are calculated simultaneously through an integrated calculation

- The integrated calculation recognizes that resources, such as solar and storage, provide both GHG and generation capacity benefits to the system.
- GHG and generation capacity avoided costs are interdependent.



<u>Capturing the Dynamics of:</u>

1. Multiple interactive value streams (energy, capacity and GHG)
2. Multiple resources providing multiple value streams

Use as Excel-based model with two equations instead of a Python-based optimization model

Core Equation: **Resource Costs = Energy + Capacity Value + Greenhouse Gas Value**

Current Approach

Current approach uses an optimization to solve for avoided capacity and GHG costs

- Decision variables: annual avoided gen capacity & GHG costs
- Constraints: value >= costs applied to each resource vintage as an inequality on an NPV basis
- Objective: minimize NPV of net value (value – cost) across all resources & vintages

Proposed Approach

New approach uses two equations to calculate avoided capacity and GHG costs for two resources

- 2 equations (Net RECC for 2 resources)
- 2 unknowns (GHG and generation capacity value)
- Net RECC (Real Economic Charges Carrying) reflects resource costs net of energy revenues

The proposed approach improves transparency and simplicity while maintaining core calculation principles

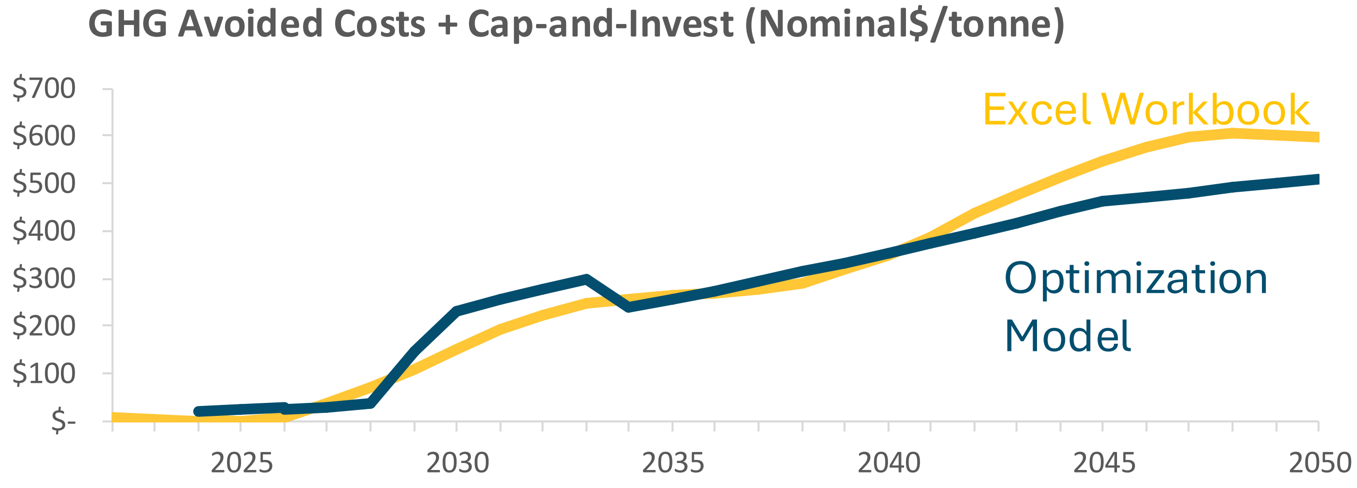
+ Compared to the current approach, the proposed approach:

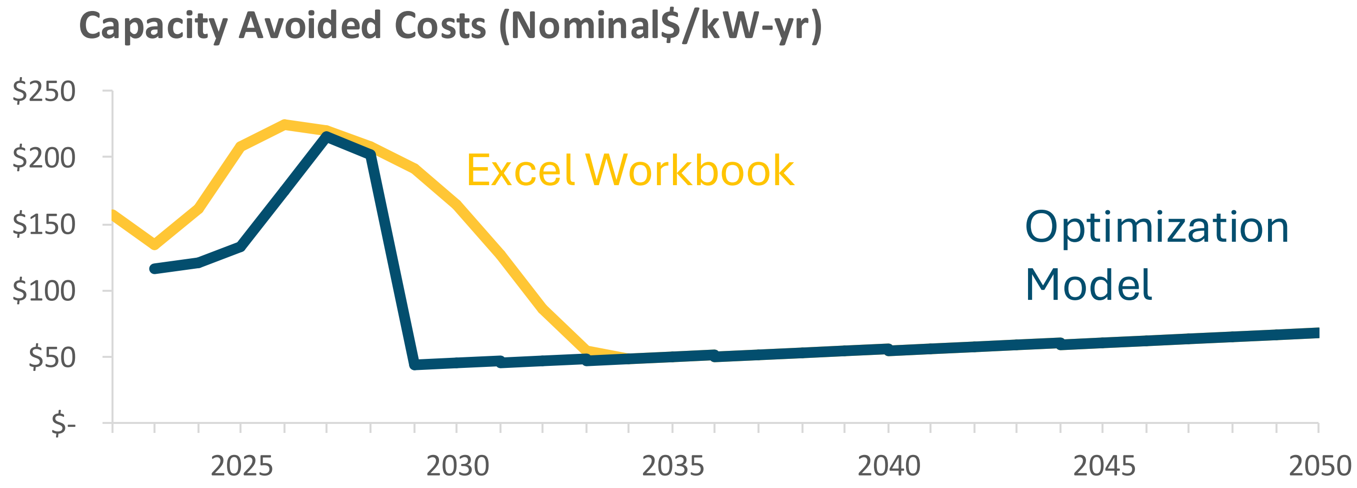
- ☑ Continues to calculate avoided generation capacity and GHG costs simultaneously
- ☑ Is more tolerant of inconsistent inputs because it does not rely on optimization
- ☑ Uses the same underlying RECC calculation as implemented in the 2022 ACC
- ☑ Calculates everything in an Excel workbook, improving transparency

- ☒ Accommodates only two resources at a time, although different combinations of two resources can be used to derive avoided costs by year

Excel model arrives at similar results with 2024 ACC inputs

- **Capacity avoided costs were forced to floor after 2040, consistent with 2024 ACC**
- **Avoided costs are not exactly the same because:**
  - Optimization solves across multiple years while the Excel model solves year by year
  - Smoothing is implemented differently in the optimization model and Excel





Proposed changes to hourly allocation of Generation Capacity value

Energy+Environmental Economics

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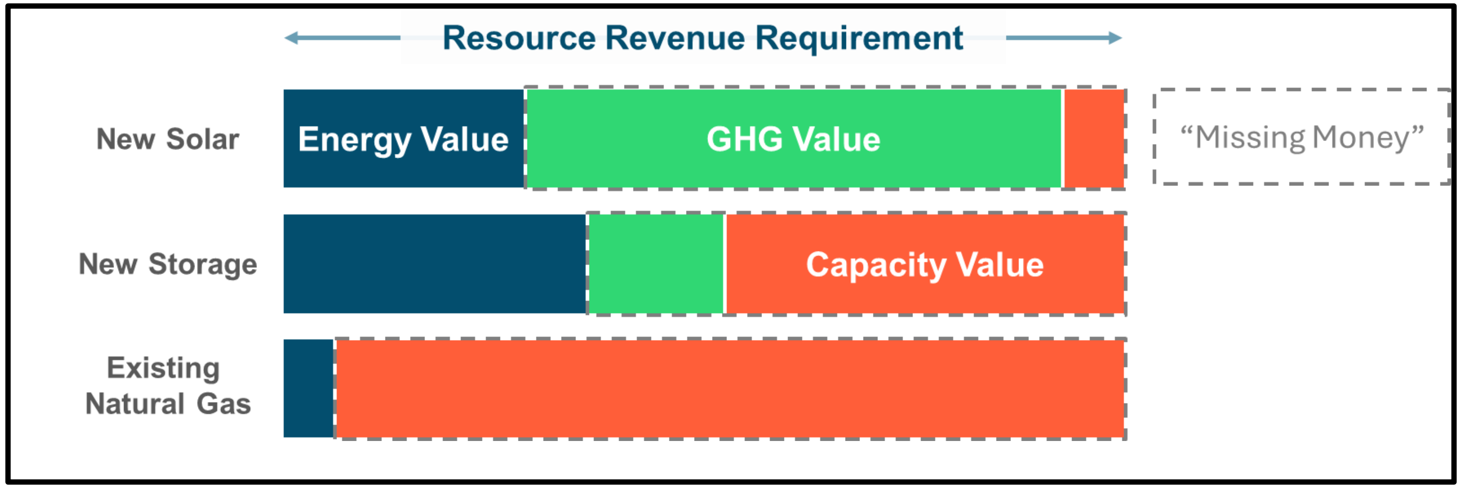
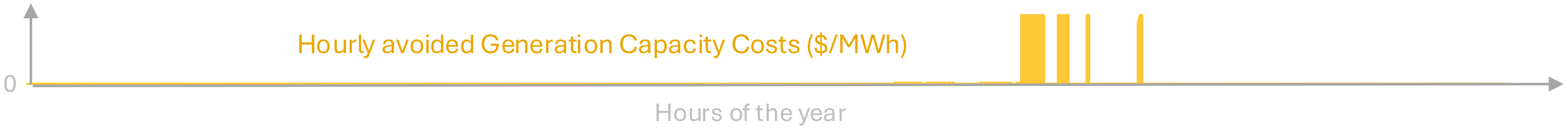
Hourly allocation of generation capacity value

Step 1: Calculate annual generation capacity value



Step 2: Allocate annual value to individual hours of the year based on reliability risk in each hour

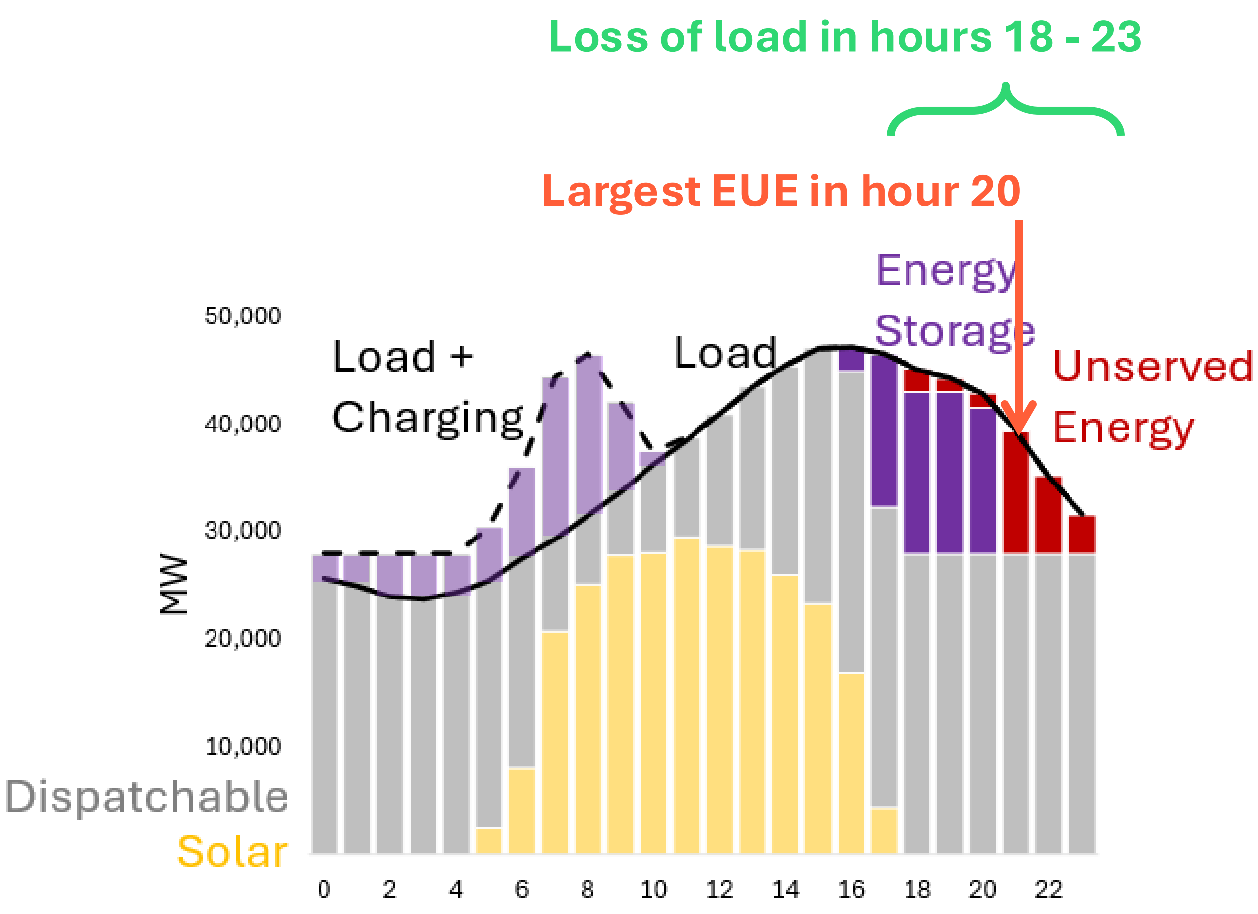
Annual generation capacity value ($/kW-yr)



Proposed refinement #1

Use LOLH rather than EUE for capacity allocation factors

- **Currently allocation factors are based on Expected Unserved Energy (EUE), which represents the size of loss of events**
  - EUE put more weight on large shortfall events and understates the value of resources that reduce loss of load across many hours.
- **Using the frequency of loss of load aligns capacity avoided costs with the consistent value of avoiding loss of load in any given hour**
  - EUE frequency is represented by Loss of Load Hours (LOLH)



Example day with loss of load

Comparison of EUE and LOLH results

+ **Allocation based on LOLH gives more weight to hours in which loss of load occurs *more frequently*, regardless of the magnitude of unserved energy.**
  - Hours with more frequent loss-of-load events are more likely to benefit from DER dispatch in reducing loss-of-load risk.

Normalized EUE (%)

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1	-	-	-	-	-	-	-	0.77%	0.73%	-	0.02%	-
2	-	-	-	-	-	-	-	0.00%	0.08%	-	0.02%	-
3	-	-	-	-	-	-	-	-	-	-	0.02%	-
4	-	-	-	-	-	-	-	-	-	-	0.02%	-
5	0.00%	-	-	-	-	-	-	-	-	-	0.02%	-
6	0.01%	-	-	-	-	-	-	-	0.06%	-	0.03%	-
7	0.01%	-	-	-	-	-	-	-	-	-	0.03%	-
8	0.01%	-	-	-	-	-	-	-	-	-	0.03%	-
9	0.01%	-	-	-	-	-	-	-	-	-	0.03%	-
10	0.00%	-	-	-	-	-	-	-	-	-	0.02%	-
11	-	-	-	-	-	-	-	-	-	-	0.00%	-
12	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	0.00%	-	-	-	-
14	-	-	-	-	-	-	-	0.05%	0.15%	-	-	-
15	-	-	-	-	-	-	-	0.10%	0.32%	-	-	-
16	-	-	-	-	-	-	-	8.94%	1.06%	-	-	-
17	-	-	-	-	-	-	-	8.95%	1.53%	-	-	-
18	-	-	-	-	-	-	-	8.94%	1.67%	-	-	-
19	-	-	-	-	-	-	-	8.99%	4.77%	-	-	-
20	-	-	-	-	-	-	-	9.05%	1.73%	-	-	-
21	-	-	-	-	-	-	-	9.00%	1.53%	-	-	-
22	-	-	-	-	-	-	-	8.95%	1.53%	-	-	-
23	-	-	-	-	-	-	-	8.94%	1.53%	-	-	-
24	-	-	-	-	-	-	-	8.84%	1.52%	-	-	-

Normalized LOLH (%)

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

0 High

These results are illustrative only

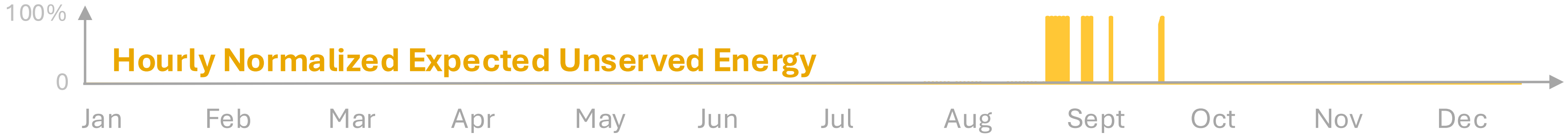
Heatmaps are for all of CAISO for 2031 and include both weekdays and weekends.

Proposed refinement #2

Use energy prices (rather than temperature) to assign days with high generation capacity value

- Month-hour average EUE is converted to 8760 hourly values to allocate generation capacity value
- Current approach uses days with highest temperature
- Proposed approach uses days with highest energy prices
  - Energy prices capture the impact of both load and renewable generation

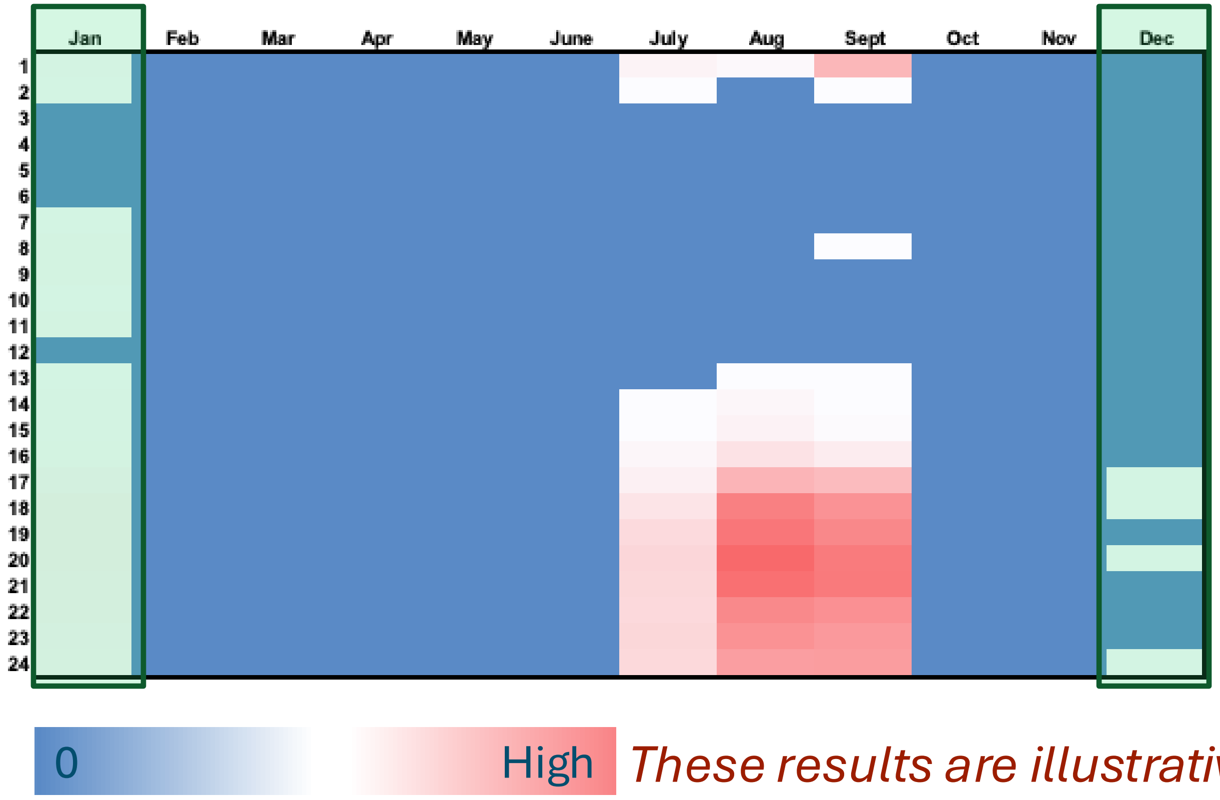
Month-Hour Averages of EUE



Remapping based on temperature distorted winter EUE hours

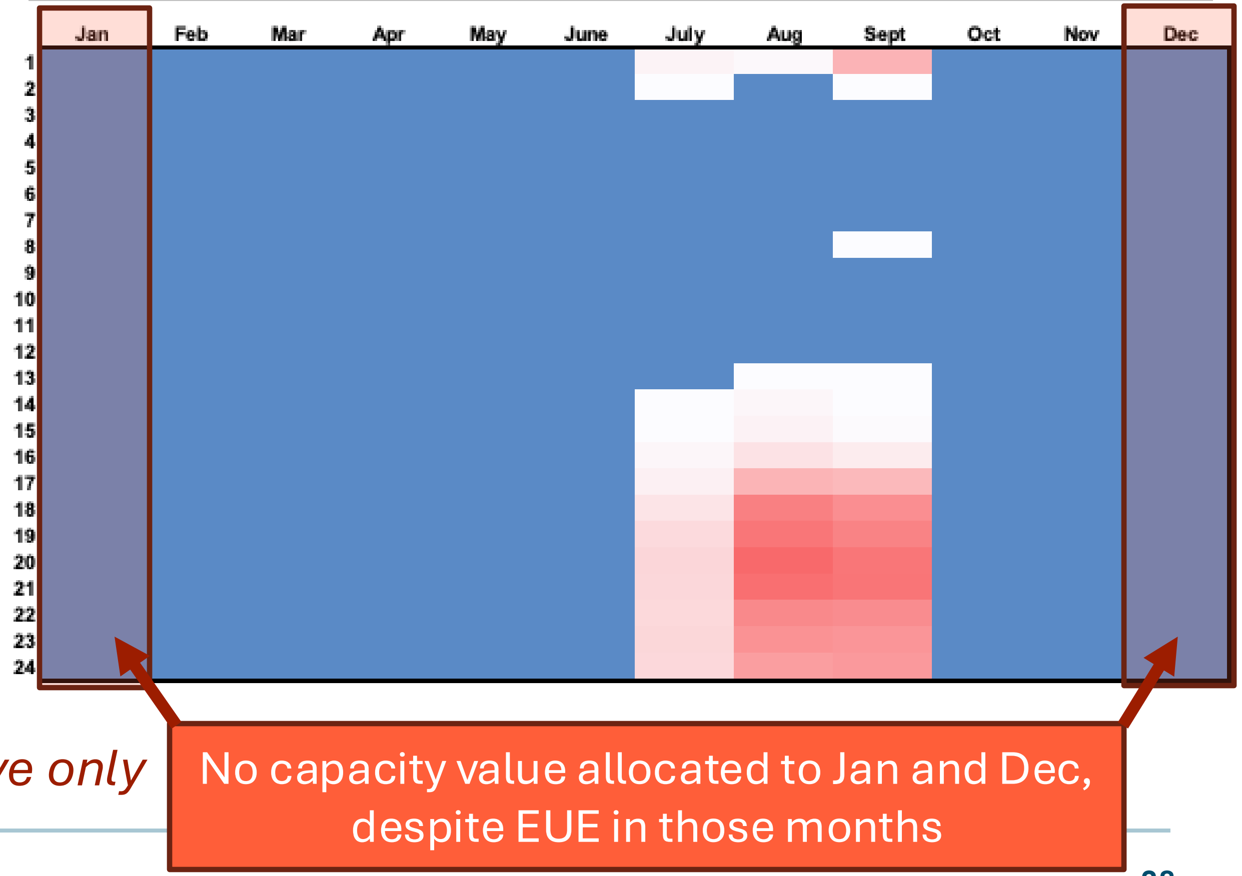
+ **Month-hour averages of Expected Unserved Energy (EUE) from 2024 ACC in year 2040**

SERVM Reliability Modeling Results



These results are illustrative only

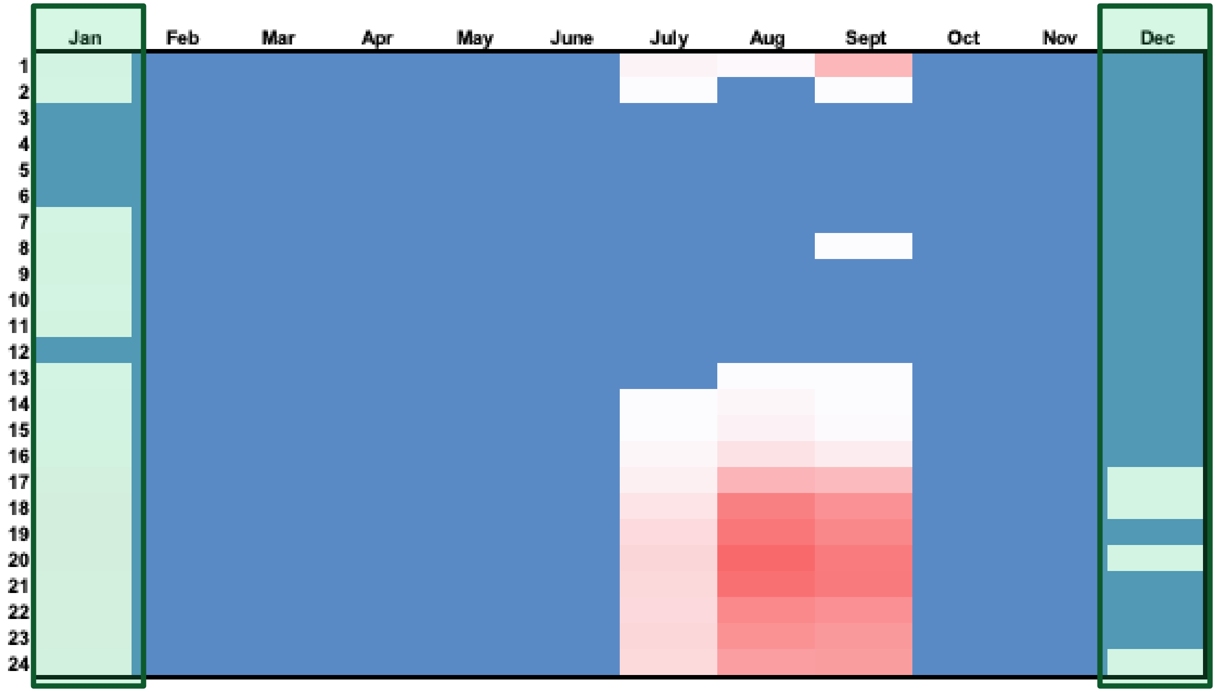
Old Remapping Method



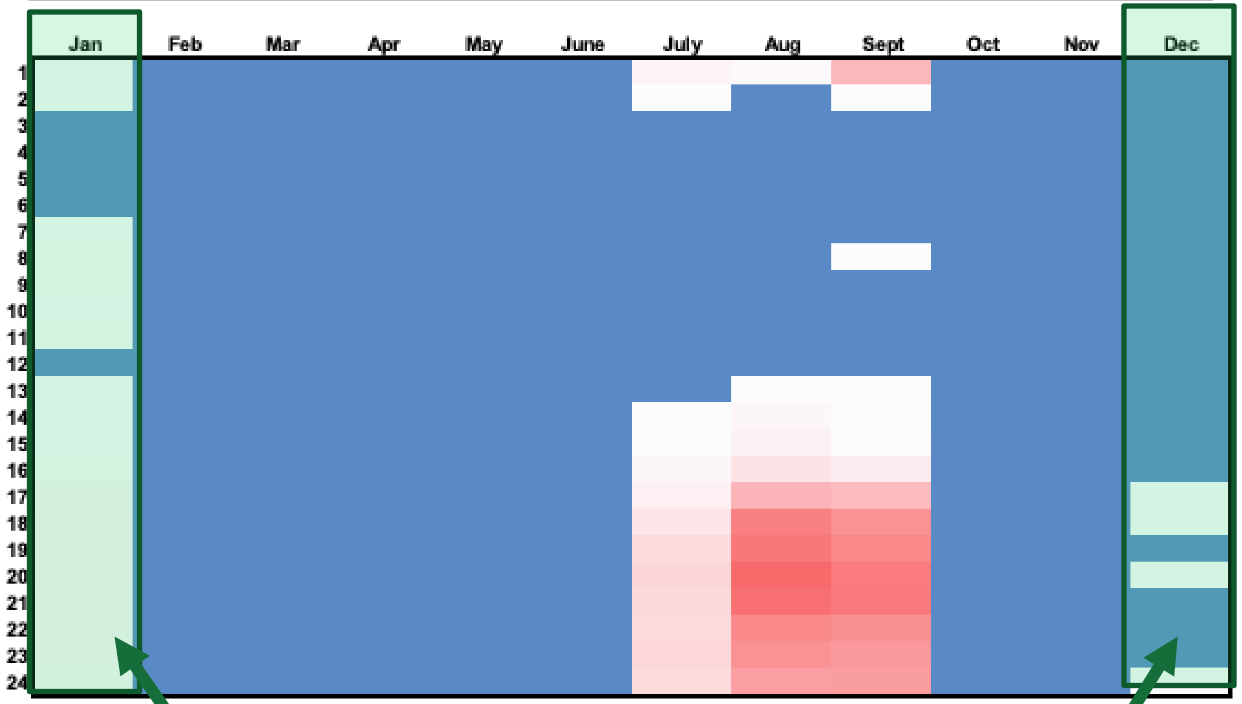
New remapping method preserves winter critical hours

+ **Month-hour averages of Expected Unserved Energy (EUE) from 2024 ACC in year 2040**

SERVM Reliability Modeling Results



New Remapping Method



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These results are illustrative only

Capacity value allocation to Jan and Dec, preserving EUE in those months

Proposed refinement #3

Represent the difference in reliability risk of weekdays versus weekends in capacity value allocation

+ **End-uses of the ACC consider weekday/weekend differences. For example:**
  - DER profiles used in cost-effectiveness evaluation may vary across days of the week
  - Net Billing Tariff (NBT) has export rates calculated from the ACC, differentiated by month, hour, and weekend/weekday
+ **Reliability modelling shows significant differences in reliability risk on weekends vs. weekdays, which have not previously been reflected in the ACC**

Weekday LOLH

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1	-	-	-	-	-	-	-	0.002	0.015	-	0.006	-
2	-	-	-	-	-	-	-	0.000	0.002	-	0.006	-
3	-	-	-	-	-	-	-	-	-	-	0.005	-
4	-	-	-	-	-	-	-	-	-	-	0.006	-
5	0.000	-	-	-	-	-	-	-	-	-	0.006	-
6	0.001	-	-	-	-	-	-	-	0.002	-	0.006	-
7	0.001	-	-	-	-	-	-	-	-	-	0.006	-
8	0.001	-	-	-	-	-	-	-	-	-	0.007	-
9	0.001	-	-	-	-	-	-	-	-	-	0.007	-
10	0.000	-	-	-	-	-	-	-	-	-	0.004	-
11	-	-	-	-	-	-	-	-	-	-	0.000	-
12	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	0.000	-	-	-	-
14	-	-	-	-	-	-	-	0.001	0.010	-	-	-
15	-	-	-	-	-	-	-	0.004	0.015	-	-	-
16	-	-	-	-	-	-	-	0.042	0.020	-	-	-
17	-	-	-	-	-	-	-	0.043	0.028	-	-	-
18	-	-	-	-	-	-	-	0.042	0.038	-	-	-
19	-	-	-	-	-	-	-	0.045	0.099	-	-	-
20	-	-	-	-	-	-	-	0.046	0.033	-	-	-
21	-	-	-	-	-	-	-	0.042	0.028	-	-	-
22	-	-	-	-	-	-	-	0.042	0.028	-	-	-
23	-	-	-	-	-	-	-	0.042	0.028	-	-	-
24	-	-	-	-	-	-	-	0.042	0.028	-	-	-

Weekend LOLH

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1	-	-	-	-	-	-	-	0.016	0.001	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-	-	-	-	-
19	-	-	-	-	-	-	-	-	0.009	-	-	-
20	-	-	-	-	-	-	-	-	0.001	-	-	-
21	-	-	-	-	-	-	-	-	-	-	-	-
22	-	-	-	-	-	-	-	-	-	-	-	-
23	-	-	-	-	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	-	-	-	-	-

These results are illustrative only

Heatmaps are for all of CAISO for 2031 and LOLH is weighted by case probability.

Refinement of hourly allocation of transmission capacity value

Energy+Environmental Economics

Proposed refinement

Calculate transmission capacity allocation factors using forecast load instead of historical load

- **Transmission capacity is allocated to hours of the year to reflect times when the transmission system is most constrained**
  - Allocation is done with Peak Capacity Allocation Factors (PCAFs)
  - ACC previously relied on **historical load** to calculate PCAFs
- **The timing of loads is expected to change over time:**
  - Increasing penetration of EVs and building electrification
  - Increasing BTM generation
- **Staff propose using forecast loads to allocate transmission capacity value**
  - Load forecasts are aligned with energy avoided costs and generation capacity allocation factors that currently used in the ACC.

CAISO Load 2026

	1	2	3	4	5	6	7	8	9	10	11	12
1	22.8	23.0	22.0	21.5	23.0	25.8	27.1	27.0	26.2	23.5	22.6	23.8
2	21.8	21.9	21.0	20.5	21.8	24.3	25.5	25.4	24.7	22.3	21.7	22.7
3	21.0	21.1	20.4	19.9	21.1	23.4	24.5	24.4	23.8	21.5	21.0	21.9
4	20.7	20.7	20.3	20.0	21.1	23.1	24.1	24.2	23.5	21.5	20.7	21.4
5	21.1	21.0	21.0	20.9	21.8	23.7	24.7	25.0	24.3	22.2	21.1	21.6
6	22.5	22.4	22.7	22.2	22.6	24.5	25.4	26.2	25.7	23.9	22.5	22.7
7	24.7	24.4	24.2	22.7	22.9	25.1	26.1	27.0	26.5	25.4	24.3	24.6
8	25.8	25.2	23.9	22.4	22.7	25.1	26.6	27.8	27.5	26.0	25.0	25.9
9	26.0	24.7	22.7	20.7	21.2	24.3	26.1	27.4	27.7	26.0	24.8	26.7
10	24.8	23.0	20.9	18.8	19.9	24.1	26.0	27.4	27.7	25.5	24.0	26.2
11	23.6	21.4	19.0	17.3	19.0	23.8	26.2	27.7	27.8	25.1	23.3	25.2
12	22.7	19.8	17.8	16.5	18.9	23.9	26.7	28.5	28.7	25.4	22.7	24.2
13	22.1	19.1	17.4	16.5	19.4	25.3	28.2	30.5	30.4	26.4	22.7	23.3
14	22.1	19.3	17.7	17.3	20.3	27.0	30.3	32.6	32.4	27.7	23.4	23.4
15	22.6	20.0	18.6	18.7	22.0	29.0	32.4	34.8	34.2	29.0	24.6	24.0
16	23.6	21.4	20.1	20.5	24.0	30.9	34.5	36.6	35.8	30.4	26.0	25.2
17	25.3	23.3	22.7	23.0	26.4	33.2	36.6	38.5	37.3	31.6	27.3	27.3
18	27.9	26.9	25.5	25.5	28.6	34.9	37.8	39.2	38.0	32.2	28.3	30.2
19	28.8	28.5	27.4	27.3	29.6	35.4	37.9	38.9	37.1	31.1	28.3	30.3
20	28.3	27.9	27.2	27.5	29.6	35.1	37.2	37.1	35.5	30.1	27.6	29.3
21	27.4	26.9	26.6	26.8	29.1	33.8	35.8	35.1	34.3	29.0	26.6	28.4
22	26.4	26.1	25.4	25.2	27.2	31.5	33.3	32.6	31.7	27.4	25.7	27.5
23	25.0	24.6	24.1	23.9	25.5	29.2	30.9	30.2	29.5	25.8	24.4	26.0
24	23.7	23.4	23.0	22.9	24.4	27.6	29.0	28.6	28.0	24.6	23.4	24.7

CAISO Load 2045

	1	2	3	4	5	6	7	8	9	10	11	12
1	52.8	52.6	47.9	46.2	46.7	50.6	52.2	52.1	51.7	47.9	52.3	54.4
2	48.9	48.1	43.0	40.2	40.5	44.0	45.5	45.3	45.1	41.6	47.7	50.2
3	44.3	43.0	39.2	36.0	36.1	39.1	40.5	40.5	40.1	37.0	42.6	45.2
4	41.0	39.3	37.4	34.0	33.7	36.5	37.8	38.0	37.4	34.7	39.2	41.5
5	40.7	38.9	38.5	35.0	34.4	36.8	38.1	38.5	38.0	35.7	38.6	40.5
6	43.3	41.4	42.8	39.0	37.7	39.5	40.8	42.0	41.6	40.2	41.3	42.4
7	50.5	48.5	49.3	44.5	41.8	43.7	45.2	46.3	46.5	46.9	47.5	48.7
8	56.3	53.6	50.6	46.8	44.6	46.2	48.3	49.8	50.4	50.9	51.5	54.2
9	57.7	53.7	47.6	44.7	43.0	45.9	48.4	50.0	51.3	51.2	52.1	56.9
10	52.7	48.6	42.5	40.4	39.7	44.8	47.5	49.3	50.8	49.2	49.2	53.9
11	47.7	43.8	37.1	35.8	36.5	42.8	46.3	48.0	49.0	46.1	46.1	50.0
12	43.4	39.1	33.7	33.1	35.2	41.3	45.2	48.0	48.9	44.8	43.0	46.3
13	40.9	36.9	32.4	32.1	35.3	42.3	46.4	50.2	50.6	45.4	41.6	43.5
14	40.0	36.6	32.1	32.3	36.1	44.0	48.9	52.8	53.4	47.0	41.8	42.8
15	39.8	36.9	32.5	33.9	39.4	47.7	52.3	56.0	57.1	49.9	43.0	42.7
16	40.3	38.3	33.2	33.5	39.4	48.2	52.8	56.1	57.1	49.0	44.7	43.7
17	40.2	38.5	36.7	37.3	43.1	51.8	55.9	59.0	59.3	50.9	44.5	44.1
18	44.3	43.6	41.8	42.0	47.1	55.1	58.4	61.0	61.1	52.7	46.1	48.0
19	46.7	46.6	44.9	44.7	48.7	56.0	58.7	60.6	60.0	51.8	46.9	48.7
20	46.5	46.1	44.8	45.2	48.4	54.8	57.1	57.9	57.2	49.9	46.2	47.9
21	45.9	45.2	45.8	47.5	50.1	[illegible]	[illegible]	56.7	57.0	50.8	45.7	47.4
22	47.6	47.2	46.5	47.8	49.7	54.4	56.6	55.8	55.2	50.6	47.6	49.4
23	48.2	47.7	48.0	49.8	51.2	55.3	57.6	56.8	56.1	52.3	48.3	49.6
24	50.9	50.2	49.7	51.0	51.8	56.0	58.0	57.4	57.2	52.8	50.8	52.0

Increasing winter loads

Larger morning peak

Evening peak extends later

Next Steps

- Links to the workshop recording, slides, and transcript will be emailed to the R.22-11-013 Service List and posted on the DER Cost-Effectiveness webpage
- Opening Comments on the Staff Proposal must be filed by May 13, 2026
- Reply Comments must be filed by May 18, 2026
- **Any questions?**
- Thank you for joining today.

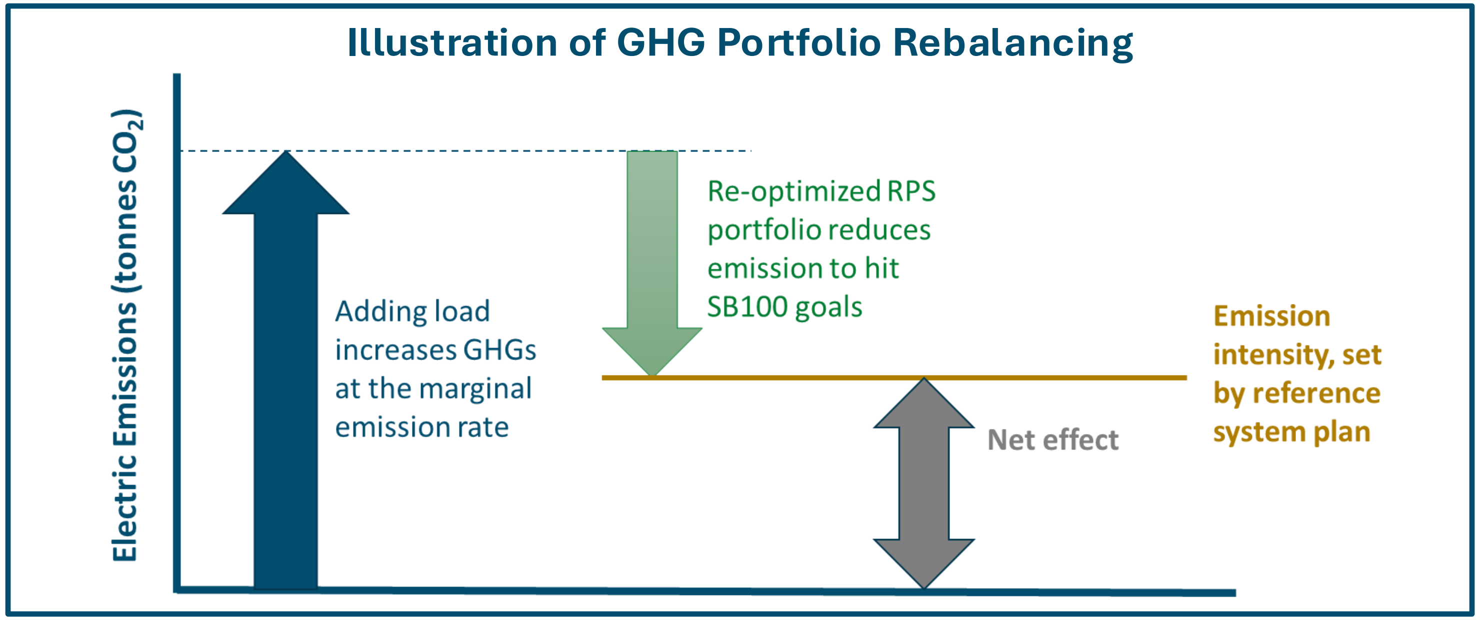
California Public Utilities Commission

Appendix

Energy+Environmental Economics

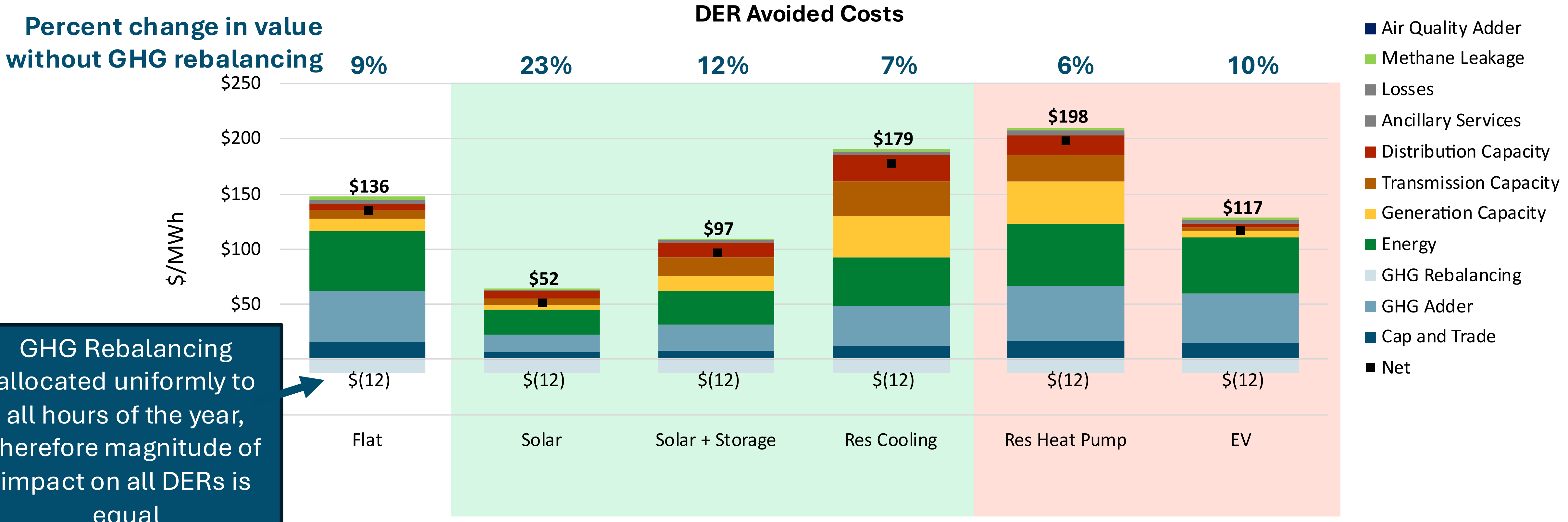
Current GHG Portfolio Rebalancing methodology

- **"If electrification load were added to an electric sector IRP portfolio, one would expect the allowable GHG emissions from the electric sector to increase proportionally, not to remain fixed at the original total emissions target" (ACC Documentation)**
  - The GHG Rebalancing value reflects the expectation that the electric sector will, in the long-term, target an emissions intensity (tonne/MWh), as opposed to an absolute emission value (MMt)
  - The intention is to avoid punishing electrification for adding load to the electric system, when it is in fact reducing economy-wide emissions



Impact of removing GHG Rebalancing on different DERs

2024 ACC



GHG Rebalancing allocated uniformly to all hours of the year, therefore magnitude of impact on all DERs is equal ($12/MWh in 2024 ACC)

Load reducing DER will have higher **avoided costs**

Load increasing DER will have higher **costs**

20-year levelized value for 2024 resource

The Integrated Calculation is based on one core equation

+ **For each supply-side resource on the margin, total resource value should be equal to resource cost :**

Resource Costs = Energy & AS Value + Capacity Value + Greenhouse Gas Value

Capacity Value: Marginal ELCC x Capacity Avoided Cost

Greenhouse Gas Value: Marginal GHG Impact x GHG Avoided Cost

Inputs

- Resource Costs: Based on levelized cost assumptions in CPUC IRP proceeding
- Energy & AS Value: Calculated based on SERVM energy & AS prices
- Marginal ELCC: Derived from RESOLVE portfolio outputs
- Capacity Avoided Cost: Calculated
- Marginal GHG Impact: Calculated based on SERVM energy prices
- GHG Avoided Cost: Calculated

Real Economic Carrying Charge (RECC) Methodology

- **The integrated calculation of GHG and Capacity avoided costs is based on the RECC**
- **RECC calculates the value of deferring an investment by one year**
  - Looks at the net costs (costs minus revenues) over the lifetime of the resource
  - Compares that to the net costs of the same resource installed the following year
  - Compensates resources from all vintages such that their avoided costs offset full NPV net costs
- **RECC was also used in the 2022 ACC to calculate generation capacity avoided costs**

RECC = NPV(Net Costs X Vintage) – NPV(Net Costs (X + 1) Vintage)

Illustrative Example

	NPV		Year 1	Year 2	Year 3	...	Year 25	Year 26
Investment in Year 1	$1,045	◀	$70	$70	$70	...	$70	$32
Investment in Year 2	$958	◀	$0	$68	$68	...	$68	$68
Difference	**$87**	RECC						

Evolving timing in grid challenges with increasing renewable penetrations

+ **Increasing levels of renewables will cause the timing of reliability challenges to shift to different times of day – and eventually to different times of year**

Drivers of Reliability Need Over Time

2000 — **2025** — **2045**

7% — Renewable Penetration — 100%

Summer Peak

In the absence of renewables, the periods of highest demand present the greatest challenge to reliability

Summer Net Peak

At moderate penetrations of renewables, solar shifts "net peak" to evening, which becomes the primary challenge

Extended Periods of Low Renewable Production in Winter

At high penetrations of renewables, periods of sustained low renewable production – most often in the winter - present the greatest challenge to operations

Reliability needs are well correlated with temperature

Reliability needs driven by renewable production