2018 RESOURCE ADEQUACY REPORT

August 2019

CALIFORNIA PUBLIC UTILITIES COMMISSION
ENERGY DIVISION

A digital copy of this report can be found at:

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

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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

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 or Commission) jurisdictional Load Serving Entities (LSEs)[1] have sufficient capacity to meet their peak load with a 15 percent reserve margin. The RA program began implementation in 2006 and continues 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 2018 RA compliance year. While this report does not make explicit policy recommendations, it provides information relevant to the currently open RA rulemaking (R.17-09-020) 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 August 2018 of 40,577, which represented a 1 percent decrease from the peak forecast of 40,944 MW for 2017. The plausibility adjustments as a percentage of each month's aggregated year-ahead forecast ranged from 2.8 percent to 15.3 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 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

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

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, on a monthly basis from July through December, the LSEs must demonstrate they have met their local obligation which is revised to reflect load migration.

In 2018, the RA program successfully provided sufficient resources to meet peak load. The 2018 peak demand (for CPUC jurisdictional LSEs, after net load migration adjustments) was forecasted to occur in August 2018 at 40,001 MW. The RA obligation for August, including a 15 percent reserve margin, totaled 46,001 MW and LSEs collectively procured 47,104 MW. Actual peak load for 2018 for CAISO, which includes CPUC and non-CPUC jurisdictional LSEs, occurred on July 25, 2018, at 5 pm, at 46,310 MW.[2] For CPUC jurisdictional LSEs, the peak occurred a day earlier, July 24, 2018, at 5:20 pm, at 40,534 MW.

CPUC jurisdictional LSEs did not collectively meet all local RA requirements during the 2018 compliance year, and the resulting shortfall in one local area was addressed through CAISO backup procurement. The 2018 local RA procurement obligations for CPUC-jurisdictional LSEs totaled 21,258 MW. LSEs and CAISO procured a monthly minimum of 21,269 MW. Physical resources, cost allocation mechanism (CAM) resources, reliability must-run (RMR) resources, and demand response (DR) resources contributed to this total.

Energy Division conducted an analysis of prices for RA capacity contracts for 2018-2022 based on data responses provided by all 35 jurisdictional LSEs. Prices for system capacity increase between 2018 (weighted average price of $2.87/kW-month, 85th percentile of $3.90/kw-month) and 2019 (weighted average price of $3.25/kW-month, 85th percentile of $4.25/kw-month) and then gradually decline for longer term contracts. Prices are generally higher for local capacity, particularly south of the Path 26

[2] Load data is from CAISO's EMS system. CAISO reported system peak at 46,310 MW. See http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx. The actual peak for CAISO is higher than the CPUC jurisdictional load because it includes CPUC non-jurisdictional load.

transmission line (SP-26). The weighted average price for flexible capacity ($2.67/kW-month) exceeds the weighted average price for system RA contracts with imports ($2.59/kW-month) but is below the weighted average price of $2.84/kW-month for system RA contracts which exclude imports. However, the difference is not statistically significant in either case.

In 2018, total committed RA resources ranged from 31,304 MW in March to 47,104 MW in August. Bilateral contracting made up most of forward capacity procurement. However, CAM, RMR, and DR procurement, the costs and benefits of which are passed through to all customers by Transmission Access Charge (TAC) area, also contributed to meeting RA obligations. Between 83 and 86 percent of all committed RA capacity, including CAM, was procured from unit-specific physical resources within the CAISO control area and 5 to 8 percent of capacity was from imports. CAM and RMR resources consisted of 15 to 22 percent of total RA capacity procured, DR resources comprised 3 to 5 percent, and resources procured by CAISO through its capacity procurement mechanism (CPM) made up 2 to 3 percent. In general, CAM procurement has continued to increase since 2011, RMR procurement decreased to one resource in 2011, but increased in 2018, and DR procurement has declined since 2013.

While new resources were added during 2018, the overall capacity that can be used to meet LSEs' RA requirements decreased due to retirement of 3,122 MW of older gas and cogeneration facilities. While this was partially offset by 759 MW of new resources, overall 2018 saw a significant decrease in available capacity.

Because the RA program requires LSEs to acquire capacity to meet load and reserve requirements, the Commission issues citations or initiates enforcement actions when LSEs do not fully comply with RA program rules.[3] In total, the Commission issued ten citations for violations related to compliance year 2018 for a total of $2,596,739.

[3] 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).

1 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 or Commission) jurisdictional Load Serving Entities (LSEs)[4] have sufficient capacity to meet their peak load with a 15 percent reserve margin. The RA program began implementation in 2006 and continues 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, summarizing RA program experience during the 2018 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 (R.17-09-020) and ongoing implementation of the RA program in California.

1.1 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 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.

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

To establish the year-ahead load forecast, the CEC first calculates each LSE's specific monthly coincidence factors[5] 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, the CEC may adjust individual IOU service area forecasts, if the aggregate LSE forecasts differ significantly from CEC's forecasts for reasons other than load migration. 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 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 were calculated using the load shares for August. The forecasts and allocations together determine both the annual and monthly system RA obligations.

1.2 Changes to the Resource Adequacy Program for 2018

Decision (D.)17-06-027 adopted several changes to the RA program for 2018. The most significant change was the implementation of Effective Load Carrying Capability (ELCC) modeling for determination of the qualifying capacity (QC) of wind and solar resources pursuant to PU Code 399.26(d). While the previous method, the exceedance

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

method, based QC values on generators' production during peak hours, ELCC is a form of reliability assessment, which seeks to quantify and measure the reliability contribution of certain generators or classes of generators to aggregate system electric reliability. Energy Division staff measure ELCC as the amount of loss of load equivalent (LOLE) mitigation that a class of generators provides relative to an equivalent amount of ideal or "perfect" electric generating capacity. The adopted ELCC values for 2018 were:

	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Wind	11%	17%	18%	31%	31%	48%	30%	27%	27%	9%	8%	15%
Solar	0%	2%	10%	33%	31%	45%	42%	41%	33%	29%	4%	0%

Adoption of ELCC values resulted in a significant reduction in QC values for solar resources compared to 2017, with August QC values reduced by approximately 50 percent.

D.17-06-027 also:

- Required all load serving entities (LSEs) to submit an August load forecast update;
- Directed Energy Division to coordinate working groups on:
  - The removal of the Path 26 constraint,
  - Weather sensitive demand response,
  - Existing demand side load impacts, and
  - Seasonal local resource adequacy; and
- Required Energy Division to work with the CAISO to define the term "dispatchable."

2 LOAD FORECAST AND RESOURCE ADEQUACY PROGRAM REQUIREMENTS

Section 2 describes the yearly and monthly load forecast process and the resulting system, local, and flexible RA requirements for CPUC-jurisdictional LSEs. It also details the types of resources used by LSEs to meet those requirements.

2.1 Yearly and Monthly Load Forecast Process

2018 RA requirements 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[6]. The 2018 revised annual forecasts were due on August 18, 2017. 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 and final allocations to LSEs on September 20, 2017.

LSEs file historical load information	**March 17, 2017**
LSEs file 2018 year-ahead load forecast	**April 21, 2017**
LSEs receive 2018 year-ahead RA obligations	**July 21, 2017**
Final date to file revised forecasts for 2018	**August 18, 2017**
LSEs receive revised 2018 RA obligations	**September 20, 2017**

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. As discussed in the RA Guide for the 2018 compliance year, LSEs must submit a revised

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

forecast prior to each compliance filing month.[7] These load forecast adjustments are solely for load migration between LSEs, not changing demographic or electrical conditions. Per D.10-06-036,[8] 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 2.3.

2.1.1 Yearly Load Forecast Results

Table 1 shows the aggregate LSE submissions for 2018 and the adjustments that were made by the CEC across the three IOU service areas.[9] 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 August 2018 of 40,577, which represented a one percent decrease from the peak forecast of 40,944 MW for 2017.[10]

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[7] Annual RA Filing Guides are available on the CPUC website: http://www.cpuc.ca.gov/General.aspx?id=6311.

[8] Available at http://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/FINAL_DECISION/119856.htm, Ordering Paragraph 6.

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

[10] The 2017 RA report can be found at: https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442458520.

Table 1. 2018 Aggregated Load Forecast Data (MW) - Results of Energy Commission Review and Adjustment to the 2018 Year-Ahead Load Forecast

Element	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Submitted LSE Forecast	27,630	26,676	26,094	26,849	28,671	32,976	35,992	39,055	34,892	28,350	25,928	26,867
Adjustment for Plausibility and Migrating Load	776	894	1,053	2,523	4,864	3,906	4,460	3,633	5,286	3,257	2,722	2,635
EE/DG/DR Adjustment	(367)	(349)	(350)	(438)	(726)	(818)	(845)	(851)	(839)	(757)	(358)	(361)
Pro Rata Adjustment	184	192	185	349	783	758	788	805	852	700	286	299
Non-Coincident Peak Demand	**28,223**	**27,411**	**26,982**	**29,283**	**33,591**	**36,823**	**40,395**	**42,642**	**40,191**	**31,550**	**28,577**	**29,440**
Coincidence Adjustment	(843)	(932)	(916)	(1,741)	(1,771)	(3,115)	(1,649)	(2,065)	(1,896)	(2,021)	(1,329)	(798)
Final Load Forecast Used for Compliance	**27,380**	**26,479**	**26,066**	**27,542**	**31,820**	**33,708**	**38,747**	**40,577**	**38,295**	**29,529**	**27,248**	**28,642**

Source: CEC Staff.

2.1.2 Year-Ahead Plausibility Adjustments and Monthly Load Migration

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. Table 2, below, presents the aggregate monthly plausibility adjustments for all LSEs from 2013 to 2018 and calculates the 2018 monthly plausibility adjustments as a percentage of the monthly year-ahead forecast for 2018.

In 2018, the CEC's plausibility adjustments increased load for all 12 months. The CEC found that 2 of 9 community choice aggregators (CCA)s, 7 of 14 ESPs, and all IOUs required plausibility adjustments in at least one month. This represents fewer adjustments than in 2017, when 13 of 14 ESPs, all nine CCAs, and all three IOUs received plausibility adjustments. The 2018 monthly plausibility adjustments as a percentage of that month's aggregated year-ahead forecast ranged from 2.84 percent to 15.29 percent. These adjustments were due in part to the fact that ten CCAs did not participate in the 2018 year-ahead load forecast process, and several others did not reflect expansion in their year-ahead forecasts, so the relevant load was assigned to the IOUs in the year-ahead timeframe. This circumstance should not repeat in future years, since D.18-06-030 now requires all LSEs to participate in the year-ahead forecast process in order to serve load in the coming year.[11]

Table 2. CEC Plausibility Adjustments, 2013-2018 (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
2018 Plaus. Adj./Load	2.8%	3.4%	4.0%	9.2%	15.3%	11.6%	11.5%	9.0%	13.8%	11.0%	10.0%	9.2%

Source: Year-ahead CEC load forecasts, 2013-2018.

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 2018. There were generally 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 a decrease of 1.8 percent for July 2018. On a megawatt basis, the net monthly load migration adjustments ranged from -680 to 409 MW.

[11] See http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M216/K634/216634123.PDF.

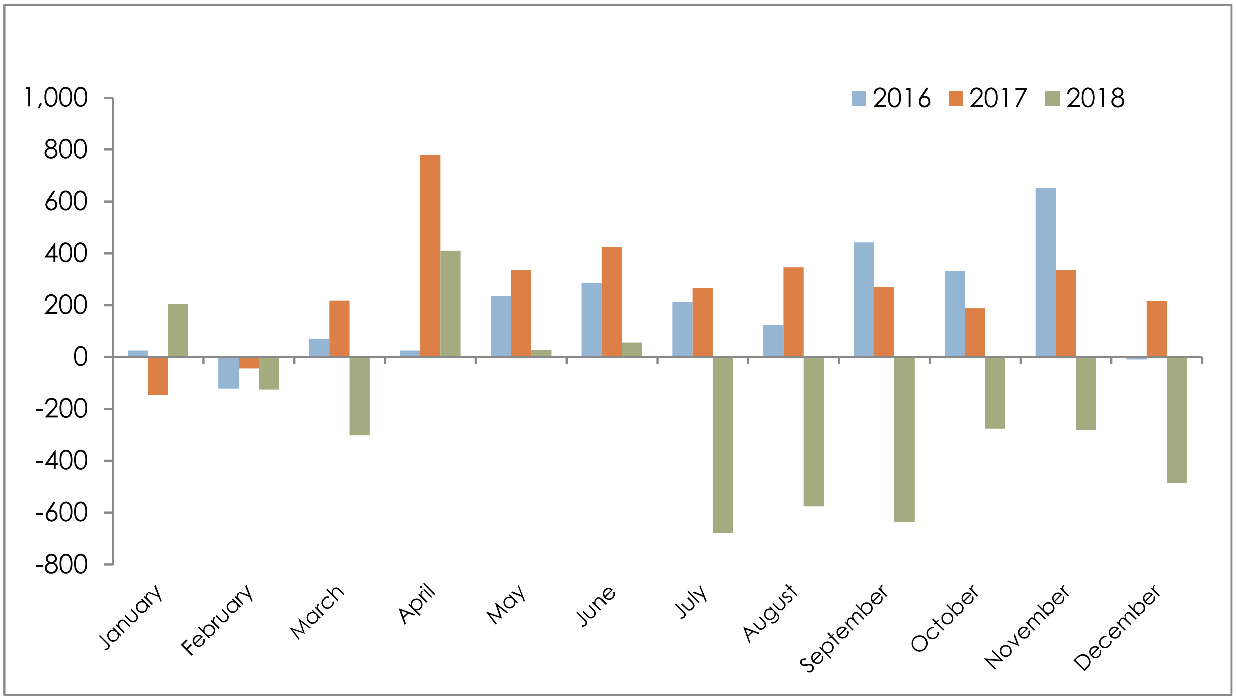
Table 3. Summary of Load Migration Adjustments in 2018 (MW)

Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Final YA Load Forecast	27,380	26,479	26,066	27,542	31,820	33,708	38,747	40,577	38,295	29,529	27,248	28,642
Monthly Adjustments	205	(126)	184	409	26	55	(680)	(576)	(636)	(276)	(282)	(487)
Final Forecasts in Monthly RA Filings	27,584	26,353	26,250	27,951	31,846	33,763	38,067	40,001	37,659	29,253	26,966	28,155
Monthly Adjustments/ Final YA Load Forecast	0.7%	-0.5%	0.7%	1.5%	0.1%	0.2%	-1.8%	-1.4%	-1.7%	-0.9%	-1.1%	-1.7%

Source: Load forecast adjustments submitted to the CEC and CPUC in 2018.

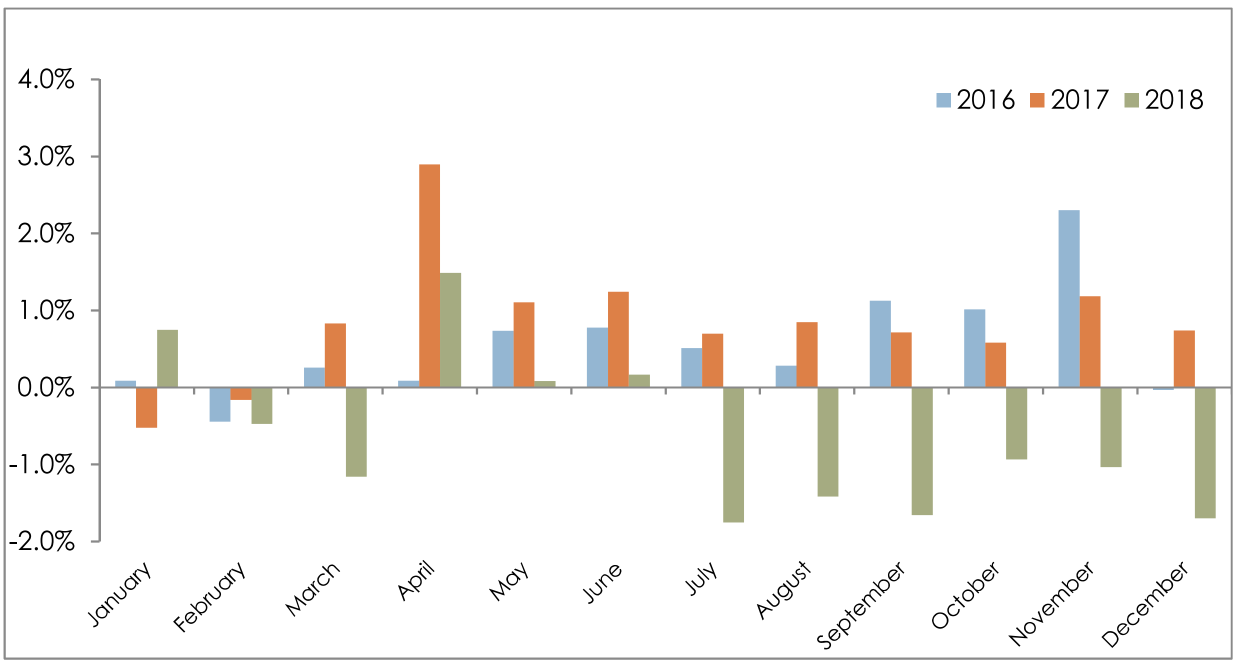
Net load migration should be close to zero, since it is defined as customers transferring directly from one LSE to another. Discrepancies in the adjustments made by LSEs gaining and losing customers, however, can cause overall load migration adjustments to deviate from zero. In recent years, the CPUC and CEC have worked to identify the reasons for these discrepancies and to encourage closer coordination between LSEs during forecast development. Figure 1 and Figure 2 illustrate the net monthly load migration between LSEs from 2016 through 2018. Load migration remained relatively low throughout this period, with monthly migration remaining below 700 MW and 2 percent of total load.

Figure 1. Net Load Migration Adjustments per Month (MW), 2016-2018



Source: Monthly forecast adjustments submitted by LSEs, 2016-2018.

Figure 2. Net Load Migration as Percentage of Total Forecasted Load



Source: Monthly forecast adjustments submitted by LSEs, 2016-2018.

2.2 System RA Requirements for CPUC-Jurisdictional LSEs

CPUC-jurisdictional LSEs met their collective system RA requirements for every month of 2018. The total MW of RA resources procured exceeded the total system Resource Adequacy Requirement (RAR) by 1.3 to 4.8 percent, depending on the month.[12] Table 4 shows the total CPUC-jurisdictional RA procurement for each month of 2018, broken down by physical resources within the CAISO's control area (including CAM resources), DR, capacity procurement mechanism (CPM), and 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. RA obligations are reported here as 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, since these resources decrease load, thereby removing the need for equivalent physical capacity and its associated PRM.

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

Table 4. 2018 RA Filing Summary – CPUC-Jurisdictional Entities (MW)

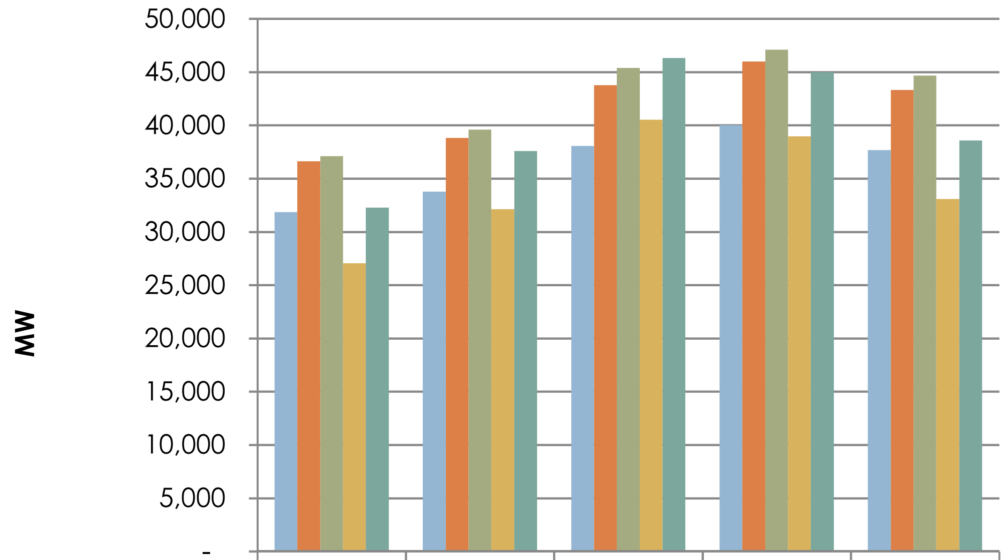
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
RAR without DR,CAM, & RMR	31,722	30,306	30,187	32,144	36,623	38,828	43,777	46,001	43,308	33,641	31,011	32,378
CAM	6,248	6,248	6,202	6,229	6,211	6,213	6,136	6,135	6,141	6,133	6,191	6,226
Phys. Res. (w/ CAM)	28,018	26,626	26,386	28,194	31,696	34,029	38,402	39,660	37,878	28,986	27,193	28,792
Imports	1,946	1,978	1,952	1,822	2,045	1,988	3,341	3,694	3,215	2,588	2,132	2,233
DR plus 15% PRM	1,222	1,266	1,244	1,425	1,656	1,755	1,846	1,945	1,761	1,660	1,279	1,167
RMR	746	746	746	746	746	746	746	746	746	746	746	746
Pref. LCR Credit	43	45	48	50	53	67	53	56	70	49	65	71
CPM	920	928	928	889	916	1,003	1,000	1,003	1,005	921	913	934
Total	32,895	31,589	31,304	33,126	37,112	39,588	45,388	47,104	44,675	34,950	32,328	33,943
Total/RAR	**103.7%**	**104.2%**	**103.7%**	**103.1%**	**101.3%**	**102.0%**	**103.7%**	**102.4%**	**103.2%**	**103.9%**	**104.2%**	**104.8%**

Source: LSE Monthly RA Filings.

In 2018, total committed RA resources, ranged from 31,304 MW in March to 47,104 MW in August. Between 83 and 86 percent of all committed RA capacity, including CAM, was procured by LSEs from unit-specific physical resources within the CAISO control area, 5 to 8 percent of capacity was from imports, and 3 to 5 percent was from DR resources. CAM and RMR resources consisted of 15 to 22 percent of total RA capacity procured, while resources procured by CAISO through CPM made up 2 to 3 percent. These resources enabled CPUC jurisdictional LSEs to meet between 101.3 and 104.8 percent of total procurement obligations in each summer month. The actual peak demand in CAISO of 46,310 MW, which includes CPUC-jurisdictional and non-CPUC jurisdictional LSEs, occurred on July 25, 2018. This peak was lower than the 2017 peak of 49,900 MW.

Figure 3 shows the 2018 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 forward commitment obligation and the total RA resources committed reflects the excess capacity committed to meet the monthly RA requirement. The CAISO jurisdictional peak can be higher than CPUC RA obligations and total RA committed because it includes non-CPUC jurisdictional load.

Figure 3. 2018 CPUC Load Forecast, RA Requirements, Total RA Committed Resources, and Actual Peak Load For Summer Months



	May	Jun	Jul	Aug	Sep
Load Forecast (CPUC-Jurisd.)	31,846	33,763	38,067	40,001	37,659
Forward Commitment Obligation	36,623	38,828	43,777	46,001	43,308
Total RA Resources Committed	37,112	39,588	45,388	47,104	44,675
Peak Load for CPUC Jurisdictionals	27,050	32,126	40,534	38,977	33,072
Actual Peak Load (CAISO)	32,256	37,595	46,310	44,996	38,559

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

2.3 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.[13] The results of the analysis are adopted in the annual CPUC RA decision and allocated to each LSE based on their load ratio in each TAC area during the month with the highest forecast peak load.

In D.17-06-027, the CPUC adopted the 2018 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). As in previous years, the following local areas were aggregated into "Other PG&E Areas" in 2018 for RA compliance: Humboldt, North Coast/North Bay, Sierra, Stockton, Fresno, and Kern.

2.3.1 Year-Ahead Local RA Procurement

Table 5 summarizes the 2018 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. Procurement exceeded local RA obligations in four of the five local areas by 1.23 to 3.65 percent. After year-ahead RA filings, CAISO used its CPM authority to procure capacity in the Greater Bay Area local area (Moss Landing, 510 MW) and in the San Diego-IV local area (Encina, 565 MW). The latter CPM addressed the shortfall shown in Table 5.

[13] Local Capacity Requirement (LCR) studies and materials for 2018 and previous years are posted at http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityRequirementsProcess.aspx.

Table 5. Local RA Procurement in 2018, CPUC-Jurisdictional LSEs

Local Areas in 2018	Total LCR	CPUC-Jurisdictional Local RAR	Minimum Physical Resources per Month	Local RMR & CAM Credit	Local DR	Minimum Procurement/ Local RAR
LA Basin	7,525	6,693	6,884	2,365	751	102.9%
Big Creek/Ventura	2,321	1,778	1,800	491	185	101.2%
San Diego-IV	4,032	4,033	3,567	411	34	88.5%
Greater Bay Area	5,160	3,812	3,951	1506	47	103.7%
Other PG&E Areas	6,169	4,942	5,066	398	136	102.5%
Totals	25,207	21,258	21,269	5,171	1,153	100.0%

Source: 2018 Year Ahead RA filings.

2.3.2 Local and Flexible RA True-Ups

As part of the partial reopening of direct access in 2010, the Commission 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.

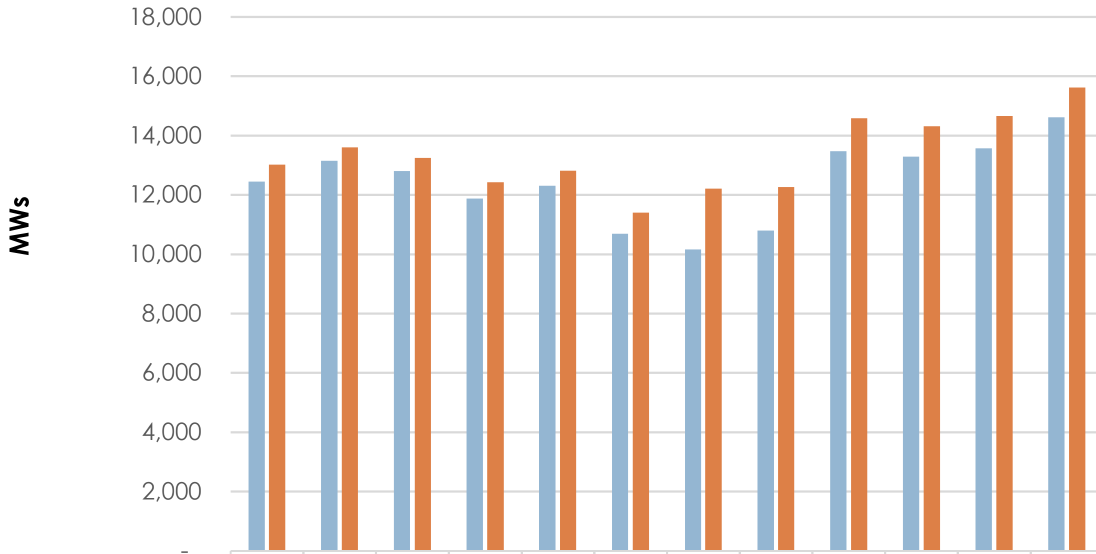
In the allocation cycle for 2018, LSEs submitted revised June-December forecasts to the CEC on March 17, 2018. After reviewing these values, the CEC revised the August load shares. Energy Division used the revised load shares to recalculate individual LSE local requirements, which were then sent to LSEs on April 12, 2018. 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.

2.4 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.[14] 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 4 shows the flexible capacity requirement and the flexible capacity shown on month-ahead RA plans by CPUC-jurisdictional LSEs for each month of 2018.

[14] 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 4. Flexible RA Procurement in 2018, CPUC-Jurisdictional LSEs



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Flexible RA Requirements	12,439	13,148	12,796	11,875	12,304	10,689	10,156	10,795	13,468	13,291	13,568	14,609
Flexible Capacity on RA Plan	13,021	13,599	13,240	12,426	12,816	11,399	12,212	12,257	14,580	14,308	14,657	15,612

Source: 2018 RA filings.

3 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 3.1.

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 3.2 and 3.3.

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 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 3.4.

3.1 Resource Adequacy Contract Price Analysis

On February 5, 2019, Energy Division issued a data request to all 35 CPUC-jurisdictional LSEs (encompassing three IOUs, 13 ESPs, and 19 CCAs) asking for monthly capacity prices paid by (or to) LSEs for every RA capacity contract covering the 2018-2022 compliance years. The data request was confined to RA-only capacity contracts bought or sold covering the period from January 2018 – December 2022. Since

RA prices can vary by month, the data request asked for specific monthly prices from each contract. QF contracts, imports, DR, and new generation contracts are excluded from the data set. All prices are reported in nominal dollars per kW-month.

Energy Division received responses from all 35 LSEs. However, some provided a limited response, based on data they believed were required by the Power Charge Indifference Adjustment (PCIA) decision, D.18-10-019. For that reason, data responses are skewed towards contracts for 2019 capacity. The final data set consisted of 9,560 monthly contract values, of which 4,813 (approximately 50 percent) are for 2019 delivery.

3.1.1 System Capacity Prices

Table 6 provides a summary of capacity prices by compliance year. Most of the contracted capacity is for the 2018 (30%) and 2019 (44%) compliance years. Prices appear to increase from 2018 (weighted average price of $2.87/kW-month, 85th percentile of $3.90/kw-month) to 2019 (weighted average price of $3.25/kW-month, 85th percentile of $4.25/kw-month), then gradually decline for longer term contracts.

Table 6. Capacity Prices by Compliance Year, 2018-2022

	2018 Capacity	2019 Capacity	2020 Capacity	2021 Capacity	2022 Capacity
Contracted Capacity (MW)	119,819	177,160	70,400	25,833	9,084
Percentage of total contracted MW in dataset	30%	44%	17%	6%	2%
Weighted Average Price ($/kW-month)	$2.87	$3.25	$3.10	$2.98	$2.96
Average Price ($/kW-month)	$2.65	$3.24	$2.91	$2.97	$3.04
Minimum Price ($/kW-month)	$0.08	$0.12	$0.90	$1.16	$1.50
Maximum Price ($/kW-month)	$10.09	$8.00	$6.00	$6.00	$6.00
85% of MW at or below ($/kW-month)	$3.90	$4.25	$3.65	$3.93	$3.33

Source: 2018-2022 price data submitted by the LSEs.

System capacity is comprised of resources that count only towards system capacity and those located in local areas that also 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 2019 Net Qualifying Capacity list is used to identify resources' local area and Path 26 zone.[15] The data set represents 402,296 MW-months of capacity under contract. Of that capacity, 57 percent is located in the NP-26 zone, and 43 percent is located SP-26.[16] The data set also shows that 75 percent of the total capacity is located in local areas, with the remaining 25 percent located in the CAISO System area. The local RA capacity reported

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[15] The 2019 Net Qualifying Capacity list can be found at http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx.

[16] Path 26 is defined in the WECC Path Rating Catalog, viewable at https://www.wecc.biz/Reliability/NDA/WECC_2016_Path_Rating_Catalog.pdf.

is divided roughly evenly between NP-26 and SP-26, while most system capacity is NP-26.

As seen below, prices are typically higher for local capacity, particularly in the SP-26 zone. The weighted average price for all capacity is $3.09/kW-month, which is $0.38 higher than the weighted average price reported in the 2017 RA price analysis. The weighted average price for SP-26 capacity (including local and system RA) is $3.36/kW-month, which is about 17 percent higher than the NP-26 weighted average price of $2.88/kW-month. Higher prices in SP-26 are also revealed through the 85th-percentile statistics, the price under which 85 percent of the contracted MW values in a given category fall. In SP-26, 85 percent of contracted MW prices are at a price of $4.10/kW-month or less, while in NP-26, 85 percent of the MWs contracted are at a price of $4.00/kW-month or less.

The weighted average price of local RA capacity ($3.20/kW-month) is 16 percent higher than the weighted average price of system RA capacity ($2.76/kW-month). This is expected, as local RA is a more constrained product. However, the premium for local RA has decreased from 40 percent above system-only capacity as reported in the 2017 RA Report, to 16 percent, indicating that the market for system RA has tightened.

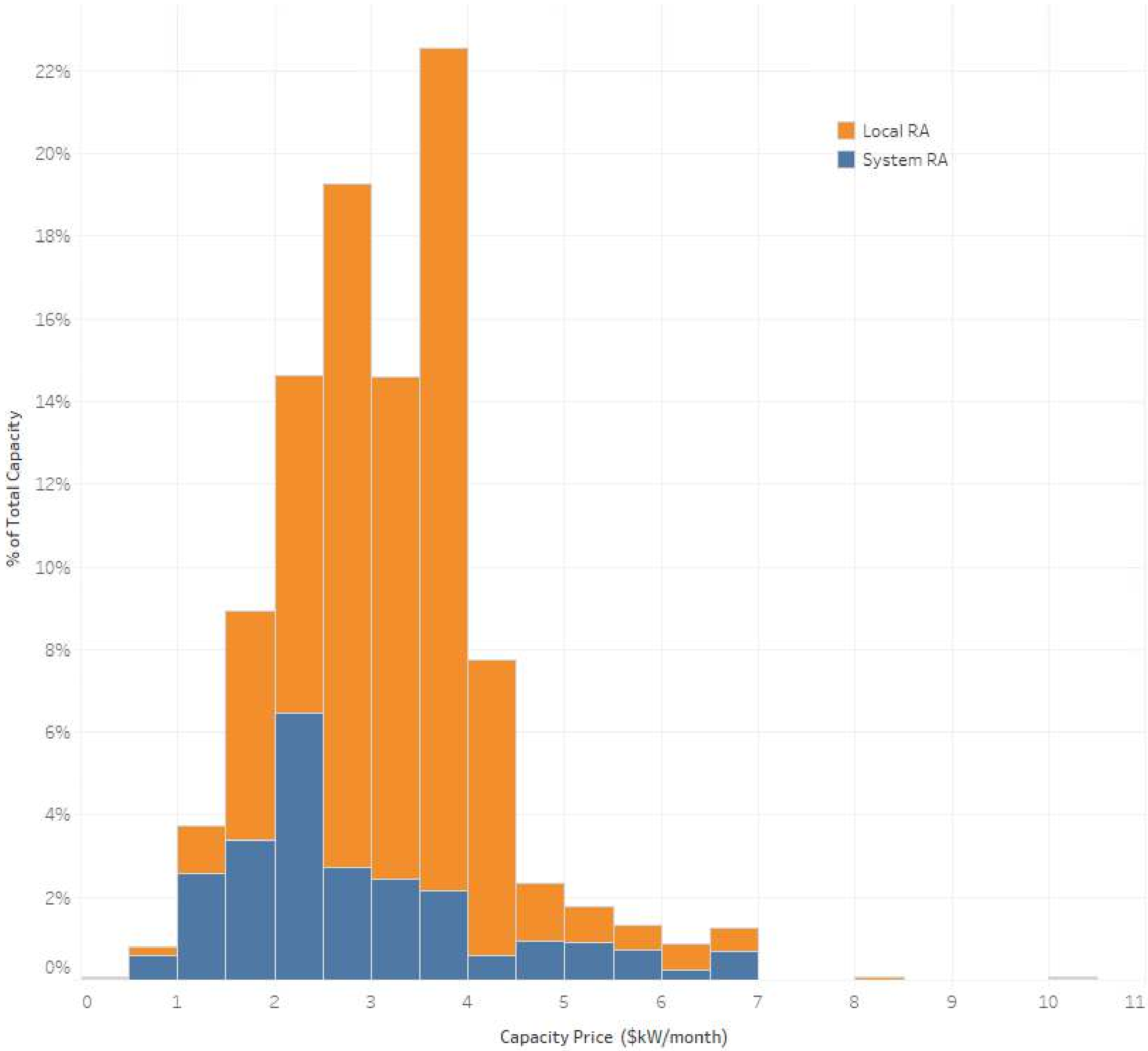
Table 7. Aggregated RA Contract Prices, 2018-2022

	All RA Capacity Contracts			Local RA Capacity Contracts			CAISO System RA Capacity Contracts		
	Total	NP-26	SP-26	**Subtotal**	NP-26	SP-26	**Subtotal**	NP-26	SP-26
Contracted Capacity (MW)	**402,296**	229,948	172,348	**303,637**	153,330	150,307	**98,659**	76,618	22,041
Percentage of Total Capacity in Data Set	**100%**	57%	43%	**75%**	38%	37%	**25%**	19%	5%
Number of Monthly Values	**9,560**	6,124	3,436	**7,086**	4,724	2,362	**2,474**	1,400	1,074
Weighted Average Price ($/kW-month)	**$3.09**	$2.88	$3.36	**$3.20**	$2.89	$3.51	**$2.76**	$2.87	$2.38
Average Price ($/kW-month)	**$3.01**	$3.04	$2.97	**$3.19**	$3.12	$3.34	**$2.49**	$2.76	$2.14
Minimum Price ($/kW-month)	**$0.08**	$0.08	$0.12	**$0.35**	$0.75	$0.35	**$0.08**	$0.08	$0.12
Maximum Price ($/kW-month)	**$10.09**	$10.09	$7.25	**$10.09**	$10.09	$6.81	**$10.09**	$10.09	$7.25
85% of MW at or below ($/kW-month)	**$4.05**	$4.00	$4.10	**$4.15**	$4.00	$4.25	**$3.75**	$4.45	$3.50

Source: 2018-2022 price data submitted by the LSEs.

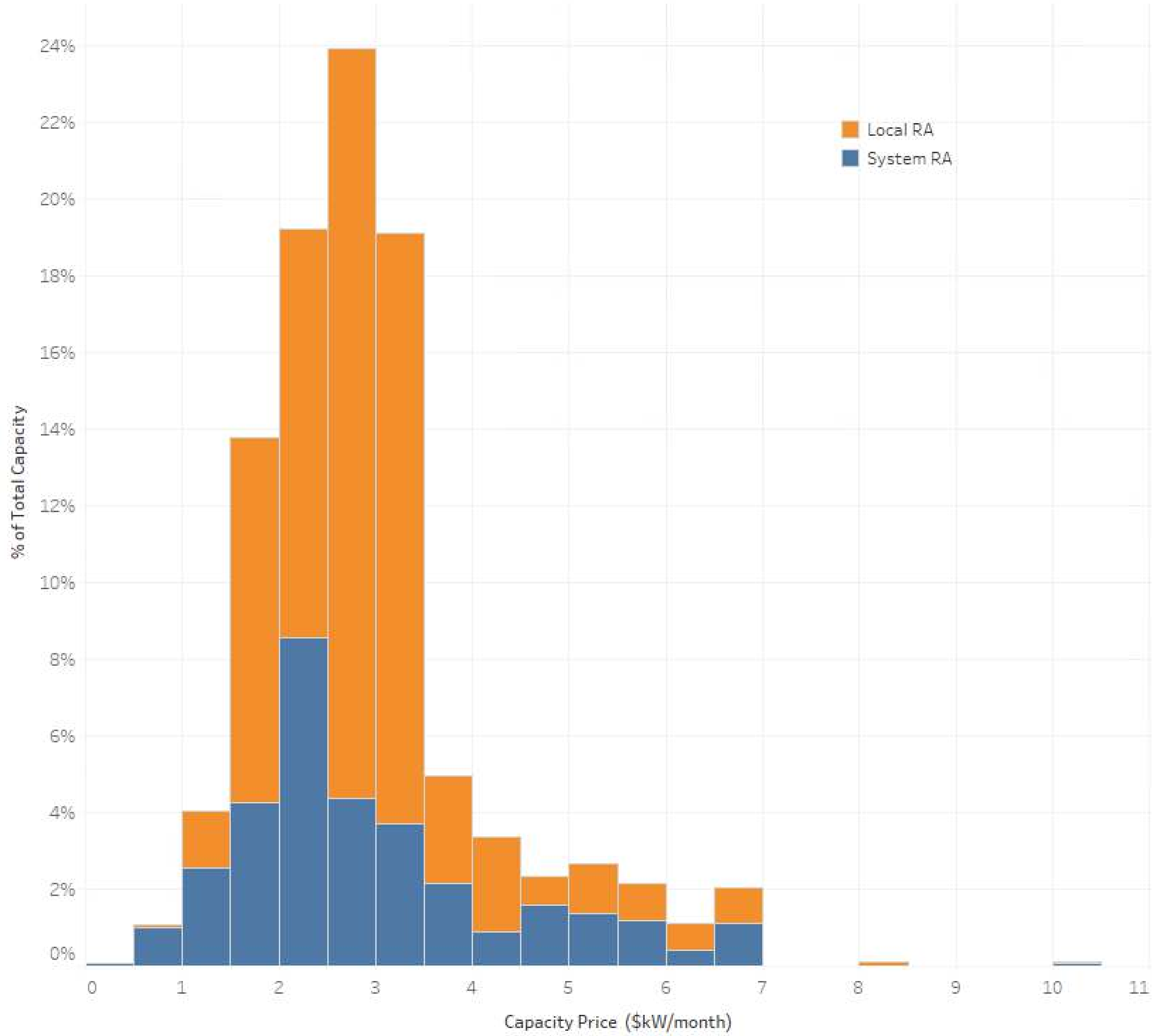
The price distribution of RA-only contracts is shown in Figure 5, Figure 6, and Figure 7 show similar distributions for NP-26 and SP-26 capacity contracts, respectively. These figures underscore both the high percentage of RA contracts that are for local capacity and the generally higher contract prices seen in local areas.

Figure 5. Price Distribution for RA Capacity Contracts, 2018-2022 Compliance Years



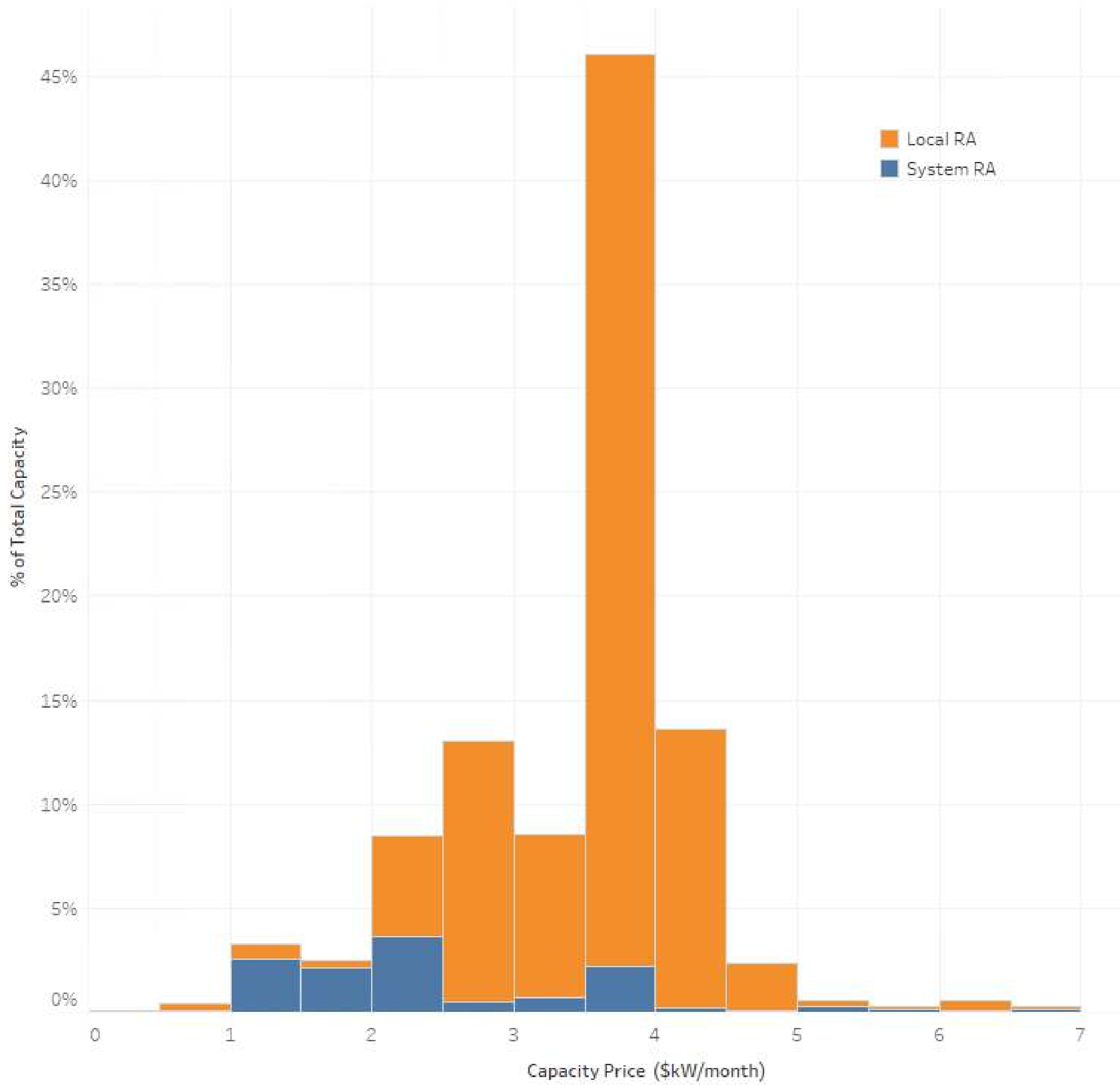
Source: 2018-2022 price data submitted by the LSEs.

Figure 6. Price Distribution for RA Capacity Contracts North of Path 26, 2018- 2022



Source: 2018-2022 price data submitted by the LSEs.

Figure 7. Price Distribution for RA Capacity Contracts South of Path 26, 2018- 2022



Source: 2018-2022 price data submitted by the LSEs.

The monthly weighted average capacity prices shown in Table 8, below, illustrate that capacity prices are generally higher from July through September and in the zone south of Path 26. Monthly prices have increased from those reported in the 2017 RA Report, particularly for August and September, where weighted average prices increased by $0.60/kW-month and $0.47/kW-month, respectively.

Table 8. RA Capacity Prices by Month and Path 26 Zone, 2018-2022

	Path 26 Zone	Contracted Capacity (MW)	Percentage of Total Capacity in Data Set	Weighted Average Price ($/kW-month)	Average Price ($/kW-month)	Minimum Price ($/kW-month)	Maximum Price ($/kW-month)	85th Percentile ($/kW-month)
	North	16,858	4.19%	$2.50	$2.66	$0.75	$5.65	$3.50
Jan	South	12,036	2.99%	$3.19	$2.77	$0.35	$5.20	$4.00
	Total	28,894	7.18%	$2.79	$2.70	$0.35	$5.65	$3.85
	North	16,893	4.20%	$2.50	$2.67	$0.75	$6.00	$3.50
Feb	South	11,799	2.93%	$3.20	$2.77	$0.35	$5.20	$4.00
	Total	28,692	7.13%	$2.79	$2.70	$0.35	$6.00	$3.90
	North	16,838	4.19%	$2.50	$2.61	$0.80	$6.00	$3.50
Mar	South	10,969	2.73%	$3.26	$2.78	$0.83	$5.20	$4.00
	Total	27,807	6.91%	$2.80	$2.67	$0.80	$6.00	$3.78
	North	17,813	4.43%	$2.48	$2.68	$0.08	$6.00	$3.50
Apr	South	11,044	2.75%	$3.30	$2.80	$0.85	$6.70	$3.99
	Total	28,857	7.17%	$2.79	$2.72	$0.08	$6.70	$3.75
	North	18,353	4.56%	$2.56	$2.81	$0.80	$6.66	$3.69
May	South	11,545	2.87%	$3.28	$2.86	$0.85	$6.70	$4.00
	Total	29,898	7.43%	$2.83	$2.83	$0.80	$6.70	$3.93
	North	21,273	5.29%	$2.83	$3.09	$0.80	$7.00	$4.50
Jun	South	15,783	3.92%	$3.31	$2.94	$0.12	$6.70	$4.00
	Total	37,056	9.21%	$3.04	$3.03	$0.12	$7.00	$4.15
	North	20,830	5.18%	$3.69	$3.84	$0.25	$10.09	$5.85
Jul	South	17,582	4.37%	$3.57	$3.27	$0.85	$6.70	$4.25
	Total	38,412	9.55%	$3.63	$3.64	$0.25	$10.09	$5.25
	North	21,527	5.35%	$3.80	$3.82	$0.25	$10.09	$5.92
Aug	South	17,369	4.32%	$3.64	$3.40	$0.85	$6.90	$4.73
	Total	38,895	9.67%	$3.73	$3.67	$0.25	$10.09	$5.47
Sep	North	21,327	5.30%	$3.28	$3.47	$0.80	$10.09	$5.10
	South	17,339	4.31%	$3.58	$3.28	$0.85	$7.25	$4.25

	Path 26 Zone	Contracted Capacity (MW)	Percentage of Total Capacity in Data Set	Weighted Average Price ($/kW-month)	Average Price ($/kW-month)	Minimum Price ($/kW-month)	Maximum Price ($/kW-month)	85th Percentile ($/kW-month)
	Total	38,666	9.61%	$3.42	$3.40	$0.80	$10.09	$4.75
	North	19,422	4.83%	$2.74	$2.97	$0.80	$6.70	$3.94
Oct	**South**	16,826	4.18%	$3.23	$2.82	$0.85	$5.50	$3.95
	Total	36,248	9.01%	$2.97	$2.92	$0.80	$6.70	$3.95
	North	19,133	4.76%	$2.67	$2.79	$0.80	$6.76	$3.71
Nov	**South**	15,453	3.84%	$3.30	$2.90	$0.80	$5.20	$4.00
	Total	34,586	8.60%	$2.95	$2.83	$0.80	$6.76	$3.90
	North	19,681	4.89%	$2.64	$2.80	$0.80	$6.00	$3.74
Dec	**South**	14,603	3.63%	$3.27	$2.86	$0.85	$5.20	$3.98
	Total	34,284	8.52%	$2.91	$2.82	$0.80	$6.00	$3.90

Source: 2018-2022 price data submitted by the LSEs.

3.1.2 Local Capacity Prices

Table 9 reports capacity prices by local capacity area. A CAISO system price for capacity outside of the local areas is included for comparison. Weighted average prices for local areas range from $2.77/kW-month in the Bay Area to $3.66/kW-month in LA Basin, while 85th percentile prices ranged from $3.93/kW-month in the Bay Area to $4.75/kW-month in PG&E Other.

Table 9. Capacity Prices by Local Area, 2018-2022

	LA Basin	Big Creek/Ventura	Bay Area	PG&E Other	San Diego-IV	CAISO System
Contracted Capacity (MW)	105,662	31,064	100,666	52,795	13,450	98,659
Percentage of Total Capacity in Data Set	26%	8%	25%	13%	3%	25%
Weighted Average Price ($/kW-month)	$3.66	$3.19	$2.77	$3.11	$3.07	$2.76
Average Price ($/kW-month)	$3.44	$3.12	$3.10	$3.15	$3.39	$2.49
Minimum Price ($/kW-month)	$0.85	$0.35	$0.90	$0.75	$1.00	$0.08
Maximum Price ($/kW-month)	$6.81	$6.76	$8.00	$10.09	$6.25	$10.09
85th Percentile ($/kW-month)	$4.25	$4.00	$3.93	$4.75	$4.50	$3.75

Source: 2018-2022 price data submitted by the LSEs.

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. While Table 8 showed higher prices in the summer for the system as a whole, Table 10 indicates that this correlation is not uniform across the state. While some local areas such as San Diego-IV and PG&E Other have significant price differences between January and August, others such as LA Basin and the Bay Area have relatively consistent prices throughout the year.

Table 10. Local RA Capacity Prices by Month, 2018-2022

	LA Basin		Big Creek/ Ventura		Bay Area		PG&E Other		San Diego-IV		CAISO System	
	Wtd Avg	85th Pct	Wtd Avg	85th Pct	Wtd Avg	85th Pct	Wtd Avg	85th Pct	Wtd Avg	85th Pct	Wtd Avg	85th Pct
Jan	$3.72	$4.24	$2.79	$4.00	$2.66	$3.55	$2.61	$3.50	$2.68	$3.57	$2.05	$2.50
Feb	$3.56	$4.18	$2.84	$3.96	$2.67	$3.75	$2.62	$3.75	$2.95	$3.70	$2.04	$2.63
Mar	$3.62	$4.19	$3.03	$3.94	$2.69	$3.71	$2.59	$3.74	$2.97	$3.87	$2.05	$2.50
Apr	$3.72	$4.21	$3.02	$3.84	$2.71	$3.51	$2.59	$3.50	$3.01	$4.25	$2.04	$3.00
May	$3.71	$4.25	$3.00	$3.90	$2.71	$3.88	$2.62	$4.00	$2.98	$4.25	$2.27	$3.00
Jun	$3.62	$4.25	$2.90	$3.80	$2.76	$4.00	$3.12	$5.10	$3.30	$4.29	$2.67	$3.56
Jul	$3.68	$4.25	$3.64	$4.00	$3.04	$5.00	$4.15	$6.45	$3.30	$4.43	$3.87	$5.42
Aug	$3.74	$4.53	$3.68	$4.50	$3.03	$5.00	$4.06	$6.00	$3.59	$4.86	$4.19	$5.50
Sept	$3.74	$4.44	$3.67	$4.49	$2.81	$4.00	$3.73	$5.67	$3.44	$4.86	$3.36	$4.75
Oct	$3.61	$4.18	$2.81	$3.93	$2.75	$3.93	$3.18	$4.76	$3.20	$4.50	$2.35	$3.13
Nov	$3.61	$4.16	$2.97	$3.88	$2.74	$3.93	$2.96	$4.00	$3.00	$4.50	$2.34	$3.52
Dec	$3.56	$4.15	$3.00	$3.93	$2.72	$3.92	$2.91	$3.98	$3.01	$4.25	$2.31	$3.00

Source: 2018-2022 price data submitted by the LSEs.

3.1.3 Flexible Capacity Prices

Past RA Reports have not reported on prices for flexible capacity, as there was no evidence that there was a premium paid for flexible capacity. However, since the PCIA will be valuing flexible capacity, we take an initial look at flexible RA prices here. As with the PCIA, any contract for local capacity, even if also for flexible capacity, is not included in the calculations below.

As demonstrated in Table 11 and Table 12, the weighted average price for flexible capacity is $2.67/kW-month. This exceeds the weighted average price for system RA contracts that includes imports ($2.59/kW-month) but is below the weighted average price of $2.84/kW-month for system RA contracts that excludes imports. However, the difference is not statistically significant in either case.

Table 11. Aggregated Non-Local RA Contract Prices Excluding Imports, 2018-2022

	All Non-Local Capacity Contracts	Flexible Capacity Contracts	System RA Only - Excluding Imports
Contracted Capacity (MW)	**98,659**	46,500	52,159
Percentage of Total Capacity in Data Set	**100%**	47%	53%
Number of Monthly Values	**2,474**	938	1,536
Weighted Average Price ($/kW-month)	**$2.76**	$2.67	$2.84
Average Price ($/kW-month)	**$2.49**	$2.47	$2.51
Minimum Price ($/kW-month)	**$0.08**	$0.25	$0.08
Maximum Price ($/kW-month)	**$10.09**	$10.09	$10.09
85% of MW at or below ($/kW-month)	**$3.75**	$3.76	$3.75

Source: 2018-2022 price data submitted by the LSEs.

Table 12. Aggregated Non-Local RA Contract Prices Including Imports, 2018-2022

	All Non-Local Capacity Contracts	Flexible Capacity Contracts	System RA Only - Including Imports
Contracted Capacity (MW)	**123,666**	46,500	77,166
Percentage of Total Capacity in Data Set	**100%**	38%	62%
Number of Monthly Values	**3,034**	938	2,096
Weighted Average Price ($/kW-month)	**$2.62**	$2.67	$2.59
Average Price ($/kW-month)	**$2.40**	$2.47	$2.36
Minimum Price ($/kW-month)	**$0.00**	$0.25	$0.00
Maximum Price ($/kW-month)	**$10.09**	$10.09	$10.09
85% of MW at or below ($/kW-month)	**$3.75**	$3.76	$3.75

Source: 2018-2022 Price Data submitted by the LSEs

3.2 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 include Condition 1 resources, which can be dispatched by the CAISO for reliability purposes, but are also allowed to operate in the energy market. Condition 2 units are not allowed to operate in the energy market, but are fully under the control of the CAISO for reliability purposes. Both types of RMR contracts are paid for by all customers in the transmission area.

In D.06-06-064, the CPUC ordered that capacity from Condition 1 RMR contracts be allocated to LSEs to count towards their local RA obligations only, while Condition 2 RMR units may be counted towards both system and local RA obligations. Because they are able to participate in the market, Condition 1 units are allowed to sell their system RA credit to a third party. This decision also 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 Commission,[17] 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 (Dynegy Oakland).

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, three generating stations have been designated by the CAISO for RMR Condition 2: Calpine Corporation's Feather River Energy Center

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

(45 MW) and Yuba City Energy Center (46 MW), were extended as Condition 2 RMR resources for Other PG&E Areas. Dynegy Oakland, LLC's units 1, 2, and 3 were also extended.

3.3 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; and
- 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 an annual or monthly RA plans.[18]

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. If a resource at-risk of retirement qualifies under CAISO's list of criteria, the resource can be procured for a period of 30 days to one year.[19]

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

[19] See CAISO Tariff 43A.2.6, http://www.caiso.com/Documents/Section43A-CapacityProcurementMechanism-asof-Apr1-2019.pdf.

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.[20] The Competitive Solicitation Process applies to all potential CPM designations, except risk of retirement designations. Table 13 shows CAISO's CPM designations for 2018.[21]

Table 13. CAISO CPM Designation for 2018 (Chronological by Start Date)

Resource ID	County	MW	CPM Type	Term (days)	Start Date	End Date	Est. Cap. Cost /kW-mth	Total Cost
MNDALY_7_UNIT 1	Ventura	215	Local Reliability Issue	60	12/5/2017	2/2/2018	$6.28	$2,700,000
MNDALY_7_UNIT 2	Ventura	215	Local Reliability Issue	60	12/6/2017	2/3/2018	$6.28	$2,700,000
MNDALY_7_UNIT 3	Ventura	130	Local Reliability Issue	60	12/7/2017	2/4/2018	$6.15	$1,600,000
MOSSLD_2_PSP1	Monterey	510	Local Reliability Issue	365	1/1/2018	12/31/2018	$6.19	$37,882,800
ENCINA_7_EA4	San Diego	272	Local Reliability Issue	365	1/1/2018	12/31/2018	$6.31	$20,595,840

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

21 CAISO Capacity Procurement Mechanism Report, http://www.caiso.com/market/Pages/ReportsBulletins/Default.aspx.

Resource ID	County	MW	CPM Type	Term (days)	Start Date	End Date	Est. Cap. Cost /kW-mth	Total Cost
ENCINA_7_EA5	San Diego	273	Local Reliability Issue	365	1/1/2018	12/31/2018	$6.31	$20,671,560
ENCINA_7_EA3	San Diego	20	Local Reliability Issue	60	5/9/2018	7/9/2018	$6.31	$252,400
HYTTHM_2_UNITS	Butte	60	Significant Event	30	9/1/2018	9/30/2018	$2.00	$120,000
ELKHIL_2_PL1X3	Kern	12	Significant Event	30	9/1/2018	9/30/2018	$3.25	$39,000
MOSSLD_2_PSP2	Monterey	29	Significant Event	30	9/1/2018	9/30/2018	$4.25	$123,250
PWRX_MALIN500_I_F_CPM01	Import	210	Significant Event	30	9/1/2018	9/30/2018	$5.00	$1,050,000
SYCAMR_2_UNIT 2	Kern	11	Significant Event	30	9/1/2018	9/30/2018	$5.07	$55,770
SYCAMR_2_UNIT 3	Kern	10	Significant Event	30	9/1/2018	9/30/2018	$5.07	$50,700
BIGCRK_2_EXESWD	Fresno	64	Significant Event	30	9/1/2018	9/30/2018	$5.07	$324,480
ETIWND_6_GRPLND	San Bernardino	46	Significant Event	30	9/1/2018	9/30/2018	$5.07	$233,220
SYCAMR_2_UNIT 4	Kern	11	Significant Event	30	9/1/2018	9/30/2018	$5.07	$55,770
SYCAMR_2_UNIT 1	Kern	10	Significant Event	30	9/1/2018	9/30/2018	$5.07	$50,700
COLEMN_2_UNIT	Shasta	2	Significant Event	30	9/1/2018	9/30/2018	$5.50	$11,000
BLACK_7_UNIT 2	Shasta	84	Significant Event	30	9/1/2018	9/30/2018	$5.50	$462,000
PIT1_7_UNIT 2	Shasta	8	Significant Event	30	9/1/2018	9/30/2018	$5.50	$44,000
PIT5_7_PL3X4	Shasta	28	Significant Event	30	9/1/2018	9/30/2018	$5.50	$154,000
PIT6_7_UNIT 1	Shasta	39	Significant Event	30	9/1/2018	9/30/2018	$5.50	$214,500
HUMBPP_6_UNITS	Humboldt	25.73	Local Reliability Issue	60	9/10/2018	11/9/2018	$6.31	$324,713

Resource ID	County	MW	CPM Type	Term (days)	Start Date	End Date	Est. Cap. Cost /kW-mth	Total Cost
ARBWD_6_QF	Kern	1.75	Significant Event	30	10/1/2018	10/31/2018	$3.79	$6,633
BASICE_2_UNITS	Monterey	88.91	Significant Event	30	10/1/2018	10/31/2018	$3.79	$336,969
BLACK_7_UNIT 2	Shasta	2.3	Significant Event	30	10/1/2018	10/31/2018	$5.50	$12,650
BRODIE_2_WIND	Kern	8.97	Significant Event	30	10/1/2018	10/31/2018	$3.79	$33,996
CARBOU_7_PL4X 5	Plumas	68.89	Significant Event	30	10/1/2018	10/31/2018	$3.79	$261,093
CARBOU_7_UNIT 1	Plumas	4.98	Significant Event	30	10/1/2018	10/31/2018	$3.79	$18,874
CHEVCD_6_UNI T	Kern	1.27	Significant Event	30	10/1/2018	10/31/2018	$3.79	$4,813
CHEVCY_1_UNIT	Kern	4.96	Significant Event	30	10/1/2018	10/31/2018	$3.79	$18,798
COLEMN_2_UNI T	Shasta	2	Significant Event	30	10/1/2018	10/31/2018	$5.5	$11,000
CONTRL_1_CAS AD1	Mono	3	Significant Event	30	10/1/2018	10/31/2018	$3.79	$11,370
CONTRL_1_CAS AD3	Mono	5	Significant Event	30	10/1/2018	10/31/2018	$3.79	$18,950
DIABLO_7_UNIT 1	San Luis Obispo	470.69	Significant Event	30	10/1/2018	10/31/2018	$3.79	$1,783,915
DIABLO_7_UNIT 2	San Luis Obispo	977	Significant Event	30	10/1/2018	10/31/2018	$3.79	$3,702,830
DSABLA_7_UNIT	Butte	1.63	Significant Event	30	10/1/2018	10/31/2018	$3.79	$6,178
ELECTR_7_PL1X3	Amador	35.92	Significant Event	30	10/1/2018	10/31/2018	$3.79	$136,137
ENCINA_7_EA2	San Diego	104	Significant Event	30	10/1/2018	10/31/2018	$3.47	$360,880
ENCINA_7_EA3	San Diego	110	Significant Event	30	10/1/2018	10/31/2018	$2.98	$327,800
ENCINA_7_EA4	San Diego	28	Significant Event	30	10/1/2018	10/31/2018	$3.96	$110,880
ENCINA_7_EA5	San Diego	57	Significant Event	30	10/1/2018	10/31/2018	$3.96	$225,720

Resource ID	County	MW	CPM Type	Term (days)	Start Date	End Date	Est. Cap. Cost /kW-mth	Total Cost
ENCINA_7_GT1	San Diego	14.5	Significant Event	30	10/1/2018	10/31/2018	$3.96	$57,420
ETIWND_6_GRPLND	San Bernardino	46	Significant Event	30	10/1/2018	10/31/2018	$5.07	$233,220
FELLOW_7_QFUNTS	Kern	1.38	Significant Event	30	10/1/2018	10/31/2018	$3.79	$5,230
FLOWD2_2_FPLWND	San Joaquin	1.58	Significant Event	30	10/1/2018	10/31/2018	$3.79	$5,988
HATCR2_7_UNIT	Shasta	2.18	Significant Event	30	10/1/2018	10/31/2018	$3.79	$8,262
HATRDG_2_WIND	Shasta	8.97	Significant Event	30	10/1/2018	10/31/2018	$3.79	$33,996
JAWBNE_2_NSRWND	Kern	14.08	Significant Event	30	10/1/2018	10/31/2018	$3.79	$53,363
MNDALY_6_MCGRTH	Ventura	47.2	Significant Event	30	10/1/2018	10/31/2018	$3.39	$160,008
MOSSLD_2_PSP2	Monterey	29	Significant Event	30	10/1/2018	10/31/2018	$4.25	$123,250
MOSSLD_2_PSP2	Monterey	7	Significant Event	30	10/1/2018	10/31/2018	$6.00	$42,000
PEABDY_2_LNDFL1	Solano	5	Significant Event	30	10/1/2018	10/31/2018	$3.79	$18,950
PIT1_7_UNIT 1	Shasta	6.59	Significant Event	30	10/1/2018	10/31/2018	$3.79	$24,976
PIT1_7_UNIT 2	Shasta	8	Significant Event	30	10/1/2018	10/31/2018	$5.50	$44,000
PIT4_7_PL1X2	Shasta	25	Significant Event	30	10/1/2018	10/31/2018	$3.79	$94,750
PIT5_7_PL3X4	Shasta	28	Significant Event	30	10/1/2018	10/31/2018	$5.50	$154,000
PIT6_7_UNIT 1	Shasta	39	Significant Event	30	10/1/2018	10/31/2018	$5.50	$214,500
PIT6_7_UNIT 2	Shasta	37	Significant Event	30	10/1/2018	10/31/2018	$3.79	$140,230
PIT7_7_UNIT 1	Shasta	51	Significant Event	30	10/1/2018	10/31/2018	$3.79	$193,290

Resource ID	County	MW	CPM Type	Term (days)	Start Date	End Date	Est. Cap. Cost /kW-mth	Total Cost
PIT7_7_UNIT 2	Shasta	51	Significant Event	30	10/1/2018	10/31/2018	$3.79	$193,290
PWRX_MALIN500_I_F_CPM01	Import	500	Significant Event	30	10/1/2018	10/31/2018	$5.00	$2,500,000
RTREE_2_WIND2	Kern	1.74	Significant Event	30	10/1/2018	10/31/2018	$3.79	$6,595
SALTSP_7_UNITS	Amador	5.88	Significant Event	30	10/1/2018	10/31/2018	$3.79	$22,285
SISQUC_1_SMARIA	Santa Barbara	1.07	Significant Event	30	10/1/2018	10/31/2018	$3.79	$4,055
SOUTH_2_UNIT	Tehama	1.54	Significant Event	30	10/1/2018	10/31/2018	$3.79	$5,837
SPBURN_2_UNIT 1	Shasta	5	Significant Event	30	10/1/2018	10/31/2018	$3.79	$18,950
SPIAND_1_ANDSN2	Shasta	4	Significant Event	30	10/1/2018	10/31/2018	$3.79	$15,160
SPQUIN_6_SRPCQU	Plumas	5	Significant Event	30	10/1/2018	10/31/2018	$3.79	$18,950
SUNSHN_2_LNDFL	Los Angeles	5.76	Significant Event	30	10/1/2018	10/31/2018	$3.79	$21,830
TIGRCK_7_UNITS	Amador	3.18	Significant Event	30	10/1/2018	10/31/2018	$3.79	$12,052
TXMCKT_6_UNIT	Kern	1.25	Significant Event	30	10/1/2018	10/31/2018	$3.79	$4,738
UNCHEM_1_UNIT	Contra Costa	1.88	Significant Event	30	10/1/2018	10/31/2018	$4	$7,520
VOLTA_2_UNIT 1	Shasta	2	Significant Event	30	10/1/2018	10/31/2018	$3.79	$7,580
WESTPT_2_UNIT	Amador	8.47	Significant Event	30	10/1/2018	10/31/2018	$3.79	$32,101
HUMBPP_1_UNITS3	Humboldt	15.73	Local Reliability Issue	60	11/12/2018	1/12/2019	$6.31	$198,513
HUMBPP_6_UNITS3	Humboldt	12.46	Local Reliability Issue	60	11/14/2018	1/14/2019	$6.31	$157,245
STANIS_7_UNIT 1	Tuolomne	5.4	Local Reliability Issue	60	11/28/2018	1/28/2019	$6.31	$68,148

In 2017, CAISO's 2018 Year Ahead local residual analysis led CAISO to make CPM designations for Moss Landing and Encina Units 4 and 5 based on LSEs' collective and individual capacity deficiencies. This was the first time CAISO made CPM designations for collective and individual capacity deficiencies. As Table 13 shows, most of the other CPM designations prior to 2018 were due to significant events and exceptional dispatch.

This past year was also extraordinary in the number of CPM designations. The CAISO issued a Significant Event CPM designation in light of an alternate load forecast presented by CEC staff. The CEC load forecast is the basis for establishing the annual resource adequacy requirements. This alternate forecast, while not officially adopted by the CEC, prompted the CAISO to designate a Significant Event CPM of 624 MW for the month of September.[22] Similarly, the CPM designations of October 1, 2018, are also based on the CEC alternate forecast. The CAISO concluded that "considering the differential in forecasts, along with the October RA showings, and the accepted 60-day extensions of the September significant event designations, […] it would designate up to 2,946 MW of additional capacity for the month of October."[23] Beyond these large designations, additional designations were made for reliability in the San Diego (Encina) and Humboldt areas.

3.4 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 Commission decision.

3.4.1 System Reliability Resources

D.06-07-029 adopted a process known as the Cost Allocation Mechanism, or CAM, which allows the Commission to designate IOUs to procure new generation for system reliability within an IOU's distribution service territory. Under CAM, all related costs

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[22] The 624 MW is the difference between the requirements of the alternate load forecast (including the planning reserve margin on that alternate forecast) and the quantity of Resource Adequacy capacity shown. See http://www.caiso.com/Documents/September_1_2018_Significant_Event_CPM_Designation_Report.pdf.

[23] http://www.caiso.com/Documents/CapacityProcurementMechanismDesignation100118.html.

and benefits are allocated to all benefiting customers, including bundled utility customers, direct access customers, and community choice aggregator customers. 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 14 provides the scheduling resource ID, the contract dates that the CAM was approved to cover, the authorized IOU, and August NQC values for all 2018 CAM resources. The list includes all conventional generation resources subject to the CAM mechanism since its inception. Utility owned generation (UOG) remains a CAM resource while the generator is operational and thus has no CAM end date.

Table 14. 2018 CAM Reliability Resources

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
BARRE_6_PEAKER	8/1/2007	UOG	SCE	47.00
BUCKBL_2_PL1X3	8/1/2010	7/31/2020	SCE	490.00
CENTER_6_PEAKER	8/1/2007	UOG	SCE	47.00
ETIWND_6_GRPLND	8/1/2007	UOG	SCE	46.00
MIRLOM_6_PEAKER	8/1/2007	UOG	SCE	46.00
VESTAL_2_WELLHD	2/1/2013	5/31/2022	SCE	49.00
WALCRK_2_CTG1 - 5	6/1/2013	5/31/2023	SCE	479.32
SENTNL_2_CTG1 - 8	8/1/2013	7/31/2023	SCE	728.80
ELSEGN_2_UN1011 & UN2021	8/1/2013	7/31/2023	SCE	550.00
COCOPP_2_CTG1- COCOPP_2CTG4	7/1/2013	4/30/2023	PG&E	563.64
ESCNDO_6_PL1X2	5/1/2014	12/31/2038	SDG&E	48.71
MNDALY_6_MCGRTH	11/1/2014	UOG	SCE	47.20

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
CHINO_2_APEBT1	2/1/2017	12/30/2026	SCE	20.00
Powin Energy – Milligan ESS 1	7/1/2017	12/31/2026	SCE	2.00
ESCNDO_6_EB1BT1	3/6/2017	UOG	SDG&E	10.00
ESCNDO_6_EB2BT2	3/6/2017	UOG	SDG&E	10.00
ESCNDO_6_EB3BT3	3/6/2017	UOG	SDG&E	10.00
MIRLOM_2_MLBBTA	7/1/2017	6/30/2027	SCE	10.00
MIRLOM_2_MLBBTB	7/1/2017	6/30/2027	SCE	10.00
CARLS1_2_CARCT1	12/1/2018	9/30/2038	SDG&E	422.00
CARLS2_1_CARCT1	12/1/2018	9/30/2038	SDG&E	105.00

*NQC values are from the year the resource is listed under. NQC values can change monthly and annually.

3.4.2 QF/CHP Resources

D.10-12-035[24] 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.[25] 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,

[24] http://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/FINAL_DECISION/128624.htm

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

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.[26] Table 15, below, lists the CHP resources whose RA capacity was allocated in 2018.

Table 15. 2018 CHP Resources Allocated for CAM

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
KERNFT_1_UNITS	4/1/2012	11/30/2020	PG&E	47.00
SIERRA_1_UNITS	4/1/2012	11/30/2020	PG&E	47.00
DOUBLC_1_UNITS	4/1/2012	11/30/2020	PG&E	47.00
TANHIL_6_SOLART	10/1/2012	9/30/2019	PG&E	10.35
FRITO_1_LAY	10/1/2012	9/30/2019	PG&E	0.08
KERNRG_1_UNITS	10/1/2012	9/30/2019	PG&E	1.23
CALPIN_1_AGNEW	11/1/2012	4/18/2021	PG&E	28.00
OROVIL_6_UNIT	1/1/2014	10/14/2020	PG&E	7.50
OMAR_2_UNIT 1	1/1/2014	12/31/2020	PG&E	77.25
OMAR_2_UNIT 2	1/1/2014	12/31/2020	PG&E	77.25
OMAR_2_UNIT 3	1/1/2014	12/31/2020	PG&E	77.25
OMAR_2_UNIT 4	1/1/2014	9/30/2020	PG&E	77.25
LMEC_1_PL1X3	1/1/2014	12/31/2021	SCE	135.00
GILROY_1_UNIT	1/1/2014	12/31/2018	SCE	52.50
SYCAMR_2_UNIT 1	1/1/2014	12/31/2021	SCE	56.53
SYCAMR_2_UNIT 2	1/1/2014	12/31/2021	SCE	56.54
SYCAMR_2_UNIT 3	1/1/2014	12/31/2021	SCE	56.53
SYCAMR_2_UNIT 4	1/1/2014	12/31/2021	SCE	56.53
STOILS_1_UNITS	10/1/2014	7/31/2026	PG&E	1.72
SMPRIP_1_SMPSON	4/1/2015	5/31/2018	PG&E	45.60
BEARMT_1_UNIT	5/1/2015	4/30/2022	PG&E	44.58

[26] 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	Authorized IOU	August NQC*
SUNSET_2_UNITS	7/1/2015	12/31/2020	PG&E	218
BDGRCK_1_UNITS	5/1/2015	4/30/2022	PG&E	36.29
CHALK_1_UNIT	5/1/2015	4/30/2022	PG&E	36.53
MKTRCK_1_UNIT 1	5/1/2015	4/30/2022	PG&E	35.96
LIVOAK_1_UNIT 1	5/1/2015	4/30/2022	PG&E	41.14
TIDWTR_2_UNITS	7/1/2015	4/30/2022	PG&E	22.75
CHEVMN_2_UNITS	7/10/2014	12/31/2050	SCE	6.20
UNVRSY_1_UNIT 1	7/1/2015	6/30/2022	SCE	34.87
HOLGAT_1_BORAX	7/1/2015	6/30/2022	SCE	19.17
ARCOGN_2_UNITS	7/1/2015	6/30/2022	SCE	270.87
TENGEN_2_PL1X2	7/1/2015	6/30/2021	SCE	36.00
ETIWND_2_UNIT1	1/1/2016	4/23/2021	SCE	14.74
SNCLRA_2_UNIT1	4/1/2016	3/30/2023	SCE	13.61
ELKHIL_2_PL1X3	1/1/2016	12/31/2020	SCE	200.00
DEXZEL_1_UNIT	12/1/2015	3/31/2022	PG&E	18.65
GRZZLY_1_BERKLY	8/1/2017	7/31/2024	PG&E	24.57
HINSON_6_CARBGN	12/30/2017	12/31/2020	SCE	29.30
SNCLRA_2_HOWLNG	4/1/2017	10/31/2023	SCE	7.63
VESTAL_2_UNIT1	4/1/2017	3/31/2026	SCE	2.93
SAMPSN_6_KELCO1	6/1/2017	6/2/2022	SDG&E	6.39
CHINO_6_CIMGEN	3/11/2018	3/10/2025	SCE	25.96
SNCLRA_2_UNIT	4/12/2018	3/31/2020	SCE	27.50

*NQC values are from the year the resource is listed under. NQC values can change monthly and annually.

3.4.3 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 for delivery in 2016 and 2017. The pilot was later extended to 2018 and 2019. Capacity procured through DRAM is allocated to all customers similarly to that of CAM and CHP resources. Table 16 lists the DRAM capacity procured by the IOUs for 2018.

Table 16. 2018 DRAM Capacity Allocated for CAM

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
Multiple	1/1/2018	12/31/2018	PG&E	75.56
Multiple	1/1/2018	12/31/2018	SCE	54.10
Multiple	1/1/2018	12/31/2018	SDG&E	8.33

*NQC values can vary by month.

Event-based DR resources are also treated as an RA credit. The costs for most DR programs are allocated through the distribution charge which means that most DR programs are paid for by bundled, direct access, and community choice aggregator customers. The exception is rate-based programs such as SCE's Save Power Day (SPD) and SCE and PG&E's Critical Peak Pricing (CPP) programs. The RA credit associated with DR is calculated using the CPUC-adopted Load Impact Protocols. The IOUs submit ex-ante load impact values associated with each 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 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.

In 2018, a total of 2,004 MW of DR RA credit (excluding DRAM) was allocated to benefiting LSEs to meet August RA obligations. These DR values include an added Transmission and Distribution (T&D) loss factor and a 15 percent planning reserve margin.

Table 17 and

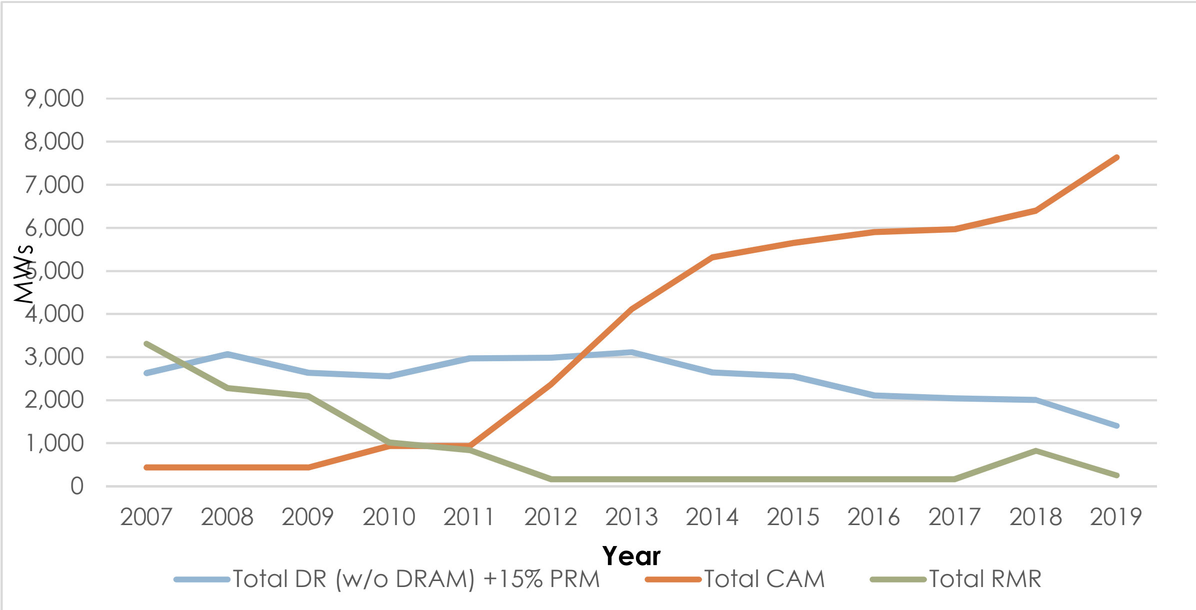
Figure 8 illustrate the amounts and types of procurement credit that have been allocated since the beginning of the RA program. The graph reflects the decline in RMR units until 2018 and the increase in CAM units. DR RA credits have declined slightly since 2013. The total amount of capacity procured through DR, CAM, and RMR for August 2018 was 9,232 MW. This is 20 percent of the total CPUC-jurisdictional LSE obligation for August 2018 (46,001 MW). In August 2018, total CAM procurement reached 6,402

MW where RMR procurement increased from 165 MW in 2017 to 826 MW in 2018 (CPUC jurisdictional LSEs were allocated 746.18 MW of the 826 MW in August 2018).

Table 17. DR, CAM, and RMR Allocations for August (MW)

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
DR	SCE		1,705	1,616	1,613	1,838	2,067	2,195	1,615	1,626	1,480	1,437	1,397	979
	PG&E		1018	912	846	888	744	783	933	807	565	566	562	390
	SDG&E		346	104	97	241	177	135	96	121	53	37	40	34
	Total DR w/out DRAM (Aug)	**2,628**	**3,069**	**2,633**	**2,556**	**2,967**	**2,987**	**3,114**	**2,644**	**2,554**	**2,105**	**2,045**	**2,004**	**1,403**
CAM	SCE	436	436	436	936	936	1,529	2,763	3,477	3,583	3,848	3,702	4,091	4,730
	PG&E						703	1,351	1,790	2,020	2,008	1,868	1,897	1,963
	SDG&E						130		49	49	49	399	413	943
	Total CAM (Aug)	**436**	**436**	**436**	**936**	**936**	**2,362**	**4,114**	**5,316**	**5,652**	**5,905**	**5,969**	**6,402**	**7,636**
RMR	SCE													
	PG&E	1,348	1,303	1,263	709	527	165	165	165	165	165	165	826	256
	SDG&E	1,961	973	828	311	311								
	Total RMR	**3,309**	**2,276**	**2,091**	**1,020**	**838**	**165**	**165**	**165**	**165**	**165**	**165**	**826**	**256**

Figure 8. RA Procurement Credit Allocation, 2006 – 2019 (RMR, August DR, and August CAM)



4 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[27] and has updated counting methodologies in subsequent decisions. The applicable data sets and data conventions are contained in the adopted QC methodology manual.[28]

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 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 exceeds the resource's deliverable capacity, the NQC is adjusted to the deliverable capacity value. The CAISO conducts deliverability assessments for both new and existing resources two to three times a year pursuant to the Large Generator Interconnection Procedures (LGIP).

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[27] http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/119856.htm (QC manual adopted as Appendix B).

[28] http://www.cpuc.ca.gov/General.aspx?id=6311.

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.

4.1 New Resources and Retirements in 2018

Numerous, older gas-fired generators including Encina, Etiwanda, and Mandalay retired in 2018 and some newer gas units at Inland Empire and La Paloma mothballed. This resulted in a loss of 3,122 MW of capacity. While this was partially offset by 759 MW of new resources, including the 528 MW Carlsbad facility, overall 2018-2019 saw a decrease in available capacity.

Table 18 and Table 19 list the new and retiring facilities for 2018. Net dependable capacity, the amount of deliverable capacity as determined by the CAISO, is also listed for new facilities. Generators are increasingly coming 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 2018, the net dependable capacity of new facilities was about 600 MW greater than the assigned NQC values.

Table 18. New NQC Resources Online in 2018[29]

Resource ID	Resource Name	Technology	NQC	Net Dependable Capacity
BGSKYN_2_AS2SR1	Antelope Solar 2	Solar PV	43.05	105.00
CARLS1_2_CARCT1	Carlsbad 1	Combustion Turbine	422.00	422.00
CARLS2_1_CARCT1	Carlsbad 2	Combustion Turbine	105.50	105.50
CRELMN_6_RAMSR3	Ramona Solar Energy	Solar PV	1.42	4.32
CUMMNG_6_SUNCT1	SunSelect 1	Cogeneration	3.56	4.00
DAIRLD_1_MD1SL1	Madera 1	Solar PV	0.00	1.50
DELSUR_6_BSOLAR	Central Antelope Dry Ranch B	Solar PV	1.23	3.00
DEVERS_2_CS2SR4	Caliente Solar 2	Solar PV	0.00	0.91
GANSO_1_WSTBM1	Weststar Dairy Biogas	Biogas	0.00	1.00
GASKW1_2_GW1SR1	Gaskell West 1	Solar PV	8.20	20.00
LAMONT_1_SOLAR2	Redwood Solar Farm 4	Solar PV	8.20	20.00
LITLRK_6_GBCSR1	Green Beanworks C	Solar PV	1.23	3.00
OASIS_6_GBDSR4	Green Beanworks D	Solar PV	1.23	3.00
OLDRIV_6_CESDBM	CES Dairy Biogas	Biogas	0.94	1.00
OLDRIV_6_LKVBM1	Lakeview Dairy Biogas	Biogas	0.94	1.00
ORTGA_6_ME1SL1	Merced 1	Solar PV	0.00	3.00
PIUTE_6_GNBSR1	Green Beanworks B	Solar PV	1.23	3.00
SUMWHT_6_SWSSR1	Summer Wheat Solar Farm	Solar PV	7.58	18.50
TRNQL8_2_ROJSR1	Tranquility 8 Rojo	Solar PV	15.58	100.00
TRNQL8_2_VERSR1	Tranquility 8 Verde	Solar PV	0.00	60.00
TULEWD_1_TULWD1	Tule Wind	Wind	33.81	127.60
VOYAGR_2_VOYWD2	Voyager Wind 2	Wind	34.11	128.70

[29] This list does not include the many new demand response resources that have been added to the NQC list as demand response is integrated into the CAISO market.

Resource ID	Resource Name	Technology	NQC	Net Dependable Capacity
VOYAGR_2_VOYWD3	Voyager Wind 3	Wind	11.45	43.20
VOYAGR_2_VOYWD4	Voyager Wind 4	Wind	5.72	21.60
VSTAES_6_VESBT1	Vista Energy Storage	Energy Storage	11.00	40.00
WISTRA_2_WRSSR1	Wistaria Ranch Solar	Solar PV	41.00	100.00
		Total	**758.98**	**1340.83**

Source: 2018-2019 NQC lists posted to the CAISO website.[30]

Table 19. Resources that Retired in 2018

Resource ID	Resource Name	Technology	NQC	Status
DIVSON_6_NSQF	Division Naval Station Cogen	Cogeneration	44.23	Retired
ENCINA_7_EA2	Encina Unit 2	Steam	104.00	Retired
ENCINA_7_EA3	Encina Unit 3	Steam	110.00	Retired
ENCINA_7_EA4	Encina Unit 4	Steam	300.00	Retired
ENCINA_7_EA5	Encina Unit 5	Steam	330.00	Retired
ENCINA_7_GT1	Encina Gas Turbine Unit 1	Combustion Turbine	14.50	Retired
ETIWND_7_UNIT 3	Etiwanda Gen Sta. Unit 3	Steam	320.00	Retired
ETIWND_7_UNIT 4	Etiwanda Gen Sta. Unit 4	Steam	320.00	Retired
INLDEM_5_UNIT 2	Inland Empire Energy Center, Unit 2	Combined Cycle	335.00	Mothballed
KEARNY_7_KY3	Kearny GT3 Aggregate	Combustion Turbine	61.00	Retired
LAGBEL_2_STG1	Bell Bandini Commerce Refuse	Biogas	9.60	Retired
LAPLMA_2_UNIT 3	La Paloma Generating Plant Unit #3	Combined Cycle	256.15	Mothballed

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

Resource ID	Resource Name	Technology	NQC	Status
LAPLMA_2_UNIT 4	La Paloma Generating Plant, Unit #4	Combined Cycle	259.54	Mothballed
MNDALY_7_UNIT 1	Mandalay Gen Sta. Unit 1	Steam	215.00	Retired
MNDALY_7_UNIT 2	Mandalay Gen Sta. Unit 2	Steam	215.29	Retired
MNDALY_7_UNIT 3	Mandalay Gen Sta. Unit 3	Combustion Turbine	130.00	Retired
MRGT_7_UNITS	Miramar CT Aggregate	Combustion Turbine	36.00	Retired
NIMTG_6_NIQF	North Island QF	Cogeneration	36.15	Retired
PTLOMA_6_NTCQF	NTC/MCRD Cogeneration	Cogeneration	19.76	Retired
THMENG_1_UNIT 1	Tracy Biomass	Biomass	4.89	Retired
VALLEY_7_BADLND	Badlands Landfill Gas to Energy Facility	Biogas	0.58	Retired
		Total	**3121.69**	

Source: 2018-2019 NQC lists posted to the CAISO website.[31]

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.[32]

4.2 Aggregate NQC Values 2014 through 2019

Table 20 shows aggregate NQC values from the CAISO NQC lists for 2014 through 2019.[33] The total 2019 NQC (as reported on the CAISO NQC list) decreased by 960 MW from the 2018 NQC list. The number of resources on the NQC list continued to grow as demand response resources were integrated into the CAISO market. There also may be

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

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

[33] Note that MW changes in NQC lists do not align with the calendar year changes described in section 4.1 since the NQC list for each year is prepared in the fall of the previous year.

a change in NQC for facilities that began operation in the previous year, but not in time to receive an August NQC value or for facilities that come online in phases and receive an initial NQC value for partial capacity.

Table 20. Final NQC Values for 2014 – 2019

Year	Total NQC (MW)	Total Number of Scheduling Resource IDs	Net NQC Change (MW)	Net Gain in CAISO IDs on List
2014	53,112	765	Base Year	Base Year
2015	52,996	802	-116	37
2016	53,173	972	177	170
2017	55,871	1,097	2,698	125
2018	49,389	1,198	-6,482	101
2019	48,429	1,684	-960	486
2014-19			**-4,683**	**919**

Source: NQC lists from 2014 through 2019.

5 COMPLIANCE WITH RA REQUIREMENTS

5.1 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 2018 compliance year. The workshop, RA guide, and templates were designed to assist LSEs in demonstrating compliance with the RA program.

The final 2018 filing guide[34] and templates were made available to LSEs in September 2017. Changes were made to implement the new RA rules adopted in D.17-06-027. As in previous years, the CPUC required all filings to be submitted simultaneously to the CAISO and CEC.

5.2 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, confirming compliance with local area and Path 26 requirements, 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 compliance, approves compliant filings, and sends an approval letter to each LSE (noncompliant filings are discussed in the Subsections 5.3 and 5.4).

[34] See https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442454920.

5.3 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.

5.4 Enforcement Actions in the 2012 through 2018 Compliance Years

Pursuant to Commission Resolution E-4195,[35] 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 Commission.

Table 21 summarizes enforcement actions and citations taken by the Commission since 2012. From 2012 through 2018, the Commission issued 35 citations for violations and took no enforcement action, for a total penalty of $2,844,449. In 2017, the Commission issued six citations for a total penalty of $150,110 and took no enforcement action. In 2018, due to an increased number of deficiencies, ten citations were issued for penalties of $2,596,739.

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[35] See: http://docs.cpuc.ca.gov/PUBLISHED/FINAL_RESOLUTION/93662.htm.

Table 21. Enforcement Summary Pursuant to the RA Program Since 2012

Compliance Year	Citations Issued	LSEs Cited	Citation Penalties	Enforcement Cases	LSEs Enforced	Enforcement Penalties
2012	4	Glacial Energy of CA, Shell Energy, SDG&E, Direct Energy Business	$14,600	0		0
2013	5	SDG&E, Commerce Energy, 3 Phases, Liberty Power (2)	$26,500	0		0
2014	1	3 Phases	$5,000	0		0
2015	6	3 Phases (2), Commerce Energy (2), EDF Industrial, Glacial Energy	$38,000	0		0
2016	3	Tiger Natural Gas, Glacial Energy, Shell Energy	$13,500	0		0
2017	6	Commercial Energy of Montana (2), CleanPowerSF, Southern California Edison, Direct Energy Business, Tiger Natural Gas	$150,110	0		0
2018	10	AmericanPowerNet Management, Just Energy Solutions (5), Direct Energy Business, Pilot Power Group, Pioneer Community Energy (2)	$2,596,739	0	0	0
Total	35		$2,844,449	0		0

6 APPENDIX

2018 List of CPUC Jurisdictional LSEs

1. Pacific Gas & Electric
2. Southern California Edison
3. San Diego Gas & Electric
4. 3 Phases Renewables Inc.
5. American PowerNet Management
6. Apple Valley Clean Energy
7. Just Energy Solutions, Inc.
8. Commercial Energy of Montana
9. Constellation New Energy Inc.
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. Agera Energy LLC
19. Lancaster Choice Energy
20. Liberty Power Holdings, LLC
21. Monterey Bay Community Power Authority
22. Marin Clean Energy
23. Calpine Energy Solutions, LLC
24. Peninsula Clean Energy Authority
25. Pioneer Community Energy
26. Pilot Power Group, Inc.
27. Pico Rivera Innovative Municipal Energy
28. Redwood Coast Energy Authority
29. Rancho Mirage Energy Authority
30. Shell Energy North America
31. San Jose Clean Energy

32. San Jacinto Power
33. Sonoma Clean Power Authority
34. Silicon Valley Clean Energy Authority
35. Tiger Natural Gas, Inc.
36. The Regents of the University of California
37. Valley Clean Energy Alliance