2021 RESOURCE ADEQUACY REPORT

March 2023

CALIFORNIA PUBLIC UTILITIES COMMISSION
ENERGY DIVISION

A digital copy of this report can be found at:

https://www.cpuc.ca.gov/RA/

Report Authors:
Sasha Cole – Analyst
Lily Chow – Senior Analyst
Simone Brant – Senior Analyst
Michele Kito – Supervisor, Resource Adequacy and Procurement Section
Molly Sterkel – Program Manager, Electric Planning and Market Design Branch, Energy Division

TABLE of CONTENTS

TABLES

FIGURES

LIST OF ACRONYMS

AS	Ancillary Services	kW	Kilowatt
CAISO	California Independent System Operator	LCR	Local Capacity Requirement
CAM	Cost-Allocation Mechanism	LGIP	Large Generator Interconnection Procedures
CARB	California Air Resources Board	LOLP	Loss of Load Probability
CEC	California Energy Commission	LSE	Load Serving Entity
CCA	Community Choice Aggregator	LTPP	Long Term Procurement Plan
CHP	Combined Heat and Power	MCC	Maximum Cumulative Capacity
CPM	Capacity Procurement Mechanism	MOO	Must-Offer Obligation
CPP	Critical Peak Pricing	MA	Month Ahead
CPUC	California Public Utilities Commission	MW	Megawatt
CSP	Competitive Solicitation Process	NERC	North American Reliability Corporation
DA	Direct Access	NQC	Net Qualifying Capacity
DG	Distributed Generation	PCIA	Power Charge Indifference Adjustment
DR	Demand Response	PMax	Maximum capacity of a resource
DRAM	Demand Response Auction Mechanism	PMin	Minimum capacity of a resource
ED	Energy Division	PRM	Planning Reserve Margin
EE	Energy Efficiency	QC	Qualifying Capacity
ELCC	Effective Load Carrying Capacity	QF	Qualifying Facility
EFC	Effective Flexible Capacity	RA	Resource Adequacy
ESP	Electricity Service Provider	RAR	Resource Adequacy Requirement
ExD	Exceptional Dispatch	RMR	Reliability Must Run
FERC	Federal Energy Regulatory Commission	RPS	Renewable Portfolio Standard
GHG	Greenhouse Gas	RUC	Residual Unit Commitment
HE	Hour Ending	SPD	Save Power Day
IOU	Investor-Owned Utility	SFTP	Secure File Transfer Protocol
IV	Imperial Valley	TAC	Transmission Access Charge

1 EXECUTIVE SUMMARY

The Resource Adequacy (RA) program was developed in response to the 2001 California energy crisis. The program is designed to ensure that California Public Utilities Commission (CPUC) jurisdictional Load Serving Entities (LSEs)[1] have sufficient capacity to meet their peak load with a reserve margin that was initially set at 15 percent.[2] The RA program began implementation in 2006 and is intended to provide the energy market with sufficient forward capacity to meet peak demand and integrate renewables. This capacity includes system RA, local RA, and flexible RA, all of which are measured in megawatts (MWs). The CPUC sets the annual and monthly system, local, and flexible RA requirements for CPUC-jurisdictional LSEs.

This report provides a review of the CPUC's RA program, summarizing RA program experience during the 2021 RA compliance year. While this report does not make explicit policy recommendations, it provides information relevant to the currently open RA rulemaking and ongoing implementation of the RA program in California.

A key to establishing accurate RA procurement targets is accurate demand forecasts. The California Energy Commission (CEC) assesses the reasonableness of LSE-submitted forecasts, then makes demand side management adjustments, plausibility adjustments, and a prorated adjustment to each LSE's forecast to ensure that the total for all forecasts is within 1 percent of the CEC's overall service area forecast. The overall CEC-adjusted forecast for CPUC-jurisdictional LSEs had an expected peak in September 2021 of 40,363, which represented a 0.13 percent decrease from the peak forecast of 40,416 MW for August 2020. The plausibility adjustments as a percentage of each month's aggregated year-ahead forecast ranged 2.13 percent to 6.02 percent.

Each October, the RA program requires LSEs to make annual system, local, and flexible compliance showings for the coming year. For the system showing, LSEs must

[1] CPUC jurisdictional LSEs include Investor-Owned Utilities (IOUs), Electricity Service Providers (ESPs), and Community Choice Aggregators (CCAs).

[2] Recent analysis has questioned the sufficiency of the 15% reserve margin to ensure reliability, and D. 22-06-050 raised the reserve margin to 16% for 2023 and 17% for 2024 as the proceeding continues to gather data.

demonstrate that they have procured 90 percent of their system RA obligation for the five summer months. For the local showing, LSEs must demonstrate that they have procured 100 percent of their local RA obligation for all twelve months. LSEs are also required to demonstrate that they have procured 90 percent of their flexible RA obligation for all twelve months. In addition to the annual RA requirement, the RA program has monthly requirements. On a month-ahead basis, LSEs must demonstrate they have procured 100 percent of their monthly system and flexible RA obligations. Additionally, from July through December, the LSEs must demonstrate on a monthly basis that they have met 100 percent of their local obligation which is revised to reflect load migration.

In 2021, CPUC-jurisdictional LSEs met their peak load RA obligations. The 2021 peak demand (for CPUC-jurisdictional LSEs, after net load migration adjustments) was forecasted to occur in September 2021, at 40,363 MW. The RA obligation for September, including a 15 percent planning reserve margin, totaled 46,439 MW and LSEs collectively procured 47,576 MW.

The peak demand in CAISO for 2021 of 43,789 MW, which includes CPUC-jurisdictional and non-CPUC jurisdictional LSEs, occurred on September 8, 2021, during the hour between 6 and 7 pm.[3] The 2021 CAISO peak was lower than the 2020 peak of 46,974 MW. About 90 percent of 2021 actual peak load, or about 39,410 MW, could be attributed to CPUC-jurisdictional LSEs.

CPUC-jurisdictional LSEs collectively met all local RA requirements during the 2021 compliance year. The 2021 local RA procurement obligations for CPUC-jurisdictional LSEs totaled 21,851 MW. LSEs and CAISO procured a monthly minimum of 23,534 MW. Physical resources, cost allocation mechanism (CAM) resources, reliability must-run (RMR) resources, and demand response (DR) resources contributed to this total.

In 2021, total committed RA resources ranged from 33,537 MW in November to 48,568 MW in July. Bilateral contracting made up most of forward capacity procurement. However, CAM, RMR, and DR procurement, the costs and benefits of which are passed

[3] This peak is the average used over the hour. The technical peak minute is recorded by CAISO as 43,982 MW at 17:50. See http://www.caiso.com/documents/californiaisopeakloadhistory.pdf. When used in this report, the peak will refer to the peak hour measurement.

through to all customers by Transmission Access Charge (TAC) area, also contributed to meeting RA obligations. Between 85 and 92 percent of all committed RA capacity, including CAM, was procured by LSEs from unit-specific physical resources within the CAISO control area. Unspecified Imports accounted for 1 to 8 percent of capacity, and DR made up 3.0 to 3.6 percent. CAM and RMR resources consisted of 14.9 and 22.3 percent of total RA capacity procured.

2020 saw the margin between the weighted prices of system and local decrease. In 2021, the weighted average price of system RA surpassed that of local RA. The weighted average price of local RA in 2021 was $6.49/kW-month compared to $7.02/kW-month for system RA capacity. Local RA prices have also increased significantly-- 2021 weighted average prices for local areas ranged from $6.04/kW-month in Humboldt to $9.24/kW-month in Kern, while 85th percentile prices ranged from $7.50/kW-month for San Diego and Fresno local capacity to $8.88/kW-month in Big Creek-Ventura. While the weighted average incrased, the 85th percentile price decreased in some areas while increasing in others when comared to the previous year. For flexible capacity, prices are slightly lower than those for system capacity overall. The 2021 weighted average price for flexible capacity is $5.27/kW-month while it is $6.48/kW-month for non-flexible system capacity.

Because the RA program requires LSEs to acquire capacity to meet load and reserve requirements, the CPUC issues citations or initiates enforcement actions when LSEs do not fully comply with RA program rules.[4] In total, the CPUC issued twenty-one citations for violations related to compliance year 2021 for a total of $13,425,486.

[4] Due to either a procurement deficiency (i.e., the LSE did not meet its RA obligations) or filing-related violations of compliance rules (e.g., files late, or not at all).

2 INTRODUCTION

The Resource Adequacy (RA) program was developed in response to the 2001 California energy crisis. The program is designed to ensure that California Public Utilities Commission (CPUC) jurisdictional Load Serving Entities (LSEs)[5] have sufficient capacity to meet their peak load with a 15 percent reserve margin.[6] The RA program began implementation in 2006 and is intended to provide the energy market with adequate forward capacity to meet peak demand and integrate renewables. This capacity includes system RA, local RA, and flexible RA, all of which are measured in megawatts (MWs). The CPUC sets the annual and monthly system, local, and flexible RA requirements for CPUC-jurisdictional LSEs.

This report, produced annually on Staff's own motion, provides a review of the CPUC's RA program and summarizes RA program experience during the 2021 RA compliance year. It is designed to shed light on the current state of the RA program. While this report does not make explicit policy recommendations, it provides information relevant to the currently open RA rulemaking and ongoing implementation of the RA program in California.

2.1 Resource Adequacy Program Requirements

Monthly and annual system RA requirements are based on load forecast data filed annually by each LSE and adjusted by the California Energy Commission (CEC). Jurisdictional and non-jurisdictional LSEs must submit historical hourly peak load data for the preceding year, and monthly energy and peak demand forecasts for the coming compliance year based on a "best estimate approach" that are based on reasonable assumptions for load growth and customer retention. The CEC then adjusts the LSE-submitted load forecasts, which form the basis for the final LSE load forecasts used for

[5] CPUC jurisdictional LSEs include Investor Owned Utilities (IOUs), Electricity Service Providers (ESPs), and Community Choice Aggregators (CCAs).

[6] Recent analysis has questioned the sufficiency of the 15% reserve margin to ensure reliability, and D. 22-06-050 raised the reserve margin to 16% for 2023 and 17% for 2024 as the proceeding continues to gather data.

year-ahead RA compliance. LSEs are also required to submit monthly load forecasts to the CEC that account for load migration throughout the compliance year.

To establish the year-ahead load forecast, the CEC first calculates each LSE's specific monthly coincidence factors[7] using the historic hourly load data filed by each LSE. The adjustment factors are calculated by comparing each LSE's historic hourly peak loads to the historic coincident California Independent System Operator (CAISO) hourly peak loads. These factors make each LSE's peak load forecast reflective of the LSE's contribution to total load when CAISO's load peaks. The CEC then reconciles the aggregate of the jurisdictional LSEs' monthly peak load forecasts against the CEC's monthly 1-in-2, weather normalized peak-load forecast, for each Investor-Owned Utility (IOU) service area. This reconciliation evaluates the reasonableness of the LSEs' forecasts. As part of the reconciliation, if the aggregate LSE forecasts differ significantly from CEC's forecasts for reasons other than load migration, the CEC may adjust individual IOU service area forecasts. Additionally, as specified in D.05-10-042, the CEC makes adjustments to account for the impact of energy efficiency (EE) and distributed generation (DG). The sum of the adjusted forecasts must be within 1 percent of the CEC service area forecast. If the aggregated LSE forecasts diverge more than 1 percent from the CEC's monthly weather normalized forecasts, the CEC makes a pro-rata adjustment to reduce the divergence to below 1 percent.

The CEC uses the aggregated LSE forecasts to create monthly load shares for each transmission access charge (TAC) area, which Energy Division then uses to allocate demand response (DR), cost allocation mechanism (CAM), and reliability must run (RMR) RA credits. Flexible RA requirements are also allocated to LSEs using these 12 monthly load ratio shares. Local obligations are calculated using the load shares for September 2021 of the projected year ahead. The forecasts and allocations together determine both the annual and monthly system RA obligations.

2.2 Changes to the Resource Adequacy Program for 2021

In D. 20-06-002, the CPUC adopted a hybrid procurement structure in which a Central Procurement Entity ("CPE") would "secure a portfolio of the most effective local

[7] Adopted in D.12-06-025, Ordering Paragraph 4, available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/169718.PDF.

resources, use its purchasing power in constrained local areas, mitigate the need for costly backstop procurement in certain local areas, and ensure a least cost solution for customers and equitable cost allocation."

D.20-06-002 also ordered the following regarding the hybrid procurement structure:

- Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) will act as the central procurement entities for their respective distribution service areas for the multi-year local Resource Adequacy (RA) program beginning for the 2023 RA compliance year.
- Load serving entities in PG&E's and SCE's distribution service areas no longer receive a local allocation beginning for the 2023 Resource Adequacy compliance year.
- If a load serving entity's (LSE) procured resource also meets a local Resource Adequacy (RA) need, the LSE may choose to:
  - (1) self-show the resource to the CPE to reduce the CPE's overall local procurement obligation and retain the resource to meet the LSE's system or flexible RA needs, (2) bid the resource into the CPE's solicitation, or (3) elect not to show or bid the resource to the CPE and only use the resource to meet its own system and flexible RA needs, or (3) elect not to show or bid the resource to the CPE and only use the resource to meet its own system and flexible RA needs.
- An LSE that choses to show a resource may:
  - (1) do so in advance of the CPE's solicitation, if it does not intend to bid it into the solicitation, or (2) bid the resource into the CPE's solicitation but indicate in its bid that the resource will be available to meet local RA requirements even if it is not procured by the CPE, which may reduce the total procurement costs the CPE incurs on behalf of all LSEs.
- The CPE shall have discretion to defer procurement of a local resource to the CAISO's backstop mechanisms, rather than through the solicitation process, if bid costs are deemed unreasonably high.

D.20-06-002 also directed the CPEs to begin procurement in 2021 for 100 percent of the 2023 local requirements and 50 percent of the 2024 local requirements.

In D. 20-06-028, the CPUC adopted revisions to the Resource Adequacy import rules, including documentation requirements for "resource specific" and "non-resources specific" imports.

In D. 20-06-031, the CPUC adopted all local capacity requirements recommended by CAISO for 2021. It also adopts the CAISO recommended flexible and system RA requirements. However, CAISO's 2021 local capacity requirement study had recommended a value for the 2022 and 2023 Greater Bay Area local area that was 1,803 MW greater than the 2020 value adopted in the prior LCR study. Because the CPUC could not properly vet the factors causing this large year-on-year change before adopting local capacity values, D.20-06-013 adopted the 2020 local capacity requirement for the Greater Bay Area local area as 2022 and 2023 requirements instead of adopting the value recommended in the 2021 CAISO study. D.20-06-031 established a working group to evaluate the CAISO's updated criteria used to establish local procurement obligations and other local requirement issues.

In addition to adopting local, flexible and system RA requirements, D. 20-06-031 also:

- Authorizes Energy Division to establish a working group to develop a set of assumptions for use in a loss of load expectations (LOLE) study to support review of the planning reserve margin.
- Adopts or modifies qualifying capacity (QC) methodologies for dispatchable hydroelectric resources, in-front-of-the-meter hybrid and co-located resources that plan to access the Investment Tax Credit.
- Establishes testing requirements for third-party demand response (DR) resources.
- Revises the maximum cumulative capacity buckets to the following:

Category	Availability	Maximum Cumulative Capacity for Bucket and Buckets Above
DR	Varies by contract or tariff provisions, but must be available Monday – Saturday, 4 consecutive hours between 4 PM and 9 PM, and at least 24 hours per month from May – September.	8.3%
1	Monday – Saturday, 4 consecutive hours between 4 PM and 9 PM, and at least 100 hours per month. For the month of February, total availability is at least 96 hours.	17.0%
2	Every Monday – Saturday, 8 consecutive hours that include 4 PM – 9 PM.	24.9%
3	Every Monday – Saturday, 16 consecutive hours that include 4 PM – 9 PM.	34.8%
4	Every day of the month. Dispatchable resources must be available all 24 hours.	100% (at least 56.1% available all 24 hours)

- Adopted system penalty prices of $8.88/kW-month in summer months (May through October) and $4.44/kW-month in non-summer months.

In D.20-12-006, the CPUC:

- Adopted a local capacity requirement compensation mechanism. The mechanism establishes how new preferred resources and new energy storage resources, including utility-owned generation, that is shown will be compensated.

- Adopted competitive neutrality rules for central procurement entities. The competitive neutrality rules state that, "a distribution utility shall have the same options as other load-serving entities in deciding whether to bid or show its resources into the central procurement entity's (CPE) solicitation process, including showing resources to the CPE for no compensation and being eligible for the local capacity requirements reduction compensation mechanism."[8]

[8] D.20-12-006, Ordering Paragraph 2.

3 LOAD FORECAST AND RESOURCE ADEQUACY PROGRAM REQUIREMENTS

3.1 Yearly and Monthly Load Forecast Process

RA requirements for 2021 were developed according to the following schedule. LSEs have been able to revise their April annual load forecast for load migration since 2012, and revised forecasts have been required starting in 2018.[9] The 2021 revised annual forecasts were due on August 17, 2020. These revised forecast values updated and informed the final year-ahead allocations, which were used in the year-ahead filing process. CPUC staff sent initial allocations to LSEs on July 21, 2020, and final allocations to LSEs on September 18, 2020.

LSEs file historical load information	**March 16, 2020**
LSEs file 2021 year-ahead load forecast	**April 20, 2020**
LSEs receive 2021 year-ahead RA obligations	**July 21, 2020**
Final date to file revised forecasts for 2021	**August 17, 2020**
LSEs receive revised 2021 RA obligations	**September 18, 2020**

The CPUC and CEC do not rely exclusively on year-ahead load forecasts because load migration can significantly affect LSE forecasts, particularly for small energy service providers (ESPs). During the compliance year, LSEs adjust their load forecasts on a monthly basis to account for load migration. This process is outlined in D.05-10-042.[10] As discussed in the RA Guide for the 2021 compliance year, LSEs must submit a revised forecast prior to each compliance filing month.[11] These load forecast adjustments are solely for load migration between LSEs, not changing demographic or electrical

[9] D.17-06-027, available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M192/K027/192027253.PDF.

[10] D.05-10-042 available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/50731.PDF.

[11] Annual RA Filing Guides are available on the CPUC website: Resource Adequacy Compliance Materials (ca.gov).

conditions. Per D.10-06-036,[12] LSEs must submit any load forecast changes or adjustments at least 25 days before the due date of the month-ahead compliance filings.

LSEs submit these monthly forecasts to the CEC for evaluation; the CEC then reviews the revised forecasts and customer load migrating assumptions. The revised monthly load forecasts update the year-ahead forecast and inform monthly RA obligations. Energy Division also uses these monthly forecasts to recalculate load shares, which are then used to reallocate CAM and RMR credits on a quarterly basis. The revised load forecasts also inform the local true-up process discussed in Section 3.5.2.

3.2 Yearly Load Forecast Results

Table 1 shows the aggregate LSE submissions for 2021 and the adjustments that were made by the CEC across the three IOU service areas.[13] These adjustments include plausibility adjustments, demand side management adjustments, and a prorated adjustment to each LSE's forecast to ensure that the total for all forecasts is within one percent of the CEC's overall service area forecast. The forecast also includes a coincident adjustment that calculates each LSE's expected contribution towards the CAISO peak. The overall CEC-adjusted forecast for CPUC-jurisdictional LSEs had an expected peak in September 2021 of 40,363, which represented a 0.13 percent decrease from the peak forecast of 41,366 MW for August 2020.[14]

[12] Available at https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/119856.PDF, Ordering Paragraph 6.

[13] Because the historical and forecast data submitted by participating LSEs contain market-sensitive information, results are presented and discussed in aggregate.

[14] The 2020 RA report can be found at: Microsoft Word - 2020 RA Report_v14 (ca.gov)

Table 1. 2021 Aggregated Load Forecast Data (MW) - Results of Energy Commission Review and Adjustment to the 2021 Year-Ahead Load Forecast

Element	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Submitted LSE Forecast	27,605	27,065	26,825	28,557	30,681	35,790	38,721	39,020	38,848	31,711	27,876	28,139
Adjustment for Plausibility and Migrating Load	1,058	1,105	746	938	1,970	1,696	1,407	1,409	1,653	1,365	592	1,193
EE/DG/DR Adjustment	(122)	(122)	(130)	(122)	(159)	(185)	(222)	(217)	(207)	(160)	(145)	(131)
Pro Rata Adjustment	678	659	583	837	892	682	810	579	1,150	921	410	891
Non-Coincident Peak Demand	**29,219**	**28,707**	**28,025**	**30,211**	**33,383**	**37,983**	**40,716**	**40,791**	**41,444**	**33,838**	**28,733**	**30,092**
Coincidence Adjustment	(667)	(956)	(1,146)	(1,117)	(688)	(1,101)	(1,122)	(1,052)	(1,081)	(983)	(936)	(996)
Final Load Forecast Used for Compliance	**28,552**	**27,752**	**26,879**	**29,095**	**32,696**	**36,882**	**39,595**	**39,739**	**40,363**	**32,855**	**27,797**	**29,096**

Source: CEC Staff.

3.3 Year-Ahead Plausibility Adjustments and Monthly Load Migration

Table 2 below presents the aggregate monthly plausibility adjustments for all LSEs from 2013 to 2021 and calculates the 2021 monthly plausibility adjustments as a percentage of the monthly year-ahead forecast for 2021.

In 2021, the CEC's plausibility adjustments increased the load forecast for all months. The 2021 monthly plausibility adjustments as a percentage of that month's aggregated year-ahead forecast ranged from 2.13 percent for November to 6.02 percent for May. Plausibility adjustments most commonly indicate mismatches between an LSE's own forecast assumptions and the CEC's assumptions regarding economic growth, responsiveness of load to weather conditions, and customer retention or migration. The CEC develops a reference estimate for each LSE based on historic loads and load migration data and makes an adjustment when the LSE's forecast is significantly different. IOU forecasts are also revised to account for differences between the CEC and the IOU forecasts of the total service area and aggregate estimates of departing load.

Table 2. CEC Plausibility Adjustments, 2013-2021 (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2013	0	56	63	60	61	95	99	(985)	249	102	70	64
2014	61	67	69	74	77	78	81	(147)	89	88	79	71
2015	(218)	(355)	(51)	(126)	(7)	(298)	(205)	(481)	(311)	(307)	(260)	(199)
2016	(46)	(55)	(95)	(130)	(227)	(357)	(27)	(379)	84	(195)	(293)	80
2017	152	(98)	191	(869)	(401)	(820)	(888)	(1,462)	170	(431)	511	603
2018	776	894	1,053	2,523	4,864	3,906	4,460	3,633	5,286	3,257	2,722	2,635
2019	(104)	31	(181)	1,510	1,803	3,884	2,606	(586)	4,784	3,962	137	(349)
2020	811	873	514	1,362	1,895	1,821	1,673	1,522	1,570	786	870	871
2021	1,058	1,105	746	938	1,970	1,696	1,407	1,409	1,653	1,365	592	1,193
2021 Plaus Adj ÷ Load	3.71%	3.98%	2.77%	3.22%	6.02%	4.60%	3.55%	3.55%	4.09%	4.15%	2.13%	4.10%

Source: Year-ahead CEC load forecasts, 2013-2021.

Monthly load forecasts, adjusted for load migration, form the basis of monthly RA obligations. Table 3 shows the monthly total load forecasts and the monthly adjustments for load migration for 2021. There were only small net load migration adjustments from the year-ahead load forecast to the final monthly load forecasts used to calculate monthly RA obligations. The largest such adjustment, on a percentage basis, was an increase of 0.72 percent for February 2021. On a megawatt basis, the net monthly load migration adjustments ranged from -39 to 199 MW.

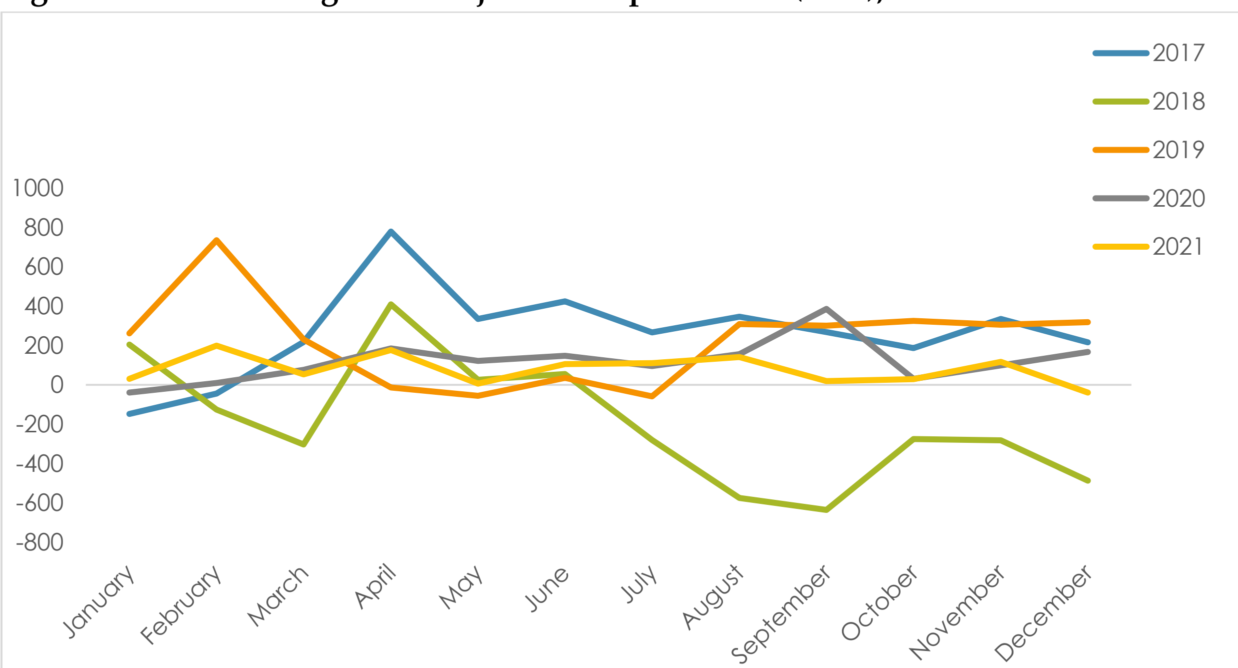
Table 3. Summary of Load Migration Adjustments in 2021 (MW)

Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Final YA Load Forecast	28,552	27,752	26,879	29,095	32,696	36,882	39,595	39,739	40,363	32,855	27,797	29,096
Monthly Adjustments	30	199	53	176	6	106	111	141	18	28	117	(39)
Final Forecasts in Monthly RA Filings	28,581	27,951	26,932	29,271	32,702	36,988	39,706	39,880	40,381	32,883	27,914	29,057
Monthly Adjustments/ Final YA Load Forecast	0.10%	0.72%	0.20%	0.61%	0.02%	0.29%	0.28%	0.35%	0.05%	0.09%	0.42%	-0.14%

Source: Load forecast adjustments submitted to the CEC and CPUC in 2020.

Net load migration should be close to zero since it is defined as customers transferring directly from one LSE to another. Discrepancies in the adjustments made by LSEs gaining and losing customers, however, can cause overall load migration adjustments to deviate from zero. In recent years, the CPUC and CEC have worked to identify the reasons for these discrepancies and to encourage closer coordination between LSEs during forecast development. Figure 1 illustrates the net monthly load migration between LSEs from 2017 through 2021. Monthly load migration remained below 800 MW (or 3 percent of total load) during this period. There was similarly little load migration in 2021 — the largest monthly net load migration occurred in February and was 199 MW, or 0.72 percent of load.

Figure 1. Net Load Migration Adjustments per Month (MW), 2017-2021



Source: Monthly forecast adjustments submitted by LSEs, 2017-2021

3.4 System RA Requirements for CPUC-Jurisdictional LSEs

CPUC-jurisdictional LSEs met their collective system RA requirements for every month of 2021. The total MW of RA resources procured exceeded the total system Resource

Adequacy Requirement (RAR) by 2.4 to 8.9 percent, depending on the month.[15] Table 4 shows the total CPUC-jurisdictional RA procurement for each month of 2021, broken down by physical resources within the CAISO's control area (including CAM resources), DR, capacity procurement mechanism (CPM), and reliability must run (RMR) resources, imports, and the additional preferred local capacity requirement (LCR) credit for the Southern California Edison (SCE) TAC area. CAM resources are deducted from a non-IOU LSE's RA requirement, while IOUs receive an increase in their RA requirement that is offset by their showing the full CAM resources (on behalf of all LSEs' customers) in their RA filings. Physical resources include CAM resources, which are reported separately. The RA obligation includes the aggregate monthly load forecast plus the 15 percent planning reserve margin (PRM). DR resources, including Demand Response Auction Mechanism (DRAM) resources, are also reported with the 15 percent PRM applied.

[15] System requirements include a 15 percent Planning Reserve Margin above jurisdictional LSEs' aggregate monthly peak forecast.

Table 4. 2021 RA Filing Summary - CPUC-jurisdictional Entities (MW)

`	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
RAR without DR, CAM, & RMR	32,869	32,143	30,971	33,661	37,607	42,536	45,662	45,862	46,439	37,816	32,101	33,415
CAM	6,485	6,519	6,393	6,393	6,465	6,912	6,804	6,915	6,839	6,994	7,046	7,085
Phys. Res. (w/ CAM)	31,995	31,176	31,176	32,427	35,890	40,290	42,410	41,257	40,211	35,256	30,641	32,192
Import (Resource Specific)	1,101	1,084	1,084	1,167	1,220	1,535	1,460	1,507	1,426	1,031	864	1,074
Import (Unspecified)	220	203	203	646	1,263	1,603	2,582	2,831	3,697	1,261	278	189
Total Imports	1,190	1,189	1,189	1,436	1,693	3,138	4,042	4,337	5,123	2,292	1,142	1,263
DR plus 15% PRM	1,061	1,106	1,106	1,243	1,378	1,529	1,668	1,704	1,711	1,443	1,203	1,063
RMR	179	179	179	179	394	389	416	416	417	428	431	433
Pref. LCR Credit	80	80	80	22	22	22	33	33	114	121	121	122
CPM	0	0	0	0	0	0	0	0	0	0	0	0
Total	34,504	33,729	33,729	35,307	39,377	45,368	48,568	47,746	47,576	39,540	33,537	35,072
Total/RAR	**105.0%**	**104.9%**	**108.9%**	**104.9%**	**104.7%**	**106.7%**	**106.4%**	**104.1%**	**102.4%**	**104.6%**	**104.5%**	**105.0%**

Source: LSE Monthly RA Filings.

In 2021, total committed RA resources ranged from 33,537 MW in November to 48,568 MW in July. Between 85 and 92 percent of all committed RA capacity (including CAM) was procured by LSEs from unit-specific physical resources within the CAISO control area. Unspecified Imports accounted for 1 to 8 percent of capacity, and Demand Response made up 3.0 to 3.6 percent of capacity. CAM and RMR resources made up between 14.9 and 22.3 percent of total RA capacity procured. These resources enabled CPUC-jurisdictional LSEs to meet between 102.4 and 108.9 percent of total procurement obligations in each summer month. The actual peak demand in CAISO of 43,789 MW, which includes CPUC-jurisdictional and non-CPUC jurisdictional LSEs, occurred on September 8, 2021, during the hour between 6 and 7 pm.[16] The 2021 CAISO peak was

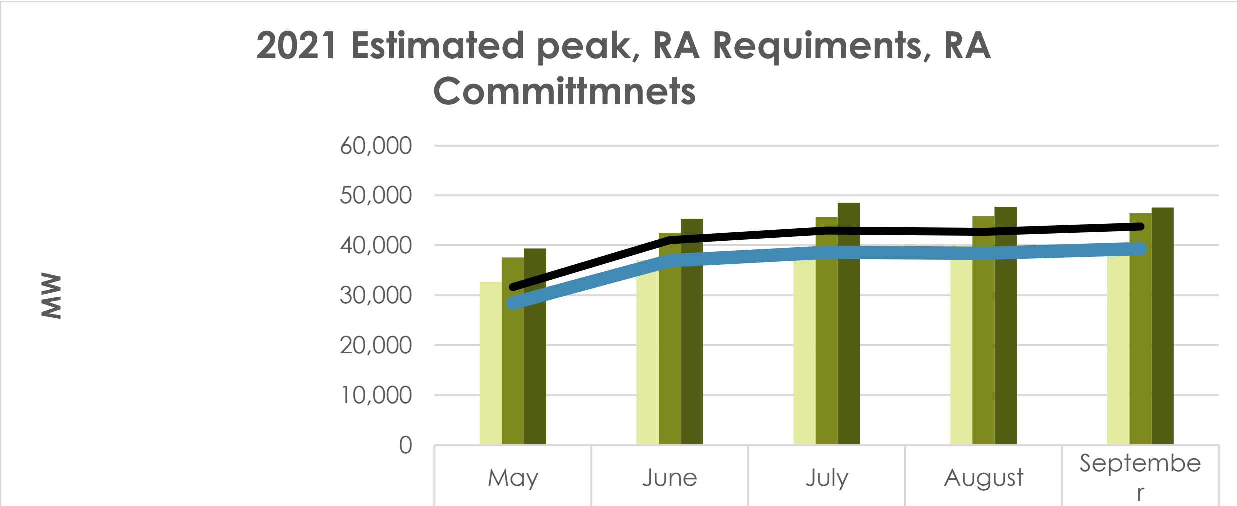
[16] This peak is the average used over the hour. The technical peak minute is recorded by CAISO as 43,982 MW at 17:50. When used in this report, the peak will refer to the peak hour measurement.

lower than the 2020 peak load of 46,974 MW, and was the lowest peak since 2003.[17] Around 90 percent of 2021 actual peak load, or about 39,410 MW, could be attributed to CPUC-jurisdictional LSEs.

Figure 2 shows the 2021 total load forecast, procurement obligation (forecast plus PRM), and total committed RA capacity for CPUC-jurisdictional LSEs, compared with the CAISO-jurisdictional actual peak load. The difference between the total RA resources committed (orange line) and LSEs' collective forward commitment obligation (green line) reflects the excess capacity committed to meet the monthly RA requirement. The CAISO jurisdictional peak (yellow line) includes non-CPUC jurisdictional load and therefore can be higher than CPUC RA obligations (green line) and total RA committed (orange line).

[17] http://www.caiso.com/documents/californiaisopeakloadhistory.pdf

Figure 2. 2021 CPUC Month Ahead Load Forecast, RA Requirements, Total RA Committed Resources, and Actual Peak Load For Summer Months



	May	June	July	August	September
Load Forecast (CPUC-juris.)	32,702	36,988	39,706	39,880	40,381
Forward Commitment Obligation	37,607	42,536	45,662	45,862	46,439
Total RA Resources Committed	39,377	45,368	48,568	47,746	47,576
Est. Peak Load (CPUC-juris.)	28,446	36,924	38,641	38,395	39,356
Actual Peak Load (CAISO)	31,651	41,083	42,994	42,720	43,789

Source: CPUC RA Filings, CEC load forecasts, and CAISO EMS data.

3.5 Local RA Program – CPUC-Jurisdictional LSEs

The CPUC requires LSEs to file an annual local RA filing showing that they have met 100 percent of their local capacity requirement for each of the 12 months of the coming compliance year. Local RA requirements are developed through the CAISO's annual Local Capacity Technical Analysis, which identifies the capacity required in each local area to meet energy needs using a 1-in-10 weather year and N-1-1 contingencies.[18] The results of the analysis are adopted in the annual CPUC RA decision and allocated to

[18] Local Capacity Requirement (LCR) studies and materials for 2021 and previous years are posted at California ISO - Reliability Requirements (caiso.com).

each LSE based on their load ratio in each TAC area during the month with the highest forecast peak load.

In D.20-06-031, the CPUC adopted the 2021 local RA obligations for the ten locally constrained areas (Big Creek/Ventura, LA Basin, San Diego-Imperial Valley (IV), Greater Bay Area, Humboldt, North Coast/North Bay, Sierra, Stockton, Fresno, and Kern). Unlike previous years, local areas were not aggregated for RA compliance. Additionally, D.20-06-031 adopted multi-year local RA requirements, discussed below.

3.5.1 Year-Ahead Local RA Procurement

Table 5 summarizes the 2021 local RA requirements and year-ahead procurement by CPUC-jurisdictional LSEs, including physical capacity procured by or on behalf of individual LSEs, CAM and RMR capacity, and local DR capacity.

Table 5. Local RA Procurement in 2021, CPUC-Jurisdictional LSEs

Local Areas in 2021	Total LCR	CPUC-Jurisdictional Local RAR	Minimum Physical Resources per Month	Local RMR & CAM Credit	Local DR	Minimum Procurement/ Local RAR
LA Basin	6,127	5,420	6,279	3,906	599	115.8%
Big Creek/Ventura	2,296	2,029	3,115	305	144	153.6%
San Diego-IV	3,888	3,889	3,860	1,007	16	99.3%
Greater Bay Area	6,353	5,578	5,462	1,191	53	97.9%
Fresno	1,694	1,518	1,907	-	29	125.6%
Sierra	1,821	1,633	1,261		20	77.2%
Stockton	596	536	460		12	85.7%
Kern	413	373	391	144	58	104.8%
Humboldt	130	122	118	-	0	96.8%
NCNB	842	753	682	-	4	90.5%
Totals	24,160	21,851	23,534	6,553	935	107.7%

Source: 2020 Year Ahead RA filings.

3.5.2 Local and Flexible RA True-Ups

As part of the partial reopening of direct access in 2010, the CPUC adopted a true-up mechanism in D.10-03-022 to adjust each LSE's local RA obligation to account for load migration. Since the true-up process was revised in D.14-06-050, there has been one mid-year reallocation per year.

The current true-up process requires LSEs to file revised load forecasts for the second half of the year (July to December), which the CEC uses to establish revised load ratios for those months. In turn, the CPUC uses the revised August load ratios to adjust each LSE's local capacity requirements. Since 2015, the true-up process has also included flexible RA requirements. The difference between the original allocations and the new requirements is allocated to LSEs as an incremental local and flexible RA requirement, which the LSEs must meet in their monthly compliance filings for July through December.

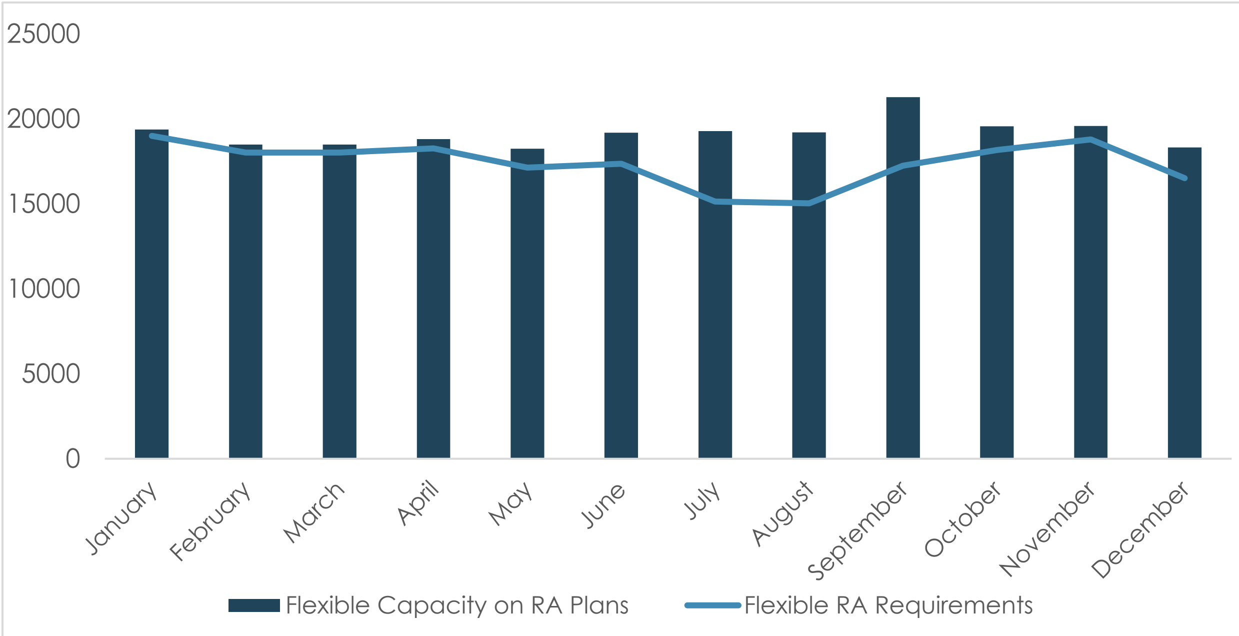
In the allocation cycle for 2021, LSEs submitted revised June through December forecasts to the CEC on March 17, 2021. After reviewing these values, the CEC revised the September load shares. Energy Division used the revised load shares to recalculate individual LSE local requirements, which were then sent to LSEs on April 9, 2021. LSEs were instructed to incorporate these incremental local and flexible allocations into their July to December RA month-ahead (MA) compliance filings. Through its review, Energy Division staff verified that each LSE met its reallocated local and flexible requirement for July to December.

3.6 Flexible RA Program – CPUC-Jurisdictional LSEs

The CPUC adopted a flexible RA requirement for LSEs beginning with the 2015 compliance year. LSEs must demonstrate that they have procured 90 percent of their monthly flexible capacity requirements in the year-ahead process and 100 percent of their flexible capacity requirements in the month-ahead process.[19] Flexible capacity needs are developed through CAISO's annual Flexible Capacity Study and are defined as the quantity of economically dispatched resources needed by CAISO to manage grid reliability during the largest three-hour continuous ramp in each month. Flexible resources must be able to ramp up or sustain output for 3 hours. Figure 3 shows the flexible capacity requirement and the flexible capacity shown on month-ahead RA plans by CPUC-jurisdictional LSEs for each month of 2021.

[19] D.13-06-024, available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M070/K423/70423172.PDF; D.14-06-050, available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M097/K619/97619935.PDF.

Figure 3. Flexible RA Procurement in 2021, CPUC-Jurisdictional LSEs



Source: 2021 RA filings.

4 RESOURCE ADEQUACY PROCUREMENT, COMMITMENT, AND DISPATCH

The RA program requires LSEs to enter into forward commitment capacity contracts with generating facilities. Only contracts that carry a "must-offer obligation" (MOO) are eligible to meet this RA obligation. The must-offer obligation requires owners of these resources to submit self-schedules or bids into the CAISO market, making these resources available for dispatch. In other words, the MOO commits these RA resources to CAISO market mechanisms. Prices for bilateral RA contracts are discussed in Section 4.1.

The CAISO utilizes these committed resources through its day ahead market, real time market, and Residual Unit Commitment (RUC) process. The CAISO also relies on out-of-market commitments (e.g., Exceptional Dispatch (ExD), CPM, and RMR contracts) to meet reliability needs that are not satisfied by the Day Ahead, Real Time, and RUC market mechanisms. Recent RMR and CPM designations are described in Sections 4.2 and 4.3.

Since 2007, the CPUC has authorized the IOUs to procure new generation resources when needed for grid reliability. The Cost Allocation Mechanism (CAM) allows the net costs of these resources to be recovered from all benefiting customers in the IOU's TAC area. Since 2015, the RA capacity of CAM resources has been allocated as an increase to the IOUs' RA requirements and a credit towards non-IOU LSEs' RA requirements, with the IOUs showing the resources in their RA filings. These CAM resources carry the same must-offer obligation as all other RA resources. Certain other resource types including combined heat and power (CHP) and DRAM resources are similarly allocated. Current CAM resources are summarized in Section 4.4.

4.1 Resource Adequacy Contract Price Analysis

Energy Division issued several data requests to all CPUC-jurisdictional LSEs requesting monthly capacity prices paid by (or to) LSEs for every RA capacity contract executed during 2020, 2021, and 2022 for use in calculating the Power Charge Indifference Adjustment (PCIA) RA adder and this RA price analysis. Since RA prices can vary by month, the data request asked for specific monthly prices from each contract. All prices are reported in nominal dollars per kW-month.

Energy Division received responses from all LSEs. With the exception of Table 6, which includes contracts executed through Q3 of 2021 for delivery in 2021-2023, data used in this analysis were restricted to contracts executed in 2019 or 2020 for delivery in 2021. Because Table 6 includes data from contracts executed in 2021, the weighted average, average, and 85th percentile prices all differ slightly from the same data categories in other tables.

4.1.1 System Capacity Prices

Table 6 provides a summary of 2021-2023 system capacity prices.

Table 6. RA System Capacity Prices in 2021, 2022, and 2023

	2021 Capacity	2022 Capacity	2023 Capacity
Contracted Capacity (MW)	182,029	170,079	114,796
Weighted Average Price ($/kW-month)	$6.50	$6.54	$6.35
Average Price ($/kW-month)	$6.93	$6.87	$6.54
85% of MW at or below ($/kW-month)	$9.00	$8.00	$7.54

Source: 2021-2023 price data submitted by LSEs.

System capacity is comprised of both resources that count only towards system capacity (or both system and flexible capacity) and those located in local areas that also have a local RA value and may count towards local RA requirements. Table 7 provides aggregated capacity prices for all responses, categorized as system-only or local capacity, either north or south of Path 26 (NP-26 and SP-26, respectively). The 2021 Net Qualifying Capacity list is used to identify resources' local area and Path 26 zone.[20] The data set represents 180,702 MW-months of capacity under contract. Of that capacity, 48 percent is located in the NP-26 zone, and 48 percent is located in SP-26. Just under 4 percent is comprised of capacity imports to CAISO. Of the capacity located within

[20] The 2021 Net Qualifying Capacity list can be found at Resource Adequacy Compliance Materials (ca.gov).

CAISO, 63 percent is located in local capacity areas, with 33 percent located in the CAISO System area.

The weighted average price for all capacity is $6.51/kW-month. The weighted average price for SP-26 capacity (including local and system RA) is $6.58/kW-month, which is about 5 percent higher than the NP-26 weighted average price of $6.27/kW-month.

The weighted average price of local RA is $6.53/kW-month compared to $6.24/kW-month for system RA capacity. In 2021 the average price of System RA sold for about $ 0.29/ kW-month more than Local RA on average.

Table 7. Aggregated RA Contract Prices, 2021

	All RA				Local RA			CAISO System RA		
	Total[21]	NP-26	SP-26	Import	**Subtotal**	NP26	SP26	**Subtotal**	NP26	SP26
Contracted Capacity (MW)	**180,702**	87,354	86,248	7,100	**113,828**	50,799	63,029	**59,774**	36,555	23,219
Percentage of Total Capacity in Data Set	**100%**	48%	48%	4%	**63%**	28%	35%	**33%**	20%	13%
Number of Monthly Values	**7,218**	4,062	2,959	197	**4,119**	2,351	1,768	**2,902**	1,711	1191
Weighted Average Price ($/kW-month)	**$6.51**	$6.27	$6.58	$8.54	**$6.53**	$6.53	$6.52	**$6.24**	$5.91	$6.75
Average Price ($/kW-month)	**$6.93**	$6.98	$6.86	$6.99	**$7.02**	$7.06	$6.97	**$6.79**	$6.87	$6.69
85% of MW at or below ($/kW-month)	**$9.00**	$9.00	$8.88	$9.80	**$8.37**	$8.50	$8.00	**$11.00**	$11.00	$11.50

Source: 2021 price data submitted by LSEs.

The monthly weighted average capacity prices for CAISO resources are shown in Table 8 below.

[21] Table 7 differs slightly from Table 6 because it excludes contracts, such as Demand Response contracts, that don't specify whether they are north or south of path 26.

Table 8. RA Capacity Prices by Month and Path 26 Zone, 2021

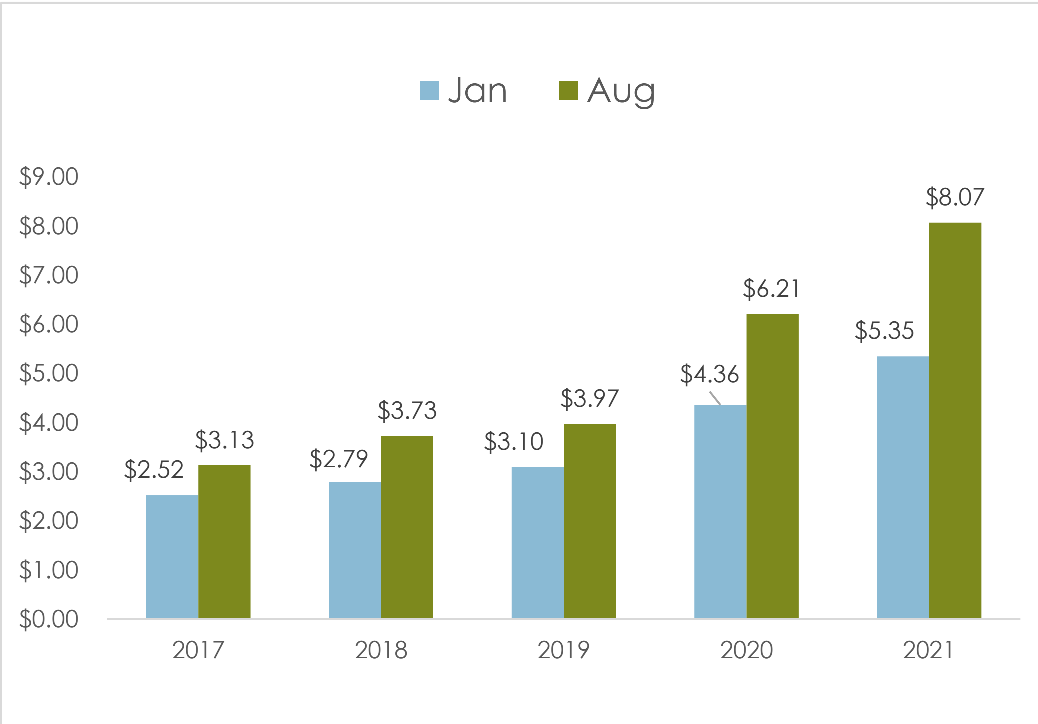
	Path 26 Zone	Contracted Capacity (MW)	Percentage of Total Capacity in Data Set	Weighted Average Price ($/kW-month)	Average Price ($/kW-month)	85th Percentile ($/kW-month)
Jan	North	12,149	4.32%	$5.09	$5.78	$7.50
	South	9,148	3.26%	$5.70	$5.37	$7.25
	Total	21,297	7.58%	$5.35	$5.63	$7.50
Feb	North	12,169	4.33%	$4.98	$5.68	$7.50
	South	9,499	3.38%	$5.56	$5.39	$7.25
	Total	21,668	7.71%	$5.23	$5.57	$7.50
Mar	North	13,445	4.79%	$4.73	$5.56	$7.50
	South	9,883	3.52%	$5.53	$5.33	$7.25
	Total	23,328	8.30%	$5.07	$5.48	$7.50
Apr	North	15,045	5.36%	$4.78	$5.56	$7.50
	South	9,822	3.50%	$5.53	$5.23	$7.23
	Total	24,867	8.85%	$5.08	$5.44	$7.49
May	North	13,785	4.91%	$5.07	$5.95	$7.50
	South	10,172	3.62%	$5.62	$5.49	$7.23
	Total	23,957	8.53%	$5.31	$5.79	$7.50
Jun	North	12,519	4.46%	$5.60	$6.62	$7.99
	South	10,219	3.64%	$6.08	$6.04	$7.25
	Total	22,738	8.09%	$5.81	$6.40	$7.75
Jul	North	12,775	4.55%	$7.00	$8.46	$14.00
	South	11,054	3.94%	$7.68	$8.33	$14.20
	Total	23,829	8.48%	$7.31	$8.40	$14.00
Aug	North	13,642	4.86%	$7.84	$9.01	$15.00
	South	11,056	3.94%	$8.35	$9.08	$15.00
	Total	24,698	8.79%	$8.07	$9.04	$15.00
Sep	North	14,670	5.22%	$8.17	$9.92	$16.00

	Path 26 Zone	Contracted Capacity (MW)	Percentage of Total Capacity in Data Set	Weighted Average Price ($/kW-month)	Average Price ($/kW-month)	85th Percentile ($/kW-month)
	South	10,569	3.76%	$9.24	$10.46	$16.45
	Total	25,239	8.99%	$8.62	$10.12	$16.00
Oct	North	13,478	4.80%	$6.60	$7.13	$8.94
	South	10,515	3.74%	$6.57	$6.71	$8.75
	Total	23,993	8.54%	$6.59	$6.97	$8.75
Nov	North	13,015	4.63%	$5.65	$5.69	$7.50
	South	10,490	3.73%	$5.51	$5.03	$7.17
	Total	23,505	8.37%	$5.59	$5.42	$7.50
Dec	North	12,727	4.53%	$5.65	$5.83	$7.50
	South	9,055	3.22%	$5.95	$5.67	$7.25
	Total	21,782	7.75%	$5.78	$5.78	$7.50

Source: 2021 price data submitted by LSEs.

Figure 4 shows the monthly weighted average price of System RA for January and August from 2017 -2021. The weighted average price of system RA for both seasons has increased each year, and at an accelerating pace. Average August prices were $3.13/kW-month in 2017 but increased each year thereafter. By 2021 the average price had risen to $8.07 kW/month, an increase of 158 percent over just 5 years. January RA prices increased a more modest 112 percent between 2017 and 2021, from $2.52/kW-month to $5.35/kW-month. These price increases appear to be driven by issues related to supply and demand balances due to resource retirements, load forecast increases, and changes in counting conventions for certain resources.

Figure 4: Weighted Average Price of System RA ($/kW-month), January and August 2017- 2021



Source: 2017-2021 price data submitted by LSEs.

4.1.2 Local Capacity Prices

Table 9 reports capacity prices by local capacity area. A CAISO system price for capacity outside of the local areas, excluding imports, is included for comparison. 2021 weighted average prices for local areas range from $6.04/kW-month in Humboldt and $6.07 in Fresno to $9.24/kW-month in Kern, while 85th percentile prices ranged from $7.50/kW-month Fresno and San Deigo local capacity to $8.88/kW-month in Big Creek-Venture.

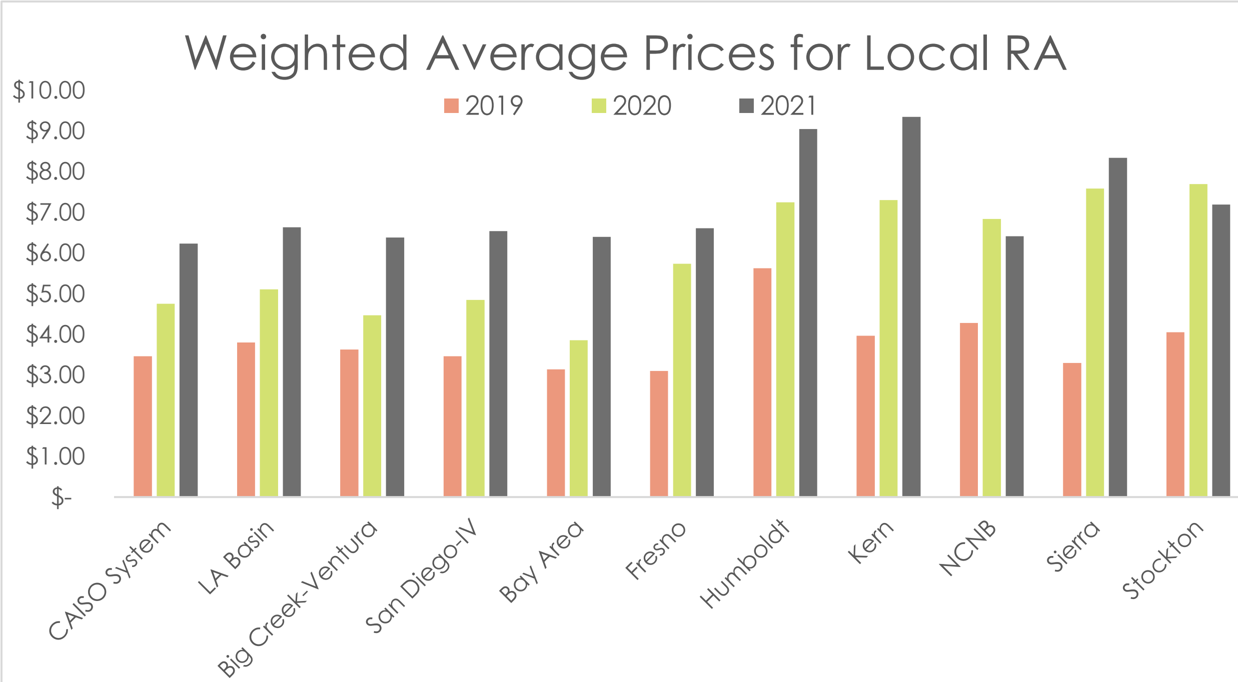
Table 9. Capacity Prices by Local Area, 2021

	Contracted Capacity (MW)	Percentage of Total Capacity in Data Set	Weighted Average Price ($/kW-month)	Average Price ($/kW-month)	85% of MW at or below ($/kW-month)
CAISO System	59,774	33%	$ 6.24	$ 6.79	$ 11.00
LA Basin	24,178	13%	$ 6.64	$ 7.14	$ 8.00
Big Creek-Ventura	22,753	13%	$ 6.39	$ 7.09	$ 9.60
San Diego-IV	16,097	9%	$ 6.54	$ 6.71	$ 7.50
Bay Area	42,077	23%	$ 6.40	$ 6.88	$ 8.15
Fresno	3,825	2%	$ 6.61	$ 6.88	$ 8.50
Humboldt	78	0%	$ 9.05	$ 8.11	$ 14.73
Kern	503	0%	$ 9.35	$ 7.63	$ 8.88
NCNB	2,029	1%	$ 6.41	$ 7.29	$ 8.84
Sierra	1,722	1%	$ 8.34	$ 7.50	$ 8.75
Stockton	465	0%	$ 7.19	$ 7.05	$ 8.00

Source: 2021 price data submitted by LSEs.

Figure 5 shows weighted average RA prices for 10 local areas and, for comparison purposes, CAISO system RA, for the years 2019-2021. The figure reveals the increased pricing each year during the period shown. Prices for the LA Basin, Big Creek-Ventura, San Diego-IV, and the Greater Bay Area — which collectively account for most local RA requirements and contracted capacity — have closely tracked CAISO system prices. RA in Fresno, Humboldt, Kern, Sierra, and Stockton have commanded a lager premium when compared to CAISO system prices. This price divergences were particularly salient in 2020 and 2021.

Figure 5. Weighted Average Price of Local RA ($/kW-month), 2019-2021



Source: 2017-2021 price data submitted by LSEs and presented in past RA Reports

Table 10 shows weighted average and 85th percentile prices by month for each local area and for CAISO System resources not sited in a local area. Table 10 indicates that the price of local RA where it commands a significant premium over CAISO prices (such as Kern, Sierra, Stockton, and Humboldt) increases significantly between summer and non-summer months. San Diego-IV and the Bay Area, by contrast, have relatively consistent prices throughout the year.

Table 10. Local RA Capacity Prices by Month, 2021

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CAISO System	**Weighted Average**	$4.36	$4.24	$3.72	$3.70	$4.05	$5.04	$7.33	$8.83	$9.68	$6.12	$4.47	$4.69
	85th Percentile	$6.50	$6.50	$6.50	$6.50	$6.50	$7.33	$14.50	$15.00	$22.00	$8.75	$6.50	$6.50
LA Basin	**Weighted Average**	$6.51	$6.52	$6.41	$6.46	$6.52	$7.01	$7.55	$7.81	$8.41	$6.95	$6.45	$6.62
	85th Percentile	$9.16	$9.25	$9.00	$9.16	$9.25	$9.50	$14.00	$15.00	$15.24	$9.14	$9.03	$9.25
Big Creek-Ventura	**Weighted Average**	$5.97	$5.90	$5.91	$5.81	$5.88	$5.90	$6.98	$7.35	$7.59	$6.28	$5.61	$6.00
	85th Percentile	$7.25	$7.25	$7.25	$7.25	$7.24	$7.00	$14.00	$11.33	$14.80	$7.25	$7.21	$7.25
San Diego-IV	**Weighted Average**	$6.13	$5.25	$5.55	$5.53	$5.58	$6.36	$7.53	$8.19	$8.65	$6.94	$6.48	$6.44
	85th Percentile	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$10.23	$14.00	$10.69	$8.75	$7.23	$7.10
Bay Area	**Weighted Average**	$5.03	$4.94	$5.27	$5.38	$5.67	$5.75	$6.74	$7.09	$8.07	$7.09	$6.26	$6.19
	85th Percentile	$7.25	$7.25	$7.25	$7.25	$7.25	$7.25	$12.52	$12.69	$15.00	$8.88	$7.25	$7.25
Fresno	**Weighted Average**	$4.93	$4.91	$4.60	$4.98	$5.09	$5.33	$8.40	$7.98	$7.68	$6.01	$5.50	$5.69
	85th Percentile	$7.33	$7.29	$7.25	$7.00	$7.25	$7.50	$11.17	$10.47	$12.00	$8.10	$7.44	$7.50
Humboldt	**Weighted Average**	$5.98	$5.88	$5.96	$5.88	$5.88	$6.05	$9.84	$9.89	$8.83	$6.93	$6.36	$6.44
	85th Percentile	$7.57	$7.60	$7.60	$7.57	$7.50	$7.66	$13.55	$14.40	$11.10	$7.75	$7.50	$7.57
Kern	**Weighted Average**	$7.12	$7.15	$6.75	$7.16	$7.35	$8.39	$8.91	$9.15	$8.73	$7.24	$6.71	$7.31
	85th Percentile	$7.75	$7.75	$7.75	$7.75	$7.85	$7.85	$8.90	$8.41	$7.85	$7.85	$7.75	$7.83
NCNB	**Weighted Average**	$5.96	$6.02	$5.76	$5.95	$5.93	$5.73	$6.08	$6.79	$7.12	$6.77	$5.91	$5.99
	85th Percentile	$7.50	$7.50	$7.52	$7.50	$7.60	$7.62	$8.50	$8.84	$8.73	$8.50	$7.50	$7.50
Sierra	**Weighted Average**	$6.34	$6.32	$6.26	$6.25	$6.26	$6.56	$8.26	$8.27	$8.27	$7.60	$6.22	$6.28
	85th Percentile	$7.50	$7.50	$7.50	$7.50	$7.51	$7.97	$14.50	$15.00	$15.45	$10.00	$7.50	$7.50
Stockton	**Weighted Average**	$7.00	$6.55	$6.54	$6.64	$6.91	$7.03	$8.60	$8.76	$8.62	$7.45	$6.61	$6.61
	85th Percentile	$8.00	$7.20	$7.34	$7.34	$7.23	$7.20	$10.45	$13.05	$10.67	$8.09	$7.64	$7.93

Source: 2021 price data submitted by LSEs

4.1.3 Flexible Capacity Prices

Table 11 shows capacity prices for flexible capacity located outside of local areas. Prices for flexible capacity are considerably lower than those for system capacity. The 2021 weighted average price for flexible capacity is $5.27/kW-month, while it is $6.49/kW-month for non-flexible system capacity.

Table 11. Flexible vs. Non-Flexible CAISO System Prices (Excluding Imports), 2021

	Flexible Capacity	Non-Flexible Capacity	All CAISO System
Contracted Capacity (MW)	18,474	24,606	43,401
Percentage of Total Capacity in Data Set	100%	100%	100%
Weighted Average Price ($/kW-month)	$5.27	$6.49	$5.88
Average Price ($/kW-month)	$5.63	$6.48	$6.19
85% of MW at or below ($/kW-month)	$7.81	$11.75	$9.26

Source: 2021 price data submitted by LSEs.

4.2 CAISO Out of Market Procurement – RMR Designations

The CAISO performs RMR studies to determine whether resources are needed for reliability. Generating resources with existing RMR contracts must be re-designated by the CAISO for the next compliance year and presented to the CAISO Board of Governors for approval by October 1st of each year. Designations for new RMR contracts are more flexible and may arise at any time. RMR resources can be dispatched by the CAISO for reliability and are paid for by customers in the transmission area or by all customers, depending upon the underlying reason for the designation. D.06-06-064 authorized the CPUC to allocate the RMR benefits as an RMR credit that is applied towards RA requirements.

Pursuant to the stated policy preference of the CPUC,[22] local RA requirements began to supplant RMR contracting in the 2007 compliance year and there was a significant decline in 2007 RMR designations. That trend continued through the 2011 compliance year, with only one remaining RMR contract.[23]

In 2017, for the 2018 compliance year, RMR designations increased dramatically. Four units received RMR Condition 2 designations. Calpine Corporation's Feather River Energy Center (45 MW) and Yuba City Energy Center (46 MW) received Condition 2 RMR contracts for Other PG&E Areas and Metcalf Energy Center (570 MW) received a Condition 2 RMR contract for the Bay Area. Dynegy Oakland's units 1, 2, and 3 were also designated to ensure local reliability in Oakland, California.

In 2018, for the 2019 compliance year, CAISO extended RMR contracts for three generating facilities: Calpine Corporation's Feather River Energy Center (45 MW), Yuba City Energy Center (46 MW), and Dynegy Oakland, LLC's units 1, 2, and 3.

In 2020, for the 2021 compliance year, CAISO extended and signed RMR contracts for four generating facilities: Green Leaf (49.2 MW), CSU Channel Islands (27.5 MW), Midway Cogen (263.5 MW in August), and Dynegy Oakland, LLC's units 1 and 2 (110 MW).

4.3 CAISO Out of Market Procurement – CPM Designations

CAISO implemented the Capacity Procurement Mechanism (CPM) effective April 1, 2011, to procure capacity to maintain grid reliability if there is:

- Insufficient local capacity area resources in an annual or monthly RA plan;
- Collective deficiency in local capacity area resources;
- Insufficient RA resources in an LSE's annual or monthly RA plan;
- A CPM significant event;
- A reliability or operational need for an exceptional dispatch CPM;

[22] D.06-06-064, Section 3.3.7.1., Available at: http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/57644.DOC.

[23] Dynegy Oakland LLC's Units 1, 2 and 3 (165 MW).

- Capacity at risk of retirement within the current RA compliance year that will be needed for reliability by the end of the calendar year following the current RA compliance year; and
- Cumulative flexible capacity deficiency in annual or monthly RA plans.[24]

Eligible capacity is limited to resources that are not already under a contract to be an RA resource, are not under an RMR contract, and are not currently designated as CPM capacity. Eligible capacity must be capable of effectively resolving a procurement shortfall or a reliability concern.

Under the exceptional dispatch CPM, CAISO can procure resources for an initial term of 30 days. The term can be extended beyond the initial period if CAISO determines that the circumstances leading to exceptional dispatch continue to exist.

The CPM price is based on the going forward fixed costs of a reference resource. Since 2016, the CPM price has been determined by a Competitive Solicitation Process (CSP). The CPM tariff includes a soft offer cap initially set at $75.68/kW-year (or $6.31/kW-month) by adding a 20 percent premium to the estimated going-forward fixed costs for a mid-cost 550 MW combined cycle resource with duct firing, as estimated in a 2014 report by the California Energy Commission. However, a supplier may apply to FERC to justify a price higher than the soft offer cap prior to offering the resource into the competitive solicitation process or after receiving a capacity procurement mechanism designation by the ISO.[25] Table 12 shows CAISO's CPM designations for 2021.

Table 12. CAISO CPM Designations for 2021

Resource ID	MW		Term (days)	Start Date	End Date	Est. Cap. Cost /kW-mth	Total Cost
KRNCNY_6_UNIT	4.74	Significant Event	30	7/9/2021	8/8/2021	6.31	$ 142,200.00
KRNCNY_6_UNIT	3.25	Significant Event	30	8/1/2021	8/31/2021	6.31	$ 97,500.00
BLKCRK_2_GMCBT1	132.5	Significant Event	30	7/9/2021	8/8/2021	6.31	$ 3,975,000.00

24 CAISO Reliability BPM, version 41, page 138. https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Reliability%20Requirements.

25 CAISO 2016 Fourth Quarter Market Issues and Performance Report, March, 2017, page 68, http://www.caiso.com/Documents/2016FourthQuarterReport-MarketIssuesandPerformanceMarch2017.pdf.

HINSON_6_LBECH1	5	Significant Event	30	7/9/2021	8/8/2021	6.31	$	150,000.00
HINSON_6_LBECH2	7	Significant Event	30	7/9/2021	8/8/2021	6.31	$	210,000.00
HINSON_6_LBECH3	7	Significant Event	30	7/9/2021	8/8/2021	6.31	$	210,000.00
HINSON_6_LBECH4	4	Significant Event	30	7/9/2021	8/8/2021	6.31	$	120,000.00
VESTAL_2_WELLHD	38	Significant Event	30	7/9/2021	8/8/2021	6.31	$	1,140,000.00
SBERDO_2_PSP4	45	Significant Event	30	7/9/2021	8/8/2021	6.31	$	1,350,000.00
SBERDO_2_PSP3	15	Significant Event	30	7/9/2021	8/8/2021	6.31	$	450,000.00
BUCKBL_2_PL1X3	51	Significant Event	30	7/9/2021	8/8/2021	6.31	$	1,530,000.00
ELKHIL_2_PL1X3	30	Significant Event	30	8/1/2021	8/31/2021	6.31	$	900,000.00
JOANEC_2_STABT1	20	Significant Event	30	7/12/2021	8/11/2021	6.31	$	600,000.00
BARRE_6_PEAKER	44	Significant Event	30	7/12/2021	8/11/2021	6.31	$	1,320,000.00
ARCOGN_2_UNITS	16.61	Significant Event	30	7/22/2021	8/21/2021	6.31	$	498,300.00
DRACKR_2_DSUBT3	81.25	Significant Event	30	8/2/2021	9/1/2021	6.31	$	2,437,500.00
VISTRA_5_DALBT4	100	Significant Event	30	8/2/2021	9/1/2021	6.31	$	3,000,000.00
OMAR_2_UNIT 1	0.72	Significant Event	30	8/2/2021	9/1/2021	6.31	$	21,600.00
OMAR_2_UNIT 2	1.52	Significant Event	30	8/2/2021	9/1/2021	6.31	$	45,600.00
OMAR_2_UNIT 3	2	Significant Event	30	8/2/2021	9/1/2021	6.31	$	60,000.00
OMAR_2_UNIT 4	2	Significant Event	30	8/2/2021	9/1/2021	6.31	$	60,000.00
SYCAMR_2_UNIT 1	3	Significant Event	30	8/2/2021	9/1/2021	6.31	$	90,000.00
SYCAMR_2_UNIT 2	4	Significant Event	30	8/2/2021	9/1/2021	6.31	$	120,000.00
SYCAMR_2_UNIT 3	73	Significant Event	30	8/10/2021	9/9/2021	6.31	$	2,190,000.00
INTKEP_2_UNITS	121.43	Exceptional Dispatch	30	7/9/2021	8/8/2021	6.31	$	3,642,900.00
MNDALY_6_MCGRTH	43	Exceptional Dispatch	30	7/9/2021	8/8/2021	6.31	$	1,290,000.00
SYCAMR_2_UNIT 3	70	Exceptional Dispatch	30	7/10/2021	8/9/2021	6.31	$	2,100,000.00
RUSCTY_2_UNITS	350	Significant Event	30	8/11/2021	9/10/2021	6.31	$	10,500,000.00
DRACKR_2_DSUBT1	63	Significant Event	30	9/1/2021	10/1/2021	6.31	$	1,890,000.00
OMAR_2_UNIT 1	0.72	Significant Event	30	9/1/2021	10/1/2021	6.31	$	21,600.00
OMAR_2_UNIT 2	1.52	Significant Event	30	9/1/2021	10/1/2021	6.31	$	45,600.00
OMAR_2_UNIT 3	2	Significant Event	30	9/1/2021	10/1/2021	6.31	$	60,000.00
OMAR_2_UNIT 4	2	Significant Event	30	9/1/2021	10/1/2021	6.31	$	60,000.00
SYCAMR_2_UNIT 1	3	Significant Event	30	9/1/2021	10/1/2021	6.31	$	90,000.00
SYCAMR_2_UNIT 2	3	Significant Event	30	9/1/2021	10/1/2021	6.31	$	90,000.00
SYCAMR_2_UNIT 3	3	Significant Event	30	9/10/2021	10/10/2021	6.31	$	90,000.00
SCE1_MALIN500_I_F_262626	42	Significant Event	30	9/1/2021	10/1/2021	6.31	$	1,260,000.00
SCE1_MALIN500_I_F_272727	25	Significant Event	30	9/1/2021	10/1/2021	6.31	$	750,000.00
SCE1_MALIN500_I_F_262626	25	Significant Event	30	9/1/2021	10/1/2021	6.31	$	750,000.00
SCE1_MALIN500_I_F_262626	25	Significant Event	30	9/1/2021	10/1/2021	6.31	$	750,000.00
SCE1_MALIN500_I_F_262626	50	Significant Event	30	9/1/2021	10/1/2021	6.31	$	1,500,000.00

SCE1_MALIN500_I_F_262626	50	Significant Event	30	9/1/2021	10/1/2021	6.31	$ 1,500,000.00
SCE1_MALIN500_I_F_262626	25	Significant Event	30	9/1/2021	10/1/2021	6.31	$ 750,000.00
Garlnd_2_GARBT1	44.53	Significant Event	30	9/1/2021	10/1/2021	6.31	$ 1,335,900.00
CALFTN_2_CFSBT1	60	Significant Event	30	9/1/2021	10/1/2021	6.31	$ 1,800,000.00
OMAR_2_UNIT 1	2.32	Significant Event	30	10/1/2021	10/31/2021	6.31	$ 69,600.00
OMAR_2_UNIT 2	2.12	Significant Event	30	10/1/2021	10/31/2021	6.31	$ 63,600.00
OMAR_2_UNIT 3	2	Significant Event	30	10/1/2021	10/31/2021	6.31	$ 60,000.00
OMAR_2_UNIT 4	2	Significant Event	30	10/1/2021	10/31/2021	6.31	$ 60,000.00
SYCAMR_2_UNIT 1	3	Significant Event	30	10/1/2021	10/31/2021	6.31	$ 90,000.00
SYCAMR_2_UNIT 2	8	Significant Event	30	10/1/2021	10/31/2021	6.31	$ 240,000.00
JAWBNE_2_SRWWD2	2.36	Significant Event	30	10/1/2021	10/31/2021	6.31	$ 70,800.00
GATEWT_2_GESTBT1	5	Significant Event	30	10/1/2021	10/31/2021	6.31	$ 150,000.00

Source: CPM Designation posted by CAISO at http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=33EB5656-7056-4B8E-87B2-3EA3D816DA62.

4.4 IOU Procurement for System Reliability and Other Policy Goals

This subsection discusses the different types of procurement that IOUs have been directed to perform for all LSEs, either by statute or CPUC decision.

4.4.1 System Reliability Resources

D.06-07-029 adopted a process known as the Cost Allocation Mechanism, or CAM, which allows the CPUC to designate IOUs to procure new generation for system reliability within an IOU's distribution service territory. Under CAM, all related costs and benefits are allocated to all benefiting customers, including bundled utility customers, direct access customers, and customers of community choice aggregators. The LSEs serving these customers are proportionately allocated the capacity in each service territory, which is applied towards meeting LSEs' RA requirements. The LSEs receiving a portion of the CAM capacity pay only for the net cost of the capacity, which is the total cost of the power purchase contract price, minus any energy revenues associated with the dispatch of the resource.

D.11-05-005 eliminated the IOUs' authority to elect or not elect to use CAM for new generation resources. In addition, the decision permitted CAM for utility-owned generation and allowed CAM to match the duration of the contract for the resource.

Table 13 provides the scheduling resource ID, the contract dates that the CAM was approved to cover, the authorized IOU, and August NQC values for all 2020 CAM resources. The list includes all conventional generation resources currently subject to the CAM mechanism. Utility owned generation (UOG) remains a CAM resource while the generator is operational and thus has no CAM end date.

Table 13. CAM Reliability Resources as of 2021

`	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
AES ES Alamitos, LLC	3/1/2021	12/31/2040	SCE	100
ALAMIT_2_PL1X3	6/1/2020	5/31/2040	SCE	674.7
BARRE_6_PEAKER	7/19/2007	UOG	SCE	47
CARLS1_2_CARCT1	12/1/2018	9/30/2038	SDG&E	422
CARLS2_1_CARCT1	12/1/2018	9/30/2038	SDG&E	105.50
CENTER_6_PEAKER	7/20/2007	UOG	SCE	47.11
CHINO_2_APEBT1	12/31/2016	12/30/2026	SCE	20
COCOPP_2_CTG1	5/1/2013	4/30/2023	PG&E	192.29
COCOPP_2_CTG2	5/1/2013	4/30/2023	PG&E	191.53
COCOPP_2_CTG3	5/1/2013	4/30/2023	PG&E	190.77
COCOPP_2_CTG4	5/1/2013	4/30/2023	PG&E	192.12
ELCAJN_6_EB1BT1	2/21/2017	12/30/2099	SDG&E	12
ELKHIL_2_PL1X3	1/1/2021	1/1/2024	SCE	100
ELSEGN_2_UN1011	8/1/2013	7/31/2023	SCE	263
ELSEGN_2_UN2021	8/1/2013	7/31/2023	SCE	263.68
ESCNDO_6_EB1BT1	3/6/2017	12/30/2099	SDG&E	20
ESCNDO_6_EB2BT2	3/6/2017	12/30/2099	SDG&E	20
ESCNDO_6_EB3BT3	3/6/2017	12/30/2099	SDG&E	20.00
ESCNDO_6_PL1X2	5/1/2014	12/31/2039	SDG&E	48.71
ETIWND_6_GRPLND	7/17/2007	UOG	SCE	47.39
HNTGBH_2_PL1X3	5/1/2020	4/30/2040	SCE	673.8
Miramar Energy Storage	6/1/2021	NA	SDG&E	30
MIRLOM_2_MLBBTA	7/1/2017	6/30/2027	SCE	10
MIRLOM_2_MLBBTB	7/1/2017	6/30/2027	SCE	10
MIRLOM_6_PEAKER	7/19/2007	UOG	SCE	46
MNDALY_6_MCGRTH	8/1/2012	UOG	SCE	47.2
OhmConnect, Inc.	1/1/2019	12/31/2024	SDG&E	4.5
Orni 34 LLC	7/1/2021	4/30/2041	SCE	10

`	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
PIOPIC_2_CTG1	6/1/2017	12/31/2037	SDG&E	111.3
PIOPIC_2_CTG2	6/1/2017	12/31/2037	SDG&E	112.7
PIOPIC_2_CTG3	6/1/2017	12/31/2037	SDG&E	112
SANTGO_2_MABBT1	10/1/2017	12/31/2026	SCE	2
SCE_1_PDR P173, P34; SCEW_2_PDR P160, P161, P162, P163, P164, P169.	3/1/2020	2/28/2030	SCE	15
SCEC_1_PDRP21, PDRP22, PDRP60, PDRP85, PDRP86, PDRP87, PDRP88; SCEW_2_PDRP89, PDRP90, PDRP91	12/1/2016	4/30/2027	SCE	20
SCEW_2_PDRP03	11/1/2017	4/29/2028	SCE	5
SCEW_2_PDRP09, PDRP10	2/1/2018	7/31/2028	SCE	5
SCEW_2_PDRP22, PDRP114, PDRP115, PDRP124, PDRP158, PDRP159, PDRP167, PDRP172	4/1/2019	3/31/2029	SCE	25
SENTNL_2_CTG1	8/1/2013	7/31/2023	SCE	103.76
SENTNL_2_CTG2	8/1/2013	7/31/2023	SCE	95.34
SENTNL_2_CTG3	8/1/2013	7/31/2023	SCE	96.85
SENTNL_2_CTG4	8/1/2013	7/31/2023	SCE	102.47
SENTNL_2_CTG5	8/1/2013	7/31/2023	SCE	103.81
SENTNL_2_CTG6	8/1/2013	7/31/2023	SCE	100.99
SENTNL_2_CTG7	8/1/2013	7/31/2023	SCE	97.06
SENTNL_2_CTG8	8/1/2013	7/31/2023	SCE	101.8
Silverstrand Grid, LLC	7/1/2021	12/31/2040	SCE	11
STANTN_2_STAGT1	7/1/2020	6/30/2040	SCE	49
STANTN_2_STAGT2	7/1/2020	6/30/2040	SCE	49
Strata Saticoy, LLC	6/1/2021	3/31/2041	SCE	100
VESTAL_2_WELLHD	1/16/2013	1/15/2023	SCE	49
VISTRA	6/1/2021	5/31/2041	PG&E	300
WALCRK_2_CTG1	6/1/2013	5/31/2023	SCE	96.43
WALCRK_2_CTG2	6/1/2013	5/31/2023	SCE	96.91
WALCRK_2_CTG3	6/1/2013	5/31/2023	SCE	96.65
WALCRK_2_CTG4	6/1/2013	5/31/2023	SCE	96.49
WALCRK_2_CTG5	6/1/2013	5/31/2023	SCE	96.65

*NQC values are from August 2021. For resources that began after August 2021, the August 2021 NQC is provided. NQC values can change monthly and annually.

4.4.2 QF/CHP Resources

D.10-12-035[26] adopted a Settlement for Qualifying Facilities and Combined Heat and Power (QF/CHP Settlement). The Settlement established the CHP program, which aims to have IOUs procure a minimum of 3,000 MWs over the program period and to reduce greenhouse gas (GHG) emissions consistent with the California Air Resources Board (CARB) climate change scoping plan. D.15-06-028 lowered the GHG emissions reductions target to 2.72 million metric tons.

The Settlement also established a cost allocation mechanism to be used to share the benefits and costs associated with meeting the CHP and GHG goals.[27] The adopted cost allocation mechanism was almost identical to the mechanism adopted in the long-term procurement plan (LTPP) for reliability (D.06-07-029). The settlement allows for the net capacity costs of an approved CHP resource to be allocated to all benefiting customers, including bundled, ESP, and CCA customers. The RA benefits associated with the CHP contract are also allocated to all customers paying the net capacity costs.[28] Table 14 below lists the CHP resources whose RA capacity was allocated as of 2021.

Table 14. CHP Resources Allocated for CAM as of 2021

Scheduling Resource ID	CAM Start Date	CAM End Date	August NQC*	Authorized IOU
ARCOGN_2_UNITS	7/1/2015	6/30/2022	259.89	SCE
BDGRCK_1_UNITS	8/1/2014	7/31/2026	40.2	PG&E
BEARMT_1_UNIT	7/1/2014	6/30/2021	44	PG&E
CALPIN_1_AGNEW	5/1/2013	4/30/2022	28.56	PG&E
CHALK_1_UNIT	10/1/2014	7/31/2026	43.06	PG&E
CHARMN_2_PGONG	8/1/2020	12/31/2026	19.7	SCE
CHEVMN_2_UNITS	1/1/2016	12/31/2022	7.54	SCE
CHINO_6_CIMGEN	7/1/2018	3/11/2025	26	SCE

[26] https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/128624.PDF

[27] CHP Program Settlement Agreement Term Sheet 13.1.2.2 http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124875.PDF.

[28] Section 13.1.2.2 of the QF settlement states:" In exchange for paying a share of the net costs of the CHP Program, the LSEs serving DA and CCA customers will receive a pro-rata share of the RA credits procured via the CHP Program."

Scheduling Resource ID	CAM Start Date	CAM End Date	August NQC*	Authorized IOU
DEXZEL_1_UNIT	4/1/2016	3/30/2023	17.78	PG&E
DOUBLC_1_UNITS	4/1/2012	11/30/2020	49.5	PG&E
ETIWND_2_UNIT1	4/1/2016	3/30/2023	10.34	SCE
FRITO_1_LAY	6/1/2017	5/31/2021	0.08	PG&E
GRZZLY_1_BERKLY	6/1/2017	6/2/2022	9.90	PG&E
HINSON_6_CARBGN	6/1/2017	5/31/2021	28.85	SCE
HOLGAT_1_BORAX	6/1/2017	6/2/2022	12.56	SCE
KERNFT_1_UNITS	12/29/1987	8/31/2026	48.6	PG&E
KERNRG_1_UNITS	8/1/2017	7/31/2024	0.20	PG&E
LIVOAK_1_UNIT 1	5/1/2015	4/30/2022	42.5	PG&E
LMEC_1_PL1X3	1/1/2014	12/31/2021	135.00	SCE
MKTRCK_1_UNIT 1	4/1/2015	5/31/2018	42	PG&E
OMAR_2_UNIT 1	1/1/2014	12/31/2020	70.3	PG&E
OMAR_2_UNIT 2	1/1/2014	12/31/2020	71.24	PG&E
OMAR_2_UNIT 3	1/1/2014	12/31/2020	74.03	PG&E
OMAR_2_UNIT 4	1/1/2014	9/30/2020	81.44	PG&E
OROVIL_6_UNIT	1/1/2014	10/14/2020	7.50	PG&E
SAMPSN_6_KELCO1	4/12/2018	3/31/2020	0.85	SDG&E
SIERRA_1_UNITS	4/1/2012	11/30/2020	49.57	PG&E
SNCLRA_2_UNIT	7/1/2015	3/31/2020	27.5	SCE
SNCLRA_2_UNIT1	10/1/2019	9/30/2026	15.63	SCE
SNCLRA_6_PROCGN	10/1/2019	9/30/2026	20.50	SCE
STOILS_1_UNITS	11/1/2019	10/31/2026	5.14	PG&E
SUNSET_2_UNITS	7/10/2014	12/31/2050	229.5	PG&E
SYCAMR_2_UNIT 1	11/1/2019	10/31/2026	77.41	SCE
SYCAMR_2_UNIT 2	1/1/2014	12/31/2021	74	SCE
SYCAMR_2_UNIT 3	1/1/2014	12/31/2021	74	SCE
SYCAMR_2_UNIT 4	1/1/2014	12/31/2021	74	SCE
TANHIL_6_SOLART	12/1/2019	11/30/2026	9.92	PG&E
TENGEN_2_PL1X2	12/1/2019	11/30/2026	37.60	SCE
TIDWTR_2_UNITS	1/1/2020	12/30/2026	11.19	PG&E
UNVRSY_1_UNIT 1	8/1/2020	12/31/2026	34.03	SCE

*NQC values are from August 2021. If the unit was not CHP CAM in August 2021, then the applicable August NQC is shown. NQC values can change monthly and annually.

4.4.3 DR Resources

D.14-12-024 authorized pilot DRAM auctions as a means for the IOUs to procure DR capacity from third party DR providers. Capacity procured through DRAM is allocated to all customers similarly to that of CAM and CHP resources. Table 15 lists the DRAM capacity procured by the IOUs for 2021.

Table 15. DRAM Capacity Allocated for CAM for 2021

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
Multiple	1/1/2021	12/31/2021	PG&E	82.94
Multiple	1/1/2021	12/31/2021	SCE	100.06
Multiple	1/1/2021	12/31/2021	SDG&E	23.05
			TOTAL	**206.05**

*NQC values can vary by month.

Event-based DR resources are market-integrated and are also treated as an RA credit. The costs for most DR programs are allocated through the distribution charge, which means that these DR programs are paid for by bundled customers, direct access customers, and the customers of community choice aggregators. The exceptions are SCE's Smart Energy Program and rate-based programs such as SCE and PG&E's Critical Peak Pricing (CPP) programs. The RA credit associated with DR is based on capacity estimated using the CPUC-adopted Load Impact Protocols. The IOUs and third-party DR providers submit ex-ante load impact values associated with each market-integrated DR program on April 1st for the coming RA compliance year. Energy Division verifies and evaluates the ex-ante load impact values using the ex-post actual performance load impacts from the previous year and the programs' forecast assumptions. When the values are final, DR RA credits are posted on the CPUC's RA compliance website and then allocated to all LSEs for the coming compliance year.

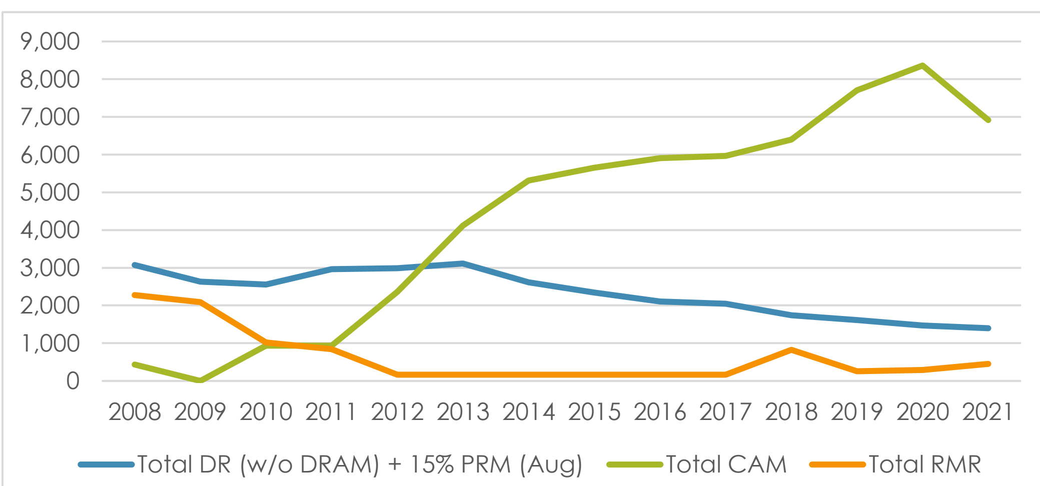
Table 16 and Figure 6 below illustrate the amounts and types of procurement credit that have been allocated since the beginning of the RA program. The graph reflects the decline in RMR units, but with a spike in 2018, and the increase in CAM units through 2020, declining in 2021. DR RA credits have declined slightly since 2013. The total amount of capacity procured through DR, CAM, and RMR for August 2021 was 8,762 MW. This is about 19 percent of the total CPUC-jurisdictional LSE obligation for

August 2021 (45,422 MW). In August 2021, total CAM procurement reached 6,915 MW and RMR procurement increased from 290 MW in 2020 to 450 MW in 2021.

Table 16. DR, CAM, and RMR Allocations for August, 2007-2021 (MW)

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
DR	SCE		1,705	1,616	1,613	1,838	2,067	2,195	1583	1593	1480	1437	1215	1125	1031	977
	PG&E		1018	912	846	888	744	783	933	689	565	566	488	448	424	402
	SDG&E		346	104	97	241	177	135	96	63	60	42	40	39	17	19
	Total DR w/out DRAM (Aug)	**2,628**	**3,069**	**2,632**	**2,556**	**2,967**	**2,988**	**3,113**	**2,613**	**2,345**	**2,105**	**2,045**	**1,743**	**1,612**	**1,472**	**1,397**
CAM	SCE	436	436	436	936	936	1,529	2,763	3,477	3,583	3,848	3,702	4,091	4,742	5,535	4,480
	PG&E						703	1,351	1,790	2,020	2,008	1,868	1,897	1,989	1,848	1,422
	SDG&E						130		49	49	49	399	413	975	980	1,012
	Total CAM (Aug)	**436**	**436**	**436**	**936**	**936**	**2,362**	**4,114**	**5,316**	**5,652**	**5,905**	**5,969**	**6,401**	**7,706**	**8,363**	**6,915**
RMR	SCE														76	28
	PG&E	1,348	1,303	1,263	709	527	165	165	165	165	165	165	826	256	214	159
	SDG&E	1,961	973	828	311	311									0	
	System															264
	Total RMR	**3,309**	**2,276**	**2,091**	**1,020**	**838**	**165**	**165**	**165**	**165**	**165**	**165**	**826**	**256**	**290**	**450**

Figure 6. RA Procurement Credit Allocation, 2006 – 2021 (RMR, August DR, and August CAM)



5 NET QUALIFYING CAPACITY

Qualifying Capacity (QC) represents a resource's maximum capacity eligible to be counted towards meeting the CPUC's RA Requirements prior to an assessment of its deliverability. The CPUC adopted QC counting conventions, which are computed based on the applicable resource type, in D.10-06-036[29] and has updated counting methodologies in subsequent decisions. The applicable data sets and data conventions are contained in the most recent adopted QC methodology manual.[30]

The QC methodology varies by resource type:

- The QC value of dispatchable resources is based on the most recent maximum capability (Pmax) test.
- Non-dispatchable hydro and geothermal resources receive QC values based on historical production.
- Combined heat and power (CHP) and biomass resources that can bid into the day ahead market, but are not fully dispatchable, receive QC values based on the MW amount bid or self-scheduled into the day ahead market.
- Wind and solar QC values are based on effective load carrying capability (ELCC) modeling.

The CPUC executes a subpoena for settlement quality meter and bidding data from the CAISO and performs QC calculations for non-dispatchable resources annually. ELCC values are periodically updated.

After the QC values are calculated, the CAISO conducts a deliverability assessment to produce the annual Net Qualifying Capacity (NQC) value of each resource. When the QC for a resource is greater than the resource's deliverable capacity, the NQC is adjusted to the deliverable capacity value. The CAISO conducts deliverability assessments two to three times a year pursuant to the Large Generator Interconnection Procedures (LGIP) for both new and existing resources.

[29] https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/119856.PDF (QC manual adopted as Appendix B).

[30] Microsoft Word - Adopted QC Methodology Manual 2020 final.docx (ca.gov).

After the CAISO has completed its deliverability study, it posts a draft NQC list and generators typically have three weeks to file comments with the CAISO and CPUC regarding the proposed NQC values. After the comment period, the values are updated, if needed, and a final NQC list is posted. This NQC list includes information on the local area, the zonal area, and the deliverability of each resource.

5.1 New Resources and Retirements in 2021

Overall, 2021 saw an increase in available capacity. A total of 2033.34 MW of capacity (NQC) was brought onto the system in 2020 while just 59 MW of capacity was retired.

Table 17 lists the new facilities that came online in 2021 and Table 18 lists the retiring and mothballed facilities for 2021. Net dependable capacity, the amount of deliverable capacity as determined by the CAISO, is also listed for new facilities. Generators can come online as energy-only facilities with no NQC value or in phases with the initial NQC value well below the planned capacity. Solar and wind generators also have NQC values well below net dependable capacity, since their NQC is based on ELCC modeling. For example, in 2021, the net dependable capacity of new facilities was about 3,258.3 MW which was more than 1,200 MW over the assigned NQC values.

Table 17. New NQC Resources Online in 2021

Resource ID	Resource Name	Technology	NQC	Net Dependable Capacity
ALMASL_2_GS6SR6	Almasol Generating Station 6	Solar	20.55	100
ALMASL_2_GS7SR7	Almasol Generating Station 7	Solar	35.64	132
ALTWD_2_AT3WD3	Altech 3	Wind	2.06	9.8
ALTWD_2_COAWD1	Coachella 1	Wind	10.58	50.4
AQUAWS_2_AQWSR1	Aquamarine Westside	Solar	67.5	250
ATHOS_5_AP2X2	Athos Power Plant 2	Solar	54	200
BGSKYN_2_ASSR3A	Antelope Solar 3A	Solar	4.05	15
BGSKYN_2_ASSR3B	Antelope Solar 3B	Solar	1.35	5
BLKCRK_2_GMCBT1	Genesis McCoy Bess	Battery Storage	230	230
CALFTN_2_CFSBT1	California Flats Solar Battery	Battery Storage	60	60
CENT40_1_C40SR1	CENTRAL 40	Solar	10.8	40
COLPIN_6_COLLNS	Collins Pine	Biomass	0	3.3

DRACKR_2_DSUBT1	Dracker Solar Unit 1 BESS	Battery Storage	63	63
DRACKR_2_DSUBT2	Dracker Solar Unit 2 BESS	Battery Storage	115	115
DRACKR_2_DSUBT3	Dracker Solar Unit 3 BESS	Battery Storage	115	115
DSRTHV_2_DH2BT1	Desert Harvest BESS	Battery Storage	35	35
EDWARD_2_E23SB1	EdSan 2 Edwards 3	Hybrid	11.71	24
ESNHWR_2_WC1BT1	Wildcat I BESS	Battery Storage	1.5	3
ESTWND_2_OPPWD1	Oasis Power Plant Eastwind	Wind	12	57.14
GARNET_2_COAWD2	Coachella 2	Wind	2.27	10.8
GOLETA_2_VALBT1	Vallecito Energy Storage	Battery Storage	10	10
HAYPRS_6_HAYHD1	Haypress Lower	Hydro	0.04	5.8
HAYPRS_6_HAYHD2	Haypress Middle	Hydro	0.04	6.7
HENRTA_6_HDEBT1	Henrietta D Energy Storage	Battery Storage	10	10
HIGHDS_2_H5SBT1	High 5 Solar BESS	Battery Storage	50	50
HIGHDS_2_H5SSR1	High 5 Solar	Solar	27	100
JAWBNE_2_SRWND	Sky River Wind Repower A	Wind	6.85	30
JAWBNE_2_SRWWD2	Sky River Wind Repower B	Wind	6.19	30.2
JOANEC_2_STABT1	Santa Ana Storage 1	Battery Storage	20	20
JOHANN_2_JOSBT1	Johanna Storage 1	Battery Storage	10	10
JOHANN_2_JOSBT2	Johanna Storage 2	Battery Storage	10	10
JOHANN_2_OCEBT2	Orange County Energy Storage 2	Battery Storage	9	9
JOHANN_2_OCEBT3	Orange County Energy Storage 3	Battery Storage	6	6
KRAMER_2_SEGS 9	Kramer Junction 9	Solar	21.6	80
KRNCNY_6_UNIT	KERN CANYON POWERHOUSE	Hydro	3.25	10.6
LNCSTR_6_SOLAR2	SEPV Sierra NGR	Hybrid	4.51	8.25
MOORPK_2_ACOBT1	Acorn I BESS	Battery Storage	1	1.95
MRGT_6_TGEBT1	Top Gun Energy Storage	Battery Storage	30	30
MSTANG_2_MTGBT1	Mustang 1 BESS	Battery Storage	75	75
SANBRN_2_ESABT1	EdSan 1A	Battery Storage	50	100
SANBRN_2_ESBBT1	EdSan 1B	Hybrid	100	100
SLATE_2_SLASR1	Slate	Hybrid	31.97	50.5
SNCLRA_2_SILBT1	Silverstrand BESS	Battery Storage	11	11
SNCLRA_2_VESBT1	Ventura Energy Storage	Battery Storage	100	100

SUNST2_5_SS2SR1	Sun Streams Solar 2	Solar	40.5	150
TEHAPI_2_PW1WD1	Point Wind 1	Wind	9.97	47.49
TEHAPI_2_PW2WD2	Point Wind 2	Wind	3.02	14.4
TEHAPI_2_WIND1	Wind Wall Monolith 1	Wind	3.13	19.85
TEHAPI_2_WIND2	Wind Wall Monolith 2	Wind	4.22	23.66
USWPFK_6_FRICK	Frick Summit Wind Repower	Wind	2.1	10
VENWD_1_WIND3	Painted Hills	Wind	9.35	44.53
VESTAL_6_QF	Isabella Hydro Dam 1	Hydro	8.65	11.95
VISTRA_5_DALBT1	Dallas Energy Storage	Battery Storage	100	100
VISTRA_5_DALBT2	Dallas Energy Storage 2	Battery Storage	100	100
VISTRA_5_DALBT3	Dallas Energy Storage 3	Battery Storage	100	100
VISTRA_5_DALBT4	Dallas Energy Storage 4	Battery Storage	100	100
VLCNTR_6_VCEBT1	Valley Center Energy Storage	Battery Storage	54	54
VLCNTR_6_VCEBT2	Valley Center Energy Storage B	Battery Storage	50	85
VOYAGR_2_VOAWD 5	Voyager Wind Oasis Alta	Wind	2.94	13.98
		Total	2033.34	3258.3

Source: 2020-2021 NQC lists posted to the CAISO website.[31]

Table 18. Resources Retired in 2021

Resource ID	Resource Name	Technology	NQC	Status
OAK C_7_UNIT 2	Oakland Station C Unit 2	Thermal	55	Retired
VACADX_1_NAS	Vaca-Dixon Battery	Battery Storage	1	Retired
SWIFT_1_NAS	Yerba Buena Battery	Battery Storage	3	Retired
		Total	**59**	

Source: CAISO Announced Retirement and Mothball list. [32]

[31] See http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx and http://www.caiso.com/planning/Pages/ReliabilityRequirements/ReliabilityRequirementsArchive.aspx.

[32] http://www.caiso.com/Documents/AnnouncedRetirementAndMothballList.xlsx

A summary of the current status of plants subject to CEC siting review and under construction, which may eventually be added to California's resource pool, is available on the CEC website.[33]

5.2 Aggregate NQC Values 2016 through 2021

Table 19 shows aggregate NQC values from the CAISO NQC lists for 2016 through 2021.[34] The total 2021 NQC (as reported on the CAISO NQC list) decreased by 1,745 MW from the 2020 NQC list. The number of resources on the NQC list also fell from 1,961 in 2020 to 1,718 in 2021.

Table 19. Final NQC Values for 2016-2021

Year	Total NQC (MW)	Total Number of Scheduling Resource IDs	Net NQC Change (MW)	Net Gain in CAISO IDs on List
2016	53,173	972		
2017	55,871	1,097	2,698	125
2018	49,389	1,198	-6,482	101
2019	48,429	1,684	-960	486
2020	48,989	1,961	560	277
2021	47,244	1,718	-1,745	-243
2016-21			**-7,176**	**642**

Source: NQC lists from 2016 through 2021.[35]

[33] https://ww2.energy.ca.gov/sitingcases/alphabetical_cms.html.

[34] Note that MW changes in NQC lists do not align with the calendar year changes described in section 5.1 since the NQC list for each year is prepared in the fall of the previous year.

[35] NQC lists change throughout the year, so the Total NQC will vary depending on the month that the measurement was taken.

6 COMPLIANCE WITH RA REQUIREMENTS

6.1 Overview of the RA Filing Process

The RA filing process requires compliance documents to be submitted by the LSEs, load forecasting to be performed by the CEC, supply plan validation to be performed by the CAISO, and DR, local RA, CAM, and RMR allocations to be performed by Energy Division. Additionally, the Energy Division evaluates each RA filing submission and continually works with LSEs to improve the RA administration process.

As in previous years, Energy Division hosted a workshop to discuss general compliance rules as well as to highlight changes in procedures and filing rules new to the 2021 compliance year. The workshop, RA guide, and templates were designed to assist LSEs in demonstrating compliance with the RA program.

The final 2021 filing guide[36] and templates were made available to LSEs in April 2021. Changes were made to implement the new RA rules discussed in section 2.2. As in previous years, the CPUC required all filings to be submitted simultaneously to the CAISO and CEC.

6.2 Compliance Review

CPUC staff, in coordination with the CEC and CAISO, reviewed all compliance filings received in accordance with the following comprehensive RA program procedures:

- Verifying timely arrival of the filings,
- Matching resources listed against those of the NQC list,
- Verifying matching supply plans, and
- Requesting corrections from LSEs.

A crucial step in this process relies on CAISO collection and organization of supply plans submitted by scheduling coordinators for generators. Energy Division verifies

[36] Available at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials

compliance, approves compliant filings, and sends an approval letter to each LSE (noncompliant filings are discussed in the Subsections 6.3 and 6.4).

6.3 Enforcement and Compliance

The essence of the RA program is mandatory LSE acquisition of capacity to meet load and reserve requirements. The short timeframes in which the CPUC, CAISO, and CEC staff must verify that adequate capacity has been procured and, if necessary, complete backstop procurement requires filings to arrive on time and to be accurate. Non-compliance occurs if an LSE files with a procurement deficiency (i.e., insufficient capacity to meet its RA obligations), does not file at all, files late, or does not file in the manner required. These types of non-compliance generally lead to enforcement actions or citations by the CPUC. The CAISO does not typically need to engage in backstop procurement for collective and CPUC-jurisdictional LSE procurement deficiencies, although this might be expected to occur more frequently if the CPUC did not strictly enforce RA program compliance.

6.4 Enforcement Actions in the 2012 through 2021 Compliance Years

Pursuant to CPUC Resolution E-4195,[37] D.11-06-022, and D.14-06-050, Energy Division refers potential violations to the CPUC's Consumer Protection and Enforcement Division (CPED), which pursues enforcement cases related to the RA program on behalf of the CPUC.

Table 20 summarizes citations issued and enforcement actions taken by the CPUC since 2012. From 2012 through 2021, the CPUC issued 102 citations for violations and took no enforcement action. In 2021, twenty-one citations were issued for penalties of $13,425,486.[38] Citations and penalties have increased in recent years, likely driven by

[37] See: https://docs.cpuc.ca.gov/word_pdf/FINAL_RESOLUTION/93662.pdf.

[38] For a list of all penalties, please see: UEB Citations-Fines-Restitutions -- Active (1).xlsx (ca.gov) For waivers, please see: Local Waivers Issued

issues related to supply and demand balances due to resource retirements, load forecast increases, and changes in counting conventions.

Compliance Year	Citations Issued	LSEs Cited	Citation Penalties
2012	4	Glacial Energy of CA, Shell Energy, SDG&E, Direct Energy Business	$14,600
2013	5	SDG&E, Commerce Energy, 3 Phases, Liberty Power (2)	$26,500
2014	1	3 Phases	$5,000
2015	6	3 Phases (2), Commerce Energy (2), EDF Industrial, Glacial Energy	$38,000
2016	3	Tiger Natural Gas, Glacial Energy, Shell Energy	$13,500
2017	6	Commercial Energy of Montana (2), CleanPowerSF, Southern California Edison, Direct Energy Business, Tiger Natural Gas	$150,110
2018	10	AmericanPowerNet Management, Just Energy Solutions (5), Direct Energy Business, Pilot Power Group, Pioneer Community Energy (2)	$2,596,739
2019	26	AmericanPowerNet Management, Just Energy Solutions (5), Direct Energy Business, Pilot Power Group, Pioneer Community Energy (2)	$9,553,046
2020	20	American PowerNet Management, Clean Power Alliance of Southern California, Commercial Energy (10), East Bay Community Energy, Just Energy Solutions (3), Monterey Bay Community Energy, Peninsula Clean Energy, San Jose Clean Energy, Tiger Natural Gas	$2,707,435
2021	21	Central Coast Community Energy (3), Commercial Energy (3), East Bay Community Energy (4), EDF Industrial Power Services, Pilot Power Group (4), San Diego Community Power (2), San Jose Clean Energy, Silicon Valley Clean Energy Authority, Shell Energy North America (SENA), Western Community Energy	$13,425,486
Total	**102**		**$28,530,406**

Compliance Year	Citations Issued	LSEs Cited	Citation Penalties

Source: UEB Citations-Fines-Restitutions -- Active (1).xlsx (ca.gov)

7 APPENDIX

7.1 2021 List of CPUC Jurisdictional LSEs

1. Pacific Gas & Electric
2. Southern California Edison
3. San Diego Gas & Electric
4. 3 Phases Renewables Inc.
5. Apple Valley Clean Energy
6. Commercial Energy of Montana
7. Constellation New Energy Inc.
8. City of Baldwin Park
9. City of Pomona
10. City of Solana Beach / Solana Energy Alliance
11. Calpine Power America-CA, LLC
12. Clean Power Alliance of Southern California
13. CleanPowerSF
14. Direct Energy Business, LLC
15. East Bay Community Energy
16. EDF Industrial Power Services, LLC
17. King City Community Power
18. Lancaster Choice Energy
19. Monterey Bay Community Power Authority
20. Marin Clean Energy
21. Calpine Energy Solutions, LLC
22. Peninsula Clean Energy Authority
23. Pioneer Community Energy
24. Pilot Power Group, Inc.
25. Pico Rivera Innovative Municipal Energy
26. Redwood Coast Energy Authority

27. Rancho Mirage Energy Authority
28. Shell Energy North America
29. San Jose Clean Energy
30. San Jacinto Power
31. Sonoma Clean Power Authority
32. Silicon Valley Clean Energy Authority
33. Tiger Natural Gas, Inc.
34. The Regents of the University of California
35. Valley Clean Energy Alliance
36. Western Community Energy
37. Desert Community Energy
38. San Diego Community Energy
39. Clean Energy Alliance