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Witness: Ryan Matley

PREPARED DIRECT TESTIMONY OF RYAN MATLEY
ON BEHALF OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) FOR AUTHORITY, AMONG OTHER THINGS, TO INCREASE RATES AND CHARGES FOR ELECTRIC AND GAS SERVICE EFFECTIVE ON JANUARY 1, 2027

PUBLIC VERSION

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I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

The California Community Choice Association ("CalCCA") presents this Direct Testimony in the Application of Pacific Gas and Electric Company (U 39 E) for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2027 ("Application"). This testimony was prepared on behalf of CalCCA by Ryan Matley, Senior Manager at NewGen Strategies and Solutions, LLC ("NewGen"). Mr. Matley's qualifications are set forth in Attachment RAM-1.

CalCCA represents 24 community choice aggregator ("CCA") electricity providers in California, including 11 that are located in Pacific Gas and Electric Company's ("PG&E") service territory.[1] CCA customers receive generation services from their local CCA and receive transmission, distribution, billing, and other services from their investor-owned utility ("IOU"). As such, CCA customers in PG&E's service territory pay the same electric distribution, transmission, and non-bypassable charges ("NBC") as PG&E's bundled customers, including the Power Charge Indifference Adjustment charge ("PCIA"). The PCIA charge—which recovers the cost of procurement on behalf of bundled customers and allocates to unbundled customers the above-market costs of resources procured on their behalf—is derived from the Electric Generation revenue requirement set in Phase I General Rate Cases ("GRC") such as this one, as well as from other generation cost recovery proceedings. This charge significantly impacts CCAs' competitive position as IOU-alternative generation providers.

[1] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

In this 2027 GRC, PG&E has proposed a substantial increase to the Electric Generation functional revenue requirement. The 2027 forecasted Electric Generation revenue requirement of $1,507 million[2] reflects a $283 million increase over the 2026 forecasted Electric Generation revenue requirement of $1,224 million[3]—a 23 percent increase in a single year. The 2027 forecasted Electric Generation revenue requirement reflects an even larger $352 million increase, or 30 percent, over the 2024 actual Electric Generation revenue requirement of $1,155 million.[4] This increase is primarily the result of PG&E's significant proposed investment in its hydro facilities in this case. PG&E is planning capital investment that will, in just six years' time, more than double the rate base associated with its hydro facilities, many of which have been in operation for up to and in some cases over 100 years. PG&E is also forecasting a 35 percent increase in operational expenses for its hydro facilities as compared to 2024 actuals, despite the fact that it has plans to retire or sell multiple facilities.

CalCCA recommends that the California Public Utilities Commission ("Commission") make the following adjustments to PG&E's request in this case:

- Remove thirteen hydro facilities that erroneously remain on PG&E's books and that are no longer used and useful in providing generation services for the benefit of customers from the Electric Generation revenue requirement, while recovering any remaining balance of the original investment through a regulatory asset, with no return on rate base;
- Move eight hydro facilities from the Legacy Utility-Owned Generation ("UOG") vintage to the 2027 vintage for purposes of PCIA cost recovery to reflect the fact

[2] Exh. PG&E-10, App. A, p. AppA-18 (Table 17) (Nov. 15, 2025).
[3] *Id*. at 1-1 (Table 1-1).
[4] Exh. PG&E-10 Workpapers at WP 14-51 Line 1, Columns (B) and (E).

that the substantial proposed investments in these assets of over $1.6 billion would result in a significant overhaul of these facilities, supporting life extensions as well as changed functions for these assets;

- Reduce the depreciation expense in the 2027-2030 forecasted revenue requirement for hydro facilities by $16 million annually to account for the actual book accumulated depreciation as reported by PG&E;
- Order PG&E to begin recording all elements of its hydro facilities' capital accounting at the hydro facility level, not just at the Federal Energy Regulatory Commission ("FERC") account level;
- Remove the Deferred Tax Asset ("DTA") associated with the Diablo Canyon Power Plant ("DCPP") from the Electric Generation revenue requirement since it was incorrectly accounted for and is not required to be included to avoid a potential normalization violation with the Internal Revenue Service ("IRS");
- Reclassify assets according to FERC Order 898 so that reclassification is reflected in the 2027–2030 GRC-approved revenue requirement, particularly since Order 898 required this to be complete by January 1, 2025;
- Reduce PG&E's Production Operations and Maintenance ("O&M") forecast by $34.8 million annually in 2027-2030 because (1) PG&E has not justified the need for its proposed substantial increase in hydro operators; and (2) PG&E has not forecasted any offsetting savings from its increased asset and risk management investments, despite recent experience demonstrating that substantial savings are possible;

- Reject PG&E's request to make a one-off change in allocation for the hydro license electric intangible assets without a comprehensive study of allocation changes for all Common, General, and Intangible ("CGI") assets;
- Require PG&E to cap its revenues associated with CCA/Direct Access ("DA") billing services at the cost included in its forecast for such services and refund any revenue received above that revenue cap to CCA/DA customers through the Energy Resource Recovery Account ("ERRA") proceeding; and
- Limit the use of the Hydro Licensing Balancing Account ("HLBA") to costs that are truly unpredictable, variable, and generally outside of the utility's control, therefore: (1) disallowing HLBA recovery of the Large Uncontrolled Water Release ("LGUWR"), Security, and Spillway categories of costs; and (2) limiting HLBA recovery of the License Conditions projects such that PG&E may only recover for facilities that have not yet received their FERC license at the time of filing a GRC.

The following table summarizes the estimated 2027 revenue requirement impact of CalCCA's recommendations.

Table RAM-1
2027 Electric Generation Revenue Requirement Impact of CalCCA's Recommendations

CalCCA Recommendation	CalCCA 2027 Electric Generation Recommended Revenue Requirement Change	Walk Forward of Electric Generation Revenue Requirement (in Millions)
PG&E's Requested Revenue Requirement	N/A	$1,507.2[5]
Remove Hydro Plants Recorded in Error and no Longer Used and Useful	($10.6 million)	$1,496.6
Reduce Depreciation Expense Associated with Hydro Units	($15.7 million)	$1,480.9
Remove DCPP DTA from Rates	($4.3 million)	$1,476.6
Implement FERC Order 898 Reclassifications	($18.8 million)	$1,457.8
Refrain from Additional One-Off CGI Allocation Changes	($36.0 million)	$1,421.8
Cap Billing Service Revenue Included in Expense Forecast	($2.5 million)	$1,419.3
Reduce Forecasted Production O&M Expenses	($34.8 million)	$1,384.5
Total Recommended Revenue Requirement		**$1,384.5 ($122.7 less than PG&E's $1,507.2 request)**

In addition to these adjustments to the overall Electric Generation revenue requirement, CalCCA's recommendations also result in PCIA vintaging adjustments of the Balch, DeSabla-Centerville, Drum-Spaulding, Helms, Kerckhoff 2, McCloud-Pit, Phoenix, and Upper North Fork Feather River hydro facilities. CalCCA's revintaging recommendations do not change the overall Electric Generation revenue requirement, but do impact the customer group—*i.e.*, bundled versus unbundled—from which portions of that revenue requirement are recovered via PG&E's ERRA proceedings. CalCCA recommends the revenue requirements for these eight hydro facilities be reassigned from the Legacy UOG vintage to the 2027 vintage for cost recovery purposes.

[5] Exh. PG&E-10, App. A, p. AppA-18 (Table 17) (Nov. 15, 2025).

The revintaging of these eight facilities will ensure that unbundled customers are not required to subsidize PG&E's proposed generation investments on behalf of its bundled customers. Absent this revintaging, unbundled customers would be unfairly saddled with between $81 million to $120 million of extra costs recovered via the Legacy UOG vintage over the course of the 2027-2030 time period governed by this GRC. That would result in departed load customers providing a significant subsidy to bundled customers, contrary to state law and the Commission's principle of bundled customer indifference.

Table RAM-2[6]
2026 Actual and 2027-2030 Forecast (With CalCCA's Proposed Revintaging) – PCIA Revenue Requirement Split Between Bundled and Unbundled Customers

($ million)	**2026 PCIA - Actual**	**2027 Forecast – With Revintaging**	**2028 Forecast – With Revintaging**	**2029 Forecast – With Revintaging**	**2030 Forecast – With Revintaging**
CCA/DA Revenue Requirement	$1,544.8	$1,463.8	$1,461.4	$1,441.3	$1,424.5
Bundled Customer Revenue Requirement	($243.5)	($162.7)	($160.3)	($140.2)	($123.5)
Total PCIA Revenue Requirement	$1,301.2	$1,301.2	$1,301.2	$1,301.2	$1,301.2
Change in CCA/DA Revenue Requirement from 2026 PCIA Actual	**N/A**	**($81.0)**	**($83.4)**	**($103.5)**	**($120.3)**

[6] These figures are calculated based on the current inputs and assumptions to the 2026 PCIA currently in effect. Some of these inputs will change through the course of the 2027–2030 implementation of the PCIA through the ERRA proceedings, but this analysis provides a snapshot at a point in time of the magnitude of the revintaging impact.

II. THIRTEEN HYDRO FACILITIES, POWERHOUSES AND ASSOCIATED ASSETS SHOULD BE REMOVED FROM PG&E'S REQUESTED REVENUE REQUIREMENT BECAUSE THEY NO LONGER BENEFIT CUSTOMERS

Through this GRC filing, PG&E continues to request cost recovery for four hydro facilities and associated assets that it has already retired or sold. In addition, there are nine other hydro facilities, powerhouses and associated assets which appear to no longer be operational and yet would still earn a return through PG&E's proposed revenue requirement, despite not being used and useful for customers.

Foundational regulatory accounting principles dictate that a generation asset generally should only remain on a utility's books if it is used and useful for the purposes of generating energy and providing capacity. That fundamental principle is also codified in the California Public Utilities Code:

> In establishing rates for any electrical . . . corporation, the commission may eliminate consideration of the value of any portion of any electric . . . generation or production facility which, after having been placed in service, remains out of service for nine or more consecutive months, and may disallow any expenses related to that facility. Upon eliminating consideration of any portion of a facility or disallowing any expenses related thereto under this section, the commission shall reduce the rates of the corporation accordingly . . . [7]

Based on the current operational condition of these thirteen hydro assets, the Commission should require PG&E to remove them from the revenue requirement in this case. The table below presents a summary of the units that should be removed because they are no longer used and useful.

[7] California Public Utilities Code § 455.5(a).

Table RAM-3
Hydro Powerhouses and Associated Assets Retired, Sold, or Otherwise Not Used and Useful

Hydro Facility	Powerhouse(s)	Capacity	2027 Revenue Requirement[8]	Status
Coal Canyon	Coal Canyon	N/A	$0.3 million	Operationally retired in 2023; plant erroneously left on books.
Lime Saddle	Lime Saddle	2.0 MW	$1.2 million	Operationally retired in 2023; plant erroneously left on books.
Kern Canyon	Kern Canyon	11.5 MW	$0.0 million	Plant sold; not all plant assets retired.
Chili Bar	Chili Bar	7.0 MW	$0.0 million	Plant sold; not all plant assets retired.
Kilarc-Cow Creek	Kilarc and Cow Creek	3.4 MW	($0.1) million	Operationally retired in 2024; asset retirement pending CAISO determination.
Kerckhoff 1	Kerckhoff 1	25.4 MW	$3.2 million	Last operated in 2017, mothballed[9] since 2018; not capable of generating electricity; retirement planned in 2028.
Potter Valley	Potter Valley	9.2 MW	$5.2 million	Last operated in 2021, mothballed since 2023; not capable of generating electricity; no plans to return to service; retirement planned in 2028.
Crane Valley	San Joaquin #1A, #2, and #3	7.4 MW	$7.2 million	#1A last operated in 2016; #2 last operated in 2023; #3 last operated in 2017; no firm plans to return any to service.

[8] *See* Attachment RAM-3. This represents the estimated amount of revenue requirement associated with each hydro powerhouse and associated assets that should be removed from the total GRC revenue requirement.

[9] *See* Attachment RAM-2 (PG&E's response to DR CalCCA 013-004) ("The term mothball is an official CAISO approved status for a generating unit and describes a unit that is no longer available to the grid, while keeping the unit and interconnection facilities in place until a final decision is made regarding the future of the unit (return to service, sale, or decommission)").

Table RAM-3
Hydro Powerhouses and Associated Assets Retired, Sold, or Otherwise Not Used and Useful

Hydro Facility	Powerhouse(s)	Capacity	2027 Revenue Requirement[8]	Status
DeSabla-Centerville	Centerville	6.4 MW	$1.0 million	Last operated in 2011, mothballed since 2021; not capable of generating electricity; active sale process ongoing.
Battle Creek	Inskip	8.0 MW	$1.9 million	Last operated in 2017; not capable of generating electricity; diversion dam removed.
Hamilton Branch	Hamilton Branch	4.8 MW	$0.6 million	Last operated in 2018; active sale process ongoing.
Total		**85.1 MW**	**$20.5 million**	

A. Four Hydro Facilities on PG&E's Books Have Been Retired or Sold

Four of the hydro facilities[10] listed in Table RAM-3 erroneously remain on PG&E's books despite having been either sold or retired. Specifically, the following facilities still appear in PG&E's calculations of its Electric Generation revenue requirement:

- Coal Canyon;
- Lime Saddle;
- Kern Canyon; and
- Chili Bar.

PG&E admitted in discovery that the Coal Canyon[11] and Lime Saddle[12] facilities remain in PG&E's accounting records in error. It has committed to correcting that error in an upcoming

[10] I will use the term "hydro facilities" to refer to the collection of dams, conveyances, powerhouses, turbines, and supporting equipment all contained under a single FERC license. It is the facilities within a FERC license to which PG&E applies the remaining life method in its depreciation study.
[11] Attachment RAM-2 (PG&E's response to DR CalCCA 002-007).
[12] Attachment RAM-2 (PG&E's response to DR CalCCA 002-006).

errata filing.[13] In addition, there is a small amount of net plant attributable to the Kern Canyon and Chili Bar hydro facilities that remains on PG&E's books.[14] The Kern Canyon facility was mothballed in 2017 and sold in 2020.[15] The Chili Bar facility was sold in 2021, and PG&E filed final accounting information from the sale with the Commission on September 20, 2023, which showed an adjustment to remove gross plant and accumulated depreciation from rate base.[16] PG&E has admitted in discovery that the net plant attributable to Kern Canyon and Chili Bar remains on its books erroneously and that it plans to update that in a future Results of Operations ("RO") model.[17]

B. Nine Hydro Powerhouses and Associated Assets on PG&E's Books Are No Longer Used and Useful

In addition to the accounting errors identified at the Coal Canyon, Chili Bar, Lime Saddle, and Kern Canyon facilities, there are nine other hydro powerhouses and associated assets that are non-operational,[18] per PG&E's own admissions, and that PG&E is either (1) planning to decommission, (2) actively in the process of selling, or (3) not actively planning to return to service. Table RAM-4 below summarizes the status of these hydro assets.

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[13] Attachment RAM-2 (PG&E's response to DR CalCCA 012-005) indicating the correction was not made in the Nov. 11, 2025, errata filing, but would be completed later in the GRC cycle.
[14] Attachment RAM-2 (PG&E's response to DR CalCCA 002-001) showing $6,898 of net plant attributable to Kern Canyon in FERC account 335 as of December 31, 2024.
[15] Exh. PG&E-5 Workpapers at WP 3-145.
[16] PG&E's Advice Letter 7031-E, filed September 20, 2023.
[17] Attachment RAM-2 (PG&E's response to DR CalCCA 010-007); Attachment RAM-2 (PG&E's response to DR CalCCA 010-012).
[18] For purposes of this testimony, I define "non-operational" as facilities that have not generated electricity in the past nine or more consecutive months. This standard is consistent with the standard laid out in California Public Utilities Code § 455.5(a).

Table RAM-4
Hydro Assets No Longer Used and Useful

Hydro Powerhouses and Associated Assets	Status
Kilarc and Cow Creek	No longer operational per PG&E's own admissions and its energy and capacity data;[19] decommissioning to begin during the 2027–2030 GRC period.
Kerckhoff 1	Last operated in 2017; decommissioning planned during the 2027–2030 GRC period.
Potter Valley	Has not operated since 2021; decommissioning planned in future.
San Joaquin #1A, San Joaquin #2, and San Joaquin #3 powerhouses, part of the Crane Valley FERC license	Have not operated since 2016 (#1A), 2023 (#2), and 2017 (#3); no firm plans to return to service.
Centerville powerhouse, part of the DeSabla-Centerville FERC license	Has not operated since 2011; active sale process ongoing.
Inskip powerhouse, part of the Battle Creek FERC license	Has not operated since 2017; decommissioning planned in future.
Hamilton Branch	Has not operated since 2018; active sale process ongoing.

Each of these assets is discussed in more detail in the subsections below. As these assets are no longer used and useful, they should be removed from PG&E's revenue requirement request in this case.

1. Kilarc-Cow Creek

The Kilarc-Cow Creek hydro project is a 5 megawatt ("MW") facility[20] consisting of the Kilarc powerhouse, originally constructed in 1903,[21] and the Cow Creek powerhouse, originally constructed in 1907.[22] Both units were retired by PG&E on October 17, 2024.[23] According to

[19] PG&E provided the annual energy generation from each of its hydro powerhouses over the 2022–2024 time period (*see* Attachment RAM-2 (PG&E's response to DR CalCCA 006-001, Attach. 1)), as well as the monthly peak capacity contribution of each powerhouse over the 2016–2025 time period (*see* Attachment RAM-2 (PG&E's response to DR CalCCA 009-006, Attach. 1)).
[20] Exh. PG&E-5 Workpapers at WP 3-299.
[21] *Id*. at WP 3-131 line 18.
[22] *Id*. at WP 3-131 line 19.
[23] *Id*. at WP 3-131 lines 18-19.

PG&E, it has not removed these units from its plant accounts because it has not yet received the California Independent System Operator's ("CAISO") approval to permanently remove these generation units from service.[24] PG&E has indicated that only after it receives that approval will it retire those units from its financial accounting. Until that time, PG&E plans to allow Kilarc-Cow Creek to remain in the 2027–2030 revenue requirement.

This proposed approach to regulatory accounting is unreasonable and inconsistent with the overwhelming factual evidence confirming that this asset is functionally retired. Kilarc powerhouse last generated electricity in May 2019 due to damage to the conveyance/canal and has been officially mothballed with CAISO since June 30, 2021.[25] Cow Creek powerhouse last generated electricity in March 2023 due to storm damage to the headgate.[26] According to PG&E, both units would require significant investment to return to service, and the associated work would take months to complete and would not be cost-effective to perform.[27]

In addition to the operational evidence suggesting that Kilarc-Cow Creek is functionally retired, PG&E has also taken substantial regulatory steps to effectuate the retirement. PG&E filed its FERC license surrender application for Project No. 606 on May 12, 2009.[28] The surrender order was issued on October 17, 2024, the same date that PG&E indicated it officially retired the units. Therefore, PG&E has been actively working toward retiring these units for the past 16 years. With respect to CAISO approval, the timing of the request to CAISO to permanently retire the units is fully within PG&E's control. As of November 13, 2025, PG&E forecasted submitting that retirement request in November 2025 with a requested effective date of December 31, 2025.[29]

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[24] Attachment RAM-2 (PG&E's response to DR CalCCA 002-005).
[25] Attachment RAM-2 (PG&E's response to DR CalCCA 005-001).
[26] *Id.*
[27] *Id.*
[28] Exh. PG&E-5 Workpapers at WP 3-146.
[29] Attachment RAM-2 (PG&E's response to DR CalCCA 005-001).

In light of all this operational and regulatory evidence, it is clear that Kilarc-Cow Creek is no longer used and useful. To argue against the obvious conclusion that Kilarc-Cow Creek should be removed from the 2027 GRC revenue requirement, PG&E points to one fact: that CAISO has not yet approved the asset's permanent retirement. This one fact should not outweigh all the others demonstrating the status of the asset, especially given that the timing of making this request to the CAISO is fully within PG&E's control.

As of the end of 2026, PG&E will have collected a return on the Kilarc and Cow Creek invested value *for seven years and three years, respectively, since each powerhouse last operated*. PG&E plans to extend that return *for another four years* through this GRC cycle.[30] This proposal is unreasonable because it would result in PG&E collecting a return on the Kilarc and Cow Creek powerhouses for an eleven-year period and a seven-year period, respectively, during which time the assets will not be used and useful.

2. Kerckhoff 1

The Kerckhoff hydro facilities consist of two powerhouses: Kerckhoff 1 and 2. Kerckhoff 1 is a 25.4 MW powerhouse with two turbine units (Unit 1 and Unit 3) that began operations in 1920.[31] Kerckhoff 2 is a 155.0 MW powerhouse with one turbine unit that began operations in 1983.[32] Both powerhouses are licensed by FERC under a single license, Project No. 96, which was granted on November 8, 1976.[33] PG&E applied for a Final License Application to extend the FERC license for the Kerckhoff 2 unit in November 2020, and as part of that application, it filed

[30] *See* Attachment RAM-2 (PG&E's response to DR CalCCA 002-005).
[31] Exh. PG&E-5 Workpapers at WP 3-133 line 82.
[32] *Id*. at WP 3-133 line 83.
[33] *Id*. at WP 3-146.

a Proposed Retirement Plan for the Kerckhoff 1 unit.[34] PG&E currently anticipates receiving an order on this FERC application in December 2026.[35]

Units 1 and 3 at the Kerckhoff 1 powerhouse last operated in 2017[36] and were mothballed in September 2018.[37] The Kerckhoff 1 unit last contributed capacity during the peak hour on PG&E's system on June 22, 2017.[38] The Kerckhoff 1 powerhouse is physically incapable of generating electricity due to several inoperable components that are uneconomic to restore, and PG&E has no plans to return it to service.[39]

Despite the fact that the Kerckhoff 1 powerhouse has not operated since 2017, as of the end of 2026, PG&E will have collected a return on its invested value *for nine years since the asset last operated*. PG&E plans to extend that return *for another four years* through this GRC cycle. This proposal is unreasonable because it would result in PG&E collecting a return on the Kerckhoff 1 asset for a 13-year period, during which time the asset will not be used and useful.

3. Potter Valley

Potter Valley is a three-unit powerhouse with a total capacity of 9.2 MW that began operations in 1908.[40] PG&E determined that the project was no longer economically viable to operate in 2019 and began the formal license surrender process with FERC at that time.[41] The FERC license for the facility, Project No. 77, expired on April 4, 2022,[42] and PG&E has been operating under annual FERC license extensions since then.[43] PG&E estimates that FERC may

[34] Attachment RAM-2 (PG&E's response to DR CalCCA 013-004).
[35] Exh. PG&E-5 Workpapers at WP 3-146.
[36] Attachment RAM-2 (PG&E's response to DR CalCCA 013-004).
[37] Exh. PG&E-5 Workpapers at WP 3-145.
[38] Attachment RAM-2 (PG&E's response to DR CalCCA 009-006, Attach. 1).
[39] Attachment RAM-2 (PG&E's response to DR CalCCA 013-004).
[40] Exh. PG&E-5 Workpapers at WP 3-132 line 4.
[41] *Id*. at WP 3-374.
[42] *Id*. at WP 3-146.
[43] *Id*. at WP 3-374.

issue a license surrender order in 2028.[44] However, PG&E has no plans to remove the Potter Valley revenue requirement from the Electric Generation revenue requirement calculated for the 2027-2030 GRC period.[45]

Potter Valley powerhouse is no longer operational. It has been out of service since July 2021, when its GSU[46] transformer failed to pass inspection testing,[47] and it last contributed capacity toward PG&E's monthly peak demand on April 29, 2021.[48] The Potter Valley powerhouse does not have the physical capacity to generate electricity and PG&E has no plans to return it to service.[49]

As of the end of 2026, PG&E will have collected a return on Potter Valley's invested value *for five years since it last operated*. PG&E plans to extend that return *for another four years* through this GRC cycle. This proposal is unreasonable because it would result in PG&E collecting a return on the Potter Valley asset for a nine-year period during which time the asset will not be used and useful (and for approximately two years after the asset's expected license surrender).

4. San Joaquin #1A, San Joaquin #2, and San Joaquin #3 Powerhouses

San Joaquin #1A is a 0.4 MW single turbine unit powerhouse that was placed into service in 1919.[50] San Joaquin #2 is a 3.2 MW single turbine unit powerhouse that was placed into service in 1917.[51] San Joaquin #3 is a 4.2 MW single turbine unit powerhouse that was placed into service in 1923.[52] The three powerhouses are operating under one FERC license, Project No. 1354, which

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[44] Attachment RAM-2 (PG&E's response to DR CalCCA 010-008).
[45] *Id.*
[46] This is likely an acronym for Generation Step-Up transformer, but it was not spelled out in PG&E's response to DR CalCCA 013-005.
[47] Attachment RAM-2 (PG&E's response to DR CalCCA 013-005).
[48] Attachment RAM-2 (PG&E's response to DR CalCCA 009-006, Attach. 1).
[49] Attachment RAM-2 (PG&E's response to DR CalCCA 013-005).
[50] Exh. PG&E-5 Workpapers at WP 3-133 line 80.
[51] *Id*. at WP 3-133 line 79.
[52] *Id*. at WP 3-133 line 78.

also includes the Crane Valley and A.G Wishon powerhouses. This license was received on September 16, 2003, and is set to expire on August 31, 2043.[53]

The San Joaquin #1A, San Joaquin #2, and San Joaquin #3 powerhouses are no longer operational. The San Joaquin #1A powerhouse last operated in December 2016, the San Joaquin #2 powerhouse last operated in February 2023, and the San Joaquin #3 powerhouse last operated in February 2017.[54] The San Joaquin #2 powerhouse last contributed to PG&E's monthly peak demand on December 15, 2022, while the San Joaquin #3 powerhouse last contributed to PG&E's monthly peak demand sometime prior to January 2016.[55] The San Joaquin #1A powerhouse shares a meter with the A.G. Wishon unit, and as such its peak contribution cannot be separately determined.[56]

PG&E could restore the San Joaquin #1A powerhouse to service if economics or operational needs change,[57] but it has not stated any plans to do so. PG&E is planning to return the San Joaquin #2 powerhouse to service, but that return to service is pending budget allocation to repair the culvert failure that resulted in the forced outage of the unit.[58] PG&E has not clearly shown in its list of forecasted capital projects that it has allocated that budget in the 2027-2030 forecast. Finally, the San Joaquin #3 powerhouse ceased operation due to dam integrity issues and was placed in mothball status with the CAISO on July 30, 2021.[59] In order to return the powerhouse to service, PG&E would need to complete a dam assessment and evaluate whether the dam repairs plus needed replacements of several powerhouse components would be economic

[53] *Id*. at WP 3-146.
[54] Attachment RAM-2 (PG&E's response to DR CalCCA 013-006).
[55] Attachment RAM-2 (PG&E's response to DR CalCCA 009-006, Attach. 1).
[56] Attachment RAM-2 (PG&E's response to DR CalCCA Oral001-001).
[57] Attachment RAM-2 (PG&E's response to DR CalCCA 013-006).
[58] *Id.*
[59] *Id.*

to complete. It has not provided a timeline for that evaluation nor firm plans to complete that evaluation.[60]

As of the end of 2026, PG&E will have collected a return on the San Joaquin #1A powerhouse for *ten years*, on the San Joaquin #2 powerhouse for *three years*, and on the San Joaquin #3 powerhouse for *nine years* since these powerhouses last operated. PG&E plans to extend that return for *another four years* through this GRC cycle.[61] This proposal is unreasonable because it would result in PG&E collecting a return on the San Joaquin #1A, #2, and #3 powerhouses for periods of fourteen, six, and thirteen years, respectively, during which periods the assets will not be used and useful.

5. Centerville

Centerville is a 6.4 MW two-unit powerhouse that was placed into service in 1900.[62] The powerhouse is operating under a FERC license, Project No. 803, which also includes the DeSabla and Toadtown powerhouses. This license expired in 2009, and PG&E has been operating on an annual license extension since that time.[63] PG&E has been in the relicensing process with FERC since prior to the license's expiration in 2009 and currently expects to receive relicensing approval in June 2028.[64]

The Centerville powerhouse is not operational. It has been out of service since February 2011 due to penstock integrity issues[65] and was placed in mothball status with the CAISO in June 2021.[66] The Centerville powerhouse is not physically capable of generating electricity, and PG&E

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[60] *Id*.
[61] Exh. PG&E-10 Workpapers at WP 9-36.
[62] Exh. PG&E-5 Workpapers at WP 3-131 line 26.
[63] *Id*. at WP 3-215.
[64] *Id*. at WP 3-146.
[65] Attachment RAM-2 (PG&E's response to DR CalCCA 013-007).
[66] Attachment RAM-2 (PG&E's response to DR CalCCA Oral001-001).

has no stated plans to return it to service.[67] Instead, PG&E is actively working to sell the DeSabla-Centerville project.[68] In addition, PG&E intends to surrender the FERC license for the DeSabla-Centerville project (presumably if it is unsuccessful in selling the project).[69]

As of the end of 2026, PG&E will have collected a return on the Centerville powerhouse *for 15 years since it last operated*. PG&E plans to extend that return *for another four years* through this GRC cycle. This proposal is unreasonable because it would result in PG&E collecting a return on the Centerville powerhouse for a 19-year period during which time the asset will not be used and useful.

6. Inskip

Inskip is an 8.0 MW one-unit powerhouse that was placed into service in 1979.[70] The powerhouse is operating under a FERC license, Project No. 1121, which also includes the Volta #1, Volta #2, South, and Coleman powerhouses. This license expires July 31, 2026, and PG&E informed FERC of its decision to not relicense the project in October 2020.[71] PG&E plans to file its License Surrender Application and Decommissioning Plan for FERC Project No. 1121 in May 2028.[72]

PG&E has separately filed a license amendment application for Inskip Removal.[73] That application, filed on October 22, 2022, requested permission to remove the Inskip Diversion Dam

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67 Attachment RAM-2 (PG&E's response to DR CalCCA 013-007).
68 *Id.*
69 Attachment RAM-2 (PG&E's response to DR CalCCA 013-008).
70 Exh. PG&E-5 Workpapers at WP 3-131 line 16.
71 *Id*. at WP 3-146.
72 Attachment RAM-2 (PG&E's response to DR CalCCA 010-019).
73 Exh. PG&E-5 Workpapers at WP 3-181.

due to significant safety concerns, and was approved by FERC on March 3, 2025.[74] The diversion dam has subsequently been removed by PG&E.[75]

The Inskip powerhouse is not operational. It has been out of service since October 2017 due to significant sand and erosion damage sustained as a result of a wildfire,[76] and it last contributed to PG&E's monthly peak demand on September 2, 2017.[77] PG&E determined that, as a result of this damage, it was not economic to return Inskip powerhouse to service.[78] The powerhouse has been in mothball status with CAISO since June 30, 2021, and it is not physically capable of generating electricity if called upon by PG&E.[79]

As of the end of 2026, PG&E will have collected a return on the Inskip powerhouse *for nine years since it last operated*. PG&E plans to extend that return *for another four years* through this GRC cycle. This proposal is unreasonable because it would result in PG&E collecting a return on the Inskip powerhouse for a 13-year period during which time the asset will not be used and useful.

7. Hamilton Branch

Hamilton Branch is a 4.8 MW two-unit powerhouse that was placed into service in 1921.[80] The powerhouse is not FERC jurisdictional and therefore does not have a FERC license.

The Hamilton Branch facility is not operational. It has been out of service since June 2018 as a result of dam integrity issues; has been in mothball status with CAISO since July 30, 2021;

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[74] Attachment RAM-2 (PG&E's response to DR CalCCA 013-010, Attach. 1).
[75] Attachment RAM-2 (PG&E's response to DR CalCCA 013-010).
[76] Attachment RAM-2 (PG&E's response to DR CalCCA 013-002).
[77] Attachment RAM-2 (PG&E's response to DR CalCCA 009-006, Attach. 1).
[78] Attachment RAM-2 (PG&E's response to DR CalCCA 013-002).
[79] *Id*.
[80] Exh. PG&E-5 Workpapers at WP 3-131 line 29.

and is currently not capable of generating electricity if called upon by PG&E.[81] The Hamilton Branch facility last contributed to PG&E's monthly peak hour on May 29, 2018.[82]

The facility is currently the subject of an active sale process, and the buyer plans to restore the facility to service after acquisition.[83] As a result, Hamilton Branch's planned depreciation end of life is 2029. However, PG&E has no plans to remove the Hamilton Branch revenue requirement from the Electric Generation revenue requirement calculated for the 2027-2030 GRC period.[84]

As of the end of 2026, PG&E will have collected a return on Hamilton Branch *for eight years since the facility last operated*. PG&E plans to extend that return *for another four years* through this GRC cycle. This proposal is unreasonable because it would result in PG&E collecting a return on the Hamilton Branch asset for a 12-year period during which time the facility will not be used and useful.

C. Recommendation

PG&E should remove all remaining plant assets associated with the Chili Bar, Kern Canyon, Coal Canyon, and Lime Saddle hydro facilities from its books and records. PG&E should also remove the revenue requirement associated with the Kilarc-Cow Creek, Kerckhoff 1, Potter Valley, San Joaquin #1A, San Joaquin #2, San Joaquin #3, Centerville, Inskip, and Hamilton Branch powerhouses from its Electric Generation revenue requirement in this case. Any remaining Net Book Value ("NBV") for these thirteen assets as of the end of 2026 should be placed in a regulatory asset with no return to be recovered through this GRC over a four-year period. CalCCA estimates the Electric Generation revenue requirement impact of this recommendation for all thirteen assets in the table below:

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[81] Attachment RAM-2 (PG&E's response to DR CalCCA 013-009).
[82] Attachment RAM-2 (PG&E's response to DR CalCCA 009-006, Attach. 1).
[83] Attachment RAM-2 (PG&E's response to DR CalCCA 009-009).
[84] Attachment RAM-2 (PG&E's response to DR CalCCA 010-011).

Table RAM-5
Revenue Requirement Impact of Accounting Changes to Accurately Reflect Hydro Asset Status[85]

	2027	2028	2029	2030
Revenue Requirement Adjustment	($20.5 million)	($20.4 million)	($20.5 million)	($22.0 million)
Amortization of 2026 EOY NBV[86]	$9.9 million	$9.9 million	$9.9 million	$9.9 million
Net Change to Electric Generation Revenue Requirement	($10.6 million)	($10.5 million)	($10.6 million)	($12.1 million)

III. PG&E SHOULD REVINTAGE EIGHT HYDRO FACILITIES TO ENSURE PROPER COST ALLOCATION ACROSS BUNDLED AND UNBUNDLED CUSTOMERS

In this case, PG&E is proposing to invest over $1.6 billion[87] in eight of its hydro facilities to keep these assets in service beyond their originally anticipated lifespans and to continue the ongoing project of adapting these assets to serve new functions to accommodate PG&E's bundled customers' evolving electricity needs.

The Commission has indicated in past decisions that certain new, significant investments in UOG assets should trigger reconsideration of the default assignment of the asset's revenue requirement to the asset's original PCIA vintage.[88] This reconsideration of an asset's PCIA vintage assignment is to be considered on a case-by-case basis, based on a fact-specific analysis of whether the investment causes one of the following triggering events to occur:[89]

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[85] *See* Attachment RAM-3 for more detailed calculations.
[86] 2026 EOY NBV estimated at $45.2 million.
[87] *See* Attachment RAM-5, which also shows total hydro capital investment from 2027–2030 of over $2.1 billion when including investment proposed and approved in the Helms Uprate proceeding, and 2025–2030 forecasted hydro investment of over $2.6 billion when including the Helms Uprate proceeding capital.
[88] D.18-10-019, p. 135.
[89] D.23-11-069, p. 511; D.18-10-019, p. 135.

- An extension in the asset's useful life (*i.e.*, the original investment in the asset is fully depreciated, and the investment is used to extend the asset's lifespan);
- A capacity expansion of the asset;
- A change in the function of the asset; and/or
- A large investment in the asset that leads to a "significant overhaul" of the facility.

Despite PG&E's assertion in testimony that none of its proposed investments in its PCIA-eligible generation assets will result in an asset life extension, a capacity addition, or a change in function,[90] PG&E's proposed investments in eight of these facilities implicate several of the Commission's revintaging triggers.

PG&E bears responsibility for providing capacity and generation service to its bundled customers, while CCAs bear responsibility for providing capacity and generation service to their customers who have elected to leave PG&E's generation service. Therefore, by definition, when PG&E decides to invest in an existing asset today to extend the life of the asset so that the facility may continue to contribute to PG&E's resource adequacy obligations and to serve its customers' generation needs, it is making this decision on behalf of its bundled customers. Because PG&E is making these new investments to serve its current bundled customer set, these eight assets should be revintaged from the Legacy UOG vintage[91] to the 2027 vintage. This will ensure that bundled customers remain responsible for new generation investments made on their behalf, and that costs are not unfairly shifted to departed load customers.

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[90] Exh. PG&E-5 at 7-21 (Table 7-5).
[91] With the exception of select customers that are exempt from PG&E's PCIA surcharge.

A. The Commission's Foundational PCIA Principles Should Inform Cost Responsibility for PG&E's Proposed UOG Investments in This Case

The Commission has set forth clear directives regarding departing load cost responsibility. In Decision ("D.") 08-09-012, the Commission found that "[t]he law permits the recovery of stranded costs from those customers who are responsible for stranded costs related to resource and contractual commitments made by the IOU *up until the time of the customer's departure*[,]" but that "departing customers should bear no cost responsibility for such commitments the IOU makes after their departure."[92] This directive helps ensure that each customer will "pay its fair share of the costs the IOU incurred on [its] behalf[,]" which "is an integral part of the principles of bundled customer indifference and prevention of cost-shifting."[93]

Based on these underlying principles, the Commission relies on the PCIA mechanism to recover the cost of procurement on behalf of bundled customers and allocate to unbundled customers the above-market costs of resources procured on their behalf. The above-market costs associated with each of PG&E's generation resources are recovered from different subsets of customers via the PCIA charge depending on when PG&E made the commitment to invest in that resource and whether a customer was receiving bundled service from PG&E at that time. The process of assigning resources and customers to particular cost recovery tranches is called PCIA "vintaging."

A distinct portfolio of generation resources is identified for each vintage year based on the year in which the generation resource commitment was made. The Commission's current approach to determining the year in which the generation resource commitment was made is set forth in PG&E Electric Preliminary Statement HS—for UOG resources, it is the year that the resource

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[92] D.08-09-012, p. 59 (emphasis added).
[93] *Id*., Finding of Fact 2.

commitment was made, which is historically the date of Commission approval of UOG construction.[94] Unbundled customers are assigned to a vintage year corresponding to their departure date and are responsible for their share of above-market costs associated with generation resource commitments made through the end of their assigned vintage year.[95] Current bundled customers are effectively assigned to the most recent PCIA vintage and are responsible for their share of all PCIA-eligible resources.

PCIA rates are derived from the utility's Indifference Adjustment, which is updated annually in each IOU's ERRA forecast proceeding. The Indifference Adjustment is the difference in the target year between the cost of the IOU's supply portfolio and the market value of the IOU's supply portfolio, as shown in the graphic below.

Figure RAM-1: Indifference Adjustment Calculation

Total Portfolio Cost includes variable power supply costs, which are determined in the IOU's annual ERRA forecast proceedings,[96] *plus* the UOG capital investment recovery and fixed maintenance costs determined in GRCs and other generation cost recovery proceedings.[97]

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[94] PG&E Preliminary Statement HS, Sheet 1, *available at* https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_HS.pdf.
[95] D.08-09-012, Finding of Fact 38 and Conclusion of Law 14.
[96] Variable power supply costs include purchased power such as that from power purchase agreements ("PPAs"), fuel costs for UOG and PPAs with tolling agreements, and CAISO grid charges and revenues, net of any sales.
[97] D.11-12-018, pp. 8–9.

An Indifference Adjustment is calculated for each vintage, and customers are responsible for the cumulative costs included in all vintages prior to and including their assigned vintage year.[98] The total Indifference Adjustment is collected through PCIA rates, ensuring that PG&E receives full recovery of the generation-related revenue requirement approved by the Commission in the GRC and any other proceedings.[99] As significant new investments in PG&E's UOG may be approved in this proceeding, it is critical that any such investments be properly and equitably assigned to a vintage year that accurately reflects customer cost responsibility.

B. The Commission's Evolving Precedent on the Vintaging of Utility Reinvestments in UOG Should Inform Cost Responsibility for These New UOG Investments

Currently, PG&E has a general practice of assigning each PCIA-eligible UOG resource to a specific PCIA vintage based on the year in which the generation resource commitment was originally made (*i.e.*, Commission approval of UOG construction) and assigning *all* future costs at that facility, even new investments to serve current bundled customers, to the same initial vintage.[100] This approach requires unbundled customers to continue to pay costs associated with significant changes to, and new investments in, UOG resources made after those unbundled customers have departed—*i.e.*, investment decisions that were not made on departed customers' behalf. This vintaging practice contravenes the indifference principle and the statutory prohibition on cost shifting because it requires unbundled customers to continue to bear costs that PG&E

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[98] *Id.*, p. 9.

[99] Prior to D.18-10-019, the PCIA rate was set only on a forecast basis with no after-the-fact true-up for unbundled customers. D.18-10-019 approved a true-up for the PCIA using actual recorded net costs for PCIA-eligible resources and billed revenues from both bundled and unbundled customers. This true-up now occurs via the PABA, a rolling true-up between the forecasted Indifference Adjustment and the actual costs and revenues that PG&E realizes during the year related to its PCIA eligible resource portfolio.

[100] PG&E Electric Preliminary Statement Part HS, Sheet 1, *available at* https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_HS.pdf.

incurred solely to serve its bundled customers. Unbundled customers are thus not at all "indifferent." They are instead subsidizing bundled customers' generation costs.

Under this default approach, PG&E can, for example, extend the life of a generation resource beyond the original expected life—either through life-extending capital investment or via an administrative process (*e.g.*, an updated depreciation study)—but continue to assign that resource to its original PCIA vintage for cost recovery purposes. As there is no limitation on the number of years that a PCIA vintage may be applied to an unbundled customer or any end date associated with initial vintage assignments, departed customers could be required to continue to compensate PG&E for generation costs long after the original anticipated life of the resource procured on their behalf.

The Commission's stance on the treatment of ongoing generation-related costs has been evolving in response to concerns raised by CCAs in various proceedings. In D.18-10-019, the Commission recognized CCAs' concerns regarding ongoing costs of UOG and the need to develop a framework to ensure that such costs are equitably allocated. Specifically, the Commission found that "[i]t is possible that new investments in an old power plant may represent such a significant overhaul of the facility as to justify a 're vintaging' of the facility. Likewise, it is possible that plant investments for certain upgrades may justify a different vintage treatment for those investments than for the underlying facility."[101] The Commission concluded that "any such analysis must be fact-specific to the plants and spending in question and is better suited to a GRC evaluating such spending."[102]

In response to this directive, the CCAs took this concern to utility GRCs. In the final decision issued in PG&E's most recent GRC, D.23-11-069, the Commission again recognized the

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[101] D.18-10-019, p. 135.
[102] *Id*.

need to ensure that new investments in UOG are properly categorized for PCIA vintaging and cost recovery. To ensure that these issues can be analyzed in future GRCs, the Commission directed PG&E:

> …to include in its future GRC filings its position and any supporting evidence concerning (1) the details of any PG&E proposal for new asset life extensions, incremental capacity additions, or changed functions for any of its UOG assets and why it is undertaking these changes, (2) on whose behalf it is making these new investments, and (3) the appropriate vintaging treatment for each asset in light of this testimony along with any future GRC proposals.[103]

The Commission has therefore implicitly acknowledged that these are the critical details for any revintaging analysis triggered by new investments in UOG. These types of major proposed changes to UOG—asset life extensions, incremental capacity additions, or changed functions—should be treated as new resource "commitments" that trigger an evaluation of the asset's vintage assignment and whether full or partial asset revintaging is appropriate. In contrast, routine, expected, or preventative maintenance types of operating and capital costs at a UOG resource should by default remain tied to the initial vintage, as such costs were expected at the time that the utility made the original generation resource commitment. This direction from the Commission in D.23-11-069 also confirms that the key question for determining cost responsibility is the question of cost causation—*i.e.*, on whose behalf is PG&E making this new investment?

C. PG&E Proposes to Extend the Asset Life of Eight Hydro Facilities Due to FERC Relicensing in This Proceeding

The Commission has indicated that an asset life extension is one of the triggering events that necessitate a review of the original vintage assignment of the asset.[104] While to date the Commission has not defined in detail what factual circumstances constitute a "life extension" for the purposes of revintaging, CalCCA submits that the following factors are highly relevant to and

[103] D.23-11-069, p. 511.
[104] *See id*.

indicative of UOG asset life extensions: (1) FERC license expiration and relicensing; (2) asset life extensions as reflected in PG&E's depreciation studies; and (3) full depreciation of the original cost of the asset.

1. FERC License Expiration and Relicensing

A decision by PG&E to pursue a FERC relicensing following the expiration of an operating license in order to keep the facility in service represents a new commitment by PG&E to extend the service life of the facility. Relicensing often extends the license term by between 40 and 50 years. Generally, there is a significant financial investment associated with this decision to meet new license conditions and to prepare these facilities for additional decades of service; for example, PG&E has invested between $150 million and $350 million during the ongoing relicensing process for three large hydro facilities.[105] Importantly, these decisions to relicense are not compulsory—PG&E has full discretion over whether it decides to retire, sell, or relicense its facilities at the license expiration date.

The following table shows the FERC license expiration dates as well as the expected dates of relicensing orders for the eight facilities for which PG&E is currently pursuing relicensing.[106]

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[105] The Upper North Fork Feather River, McCloud-Pit, and Drum-Spaulding hydro facilities had their FERC licenses expire in 2004, 2011, and 2013, respectively, and have been in the relicensing process since then (Exh. PG&E-5 Workpapers at WP 3-146). Those plants have received significant capital investment since their license expiration, with Upper North Fork Feather River receiving $350 million in plant additions from 2005–2023, McCloud-Pit receiving $148 million in plant additions from 2012–2023, and Drum-Spaulding receiving $231 million in plant additions from 2014–2023 (Attachment RAM-7).

[106] Exh. PG&E-5 Workpapers at WP 3-146.

Table RAM-6
FERC License Expiration for Facilities Undergoing Relicensing

FERC License	Project Name	License Expiration Date	Application Filing Deadline/Date Filed	Estimated Order Issuance
1061	Phoenix	8/31/2022	8/31/2020	Jun. 2025
2105	Upper NF Feather River	10/31/2004	10/31/2002	Nov. 2025
96	Kerckhoff #1 and #2	11/30/2022	11/30/2020	Dec. 2026
2310 (Upper Drum)/ 14531 (Lower Drum)[107]	Drum-Spaulding	4/30/2013	4/30/2011	May 2027
803	DeSabla-Centerville	10/11/2009	10/11/2007	Jun. 2028
2106	McCloud-Pit	7/31/2011	7/31/2009	Dec. 2026
175	Balch #1 and #2	4/30/2026	4/18/2024	Apr. 2029
2735	Helms	4/30/2026	4/19/2024	Apr. 2029

2. Asset Life Extensions via PG&E's Depreciation Study

Another indicator of an asset life extension is a regulatory accounting decision by PG&E to update its depreciation study to reflect a new expected end of life date for the asset. Generally, a decision by PG&E to pursue relicensing for a hydro facility is the main driver in its decision to extend the facility's accounting end-of-life.

The following table shows the probable retirement dates for each hydro facility going back to the 2014 GRC.[108] In the current GRC, the probable retirement dates for 15 hydro facilities have been extended.

[107] PG&E has proposed the split the license for Drum-Spaulding into multiple licenses.
[108] Attachment RAM-2 (PG&E's response to DR CalCCA 002-002).

Table RAM-7
Hydro Facility Probable Retirement Date, 2014–2027 GRCs

Retirement Date	2014 GRC	2017 GRC	2020 GRC	2023 GRC	2027 GRC
Upper NF Feather River	2047	2055	2055	2061	2075
Kilarc-Cow Creek	2014	2020	2020	2021	2024
DeSabla-Centerville	2047	2029	2029	2022	2038
McCloud-Pit	2048	2055	2055	2061	2075
Drum-Spaulding	2051	2057	2057	2063	2077
Potter Valley	2022	2030	2030	2026	2028
Phoenix	2022	2030	2030	2022	2064
Kerckhoff 1	2022	2057	2057	2027	2028
Kerckhoff 2	2022	2057	2057	2065	2076
Battle Creek	2026	2026	2026	2026	2037
Balch	2026	2026	2026	2069	2079
Helms	2026	2026	2026	2069	2079
Mokelumne	2031	2031	2031	2031	2031
Hat Creek 1 and 2	2032	2032	2032	2032	2032
Rock Creek	2031	2031	2031	2031	2034
Haas-Kings River	2041	2041	2041	2041	2041
Pit 1	2042	2042	2042	2042	2042
Pit 3, 4, 5	2043	2043	2043	2043	2043
Crane Valley	2043	2043	2043	2035	2043
Spring Gap-Stanislaus	2047	2047	2047	2047	2047
Poe	2047	2053	2053	2068	2068
Bucks Creek	2018	2055	2056	2062	2072

The eight highlighted facilities in the table are currently undergoing relicensing and generally show the largest changes in retirement dates across the past four GRCs. But other facilities have also seen changes proposed to their retirement dates in the current GRC outside of the relicensing process, as PG&E adjusts to other operating or regulatory changes.

3. Depreciation of Original Cost of Asset

Finally, if an asset has achieved full depreciation, this is another indicator that PG&E has recovered its original investment in the asset—*i.e.*, its original generation commitment—and that any further significant investment in the asset represents a new investment distinct from PG&E's original commitment.

The following table shows the original cost, book reserve, and NBV by hydro facility at the end of 2024.[109]

Table RAM-8
Hydro Facility NBV, EOY 2024

($ millions) Hydro Facility	Original Cost	Book Reserve	NBV
Drum-Spaulding	$596	$150	$446
Upper NF Feather River	$526	$154	$373
Pit 3, 4, 5	$458	$198	$260
Helms	$1,060	$870	$190
Miscellaneous Hydro	$236	$57	$179
McCloud-Pit	$244	$95	$149
Mokelumne	$329	$202	$127
Rock Creek	$298	$180	$118
Kerckhoff 2	$196	$87	$109
Poe	$149	$44	$105
Spring Gap-Stanislaus	$141	$50	$91
Crane Valley	$203	$113	$90
Bucks Creek	$113	$24	$89
Haas-Kings River	$142	$63	$80
Pit 1	$108	$39	$69
Balch	$78	$26	$52
Battle Creek	$119	$102	$17
Potter Valley	$66	$56	$10
Hat Creek 1 and 2	$23	$14	$9
Kerckhoff 1	$22	$16	$6
Hamilton Branch	$8	$7	$1
Lime Saddle	$16	$15	$0
Chili Bar	$0	($0)	$0
Kern Canyon	$0	$0	$0
Coal Canyon	$6	$6	($0)
Kilarc-Cow Creek	$8	$9	($1)
Phoenix	$28	$30	($2)
DeSabla-Centerville	$91	$97	($6)
Total	**$5,266**	**$2,704**	**$2,563**

[109] Attachment RAM-2 (PG&E's response to DR CalCCA 002-001, Attach. 1). PG&E indicated on January 16, 2026 it planned to provide a revised version of Attachment 1 to PG&E's response to DR CalCCA 002-001, but as of the filing of this testimony PG&E has not provided that revision.

The NBV shown in the above table is indicative of how much each facility's total investment is fully depreciated on a relative basis. It is more challenging to draw conclusions for each facility on an absolute basis due to PG&E's process for reallocating book reserves in each GRC, which will be discussed in more depth in Section IV. Two of the eight facilities currently undergoing relicensing and life extensions (highlighted in the above table), Phoenix and DeSabla-Centerville, have a NBV less than zero as of the end of 2024 which indicates the original investment is fully depreciated. The remaining six (Drum-Spaulding, Upper NF Feather River, Helms, McCloud-Pit, Kerckhoff 2, and Balch) have NBVs as of the end of 2024 ranging from $52 million to $446 million. That these facilities do not appear to be fully depreciated despite operating past their initial FERC license period (and therefore initial depreciation lifetime) is a function of PG&E's accumulated depreciation allocation process[110] and does not represent the cumulative depreciation expense paid by existing customers. It is also a result of capital investment incurred after the initial FERC license has expired,[111] which is investment related to extending the life of the facility.

In sum, for eight of PG&E's hydro facilities, PG&E is (1) pursuing FERC relicensing, (2) changing the probable retirement date for the asset in its depreciation study, and (3) has cumulatively collected the original cost of the asset through depreciation expense, despite its allocation procedures attributing that accumulated depreciation to other facilities.

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[110] As detailed in Section IV.B, PG&E's allocation method has the result of decreasing the accumulated depreciation attributed to a specific facility when it extends its depreciable end of life of that facility, all else equal. As a result, once a facilities life is extended in PG&E's depreciation study, its NBV appears to be higher than it otherwise would be.

[111] For example, PG&E has placed in service $231 million in plant at the Drum-Spaulding Facility since its 2013 FERC license expiration, $349 million at the Upper NF Feather River facility since its 2004 FERC license expiration, and $148 million at the McCloud-Pit facility since its 2011 FERC license expiration (Attachment RAM-7). This investment increases the 2024 NBV of those facilities but represents investment specific to the life extension, not to the original investment.

D. PG&E's Hydro Facilities Have Experienced a Change in Function

The Commission has also indicated that a change in function in a UOG asset should trigger review of the default vintage assignment for the asset.[112] PG&E's entire hydro fleet is serving a different function today than that for which it was originally designed. According to PG&E, this fleet was originally constructed as a source of capacity and energy, and now it is a source of flexibility needed to integrate high levels of renewable generation. This change has occurred over approximately the last 10 to 15 years.[113] This change in function reflects the evolving needs of PG&E's current customer base. PG&E is responding to those evolving needs by undertaking new investments in its fleet to serve current customer demands. PG&E is investing broadly across its hydro fleet, and while that investment could be a triggering event to propose revintaging of all of PG&E's hydro facilities, in this testimony CalCCA focuses on the need to revintage the eight hydro facilities that reflect the most egregious examples of improper vintaging.

1. Meeting Demands of New Net Load Curve

PG&E's hydro fleet is already demonstrating that it has responded to changing demands resulting from increasing penetrations of renewable generation, and PG&E has stated that it plans to invest further as those demands continue to change. In seeming contradiction to its position that its generation units have not and are not planned to undergo a change in function, PG&E discussed the "Changed Demands on Generating Equipment"[114] as support for its large, forecasted increase in capital expenditures and operating costs, particularly for its hydro units. In testimony, PG&E stated:

> With large amounts of intermittent renewables added to the grid and climate change creating extreme periods of heat during the summer months and extreme rainfall

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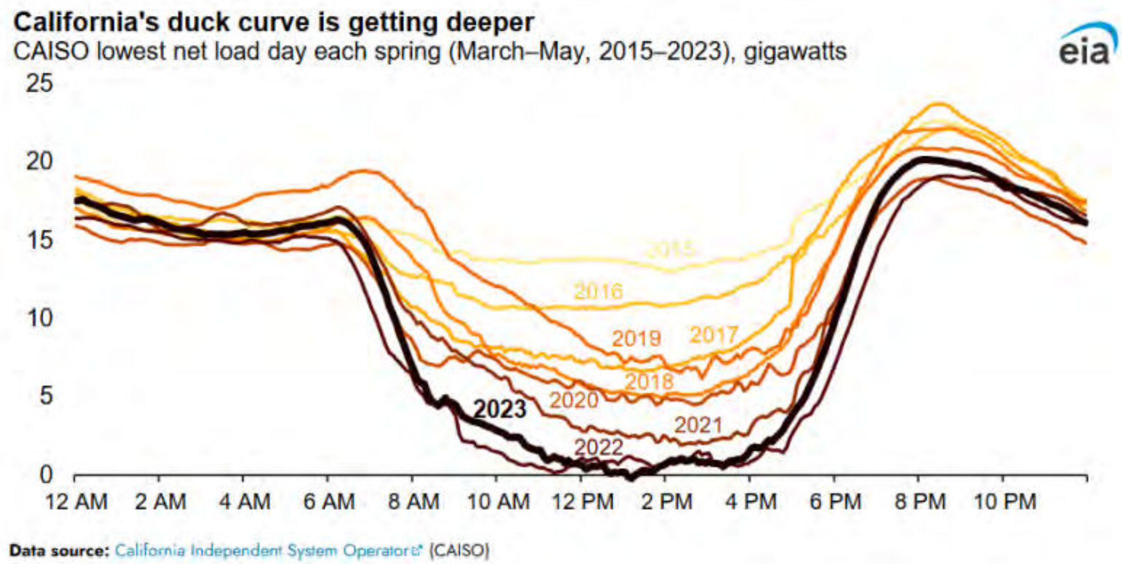
[112] *See* D.23-11-069, p. 511.
[113] Attachment RAM-2 (PG&E's response to CalCCA DR 005-025); Attachment RAM-2 (PG&E's response to CalCCA DR 005-025, Attach. 1).
[114] Exh. PG&E-5 at 3-2 to 3-3.

> from atmospheric rivers during the winter months, PG&E has experienced new challenges and greater operational demands to support grid reliability and flexible operation of its generation fleet, requiring assets to be operated differently than the modes for which they were originally designed. These changing demands on existing aging generation infrastructure requires significant investment so that the CAISO can rely on PG&E's fleet for both flexible and reliable power when called upon. For example, PG&E's hydro and natural gas resources have been called on more frequently in recent years, requiring plants to adjust schedules to ramp up and down to meet hourly fluctuations in electricity demand and offset short-notice outages or curtailments at base-load power plants. PG&E expects continued increases in expense and capital costs in its generation portfolio to address cycling-induced life-cycle impact to various components of its facilities.[115]

The increase of intermittent renewables has changed the operational profile, characteristics, and role of hydro units in PG&E's generation fleet. According to PG&E, the CAISO "duck curve" has been getting more pronounced since 2015.[116] The duck curve shows net load, which is total forecasted load less variable generation, and is characterized by a trough in the middle of the day as solar output is highest, followed by a steep increase in the evening hours as solar production falls off and load increases. It is the role of dispatchable generation, namely hydro, natural gas, and energy storage, to meet the net load in each hour of the day. The following curve from the Energy Information Administration ("EIA"), provided by PG&E, shows the change in net load across CAISO from 2015 to 2023.

[115] *Id*. at 3-2 line 21 to 3-3 line 2.
[116] Attachment RAM-2 (PG&E's response to DR CalCCA 005-025).

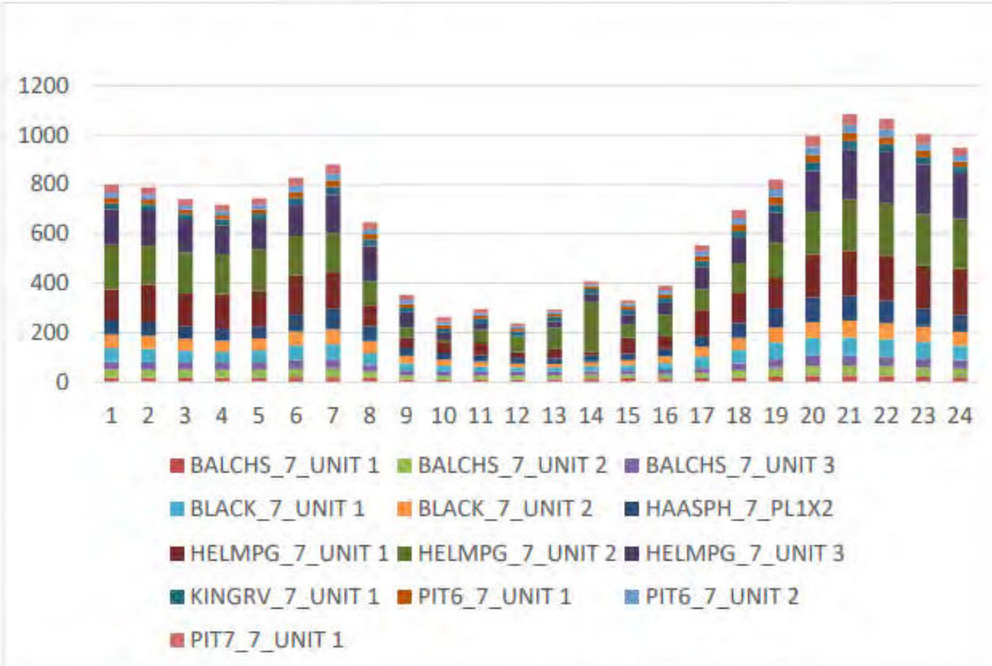
Figure RAM-2: CAISO Net Load, 2015–2023



PG&E's hydro fleet's dispatch has changed in response to the changing net load curve. Data provided by PG&E[117] shows the average hydro generation profile for 2024 and 2025, which shows the hydro fleet output backing down during midday and ramping up in the evening.

[117] Attachment RAM-2 (PG&E's response to DR CalCCA 005-025).

Figure RAM-3: Hydro Average Generation Profile – 1/1/24 to 11/5/25



PG&E's hydro fleet is well suited for this role of helping to meet the net load curve and therefore integrating high levels of renewable generation. According to PG&E, "PG&E's hydro generation facilities typically start up quickly, have fast ramp rates, and can easily, quickly, and economically vary output in response to changing customer loads and system conditions. In addition, PG&E's hydro generating units can operate at no load or low load with much higher efficiency than the alternative natural gas-fueled peaking plants."[118]

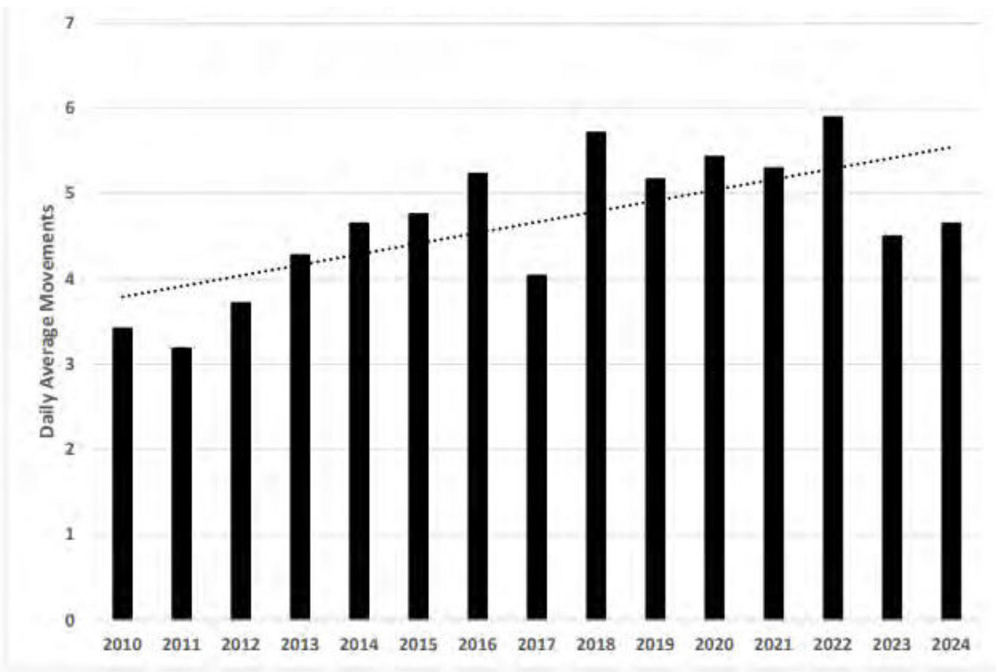
2. Changed Operational Performance of PG&E's Hydro Fleet

One result of the changed demands on PG&E's hydro fleet is that it is being dispatched differently and in a way that is less efficient and creates more wear and tear on the units—a change that is forecasted to lead to more operational and maintenance expense in the future. The changing operational characteristics of PG&E's fleet are illustrated in the following chart compiled by

[118] *Id.*

PG&E. This shows that PG&E increasingly needs to deviate from the typical operating setpoint, which maximizes efficiency and minimizes wear and tear,[119] as shown by the trendline of daily average movements away from the unit set point.[120]

Figure RAM-4: Daily Average Movements Off Typical Operating Set Point



The changing role of PG&E's hydro fleet is further evidenced by data on the annual output of hydro units from CAISO.[121] An analysis of this data for large hydro generation on an annual basis shows that hydro generation statewide has become more variable.

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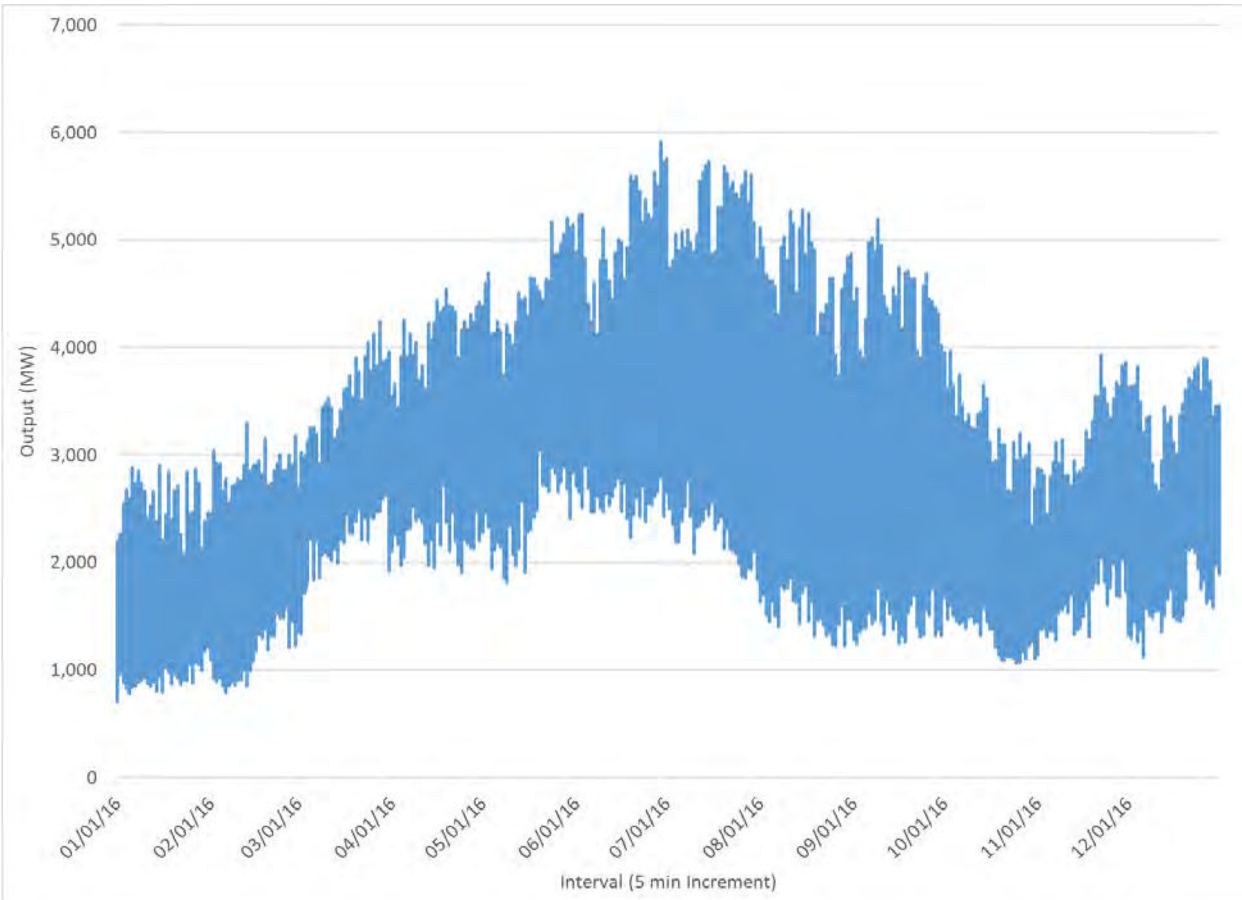
[119] *Id.*

[120] Attachment RAM-2 (PG&E's response to DR CalCCA 008-012).

[121] CAISO Library, Production and Curtailments data, accessed at https://www.caiso.com/library/production-curtailments-data on December 9, 2025. This data is for all hydro units in California, but since PG&E's hydro units make up 28% of all hydro capacity in the state, it seems a safe assumption that the characteristics of statewide hydro generation would hold true for PG&E's hydro units. CAISO provides historical generation output in five-minute increments for each generation technology.

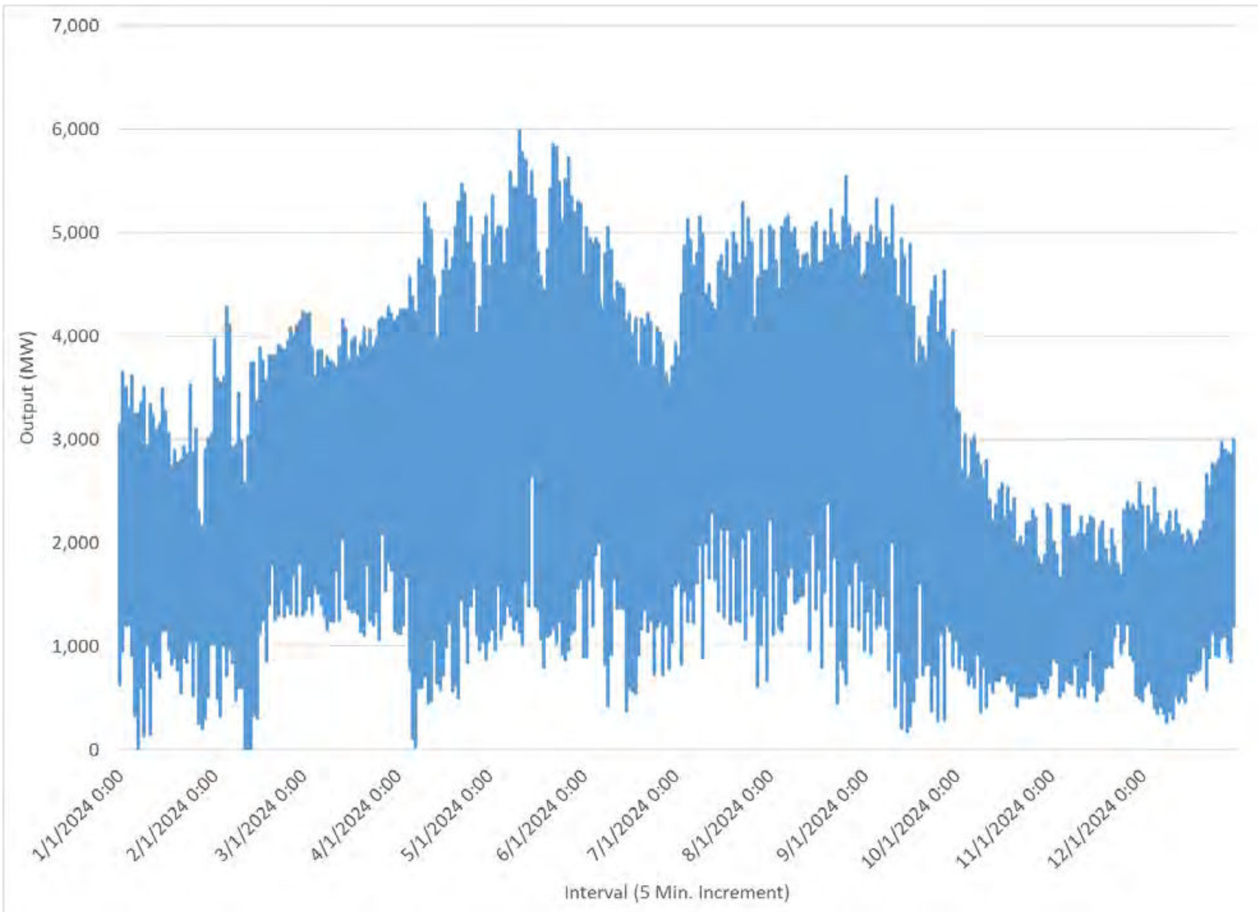
The following chart shows hydroelectric output every five minutes in calendar year 2016. The mean generation output was 2,574 MW with a minimum generation output of 941 MW, a maximum generation output of 5,909 MW, and a standard deviation around the mean of 941 MW.

Figure RAM-5: CA Large Hydro 2016 Output in 5-Minute Increments



In contrast, the following chart shows hydroelectric output every five minutes in calendar year 2024, which shows a marked change in output variability from 2016. The mean generation output in 2024 was 2,344 MW with a minimum generation output of 0 MW, a maximum generation output of 5,984 MW, and a standard deviation around the mean of 1,207 MW. The standard deviation—a statistical measure of variability—of hydro generation output increased by 28 percent from 2016 to 2024. In addition, large hydro generation output was 0 in 131 instances in the 2024 data set, meaning that for 10 hours and 55 minutes in 2024, the entire hydro fleet in California was not producing any electricity.

Figure RAM-6: CA Large Hydro 2024 Output in 5-Minute Increments



The mean large hydro generation was similar between 2016, when the mean was 2,574 MW, and 2024, when the mean was 2,344 MW. However, 2016 was categorized as a Dry water year in the San Joaquin basin and a Below Normal water year in the Sacramento Valley by the California Department of Water Resources, while 2024 was characterized as an Above Normal water year.[122] Therefore, California's large hydro generation fleet was called upon on average at

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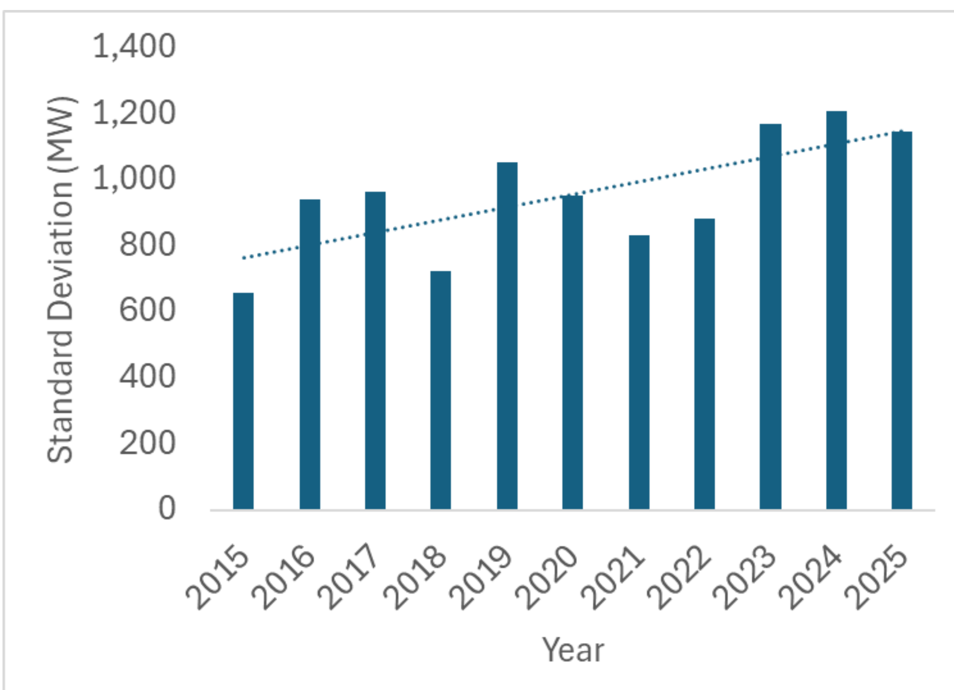
[122] Department of Water Resources, Chronological Reconstructed Sacramento and San Joaquin Valley Water Year Hydrologic Classification Indices, accessed at https://data.ca.gov/dataset/cdec-water-year-type-dataset/resource/105614f4-c71d-4191-b1f9-ea510afd8b62 on December 9, 2025.

the same level in 2024 and 2016 despite the state having a greater supply of water in 2024 which would allow for more electricity production in that year as compared to 2016. The fact that large hydro output was more variable in 2024 than 2016 but had the same average capacity underscores the fact that in 2024 the hydro resources were being called upon to integrate renewable energy while in 2016 they were relied on as a source of energy and capacity during system peaks.

The increasing variability in large hydro output can also be seen by looking at the standard deviation around mean for large hydro production in each year from 2016 through 2025. The trendline on the chart below shows increasing standard deviation over time. That trend might be even more pronounced were 2021 and 2022 not Critically Dry water years. Lack of water supply limited average generation in those years to 1,131 and 1,502 MWs, respectively, which reduced the standard deviation as compared to years with higher mean generation since the minimum generation cannot fall below zero.

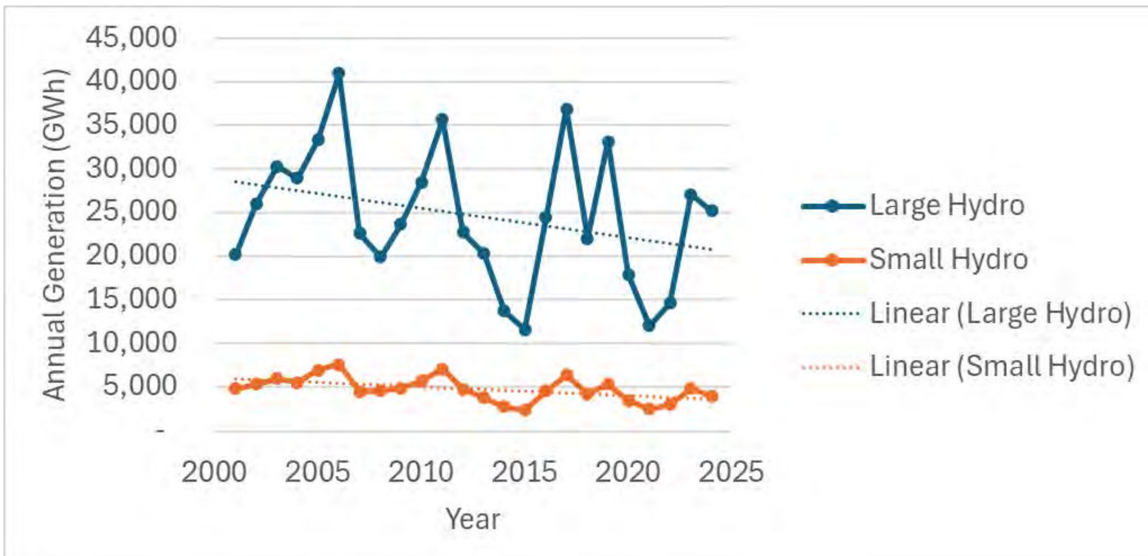
Figure RAM-7: Standard Deviation of CA Large Hydro Generation, 2016–2025



3. Reduction in Energy and Contribution to Peak Capacity During System Peak

A consequence of the changed function of PG&E's hydro fleet is that it is therefore less available to provide its original function: the provision of energy and capacity during PG&E's system peaks. The annual generation for both large hydro and small hydro across California has trended downward over time as can be seen in the following chart.[123] On a trended basis, large hydro generation has fallen by 27 percent from 2001 to 2024 while small hydro production has fallen by 40 percent over the same time period.

Figure RAM-8: CA Annual Hydro Generation, 2001–2024



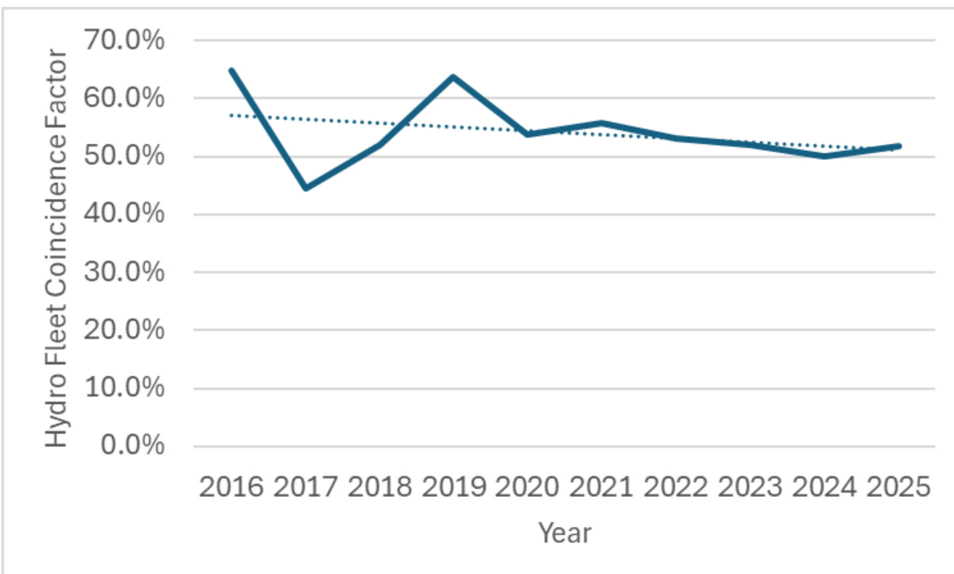
This change in function can also be seen from the change in PG&E's hydro fleet's contribution to peak capacity during PG&E's system peak. One of the original purposes of the hydro fleet was to provide capacity at system peak, which is particularly true of the Helms plant,

[123] California Energy Commission, Electric Generation and Capacity data for all power plants sited in CA that are greater than 1 MW, accessed at: https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/electric-generation-capacity-and-energy on January 6, 2026.

which contains 32 percent of the peak capacity of PG&E's entire hydro fleet.[124] That plant was built explicitly for capacity;[125] because it is a pumped hydro unit (which switches from an electricity consumer when in pumping mode to an electricity producer when in generating mode), it is a net consumer of energy. An analysis[126] of PG&E's hydro unit production during the system peak[127] shows that over the past 10 years, hydro's contribution to peak has been decreasing, as shown in the following chart.

An analysis of the coincidence factor[128] for each of PG&E's hydro units[129] and for the system as a whole from 2016 to 2025 shows that the coincidence factor has been decreasing.

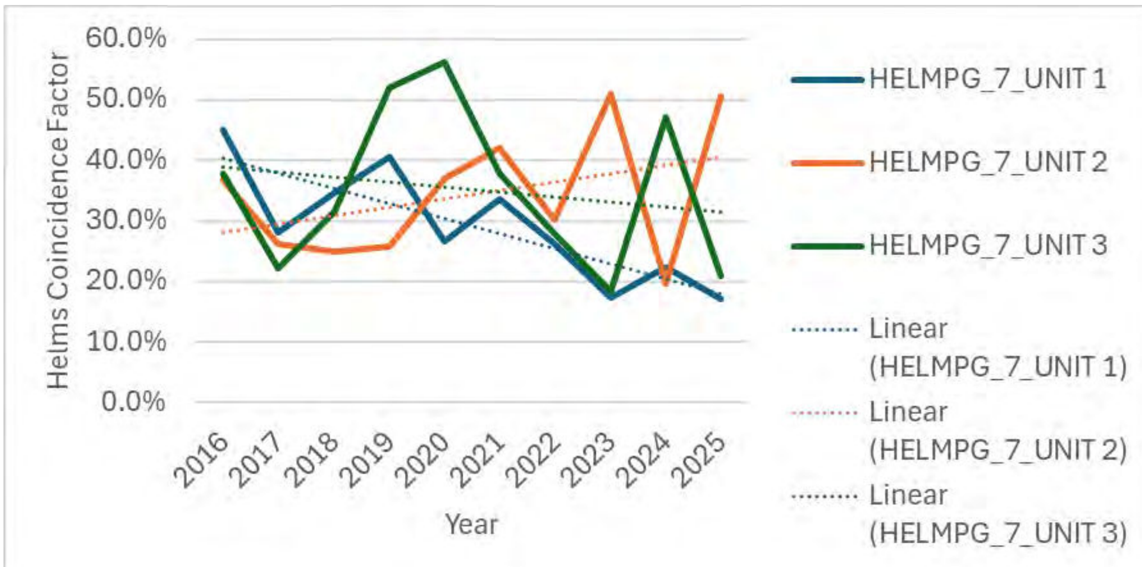
Figure RAM-9: PG&E Hydro Fleet Coincidence Factor, 2016–2025



[124] Exh. PG&E-5 Workpapers at WP 3-133 where it shows Helms has 1,212.0 MW of PG&E's 3,839.6 MW of total hydro capacity.
[125] *Pacific Gas & Elec. Co.*, Project Nos. 2735 & 1988, 56 F.P.C. 2802 (1976).
[126] The analysis looked at hydro contribution to peak load during the months of June through September. That is because on average the load in those months is significantly higher than load in other months.
[127] Data provided in Attachment 1 to PG&E's response to DR CalCCA 009-006.
[128] Coincidence factor is the ratio of hydro unit output during the peak hour to its nameplate capacity. A decreasing coincidence factor indicates that the hydro fleet is being called upon to deliver less capacity than it is capable of delivering at peak, most likely because other resources, particularly solar, are displacing the need for hydro capacity.
[129] Hydro units that were sold or retired during the time period at issue were excluded from the analysis.

Of the 62 hydro units included in the analysis, 40 showed a downward trend in coincidence factor and 20 showed an upward trend. The trend of hydro units decreasing their contribution to capacity can be seen at Helms as well. Two of its three units have on average contributed less of their available capacity at peak over the past 10 years, which is particularly notable since the facility's sole original purpose was to provide peak capacity.

Figure RAM-10: Helms Coincidence Factor, 2016–2025



In summary, PG&E's hydro fleet has evolved over the past 10 to 15 years to serve different functions that are distinct from those it originally served. PG&E has accomplished this shift—and continues to effectuate this shift—through significant capital investments in its hydro fleet. These changed functions for PG&E's hydro fleet underscore the need to reconsider the default vintage assignments for PG&E's hydro assets.

E. PG&E Is Proposing Significant Investment in Its Hydro Facilities

Finally, the Commission has indicated that, more generally, new investments in UOG may in certain circumstances be substantial enough to represent a "significant overhaul" of the asset, such that revintaging would be appropriate.[130] In order to support its proposed life extensions and the changing function of its hydro fleet, PG&E has requested $3.7 billion in forecasted capital investment in its hydro assets from 2025 through 2030.[131] That is an extraordinary amount of investment by any measure.

PG&E's year-end 2024 functional hydro generation gross plant was $4.9 billion.[132] PG&E's year-end 2024 functional hydro generation reserve was $2.6 billion,[133] which when subtracted from the gross plant value results in hydro generation net plant of $2.3 billion. Therefore, PG&E's forecasted investment over the coming six years is *161 percent* of the current net plant value of existing hydro generation. In other words, in six years' time, PG&E is proposing to *more than double* the rate base of its hydro fleet—a fleet that it has built and operated for over a century. This level of investment arguably amounts to a "significant overhaul"[134] of PG&E's entire hydro fleet.

The following table shows PG&E's proposed capital expenditures by facility.

[130] *See* D.18-10-019, p. 135.
[131] *See* Attachment RAM-5. This figure includes 2025–2026 investment which was governed by the 2023 GRC as well as Helms investment agreed to in the Helms Uprate proceeding but is shown here to provide the full scale of forecasted hydro capital investment.
[132] Exh. PG&E-10 Workpapers at WP 7-48, Table 7-15.
[133] *Id*. at WP 8-72, Table 8-28.
[134] *See* D.18-10-019, p. 135.

Table RAM-9
Forecasted Capital Expenditure by Hydro Facility, 2025–2030

Hydro Facility	2025–2030 Forecasted Capital Expenditure	Capex as a Percentage of Original Cost (2024 Real $)[135]
Helms[136]	$937.0	34%
McCloud-Pit	$648.6	54%
Drum-Spaulding	$463.2	38%
Upper NF Feather River	$286.7	17%
Mokelumne	$252.5	23%
Pit 3, 4, 5	$166.4	11%
Rock Creek	$159.3	16%
Spring Gap-Stanislaus	$155.3	46%
Balch	$100.1	35%
Bucks Creek	$95.7	35%
Kerckhoff 2	$86.2	17%
Haas-Kings River	$84.2	17%
Poe	$63.8	12%
Crane Valley	$60.0	16%
DeSabla-Centerville	$59.8	24%
Pit 1	$26.2	10%
Kerckhoff 1	$23.8	24%
Battle Creek	$23.3	8%

[135] The forecasted capital expenditure is shown as a percentage of the original cost of each hydro facility converted to real 2024 dollars. That is because some hydro facilities have experienced investment across a time period greater than 100 years, and the original cost is recorded based on expenditures occurred at the time of investment. Converting those costs to real 2024 dollars removes the effect of inflation from the comparison of capital investment today compared to investment across a long time period. Attachment RAM-7 shows the conversion of original cost to 2024 dollars.
[136] There is $371.6 million of Helms capital investment forecasted in this GRC that is incremental to the $544.1 million forecasted from 2025–2030 for the Helms Uprate and Lifecycle Replacement Cost in the Helms Uprate proceeding. (Attachment RAM-2 (PG&E's response to DR CalCCA 007-004); Attachment RAM-2 (PG&E's response to DR CalCCA 003-017)) The total Helms investment forecasted between the GRC and the Uprate proceeding is $937.0 million.

Table RAM-9
Forecasted Capital Expenditure by Hydro Facility, 2025–2030

Hydro Facility	2025–2030 Forecasted Capital Expenditure	Capex as a Percentage of Original Cost (2024 Real $)[135]
Phoenix[137]	$23.9	41%
Hat Creek 1 and 2	$11.3	16%
Potter Valley	$9.5	5%
Hamilton Branch	$3.3	14%
Total GRC & Helms Uprate	**$3,740.9**	**26%**

The six-year forecast period presented in the table above results in an average capital expenditure of $623.5 million per year. That compares to the $818.2 million of gross additions to hydro production plant over the 2020 to 2024 time period,[138] which is an average of $163.6 million per year. PG&E is therefore proposing capital investment in its hydro fleet at nearly *four times* historical levels.

F. Revintaging Recommendations and Impact on the PCIA

Based on the evidence detailed above, PG&E's proposals in this case related to eight of its hydro UOG facilities should trigger PCIA revintaging for those assets. For these eight hydro facilities, PG&E is (1) pursuing FERC relicensing and associated extension to each facility's useful life; (2) continuing to effectuate a change in plant function during this GRC period; and (3)

[137] At the 2 MW Phoenix powerhouse, PG&E is proposing $23.9 million in capital investment over the 2025–2030 time period. That level of investment translates to nearly $12,000 per kilowatt ("kW") of capacity proposed to prepare the Phoenix station to run for an additional FERC license term, which raises significant concerns about the cost-effectiveness of their plans. This is a significant expense for a plant that provides minimal capacity and energy benefit to the system. PG&E is in discussions to potentially sell the Phoenix facility (PG&E's response to DR CalCCA 009-009). The Commission should look closely at the prudency of any capital investment made in that plant from 2025 onward, when PG&E was aware of a potential sale, in light of the purchase price achieved through the sale. PG&E's customers should not pay for investments that a potential buyer is unwilling to pay.
[138] Exh. PG&E-10 Workpapers at WP 8-356, Line No. 137 on Table 8-50.

proposing a significant capital investment of between 17 and 54 percent of each asset's original cost in this case. Any one of these three developments could trigger full facility revintaging; these eight facilities are undergoing all three of them.

Specifically, the following hydro facilities should be reassigned from the Legacy UOG vintage to the 2027 vintage: Phoenix, DeSabla-Centerville, Helms, Balch, Drum Spaulding, Kerckhoff 2, McCloud-Pit, and Upper NF Feather River.[139] The following table summarizes each facility's characteristics relative to the Commission's revintaging criteria.

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[139] Refer to Attachment RAM-12 for a summary of each plant's financial, operational, and regulatory history.

Table RAM-10
Hydro Facilities To Be Revintaged

Hydro Facility	Relicensing Life Extension?	Changing Function?	2025–2030 Investment
Phoenix	Yes, 2022 -> 2064	Yes	$23.9 million; 41% of original cost
DeSabla-Centerville	Yes, 2022 -> 2038	Yes	$59.8 million; 24% of original cost
Helms	Yes, 2069 -> 2079	Yes	$937.0 million; 34% of original cost
Balch	Yes, 2069 -> 2079	Yes	$100.1 million; 35% of original cost
Drum-Spaulding	Yes, 2063 -> 2077	Yes	$463.2 million; 38% of original cost
Kerckhoff 2	Yes, 2065 -> 2076	Yes	$86.2 million; 17% of original cost
McCloud-Pit	Yes, 2061 -> 2075	Yes	$648.6 million; 54% of original cost
Upper North Fork Feather River	Yes, 2061 -> 2075	Yes	$286.7 million; 17% of original cost

CalCCA proposes that the new vintage for these facilities should be 2027, the first year of requested cost recovery through this GRC. This approach is consistent with the Commission's current approach of using the year in which the resource commitment is made to determine the vintage assignment. Approval of PG&E's proposed investments in its hydro facilities would trigger a new generation commitment starting in 2027, the first year that rates would be in effect from this GRC.

The revintaging of these eight facilities will ensure that unbundled customers are not required to subsidize PG&E's proposed generation investments on behalf of its bundled customers. Absent this revintaging, unbundled customers would be saddled with between $81 million to $120 million[140] of extra costs recovered via the UOG legacy revenue requirement over the course of the 2027-2030 time period governed by this GRC. That would result in departed load customers providing a significant subsidy to bundled customers, contrary to state law and the Commission's principle of bundled customer indifference.

The following table presents the estimated 2027 revenue requirement for each of the proposed revintaged facilities which are the inputs to the PCIA impact calculation. [141]

Table RAM-11
Revenue Requirement of Proposed Revintaged Hydro Facilities

Facility	2027 Rev. Req. ($ million)	Decommissioning Cost ($ million)[142]	2027 Rev. Req. to Revintage ($ millions)
Upper NF Feather River	$103.4	$0.0	$103.4
DeSabla-Centerville	$27.7	$9.5	$18.2
McCloud-Pit	$62.1	$0.0	$62.1
Drum-Spaulding	$171.5	$0.0	$171.5
Kerckhoff 2	$30.3	$0.0	$30.3
Phoenix	$8.9	$0.0	$8.8
Balch	$23.7	$0.0	$23.7
Helms	$89.2	$0.0	$89.2
Total	**$516.8**	**$9.5**	**$507.3**
Total Hydro UCC			**$1,127.7**

[140] These figures are calculated based on the current inputs and assumptions to the 2026 PCIA currently in effect. Some of these inputs will change through the course of the 2027–2030 implementation of the PCIA through the ERRA proceedings, but this analysis provides a snapshot at a point in time of the magnitude of the revintaging impact.

[141] These calculations are shown in Attachment RAM-3 and draw on the inputs developed in Attachments RAM-4, RAM-5, and RAM-6 which all are based on data provided by PG&E through DR responses. These attachments demonstrate the calculation of a facility-by-facility revenue requirement through time, tracking by facility all elements of plant as recommended in Section IV.B. The starting point for these calculations is the breakdown of plant by facility at the end of 2024 as provided by PG&E. The revenue requirement calculations do not include the impact of the Helms Uprate Investment, which will increase the hydro revenue requirement and therefore the magnitude of revintaging cost shift. The revenue requirement calculations do account for the impact of the CalCCA recommendation to remove plants no longer used and useful in Section II, but do not attempt to estimate the impact of any of the other recommendations presented herein which would reduce the overall Electric Generation revenue requirement.

[142] The $0.0 in decommission costs shown in this table for some facilities does not indicate there will be no decommissioning costs, rather it reflects that PG&E has not yet estimated a decommissioning cost nor started recovering that estimated cost from customers.

IV. PG&E SHOULD FIX TWO SIGNIFICANT DEPRECIATION ACCOUNTING ISSUES THAT UNNECESSARILY RAISE RATES FOR CUSTOMERS AND RISK COST SHIFTS BETWEEN CUSTOMER GROUPS

PG&E performed a depreciation study in this case in order to determine the average service life, net salvage rate, and applicable aging curve for all its electric and gas assets.[143] Through this study, PG&E determined a depreciation rate that allows for the capital cost of utility assets to be recovered from customers in equal portions over the life of the asset, ensuring that all customers who benefit from an asset share cost responsibility for that asset. The proposed depreciation rates for the electric generation function that are a result of PG&E's depreciation study would increase depreciation expense by $28.5 million, from $278.7 million in 2024 to a forecast of $307.2 million in 2027.[144]

There are two issues with PG&E's accounting of accumulated depreciation for its hydro assets. First, PG&E's depreciation study omits approximately $507 to $562 million of accumulated depreciation as compared to what PG&E separately reports on its books, the result of which is hydro depreciation expense that is $16 million greater than it otherwise would be. Second, PG&E does not track accumulated depreciation at the hydro facility level, only at the FERC account level for the entire hydro function. This accounting approach will result in inequitable cost shifts between bundled and departed load customers in the event the Commission orders PG&E to revintage any of its hydro facilities—either in response to CalCCA's proposals in this case, or at any point in the future.

A. PG&E's Hydro Depreciation Expense Request Is Artificially Inflated

PG&E's requested depreciation expense for its hydro assets is artificially inflated by approximately $16 million annually. This is the result of PG&E omitting approximately $507 to

[143] Exh. PG&E-10 at 8-5 line 6 to 8-6 line 5.
[144] *Id*. at 8-11 (Table 8-4).

$562 million of accumulated depreciation from its depreciation study calculations as compared to what PG&E separately reports on its books. Revising PG&E's depreciation study to account for the actual book accumulated depreciation as reported by PG&E, allocated to each plant, remedies this issue and results in an annual savings of $30 million.

PG&E's depreciation study uses a remaining life method to calculate the depreciation rates for electric production assets. The remaining life method depreciates the net plant balance (gross plant less accumulated depreciation), adjusted for net salvage, over the estimated remaining life of the asset.[145] PG&E generally applies this method to its hydro facilities at the FERC license level. That is because it is PG&E's typical practice to set the depreciation end of life of a collection of hydro facilities contained under a single FERC license to the end of that license period, typically anywhere from 40 to 50 years from license issuance.[146]

In order to apply the remaining life method to each group of hydro facilities, PG&E must determine the gross plant and accumulated depreciation for each hydro facility. PG&E only tracks accumulated depreciation at the FERC account level,[147] so in order to determine the remaining NBV[148] for each hydro facility, it must therefore allocate that book accumulated depreciation to each facility in order to create a theoretical reserve for each facility for the purposes of determining the annual depreciation expense for each facility.[149]

The theoretical reserve calculated for the purposes of the depreciation study is not equivalent to the book reserve because of the impact of net salvage. However, it is possible to

[145] *Id*. at 8-16 lines 22-33.
[146] Exh. PG&E-10 Workpapers at WP 9-35.
[147] Attachment RAM-2 (PG&E's response to DR CalCCA 005-026).
[148] The NBV is the balance to be depreciated over the remaining life of the hydro facility.
[149] Attachment RAM-2 (PG&E's response to DR CalCCA 012-013).

translate the information presented in the depreciation study into a book reserve per hydro facility, using the formula provided by PG&E:[150]

Accumulated Depreciation = Original Cost * (100% - Net Salvage %) - Future Accruals w/ Net Salvage Adjustment

Using this method across all of PG&E's hydro facilities results in a total calculated book accumulated depreciation of $2.061 billion as of December 31, 2023.[151] This book accumulated depreciation for hydro facilities is markedly different from the book accumulated depreciation reported by PG&E in multiple other locations, as shown in the table below.

Table RAM-12
2023 EOY Hydro Accumulated Depreciation Across Sources

Hydro Accumulated Depreciation as of 12/31/2023	2027 GRC Depreciation Study[152]	Att. 1 to PG&E's Response to DR CalCCA 012-009[153]	Att. 1 to PG&E's Response to DR CalCCA 002-001[154]	2023 FERC Form 1[155]
Total	$2.061 billion	$2.625 billion	$2.626 billion	$2.571 billion
Difference from 2027 GRC Depreciation Study	N/A	$0.561 billion	$0.562 billion	$0.507 billion

The implication of the $507 to $562 million difference in PG&E's reported hydro accumulated depreciation as compared to the accumulated depreciation used in the depreciation

150 Attachment RAM-2 (PG&E's response to DR CalCCA 012-009).
151 *See* Attachment RAM-4.
152 *See id*.
153 Attachment RAM-2 (PG&E's response to DR CalCCA 012-009, Attach. 1).
154 Attachment RAM-2 (PG&E's response to DR CalCCA 002-001, Attach. 1). PG&E provided a revised response in DR CalCCA 012-007 stating "The balances provided in CalCCA002-001 Attachment 1 were prepared prior to the depreciation study and, as a result, have some differences." PG&E's Attachment 1 to DR CalCCA 012-007 revises its 2023 accumulated depreciation book balances downward by $169 million to $2.455 billion, which again highlights the mismatch between the accumulated depreciation on PG&E's books and that used in the depreciation study to calculate depreciation rates.
155 PG&E 2023 FERC Form 1, Page 219, Lines 22–23.

study is that PG&E is proposing depreciation expense, and therefore depreciation rates, that are too high. That is because PG&E is targeting a remaining accrual that is $507 to $562 million more than is needed to fully depreciate its hydro facilities. In other words, in the hypothetical situation where the underlying assumptions used in this depreciation study remain unchanged for the life of the hydro assets, PG&E's customers will have paid $507 to $562 million more than the original investment in the plant once all hydro assets are retired.

Revising PG&E's depreciation study to account for the actual book accumulated depreciation as reported by PG&E, allocated to each plant, would result in an annual depreciation expense using the remaining life method that is approximately $15.7 million less than PG&E's request in this case.[156] The Commission should therefore reduce the electric generation depreciation expense in the 2027–2030 forecasted revenue requirement by $15.7 million annually.

B. PG&E's Method of Tracking Accumulated Depreciation Hinders Its Ability to Fairly Allocate Costs to Its Current Customer Base

PG&E's current practice of tracking accumulated depreciation only at the FERC account level is no longer reasonable in light of the fact that PG&E's customer base now primarily consists of departed load customers. In this new landscape, not all customers are similarly situated when it comes to cost responsibility for various PG&E generation assets. For certain hydro assets, PG&E's status quo method of tracking accumulated depreciation makes it difficult, if not impossible, to modify ratemaking treatment—*e.g.,* PCIA vintaging treatment—when appropriate. Unless PG&E begins tracking accumulated depreciation and the other related components of rate base, at the individual hydro facility level, it will not be able to accurately and efficiently account for future changes to ratemaking for these generation assets. Therefore, the status quo approach risks improper cost shifts between departed and bundled customers.

[156] Attachment RAM-4.

PG&E generally depreciates its hydro facilities[157] over the term of their FERC licenses, which can be anywhere from 40 to 50 years.[158] The depreciation expense for each generation unit is calculated based on what is known as "life span" depreciation, in which the estimated remaining life for that generation unit is largely based directly on the time remaining to the terminal retirement date.[159] Depreciation expense is then calculated with the goal of that unit's value being fully depreciated at the terminal retirement date. As the remaining life reaches zero, the unit's service value should be fully depreciated.

Observing an individual hydro facility's service value approaching zero as it approaches its terminal retirement date in the data provided by PG&E is challenging. That is because PG&E does not track accumulated depreciation at the hydro facility level—it is tracked only at the FERC account level.[160] In instances in which PG&E needs to determine the book accumulated depreciation by hydro facility, the accumulated depreciation at the FERC account level is allocated to the facility level in proportion to the calculated accrued depreciation based on the currently adopted service life and net salvage estimates.[161]

The practical result of this allocation process is that the level of accumulated depreciation allocated to a specific hydro facility can change dramatically when its probable retirement date changes. The allocation of accumulated depreciation to the Helms facility over the last three GRCs provides an example of this impact. Prior to the 2020 GRC, the probable retirement date for Helms was 2026, the year in which its FERC license expires. This is 50 years after the license issuance

[157] I will use the term "hydro facilities" to refer to the collection of dams, conveyances, powerhouses, turbines, and supporting equipment all contained under a single FERC license. It is the facilities within a FERC license to which PG&E applies the remaining life method in its depreciation study.
[158] Exh. PG&E-10 Workpapers at WP 9-25.
[159] The impact of interim retirements and net salvage is also taken into account, which I am ignoring at the moment for the sake of simplicity.
[160] Attachment RAM-2 (PG&E's response to DR CalCCA 002-004).
[161] Attachment RAM-2 (PG&E's response to DR CalCCA 005-026).

in 1976 and 42 years after the facility was placed into service in 1984. The plant was being depreciated using the life span method so that it would be fully depreciated at the end of 2026. In the 2023 GRC, the probable retirement date for Helms was extended to 2069 as the relicensing process got underway.[162] And PG&E has proposed to further extend Helm's life in this GRC to 2079.[163] The extension of Helms' probable retirement date had the impact of increasing the total future accruals[164] needed to fully depreciate the plant, in the absence of significant new investment at the time. This was due to PG&E's accumulated depreciation allocation process and the fact that the probable retirement date is one of the inputs.[165] The following table shows the original plant, total future accruals, and average remaining life for Helms across the past three GRCs.

Table RAM-13
Helms Original Plant and Total Future Accruals in 2027, 2023, and 2020 GRCs

	Original Plant	Total Future Accruals	Avg. Remaining Life
2027 GRC[166]	$1,057	$689	43.87
2023 GRC[167]	$1,064	$697	40.69
2020 GRC[168]	$1,011	$326	8.22

[162] Attachment RAM-2 (PG&E's response to DR CalCCA 002-002, Attach. 1).
[163] Exh. PG&E-10 Workpapers at WP 9-36.
[164] An increase in future accruals would imply a decrease in the accumulated depreciation allocated to Helms.
[165] Attachment RAM-2 (PG&E's response to DR CalCCA 012-009).
[166] *See* Attachment RAM-4.
[167] *See id*.
[168] PG&E 2020 GRC, Exh. PG&E-10 Workpapers at WP 11-42, WP 11-43, WP 11-90, WP 11-93, WP 11-152, WP 11-157, WP 11-197, WP 11-199, WP 11-243, WP 11-245, WP 11-286, WP 11-289, WP 11-318, and WP 11-321.

In the three years between the 2020 GRC[169] and the 2023 GRC,[170] the Helms facility did not actually have its accumulated depreciation decrease by $371 million.[171] The fact that a probable retirement date extension results in an increase to the amount of depreciation needed until the facility is fully depreciated results in it being impossible to precisely determine when the original investment in a hydro facility has been fully depreciated, and therefore when the cost responsibility of departed load customers for that facility should cease.

Without tracking the accumulated depreciation at a facility level, it is extremely difficult to determine the amount of depreciation that has been accrued on any given facility. In order to accurately estimate the amount of accrued depreciation, one would need to retroactively calculate the accrued depreciation on each unit based on the accurate rates applied to each account within that unit year by year, back through the full life of the asset. Since it is challenging and impractical—if not impossible—to do this calculation, rather than allocating accumulated depreciation at specific points in time across a facility's lifecycle, CalCCA proposes that PG&E begin tracking accumulated depreciation by plant with the 2024 net plant data.[172]

The Commission should order PG&E to begin tracking all components of plant by hydro facility. The practice of tracking accumulated depreciation at the FERC account level and allocating it to hydro facilities may be reasonable for a vertically integrated utility with a monopoly service territory in which all its customers are similarly situated and bear comparable cost

[169] The depreciation study was based upon December 31, 2017, plant balances.

[170] The depreciation study was based upon December 31, 2020, plant balances.

[171] This would be necessary to generate the change from $326 million to $697 million in total future accruals. For that to happen, the facility would need to *appreciate* by $123.7 million each year from 2018–2020. Given that the proposed annual depreciation for Helms from the 2017 GRC (in effect in 2018 and 2019) was to *depreciate* the facility by $29.0 million annually and from the 2020 GRC (in effect in 2020) was to *depreciate* the facility by $39.7 million, that is impossible.

[172] Note that CalCCA uses this methodology to produce the going forward calculations and recommendations for revintaging in Section III herein as well as the detailed calculations in Attachment RAM-3.

responsibility for the full fleet of hydro resources over the life of those resources. In that situation, to which specific facility the accumulated depreciation is apportioned would not change the overall electric generation revenue requirement, nor customer rates.

That is no longer the case for PG&E. The fact that a significant share of PG&E's service is provided to departed load customers means that not all customers are similarly situated. CalCCA proposes in Section III herein that the Commission order PG&E to revintage a portion of PG&E's hydro assets. Should the Commission agree and order PG&E to place some hydro assets into a new vintage, then accumulated depreciation must be tracked along with all related components of plant over time at the facility level. Otherwise, revenue requirements will be improperly shifted between departed load and bundled customers. CalCCA therefore recommends that the Commission order PG&E to begin tracking plant, accumulated depreciation, depreciation expense, and Accumulated Deferred Income Tax ("ADIT") by hydro facility.

V. RATEMAKING ISSUES

A. PG&E's Improper Calculation of Deferred Tax Assets for the Diablo Canyon Power Plant Increases the Electric Generation Revenue Requirement

Despite Senate Bill 846's (SB 846) explicit prohibition on PG&E earning returns on extended operations investments at DCPP, [173] and despite the Commission's clear directive to track DTA revenue requirements in a memorandum account pending IRS guidance,[174] PG&E now seeks to include a separate DTA balance for pre-extension investments in its rate base calculation in this General Rate Case—effectively circumventing regulatory restrictions and forcing customers to pay inflated revenue requirements for a plant that was supposed to operate under a unique, no-

[173] SB 846, 2021-2022 Reg. Sess. (Cal. 2022); *see* Cal. Pub. Util. Code § 712.8(h)(1).
[174] A.24-12-033, Application of Pacific Gas and Electric Company to Recover in Customer Rates the Costs to Support Extended Operation of Diablo Canyon Power Plant from September 1, 2023 through December 31, 2025 and for Approval of Planned Expenditure of 2025 Volumetric Performance Fees, at 36, section 6.5.

return ratemaking structure. This improper calculation violates the statutory framework, ignores Commission orders, and unjustifiably increases the electric generation revenue requirement that ratepayers must shoulder.

PG&E's inclusion of the DCPP DTA in the 2027 GRC rate base is improper for four reasons. ***First***, because the DCPP investments should have been fully depreciated for tax purposes by 2025/26 retirement dates, there should not be a DTA in the first place. ***Second***, PG&E could have avoided the creation of a DTA by taking advantage of recent tax laws allowing accelerated depreciation option for nuclear plants. ***Third***, if there is any amount of DTA (or deferred tax liability) rightly accumulated, it would be a violation of the Internal Revenue Code's ("IRC") Consistency Rule to include it in rate base in this GRC. ***Fourth***, PG&E does not need to place the DTA into the rate base since it could avail itself of the IRS's Safe Harbor for Inadvertent Normalization Violations provision applies here. Accordingly, the Commission should order the DTA balance be removed from the 2027 – 2030 revenue requirement, order PG&E to submit a PLR on this issue prior to the processing of this case. and require PG&E to provide balancing account treatment to the DTA revenue requirement so while PG&E seeks IRS guidance.

1. Overview of Accumulated Deferred Income Taxes

ADIT arises from the difference in depreciation expense incurred by utility customers through rates and the depreciation expense claimed by the utility on its federal taxes. For rate making purposes, utilities use straight-line depreciation. Under straight-line depreciation (referred to as book depreciation), the initial capital cost of the asset is depreciated in equal portions over the life of the asset. On the other hand, IRS rules allow a utility to depreciate capital investments for tax purposes using accelerated depreciation methods resulting in faster depreciation schedules, allowing a utility to write off the cost of the asset more quickly and thus reducing a utility's tax expense in the years directly following the investment.

The use of different depreciation methods for rate making and tax purposes results in a difference between the tax expense a utility collects from customers and the amount it pays to the IRS. Because accelerated depreciation methods reduce the amount of taxes the utility pays in the years immediately following a capital investment, the utility will typically collect from its customers a higher amount to cover its tax liability than the amount the utility pays to the IRS. This difference between the tax expense amount collected from customers and the actual amount paid to the IRS is known as Deferred Income Tax ("DIT"). The DIT generated annually is accumulated as a balance (ADIT) that the utility places into rate base. When the ADIT balance is positive, meaning that the utility has paid more taxes to the IRS than it has collected from customers, it is a Deferred Tax Asset—an addition to the rate base. When the ADIT is negative, meaning that the utility has collected more of its tax expense from customers than it has paid to the IRS, it is a Deferred Tax Liability—a reduction from the rate base.

2. DCPP Pre-Extended Operations Investments Should Have Been Fully Depreciated by 2026

There should not be any remaining book to tax timing differences from DCPP investment prior to the extended operations period, and therefore no DTA, since it was planned to be fully retired by 2026 prior to the rates for the 2027 GRC going into effect. This subsection will walk through why PG&E's assumptions have resulted in a DTA remaining on their books, and how those assumptions should be modified.

Because the utility will, in the years following a capital investment, collect more in tax expense from customers than is due to the IRS, plant-related ADIT balances are typically negative and are a reduction to rate base. The DCPP DTA in this case is positive—an addition to rate base.[175] This is because that the DCPP was fully depreciated for book purposes through the 2023 GRC period as DCPP was to retire by the end of 2026. The 2027 GRC maintains that DCPP is fully depreciated for book purposes,[176] thus there is no rate base investment nor depreciation expense for DCPP included in the 2027 GRC, which is also consistent with the extended operations required rate-making treatment.

However, a tax depreciation life is still assumed in the 2027 GRC. PG&E confirmed this when it stated "DCPP assets placed in service during . . . 2023 through 2026. . . have a federal tax life of 15-years that continues past 2026 (final attrition year) but which originate from the 2023 GRC."[177] PG&E went on to state "The DTA should be reduced to zero by 2041 at the latest."[178] Using a 15-year federal tax life for investments made from 2023-26 is not reasonable. The plant was originally scheduled to retire in 2026, and its pre-extended operations capital investment should have been fully depreciated by 2026 for tax purposes.

3. Had PG&E Taken Advantage of Accelerated Depreciation Options Available to It, There Would Likely be No DCPP DTA

PG&E could have also avoided the creation of a DTA had it taken advantage of recently enacted tax provisions. Recent tax law changes in the Inflation Reduction Act ("IRA") of 2022 and the One Big Beautiful Bill Act ("OBBBA") of 2025 specifically address the Depreciation of Nuclear Plant Extensions in order to significantly boost nuclear power, especially from existing plants. These recent tax laws allow usage of the 5-Year MACRS schedule with the 200% declining

[175] Attachment RAM-2 (PG&E's response to DR CalCCA 003-14(b)).
[176] Attachment RAM-2 (PG&E's response to DR CalCCA 005-023(b)); Attachment RAM-2 (PG&E's response to DR CalCCA 003-007(a)).
[177] Attachment RAM-2 (PG&E's response to DR CalCCA 005-023(a)).
[178] Attachment RAM-2 (PG&E's response to DR CalCCA 005-023(c)).

balance method for the nuclear power plant extensions.[179] Additionally, for these nuclear power plant extensions, the MACRS depreciation rates could be combined with bonus depreciation which could be up to a 100 percent first-year bonus.[180] PG&E has not stated whether it has been able to leverage the recent tax laws and the possibility of taking 100 percent first-year bonus depreciation for the Diablo Canyon nuclear plant 2023-26 additions. But the presence of a DCPP DTA indicates it did not. Had it taken advantage of these tax provisions, there would likely be not DTA or the DTA would be significantly smaller than its current forecasted balance.

4. The Inclusion of the DCPP DTA in the GRC 2027 Violates the Consistency Rule

The "consistency rule," established by IRC section 168(i)(9)(B)(i), states that if PG&E uses an estimate or projection for any one of (1) tax expense, (2) depreciation expense, or (3) the deferred tax reserve, it must also use consistent estimates or projections for all three of those items and for the rate base itself.[181] In this case, PG&E has projected the ADIT derived from DCPP but has not included projections of any of the other three plant-related rate components associated with DCPP: gross plant balances, accumulated depreciation balances, and depreciation expense. PG&E's treatment of the DTA for the DCPP, therefore, violates the consistency rule.

Even if there is a properly generated DTA balance, restoring the DTA to rate base does not, in and of itself, protect PG&E from a normalization violation. That is because normalization requires PG&E to recover the tax timing differences over the life of the investment and therefore requires customers to be credited for any ADIT as a credit to rate base. It also requires consistency when updating any element of a plant in rates. In an attempt to avoid a normalization violation by

[179] 26 U.S.C. § 168(e)(3)(B).
[180] 25 U.S.C. § 168(k).
[181] IRS, PLR-101961-21 at 7 (2021).

including the DCPP DTA in rate base, PG&E may have created a separate potential normalization violation of the consistency rule.

5. PG&E Does Not Need to Include the DCPP DTA in the 2027 GRC Rate Base Because IRS's Safe Harbor Provision Protects PG&E from Inadvertent Normalization Violations

The IRS also has a safe harbor provision associated with its normalization rules. In plain language, the safe harbor provision provides a utility or regulator that discovers a potential normalization violation the ability to cure (or fix) that error at its next available opportunity to avoid the penalty of losing access to accelerated depreciation.[182] Given the facts and circumstances surrounding the DCPP DTA, PG&E and the Commission the safe harbor provision applies here. IRS Revenue Procedure 2017-47, Safe Harbor for Inadvertent Normalization Violations ("Safe Harbor") provides in Section 4.07(3) the following:

> If, at the conclusion of a Rate Proceeding, **the taxpayer has a private letter ruling request pending before the Service to address whether or not a practice or procedure addressed in the Rate Proceeding is a Consistent Practice or Procedure,** and the Taxpayer's Regulator later establishes or approves rates subject to adjustment from the effective date of the unadjusted rates in order to conform to the Service's ruling, the taxpayer shall have corrected its Inconsistent Practice or Procedure at the Next Available Opportunity.

PG&E requested a PLR for a determination related to PG&E's extended operations DTA.[183] On January 30, 2026, the IRS issued a PLR stating that "excluding these revenue requirements is not considered a normalization violation under this ruling."[184] This determination strongly suggests that the IRS would not find the removal of the DCPP DTA to be a normalization violation. Accordingly, PG&E should similarly submit a PLR on the DCPP DTA issue prior to the conclusion of the 2027 GRC, in order to access the safe harbor provision so long as it adjusts rates

[182] IRS Rev. Proc. 2017-47 § 4.07(3).
[183] Attachment RAM-2 (PG&E's response to DR CalCCA 006-03); Attachment RAM-2 (PG&E's response to DR CalCCA 005-023(c)); Attachment RAM-2 (PG&E's response to DR CalCCA 014-011).
[184] PG&E Advice Letter (AL) 7835-E (Feb. 12, 2026).

pending a PLR decision. This will allow PG&E to remove the DCPP DTA from rates without risking a normalization violation.

6. PG&E's Should Remove the DCPP DTA from Rates or Provide Balancing Account Treatment to Allow for a Future Refund.

PG&E's position in its direct case in the 2027 GRC is that, should the IRS determine after the close of this GRC that the DCPP DTA should not be included in base rates, it can make any necessary adjustments using the electric generation revenue requirement adjustment mechanisms during the Annual Electric True-Up.[185] However that position shifts risks unnecessarily onto customers if for any reason resolving the issue extends past future true-up windows. That risk can be mitigated simply by taking the DTA out of base rates or moving the DTA related revenue requirement to a balancing account.

The Commission should order PG&E to remove the DCPP DTA from rate base. Doing so would reduce the Electric Generation revenue requirement by $4.3 million annually.[186] To protect against any potential normalization violations, the Commission should also order PG&E to submit a Private Letter Ruling to the IRS for guidance on the appropriate rate-making treatment of the DCPP DTA prior to the end of 2026, which would give PG&E access to safe harbor from a potential normalization violation on this issue. The Commission should also order PG&E to subject the DCPP DTA to balancing account treatment, so that any future IRS determinations can be properly implemented and resulting in customers neither overpaying or underpaying for the appropriate treatment of this asset.

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[185] Exh. PG&E-10 at 10-8 lines 6-13.
[186] Attachment RAM-2 (PG&E's response to DR CalCCA 003-014, Rev 1, Attach. 1).

B. PG&E's Failure to Implement Changes to the Uniform System of Accounts Required Under FERC Order No. 898 Overstates the Revenue Requirement by $18.8 Million

PG&E's failure to comply with FERC Order No. 898—nearly six months after the order's January 1, 2025 effective date—is passing millions in incorrectly allocated costs directly onto CCA customers' bills. Although PG&E completed the required plant account reclassifications for book purposes in April 2025, it chose to exclude these mandatory reclassifications from its revenue requirement proposal in this GRC, continuing to rely on obsolete functional allocations that inflate the distribution of general and intangible plant costs to the Electric Generation function by $7.2 million. This unjustified non-compliance effectively subsidizes PG&E's operations at the expense of CCA customers, who are forced to pay their share of improperly allocated overhead costs while PG&E avoids the adjustment that FERC accounting standards now require.

FERC Order No. 898 modified the Uniform System of Accounts to create new FERC accounts specific to renewable generation, a new function with new FERC accounts specific to energy storage, and new FERC accounts within each function to allow for the functionalization of intangible and general plant, where possible.[187] Prior to FERC Order 898, all intangible and general plant were booked to specific intangible and general accounts, which PG&E functionally allocated based on a labor factor in previous GRCs and a labor plus capitalized labor factor in the current GRC.[188] FERC Order 898 became effective January 1, 2025.

In its application, filed May 15, 2025, PG&E indicated that it had not yet complied with FERC Order 898 because it was still compiling the data it allegedly needed to translate to the new FERC accounts.[189] While PG&E confirmed that plant account reclassifications were made in April

[187] Accounting and Reporting Treatment of Certain Renewable Energy Assets, Order No. 898, 183 FERC ¶ 61,205 (2023).
[188] Exh. PG&E-10 at 2-5.
[189] *Id*. at 7-23.

2025 for book purposes, PG&E's proposed revenue requirement in this case does not implement the account reclassifications required by FERC.[190]

In response to data requests, PG&E provided its actual plant balances subject to reclassification under Order 898 as of June 30, 2025.[191] The following table summarizes the gross plant from FERC Accounts 303 (intangible software), 391 (general office furniture), and 397 (general communication equipment) subject to reclassification to new functional hardware, software, and communication equipment FERC accounts.

Table RAM-14
Gross General and Intangible Plant Balances Subject to FERC Order 898 Reclassification

FERC Account	Pre-Order 898 Balance	FERC Account	Post-Order 898 Balance
303 – Misc Intangible Plant	$1,129,578,784	334.2 – Hydraulic Production Software	$18,716,245
		351.2 – Transmission Software	$175,729,103
		363.2 – Distribution Software	$928,365,221
		387.9 – Energy Storage Computer Software	$2,436,496
		397.2 – General Plant Software	$4,331,719
		Subtotal Software	**$1,129,578,784**
391 – Office Furniture Equip.	$55,157,839	334.1 – Hydraulic Production Hardware	$909,264
		351.1 – Transmission Hardware	$698,299,530
		363.1 – Distribution Hardware	$20,085,501
		Subtotal Hardware	**$719,294,295**
		315.3 – Steam Production Communication Equip.	$913,258
		334.3 – Hydraulic Production Communication Equip.	$27,621,047

[190] Attachment RAM-2 (PG&E's response to DR CalCCA 002-003).
[191] Attachment RAM-2 (PG&E's Response to DR CalCCA 004-007, Attach. 1).

397 – Communication Equip.	$1,490,753,097	338.11 – Solar Communication Equip.	$42,607
		351.3 – Transmission Communication Equip.	$210,909,254
		363.3 – Distribution Communication Equip.	$585,703,338
		387.10 – Energy Storage Communication Equip.	$448,563
		397.3 – General Plant Communication Equip.	$978,575
		Subtotal Communication Equip.	**$826,616,642**
Total	**$2,675,489,720**	**Total**	**$2,675,489,720**

Note: There is not a one-to-one translation between the total Communication Equipment in FERC account 397 pre-Order 898 and the total Communication Equipment in FERC Accounts 315.3, 334.3, 338.11, 351.3, 363.3, 387.10, and 397.3 post-Order 898 because some Communication Equipment was reclassified to the Hardware subaccounts.

Comparing PG&E's allocation of General and Intangible plant prior to the direct-assigned plant accounting required by FERC Order 898 shows that PG&E's proposed revenue requirement by business function in this case is quite different from what it would be if PG&E's filing included the effects of FERC Order 898. The following table illustrates the change in net plant allocated to the Electric Generation function from the implementation of FERC Order 898.

Table RAM-15
Change in Electric Generation Allocated Net Plant from FERC Order 898[192]

	CGI Net Plant in FERC Accounts 303, 391, and 397	**Electric Generation Allocated**
Prior to FERC Order 898		$103,717,420
Post-FERC Order 898		
Direct Assigned Production		$31,658,125
Direct Assigned Energy Storage		$2,743,307
Remaining CGI Plant	$4,557,438	$271,168
Total Post-FERC Order 898		**$34,672,599**
Total Change in CGI Plant Allocated to Electric Generation from FERC Order 898		**($69,044,821)**

[192] Attachment RAM-9.

Attachment RAM-9 contains detailed calculations of the impact of FERC Order 898 on the Electric Generation revenue requirement. Reclassifying general and intangible plant balances to the new functional FERC accounts would reduce the Electric Generation revenue requirement by an estimated \$6.9 million based on the June 30, 2025 balances provided.[193] The revenue requirement would also be reduced by the associated depreciation expense that would also be reallocated to the new functional FERC accounts, reducing the revenue requirement an additional \$11.9 million, for a total of \$18.8 million.[194]

The Commission should require PG&E to update its revenue requirement for the 2027–2030 GRC period to include the impact of FERC Order 898. To the extent that FERC Order 898 requires certain General and Intangible plant to be directly assigned to functional FERC accounts, it should be reflected in PG&E's proposed revenue requirement. It would be unjust and unreasonable to set rates through 2030, 5 years after FERC Order 898 was required to be implemented, without reflecting the impacts of the FERC decision.

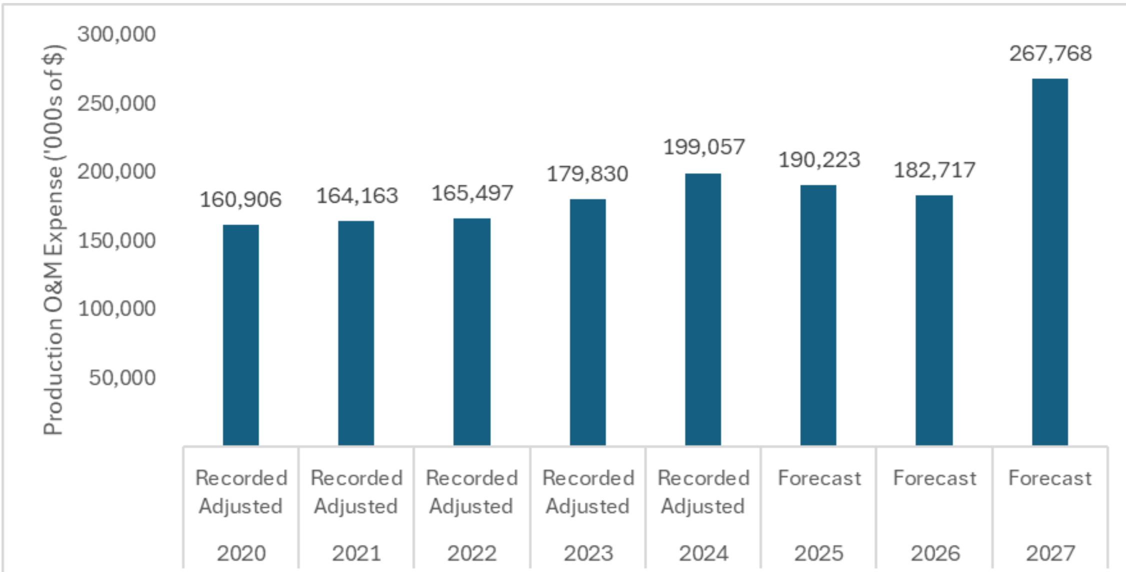
VI. PRODUCTION O&M EXPENSE FORECAST

PG&E is claiming a bloated 35 percent spike in hydro production O&M expenses for 2027—jumping from \$199.1 million in 2024 to \$267.8 million[195]—yet ignores the substantial operational savings that its own strategic investments in advanced asset management systems should deliver. While PG&E justifies this dramatic expense increase by citing investments in additional staffing and enhanced asset and risk management capabilities,[196] the company makes no attempt to quantify or pass through the efficiency gains and cost reductions these investments are designed to generate. This one-sided treatment inflates ratepayers' bills: customers are forced

[193] *Id.*
[194] Attachment RAM-9.
[195] Exh. PG&E-5 at 1-23, Table 1-1 (Nov. 15, 2025).
[196] *Id*. at 3-1 lines 16–27.

to absorb the full upfront cost of PG&E's operational improvements while the company pockets the downstream savings, turning what should be prudent investment into a hidden rate increase.

Figure RAM-11: Production O&M Expense, 2020–2024 Actuals, 2025–2027 Forecast



A. PG&E's Forecasts Overestimate Its Expense for Hydro Operators

PG&E's proposed increased staffing of hydro operators results in a $10.3 million increase in 2027 forecasted expense compared to 2024 from both the direct cost of those operators and the indirect cost of additional training and support staff.[197] PG&E plans to hire 48 additional hydroelectric operators by 2027 and has already begun hiring such that as of June 30, 2025, it has 55 operators, or 6 more than on December 31, 2024.[198] Those 48 additional operators would be an addition to the 49 existing operators as of the end of 2024, effectively doubling the number of hydro operators on staff. Yet, although these hirings are intended to address staffing attrition and

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[197] *Id*. at 3-42, Table 3-14.
[198] Attachment RAM-2 (PG&E response to DR CalCCA 005-013).

overtime,[199] PG&E fails to account for the savings that would come from reduced overtime hours, existing staff attrition, and future facility sales and retirements.

Table RAM-16
Existing and Additional Hydro Operators by Location

Location	DeSabla	Drum	Helms	Kings-Crane Valley	Motherlode	Shasta	Total
Existing Operators	9	13	3	5	8	11	49
Additional Operators	12	9	3	7	6	11	48
Total Operators	**21**	**22**	**6**	**12**	**14**	**22**	**97**

PG&E's O&M expense does not reflect the staff attrition it is attempting to solve. PG&E describes that it takes three years to turn a new hire into a qualified hydro operator, and due to that long lead time it is necessary to maintain a pipeline of hiring in order to maintain staffing levels in the face of existing operator attrition.[200] PG&E has a history of doing just that; from 2015 through 2024 it has hired an average of 8.1 hydro operators per year, with a low of one hire in 2019 and 2021 and a high of 13 hires in 2020.[201] Over that same time period, PG&E experienced attrition of 9.1 hydro operators per year, on average, which resulted in its year-end head count decreasing from 58 hydro operators in 2015 to 49 operators in 2024.[202] Just because attrition is a factor that necessitates new hires does not mean that it results in an operational expense increase. Since the expense from the new hire to backfill for attrition replaces the expense that is reduced from the operator who departed, there should be no net change to the forecast as a result of attrition. PG&E

[199] Exh. PG&E-5 at 3-5 lines 7–15.
[200] *Id*. at 3-43 lines 24–31.
[201] Attachment RAM-2 (PG&E's response to DR CalCCA 005-014).
[202] Attachment RAM-2 (PG&E's response to DR CalCCA 014-007).

did not adjust its forecast for future hydro operator attrition. Therefore, the forecast overestimates PG&E's expense for hydro operators.

Although PG&E's hiring plans are intended to address its significant overtime expense, PG&E's proposed O&M expense does not show reflect those savings. PG&E states that it "must often ask operators to work overtime to continue to staff its switching centers and be able to conduct necessary surveillance activities to ensure public safety"[203] and that the additional staffing will address fatigue management challenges and therefore reduce overtime.[204] PG&E then contradicts itself to say that it does not expect fewer overtime hours as a result of hiring but that there could be overtime reduction on nights and weekends in the specific circumstance when a second operator could respond to a remote event without having to call out a roving operator on overtime.[205] However, the estimated cost reduction from this specific circumstance is only $0.18 million out of a total 2024 hydro operator overtime expense of $7.4 million. It seems highly implausible that the planned doubling of the number of hydroelectric operators, with the stated intention to reduce overtime, could not significantly reduce the $7.4 million in overtime expense incurred by PG&E in 2024.

Further, PG&E has not made an adjustment to the number of planned hydro operators due to the planned sale or retirement of the Phoenix, Kerckhoff 1, Potter Valley, Hamilton Branch, and Battle Creek hydro facilities.[206] The fact that these plants are no longer planned to be operated through the GRC period should result in a downward adjustment to operator as well as maintenance expense.

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[203] Exh. PG&E-5 at 3-43 lines 6–8.
[204] *Id*. at 3-5 lines 9–10.
[205] Attachment RAM-2 (PG&E's response to DR CalCCA 005-012).
[206] Attachment RAM-2 (PG&E's response to DR CalCCA 014-010).

In addition to failing to pass on to customers the expected savings resulting from its hiring plans, there appears to be a more fundamental flaw in PG&E's plan: it has not demonstrated that it has the ability to actually hire all the operators it has forecasted. PG&E hired six net new hydro operators in the first six months of 2025.[207] To achieve its planned headcount of 97 operators, PG&E would need to hire 42 new operators (net of attrition) over an 18-month period. Given PG&E's average annual hydro operator attrition rate of 9.1 operators per year,[208] it would also need to hire an additional 14 hydro operators to backfill for likely attrition As a result, PG&E must hire 56 operators over an 18-month period, which is a rate of 37 operator hires/year. Given that the most operators PG&E has hired in a year over the last 10 years is 13,[209] its plans do not seem achievable.

CalCCA recommends that the Commission reject the proposed $10.3 million increase to operational expense from PG&E's plans to nearly double its number of hydro operators. PG&E has not justified the need for the substantial increase in operators it proposes, particularly in light of its shrinking hydro fleet; it has not accounted for the full amount of overtime savings its plans should produce; it has not accounted for existing operator attrition; and it has not demonstrated that it can even reach the levels of forecasted costs.

B. PG&E Must Include in Its Revenue Requirement Cost Savings Realized from Its Asset Management System Investments

PG&E acknowledges that its Asset Management System generates significant cost savings through waste elimination and efficiency improvements—yet fails to pass these benefits on to ratepayers. While seeking to recover the full cost of the AMS investment in its O&M expenses, PG&E makes no offsetting adjustment for the measurable savings these investments are designed

[207] Attachment RAM-2 (PG&E's response to DR CalCCA 005-013).
[208] Attachment RAM-2 (PG&E's response to DR CalCCA 014-007).
[209] Attachment RAM-2 (PG&E's response to DR CalCCA 005-014).

to produce, effectively allowing the company to pocket windfalls from continuous improvement while customers bear the full expense burden.[210]

Since the 2023 GRC, PG&E has adopted an asset and risk management practice with objectives of continuous improvement, compliance with industry standards, and implementation of risk management best practices. Its approach involves the implementation of an Asset Management System ("AMS") to integrate strategic planning, risk management, and reliability optimization throughout the asset lifecycle. Power Generation received ISO 55001 certification in March 2022 for its AMS.[211]

The planned continued investment in its AMS has been identified by PG&E as an O&M expense increase driver. PG&E has identified enhanced asset and risk management as the reason for the increase in O&M expense between 2024 actuals and the 2027 forecast of $16.3 million in the Major Work Category KH – Maintain Hydro Generating Equipment;[212] $1.1 million in the MWC KI – Maintain Hydro Buildings, Grounds, and Infrastructure;[213] and $13.3 million in the MWC AX – Maintain Reservoirs, Dams, and Waterways.[214] In total, enhanced asset management is a driver for approximately $30.7 million of O&M expense increases from 2024–2027.

The investment in the AMS is necessary to achieve the desired objectives: improved safety and reliability, reduced operational risk, and improved regulatory compliance. An additional benefit of the implementation of AMS comes in the form of cost reductions from the elimination of waste.[215] PG&E provides an example of these savings in the form of an innovative construction technique that saved an estimated $3.5 million in labor costs in 2024 on the Canyon Dam spillway

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[210] *See* Attachment RAM-2 (PG&E's response to DR CalCCA 010-22).
[211] Exh. PG&E-5 at 1-15 lines 4–21.
[212] *Id*. at 3-48, Table 3-19.
[213] *Id*. at 3-53, Table 3-22.
[214] *Id*. at 3-57, Table 3-26.
[215] *See* Attachment RAM-2 (PG&E's response to DR CalCCA 010-24).

project.[216] These benefits would be expected to recur on a regular basis. PG&E quantified that the total cost savings achieved across all of Power Generation through its efforts to eliminate waste and adopt lean operating principles was $24.5 million in 2024.[217] In the absence of a specific forecast for planned cost savings from AMS, the historical cost savings achieved can be a reasonable proxy as they represent the level of savings possible from the presence of a waste reduction, continuous improvement program.

If increased costs associated with AMS are included in the revenue requirement, offsetting savings must also be included; otherwise, PG&E is overestimating its 2027 expense. If increased investment in AMS does not continue to achieve year-over-year operational cost savings, then PG&E should reevaluate the value of that investment. Absent any more specific information about potential cost savings, PG&E should reduce its 2027 O&M expense by $24.5 million, the level of achieved savings in 2024.

VII. COST ALLOCATION ISSUES

A. PG&E's Allocation of Common, General, and Intangible Plant Violates the Requirements of FERC Order No. 898 and Results in Improperly Allocated Costs to the Functional Revenue Requirements

PG&E's selective and piecemeal changes to how it allocates Common, General, and Intangible ("CGI") costs is artificially shifting expenses between customer classes, forcing some ratepayers to pay far more than their cost to serve while unfairly subsidizing others. By cherry-picking the direct assignment of hydro license costs to generation while failing to investigate or adjust the allocation of any other CGI plant costs despite FERC Order 898's clear requirements, PG&E is creating an inconsistent cost allocation that distorts rates across all functions.

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[216] Exh. PG&E-5 at 3-6 lines 3–11.
[217] Attachment RAM-2 (PG&E's response to DR CalCCA 010-023).

FERC Order 898 requires PG&E to functionally allocate intangible plant booked to FERC Account 303 and general plant booked to FERC Accounts 391 and 397.[218] Here instead, PG&E proposes to functionally allocate all CGI plant based on a labor allocator, consistent with past GRCs.[219] PG&E maintains that approach in this case with one notable exception: it proposes to direct assign the intangible hydro license costs to the Electric Generation function.[220] PG&E has not proposed to direct assign any other category of CGI plant, despite the requirements of FERC Order 898, nor has it indicated that it investigated the potential to direct assign any other category of CGI plant.[221]

If PG&E wants to depart from the historical precedent of allocating all CGI plant based on a labor factor, it should not perform such changes piecemeal. Departing from an allocation method for one portion of CGI plant without even investigating the direct assignment or more precise allocation of other CGI plant would result in cost allocations, and therefore rates, that are inconsistent across all functions, leading to some customers paying more than their cost to serve and other customers paying less than their cost to serve. Instead, PG&E should conduct a comprehensive study of all CGI cost allocations to determine their appropriateness and should refrain from making any adjustments until that study is complete, with the exception of the reclassifications originating from FERC Order 898 as it is a regulatory requirement that those be reclassified. Even with the FERC Order 898 reclassification, there remain balances in the intangible, general, and common accounts that would require further investigation to determine

[218] Order No. 898, 183 FERC ¶ 61,205 at PP 99-100, 110.
[219] Exh. PG&E-10 at 7-11 lines 2–3. In prior GRCs, that labor allocator was based solely on O&M labor, excluding capitalized labor. In this case, PG&E proposes to modify the labor allocator to instead be based upon the sum of O&M and capitalized labor. This change is due to the requirements of SB 846 that the Diablo Canyon investment not be capitalized, and as a result PG&E no longer incurs capitalized labor to support DCPP operations.
[220] Exh. PG&E-10 at 7-12 lines 7–25.
[221] Attachment RAM-2 (PG&E’s response to DR CalCCA 014-001).

more precise functional allocations. PG&E can then propose a more refined and fair allocation method for CGI plant that considers all CGI plant in the next GRC.

Should the Commission not order PG&E to refrain from any CGI allocation changes prior to the completion of a comprehensive study aside from FERC Order 898 requirements, then CalCCA recommends that PG&E still complete a comprehensive study prior to the next GRC but also make the following CGI allocation changes in addition to direct assigning the intangible hydro licenses to the extent that it is not already required to be reclassified by FERC Order 898:

- Electric General ("EGP") and Electric General Land ("EGPL")[222] – These should only be allocated to Electric UCCs. These assets are specific to the electric utility by definition, and therefore it is not reasonable to allocate a portion of their costs to the gas utility.
- Gas General – Line 401 ("GGE"), Gas General-Land – Line 401 ("GGEL"), Gas General ("GGP"), Gas General Land ("GGPL"), Gas Intangible-Line 401 ("GIE"), and Gas Intangible ("GIP")[223] – These should only be allocated to Gas UCCs. These assets are specific to the gas utility by definition, and therefore it is not reasonable to allocate a portion of their costs to the electric utility.

In order to achieve these more specific allocations, PG&E should develop new labor allocators to allocate costs only within the Electric utility and the Gas utility. The following table shows a recommendation for that allocator.[224]

[222] Exh. PG&E-10 at WP7-1, Table 7-5; *id.* at WP7-138, Table 7-45.
[223] *Id.*
[224] *See* Attachment RAM-10 for the derivation of the allocators.

Table RAM-17
Recommended Allocation for Electric General and Gas General & Intangible Plant

	Electric Generation	Electric Distribution	Gas Distribution	Gas Transmission & Storage	Non-GRC	Total
PG&E Proposed	5.95%	57.59%	18.28%	8.09%	10.09%	100.00%
Electric General	8.08%	78.22%	0%	0%	13.70%	100.00%
Gas General & Intangible	0%	0%	69.32%	30.68%	0%	100.00%

The following table shows the net change in WAVG 2027 general plant balances by function. This table assumes that none of the EGP, EGPL, GGE, GGEL, GGP, GGPL, GIE, and GIP are impacted by FERC Order 898.

Table RAM-18
Net Change in CGI Plant Allocation

	Total Investment	Electric Generation	Electric Distribution	Gas Distribution	Gas Transmission & Storage	Non-GRC
Change from Electric General Reallocation	$0	$30,939	$299,502	($259,419)	($114,797)	$43,776
Change from Gas General & Intangible Reallocation	$0	($58,399)	($565,328)	$502,599	$222,408	($101,280)
Total Allocation Change	**$0**	**($27,460)**	**($265,826)**	**$243,180**	**$107,611**	**($57,504)**

The impact of these reallocations is estimated to reduce the Electric Generation revenue requirement by $2.7 million, reduce the Electric Distribution revenue requirement by $26.6 million, increase the Gas Distribution revenue requirement by $24.3 million, and increase the Gas Transmission & Storage revenue requirement by $10.8 million. To the extent that any of the balances are already impacted by FERC Order 898, the impact of the more precise allocation of any remaining balances on the functional revenue requirement will be smaller.

B. PG&E's Outdated Fees for Performing Billing Services on Behalf of CCAs Are Resulting in CCA Customers Paying More to PG&E than the Cost to Serve Those Customers

PG&E is charging CCA customers metering and billing fees locked in at 2015 cost levels, creating a systematic overbilling scheme that forces CCA customers to pay inflated rates that no longer reflect PG&E's actual cost to serve them. By refusing to reconcile what PG&E actually spends to provide billing services against what it charges CCA customers for those services, the utility creates a hidden cost-shift, overbilling CCAs and allowing bundled customers to benefit from the surplus.

PG&E provides billing services to CCA customers. CCAs are directly charged for metering and billing costs by PG&E on a per meter or per customer basis to provide that service. Those fees include the Meter Data Management ("MDM") Fee, Rate-Ready Billing ("RRB"), and Bill-Ready Billing ("BRB").[225] These rates, like all other rate schedules, are determined in a Phase 2 GRC based on the cost to provide those services as determined during the Phase 1 GRC. The currently applicable MDM, RRB, and BRB rates were determined based on a cost study included in PG&E's

[225] PG&E Electric Schedule E-CCA, Sheets 4 & 6 (effective March 1, 2018).

2017 GRC which is based upon 2015 costs and billing units.[226] These fees must be updated as they no longer reflect PG&E's cost to serve CCA customers.

Based upon data provided by PG&E in response to CalCCA's data requests, from 2020 through 2024, the revenue from DA/CCA billing services received by PG&E was greater than the DA/CCA billing services expense by $10.3 million.[227] The resulting impact of that imbalance is that a net credit is embedded as a customer cost which is allocated by PG&E to the Gas and Electric Distribution functions.[228] Therefore, the net credit, or the amount of revenue paid by DA/CCA customers that is greater than their costs to serve, gets allocated out to bundled customers as well as to DA/CCA customers. PG&E's bundled customers have therefore been receiving a benefit from DA/CCA customers as opposed to being held indifferent.

Updating PG&E's metering and billing fees based on costs from the ongoing Phase 2 GRC proceeding would almost certainly result in a reduction in fees for CCA customers. Since 2017, the number of DA/CCA customers has grown dramatically.[229] DA/CCA billing revenue scales linearly with the number of DA/CCA customers; in other words, each incremental DA/CCA customer brings in the same amount of incremental revenue. It is not likely, however, that incremental DA/CCA customers result in PG&E incurring the same amount of incremental cost

[226] Attachment RAM-2 (PG&E's response to DR CalCCA 001-020 from the 2023 Phase 2 GRC, A.24-09-014, Attach. 1). *See also* Attachment RAM-2 (PG&E's response to DR CalCCA 012-015).
[227] Attachment RAM-2 (PG&E's response to DR CalCCA 005-016, Attach. 1). The attachment shows a net credit in most years, which is consistent with PG&E's stated practice of reducing costs by the revenue received, and therefore the sum of the total expense shown is equal to the net cost or net revenues from CCA/DA billing services. *See also* Attachment RAM-2 (PG&E response to DR CalCCA 002-022).
[228] Attachment RAM-2 (PG&E's response to DR CalCCA 014-002).
[229] National Renewable Energy Laboratory, *Community Choice Aggregation: Challenges, Opportunities, and Impacts on Renewable Energy Markets* at 7 (Feb. 2019) which shows an estimated 5% of state sales served by CCAs in 2017; California Public Utilities Commission, *Community Choice Aggregation and Energy Service Provider Formation Report* at 7 which shows 38% of load statewide served by CCAs in 2017, and 49% of PG&E's load.

for each customer added. That is because there are economies of scale in meter reading and billing functions, so each new DA/CCA customer should result in incrementally lower marginal costs.

The most reasonable way to fix the current mismatch between CCA billing service revenue and CCA billing service cost is for PG&E to complete an updated cost study to base the billing service rate on more accurate and current costs. That would result in the revenue and expense being much more closely aligned moving forward. However, that update is required to be performed in a GRC Phase 2 case. PG&E should update its billing service rates in the ongoing GRC Phase II, which would result in billing revenues and costs being aligned by the first quarter of 2027.

Until the billing services rates can be updated through the GRC Phase II proceeding, the Commission should order PG&E to cap its revenues associated with CCA/DA billing services at the cost included in its forecast for such services. Any revenue received above that cap within the GRC should be tracked and refunded to CCA/DA customers through the ERRA proceeding.

VIII. HYDRO LICENSING BALANCING ACCOUNT EXPANSION

A. PG&E's Expansive Use of Its Hydro Licensing Balancing Account Is Unwarranted and Reduces the Incentive for PG&E to Control Costs

PG&E's use of the Hydro Licensing Balancing Account ("HLBA") has morphed from a limited true-up mechanism into a blank check that eliminates any financial incentive for the company to control or efficiently manage hydro-related costs. By allowing PG&E to recover every dollar of hydro licensing, regulatory fees, and miscellaneous costs through automatic balancing account adjustments—rather than requiring the company to forecast and manage these expenses within a fixed rate base like it must do with other operational costs—PG&E has eliminated the fundamental ratemaking discipline that compels cost control. When a utility knows that any expense variance will be automatically recovered through a balancing account, it loses the powerful financial incentive to make tough resource allocation decisions, negotiate aggressively with contractors, or implement efficiency improvements. The result is a moral hazard that invites cost escalation, with ratepayers bearing the full burden of every overage, regardless of whether the increases stem from prudent necessity or preventable inefficiency.

Balancing account treatment is appropriate for costs which are unpredictable, variable, and generally outside of the utility's control. That treatment ensures that the utility is not financially harmed by factors beyond its direct control and allows for customers to pay the exact costs associated with the underlying expense. On the other hand, base rate treatment is appropriate for costs which are largely under the utility's control and therefore can be forecasted and managed. It is up to the utility to manage its costs relative to that forecast to ensure safe and reliable service to customers while maintaining its financial health and achieving its authorized return. The risk of achieving the earned rate of return rests with the utility, which provides an incentive to manage capital and operational spending on an ongoing basis. Balancing account treatment removes that incentive.

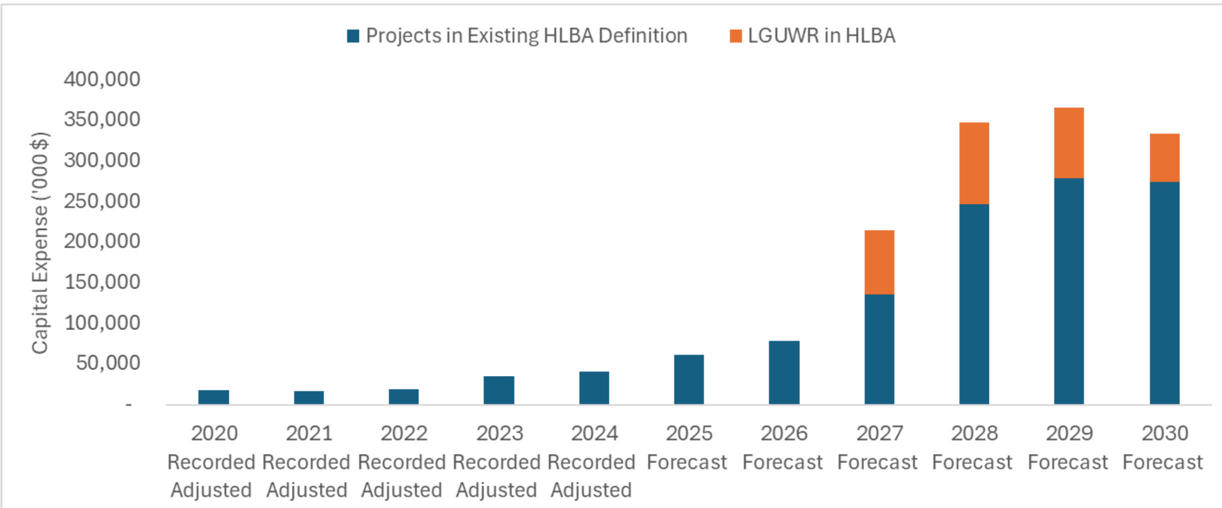
The HLBA is a two-way balancing account that was established in 2014 to capture operational and capital costs associated with FERC relicensing activities for licenses issued beginning on January 1, 2012. Its use has since been expanded to also include federal and state regulatory fees, the costs of implementing the 2003 Crane Valley Recreation Settlement Agreement, and costs stemming from the 2017 Oroville spillway incident.[230] The 2023 GRC further modified the HLBA to include a reasonableness review for all costs greater than 20 percent above the authorized revenue requirement.[231]

While balancing account treatment is appropriate for hydro licensing costs, particularly expenses, that are unpredictable and beyond the utility's control, PG&E has expanded the amount

[230] Exh. PG&E-5 at 7-7 lines 9–16.
[231] *Id*. at 7-7 lines 17-19.

of costs proposed to be passed through the HLBA far beyond a reasonable interpretation of this definition. The following graph shows actual costs incurred through the HLBA from 2020–2024 as well as forecasted costs from 2025–2030.

Figure RAM-12: Capital Costs in HLBA, Actual 2020–2024, Forecasted and Proposed 2025–2030



PG&E has expanded the amount of capital expenditure proposed to receive balancing account treatment to a substantial share of its total forecasted capital expenditure on its hydro facilities, specifically 43 percent in 2027, 55 percent in 2028, 57 percent in 2029, and 49 percent in 2030.[232] Effectively, PG&E is stating that approximately half of its hydroelectric capital expenditures in 2028, 2029 and 2030 are unpredictable, variable, and generally outside of the utility's control. Yet, many of the projects proposed for each category of the HLBA do not warrant balancing account treatment.

The following table shows a categorization of the capital costs proposed for inclusion under the existing scope of the HLBA,[233] with a more detailed table presented in Attachment RAM-11.

[232] Attachment RAM-11.
[233] This categorization is based on the groupings shown in the electronic version of Exhibit PG&E-5 WP 3-64 to 95.

Table RAM-19
Forecasted Capital Expenditure by Category for Inclusion in HLBA, 2027–2030

(‘000s of $) Category	2027	2028	2029	2030
Security	$34,117	$41,643	$26,430	$25,394
Spillway	$64,836	$151,564	$146,686	$136,720
License Conditions	$37,165	$54,255	$105,481	$112,658
HLBA Expansion	$78,816	$100,512	$87,442	$59,074
Total	**$214,935**	**$347,974**	**$366,040**	**$333,846**

The total costs of $127.6 million across the 2027–2030 time period for security investments consist primarily of upgrades to or installation of fencing and security cameras across PG&E’s hydro facilities.[234] While those investments come as the result of FERC requirements, that alone does not make these expenses unpredictable, variable, and outside of the utility’s control. In fact, for some of these investments PG&E has been aware of the requirements since 2011.[235] Given that this program also implements risk mitigation strategies developed in the 2024 Risk Assessment and Mitigation Phase (“RAMP”) report[236] and consists largely of the same types of investment across multiple facilities, it is the type of investment well suited to recovery in base rates.

The spillway category includes projects intended to mitigate the risk of large uncontrolled water release and to maintain the spillways as required by state and federal regulations.[237] The largest project in this category, the McCloud Spillway Improvement, represents 72 percent of the total 2027–2030 forecasted spillway investment of $499.8 million.[238] The need for this project originated in the wake of the 2017 Lake Oroville Dam spillway incident, when PG&E assessed its

[234] Exh. PG&E-5 at WP3-90 to 95, lines 1,634–1,635, 1,709–1,711, 1,714, 1,716–1,718, 1,720–1,739, 1,741–1,743, 1,748, 1,752–1,757, 1,763–1,795, 1,797–1,851, 1,856–1,864, 1,866, and 1,890–1,918.
[235] *Id*. at WP 3-452.
[236] *Id*. at WP 3-453.
[237] *Id*. at WP 3-382.
[238] *Id*. at WP 3-381 to 384.

inventory of similar spillways. While this project originated from safety-related regulatory requirements, in its implementation it appears to be comparable to any other large capital project. PG&E has provided no evidence on why it is reasonable to provide balancing account treatment for $358.1 million of forecasted capital investment for the McCloud Spillway project. Providing guaranteed recovery of the forecasted cost plus 20 percent[239] reduces the incentive for PG&E to control costs, an incentive that is a critical element of ratemaking in this case given PG&E's substantial proposed generation capital investment and operating expense increases.

The category of license conditions refers to specific projects that are required as a result of the FERC relicensing process. While there's often uncertainty because the timing and scope of those projects are unknown until that license is issued, projects totaling $62.5 million in forecasted capital expenditure from 2027–2030 are the result of license conditions stemming from the issuance of a FERC license prior to the filing of this GRC.[240] For those projects, the license conditions are already known, and the scope and timing uncertainty that would justify balancing account treatment no longer exists. Therefore, those costs should not be subject to balancing account treatment. The following table details the forecasted $62.5 million in capital expenditures for licenses already issued prior to the filing of this case.

[239] Costs more than 20% above forecast are subject to a reasonableness review, in effect guaranteeing costs expended up to 120% of forecast.
[240] Attachment RAM-11.

Table RAM-20
Capital Expenditure Forecast for License Condition Projects by Hydro Facility

Hydro Facility	FERC License Date	Capital Expenditure Forecast ('000s of $)			
		2027	2028	2029	2030
Mokelumne	2001	$5,098	$4,654	$2,311	$2,554
Rock Creek	2001	$285	$665	$1,541	$4,966
Hat Creek 1 & 2	2002	$778	$2,557	$2,371	$1,091
Pit 1	2003	$571	$23	$0	$0
Crane Valley	2003	$2,568	$2,294	$1,845	$469
Poe	2018	$890	$327	$2,080	$586
Bucks Creek	2022	$3,185	$4,145	$7,270	$7,392
Total Pre-2025		**$13,376**	**$14,666**	**$17,418**	**$17,057**

PG&E's proposed expansion of the HLBA to include LGUWR projects is also not reasonable based on the types of capital costs included. The LGUWR includes capital and operational expenses related to vegetation management and rodent abatement, erosion mitigation, spill way remediations, seismic retrofits, outlet refurbishments, and physical security.[241] None of these categories present the level of uncertainty and variability in cost to warrant balancing account treatment. They represent the standard course of business for a utility of PG&E's size and capacity. Costs for capital projects and operational expenses of these types should be recovered through base rates to continue to provide an incentive for PG&E to control costs.

PG&E argues that these projects take years to plan, design, and construct; that construction windows are uncertain and narrow; and that the scope of the projects is dependent on government agencies.[242] But those factors are also likely present in other hydro investments that do not receive

[241] Exh. PG&E-5 at 2-17, Table 2-2.
[242] *Id*. at 1-18; *id.* at 3-94.

HLBA treatment. And the fact that projects take place over multiple years, even multiple years to simply design, is a reason that they should be included in base rates set in a GRC. PG&E should be developing specific cost estimates over those multiple years that it can manage in order to meet during project implementation. Given these long time frames, there is plenty of time to include those costs in a GRC forecast.

In summary, the Commission should limit the use of the HLBA to costs that are truly unpredictable, variable, and generally outside of the utility's control. In rigorously applying that definition, the Commission should not allow HLBA recovery of the LGUWR Security and Spillway categories of costs, and it should limit the License Conditions projects only those facilities that have not yet received their FERC license at the time of filing a GRC. Adopting this recommendation would result in the recovery of the following forecast capital expenditures moving from the HLBA to base rates:

Table RAM-21
Capital Expenditure from HLBA to Base Rates[243]

('000s of $) Year	2027	2028	2029	2030	Total
Capital Expenditure from HLBA to Base Rates	$191,146	$308,385	$277,977	$238,245	$1,015,753

[243] Attachment RAM-11.

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Flexible Connections All-Party Workshop
R.21-06-017

February 20, 2026

Who Are Community Choice Aggregators?

CalCCA Interactive CCA Map & Address Lookup:
https://cal-cca.org/cca-map/

CCA Launch Timeline

California CCAs: By the Numbers

Number of California communities served by CCAs: 229

Number of Counties with CCA: 21 of 58 counties (36%)

Number of Cities/Towns with CCA: 208 of 483 Cities (43%)

California Population served by CCAs: 16 Million+ (38%)

2025 and 2026 CCA Expansions

2025

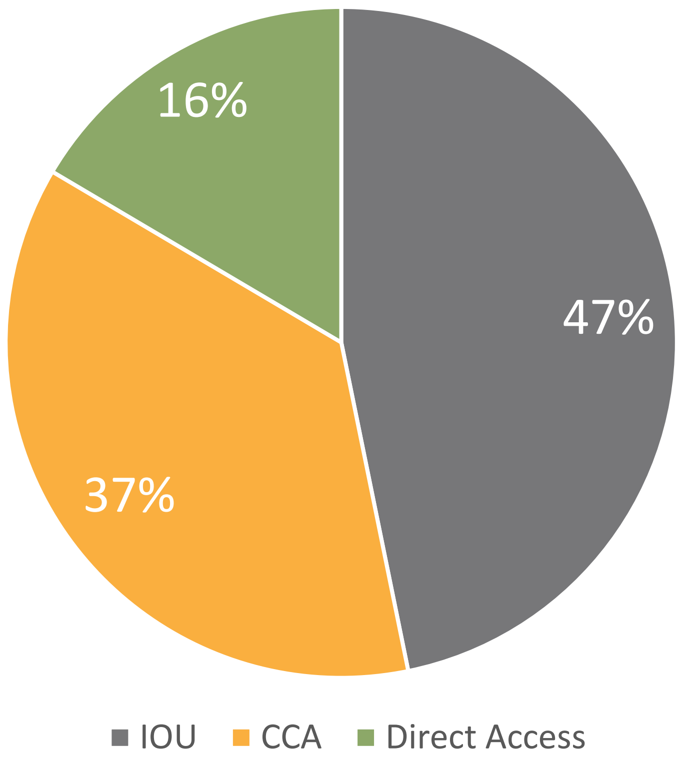
CCA	New/Expansion	Cities/Counties	Start of Service
Central Coast Community Energy	Expansion	County of SLO, City of Atascadero	January 2025
Ava Community Energy	Expansion	City of Stockton and Lathrop	April 2025
Marin Clean Energy	Expansion	City of Hercules	April 2025
Clean Power Alliance	Expansion	Cities of La Canada Flintridge, Lynwood, Port Hueneme	October 2025

2026

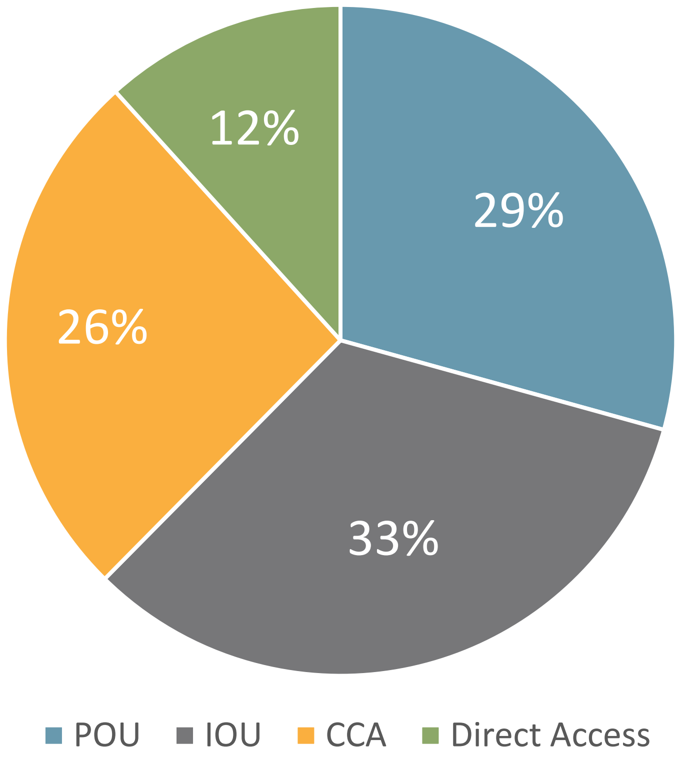
CCA	New/Expansion	Cities/Counties	Start of Service
Ava Community Energy	Expansion	County of San Joaquin	May 2026
Orange County Power Authority	Expansion	City of Fountain Valley	October 2026

2024 Percentage of CA Retail Load by Energy Provider (Electricity deliveries GWh to End Users)

2024 Percentage of LSE Retail Load In IOUs Territories



2024 Percentage of CA Retail Load by Energy Provider



Source: 2023 IEPR Forecast. California Energy Demand 2023-2040 Forecast - Planning Forecast

CALCCA ADVANCING LOCAL ENERGY CHOICE

Why Are CCAs Interested in Flexible Service Connections?

CCA APPEAL

- Climate Impact
- Local, transparent decision-making/accountability
- Rate competition/rate stability
- Green energy choices
- Community-based programs
- Economic Development, Jobs

CCA Programs

- As CCAs continue to grow and flourish in California, they are advancing innovative, industry-leading projects and programs
- Many are now focusing on DERs, including Virtual Power Plants
- Several CCAs now operate DERMS platforms to directly control customer DERs and smart appliances

"CCAs can design and deploy innovative initiatives and community-centered programs that provide financial and environmental benefits and can respond to communities' needs."

-UCLA Luskin Center for Innovation

Sonoma Clean Power Your Public Electricity Provider

Alerts Through GridSavvy Rewards

Stay Cool, Save Energy, and Keep Your Neighborhood Bright With GridSavvy Rewards From Sonoma Clean Power.

GET $25 WHEN YOU ENROLL

Save Energy. Share Energy. This Summer and Beyond.

When it's really hot, everyone uses more electricity. To make sure there's enough to go around, there's an easy way to help: **Save Energy. Share Energy.** Saving energy when asked helps your whole neighborhood. When you save energy, you share energy, to help keep the lights on in the neighborhood **all summer long**.

Earn rewards by lowering your energy use when electricity use is high. By reducing electricity use during peak hours, you can help decrease the need for natural gas power plants and prevent power outages.

When you sign up for GridSavvy Rewards, you'll get paid for helping us power the electric grid with more local, clean energy. SCP will send an energy saving alert when there is high demand for electricity. You choose how to reduce your energy use.

SIGN ME UP!

MCE

How to Help California's Grid? Go Virtual

At first glance, there's nothing atypical about the small gray house located on a quiet residential street in Richmond, Calif. But look further and you'll see that it's the first piece of a revolutionary new type of power plant. Unlike traditional plants, you won't find any massive cooling towers or transmission lines. That's because this electrified home is part of a virtual power plant, or VPP.

How It Works

The homes MCE is equipping to participate in its VPP are outfitted with numerous grid-smart devices that not only provide grid flexibility but also make for a better experience for the homeowner.

VPP in the News

News Release – November 3, 2025

Peninsula Clean Energy, Silicon Valley Clean Energy Jointly Launch Demand Flexibility Initiatives

Lunar Energy's Gridshare software will enable new battery and other programs to reduce customer energy bills and harmful emissions

PENINSULA CLEAN ENERGY   SILICON VALLEY CLEAN ENERGY

REDWOOD CITY/SUNNYVALE, CA – Peninsula Clean Energy (PCE) and Silicon Valley Clean Energy (SVCE) are jointly launching cutting-edge demand flexibility efforts, highlighted by a Distributed Energy Resource Management System (DERMS) that will support a range of new programs.

The DERMS is a powerful software platform that both agencies will use as a foundation to expand their clean and smart energy programs. The new platform will enable participating customers to easily, automatically and comfortably shift daily electricity use – earning them direct bill savings, while also helping to reduce grid costs and harmful emissions.

PCE and SVCE have contracted with Mountain View-based Lunar Energy for its Gridshare DERMS platform to connect, control and optimize devices located at customer sites.

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Residential Battery Rebate Program

Power up and protect your home with a battery energy storage system

Overview | Eligibility | Resources | Application

Power Up and Reduce Electricity Costs with a Home Battery

Orange County Power Authority's (OCPA) Residential Battery Storage Rebate Program helps customers manage their energy consumption and save money by storing electricity during lower-cost, off-peak hours for use during more expensive, on-peak hours ("load shifting"). Adding battery backup can protect your home from outages and help strengthen the electric grid. A battery will also reduce greenhouse gas emissions.

Rebate amount per customer: $1,000.

Clean Power Alliance Approves New Program to Install Virtual Power Plant and Provide Low Income Customers Access to Solar Energy at No Cost

CPA CLEAN POWER ALLIANCE

Clean Power Alliance Approves New Program to Install Virtual Power Plant and Provide Low Income Customers Access to Solar Energy at No Cost

CPA will work with Haven Energy to install networked solar and battery storage systems on eligible low-income residents' homes to provide localized clean power and significant savings on customer electricity bills while managing peak energy demand

Ava Community Energy Announces Ambitious Virtual Power Plant Initiative to Help its 2M Customers Optimize Their Energy Investments While Relieving Stress on the Grid

April 24, 2025

Lunar Energy's Gridshare DERMS Platform Selected to Underpin the Effort

Oakland, CA April 24, 2025 – Ava Community Energy (Ava) today announced the launch of its comprehensive Virtual Power Plant (VPP) strategy. VPPs are systems that aggregate distributed energy resources (DERS), such as electric vehicles and home batteries, so they can be controlled remotely to enhance grid reliability and lower costs.

SAN JOSE CLEAN ENERGY

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Let your smart device earn you rewards!

Peak Rewards for Smart Homes makes it easy to earn rewards. Simply enroll an eligible smart device in the program and you'll automatically start earning rewards each quarter. We communicate directly with your device to make small adjustments that keep you comfortable and earn you rewards. You are always in control and can override our signals when needed.

SAN DIEGO COMMUNITY POWER

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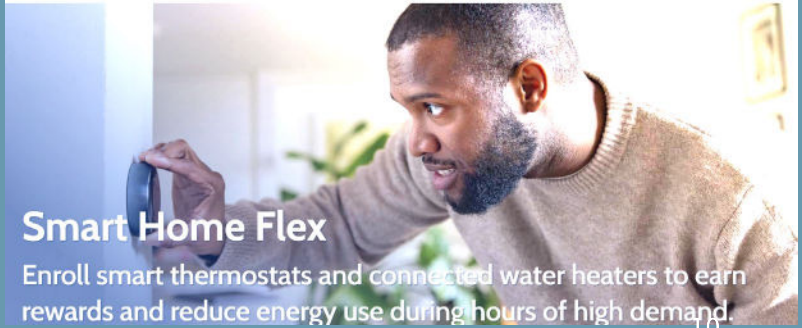

CALCCA ADVANCING LOCAL ENERGY CHOICE

CalCCA Positions on Flexible Connection Topics

CalCCA Positions on Flexible Connection Topics

- **CCAs are open to engaging with IOUs to accelerate deployment of grid-edge capabilities**
- OpenADR is complementary to IEEE 2030.5, but more cost-effective, scalable and better-suited for demand flexibility events or pricing signals
- **The definition of 'aggregator' should not be limited to an IEEE 2030.5 cloud service provider**
- DERs and grid-edge DERMS could serve as non-bridging solutions, subject to cost-effectiveness and equity considerations
- **The IOUs should establish flexible connection pilot programs for secondary system customers**
- Customers with variable operating envelopes should not be defaulted to dynamic rates

Optimizing Existing Grid Capacity Requires Coordination Between IOUs and Aggregators

- **Without grid-edge DERMS capabilities, DERs could inadvertently exacerbate local (circuit-, line-segment-, or substation-level) capacity constraints**
- Leveraging *all DERs,* including non-IOU DERS, is crucial to optimizing existing grid capacity and helping lower costs
- **CCAs have a unique role as not-for-profit LSEs that can both help reduce systems costs (*e.g.*, RA, grid investments) and share value with ratepayers**
- However, CCAs need timely access to grid data and/or signals from IOUs to accomplish these grid-level objectives

OpenADR and IEEE 2030.5 are Compatible and Complementary

- **IEEE 2030.5 allows for precise control of individual inverter-based DER, but is not efficiently or economically scalable to millions of devices**
  - IEEE 2030.5 is designed for inverter-based resources, but not smart appliances
- **OpenADR is better suited to delivering price- or event-based signals to aggregators and end-users, making it scalable and reducing the burden on DSOs**
  - OpenADR can convey precise device-level signals via IEEE 2030.5, SunSpec Modbus, Matter, or other interoperability standards.
  - OpenADR can control inverter- and non-inverter-based resources
  - OpenADR offers greater flexibility and is more cost-effective to deploy at scale
  - Most IOUs already use OpenADR for their DR programs
- **The use of OpenADR and IEEE 2030.5 is compatible and complementary**

Aggregator Should Not Be Defined as Merely IEEE 2030.5 Cloud Services

- **Limiting 'Aggregators' to only IEEE 2030.5 cloud service providers could limit the participation of grid-edge DERMS providers using OpenADR or other communications protocols**
  - Many aggregators use other communications standards to control on-site inverters
- **Rule 21 does not preclude the use of other protocols**
  - While Rule 21 states the default application-level protocol shall be IEEE 2030.5, it also states that "other application-level protocols may be used by mutual agreement of the parties"

Dynamic Flexible Connections Should Be Considered for Non-Bridging Solutions

- **Non-bridging solutions should consider IOU and non-IOU solutions**
  - CCAs are particularly well-positioned to provide non-bridging flexible connection services as community-led, not-for-profit load-serving entities
- **Any proposed solutions should be subject to cost-effectiveness evaluations and equity considerations**

The IOUs Should Establish Flexible Connection Pilots for Secondary Service Customers

- **Grid-edge DERMS could enable participation of customers on the secondary system to participate in flexible connections**
  - Grid-leveraging using OpenADR may prove to be more cost-effective than enabling solely IEEE 2030.5 options
- **CCAs are open to exploring joint CCA-IOU pilot program opportunities**

Customers Should Not Be Opted Into Dynamic Rates

- **Customers with variable operating envelopes should not be opted into dynamic rates**
  - Customers should be given information regarding available dynamic rate pilots and offerings, but should not be automatically enrolled, regardless of the ability to opt out
- **Dynamic rates are still in pilot phases and pending evaluation on performance and cost-effectiveness**
  - Earlier evaluations did not find evidence of consistent or large changes in customer energy usage in response to hourly prices
- **Requiring customers to opt-out of dynamic rates could create confusion and discourage participation in flexible service options**

Comments of Marin Clean Energy, Pioneer Community Energy, San Diego Community Power, and San José Clean Energy on Proposed Revision Requests 1658 and 1659

Dear CAISO,

Marin Clean Energy, Pioneer Community Energy, San Diego Community Power, and San José Clean Energy (collectively the "Joint CCAs") appreciate the opportunity to comment on CAISO's Proposed Revision Requests ("PRRs") 1658 and 1659. The Joint CCAs respectfully urge CAISO to withdraw PRR 1658, related to business processes for the Off Grid Charging Indicator ("OGCI"), a biddable parameter that permits co-located storage resources to elect not to "grid charge," and its companion proposed revision, PRR 1659, for resources offering Flexible Resource Adequacy (Flexible "RA"). These revisions would undermine the purpose of a tariff amendment CAISO proposed and FERC approved in 2023; they reflect a policy proposal with significant ramifications for market participants that should not be contemplated through the Business Practice Manual Change Management Process via PRRs. Instead, these changes should be explored, if at all, through CAISO's Policy Initiative process to ensure adequate and meaningful stakeholder engagement and feedback.

CAISO's Energy Storage Enhancements – Phase 2 Initiative culminated in a Tariff Amendment to create a "Charging Constraint," known as OGCI. OGCI created a biddable parameter reflecting a storage resource's election not to bid beyond the output of its co-located Variable Energy Resource.[1] FERC accepted the Tariff revisions on September 29, 2023.[2] As CAISO explained at the time, local and federal taxes that incentivize renewable development discourage storage resources from "grid charging," *i.e.*, charging from sources other than a co-located renewable resource.[3] This resulted in power purchase agreements that limit grid charging by storage resources. The stakeholder engagement process surfaced the delicate balance faced by storage resources with contractual grid charging limitations – must-offer obligations require them to bid economically or self-schedule, potentially resulting in a schedule to charge during a real-time interval, and resources are also required to follow dispatch instructions.[4]

CAISO therefore created a "new functionality for storage resources to help address some of the concerns voiced by stakeholders."[5] In particular, "[t]his functionality will be electable on an hour by hour basis and offered to any co-located storage resources and will prevent 'grid charging.'"[6] CAISO implemented this new functionality by amending the Tariff to allow a

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[1] Aug1-2023-TariffAmendment-EnergyStorageEnhancements-Phase2-ER23-2537.pdf ("August 1, 2023 Tariff Amendment").

[2] 184 FERC ¶61,209.

[3] August 1, 2023 Tariff Amendment at page 4; Energy Storage Enhancements, Final Proposal (Oct 27, 2022) ("Final Proposal" available at California ISO - Energy storage enhancements) at page 20.

[4] Final Proposal at 21.

[5] *Id.* at 21.

[6] *Id.*; *see also* August 1, 2023 Tariff Amendment at page 5 ("The CAISO proposes to create a "Charging Constraint" co-located storage resources can use to help avoid grid-charging.").

storage resource to "include Charging Constraints in its Bids."[7] "The Charging Constraints will reflect an election not to charge beyond the output of the co-located Variable Energy Resource(s) in a given hour."[8] At the same time, CAISO also amended the Tariff "to expressly allow co-located storage resources to deviate from any dispatch instructions that would conflict with their charging constraints."[9] As CAISO stated and FERC acknowledged, "the storage resources would still be subject to imbalance energy charges for the deviation but would not be subject to the other penalties in the CAISO Tariff."[10]

In adopting the Tariff amendment, CAISO also acknowledged the limitations of OGCI. It made clear that OGCI "will not apply in operating intervals where the storage resources receive an award to provide regulation."[11] And it made clear that even where a storage resource elects OGCI, "the CAISO may still use its authority to issue exceptional dispatches to manage reliability."[12]

FERC accepted the Tariff amendment based on its finding "that establishing the Charging Constraint bidding parameter improves the ability of co-located resources to avoid grid-charging and improves the accuracy of dispatch instructions to co-located storage resources. Moreover, by allowing co-located resources to avoid grid-charging, the proposed Tariff revisions will enhance the ability of co-located resource owners to manage grid-charging."[13]

PRR 1658, however, now proposes to add language to the BPM for OGCI that would materially limit the application of OGCI and undercut CAISO's stated purpose of OCGI. PRR 1658 states:

> It would raise serious compliance questions [related to tariff section 37.3.1 for resources to submit feasible bids] if the co-located storage resource submitted charging bids with the parameter selected for hours after sunset. This is particularly so where the co-located storage resource is a Resource Adequacy Resource and may have submitted infeasible bids to meet the Resource Adequacy must-offer obligation.

The PRR strongly suggests that submission of bids during non-solar hours, with OGCI elected, would violate the Tariff's feasible bid requirements. The PRR materially undercuts CAISO's stated purpose in creating OGCI, which was "to prevent grid charging."[14] In amending the Tariff, CAISO carefully signaled to stakeholders the limitations of OGCI – it does not apply when a storage resource receives a regulation award and it does not preclude issuance of an

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[7] Tariff Section 30.5.6.3.
[8] *Id.*
[9] August 1, 2023 Tariff Amendment at page 6; *see also* Tariff Section 34.13.3.
[10] 184 FERC ¶61,209 at ¶12.
[11] August 1, 2023 Tariff Amendment at page 6.
[12] *Id.*
[13] 184 FERC ¶61,209 at ¶25.
[14] Final Proposal at 21.

Exceptional Dispatch.[15] In proposing OGCI and updating its Tariff there was no indication that OGCI would not apply in non-solar hours. Both CAISO in proposing and FERC in approving the Tariff amendment spoke of OGCI in broad terms as allowing storage resources to avoid grid charging. Now, through a PRR CAISO is proposing a significant retreat from the purpose underlying the Tariff amendment. The proposed revisions amount to material policy changes, not mere clarifications, which should be addressed through the Policy Initiative process.

Specifically, if adopted, PRR 1658 would now appear to limit OGCI's use to solar hours, and presumably to apply solely to the narrow circumstance when a storage resource is dispatched to charge based on forecast but actual generation deviates from forecast. This narrow application, while important, hardly addresses the broader needs of storage resources contractually restricted from grid charging, needs that CAISO stated OGCI was intended to address.

Particularly troubling is the suggestion that the election of OGCI during non-solar hours violates the Tariff's feasible bid requirement. CAISO's Final Proposal recognized that storage resources have must-offer obligations to submit bids.[16] The 2023 Tariff amendment was carefully drafted to create OGCI as a "*biddable* parameter."[17] In particular, CAISO adopted Section 30.5.6.3 to permit a storage resource to "elect" not to grid charge and designate the election as a "Charging Constraint *in its Bids*."[18] By specifically including OGCI as a parameter *in the bid*, a charging bid with the parameter selected transparently conveys to CAISO that the resource is not available to grid charge. The feasible bid provision of the Tariff requires market participants to submit bids "from resources that are reasonably expected to be available and capable of performing *at the levels specified in the Bid*."[19] Under the plain language of the feasible bid provision, a charging bid with OGCI elected *is* feasible because the charging constraint is *specified in the bid* and the market participant is reasonably conveying that limitation. At the same time, the charging bid is not pointless; it still signals to CAISO the resource's availability for an Exceptional Dispatch, which CAISO expressly indicated OGCI would not override.

In addition, the Tariff amendment authorizes deviations from dispatch instructions when OGCI is elected.[20] As CAISO and FERC explained, where resources deviate from dispatch, "the storage resources would still be subject to imbalance energy charges for the deviation *but would not be subject to the other penalties in the CAISO Tariff*."[21] The Tariff amendment therefore clearly contemplated that storage resources would submit bids to charge that include an election not to grid charge, or there would be no need to authorize deviations from dispatch. And, the Tariff amendment created an explicit consequence when a resource that submits a bid with OGCI elected deviates from dispatch – uninstructed imbalance energy charges. It would be illogical to

[15] August 1, 2023 Tariff Amendment at page 6.
[16] Final Proposal at 21.
[17] August 1, 2023 Tariff Amendment at page 5 (emphasis added).
[18] Tariff Section 30.5.6.3 (emphasis added).
[19] Tariff Section 37.3.1.1 (emphasis added).
[20] Tariff Section 34.13.3.
[21] 184 FERC ¶61,209 at ¶12 (emphasis added).

authorize storage resources to submit charging bids with OGCI elected, to deviate from dispatch, and to incur uninstructed imbalance energy charges under those circumstances, if those bids were actually infeasible bids that should not have been submitted at all.

For these reasons, PRR 1658 materially undercuts the CAISO's 2023 Tariff amendment and represents a significant departure from the policy underlying that amendment to allow contractually restricted storage resources to avoid grid charging. Such a consequential policy shift is unsuited to a PRR and should instead be addressed in CAISO's Policy Initiative process to ensure adequate and meaningful stakeholder feedback.

PRR 1659, the companion to PRR 1658, should be withdrawn for similar reasons. PRR 1659 appears to suggest that the mechanism for addressing the needs of storage resources contractually restricted from grid charging is not to use OGCI but instead to alter their Flexible RA showing. PRR 1659 also proposes to add language indicating that a resource's Effective Flexible Capacity ("EFC") value is its "maximum" value, suggesting that the MW quantity of flexible capacity a storage resource may qualify to provide is lower than its EFC. Disqualifying capacity from providing EFC based on when a Scheduling Coordinator could "reasonably foresee" an "operating limitation" is ambiguous. Operating limitations of OGCI resources are highly dependent upon CAISO market dispatches *in real-time*. The CAISO does not provide any examples of situations when a Scheduling Coordinator could "reasonably foresee" operating limitations at the time of the RA showing.

As discussed above, federal and state tax incentives resulted in power purchase agreements that contain contractual limitations on grid charging to incentivize development of renewable resources. CAISO observed in the course of the Energy Storage Enhancements Policy Initiative that such resources may face challenges in complying with Tariff provisions, referencing must-offer obligations and requirements to comply with dispatch instructions.[22] CAISO's Final Proposal did not suggest that the mechanism for addressing these compliance needs was for these resources instead to include in their RA Supply Plans a lower MW quantity of flexible capacity than their EFC. Such an approach would significantly upend market participants' expectations, and like PRR 1658, PRR 1659 represents a highly consequential policy proposal that would make changes to rates, terms, or conditions of the Flexible RA product. It therefore is not a change that should be contemplated in the PRR process.

For the above stated reasons, the Joint CCAs respectfully request that CAISO withdraw PRRs 1658 and 1659. The changes proposed in these PRRs should be explored, if at all, through the CAISO's Policy Initiative process to ensure adequate and meaningful stakeholder engagement and feedback.

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[22] Final Proposal at 21.

Respectfully Submitted,

Dated: February 18, 2026

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February 19, 2026

Via Electronic Email

California Public Utilities Commission – Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, California 94102
(EDTariffUnit@cpuc.ca.gov)

Re: Protest of Joint CCAs to Pacific Gas and Electric Company Advice Letter 7822-E – PG&E's 2026 Low Carbon Fuel Standard Implementation Plan

Dear Energy Division Tariff Unit:

Pursuant to the California Public Utilities Commission's ("Commission") General Order ("GO") 96-B, Sonoma Clean Power ("SCP"), Peninsula Clean Energy Authority ("PCE"), San José Clean Energy ("SJCE"), and Marin Clean Energy ("MCE") ("Joint CCAs") hereby protest Pacific Gas and Electric Company's ("PG&E") Advice Letter ("AL") 7822-E, 2026 Low Carbon Fuel Standard ("LCFS") Implementation Plan.[1] AL 7822-E was submitted by PG&E on January 30, 2026. Pursuant to GO 96-B, the Joint CCAs submit this protest on the grounds that the "relief requested in the advice letter would violate statute or Commission order,"[2] and "is unjust, unreasonable, or discriminatory[.]"[3]

AL 7822-E should not be approved as filed because PG&E's 2026 LCFS Implementation Plan lacks the required implementation details in violation of prior Commission decisions.[4] Furthermore, approval of AL 7822-E as filed would be unjust, unreasonable, and discriminatory to affected Community Choice Aggregators ("CCAs") and their customers. PG&E's proposed programs would operate on CCA-served electric load and would provide electric vehicle ("EV") incentives to CCA customers, but the AL currently lacks the required implementation details to

[1] References below to "General Rules" are to the general rules identified in GO 96-B.
[2] General Rule 7.4.2(2).
[3] General Rule 7.4.2(6).
[4] Decision 20-12-027, *Concerning Low Carbon Fuel Standard Holdback Revenue Utilization* (December 17, 2020) (citing D.14-12-083)
https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M356/K223/356223853.PDF

ensure just, reasonable, and competitively neutral program implementation, including coordination with CCAs that operate EV programs affecting the same customers and load.

PG&E acknowledges[5] that dual participation in CCA managed charging programs is within the scope of the Commission's Demand Response ("DR") Order Instituting Rulemaking ("OIR") (R. 25-09-004),[6] however that proceeding does not have a timeline for addressing dual participation policy.[7] Deferring a critical implementation process to a separate proceeding that explicitly lacks any near-term resolution is unjust, unreasonable, and risks conferring a competitive program advantage to PG&E.

Accordingly, the Joint CCAs request that Energy Division conditionally approve AL 7822-E, subject to the following conditions of approval:

- PG&E shall, in coordination with and approval by CCAs serving affected customers, develop and implement a CCA coordination process inclusive of an interim dual enrollment process that is applicable to all proposed enrollment channels, including any point-of-sale enrollment design; and

- Within ninety (90) days of approval of AL 7822-E, PG&E shall file a supplemental Tier 2 Advice Letter that includes the following:

    - a description of the interim dual enrollment review process, which shall remain in effect until superseded by an applicable decision in the DR OIR;
    - a description of how the Residential Optimized Charging Program will be marketed in a manner competitively neutral to the customer's LSE choice, including at the point-of-sale;
    - updates to the Non-Residential Behind-the-Meter Infrastructure Incentive program identifying Level 1 charging as an eligible technology, including Level 1 charging in assigned MFH parking spaces.

BACKGROUND

On December 17, 2020, the Commission adopted Decision ("D.") 20-12-027 Concerning Low Carbon Fuel Standard Holdback Revenue Utilization. The Decision requires utilities to file LCFS Holdback Implementation Plans, via a Tier 2 AL.[8] The Decision requires Implementation Plans to include: (1) a proposal for at least one program, and (2) a description for how the large IOU plans to spend the rest of the funds, which shall include the status of the program

[5] AL 7822-E, Attach. A, at pg. 28.
[6] Rulemaking 25-09-004, *Order Instituting Rulemaking to Enhance Demand Response in California* (September 25, 2025). https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M582/K072/582072320.PDF
[7] R. 25-09-004, *Assigned Commissioner's Scoping Memo and Ruling* (February 12, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M599/K038/599038857.PDF (scoping schedule through Q4 2026 does not include addressing dual participation policies).
[8] D. 20-12-027, Conclusion of Law ("COL") 17; Ordering Paragraph ("OP") 3.

development of the remaining program(s), an implementation timeline, and the approximate budget.[9] Once a subsequent LCFS program is developed, utilities submit additional Implementation Plans, and as programs change or conclude over time, utilities submit revised Implementation Plans to reflect such updates.

Within each Implementation Plans, the utilities are required to specify:

1) How LCFS holdback expenditures are dedicated to equity projects or resiliency projects.
2) How each of its LCFS holdback expenditures and planned investments benefit current or future EV drivers in the state.
3) How the LCFS holdback expenditures comply with all other CARB regulations regarding the use of LCFS holdback funds (e.g., administrative cost caps and prohibited uses).
4) How any proposal for its LCFS holdback expenditure:
    a. Demonstrates input from environmental justice groups and/or community-based organizations.
    b. Will address gaps in program design not already addressed through the utility's transportation electrification (TE) expenditures or other publicly funded program, or in the alternative how the proposed expenditure will reduce costs to ratepayers.
    c. Will address a barrier to TE, equity, and/or resiliency.
    d. Includes data collection requirements that allow for an evaluation of the effectiveness of the proposal in addressing TE, equity, and/or resiliency.
5) How any proposal for an equity project will be for the primary benefit of, or primarily serve, communities eligible for equity project expenditures.
6) How any proposal for a resiliency project is aligned with other TE-related utility resiliency efforts, including but not limited to, Public Safety Power Shutoffs (PSPS) and Wildfire Mitigation Plans, and reflects consultation with electric vehicle service providers, where appropriate.
7) How any proposal for a resiliency project aligns with Commission policy on vehicle-grid integration (VGI).[10]

The Implementation Plans are also required to address general informational questions, as ordered by the Commission in D.14-12-083:

1) How will the large electrical corporation calculate the number of LCFS credits generated by each customer?
2) Who receives the revenue from the sale of LCFS credits?
3) How are LCFS revenue recipients identified?
4) How will the large electrical corporation calculate the amount of revenue to be distributed to each customer, if appropriate?

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[9] D. 20-12-027, at pg. 26.
[10] D. 20-12-027, at pgs. 26 – 28.

5) By what means is the revenue distributed to the customer and how frequently is revenue distributed?
6) How will vehicle ownership changes be identified, addressed, and tracked?
7) How will the large electrical corporation track and true-up revenues and disbursements from the program?
8) How will the program be marketed in a competitively neutral manner so that plug-in EV owners, regardless of their load serving entity, are aware that they are eligible to receive LCFS revenue?
9) How will the large electrical corporation receive and distribute credits generated by non-residential customers?

Pursuant to OP 3 of D.12-20-027, PG&E submitted its 2026 LCFS Implementation Plan via AL 7822-E, filed on January 30, 2026. Therein, PG&E proposes two new holdback programs:[11]

Proposed Program	Description	Program Duration	Total Cost
Residential Optimized Charging	Monthly incentive program to promote customer enrollment in Optimized Charging to reduce costs associated with upgrading distribution grid assets	2027-2029	$31.30M
Non-Residential Behind-the-Meter Infrastructure Incentive	Incentives to reduce the cost of EV charger installation at non-residential sites	2027-2030	$31.99M

Residential Optimized Charging Program (i.e. managed EV charging)

PG&E plans to market the Residential Optimized Charging program to new and existing EV customers with a residential level 2 ("L2") charger (among other eligibility criteria, some of which has not yet been determined).[12] PG&E plans to implement the program under a hybrid approach, which may include bundling "Original Equipment Manufacturer (OEM), third party, and/or EV retailer incentives and PG&E incentives (including optimized charging) into an offering available ***at the point of purchase or lease***."[13] PG&E states that if the Residential Optimized Charging program "proves successful, PG&E may request to extend the program in future LCFS filings, and potentially create a scaled, generally available program via the General Rate Case (GRC)."[14]

PG&E acknowledges the current limitations for customers to participate in PG&E programs and CCA programs, and notes that this limits both the potential system value and the

[11] AL 7822-E, Attach. A, at pg. 5, Table 1.
[12] *Id.* at pg. 30.
[13] *Id.* at pg. 26.
[14] *Id.* at pg. 21.

potential for customers to stack related incentives.[15] PG&E's Plan notes that while the Residential Optimized Charging program is focused on distribution system value, CCA programs are focused on generation value and resource adequacy, and that PG&E anticipates the DR OIR will address "some of the key issues to enable participating in multiple managed charging programs, including dual participation policy, valuation methodologies, and standardized data systems."[16]

Non-Residential Behind-the-Meter (BTM) Infrastructure Incentive

PG&E plans to offer the Non-Residential Behind-the-Meter ("BTM") Infrastructure Incentive to new or existing non-residential customers installing L2, DC fast chargers ("DCFC"), or Megawatt Charging System ("MCS") chargers.[17] PG&E's Plan specifies that CCA customers are eligible to participate, and that the program is designed to work with other grant and incentive programs to maximize customer savings.[18] PG&E also describes the relationship between the EV Advisory Services ("EVAS") program, and the Commission's recent authorization of the Technical Assistance program, stating that under this expansion, "EVAS will be able to support all customer segments that are eligible for the BTM incentive program."

Joint CCAs appreciate that the program design includes CCA customer eligibility and allows for incentive stacking. In the AL, PG&E provides a non-exhaustive list of other external relevant funding sources, however the Joint CCAs note that the example list is thus far limited to state-level incentives.[19] The Joint CCAs ask that PG&E coordinate with CCAs as early as possible regarding CCA EV incentives and technical assistance programs, and propose doing so through the development of the communication channels and established practices envisioned for the Technical Assistance program in accordance with D. 22-11-040.[20]

JOINT CCA INTEREST

Joint CCAs are the default Load Serving Entities ("LSEs") within PG&E's service territory.[21] CCAs currently serve more electric load in PG&E's service territory than PG&E does. As local public agencies, CCAs are also tasked with reducing GHG emissions associated with the electricity used by their customers. To that end, CCAs offer many programs aimed at achieving California's transportation electrification goals including, but not limited to, the following EV programs:

- Managed EV charging programs

[15] *Id.* at pg. 28.
[16] *Id.*
[17] *Id.* at pg. 54.
[18] *Id.* at pg. 49.
[19] *Id.* at pg. 50.
[20] R. 18-12-006 *Decision on Transportation Electrification Policy and Investment* (November 17, 2022) at pg. 192 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M499/K005/499005805.PDF
[21] CCA customers receive generation services from their respective CCA, and receive transmission, distribution, billing, and other such services from PG&E.

- Ava SmartHome Charging, launched in March 2025, is an EV managed charging program that automatically shifts home charging to off-peak times and when renewable energy is cheaper and more available. Eligible Ava customers who charge their EVs at home can earn both one-time rewards and monthly rewards per vehicle.[22]
- MCE Sync, launched in 2021, is an app-based managed EV charging and load shifting program that helps customers to reduce EV charging load during peak times, while also seeking to align EV charging load with high-solar daytime hours. The program provides eligible MCE customers with an enrollment bonus and monthly cash back for charging during low-carbon events.[23]
- SJCE's Peak Rewards for Smart Homes program, launched in May 2025, offers a Managed Charging option to automatically shift participant home charging to off-peak times. Customers that successfully shift their charging receive $3/month in rewards. In 2026, SJCE will add the Midday Charging Bonus to encourage customers to plug in during peak solar generation hours. Participants that maximize charging during these hours will be able to earn up to $160/year in rewards.[24]

- EV rebate programs
  - PCE's Used EV Rebate Program offers savings toward the purchase of a used plug-in hybrid or fully-electric vehicle for income-qualifying eligible PCE residents. In combination with PCE's rebate, income-qualified residents may also qualify for additional incentives from regional and state programs.[25]
  - MCE's EV Instant Rebate Program lowers the cost of purchasing or leasing EVs for income-qualified MCE customers. Launched in May 2023, the program offers savings on the purchase or lease of an eligible EV at participating dealerships. This rebate may also be combined with other available incentives to further reduce the final vehicle costs.[26]
  - SJCE's EV Instant Rebate Program provides income-qualified customers with discounts when purchasing or leasing a new or used EV from participating car dealerships. EV Instant Rebates can be stacked with other available incentives to make EVs accessible for all.[27]

- EV charger incentive programs
  - MCE's EV Charging program, launched in 2018, provides rebates for EV charging stations at multifamily properties, businesses, and community-serving public locations. The program also offers bonus incentives for stations powered

[22] https://avaenergy.org/go-electric/electric-vehicles/smarthome-charging/
[23] https://mcecleanenergy.org/mce-sync/
[24] https://sanjosecleanenergy.org/peak-rewards-for-smart-homes/
[25] https://www.peninsulacleanenergy.com/residential/rebates-offers/ev-rebate-program/
[26] https://mcecleanenergy.org/ev-rebate/
[27] https://sanjosecleanenergy.org/ev-rebates/

by 100% renewable energy service, and free technical assistance to help accelerate EV adoption.[28]

- PCE's EV Ready program provides free technical support and rebates to help offset the costs of installing EV charging infrastructure at businesses and multifamily properties.[29]
- PCE's GovEV public fleet electrification program provides free technical assistance, project planning, and funding to public agencies for new EVs and charging infrastructure for their fleets.[30]
- SJCE's Multifamily EV Charger Assistance Program, launched in 2024, provides incentives to multifamily properties to install Level 1 EV charging outlets, Level 2 EV charging outlets, and Level 2 EV charging ports[31]

PROTEST

The Joint CCAs submit this protest to AL 7822-E on the grounds that the requested relief is unjust, unreasonable, or discriminatory, and in violation of the Commission's orders. Although the Joint CCAs appreciate PG&E's efforts to support the growth of EV adoption, the Joint CCAs find that AL 7822-E, as filed, lacks the required implementation information required by D. 20-12-027 and D. 14-12-083. Additional implementation information is necessary to ensure that PG&E designs and implements the proposed LCFS holdback programs in a manner that is just, reasonable, and competitively neutral with respect to CCAs that operate EV programs affecting the same customers and load.

1. PG&E fails to provide the necessary implementation details regarding dual participation

In AL 7822-E, PG&E acknowledges that:

> "[T]here are currently limitations for customers wanting to participate in PG&E and other managed charging programs (e.g., through a CCA). This limits the total system value that can be achieved (e.g., CCAs focus on generation value and resource adequacy and PG&E focus on value to the distribution system) and the ability for customers to stack value. PG&E anticipates that the CPUC Demand Response (DR) Order Instituting Rulemaking (OIR) (R.25-09-004) will address some of the key issues to enable participating in multiple managed charging programs, including dual participation policy, valuation methodologies, and standardized data systems."[32]

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[28] https://mcecleanenergy.org/ev-charging/
[29] https://www.peninsulacleanenergy.com/business/rebates-offers-business/ev-ready-program/
[30] https://www.peninsulacleanenergy.com/public-organization/govev-program-public-fleet-electrification/
[31] https://sanjosecleanenergy.org/ev-charger-assistance/
[32] AL 7822-E, Attach. A, at pg. 28.

PG&E further states that it "will determine additional eligibility criteria during program development ... [which] could include…[meeting] any dual participation requirements (e.g., checks for participation in other PG&E programs and other managed charging programs)."[33]

While the Joint CCAs appreciate that PG&E acknowledges the potential for future value stacking of managed EV charging programs,[34] and the need for dual participation checks in the meantime, the Joint CCAs submit this protest due to the lack of required implementation detail within AL 7822-E regarding CCA coordination and dual enrollment. PG&E has correctly noted that dual participation policy falls within the scope of the DR OIR. However, that proceeding has no defined timeline for addressing dual participation. The recently released Scoping Ruling outlines a schedule through Q4 of 2026, and it does not include dual participation. Thus, it is unreasonable to defer a critical program detail and implementation process to a separate proceeding that explicitly lacks any near-term resolution.

Since 2024, PG&E has been testing managed charging through the pilot-scale EV Charge Manager ("EVCM") program, which is currently slated to run through 2026. To date, PG&E has coordinated with MCE and Ava in an informal manner to develop and implement a dual enrollment check to ensure that customers are enrolled in only one managed charging program of their choice. Ava and MCE are appreciative of PG&E's past coordination on the dual enrollment review for the EVCM pilot. Due to the size of the EVCM pilot, an informal process has generally been administratively manageable.

However, the informal dual enrollment process developed for the pilot-scale EVCM program likely will not suffice for the size and scale of PG&E's Residential Optimized Charging program as proposed in AL 7822-E. If successful, PG&E also hopes to further scale the program in future LCFS or GRC filings, which further highlights the need for additional implementation details on dual enrollment at the early stages of program design. Ava and MCE have endeavored to be good partners with PG&E given the clear benefits that EV managed charging programs provide to our customers. The Joint CCAs look forward to continuing that collaborative partnership to develop and implement a coordinated dual enrollment process for the Residential Optimized Charging program, to govern in the interim until superseded by a Commission decision on dual participation policy in the DR OIR.

2. PG&E fails to describe how the Residential Optimized Charging program will be marketed in a competitively neutral manner

Under current LCFS regulations, electric distribution utilities ("EDUs") are the exclusive credit generator of base credits for residential loads, including the "holdback credits" which serve as the primary funding for the two new programs proposed by PG&E in AL 7822-E.

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[33] *Id.* at pg. 31.

In prior comments to CARB, Joint CCAs encouraged CARB to revise the LCFS base credit provisions to define an LSE as the base credit generator, instead of just an EDU.[35] Since the LCFS is intended to lower the GHG intensity of transportation fuels, CCAs argued that it is reasonable that an LSE should receive the base credit for displacing diesel and gasoline, and in turn, that residential base credits should be allocated to the LSE that procures the energy for and serves the credit-generating EV load. Unfortunately, these arguments have been unsuccessful to date. As such, PG&E alone receives LCFS credits for residential EV charging customers, and CCAs have no direct access to those credits even though a significant portion of those credits are generated by EV charging from CCA-served load.

This inequitable base credit structure stresses the importance of the requirement that all Implementation Plans shall describe how "the program be marketed in a competitively neutral manner so that plug-in EV owners, regardless of their load serving entity, are aware that they are eligible to receive LCFS revenue."[36]

In AL 7822-E, PG&E proposes implementing an incentive bundling design for the Residential Optimized Charging program that would potentially enroll customers at the point of vehicle purchase or lease. However, the AL does not demonstrate how PG&E will market this program in a competitively neutral manner consistent with D. 14-12-083. Specifically, PG&E does not address dual enrollment or coordination with CCA programs when marketing its program at the point-of-sale ("POS"). Lack of coordination will lead to customer confusion, administrative challenges, and enrollment barriers. Moreover, a POS enrollment process that lacks the necessary CCA coordination safeguards runs the risk of conferring a competitive advantage onto PG&E by way of customer capture and lock-in at arguably the most influential customer decision point. Maintaining competitive neutrality between PG&E and CCA programs is particularly important as CCAs have interest in leveraging managed charging and other demand response strategies to provide value to the distribution system,[37] targeting the same value stream as PG&E's Residential Optimized Charging program.

The Joint CCAs recognize that PG&E plans to explore POS incentive bundling under the 2026 scope of the EVCM pilot, and that the potential implementation of bundled POS enrollment for the Residential Optimized Charging program depends on the success of those EVCM pilot efforts.[38] However, the Joint CCAs are concerned that without modification, approval of AL 7822-E as filed would constitute approval of a POS enrollment program design that lacks the necessary implementation and coordination details and safeguards. A bundled POS enrollment structure materially differs from existing standard enrollment channels, and would significantly affect customer choice, coordination with CCAs, and operational outcomes.

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[32] Comments of the Joint CCAs on Potential Future Changes to the LCFS Program (January 7, 2022) https://sdcommunitypower.org/wp-content/uploads/2022/09/LCFS-Comments.pdf
[36] D.14-12-083, pg. 32-33
[37] *See e.g., Ava Community Energy Opening Comments on DR OIR* (November 13, 2025) https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M587/K122/587122342.PDF
[38] AL 7822-E, Attach. A, at pg. 20-21.

3. PG&E fails to include Level 1 charging without a reasoned analysis

PG&E's proposed Non-Residential Behind-the-Meter Infrastructure Incentive program ("BTM Program") identifies L2 and DCFC as eligible technologies but does not include Level 1 ("L1") charging. In the Program Overview, PG&E describes the BTM Program as providing incentives "to reduce the cost of EV charger installation at non-residential sites."[39] The AL specifies the charger types that are eligible for incentives but does not list L1 chargers.[40] The Implementation Plan does not provide any explanation for excluding L1 chargers.

This exclusion is consequential because the charging needs at MFH properties differ materially from other applications. While PG&E explains how the BTM Program supports fleets and public charging applications, it does not provide a comparable analysis of MFH charging needs or evaluate whether L1 may more efficiently address those needs.

At MFH properties, vehicles are typically parked for extended periods. Based on census data analyzed by PCE, most drivers park their vehicles for at least 12 hours per day.[41] When EVs are plugged into L2 chargers at MFH properties, vehicles often remain parked overnight by may only draw electricity for fewer than three hours. L1 charging delivers lower power over a longer dwell period, which is sufficient to meet driver needs and aligns with overnight residential charging patterns. Excluding L1 from eligibility therefore disregards a technology that aligns with observed residential charging behavior and risks over-sizing infrastructure relative to actual demand.

Including L1 would advance the BTM Program's stated objectives. PG&E identifies the BTM Program's purpose as reducing installation costs and increasing access to charging.[42] PG&E further proposes to provide incentives covering up to 75% of the eligible BTM project costs.[43] PCE's EV Ready program provides MFH charging incentives of up to 100% of costs, or $2,500 per L1 charger, and requires a minimum of a 25% cost share for the property for L2 chargers. To date, the average cost, including both equipment and installation, for MFH projects is $2,700 per L1 charger versus $8,000 per L2 charger. Because L1 chargers are materially less expensive, a fixed program budget would support a greater number of individual chargers if L1 were eligible. In other words, including L1 would allow the BTM Program to maximize charging access within the same budgetary limits.

The infrastructure implications are equally important. Higher-power infrastructure is more likely to trigger the need to upsize the electrical service to serve the new charging project. The costs of upsizing the services, as well as any upstream distribution work that they implicate, are recovered through electric rates. By contrast, L1 charging can often be deployed within the property's existing service capacity. PCE completed a project in 2025 that delivered charging for all 143 residential units at

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[39] AL 7822-E, Attach. A, at pg. 41.
[40] AL 7822-E, Attach. A, at pg. 54-55.
[41] https://www.peninsulacleanenergy.com/wp-content/uploads/2021/09/Determining-the-Appropriate-Level-of-Power-Sharing-for-EV-Charging-in-Multifamily-Properties-1.pdf.
[42] AL 7822-E, Attach. A, at pg. 41.
[43] AL 7822-E, Attach. A, at pg. 48.

a MFH property using smart L1 outlets and without needing to upsize the utility electrical service.[44] The project illustrates charging access can be delivered at scale with infrastructure that is right-sized to meet customer needs rather than higher-power infrastructure that may require service upsizing.

L1 charging also advances the Commission's stated focus on removing barriers to transportation electrification deployment and support timely energization.[45] Projects that avoid service upsizing entirely can be energized more quickly and would enable faster deployment of MFH charging projects. Allowing L1 as an eligible technology would therefore enable faster deployment of MFH charging projects and allow PG&E to prioritize more complex projects where service upsizing and distribution upgrades are unavoidable.

Finally, the BTM Program should provide incentives for L1 chargers installed in assigned parking spaces. PG&E suggests that the BTM Program will only be available for shared MFH chargers. "For public charging and shared private (i.e., MFH and workplace) charging, the program aims to increase access to EV charging in these locations by accelerating the widespread installation of charging through BTM incentives to reduce development costs."[46] However, assigned parking installations are the most effective way to ensure equitable and reliable access for MFH residents. Dedicated charging spaces reduce conflicts among residents, limit the need for property owners to manage the residents' use of the chargers, avoids triggering costly accessibility upgrades that often require reducing available parking for MFH residents, and provide predictable access to overnight charging.

The California Energy Commission's ("CEC") Communities in Charge program allows incentives for L1 installations in MFH settings, including installations serving assigned parking spaces.[47] This demonstrates that assigned L1 charging in MFH properties is administratively feasible and consistent with state policy to expand EV charging access. Therefore, the BTM Program Implementation Plan should make it clear that incentives will be available for L1 chargers installed in assigned MFH parking spaces, not solely for shared configurations.

For these reasons, the exclusion of L1 charging from the BTM program is inconsistent with actual MFH charging behavior, undermines the Program's stated goals of cost reduction and expanded access to charging, increases the likelihood of unnecessary and costly infrastructure upsizing, may slow deployment timelines, and contradicts recent developments in state CEC programs that are now encouraging L1 charging. Including L1 charging, and clarifying eligibility for assigned parking installations, would better align the BTM program with observed MFH charging needs and the Commission's policy objectives.

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[44] https://www.peninsulacleanenergy.com/news-releases/local-leaders-celebrate-groundbreaking-bayview-condos-ev-charging-installation/

[45] D.25-12-005, *Decision Adopting Revised Data Gathering And Reporting Requirements For Transportation Electrification Programs And Providing Clarification On Programs Adopted In Decision 22-11-040*, at pg. 15.

[46] AL 7822-E, Attach. A, at pg. 45.

[47] https://thecommunitiesincharge.org/

CONCLUSION

For the foregoing reasons, the Joint CCAs request that Energy Division conditionally approve AL 7822-E, subject to the following:

- PG&E shall, in coordination with and approval by CCAs serving affected customers, develop and implement a CCA coordination process inclusive of an interim dual enrollment process that is applicable to all proposed enrollment channels, including any point-of-sale enrollment design; and

- Within ninety (90) days of approval of AL 7822-E, PG&E shall file a supplemental Tier 2 Advice Letter that includes the following:

    - a description of the interim dual enrollment review process, which shall remain in effect until superseded by an applicable decision in the DR OIR;
    - a description of how the Residential Optimized Charging Program will be marketed in a manner competitively neutral to the customer's LSE choice, including at the point-of-sale;
    - updates to the Non-Residential Behind-the-Meter Infrastructure Incentive program identifying Level 1 charging as an eligible technology, including Level 1 charging in assigned MFH parking spaces.

The Joint CCAs thank the Commission for its consideration of this protest.

Respectfully,

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Service List of R.23-12-008

MARCH FILINGS

Docket No.	R.25-02-005
Exhibit No.	
Date	March 2, 2026
Witness	Brian Dickman

TRACK 2 DIRECT TESTIMONY OF BRIAN DICKMAN
ON BEHALF OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

ORDER INSTITUTING RULEMAKING TO UPDATE AND REFORM ENERGY RESOURCE RECOVERY ACCOUNT AND POWER CHARGE INDIFFERENCE ADJUSTMENT POLICIES AND PROCESSES

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Attachment A: Pre-2019 Banked RECs Numerical Example
Attachment B: Curriculum Vitae of Brian Dickman
Attachment C: Select Discovery Responses

I. INTRODUCTION AND SUMMARY

The California Community Choice Association (**CalCCA**)[1] presents this Track 2 direct testimony in the *Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes* (**OIR**). This testimony was prepared on behalf of CalCCA by Brian Dickman, Partner, NewGen Strategies and Solutions, LLC. Mr. Dickman's qualifications are set forth in Attachment B.

California law obligates the Commission to ensure that both investor-owned utility (**IOU**) bundled customers *and* departed community choice aggregator (**CCA**) and electric service provider (**ESP**) unbundled customers remain indifferent to retail customer choice. That is, no one customer group should experience a shift of costs in their direction caused by the other customer group. Track 2 is considering how to address a discrete cost shift resulting from one cost and value stream within the Power Charge Indifference Adjustment (**PCIA**): certain unbundled customers paying, *and receiving no value in return,* for renewable energy credits (**REC**) generated and banked prior to 2019 (**Pre-2019 Banked RECs**) that are being used in 2026 and later for bundled customer (**Current Bundled Customer**) Renewables Portfolio Standard (**RPS**) compliance. The unbundled customers at issue are those that depart bundled service *after* the Pre-2019 Banked RECs were generated and banked (**Later Departing Customers**), as discussed in detail below.

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[1] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

Commissioner John Reynolds' February 3, 2026, Scoping Ruling determined the following issues are to be considered in Track 2 of this proceeding:[2]

1. Is the proposal to value Pre-2019 Banked RECs at a value other than zero dollars consistent with applicable law and Commission precedent? This question includes but is not limited to the following sub-questions:

    a. Do the indifference principles and mandate to prevent cost shifts contained in Public Utilities Code Sections 365.2, 366.2, and 366.3 and prior Commission Decisions require that when an [IOU] uses Pre-2019 Banked RECs for compliance on behalf of its bundled service customers, Later Departing Customers must receive a credit from bundled service customers for the use of the Pre-2019 Banked REC?

    b. Are there potential "downstream" consequences or other policy considerations stemming from the proposal to value Pre-2019 Banked RECs at a value other than zero dollars that would render the proposal unreasonable pursuant to Public Utilities Code section 451, or any other statute or Commission decision?

    c. Are there characteristics of RECs generated prior to January 1, 2019, that make them categorically different from RECs generated after January 1, 2019, impacting whether it is reasonable for the Commission to adopt a valuation methodology for Pre-2019 Banked RECs that assigns them other than a zero-dollar valuation?

    d. Did bundled service customers who paid the cost of RECs at the time they were generated and banked under the methodology in effect prior to adoption of the methodology adopted in D.19-10-001 permanently give up their claim to those RECs if they departed from bundled service while those RECs were still retained by an IOU?

2. If the answer to Issue 1 is determined to be yes, should the Commission direct IOUs to apply a value other than zero dollars when Pre-2019 Banked RECs are valued for ratemaking in the 2026 and later ERRA Forecast proceedings? If so, how should such value be determined and allocated while adhering to indifference principles for all customers? This question includes but is not limited to the following sub-questions:

    a. Is it reasonable for RECs generated prior to January 1, 2019, to be valued using MPBs developed using data from later years? If not, is there another value that would be appropriate?

    b. Does the methodology used to allocate the value of RECs, expenses, or

[2] *Assigned Commissioner's Scoping Memo and Ruling*, Rulemaking (**R.**) 25-02-005 (February 3, 2026), at 3-5 (Scoping Ruling).

revenues from RPS-eligible resources prior to 2019 impact the manner or extent to which the Commission should allocate the value of Pre-2019 Banked RECs to bundled and unbundled customers, and, if so, how?

c. If the Commission is to establish a valuation for Pre-2019 Banked RECs other than zero dollars, how should the Commission modify the PCIA ratemaking, balancing accounts, and/or tariffs to effectuate the valuation?

To ensure Later Departing Customers remain indifferent, CalCCA recommends that Pre-2019 Banked RECs be valued at the current RPS market price benchmark (**MPB**) when used for bundled customer compliance. The current RPS MPB best measures the cost avoided when bundled customers rely on banked RECs rather than procuring additional RECs in the market. That value should be provided to Later Departing Customers by crediting the PCIA in the customer vintage corresponding to the year the RECs were generated. Alternatively, Pre-2019 Banked RECs that were paid for by Later Departing Customers could reduce the Net RPS Procurement Need for the load serving entities (**LSE**) that serve those customers when those Pre-2019 Banked RECs are used for compliance.

My testimony describes CalCCA's recommendations in detail and addresses each of the issues identified in the Scoping Ruling. Specifically, my testimony:

- Explains how the PCIA framework operates to ensure statutory indifference between bundled and unbundled customers, including how REC value is conveyed to customers;

- Demonstrates that Later Departing Customers paid for their share of Pre-2019 Banked RECs when those RECs were generated but have not received the value of those RECs when they are later used for Current Bundled Customer RPS compliance;

- Shows that failure to credit Later Departing Customers when Pre-2019 Banked RECs are used for Current Bundled Customer compliance results in a cost shift from Current Bundled Customers to Later Departing Customers;

- Recommends that Pre-2019 Banked RECs be valued at the current RPS MPB – the avoided cost of procuring new RECs in the market – when used for Current Bundled Customer compliance, with the full value recorded as a vintage-specific credit to the PCIA corresponding to the year the RECs were generated;

- Explains why vintage-specific crediting ensures only the correct customer vintages receive the correct values and prevents double compensation;
- Concludes that CalCCA's proposal is consistent with Commission precedent, maintains statutory indifference, and can be implemented within the existing PCIA framework; and that
- In the absence of valuation, the Commission is required pursuant to Public Utilities Code section 366.2(g) to provide an allocation to Later Departing Customers for their share of RECs used by the IOU of Pre-2019 Banked RECs, which could be achieved by reducing the Net RPS Procurement Need as measured on the Commission's Renewable Net Short Calculation template for the LSEs serving those Later Departing Customers.

II. BACKGROUND

A. The Legislature Enabled Community Choice Aggregation to Promote Customer Retail Choice and Competition

Through the passage of Assembly Bill (**AB**) 117 in 2002, the California Legislature broadened opportunities for retail electric competition previously allowed only through Direct Access (**DA**) service via ESPs by authorizing Community Choice Aggregation. Instead of receiving all services (*i.e.,* generation, transmission, distribution, and other services) from their IOU (**Bundled Customer**), CCA customers receive generation service from their local CCA, and continue receiving transmission, distribution, and all other services from the IOU (**Unbundled or Departed Load Customer**).[3] Today, 25 CCAs are in operation in California serving more than 15 million customers.

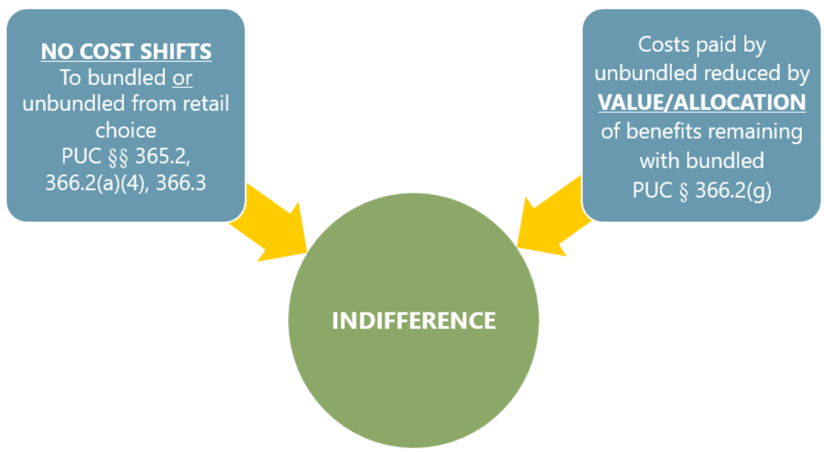
B. California Law Requires All Customers to Remain Indifferent as a Result of Customers Departing IOU Generation Service

California law requires customer indifference when customers depart IOU generation service. In other words, no customer – either bundled or unbundled – should

[3] DA/ESP customers are also Unbundled or Departed Load Customers.

have additional costs shifted to them as a result of retail choice. California statutes require CCA customers to continue paying the above-market costs of IOU resources originally procured on their behalf, even after they depart.[4] In return, CCA customers are entitled to receive the value of the resources' attributes that remain with bundled customers or an allocated share of the attributes, to compensate the unbundled customers for the payments they continue to make for those resources.[5] These two components of indifference are shown in Figure 1 below:

Figure 1: Statutory Indifference Requirements



[4] Cal. Pub. Util. Code §§ 365.2 ("The commission shall ensure that bundled retail customers of an electrical corporation do not experience any cost increases as a result of retail customers of an electrical corporation electing to receive service from other providers. The commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load."); 366.2(a)(4) ("The implementation of a community choice aggregation program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation."); 366.3 ("Bundled retail customers of an electrical corporation shall not experience any cost increase as a result of the implementation of a community choice aggregator program. The commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load.").

[5] Cal. Pub. Util. Code § 366.2(g) ("Estimated net unavoidable electricity costs paid by the customers of a community choice aggregator shall be reduced by the value of any benefits that remain with bundled service customers, unless the customers of the community choice aggregator are allocated a fair and equitable share of those benefits.").

C. The Commission Adopted the PCIA to Implement the Legislature's Indifference Requirements

The PCIA is the tool the Commission adopted consistent with the statutes referenced above "to equalize cost sharing" between these two groups of customers and ensure indifference.[6] Therefore, when customers of IOUs depart from bundled service and receive their electricity from a non-IOU provider, such as a CCA, "those customers remain responsible for costs previously incurred on their behalf by the IOUs — but only those costs."[7] Consistent with these indifference statutes, the PCIA also conveys to departed load customers the value of resource attributes retained by the IOU for bundled customers.

PCIA rates are established to recover the IOU's Indifference Amount, or the above-market costs related to PCIA-eligible resources. The Indifference Amount is the difference between the cost of the IOU's supply portfolio and the market value of the IOU's supply portfolio as demonstrated in Figure 2.

Figure 2: Indifference Amount Calculation

The PCIA therefore tracks both: (a) the costs of resources; and (b) the value of the benefits provided by the IOUs' PCIA-eligible portfolios and retained by the IOU for bundled customers. Since D.11-12-018, the value of the IOUs' supply portfolio has been derived from administratively determined proxy values that are intended to estimate the

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[6] *See* Decision (**D.**) 18-10-019, at 3.

[7] *Scoping Memo and Ruling of Assigned Commissioner*, R.17-06-026 (Sept. 25, 2017), at 2; *see also* D.18-10-019, *Decision Modifying the Power Charge Indifference Adjustment Methodology*, R.17-06-026 (Oct. 11, 2018), at 3.

market value of the resource portfolio attributes: Energy Value, RPS Value, and Resource Adequacy (**RA**) Value.[8] These values are calculated by multiplying eligible resource output (quantities) by the relevant MPBs (prices).

Each generation resource and customer is assigned a "vintage." A distinct portfolio of generation resources is identified for each vintage year based on when a commitment to procure each resource was made. Customers are assigned vintage years according to the date the customer departed bundled IOU service. Customers continuing to receive bundled service from the IOU are included in the latest vintage (*e.g.*, bundled customers are currently vintage 2026). An Indifference Amount is calculated for each vintage (summing portfolio costs and values), and all customers are responsible for the cumulative Indifference Amount for years prior to and including their vintage. Thus, when a cost is included in a particular vintage, customers in that vintage and all later vintages are responsible for that cost. Customers in prior vintages are not responsible for that cost. Conversely, when a credit is attributed to a particular vintage, customers in that vintage and all later vintages receive the credit. Customers in prior vintages do not receive the credit.

This can be seen in Figure 3 below, which provides a summary of the latest Indifference Amount forecast for Pacific Gas and Electric Company (**PG&E**) by vintage:

8 *See, e.g.*, D.11-12-018, at 9-10, Ordering Paragraph (**OP**) 5, OP 8; D.19-10-001, at 6 ("Market Value is the estimated financial value, measured in dollars, that is attributed to a utility portfolio of energy resources for the purpose of calculating the Power Charge Indifference Adjustment for a given year."). D.23-06-006 subsequently also required Energy Division to calculate a separate adder for Greenhouse-Gas Free (**GHG-Free**) energy.

Figure 3: PG&E 2026 Indifference Amount by Vintage ($000)

	UOG Legacy	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Portfolio Costs	$910,406	$1,439,267	$432,238	$127,428	$160,483	$49,165	$3,672	$6,121	$1,775	$9,342	$482	$37,053	$496	$155,405	$495	$19,156	$478	$593	$3,354,055
Portfolio Market Value	$665,282	$917,396	$372,308	$126,736	$168,059	$84,511	$6,713	$11,514	$3,744	$23,724	$0	$56,144	$0	$238,759	$0	$14,387	$662	$1,104	$2,691,042
Vintage Indifference Amount	$245,125	$521,872	$59,930	$692	($7,576)	($35,346)	($3,041)	($5,393)	($1,969)	($14,382)	$482	($19,091)	$496	($83,354)	$495	$4,769	($184)	($512)	$663,013
Cumulative Indifference Amount	$245,125	$766,996	$826,927	$827,619	$820,042	$784,696	$781,655	$776,262	$774,293	$759,911	$760,393	$741,302	$741,798	$658,444	$658,940	$663,709	$663,525	$663,013	

For the 2015 vintage, for example, a market value credit of $11.5 million is subtracted from a portfolio cost of $6.1 million, producing a negative indifference amount for the 2015 vintage of ($5.4 million). However, customers in the 2015 vintage do not pay PCIA rates based solely on that negative indifference amount. They pay PCIA rates based on the sum of that indifference amount plus the vintage indifference amounts for the years before 2015, *i.e.*, the vintage indifference amounts to the left of the 2015 column in Figure 3 above. Customers in the 2015 vintage do not pay the vintage indifference amounts for any year after 2015, *i.e.*, those amounts to the right of the 2015 column in Figure 3 above. Thus, if a credit is made to the 2016 vintage, customers in the 2015 vintage (and earlier) do not receive that credit; only customers in the 2016 vintage and later will receive the credit.

D. RPS-Eligible Resources Produce Value Through RECs the IOUs Use Immediately or Bank for Later RPS Compliance

RPS Value, as one of the components of Utility Portfolio Value, estimates the financial value attributable to RECs generated by PCIA-eligible resources and retained by the IOU for bundled customer RPS compliance obligations.[9] This RPS Value is determined by applying the RPS MPB to the quantity of RECs used by the IOU.[10] To the extent an IOU uses RECs to meet the needs of bundled customers, the PCIA design requires that bundled customers 'purchase' departed load customers' share of the RECs to convey the

[9] D.19-10-001, at 6, 26; D.11-12-018, at 8, 10, Conclusion of Law (**COL**) 3.

[10] RPS Value may also include revenue received when the IOU's RECs are sold to third parties.

value of the RECs to departed load and ensure indifference according to California law. That 'purchase' is priced at the RPS MPB.

The issue being considered in this Track 2 arises from a unique characteristic of RECs, which makes them different from other generation resource attributes (*e.g.*, energy and RA): RECs can be banked and stored by the IOUs for later use.[11] This leads to the question of how and when value should be provided to unbundled customers for these RECs for which they pay but that the IOU stores for later use.

Prior to 2019, bundled customers paid for the cost of IOU generation resources through generation rates, including RPS-eligible resources that generated RECs whether they were used for compliance in the year generated or banked for later use. Departed load customers also paid for a share of these IOU generation resources on a vintaged basis through PCIA rates. Each year, the IOUs would forecast the quantity of RECs from PCIA-eligible resources that would not be sold to third parties, and these RECs were valued in the PCIA for departed load customers using the RPS MPB in the year of generation. The value was credited to the PCIA, providing a partial offset to the costs paid by then departed load customers. In essence, all customers who were bundled customers at the time the REC was generated pre-paid for RECs banked for later use.

In 2019, the Commission refined D.11-12-018's requirement to compensate departed load for the renewable value of RPS-eligible PCIA resources via more specific PCIA accounting requirements.[12] These new requirements recognized that customers do not realize the value of the IOUs' REC banks until those RECs are used for bundled

11 *See* Cal. Pub. Util. Code § 399.13(a)(5)(B).

12 *See generally* D.19-10-001.

customer RPS compliance (or sold):[13] "Any of the offered [RPS resource] quantity that is not sold will be considered as Actual Unsold RPS and should not be assigned credit in PABA until the value of the RPS product, if any, is known. If previously unsold RPS is sold in a future year, it should be valued at the actual transacted price. If previously unsold RPS is used by the IOU for compliance in a future year, it should be valued at the applicable future year's RPS Adder [MPB]. If Unsold RPS is never used, it should not be assigned credit."[14]

The Commission required the IOUs to treat banked RECs as Retained RPS when those banked RECs are later used for compliance for bundled customers. This is reflected in the IOU accounting as charging bundled customers for the cost of those RECs at the then-current market value (*i.e.*, the RPS MPB) and including an offsetting credit in the PCIA. This credit to the PCIA for the value of RECs compensates departed load customers for the value of their share of the RECs. As discussed in more detail below, these refinements did not upset the original accounting for RECs generated before 2019. They merely created a more granular accounting for such RECs, which, until recent years, had not been used for bundled customers' RPS compliance.

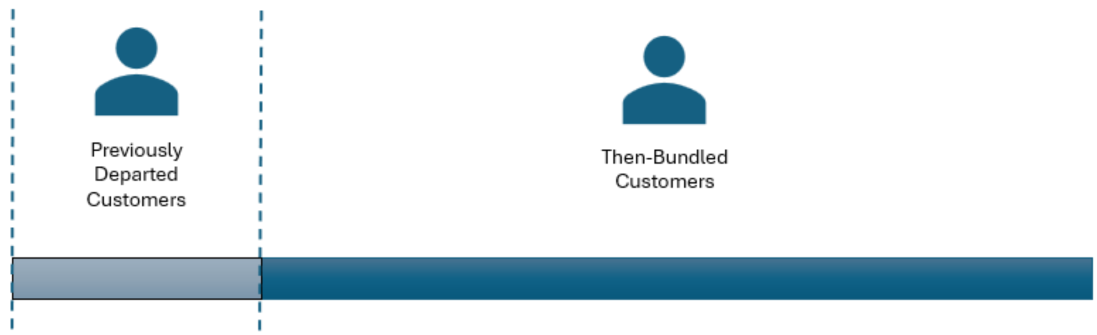
III. LATER DEPARTING CUSTOMERS CURRENTLY RECEIVE NO BENEFIT FOR PRE-2019 BANKED RECS NOW BEING USED BY THE IOUS FOR CURRENT BUNDLED CUSTOMER RPS COMPLIANCE

Four categories of customers exist in the context of Pre-2019 Banked RECs (*i.e.,* RECs generated by PCIA resources from 2011 through 2018 that were not needed for RPS compliance and were stored in the 'bank' for later use.) At the time the Pre-2019 Banked RECs were generated, there were two categories of customers. First, there were customers

[13] *Id.*, at 35.
[14] *Id.*, at 30.

receiving bundled service at the time the RECs were generated (**Then-Bundled Customers**). Second, there were customers that had *already departed* bundled service (**Previously Departed Customers**). Figure 4, below, demonstrates these two categories of customers:

Figure 4: Customer Groups When Pre-2019 Banked RECs Were Generated

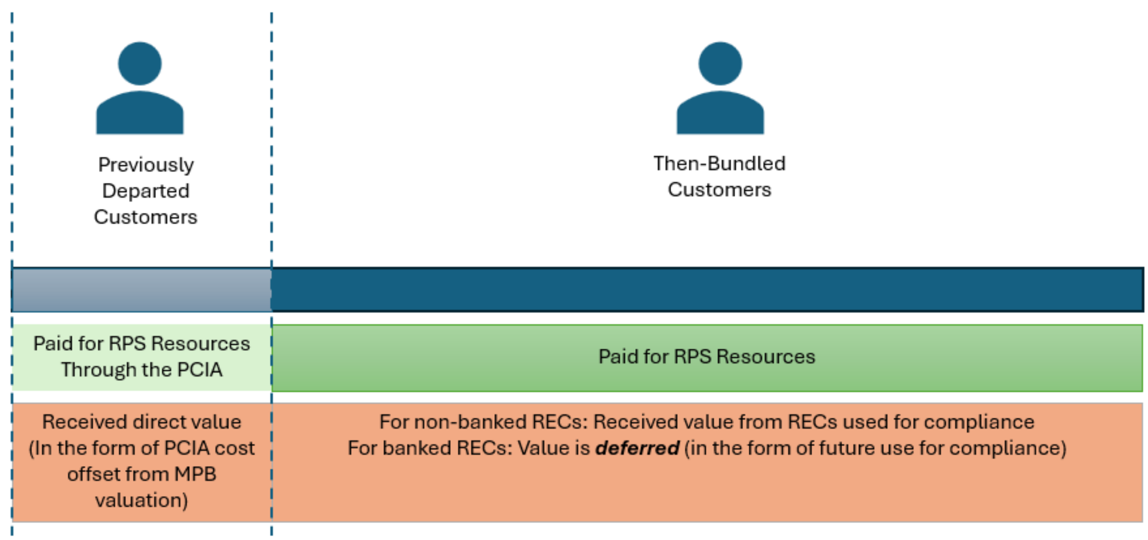


Both Then-Bundled Customers and Previously Departed Customers *paid* for their share of the RECs when they were generated. Because Previously Departed Customers had paid the cost of their share of the RECs, but those RECs were retained by the IOU for bundled customers, Previously Departed Customers received a credit against their PCIA obligations for the value of their share of the RECs. That credit was calculated using the value of the RPS MPB at the time. These Previously Departed Customers therefore were fairly compensated for their share of the Pre-2019 Banked RECs and no longer have any claim to further value or allocation for those RECs.

The benefits Then-Bundled Customers received at that time depended on whether the RECs were needed for compliance. If the RECs were counted at that time toward Then-Bundled Customer compliance, Then-Bundled Customers benefited immediately. However, if the RECs were not needed at that time for bundled customer compliance, the IOUs placed the RECs in the 'bank' for later use. Then-Bundled Customers received no credit at the RPS MPB at that time for the share of the RECs for which they paid.[15] Therefore, the *only customers that received a credit at the RPS MPB for the RECs for which they paid were Previously Departed Customers*. The only 'value' provided to Then-Bundled Customers for banked RECs was the deferred ability to use the RECs at some future point.

Figure 5 below provides a graphic illustration of: (1) the immediate benefit to Previously Departed Customers when RECs were generated; and (2) the deferred benefit to Then-Bundled Customers when RECs were banked.

Figure 5: REC Benefit Conveyed to Customer Groups When RECs Were Generated and Banked



In fact, Then-Bundled Customers paid for the value conveyed to Previously Departed Customers for the RECs retained by the IOU by virtue of the PCIA framework, as shown in Figure 6.

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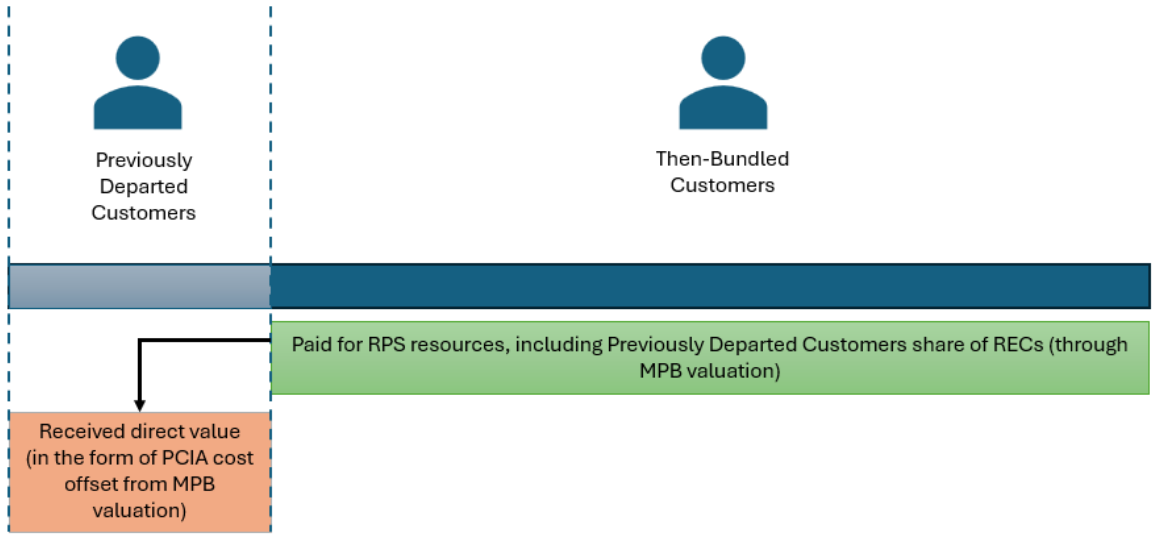
15 *See* PG&E Response to CalCCA DR 3.04 and 3.05. All discovery responses referred to herein are included in Attachment C.

Figure 6: REC Benefits Were Conveyed to Previously Departed Customers



After the Pre-2019 Banked RECs were banked, some of the Then-Bundled Customers departed bundled service to be served by CCAs or ESPs (*i.e.,* Later Departing Customers). This split the category of Then-Bundled Customers in two, creating two further categories of customers: Current Bundled Customers and Later Departing Customers. Current Bundled Customers are those customers that continue to take bundled service after the Later Departing Customers leave bundled service.[16]

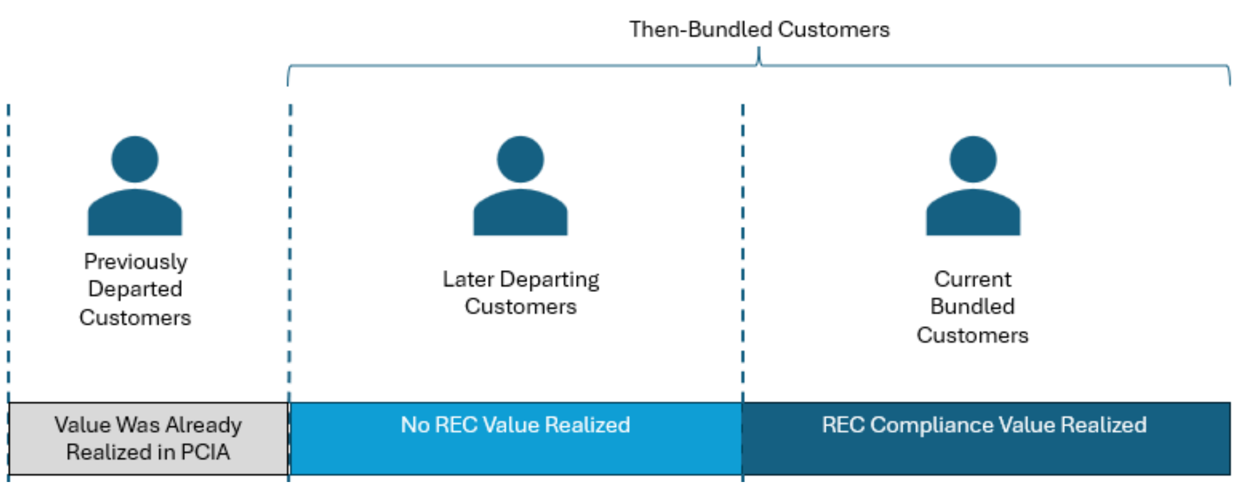
Later Departing Customers paid for the Pre-2019 Banked RECs when they were Then-Bundled Customers, but upon their departure from bundled service were not paid for those RECs which remained in the bank, ready for future use. These Later Departing Customers number in the millions, constituting between 29 percent and 66 percent of

[16] There is arguably a fifth category of customers within the pool of "Current Bundled Customers" who were Later Departing Customers that then returned to bundled service. They are a very small portion of customers that I do not address in this opening testimony.

customers in each IOU's service territory, depending on the IOU and the REC generation year.[17]

Recently, the Joint IOUs began to use Pre-2019 Banked RECs to meet their RPS compliance requirements for Current Bundled Customers, thus avoiding the purchase of additional RECs at current market prices. In doing so, Current Bundled Customers receive the deferred value of the Pre-2019 Banked RECs. However, Later Departing Customers still have not received *any* value for the Pre-2019 Banked RECs for which they also paid when they were Then-Bundled Customers – neither the 'avoided cost' value Current Bundled Customers enjoy nor the ability to use those banked RECs. These Later Departing Customers will not otherwise receive any benefit when the IOUs use the RECs for Current Bundled Customer compliance needs. Absent a credit to the PCIA or an allocation of these Pre-2019 Banked RECs, Later Departing Customers will not receive a share of the value of those RECs despite paying for them, as illustrated in Figure 7 below.

Figure 7: Customer Groups When Pre-2019 Banked RECs Are Later Used for Compliance



[17] *See* SCE response to CalCCA 3.14, PG&E response to CalCCA 3.14, and SDG&E response to CalCCA 3.14.

The following is a hypothetical example that will be utilized throughout my testimony to illustrate how each category of customers discussed above bears the costs and receives the values of Pre-2019 Banked RECs:

- Assume in 2015:
  - 90 percent of customers were bundled;
  - 10 percent of customers were unbundled;
  - The IOU generated and banked 100,000 MWh of RECs;
  - The RPS MPB was $50 per MWh.
- Assume in 2026:
  - An *additional* 60 percent of the IOU's customers have departed bundled service (*i.e.*, 60 percent of Then-Bundled Customers have departed and become Later Departing Customers, with the remaining 40 percent constituting Current Bundled Customers);
  - The RPS MPB is $60 per MWh.

In 2015, the value of the banked RECs was credited to the PCIA and Previously Departed Customers would have received 10 percent of that value ($500,000 in this example[18]) through PCIA rates in exchange for the IOU retaining the RECs. Then-Bundled Customers (which includes Later Departing Customers that will depart IOU service after 2015) paid for all of the RECs to be generated and banked but received no benefit in 2015 other than the deferred ability to use the banked RECs in the future.

In 2026, when an IOU uses the banked RECs for Current Bundled Customer RPS compliance, it does not provide any credit to the Later Departing Customers, even though they paid the same total amount as those Current Bundled Customers back in 2015 (when both categories were Then-Bundled Customers). At the same time, the IOU can use the

[18] 100,000 MWh * $50 / MWh * 10% = $500,000.

Pre-2019 Banked RECs for Current Bundled Customer RPS compliance, resulting in the realization of the value previously deferred when the RECs were banked in 2015. Because 60 percent of the banked RECs were paid for by Later Departing Customers, they should receive 60 percent of the value of the banked RECs ($3.6 million in this example[19]) for their share of the RECs when they are used by Current Bundled Customers for RPS compliance. Failure to convey this value to Later Departing Customers results in a cost shift of $3.6 million in this example from bundled to unbundled customers.

While that may seem like a small cost shift, it is enormous when applied to all of the IOUs' Pre-2019 Banked RECs. For example, if all Pre-2019 Banked RECs that remain in the IOUs' REC banks are valued at the 2026 RPS MPB of $62.45/MWh, over $1.5 billion in costs would be shifted from bundled customers to departed customers.

IV. VALUATION OR ALLOCATION OF PRE-2019 BANKED RECS PREVENTS COST SHIFTS AND MAINTAINS INDIFFERENCE AS REQUIRED BY STATUTE

Valuation or allocation of Pre-2019 Banked RECs is necessary to ensure indifference and prevent a cost shift from Current Bundled Customers to Later Departing Customers. To ensure Later Departing Customers remain indifferent to an IOU's use of Pre-2019 Banked RECs for Current Bundled Customer RPS compliance, CalCCA provides the following proposal to ensure either the value or allocation of attributes is provided in accordance with section 366.2(g):

- **Value:** The Commission should provide value to Later Departing Customers for their share of RECs used by the IOU at the current RPS MPB through a vintage-specific credit to the PCIA. The credit should be recorded to the PCIA vintage of the year in which the RECs were generated.
- **Allocation:** Alternatively, Pre-2019 Banked RECs should reduce the Net RPS Procurement Need as measured on the Commission's Renewable Net

19 100,000 MWh * $60 / MWh * 60% = $3,600,000.

Short Calculation template for the LSEs that serve customers who paid for the Pre-2019 Banked RECs when they were generated and then later departed bundled service.

These proposed frameworks ensure indifference for Later Departing Customers and are described more fully below.

A. Later Departing Customers Should Receive Value at the Current RPS MPB, Through a Vintage-Specific Credit to the PCIA

1. The Best Measure of Value Accruing to Current Bundled Customers When the IOU Uses Pre-2019 Banked RECs for Compliance is the Current RPS MPB

Current Bundled Customers are responsible for the cost of RPS compliance on their behalf. Value is derived from RECs based on the ability to count those RECs toward an LSE's RPS compliance obligation; in using banked RECs for compliance, Current Bundled Customers avoid the cost of procuring an equivalent amount of RECs at current market prices. Because the IOUs can bank and store RECs, their value may change over time as the IOUs' need for RPS procurement changes. Southern California Edison Company (**SCE**) and PG&E both confirmed that, regarding RPS, there is no difference between RECs generated before or after 2019.[20] SCE explained, "For RPS compliance purposes, there is no difference between RECs banked prior to 2019 and those banked in 2019 or later, provided they meet standard RPS eligibility. Both types of banked RECs may be used to satisfy SCE's RPS obligations."[21]

The IOUs routinely use banked RECs as a tool to manage their RPS procurement as approved in the annual RPS Procurement Plans filed with the Commission. For example, in D.24-12-035 the Commission describes that according to San Diego Gas & Electric

[20] *See* SCE Response to CalCCA 3.09. *See also* PG&E Response to CalCCA 3.09.

[21] *See* SCE Response to CalCCA 3.09.

Company's (**SDG&E**) Draft 2024 RPS Plan, "SDG&E plans to meet its compliance requirements through 2034 by utilizing its bank and/or, after considering the benefits to customers, holding a solicitation or entering into bilateral agreements to procure long-term and/or short-term resources to meet its Procurement Quantity Requirements."[22] In D.24-12-035, the Commission approved SDG&E's request for the ability to procure short-term and long-term RECs as an alternative to utilizing its banked RECs for compliance.[23] In other words, if an IOU does not have banked RECs, or decides not to use them, it can seek to procure RPS resources from the market as needed to meet a shortfall in its compliance obligation.[24]

The RPS MPB is designed to reflect the price at which the RPS resource attributes can be purchased and sold in the market.[25] Consequently, the RPS MPB is the best available estimate of the current market value of a REC, and Current Bundled Customers should be required to pay that price to Later Departing Customers when the Later Departing Customers' share of the Pre-2019 Banked RECs are used for compliance. Notably, the Commission recognized this fact in D.19-10-001. When the Commission adopted PG&E's recommendation to assign a zero value to Unsold RPS in the year of generation, it explained the following:

> The IOUs' RPS procurement planning takes place in formal proceedings subject to stakeholder review. The Commission may authorize the IOUs to retain RPS resources based on their procurement planning needs. If the IOUs use RECs in the future based on their approved procurement plans, the value in the year of generation may be different from the value at the time of the future transaction. To value all RECs in the year of generation, as TURN notes, could conflict with the Commission-approved procurement

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[22] D.24-12-035, at 42.

[23] *Id.*, at 43.

[24] *See* SCE Response to CalCCA 3.07 (confirming that IOUs can either use RECs from the bank, produce more RECs, or purchase RECs on the market).

[25] *See* D.18-10-019, at 73.

> plans. It effectively shifts market risks and opportunities associated with changing REC prices to bundled customers even though the resources generating those RECs were not procured solely on their behalf.[26]

As a result, the Commission directed that excess RPS that is not sold should be considered as Unsold RPS and not assigned credit in the PCIA until some point in the future when the RECs are either sold or used for bundled customer compliance.[27] The Commission also directed that when previously Unsold RPS is used by the IOU for compliance in a future year, it should be valued at the applicable future year's RPS MPB.[28]

It is important to reiterate that, unlike Previously Departed Customers that were already departed when the Pre-2019 Banked RECs were generated, Later Departing Customers – those that departed bundled service *after* the RECs were generated – have never been compensated for the value of Pre-2019 Banked RECs that are being used by the IOU for Current Bundled Customer RPS compliance. When Current Bundled Customers benefit from using the Pre-2019 Banked RECs for compliance, they should be required to purchase the share of Pre-2019 Banked RECs originally paid for by Later Departing Customers, thus ensuring Later Departing Customers receive a share of the benefit.

Returning to the 2015 example to demonstrate these points, Then-Bundled Customers paid for the RECs the IOU banked in 2015 but did not benefit from those RECs at that time, *i.e.*, the value of the RECs was deferred to a future date. Sixty percent of those banked RECs were paid for by Later Departing Customers, *e.g.*, customers that departed bundled service after 2015 but prior to 2026. In other words, if 100,000 MWh of 2015

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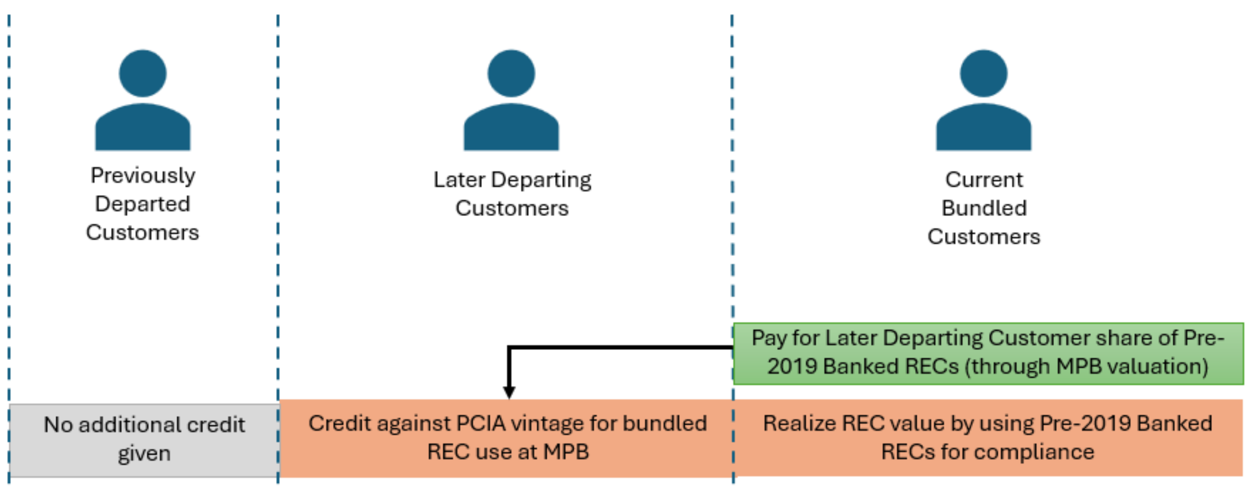
26 D.19-10-001, at 35.

27 *Id.*, at 30.

28 *Id.*

banked RECs are used for compliance on behalf of Current Bundled Customers in 2026, 60 percent of those banked RECs were originally paid for by Later Departing Customers. These Later Departing Customers were part of the group of Then-Bundled Customers that originally paid for the 100,000 MWh of RECs in 2015 and are waiting to receive their share of the benefits. Absent a credit to the PCIA, Current Bundled Customers will retain all the benefits from these RECs even though Later Departing Customers paid for a share of the RECs when they were generated. Figure 8 illustrates how such a credit should be conveyed to Later Departing Customers.

Figure 8: REC Benefit Conveyed to Customer Groups When Pre-2019 Banked RECs Are Used for Compliance



2. Providing Vintage-Specific Value of Pre-2019 Banked RECs Ensures Only the Right Customers are Credited

As noted above, the PCIA framework in place prior to 2019 ensured that Previously Departed Customers who had already departed when the RECs were generated received the benefit of the RECs through the RPS Value credit embedded in the PCIA. Those Previously Departed Customers were fully compensated in the year the RECs were generated. Then-Bundled Customers receiving bundled service when the RECs were generated, but who later departed (*i.e.,* Later Departing Customers), paid for the RECs but have not yet received the benefit of those RECs. Those customers, and not the Previously Departed Customers, should benefit from the Pre-2019 Banked RECs when they are used for bundled customer compliance.

Conveying the value of Pre-2019 Banked RECs through a vintage-specific credit to the PCIA ensures *only* the Later Departing Customers (and not the Previously Departed Customers) receive the value of their share of the RECs used by the IOU. In my 2015 REC example, the value of RECs banked in 2015 but used for compliance in 2026 would be measured using the RPS MPB for 2026 and recorded as a credit to PCIA vintage 2015. This method ensures that customers departing bundled service in 2015 or later receive credit for the share of RECs they paid for when they were generated in 2015; the credit will convey the same value received by Current Bundled customers, the avoided cost of additional procurement measured by the RPS MPB. This method also ensures that customers who had already departed bundled service (Previously Departed Customers) prior to 2015, and who received credit for RECs through the PCIA in 2015, are not given additional credit for the same RECs.

B. Allocation of Pre-2019 Banked RECs to Later Departing Customers is an Alternative Valuation Method Consistent with Indifference Requirements

Allocating the Pre-2019 Banked RECs to Later Departing Customers rather than charging Current Bundled Customers for the REC value is an alternative method that is also consistent with the indifference requirements. As noted above, Public Utilities Code section 366.2(g) entitles departed load customers to receive *either* the value of resource attributes or an allocated share of the attributes. Specifically, using the same formulaic approach to determine which PCIA vintages should receive a monetary credit, the

Commission could determine the share of each IOU's Pre-2019 Banked RECs that was paid for by Later Departing Customers in each PCIA vintage. That share of RECs could then be inserted as a reduction to the relevant LSE's Net RPS Procurement Need as measured on the Commission's Renewable Net Short Calculation template and an offsetting increase to each IOU's Net RPS Procurement Need.[29]

The idea is similar to the allocation of RA capacity from Cost Allocation Mechanism (**CAM**) resources for the Commission's RA compliance program. Jurisdictional LSEs are required to demonstrate that they have procured enough RA capacity to meet their RA requirement as prescribed by the Commission. Under the CAM framework, when the IOU procures a resource on behalf of bundled and unbundled customers (as directed by the Commission), each LSE in the IOU service territory is allocated a load ratio share of the RA provided by the resource. Rather than transfer ownership of the allocated portion of RA, however, the Commission increases the IOU RA requirement and reduces each LSE's RA requirement by its allocated share of the CAM resources.

A similar process could be followed for Pre-2019 Banked RECs. All retail sellers are required to submit Renewable Net Short calculations to the Commission each year with their RPS Procurement Plans. The Commission's Renewable Net Short calculation template quantifies each LSE's Gross RPS Procurement Quantity Requirement as a percentage of retail sales volume. Adjustments are then made to determine the LSE's Net RPS Procurement Need and Net RPS Position after considering available resources. To treat Pre-2019 Banked RECs similar to CAM, the relevant IOU would retain ownership of

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[29] *See, e.g.,* 2023 Renewable Net Short Template, https://webtraininga.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/documents/energy/rps/2023/renewable-net-short-template-2023.xlsx.

the banked RECs, but the Commission would adjust an individual LSE's Net RPS Procurement Need for its allocated share of the RECs (*i.e.,* a reduction to non-IOU Net RPS Procurement Need, offset by an increase to IOU Net RPS Procurement Need).[30] Figure 9 and Figure 10 below show an excerpt from the Commission's Renewable Net Short template and how an adjustment for Pre-2019 Banked RECs could be made in the template.

Figure 9: Current Renewable Net Short Template Excerpt

Variable	Calculation	Item	2025 Forecast	2026 Forecast	2027 Forecast	2025-2027
		Forecast Year	3	4	5	CP 5
		Annual RPS Requirement				
A		**Total Retail Sales (MWh)**				-
B		RPS Procurement Quantity Requirement (%)	46.7%	49.3%	52.0%	NA
C	A*B	**Gross RPS Procurement Quantity Requirement (MWh)**	-	-	-	-
D		Voluntary Margin of Over-procurement (MWh)				-
E	C+D	**Net RPS Procurement Need (MWh)**	-	-	-	-
		RPS-Eligible Procurement				

Figure 10: Renewable Net Short Template Excerpt With Proposed Pre-2019 Banked REC Adjustment

Variable	Calculation	Item	2025 Forecast	2026 Forecast	2027 Forecast	2025-2027
		Forecast Year	3	4	5	CP 5
		Annual RPS Requirement				
A		**Total Retail Sales (MWh)**				-
B		RPS Procurement Quantity Requirement (%)	46.7%	49.3%	52.0%	NA
C	A*B	**Gross RPS Procurement Quantity Requirement (MWh)**	-	-	-	-
D		Voluntary Margin of Over-procurement (MWh)				-
E		Pre-2019 Banked REC Allocation (MWh)				
F	C+D + E	**Net RPS Procurement Need (MWh)**	-	-	-	-
		RPS-Eligible Procurement				

The quantity of Pre-2019 Banked RECs to be allocated each year would be determined by an IOU's need to use its share of the Pre-2019 Banked RECs for Current Bundled Customers. For example, if Later Departing Customers paid for 60 percent of the IOU's 100,000 MWh of Pre-2019 Banked RECs, when the IOU needs to use 40,000 MWh of RECs for Current Bundled Customers, it would also allocate 60,000 MWh of additional

[30] The offsetting increase would not increase the IOU's RPS obligation; it would simply reflect the idea that the RECs remain on the IOU's books but should not be counted towards their RPS procurement.

RECs among the LSEs serving Later Departing Customers and would no longer be able to use those RECs for its own compliance. Each LSE's share of the Pre-2019 Banked RECs allocated to Later Departing Customers would be based on the relevant vintage's load share of all non-exempt LSEs in the IOU service territory. The IOUs' need to use Pre-2019 Banked RECs, and the quantities allocated to Current Bundled Customers and Later Departing Customer LSEs, would be determined in the IOUs' annual ERRA proceedings.

V. CALCCA'S PROPOSAL IS CONSISTENT WITH APPLICABLE LAW AND COMMISSION PRECEDENT (SCOPING RULING ISSUE 1)

The Scoping Ruling asks two overall questions. First, is the proposal to value Pre-2019 Banked RECs at a value other than zero consistent with applicable law and Commission precedent? Next, if the answer to Issue 1 is determined to be yes, should the Commission direct IOUs to apply a value other than zero dollars when Pre-2019 Banked RECs are valued for ratemaking in the 2026 and later ERRA Forecast Proceedings? If so, how should such value be determined and allocated while adhering to indifference principles for all customers.[31]

As demonstrated in detail throughout my testimony above, CalCCA's proposal to value Pre-2019 Banked RECs at the current RPS MPB is consistent with California statutes applying to bundled and unbundled customers, and is consistent with Commission decisions and precedent related to the PCIA. To ease the Commission's review of CalCCA's proposal, the remainder of my testimony takes each sub-question in the Scoping Ruling and provides a specific response to it.

[31] Scoping Ruling, at 3-4.

A. Statutory Indifference Principles, the Mandate to Prevent Cost Shifts, and Prior Commission Decisions All Require that Later Departing Customers Receive Their Share of Value for Bundled Customer Use of Pre-2019 Banked RECs (Scoping Ruling Issue 1.a.)

As demonstrated in my testimony, ensuring Later Departing Customers receive value for Pre-2019 Banked RECs prevents a cost shift from Current Bundled Customers to Later Departing Customers that would otherwise occur if such value is not provided when the IOUs use the Pre-2019 Banked RECs for Current Bundled Customer RPS compliance. Valuing the Pre-2019 Banked RECs as proposed by CalCCA ensures Later Departing Customers are indifferent to the IOUs using RECs originally paid for by those customers for Current Bundled Customers' RPS compliance obligations. On the other hand, giving Later Departing Customers no value for Pre-2019 Banked RECs used for Current Bundled Customers' RPS compliance obligations would not leave Later Departing Customers indifferent. As a policy matter, customers would not be indifferent if they were forced to leave behind these valuable banked RECs and get nothing in return when departing IOU bundled service.

Not only would Later Departing Customers remain indifferent under CalCCA's proposal, Current Bundled Customers also would remain indifferent. As shown in my examples above, and in the numerical example in Attachment A to my testimony, Then-Bundled Customers paid for the RECs generated and banked in 2015. Thus, a portion of the Pre-2019 Banked RECs was paid for by Current Bundled Customers, and a portion of those RECs was paid for by Later Departing Customers (customers who departed bundled service since 2015). Valuing the 2015 Banked RECs at the RPS MPB when they are finally used for Current Bundled Customers in 2026 does not result in Current Bundled Customers paying twice for the same RECs. Rather, it results in Current Bundled Customers purchasing the portion of the 2015 RECs that were paid for by Later Departing Customers (who were Then-Bundled Customers in 2015 and paid for a share of the REC bank). That is in line with the costs Current Bundled Customers avoid by using RECs paid for by another group of customers. It is also in line with the Commission's existing indifference framework, and not contrary to it.

B. No Policy Considerations or Other Downstream Consequences Negate the Commission's Statutory Obligation to Maintain Indifference and Ensure Charges are Just and Reasonable (Scoping Memo Issue 1.b.)

The Scoping Ruling asks whether there are potential "downstream" consequences or other policy considerations stemming from the proposal to value Pre-2019 Banked RECs at a value other than zero dollars that would render the proposal unreasonable pursuant to Public Utilities Code section 451, or any other statute or Commission decision. My understanding of Public Utilities Code section 451 is that it requires rates to be just and reasonable. As stated throughout my testimony, because Later Departing Customers paid for their share of Pre-2019 Banked RECs, it is just, reasonable, and required by the indifference principle for Current Bundled Customers to compensate Later Departing Customers when those RECs are used by the IOU to meet RPS compliance needs of Current Bundled Customers.

C. Differences Between Pre-2019 and Post-2018 Banked RECs Do Not Impact the Reasonableness of Assigning, or the Commission's Obligation to Assign, Value to the Pre-2019 RECs (Scoping Issue 1.c.)

Distinguishing RECs as either 'Pre-2019' or 'Post-2018' is a consequence of D.19-10-001 that created the PCIA category of Unsold RPS effective January 1, 2019. In response to discovery, PG&E and SCE both confirmed that for RPS compliance there is no distinction between RECs generated before and after 2019.[32] The need to determine the value of the Pre-2019 Banked RECs arises because the IOUs plan to use the RECs to meet RPS compliance needs for Current Bundled Customers. If an IOU did not have banked RECs or decided not to use them, it would procure RPS resources from the market as needed to meet a shortfall in its compliance obligation. Consequently, the current RPS MPB best measures the cost avoided when bundled customers rely on banked RECs rather than procuring additional RECs in the market, and Current Bundled Customers should be required to pay that price to Later Departing Customers when the Pre-2019 Banked RECs are used for compliance.

D. Banking of RECs Under the Pre-2019 Rate Methodology Does Not Result in Forfeiture of Value by Later Departing Customers (Scoping Issue 1.d.)

As a matter of policy, customer groups that pay the cost of IOU resources should receive the benefit of those resources. The Commission has enshrined this policy in a PCIA framework that requires departing load to continue to pay for IOU generation resources even after their departure from bundled IOU service. In fact, many of the resources that generated the Pre-2019 Banked RECs are still included in the PCIA rates paid by unbundled customers today. My testimony demonstrates that a portion of the Pre-2019 Banked RECs was paid for by Later Departing Customers. By banking those RECs for future compliance needs, the IOUs deferred conveying the value of the RECs to customers. When the benefits of the banked RECs are realized, the benefits should follow the customer groups that paid for the RECs to be generated.

I am not aware of any Commission directive that would preclude customers from receiving the value of the RECs for which they previously paid. I am also not aware of any

32 *See* PG&E Response to CalCCA 3.09; *see also* SCE Response to CalCCA 3.09.

Commission directive that would require Later Departing Customers to forfeit the value they are owed to ensure indifference.

VI. THE IOUS SHOULD BE DIRECTED TO APPLY CALCCA'S VALUATION OR ALLOCATION PROPOSAL (SCOPING ISSUE 2)

A. Using Current RPS MPB Data is Reasonable and Required to Maintain Indifference (Scoping Issue 2.a.)

Current Bundled Customers should be responsible for the cost of RPS compliance on their behalf. The value of Pre-2019 Banked RECs is based on the IOU's ability to count those RECs toward its RPS compliance obligation for Current Bundled Customers rather than procure additional RECs at current market prices. Because RECs can be banked and stored by the IOUs, their value may change over time as the IOUs' need for RPS procurement changes. The RPS MPB is designed to reflect the price at which the resource attributes can be purchased and sold in the market. Consequently, the current RPS MPB is the best available estimate of the cost Current Bundled Customers avoid by not having to procure at the current market value of a REC, and Current Bundled Customers should be required to pay that price to Later Departing Customers when the Pre-2019 Banked RECs are used for compliance.

B. The Only Impact the Pre-2019 PCIA Methodology Has on How the Commission Should Value or Allocate Pre-2019 Banked RECS to Customers Now is That Such Valuation Must be Vintage-Specific to Avoid Double-Payment to Previously Departed Customers (Scoping Issue 2.b.)

As described in detail throughout my testimony, prior to 2019 Then-Bundled Customers paid for the RECs that were generated and banked by the IOUs, but only Current Bundled Customers will receive the benefit of those RECs when the IOU uses them for compliance. Following CalCCA's recommended approach to valuing Pre-2019 Banked RECs and crediting the PCIA resolves the unfair treatment of Later Departing Customers and ensures three outcomes. First—and most importantly—customers that originally paid for the RECs but later departed bundled service will finally receive the benefit of the RECs for which they originally paid. Second, Current Bundled Customers only purchase Later Departing Customers' share of RECs used by the IOU, meaning they never pay twice for the same RECs. Third, Previously Departed Customers are not credited twice for the same RECs.

While ensuring these fair outcomes, CalCCA's proposal does not upset the prior PCIA methodology and ratemaking treatment. The IOUs suggest otherwise in their responses to CalCCA's discovery.[33] However, the Commission's prior ratemaking treatment addressed the question of indifference between Previously Departed Customers and Then-Bundled Customers. That is different than the question before the Commission in Track 2, which asks how to ensure indifference between the two sub-groups of Then-Bundled Customers: Later Departing Customers and Current Bundled Customers. In other words, the IOUs' arguments focus on the wrong groups of customers.

Prior to the accounting changes adopted in D.19-10-001, the general framework of the PCIA described above was already in place. Decision 19-10-001 did not change the fact that: (1) Then-Bundled Customers paid for the RECs at the time they were generated; (2) only Current Bundled Customers benefit when the IOU uses the RECs to meet current compliance obligations; and (3) Later Departing Customers will not receive any value for the RECs unless the Commission adopts CalCCA's recommendations in this proceeding. CalCCA's proposal does not constitute reopening past cases or partially refunding generation rates paid for by Later Departing Customers in the years Pre-2019 Banked RECs

[33] *See* SCE Response to CalCCA 3.09.

were generated. Those rates were paid and they remain paid. But when a resource is paid for through those generation rates and the attributes are placed on the shelf for later use, customers who originally paid those rates should receive the value of the attributes when they are eventually taken off the shelf and used.

CalCCA also does not propose truing-up rates set in prior years. Using my prior example, a true-up would update the value of the RECs when they were generated in 2015 ($50/MWh) with the value of the RECs when they were used for compliance in 2026 ($60/MWh). That approach is similar to the approach adopted in SDG&E's ERRA Forecast cases, which suffers from significant short-comings.[34] As PG&E explained in response to discovery,[35] only Previously Departed Customers received a credit at the RPS MPB when the RECs were originally generated so it would not make sense to true-up the prior MPB when addressing a cost shift tied to Then-Bundled Customers that later departed.

At most, the prior ratemaking treatment necessitates avoiding double-compensating Previously Departed Customers, *i.e.*, it necessitates the vintage-specific credit or allocation approach CalCCA proposes here (rather than spreading credits or allocations to all vintages) when the Pre-2019 Banked RECs are used for compliance. If the Pre-2019 Banked REC credit is applied to the PCIA vintage corresponding with the year the RECs were generated, the value of the RECs will be allocated to customers that departed service in the year the REC was generated and later. Under this approach, Later Departing Customers will receive their proportionate share of the credit as will Current Bundled Customers, while Previously Departed Customers that were already credited in the PCIA

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[34] *See* Attachment A. Another shortcoming to the SDG&E ERRA Forecast approach is that the 2015 RPS MPB was calculated using a different methodology than the 2026 RPS MPB, meaning the Commission would be truing up an apple with an orange.

[35] *See* PG&E response to CalCCA 3.05.

when the RECs were generated will not receive any of the new credit. Beyond that need to avoid a double payment, the prior ratemaking treatment should have no impact on ensuring all customers remain indifferent by crediting all RECs used for Current Bundled Customer compliance at the RPS MPB.

C. CalCCA's Valuation Proposal Would Not Require Changes to PCIA Ratemaking, Balancing Accounts, and/or Tariffs (Scoping Issue 2.c.)

Following CalCCA's proposed approach fits within the existing PCIA framework and would not require modification to balancing accounts or tariffs. In fact, this approach is not new. PG&E has used the approach endorsed by CalCCA for valuing banked RECs in its ERRA Forecasts since 2023, including its 2023 ERRA Forecast (A.24-05-009),[36] 2024 ERRA Forecast (A.23-05-012),[37] and 2025 ERRA Forecast (A.24-05-009).[38] In each of these proceedings, PG&E's forecasted RPS generation was less than the annual RPS compliance obligation. In each proceeding, PG&E used banked RECs to make up the difference and applied a credit to the PCIA vintage matching the year the banked RECs were generated.

PG&E explained the logic of this approach in its 2023 ERRA Forecast testimony. PG&E explained that in previous years its ERRA revenue requirement was calculated to recover the full RPS market value associated with its annual RPS generation volumes, even if the volume exceeded the annual RPS compliance requirement.[39] As a result, all of PG&E's banked RECs through that point were paid for by customers who received bundled

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36 A.22-05-029, PG&E 2023 ERRA Forecast Prepared Testimony, at 11-13 through 11-21.

37 A.23-05-012, PG&E 2024 ERRA Forecast Prepared Testimony, at 9-17 through 9-24.

38 A.24-05-009, PG&E 2025 ERRA Forecast Fall Update Testimony, at 9. *See also* A.25-05-011, Confidential Tr. Vol. 1, at 110:2-24.

39 A.22-05-029, PG&E 2023 ERRA Forecast Prepared Testimony, at 11-14, lines 10-21.

service in the year the RECs were generated.[40] PG&E explained, "It is precisely those customers that earlier procured surplus RPS generation who will benefit from an accounting adjustment for 2023 ratesetting."[41] Accordingly, PG&E credited the PCIA vintages corresponding to the years in which the banked RECs were generated by applying the then-current forecast RPS Adder to the quantity of banked RECs utilized.

This concludes my testimony.

[40] *Id.*, at 11-16, lines 28-33.
[41] *Id.*, at 11-17, lines 1-4.

ATTACHMENT A

Pre-2019 Banked RECs Numerical Example

The following tables demonstrate the payments and credits for my 2025 example made through the PCIA framework when the RECs were generated, and show the credit required when banked RECs are used for compliance. Table 1 below illustrates the overall PCIA framework with generic assumptions for resource costs and portfolio market value as it would have occurred in 2015 when the RECs were generated. As previously noted, the assumption for this example is that 10 percent of the IOU's customers had departed bundled service prior to 2015.

Table 1: Example PCIA Mechanics in 2015

	Total ($000)
Then-Bundled Customers	
Pay: Generation Resource Cost	$50,000
Less: Departed Load Share of Above Market Cost	($4,500)
Net Paid by Then-Bundled Customers	$45,500
Previously Departed Customers	
Pay: Departed Load Share of Generation Resource Cost	$5,000
Less: RPS Value	($500)
Departed Load Share of Above Market Cost	$4,500
Total Cost Responsibility	$50,000

As Table 1 demonstrates, Then-Bundled Customers would pay $45.5 million in generation rates, comprising their share of resource costs ($50 million * 90% = $45 million) plus the market value ($500,000) of Previously Departed Customers' share of RPS attributes that remained with the IOU for bundled customers. Previously Departed Customers would pay for their share of expected resource costs, reduced by a credit for the expected value of the Previously Departed Customers' share of the RECs that remained with Then-Bundled Customers. Through this framework, Then-Bundled Customers paid for all RECs generated and banked in 2015, and there was a value credit only to Previously Departed Customers in exchange for their share of RECs that remained with Then-Bundled Customers. Then-Bundled Customers *did not receive a similar* *credit*, meaning they received $0 for their own share of the RECs.[42] That treatment is intuitive because the RECs were banked for later use: Then-Bundled customers eventually realize the value of the RECs for which they paid when they are used for compliance.

Continuing with my example from above, the IOU generated and banked 100,000 MWh of RECs in 2015, and the RPS MPB was $50 per MWh in 2015. Table 2 demonstrates how Then-Bundled Customers (still 90 percent of all customers at the time) would have been attributed a 90 percent share of RECs generated in 2015 (*i.e.,* 90,000 MWh) because they paid their 90 percent share of the resource costs. Then-Bundled Customers also purchased the 10 percent share of RECs belonging to Previously Departed Customers (*i.e.,* 10,000 MWh). After the payments and credits, Then-Bundled Customers paid for all 100,000 MWh of these illustrative RECs generated in 2015 but received no value for the RECs as they were placed in the bank and the benefits (value realization) were deferred.

Table 2: Allocation of RECs, RPS Payments and Credits in 2015

	Bundled Load (2015)	Departed Load (Pre-2015)	Total
MWh	90,000	10,000	100,000
Price ($/MWh)		$50.00	
RPS Value Realized		$500,000	
Share of RECs (MWh)			
Share of RECs Generated	90,000	10,000	100,000
Share of RECs Paid for at Market	10,000	(10,000)	-
Total RECs Banked	100,000	-	100,000

Continuing my example from above, the IOU needs to use the 100,000 MWh of RECs banked in 2015 to meet its compliance obligations for Current Bundled Customers in 2026. Since 2015, 60 percent of the IOU's Then-Bundled Customers have departed bundled service (meaning that in 2026, only 40 percent of the Then-Bundled Customers still receive bundled service as Current Bundled Customers). Consequently, 60 percent of the 2015 banked RECs were paid for

42 *See* PG&E Response to CalCCA DR 3.04 and 3.05.

by Later Departing Customers. Current Bundled Customers should receive the benefits from their *own* share of the 2015 banked RECs (*i.e.,* 40 percent * 100,000 = 40,000 MWh). Later Departing Customers (who departed after 2015) should receive value for *their* share of the banked RECs (*i.e.,* 60 percent * 100,000 = 60,000 MWh). As shown in Table 3, assuming the 2026 RPS MPB is $60 per MWh, the 2015 banked RECs have a total value of $6 million and Later Departing Customers should be given a credit of $3.6 million in exchange for their share of the banked RECs.

Table 3: Allocation and Value of 2015 Banked RECs in 2026

	Bundled Load (2015)	Departed Load (Pre-2015)
Banked REC Share (MWh)		
Bundled Customers (2026)	40,000	-
Later Departing Customers (2015-2025)	60,000	-
Total Banked RECs (MWh)	100,000	-
RPS MPB	$60.00	
Banked REC Value		
Current Bundled Share (40%)	$2,400	-
Later Departing Share (60%)	$3,600	-
Total Banked RECs Value ($000)	$6,000	-

When the 2015 banked RECs are counted toward the IOU's compliance obligation, Current Bundled Customers will receive value from: (1) their own RECs (the 40,000 MWh); and (2) the avoided cost of buying additional RECs (60,000 MWh) in the market. Later Departing Customers should receive the same value as that avoided cost through credit to the PCIA to reflect the fact that RECs paid for by Later Departing Customers will be retained for Current Bundled Customers. This provision of value will avoid shifting the cost of Current Bundled Customer RPS compliance to the Later Departed Customers.

If the Pre-2019 Banked REC credit is applied to the PCIA vintage corresponding with the year the RECs were generated, the value of the RECs will be allocated to customers that departed service in the year the REC was generated and later (*i.e.,* Later Departing Customers). As described earlier, customers in a given vintage pay all costs and receive all credits recorded to their vintage and earlier. So if a credit for the value of banked RECs is recorded to PCIA vintage 2015, customers assigned to PCIA vintage 2015 and later (*i.e.,* Later Departing Customers in this example) will receive a share of the credit, while customers assigned to PCIA vintage 2014 and earlier (*i.e.,* Previously Departed Customers in this example) will not receive any of the new credit. As shown in Table 4, crediting the total value of banked RECs (*i.e.*, $6 million) to vintage 2015 results in $3.6 million returning through PCIA rates to Later Departing Customers that departed bundled service between 2015 and 2025.[43] The remaining $2.4 million stays with vintage 2026, which is Current Bundled Customers.

Table 4: PCIA Rate Impact of Vintage-Specific Credit

PCIA Template (Simplified)

Vintage	UOG Legacy	2009	# # # # #	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Cost of Portfolio ($000)																
Market Value of Portfolio ($000)																
RPS Value				($6,000)												($6,000)
Indifference Amount	$0	$0	# # # # #	($6,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($6,000)
IOU System Sales by Vintage (GWh)	70,000	70,000		63,000	59,564	56,127	52,691	49,255	45,818	42,382	38,945	35,509	32,073	28,636	25,200	
PCIA Rates	-	-		(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	
Value to Bundled Load															($2,400)	($2,400)
Value to Later Departed Load	$0	$0	# # # # #	($327)	($327)	($327)	($327)	($327)	($327)	($327)	($327)	($327)	($327)	($327)		($3,600)
Total Banked REC Value ($000)	**$0**	**$0**	**# # # # #**	**($327)**	**($327)**	**($327)**	**($327)**	**($327)**	**($327)**	**($327)**	**($327)**	**($327)**	**($327)**	**($327)**	**($2,400)**	**($6,000)**

In this example, customers in vintages 2014 and earlier would not receive any benefit since Previously Departed Customers received their benefit in 2015 when the RECs were generated.

Adopting the vintage-specific credit mechanism demonstrated above is required to avoid unintended outcomes of other allocation methods like the one adopted in SDG&E’s 2025 and 2026

43 Note that this example assumes customers depart at a linear rate although the model would work for any rate of customer departure.

ERRA Forecast proceedings.[44] The method adopted in those cases has two distinct components: (1) the price used to value banked RECs is determined by the difference between the current RPS MPB and the RPS MPB when the REC was originally generated; and (2) the value of banked RECs is applied as a credit to all PCIA vintages.

Using the incremental change in the RPS MPB as the price of banked RECs assumes the value of RECs needs to be trued up to a previous inaccurate value. Using the hypothetical example, the SDG&E method would credit all departing load for the $10 per MWh increase in the RPS MPB (from $50 in 2015 to $60 in 2026). However, there is no previous inaccurate value that needs to be trued up in this case—Later Departing Customers never received the value of the REC at the prior $50 per MWh RPS MPB. That is why CalCCA's proposal is not intended to be a true-up like the mechanism implemented in D.19-10-001 (*i.e.*, one that adjusts a forecasted price or quantity of RECs to an updated, or actual, price or quantity). Rather, valuing Pre-2019 Banked RECs using the current RPS MPB and applying a vintage-specific credit for the full value will, for the first time, convey the current market value of the RECs to Later Departing Customers who have not yet received any value of the Pre-2019 Banked RECs they paid for.

Applying the credit to all PCIA vintages also results in the incorrect customer groups receiving the value of the Pre-2019 Banked RECs. If the credit is applied to all vintages, Previously Departed Customers who departed before the RECs were generated and who already received value for their share of the RECs retained by the IOU will receive *additional* value. In the 2015 example, some of the banked REC value will flow to customers in vintages 2014 and earlier. Those Previously Departed Customers already received a credit for RECs according to the proportion of their generation responsibility in 2015 and the market value at the time. To convey credit again

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44 *See* D.24-12-040, at 28-29; *see also* D.25-12-008, at 29-30.

would double-compensate some customers. That would not be just or reasonable, and it would not leave all customers indifferent.

ATTACHMENT B

Curriculum Vitae of Brian Dickman

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Financial Analysis and Modeling

Power Charge Indifference Amount

Regulatory Strategy

Revenue Requirement

Mr. Brian Dickman is a partner in NewGen's energy practice with over 20 years of utility industry experience. Mr. Dickman's career includes over a decade working for PacifiCorp, a vertically integrated investor-owned utility, including senior-level positions in regulatory, financial, and commercial roles. He began consulting in 2017, assisting a wide array of clients across the United States and internationally, including utilities, large consumers, and private investment firms. Mr. Dickman has extensive experience preparing and evaluating utility revenue requirements and cost allocation studies, developing utility-avoided costs, and analyzing the impact of new initiatives and transactions on a utility and its customers. In addition to his extensive technical experience, Mr. Dickman understands the regulatory governance process, and he has personally testified as an expert witness before state public utility commissions in California, Idaho, Indiana, Oregon, Utah, Washington, and Wyoming.

Mr. Dickman advises numerous Community Choice Aggregator (CCA) clients in California, focusing on regulatory and rate issues such as the state-mandated exit fee known as the Power Charge Indifference Adjustment (PCIA). He also represents California CCAs as a member of the Cost Allocation Mechanism Procurement Review Groups for PG&E and Southern California Edison, which the California Public Utility Commission established to provide an independent review of the centralized procurement of local generation capacity requirements.

RELEVANT EXPERIENCE

Electric Cost of Service, Rate Design, and Regulatory Analysis

Mr. Dickman leads projects developing utility revenue requirements, preparing cost of service and rate design studies, and performing financial and regulatory analyses for electric utilities. Mr. Dickman previously held leadership positions at a multi-billion-dollar utility. He interfaced with state regulatory agencies in support of revenue requirements, cost recovery mechanisms, avoided costs, valuations of potential asset acquisitions and other commercial opportunities, and financial impacts of utility initiatives. Mr. Dickman now works with clients and stakeholders to prepare pro forma financial models to determine revenue sufficiency, evaluate the cost of service studies and rate design proposals, and support such proposals before local and state governing bodies. Mr. Dickman's experience also includes evaluating the financial and rate impact of proposed mergers and acquisitions, acquisition and divestiture of utility assets, negotiated retail service contracts, changing business models, and stranded costs due to exiting load. A sample of Mr. Dickman's utility clients includes the following:

- Abu Dhabi Distribution Company, UAE
- Central Coast Community Energy, CA
- City and County of San Francisco, CA
- Clean Power Alliance, CA
- Duke Energy, NC
- East Bay Community Energy, CA
- Hydro One, Ontario, Canada
- Liberty Utilities, CA

NewGen Strategies & Solutions

Electric Cost of Service, Rate Design, and Regulatory Analysis (cont.)

- Lubbock Power and Light, TX
- Minnesota Power, MN
- New York Power Authority, NY
- Portland General Electric, OR
- San Diego Community Power, CA
- San Jose Clean Energy, CA
- Silicon Valley Clean Energy Authority, CA
- Vermont Gas Systems, VT

Non-Utility Clients

A sample of Mr. Dickman's non-utility clients includes the following:

- Blackstone Group, NY
- California Community Choice Association, CA
- Facebook, CA
- Hemlock Semiconductor, MI
- Newmont Mining, NV
- SABIC Innovative Plastics, IN
- Tri-County Metropolitan Transportation District, OR
- Vistra Energy, TX

Expert Witness and Litigation Support

Mr. Dickman provides comprehensive expert witness testimony related to utility revenue requirements, cost of service, rate design, and other ratemaking issues before state and local regulatory bodies. He has provided litigation support in wholesale and retail jurisdictions, including California, Idaho, Indiana, Oregon, Washington, Wyoming, Utah, the Federal Energy Regulatory Commission, and Ontario Energy Board. Mr. Dickman offers expert witness testimony and litigation support in the following areas.

Revenue Requirement | Cost Allocation | Rate Design

Mr. Dickman prepared revenue requirements, inter-jurisdictional cost allocation, coincident peak allocation studies, and supporting testimony for PacifiCorp over many years. He now provides litigation support and expert testimony for clients wishing to review utility filings on revenue requirements, cost allocation, and rate design, including program-specific rate tariffs.

Power Supply Costs | Stranded Costs | Rate Adjustment Mechanisms

Mr. Dickman has prepared and evaluated variable power supply cost forecasts, power supply cost balancing accounts and other rate mechanisms, stranded costs, and exit fees for departing loads. Since 2019, Mr. Dickman has actively participated in PCIA matters in California on behalf of CCA clients.

Avoided Costs | Resource Valuation

Mr. Dickman provided expert testimony for PacifiCorp on various components included in a proposed method for valuing solar generation resources, the calculation of Public Utility Regulatory Policies Act avoided costs for large resources and support of modifications to the avoided cost calculation for small resources.

BRIAN DICKMAN

Partner

WORKSHOPS AND PRESENTATIONS

Host organizations and the topics Mr. Dickman presented are displayed below.

Advanced Workshop in Regulation and Competition, Center for Research in Regulated Industries, 2018

Customer Choice at a Vertically Integrated Utility
Advanced Workshop in Regulation and Competition, Center for Research in Regulated Industries, 2018

Record of Testimony: **Brian Dickman**

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
1. PG&E	A.25-02-013	Expert testimony evaluating the recovery of costs recorded to the Portfolio Allocation Balancing Account	California Public Utilities Commission	California Community Choice Association	2025
2. PG&E	A.25-05-011	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	California Community Choice Association	2025
3. SCE	A.25-05-008	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	California Community Choice Association	2025
4. PG&E SCE SDG&E	R.25-02-005	Rebuttal testimony addressing resource adequacy market price benchmark calculation for the power charge indifference adjustment	California Public Utilities Commission	California Community Choice Association	2025
5. PG&E SCE SDG&E	A.23-05-012 A.23-07-012 A.23-06-001 A.23-05-013	Expert testimony addressing definition of fixed generation costs and recovery from bundled and unbundled customers	California Public Utilities Commission	California Community Choice Association, San Diego Community Power, Clean Energy Alliance	2024
6. PG&E	A.24-05-009	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	California Community Choice Association	2024
7. SCE	A.24-05-007	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	California Community Choice Association	2024
8. PG&E	A.24-03-018	Expert testimony evaluating allocation of generation benefits during period of extended operations at Diablo Canyon Nuclear Power Plant	California Public Utilities Commission	California Community Choice Association	2024

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
9. SCE	A.23-06-001	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	California Community Choice Association	2023
10. PG&E	A.22-09-018	Expert testimony evaluating customer benefits of a proposal to transfer generation assets to a newly created regulated utility subsidiary	California Public Utilities Commission	California Community Choice Association	2023
11. PG&E	R.23-01-007	Expert testimony proposing new rate design and allocation of generation benefits during period of extended operations at Diablo Canyon Nuclear Power Plant	California Public Utilities Commission	California Community Choice Association	2023
12. Joint IOUs	R.22-07-005	Expert testimony addressing inclusion of stranded costs in newly proposed income graduated fixed charges for residential customers	California Public Utilities Commission	California Community Choice Association	2023
13. SCE	A.12-01-008 A.12-04-020 A.14-01-007	Declaration supporting response to petition for modification of D.15-01-051, addressing changes to optional green tariff program rates	California Public Utilities Commission	Clean Power Alliance, California Choice Energy Authority	2022
14. SCE	A.22-05-014	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Clean Power Alliance, California Choice Energy Authority, and Central Coast Community Energy	2022
15. PG&E, SCE, SDG&E	A.20-02-009 A.20-04-002 A.20-06-001 (Consolidated)	Expert testimony evaluating the unrealized sales volumes and revenue due to Public Safety Power Shutoff events	California Public Utilities Commission	CCA Parties (9 individual CCAs)	2022

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
16. San Diego Gas & Electric	A.21-09-001	Expert testimony responding to proposed residential electrification tariff	California Public Utilities Commission	San Diego Community Power and Clean Energy Alliance	2022
17. San Diego Gas & Electric	R.20-05-003	Declaration supporting motion for clarification of D.19-11-016, quantifying impact to allocated incremental reliability procurement requirement due to departing load	California Public Utilities Commission	San Diego Community Power	2021
18. Southern California Edison	A.21-06-003	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Clean Power Alliance and California Choice Energy Authority	2021
19. Pacific Gas & Electric	A.21-06-001	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Joint Community Choice Aggregators	2021
20. San Diego Gas & Electric	A.21-04-010	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	San Diego Community Power and Clean Energy Alliance	2021
21. Pacific Gas & Electric	A.12-01-008 A.12-04-020 A.14-01-007	Declaration supporting petition for modification of D.15-01-051, recommending changes to optional green tariff program rates designed to avoid shifting costs of resource capacity to non-participants	California Public Utilities Commission	Joint Community Choice Aggregators	2021
22. Pacific Gas & Electric	A.19-11-019	Expert testimony (adopted) addressing use of marginal costs to determine economic development rates and responding to proposed electrification tariff for retail customers	California Public Utilities Commission	Joint Community Choice Aggregators	2021

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
23. Pacific Gas & Electric	A.20-07-002	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Joint Community Choice Aggregators	2020
24. Southern California Edison	A.20-07-004	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Clean Power Alliance and California Choice Energy Authority	2020
25. Pacific Power	Docket UE 375	Joint testimony supporting a settlement agreement resolving the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon	Facebook, Inc.	2020
26. Pacific Gas & Electric	A.20-02-009	Expert testimony evaluating the appropriateness of entries recorded to the Portfolio Allocation Balancing Account to true up the Power Charge Indifference Amount	California Public Utilities Commission	Joint Community Choice Aggregators	2020
27. Vectren Energy Delivery of Indiana	Cause No. 43354 MCRA 21 S1	Expert testimony supporting a settlement agreement regarding the calculation and use of a 4CP load study to allocate tariff rider costs among customer classes	Indiana Utility Regulatory Commission	SABIC Innovative Plastics Mt. Vernon, LLC	2020
28. PacifiCorp	Docket UE 307	Expert testimony supporting the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon		2016
29. PacifiCorp	Docket UM 1662	Joint testimony with Portland General Electric regarding the need for a renewable resource tracking mechanism to provide cost recovery related to the impacts of renewable resource generation	Public Utility Commission of Oregon		2015

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
30. PacifiCorp	Docket UE 296	Expert testimony supporting the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon		2015
31. PacifiCorp	Docket No. 20000-469-ER-15	Expert testimony regarding the annual variable power supply cost forecast and modifications to the Energy Cost Adjustment Mechanism	Public Service Commission of Wyoming		2015
32. PacifiCorp	Docket No. 15-035-03	Provided expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah		2015
33. PacifiCorp	Docket UM 1716	Expert testimony proposing changes to the calculation of PURPA avoided costs for large resources	Public Utility Commission of Oregon		2015
34. PacifiCorp	Docket No. 20000-481-EA-15	Expert testimony proposing changes to the calculation of PURPA avoided costs for large resources	Public Service Commission of Wyoming		2015
35. PacifiCorp	Docket No. 15-035-T06	Expert testimony updating standard PURPA avoided cost prices and supporting modifications to the avoided cost calculation for small resources	Public Service Commission of Utah		2015
36. PacifiCorp	Case No. PAC-E-15-03	Expert testimony proposing changes to the calculation of PURPA avoided costs for large resource	Idaho Public Utilities Commission		2015

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
37. PacifiCorp	Docket UE-144160	Declaration supporting updates to standard PURPA avoided cost prices and supporting modifications to the avoided cost calculation for small resources	Washington Utilities and Transportation Commission		2014
38. PacifiCorp	Docket UE 287	Expert testimony supporting the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon		2014
39. PacifiCorp	Case No. PAC-E-14-01	Expert testimony regarding the true up of variable power supply costs in the Energy Cost Adjustment Mechanism	Idaho Public Utilities Commission		2014
40. PacifiCorp	Docket A.14-08-002	Expert testimony supporting the annual variable power supply cost forecast and the true up of costs in the Energy Cost Adjustment Clause mechanism	California Public Utilities Commission		2014
41. PacifiCorp	Docket No. 20000-447-EA-14	Expert testimony regarding the true up of annual variable power supply cost in the Energy Cost Adjustment Mechanism	Public Service Commission of Wyoming		2014
42. PacifiCorp	Docket No. 14-035-31	Expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah		2014
43. PacifiCorp	Case No. PAC-E-13-03	Expert testimony regarding the true up of variable power supply costs in the Energy Cost Adjustment Mechanism	Idaho Public Utilities Commission		2013

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
44. PacifiCorp	Docket A.13-08-001	Expert testimony supporting the annual variable power supply cost forecast and the true up of costs in the Energy Cost Adjustment Clause mechanism	California Public Utilities Commission		2013
45. PacifiCorp	Docket No. 13-035-32	Expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah		2013
46. PacifiCorp	Docket UM 1610	Expert testimony proposing changes to the calculation of PURPA avoided costs for large and small generation resources	Public Utility Commission of Oregon		2012
47. PacifiCorp	Docket A.12-08-003	Expert testimony supporting the annual variable power supply cost forecast and the true up of costs in the Energy Cost Adjustment Clause mechanism	California Public Utilities Commission		2012
48. PacifiCorp	Docket No. 12-035-67	Expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah		2012
49. PacifiCorp	Docket No. 20000-389-EP-11	Expert testimony regarding the collection of deferred balances accrued through previous Power Cost Adjustment Mechanisms	Public Service Commission of Wyoming		2011
50. PacifiCorp	Docket No. 20000-405-ER-11	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming		2011
51. PacifiCorp	Case No. GNR-E-11-03	Expert testimony proposing changes to the calculation of PURPA avoided costs for large and small generation resources	Idaho Public Utilities Commission		2011

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
52. PacifiCorp	Case No. PAC-E-06-10	Expert testimony regarding low-income customer weatherization rebates	Idaho Public Utilities Commission		2010
53. PacifiCorp	Docket No. 20000-405-ER-10	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming		2010
54. PacifiCorp	Docket No. 10-035-89	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Utah		2010
55. PacifiCorp	Docket No. 20000-352-ER-09	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming		2009
56. PacifiCorp	Case No. PAC-E-08-07	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Idaho Public Utilities Commission		2008
57. PacifiCorp	Docket No. 20000-333-ER-08	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming		2008

ATTACHMENT C

Select Discovery Responses

PACIFIC GAS AND ELECTRIC COMPANY
ERRA and PCIA Policies – Update and Reform OIR
Rulemaking 25-02-005
Data Response

PG&E Data Request No.:	CalCCA_003-Q004
PG&E File Name:	ERRAandPCIA-Policies-UpdateReformOIR_DR_CalCCA_003-Q004
Request Date:	February 2, 2026
Requester DR No.:	003
Requesting Party:	California Community Choice Association
Requester:	Tim Lindl
Date Sent:	February 17, 2026
PG&E Witness(es):	Christa Hoffman and Angelia Vega – Energy Policy and Procurement

QUESTION 004

For any year during which PG&E's banked RECs have been counted and valued as Retained RPS for purposes of the PCIA, please respond to the following:

a. Quantify the banked RECs used by year.

b. Identify original generation year for the banked RECs that have been counted as Retained RPS in the PCIA annually.

c. Identify the price used to value the banked RECs, and the total value credited to the PCIA annually.

ANSWER 004

PG&E clarifies that actual RECs generated prior to 2019 were not categorized as "Retained RPS" for PCIA ratemaking purposes. Instead, for PCIA ratemaking, the value of RECs that were "forecast to be generated, net of sales" in PG&E's ERRA Forecast proceedings from 2013 through 2018 were valued in the indifference calculations based on the vintaged MPBs using the methodology approved in D.06-07-030, as modified by D.11-12-018, and Resolution E-4475. Given that the pre-2019 PCIA rate was not trued-up for actual generation, there will be differences in the generation volumes reflected in Annual RPS Compliance Reports and minimum retained generation tables, compared to the forecast RPS generation used for PCIA rate setting in those years.

a. PG&E refers CalCCA to PG&E's response to Question 1.a which summarizes the quantity of RECs used towards the minimum retained RPS requirement.

   PG&E refers CalCCA to PG&E's response in Question 1.a which includes the delivery year of RECs used towards the minimum retained RPS requirement, by year.

   Prior to 2019, the PCIA rate was set based on a forecast of RECs that were expected to be generated, net of sales, and those RECs were valued only in the indifference calculation, which was used to set PCIA rates.

These forecast of RECs were never categorized as “Retained RPS” in the ERRA Forecast proceedings, prior to 2019.

b. Banked RECs were presented and verified in the RPS Plan Rulemaking dockets. The final amounts to be counted Retained RECs were determined through the Final Verified RPS Compliance Period Report submitted to the Commission, after the compliance period that RECs had been verified by the California Energy Commission.

Prior to 2020, actual retained RECs determined through RPS Compliance Reports were never presented or used in the ERRA Forecast Proceedings to determine PCIA rates.

Pre-2019 REC Forecast for PCIA Ratemaking

For the Pre-2019 period, only a forecast of RECs from the PCIA-eligible portfolio were valued when determining the indifference amount, for each cumulative vintage PCIA-eligible portfolio.

The REC Benchmark applicable for the years 2013 – 2018 are shown on line 8 in the table below.

Line No.		Description	2013	2014	2015	2016	2017	2018
1	PG&E ERRA Forecast - November Updates	IOU Green - ERRA Forecast - provided by ED	119.95	128.09	118.43	92.13	73.92	61.47
2		less Load Wt. Energy - PG&E Forecast (at GenMeter)	38.93	39.05	41.25	32.9	35.22	33.77
3 =l.1- l.2		**IOU RPS Green Adder**	81.02	89.04	77.18	59.23	38.70	27.70
4		DOE WECC Survey - Adder - Compliance AL by IOUs	15.870	16.450	16.280	16.550	16.640	16.640
5 = l.3 x .68		IOU RPS Green @ 68%	55.09	60.55	52.48	40.28	26.32	18.84
6 = l.4 x .32		DOE @ 32%	5.08	5.26	5.21	5.30	5.32	5.32
7 - l.5 + l.6		**ERRA Forecast Green Adder @ Generator Meter**	60.17	65.81	57.69	45.57	31.64	24.16
8 = l.7 x 1.06		**ERRA Forecast Green Adder @ Customer Meter (w/ lline loss)**	63.78	69.76	61.15	48.31	33.54	25.61
9 = l.2 x 1.06		**ERRA Forecast - Brown Power @ Customer Meter (w/ line loss)**	41.27	41.39	43.73	34.87	37.33	35.80

The REC value credited in the indifference amount was embedded in the total portfolio MPBs, that are calculated for each vintage portfolio. Thus, there is not a single line-item value in the Pre-2019 PCIA workpapers that reflects just the REC valuation.

To illustrate how the PCIA MPBs and indifference calculations were presented in years prior to 2019, the tables below show PG&E’s *2016 November Update* indifference calculations. Table 9-3 below shows the derivation of the vintage MPBs and an RPS premium in each vintage MPB is presented on lines 15 - 26. This presentation aligns with the requirements in Resolution E-4475, Attachment A.

The RPS inputs on lines 21 and 22 for the IOUs’ RPS Adders are weighed at 68 percent and the DOE REC value is weighed at 32 percent. The weighted average renewable premium (line 23, in Table 9-3) is then weighted based on percentage of renewable generation in the portfolio and then added to the brown power MPB and the capacity MPB to determine a MPB for each cumulative vintage total portfolio. Table 9-2, below, shows the application of the vintage portfolio’s MPBs in the indifference calculation.

TABLE 9-3
PACIFIC GAS AND ELECTRIC COMPANY
2016 VINTAGED MARKET PRICE BENCHMARK

					PCIA							
Line No.	Description		2016 Portfolio TBCC Adders	Ongoing CTC	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage
1	Forward Price Location: NP 15											
2	Average Prices from October Postings											
3	On Peak			$ 35.77	$ 35.77	$ 35.77	$ 35.77	$ 35.77	$ 35.77	$ 35.77	$ 35.77	$ 35.77
4	Off Peak			$ 28.27	$ 28.27	$ 28.27	$ 28.27	$ 28.27	$ 28.27	$ 28.27	$ 28.27	$ 28.27
5	Publication: Platts ICE											
6	On-Peak Weighting			61.7%	61.7%	61.7%	61.7%	61.7%	61.7%	61.7%	61.7%	61.7%
7	Off-Peak Weighting			38.3%	38.3%	38.3%	38.3%	38.3%	38.3%	38.3%	38.3%	38.3%
8												
9	Calculated Baseload Price			$ 32.90	$ 32.90	$ 32.90	$ 32.90	$ 32.90	$ 32.90	$ 32.90	$ 32.90	$ 32.90
10	Capacity Adder	TBCC	$ 12.87	$ 8.89	12.49	12.27	12.26	12.15	12.87	12.89	12.88	12.88
11	Subtotal Before Line Loss			41.79	45.39	45.17	45.15	45.05	45.77	45.79	45.78	45.78
12	Line Loss			1.060	1.060	1.060	1.060	1.060	1.060	1.060	1.060	1.060
13	**Brown Market Price Benchmark, by Vintage**			**$ 44.29**	**$ 48.11**	**$ 47.88**	**$ 47.86**	**$ 47.75**	**$ 48.51**	**$ 48.54**	**$ 48.52**	**$ 48.52**
14												
15	**Renewable Premium**											
16	Green Benchmark – Energy Division		$ 92.13									
17	Less Brown Power BM (No Capacity Value, See Line 11)		$ 32.90									
18	IOU RPS Premium		$ 59.23									
19												
20	Weighting for RPS Adder											
21	IOU 2015 RPS Premium, Delivered Energy @	68%	$ 40.28	$ 40.28	$ 40.28	$ 40.28	$ 40.28	$ 40.28	$ 40.28	$ 40.28	$ 40.28	$ 40.28
22	DOE REC Value $16.55/MWh @	32%	5.30	5.30	$ 5.30	$ 5.30	$ 5.30	$ 5.30	$ 5.30	$ 5.30	$ 5.30	$ 5.30
23	Weighted Average Renewable Premium		$ 45.57	$ 45.57	$ 45.57	$ 45.57	$ 45.57	$ 45.57	$ 45.57	$ 45.57	$ 45.57	$ 45.57
24												
25	Renewable Percentage in Portfolio		30.4%	34.4%	28.1%	34.1%	35.47%	36.5%	36.9%	36.9%	36.9%	36.9%
26	**Renewable Adder, by Vintage**	**TBCC**	**$ 13.87**	**$ 15.68**	**$ 12.81**	**$ 15.54**	**$ 16.17**	**$ 16.62**	**$ 16.81**	**$ 16.80**	**$ 16.83**	**$ 16.83**
27												
28	MPB at Generator With Renewable Premium, by Vintage			57.47	58.20	60.71	61.32	61.66	62.57	62.59	62.61	62.61
29	Line Loss			1.060	1.060	1.060	1.060	1.060	1.060	1.060	1.060	1.060
30	MPB With Renewable Premium, by Vintage			**$ 60.92**	**$ 61.69**	**$ 64.35**	**$ 65.00**	**$ 65.36**	**$ 66.33**	**$ 66.34**	**$ 66.36**	**$ 66.36**

Actual REC Value Supporting Recorded Entries to ERRA for 2019 - 2025

For the period 2019 – 2025, the Retained RECs were recorded to the ERRA and the entries in the balancing account, including any adjusting entries made in October to reflect the ***Final REC MPB*** issued by the Commission's Energy Division in the Fall, would be reflected in the ERRA line item dedicated to showing the costs for retained RECs for the record period. The Final REC MPBs for the period 2019 – 2025 are shown below:

RPS MPB ($/MWh)	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Final MPB	16.44	15.10	14.23	13.24	30.30	54.56	63.86

PG&E has not provided the actual values recorded to ERRA for Retained RPS values for the period 2019 - 2025 but can provide this information in a supplemental response to this data request.

2016 INDIFFERENCE CALCULATION

Line No.	Description	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage
1	Total Portfolio Generation at generator (GWh)	56,350	59,427	60,956	63,231	63,649	63,793	63,934
2	Total Portfolio Generation at customer meter (includes line losses) (GWh)	52,969	55,862	57,299	59,437	59,830	59,966	60,098
3	Total Portfolio Cost ($1000)	$ 4,766,664	$ 5,225,679	$ 5,405,749	$ 5,580,328	$ 5,639,105	$ 5,646,227	$ 5,656,460
4	Benchmark ($/MWh)	61.69	64.35	65.00	65.36	66.33	66.34	66.36
5	Market Cost ($1000)	$ 3,267,632	$ 3,594,707	$ 3,724,431	$ 3,884,815	$ 3,968,505	$ 3,978,129	$ 3,988,073
6	NBC Vintaged Portfolio of Above Market Costs (Line 3 - Line 5)	$ 1,499,031	$ 1,630,972	$ 1,681,318	$ 1,695,513	$ 1,670,601	$ 1,668,098	$ 1,668,386
7								
8	**Indifference Results, current year (excludes ff&u) ($1000)**	$ 1,499,031	$ 1,630,972	$ 1,681,318	$ 1,695,513	$ 1,670,601	$ 1,668,098	$ 1,668,386
9	2015 Cummulative Indifference Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	2016 Cumulative Indifference Amount (prior year(s) + current year results)	$ 1,499,031	$ 1,630,972	$ 1,681,318	$ 1,695,513	$ 1,670,601	$ 1,668,098	$ 1,668,386
11	2016 Cumulative Indifference Amount w/ ff&u	$ 1,516,847	$ 1,650,356	$ 1,701,301	$ 1,715,664	$ 1,690,456	$ 1,687,923	$ 1,688,215
12	Indifference Amount Revenue Requirement	$ 1,516,847	$ 1,650,356	$ 1,701,301	$ 1,715,664	$ 1,690,456	$ 1,687,923	$ 1,688,215
13	Ongoing CTC Cost RRQ ($1000)	$ 101,746	$ 101,746	$ 101,746	$ 101,746	$ 101,746	$ 101,746	$ 101,746
14	Ongoing CTC - EOY MTCBA Balance ($1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	PCIA RRQ ($1000) = Indifference - Ongoing CTC (Line 12 - line 13)	$ 1,415,101	$ 1,548,610	$ 1,599,555	$ 1,613,918	$ 1,588,710	$ 1,586,177	$ 1,586,469

The total market value credited to the cumulative 2015 vintage portfolio was $3.988 Billion. To determine the imputed value for RPS generation in PG&E's 2015 vintage total portfolio, one could multiply the Green Adder Premium presented in the Table included in response to Q.3.b ($48.31/MWh) by 36.9 percent of the 2015 vintage portfolio energy of 60,098 GWh. The imputed value of the RECs in the PCIA-eligible portfolio in 2015 would have been equal to $48.31/MWh x 60,098 x 36.9 = $1.071 billion.

PG&E's annual ERRA Forecast November/Fall Updates and respective Commission decisions are listed below. The relevant proceeding documents and associated decisions can be found on the Commission's Documents page at the following link: https://apps.cpuc.ca.gov/apex/f?p=401:1:0

Year	ERRA Forecast Application	ERRA Forecast Decisions
2013	A.12-06-002	D.12-12-008
2014	A.13-05-015	D.13-12-043
2015	A.14-05-024	D.14-12-053
2016	A.15-06-001	D.15-12-022
2017	A.16-06-003	D.16-12-038
2018	A.17-06-005	D.18-01-009

PACIFIC GAS AND ELECTRIC COMPANY
ERRA and PCIA Policies – Update and Reform OIR
Rulemaking 25-02-005
Data Response

PG&E Data Request No.:	CalCCA_003-Q005
PG&E File Name:	ERRAandPCIA-Policies-UpdateReformOIR_DR_CalCCA_003-Q005
Request Date:	February 2, 2026
Requester DR No.:	003
Requesting Party:	California Community Choice Association
Requester:	Tim Lindl
Date Sent:	February 17, 2026
PG&E Witness(es):	Christa Hoffman – Energy Policy and Procurement

QUESTION 005

Regarding the function of the PCIA and bundled generation rates before 2019:

a. Confirm that the forecasted indifference amount calculated each year included a credit for the value of RECs generated during the year, valued at the then-current RPS market price benchmark. If not confirmed, please explain.

b. Confirm that the indifference amount credit described in part a was shared between departed load and bundled customers, as constituted at the time rates are set. If not confirmed, please explain.

c. Confirm that bundled customers' generation rates included the market cost of RECs, the opposite of the REC credit included in the indifference amount. If not confirmed, please explain.

ANSWER 005

a. Not confirmed. Prior to 2019, the forecasted indifference amount was based on forecasted RECs to be generated during the year. The value of the renewable attributes in PG&E's PCIA-eligible total portfolio indifference calculation was included in the vintage specific market price benchmark that was established for the forecast year. See Resolution E-4475, Appendix A, which provides a formula for determining the MPB for vintage portfolios v, in year n, where n = the forecast year covered in the calculation and v = PCIA vintage year. Resolution E-4475 can be found at the following link: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_RESOLUTION/166454.PDF

b. Not confirmed. The calculation of the total portfolio indifference amount did not allocate the total portfolio costs or market value to bundled and non-exempt departing load customers as part of the steps to calculate the indifference amount. The total portfolio indifference calculation was calculated at the cumulative vintage portfolio level, for each vintage. It was not practical nor required that the individual portfolio costs and portfolio market value be allocated load prior to determining the indifference amount used to set vintaged PCIA rates.

See D.06-07-030, as modified by as modified by D.07-01-030, and D.17-08-026. Links to these decisions are included below:

D.06-07-030: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/58302.PDF

D.07-01-030: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/64048.PDF

D.17-08-026: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M195/K123/195123481.pdf

See also D.08-09-012 and associated appendices, which reaffirmed the D.06-07-030 Total Portfolio Indifference calculation methodology would apply to new generation resources on a vintage basis.

D.08-09-012: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/87615.PDF

Appendix D: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/87617.PDF

Appendix E: https://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/GRAPHICS/87618.PDF

c. Not confirmed. There was no explicit line item in the ERRA Forecast for an MPB-based market value.

Prior to 2019, bundled customer's generation revenue requirement and rates were set based on the total portfolio resource forecast that would be recorded to the ERRA balancing account, net of PCIA revenues that were forecast to be received from non-exempt departing load based on the CPUC required templates for calculating forecast PCIA revenue requirements and rates, plus amortization of the ERRA balancing account balance. That is, the PCIA revenues were a line item forecast credit in the ERRA revenue requirement determination.

PACIFIC GAS AND ELECTRIC COMPANY
ERRA and PCIA Policies – Update and Reform OIR
Rulemaking 25-02-005
Data Response

PG&E Data Request No.:	CalCCA_003-Q009
PG&E File Name:	ERRAandPCIA-Policies-UpdateReformOIR_DR_CalCCA_003-Q009
Request Date:	February 2, 2026
Requester DR No.:	003
Requesting Party:	California Community Choice Association
Requester:	Tim Lindl
Date Sent:	February 17, 2026
PG&E Witness(es):	Christa Hoffman – Energy Policy and Procurement

QUESTION 009

Assume PG&E's REC bank contains RECs generated and banked from the same RPS-eligible resource prior to 2019 as well as in 2019 or later. For purposes of RPS compliance, is there any difference between the RECs banked prior to 2019 versus the RECs banked in 2019 and later? Please explain.

ANSWER 009

While in RPS compliance there is not a distinction between RECs generated before or after 2019, there is a significant difference between these RECs when valued for ratemaking purposes due to changes in revenue requirements and ratemaking adopted by D.18-10-019 and D.19-10-001.

PACIFIC GAS AND ELECTRIC COMPANY
ERRA and PCIA Policies – Update and Reform OIR
Rulemaking 25-02-005
Data Response

PG&E Data Request No.:	CalCCA_003-Q014
PG&E File Name:	ERRAandPCIA-Policies-UpdateReformOIR_DR_CalCCA_003-Q014
Request Date:	February 2, 2026
Requester DR No.:	003
Requesting Party:	California Community Choice Association
Requester:	Tim Lindl
Date Sent:	February 20, 2026
PG&E Witness(es):	Donna Barry – Energy Policy and Procurement

QUESTION 014

Please provide the proportion of PG&E's customers who have received bundled service for every year from 2011 through 2025.

ANSWER 014

The bundled customer percentage as a percent of all PCIA non-exempt customers is shown in the table below:

		Percent of VPCIA Non-Exempt Load		
Rate Effective	**System Total for Bundled, DA, CCA**	**Bundled**	**Pre-2009 DA**	**Post-2008 DA/CCA**
2011	100%	90.1%	6.2%	3.7%
2012	100%	89.5%	6.4%	4.2%
2013	100%	88.0%	5.9%	6.1%
2014	100%	87.9%	5.9%	6.2%
2015	100%	91.9%		8.1%
2016	100%	89.6%		10.4%
2017	100%	84.9%		15.1%
2018	100%	65.7%		34.3%
2019	92%	47.2%		45.2%
2020	100%	48.7%		51.3%
2021	100%	44.4%		55.6%
2022	100%	40.0%		60.0%
2023	100%	42.4%		57.6%
2024	100%	40.7%		59.3%
2025	100%	36.9%		63.1%

Southern California Edison
R.25-02-005 – OIR to Consider ERRA and PCIA Rules and Processes

DATA REQUEST SET C a l C C A - S C E - 0 0 3

To: CalCCA
Prepared by: Eric Lee
Job Title: Sr. Advisor
Received Date: 2/2/2026

Response Date: 2/17/2026

Question 3.7:
If SCE's available RPS-eligible generation during an RPS compliance period is less than its RPS requirement for that period, does SCE agree it must meet its RPS compliance obligation by using banked RECs, procuring RECs, or procuring additional RPS-eligible generation? If no, please explain.

Response to Question 3.7:
Generally, yes.

Southern California Edison
R.25-02-005 – OIR to Consider ERRA and PCIA Rules and Processes

DATA REQUEST SET C a l C C A - S C E - 0 0 3

To: CalCCA
Prepared by: Eric Lee
Job Title: Sr. Advisor
Received Date: 2/2/2026

Response Date: 2/17/2026

Question 3.9:
Assume SCE's REC bank contains RECs generated and banked from the same RPS-eligible resource prior to 2019 as well as in 2019 or later. For purposes of RPS compliance, is there any difference between the RECs banked prior to 2019 versus the RECs banked in 2019 and later? Please explain.

Response to Question 3.9:
For RPS compliance purposes, there is no difference between RECs banked prior to 2019 and those banked in 2019 or later, provided they meet standard RPS eligibility. Both types of banked RECs may be used to satisfy SCE's RPS obligations.

However, there are important differences from a ratemaking perspective. Under the current PCIA methodology, RECs generated and banked on and after January 1, 2019 have a zero-dollar value applied in the year they are generated. The RPS MPB is only applied if and when those banked RECs are used for bundled compliance. There is then a crediting and debiting methodology that applies specifically to Retained RPS across the ERRA BA and the PABA. Under the prior PCIA methodology, there was no concept of valuing banked RECs based on how or when they were used. Instead, a market value for renewable energy was calculated each year using a forecast volume of renewable energy to be generated in the given year multiplied by an administratively-set weighted average renewable benchmark. That calculated market value was then added to the other forecast value amounts and subtracted from the PCIA-eligible resource and contract costs to set a composite PCIA rate for that year. Any differences between the forecast and actual amounts and costs resulted in over- or under-collections in the ERRA BA that remained solely with bundled service customers.

Additionally, there is a 36-month rolling timeframe where RECs that have been generated can still be sold/transferred to third-parties. Once that time has passed and the REC is banked (retired in WREGIS), the RECs can only be used for SCE's compliance requirements and cannot be transferred to third parties.

Southern California Edison
R.25-02-005 – OIR to Consider ERRA and PCIA Rules and Processes

DATA REQUEST SET C a l C C A - S C E - 0 0 3

To: CalCCA
Prepared by: Eric Lee
Job Title: Sr. Advisor
Received Date: 2/2/2026

Response Date: 2/17/2026

Question 3.14:
Please provide the proportion of SCE's customers who have received bundled service for every year from 2011 through 2025.

Response to Question 3.14:
See attached Excel spreadsheet, titled "Response to CalCCA Q3.14.xlsx" for the proportion of SCE's customers who have received bundled service for every year from 2012 through 2025. SCE is unable to provide data for 2011 due to verification issues.

	Year													
SCE Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Bundled	4,952,530	4,979,877	5,008,690	4,986,834	5,010,532	5,001,107	4,980,153	4,081,679	3,869,492	3,896,477	3,662,958	3,679,390	3,747,609	3,765,408
Unbundled	30,199	29,866	29,047	80,516	78,631	119,624	179,749	1,114,558	1,360,880	1,321,852	1,596,274	1,616,164	1,585,283	1,621,561
Total Customers	4,982,729	5,009,743	5,037,737	5,067,350	5,089,163	5,120,731	5,159,902	5,196,237	5,230,372	5,218,329	5,259,232	5,295,554	5,332,892	5,386,969
Percent Bundled	99%	99%	99%	98%	98%	98%	97%	79%	74%	75%	70%	69%	70%	70%
Percent Unbundled	1%	1%	1%	2%	2%	2%	3%	21%	26%	25%	30%	31%	30%	30%

Notes
1. 2011 data is not available as SCE was unable to verify the data from that year.
2. SCE implemented its Customer Service Re-Platform (CSRP) system in March/April 2021. Prior to CSRP, streetlights had an account per streetlight. Post-CSRP, an entire string of streetlights would be on a single account. This resulted in a decrease to the total number of customers.
3. In June 2021, a CCA, Western Community Energy (WCE), failed and reverted all 113,000 WCE customers back to SCE. This resulted in a net decrease to the unbundled customer percentage for 2021 when compared to the previous year.
4. Reversion of approximately 65,000 customers from Orange County Power Authority (OCPA) in 2024 also resulted in a net decrease of unbundled customers.

<u>QUESTION 3.14</u>

Please provide the proportion of SDG&E's customers who have received bundled service for every year from 2011 through 2025.

SDG&E Response:

SDG&E objects to this request on the grounds that it seeks information that is not reasonably calculated to lead to the discovery of admissible evidence. Subject to and without waiving the foregoing objections, SDG&E responds as follows:

Please refer to the attached excel file "PUBLIC_CalCCA_DR-003_Q 3.14.xlsx".

SDG&E - PCIA Reform Track 2
CalCCA 3rd DR, Q3.14
MWh usage over each year

	Bundled customers	Direct Access	CCA	Total	Percent bundled	Percent unbundled
2011	16,249,031	3,265,472	-	19,514,503	83%	17%
2012	16,626,721	3,398,978	-	20,025,699	83%	17%
2013	16,164,015	3,592,677	-	19,756,692	82%	18%
2014	16,467,854	3,648,099	-	20,115,954	82%	18%
2015	16,266,949	3,651,846	-	19,918,795	82%	18%
2016	15,653,136	3,515,568	-	19,168,704	82%	18%
2017	15,623,204	3,393,906	-	19,017,111	82%	18%
2018	15,139,149	3,593,995	33,704	18,766,848	81%	19%
2019	14,405,887	3,487,355	61,318	17,954,559	80%	20%
2020	14,398,202	3,424,013	57,771	17,879,986	81%	19%
2021	11,898,924	3,570,714	1,899,782	17,369,420	69%	31%
2022	7,800,107	3,840,740	6,059,056	17,699,903	44%	56%
2023	4,619,558	3,917,877	8,309,914	16,847,349	27%	73%
2024	3,207,210	3,961,841	9,522,238	16,691,289	19%	81%
2025	2,884,273	3,991,384	9,912,807	16,788,465	17%	83%

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Improve the California Climate Credit.	R.25-07-013

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON ASSIGNED COMMISSIONER'S SCOPING MEMO AND RULING

Leanne Bober,
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March 2, 2026

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3. If the Commission approves the pause in the distribution of the residential electric 2026 Climate Credit, should it order the spring credit to instead be delivered in summer 2026 as well? Since Climate Credit amounts are set, should the two 2026 credits be delivered in August and September, respectively? 11

4. Would it benefit customer affordability for the Commission to order the spring 2027 gas Climate Credit to instead be delivered as a winter credit in February 2027? 11

5. Should the Commission order any other changes to the residential Climate Credit to maximize affordability that can take effect in 2026? 12

6. Due to timelines driven by ERRA proceedings, should changes to the residential electric Climate Credit made in Phase 1A also apply for 2027, such that these interim benefits may be experienced in that year as well? 12

7. Should Phase 1A changes be explicitly designated as interim, applicable only until the resolution of Phase 1B and without prejudice to any of the broader changes being considered in that phase? 12

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V. CONCLUSION 13

SUMMARY OF RECOMMENDATIONS[1]

CalCCA recommends the following in response to the Phase 1A questions in the Scoping Ruling:

- Immediate modifications to the Climate Credit for 2026 and 2027 are premature and should be postponed given risks of increasing administrative costs, reducing net affordability benefits, and potential customer confusion;

- The Commission must ensure clear and accurate customer communications regarding any Climate Credit changes, with CCAs meaningfully involved in developing and reviewing messaging to avoid customer confusion and ensure neutrality; and

- Prior to implementing Climate Credit changes, the Commission should reevaluate its Climate Credit objectives and priorities, and only base decisions on an in-depth analysis and a full evidentiary record.

[1] Acronyms used herein are defined in the body of this document.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Improve the California Climate Credit.	R.25-07-013

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON ASSIGNED COMMISSIONER'S SCOPING MEMO AND RULING

California Community Choice Association[2] (CalCCA) submits these opening comments pursuant to the *Assigned Commissioner's Scoping Memo and Ruling*[3] (Scoping Ruling), dated February 3, 2026. The Scoping Ruling directs the investor-owned utilities (IOU), and authorizes other parties to file comments responding to the questions in Section 4.2 of the Scoping Ruling regarding proposed immediate changes to the residential Climate Credit.

I. INTRODUCTION

California is facing a profound and well-documented affordability crisis. As highlighted in Governor Gavin Newsom's 2024 Executive Order N-5-24, the State has recognized the urgent need for remedies, including "maximizing" the Climate Credit.[4] That urgency is now being echoed nationally, with California "having the highest cost of living in the nation" with prices

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[2] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[3] *Assigned Commissioner's Scoping Memo and Ruling*, Rulemaking (R.) 25-07-013 (Feb. 3, 2026).

[4] Exec. Order No. N-5-24 (Oct. 30, 2024).

"11 percent higher than the national average."[5] Energy costs are a significant contributor to this burden. Monthly energy bills in California are 13 percent higher than the national average, and retail electricity prices experienced larger increases than any other state between 2019 and 2024.[6] Electricity rates have far outpaced inflation and, outside of the District of Columbia, California is the only state to have seen electricity rates rise faster than national median weekly earnings.[7]

For many households, particularly low- and moderate-income families, these trends are not abstract statistics. They translate into difficult financial trade-offs and ongoing instability. In this environment, the California Climate Credit is not a silver bullet, but it remains an important tool among the broader set of mechanisms under consideration.

The Scoping Ruling proposes in Phase 1A to pause the 2026 Climate Credit to consider immediate but potentially interim changes pending broader consideration of changes to the timing, eligibility, or administration of the residential gas and electric Climate Credit in Phase 1B.[8] These Phase 1A changes, whether on an interim or permanent basis, are being proposed prior to any reevaluation of the Commission's previously established Climate Credit objectives and priorities. They are also being proposed prior to any record development or analysis as to the impact such changes will have on Californians struggling with the affordability crisis. In fact, altering the timing without understanding high-bill seasonality, arrearages, and customer payment behavior may reduce the practical value of the benefit, create additional cash flow challenges for vulnerable households, and increase customer confusion. Overall, there is simply

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5 Hanna Panreck, *Newsom confronted on California being the 'highest cost of living' state in the US amid affordability crisis*, Yahoo News (Feb. 22, 2026).

6 Naveena Sadasivam & Clayton Aldern*, What's Behind Your Eye-Popping Power Bill? We Broke It Down, Region by Region,* Grist (Feb. 18, 2026).

7 Severin Borenstein, *Locating the U.S. Electricity Affordability Crisis,* Energy Institute Blog, (Jan. 26, 2026,

8 Scoping Ruling at 7.

no evidence in this proceeding which demonstrates that moving the Climate Credit from its established April and October distribution will improve affordability outcomes.

If the Commission's goal is to improve affordability for Californians, the 2026 Climate Credit should proceed as scheduled. At the same time, the Commission and stakeholders can revisit the Commission's previously established Climate Credit objectives and priorities, and undertake a deliberate, data-driven process to evaluate how best to maximize the Climate Credit's impact going forward. Evidence-based policymaking, grounded in a clear record and meaningful stakeholder input, must guide any changes to a program that millions of Californians depend upon.

CalCCA provides the following recommendations, as well as answers to the Scoping Ruling's questions:

- Immediate modifications to the Climate Credit for 2026 and 2027 are premature and should be postponed given risks of increasing administrative costs, reducing net affordability benefits, and potential customer confusion;

- The Commission must ensure clear and accurate customer communications regarding any Climate Credit changes, with CCAs meaningfully involved in developing and reviewing messaging to avoid customer confusion and ensure neutrality; and

- Prior to implementing Climate Credit changes, the Commission should reevaluate its Climate Credit objectives and priorities, and only base decisions on an in-depth analysis and a full evidentiary record.

II. SHORT-TERM SPECULATIVE CLIMATE CREDIT CHANGES MAY NOT IMPROVE AFFORDABILITY AND SHOULD BE POSTPONED PENDING ADEQUATE ANALYSIS AND RECORD DEVELOPMENT

The short-term, speculative proposed Phase 1A changes to the Climate Credit may not meaningfully improve affordability and will be based on assumption or speculation rather than fact. As explained below, multiple questions require consideration and analysis before Climate Credit changes should be made, including:

- Does moving the Climate Credit to summer-peaking months adequately protect customers in winter-peaking areas?
- Do the increased administrative costs and operational inefficiencies associated with moving the Climate Credit provide a net benefit in terms of affordability?
- Is pausing the Climate Credit to later in the year instead of any earlier distribution better for customers from a time value of money perspective?
- Is changing the Climate Credit already expected in April fair to customers?
- How will customer confusion with an interim and then potentially different permanent change to the timing, eligibility, and number of distributions impact customers?

Until each of these questions (and likely other considerations) are adequately analyzed through a fact-based record, the Commission should postpone any changes to the Climate Credit.

A. Changing the Climate Credit Timing Based on Presumptions of "High-Billed Months" Without any Analysis of Impacts Should be Rejected

California's diverse climate zones and varying degrees of customer access to technologies mean there may not be an obvious, one-size-fits-all choice for when the Climate Credit should be dispersed. While moving distributions to summer months may benefit customers in cooling-dominant regions, it does not address winter-peaking areas or Commission designated Areas of Affordability Concern. The Commission is considering pausing the April Climate Credit, but the record does not demonstrate that April is categorically inappropriate as a "high-billed" month. The Scoping Ruling acknowledges this variation by leaving the small and multi-jurisdictional utilities territories unchanged, yet it does not analyze comparable winter-bill dynamics within the larger IOU territories.[9] Absent granular analysis, pausing and shifting the Climate Credit cannot be demonstrated to improve affordability for *all* Californians and may do the opposite.

[9] Scoping Ruling at 9.

B. Proposed Interim Changes to the Climate Credit Fail to Consider Increased Administrative Costs and Operational Inefficiencies

Operational realities further underscore the impracticality of a near-term pause and shift. Pacific Gas and Electric Company (PG&E) explained in a recent motion that bill inserts for the April Climate Credit need to be finalized as of March 2, the same day these comments are due.[10] Discarding finalized communications, reprinting materials, revising master meter notices, and coordinating revised messaging will result in costs that are either already incurred or imminent and are likely recoverable costs from customers.[11] IOUs have previously indicated that shifting a Climate Credit distribution requires *at least* four months of preparation.[12] The costs associated with such changes remain unknown and even if IOUs provide cost estimates in response to Section 4.2 of the Scoping Ruling, CalCCA and other parties would have only five days to evaluate and respond. It also fails to consider anticipated increases in customer inquiries for community choice aggregators (CCA) that will require staff resources and potentially additional costs.

C. The Proposed Timing Changes to Distribution of the Climate Credit Fail to Address the Time Value of Money

If the Commission's singular objective is to improve affordability, then the timing question warrants closer scrutiny. If earlier distribution maximizes affordability, why is the Climate Credit not being issued in January? Basic principles of the time value of money suggest

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10 *Motion of Pacific Gas and Electric Company (U 39 E) for Leave to File Comments Concerning Issue 1 of Phase 1A on the Commissioner's February 3, 2026 Scoping Memo and Ruling (including Attachment A: PG&E's Proposed Comments on the Commissioner's Scoping Memorandum and Ruling)* (PG&E Motion), R.25-07-013 (Feb. 6, 2026), Attachment A, at 2 (emphasis added).

11 *Id.* at 3.

12 *Post-Prehearing Conference Statement of Southern California Edison Company (U 338-E)*, R.25-07-013 (Dec. 8, 2025), at 5 (SCE estimating the process to move the October 2026 credit to September 2026 would require six months); *Post-Prehearing Conference Statement of Pacific Gas and Electric Company (U 39 M),* R.25-07-013 (Dec. 8, 2025), at 7 (PG&E estimating at least four months to accelerate the October 2026 credit); *Post-Prehearing Conference Comments of San Diego Gas & Electric Company (U 902 M) on Order Instituting Rulemaking to Improve the California Climate Credit*, R.25-07-013 (Dec. 8, 2025), at 2 (SDG&E estimating 14-16 weeks just to move the October credit.).

that customers derive the greatest benefit from receiving funds sooner rather than later, allowing them to retain and deploy their own resources during periods of financial strain. Yet the total annual Climate Credit does not change based on whether it is distributed in one, two, or multiple installments, nor does it change based on the month in which it is issued. What does change is the net value customers ultimately receive if the Commission's action increases administrative implementation costs. Those costs are particularly consequential in a year when the total Credit amount is already $40 to $63.28 lower than 2025,[13] and increased costs would likely erode the remaining financial and affordability benefits to customers.

D. The Proposed Changes Fail to Consider Customer Expectations of the Climate Credit's Distribution

Customers have come to anticipate and budget around the established April distribution. Altering that timing imposes real costs in the form of disrupted household planning and reduced predictability. If greater affordability is truly the guiding principle, then immediate changes that introduce new costs, diminish net benefits, and disrupt customer expectations are not supported by either economic logic or the current record.

E. Customer Confusion and Inaccurate Messaging Outweigh Any Perceived Benefits of Interim Changes to the Climate Credit and Necessitate Future CCA Involvement

The timing of the proposed pause and shift in eventual distribution of the Climate Credit also presents acute customer communication risks. The Pause PD may be approved only weeks before the April Climate Credit would otherwise be distributed and the results of this phase remain unknown.[14] That compressed timeline leaves insufficient opportunity for utilities, CCAs,

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13 *See* R.25-07-013, Proposed *Decision Pausing the Distribution of the Large Electric Utilities' 2026 Residential Climate Credit* (Feb. 9, 2026) (Pause PD), at 6.

14 Pause PD.

and the Commission to develop and implement clear, coordinated messaging about the potential pause and future distributions.

1. Risks of Customer Confusion Must be Mitigated in any Change to the Climate Credit

First, it is not sufficient to inform customers that the credit will be received "later." Provided the broad call for "immediate" changes in Questions 1 and 5, there is the potential for uncertainty regarding eligibility in future distributions. For example, customers expecting the credit in April, who may have made financial decisions based on the expected credit, would not be able to make further financial adjustments without knowing when they would receive the delayed credit. Or what about a customer who moves out of California in June? Normally they would have received the April credit, but now they would receive nothing. In addition, if the Commission ultimately determines that a certain customer class or customers exceeding a certain income threshold would no longer receive the Climate Credit, then customers falling into the new ineligible categories will not be credited for the Climate Credit that had been delayed in April.

Second, the language surrounding both the proposed pause and any future distribution requires careful attention and sufficient time to incorporate meaningful input from all impacted parties. Customer communication must be precise, accurate, and conspicuous. While the phrase "top of customer bills" may invite different interpretations, the intent is to ensure that Climate Credit information is prominent.[15] Whether through contrasting colors or clear placement within the bill, the message must clearly state that the credit is part of the Cap-and-Invest program and that changes are a result of the Commission's interpretation of Assembly Bill (AB) 1207.[16] For electronic bills, pop up notices on websites and upon login for payment, with required click

15 Pub. Util. Code § 748.5 (b)(2).
16 Assembly Bill No. 1207 (AB 1207), Ch. 117, Stats. 2025 (Sept. 19, 2025).

through acknowledgment, could provide conspicuous notice. Again, the cost and implementation timeline for such modifications are unknown. IOUs have indicated that four months are needed simply to move the October Climate Credit. That estimate does not account for new formatting requirements such as prominent placement on the website and bills.

2. Climate Credit Communications Must be Neutral to Prevent CCA Customer Confusion

Climate Credit communications must also be clear and neutral to prevent CCA customer confusion. In fact, CCAs should be involved in reviewing and shaping these communications. Although CalCCA believes short-term changes are misaligned with affordability goals, if the Commission proceeds with immediate modifications, adequate time must be provided for CCA participation in the many communications to customers.

Issues relating to the communication of Climate Credit changes raise larger issues that CalCCA seeks to address in this proceeding regarding neutrality in Climate Credit communications. Maintaining competitive neutrality across load serving entities was reaffirmed as a high priority policy objective in the previous Climate Credit decision.[17] For example, the Pause PD includes language that illustrates a common issue and concern when communicating the Climate Credit. Table 1 of the Pause PD refers to "Investor-owned Electric Utilities Residential Climate Credit Amounts for 2025 and 2026."[18] While IOUs administer the credit, it is *not* an IOU benefit—it is a state-mandated Climate Credit. This language is repeated in the title of the Pause PD as well as in other portions of the body. That misperception is problematic. With a potential pause and redistribution, the importance of accurate and neutral communication

[17] D.12-12-036, at 69-70; D.21-08-026, at 12-13.
[18] Pause PD at 6.

becomes even greater. CCAs must have the opportunity to participate in crafting *all* communications surrounding the Climate Credit that will reach their customers.

Communications must clearly explain the source of the Climate Credit, the reason for any pause, and the timing of future distributions. Follow up communications will also be required when the Climate Credit is ultimately issued. These challenges cannot be fully addressed within the compressed timeframe currently contemplated and without CCA involvement. Because the "top of customer bills" requirement and outreach plan updates must be completed by January 1, 2027, limiting additional changes will make meeting that deadline more feasible.

III. INSTEAD OF RUSHING TO CHANGE THE CLIMATE CREDIT ON AN INTERIM BASIS, THE COMMISSION SHOULD REVISIT THE CLIMATE CREDIT POLICY OBJECTIVES AND PRIORITIES AND MAKE DECISIONS BASED ON IN-DEPTH ANALYSIS AND A COMPLETE RECORD

Given these and other likely considerations that must be analyzed prior to any change to the Climate Credit, CalCCA recommends that the Commission: (1) reconsider and update the policy objectives and priorities originally adopted with substantial stakeholder input in the prior Climate Credit proceedings in Decisions (D.) 12-12-033 and D.21-08-026; and (2) develop and make any decisions on Climate Credit changes only based on an evidence-based record.

A. The Commission Should Revisit the Climate Credit Objectives and Priorities Prior to Any Changes to the Climate Credit

CalCCA stated in its Opening Comments on the Order Instituting Rulemaking to Improve the California Climate Credit (OIR) that the Commission should first revisit the Climate Credit policy objectives and priorities originally adopted with substantial stakeholder input in D.12-12-033[19] and affirmed in D.21-08-026.[20] Among other objectives, the Commission

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19 D.12-12-033, *Decision Adopting Cap-and-Trade Greenhouse Gas Allowance Revenue Allocation Methodology for the Investor-Owned Electric Utilities*, R.11-03-012 (Dec. 20, 2012).

20 D.21-08-026, *Decision Adopting Customer Climate Credit Updates*, R.20-05-002 (Aug. 19, 2021).

prioritized reducing adverse impacts on low-income households, maintaining competitive neutrality across load serving entities, preserving the carbon price signal, and preventing economic leakage. Revisiting the objectives and determining current priorities will assist in framing stakeholder positions on potential Climate Credit modifications. However, the Commission appears to have abandoned these considerations for the stated rationale of needing to "improve the affordability benefit" and the requirement in Public Utilities Code section 748.5(a)(3)[21] to distribute credits in "high-billed" months.[22]

B. A Data-Driven Process and Full Evidentiary Record Should be Developed Prior to Any Changes to the Climate Credit

Public Utilities Code section 748.5(a)(3) also does not require the Commission to take immediate action. In fact, to properly carry out the Legislature's goal of maximizing customer electric bill affordability, the Commission should be engaging stakeholders to develop a robust record that supports potential movement of the credit. Instead, in a rush to move credits to the perceived "high-bill" months of the summer, analysis and consideration of *all* customers have been eschewed. Section 748.5(a)(3) does instruct that the credit be provided in no more than four "high-billed months" to maximize bill affordability, but it also allows the Commission discretion "to address extreme, unforeseen, and temporary circumstances." Moving the credit on an interim basis based on responses to the questions in Section 4.2 of the Scoping Ruling cannot be proven to maximize bill affordability.

CalCCA supports aligning the Climate Credit with periods of greatest affordability impact. But that determination must be supported by evidence, not assumption. The responses by parties to questions in Section 4.2 of the Scoping Ruling will not provide the opportunity for

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[21] All subsequent code sections cited herein are references to the California Public Utilities Code unless otherwise specified.

[22] Scoping Ruling at 8-9.

parties to engage and test those assumptions. To accurately implement section 748.5 as intended by the Legislature, the Commission should refrain from immediate action and instead proceed through a structured, data driven process that allows for the evaluation of eligibility, timing, frequency, customer communications, and bill impacts under a set of guiding principles. Otherwise, the notion that the Climate Credit will be used to address "high billed" months will likely only be true for a select portion of customers.

IV. CALCCA'S RESPONSES TO SECTION 4.2 OF THE SCOPING RULING

1. What immediate changes can be made to the residential electric and gas Climate Credit in the near term to improve its affordability impact while this proceeding considers broader, permanent changes to Climate Credit methodologies, eligibility, distribution, and other factors?

None. See Sections II and III, herein.

2. Current timing of the residential Climate Credit is based on a basic assumption that spring and fall are relatively low energy usage seasons, and that awareness of the credit would be maximized if delivered at this time; the primary objective has not been focused on affordability impacts. Given the Legislature's mandate to maximize affordability, should the Commission order the utilities to move up the fall 2026 electric residential Climate Credit, delivering it instead as a summer Climate Credit in August or September 2026?

See Sections II and III, herein.

3. If the Commission approves the pause in the distribution of the residential electric 2026 Climate Credit, should it order the spring credit to instead be delivered in summer 2026 as well? Since Climate Credit amounts are set, should the two 2026 credits be delivered in August and September, respectively?

See Sections II and III, herein.

4. Would it benefit customer affordability for the Commission to order the spring 2027 gas Climate Credit to instead be delivered as a winter credit in February 2027?

Maybe, but it should be supported by data and analysis.

5. **Should the Commission order any other changes to the residential Climate Credit to maximize affordability that can take effect in 2026?**

No. See Sections II and III, herein.

6. **Due to timelines driven by ERRA proceedings, should changes to the residential electric Climate Credit made in Phase 1A also apply for 2027, such that these interim benefits may be experienced in that year as well?**

The question assumes "benefits" will be achieved by moving the Climate Credit without further defining those benefits or providing analysis. See Sections II and III, herein.

7. **Should Phase 1A changes be explicitly designated as interim, applicable only until the resolution of Phase 1B and without prejudice to any of the broader changes being considered in that phase?**

No interim changes should be made. See Sections II and III, herein.

8. **What specific direction and authority do the utilities need to implement the immediate affordability actions approved in Phase 1A?**

CalCCA will reserve its response to this question, if any, to potential reply comments.

9. **What outreach changes are possible for Phase 1A immediate affordability actions? Should the Commission require messaging delivered in 2026 to refer to the Cap-and-Invest Program?**

See Sections II D. and E, herein.

10. **What direction must the Commission give to ensure compliance with Pub. Util. Code Section 748.5 (b)(2), regarding updates to the customer outreach plan?**

    a. **How should "the top of customer bills" be defined and implemented, in line with this code section? What billing limitations exist?**

    b. **For customers who receive paper bills, do bill inserts placed on top of paper bills qualify? What placement complies for e-billed customers?**

    c. **How can other outreach be aligned with these messages in line with the spirit of this code section?**

    d. **What approval process should apply to these updates to outreach? What new authority, if any, should be delegated to Commission staff?**

See Sections II D. and E, herein.

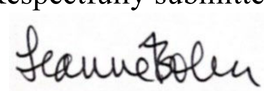
11. What direction do the utilities need to effectuate the transfer of 5% of revenues to the State Treasury for deposit in the California Transmission Accelerator Revolving Fund pursuant to Pub. Util. Code Section 748.5(d)? What documentation should the Utilities provide to the Commission demonstrating their transmittal of the funds annually? Overall, what action must the Commission take to ensure compliance with this code section?

CalCCA reserves its response to this question, if any, to reply comments.

V. CONCLUSION

CalCCA supports thoughtful reform of the Climate Credit to maximize affordability benefits. However, short-term changes both in 2026 and 2027—without a developed evidentiary record, without meaningful opportunity for party input, and without analysis of operational and customer impacts—does not advance that objective. A deliberate and evidence-based approach will ensure that any modifications to the Climate Credit will enhance affordability, maintain transparency, and avoid unnecessary customer confusion and cost.

Respectfully submitted,



Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

March 2, 2026

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Improve the California Climate Credit.	R.25-07-013

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON THE PROPOSED DECISION PAUSING THE DISTRIBUTION OF THE LARGE ELECTRIC UTILITIES' 2026 RESIDENTIAL CLIMATE CREDIT

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March 2, 2026

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SUMMARY OF RECOMMENDATIONS[1]

CalCCA recommends the Commission withdraw the Proposed Decision pausing the Climate Credit, because:

- The Proposed Decision was issued without any notice or opportunity for parties to weigh in on the reasonableness of the pause;
- Rather than increasing affordability for all customers, the Proposed Decision will likely increase costs of issuing the Climate Credit and harm customers who experience high-billed months in April; and
- Pausing the Climate Credit in April, without sufficient education and outreach, will cause customer confusion and detract from customer affordability.

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1 Acronyms used herein are defined in the body of this document.

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Improve the California Climate Credit.	R.25-07-013

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON THE PROPOSED DECISION PAUSING THE DISTRIBUTION OF THE LARGE ELECTRIC UTILITIES' 2026 RESIDENTIAL CLIMATE CREDIT

The California Community Choice Association[2] (CalCCA) submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure[3] on the proposed *Decision Pausing the Distribution of the Large Electric Utilities' 2026 Residential Climate Credit*[4] (Proposed Decision), dated February 9, 2026. CalCCA respectfully requests the Proposed Decision be withdrawn to remove consideration of pausing the April Climate Credit.

I. INTRODUCTION

CalCCA is committed to improving customer affordability and the Climate Credit remains an important tool in achieving that goal. Therefore, the Proposed Decision pausing the April 2026 Climate Credit distribution should be withdrawn as it: (1) is procedurally deficient; (2) will not advance affordability as it will likely increase costs and cause operational disruption; and (3) risks significant customer confusion.

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2 California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

3 *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021), https://webproda.cpuc.ca.gov/-/media/cpuc-website/divisions/administrative-law-judge-division/documents/rules-of-practice-and-procedure-may-2021.pdf.

4 Proposed *Decision Pausing the Distribution of the Large Electric Utilities' 2026 Residential Climate Credit*, Rulemaking (R.) 25-07-013 (Feb. 9, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M598/K101/598101732.PDF.

Any modification to the timing, eligibility, or administration of the Climate Credit must be supported by a clear record and careful analysis of customer impacts. The Proposed Decision lacks the evidentiary foundation necessary to demonstrate that pausing the April Climate Credit will improve affordability, particularly in light of the near-term costs and confusion the pause would create. Absent such support, the Commission should refrain from making immediate changes and instead proceed through a structured, data-driven Phase 1 process.

As set forth below, CalCCA recommends withdrawal of the Proposed Decision for the following reasons:

- The Proposed Decision was issued without any notice or opportunity for parties to weigh in on the reasonableness of the pause;
- Rather than increasing affordability for all customers, the Proposed Decision will likely increase costs of issuing the Climate Credit and harm customers who experience high-billed months in April; and
- Pausing the Climate Credit in April, without sufficient education and outreach, will cause customer confusion and detract from customer affordability.

II. THE PROPOSED DECISION SHOULD BE REJECTED BECAUSE OF PROCEDURAL DEFICIENCIES AND LACK OF NOTICE OF AN APRIL CLIMATE CREDIT PAUSE

The Proposed Decision should be rejected based on procedural deficiencies and the lack of any record regarding the reasonableness of such a pause. Parties were never afforded a meaningful opportunity to comment, analyze, or develop a record regarding the operational, legal, and customer impacts of such a pause. The *first time* the potential for an April Climate Credit pause was raised was in the Scoping Ruling issued February 3, 2026.[5] Pacific Gas and Electric Company (PG&E) voiced shared concerns regarding such a pause in a Motion filed three days later on February 6, 2026, when it stated that:

[5] *See Assigned Commissioner's Scoping Memo and Ruling* (Scoping Ruling), R.25-07-013 (Feb. 3, 2026), at 7 (Phase 1A, Issue 1 asks "[w]hether the Commission should order the large electric utilities to pause the distribution of the 2026 residential [CC] while considering other issues in this phase"), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M597/K166/597166396.PDF.

> At no point in the Order Instituting Rulemaking, the prehearing conference notice and draft agenda, the prehearing conference itself, or at any other time, did the Commission raise the *possibility* that it might order investor-owned utilities to pause the April 2026 Climate Credit distribution.[6]

PG&E expressed legal concerns regarding the procedural deficiencies of pausing the April 2026 Climate Credit distribution given that no notice or opportunity to be heard on the matter was afforded to parties. In addition, PG&E raised concerns about operational issues, affordability, and customer confusion. CalCCA agrees with the concerns cited by PG&E, which should have been addressed prior to this Proposed Decision being issued on February 9, 2026.

The Proposed Decision's attempts to explain away the procedural deficiencies fall short for many reasons. As noted in the Proposed Decision, one justification for this rapid and unanticipated "pause" was that "[n]o party specifically contemplated *pausing* the spring 2026 distribution to allow it to be distributed later this year, *but neither did any party identify any reason why the utilities could not do so.*"[7] Parties cannot be expected to preemptively address every hypothetical modification that the Commission might consider, particularly when such modifications were never identified as issues in the proceeding. The absence of opposition to an unraised proposal does not constitute support, nor does it substitute for a developed record.

In addition, the Proposed Decision cites a past change to the timing of the upcoming Climate Credit when, in February 2023, the Climate Credit was *accelerated* in response to natural gas price spikes in winter 2023.[8] However, an acceleration of the distribution of the Climate Credit (*i.e.*, that the Climate Credit would be provided one or two months earlier) does not necessarily justify a "pause" (*i.e.*, withholding) the Climate Credit. Accelerating the distribution of the Climate Credit resulted in protecting customers from bill increases, whereas pausing the distribution of the Climate Credit would likely result in customer confusion, and harm customers who have been expecting the Climate Credit to help reduce their bills in April.

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6 *See Motion of Pacific Gas and Electric Company (U 39 E) for Leave to File Comments Concerning Issue 1 of Phase 1A on the Commissioner's February 3, 2026 Scoping Memo and Ruling (including Attachment A: PG&E's Proposed Comments on the Commissioner's Scoping Memorandum and Ruling)* (PG&E Motion), R.25-07-013 (Feb. 6, 2026), at 2 (emphasis added), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M598/K100/598100966.PDF.

7 Proposed Decision at 8 (emphasis added).

8 *Ibid*.

Finally, the Proposed Decision notes the "advance notice" of the "possibility" of a pause in the Scoping Ruling issued *six days earlier.*[9] Six days essentially equates to *no notice*, especially without the ability of parties to comment on the idea of a potential pause prior to the issuance of a Proposed Decision.

Had pausing the April Climate Credit been noticed as a potential outcome, CalCCA would have fully engaged on this issue and provided evidence or raised concerns regarding operational impacts, customer communications, and affordability consequences, which are discussed in detail below. In addition, if the Commission believed immediate action was statutorily required following enactment of Assembly Bill 1207,[10] it is unclear why such action was not initiated earlier considering the bill was signed September 19, 2025, and the Order Instituting Rulemaking has been open since July 24, 2025.[11] Moreover, Public Utilities Code section 748.5(a)(3) provides the Commission discretion to distribute the credit "to address extreme, unforeseen, and temporary circumstances."[12] Withdrawing the Proposed Decision to avoid customer confusion, stranded communication costs, and administrative inefficiencies caused by a last-minute pause squarely fits within that discretion.

CalCCA agrees with PG&E that the Commission's departure from standard Commission practice raises concerns regarding the lack of notice and opportunity to be heard. In addition, as discussed below, serious affordability and customer communication issues arise in the context of the pause. For these reasons, the Proposed Decision should be withdrawn and further consideration of the reasonableness of this pause should be undertaken.

III. THE PROPOSED DECISION'S AFFORDABILITY RATIONALE IS UNSUPPORTED AND SHOULD BE REJECTED

Aside from the procedural infirmities, the Proposed Decision should be rejected as its explanation for pausing the April Climate Credit based on the possibility of "greater affordability impacts" is unsubstantiated.[13] First, the record contains no data, modeling, or analysis demonstrating that delaying the April distribution will actually increase affordability across the

[9] *Ibid.*

[10] Assembly Bill No.1207 (AB 1207), Ch. 117, Stats. 2025 (Sept. 19, 2025), https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202520260AB1207.

[11] Proposed Decision at 2.

[12] Pub. Util. Code § 748.5(a)(3). All section references herein are to the California Public Utilities Code, unless otherwise noted.

[13] Proposed Decision at 2.

board. To the contrary, if pausing the credit generates additional administrative and communication costs that are ultimately recovered from ratepayers, the net Climate Credit benefit will be reduced. In addition, while the Proposed Decision states that it is increasing affordability in accordance with section 748.5(a)(3) by ensuring that the credits be distributed in "high-billed" months, this rationale fails to recognize that some customers actually experience "high-billed" months in April (*i.e.*, winter peaking customers) and therefore moving the Climate Credit will decrease affordability for those customers.

A. The Proposed Decision's Unsupported Affordability Justification Ignores the Increased Costs Caused by an Unanticipated Pause

The Proposed Decision does not evaluate the incremental administrative and communication costs associated with a late stage pause. PG&E explained in its Motion that bill inserts need to be finalized as of March 2, the day these comments are due.[14] Not to mention, the investor-owned utilities (IOU) have previously indicated that shifting a Climate Credit distribution requires a *minimum* of four months of preparation.[15] Discarding finalized communications, reprinting materials, revising master meter notices, and coordinating revised messaging will generate real and likely recoverable costs from customers.[16] In addition, community choice aggregators (CCA) anticipate increased customer inquiries that will require staff resources and therefore costs. These costs diminish the net affordability benefit of the Climate Credit. The record of this proceeding does not address these impacts in any meaningful way.

Those costs, already incurred and forthcoming, are expected to be recovered from ratepayers, thereby eroding the intended affordability gains. When combined with unrecoverable CCA administrative burdens, the overall effect of the Climate Credit will be diminished for customers.

CalCCA supports aligning the Climate Credit with periods of greatest affordability impact. However, that determination must be supported by evidence, not assumption. To

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14 PG&E Motion, Attachment A, at 2.

15 *Post-Prehearing Conference Statement of Southern California Edison Company (U 338-E)*, R.25-07-013 (Dec. 8, 2025), at 5 (SCE estimating the process to move the October 2026 credit to September 2026 would require six months); *Post-Prehearing Conference Statement of Pacific Gas and Electric Company (U 39 M),* R.25-07-013 (Dec. 8, 2025), at 7 (PG&E estimating at least four months to accelerate the October 2026 credit); *Post-Prehearing Conference Comments of San Diego Gas & Electric Company (U 902 M) on Order Instituting Rulemaking to Improve the California Climate Credit*, R.25-07-013 (Dec. 8, 2025), at 2 (SDG&E estimating 14-16 weeks just to move the October credit.).

16 PG&E Motion, Attachment A at 3.

accurately implement section 748.5, the Commission should refrain from immediate action and instead proceed through a structured Phase 1 process that establishes guiding principles for Climate Credit policy and simultaneously evaluates eligibility, timing, frequency, customer communications, and bill impacts in a standardized manner. Only through a comprehensive and integrated analysis can the Commission ensure that any modifications maximize transparency and affordability benefits.

B. An Affordability Justification Based on Moving the Climate Credit to High Billed Months Fails to Recognize that April is a High-Billed Month for Some Customers

Any affordability justification based on moving the Climate Credit to "high billed months" fails to recognize that April is a high-billed month for some customers. The Proposed Decision does acknowledge that peak billing periods vary by service territory.[17] For example, customers in certain regions experience high winter bills, while others peak in summer. The record does not demonstrate that April is categorically inappropriate as a "high-billed" month, nor does it analyze regional or climate-zone variability across the large IOU territories. While moving distributions to summer months may benefit customers in cooling-dominant regions, it does not address winter-peaking areas, some of which are Commission-designated Areas of Affordability Concern.[18] The Proposed Decision acknowledges variation by leaving the small and multi-jurisdictional utilities territories unchanged, yet it does not analyze comparable winter-bill dynamics within the larger IOU territories. Absent granular analysis, pausing the April Climate Credit risks could create outsized affordability impacts in regions where April distributions meaningfully offset seasonal bills.

IV. POTENTIAL CUSTOMER CONFUSION AND MESSAGING RISKS OUTWEIGH ANY PERCEIVED BENEFITS OF A CLIMATE CREDIT PAUSE

The timing of the proposed pause also presents acute customer communication risks. The Proposed Decision may be approved only weeks before the April Climate Credit would otherwise be distributed. Additionally, the multiple and complex public policy discussions and

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17 Proposed Decision at 5 (citing the Scoping Ruling at 9).

18 *See* California Public Utilities Commission, *2021 and 2022 Annual Affordability Report* (2023), https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/affordability-proceeding/2021-2022/2021-and-2022-annual-affordability-report.pdf.

rulemakings involving the Climate Credit occurring in the Legislature,[19] California Air Resources Board,[20] and the Commission require thoughtful messaging to ensure sufficient customer awareness prior to implementing a change that directly impacts bills. That compressed timeline leaves insufficient opportunity for the large electric utilities, CCAs, and the Commission to develop and implement clear, coordinated messaging to customers.

Moreover, it is not sufficient to inform customers that the credit will be received "later." Phase 1A Part Two may make other "immediate" changes that create uncertainty regarding future distributions. For example, customers expecting the credit in April may have made financial decisions based on the expected credit and would now not be able to make further financial adjustments without knowing when they would receive the delayed credit.

The Proposed Decision's language itself illustrates the communication challenge. For example, Table 1 refers to "Investor-owned Electric Utilities Residential Climate Credit Amounts for 2025 and 2026."[21] While IOUs administer the credit, it is *not* an IOU benefit—it is a state-mandated Climate Credit. This language is repeated in the title of the Proposed Decision as well as in other portions of the body. Framing the credit as belonging to IOUs risks reinforcing the mistaken perception that it is an IOU-driven benefit or goodwill gesture. This could be further exacerbated if a customer departs IOU service for a CCA and may believe they are losing the April Climate Credit because of this change.

The language surrounding both the proposed pause and any future distribution of the credit will require significant attention to detail and sufficient time to ensure meaningful input from all impacted parties. CalCCA believes the nature of the pause and the appropriate language surrounding the credit both used in the Proposed Decision and contemplated in Phase 1A Part Two, requires CCA participation and feedback. Language must be precise, accurate, and delivered in a manner that does not confuse the average customer. Achieving this clarity for

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19 *See* Air Resources Board, *Cap-and-Invest Program Amendments: CANDI Updates — Joint Legislative Committee on Climate Change Policies Presentation* (Feb. 23, 2026), https://climatechangepolicies.legislature.ca.gov/system/files/2026-02/carb_202602_candi-updates-jlcccp-presentation.pdf.

20 *See* California Air Resources Board, *Regulation for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms: 2024 Amendments — Standardized Regulatory Impact Assessment* (Apr. 9, 2024), https://ww2.arb.ca.gov/sites/default/files/2024-04/nc-Cap-and-Trade_SRIA2024.pdf.

21 Proposed Decision at 6.

customers is impossible in the two weeks between potential approval of this Proposed Decision and the April Climate Credit distribution date.

V. CONCLUSION

CalCCA recognizes the value of optimizing the affordability benefits of the Climate Credit and supports thoughtful reform. However, pausing the April 2026 distribution on such short notice—without a developed evidentiary record, without meaningful opportunity for party input, and without analysis of operational and customer impacts—does not advance that objective.

The Commission should decline to pause the April 2026 Climate Credit and withdraw the Proposed Decision.

Respectfully submitted,

Leanne Bober

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

March 2, 2026

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON THE PROPOSED DECISION PAUSING THE DISTRIBUTION OF THE LARGE ELECTRIC UTILITIES' 2026 RESIDENTIAL CLIMATE CREDIT

PROPOSED CHANGES TO FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDERING PARAGRAPHS

Proposed text deletions show as ~~**bold and strikethrough**~~
Proposed text additions show as <u>**bold and underlined**</u>

FINDINGS OF FACT

CONCLUSIONS OF LAW

ORDERING PARAGRAPHS

New Order:

<u>**The Proposed Decision is withdrawn.**</u>

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.25-10-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
TRACK 1 PROPOSALS ON TRANSACTABILITY ISSUES

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March 3, 2026

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APPENDIX A

SUMMARY OF RECOMMENDATIONS[1]

CalCCA proposes the Commission:

- Adopt hourly load obligation trading to allow LSEs to transact at the same granularity as the SOD requirements to promote affordability while maintaining reliability requirements;

- Invest in the software and systems to automate the RA validation process, given it appears the existing manual process is interfering with the adoption of fully vetted and well-supported policy proposals; and

- If the Commission declines to invest in automation of the RA validation process, adopt temporary guardrails to aid in assessing compliance.

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1 Acronyms used herein are defined in the body of this document.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.25-10-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
TRACK 1 PROPOSALS ON TRANSACTABILITY ISSUES

California Community Choice Association[2] (CalCCA) submits these proposals pursuant to the *Assigned Commissioner's Scoping Memo and Ruling*[3] (Scoping Ruling), dated December 12, 2025, and *Administrative Law Judge's Ruling on Energy Division's Transactability Report and Modifying Track 1 Schedule*,[4] dated February 24, 2026.

I. INTRODUCTION

Energy Division's *Report on Transactability within the Slice of Day Resource Adequacy Framework*,[5] authorized in Decision (D.) 25-06-048,[6] severely misses the mark in finding that,

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2 California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

3 *Assigned Commissioner's Scoping Memo and Ruling*, Rulemaking (R.) 25-10-003 (Dec. 12, 2025).

4 *Administrative Law Judge's Ruling on Energy Division's Transactability Report and Modifying Track 1 Schedule*, R.25-10-003 (Feb. 24, 2026).

5 *Report on Transactability within the Slice of Day Resource Adequacy Framework*, R.25-10-003 (Feb. 2026) (Report).

6 D.25-06-048 authorizes Energy Division to, "conduct an evaluation after a full year of [SOD] implementation to assess the need, benefits, and feasibility of an hourly load obligation trading

"[g]iven the limited evidence of need, uncertain magnitude of benefits, and heightened implementation risks, … the potential gains do not outweigh the added complexity and risk of unintended consequences," of hourly load obligation trading.[7] The Report:

- Applies the wrong standard in its assessment, focusing on whether the measure is "necessary" rather than seizing the opportunity to adopt a tool that will bring greater efficiency and affordability to resource adequacy (RA) procurement as market conditions change;
- Materially understates the potential affordability benefits this optimization tool could deliver for ratepayers by ignoring the increased cost resulting from slice-of-day (SOD) implementation;
- Presents a "penny wise, pound foolish" approach to RA regulation, failing to acknowledge the criticality of automating RA compliance; and
- Continues to seek cover behind potential "unintended consequences".

Energy Division's recommendation to continue monitoring market performance leaves CalCCA's fully vetted and well-supported proposal with the potential to offer significant cost savings hanging in the balance at ratepayers' expense.

As discussed below, the Energy Division assertions are not well supported and do not address the core issue hourly load obligation trading is intended to address: the exorbitant costs caused by making the Commission's RA program exceedingly difficult to comply with, while at the same time assessing severe penalties on those who cannot comply.[8] CalCCA addresses several shortcomings of the Report below and will provide a more detailed response in its opening comments due on March 16, 2026.

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mechanism. D.25-06-048, *Decision Adopting Local Capacity Obligations for 2026-2028, Flexible Capacity Obligations for 2026, and Program Refinements*, R.23-10-011 (June 26, 2025), Ordering Paragraph 11, at 125.

[7] Report at 7.

[8] These penalties include a financial consequence with a multiplier effect for multiple infractions and, for ESPs and CCAs, a restriction on expansion plans. The severity of these penalties has been readily noticed by LSEs, who will likely procure expensive RA even if it is not necessary to meet their reliability requirements.

Hourly load obligation trading offers an opportunity to chip away at the affordability crisis at a time when the Commission should be seizing every opportunity to reduce procurement costs. The inability for load-serving entities (LSE) to transact at the same granularity as the compliance requirement forces LSEs to procure more RA than needed to meet pre-determined reliability targets, unnecessarily driving up RA procurement costs that fall directly on ratepayers. CalCCA's analysis, attached to this proposal as Appendix A, suggests hourly obligation trading could save all LSEs $144-$179 million each year. At a time when Californians are struggling to manage rapidly increasing electric bills, dismissing a proposal with such significant potential for cost savings is misguided.

The proposal also recommends guardrails for the initial year of implementation to help manage new administrative tasks that may be necessary to validate showings with load obligation trades. CalCCA is concerned that Energy Division's continued rejection of hourly load obligation trading is driven largely by the fact that the existing RA compliance mechanisms are no longer sufficient to operate the SOD program. The RA program has become increasingly complex in its over 20-year history, and continued reliance on spreadsheets for validation should not be a barrier to the adoption of sound policy proposals. Given the significant potential benefits of hourly load obligation trading, the Commission should invest in the necessary tools to make the validation process more automated and manageable for Energy Division staff. Still, if the Commission is concerned with the amount of administrative effort this proposal would create, guardrails could help keep those efforts manageable.

In summary, CalCCA recommends that the Commission:

- Adopt hourly load obligation trading to allow LSEs to transact at the same granularity as the SOD requirements to promote affordability while maintaining reliability requirements;

- Invest in the software and systems to automate the RA validation process, given it appears the existing manual process is interfering with the adoption of fully vetted and well-supported policy proposals; and
- If the Commission declines to invest in automation of the RA validation process, adopt temporary guardrails to aid in assessing compliance.

II. THE REPORT DIMINISHES THE PROBLEMS WITH SOD AND DOES NOT ADDRESS THE CORE AFFORDABILITY ISSUE HOURLY LOAD OBLIGATION TRADING IS INTENDED TO ADDRESS

The Report attempts to answer the question of whether transactability issues exist by evaluating whether the measure was necessary to achieve compliance with 2025 RA requirements. The Report finds that "LSEs were able to procure and trade sufficient capacity to meet hourly obligations, with no evidence of unresolved deficiencies or structural market barriers attributable to SOD."[9] Using this information to imply that there is insufficient justification for hourly load obligation trading ignores the core affordability issue hourly load obligation trading is intended to address. This rationale also ignores the potential for capacity scarcity to return in the future causing an apparent shortfall based on the compliance framework while no actual system reliability gap exists. CalCCA demonstrated this effect with the 2024 test case. While the Report states that over-procurement was "modest" because September 2025 month-ahead showings in the tightest hour showed surplus procurement of 262 megawatts (MW),[10] this does not tell the whole story.

In 2025, LSEs procured significantly more RA capacity than needed to meet their compliance obligations when compared to prior years. This phenomenon can be observed by evaluating aggregated historical RA procurement data from the California Independent System Operator (CAISO), as discussed below. To be clear, CalCCA does not contend that the lack of

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9 Report at 6.

10 *See* Report at 34.

transactability has caused ***all*** of the incremental procurement observed. Rather, if the new SOD RA mechanism is going to force the procurement of significantly more RA than previously, the system must be made as efficient as possible to avoid unnecessary costs, given the magnitude of the change.

The CAISO annually presents data on the resources shown to meet RA needs.[11] The CAISO data includes the years 2019 through 2025. The CAISO data shows a significant increase in the number of RA resources shown starting in 2025, the first year of SOD implementation. The CAISO uses a single daily value for RA and while SOD uses hourly values, the data is informative in showing the significant increase in the amount of RA shown. This increase comes at a cost. As shown in Figure 1, below, using the 2025 final market price benchmark (MPB) for RA of $11.21/ kilowatt (kW)-month[12], the increased cost of SOD is nearly $339 million for the months of May through October.

Figure 1: Average Procurement Relative to RA Target

Figure 1. Average Procurement to RA Target							
		May	June	July	August	September	October
Prior to SOD (% of target shown)	2019 -2024	103%	104%	102%	101%	100%	103%
SOD (% of targe shown)	2025	109%	118%	118%	109%	114%	108%
Difference		6%	14%	15%	8%	14%	5%
2025 RA Requirement (MW)		38,996	47,496	52,349	50,856	52,091	41,872
Amount of Procurement in 2025 Beyond the Normal Procurement in 2019-2024 (MW)		2,384	6,512	8,002	4,170	7,219	1,948
2026 RA Market Price Benchmark ($/kW-mo)		$ 11.21	$ 11.21	$ 11.21	$ 11.21	$ 11.21	$ 11.21
Total Incremental Cost ($/mo)		$ 26,720,203	$ 73,000,172	$ 89,698,883	$ 46,748,335	$ 80,929,640	$ 21,837,678

Total Incremental Cost
$ 338,934,910

California's customers served by LSEs that must comply with the Commission's SOD regulations should be afforded every opportunity possible to efficiently transact given the significant impact on affordability that the move to SOD has caused.

11 *See* CAISO Historical Resource Adequacy Showings Aggregate Data.
12 *See* CPUC MPB Calculations 2025 (Oct. 1, 2025) (2025 MPBs).

Data provided in the Report similarly provides evidence of this over-procurement, well beyond the "modest" 262 MW the Report identifies. *First*, the net qualifying capacity (NQC) of resources under contract in September 2025 "increased by approximately 3,725 MW (8.2 percent)"[13] relative to 2024, while requirements went down by 1,555 MW (3.1 percent),[14] a net gain of 5,280 MW of NQC relative to 2024. *Second*, the achieved reserve margin in September 2025 was far above the required 17 percent. Because reliability is a system attribute, the achieved reserve margin depends on the total contracted resources and the total system requirements. The storage contracted for September 2025 could have contributed to meeting system RA at much greater levels than suggested in the Report. The Report dispatches storage only to meet the requirements and then allocates the 16,269 MW hours of "unused storage" evenly throughout the day.[15] Alternatively the "unused storage" could have been allocated to maximize the avoidable thermal generation. Allocating the "unused storage" in the manner shown in Figure 2, below, achieves a reserve margin of at least 23 percent in all hours of September 2025 or allows 2,175 MW of thermal capacity to be removed while maintaining at least a 17 percent reserve margin in all hours.[16] At the current RA MPB, 2,175 MW of capacity beyond that needed to meet RA is valued at $24 million for this single month.[17] If instead we assume that the 2,175 MW of highest priced RA transactions between the year-ahead and month-ahead deadlines could have been avoided, the savings would be almost $37 million for the single month.[18]

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[13] Report at 21.

[14] Report at Table 7 (comparing 2024 requirements to 2025 HE18 requirements).

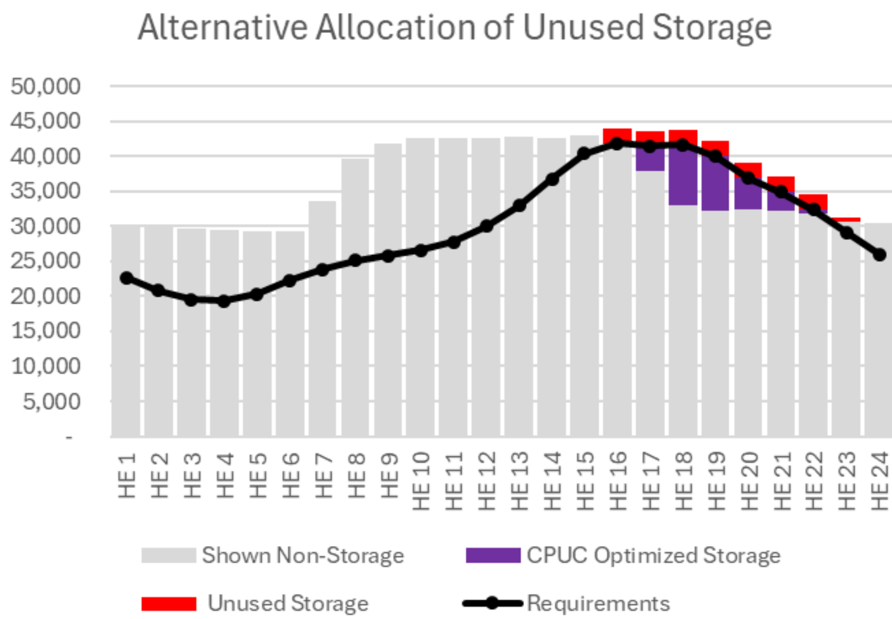
[15] Report at 28.

[16] CalCCA verified that the charging energy remains sufficient for the storage even after removing 2,175 MW of thermal capacity from the September 2025 portfolio.

[17] MPB $11.21/kW-month * 2,175 MW * 1,000 (conversion of MW to kW) = $24,381,750. *See* 2025 MPBs.

[18] Capacity transactions are from FERC electronic quarterly reports downloaded from https://eqrreportviewer.ferc.gov/ and cleaned by CalCCA. Included transactions have California LSE as

Figure 2. Alternative Allocation of Unused Storage Achieves 23% Reserve Margin in September 2025



The Report states that "this incremental margin is not simply "excess" capacity, but represents additional contracted, deliverable resources that may provide value under conditions that exceed forecasted load."[19] This implies an intent to ensure reliability by making compliance exceedingly difficult and allowing the system to lean on LSEs that must procure excess RA to meet their SOD requirements, rather than through transparent and defined reliability standards. The Commission is obligated through Public Utilities Code section 380(h)(4)[20] to ensure that the RA program "can reasonably maintain a standard measure of reliability, such as a one-day-in-10-year loss-of-load expectation or a similarly robust reliability metric adopted by the commission..." The Commission should meet the objectives of section 380 by planning for pre-

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the buyer for delivery in September 2025 with a trade date between November 1, 2024, and July 31, 2025. CalCCA sorted these transactions from highest to lowest price and summed the transaction cost for the highest priced transactions up to a cumulative capacity of 2,175 MW.

19 Report at 35.

20 All subsequent code sections cited herein are references to the California Public Utilities Code unless otherwise specified.

determined reliability targets established through the Commission's loss-of-load expectation study process and planning reserve margin, rather than by imposing transactional barriers that force over-procurement.

Energy Division finds that the potential gains of hourly load obligation trading do not outweigh "risk of unintended consequences."[21] This is a red herring. Throughout the five years of discussing hourly load obligation trading, no party has been able to articulate an "unintended consequence" that CalCCA has not addressed.[22] If there are "unintended consequences" that arise following the implementation of hourly load obligation trading, the Commission has the power to modify the rules to close any reliability or compliance gaps that may emerge. The Commission should not decline to adopt measures with demonstrated affordability benefits based upon undefined "unintended consequences."

III. HOURLY LOAD OBLIGATION TRADING SHOULD BE ADOPTED TO ALLOW LSES TO TRANSACT AT THE SAME GRANULARITY AS THE SOD REQUIREMENTS

The Commission should adopt CalCCA's proposal in R.23-10-011 to allow LSEs to transact load obligations on an hourly basis.[23] Under existing rules, LSEs are restricted in how they can transact with other entities to ensure RA compliance. Adjustments to an LSE's portfolio are limited to transacting a product for all hours it is available for the whole month, even though obligations are unique to each hour. This mismatch means LSEs must purchase more RA than they need to meet their obligations, creating artificial market scarcity and unnecessarily driving up RA demand (and prices). CalCCA's proposal would provide LSEs with the flexibility to

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[21] Report at 7.

[22] *See California Community Choice Association's Opening Comments on the Proposed Decision*, R.23-10-011 (June 11, 2025).

[23] *See California Community Choice Association's Proposals on Track 3*, R.23-10-011 (Jan. 17, 2025) (CalCCA Track 3 Proposals), at 8-18.

transact load obligations at the hourly level in order to reduce costs to consumers. If RA requirements are set on an hourly basis, some or all of the products should be transactable on an hourly basis.

CalCCA's analysis of 2025 year-ahead RA filings submitted in R.23-10-011 demonstrates significant affordability benefits to increasing the transactability of the RA SOD program.[24] CalCCA expects that all LSEs would benefit from a load obligation trading structure and expects that transactions among investor-owned utilities, community choice aggregators (CCA), and electric service providers (ESP) would occur. The larger the market, the more efficient the outcome. Since its analysis of 2025 year-ahead RA filings, CalCCA has issued a Whitepaper, attached as Appendix A, further documenting the benefits of hourly trading by simulating competitive market trades between LSEs. CalCCA has also performed additional analysis on 2025 month-ahead RA showings from CCAs demonstrating that, averaged across five peak summer months, CCAs in aggregate, purchased about 540 MW more RA capacity each month than they would have needed had a mechanism like hourly load obligation trading been available.[25] At the 2025 final RA MPB,[26] those excess purchases cost CCA consumers more than $30 million in the summer of 2025. If the tight market conditions observed in the summer of

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[24] *See* CalCCA Track 3 Proposals, at 8-11.

[25] To quantify the excess RA capacity that could have been avoided with hourly load obligation trading, CalCCA first calculated the amount of thermal capacity each individual CCA could have sold from their final month-ahead portfolio, while still remaining compliant. To perform this calculation, CalCCA adjusted the way that an individual CCA would show its contracted storage capacity such that it maximized the amount of thermal capacity that could be removed. Next, CalCCA aggregated all CCA portfolios and requirements, and recalculated the excess thermal capacity from the aggregate showing. The aggregation is a proxy for what could be achieved through frictionless trade between LSEs, which is enabled through a policy like hourly load obligation trading. Finally, the excess RA capacity that could be avoided through hourly load obligation trading was calculated as the difference between the excess of the aggregate and the excess for individual CCAs. On average across the five peak months from May to September, CalCCA observed 540 MW of excess thermal capacity that could have been avoided with hourly load obligation trading.

[26] *See* 2025 MPBs.

2024 arise again, as suggested by the Commission's recommendation for additional procurement in R.25-06-019,[27] demand for capacity and RA prices could rise again to the levels observed in 2024. The CCAs' excess RA purchases valued at the 2024 RA prices described in CalCCA's RA Whitepaper would cost CCA customers nearly $51 million. Using similar assumptions about the indirect price reduction effect from lowering RA demand and the potential benefit of hourly load obligation trading across all Commission-jurisdictional LSEs, CalCCA's findings from the 2025 month-ahead RA data suggest hourly obligation trading could save all LSEs $144-$179 million each year. These savings could then directly improve affordability for ratepayers.

Throughout R.23-10-011, CalCCA thoroughly addressed all critical concerns with its proposal expressed by Energy Division and parties by: (1) explaining why existing trading mechanisms are insufficient for the SOD program; (2) proposing a potential guardrail that would limit the amount of load an LSE can trade (of which CalCCA expands upon below); and (3) addressing how penalties would apply to LSEs using load obligation trades that are found noncompliant.[28] The proposal received support from a broad range of stakeholders, including LSEs, suppliers, ratepayer advocates, and environmental groups,[29] and as described above, is supported by extensive analysis of cost benefits. For these reasons, the Commission should adopt hourly load obligation trading.

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[27] *Administrative Law Judge's Ruling Seeking Comments on Electricity Portfolios for 2026-2027 Transmission Planning Process and Need for Additional Reliability Procurement*, R.25-06-019 (Sept. 30, 2025).

[28] *See California Community Choice Association's Opening Comments on the Proposed Decision*, R.23-10-011 (June 11, 2025).

[29] *See* Opening Comments filed in R.23-10-011 on or about March 3, 2025: American Clean Power – California Opening Comments, at 15; Alliance for Retail Energy Markets Opening Comments, at 3; The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) Opening Comments, at 10-11; Clean Energy Buyers Association Opening Comments, at 7; Center for Energy Efficiency and Renewable Technologies Opening Comments, at 3; California Environmental Justice Alliance Opening Comments, at 11- 12; Hydrostor, Inc. Opening Comments, at 9; Microsoft Corporation Opening Comments, at 12-13; and Shell Energy North America (US), L.P. Opening Comments, at 4-5.

IV. THE COMMISSION SHOULD INVEST IN SOFTWARE AND SYSTEMS TO AUTOMATE THE RA VALIDATION PROCESS

Energy Division's manual RA validation process may result in the Commission passing up significant efficiency improvements over concerns with the administrative effort they would add to existing processes. Currently, all LSEs submit to the Commission a RA showing in Excel on an annual and monthly basis. Over the 20-plus year history of the RA program, the Excel spreadsheet has grown to include 14 visible sheets, 18 hidden sheets (used to perform calculations and validations), six macros, and requires a 58-page user guide to navigate. Energy Division's continued rejection of hourly transactability as an affordability measure appears largely driven by the fact that the existing RA compliance review processes are no longer sufficient to operate the SOD program. The RA program procures billions of dollars of capacity annually and carries strict fines that can be up to $26.64/kw-month. In addition, the program is a major component in grid reliability. With the program's growing complexity, including hourly verification, customized storage showings by hour, and charging sufficiency verifications, the compliance program has outgrown spreadsheets. The RA program needs a more robust and user-friendly compliance program to evaluate RA showings quickly and effectively.

Continued reliance on spreadsheets for validation of an increasingly complex RA program should no longer be a barrier to the adoption of sound policy proposals. The Commission regularly authorizes millions of dollars of IT work for a variety of purposes; for example, Item 6 on the February 26, 2026, Consent Agenda contemplates a $2.6 million increase for improvements to the California Distributed Generation Statistics Website. Given the critical importance of the RA program – supporting both reliability and affordability -- the Commission should invest in tools to make the validation process more automated and manageable for Energy

Division staff. If the Commission's existing budget is inadequate, CalCCA would gladly support any Budget Change Proposal for the IT funding necessary for this project.

V. IF THE COMMISSION DECLINES TO INVEST IN SYSTEMS TO AUTOMATE THE RA VALIDATION PROCESS, IT SHOULD ADOPT TEMPORARY GUARDRAILS TO AID IN ASSESSING COMPLIANCE

If the Commission foregoes these investments and is concerned with the amount of administrative effort this proposal would create, the Commission should adopt two temporary guardrails that would help keep validation efforts manageable. Then, the Commission should scope into the RA proceeding a process to revisit the necessity of these guardrails after a year of implementation.

First, on an interim basis, the Commission could set an initial trading limit of no more than 25 percent of an LSE's compliance obligation, as proposed in CalCCA's March 3, 2025, Opening Comments in R.23-10-011.[30] Given this limit may prohibit the use of hourly load obligation trading by smaller LSEs, the Commission should also adopt a de minimis threshold allowing LSEs with RA requirements less than 200 MW to trade up to 50 MW of their obligation. Furthermore, if the Commission is concerned with the administrative burden of multiple layers of load obligation trades, the Commission can require that if an LSE purchases a load obligation trade and then sells it to another LSE, that sale will count towards that LSE's 25 percent limit.

*Second***,** if the Commission believes Energy Division will have administrative difficulties validating showings with hourly load obligation trades, then on an interim basis the Commission could require hourly load transactions to be shown five business days prior to the RA showings to provide Energy Division staff with additional time to validate the showings. This change is not

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30 *California Community Choice Association's Opening Comments on the Assigned Commissioner's Amended Scoping Memo and Ruling*, R.23-10-011 (Mar. 3, 2025) at 10-11.

ideal because CalCCA anticipates hourly load obligation trades would be used to fill marginal deficiencies after first procuring resources to fill open positions. However, it would be worth pursuing if it enables hourly load obligation trades to be a feature of the RA program.

VI. CONCLUSION

CalCCA respectfully requests consideration of the proposals herein and looks forward to an ongoing dialogue with the Commission and stakeholders.

Respectfully submitted,

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

March 3, 2026

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
TRACK 1 PROPOSALS ON TRANSACTABILITY ISSUES

EFFECTIVE MECHANISMS FOR SLICE-OF-DAY RA TRADING
April 24, 2025

Effective Mechanisms for Slice-of-Day RA Trading

Andrew Mills[1]

April 24, 2025

[1] Director of Data Analytics, California Community Choice Association. Email: andrew@cal-cca.org. Special thanks to Evelyn Kahl (CalCCA), Eric Little (CalCCA), Lauren Carr (CalCCA), Desik Somasundaram (CalCCA), Maren Wenzel (Silicon Valley Clean Energy), Frias Abu-Sneneh (CleanPowerSF), Geoffrey Ihle (Central Coast Community Energy), and John Newton (Ava Community Energy) for feedback and guidance on this analysis.

1. Introduction

California is in the first year of a new Slice-of-Day (SOD) resource adequacy (RA) program. In the new SOD program, Load Serving Entities (LSEs) must show a portfolio of resources that are sufficient to meet all 24-hours of a peak load day in each month of the year. Experience from the 2024 test year, in which LSEs submitted a non-binding SOD filing in parallel with their binding legacy filings for a single monthly RA product, shows many LSEs had resources that exceeded their RA obligations during the same hours when other LSEs were short.[2] This dynamic – whereby some LSEs possess excess RA while others are short – suggests there are additional opportunities for trade that are currently unrealized due to regulatory barriers. At present, rules set by the California Public Utilities Commission (CPUC) only allow trade of resources at a monthly level, not individual hourly obligations. CalCCA has advocated for hourly obligation trading, noting that a program that assigns obligations on an hourly basis should allow trade on an hourly basis to reduce costs to consumers.[3] This analysis quantifies the value of trade, contrasts trading in a SOD policy environment with trading in the more familiar legacy RA program, and demonstrates the advantages of hourly obligation trading.

In addition to the 24-hour obligation, a primary feature of the SOD program is 24-hour accreditation of resources. Conventional thermal powerplants, such as natural gas fired generators, geothermal, and biomass plants are generally accredited with constant generation over all 24 hours. Variable resources, like wind and solar, on the other hand, are accredited based on a technology and region-specific exceedance profile of generation on peak days.[4] Storage accreditation is constrained by the storage power rating, energy storage capability, and availability of excess energy to charge storage on the peak day. Altogether, the value of a resource depends on its contribution to the LSE's assigned RA obligation coupled with its interaction with other resources in the LSEs portfolio.

To quantify the potential benefits of hourly trading, we developed a tool to simulate competitive market trades between LSEs. In the simulations, we quantify the benefits of trade for both monthly resource trading, which is currently allowed by CPUC rules, and hourly obligation trading, which has not yet been authorized. Hourly obligation trading allows an LSE with excess resources to take on a portion of the obligation of another LSE in individual hours. We simulate monthly resource trading and hourly obligation

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[2] CPUC Energy Division, 2024. *Report on Resource Adequacy Slice of Day Implementation and Year Ahead Showings.* February. Available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/slice-of-day-compliance-materials/energy-division-report-on-ra-sod-implementation-and-year-ahead-showings.pdf

[3] CalCCA 2024. California Community Choice Association's Comments on Assigned Commissioner's Scoping Memo and Ruling. January 17. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M524/K571/524571013.PDF

[4] Exceedance profiles are set by the CPUC program rules across all variable resources and are not unique to LSEs or specific generators.

trading in the same manner with a broker announcing prices and LSEs responding with bids and offers for obligations in specific hours.

Broadly, the simulations are based on an intermediary, like a broker, announcing prices for SOD RA products and LSEs simultaneously responding with bids to buy or offers to sell RA products at the announced prices. The LSE bids and offers take into consideration the requirement that their portfolios meet their obligations in each hour. The LSEs develop their bids and offers by minimizing their cost, net of any revenue from selling RA products.[5] The broker matches bids and offers between participants with the goal of maximizing internal trading opportunities, or conversely, minimizing the amount of RA products that must be purchased from external sources to meet obligations. The broker's objective includes taking advantage of favorable opportunities for LSEs to sell any excess resources, not needed by participants, to external markets. In an auction-like process, the broker continuously revises the announced prices and collects additional bids and offers from LSEs until settling on final prices and quantities that maximize the trading opportunities. LSEs then make bilateral trades at the designated prices and quantities. The final quantities and prices are equivalent to the solution of a centralized optimization, in which an intermediary uses each LSE's obligation and resource portfolio to come to an optimal reallocation of resources between participants. In the case of a broker and LSE bidding process, however, the LSEs only announce responses to prices without needing to hand over their commercially sensitive RA filings to the intermediary.

The direct benefits for participants are the gains from trade – the difference between the LSEs' costs before trade, in which they must purchase external RA products to meet their obligations on their own, and the costs after trade.[6] The costs of internal trades across all participants nets to zero, since each purchase is met by an equivalent sale to another participant, such that the total gains from trade is simply the reduction in the need to purchase RA products from external sources and the revenue from selling excess resources to external markets. For these simulations, we assume that excess resources would be sold to utilities under the rules of the Western Resource Adequacy Program (WRAP),[7] at prices that are only 1/10th of the assumed cost of RA products for California LSEs.[8]

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[5] We assume that all LSEs behave as cost-minimizing price-takers and do not consider any potential strategic bidding behavior that may impact prices in a non-competitive manner.

[6] Our analysis is limited to the short-run gains from trade because we assume the initial LSE resource portfolios do not change depending on the policy environment. In the long run, LSEs may alter their procurement decisions depending on exposure to different trading environments. We ignore these potential long-run impacts when quantifying the gains from trade.

[7] WRAP. 2024. *Review of Preliminary, Non-Binding WRAP Regional Data for the Current Participating Footprint for the Summer 2025 and Advisory Data for the Summer 2028.* January 31. https://www.westernpowerpool.org/private-media/documents/2024-1-16_Webinar_Summer_2025_and_2028_Data_updated_2024-12-12.pdf

[8] Because the WRAP program has not yet gone into effect, the volume of market-based capacity transactions outside of California is low, making it difficult to estimate the value of capacity outside of California. From the limited set of non-California capacity transactions, we see that recent capacity prices are on average lower than in California. Based on the thin volume and lower prices, we simply assume that sales of capacity outside of California would occur at a price of 1/10th of the price in California. We expect

Notably, trade between participants also provides indirect benefits to all California LSEs due to the reduction in demand for RA products. Reduced demand for RA products lowers the price of RA, which lowers the cost of meeting RA obligations to all California LSEs. The magnitude of the indirect benefits depends on the avoided external RA purchases by the participants, the price elasticity of RA products, and the quantity of RA bought at market prices by California LSEs. Reducing the cost of RA in California has grown in importance in recent years following the rapid increase in RA prices. While the weighted-average price for RA was $2.77/kW-mo in 2019,[9] tight market conditions[10] caused the weighted-average price to rise by a factor of nine to $26.26/kW-mo in 2024.[11] The ability for trade to reduce the cost of RA has significant affordability implications for all of California.

To compare trading in the new SOD program with trading in the legacy RA program, we also simulate resource and obligation trading with a single monthly RA product. In the legacy RA program, resource accreditation is based on an effective load carrying capability (ELCC) and obligations are based on the highest demand in each month. Although a broker is used to coordinate trading in the legacy RA program simulations, the broker is not strictly necessary. LSEs that are long could simply match with LSEs that are short and trade directly, resulting in the same outcome as with a broker. Hourly obligation trading offers a similar opportunity for LSEs simply matching long and short hours without an intermediary to coordinate trades. We call hourly obligation trading without an intermediary "uncoordinated hourly obligation trading," because this simple matching does not consider inter-temporal coupling nor the potential economic benefits of selling excess resources to external markets. An analogous uncoordinated approach for resource trading would be to only match LSEs that have excess thermal capacity with LSEs that are short in any hour.[12] We call the simple matching of LSEs with excess thermal and LSEs that are short on thermal resources "uncoordinated resource trading". We compare the effectiveness of uncoordinated trading to coordinated trading within the new SOD program.

The simulation results that follow are based on the confidential SOD RA filings for a subset of California LSEs, 24 community choice aggregators (CCAs), for the 2024 test

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non-California markets for RA to become more robust in the future with the implementation of WRAP, enabling better estimates of market prices.

[9] CPUC. 2019. Calculation of the 2019 True Up and Forecast 2020 Market Price Benchmarks for the Power Charge Indifference Adjustment. R. 17-06-026. November. Available athttps://webproda.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/community-choice-aggregation-and-direct-access/2019-final-calculation-of-the-pcia-market-price-benchmarks.pdf

[10] CalCCA. 2024. California's Constrained Resource Adequacy Market:
Ratepayers Left Standing in a Game of Musical Chairs. January. : Available at: https://cal-cca.org/wp-content/uploads/2024/02/CalCCA-Stack-Analysis-2023-2026-updated-01_16_24-.pdf

[11] CPUC. 2025. *Market Price Benchmark Calculations 2024* (Revised). November. Available at 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

[12] Presumably other resources or bundles of resources could be chosen as the resource to trade in an uncoordinated fashion. We chose thermal resources for the simplicity of being able to quantify how much excess or how much shortage of thermal resources an LSE has. An LSE is long on thermal by the amount the aggregate resource showing exceeds their obligation in the tightest hour. An LSE is short on thermal by the amount the aggregate showing is less than their obligation in the hour with the greatest deficit.

year and the first binding year of 2025. The 2025 filings are "year-ahead" filings in which the obligations were set at 90% of the final requirements for the operating month. To quantify the gains from trade, we scaled the year-ahead obligations to the full 100% requirements and, in effect, ask how much of the remaining RA purchases for each CCA could be met through trade with other CCAs instead of going out to the market to buy incremental RA from external sources.

2. Results and Discussion

2.1 Trade Between CCAs Creates Substantial Value

Across the five summer months in 2025, simulated trading between CCAs directly reduces costs to participants by $60 million per year[13] and the reduced demand for RA products produces $50 million per year in indirect benefits to all Californians.

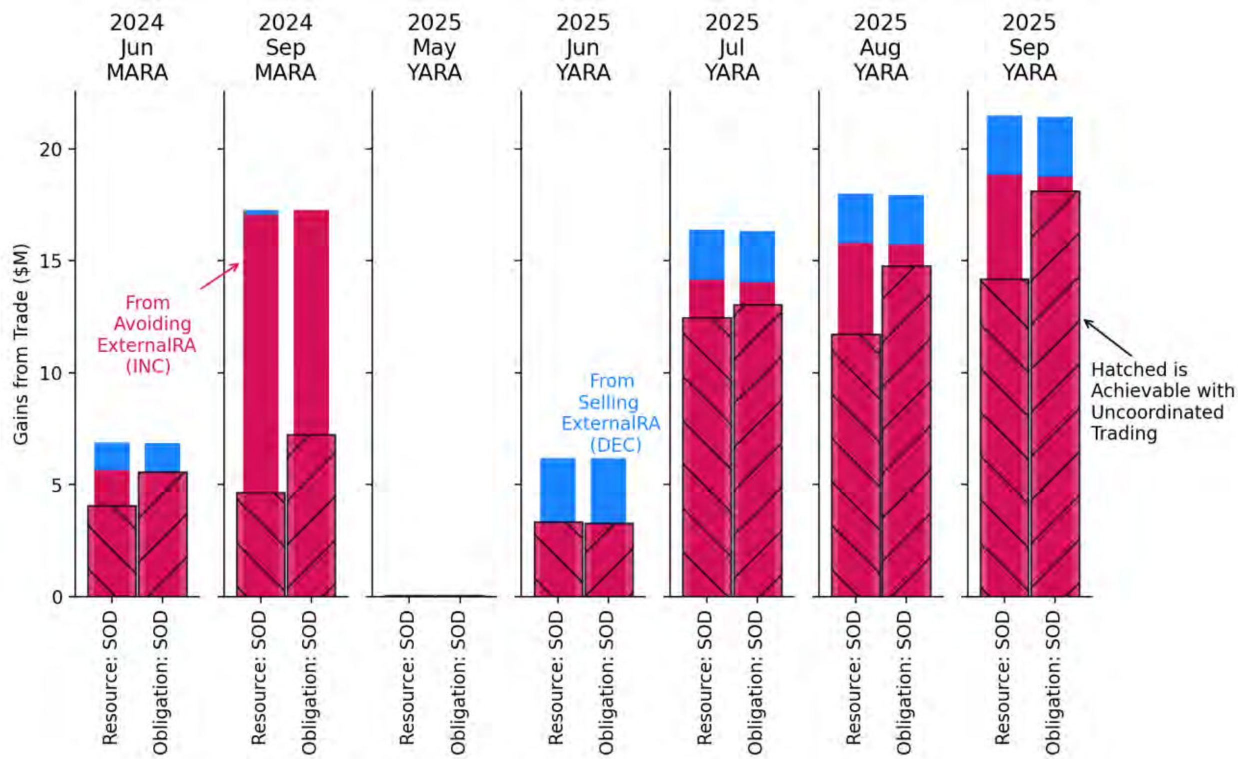
2.1.1 Direct Benefits

For 2025, over 85% of the direct benefits of trade are from the reduced purchases of RA products from external sources while the remaining 15% are from the sales of excess resources to external markets. The gains from trade occur primarily in the months of July, August, and September when loads are highest and the accreditation of variable resources is lowest (see Figure 1).

The June gains from trade are also lower due to lower prices for external RA products in June compared to later months. The gains from trade are zero in May because each of the CCAs could meet their obligations on their own, obviating the need to purchase external RA even before trade, and the lack of a binding requirement for WRAP utilities in May.

The gains from trade in the June and September 2024 test-year filings are similar to the gains from trade in the corresponding month of the 2025 binding year. One exception is that sales of excess RA in September 2024 were near zero because the participating CCAs did not have sufficient resources to meet the obligations on their own, even after trade (see Table 1). As a result, some CCAs needed to purchase incremental RA from external sources even after trading with other CCAs.

[13] The direct benefits of trade are proportional to the avoided purchases of external RA (or increased sales of external RA in cases with a net excess) and the assumed price of external RA. The external RA prices in this analysis are based on observed sales of capacity to California LSEs reported in FERC Electronic Quarterly Reports, as described in Section 5.3. Actual external RA prices faced by LSEs are uncertain, though the direct benefits would increase or decrease commensurate with changes in the external RA prices.



Note: Further details of gains from trade for September 2024 and 2025 are in Table 1 and Table 2, respectively. Gains from trade in all months are described in Appendix C.

Figure 1. Total gains from trade across all 24 CCAs with the 2024 test-year and 2025 year-ahead Slice-of-Day filings, with either resource trading (Resource: SOD) or hourly obligation trading (Obligation: SOD). Gains from trade with uncoordinated trading, without an intermediary to coordinate trades, is shown by the wide, hatched bar.

2.1.2 Indirect Benefits

The $50 million per year in indirect benefits stem from the reduced demand for external RA products after trade and the downward pressure that places on RA prices. Across the five summer months of 2025, trade reduces purchases of RA from external sources by 455 MW on average. Based on our observations of the average RA price and the net surplus from year to year,[14] we estimate that average RA prices decrease by $1/kW-mo for every 1 GW demand reduction.[15] In 2024, California LSEs purchased roughly 20 GW of RA products at market prices in each summer month.[16] Altogether, trade between CCAs lowers demand for RA products and reduces costs for all California LSEs (CCAs, ESPs, IOUs, and POUs).

[14] CalCCA. 2024. *California's Constrained Resource Adequacy Market: Ratepayers Left Standing in a Game of Musical Chairs*. January: Available at: https://cal-cca.org/wp-content/uploads/2024/02/CalCCA-Stack-Analysis-2023-2026-updated-01_16_24-.pdf
[15] Estimating the sensitivity of RA prices to shifts in RA demand is particularly challenging because of the bilateral nature of the California RA market. We describe our approach for estimating the sensitivity of RA prices to RA demand in Appendix B.
[16] CalCCA analysis of FERC EQR capacity transactions downloaded from https://eqrreportviewer.ferc.gov/.

2.1.3 Benefits Would Grow if Participants Extended Beyond CCAs

While trade between the 24 CCAs creates substantial direct and indirect benefits, the benefits would be even greater if trades occurred between all CPUC-jurisdictional entities (CCAs, ESPs, and IOUs). The CPUC's analysis of 2024 test-year SOD filings[17] identified short positions that were about 70 percent greater than the short positions of CCAs alone. Based on this finding, we estimate that trade between all CPUC-jurisdictional LSEs could reduce RA demand by 70 percent more than trade between CCAs. The greater reduction in RA purchases and further downward pressure on RA prices could increase the benefits of trade to more than $180 million per year ($105 million of direct benefits and $77 million of indirect benefits).

		Short Position (a.k.a., ExternalRA INC)			Internal Trades				
	Scenario	Before Trade (MW)	After Trade (MW)	Gains from Trade ($M)	Volume (MW)	Count	Average Connections	Monetary Transfer ($M)	Requires Intermediary
I.	Resource: ELCC	467	0	12.3	467	22	1.9	1.2	No
II.	Obligation: ELCC	467	0	12.3	467	22	1.8	1.2	No
III.	Resource: SOD	926	269	17.3	2,642	185	15.4	23.4	Yes
IV.	Obligation: SOD	926	261	17.3	3,591	150	12.5	11.7	Yes
III.*	Uncoordinated Resrc.: SOD	926	748	4.7	185	7	1.8	N/A	No
IV.*	Uncoordinated Oblg.: SOD	926	645	7.2	4,654	122	10.2	N/A	No

Table 1. Summary of trade between CCAs across policy environments with September 2024 test-year data

		Short Position (a.k.a., ExternalRA INC)			Internal Trades				
	Scenario	Before Trade (MW)	After Trade (MW)	Gains from Trade ($M)	Volume (MW)	Count	Average Connections	Monetary Transfer ($M)	Requires Intermediary
I.	Resource: ELCC	541	0	15.1	541	22	1.9	1.4	No
II.	Obligation: ELCC	541	0	15.1	541	22	1.8	1.4	No
III.	Resource: SOD	727	0	21.5	3,500	167	13.9	6.7	Yes
IV.	Obligation: SOD	727	0	21.4	8,062	163	13.6	2.4	Yes
III.*	Uncoordinated Resrc.: SOD	727	182	14.2	561	16	1.9	N/A	No
IV.*	Uncoordinated Oblg.: SOD	727	27	18.1	6,613	120	10.0	N/A	No

Table 2. Summary of trade between CCAs across policy environments with September 2025 binding-year data

2.2 With an Intermediary, Resource Trading and Hourly Obligation Trading Achieve the Same Benefits

In the simulations of trade, the broker coordinates trades between LSEs, ensuring that any opportunity for an LSE to meet its obligations by purchasing RA products from a

[17] CPUC Energy Division, 2024. *Report on Resource Adequacy Slice of Day Implementation and Year Ahead Showings.* February. Available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/slice-of-day-compliance-materials/energy-division-report-on-ra-sod-implementation-and-year-ahead-showings.pdf

participant is realized, without adversely affecting the other LSEs ability to meet its own obligations or to sell to an external market if more lucrative. LSEs participate by responding to broker-announced prices with bids and offers of RA products at quantities that are both feasible, in the sense that the LSE's obligations will be met if the bids and offers are accepted, and minimize costs to the LSE. With this sophisticated trading mechanism, trading either resources or hourly obligations achieve roughly the same reduction in purchases of external RA and the same gains from trade, Figure 1. Later sections discuss important differences between resource trading and hourly obligation trading, in terms of differences in internal monetary transfer between participants in Section 2.4 and ability to trade without the need for an intermediary in Section 2.5, but in terms of aggregate benefits, the two policy environments produce similar direct and indirect benefits.

2.3 Benefits of Participation are Widespread, Though Uneven

For a participant, the most salient question is whether it benefits from trade, not necessarily the aggregate benefits to all participants. We find that all participants are economically better off by participating in the coordinated trades than on their own. Individual CCA gains from trade across the five summer months of 2025 are quantified in Figure 2, shown as a percentage of the LSEs' maximum cost if they met all of their RA obligations by buying RA from external sources (ExternalRA INC). We normalize the individual gains from trade in this manner to remove the effect of CCA size on the individual LSE gains from trade.

While all participants benefit from trade, some LSEs benefit more than others. For the summer months of 2025, roughly half of the participants reduce compliance costs by 10-30% through trade, while the remaining half see less than 5% reductions in cost.

The only contributor to gains from trade with uncoordinated trading are the avoided costs of purchasing RA from external sources (ExternalRA INC). This is because the way we simulate uncoordinated trading does not involve internal monetary transfer and does not involve sales of RA to external markets (ExternalRA DEC). Therefore, the only beneficiaries from uncoordinated trading in the simulations are LSEs that are short prior to trade.

Comparison of the beneficiaries of trade with uncoordinated and coordinated resource or hourly obligation trading in Figure 2 reveals that the LSEs that benefit the most from trade in 2025 are those that are short prior to trade. LSEs that are long prior to trade see proportionally smaller benefits from selling RA products internally or to external markets. The relatively low benefits to participants that are long prior to trade is in part due to low internal RA prices in the summer of 2025 resulting from coordinated trades eliminating the short positions of all participants even in September 2025 (see Table 2). In contrast, internal RA product prices remain high in September 2024, when some participants still must purchase RA from external sources (ExternalRA INC) even after trade (see Table 1), and therefore LSEs that are long prior to trade see proportionally higher benefits from trade.[18]

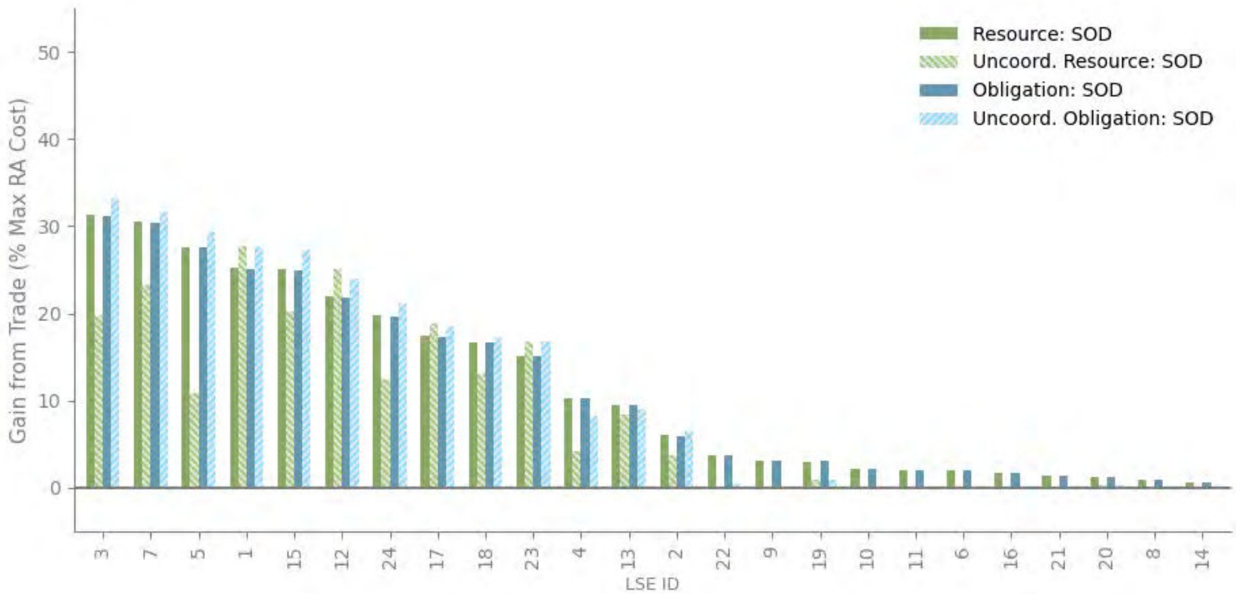


Figure 2. Aggregate direct benefits across May to September 2025 for each CCA, scaled by the CCA's maximum RA cost if it met all obligations at the assumed external RA price.

2.4 Hourly Obligation Trading Targets Periods with Scarce Resources

Even though the simulations show that hourly obligation trading and resource trading yield similar gains for participants, we observe important differences between the two policy environments. One difference is the way that hourly obligation trading directs internal monetary transfer toward hours that are most constrained in aggregate.

With the September 2024 test-case data, trade reduced the need to purchase RA products from external sources (ExternalRA INC), but it did not eliminate it entirely (see Table 1). We illustrate differences in internal monetary transfer in this constrained month by showing the trade volume and final prices with resource trading and hourly obligation trading for September 2024 in Figure 3. The product of the trade volume for the internal RA product and its corresponding price sums to the total internal monetary transfer. The product of external RA volume and prices, in contrast, is the post-trade external RA cost which is minimized by the broker by coordinating trades.

Final prices for internal RA products from the broker auctions differ across resources or hours, for policy environments that allow resource trading or hourly obligation trading, respectively, depending on how much another increment of that product

[18] Relatively low benefits of trade for LSEs that are long prior to trade raises the question of whether these entities would participate in trade. We find that even if LSEs that are long prior to trade decide to abstain from trade, there continue to be trading benefits for the LSEs that are short prior to trade. The direct benefits of trade when only short LSEs participate are $20-21 million in 2025, which is 42-44% of the gains the short participants would have realized if all of the LSEs were to participate.

would reduce the need to buy RA from external sources (ExternalRA INC). With hourly obligation trading, the only hour with a final non-zero price was hour ending 19 (HE19). In all other hours the final price for hourly obligations was zero because participating LSEs could easily take on additional obligations in hours other than HE19 without triggering the need to buy additional RA from external sources. Even though hourly obligation trading involves a large volume of internal trades, the final auction price of zero for hourly obligations in most hours results in monetary transfers being concentrated only in the subset of trades involving obligations in HE19.

With resource trading, on the other hand, final prices are non-zero for all RA products, meaning that every internal trade also requires an internal monetary transfer between participants. The internal monetary transfer is largest for trades involving natural-gas fired thermal resources, unspecified imports, and 4-hour batteries. Prices for wind and solar resources are lower and therefore contribute less to the internal monetary transfer even though the internal trade volume is large. For some participants, favorable trades involve selling one high-cost resource, such as a battery, while simultaneously buying a high-cost resource with different characteristics, such as a thermal resource, to marginally lower the participant's net cost. Such a trade involves a large internal monetary transfer yet only contributes a small amount to the overall gains from trade. Similar transactions were not required in the policy environment with hourly obligation trading.

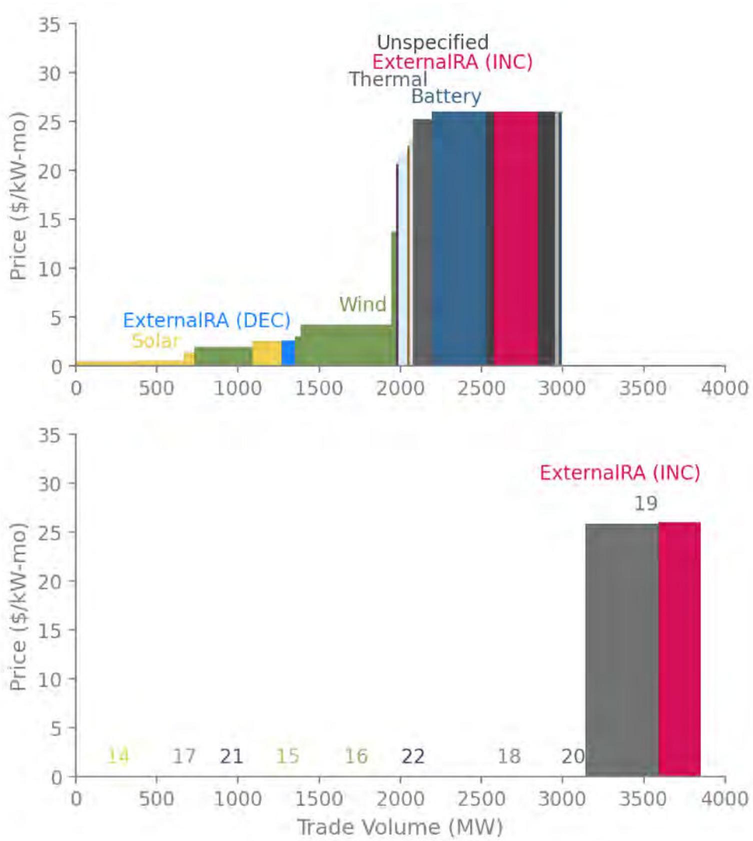


Figure 3. Comparison of SOD trade volume and price using September 2024 test-year data with the resource (top) and obligation (bottom) trading policy

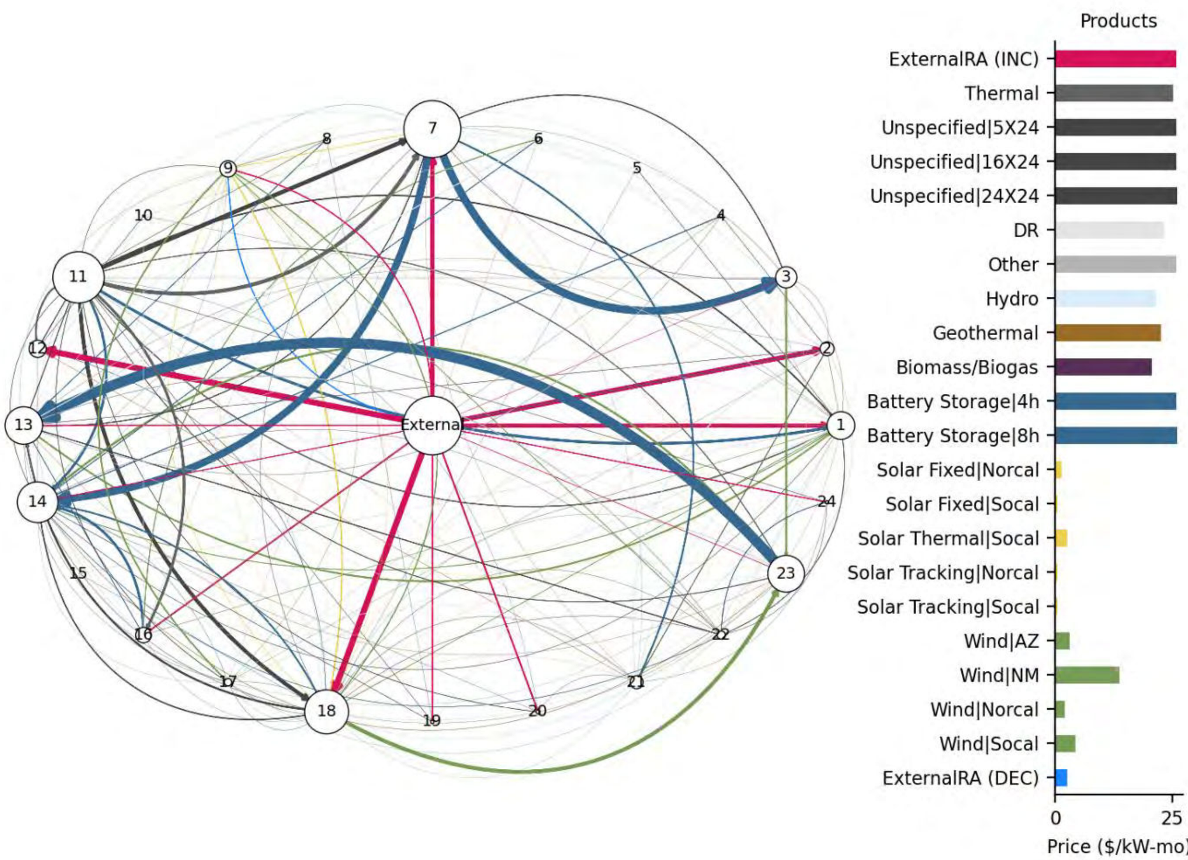
2.5 Slice-of-Day Trading is 6-9 Times More Complex

Gains from trade are not unique to the new SOD RA program. Even with the legacy RA program, where different resources would be converted to a comparable RA product with a single qualifying capacity value through an accreditation factor called the ELCC, LSEs that are long can benefit from selling excess RA to LSEs that are short. What is unique to the SOD RA program is the complexity of trades required to achieve the benefits. Overall, we estimate SOD trading to be 6-9 times more complex than trading with the legacy RA program.

We quantify the complexity of internal trade through three related metrics: volume, transaction count, and average number of connections.[19] These metrics are shown for each of the policy environments with September 2024 test-year data and September 2025 binding data in Table 1and Table 2, respectively. In the legacy RA program, every internal trade results in a comparable reduction in the short position of the purchasing LSE meaning that the trade volume is equal to the reduction in short positions before and after trade. In contrast, trading with SOD products across the summer months of 2025 requires an internal trade volume that is nine times the reduction in purchases of external RA. The count of transactions with SOD trading is more than 6 times the count of transactions in the legacy RA policy environment, where a unique transaction is the bundle of all RA products sold by one LSE to another. Finally, the average number of trading partners with SOD trades is 6 times more than in the legacy RA policy environment.

To illustrate the complexity of SOD resource trading, we visualize the trading network between 24 CCAs and external sources of RA using September 2024 test-year data, Figure 4. Each node represents a CCA, with the size of the bubble proportional to the CCA's transaction costs (price times quantity). Each edge of the network is a transaction involving a particular type of RA resource, with arrows showing the direction from seller to buyer and the width of the arrow based on the transaction cost. Even though the volume of wind and solar RA product trades is large, the low prices for these products leads to smaller transaction costs and less prominent edges.

[19] As is common in any optimization-based simulation, numerical issues can sometimes lead to trades with very small quantities being included in the final allocation, impacting metrics such as transaction count and number of trading partners. For these two metrics, we exclude any transaction with a quantity below 0.5 MW in the tally of transaction count and trading partners.

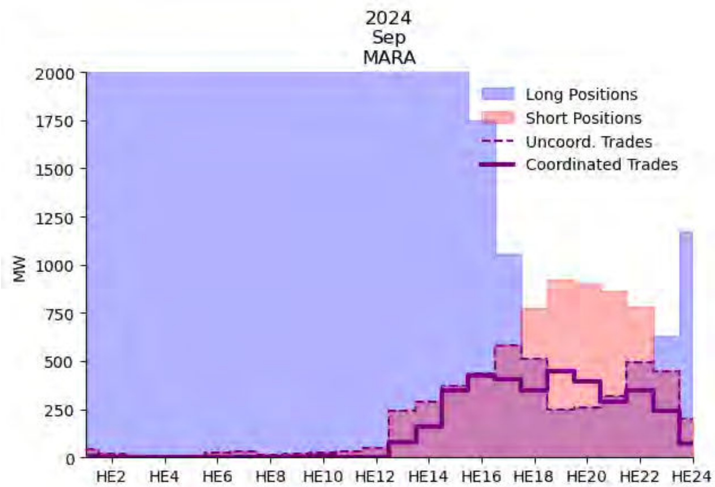


Note: Bubbles are CCAs, sized based on transaction costs. Lines are transactions sized by transaction cost.

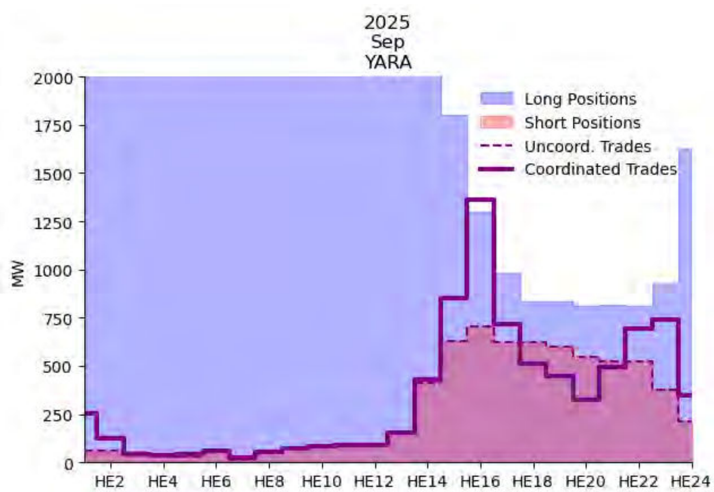
Figure 4. Visualization of trading networks in the SOD resource trading policy environment using September 2024 test-year data

2.6 Hourly Obligation Trading Allows Simple Trades without an Intermediary

With the increased complexity of SOD trading, it is important for policy makers to provide LSEs with tools necessary to simplify trade to manage the risk that LSEs forgo trading and instead purchase additional unnecessary external RA products, at the expense of ratepayers. Previous results demonstrated that hourly obligation trading can achieve the same benefits as resource trading when an intermediary is available to coordinate trades (Sections 2.2) and that hourly obligation trading can target hours where aggregate resources of participants are insufficient to meet the aggregate obligation (Section 2.4). One more potential advantage of hourly obligation trading is that it provides a pathway for LSEs to achieve some of the same benefits of coordinated trades without the need for an intermediary. In the simplest form, participants that show resources in excess of their obligations in some hours can take on the obligations of LSEs that are short in those hours. Trades made in this manner, without further consideration of impacts on storage charging energy or impacts to opportunities to sell excess to external markets, is what we call uncoordinated hourly obligation trading and is illustrated for September 2024 and 2025 in Figure 5. For the summer months of 2025, even the uncoordinated trades achieve 80% of the gains from trade observed with a sophisticated intermediary to coordinate trades (see Figure 1).



(a)



(b)

Figure 5. Comparison of uncoordinated and coordinated hourly obligation trades when CCAs have (a) a net deficit of resources in September 2024 or (b) a net surplus of resources in September 2025.

The uncoordinated approach is not always as effective, however. With the September 2024 test-year some of the participants still need to purchase RA products from external sources, even after trades coordinated by an intermediary. For this month, the uncoordinated hourly obligation trading only achieved 35% of the gains of trade possible with an intermediary. In this case, the intermediary helps to find trading opportunities involving HE19 that come from adjusting storage charging, storage discharge, and obligations of LSEs to better align with overall needs. The possibility of these adjustments to generate gains from trade is not evident with uncoordinated hourly obligation trading alone, as shown in Figure 5a.

In months where long positions exceed short positions in all hours, as in the September 2025 filings, there are again differences in trading opportunities identified by uncoordinated hourly obligation trading and with an intermediary to coordinate trades, as in Figure 5b. However, the differences are much less impactful on the gains from trade since trades from both approaches can largely eliminate the need to purchase RA from external sources. Allowing hourly obligation trading opens a pathway for LSEs to begin to realize the benefits of trade without the need to develop a novel sophisticated intermediary to coordinate trades.

3. Practical Considerations for Implementing Trading Mechanisms

The previous results are based on simulations comparing alternative policy environments. Moving from simulation to real-world implementation would require a much more in-depth investigation. Here we describe some of the important practical considerations but note that much more work on this question remains.

Three different mechanisms for SOD trading have been mentioned in this analysis: (1) a centralized optimization; (2) a broker running an auction; and (3) uncoordinated trades. *First*, a centralized optimization across all participating LSEs involves an intermediary having access to each LSEs confidential resource portfolio and obligations then using that information to reallocate resources an optimal manner. *Second*, a broker running an auction-like process would involve LSEs responding to announced prices with bids and offers. While both mechanisms lead to the same solution and gains from trade, under the auction approach, the LSEs can maintain the confidentiality of their portfolios and obligations. *Finally*, even an uncoordinated form of trade could achieve significant benefits without requiring an intermediary. In this case, trading could be as simple as participating LSEs posting hourly bids and offers to a bulletin board and making bilateral trades from there. Although this would not achieve all the benefits available with an intermediary, it would still maintain confidentiality and would be simple to implement. These high-level considerations are summarized in Table 3.

	Centralized Optimization	**Broker Running an Auction**	**Posting Hourly Obligation Bid/Offers to a Bulletin Board**
LSEs keep contracts confidential	No	Yes	Yes
Achievable without intermediary	No	No	Yes
Maximizes trading opportunities	Yes	Yes	No

Table 3. Comparison of slice-of-day trading mechanisms

4. Conclusions

Hourly obligation trades can create substantial value. In the five summer months of 2025, simulated trading between the 24 CCAs could provide as much as $60 million per year in direct benefits from avoiding the need to buy incremental RA from external sources and even enabling sales of excess resources to external markets. The benefits of trade are widespread across all participants, though CCAs that are short prior to trade benefit more than CCAs that are long. Furthermore, the trade between CCAs lowers overall demand for RA products. Lower demand reduces RA prices for all California LSEs, creating a collective indirect benefit of $50 million per year.

With some form of sophisticated intermediary to coordinate trades, resource and hourly obligation trading can both achieve these benefits. An advantage of hourly obligation trading is that it requires only 2/5 of the internal monetary transfer between participants yet achieves the same benefits of resource trading. If part of the justification for the SOD program is a fair allocation of the costs of maintaining a reliable system, hourly obligation trading is better suited to valuing hours of the day with scarcity at the aggregate level.

Implementing an effective trading mechanism with the SOD program will not be easy. Trading in the SOD policy environment is 6-9 times more complex than that of the legacy monthly RA product. It will require a greater volume of trades, more transactions, and more trading partners. Achievement of the full benefits of trade requires a much more sophisticated coordination mechanism than participants might be accustomed to. Hourly obligation trading allows for simple trades without an intermediary, while still achieving 80% of the benefits.

With rapidly rising electricity costs in California, all ratepayers would benefit from having more flexibility in the way RA obligations are met. Trade is important and fundamentally more complex in the new SOD program. Policy makers should support the development of effective trading mechanisms that go hand in hand with the transition to SOD. Otherwise, the SOD RA program will drive up costs for consumers with no direct benefit to reliability.

5. Methods and Data

5.1 Policy Environments and ExternalRA

We developed a common analysis approach to compare trading under four different policy environments: two with RA based on a single monthly product where resources are accredited by an ELCC and two based on the SOD accreditation. With either ELCC or SOD accreditation, we compare resource trading and obligation trading, Table 4.

		Accreditation	
		ELCC	**SOD**
Trading Product	**Resources**	I: Resource trading with ELCC	III. Resource trading with SOD
	Obligations	II. Obligation trading with ELCC	IV. Hourly obligation trading with SOD

Table 4. Four policy environments in RA trading analysis

The trading analysis is based on a simulation of LSEs each having obligations and resources characterized in a regulatory filing for the CPUC called an RA filing. All participants in the trade are CPUC jurisdictional and subject to common RA program rules. Any RA obligations that are not met by internal trades with participants or any short positions prior to trade are met through incremental purchases of RA from external sources (ExternalRA INC), Figure 6. Assuming transmission capacity is available, the source of external RA can be from any resource in the western interconnection, whose reliability is assured by the Western Electricity Coordinating Council (WECC). We assume that purchases of ExternalRA INC contribute to a participant's portfolio similar to an unspecified resource available 24-hours a day (Unspecified|24X24). All ExternalRA INC is purchased at a single price, varying only by month of the year.

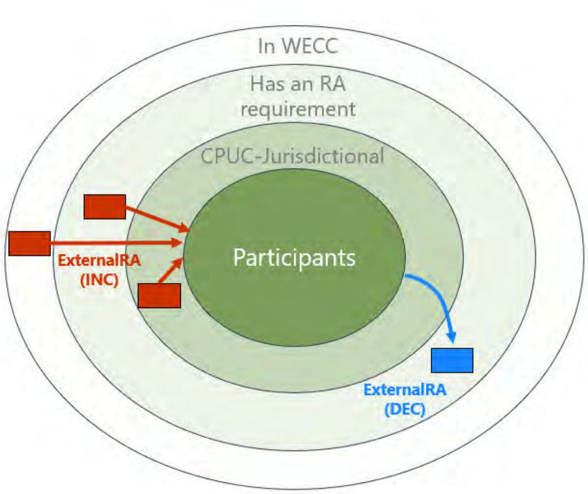


Figure 6. Illustration of the relationship of ExternalRA INC and DEC to participants in trade

In cases where an LSE's resources exceed its obligations, it may also be able to sell that excess to an external market (ExternalRA DEC). We assume that the purchaser of external RA would be an entity in WECC that has an RA requirement but is not CPUC jurisdictional. This assumption allows us to set a single price for external sales each month. An LSE that sells a resource to an external market removes the resource from its portfolio and converts it to ExternalRA DEC using the ELCC factors applicable to the external market.

The primary driver of the gains from trade is the reduction in purchases of ExternalRA across all participants before and after trade. Figure 7 illustrates how purchases of internal RA products can reduce the need to purchase ExternalRA across all four policy environments.

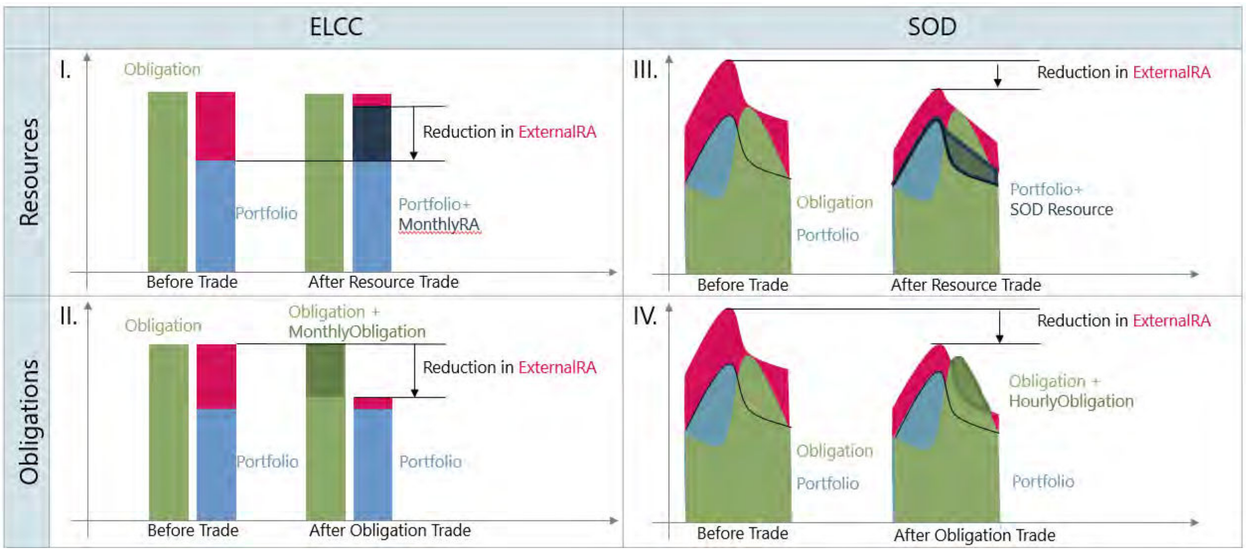


Figure 7. Illustration of the effect of trade on the need to purchase ExternalRA in each of the four policy environments

5.2 Trade Simulation

The Broker and LSE Bidding Strategy models are derived from a Central Optimization Problem in which the costs of meeting all LSE obligations are minimized, as in an RA pool. In the Central Optimization, a planner uses its visibility into the obligations and resources of every participating LSE to reallocate RA products (either resources or obligations, depending on the environment), such that the residual need to purchase RA products from an external source (ExternalRA INC), is minimized.

5.2.1 Central Optimization Problem

At a high level, the Central Optimization Problem is formulated as follows:

Central Optimization Problem:

Minimize: $ExternalCosts + TradeFriction$

Subject To:

$ExcessDemand_p = 0$, for each p in set of internal RA Products

$Deficit_l = 0$, for each l in the set of participating LSEs

$ExternalRA^{INC}_l <= Max\_Deficit\_Prior\_to\_Trade_l$, for each l in set of LSEs

Where:

$ExternalCosts = ExternalRA^{INC} * ExternalRA^{INC}\_Price - ExternalRA^{DEC} * ExternalRA^{DEC}\_Price$

$TradeFriction = \Sigma_p(InternalPurchase_p + InternalSale_l) * UnitFrictionCost$

$ExcessDemand_p = InternalPurchase_p - InternalSale_p$

The disadvantage of the Central Optimization is that each participant must share information about its full portfolio of RA contracts and its RA obligation with the entity operating the optimization. Such information is confidential and commercially sensitive, potentially limiting the set of LSEs willing to participate.

5.2.2 Decomposition to Broker and LSE Bidding

An alternative is to have an independent broker operate an auction-like process where it announces prices and participants respond with bid/offer quantities at those prices. The broker revises prices and continues to collect bids until it can balance supply and demand for RA products between participants while maximizing the gains from trade. The Broker/LSE Bidding Strategy models arise from a Dantizg-Wolfe Decomposition of the Central Optimization Problem.[20] The Broker is equivalent to the master problem and the LSE Bidding Strategy is part of the subproblem. The decomposition yields an equivalent solution to the Central Optimization, though it is solved through an iterative process rather than a single optimization.[21] More importantly, the Broker needs to only collect bid/offer responses from LSEs and does not need confidential information on each LSE participant's resource contracts or obligations.[22]

Broker:

Minimize: $\Sigma_r((ExternalCost_r + TradeFriction_r) * weight_r)$

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[20] Conejo, A.J., Castillo, E., Minguez, R. and Garcia-Bertrand, R., 2010. *Decomposition Techniques in Mathematical Programming: Engineering and Science Applications*. Springer Science & Business Media.

[21] The use of Dantizg-Wolfe decomposition to model coordinated markets has been used elsewhere in the literature, e.g., Najafi, F. and Fripp, M., 2023. "Market-based Coordination of Price-responsive Demand Using Dantzig-Wolfe Decomposition Method". *Energy and AI*, 14, p.100277. https://doi.org/10.1016/j.egyai.2023.100277

[22] The code used to create the simulations of trade in all policy environments is available at: https://github.com/CalCCA-Data-Team/agent_based_ra_market

Subject To:

$\Sigma_r\ (weight_r) = 1$

$\Sigma_r(ExcessDemand_{r,p} * weight_r) <= 0$, for each p in the set of internal RA products

LSE Bidding Strategy:

Minimize: $ExternalCost_l + TradeFriction_l + InternalCost_l$

Subject To:

$Deficit_l = 0$

$ExternalRA^{INC}_l <= Max\_Deficit\_Prior\_to\_Trade_l,$

Where:

$InternalCost_l = \Sigma_p\ (InternalRA\_product\_price_p * (Internal\_RA\_bought_{p,l} - Internal\_RA\_sold_{p,l}))$

5.2.3 LSE Bidding

In each round of the auction, LSEs respond to the Broker's prices with bids to purchase or offers to sell RA products. The bid/offers include both internal RA and external RA (INC or DEC) products. The LSE chooses bid/offers that minimize its cost of eliminating deficiencies. We further assume that LSEs will not purchase more ExternalRA_INC during trade than they would have had to purchase before trade. In other words, for LSEs that were already in compliance with RA requirements before trade, their ExternalRA_INC bids will always be zero.

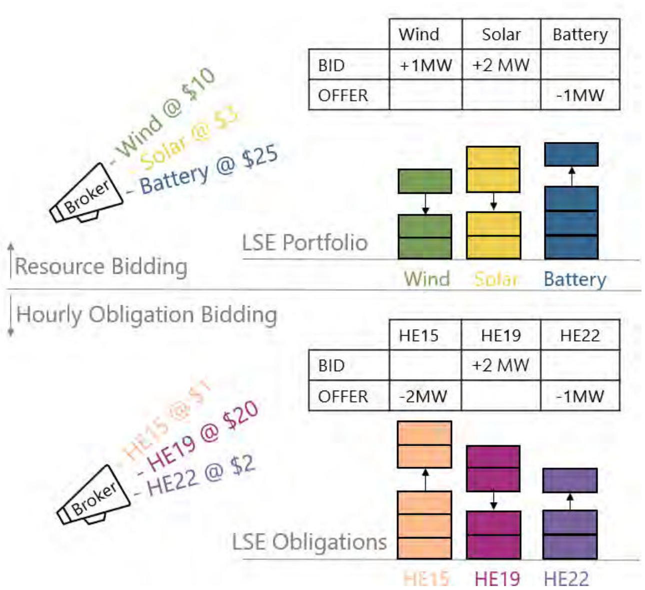


Figure 8. Illustration of LSE bidding either resources (top) or hourly obligations (bottom) in response to prices announced by the broker

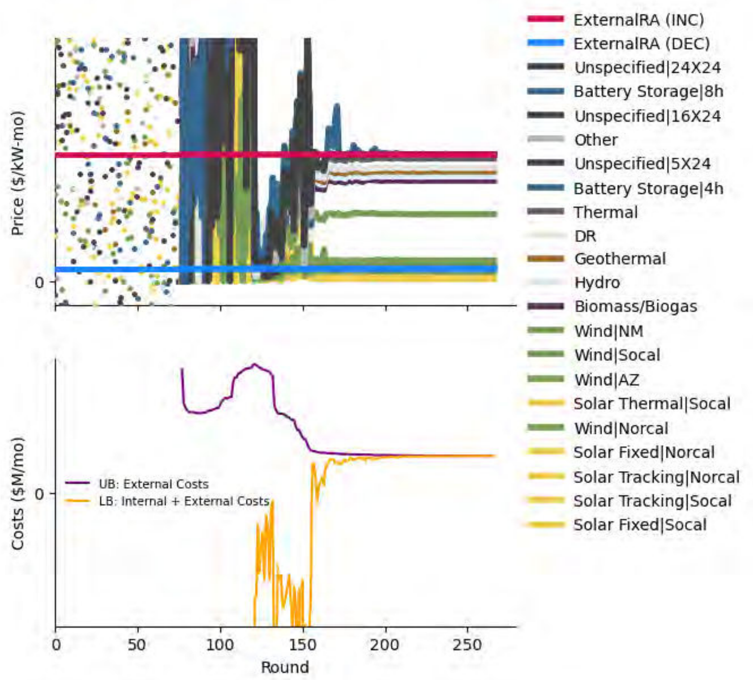
Figure 8 illustrates the process of a broker announcing prices for RA products and an LSE responding with bids to purchase or offers to buy the RA products at those prices. The LSE's bids and offers are made with the expectation that all bids and offers will be successful. In other words, there is no risk that an LSE offers to sell a product and then their bids for other RA products are unmet causing a deficiency. As described next, an important role of the broker is to collect all feasible bids and offers at different price points, then coordinate trades based on a final determination of quantities and prices that maintains feasibility for each participating LSE.

5.2.4 Broker Auction

In every auction round, *r*, the Broker finds weights to place on previous rounds to minimize costs, while ensuring that supply and demand for internal RA products are balanced. The shadow value of the supply and demand balance constraint for each product, representing the marginal reduction in total costs from another unit of supply, sets the prices for next round of the auction.[23]

The Broker continues the auction process until the Broker finds no further opportunity to reduce total costs. More precisely, the auction is completed when the weighted sum of all external RA costs matches the sum of the costs across all LSEs in the most recent auction round.[24] The final allocation of trades is based on applying the final weights to the bids collected in previous auction rounds. LSEs trade RA products with the other participants at the final auction prices. An example of the history of RA product prices and the convergence of external costs with the sum of LSE costs across auction rounds is shown in Figure 9.

[23] To begin the auction process, the Broker first collects bids based on randomly chosen prices. Bids in response to random prices are used to initialize the model. After initializing, all subsequent prices are from the shadow value of the supply and demand balance constraint in the Broker problem.
[24] We continue until the gap is less than 0.05% of the total costs across LSEs.



Note: UB is upper bound and LB is lower bound as defined in the Dantizg -Wolfe decomposition by Conejo et al (2010).

Figure 9. Example of auction process using September 2024 test-year data

5.2.5 Bilateral Matching

The broker tells participants their final quantity of RA product purchases and sales along with announcing final prices. Participants then bilaterally trade these products with other participants at the specified prices. We randomly match sellers of an RA product with buyers of a product, setting the transaction quantity to the lower of the bid or offer. Any residual quantity is again randomly matched with another buyer or seller in the list of participants. The bilateral matching ends when the final quantities specified by the broker are met.

5.3 Data and Assumptions

5.3.1 Slice-of-Day RA Filings

All data used in this analysis is from the confidential SOD RA filings provided by the 24 CCA members of CalCCA to the CPUC. The June and September 2024 filings were test-year filings that were not binding. The May-September 2025 filings were the year-ahead binding filings submitted to the CPUC at the end of October 2024. CalCCA preserves all confidential information and reports only anonymized or aggregate results that mask the original filer.

5.3.2 LSE Portfolio and Obligations

The SOD RA filings contain the confidential hourly obligations and the contracts with resources to meet the obligations. With the 2024 test-year filings, we use the obligations directly provided in the CCA filing. In the 2025 year-ahead filings, however, CCAs are only required to demonstrate sufficient resources to meet 90% of the operating month's obligation. To determine how much more resources CCAs must procure between the year-ahead filing and the operating month, we scale the obligation in the YARA filing to the full 100% obligation.

We characterize the CCA's portfolio based on the contracted nameplate capacity of each technology type, accounting for regional variation in resource portfolios. We also extract the 24-hour profile the CCA uses for each non-storage contract. For storage contracts, we ignore the profile and instead dispatch the storage within the LSE bidding process based on power, energy capacity, and charging sufficiency constraints.

5.3.3 Slice-of-Day RA Product Definitions

The 24-hour profiles often vary across CCA filings, even for the same technology type. To simplify the analysis, we create standard RA product definitions with common profiles and parameters. The standard hydro RA product, for example, is the contracted-capacity weighted average of all hydro profiles across the CCAs (varying only by hour and month, but not by CCA). Similarly, we group batteries by duration (1, 2, 4, or 8 hour) and then use the weighted-average efficiency and duration for the standardized product. For Unspecified resources, we group them by the average capacity factor into three standard buckets: 5X24, 16X24, and 24X24. Within each of these buckets we use the capacity-weighted average profile.

5.3.4 Legacy Monthly RA

Data from the CCAs' SOD filings are also used in create the parameters necessary for simulating trade in the legacy RA program. We estimate each CCA's monthly RA obligation as the maximum hourly obligation. We estimate the monthly RA portfolio by converting the contracted nameplate to contracted net qualifying capacity using the 2024 technology factors by technology and month reported by the CAISO.[25]

5.3.5 External RA INC Prices

We estimate the cost of purchasing RA from external sources based on the recently observed capacity-weighted average price of RA sold to California LSEs during the period between the year-ahead filings (October 31, 2023) and the final RA filing date 45 days before the start of the operating month. CalCCA collects and cleans public RA transaction data from FERC Electronic Quarterly Reports. Assumed prices for purchases of external RA (ExternalRA INC) in each month are listed in Table 5. Because FERC EQR data only reports historical prices, we assume the same prices for analysis of both the 2024 test-year and 2025 binding year filings.

[25] CAISO. 2024. Final Net Qualifying Capacity for Compliance Year 2024.Available at: https://www.caiso.com/documents/final-net-qualifying-capacity-report-for-compliance-year-2024.xlsx

Month	Weighted-average RA price ($/kW-mo)
May	11.7
June	13.2
July	21.1
August	25.5
September	26.0

Table 5. Assumed prices for purchases of RA from external sources (ExternalRA INC)

5.3.6 External RA DEC Prices and ELCC factors

We assume that sales of excess resources to external markets would be based on the conversion of the nameplate capacity to an external RA product based on the ELCC factors announced by WRAP.[26]

Few sales for RA products to non-California loads are reported in the FERC EQRs, especially for the period between the year-ahead filing and operating month. Rather than set the price for sales of RA to external markets based on this thin volume of transactions, we instead assume that the price for ExternalRA DEC is 1/10th of the price of External RA INC, reported in Table 5.

[26] WRAP. 2024. *Review of Preliminary, Non-Binding WRAP Regional Data for the Current Participating Footprint for the Summer 2025 and Advisory Data for the Summer 2028.* January 31. https://www.westernpowerpool.org/private-media/documents/2024-1-16_Webinar_Summer_2025_and_2028_Data_updated_2024-12-12.pdf

Appendix A. Sensitivity of Gains from Trade to Changes in Portfolio Composition

Across California, LSE portfolios are transitioning toward a greater share of renewables and storage and away from thermal generation. In 2019, 67% of the resources shown for compliance with September resource adequacy compliance were from natural gas-fired generation and unspecified imports, while less than 0.2% was from battery storage. By 2024, the share of RA from natural gas and unspecified imports dropped to 56% while the share from energy storage and hybrid plants increased to over 17% of the September showings.[27] Pathways to achieving greenhouse gas emission reduction goals associated with California's SB 100 policy continue the trend of adding energy storage and reducing reliance on natural-gas generation.[28] This transition of the LSE portfolios impacts the gains from trade.

To quantify the impact, we evaluate the September 2025 gains from trade as thermal capacity is swapped out with 4-hour duration battery storage capacity, Figure 10. Prior to trade, we ensure replacement of thermal capacity with 4-hour battery does not worsen the LSE's maximum deficits by increasing the size of the replacement 4-hour battery when needed. As more of the thermal capacity is replaced, the size of the replacement battery relative to the thermal capacity also grows to maintain the same level of pre-trade compliance. We cap the ratio of replacement 4-hour battery to thermal capacity at 4:1. We therefore allow maximum pre-trade deficits to increase if it would otherwise require more than a 4:1 ratio of replacement 4-hour battery to thermal capacity.

[27] CAISO Historical Resource Adequacy Aggregate Data as of January 22, 2025: https://www.caiso.com/documents/historicalresourceadequacyaggregatedata.xlsx
[28] CEC *2021 SB 100 Joint Agency Report, Achieving 100 Percent Clean Electricity in California: An Initial Assessment* https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349

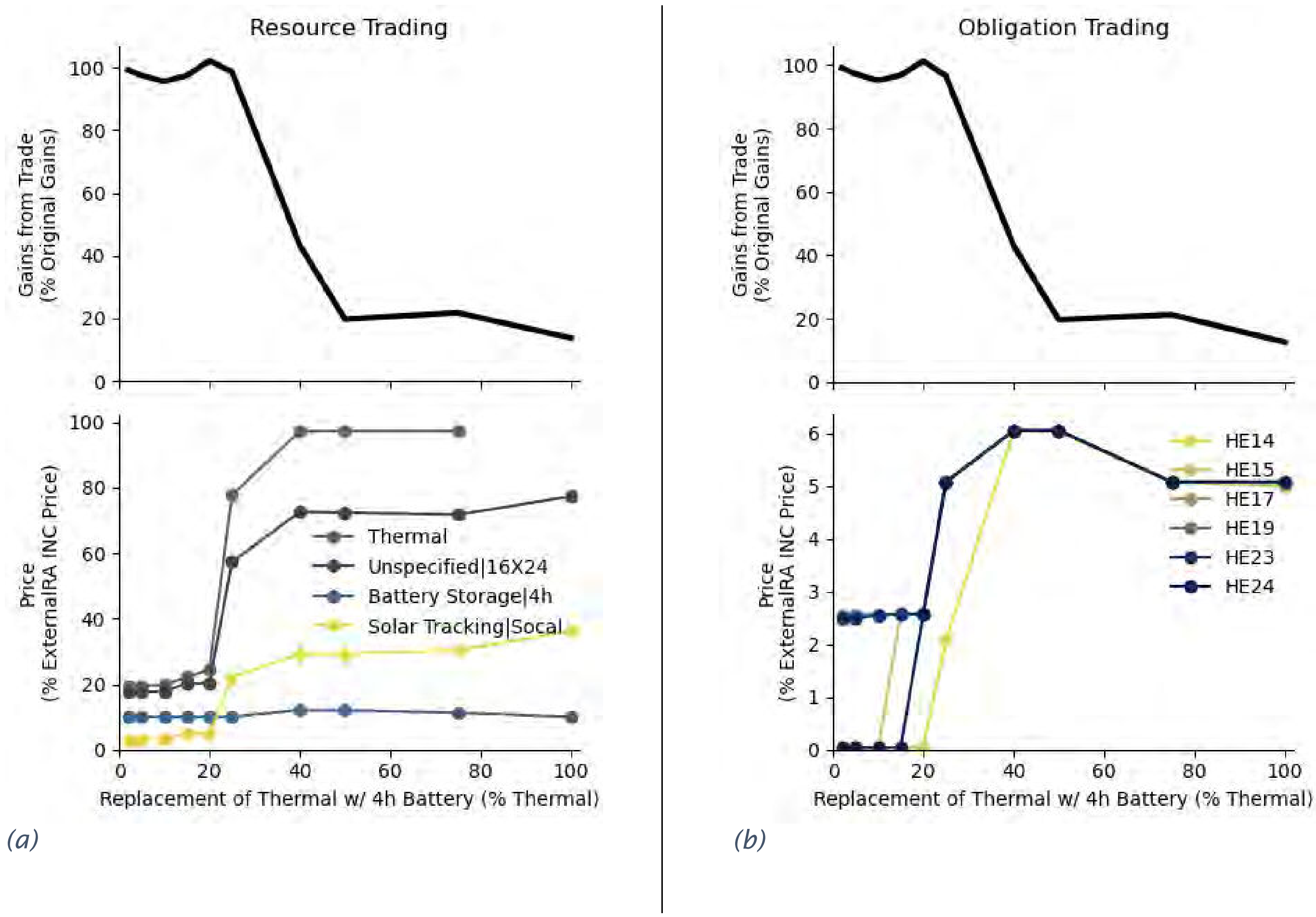


Figure 10. Sensitivity of September 2025 Gains from Trade to LSE Portfolio Composition with (a) SOD Resource Trading and (b) SOD Obligation Trading.

Modest shifts in the LSEs' portfolios from thermal capacity to 4-hour battery capacity of up to 25% of the original thermal capacity, have little impact on the gains from trade with both resource trading and obligation trading. After about 25% of the thermal capacity is replaced, however, the gains from trade rapidly decline. By the time all thermal capacity is replaced with 4-hour batteries, the gains from trade are only 10% of the gains with the original portfolio.

Changes in the internal prices of RA products with shifts in the portfolio composition help explain the reasons for the decline in the gains from trade. With the original portfolios, the aggregate accreditation of the resources in the LSE portfolios exceeded the aggregate obligations, allowing trades between LSEs to offset the need to purchase external RA. After about 20% of the thermal capacity is replaced by storage, the price of RA from thermal resources jumps to the level of the price of purchasing ExternalRA INC, indicating the aggregate surplus relative to obligations has disappeared. At this point trade between participants continues to be as high as with the original portfolios, though as thermal capacity is further removed, the ability for 4-hour battery storage to meet obligations begins to decline. At 20% reduction in thermal capacity, the price of solar and other sources of charging energy increases, and the price of hourly obligations outside of the traditional early evening peak net load hours also starts to increase. The broadening of hours where energy is needed to meet obligations reduce the diversity across LSEs and lowers the potential trading opportunities.

Future changes to the composition of LSE portfolios are uncertain. However, replacing 25% of the thermal resources by 4-hour battery storage would likely take multiple years. In the interim, mechanisms to enable trading between LSEs will continue to provide benefits comparable to the levels calculated with 2025 portfolios.

Appendix B. Calculating the Indirect Benefits of Reduced RA Demand

Mechanisms to enable trade between LSEs lowers demand for RA products from the external RA market. Lower demand for RA puts downward pressure on RA prices, indirectly lowering the costs of RA for all California LSEs. A general framework for quantifying these sorts of benefits to consumers comes from the "Demand Response Induced Price Reduction" or DRIPE that is used in Northeastern states as part of their evaluation of the costs and benefits of demand-side measures.[29] At a conceptual level, this indirect benefit of trade is illustrated in Figure 11. Small reductions in prices can create significant consumer savings when consumers purchase a large volume at market prices.

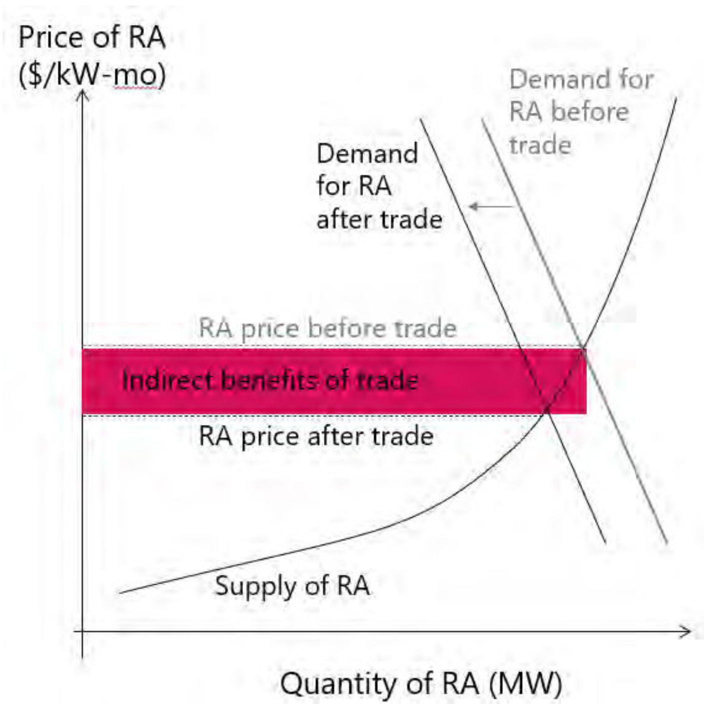


Figure 11. Illustration of the indirect benefits of trade from lower RA market prices

The indirect benefits are the area of the red rectangle. The height of the rectangle depends on the sensitivity of RA prices to RA demand (represented as *E*) and the reduction in RA demand attributable to trade (represented as *D*). The width of the rectangle is the volume of RA purchases that see the lower price due to decreased RA demand (represented as *Q*). Indirect benefits of trade are therefore *E*D*Q*.

One important caveat is that from an economic perspective, the price reduction effect is often seen as a transfer between suppliers and consumers rather than a net welfare

[29] State and Local Energy Efficiency Action Network (2015). *State Approaches to Demand Reduction Induced Price Effects: Examining How Energy Efficiency Can Lower Prices for All.* Prepared by: Colin Taylor, Bruce Hedman, and Amelie Goldberg from the Institute for Industrial Productivity under contract to Oak Ridge National Laboratory. Available at: https://www.energy.gov/sites/default/files/2021-07/SEEAction-DRIPE.pdf

gain. From a consumer perspective, however, lower prices do make consumers better off at least in the short run. In addition, the California Public Utilities Commission recently suggested that high prices in the RA market are due in part to the exercise of market power.[30] Under non-competitive market conditions, mechanisms that provide additional pathways for trade between participants can mitigate suppliers' ability to raise prices. Lowering prices through increasing the competitiveness of markets can create a net increase economic welfare by reducing the deadweight loss associated with non-competitive behavior.[31]

The most uncertain parameter is the sensitivity of RA prices to RA demand (*E*). To estimate the price sensitivity, we compare the weighted-average price of RA sold to California LSEs in September to our estimate of the net supply in September for the California resource adequacy market for 2019 to 2024. The net supply is based on an RA stack analysis which compares the available supply of RA to the demand for RA using the legacy capacity accreditation approach based on ELCC factors.[32] As a coarse approximation, the sensitivity of RA price to RA demand is estimated as the slope of simple regression across these data points. The resulting slope of -1.0, seen in Figure 12, represents a decrease in the weighted-average RA price of $1.0/kW-mo for every GW decrease in RA demand (*E* = $1.0 kW/mo per GW).

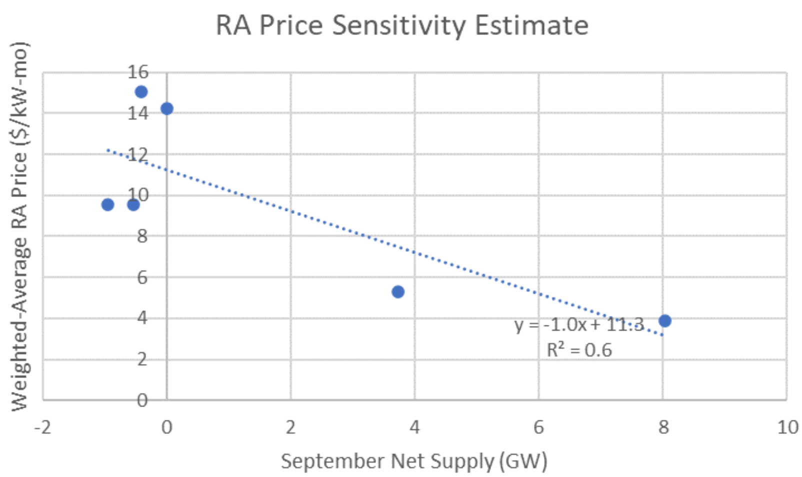


Figure 12. Approximation of sensitivity of RA prices to RA demand using September data from 2019-2024

The reduction in RA demand resulting from trade (*D*) is a direct result of our analysis of the CCA's 2025 year-ahead RA filings for the months of May through September, with

[30] Energy Division Staff Report of the 2024-2025 Resource Adequacy Market Price Benchmark (Feb., 26, 2025). Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M557/K608/557608990.PDF
[31] For an example of deadweight loss arising from non-competitive behavior in California electricity market see Borenstein, S., Bushnell, J.B. and Wolak, F.A., 2002. Measuring market inefficiencies in California's restructured wholesale electricity market. *American Economic Review*, *92*(5), pp.1376-1405.
[32] CalCCA. 2024. *California's Constrained Resource Adequacy Market: Ratepayers Left Standing in a Game of Musical Chairs.* January. : Available at: https://cal-cca.org/wp-content/uploads/2024/02/CalCCA-Stack-Analysis-2023-2026-updated-01_16_24-.pdf

obligations scaled to 100% the final obligations. Across the five summer months, we find that trade between CCA lowers demand for external RA (ExternalRA INC) by roughly 500 MW per month (*D* = 0.5 GW per mo). Additional details on the reduction in demand for external RA with trade in each month are provided in Appendix C.

Finally, we estimate the volume of RA that would be purchased at lower prices due to the reduction in RA demand (*Q*). This is again a difficult number to quantify with precision. We observe RA purchases by California LSE's of about 20 GW of capacity products on average across summer months in the FERC EQR dataset (*Q* = 20 GW each month).

Altogether, the indirect benefits of trade between the CCAs (*E*D*Q)* total approximately $50 million per year.

Appendix C. Gains from Trade in All Months

Table 1 and Table 2 detail the gains from trade across different policy environments using data from September 2024 and 2025. For completeness, we present the calculations for all months in Table 6.

Month and Year		Scenario	Short Position (a.k.a., ExternalRA INC) Before Trade (MW)	After Trade (MW)	Gains from Trade ($M)	Internal Trades Volume (MW)	Count	Average Connections	Monetary Transfer ($M)
June 2024	I.	Resource: ELCC	258	0	3.7	257	20	1.8	0.3
	II.	Obligation: ELCC	258	0	3.7	257	21	1.9	0.3
	III.	Resource: SOD	433	0	6.9	2,921	124	10.3	2.4
	IV.	Obligation: SOD	433	0	6.9	5,632	172	14.3	0.5
	III.*	Uncoordinated Resrc.: SOD	433	123	4.1	321	21	1.8	N/A
	IV.*	Uncoordinated Oblg.: SOD	433	6	5.6	3,752	112	9.3	N/A
September 2024	I.	Resource: ELCC	467	0	12.3	467	22	1.9	1.2
	II.	Obligation: ELCC	467	0	12.3	467	22	1.8	1.2
	III.	Resource: SOD	926	269	17.3	2,642	185	15.4	23.4
	IV.	Obligation: SOD	926	261	17.3	3,591	150	12.5	11.7
	III.*	Uncoordinated Resrc.: SOD	926	748	4.7	185	7	1.8	N/A
	IV.*	Uncoordinated Oblg.: SOD	926	645	7.2	4,654	122	10.2	N/A
May 2025	I.	Resource: ELCC	31	0	0.3	31	3	1.0	0.0
	II.	Obligation: ELCC	31	0	0.3	31	2	1.0	0.0
	III.	Resource: SOD	5	5	0.0	0	0	0.0	0.0
	IV.	Obligation: SOD	5	5	0.0	0	0	0.0	0.0
	III.*	Uncoordinated Resrc.: SOD	5	0	0.1	5	3	1.2	N/A
	IV.*	Uncoordinated Oblg.: SOD	5	0	0.1	14	7	1.8	N/A
June 2025	I.	Resource: ELCC	289	0	5.7	288	20	1.8	0.4
	II.	Obligation: ELCC	289	0	5.7	288	20	1.8	0.4
	III.	Resource: SOD	252	0	6.2	2,325	158	13.2	2.3
	IV.	Obligation: SOD	252	0	6.2	4,244	155	12.9	0.6
	III.*	Uncoordinated Resrc..: SOD	252	0	3.3	263	15	1.4	N/A
	IV.*	Uncoordinated Oblg.: SOD	252	1	3.3	1,923	87	7.3	N/A
July 2025	I.	Resource: ELCC	590	0	13.4	590	23	1.9	1.2
	II.	Obligation: ELCC	590	0	13.4	590	23	1.9	1.2
	III.	Resource: SOD	674	0	16.4	2,255	177	14.7	4.2
	IV.	Obligation: SOD	674	0	16.3	8,201	171	14.2	1.8
	III.*	Uncoordinated Resrc.: SOD	674	83	12.5	616	20	1.9	N/A
	IV.*	Uncoordinated Oblg.: SOD	674	49	13.1	6,297	134	11.2	N/A
August 2025	I.	Resource: ELCC	480	0	13.3	480	23	1.9	1.2
	II.	Obligation: ELCC	480	0	13.3	480	23	1.9	1.2
	III.	Resource: SOD	623	0	18.0	3,620	128	10.7	6.5
	IV.	Obligation: SOD	623	0	17.9	7,564	181	15.1	2.3
	III.*	Uncoordinated Resrc.: SOD	623	163	11.7	478	22	1.9	N/A
	IV.*	Uncoordinated Oblg.: SOD	623	40	14.8	4,839	127	10.6	N/A
September 2025	I.	Resource: ELCC	541	0	15.1	541	22	1.9	1.4
	II.	Obligation: ELCC	541	0	15.1	541	22	1.8	1.4
	III.	Resource: SOD	727	0	21.5	3,500	167	13.9	6.7
	IV.	Obligation: SOD	727	0	21.4	8,062	163	13.6	2.4
	III.*	Uncoordinated Resrc.: SOD	727	182	14.2	561	16	1.9	N/A
	IV.*	Uncoordinated Oblg.: SOD	727	27	18.1	6,613	120	10.0	N/A

Table 6. Summary of trade between CCAs across policy environments with data from all months

March 3, 2026

VIA ELECTRONIC MAIL

Energy Division
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Email: EDTARIFFUNIT@CPUC.CA.GOV

Re: California Community Choice Association's Comments on Draft Resolution E-5440 - Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric Remediation Plans for Integration Capacity Analysis

Dear Energy Division,

Pursuant to Rule 14.5 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure,[1] and the accompanying Cover Letter to the February 11, 2026, Draft *Resolution E-5440*[2] (Draft Resolution) approving, with modifications, the Investor-owned Utilities' (IOU)[3] Integration Capacity Analysis (ICA) remediation plans and baseline reporting, California Community Choice Association[4] (CalCCA) submits these comments on the Draft Resolution.

I. INTRODUCTION

CalCCA appreciates the Commission's continued efforts to improve the reliability and usefulness of the ICA. Decision (D.) 24-10-030 states that "the ICA quantifies the maximum amount of power that can be injected into, or drawn from, the distribution system while requiring

[1] *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021).

[2] Draft *Resolution E-5440 Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric Remediation Plans for Integration Capacity Analysis* (Feb. 11, 2026).

[3] The IOUs as referred to herein are Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E).

[4] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

minimal to no distribution mitigations, upgrades, or operational restrictions."[5] Up-to-date ICA results that are aligned with engineered values provide customers and developers with valuable information for siting and designing new load and generation. While the Draft Resolution addresses many shortcomings of the IOUs' proposed ICA Remediation Plans, it does not go far enough in requiring the IOUs to implement essential measures to ensure ICA data is complete and aligned with engineered values. Specifically, the Commission should modify the Draft Resolution to:

- Strengthen the requirements for aligning the ICA results with engineered values, including:
  - Shortening the timeline for IOUs to file an Advice Letter (AL) proposing a methodology to address misalignment between ICA and engineered values; and
  - Requiring SCE to file an AL proposing near-term fixes for the Load ICA.
- Strengthen the requirement for the monthly ICA refresh of changed circuits (monthly refresh), including:
  - Changing the language in the Draft Resolution from "the IOUs should strive to update all triggered circuits every month" to "the IOUs must update all triggered circuits every month;"
  - Establishing criteria for exceptions from meeting the monthly refresh requirement;
  - Establishing a reporting requirement for violating the monthly refresh; and
  - Establishing an enforcement mechanism for repeated violations of the monthly refresh.
- Require SDG&E to cease over-redacting ICA data fields unless SDG&E provides specific evidence that the data violates the 15/15 Rule.[6]

II. THE COMMISSION SHOULD STRENGTHEN THE REQUIREMENTS FOR ALIGNING THE ICA RESULTS WITH ENGINEERING VALUES

The Commission should revise the Draft Resolution to strengthen the requirements for aligning the ICA results with engineered values. The IOUs have been unable to consistently produce usable and dependable Load and Generation ICA values, rendering those values unreliable. While the Draft Resolution takes steps to enhance tracking and reporting to improve

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5 D.24-10-030, *Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Portals, and Integration Capacity Analysis Maps* (Oct. 23, 2024), at 8.

6 *See* Draft Resolution, at 5, Footnote 12 (defining the 15/15 Rule as a "data set containing at least 15 customers with no customer receiving no more than 15 percent of the load.").

ICA usability, it should adopt the following recommendations as it does not go far enough in requiring timely ICA improvements and fails to specifically address SCE's Load ICA shortcomings.

First, the Commission should shorten the timeline for IOUs to file a joint AL proposing a methodology to address misalignment between ICA and engineered values. The Draft Resolution defines alignment as "the degree to which ICA results reflect the engineering outcomes of actual interconnection or energization applications, as determined by the distribution engineer processing those applications," referring to the latter as the engineered value.[7] The Draft Resolution then establishes requirements for the IOUs to track and report on scenarios in which the ICA and engineered values are aligned (concordant) or misaligned (discordant) to understand the root causes of any misalignment and determine corrective action. However, the Draft Resolution gives the IOUs between 18 and 30 months to file a joint AL proposing ICA improvements to address discordance.

While the ICA discordance tracking and reporting requirements are new, the misalignment between ICA and engineered values is a longstanding issue that has been reported in the IOUs' Biannual ICA Reports and discussed during quarterly ICA workshops. Providing the IOUs 18 to 30 months to submit an AL recommending improvements could delay implementation of measures to correct discordance by three or more years. The Commission should revise the timeline for filing the joint AL to between six and 12 months to ensure the timely resolution of the longstanding ICA misalignment issues.

Second, the Commission should require SCE to file an AL to propose near-term fixes for the Load ICA. The protests of the Interstate Renewable Energy Council (IREC)[8] and the Public Advocates Office of the California Public Utilities Commission (Cal Advocates)[9] detail known issues affecting the usability of SCE's ICA values, including the high number of circuits with zero Load ICA hosting capacity. The Draft Resolution fails to address this issue and instead focuses on tracking and reporting on ICA misalignment. The issue of SCE's high number of circuits with zero Load ICA has been a longstanding and well-documented concern and should be addressed in the Draft Resolution. The Commission should therefore require SCE to file an AL within 60 days of the adoption of the Draft Resolution describing how it will ensure that the Load ICA values align with engineering values and address the zero Load ICA issue.

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7 Draft Resolution, at 16.

8 *See IREC's Protest of Utility Companies' ALs – PG&E AL 7686-E (ICA Remediation Plan); SDG&E AL 4710-E (Addressing Remediation Plan for ICA), and SCE AL 5614-E (ICA Remediation Plan) – Filed in Compliance with D.24-10-030* (Sep. 15, 2025), at 3-12.

9 *See* Cal Advocates' *Protest to SCE's Tier 3 AL 5614-E, PG&E's Tier 3 AL 7686-E, and SDG&E's Tier 3 AL 4710-E: Integration Capacity Analysis Remediation Plans Pursuant to D.24-10-030* (Sept. 15, 2025), at 5-6.

III. THE REQUIREMENT FOR THE MONTHLY ICA REFRESH OF CHANGED CIRCUITS SHOULD BE STRENGTHENED

The Commission should revise the Draft Resolution to strengthen the requirements for the monthly refresh of ICA for changed circuits. The ICA values for individual circuits change as new customer load and generation come online, requiring the IOUs to refresh these values for affected circuits. The Draft Resolution agrees with IREC and Cal Advocates that the ICA results for changed circuits must be updated monthly.[10] However, the Draft Resolution states that the IOUs "*should strive to* update all triggered circuits every month," and acknowledges exceptions that may prevent the monthly refresh.[11] Further, the Draft Resolution does not propose any enforcement measures if an IOU repeatedly fails to meet the monthly refresh requirement. Without a specific requirement for IOUs to refresh ICA values on changed circuits, along with specific criteria for exceptions and a means to enforce compliance, the ICA values may not provide meaningful value to customers or developers. The Draft Resolution should be modified to address these concerns.

First, the language in the Draft Resolution should be revised to state that the IOUs "*must* update all triggered circuits every month," rather than the IOUs merely "should" provide the update. This removes ambiguity and conveys the necessity of monthly refreshing of the ICA values. Requiring a monthly refresh will provide clarity around the age of ICA values, significantly improving the usability of the maps. *Second*, the Draft Resolution should be revised to provide guidance on handling exceptions that prevent refreshing ICA values. This could include adjusting the refresh timing relative to model runs to minimize exceptions due to model run times, so that only circuits triggered a certain number of days in advance of a refresh are included. *Finally*, the Draft Resolution should include a specific requirement for the percentage of changed circuits to be refreshed monthly, reporting requirements for the IOUs to explain deviations from this requirement, and penalties for continued failure to meet this criterion.

IV. THE COMMISSION SHOULD REQUIRE SDG&E TO CEASE REDACTING ALL ICA FIELDS THAT COMPLY WITH THE 15/15 RULE

The Commission should revise the Draft Resolution to require SDG&E to cease over-redacting ICA data that do not reveal customer data. The Draft Resolution agrees with IREC and Cal Advocates that "SDG&E has failed to comply with Commission requirements for redaction methods for ICA" consistent with the 15/15 Rule for protecting customer information.[12] The Draft Resolution correctly identifies "Load Profile" and "Op Gen Flex" as data fields that could reveal customer information, yet it only directs SDG&E to cease redacting the "Total Generation" and "Existing Generation" data fields. However, SDG&E is redacting data fields that do not reveal customer information, including the "Integration Capacity NO Operational Flexibility" and "Integration Capacity" fields. These additional data fields provide necessary

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[10] Draft Resolution, at 14.
[11] *Id*. (emphasis added)
[12] *Id*.

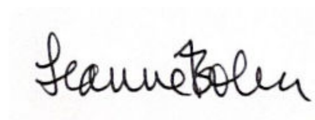
information for customers siting electric vehicle charging and other new loads or generation. The Draft Resolution should be modified to limit SDG&E's redaction to only data fields that reveal customer information consistent with the 15/15 Rule.

V. CONCLUSION

CalCCA appreciates the Commission's thoughtful and careful consideration of these comments.

Respectfully submitted,

CALIFORNIA COMMUNITY CHOICE ASSOCIATION



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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.25-10-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S TRACK 1 PROPOSALS ON TRANSACTABILITY ISSUES

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March 3, 2026

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APPENDIX A

SUMMARY OF RECOMMENDATIONS[1]

CalCCA proposes the Commission:

- Adopt hourly load obligation trading to allow LSEs to transact at the same granularity as the SOD requirements to promote affordability while maintaining reliability requirements;
- Invest in the software and systems to automate the RA validation process, given it appears the existing manual process is interfering with the adoption of fully vetted and well-supported policy proposals; and
- If the Commission declines to invest in automation of the RA validation process, adopt temporary guardrails to aid in assessing compliance.

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1 Acronyms used herein are defined in the body of this document.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.25-10-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S TRACK 1 PROPOSALS ON TRANSACTABILITY ISSUES

California Community Choice Association[2] (CalCCA) submits these proposals pursuant to the *Assigned Commissioner's Scoping Memo and Ruling*[3] (Scoping Ruling), dated December 12, 2025, and *Administrative Law Judge's Ruling on Energy Division's Transactability Report and Modifying Track 1 Schedule*,[4] dated February 24, 2026.

I. INTRODUCTION

Energy Division's *Report on Transactability within the Slice of Day Resource Adequacy Framework*,[5] authorized in Decision (D.) 25-06-048,[6] severely misses the mark in finding that,

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2 California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

3 *Assigned Commissioner's Scoping Memo and Ruling*, Rulemaking (R.) 25-10-003 (Dec. 12, 2025).

4 *Administrative Law Judge's Ruling on Energy Division's Transactability Report and Modifying Track 1 Schedule*, R.25-10-003 (Feb. 24, 2026).

5 *Report on Transactability within the Slice of Day Resource Adequacy Framework*, R.25-10-003 (Feb. 2026) (Report).

6 D.25-06-048 authorizes Energy Division to, "conduct an evaluation after a full year of [SOD] implementation to assess the need, benefits, and feasibility of an hourly load obligation trading

"[g]iven the limited evidence of need, uncertain magnitude of benefits, and heightened implementation risks, … the potential gains do not outweigh the added complexity and risk of unintended consequences," of hourly load obligation trading.[7] The Report:

- Applies the wrong standard in its assessment, focusing on whether the measure is "necessary" rather than seizing the opportunity to adopt a tool that will bring greater efficiency and affordability to resource adequacy (RA) procurement as market conditions change;
- Materially understates the potential affordability benefits this optimization tool could deliver for ratepayers by ignoring the increased cost resulting from slice-of-day (SOD) implementation;
- Presents a "penny wise, pound foolish" approach to RA regulation, failing to acknowledge the criticality of automating RA compliance; and
- Continues to seek cover behind potential "unintended consequences".

Energy Division's recommendation to continue monitoring market performance leaves CalCCA's fully vetted and well-supported proposal with the potential to offer significant cost savings hanging in the balance at ratepayers' expense.

As discussed below, the Energy Division assertions are not well supported and do not address the core issue hourly load obligation trading is intended to address: the exorbitant costs caused by making the Commission's RA program exceedingly difficult to comply with, while at the same time assessing severe penalties on those who cannot comply.[8] CalCCA addresses several shortcomings of the Report below and will provide a more detailed response in its opening comments due on March 16, 2026.

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mechanism. D.25-06-048, *Decision Adopting Local Capacity Obligations for 2026-2028, Flexible Capacity Obligations for 2026, and Program Refinements*, R.23-10-011 (June 26, 2025), Ordering Paragraph 11, at 125.

[7] Report at 7.

[8] These penalties include a financial consequence with a multiplier effect for multiple infractions and, for ESPs and CCAs, a restriction on expansion plans. The severity of these penalties has been readily noticed by LSEs, who will likely procure expensive RA even if it is not necessary to meet their reliability requirements.

Hourly load obligation trading offers an opportunity to chip away at the affordability crisis at a time when the Commission should be seizing every opportunity to reduce procurement costs. The inability for load-serving entities (LSE) to transact at the same granularity as the compliance requirement forces LSEs to procure more RA than needed to meet pre-determined reliability targets, unnecessarily driving up RA procurement costs that fall directly on ratepayers. CalCCA's analysis, attached to this proposal as Appendix A, suggests hourly obligation trading could save all LSEs $144-$179 million each year. At a time when Californians are struggling to manage rapidly increasing electric bills, dismissing a proposal with such significant potential for cost savings is misguided.

The proposal also recommends guardrails for the initial year of implementation to help manage new administrative tasks that may be necessary to validate showings with load obligation trades. CalCCA is concerned that Energy Division's continued rejection of hourly load obligation trading is driven largely by the fact that the existing RA compliance mechanisms are no longer sufficient to operate the SOD program. The RA program has become increasingly complex in its over 20-year history, and continued reliance on spreadsheets for validation should not be a barrier to the adoption of sound policy proposals. Given the significant potential benefits of hourly load obligation trading, the Commission should invest in the necessary tools to make the validation process more automated and manageable for Energy Division staff. Still, if the Commission is concerned with the amount of administrative effort this proposal would create, guardrails could help keep those efforts manageable.

In summary, CalCCA recommends that the Commission:

- Adopt hourly load obligation trading to allow LSEs to transact at the same granularity as the SOD requirements to promote affordability while maintaining reliability requirements;

- Invest in the software and systems to automate the RA validation process, given it appears the existing manual process is interfering with the adoption of fully vetted and well-supported policy proposals; and
- If the Commission declines to invest in automation of the RA validation process, adopt temporary guardrails to aid in assessing compliance.

II. THE REPORT DIMINISHES THE PROBLEMS WITH SOD AND DOES NOT ADDRESS THE CORE AFFORDABILITY ISSUE HOURLY LOAD OBLIGATION TRADING IS INTENDED TO ADDRESS

The Report attempts to answer the question of whether transactability issues exist by evaluating whether the measure was necessary to achieve compliance with 2025 RA requirements. The Report finds that "LSEs were able to procure and trade sufficient capacity to meet hourly obligations, with no evidence of unresolved deficiencies or structural market barriers attributable to SOD."[9] Using this information to imply that there is insufficient justification for hourly load obligation trading ignores the core affordability issue hourly load obligation trading is intended to address. This rationale also ignores the potential for capacity scarcity to return in the future causing an apparent shortfall based on the compliance framework while no actual system reliability gap exists. CalCCA demonstrated this effect with the 2024 test case. While the Report states that over-procurement was "modest" because September 2025 month-ahead showings in the tightest hour showed surplus procurement of 262 megawatts (MW),[10] this does not tell the whole story.

In 2025, LSEs procured significantly more RA capacity than needed to meet their compliance obligations when compared to prior years. This phenomenon can be observed by evaluating aggregated historical RA procurement data from the California Independent System Operator (CAISO), as discussed below. To be clear, CalCCA does not contend that the lack of

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9 Report at 6.

10 *See* Report at 34.

transactability has caused ***all*** of the incremental procurement observed. Rather, if the new SOD RA mechanism is going to force the procurement of significantly more RA than previously, the system must be made as efficient as possible to avoid unnecessary costs, given the magnitude of the change.

The CAISO annually presents data on the resources shown to meet RA needs.[11] The CAISO data includes the years 2019 through 2025. The CAISO data shows a significant increase in the number of RA resources shown starting in 2025, the first year of SOD implementation. The CAISO uses a single daily value for RA and while SOD uses hourly values, the data is informative in showing the significant increase in the amount of RA shown. This increase comes at a cost. As shown in Figure 1, below, using the 2025 final market price benchmark (MPB) for RA of $11.21/ kilowatt (kW)-month[12], the increased cost of SOD is nearly $339 million for the months of May through October.

Figure 1: Average Procurement Relative to RA Target

Figure 1. Average Procurement to RA Target

		May	June	July	August	September	October
Prior to SOD (% of target shown)	2019 -2024	103%	104%	102%	101%	100%	103%
SOD (% of targe shown)	2025	109%	118%	118%	109%	114%	108%
Difference		6%	14%	15%	8%	14%	5%
2025 RA Requirement (MW)		38,996	47,496	52,349	50,856	52,091	41,872
Amount of Procurement in 2025 Beyond the Normal Procurement in 2019-2024 (MW)		2,384	6,512	8,002	4,170	7,219	1,948
2026 RA Market Price Benchmark ($/kW-mo)		$ 11.21	$ 11.21	$ 11.21	$ 11.21	$ 11.21	$ 11.21
Total Incremental Cost ($/mo)		$ 26,720,203	$ 73,000,172	$ 89,698,883	$ 46,748,335	$ 80,929,640	$ 21,837,678

Total Incremental Cost
$ 338,934,910

California's customers served by LSEs that must comply with the Commission's SOD regulations should be afforded every opportunity possible to efficiently transact given the significant impact on affordability that the move to SOD has caused.

11 *See* CAISO Historical Resource Adequacy Showings Aggregate Data.
12 *See* CPUC MPB Calculations 2025 (Oct. 1, 2025) (2025 MPBs).

Data provided in the Report similarly provides evidence of this over-procurement, well beyond the "modest" 262 MW the Report identifies. *First*, the net qualifying capacity (NQC) of resources under contract in September 2025 "increased by approximately 3,725 MW (8.2 percent)"[13] relative to 2024, while requirements went down by 1,555 MW (3.1 percent),[14] a net gain of 5,280 MW of NQC relative to 2024. *Second*, the achieved reserve margin in September 2025 was far above the required 17 percent. Because reliability is a system attribute, the achieved reserve margin depends on the total contracted resources and the total system requirements. The storage contracted for September 2025 could have contributed to meeting system RA at much greater levels than suggested in the Report. The Report dispatches storage only to meet the requirements and then allocates the 16,269 MW hours of "unused storage" evenly throughout the day.[15] Alternatively the "unused storage" could have been allocated to maximize the avoidable thermal generation. Allocating the "unused storage" in the manner shown in Figure 2, below, achieves a reserve margin of at least 23 percent in all hours of September 2025 or allows 2,175 MW of thermal capacity to be removed while maintaining at least a 17 percent reserve margin in all hours.[16] At the current RA MPB, 2,175 MW of capacity beyond that needed to meet RA is valued at $24 million for this single month.[17] If instead we assume that the 2,175 MW of highest priced RA transactions between the year-ahead and month-ahead deadlines could have been avoided, the savings would be almost $37 million for the single month.[18]

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[13] Report at 21.

[14] Report at Table 7 (comparing 2024 requirements to 2025 HE18 requirements).

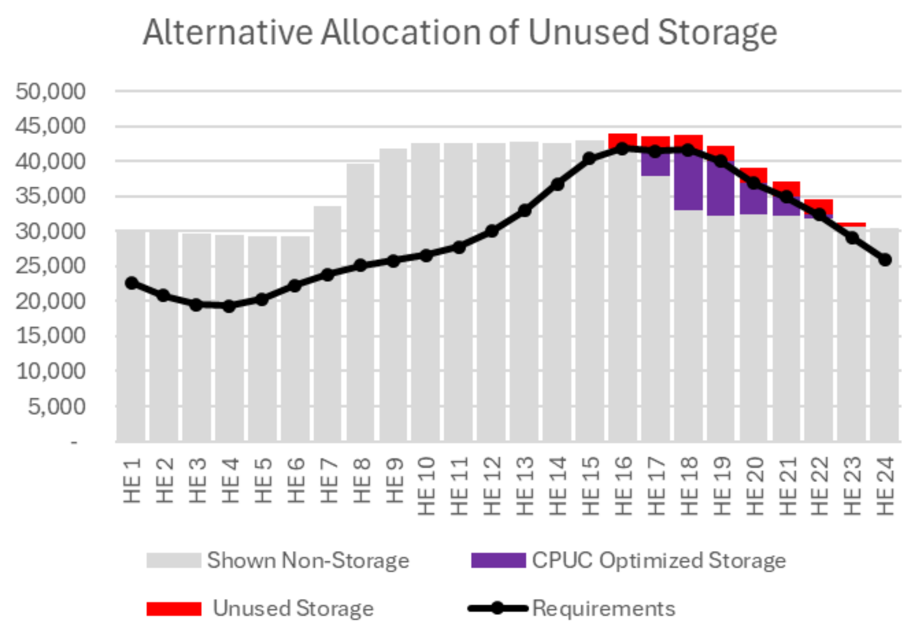
[15] Report at 28.

[16] CalCCA verified that the charging energy remains sufficient for the storage even after removing 2,175 MW of thermal capacity from the September 2025 portfolio.

[17] MPB $11.21/kW-month * 2,175 MW * 1,000 (conversion of MW to kW) = $24,381,750. *See* 2025 MPBs.

[18] Capacity transactions are from FERC electronic quarterly reports downloaded from https://eqrreportviewer.ferc.gov/ and cleaned by CalCCA. Included transactions have California LSE as

Figure 2. Alternative Allocation of Unused Storage Achieves 23% Reserve Margin in September 2025



The Report states that "this incremental margin is not simply "excess" capacity, but represents additional contracted, deliverable resources that may provide value under conditions that exceed forecasted load."[19] This implies an intent to ensure reliability by making compliance exceedingly difficult and allowing the system to lean on LSEs that must procure excess RA to meet their SOD requirements, rather than through transparent and defined reliability standards. The Commission is obligated through Public Utilities Code section 380(h)(4)[20] to ensure that the RA program "can reasonably maintain a standard measure of reliability, such as a one-day-in-10-year loss-of-load expectation or a similarly robust reliability metric adopted by the commission..." The Commission should meet the objectives of section 380 by planning for pre-

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the buyer for delivery in September 2025 with a trade date between November 1, 2024, and July 31, 2025. CalCCA sorted these transactions from highest to lowest price and summed the transaction cost for the highest priced transactions up to a cumulative capacity of 2,175 MW.

19 Report at 35.

20 All subsequent code sections cited herein are references to the California Public Utilities Code unless otherwise specified.

determined reliability targets established through the Commission's loss-of-load expectation study process and planning reserve margin, rather than by imposing transactional barriers that force over-procurement.

Energy Division finds that the potential gains of hourly load obligation trading do not outweigh "risk of unintended consequences."[21] This is a red herring. Throughout the five years of discussing hourly load obligation trading, no party has been able to articulate an "unintended consequence" that CalCCA has not addressed.[22] If there are "unintended consequences" that arise following the implementation of hourly load obligation trading, the Commission has the power to modify the rules to close any reliability or compliance gaps that may emerge. The Commission should not decline to adopt measures with demonstrated affordability benefits based upon undefined "unintended consequences."

III. HOURLY LOAD OBLIGATION TRADING SHOULD BE ADOPTED TO ALLOW LSES TO TRANSACT AT THE SAME GRANULARITY AS THE SOD REQUIREMENTS

The Commission should adopt CalCCA's proposal in R.23-10-011 to allow LSEs to transact load obligations on an hourly basis.[23] Under existing rules, LSEs are restricted in how they can transact with other entities to ensure RA compliance. Adjustments to an LSE's portfolio are limited to transacting a product for all hours it is available for the whole month, even though obligations are unique to each hour. This mismatch means LSEs must purchase more RA than they need to meet their obligations, creating artificial market scarcity and unnecessarily driving up RA demand (and prices). CalCCA's proposal would provide LSEs with the flexibility to

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21 Report at 7.

22 *See California Community Choice Association's Opening Comments on the Proposed Decision*, R.23-10-011 (June 11, 2025).

23 *See California Community Choice Association's Proposals on Track 3*, R.23-10-011 (Jan. 17, 2025) (CalCCA Track 3 Proposals), at 8-18.

transact load obligations at the hourly level in order to reduce costs to consumers. If RA requirements are set on an hourly basis, some or all of the products should be transactable on an hourly basis.

CalCCA's analysis of 2025 year-ahead RA filings submitted in R.23-10-011 demonstrates significant affordability benefits to increasing the transactability of the RA SOD program.[24] CalCCA expects that all LSEs would benefit from a load obligation trading structure and expects that transactions among investor-owned utilities, community choice aggregators (CCA), and electric service providers (ESP) would occur. The larger the market, the more efficient the outcome. Since its analysis of 2025 year-ahead RA filings, CalCCA has issued a Whitepaper, attached as Appendix A, further documenting the benefits of hourly trading by simulating competitive market trades between LSEs. CalCCA has also performed additional analysis on 2025 month-ahead RA showings from CCAs demonstrating that, averaged across five peak summer months, CCAs in aggregate, purchased about 540 MW more RA capacity each month than they would have needed had a mechanism like hourly load obligation trading been available.[25] At the 2025 final RA MPB,[26] those excess purchases cost CCA consumers more than $30 million in the summer of 2025. If the tight market conditions observed in the summer of

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[24] *See* CalCCA Track 3 Proposals, at 8-11.

[25] To quantify the excess RA capacity that could have been avoided with hourly load obligation trading, CalCCA first calculated the amount of thermal capacity each individual CCA could have sold from their final month-ahead portfolio, while still remaining compliant. To perform this calculation, CalCCA adjusted the way that an individual CCA would show its contracted storage capacity such that it maximized the amount of thermal capacity that could be removed. Next, CalCCA aggregated all CCA portfolios and requirements, and recalculated the excess thermal capacity from the aggregate showing. The aggregation is a proxy for what could be achieved through frictionless trade between LSEs, which is enabled through a policy like hourly load obligation trading. Finally, the excess RA capacity that could be avoided through hourly load obligation trading was calculated as the difference between the excess of the aggregate and the excess for individual CCAs. On average across the five peak months from May to September, CalCCA observed 540 MW of excess thermal capacity that could have been avoided with hourly load obligation trading.

[26] *See* 2025 MPBs.

2024 arise again, as suggested by the Commission's recommendation for additional procurement in R.25-06-019,[27] demand for capacity and RA prices could rise again to the levels observed in 2024. The CCAs' excess RA purchases valued at the 2024 RA prices described in CalCCA's RA Whitepaper would cost CCA customers nearly $51 million. Using similar assumptions about the indirect price reduction effect from lowering RA demand and the potential benefit of hourly load obligation trading across all Commission-jurisdictional LSEs, CalCCA's findings from the 2025 month-ahead RA data suggest hourly obligation trading could save all LSEs $144-$179 million each year. These savings could then directly improve affordability for ratepayers.

Throughout R.23-10-011, CalCCA thoroughly addressed all critical concerns with its proposal expressed by Energy Division and parties by: (1) explaining why existing trading mechanisms are insufficient for the SOD program; (2) proposing a potential guardrail that would limit the amount of load an LSE can trade (of which CalCCA expands upon below); and (3) addressing how penalties would apply to LSEs using load obligation trades that are found noncompliant.[28] The proposal received support from a broad range of stakeholders, including LSEs, suppliers, ratepayer advocates, and environmental groups,[29] and as described above, is supported by extensive analysis of cost benefits. For these reasons, the Commission should adopt hourly load obligation trading.

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27 *Administrative Law Judge's Ruling Seeking Comments on Electricity Portfolios for 2026-2027 Transmission Planning Process and Need for Additional Reliability Procurement*, R.25-06-019 (Sept. 30, 2025).

28 *See California Community Choice Association's Opening Comments on the Proposed Decision*, R.23-10-011 (June 11, 2025).

29 *See* Opening Comments filed in R.23-10-011 on or about March 3, 2025: American Clean Power – California Opening Comments, at 15; Alliance for Retail Energy Markets Opening Comments, at 3; The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) Opening Comments, at 10-11; Clean Energy Buyers Association Opening Comments, at 7; Center for Energy Efficiency and Renewable Technologies Opening Comments, at 3; California Environmental Justice Alliance Opening Comments, at 11- 12; Hydrostor, Inc. Opening Comments, at 9; Microsoft Corporation Opening Comments, at 12-13; and Shell Energy North America (US), L.P. Opening Comments, at 4-5.

IV. THE COMMISSION SHOULD INVEST IN SOFTWARE AND SYSTEMS TO AUTOMATE THE RA VALIDATION PROCESS

Energy Division's manual RA validation process may result in the Commission passing up significant efficiency improvements over concerns with the administrative effort they would add to existing processes. Currently, all LSEs submit to the Commission a RA showing in Excel on an annual and monthly basis. Over the 20-plus year history of the RA program, the Excel spreadsheet has grown to include 14 visible sheets, 18 hidden sheets (used to perform calculations and validations), six macros, and requires a 58-page user guide to navigate. Energy Division's continued rejection of hourly transactability as an affordability measure appears largely driven by the fact that the existing RA compliance review processes are no longer sufficient to operate the SOD program. The RA program procures billions of dollars of capacity annually and carries strict fines that can be up to $26.64/kw-month. In addition, the program is a major component in grid reliability. With the program's growing complexity, including hourly verification, customized storage showings by hour, and charging sufficiency verifications, the compliance program has outgrown spreadsheets. The RA program needs a more robust and user-friendly compliance program to evaluate RA showings quickly and effectively.

Continued reliance on spreadsheets for validation of an increasingly complex RA program should no longer be a barrier to the adoption of sound policy proposals. The Commission regularly authorizes millions of dollars of IT work for a variety of purposes; for example, Item 6 on the February 26, 2026, Consent Agenda contemplates a $2.6 million increase for improvements to the California Distributed Generation Statistics Website. Given the critical importance of the RA program – supporting both reliability and affordability -- the Commission should invest in tools to make the validation process more automated and manageable for Energy

Division staff. If the Commission's existing budget is inadequate, CalCCA would gladly support any Budget Change Proposal for the IT funding necessary for this project.

V. IF THE COMMISSION DECLINES TO INVEST IN SYSTEMS TO AUTOMATE THE RA VALIDATION PROCESS, IT SHOULD ADOPT TEMPORARY GUARDRAILS TO AID IN ASSESSING COMPLIANCE

If the Commission foregoes these investments and is concerned with the amount of administrative effort this proposal would create, the Commission should adopt two temporary guardrails that would help keep validation efforts manageable. Then, the Commission should scope into the RA proceeding a process to revisit the necessity of these guardrails after a year of implementation.

First, on an interim basis, the Commission could set an initial trading limit of no more than 25 percent of an LSE's compliance obligation, as proposed in CalCCA's March 3, 2025, Opening Comments in R.23-10-011.[30] Given this limit may prohibit the use of hourly load obligation trading by smaller LSEs, the Commission should also adopt a de minimis threshold allowing LSEs with RA requirements less than 200 MW to trade up to 50 MW of their obligation. Furthermore, if the Commission is concerned with the administrative burden of multiple layers of load obligation trades, the Commission can require that if an LSE purchases a load obligation trade and then sells it to another LSE, that sale will count towards that LSE's 25 percent limit.

Second, if the Commission believes Energy Division will have administrative difficulties validating showings with hourly load obligation trades, then on an interim basis the Commission could require hourly load transactions to be shown five business days prior to the RA showings to provide Energy Division staff with additional time to validate the showings. This change is not

[30] *California Community Choice Association's Opening Comments on the Assigned Commissioner's Amended Scoping Memo and Ruling*, R.23-10-011 (Mar. 3, 2025) at 10-11.

ideal because CalCCA anticipates hourly load obligation trades would be used to fill marginal deficiencies after first procuring resources to fill open positions. However, it would be worth pursuing if it enables hourly load obligation trades to be a feature of the RA program.

VI. CONCLUSION

CalCCA respectfully requests consideration of the proposals herein and looks forward to an ongoing dialogue with the Commission and stakeholders.

Respectfully submitted,

Leanne Bober

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

March 3, 2026

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
TRACK 1 PROPOSALS ON TRANSACTABILITY ISSUES

EFFECTIVE MECHANISMS FOR SLICE-OF-DAY RA TRADING
April 24, 2025

Effective Mechanisms for Slice-of-Day RA Trading

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April 24, 2025

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1. Introduction

California is in the first year of a new Slice-of-Day (SOD) resource adequacy (RA) program. In the new SOD program, Load Serving Entities (LSEs) must show a portfolio of resources that are sufficient to meet all 24-hours of a peak load day in each month of the year. Experience from the 2024 test year, in which LSEs submitted a non-binding SOD filing in parallel with their binding legacy filings for a single monthly RA product, shows many LSEs had resources that exceeded their RA obligations during the same hours when other LSEs were short.[2] This dynamic – whereby some LSEs possess excess RA while others are short – suggests there are additional opportunities for trade that are currently unrealized due to regulatory barriers. At present, rules set by the California Public Utilities Commission (CPUC) only allow trade of resources at a monthly level, not individual hourly obligations. CalCCA has advocated for hourly obligation trading, noting that a program that assigns obligations on an hourly basis should allow trade on an hourly basis to reduce costs to consumers.[3] This analysis quantifies the value of trade, contrasts trading in a SOD policy environment with trading in the more familiar legacy RA program, and demonstrates the advantages of hourly obligation trading.

In addition to the 24-hour obligation, a primary feature of the SOD program is 24-hour accreditation of resources. Conventional thermal powerplants, such as natural gas fired generators, geothermal, and biomass plants are generally accredited with constant generation over all 24 hours. Variable resources, like wind and solar, on the other hand, are accredited based on a technology and region-specific exceedance profile of generation on peak days.[4] Storage accreditation is constrained by the storage power rating, energy storage capability, and availability of excess energy to charge storage on the peak day. Altogether, the value of a resource depends on its contribution to the LSE's assigned RA obligation coupled with its interaction with other resources in the LSEs portfolio.

To quantify the potential benefits of hourly trading, we developed a tool to simulate competitive market trades between LSEs. In the simulations, we quantify the benefits of trade for both monthly resource trading, which is currently allowed by CPUC rules, and hourly obligation trading, which has not yet been authorized. Hourly obligation trading allows an LSE with excess resources to take on a portion of the obligation of another LSE in individual hours. We simulate monthly resource trading and hourly obligation

[2] CPUC Energy Division, 2024. *Report on Resource Adequacy Slice of Day Implementation and Year Ahead Showings.* February. Available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/slice-of-day-compliance-materials/energy-division-report-on-ra-sod-implementation-and-year-ahead-showings.pdf
[3] CalCCA 2024. California Community Choice Association's Comments on Assigned Commissioner's Scoping Memo and Ruling. January 17. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M524/K571/524571013.PDF
[4] Exceedance profiles are set by the CPUC program rules across all variable resources and are not unique to LSEs or specific generators.

trading in the same manner with a broker announcing prices and LSEs responding with bids and offers for obligations in specific hours.

Broadly, the simulations are based on an intermediary, like a broker, announcing prices for SOD RA products and LSEs simultaneously responding with bids to buy or offers to sell RA products at the announced prices. The LSE bids and offers take into consideration the requirement that their portfolios meet their obligations in each hour. The LSEs develop their bids and offers by minimizing their cost, net of any revenue from selling RA products.[5] The broker matches bids and offers between participants with the goal of maximizing internal trading opportunities, or conversely, minimizing the amount of RA products that must be purchased from external sources to meet obligations. The broker's objective includes taking advantage of favorable opportunities for LSEs to sell any excess resources, not needed by participants, to external markets. In an auction-like process, the broker continuously revises the announced prices and collects additional bids and offers from LSEs until settling on final prices and quantities that maximize the trading opportunities. LSEs then make bilateral trades at the designated prices and quantities. The final quantities and prices are equivalent to the solution of a centralized optimization, in which an intermediary uses each LSE's obligation and resource portfolio to come to an optimal reallocation of resources between participants. In the case of a broker and LSE bidding process, however, the LSEs only announce responses to prices without needing to hand over their commercially sensitive RA filings to the intermediary.

The direct benefits for participants are the gains from trade – the difference between the LSEs' costs before trade, in which they must purchase external RA products to meet their obligations on their own, and the costs after trade.[6] The costs of internal trades across all participants nets to zero, since each purchase is met by an equivalent sale to another participant, such that the total gains from trade is simply the reduction in the need to purchase RA products from external sources and the revenue from selling excess resources to external markets. For these simulations, we assume that excess resources would be sold to utilities under the rules of the Western Resource Adequacy Program (WRAP),[7] at prices that are only 1/10th of the assumed cost of RA products for California LSEs.[8]

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[5] We assume that all LSEs behave as cost-minimizing price-takers and do not consider any potential strategic bidding behavior that may impact prices in a non-competitive manner.

[6] Our analysis is limited to the short-run gains from trade because we assume the initial LSE resource portfolios do not change depending on the policy environment. In the long run, LSEs may alter their procurement decisions depending on exposure to different trading environments. We ignore these potential long-run impacts when quantifying the gains from trade.

[7] WRAP. 2024. *Review of Preliminary, Non-Binding WRAP Regional Data for the Current Participating Footprint for the Summer 2025 and Advisory Data for the Summer 2028.* January 31. https://www.westernpowerpool.org/private-media/documents/2024-1-16_Webinar_Summer_2025_and_2028_Data_updated_2024-12-12.pdf

[8] Because the WRAP program has not yet gone into effect, the volume of market-based capacity transactions outside of California is low, making it difficult to estimate the value of capacity outside of California. From the limited set of non-California capacity transactions, we see that recent capacity prices are on average lower than in California. Based on the thin volume and lower prices, we simply assume that sales of capacity outside of California would occur at a price of 1/10th of the price in California. We expect

Notably, trade between participants also provides indirect benefits to all California LSEs due to the reduction in demand for RA products. Reduced demand for RA products lowers the price of RA, which lowers the cost of meeting RA obligations to all California LSEs. The magnitude of the indirect benefits depends on the avoided external RA purchases by the participants, the price elasticity of RA products, and the quantity of RA bought at market prices by California LSEs. Reducing the cost of RA in California has grown in importance in recent years following the rapid increase in RA prices. While the weighted-average price for RA was $2.77/kW-mo in 2019,[9] tight market conditions[10] caused the weighted-average price to rise by a factor of nine to $26.26/kW-mo in 2024.[11] The ability for trade to reduce the cost of RA has significant affordability implications for all of California.

To compare trading in the new SOD program with trading in the legacy RA program, we also simulate resource and obligation trading with a single monthly RA product. In the legacy RA program, resource accreditation is based on an effective load carrying capability (ELCC) and obligations are based on the highest demand in each month. Although a broker is used to coordinate trading in the legacy RA program simulations, the broker is not strictly necessary. LSEs that are long could simply match with LSEs that are short and trade directly, resulting in the same outcome as with a broker. Hourly obligation trading offers a similar opportunity for LSEs simply matching long and short hours without an intermediary to coordinate trades. We call hourly obligation trading without an intermediary "uncoordinated hourly obligation trading," because this simple matching does not consider inter-temporal coupling nor the potential economic benefits of selling excess resources to external markets. An analogous uncoordinated approach for resource trading would be to only match LSEs that have excess thermal capacity with LSEs that are short in any hour.[12] We call the simple matching of LSEs with excess thermal and LSEs that are short on thermal resources "uncoordinated resource trading". We compare the effectiveness of uncoordinated trading to coordinated trading within the new SOD program.

The simulation results that follow are based on the confidential SOD RA filings for a subset of California LSEs, 24 community choice aggregators (CCAs), for the 2024 test

non-California markets for RA to become more robust in the future with the implementation of WRAP, enabling better estimates of market prices.

[9] CPUC. 2019. Calculation of the 2019 True Up and Forecast 2020 Market Price Benchmarks for the Power Charge Indifference Adjustment. R. 17-06-026. November. Available athttps://webproda.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/community-choice-aggregation-and-direct-access/2019-final-calculation-of-the-pcia-market-price-benchmarks.pdf

[10] CalCCA. 2024. California's Constrained Resource Adequacy Market:
Ratepayers Left Standing in a Game of Musical Chairs. January. : Available at: https://cal-cca.org/wp-content/uploads/2024/02/CalCCA-Stack-Analysis-2023-2026-updated-01_16_24-.pdf

[11] CPUC. 2025. *Market Price Benchmark Calculations 2024* (Revised). November. Available at 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

[12] Presumably other resources or bundles of resources could be chosen as the resource to trade in an uncoordinated fashion. We chose thermal resources for the simplicity of being able to quantify how much excess or how much shortage of thermal resources an LSE has. An LSE is long on thermal by the amount the aggregate resource showing exceeds their obligation in the tightest hour. An LSE is short on thermal by the amount the aggregate showing is less than their obligation in the hour with the greatest deficit.

year and the first binding year of 2025. The 2025 filings are "year-ahead" filings in which the obligations were set at 90% of the final requirements for the operating month. To quantify the gains from trade, we scaled the year-ahead obligations to the full 100% requirements and, in effect, ask how much of the remaining RA purchases for each CCA could be met through trade with other CCAs instead of going out to the market to buy incremental RA from external sources.

2. Results and Discussion

2.1 Trade Between CCAs Creates Substantial Value

Across the five summer months in 2025, simulated trading between CCAs directly reduces costs to participants by $60 million per year[13] and the reduced demand for RA products produces $50 million per year in indirect benefits to all Californians.

2.1.1 Direct Benefits

For 2025, over 85% of the direct benefits of trade are from the reduced purchases of RA products from external sources while the remaining 15% are from the sales of excess resources to external markets. The gains from trade occur primarily in the months of July, August, and September when loads are highest and the accreditation of variable resources is lowest (see Figure 1).

The June gains from trade are also lower due to lower prices for external RA products in June compared to later months. The gains from trade are zero in May because each of the CCAs could meet their obligations on their own, obviating the need to purchase external RA even before trade, and the lack of a binding requirement for WRAP utilities in May.

The gains from trade in the June and September 2024 test-year filings are similar to the gains from trade in the corresponding month of the 2025 binding year. One exception is that sales of excess RA in September 2024 were near zero because the participating CCAs did not have sufficient resources to meet the obligations on their own, even after trade (see Table 1). As a result, some CCAs needed to purchase incremental RA from external sources even after trading with other CCAs.

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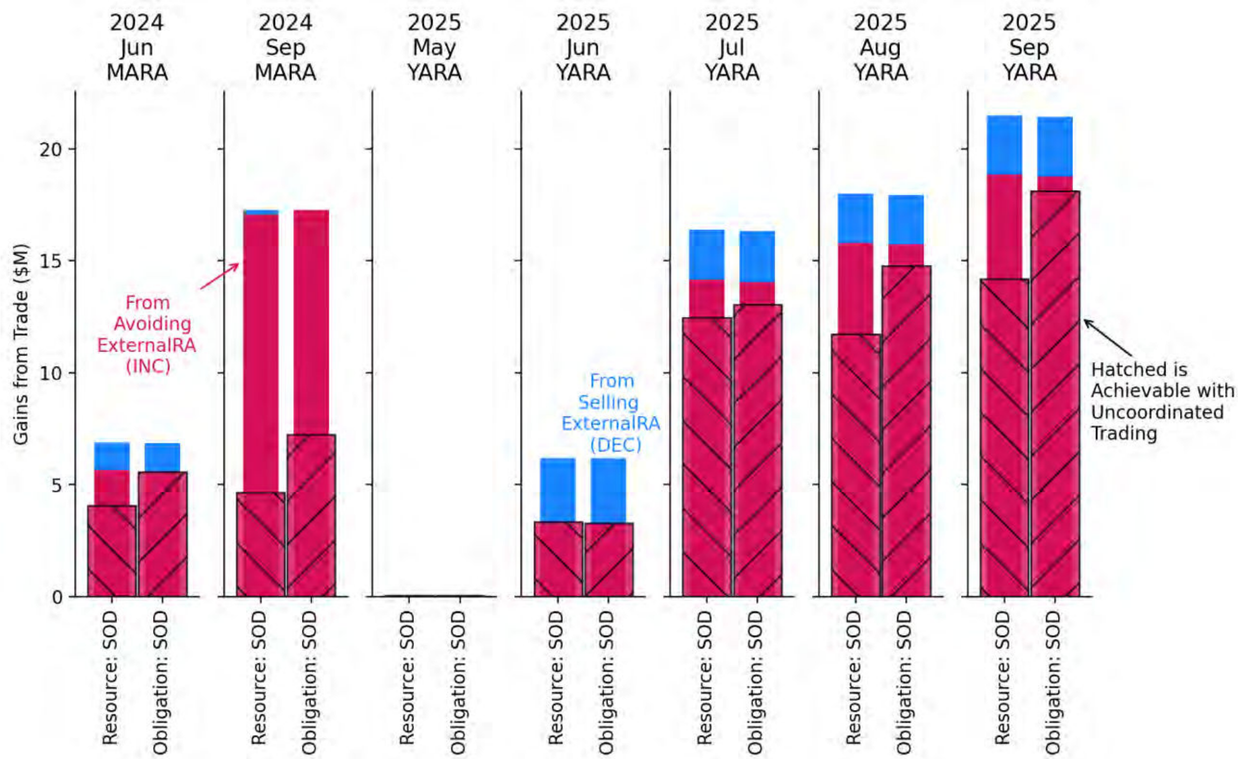
[13] The direct benefits of trade are proportional to the avoided purchases of external RA (or increased sales of external RA in cases with a net excess) and the assumed price of external RA. The external RA prices in this analysis are based on observed sales of capacity to California LSEs reported in FERC Electronic Quarterly Reports, as described in Section 5.3. Actual external RA prices faced by LSEs are uncertain, though the direct benefits would increase or decrease commensurate with changes in the external RA prices.



Note: Further details of gains from trade for September 2024 and 2025 are in Table 1 and Table 2, respectively. Gains from trade in all months are described in Appendix C.

Figure 1. Total gains from trade across all 24 CCAs with the 2024 test-year and 2025 year-ahead Slice-of-Day filings, with either resource trading (Resource: SOD) or hourly obligation trading (Obligation: SOD). Gains from trade with uncoordinated trading, without an intermediary to coordinate trades, is shown by the wide, hatched bar.

2.1.2 Indirect Benefits

The $50 million per year in indirect benefits stem from the reduced demand for external RA products after trade and the downward pressure that places on RA prices. Across the five summer months of 2025, trade reduces purchases of RA from external sources by 455 MW on average. Based on our observations of the average RA price and the net surplus from year to year,[14] we estimate that average RA prices decrease by $1/kW-mo for every 1 GW demand reduction.[15] In 2024, California LSEs purchased roughly 20 GW of RA products at market prices in each summer month.[16] Altogether, trade between CCAs lowers demand for RA products and reduces costs for all California LSEs (CCAs, ESPs, IOUs, and POUs).

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[14] CalCCA. 2024. *California's Constrained Resource Adequacy Market: Ratepayers Left Standing in a Game of Musical Chairs*. January: Available at: https://cal-cca.org/wp-content/uploads/2024/02/CalCCA-Stack-Analysis-2023-2026-updated-01_16_24-.pdf
[15] Estimating the sensitivity of RA prices to shifts in RA demand is particularly challenging because of the bilateral nature of the California RA market. We describe our approach for estimating the sensitivity of RA prices to RA demand in Appendix B.
[16] CalCCA analysis of FERC EQR capacity transactions downloaded from https://eqrreportviewer.ferc.gov/.

2.1.3 Benefits Would Grow if Participants Extended Beyond CCAs

While trade between the 24 CCAs creates substantial direct and indirect benefits, the benefits would be even greater if trades occurred between all CPUC-jurisdictional entities (CCAs, ESPs, and IOUs). The CPUC's analysis of 2024 test-year SOD filings[17] identified short positions that were about 70 percent greater than the short positions of CCAs alone. Based on this finding, we estimate that trade between all CPUC-jurisdictional LSEs could reduce RA demand by 70 percent more than trade between CCAs. The greater reduction in RA purchases and further downward pressure on RA prices could increase the benefits of trade to more than $180 million per year ($105 million of direct benefits and $77 million of indirect benefits).

		Short Position (a.k.a., ExternalRA INC)			Internal Trades				
	Scenario	Before Trade (MW)	After Trade (MW)	Gains from Trade ($M)	Volume (MW)	Count	Average Connections	Monetary Transfer ($M)	Requires Intermediary
I.	Resource: ELCC	467	0	12.3	467	22	1.9	1.2	No
II.	Obligation: ELCC	467	0	12.3	467	22	1.8	1.2	No
III.	Resource: SOD	926	269	17.3	2,642	185	15.4	23.4	Yes
IV.	Obligation: SOD	926	261	17.3	3,591	150	12.5	11.7	Yes
III.*	Uncoordinated Resrc.: SOD	926	748	4.7	185	7	1.8	N/A	No
IV.*	Uncoordinated Oblg.: SOD	926	645	7.2	4,654	122	10.2	N/A	No

Table 1. Summary of trade between CCAs across policy environments with September 2024 test-year data

		Short Position (a.k.a., ExternalRA INC)			Internal Trades				
	Scenario	Before Trade (MW)	After Trade (MW)	Gains from Trade ($M)	Volume (MW)	Count	Average Connections	Monetary Transfer ($M)	Requires Intermediary
I.	Resource: ELCC	541	0	15.1	541	22	1.9	1.4	No
II.	Obligation: ELCC	541	0	15.1	541	22	1.8	1.4	No
III.	Resource: SOD	727	0	21.5	3,500	167	13.9	6.7	Yes
IV.	Obligation: SOD	727	0	21.4	8,062	163	13.6	2.4	Yes
III.*	Uncoordinated Resrc.: SOD	727	182	14.2	561	16	1.9	N/A	No
IV.*	Uncoordinated Oblg.: SOD	727	27	18.1	6,613	120	10.0	N/A	No

Table 2. Summary of trade between CCAs across policy environments with September 2025 binding-year data

2.2 With an Intermediary, Resource Trading and Hourly Obligation Trading Achieve the Same Benefits

In the simulations of trade, the broker coordinates trades between LSEs, ensuring that any opportunity for an LSE to meet its obligations by purchasing RA products from a

[17] CPUC Energy Division, 2024. *Report on Resource Adequacy Slice of Day Implementation and Year Ahead Showings.* February. Available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/slice-of-day-compliance-materials/energy-division-report-on-ra-sod-implementation-and-year-ahead-showings.pdf

participant is realized, without adversely affecting the other LSEs ability to meet its own obligations or to sell to an external market if more lucrative. LSEs participate by responding to broker-announced prices with bids and offers of RA products at quantities that are both feasible, in the sense that the LSE's obligations will be met if the bids and offers are accepted, and minimize costs to the LSE. With this sophisticated trading mechanism, trading either resources or hourly obligations achieve roughly the same reduction in purchases of external RA and the same gains from trade, Figure 1. Later sections discuss important differences between resource trading and hourly obligation trading, in terms of differences in internal monetary transfer between participants in Section 2.4 and ability to trade without the need for an intermediary in Section 2.5, but in terms of aggregate benefits, the two policy environments produce similar direct and indirect benefits.

2.3 Benefits of Participation are Widespread, Though Uneven

For a participant, the most salient question is whether it benefits from trade, not necessarily the aggregate benefits to all participants. We find that all participants are economically better off by participating in the coordinated trades than on their own. Individual CCA gains from trade across the five summer months of 2025 are quantified in Figure 2, shown as a percentage of the LSEs' maximum cost if they met all of their RA obligations by buying RA from external sources (ExternalRA INC). We normalize the individual gains from trade in this manner to remove the effect of CCA size on the individual LSE gains from trade.

While all participants benefit from trade, some LSEs benefit more than others. For the summer months of 2025, roughly half of the participants reduce compliance costs by 10-30% through trade, while the remaining half see less than 5% reductions in cost.

The only contributor to gains from trade with uncoordinated trading are the avoided costs of purchasing RA from external sources (ExternalRA INC). This is because the way we simulate uncoordinated trading does not involve internal monetary transfer and does not involve sales of RA to external markets (ExternalRA DEC). Therefore, the only beneficiaries from uncoordinated trading in the simulations are LSEs that are short prior to trade.

Comparison of the beneficiaries of trade with uncoordinated and coordinated resource or hourly obligation trading in Figure 2 reveals that the LSEs that benefit the most from trade in 2025 are those that are short prior to trade. LSEs that are long prior to trade see proportionally smaller benefits from selling RA products internally or to external markets. The relatively low benefits to participants that are long prior to trade is in part due to low internal RA prices in the summer of 2025 resulting from coordinated trades eliminating the short positions of all participants even in September 2025 (see Table 2). In contrast, internal RA product prices remain high in September 2024, when some participants still must purchase RA from external sources (ExternalRA INC) even after trade (see Table 1), and therefore LSEs that are long prior to trade see proportionally higher benefits from trade.[18]

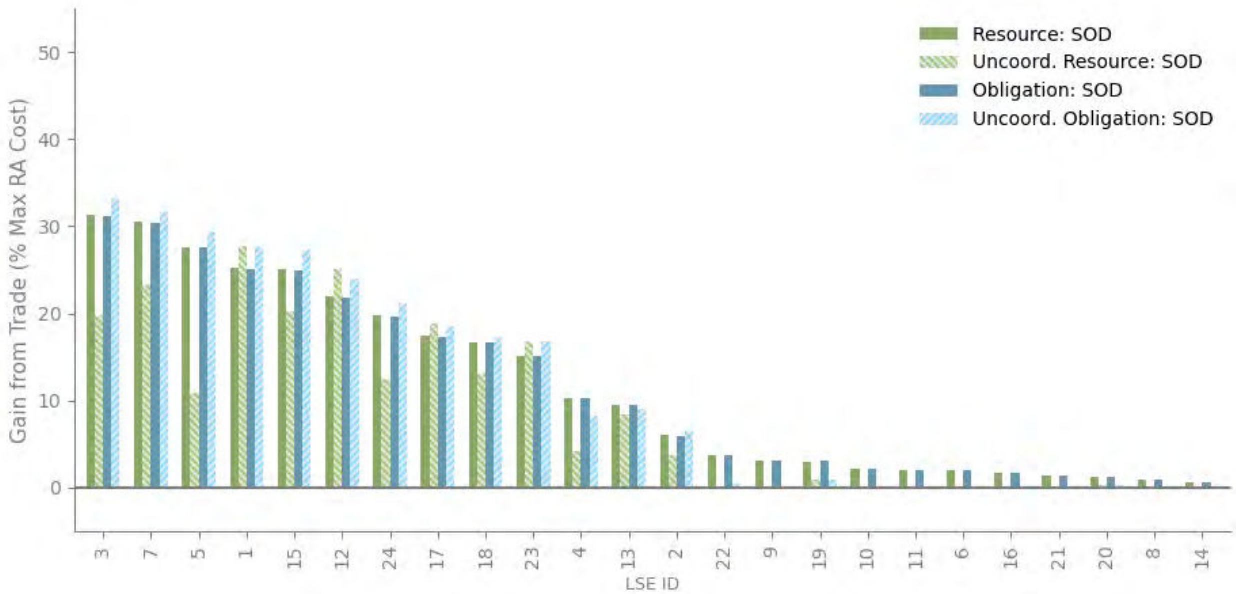


Figure 2. Aggregate direct benefits across May to September 2025 for each CCA, scaled by the CCA's maximum RA cost if it met all obligations at the assumed external RA price.

2.4 Hourly Obligation Trading Targets Periods with Scarce Resources

Even though the simulations show that hourly obligation trading and resource trading yield similar gains for participants, we observe important differences between the two policy environments. One difference is the way that hourly obligation trading directs internal monetary transfer toward hours that are most constrained in aggregate.

With the September 2024 test-case data, trade reduced the need to purchase RA products from external sources (ExternalRA INC), but it did not eliminate it entirely (see Table 1). We illustrate differences in internal monetary transfer in this constrained month by showing the trade volume and final prices with resource trading and hourly obligation trading for September 2024 in Figure 3. The product of the trade volume for the internal RA product and its corresponding price sums to the total internal monetary transfer. The product of external RA volume and prices, in contrast, is the post-trade external RA cost which is minimized by the broker by coordinating trades.

Final prices for internal RA products from the broker auctions differ across resources or hours, for policy environments that allow resource trading or hourly obligation trading, respectively, depending on how much another increment of that product

[18] Relatively low benefits of trade for LSEs that are long prior to trade raises the question of whether these entities would participate in trade. We find that even if LSEs that are long prior to trade decide to abstain from trade, there continue to be trading benefits for the LSEs that are short prior to trade. The direct benefits of trade when only short LSEs participate are $20-21 million in 2025, which is 42-44% of the gains the short participants would have realized if all of the LSEs were to participate.

would reduce the need to buy RA from external sources (ExternalRA INC). With hourly obligation trading, the only hour with a final non-zero price was hour ending 19 (HE19). In all other hours the final price for hourly obligations was zero because participating LSEs could easily take on additional obligations in hours other than HE19 without triggering the need to buy additional RA from external sources. Even though hourly obligation trading involves a large volume of internal trades, the final auction price of zero for hourly obligations in most hours results in monetary transfers being concentrated only in the subset of trades involving obligations in HE19.

With resource trading, on the other hand, final prices are non-zero for all RA products, meaning that every internal trade also requires an internal monetary transfer between participants. The internal monetary transfer is largest for trades involving natural-gas fired thermal resources, unspecified imports, and 4-hour batteries. Prices for wind and solar resources are lower and therefore contribute less to the internal monetary transfer even though the internal trade volume is large. For some participants, favorable trades involve selling one high-cost resource, such as a battery, while simultaneously buying a high-cost resource with different characteristics, such as a thermal resource, to marginally lower the participant's net cost. Such a trade involves a large internal monetary transfer yet only contributes a small amount to the overall gains from trade. Similar transactions were not required in the policy environment with hourly obligation trading.

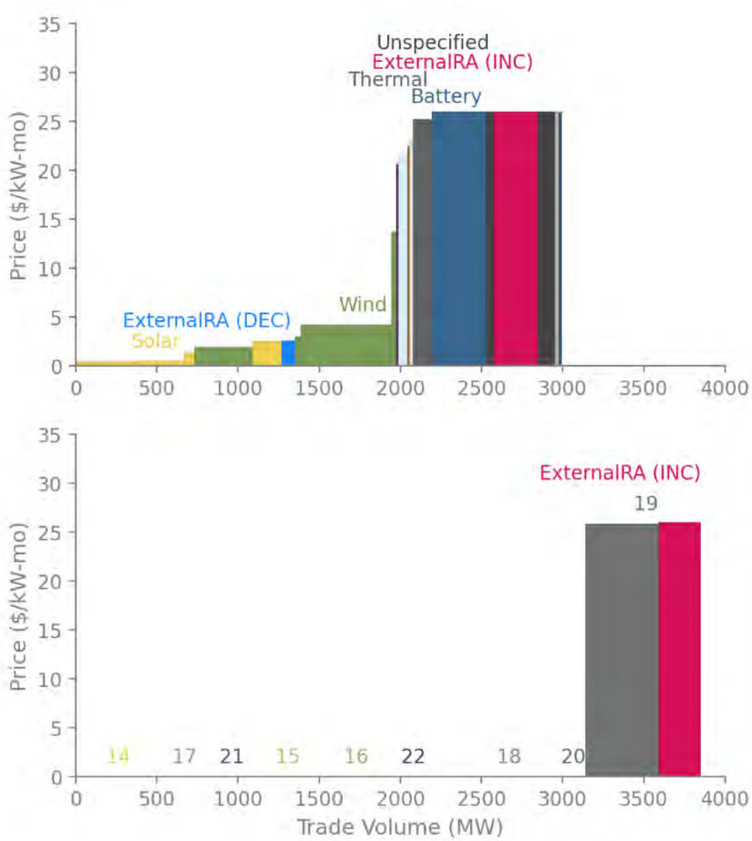


Figure 3. Comparison of SOD trade volume and price using September 2024 test-year data with the resource (top) and obligation (bottom) trading policy

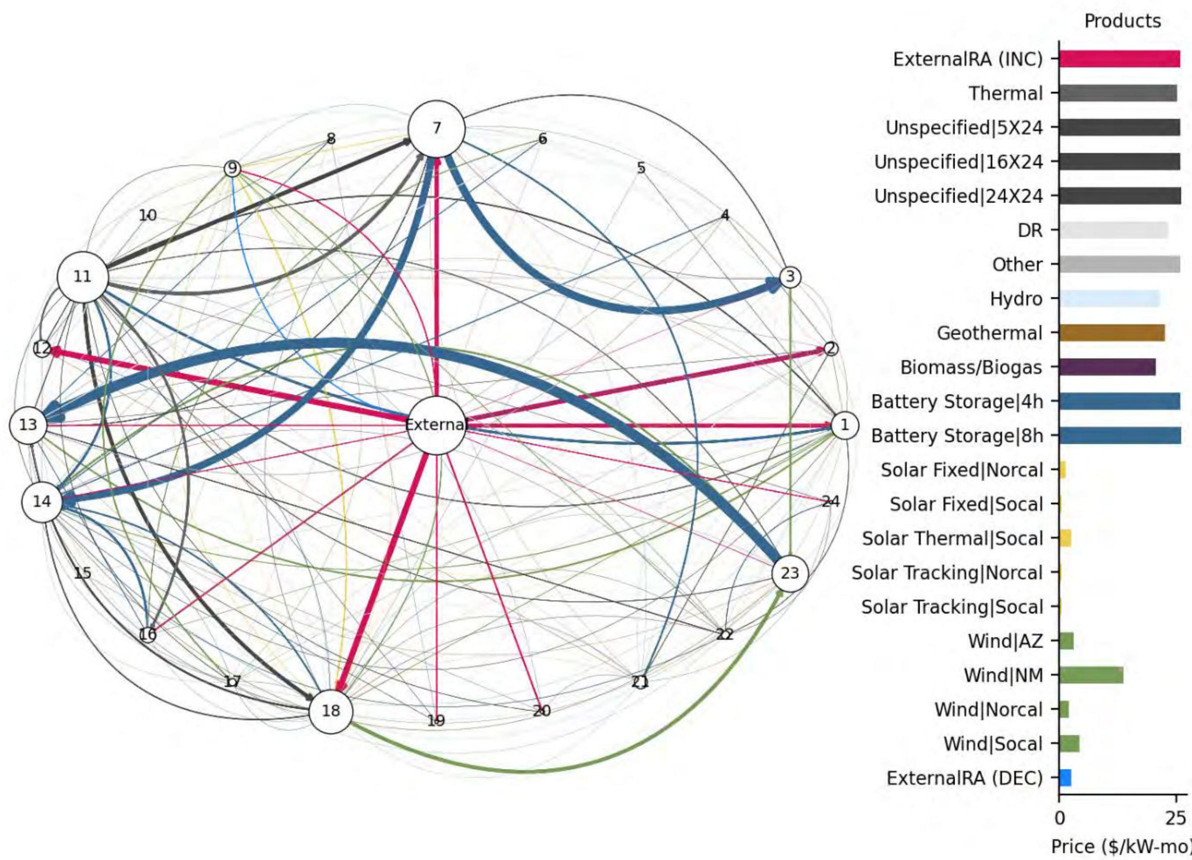
2.5 Slice-of-Day Trading is 6-9 Times More Complex

Gains from trade are not unique to the new SOD RA program. Even with the legacy RA program, where different resources would be converted to a comparable RA product with a single qualifying capacity value through an accreditation factor called the ELCC, LSEs that are long can benefit from selling excess RA to LSEs that are short. What is unique to the SOD RA program is the complexity of trades required to achieve the benefits. Overall, we estimate SOD trading to be 6-9 times more complex than trading with the legacy RA program.

We quantify the complexity of internal trade through three related metrics: volume, transaction count, and average number of connections.[19] These metrics are shown for each of the policy environments with September 2024 test-year data and September 2025 binding data in Table 1and Table 2, respectively. In the legacy RA program, every internal trade results in a comparable reduction in the short position of the purchasing LSE meaning that the trade volume is equal to the reduction in short positions before and after trade. In contrast, trading with SOD products across the summer months of 2025 requires an internal trade volume that is nine times the reduction in purchases of external RA. The count of transactions with SOD trading is more than 6 times the count of transactions in the legacy RA policy environment, where a unique transaction is the bundle of all RA products sold by one LSE to another. Finally, the average number of trading partners with SOD trades is 6 times more than in the legacy RA policy environment.

To illustrate the complexity of SOD resource trading, we visualize the trading network between 24 CCAs and external sources of RA using September 2024 test-year data, Figure 4. Each node represents a CCA, with the size of the bubble proportional to the CCA's transaction costs (price times quantity). Each edge of the network is a transaction involving a particular type of RA resource, with arrows showing the direction from seller to buyer and the width of the arrow based on the transaction cost. Even though the volume of wind and solar RA product trades is large, the low prices for these products leads to smaller transaction costs and less prominent edges.

[19] As is common in any optimization-based simulation, numerical issues can sometimes lead to trades with very small quantities being included in the final allocation, impacting metrics such as transaction count and number of trading partners. For these two metrics, we exclude any transaction with a quantity below 0.5 MW in the tally of transaction count and trading partners.

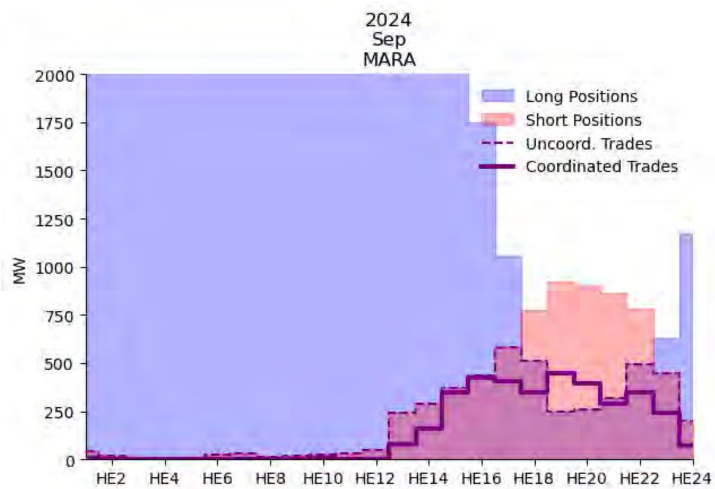


Note: Bubbles are CCAs, sized based on transaction costs. Lines are transactions sized by transaction cost.

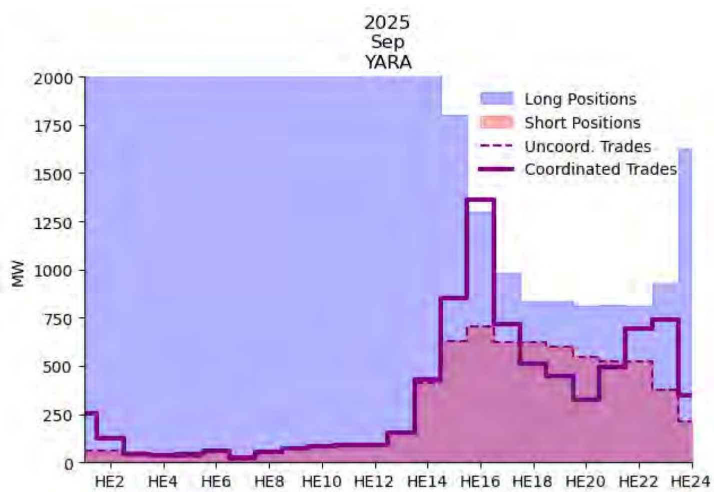
Figure 4. Visualization of trading networks in the SOD resource trading policy environment using September 2024 test-year data

2.6 Hourly Obligation Trading Allows Simple Trades without an Intermediary

With the increased complexity of SOD trading, it is important for policy makers to provide LSEs with tools necessary to simplify trade to manage the risk that LSEs forgo trading and instead purchase additional unnecessary external RA products, at the expense of ratepayers. Previous results demonstrated that hourly obligation trading can achieve the same benefits as resource trading when an intermediary is available to coordinate trades (Sections 2.2) and that hourly obligation trading can target hours where aggregate resources of participants are insufficient to meet the aggregate obligation (Section 2.4). One more potential advantage of hourly obligation trading is that it provides a pathway for LSEs to achieve some of the same benefits of coordinated trades without the need for an intermediary. In the simplest form, participants that show resources in excess of their obligations in some hours can take on the obligations of LSEs that are short in those hours. Trades made in this manner, without further consideration of impacts on storage charging energy or impacts to opportunities to sell excess to external markets, is what we call uncoordinated hourly obligation trading and is illustrated for September 2024 and 2025 in Figure 5. For the summer months of 2025, even the uncoordinated trades achieve 80% of the gains from trade observed with a sophisticated intermediary to coordinate trades (see Figure 1).



(a)



(b)

Figure 5. Comparison of uncoordinated and coordinated hourly obligation trades when CCAs have (a) a net deficit of resources in September 2024 or (b) a net surplus of resources in September 2025.

The uncoordinated approach is not always as effective, however. With the September 2024 test-year some of the participants still need to purchase RA products from external sources, even after trades coordinated by an intermediary. For this month, the uncoordinated hourly obligation trading only achieved 35% of the gains of trade possible with an intermediary. In this case, the intermediary helps to find trading opportunities involving HE19 that come from adjusting storage charging, storage discharge, and obligations of LSEs to better align with overall needs. The possibility of these adjustments to generate gains from trade is not evident with uncoordinated hourly obligation trading alone, as shown in Figure 5a.

In months where long positions exceed short positions in all hours, as in the September 2025 filings, there are again differences in trading opportunities identified by uncoordinated hourly obligation trading and with an intermediary to coordinate trades, as in Figure 5b. However, the differences are much less impactful on the gains from trade since trades from both approaches can largely eliminate the need to purchase RA from external sources. Allowing hourly obligation trading opens a pathway for LSEs to begin to realize the benefits of trade without the need to develop a novel sophisticated intermediary to coordinate trades.

3. Practical Considerations for Implementing Trading Mechanisms

The previous results are based on simulations comparing alternative policy environments. Moving from simulation to real-world implementation would require a much more in-depth investigation. Here we describe some of the important practical considerations but note that much more work on this question remains.

Three different mechanisms for SOD trading have been mentioned in this analysis: (1) a centralized optimization; (2) a broker running an auction; and (3) uncoordinated trades. *First*, a centralized optimization across all participating LSEs involves an intermediary having access to each LSEs confidential resource portfolio and obligations then using that information to reallocate resources an optimal manner. *Second*, a broker running an auction-like process would involve LSEs responding to announced prices with bids and offers. While both mechanisms lead to the same solution and gains from trade, under the auction approach, the LSEs can maintain the confidentiality of their portfolios and obligations. *Finally*, even an uncoordinated form of trade could achieve significant benefits without requiring an intermediary. In this case, trading could be as simple as participating LSEs posting hourly bids and offers to a bulletin board and making bilateral trades from there. Although this would not achieve all the benefits available with an intermediary, it would still maintain confidentiality and would be simple to implement. These high-level considerations are summarized in Table 3.

	Centralized Optimization	**Broker Running an Auction**	**Posting Hourly Obligation Bid/Offers to a Bulletin Board**
LSEs keep contracts confidential	No	Yes	Yes
Achievable without intermediary	No	No	Yes
Maximizes trading opportunities	Yes	Yes	No

Table 3. Comparison of slice-of-day trading mechanisms

4. Conclusions

Hourly obligation trades can create substantial value. In the five summer months of 2025, simulated trading between the 24 CCAs could provide as much as $60 million per year in direct benefits from avoiding the need to buy incremental RA from external sources and even enabling sales of excess resources to external markets. The benefits of trade are widespread across all participants, though CCAs that are short prior to trade benefit more than CCAs that are long. Furthermore, the trade between CCAs lowers overall demand for RA products. Lower demand reduces RA prices for all California LSEs, creating a collective indirect benefit of $50 million per year.

With some form of sophisticated intermediary to coordinate trades, resource and hourly obligation trading can both achieve these benefits. An advantage of hourly obligation trading is that it requires only 2/5 of the internal monetary transfer between participants yet achieves the same benefits of resource trading. If part of the justification for the SOD program is a fair allocation of the costs of maintaining a reliable system, hourly obligation trading is better suited to valuing hours of the day with scarcity at the aggregate level.

Implementing an effective trading mechanism with the SOD program will not be easy. Trading in the SOD policy environment is 6-9 times more complex than that of the legacy monthly RA product. It will require a greater volume of trades, more transactions, and more trading partners. Achievement of the full benefits of trade requires a much more sophisticated coordination mechanism than participants might be accustomed to. Hourly obligation trading allows for simple trades without an intermediary, while still achieving 80% of the benefits.

With rapidly rising electricity costs in California, all ratepayers would benefit from having more flexibility in the way RA obligations are met. Trade is important and fundamentally more complex in the new SOD program. Policy makers should support the development of effective trading mechanisms that go hand in hand with the transition to SOD. Otherwise, the SOD RA program will drive up costs for consumers with no direct benefit to reliability.

5. Methods and Data

5.1 Policy Environments and ExternalRA

We developed a common analysis approach to compare trading under four different policy environments: two with RA based on a single monthly product where resources are accredited by an ELCC and two based on the SOD accreditation. With either ELCC or SOD accreditation, we compare resource trading and obligation trading, Table 4.

		Accreditation	
		ELCC	**SOD**
Trading Product	**Resources**	I: Resource trading with ELCC	III. Resource trading with SOD
	Obligations	II. Obligation trading with ELCC	IV. Hourly obligation trading with SOD

Table 4. Four policy environments in RA trading analysis

The trading analysis is based on a simulation of LSEs each having obligations and resources characterized in a regulatory filing for the CPUC called an RA filing. All participants in the trade are CPUC jurisdictional and subject to common RA program rules. Any RA obligations that are not met by internal trades with participants or any short positions prior to trade are met through incremental purchases of RA from external sources (ExternalRA INC), Figure 6. Assuming transmission capacity is available, the source of external RA can be from any resource in the western interconnection, whose reliability is assured by the Western Electricity Coordinating Council (WECC). We assume that purchases of ExternalRA INC contribute to a participant's portfolio similar to an unspecified resource available 24-hours a day (Unspecified|24X24). All ExternalRA INC is purchased at a single price, varying only by month of the year.

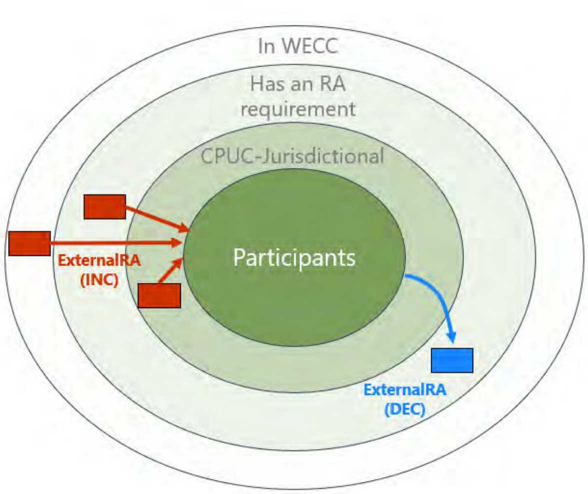


Figure 6. Illustration of the relationship of ExternalRA INC and DEC to participants in trade

In cases where an LSE's resources exceed its obligations, it may also be able to sell that excess to an external market (ExternalRA DEC). We assume that the purchaser of external RA would be an entity in WECC that has an RA requirement but is not CPUC jurisdictional. This assumption allows us to set a single price for external sales each month. An LSE that sells a resource to an external market removes the resource from its portfolio and converts it to ExternalRA DEC using the ELCC factors applicable to the external market.

The primary driver of the gains from trade is the reduction in purchases of ExternalRA across all participants before and after trade. Figure 7 illustrates how purchases of internal RA products can reduce the need to purchase ExternalRA across all four policy environments.

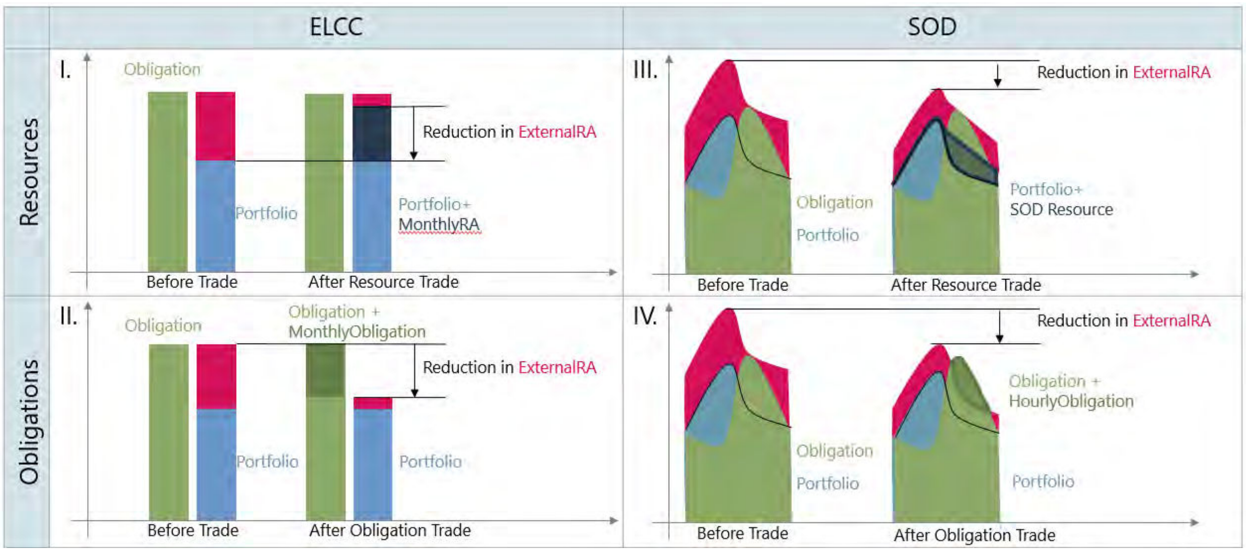


Figure 7. Illustration of the effect of trade on the need to purchase ExternalRA in each of the four policy environments

5.2 Trade Simulation

The Broker and LSE Bidding Strategy models are derived from a Central Optimization Problem in which the costs of meeting all LSE obligations are minimized, as in an RA pool. In the Central Optimization, a planner uses its visibility into the obligations and resources of every participating LSE to reallocate RA products (either resources or obligations, depending on the environment), such that the residual need to purchase RA products from an external source (ExternalRA INC), is minimized.

5.2.1 Central Optimization Problem

At a high level, the Central Optimization Problem is formulated as follows:

Central Optimization Problem:

Minimize: $ExternalCosts + TradeFriction$

Subject To:

$ExcessDemand_p$ = 0, for each p in set of internal RA Products

$Deficit_l$ = 0, for each l in the set of participating LSEs

$ExternalRA^{INC}_l$ <= $Max\_Deficit\_Prior\_to\_Trade_l$, for each l in set of LSEs

Where:

$ExternalCosts = ExternalRA^{INC} * ExternalRA^{INC}\_Price - ExternalRA^{DEC} * ExternalRA^{DEC}\_Price$

$TradeFriction = \Sigma_p(InternalPurchase_p + InternalSale_l) * UnitFrictionCost$

$ExcessDemand_p = InternalPurchase_p - InternalSale_p$

The disadvantage of the Central Optimization is that each participant must share information about its full portfolio of RA contracts and its RA obligation with the entity operating the optimization. Such information is confidential and commercially sensitive, potentially limiting the set of LSEs willing to participate.

5.2.2 Decomposition to Broker and LSE Bidding

An alternative is to have an independent broker operate an auction-like process where it announces prices and participants respond with bid/offer quantities at those prices. The broker revises prices and continues to collect bids until it can balance supply and demand for RA products between participants while maximizing the gains from trade. The Broker/LSE Bidding Strategy models arise from a Dantzig-Wolfe Decomposition of the Central Optimization Problem.[20] The Broker is equivalent to the master problem and the LSE Bidding Strategy is part of the subproblem. The decomposition yields an equivalent solution to the Central Optimization, though it is solved through an iterative process rather than a single optimization.[21] More importantly, the Broker needs to only collect bid/offer responses from LSEs and does not need confidential information on each LSE participant's resource contracts or obligations.[22]

Broker:

Minimize: $\Sigma_r((ExternalCost_r + TradeFriction_r) * weight_r)$

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[20] Conejo, A.J., Castillo, E., Minguez, R. and Garcia-Bertrand, R., 2010. *Decomposition Techniques in Mathematical Programming: Engineering and Science Applications*. Springer Science & Business Media.
[21] The use of Dantizg-Wolfe decomposition to model coordinated markets has been used elsewhere in the literature, e.g., Najafi, F. and Fripp, M., 2023. "Market-based Coordination of Price-responsive Demand Using Dantzig-Wolfe Decomposition Method". *Energy and AI*, 14, p.100277. https://doi.org/10.1016/j.egyai.2023.100277
[22] The code used to create the simulations of trade in all policy environments is available at: https://github.com/CalCCA-Data-Team/agent_based_ra_market

Subject To:

$\Sigma_r \, (weight_r) = 1$

$\Sigma_r(ExcessDemand_{r,p} * weight_r) <= 0$, for each p in the set of internal RA products

<u>LSE Bidding Strategy:</u>

Minimize: $ExternalCost_l + TradeFriction_l + InternalCost_l$

Subject To:

$Deficit_l = 0$

$ExternalRA^{INC}_l <= Max\_Deficit\_Prior\_to\_Trade_l,$

Where:

$InternalCost_l = \Sigma_p \, (InternalRA\_product\_price_p * (Internal\_RA\_bought_{p,l} - Internal\_RA\_sold_{p,l}))$

5.2.3 LSE Bidding

In each round of the auction, LSEs respond to the Broker's prices with bids to purchase or offers to sell RA products. The bid/offers include both internal RA and external RA (INC or DEC) products. The LSE chooses bid/offers that minimize its cost of eliminating deficiencies. We further assume that LSEs will not purchase more ExternalRA_INC during trade than they would have had to purchase before trade. In other words, for LSEs that were already in compliance with RA requirements before trade, their ExternalRA_INC bids will always be zero.

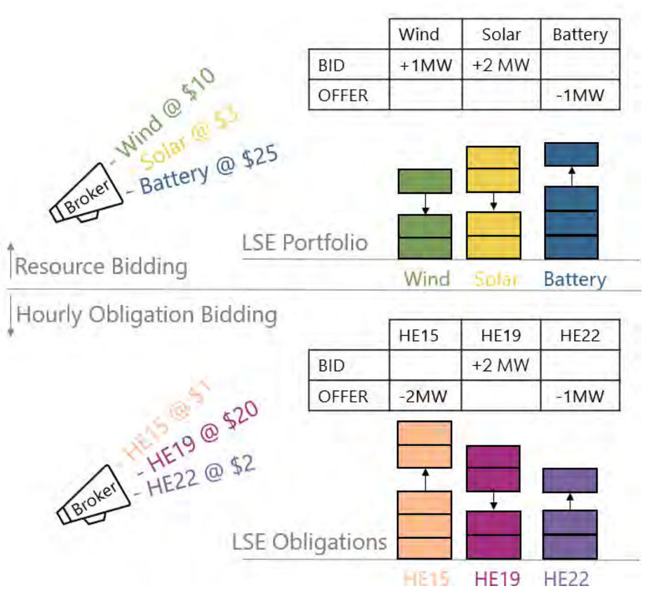


Figure 8. Illustration of LSE bidding either resources (top) or hourly obligations (bottom) in response to prices announced by the broker

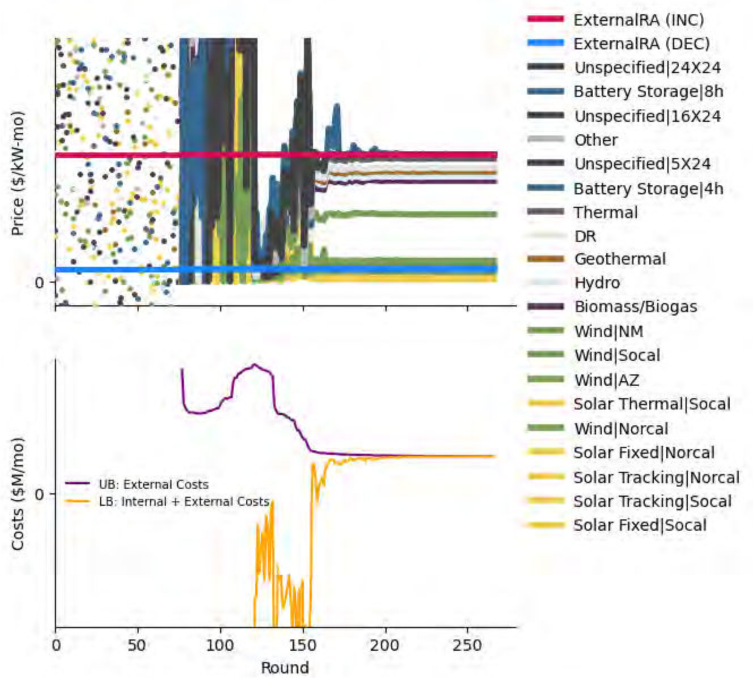
Figure 8 illustrates the process of a broker announcing prices for RA products and an LSE responding with bids to purchase or offers to buy the RA products at those prices. The LSE's bids and offers are made with the expectation that all bids and offers will be successful. In other words, there is no risk that an LSE offers to sell a product and then their bids for other RA products are unmet causing a deficiency. As described next, an important role of the broker is to collect all feasible bids and offers at different price points, then coordinate trades based on a final determination of quantities and prices that maintains feasibility for each participating LSE.

5.2.4 Broker Auction

In every auction round, *r*, the Broker finds weights to place on previous rounds to minimize costs, while ensuring that supply and demand for internal RA products are balanced. The shadow value of the supply and demand balance constraint for each product, representing the marginal reduction in total costs from another unit of supply, sets the prices for next round of the auction.[23]

The Broker continues the auction process until the Broker finds no further opportunity to reduce total costs. More precisely, the auction is completed when the weighted sum of all external RA costs matches the sum of the costs across all LSEs in the most recent auction round.[24] The final allocation of trades is based on applying the final weights to the bids collected in previous auction rounds. LSEs trade RA products with the other participants at the final auction prices. An example of the history of RA product prices and the convergence of external costs with the sum of LSE costs across auction rounds is shown in Figure 9.

[23] To begin the auction process, the Broker first collects bids based on randomly chosen prices. Bids in response to random prices are used to initialize the model. After initializing, all subsequent prices are from the shadow value of the supply and demand balance constraint in the Broker problem.
[24] We continue until the gap is less than 0.05% of the total costs across LSEs.



Note: UB is upper bound and LB is lower bound as defined in the Dantizg -Wolfe decomposition by Conejo et al (2010).

Figure 9. Example of auction process using September 2024 test-year data

5.2.5 Bilateral Matching

The broker tells participants their final quantity of RA product purchases and sales along with announcing final prices. Participants then bilaterally trade these products with other participants at the specified prices. We randomly match sellers of an RA product with buyers of a product, setting the transaction quantity to the lower of the bid or offer. Any residual quantity is again randomly matched with another buyer or seller in the list of participants. The bilateral matching ends when the final quantities specified by the broker are met.

5.3 Data and Assumptions

5.3.1 Slice-of-Day RA Filings

All data used in this analysis is from the confidential SOD RA filings provided by the 24 CCA members of CalCCA to the CPUC. The June and September 2024 filings were test-year filings that were not binding. The May-September 2025 filings were the year-ahead binding filings submitted to the CPUC at the end of October 2024. CalCCA preserves all confidential information and reports only anonymized or aggregate results that mask the original filer.

5.3.2 LSE Portfolio and Obligations

The SOD RA filings contain the confidential hourly obligations and the contracts with resources to meet the obligations. With the 2024 test-year filings, we use the obligations directly provided in the CCA filing. In the 2025 year-ahead filings, however, CCAs are only required to demonstrate sufficient resources to meet 90% of the operating month's obligation. To determine how much more resources CCAs must procure between the year-ahead filing and the operating month, we scale the obligation in the YARA filing to the full 100% obligation.

We characterize the CCA's portfolio based on the contracted nameplate capacity of each technology type, accounting for regional variation in resource portfolios. We also extract the 24-hour profile the CCA uses for each non-storage contract. For storage contracts, we ignore the profile and instead dispatch the storage within the LSE bidding process based on power, energy capacity, and charging sufficiency constraints.

5.3.3 Slice-of-Day RA Product Definitions

The 24-hour profiles often vary across CCA filings, even for the same technology type. To simplify the analysis, we create standard RA product definitions with common profiles and parameters. The standard hydro RA product, for example, is the contracted-capacity weighted average of all hydro profiles across the CCAs (varying only by hour and month, but not by CCA). Similarly, we group batteries by duration (1, 2, 4, or 8 hour) and then use the weighted-average efficiency and duration for the standardized product. For Unspecified resources, we group them by the average capacity factor into three standard buckets: 5X24, 16X24, and 24X24. Within each of these buckets we use the capacity-weighted average profile.

5.3.4 Legacy Monthly RA

Data from the CCAs' SOD filings are also used in create the parameters necessary for simulating trade in the legacy RA program. We estimate each CCA's monthly RA obligation as the maximum hourly obligation. We estimate the monthly RA portfolio by converting the contracted nameplate to contracted net qualifying capacity using the 2024 technology factors by technology and month reported by the CAISO.[25]

5.3.5 External RA INC Prices

We estimate the cost of purchasing RA from external sources based on the recently observed capacity-weighted average price of RA sold to California LSEs during the period between the year-ahead filings (October 31, 2023) and the final RA filing date 45 days before the start of the operating month. CalCCA collects and cleans public RA transaction data from FERC Electronic Quarterly Reports. Assumed prices for purchases of external RA (ExternalRA INC) in each month are listed in Table 5. Because FERC EQR data only reports historical prices, we assume the same prices for analysis of both the 2024 test-year and 2025 binding year filings.

[25] CAISO. 2024. Final Net Qualifying Capacity for Compliance Year 2024.Available at: https://www.caiso.com/documents/final-net-qualifying-capacity-report-for-compliance-year-2024.xlsx

Month	Weighted-average RA price ($/kW-mo)
May	11.7
June	13.2
July	21.1
August	25.5
September	26.0

Table 5. Assumed prices for purchases of RA from external sources (ExternalRA INC)

5.3.6 External RA DEC Prices and ELCC factors

We assume that sales of excess resources to external markets would be based on the conversion of the nameplate capacity to an external RA product based on the ELCC factors announced by WRAP.[26]

Few sales for RA products to non-California loads are reported in the FERC EQRs, especially for the period between the year-ahead filing and operating month. Rather than set the price for sales of RA to external markets based on this thin volume of transactions, we instead assume that the price for ExternalRA DEC is 1/10th of the price of External RA INC, reported in Table 5.

[26] WRAP. 2024. *Review of Preliminary, Non-Binding WRAP Regional Data for the Current Participating Footprint for the Summer 2025 and Advisory Data for the Summer 2028.* January 31. https://www.westernpowerpool.org/private-media/documents/2024-1-16_Webinar_Summer_2025_and_2028_Data_updated_2024-12-12.pdf

Appendix A. Sensitivity of Gains from Trade to Changes in Portfolio Composition

Across California, LSE portfolios are transitioning toward a greater share of renewables and storage and away from thermal generation. In 2019, 67% of the resources shown for compliance with September resource adequacy compliance were from natural gas-fired generation and unspecified imports, while less than 0.2% was from battery storage. By 2024, the share of RA from natural gas and unspecified imports dropped to 56% while the share from energy storage and hybrid plants increased to over 17% of the September showings.[27] Pathways to achieving greenhouse gas emission reduction goals associated with California's SB 100 policy continue the trend of adding energy storage and reducing reliance on natural-gas generation.[28] This transition of the LSE portfolios impacts the gains from trade.

To quantify the impact, we evaluate the September 2025 gains from trade as thermal capacity is swapped out with 4-hour duration battery storage capacity, Figure 10. Prior to trade, we ensure replacement of thermal capacity with 4-hour battery does not worsen the LSE's maximum deficits by increasing the size of the replacement 4-hour battery when needed. As more of the thermal capacity is replaced, the size of the replacement battery relative to the thermal capacity also grows to maintain the same level of pre-trade compliance. We cap the ratio of replacement 4-hour battery to thermal capacity at 4:1. We therefore allow maximum pre-trade deficits to increase if it would otherwise require more than a 4:1 ratio of replacement 4-hour battery to thermal capacity.

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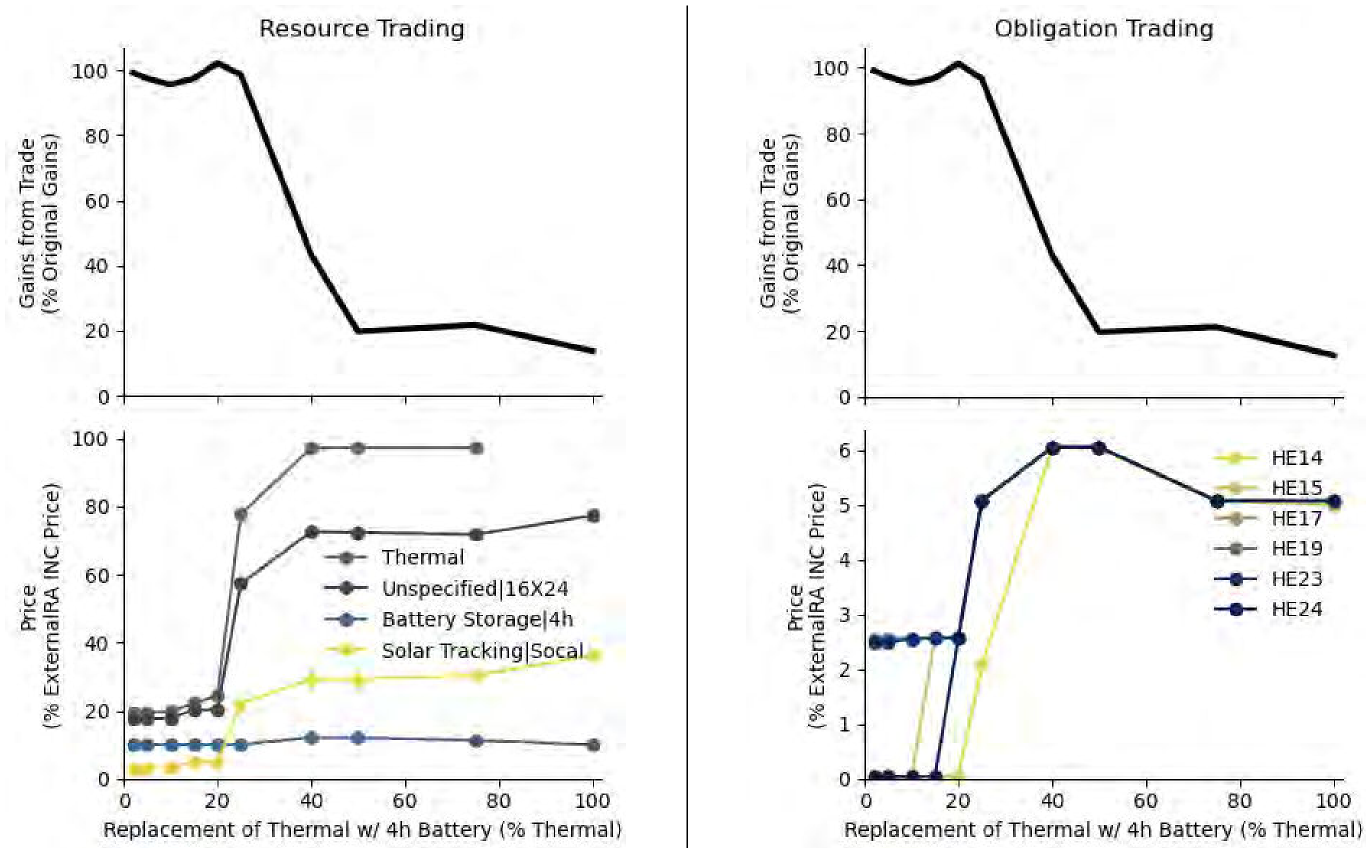
[27] CAISO Historical Resource Adequacy Aggregate Data as of January 22, 2025: https://www.caiso.com/documents/historicalresourceadequacyaggregatedata.xlsx
[28] CEC *2021 SB 100 Joint Agency Report, Achieving 100 Percent Clean Electricity in California: An Initial Assessment* https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349



(a) *(b)*

Figure 10. Sensitivity of September 2025 Gains from Trade to LSE Portfolio Composition with (a) SOD Resource Trading and (b) SOD Obligation Trading.

Modest shifts in the LSEs' portfolios from thermal capacity to 4-hour battery capacity of up to 25% of the original thermal capacity, have little impact on the gains from trade with both resource trading and obligation trading. After about 25% of the thermal capacity is replaced, however, the gains from trade rapidly decline. By the time all thermal capacity is replaced with 4-hour batteries, the gains from trade are only 10% of the gains with the original portfolio.

Changes in the internal prices of RA products with shifts in the portfolio composition help explain the reasons for the decline in the gains from trade. With the original portfolios, the aggregate accreditation of the resources in the LSE portfolios exceeded the aggregate obligations, allowing trades between LSEs to offset the need to purchase external RA. After about 20% of the thermal capacity is replaced by storage, the price of RA from thermal resources jumps to the level of the price of purchasing ExternalRA INC, indicating the aggregate surplus relative to obligations has disappeared. At this point trade between participants continues to be as high as with the original portfolios, though as thermal capacity is further removed, the ability for 4-hour battery storage to meet obligations begins to decline. At 20% reduction in thermal capacity, the price of solar and other sources of charging energy increases, and the price of hourly obligations outside of the traditional early evening peak net load hours also starts to increase. The broadening of hours where energy is needed to meet obligations reduce the diversity across LSEs and lowers the potential trading opportunities.

Future changes to the composition of LSE portfolios are uncertain. However, replacing 25% of the thermal resources by 4-hour battery storage would likely take multiple years. In the interim, mechanisms to enable trading between LSEs will continue to provide benefits comparable to the levels calculated with 2025 portfolios.

Appendix B. Calculating the Indirect Benefits of Reduced RA Demand

Mechanisms to enable trade between LSEs lowers demand for RA products from the external RA market. Lower demand for RA puts downward pressure on RA prices, indirectly lowering the costs of RA for all California LSEs. A general framework for quantifying these sorts of benefits to consumers comes from the "Demand Response Induced Price Reduction" or DRIPE that is used in Northeastern states as part of their evaluation of the costs and benefits of demand-side measures.[29] At a conceptual level, this indirect benefit of trade is illustrated in Figure 11. Small reductions in prices can create significant consumer savings when consumers purchase a large volume at market prices.

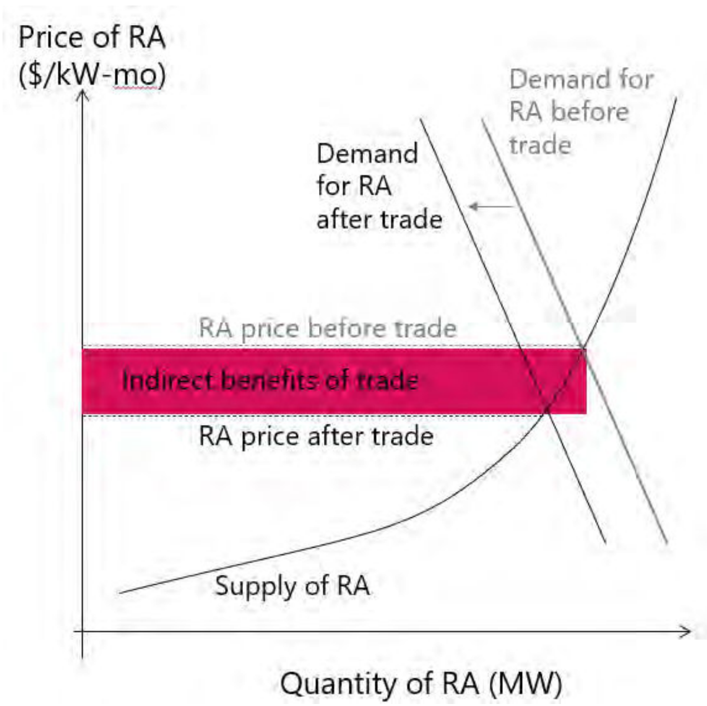


Figure 11. Illustration of the indirect benefits of trade from lower RA market prices

The indirect benefits are the area of the red rectangle. The height of the rectangle depends on the sensitivity of RA prices to RA demand (represented as *E*) and the reduction in RA demand attributable to trade (represented as *D*). The width of the rectangle is the volume of RA purchases that see the lower price due to decreased RA demand (represented as *Q*). Indirect benefits of trade are therefore *E*D*Q*.

One important caveat is that from an economic perspective, the price reduction effect is often seen as a transfer between suppliers and consumers rather than a net welfare

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[29] State and Local Energy Efficiency Action Network (2015*). State Approaches to Demand Reduction Induced Price Effects: Examining How Energy Efficiency Can Lower Prices for All.* Prepared by: Colin Taylor, Bruce Hedman, and Amelie Goldberg from the Institute for Industrial Productivity under contract to Oak Ridge National Laboratory. Available at: https://www.energy.gov/sites/default/files/2021-07/SEEAction-DRIPE.pdf

gain. From a consumer perspective, however, lower prices do make consumers better off at least in the short run. In addition, the California Public Utilities Commission recently suggested that high prices in the RA market are due in part to the exercise of market power.[30] Under non-competitive market conditions, mechanisms that provide additional pathways for trade between participants can mitigate suppliers' ability to raise prices. Lowering prices through increasing the competitiveness of markets can create a net increase economic welfare by reducing the deadweight loss associated with non-competitive behavior.[31]

The most uncertain parameter is the sensitivity of RA prices to RA demand (*E*). To estimate the price sensitivity, we compare the weighted-average price of RA sold to California LSEs in September to our estimate of the net supply in September for the California resource adequacy market for 2019 to 2024. The net supply is based on an RA stack analysis which compares the available supply of RA to the demand for RA using the legacy capacity accreditation approach based on ELCC factors.[32] As a coarse approximation, the sensitivity of RA price to RA demand is estimated as the slope of simple regression across these data points. The resulting slope of -1.0, seen in Figure 12, represents a decrease in the weighted-average RA price of $1.0/kW-mo for every GW decrease in RA demand (*E* = $1.0 kW/mo per GW).

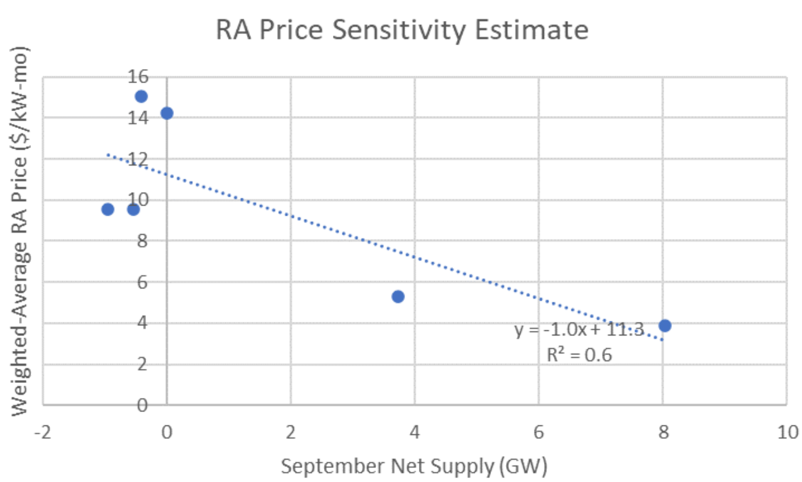

Figure 12. Approximation of sensitivity of RA prices to RA demand using September data from 2019-2024

The reduction in RA demand resulting from trade (*D*) is a direct result of our analysis of the CCA's 2025 year-ahead RA filings for the months of May through September, with

[30] Energy Division Staff Report of the 2024-2025 Resource Adequacy Market Price Benchmark (Feb., 26, 2025). Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M557/K608/557608990.PDF
[31] For an example of deadweight loss arising from non-competitive behavior in California electricity market see Borenstein, S., Bushnell, J.B. and Wolak, F.A., 2002. Measuring market inefficiencies in California's restructured wholesale electricity market. *American Economic Review*, *92*(5), pp.1376-1405.
[32] CalCCA. 2024. *California's Constrained Resource Adequacy Market: Ratepayers Left Standing in a Game of Musical Chairs.* January. : Available at: https://cal-cca.org/wp-content/uploads/2024/02/CalCCA-Stack-Analysis-2023-2026-updated-01_16_24-.pdf

obligations scaled to 100% the final obligations. Across the five summer months, we find that trade between CCA lowers demand for external RA (ExternalRA INC) by roughly 500 MW per month (D = 0.5 GW per mo). Additional details on the reduction in demand for external RA with trade in each month are provided in Appendix C.

Finally, we estimate the volume of RA that would be purchased at lower prices due to the reduction in RA demand (Q). This is again a difficult number to quantify with precision. We observe RA purchases by California LSE's of about 20 GW of capacity products on average across summer months in the FERC EQR dataset (Q = 20 GW each month).

Altogether, the indirect benefits of trade between the CCAs ($E*D*Q$) total approximately $50 million per year.

Appendix C. Gains from Trade in All Months

Table 1 and Table 2 detail the gains from trade across different policy environments using data from September 2024 and 2025. For completeness, we present the calculations for all months in Table 6.

Month and Year		Scenario	Short Position (a.k.a., ExternalRA INC) Before Trade (MW)	Short Position (a.k.a., ExternalRA INC) After Trade (MW)	Gains from Trade ($M)	Internal Trades Volume (MW)	Internal Trades Count	Internal Trades Average Connections	Internal Trades Monetary Transfer ($M)
June 2024	I.	Resource: ELCC	258	0	3.7	257	20	1.8	0.3
	II.	Obligation: ELCC	258	0	3.7	257	21	1.9	0.3
	III.	Resource: SOD	433	0	6.9	2,921	124	10.3	2.4
	IV.	Obligation: SOD	433	0	6.9	5,632	172	14.3	0.5
	III.*	Uncoordinated Resrc.: SOD	433	123	4.1	321	21	1.8	N/A
	IV.*	Uncoordinated Oblg.: SOD	433	6	5.6	3,752	112	9.3	N/A
September 2024	I.	Resource: ELCC	467	0	12.3	467	22	1.9	1.2
	II.	Obligation: ELCC	467	0	12.3	467	22	1.8	1.2
	III.	Resource: SOD	926	269	17.3	2,642	185	15.4	23.4
	IV.	Obligation: SOD	926	261	17.3	3,591	150	12.5	11.7
	III.*	Uncoordinated Resrc.: SOD	926	748	4.7	185	7	1.8	N/A
	IV.*	Uncoordinated Oblg.: SOD	926	645	7.2	4,654	122	10.2	N/A
May 2025	I.	Resource: ELCC	31	0	0.3	31	3	1.0	0.0
	II.	Obligation: ELCC	31	0	0.3	31	2	1.0	0.0
	III.	Resource: SOD	5	5	0.0	0	0	0.0	0.0
	IV.	Obligation: SOD	5	5	0.0	0	0	0.0	0.0
	III.*	Uncoordinated Resrc.: SOD	5	0	0.1	5	3	1.2	N/A
	IV.*	Uncoordinated Oblg.: SOD	5	0	0.1	14	7	1.8	N/A
June 2025	I.	Resource: ELCC	289	0	5.7	288	20	1.8	0.4
	II.	Obligation: ELCC	289	0	5.7	288	20	1.8	0.4
	III.	Resource: SOD	252	0	6.2	2,325	158	13.2	2.3
	IV.	Obligation: SOD	252	0	6.2	4,244	155	12.9	0.6
	III.*	Uncoordinated Resrc..: SOD	252	0	3.3	263	15	1.4	N/A
	IV.*	Uncoordinated Oblg.: SOD	252	1	3.3	1,923	87	7.3	N/A
July 2025	I.	Resource: ELCC	590	0	13.4	590	23	1.9	1.2
	II.	Obligation: ELCC	590	0	13.4	590	23	1.9	1.2
	III.	Resource: SOD	674	0	16.4	2,255	177	14.7	4.2
	IV.	Obligation: SOD	674	0	16.3	8,201	171	14.2	1.8
	III.*	Uncoordinated Resrc.: SOD	674	83	12.5	616	20	1.9	N/A
	IV.*	Uncoordinated Oblg.: SOD	674	49	13.1	6,297	134	11.2	N/A
August 2025	I.	Resource: ELCC	480	0	13.3	480	23	1.9	1.2
	II.	Obligation: ELCC	480	0	13.3	480	23	1.9	1.2
	III.	Resource: SOD	623	0	18.0	3,620	128	10.7	6.5
	IV.	Obligation: SOD	623	0	17.9	7,564	181	15.1	2.3
	III.*	Uncoordinated Resrc.: SOD	623	163	11.7	478	22	1.9	N/A
	IV.*	Uncoordinated Oblg.: SOD	623	40	14.8	4,839	127	10.6	N/A
September 2025	I.	Resource: ELCC	541	0	15.1	541	22	1.9	1.4
	II.	Obligation: ELCC	541	0	15.1	541	22	1.8	1.4
	III.	Resource: SOD	727	0	21.5	3,500	167	13.9	6.7
	IV.	Obligation: SOD	727	0	21.4	8,062	163	13.6	2.4
	III.*	Uncoordinated Resrc.: SOD	727	182	14.2	561	16	1.9	N/A
	IV.*	Uncoordinated Oblg.: SOD	727	27	18.1	6,613	120	10.0	N/A

Table 6. Summary of trade between CCAs across policy environments with data from all months