2023 PADILLA REPORT

Costs and Cost Savings for the RPS Program
(Public Utilities Code § 913.3)

PUBLISHED MAY 2023

California Public
Utilities Commission

About this Report

The purpose of this annual Report is to comply with Public Utilities Code § 913.3. Each May 1, the California Public Utilities Commission is required to report to the Legislature the aggregated costs and cost savings of renewable energy expenditures and contracts for the previous year.

A digital copy of this report can be found at:

https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/energy-reports-and-whitepapers/rps-reports-and-data

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1. Executive Summary

In compliance with Public Utilities Code § 913.3,[1] this report summarizes 2022 Renewables Portfolio Standard (RPS) program procurement expenditure and contract cost data. In 2022, total renewables generation decreased across load-serving entities while RPS contract costs also decreased in real-dollar value from 2021 costs.[2] The net result of this is that RPS procurement expenditures remained steady on a per GWh basis. These overall expenditures per GWh are expected to generally trend downward because RPS prices have been declining, supporting one of the original purposes of the RPS program, which was to be a cost-effective physical hedge against high and volatile fuel prices such as for fossil methane gas.

Key conclusions from this report include the following:

- The large investor-owned utilities' (IOUs) total annual RPS procurement expenditures decreased from $6.1 billion in 2021 to $5.2 billion in 2022 while total renewables generation also decreased from 54,483 GWh to 49,665 GWh, primarily as a result of load departure to Community Choice Aggregators (CCAs), resulting in a 2022 RPS percentage of retail load of 48.4%. This reflects a decrease in renewables expenditures on a per GWh basis.
- For small and multi-jurisdictional utilities (SMJUs), total annual RPS procurement expenditures decreased from $25.0 million in 2021 to $16.3 million in 2022 while total renewables generation decreased from 570 GWh to 477 GWh, resulting in a 2022 RPS percentage of retail load of 26%. This reflects a decrease in renewables expenditures on a per GWh basis.
- The large investor-owned utilities' average procurement expenditure for all RPS contracts online decreased in real-dollar value from 12.4 cents per kilowatt-hour (¢/kWh) in 2021 to 10.5 ¢/kWh in 2022. These costs included energy, capacity and renewable energy credits. In contrast, the average cost for non-RPS energy was 10.2 ¢/kWh. This represents a 0.3 ¢/kWh

[1] The full text of California Public Utilities Code (*hereinafter* Pub. Util. Code) § 913.3 can be found in Appendix D.

[2] All values in this report have been adjusted for inflation using the U.S. Bureau of Labor Statistics' Producer Price Index (PPI) for the Electric Power Generation, Transmission, and Distribution Industry. This PPI was chosen as an effective method for capturing price movement specific to a given industry prior to retail level price changes.

cost premium for their average RPS procurement expenditure compared to their average non-RPS procurement expenditure.

- Community choice aggregators' (CCAs) total annual RPS procurement expenditures for fixed price contracts increased from $286 million in 2021 to $537 million in 2022 while renewables generation also increased from 6,965 GWh in 2021 to 12,357 GWh in 2022, resulting in a 2022 RPS percentage of retail load of 52%. With the increase in both expenditures and procurement quantities, the overall expenditures per GWh remained about the same.[3]
- Electric Service Providers (ESPs) total annual RPS procurement expenditures for fixed price contracts increased from $4.1 million in 2021 to $6.7 million in 2022 while total fixed renewables generation similarly increased from 642 GWh in 2021 to 844 GWh. The net result is a 2022 RPS percentage of retail load of 37%. This reflects a decrease in renewables expenditures on a per GWh basis.
- RPS expenditures as a percent of total generation costs are on par with non-renewables. For instance, 48% of the large investor-owned utilities' retail load was generated from RPS-eligible resources, while expenditures on renewable generation was 48% of the large investor-owned utilities' total generation costs.
- The average price of RPS contracts that were executed in 2022 increased to 6.2 ¢/kWh as compared to a real dollar value of 3.0 ¢/kWh in 2021. Cost drivers include continued supply chain impacts as well as notable purchases of higher cost renewable resource types such as geothermal.

[3] See Table 3: Comparison of Community Choice Aggregator RPS Procurement and Procurement Expenditures between 2021 and 2022 at 11.

2. Background

Senate Bill (SB) 836 (Padilla, 2011) requires the California Public Utilities Commission (CPUC) to report on the Renewables Portfolio Standard (RPS) program to the Legislature regarding "the costs of all electricity procurement contracts for eligible renewable energy resources, including unbundled renewable energy credits, and all costs for utility-owned generation approved by the CPUC."[4]

The California RPS program was established in 2002 by Senate Bill (SB) 1078 (Sher, 2002) with the initial requirement that 20% of electricity retail sales must be served by renewable resources by 2017. The program was accelerated in 2006 under SB 107 (Simitian, 2006), which required that the 20% mandate be met by 2010. In April 2011, SB 2 (1X) (Simitian, 2011) codified a 33% RPS requirement to be achieved by 2020. In 2015, SB 350 (de León, 2015) mandated a 50% RPS by December 31, 2030. On September 10, 2018, SB 100 (de León, 2018) was signed into law, which further increased the RPS to 60% by December 31, 2030, with interim targets of 44% by December 31, 2024, and 52% by December 31, 2027, and sets the goal for all the state's electricity to come from zero carbon resources by 2045.[5]

The 2022 RPS procurement cost figures in this report were compiled from CPUC jurisdictional retail sellers: Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E); 3 SMJUs; 26 CCAs; and 10 ESPs.[6]

The annual procurement costs for generation in this report may not correspond precisely with the retail sellers' RPS compliance cost for the same year because the Renewable Energy Credits (RECs) associated with generation can be applied in later years for RPS program compliance purposes. Thus, the cost of procuring renewable energy might occur in one year and the RECs associated with generation may be applied in a later year.[7]

The annual expenditures for the IOUs may not be directly comparable to the SMJUs, CCAs, and ESPs because their approach to procurement and contracting differs from the other CPUC jurisdictional retail sellers. That is, the IOUs procurement contracts primarily have an "all-in" price that includes

[4] Pub. Util. Code § 913.3(a). SB 697 (Hertzberg, 2015) changed the numbering of the Pub. Util. Code sections, and specifically changed § 910 to Pub. Util. Code § 913.3. None of the original reporting requirements that were required under Pub. Util. § 910 were modified by SB 697. SB 1222 (Hertzberg, 2016) modified the reporting date for this report among other minor changes.

[5] See the CPUC's RPS website for more information about RPS program requirements and legislative history: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/rps.

[6] See Appendix E for a list of California's Active Load Serving Entities.

[7] See CPUC Decision (D.)12-06-038; D.17-06-026.

procurement of energy, capacity, and renewable energy credits (RECs) and curtailment expenditure terms. This is different than the SMJUs which are allowed to entirely procure unbundled RECs to meet their RPS requirements. By comparison, the CCAs may have contracts that only include energy and RECs and/or are priced in the manner of "Index + REC." Finally, ESPs traditionally have procured almost exclusively through such priced short-term contracts. Compliance Period 2021-2024 is the beginning of the 65 percent RPS long-term procurement requirement, and thus, there may be a decline in such contracting by the CCAs and ESPs to reduce potential cost volatility for their customers and move towards more long-term contracts.

3. Renewables Program Costs

This section addresses the costs associated with renewable resource procurement in 2022, consistent with the requirements of § 913.3(a)(1)-(2) and (b).

Section 913.3(a)(1)

For power purchase contracts, the commission shall release costs in an aggregated form categorized according to the year the procurement transaction was approved by the commission, the eligible renewable energy resource type, including bundled renewable energy credits, the average executed contract price, and average actual recorded costs for each kilowatt-hour of production. Within each renewable energy resource type, the commission shall provide aggregated costs for different project size thresholds.

Section 913.3(a)(2)

For each utility-owned renewable generation project, the commission shall release the costs forecast by the electrical corporation at the time of initial approval and the actual recorded costs for each kilowatt-hour of production during the preceding calendar year.

Section 913.3(b)

The commission shall report all electrical corporation revenue requirement increases associated with meeting the renewables portfolio standard, as defined in § 399.12, including direct procurement costs for eligible renewable energy resources and renewable energy credits.

The 2022 costs and cost savings discussed in this section include:

- RPS Procurement Expenditures
- RPS Aggregated Contract Prices
- Comparison of RPS Procurement Expenditures with Revenue Requirements (for IOUs only)

A. RPS Procurement Expenditures

This section provides information on 2022 weighted average expenditures and total RPS procurement expenditures for all categories of retail sellers. Generally, the real-dollar value of RPS expenditures[8] for retail sellers have trended down on a per GWh basis and this trend is expected to continue.[9]

Large Investor-Owned Utility Procurement Expenditures for 2022

The large IOUs' total annual RPS procurement expenditures in real-dollar value decreased from $6.1 billion in 2021 to $5.1 billion in 2022 primarily reflecting load departure to CCAs. This reflects a real-dollar value decrease in renewables expenditures on a per GWh basis. Compiled, detailed large IOU 2022 RPS procurement information is summarized in Appendix B of this report, expressed as weighted averages for RPS procurement expenditures in cents per kilowatt-hour (¢/kWh) categorized by IOU, technology, and size.[10]

Weighted Average Expenditures for Large IOUs

Based on the compiled 2022 data, weighted average RPS procurement expenditures were approximately 10.2 ¢/kWh across all RPS contracts, including REC-only contracts. This figure excludes IOU utility-owned generation (UOG) costs for renewables. This 2022 average is lower in real-dollar value than the 11.3 ¢/kWh average in 2021. When IOU UOG costs are included, this figure rises to 10.5 ¢/kWh as shown in Figure 1.

Figure 1 below illustrates the weighted average RPS procurement expenditures for renewable energy and associated RECs or bundled renewable energy in ¢/kWh for each of the large IOUs from 2003 through 2022.[11] The changes in weighted average expenditures over time for each large IOU are similar, and the key factors driving the cost differences between the large IOUs are the resource mixes and contract vintages.

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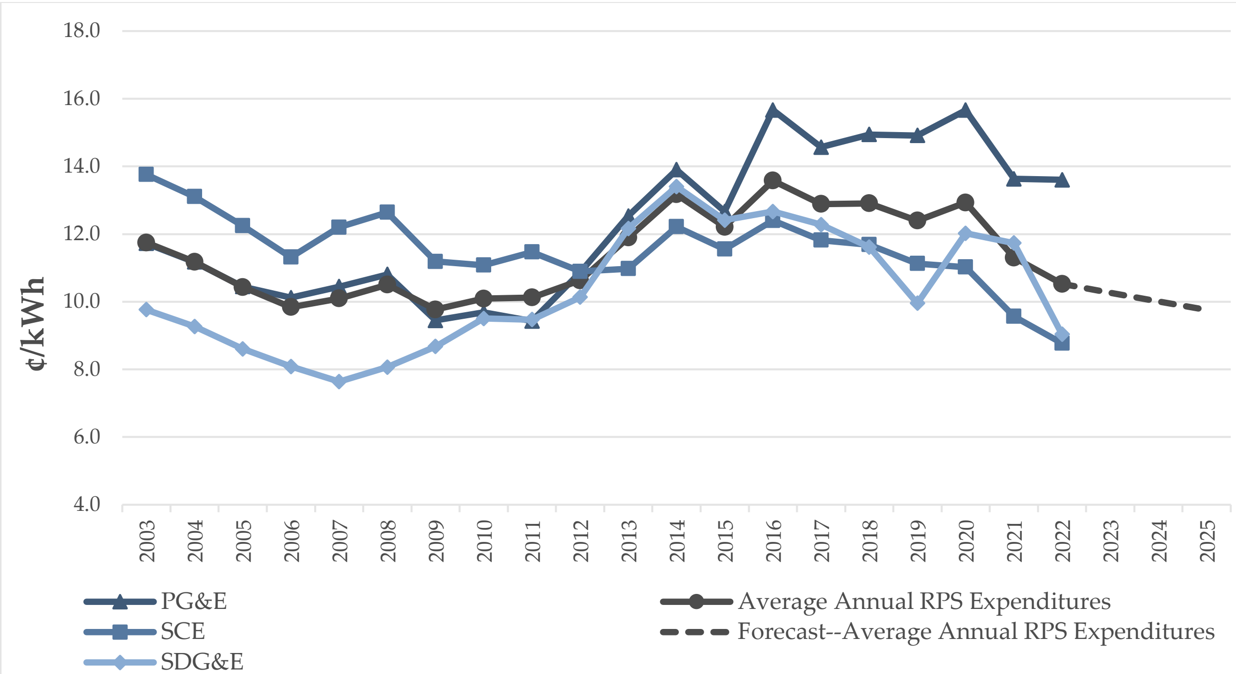
[8] Procurement Expenditures for 2022 include costs for all procurement from online RPS-eligible facilities that generated electricity in 2022. Large IOU procurement expenditures include payments for curtailment volumes which generally increases the unit price of energy reported. See California ISO's Managing Oversupply page for more information on curtailment: http://www.caiso.com/informed/Pages/ManagingOversupply.aspx.

[9] See also Lazard, Levelized Cost of Energy Analysis – Version 15.0 (October 2021) at 13: Certain renewable energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the continued cost decline of renewable energy generation technologies is the ability of technological development and industry scale to continue lowering operating expenses and capital costs for renewable energy generation technology.

[10] The cost of RPS procurement expenditures is weighted based on actual quantities of energy delivered.

[11] Bundled renewable energy is defined as renewable energy that is sold with its associated RECs as opposed to unbundled RECs that are sold separately from the underlying renewable energy generation.

Figure 1: Weighted Average RPS Procurement Expenditures of Investor-Owned Utilities' Bundled Renewable Energy from 2003-2025 (Real Dollars)



CPUC Report on RPS Costs and Cost Savings, May 2023

There was a lag between the large volume of contracts executed between 2007 and 2010 and the resulting increase in expenditures in the following years. This is because it takes several years from when a contract is executed to when the project delivers energy. Similarly, the forecast of average annual RPS expenditures decreases to reflect the fact that lower cost resources contracted with in the past several years are now starting to be reflected as lower actual RPS expenditures as those projects have been delivering energy.

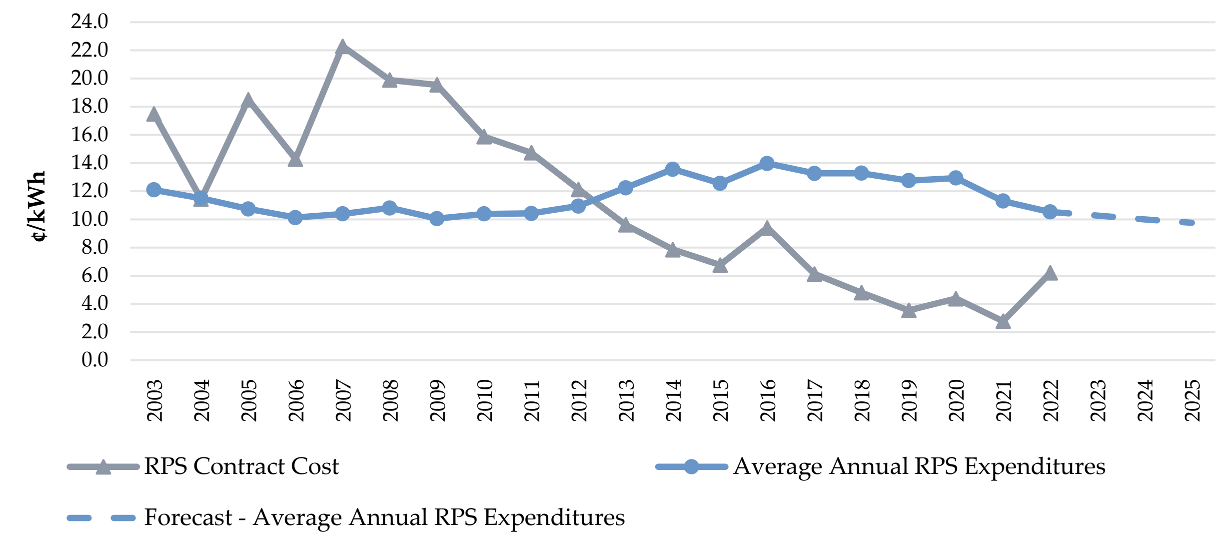
To approximate the impact of decreasing contract prices on future expenditures, Figures 1 and 2 include a forecasted decline in average annual RPS expenditures at a rate of 2.5% per year between 2022 and 2025. The forecasted 2.5% drop in total RPS expenditures is significantly less than the historic 10.3% annual decrease in contract prices.[12] This forecast was selected because the impact of falling contract prices in future years is dampened by the cumulative RPS expenditures resulting from the state's increasing renewable goals, since over time each year's newly generating contracts represent a smaller and smaller portion of the IOUs' entire renewable portfolio. Figure 2 includes RPS contract

[12] See Figure 4 at 16.

costs executed in 2019 through 2022 for all retail sellers and IOUs' contract costs executed before 2019.

Historic contract price trends for the RPS program can be seen in Figures 2 and 3, which show that executed contract prices peaked in 2007 and have been falling for RPS-eligible resources. See Appendix C for 2022 contract price data.

Figure 2: RPS Program Expenditures and Fixed Contract Costs from 2003-2025[13] (Real Dollars)



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Total Expenditures for Large IOUs

The large IOUs' total combined direct RPS procurement expenditures decreased in real-dollar value from $6.1 billion in 2021 to $5.2 billion in 2022.[14] The IOUs' renewable procurement in 2022 also

[13] All values in this report have been adjusted for inflation using the U.S. Bureau of Labor Statistics' Producer Price Index (PPI) for the Electric Power Generation, Transmission, and Distribution Industry. This PPI was chosen as an effective method for capturing price movement specific to a given industry prior to retail level price changes.

[14] See Table 4 at 12.

decreased compared to 2021 procurement, from 54,483 GWh to 49,665 GWh, or from 51.5% to 48.4% of their retail load.[15]

Large IOUs' RPS Sales Solicitations

In 2022, retail sellers procured RPS energy resulting from the large IOUs' RPS sales solicitations for RPS energy and renewable energy credits (RECs). RPS sales offer a path for smaller or newer retail sellers to procure RECs to meet their RPS compliance obligations while reducing the large IOUs' expenditures or costs for IOU customers. Table 1 below provides a summary of the large IOUs' RPS sales in 2022.

Table 1: Large IOUs' 2022 RPS Sales Summary

IOU	RPS Sales (GWh)	RPS Sales Revenue (millions)
PG&E	2,936	$38.8
SCE	5,872	$77.4
SDG&E	1,180	$15.6
Total	9,988	$131.8

Small and Multi-Jurisdictional Investor-Owned Utility Procurement Expenditures for 2022

In 2022, Liberty Utilities (Liberty), PacifiCorp, and Bear Valley Electric Service (BVES) spent approximately $16.3 million on RPS procurement as shown in Table 2. The SMJUs' RPS resources include biomass, geothermal, hydroelectric, solar photovoltaic, and wind.

Weighted SMJU Average Expenditures

In 2022, the weighted average RPS procurement expenditure for all Liberty contracts was 3.6 ¢/kWh, 3.9 ¢/kWh for PacifiCorp, and 1.2 ¢/kWh for BVES.[16]

[15] The IOUs' 2022 RPS percentage may differ from the forecast reported in the 2022 RPS Annual Report which does not account for RPS sales in 2022 and reduces the IOUs' overall RPS percentage. The IOUs' RPS percentage for 2022 will be verified and reported in the 2023 RPS Annual Report to the Legislature in November 2023 following the IOUs' compliance filings for the 2022 calendar year.

[16] BVES's 2022 procurement expenditure data includes strictly REC-only contracts; therefore, it is not comparable to the other utilities' 2022 expenditures as they procured significant quantities of contracts that include the cost of acquiring RECs, capacity, and energy.

Total SMJU Expenditures

For 2022, Liberty, PacifiCorp, and BVES had a total combined RPS procurement expenditure of $16.3 million compared to $25.0 million in 2021 in real-dollar value. The SMJUs' total renewable procurement decreased by approximately 93 GWh from 2021 to 2022 and their average RPS procurement percentage decreased to 25.9%.[17]

Table 2: Small and Multi-Jurisdictional Investor-Owned Utilities' Total RPS Expenditures in 2022

	Liberty	PacifiCorp	Bear Valley Electric Service
Total (millions)	$8.7	$6.9	$0.6

Community Choice Aggregator and Electric Service Provider Procurement Expenditures for 2022

In 2022, there were 26 Community Choice Aggregators (CCAs) and 10 Electric Service Providers (ESPs) that served load and procured RPS-eligible energy. The CCAs' and ESPs' RPS portfolios include bioenergy, geothermal, small hydroelectric, solar photovoltaic, wind, and unbundled RECs. Tables 3 and 4 provide a summary of RPS procurement in 2021 and 2022 for CCAs and ESPs. The CCAs' total RPS fixed price contract expenditures increased in 2022 primarily due to increasing load.[18] Meanwhile, ESPs' total fixed price expenditures and procurement in 2022 also increased in comparison to 2021.[19]

It is important to note that the CCA and ESP RPS expenditures reported below cannot be directly compared to the IOUs' RPS procurement expenditures because a portion of delivered energy in 2022 for CCAs and a large majority for ESPs originated from "Index plus REC" contracts. ESP and CCA Index plus REC contracting trends are shown below in Figure 3.[20] The reported contract price for Index plus REC contracts represents the incremental renewable cost, set at a negotiated amount in

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[17] *Supra* note 16 at 9.

[18] For information regarding CCAs' forecasted RPS compliance, see CCAs' average actual and forecasted RPS percentages in the 2022 RPS Annual Report to the Legislature at 15.

[19] For information regarding ESPs' forecasted RPS compliance, see ESPs' average actual and forecasted RPS percentages in the 2021 RPS Annual Report to the Legislature at 18.

[20] Index plus REC contracts generally define "Index" energy as the CAISO Integrated Forward Market Day Ahead Price for CAISO SP-15 or NP-15 when the energy is delivered.

dollars per megawatt-hour ($/MWh) for the REC, while the price for energy in these contracts can change depending on when energy is delivered to the electricity grid pursuant to the contract.[21]

Index plus REC contracts differ significantly from "all-in" price RPS contracts for energy, RECs, and capacity, which make up the entirety of the IOUs' RPS portfolios, where the price is otherwise "fixed" or set over the term of the contract. This difference in pricing constructs not only prevents comparison between the contract types, but also introduces price volatility into the RPS program which it was originally designed to address. In addition, it is important to consider contract vintages, as the IOUs executed a majority of their RPS procurement contracts in earlier years when technology prices were generally higher than that of more recent CCA and ESP contracts.

The weighted average expenditures and total expenditures for CCAs and ESPs detailed in Table 3 and Table 4 below do not incorporate the energy costs for the Index plus REC contracts – expenditures show only "fixed" costs.

Table 3: Comparison of Community Choice Aggregator RPS Procurement and Procurement Expenditures between 2021 and 2022

	2021	2022
Weighted Average Fixed Contract Expenditures (¢/kWh)	4.1	4.3
Total Fixed Contract Expenditures (millions) [22]	$286	$537
Total Renewable Energy Delivered from Fixed Contracts (GWh)[23]	6,965	12,357
Average RPS Procurement (Fixed and Indexed Contracts) Percentage[24]	49%	52%

[21] In the CAISO's most recently released Annual Report on Market Issues and Performance, the average day-ahead energy price in 2021 was $53/MWh.(See CAISO's 2020 Annual Report on Market Issues and Performance, p. 5, (http://www.caiso.com/Documents/2021-Annual-Report-on-Market-Issues-Performance.pdf)). The price varies from the average depending on grid conditions and market supply and demand. For example, the average day-ahead price in 2020 was $35/MWh.

[22] Total expenditures are derived from CCA responses to Energy Division's RPS-PCIA Semi-Annual Data Report, submitted February 1, 2023.

[23] Total renewable energy delivered is derived from CCA responses to Energy Division's RPS-PCIA Semi-Annual Data Report, submitted February 1, 2023.

[24] See Table 4 in the 2022 RPS Annual Report to the Legislature (p. 15).

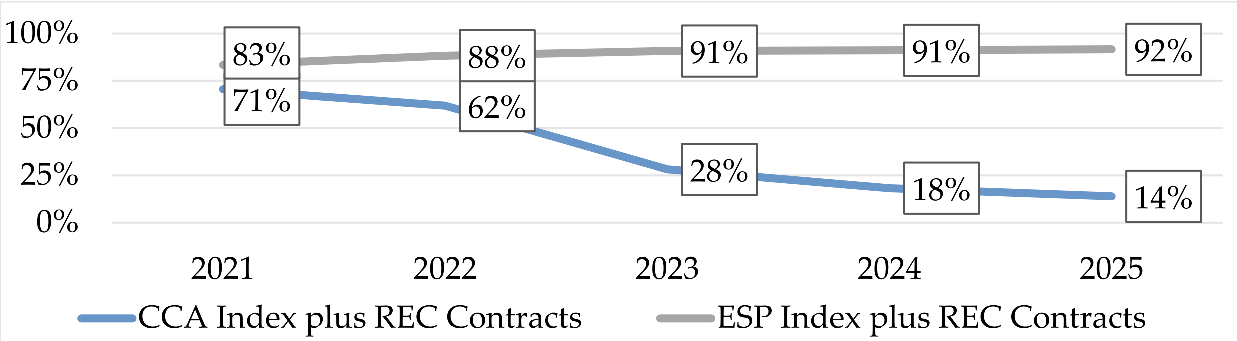
CCAs' total annual RPS procurement expenditures for all contracts, both fixed price and Index plus REC, decreased from $814 million in 2021 to $810 million in 2022, whereas renewables generation increased from 24,625 GWh in 2021 to 31,775 GWh in 2022.

Table 4: Comparison of Electric Service Provider RPS Procurement and Procurement Expenditures between 2021 and 2022

	2021	2022
Weighted Average Expenditures (¢/kWh)	0.64	0.80
Total Fixed Contract Expenditures (millions) [25]	$4.1	$6.7
Total Renewable Energy Delivered from Fixed Contracts (GWh)[26]	642	844
Average RPS Procurement (Fixed and Indexed Contracts) Percentage[27]	30%	37%

ESPs' total annual RPS procurement expenditures for all contracts, both Fixed price and Index plus REC, increased from $30 million in 2021 to $92 million in 2022 while renewables generation also increased from 3,881 GWh in 2021 to 7,191 GWh in 2022.

Figure 3: Comparision of Index plus REC Contracts in the CCAs' and ESPs' RPS Portfolios



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[25] Total expenditures are derived from ESP responses to Energy Division's RPS-PCIA Semi-Annual Data Report, submitted February 15, 2023.

[26] Total renewable energy delivered is derived from ESP responses to Energy Division's RPS-PCIA Semi-Annual Data Report, submitted February 15, 2023.

[27] See Table 6 in the 2022 RPS Annual Report to the Legislature.

Figure 3 shows the percentage of CCA and ESP RPS contracts with Index plus REC price terms. The remaining contracts in their RPS portfolios have a fixed price term, i.e. all-in RPS contract.

CCAs as a group have reduced their reliance on Index plus REC contracts in recent years, increasing the proportion of fixed price contracts. The CCAs' shift to more fixed price contracts is in part due to the prevalence of fixed price terms with long-term contracts, and the proportion of long-term contracts in all retail seller's portfolios has increased with the 65% long-term contracting rule. The CCAs increased use of fixed price contracts also means they now have a greater hedge against price fluctuations in the energy markets from their RPS portfolio.

On the other hand, ESPs as a group have increased their use of Index plus REC contracts. As a result of the ESPs' preference for Index plus REC contracts, their RPS portfolios generally do not provide much of a hedge against price volatility in the energy markets. It is worth noting that not all CCAs and ESPs follow the trends of their peer groups, i.e. some ESPs are strategically hedging their exposure to energy markets with fixed price RPS contracts and some CCAs are not.

B. Voluntary Allocation and Market Offer

Through D.21-05-030, the CPUC adopted the Voluntary Allocation and Market Offer (VAMO) framework to optimize the value of excess resources in the large IOUs' portfolios, primarily driven by IOU load shifting to CCA service. The VAMO process was implemented in the RPS proceeding.

The CPUC approved the IOUs' voluntary allocations of Power Charge Indifference Adjustment (PCIA) eligible contracts based of the retail sellers' forecasted, vintaged, annual load (MWh) shares and actual, vintaged, annual RPS energy production.[28] Appendix F lists retail sellers that accepted voluntary allocations.[29] Moreover, the CPUC has established rules for the Market Offer solicitation process that the large IOUs are implementing.[30]

VAMO cost data is not provided in this report because although the Voluntary Allocation contracts recently started transacting RPS products and the large IOUs are currently administering Market Offer solicitations, this report only reports on data from the year 2022 and earlier. While this year's report does not provide cost data on the VAMO process, this issue may have a meaningful impact on retail sellers' portfolios future costs and expenditures. For example, the low levels of RPS procurement in GWh carried out by CCAs and ESPs in 2022 may reflect an assumption of future procurement through the VAMO mechanism in this Compliance Period (2021-2024).

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28 D.22-11-021 at OP 1; D.21,05,030 at OP 7.

29 D.22-11-021 at Attachment A.

30 D.22-11-021.

C. Comparison of RPS Procurement Expenditures to Revenue Requirements (Large IOUs Only)

Large Investor-Owned Utilities

Table 5 compares IOUs' RPS procurement expenditures to revenue requirements. Specifically, the table shows the percentage of RPS procurement compared to total procurement for these IOUs' generation portfolios, as well as the RPS procurement costs as a portion of the total revenue requirement. Additionally, Table 5 shows the large IOUs' RPS generation percentages for 2022.

Table 5 also shows that in 2022, RPS procurement expenditures on average were less than 15% of the IOUs' total revenue requirements. Compared to the total generation revenue requirements, the RPS expenditures make up a significantly smaller portion of the total revenue requirements, since total revenue requirements contain many large line items such as transmission expenditures, reliability costs, wildfire safety and mitigation programs, administrative costs, and capital expenses.

Table 5: Comparison of Large Investor-Owned Utilities' RPS Procurement to Revenue Requirements in 2022[31,32]

IOU	RPS Generation	RPS Procurement Expenditures (billions)	Total Generation Revenue Requirement (billions)	RPS Procurement Expenditures to Total Generation Revenue Requirement (%)	Total Revenue Requirement (billions)	RPS Procurement Expenditures to Total Revenue Requirement (%)
PG&E	34.3%	$2.41	$4.58	53.0%	$15.11	16.0%
SCE	63.2%	$2.21	$5.12	43.0%	$15.27	14.0%
SDG&E	60.3%	$0.61	$1.14	53.5%	$4.27	14.2%

As retail sellers – including the large IOUs – are required to procure increasingly higher percentages of RPS-eligible energy, they are procuring less non-RPS-eligible energy for their electric portfolios.

[31] Revenue requirement numbers have been taken from the CPUC's "2022 California Electric and Gas Utility Cost Report" pursuant to Public Utilities Code § 913, April 2022.

[32] RPS generation percentages are calculated by dividing the IOUs' RPS generation serving retail load by the IOUs' total generation.

Consequently, the proportion of the revenue requirement that can be attributed to increased RPS procurement is difficult to calculate, particularly as RPS expenditures are largely in-line with non-RPS expenditures on a ¢/kWh basis. However, considering that RPS energy is replacing non-RPS energy, one approximation is to compare the cost of RPS energy to non-RPS energy in retail sellers' portfolios, which is explored in the next section.

In 2022, the large IOUs' average cost of renewable energy was 10.5 ¢/kWh and the average cost of non-RPS energy was 10.2 ¢/kWh.[33] Using this metric, large IOUs' renewable energy procurement likely added a premium of 0.3 ¢/kWh on average for the renewable energy procured to meet their RPS requirements.[34] However, as explained in Section 4 (below), this is an imperfect comparison, because it does not reflect likely savings from non-renewable energy demand reductions lessening their reliance on higher-cost providers and thus decreasing unit cost.

Small and Multi-Jurisdictional Investor-Owned Utilities, Community Choice Aggregators and Electric Service Providers

As the 2022 revenue requirement information for Liberty, BVES, and PacifiCorp is currently confidential pursuant to CPUC confidentiality rules,[35] the CPUC is not able to publicly analyze SMJU costs compared to their revenue requirements for 2021. For the CCAs and ESPs, the CPUC does not regulate their rates and thus does not have their revenue requirement information.

D. RPS Aggregated Contract Prices

The CPUC examined the IOUs', CCAs', and ESPs' 2019 - 2022 executed contract prices.[36] Moreover, the CPUC also reviewed IOUs' RPS contracts executed between 2003 and 2018 to provide historic contract cost trends.[37]

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[33] See Table 7 at 20.

[34] The average RPS cost savings compared to non-RPS energy on a kilowatt-hour basis is represented by the following equation: *10.5 ¢/kWh (RPS Energy) - 10.2 ¢/kWh (Non-RPS Energy) = 0.3 ¢/kWh.*

[35] See D.06-06-066 for confidentiality rules related to revenue requirements.

[36] 2019 through 2022 Contract price data for IOUs, CCAs and ESPs were obtained through a joint data request pursuant to PU Code Section 913.3 and the *Power Charge Indifference Adjustment (PCIA)* proceeding. Contract data for 2003-2019 was self-reported by the IOUs through the CPUC's RPS Executed Projects Database.

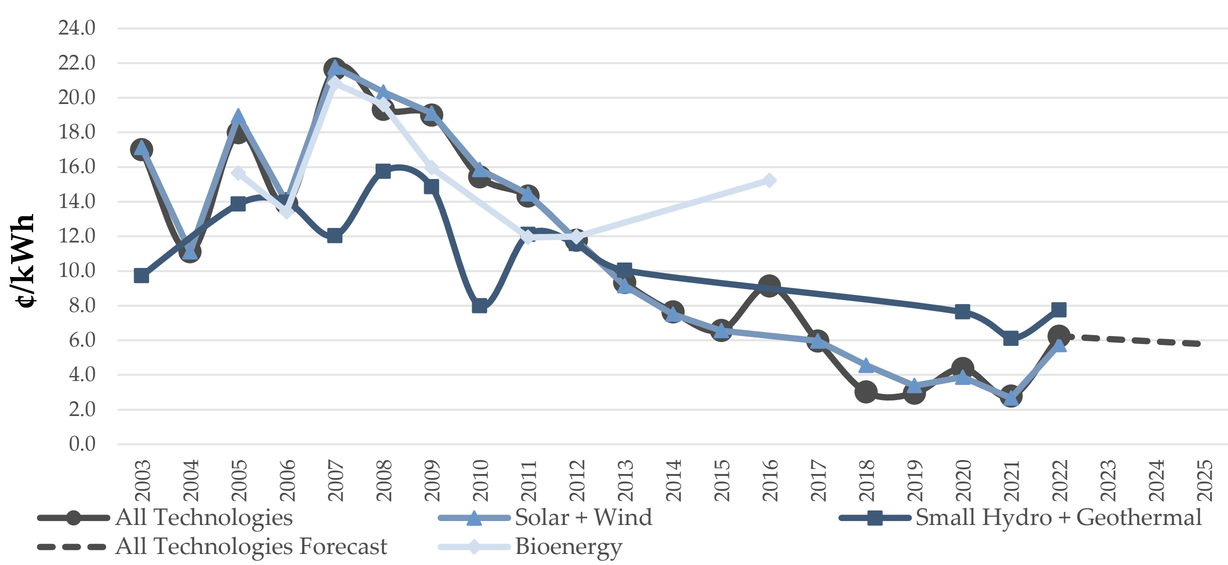
[37] *See id.*

RPS Contract Prices for Resources Greater than 3 MW

Figure 4 below shows that RPS contract prices, in real-dollar value, decreased an average of 1.3% annually between 2007 and 2022. Almost all procurement contracts with new facilities in 2022 were executed by CCAs.

To remove non-representational trends, contracts with a nameplate capacity of 3 MW or less were not included in Figure 4.[38]

Figure 4: Historical Trend of All Load Serving Entities' RPS Contract Costs by Technology and Year of Execution from 2003-2025 (Real-Dollar Value)[39]



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The average price of IOU, CCA and ESP contracts executed in 2022 that were greater than 3 MW was 6.2 ¢/kWh compared to 4.3 ¢/kWh in real-dollar value in 2021.

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[38] Projects with a capacity of 3 MW or less made up a little over 1% of all of the IOUs' contracted RPS capacity, and removing these figures eliminated non-representative trends from the data. As a result of this size exclusion, feed-in-tariff projects were not considered in the analysis above. In California, feed-in-tariff programs offer projects with a capacity of 3 MW or less a predetermined price ($/MWh) to encourage market transformation for projects at these sizes. Additionally, contracts identified as REC-only payments were excluded as these values are not comparable to all-in energy, capacity, and REC contract prices.

[39] See Appendix C for weighted average time-of-delivery (TOD) adjusted prices for RPS contracts signed in 2022, including those with a nameplate capacity below 3 MW.

RPS Contract Prices for Resources 3 MW and Less

As noted above, RPS resources with a nameplate capacity of 3 MW or less are not included in Figure 4. Accordingly, the large IOU's contracts signed in 2022 under the Renewable Market Adjust Tariff (ReMAT) and Bioenergy Market Adjusting Tariff (BioMAT) programs were not included.

IOU Renewable Market Adjusting Tariff (ReMAT) Contracts

ReMAT is a Feed-in-Tariff program for small RPS-eligible facilities such as small hydro, solar PV, and wind, to sell renewable electricity to the IOUs under standard terms and conditions. ReMAT projects fall under three product types: As-Available Peaking, As-Available Non-Peaking, and Baseload. The offered contract price for each product type is calculated using recent wholesale RPS contracts and is updated annually by CPUC resolution. No ReMAT contracts were executed in 2022, though the program was reopened in 2020,[40] and program rules were modified in 2021.[41]

IOU Bioenergy Market Adjusting Tariff (BioMAT) Contracts

BioMAT is a bioenergy Feed-in-Tariff program that deviates from the solicitation process for contracts included in Figure 4 by using a standard contract and a market-based mechanism to arrive at the offered program contract price. BioMAT intends to promote a competitive market via a simple procurement mechanism for bioenergy market entrants. BioMAT allocates procurement to the discrete bioenergy categories of Biogas, Dairy/Agriculture, and Sustainable Forest Management. Table 6 shows the average BioMAT contract price and total capacity procured in 2022 by the three IOUs.

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[40] D.20-10-005; https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M348/K746/348746212.PDF.

[41] D.21-12-032; https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M433/K005/433005845.PDF.

Table 6: Large Investor-Owned Utilities' 2022 BioMAT Procurement Summary

BioMAT Category	Contracted Capacity (MW)	Average Contract Price (¢/kWh)
Biogas	5	12.5
Dairy/Agriculture	12	18.8
Sustainable Forest Management	6	20.2
Total	**23**	**17.9**

CCA Feed-in-Tariff Contracts and Facilities 3 MW or Less

The CCAs are not required to offer BioMAT or ReMAT contracts. During 2022, the CCAs did not execute any new-build RPS-eligible facilities with 3 MW or less of capacity.[42]

Bioenergy Renewable Auction Mechanism (BioRAM) Contracts

Pursuant to the Governor's Emergency Order Addressing Tree Mortality, Senate Bill (SB) 859 and SB 901, the BioRAM program required the large IOUs to procure 146 MWs of bioenergy from High Hazard Zones to aid in mitigating the threat of wildfires. Since 2016, the IOUs have executed contracts with seven biomass facilities to meet their BioRAM procurement requirements.[43]

The total number of biomass facilities in the enrolled in the program decreased in 2022 from seven to six for a combined total capacity of 154 MW and an average contract price of 11.3 ¢/kWh, respectively.

[42] This data was obtained through the joint RPS-PCIA Semi-Annual Data Report, submitted February 15, 2023.

[43] CCAs and ESPs are not required to execute BioRAM contracts but are allocated a proportional cost through a non-bypassable charge.

4. Renewables Program Cost Premiums and/or Savings

This section addresses the cost premiums and/or savings associated with the large IOUs', SMJUs', CCAs', and ESPs' procurement of renewable resources in 2022, consistent with the requirements of § 913.3(c).

Section 913.3(c)

The commission shall report all cost savings experienced, or costs avoided, by electrical corporations as a result of meeting the renewables portfolio standard.

For the purposes of this report, the utilities' 2022 RPS procurement costs are compared to non-RPS procurement costs to determine cost savings. This comparison likely exaggerates RPS procurement costs, since any premiums for avoided construction of new, and therefore more expensive, non-RPS resources and any gas cost savings resulting from lower gas demand are not reflected in this comparison. However, it is difficult to quantify the cost savings, or avoided costs, associated with the RPS program because this would require assessing to what extent the RPS program deferred or replaced construction of alternative generation facilities and the theoretical cost of those alternative resources. The CPUC also cannot estimate the impacts that increased renewables and the resulting reduction of natural gas demand has had on the cost of natural gas in California. Further, non-RPS resource costs, such as Resource Adequacy, are based on the preexisting supply of facilities and capacity need that are not tethered to the same market considerations as RPS contracts. Additionally, CCAs and ESPs have contracts that do not provide fixed price contracts for energy and capacity and are tied to index prices. This limits and in some instances prevents cost comparisons in this report. This procurement approach may also introduce price volatility in California's RPS Standard program which the program was designed in part to address.

Consequently, there is no perfect counterfactual to assess the RPS program's cost savings, because in the absence of RPS procurement, non-RPS resources would still be procured. This challenge is also reflected in the previous section's assessment of RPS expenditures as part of utilities' revenue requirements, in which the variables that inform the cost savings analysis are described as imperfect because they are not narrowly tailored to capture the benefits and costs of the RPS program.

A. Large Investor-Owned Utilities' Cost Premiums / Savings

In 2022, the large IOUs' average annual RPS procurement expenditure represented a weighted average 0.3 ¢/kWh cost premium versus their average non-RPS procurement expenditure.[44] Individually, as per Table 7, PG&E and SCE saved 0.4 ¢/kWh and 0.1 ¢/kWh, respectively. Conversely, SDG&E paid a premium for RPS energy—compared to non-RPS energy—of 0.9 ¢/kWh.[45] This pattern is largely consistent with previous years, though it has also been influenced by factors such as supply chain constraints on renewable energy development, or fuel cost volatility for non-RPS costs.

Table 7: Large Investor-Owned Utilities' 2022 Average RPS and Non-RPS Eligible Procurement Expenditure[46] (¢/kWh)

Method	PG&E	SCE	SDG&E	Weighted Average
2022 Non-RPS	14.0	8.9	8.2	10.2
2022 RPS	13.6	8.8	9.0	10.5

Based on total volumes of RPS and non-RPS eligible procurement expenditures, the large IOUs are estimated to have realized the following cost savings or premiums versus an equivalent amount of Non-RPS procurement, displayed as positive or (negative) figures:

Table 8: Large Investor-Owned Utilities' 2022 RPS Cost Savings: Non-RPS Eligible Comparison[47]

Cost Savings Compared to 2022 Average Non-RPS Expenditure (millions)	
PG&E	$64.3
SCE	$29.3
SDG&E	($59.7)
Cost savings are displayed as positive figures while cost premiums are displayed as (negative) figures.	

[44] *Supra*, note 34 at 15.

[45] This savings appears inconsistent with Table 7 due to the RPS and Non-RPS values rounding in different directions.

[46] Derived from responses to Energy Division's RPS-PCIA Semi-Annual Data Report, submitted February 15, 2023 and CPUC's 2022 AB 67 report, published April 2023

[47] Cost savings or premiums are calculated by multiplying each IOU's average 2022 non-RPS eligible expenditure (Table 7) by its total volume of RPS procurement in 2022 then subtracting that value from the IOUs' 2022 RPS procurement expenditure (Table 5).

B. Small and Multi-Jurisdictional Investor-Owned Utilities' Cost Premiums / Savings

In 2022, the RPS procurement expenditure for SMJUs represented a 2.7 ¢/kWh cost savings compared to their average non-RPS-eligible expenditure. The cost savings for RPS energy compared to non-RPS energy for Liberty and PacifiCorp was 7.7 ¢/kWh and 1.9 ¢/kWh, respectively. BVES' RPS procurement consisted solely of REC-only products; thus, BVES' RPS expenditures are not directly comparable to their non-RPS expenditures, which include additional costs for obtaining energy and capacity benefits.

Table 9: Small and Multi-Jurisdictional Investor-Owned Utilities' 2022 Average Non-RPS Eligible Procurement Expenditure (¢/kWh)

Method	Liberty	PacifiCorp	Bear Valley Electric Service	Weighted Average
2022 Non-RPS	11.3	5.8	7.5	7.8
2022 RPS	3.6	3.9	1.2 (REC Only)	3.4[48]

Based on total volumes of RPS generation procured and non-RPS eligible procurement expenditures, the SMJUs realized the following cost savings (positive figures) or premiums (negative figures):

Table 10: Small and Multi-Jurisdictional Investor-Owned Utilities' 2022 RPS Cost Savings: Non-RPS Eligible Comparison[49]

	Cost Savings Compared to 2022 Average Non-RPS Expenditure (millions)
Liberty	$19.0
PacifiCorp	$3.6
Bear Valley Electric Service	N/A
Cost savings are displayed as positive figures while cost premiums are displayed as negative figures.	

[48] The SMJUs' 2022 average RPS procurement expenditure calculation includes BVES' RPS procurement expenditures consisting solely of REC-only products.

[49] Cost savings or premiums are calculated by multiplying each SMJU's average 2022 non-RPS eligible expenditure (Table 9) by its total volume of RPS procurement in 2022 then subtracting that value from the SMJUs' 2022 RPS procurement expenditure (Table 2).

C. Community Choice Aggregators' Cost Premiums / Savings

In 2022, the RPS procurement expenditure for CCAs represented a 1.0 ¢/kWh cost savings compared to their average non-RPS-eligible expenditure.[50] As mentioned previously, the weighted average RPS expenditures for CCAs excludes the Index plus REC contracts and cannot be directly comparable to the IOUs' and SMJUs' RPS expenditures.

Table 11: Community Choice Aggregators' 2022 Average Non-RPS Eligible Procurement Expenditure (¢/kWh)

Method	Weighted Average
2022 Non-RPS	5.4
2022 RPS	4.3

Based on total volumes of RPS generation procured and non-RPS eligible procurement expenditures, the CCAs are estimated to have realized the following cost savings versus an equivalent amount of Non-RPS procurement:

Table 12: Community Choice Aggregators' 2022 RPS Cost Savings Compared to Non-RPS Energy [51]

	Cost Savings Compared to 2022 Average Non-RPS Expenditure (million)
Community Choice Aggregators	$124.5
Cost savings are displayed as positive figures while cost premiums are displayed as negative figures.	

D. Electric Service Providers' Cost Premiums / Savings

In 2022, the RPS procurement expenditure for ESPs represented a 9.4 ¢/kWh cost savings compared to their average non-RPS-eligible expenditure. As mentioned previously, the weighted average RPS expenditures for ESPs do not incorporate the Index energy price for the Index plus REC contracts and cannot be directly comparable to the IOUs' and SMJUs' RPS expenditures.

[50] This savings appears inconsistent with Table 11 due to the RPS and Non-RPS values rounding in different directions.

[51] Cost savings or premiums are calculated by multiplying CCAs' average 2022 non-RPS eligible expenditure (Table 11) by volume of RPS procurement in 2022 (excluding Index + REC deliveries) then subtracting that value from the CCAs' 2022 RPS procurement expenditure (Table 3).

Table 13: Electric Service Providers' 2022 Average Non-RPS Eligible Procurement Expenditure (¢/kWh)

Method	Weighted Average
2022 Non-RPS	10.2
2022 RPS	0.8[52]

Based on total volumes of RPS generation procured and non-RPS eligible procurement expenditures, the ESPs are estimated to have realized the following cost savings versus an equivalent amount of Non-RPS procurement:

Table 14: Electric Service Providers' 2022 RPS Cost Savings Compared to Non-RPS Energy

	Cost Savings Compared to 2022 Average Non-RPS Expenditure (millions)
Electric Service Providers	$79.0
Cost savings are displayed as positive figures while cost premiums are displayed as negative figures.	

[52] Weighted average RPS expenditures for ESPs do not incorporate the Index energy price for the Index plus REC contracts. See footnote 21 for the most recent Index energy price reported by CAISO.

5. Appendices

Appendix A: California Public Utilities Commission RPS Activities and Milestones

January 2022	▪ CPUC adopted D.22-01-004 on the 2021 RPS Procurement Plans[53] ▪ CPUC adopted D.22-01-025 on Gexa ESP enforcement and penalty.[54] ▪ CPUC staff held a BioMAT Technical Working Group meeting to review CPUC staff's progress in the evaluation of existing greenhouse gas life cycle analysis tools
February 2022	▪ CPUC staff held three BioMAT Technical Working Group meetings to seek feedback from working group members on CPUC staff's ongoing evaluations of existing greenhouse gas life cycle analysis tools
March 2022	▪ CPUC staff conducted a follow-up BioMAT Technical Working Group meeting to seek additional feedback from working group members on CPUC staff's ongoing evaluations of existing greenhouse gas life cycle analysis tools
April 2022	▪ CPUC issued the Assigned Commissioner and Assigned Administrative Law Judge's Ruling issued identifying issues and schedule of review for 2021 RPS Procurement Plans[55] ▪ CPUC issued the Assigned Commissioner and Assigned Administrative Law Judge's Ruling Amending the Scope of R.18-07-003 to implement VAMO as adopted in D.21-05-030[56] ▪ CPUC staff held three BioMAT Technical Working Group meetings to seek feedback from working group members on CPUC staff's initial evaluation results of existing greenhouse gas life cycle analysis tools
May 2022	▪ CPUC issued the 2022 Padilla Report on Costs and Cost Savings for the RPS Program to the Legislature, pursuant to Public Utilities Code § 913.3: https://www.cpuc.ca.gov/RPS_Reports_Data/ ▪ CPUC staff held a BioMAT Technical Working Group meeting to present preliminary recommendations for the adoption of several greenhouse gas life cycle analysis tools that could potentially be used to model BioMAT project emissions

[53] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M441/K459/441459991.PDF

[54] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M446/K941/446941917.PDF

[55] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M467/K556/467556099.PDF

[56] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M465/K562/465562463.PDF

June 2022	▪ CPUC adopted D. 22-06-034 establishing rules for portfolio content category classification for voluntary allocations of RPS resources.[57] ▪ CPUC issued Resolution E-5209 adopting 2022 updated administratively set fixed avoided-cost rates for the ReMAT program. ▪ CPUC issued Resolution E-5216 approving Voluntary Allocation contract formats for allocating RPS resources subject to the PCIA as part of the VAMO process.
July 2022	▪ IOUs, CCAs, and ESPs submitted Draft 2021 RPS Procurement Plans ▪ CPUC adopted D. 22-07-003 denying two Petitions For Modification concerning the public disclosure of transmission and distribution safety information.[58]
August 2022	▪ IOUs, CCAs, and ESPs submitted annual RPS Compliance Reports ▪ CPUC issued Resolution E-5220 approving with modification PG&E Advice Letters 6528-E/E-A, and SDG&E Advice Letters 3968-E/E-A and approving SCE Advice Letters 4745-E/E-A as they include the required modifications to their ReMAT tariffs and PPAs to accommodate the eligibility of facilities enhanced with storage consistent with D.21-12-032
October 2022	▪ CPUC approved the IOUs' proposed pro-forma Market Offer contracts ▪ CPUC adopted Order Instituting Rulemaking 22-10-010 to Implement Assembly Bill 843 – the Bioenergy Market Adjusting Tariff Program
November 2022	▪ CPUC issued the 2022 Annual RPS Report to the Legislature. ▪ CPUC adopted D.22-11-021 approving Voluntary Allocations and modifying the Market Offer process for selling excess RPS resources pursuant to D. 21-05-030.[59]
December 2022	▪ CPUC adopted D.22-12-030 on the 2022 RPS Procurement Plans.[60]
January 2023	▪ IOUs, CCAs, and ESPs submitted Final 2022 RPS Procurement Plans ▪ CPUC staff approved the IOUs' short-term Market Offer solicitation protocols.
February 2023	▪ CPUC approved the IOUs' long-term pro-forma Market Offer contracts and solicitation protocols.
March 2023	▪ IOUs, CCAs, and ESPs filed Final 2017-2020 RPS Compliance Reports ▪ CPUC adopted D.22-03-009 closing Rulemaking 15-02-020.

[57] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M488/K540/488540704.PDF

[58] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M494/K572/494572241.PDF

[59] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M498/K964/498964626.PDF

[60] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M500/K015/500015918.PDF

Appendix B: RPS Procurement Expenditures per Public Utilities Code § 913.3

Overview of Tables

Table B-1 and B-2 show, for each large IOU, the weighted average time-of-delivery (TOD) adjusted RPS procurement expenditures for 2022.[61] Tables B-3 and B-4 show the weighted average RPS procurement expenditures for 2022 for CCAs and ESPs. Per the confidentiality requirements in Public Utilities Code § 913.3, some of the data within this report is redacted in order to protect market sensitive information.

For the IOUs, RPS procurement expenditures are driven by a large volume of contracts signed between 2007 and 2010 at higher prices compared to prices observed in the current market.[62] Recent RPS contracts executed at lower prices are not fully reflected in the weighted average RPS procurement expenditures below as there is a lag between when the lower cost contracts are executed and when RPS procurement expenditures will decline.

In addition:

- The "Average RPS Procurement Expenditures" represent the total weighted average payments made to renewable generators for 2022.
- Procurement expenditures represent weighted averages by capacity procured on a per kilowatt-hour basis. All figures are in 2022 dollars.

[61] Table B-1 provides all procurement expenditure information for every large IOU RPS-eligible contract, including utility-owned generation (UOG) projects. The tables break down the actual price for production in 2022 of UOG, which includes small hydroelectric and solar photovoltaic facilities. At the inception of the three IOUs' solar photovoltaic programs (SPVP-UOG), the CPUC approved an average levelized cost of energy (LCOE) for each IOU. For PG&E's UOG projects, the CPUC approved an average LCOE of $0.25/kWh. (D.10-04-052 at 36.) For SCE's UOG projects, the CPUC approved an average LCOE of $0.26/kWh. (D.09-06-049 at 31.) For SDG&E's UOG projects, the CPUC approved an average LCOE of $0.24/kWh. (D.10-09-016 at 32.) The UOG small hydroelectric facilities used for 2022 RPS generation began commercial operation primarily between 1900 and 1960.

[62] See historical trend of RPS contract costs in Figure 4 at 16.

Table B-1. Weighted Average RPS Procurement Expenditures for IOUs in 2022 (¢/kWh)

	PG&E	SCE	SDG&E	Total
Biogas				
0-3 MW	16.3	12.5	10.6	14.3
+3-20 MW	12.1	5.5	Only 2 Contracts	9.8
Biogas Total	**13.4**	**9.8**	**6.0**	**11.4**
Biomass				
0-3 MW	20.2			20.2
+3-20 MW	Only 2 Contracts	Only 1 Contract		11.6
+20-50 MW	12.1	11.3	Only 1 Contract	11.9
+50-200 MW	Only 1 Contract			-
Biomass Total	**11.4**	**11.5**	**Only 1 Contract**	**11.4**
Geothermal				
+3-20 MW	Only 2 Contracts	Only 2 Contracts		8.3
+20-50 MW		7.8		7.8
+50-200 MW		9.9		9.9
+200 MW		Only 1 Contract		-
Geothermal Total	**Only 2 Contracts**	**7.7**	**-**	**7.8**
Small Hydro				
0-3 MW	8.6	8.9	9.4	8.7
+3-20 MW	4.2			4.2
+20-50 MW	13.6			13.6
Small Hydro Total	**10.0**	**8.9**	**9.4**	**9.9**
Solar Photovoltaic				
0-3 MW	11.8	12.5	11.8	12.0
+3-20 MW	10.4	8.9	8.1	9.4
+20-50 MW	13.7	Only 1 Contract	Only 2 Contracts	13.6
+50-200 MW	11.9	5.9	11.6	8.7
+200 MW	16.5	11.6		13.7
Solar Photovoltaic Total	**13.9**	**8.9**	**11.4**	**10.9**
Solar Thermal				
+50-200 MW	16.0	16.1		16.0
+200 MW	20.4			20.4
Solar Thermal Total	**18.2**	**16.1**	**-**	**18.7**
Wind				
0-3 MW		8.3		8.3
+3-20 MW	6.7	5.7	7.4	6.6
+20-50 MW	Only 2 Contracts	9.5	Only 1 Contract	8.4
+50-200 MW	8.1	9.3	5.7	8.2
+200 MW		7.9	Only 1 Contract	8.4
Wind Total	**8.1**	**8.9**	**6.4**	**8.2**
UOG Small Hydro				
0-3 MW	117.7	4.0		56.9
+3-20 MW	47.9	1.4		37.0
+20-50 MW	Only 2 Contracts	Only 1 Contract		5.5
UOG Small Hydro Total	**44.4**	**1.2**	**-**	**30.1**
UOG Solar Photovoltaic				
0-3 MW	32.4	3.9	31.7	9.9
+3-20 MW	23.2	0.7	Only 1 Contract	20.8
UOG Solar Photovoltaic Total	**23.3**	**1.9**	**57.5**	**19.9**
Average of All Resources	**13.6**	**8.8**	**9.0**	**10.5**

Table B-2. Weighted Average RPS Procurement Expenditures for CCAs (Bundled Energy, Index plus REC, and REC-Only Transactions) for 2022 (¢/kWh)

	Total[63]	REC Total
Biogas		
0-3 MW	Only 2 Contracts	
Index + REC (excludes cost of energy index)	-	0.3
Biogas Total	**9.5**	**0.3**
Biomass		
0-3 MW	Only 1 Contract	
3-20 MW	Only 1 Contract	
Index + REC (excludes cost of energy index)	-	1.3
Biomass Total	**5.1**	**1.3**
Geothermal		
0-3 MW	Only 2 Contracts	
3-20 MW	7.0	
20-50 MW	6.2	
50-200 MW	Only 1 Contract	
Index + REC (excludes cost of energy index)	-	Only 2 Contracts
Geothermal Total	**6.3**	**Only 2 Contracts**
Small Hydro		
0-3 MW	4.6	
3-20 MW	4.9	
20-50 MW	Only 2 Contracts	
Index + REC (excludes cost of energy index)	-	Only 1 Contract
Small Hydro Total	**5.1**	**Only 1 Contract**
Solar Photovoltaic		
0-3 MW	10.5	
3-20 MW	7.1	
20-50 MW	4.3	
50-200 MW	3.2	
>200 MW	Only 1 Contract	
Index + REC (excludes cost of energy index)	-	1.5
Solar Photovoltaic Total	**3.3**	**1.5**
Various/REC-Only[64]		
0-3 MW	-	
Index + REC (excludes cost of energy index)	-	1.3
Various/REC-Only Total	-	1.3
Wind		
0-3 MW	4.6	
3-20MW	4.8	
20-50 MW	5.1	
50-200 MW	4.5	
>200 MW	Only 2 Contracts	
Index + REC (excludes cost of energy index)		1.2
Wind Total	**4.4**	**1.2**
Weighted Average of All Resources	**4.3**	**1.4[65]**

[63] Totals for each technology type exclude expenditures from Index + REC contracts.
[64] The "Various" technology type indicates energy plus REC contracts where the technology type of the procurement is not yet known by the buyer. This arrangement occurs when an LSE procures energy and RECs from multiple facilities in a seller's portfolio. The technology type is known to the buyer after the energy and RECs are delivered to the electricity grid.
[65] Excludes Various/REC-only expenditures.

Table B-3. Weighted Average RPS Procurement Expenditures for ESPs (Bundled Energy, Index plus REC, and REC-Only Transactions) for 2022 (¢/kWh)

	Total	Index + REC Total
Biogas		
0-3 MW	Only 2 Contracts	
Index + REC (excludes cost of energy index)		Only 1 Contract
Biogas Total	**Only 2 Contracts**	**Only 1 Contracts**
Biomass		
Index + REC (excludes cost of energy index)		Only 1 Contract
Biomass Total		**Only 1 Contract**
Geothermal		
Index + REC (excludes cost of energy index)		0.2
Geothermal Total		**0.2**
Small Hydro		
0-3 MW	Only 1 Contract	
Index + REC (excludes cost of energy index)		Only 2 Contracts
Small Hydro Total	**Only 1 Contract**	**Only 2 Contracts**
Solar Photovoltaic		
0-3 MW	Only 1 Contract	
Index + REC (excludes cost of energy index)		1.2
Solar Photovoltaic Total	**0.4**	**0.9**
Wind		
0-3 MW	1.1	
Index + REC (excludes cost of energy index)		1.1
Wind Total	**1.1**	**1.1**
Various/REC Only		
0-3 MW	0.4	
Index + REC (excludes cost of energy index)		2.1
REC-Only		0.3
Weighted Average of All Resources	**0.8**	**1.4** [66]

[66] Excludes Various/REC-Only expenditures.

Appendix C: Contract Price Data per Senate Bill 836 (Public Utilities Code § 913.3)

Overview of Contract Price Data

Table C-1 shows the weighted average time-of-delivery (TOD) adjusted contract price for all of the large IOUs' RPS contracts approved by the CPUC in 2022. Tables C-2 and C3 show the weighted average contract prices for the CCA and ESP RPS contracts executed in 2022.

Per the confidentiality requirements in Public Utilities Code § 913.3, some of the data within this appendix is redacted. Contract prices are redacted if a) the power purchase agreement (PPA) is not already public on the CPUC's website per the CPUC's confidentiality rules, and b) there are fewer than three facilities in each category. If there is only one facility in a category and its PPA is publicly available on the CPUC's website, then the price information for that facility is reported. In addition, the following contracts are public and reported: all qualifying facility (QF) contracts that do not require CPUC approval, feed-in tariff contracts, contracts with municipal governments, affiliate entities, and UOG costs. Weighted average contract prices represent contract prices weighted by capacity procured on a per kilowatt-hour basis. All figures are in 2022 dollars. All IOU contracts with TOD-adjusted prices have been adjusted by those TOD factors because generators are paid based on the time that the facility delivers electricity. TOD factors are intended pay a premium on generation that occurs during peak demand hours when electricity is more valuable.

Table C-1. Average TOD-Adjusted Price of All Renewable Energy Contracts Approved for 2022 for IOUs (¢/kWh)

	PG&E	SCE	SDG&E	Total
Biogas				
0-3 MW		12.8		12.8
Biogas Total		**12.8**		**12.8**
Solar Photovoltaic				
0-3 MW	Only 1 Contract			-
3-20 MW	6.6	Only 1 Contract	Only 1 Contract	4.8
Solar Photovoltaic Total	**6.8**	**-**	**-**	**6.8**
Average of All Resources	**6.8**	**8.0**	**-**	**7.0**

Table C-2. Average Contract Price of All Renewable Energy Contracts for 2022 for CCAs (¢/kWh) Including Index plus REC contracts

Executed in 2022 for CCAs (¢/kWh)	Total	REC
Biomass		
Index + REC (excludes cost of energy index)		1.1
Biomass Total		**1.1**
Geothermal		
0-3 MW	5.7	
3-20 MW	7.9	
20-50 MW	Only 1 Contract	
Index + REC (excludes cost of energy index)		
Geothermal Total	**7.0**	
Solar Photovoltaic		
0-3 MW	11.3	
3-20 MW	6.7	
20-50 MW		
50-200 MW		
200+ MW		
Index + REC (excludes cost of energy index)		1.45
Solar Photovoltaic Total	**10.8**	**1.45**
Various/REC-Only[67]		
Index + REC (excludes cost of energy index)		**1.1**
REC-Only		
Wind		
3-20 MW		
20-50 MW		
50-200 MW		
Index + REC (excludes cost of energy index)		1.0
Wind Total		**1.0**
Average of All Resources	**8.8**	**1.1**[68]

[67] The "Various" technology type indicates energy and REC contracts where the technology type of the procurement is not yet known by the buyer. This arrangement occurs when an LSE procures energy and RECs from multiple facilities in a seller's portfolio. The technology type is known to the buyer when the energy and RECs are delivered to the electricity grid.

[68] Excludes Various/REC-Only contracts.

Table C-3. Average Contract Price of All Renewable Energy Contracts for 2022 for ESPs Including Index plus REC Contracts (¢/kWh)

Executed in 2022 for ESPs (¢/kWh)	Total	REC
Biogas		
Index + REC (excludes cost of energy index)		Only 1 Contract
Biogas Total		Only 1 Contract
Biomass		
Index + REC (excludes cost of energy index)		1.5
Biomass Total		**Only 1 Contract**
Geothermal		
Index + REC (excludes cost of energy index)		1.2
Geothermal Total		**1.2**
Small Hydro		
Index + REC (excludes cost of energy index)		Only 2 Contracts
Small Hydro Total		**-**
Solar Photovoltaic		
0-3 MW	Only 1 Contract	
Index + REC (excludes cost of energy index)		0.4
Solar Photovoltaic Total		**0.4**
Various/REC-Only[69]		
0-3 MW	6.6	
Index + REC (excludes cost of energy index)		1.1
REC-Only		**0.3**
Wind		
0 – 3 MW	**5.7**	
Index + REC (excludes cost of energy index)		Only 1 Contract
Wind Total		**1.0**
Average of All Resources	**5.9**	**1.4**[70]

[69] The "Various" technology type indicates energy and REC contracts where the technology type of the procurement is not yet known by the buyer. This arrangement occurs when an LSE procures energy and RECs from multiple facilities in a seller's portfolio. The technology type is known to the buyer when the energy and RECs are delivered to the electricity grid.

[70] Excludes Various/REC-Only contracts.

Appendix D: Public Utilities Code § 913.3(a)–(d)

Text of Public Utilities Code § 913.3(a)–(d)

913.3. (a) Notwithstanding subdivision (g) of § 454.5 and § 583, no later than May 1 of each year, the commission shall release to the Legislature for the preceding calendar year the costs of all electricity procurement contracts for eligible renewable energy resources, including unbundled renewable energy credits, and all costs for utility-owned generation approved by the commission.

(1) For power purchase contracts, the commission shall release costs in an aggregated form categorized according to the year the procurement transaction was approved by the commission, the eligible renewable energy resource type, including bundled renewable energy credits, the average executed contract price, and average actual recorded costs for each kilowatt-hour of production. Within each renewable energy resource type, the commission shall provide aggregated costs for different project size thresholds.

(2) For each utility-owned renewable generation project, the commission shall release the costs forecast by the electrical corporation at the time of initial approval and the actual recorded costs for each kilowatt-hour of production during the preceding calendar year.

(b) The commission shall report all electrical corporation revenue requirement increases associated with meeting the renewables portfolio standard, as defined in § 399.12, including direct procurement costs for eligible renewable energy resources and renewable energy credits.

(c) The commission shall report all cost savings experienced, or costs avoided, by electrical corporations as a result of meeting the renewables portfolio standard.

(d) This section does not require the release of the terms of any individual electricity procurement contracts for eligible renewable energy resources, including unbundled renewable energy credits, approved by the commission. The commission shall aggregate data to the extent required to ensure protection of the confidentiality of individual contract costs even if this aggregation requires grouping contracts of different energy resource type. The commission shall not be required to release the data in any year when there are fewer than three contracts approved.

Appendix E: California's Load Serving Entities Operating in 2022

Investor- Owned Utilities (IOUs)	Small and Multi-Jurisdictional Utilities (SMJUs)	Community Choice Aggregators (CCAs)	Electric Service Providers (ESPs)
• Pacific Gas and Electric Company • Southern California Edison • San Diego Gas & Electric	• Bear Valley Electric Service • Liberty Utilities (formerly CalPeco Electric) • PacifiCorp	• Apple Valley Choice Energy • Central Coast Community Energy (formerly Monterey Bay Community Power) • City of Baldwin Park • City of Palmdale • City of Pomona • City of Santa Barbara • Clean Energy Alliance • Clean Power Alliance of Southern California • CleanPowerSF • Desert Community Energy • East Bay Community Energy • King City Community Power • Lancaster Choice Energy • Marin Clean Energy • Orange County Power Authority • Peninsula Clean Energy • Pico Rivera Innovative Municipal Energy • Pioneer Community Energy • Rancho Mirage Energy Authority • Redwood Coast Energy Authority • San Diego Community Power • San Jacinto Power • San Jose Clean Energy • Silicon Valley Clean Energy • Sonoma Clean Power Authority • Valley Clean Energy Alliance	• 3 Phases Renewables • BP Energy Retail Company (formerly EDF Energy Services) • Calpine Energy Solutions • Calpine Power America • Commercial Energy of California • Constellation New Energy • Direct Energy Business • Pilot Power Group • Shell Energy North America • UC Regents

Appendix F: Load Serving Entities that Accepted Voluntary Allocations[71]

1. 3 Phases Renewables
2. Apple Valley Choice Energy
3. City of Palmdale
4. City of Pomona
5. City of Santa Barbra
6. Clean Energy Alliance
7. Clean Power Alliance
8. Clean PowerSF
9. Commercial Energy of California
10. Desert Clean Energy
11. Direct Energy Business
12. East Bay Community Energy
13. Lancaster Choice Energy
14. Marin Clean Energy
15. Orange County Power Authority
16. Pacific Gas and Electric
17. Pico Rivera Innovative Municipal Energy
18. Pioneer Community Energy
19. Rancho Mirage Energy Authority
20. Redwood Coast Energy Authority
21. San Diego Community Power
22. San Diego Gas and Electric
23. San Jacinto Power
24. San Jose Community Energy
25. Shell Energy North America
26. Silicon Valley Clean Energy
27. Southern California Edison

[71] D.22-11-021 at Attachment A.