2022 PADILLA REPORT

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

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California Public
Utilities Commission

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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.

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1. Executive Summary

In compliance with Public Utilities Code § 913.3,[1] this report summarizes 2021 Renewables Portfolio Standard (RPS) program procurement expenditure and contract cost data.[2] In 2021, total renewables generation increased across load-serving entities and RPS procurement expenditures continued to decrease on a per GWh basis. In addition, 2021 RPS contract costs decreased in real-dollar value from 2020 costs.[3] Because it generally takes several years after contract execution for RPS procurement expenditures to occur, as less expensive contracts start delivering energy and more expensive ones begin to expire, overall expenditures are expected to continue to trend downward.

Key conclusions from this report include the following:

- The large investor-owned utilities' average procurement expenditure for all RPS contracts online decreased in real-dollar value from 12.21 cents per kilowatt-hour (¢/kWh) in 2020 to 10.67 ¢/kWh in 2021. In contrast, the average cost for non-RPS energy was 11.65 ¢/kWh. This represents a 0.98 ¢/kWh cost savings compared to their average non-RPS procurement expenditure.
- The large investor-owned utilities' (IOUs) total annual RPS procurement expenditures decreased slightly from $6.5 billion in 2020 to $5.8 billion in 2021 while increasing total renewables generation from 53,366 GWh to 54,483 GWh, resulting in a 2021 RPS percentage of retail load of 51.5%. 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 $25.6 million in 2020 to $23.6 million in 2021 while total renewables generation increased from 540 GWh to 570 GWh, resulting in

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

[2] This report addresses RPS expenditures and contract prices for Community Choice Aggregators (CCAs) and Electric Service Providers (ESPs) in 2021, but it does not address their RPS compliance. This report does not address Publicly Owned Utilities (POUs) as compliance for the POUs is determined by the California Energy Commission (CEC). See the CEC's RPS page: https://www.energy.ca.gov/programs-and-topics/programs/renewables-portfolio-standard.

[3] 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.

a 2021 RPS percentage of retail load of 29%. This reflects a decrease in renewables expenditures on a per GWh basis.

- Community choice aggregators' (CCAs) total annual RPS procurement expenditures increased from $473 million in 2020 to $814 million in 2021 while renewables generation increased from 21,497 GWh in 2020 to 24,625 GWh in 2021, resulting in a 2021 RPS percentage of retail load of 46%. Even though total RPS expenditures increased in 2021, the increase in renewable generation resulted in an overall decrease in CCAs' renewables expenditures on a per GWh basis among fixed price contracts.[4]

- Electric Service Providers (ESPs) total annual RPS procurement expenditures decreased from $135 million in 2020 to $28.4 million in 2021 while total renewables generation decreased from 7,086 GWh in 2020 to 3,350 GWh, resulting in a 2021 RPS percentage of retail load of 27%. 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, 50.5% of the large investor-owned utilities' retail load was generated from RPS-eligible resources and expenditures on renewable generation was 49.6% of the large investor-owned utilities' total generation costs.

- The average price of RPS contracts that were executed in 2021 was 2.6 ¢/kWh compared to 4.1 ¢/kWh in 2020. This decrease in real-dollar value is due to the procurement of renewable generation from technologies such as solar PV and wind, which are lower in price compared to bioenergy and geothermal, which made up a large majority of the technologies procured in 2020.

[4] See Table 3: Comparison of Community Choice Aggregator RPS Procurement and Procurement Expenditures between 2020 and 2021 at 10.

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."[5]

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.[6]

The 2021 RPS procurement cost figures in this report were compiled from CPUC jurisdictional load serving entities (LSEs): Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E); 3 SMJUs; 23 CCAs; and 10 ESPs.[7]

The annual procurement costs for generation in this report may not correspond precisely with the LSEs' 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.[8] .

[5] 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.

[6] See the CPUC's RPS website for more information about RPS program requirements and legislative history: https://www.cpuc.ca.gov/rps.

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

[8] See Commission Decision (D.)12-06-038; D.17-06-026.

3. Renewables Program Costs

This section addresses the costs associated with renewable resource procurement in 2021, 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 2021 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 and SMJUs only)

A. RPS Procurement Expenditures

This section provides information on 2021 weighted average expenditures and total RPS procurement expenditures for all categories of LSEs. Generally, the real-dollar value of RPS expenditures[9] for LSEs have trended down on a per GWh basis and this trend is expected to continue.[10]

Large Investor-Owned Utility Procurement Expenditures for 2021

The large IOUs' total annual RPS procurement expenditures in real-dollar value decreased from $6.5 billion in 2020 to $5.8 billion in 2021. This reflects a real-dollar value decrease in renewables expenditures on a per GWh basis. Compiled, detailed large IOU 2021 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.[11]

Weighted Average Expenditures for Large IOUs

Based on the compiled 2021 data, the weighted average RPS procurement expenditure was approximately 10.67 ¢/kWh across all RPS contracts, including REC-only contracts. This 2021 average is lower in real-dollar value than the 12.2 ¢/kWh average in 2020.

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 2025.[12] 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.

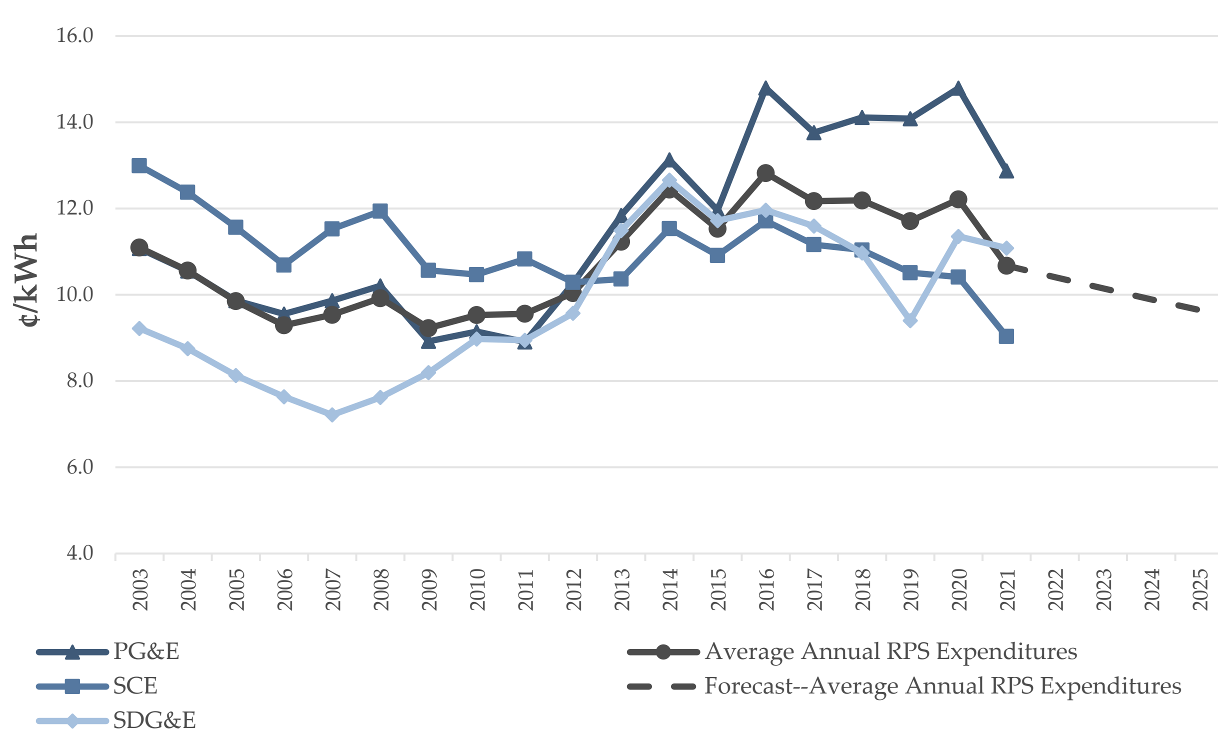
[9] Procurement Expenditures for 2021 include costs for all procurement from online RPS-eligible facilities that generated electricity in 2021. Large IOU procurement expenditures include payments for curtailment volumes which generally increases the unit price of energy reported. See California ISO's Managing Oversupply page for more information on curtailment: http://www.caiso.com/informed/Pages/ManagingOversupply.aspx.

[10] 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.

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

[12] 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 2022

Because it takes several years from when a contract is executed to when the project delivers energy, and a large volume of contracts were signed between 2007 and 2010, there was a lag between the year of execution and the resulting increase in expenditures. Similarly, the forecast of average annual RPS expenditures decreases to reflect the fact that lower cost contracts entered into in the past several years will not be reflected as lower actual RPS expenditures until after those projects begin delivering energy.

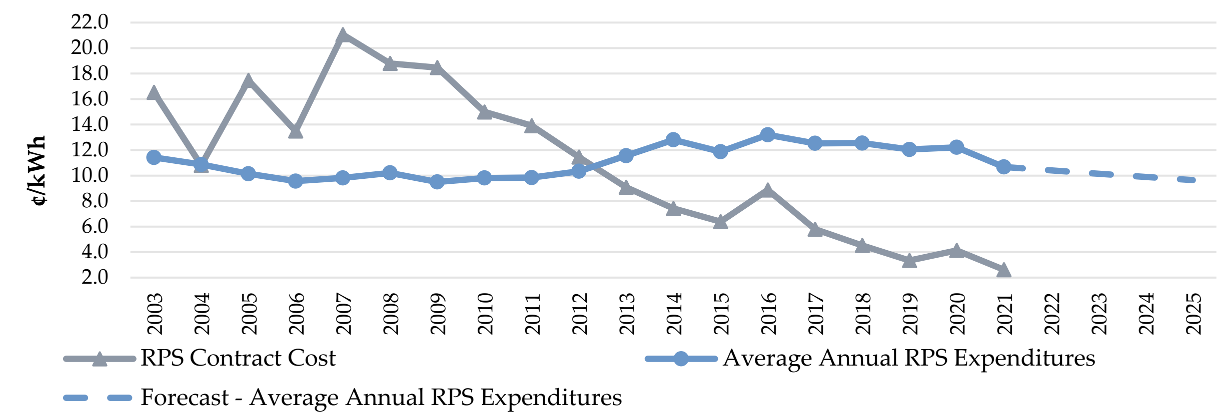
To approximate the impact of decreasing contract prices on future expenditures, Figures 1 and 2 include a forecasted decline in average annual RPS expenditures at a rate of 2.5% per year between 2021 and 2025. The forecasted 2.5% drop in total RPS expenditures is significantly less than the historic 10.3% annual decrease in contract prices.[13] 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

[13] See Figure 3 at 14.

a smaller and smaller portion of the IOUs' entire renewable portfolio. Figure 2 includes RPS contract costs executed in 2019 through 2021 for all LSEs 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 2021 contract price data.

Figure 2: RPS Program Expenditures and Contract Costs from 2003-2025[14] (Real Dollars)



CPUC Report on RPS Costs and Cost Savings, May 2022

Total Expenditures for Large IOUs

The large IOUs' total combined direct RPS procurement expenditures decreased in real-dollar value from $6.5 billion in 2020 to $5.8 billion in 2021.[15] The IOUs' renewable procurement in 2021 increased compared to 2020 procurement from 53,366 GWh to 54,483 GWh, or 43% to 51.5% of their retail load.[16]

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[14] 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.

[15] See Table 4 at 11.

[16] The IOUs' 2021 RPS percentage may differ from the forecast reported in the 2021 RPS Annual Report which does not account for RPS sales in 2021 and reduces the IOUs' overall RPS percentage. The IOUs' RPS percentage for 2021 will be verified and reported in the 2022 RPS Annual Report to the Legislature in November 2022 following the IOUs' compliance filings for the 2021 calendar year.

Large IOUs' RPS Sales Solicitations

In 2021, retail sellers received RPS energy resulting from the three 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 2021.

Table 1: Large IOUs' 2021 RPS Sales Summary

IOU	RPS Sales (GWh)	RPS Sales Revenue (millions)
PG&E	1,252	$17.2
SCE	1,691	$22.0
SDG&E	N/A	N/A
Total	2,944	$39.2

Small and Multi-Jurisdictional Investor-Owned Utility Procurement Expenditures for 2021

In 2021, Liberty Utilities (Liberty), PacifiCorp, and Bear Valley Electric Service (BVES) spent approximately $23.6 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 2021, the weighted average RPS procurement expenditure for all Liberty contracts was 4.5 ¢/kWh, 4.2 ¢/kWh for PacifiCorp, and 1.2 ¢/kWh for BVES.[17]

Total SMJU Expenditures

For 2021, Liberty, PacifiCorp, and BVES had a total combined RPS procurement expenditure of $23.6 million compared to $25.6 million in 2020 in real-dollar value. The SMJUs' total renewable

[17] BVES's 2021 procurement expenditure data includes strictly REC-only contracts; therefore, it is not comparable to the other utilities' 2021 expenditures as they procured significant quantities of contracts that include the cost of acquiring RECs, capacity, and energy.

procurement increased by approximately 30 GWh from 2020 to 2021 and their average RPS procurement percentage remained at 29%.[18]

Table 2: Small and Multi-Jurisdictional Investor-Owned Utilities' Total RPS Expenditures in 2021

	Liberty	PacifiCorp	Bear Valley Electric Service
Total (millions)	$15.8	$7.3	$0.6

Community Choice Aggregator and Electric Service Provider Procurement Expenditures for 2021

In 2021, there were 23 operating Community Choice Aggregators (CCAs) and 10 operating Electric Service Providers (ESPs) that 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 2020 and 2021 for CCAs and ESPs. The CCAs' total expenditures decreased in 2021 primarily due to the increasing proportion of less expensive renewable technologies in CCAs' portfolios.[19] Meanwhile, ESPs' total expenditures and total procurement decreased from 2020 to 2021.[20]

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 the vast majority of delivered energy in 2021 for CCAs and ESPs originated from "Index plus REC" contracts.[21] The reported contract price for Index plus REC contracts represents the incremental renewable cost, set at a negotiated amount in dollars per megawatt-hour ($/MWh), while the price for energy in these contracts is variable

[18] *Supra* note 17 at 8.

[19] For information regarding CCAs' forecasted RPS compliance, see CCAs' average actual and forecasted RPS percentages in the 2021 RPS Annual Report to the Legislature at 15.

[20] 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.

[21] 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.

and changes depending on when energy is delivered to the electricity grid pursuant to the contract.[22, 23]

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. In addition, it is important to distinguish between the vintage of the IOUs' contracts and the vintages of the CCAs' and ESPs' contracts. The IOUs executed a majority of their RPS procurement contracts when technology prices were higher overall compared to CCA and ESP contracts executed in the last several years.

The weighted average expenditures and total expenditures for CCAs and ESPs detailed in Table 3 and Table 4 below do not incorporate the Index energy price for the Index plus REC contracts – the Table 3 and 4 expenditures include only the cost of the incremental renewable adder.

Table 3: Comparison of Community Choice Aggregator RPS Procurement and Procurement Expenditures between 2020 and 2021

	2020	2021
Weighted Average Expenditures (¢/kWh)	4.5	4.1
Total Expenditures (millions) [24]	$473	$814
Total Renewable Energy Delivered (GWh)[25]	21,497	24,625
Average RPS Procurement Percentage[26]	47%	46%

[22] In the CAISO's most recently released Annual Report on Market Issues and Performance, the average Index price for energy in 2020 was $35/MWh.(See CAISO's 2020 Annual Report on Market Issues and Performance, p. 6, 2020 Annual Report (cais https://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdfo.com)). The average Index price for energy varies depending on grid conditions and market supply and demand.

[23] Approximately 72% of renewable energy delivered to CCAs and 85% of renewable energy delivered to ESPs in 2021 originated from Index plus REC contracts. The remaining deliveries were derived from fixed price contracts.

[24] Total expenditures are derived from CCA responses to Energy Division's RPS-PCIA Quarterly Data Report, submitted January 18, 2022.

[25] Total renewable energy delivered is derived from CCA responses to Energy Division's RPS-PCIA Quarterly Data Report, submitted January 18, 2022.

[26] See Table 4 in the 2021 RPS Annual Report to the Legislature.

Table 4: Comparison of Electric Service Provider RPS Procurement and Procurement Expenditures between 2020 and 2021

	2020	2021
Weighted Average Expenditures (¢/kWh)	1.5[27]	0.9
Total Expenditures (millions) [28]	$135	$28.4
Total Renewable Energy Delivered (GWh)[29]	7,086	3,350
Average RPS Procurement Percentage[30]	37%	27%

B. Comparison of RPS Procurement Expenditures to Revenue Requirements (Large IOUs and SMJUs 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 2021.

Table 5 also shows that in 2021, RPS procurement expenditures on average were less than 17.6% 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.

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[27] The ESPs' RPS procurement expenditures only represent the Index plus REC expenditures. Please refer to Appendix B-4 for weighted average expenditures.

[28] Total expenditures are derived from ESP responses to Energy Division's RPS-PCIA Quarterly Data Report, submitted January 18, 2022.

[29] Total renewable energy delivered is derived from ESP responses to Energy Division's RPS-PCIA Quarterly Data Report, submitted January 18, 2022.

[30] See Table 6 in the 2021 RPS Annual Report to the Legislature.

Table 5: Comparison of Large Investor-Owned Utilities' RPS Procurement to Revenue Requirements in 2021

IOU	RPS Generation[31]	RPS Procurement Expenditures (billions)	Total Generation Revenue Requirement (billions)	RPS Procurement Expenditures to Total Generation Revenue Requirement (%)	Total Revenue Requirement (billions) [32]	RPS Procurement Expenditures to Total Revenue Requirement (%)
PG&E	58.0%	$2.62	$5.08	51.7%	$14.38	18.2%
SCE	51.5%	$2.59	$5.22	49.5%	$14.39	18.0%
SDG&E	36.5%	$0.61	$1.50	41.0%	$4.33	14.0%

As LSEs – 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. Consequently, the proportion in 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 kilowatt-hour (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 LSEs' portfolios, which is explored in the next section.

In 2021, the large IOUs' average cost of renewable energy was 10.67 ¢/kWh and the average cost of non-RPS energy was 11.65 ¢/kWh.[33] Using this metric, large IOUs' renewable energy procurement likely resulted in a cost savings of 0.98 ¢/kWh on average for the renewable energy procured to meet their RPS requirements.[34] However, as explained in Section 4 (below), this comparison likely

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

[32] Revenue requirement numbers have been taken from the CPUC's "California Electric and Gas Utility Cost Report" pursuant to Public Utilities Code § 913, April 2021.

[33] See Table 9 at 18.

[34] The average RPS cost savings compared to non-RPS energy on a kilowatt-hour basis is represented by the following equation:

11.65 ¢/kWh (Non-RPS Energy) - 10.67 ¢/kWh (RPS Energy) = 0.98 ¢/kWh.

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.

Small and Multi-Jurisdictional Investor-Owned Utilities

The 2021 revenue requirement information for Liberty, BVES, and PacifiCorp is currently confidential pursuant to CPUC confidentiality rules.[35] Consequently, the CPUC is not able to publicly release an analysis of SMJU costs compared to their revenue requirements for 2021.

C. RPS Aggregated Contract Prices

The CPUC examined the IOUs', CCAs', and ESPs' 2019, 2020, and 2021 executed contract prices.[36] Moreover, the CPUC also reviewed IOUs' RPS contracts executed between 2003 and 2018 to provide historic contract cost trends.[37]

RPS Contract Prices for Resources Greater than 3 MW

Figure 3 below shows that RPS contract prices, in real-dollar value, decreased an average of 10.3% annually between 2007 and 2021. CCAs executed the majority of new RPS procurement contracts in 2021.

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

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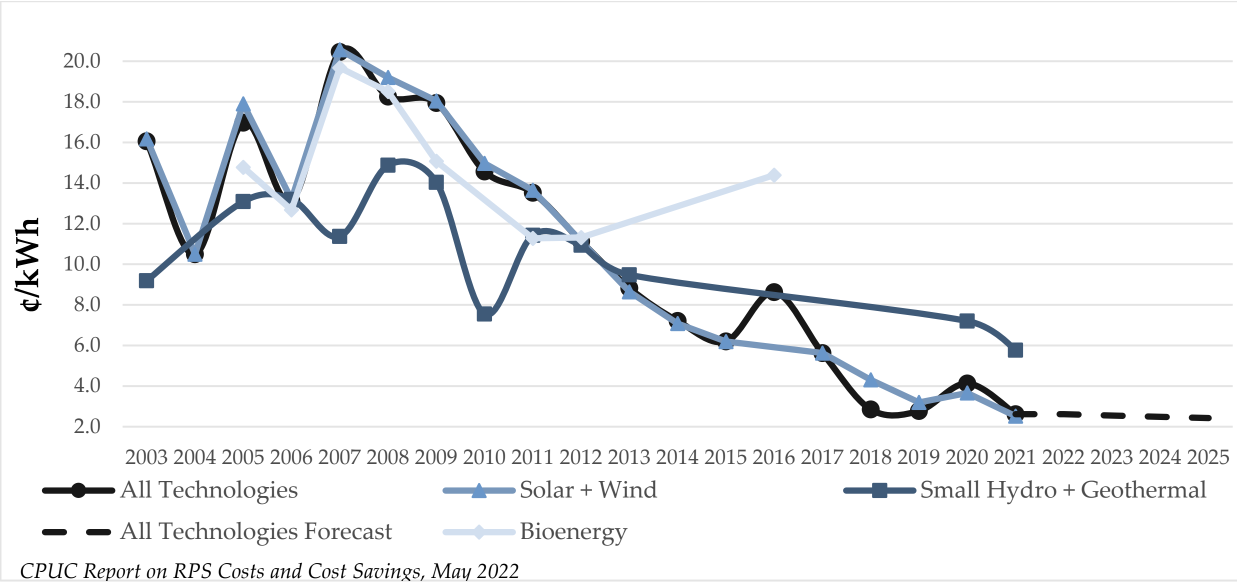
[35] See D.06-06-066 for confidentiality rules related to revenue requirements.

[36] 2019 through 2021 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.*

[38] Projects with a capacity of 3 MW or less made up roughly 2% 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.

Figure 1: Historical Trend of All Load Serving Entities' RPS Contract Costs by Technology and Year of Execution from 2003-2025 (Real-Dollar Value)[39]



The average price of IOU, CCA and ESP contracts executed in 2021 that were greater than 3 MW was 2.6 ¢/kWh compared to 4.1 ¢/kWh in real-dollar value in 2020. The IOUs executed RPS contracts for solar PV and the CCAs executed contracts for solar PV, wind, and geothermal.

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 3. Accordingly, the large IOU's contracts signed in 2021 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

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 all RPS contracts signed in 2021, including those with a nameplate capacity below 3 MW.

updated annually by CPUC resolution. Table 6 shows the average ReMAT contract price and total capacity procured in 2021 by PG&E and SCE.[40]

Table 6: Large Investor-Owned Utilities' 2021 ReMAT Procurement Summary

ReMAT Product Type	Contracted Capacity (MW)	Average Contract Price (¢/kWh)
As-Available Peaking	4	5.2
As-Available Non-Peaking	4.85	5.7
Baseload	3.52	7.3
Total[41]	**12.37**	**5.8**

IOU Bioenergy Market Adjusting Tariff (BioMAT) Contracts

BioMAT is a Feed-in-Tariff program that uses a standard contract and a market-based mechanism to arrive at the offered program contract price, which deviates from the solicitation process for contracts included in Figure 3. The goal of the BioMAT program is to promote a competitive market using a simple procurement mechanism for entrants to the bioenergy market. BioMAT allocates procurement to the discrete bioenergy categories of Biogas, Dairy/Agriculture, and Sustainable Forest Management. Table 7 shows the average BioMAT contract price and total capacity procured in 2021 by the three IOUs.

Table 7: Large Investor-Owned Utilities' 2021 BioMAT Procurement Summary

BioMAT Category	Contracted Capacity (MW)	Average Contract Price (¢/kWh)
Biogas	2.3	12.8
Dairy/Agriculture	6	18.4
Sustainable Forest Management	3	20.0
Total	**11.3**	**17.4**

[40] SDG&E's ReMAT program was closed during 2021 but will reopen in 2022 pursuant to D.21-12-032.

[41] The Total Average Contract Price represents a simple average overall price for the three ReMAT categories.

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

The CCAs are not obligated to offer BioMAT contracts. During 2021, the CCAs executed a total of 7 contracts with new-build RPS-eligible facilities with 3 MW or less of capacity.[42] The CCAs that executed these contracts include Clean Power Alliance, Marin Clean Energy, and Redwood Coast Energy Authority.

Table 8: Community Choice Aggregators' 2021 Procurement Summary of Facilities 3 MW or Less

Technology Type	Contracted Capacity (MW)	Average Contract Price ¢/kWh
Biogas	1	Only 1 Contract
Solar PV – Ground Mount	7.5	7.8
Total	**8.5**	**7.9**

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]

To date, the total capacity and average contract price of existing BioRAM contracts is 178 MW and 11.4 ¢/kWh, respectively.

[42] This data was obtained through the joint RPS-PCIA Data Request. Data is current as of January 18, 2022.

[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 2021, 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' 2021 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.

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 2021, the large IOUs' average annual RPS procurement expenditure represented a weighted average 0.98 ¢/kWh cost savings compared to their average non-RPS procurement expenditure.[44] On an individual basis, as deduced from Table 9, SDG&E paid a premium for RPS energy—compared to non-RPS energy—of 1.79 ¢/kWh. Conversely, PG&E and SCE experienced a cost savings of 3.79 ¢/kWh and 0.73 ¢/kWh, respectively. SDG&E's costs, compared to PG&E and SCE's, result from a combination of higher renewable procurement costs and lower non-renewable costs relative to the other large IOUs. The higher non-RPS costs experienced by PG&E and SCE are likely due to a combination of factors in 2021 including gas price increases and volatility, less generation from large hydro, and utilities' increased competition for scarce resources across the West as well as within California.

Table 9: Large Investor-Owned Utilities' 2021 Average RPS and Non-RPS Eligible Procurement Expenditure (¢/kWh)

Method	PG&E	SCE	SDG&E	Weighted Average
2021 Non-RPS	16.66	9.76	9.29	11.65
2021 RPS	12.87	9.03	11.08	10.67

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

Table 10: Large Investor-Owned Utilities' 2021 RPS Cost Savings: Non-RPS Eligible Comparison[45]

Cost Savings Compared to 2021 Average Non-RPS Expenditure (millions)	
PG&E	$771.0
SCE	$208.6
SDG&E	($98.5)
Cost savings are displayed as positive figures while cost premiums are displayed as negative figures.	

[44] *Supra*, note 36 at 12.

[45] Cost savings or premiums are calculated by multiplying each IOU's average 2021 non-RPS eligible expenditure (Table 9) by its total volume of RPS procurement in 2021 then subtracting that value from the IOUs' 2021 RPS procurement expenditure (Table 5).

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

In 2021, the RPS procurement expenditure for SMJUs represented a 1.6 ¢/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 2.1 ¢/kWh and 0.9 ¢/kWh, respectively. BVES's RPS procurement consisted solely of REC-only products and represented a cost premium of 1.2 ¢/kWh. However, BVES' RPS expenditures are not directly comparable to their non-RPS expenditures, which include additional costs for obtaining energy and capacity benefits.

Table 11: Small and Multi-Jurisdictional Investor-Owned Utilities' 2021 Average Non-RPS Eligible Procurement Expenditure (¢/kWh)

Method	Liberty	PacifiCorp	Bear Valley Electric Service	Weighted Average
2021 Non-RPS	6.6	5.1	7.2	5.8
2021 RPS	4.5	4.2	1.2	4.1[46]

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 12: Small and Multi-Jurisdictional Investor-Owned Utilities' 2021 RPS Cost Savings: Non-RPS Eligible Comparison[47]

	Cost Savings Compared to 2021 Average Non-RPS Expenditure (millions)
Liberty	$13.5
PacifiCorp	$6.4
Bear Valley Electric Service	N/A
Cost savings are displayed as positive figures while cost premiums are displayed as negative figures.	

[46] The SMJUs' 2021 average RPS procurement expenditure calculation includes BVES' RPS procurement expenditures consisting solely of REC-only products.

[47] Cost savings or premiums are calculated by multiplying each SMJU's average 2021 non-RPS eligible expenditure (Table 11) by its total volume of RPS procurement in 2021 then subtracting that value from the SMJUs' 2021 RPS procurement expenditure (Table 2).

C. Community Choice Aggregators' Cost Premiums / Savings

In 2021, the RPS procurement expenditure for CCAs represented a 1.4 ¢/kWh cost savings compared to their average non-RPS-eligible expenditure. As mentioned previously, the weighted average RPS expenditures for CCAs 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.

Table 13: Community Choice Aggregators' 2021 Average Non-RPS Eligible Procurement Expenditure (¢/kWh)

Method	Weighted Average
2021 Non-RPS	5.5
2021 RPS	4.1

Based on total volumes of RPS generation procured and non-RPS eligible procurement expenditures, the CCAs realized the following cost savings:

Table 14: Community Choice Aggregators' 2021 RPS Cost Savings Compared to Non-RPS Energy [48]

	Cost Savings Compared to 2021 Average Non-RPS Expenditure (million)
Community Choice Aggregators	$97.6
Cost savings are displayed as positive figures while cost premiums are displayed as negative figures.	

D. Electric Service Providers' Cost Premiums / Savings

In 2021, the RPS procurement expenditure for ESPs represented a 4.6 ¢/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.

[48] Cost savings or premiums are calculated by multiplying CCAs' average 2021 non-RPS eligible expenditure (Table 13) by volume of RPS procurement in 2021 (excluding Index + REC deliveries) then subtracting that value from the CCAs' 2021 RPS procurement expenditure (Table 3).

Table 15: Electric Service Providers' 2021 Average Non-RPS Eligible Procurement Expenditure (¢/kWh)

Method	Weighted Average
2021 Non-RPS	5.5
2021 RPS	0.9[49]

Based on total volumes of RPS generation procured and non-RPS eligible procurement expenditures, the ESPs realized the following cost savings:

Table 16: Electric Service Providers' 2021 RPS Cost Savings Compared to Non-RPS Energy [50]

	Cost Savings Compared to 2021 Average Non-RPS Expenditure (millions)
Electric Service Providers	$154.1
Cost savings are displayed as positive figures while cost premiums are displayed as negative figures.	

[49] Weighted average RPS expenditures for ESPs do not incorporate the Index energy price for the Index plus REC contracts. See footnote 22 for the most recent Index energy price reported by CAISO.

[50] Cost savings or premiums are calculated by multiplying ESPs' average 2021 non-RPS eligible expenditure (Table 15) by volume of RPS procurement in 2021 (excluding Index + REC deliveries) then subtracting that value from the ESPs' 2021 RPS procurement expenditure (Table 4).

5. Appendices

Appendix A: California Public Utilities Commission RPS Activities and Milestones

January 2021	▪ CPUC adopted D.21-01-005 approving the 2020 RPS Procurement Plans ▪ CPUC issued disposition letters approving the Joint IOUs ELCC values for RPS procurement
February 2021	▪ PG&E and SCE resumed their ReMAT programs following CPUC approval of Tier 2 Advice Letters with updated ReMAT tariffs and associated standard contracts pursuant to D.20-10-005
March 2021	▪ CPUC issued the Assigned Commissioner and Assigned Administrative Law Judge's Ruling issued identifying issues and schedule of review for 2021 RPS Procurement Plans ▪ CPUC issued Resolution E-5123 approving PG&E's BioRAM contract with Wheelabrator Shasta Energy
April 2021	▪ CPUC issued the Administrative Law Judge's Ruling seeking updated information regarding the ReMAT program ▪ CPUC issued Resolution E-5135 approving PG&E's BioRAM contract with Woodland Biomass ▪ CPUC approved via a disposition letter PG&E's Winter 2020 REC Sales contracts ▪ CPUC staff established the BioMAT Technical Working Group to develop a project-specific lifecycle analysis tool to quantify net greenhouse gas emissions from BioMAT project operations, pursuant to D.20-08-043
May 2021	▪ CPUC issued the 2021 Padilla Report on Costs and Cost Savings for the RPS Program to the Legislature, pursuant to Public Utilities Code § 913.3. ▪ CPUC adopted D.21-05-030 authorizing a new Voluntary Allocation, Market Offer, and Request for Information process for RPS contracts subject to the PCIA.
June 2021	▪ Prehearing Conference held for Liberty Utilities' Application requesting Commission approval to finance, construct, own and operate the Luning Expansion Project ▪ CPUC staff held several BioMAT Technical Working Group meetings where three technical sub-committees were formed for each technology

	category and further guidance was established for the development of a greenhouse gas emissions lifecycle analysis tool ▪ CPUC approved RPS sales contracts from SCE's 2021 RPS energy sales RFO to various counterparties via standard disposition letter ▪ CPUC approved RPS sales contracts from PG&E's Winter 2020 Bundled RPS Energy Sale Solicitation to various counterparties via non-standard disposition letter
July 2021	▪ IOUs, CCAs, and ESPs submitted Draft 2021 RPS Procurement Plans ▪ CPUC issued disposition letters approving the Joint IOUs' updated ELCC values for RPS procurement ▪ CPUC staff held a BioMAT Technical Working Group meeting and identified several existing greenhouse gas life cycle analysis tools that could be potentially adapted for BioMAT use
August 2021	▪ IOUs, CCAs, and ESPs submitted annual RPS Compliance Reports ▪ CPUC staff held a BioMAT Technical Working Group meeting where criteria were developed for the evaluation of existing greenhouse gas life cycle analysis tools
September 2021	▪ CPUC issues Proposed Decision Re: Clarifying and Improving Confidentiality Rules for RPS Program
October 2021	▪ CPUC issued letters, pursuant to SB 155, to all retail sellers that are at risk of not meeting their RPS compliance requirements ▪ CPUC approved via disposition letter SCE's 2021 REC Sales contracts
November 2021	▪ CPUC adopted D.21-11-029 clarifying and improving confidentiality rules for the RPS Program ▪ CPUC issued the 2021 Annual RPS Report to the Legislature
December 2021	▪ CPUC adopted D.21-12-032 modifying aspects of the ReMAT Program

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 2021.[51] Tables B-3 and B-4 show the weighted average RPS procurement expenditures for 2021 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.[52] 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 2021.
- Procurement expenditures represent weighted averages by capacity procured on a per kilowatt-hour basis. All figures are in 2021 dollars.

[51] 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 2021 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 2021 RPS generation began commercial operation primarily between 1900 and 1960.

[52] See historical trend of RPS contract costs in Figure 3.

Table B-1. Weighted Average RPS Procurement Expenditures for IOUs in 2021 (¢/kWh)

	PG&E	SCE	SDG&E	Total
Biogas				
0-3 MW	16.0	12.8	10.2	14.0
+3-20 MW	12.2	7.8	3.4	9.7
Biogas Total	**13.3**	**10.5**	**5.6**	**11.1**
Biomass				
0-3 MW	6.3			6.3
+3-20 MW	11.0	12.0		11.6
+20-50 MW	12.3	11.0	Only 1 Contract	11.9
+50-200 MW	8.9			8.9
Biomass Total	**11.5**	**11.3**	**Only 1 Contract**	**11.4**
Geothermal				
+3-20 MW	9.0	6.3		8.2
+20-50 MW		6.4		6.4
+50-200 MW		9.7		9.7
+200 MW	10.1	7.0		8.6
Geothermal Total	**10.0**	**7.2**	**0.0**	**8.4**
Small Hydro				
0-3 MW	8.8	8.6	9.9	8.8
+3-20 MW	7.0			7.0
+20-30 MW	17.7			17.7
Small Hydro Total	**14.9**	**8.6**	**9.9**	**14.4**
Solar Photovoltaic				
0-3 MW	12.0	12.2	11.9	12.2
+3-20 MW	10.1	9.0	8.2	9.4
+20-50 MW	13.0	11.4	14.0	13.2
+50-200 MW	11.6	6.1	13.4	9.0
+200 MW	16.1	11.6		13.5
Solar Photovoltaic Total	**13.5**	**9.0**	**12.9**	**11.0**
Solar Thermal				
+50-200 MW	15.5	15.5		15.5
+200 MW	20.5			20.5
Solar Thermal Total	**19.0**	**15.5**	**0.0**	**18.5**
Wind				
0-3 MW		8.0		8.0
+3-20 MW	6.5	5.2	1.3	3.1
+20-50 MW	10.1	9.8	5.3	8.7
+50-200 MW	7.9	9.3	13.2	9.0
+200 MW		7.8	9.7	8.0
Wind Total	**7.9**	**8.8**	**9.4**	**8.6**
UOG Small Hydro				
0-3 MW	132.3	0.7		8.1
+3-20 MW	55.5	25.1		35.9
+20-30 MW	13.3	0.4		4.6
UOG Small Hydro Total	**53.3**	**15.1**	**0.0**	**26.0**
UOG Solar Photovoltaic				
0-3 MW	42.4	2.1	8.0	0.6
+3-20 MW	22.9	1.4	79.8	20.4
UOG Solar Photovoltaic Total	**23.1**	**1.8**	**63.2**	**18.8**
Average of All Resources	**12.9**	**9.0**	**11.1**	**10.7**

Table B-2. Weighted Average RPS Procurement Expenditures for CCAs (Bundled Energy and REC-Only Transactions) for 2021 (¢/kWh)

	Total[53]	REC Total
Biogas		
0-3 MW	10.2	
Index + REC	**-**	**0.3**
Biogas Total	10.2	0.3
Biomass		
0-3 MW	Only 1 Contract	
3-20 MW	Only 2 Contracts	
Index + REC	**-**	**1.2**
Biomass Total	**3.6**	**1.2**
Geothermal		
0-3 MW	Only 2 Contracts	
3-20 MW	8.0	
20-50 MW	6.6	
Index + REC	-	1.3
Geothermal Total	**6.3**	**1.3**
Small Hydro		
0-3 MW	4.6	
3-20 MW	5.0	
20-50 MW	Only 2 Contracts	
Index + REC	-	
Small Hydro Total	**5.0**	
Solar Photovoltaic		
0-3 MW	7.4	
20-50 MW	4.4	
50-200 MW	3.0	
>200 MW	Only 1 Contract	
Index + REC	-	2.8
Solar Photovoltaic Total	**3.3**	**2.8**
Various/REC-Only[54]		
0-3 MW	1.6	
Index + Rec	-	3.2
Various/REC-Only Total	1.6	3.2
Wind		
0-3 MW	4.5	
3-20MW	4.8	
20-50 MW	5.1	
50-200 MW	4.6	
>200 MW	Only 2 Contracts	
Index + REC		1.3
Wind Total	**4.6**	**1.3**
Weighted Average of All Resources	**4.1**	**3.0**[55]

[53] Totals for each technology type exclude expenditures from Index + REC contracts.

[54] 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.

[55] Excludes Various/REC-only expenditures.

Table B-3. Weighted Average RPS Procurement Expenditures for ESPs (Bundled Energy and REC-Only Transactions) for 2021 (¢/kWh)

	Total	Index + REC Total
Biogas		
0-3 MW	Only 1 Contract	
Index + REC		Only 1 Contract
Biogas Total	**Only 1 Contract**	**Only 1 Contract**
Biomass		
Index + REC		1.4
Biomass Total		**1.4**
Geothermal		
Index + REC		0.3
Geothermal Total		**0.3**
Small Hydro		
Index + REC		Only 2 Contracts
Small Hydro Total		**Only 2 Contracts**
Solar Photovoltaic		
Index + REC		0.9
Solar Photovoltaic Total		**0.9**
Wind		
0-3 MW	0.8	
Index + REC		0.7
Wind Total	**0.8**	**0.7**
Various/REC Only		
0-3 MW	0.5	
Index + REC		1.0
REC-Only		0.4
Weighted Average of All Resources	**0.9**	**0.9** [56]

[56] 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 2021. Tables C-2 and C3 show the weighted average contract prices for the CCA and ESP RPS contracts executed in 2021.

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 utility-owned generation (UOG) costs. Weighted average contract prices represent contract prices weighted by capacity procured on a per kilowatt-hour basis. All figures are in 2021 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 2021 for IOUs (¢/kWh)

	PG&E	SCE	SDG&E	Total
Biogas				
0-3 MW		12.8		12.8
Biogas Total		**12.8**		**12.8**
Biomass				
0-3 MW	18.9			18.9
Biomass Total	**18.9**			**18.9**
Small Hydro				
0-3 MW	6.4			6.4
Small Hydro Total	**6.4**			**6.4**
Solar Photovoltaic				
0-3 MW	6.8	5.2		6.6
3-20 MW	7.2			7.2
Solar Photovoltaic Total	**7.0**	**5.2**		**6.8**
Wind				
0-3 MW		5.7		5.7
Wind Total		**5.7**		**5.7**
Average of All Resources	**8.9**	**7.9**		**8.7**

Table C-2. Average Contract Price of All Renewable Energy Contracts for 2021 for CCAs (¢/kWh)

Executed in 2021 for CCAs (¢/kWh)	Total	Index + REC Total
Biogas		
Index + REC		Only 1 Contract
Biogas Total		**Only 1 Contract**
Biomass		
Index + REC		1.2
Biomass Total		**1.2**
Geothermal		
0-3 MW	Only 1 Contract	
3-20 MW	Only 1 Contract	
20-50 MW	Only 1 Contract	
Index + REC		1.3
Geothermal Total	**5.8**	**1.3**
Hybrid Resources[57]		
3-20 MW	Only 2 Contracts	
50-200 MW	2.1	
Hybrid Total	2.1	
Small Hydro		
20-50 MW	Only 1 Contract	
Small Hydro Total	**Only 1 Contract**	
Solar Photovoltaic		
0-3 MW	6.5	
3-20 MW	Only 1 Contract	
20-50 MW	2.3	
50-200 MW	2.5	
200+ MW	Only 1 Contract	
Index + REC		1.2
Solar Photovoltaic Total	**4.1**	**1.2**
Various/REC-Only[58]		
Index + REC		**1.4**
REC-Only		**0.2**
Wind		
3-20 MW	Only 1 Contract	
20-50 MW	Only 2 Contracts	
50-200 MW	4.9	
Index + REC		1.3
Wind Total	**4.7**	**1.3**
Average of All Resources	**4.0**	**1.3[59]**

[57] Hybrid projects are defined as any combination of renewable generation or storage resources that are co-located and share a centralized system of control at the point of interconnection. The hybrid projects contracted in 2021 included solar PV plus storage.

[58] 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.

[59] Excludes Various/REC-Only contracts.

Table C-3. Average Contract Price of All Renewable Energy Contracts for 2021 for ESPs (¢/kWh)

Executed in 2021 for ESPs (¢/kWh)	Total	Index + REC Total
Biogas		
Index + REC		1.3
Biogas Total		1.3
Biomass		
Index + REC		Only 1 Contract
Biomass Total		**Only 1 Contract**
Geothermal		
Index + REC		1.2
Geothermal Total		**1.2**
Small Hydro		
Index + REC		1.6
Small Hydro Total		**1.6**
Solar Photovoltaic		
Index + REC		1.5
Solar Photovoltaic Total		**1.5**
Various/REC-Only[60]		
Index + REC		**1.2**
REC-Only		**0.4**
Wind		
Index + REC		1.0
Wind Total		**1.0**
Average of All Resources		**1.3**[61]

[60] 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.

[61] 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 2021[62]

Investor- Owned Utilities (IOUs)	Small and Multi-Jurisdictional Utilities (SMJUs)	Community Choice Aggregators (CCAs)	Electric Service Providers (ESPs)
• Pacific Gas and Electric Company (PG&E) • Southern California Edison (SCE) • San Diego Gas & Electric (SDG&E)	• Bear Valley Electric Service (BVES) • Liberty Utilities (formerly CalPeco Electric) • PacifiCorp	• Apple Valley Choice Energy (AVCE) • Central Coast Community Energy (CCCE) • City of Baldwin Park • City of Pomona • Clean Energy Alliance • Clean Power Alliance (CPA) • CleanPowerSF (CPSF) • Desert Community Energy (DCE) • East Bay Community Energy (EBCE) • King City Community Power (KCCP) • Lancaster Choice Energy (LCE) • Marin Clean Energy (MCE) • Peninsula Clean Energy (PCE) • Pico Rivera Innovative Municipal Energy (PRIME) • Pioneer Community Energy (Pioneer) • Rancho Mirage Energy Authority (RMEA) • Redwood Coast Energy Authority (RCEA) • San Jacinto Power (SJP) • San Jose Clean Energy (SJCE) • Silicon Valley Clean Energy (SVCE) • Sonoma Clean Power (SCP) • Valley Clean Energy Alliance (VCEA) • Western Community Energy (WCE)	• 3 Phases Renewables • Calpine Energy Solutions • Calpine Power America • Commercial Energy of CA • Constellation New Energy • Direct Energy Business • EDF Industrial Power Services • Pilot Power Group • Shell Energy North America • UC Regents

[62] Western Community Energy (WCE) filed for Chapter 9 bankruptcy on May 24, 2021 in United States Bankruptcy Court, Central District of California, Riverside Division. WCE is no longer serving load and is dissolving as a CCA.