2012 Resource Adequacy Report

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AS	Ancillary Services	LD	Liquidated Damages
BCR	Bid Cost Recovery	LI	Load Impact
CAISO	California Independent System Operator	LOLP	Loss of Load Probability
CAM	Cost-Allocation Mechanism	LSE	Load Serving Entity
CCGT	Combined Cycle Gas Turbine	MCC	Maximum Cumulative Capacity
CEC	California Energy Commission	MOO	Must Offer Obligation
DA	Direct Access	MW	Megawatt
DASR	Direct Access Service Request	NCF	Net Capacity Factor
DG	Distributed Generation	NDC	Net Dependable Capacity
DR	Demand Response	NERC	North American Reliability Corporation
DSM	Demand Side Management	NQC	Net Qualifying Capacity
EAF	Equivalent Availability Factor	PRM	Planning Reserve Margin
ED	Energy Division	QC	Qualifying Capacity
EFORd	Equivalent Forced Outage Rate of demand	QF	Qualifying Facility
ELCC	Effective Load Carrying Capacity	RA	Resource Adequacy
EFC	Effective Flexible Capacity	RAR	Resource Adequacy Requirement
ERRA	Energy Resource Recovery Account	RMR	Reliability Must Run
ESP	Electricity Service Provider	RPS	Renewable Portfolio Standard
ETC	Existing Transmission Contract	SCP	Standard Capacity Product
FERC	Federal Energy Regulatory Commission	SFTP	Secure File Transfer Protocol
FOH	Forced Outage Hours	TAC	Transmission Access Charge
HE	Hour Ending	TCPM	Transitional Capacity Procurement Mechanism
ICPM	Interim Capacity Procurement Mechanism	TIC	Total Installed Capacity
IOU	Investor Owned Utility	ULR	Use Limited Resources

2012 Resource Adequacy Report

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 fifteen 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. This capacity includes System RA and Local RA, both of which are measured in megawatts (MWs). The annual and monthly System and Local RA requirements for CPUC-jurisdictional LSEs are set by the CPUC; they reflect both transmission constraints and LSE load share.

This report provides a review of the CPUC's RA program, summarizing RA program experience during the 2012 RA compliance year. While this report does not make explicit policy recommendations, it is intended to provide information relevant to the currently open RA rulemaking (R.11-10-023) and ongoing implementation of the RA program in California.

Each October, the RA program requires LSEs to make an annual System and Local compliance showing for the coming year. For the System showing, LSEs are required to demonstrate they have procured 90% of their System RA obligation for the five summer months. For the Local showing, LSEs are required to demonstrate they have procured 100% of their Local 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% of their monthly System RA obligation. Additionally, on a monthly basis from May through December, the LSEs must demonstrate they have met their revised (due to load migration) local obligation.

In 2012, the RA program successfully provided sufficient resources to meet peak load. Peak demand (for both CPUC and non-CPUC jurisdictional LSEs) was forecasted to occur in August 2012 at 48,075 MW.[2] The forward procurement obligation/RA obligation to meet peak demand in August totaled 55,267 MW[3] and LSEs collectively procured 55,803 MW[4] to meet expected system needs (which included a 15 percent reserve margin). CPUC-jurisdictional LSEs had an RA obligation of 51,226 MW[5] and procured 51,597 MW.[6] Actual peak load for 2012 occurred in August at 46,682 MW.

CPUC jurisdictional LSEs fulfilled their Local RA obligations during the 2012 compliance year. Local RA procurement obligations totaled 24,022 MW for CPUC-

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[1] Commission jurisdictional LSEs include all Investor Owned Utilities (IOUs), Electricity Service Providers (ESPs), and Community Choice Aggregators (CCAs).
[2] See Figure 2. Summer 2012 Demand Forecast, RA Obligation, Procurement, Actual Peak Demand (MW).
3 Ibid.
4 Ibid.
5 See Table 4. 2012 RA Filing Summary – CPUC-Jurisdictional Entities (MW).
[6] Ibid.

jurisdictional LSEs; these obligations were met with a monthly minimum of 22,981 MW of RA capacity from physical resources and 2,770 MW of Local RA capacity from Cost Allocation Mechanism (CAM), Reliability Must-Run (RMR) and Demand Response (DR) resources,[7] for a combined total of 25,751 MW.

A key to establishing accurate RA procurement targets is review of LSE demand forecasts. The California Energy Commission (CEC) assesses the reasonableness of LSE demand forecasts and makes monthly plausibility adjustments.[8] In 2012, the CEC made negative plausibility adjustments for all summer months, except May, and positive adjustments for all non-summer months. The monthly plausibility adjustments as a percentage of the month's aggregated year-ahead forecast ranged from -2.1% to 1.7%.

Bilateral contracting makes up the majority of forward capacity procurement. However, CAM, RMR and DR procurement also contribute to meeting RA obligations. These types of procurement are done by TAC area and the costs are passed through to customers through the distribution charges. In 2012, CAM, RMR and DR procurement comprised about 10% of the overall RA requirement. The overall CAM procurement increased from 2011 whereas the RMR procurement declined. DR procurement remained relatively stable from 2011 to 2012.[9]

In late 2013, Energy Division staff issued a data request to all the jurisdictional LSEs requesting monthly capacity prices paid by (or to) LSEs for every RA capacity contract covering the 2012 – 2016 compliance years. A total of 3,463 monthly contract prices were collected from the data request and used in the price analysis contained in this report. The contract values are weighed by the number of MW in the contract and compared across zone, local area, month and year. The weighted average price for all capacity in the data set is $3.28 kW-month.[10] The price of capacity varies significantly between month, local area, and zone.

In 2012, 1,124 MW of new generation came online, including both conventional and renewable generation. The new conventional resources included the Lodi Energy Center (280 MW),[11] the Mariposa peaker (183 MW) and the GWF Tracy Expansion (328 MW).[12] In addition, 586 MW of generation retired in 2012 resulting in an incremental increase of 538 MW of Net Qualifying Capacity (NQC).

[7] See Table 5. Local RA Procurement in 2012, CPUC-Jurisdictional LSEs.
[8] To correct LSE estimations of customer retention, the CEC prepares a plausibility adjustment that estimates customer retention by certain LSEs.
[9] See Table 9. DR, CAM, and RMR Allocations (MW).
[10] See Table 11. Aggregated RA Contract Prices, 2012-2016.
[11] See Table 14. New Resources Online in 2012.
[12] Ibid.

Because the RA program requires LSE to acquire capacity to meet load and reserve requirements, when LSEs do not fully comply with RA program rules,[13] the Commission issues citations or starts enforcement actions. In total, the Commission issued four citations for violations related to compliance year 2012 and collected $14,600 in payments from LSEs from these citations. In addition, the Commission started one enforcement case in 2011 that settled in February 2012 for assessed penalties of $215,000.

2 Changes to the RA Program for 2012

Decision (D.)11-06-022 adopted several new rules for the 2012 compliance year, including the following:

- LSEs are no longer required to file a preliminary Local RA filing in September due to the reduced number of RMR contracts. LSEs that do contract with any existing RMR resource for the coming compliance year must inform the California Independent System Operator (CAISO) by the second Monday in September.
- LSEs are no longer allowed to report portfolio resources to meet RA requirements. This authority was originally granted in D.06-07-031.
- LSEs are now allowed to file updates to their year-ahead load forecasts. A specific schedule was adopted for 2012 that allows the LSE to file a revised year-ahead load forecast by August 19th revising their April 22nd year-ahead load forecast. The allocations sent out in July will be preliminary, pending a final load forecast. Final allocations for 2012 compliance year were sent out on September 15, 2011.
- The CPUC adopted changes to the penalty structure for the RA program for deficiencies cured within five business days.
- The CAISO's Standard Capacity Product that was adopted in D.09-06-028 became a mandatory part of the RA compliance program.
- To qualify as an RA resource, DR resources must be able to operate for a minimum of four hours per day for three consecutive days.
- The DR emergency trigger caps adopted by D.10-06-034 (adopting a settlement) are now being implemented in the RA program. The RA program is now enforcing the DR established caps. For 2012 compliance year, reliability-based DR programs cannot exceed 3% of CAISO's all-time coincident demand, which is currently 50,270 MW.

[13] 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).

3 Load Forecast and Resource Adequacy Program Requirements

The RA program requirements are based on a load forecasting process that uses a "best estimate approach." This approach, adopted in D.05-10-042, requires LSEs to submit historical sales and hourly load data for the preceding year and monthly peak demand forecasts for the coming compliance year that are based on reasonable assumptions for load growth and customer retention.[14] This process also requires LSEs to submit monthly load forecast to the CEC that account for load migration throughout the compliance year. During the 2012 compliance year, some LSEs took advantage of the new opportunity to adjust their year ahead forecasts in August to account for incremental load migration between April 2011 and August 2011. The total amount of reported migration in that timeframe was very small, but still increased the accuracy of overall RA obligations

In order to establish year-ahead System RA requirements, CEC staff reviews the year-ahead load forecasts submitted by each LSE and compares this with the LSEs historic load and recent monthly load forecasts. The CEC adjusts LSE forecasts for plausibility when an LSE-submitted forecast diverges unreasonably from the LSE's actual peak loads or historical usage, taking into account load migration patterns. Additionally, as specified in D.05-10-042, adjustments are made by the CEC to account for the impact of energy efficiency (EE), distributed generations (DG), and coincidence with the CAISO system peak. Finally, the CEC reconciles the aggregate of the adjusted load forecasts against its own forecast for each IOU service territory. The sum of the adjusted forecasts must be within 1% of the CEC forecast. The aggregated LSE forecasts are used by the CEC to create monthly load shares for each TAC area, which are used to allocate DR, CAM, and RMR RA credits. The forecasts and the allocations together determine the System annual and monthly RA obligations. The load forecast is also used to allocate the Local RA obligations. Local obligations are calculated using the load shares for August of the coming compliance year.

3.1 Yearly and Monthly Load Forecast Process

Beginning with the 2012 compliance year, the LSEs were given the opportunity to revise their April annual load forecast for load migration. The revised annual forecast was due on August 19, 2011. These revised forecast values updated and informed the final year-ahead allocations, which were used in the year-ahead filing process. The following timeline was adopted in D.11-06-022:

[14] CPUC decisions may be found at http://docs.cpuc.ca.gov/DecisionsSearchForm.aspx

2012 Year-Ahead Forecast Process with Due Date for Revisions		
Filing	**Due Date**	**Days before Year-Ahead RA Filing**
LSEs file historical load information	15-Mar	230
LSEs file 2012 year-ahead load forecast	22-Apr	192
LSEs receive 2012 year-ahead RA obligations	25-Jul	98
Final date to file revised forecasts for 2012	19-Aug	73
LSEs receive revised 2012 RA obligations	15-Sep	46
LSEs receive RMR allocations	7-Oct	24
LSEs file final 2012 year-ahead RA filing	31-Oct	0

For the 2012 year-ahead System RA filings, CPUC staff sent allocations on July 25th and revised allocations on September 15th. The allocations included a spreadsheet containing Local RA obligations, load forecasts, and DR, RMR, and CAM RA credits. The spreadsheets were emailed to each LSE via password protected email on July 25, 2011.

During the compliance year, LSEs adjusted 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 2012 compliance year, LSEs must submit a revised forecast two months prior to each compliance filing month.[15] These load forecast adjustments are solely to account for load migration between LSEs, not to account for changing demographic or electrical conditions. D.10-06-036[16] updated this process to allow for load forecast changes/adjustments to be submitted up to 25 days before the due date of the month-ahead compliance filings.

LSEs submit these monthly forecasts to the CEC for evaluation; the CEC reviews the revised forecasts and customer load migrating assumptions. The revised monthly load forecasts update the year-ahead forecast and inform the monthly RA obligations. These monthly forecast are also used to calculate updated load shares which are used to reallocate CAM and RMR credits which count towards monthly RA compliance. It is important not to rely exclusively on year-ahead load forecasts, which are based on forecast assumptions made more than six months prior to the compliance year, because load migration can have very large effects on LSE forecasts, particularly for small ESPs.

3.1.1 Yearly Load Forecast Results

Table 1 shows the aggregate LSE submissions for 2012 and the adjustments that were made by the CEC across all three IOU service areas.[17] These adjustments include plausibility adjustments, demand side management adjustments, and a prorated

[15] Annual RA Filing Guides are available on the CPUC website: http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_compliance_materials.htm
[16] http://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/FINAL_DECISION/119856.htm Ordering Paragraph 6.
[17] Because the historical and forecast data submitted by participating LSEs contain market-sensitive information, results are presented and discussed in aggregate.

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 forecasts. The forecast also includes a coincident adjustment which calculates each LSE's expected contribution towards coincident service area peak. The forecast for CPUC-jurisdictional LSEs showed an expected peak in August 2012 of 44,167 MW, which represents a 1.5% decrease from the peak forecast of 44,847 MW in 2011.[18]

Table 1. 2012 Aggregated Load Forecast Data (MW) - Results of Energy Commission Review and Adjustment to the 2012 Year-Ahead Load Forecast

Element	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Submitted LSE Forecast (Metered Load + T&D Losses + UFE)	29,444	28,457	28,352	30,142	34,241	39,603	42,769	46,044	40,705	33,550	29,586	31,083
CEC Adjustment for Plausibility/ Migrating Load	88	72	55	67	67	(545)	(60)	(947)	(218)	576	95	68
EE/DG Adjustment	(46)	(50)	(51)	(53)	(56)	(57)	(57)	(57)	(57)	(55)	(54)	(47)
Pro Rata Adjustment to CEC Forecast	0	0	(2)	0	0	0	0	(9)	(12)	0	(52)	(48)
Non-Coincident Peak Demand	29,485	28,479	28,355	30,156	34,251	39,001	42,652	45,031	40,418	34,070	29,575	31,056
Coincidence Adjustment	(373)	(508)	(223)	(346)	(687)	(603)	(539)	(865)	(673)	(559)	(532)	(358)
Final Load Forecast Used for Compliance	29,112	27,971	28,131	29,810	33,564	38,398	42,113	44,167	39,745	33,511	29,043	30,697

Source: CEC Staff.

3.1.2 Year-Ahead Plausibility Adjustments and Monthly Load Migration

Plausibility adjustments most commonly indicate mismatches between LSE forecasts of customer retention and the CEC's forecasts of each LSE's customer retention. Table 2 below illustrates the magnitude of plausibility adjustments in each month from 2009 through 2012 compliance years and reports the 2012 plausibility adjustment to the year ahead forecast as a percentage. In 2012, the CEC's plausibility adjustments increased total load from October-May and decreased total load from June-September (all summer months except for May). These adjustments were applied to a larger number of LSEs than in 2011; the CEC found that three of fourteen ESPs and two of three IOUs serving load in 2012 required plausibility adjustments in at least one month of 2012. In 2012, monthly plausibility adjustments as a percentage of that month's aggregated year-ahead forecast ranged from -2.1% to 1.7%. These adjustments to ESP forecasts reflect

[18] The 2011 RA report can be found at: http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/.

uncertainty in assumptions with regards to the migration of direct access load. Adjustments to IOU forecasts typically reflect differences in fundamental forecast assumptions compared to the CEC forecast, such as expected economic growth or the temperature response of load.

Table 2. CEC Plausibility Adjustments, 2009-2012 (MW)

Compliance Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009	437	436	441	459	519	553	605	(188)	595	514	484	481
2010	50	48	19	65	21	22	225	(44)	352	155	17	15
2011	(0)	28	38	39	161	210	1,381	115	1,256	42	33	66
2012	88	72	55	67	67	(545)	(60)	(947)	(218)	576	95	68
2012 Plausibility Adjustment/ Load	0.3%	0.3%	0.2%	0.2%	0.2%	-1.4%	-0.1%	-2.1%	-0.5%	1.7%	0.3%	0.2%

Source: Aggregated year-ahead CEC load forecasts, 2009-2012.

Monthly load forecasts, which are adjusted for load migration, are the basis of monthly RA obligations.

Table 3 shows the monthly total load forecasts and the monthly adjustments for 2012. There were generally only small net load migration adjustments from the annual 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 1.37%; most months' adjustments were less than one percent. On a megawatt basis, the net monthly load migration adjustments ranged from 117 to 406 MW in 2012.

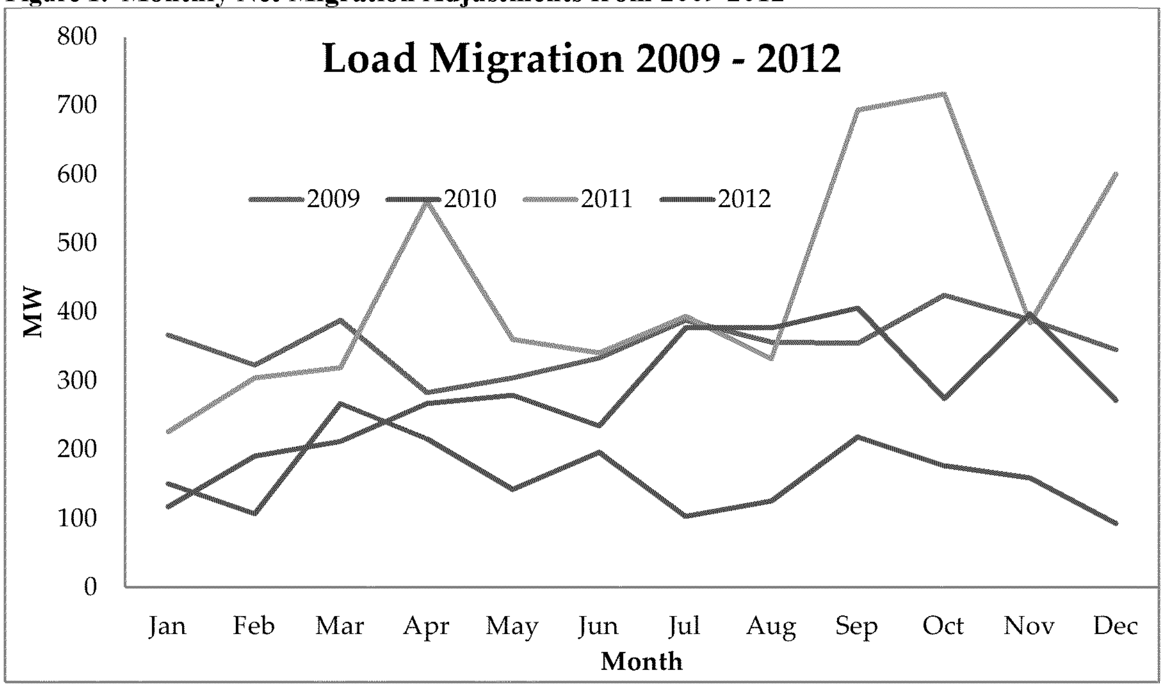
Table 3. Summary of Load Migration Adjustments in 2012 (MW)

Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Forecasts , July 2011	29,112	27,971	28,131	29,810	33,564	38,398	42,113	44,167	39,745	33,511	29,043	30,697
Monthly Adjustments, 2012	117	191	213	267	279	235	378	378	406	275	398	272
Final Forecasts in Monthly RA Filings	29,229	28,162	28,344	30,078	33,843	38,632	42,491	44,544	40,151	33,786	29,441	30,969
Monthly Adjustments/ Final Load Forecast	0.40%	0.68%	0.76%	0.90%	0.83%	0.61%	0.90%	0.86%	1.02%	0.82%	1.37%	0.89%

Source: Aggregated load forecast adjustments submitted to the CEC and CPUC through 2012.

Figure 1 illustrates the net load migration applied to LSEs' monthly forecasts used for month-ahead compliance during 2009 - 2012. Net load indicates the net load shifting activity in LSEs' monthly load forecasting from their year-ahead load forecast. There was a significant decrease in net load adjustments from 2009 to 2010. From 2010 to 2011, there was a significant increase in net migration adjustments, which correlates with the 2010 reopening of Direct Access (DA) and may have created uncertainty regarding customer migration. The load migration adjustments for 2012 decreased from 2011 levels, suggesting more certainty in customer retention and load forecasting.

Figure 1. Monthly Net Migration Adjustments from 2009-2012



Source: Monthly forecast adjustments submitted by LSEs, 2009-2012.

Comparing the range of 2012 plausibility adjustments as a percentage of total monthly year-ahead load forecasts, -2.1% to 1.7 %, to the range of 2012 load migration as a percentage of total monthly year-ahead load forecasts, 0.4% to 1.37%, it appears there is less uncertainty regarding load migration in the monthly RA filing process than in the annual RA filing process, reflecting the improved information LSEs have about customer plans in the shorter time frame of the month-ahead process.

Load migration in 2011 was largely driven by the partial reopening of direct access and whether there was "room under the cap". Direct Access was reopened in several "tranches" with the largest amount of new direct access load being able to leave IOU bundled service during 2011 and 2012. When the last tranche has migrated away from IOU bundled service after the 2013 RA compliance year, there will be much less migration and less uncertainty about customer retention.

3.2 System RA Requirements for CPUC-Jurisdictional LSEs

In 2012 CPUC-jurisdictional LSEs satisfied their individual and collective system Resource Adequacy Requirements (RAR) for every month of 2012. The total MW of RA resources procured exceeded the total System RAR by 1.1 percent to 4.2 percent, depending on the month. Table 4 shows the total CPUC-jurisdictional RA procurement for each month of 2012 broken down by: physical resources within the CAISO's control area, DR, CAM/RMR resources, imports, and remaining DWR contracts. RA obligations are reported here as the aggregate monthly load forecast plus the 15% Planning Reserve Margin (PRM). DR resources are also reported with the 15% PRM applied.

Table 4. 2012 RA Filing Summary – CPUC-Jurisdictional Entities (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
RAR before DR,CAM, & RMR	33,617	32,387	32,594	34,591	38,919	44,427	48,865	51,226	46,174	38,856	33,861	35,618
Phys. Res.	30,089	29,109	28,830	30,379	34,607	38,038	38,162	39,165	36,976	31,588	30,417	31,182
DWR	595	595	298	298	298	595	0	0	0	0	0	0
Imports	1,174	1,439	1,907	1,745	1,165	2,365	6,145	6,932	4,036	3,047	1,418	1,595
DR plus 15% PRM	1,168	1,199	1,180	1,463	2,070	2,745	3,055	2,987	2,951	2,157	1,399	1,272
CAM & RMR	1,084	1,084	1,084	1,324	1,274	1,274	2,020	2,513	2,491	2,496	2,043	2,074
Total	34,111	33,426	33,299	35,210	39,414	45,018	49,384	51,597	46,455	39,288	35,277	36,123
Total/ RAR	**101.5%**	**103.2%**	**102.2%**	**101.8%**	**101.3%**	**101.3%**	**101.1%**	**100.7%**	**100.6%**	**101.1%**	**104.2%**	**101.4%**

Source: Aggregated LSE Monthly RA Filings.

3.3 Local RA Program – CPUC-Jurisdictional LSEs

Beginning with the 2007 compliance year, the CPUC required LSEs to file an annual Local RA showing. The annual requirement is determined by the CPUC informed by the CAISO's annual Local Capacity Technical Analysis, which is done the previous year. This annual study determines the aggregate local requirement for each local area using a one in ten weather year and an N-1-1 contingency.[19] The aggregate values are adopted in the previous year's RA decision and allocated to each LSE based on their August load ratio in each TAC area.

Each LSE is required to make a 12 month showing of their local requirement on or around October 31st, with their system year-ahead showing.[20] In D.11-06-022, the CPUC adopted the 2012 Local RA obligations for the ten locally constrained areas (Big Creek/Ventura, LA Basin, San Diego, Greater Bay Area, Humboldt, North Coast/North

[19] Local Capacity Requirement (LCR) studies and materials for 2012 and previous years are posted at http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityRequirementsProcess.aspx .
[20] More detail regarding the overall Local RA program can be found in Section 3.3 of the 2007 Resource Adequacy Report.

Bay, Sierra, Stockton, Fresno, and Kern).[21] As in previous years, the following local areas are aggregated to one area known as other PG&E areas: Humboldt, North Coast/North Bay, Sierra, Stockton, Fresno, and Kern. Effective for the 2012 RA compliance year, that aggregation was made permanent.

3.3.1 Year-Ahead Local RA Procurement

CPUC-jurisdictional LSEs' overall Local RA procurement for 2012 is summarized in Table 5. CPUC-jurisdictional LSE procurement exceeded Local RA obligations in each of the five Local Areas by 1 to 22 percent. Aggregate minimum procurement across all Local Areas exceeded Local RA Requirements (Local RAR) by 7 percent. Local requirements are allocated to LSEs net of the DR, RMR, and CAM, as these resources are used to reduce an LSE's Local RA obligation. The net local obligation was 21,252 MW (24,022MW - 2,770 MW = 21,252 MW).

Table 5. Local RA Procurement in 2012, CPUC-Jurisdictional LSEs

Local Areas in 2012	Total LCR	CPUC-Jurisdictional Local RAR	Minimum Physical Resources per Month	Local RMR/DR/CAM Credit	Minimum Procurement/ Local RAR
LA Basin	10,865	9,857	8,115	1,817	101%
Big Creek/Ventura	3,093	2,806	2,664	271	105%
San Diego	2,849	2,849	2,694	154	100%
Greater Bay Area	4,278	3,893	4,408	348	122%
Other PG&E Areas	5,073	4,617	5,099	180	114%
Totals	26,158	24,022	22,981	2,770	107%

3.3.2 Local RA True-Ups

As part of the partial reopening of direct access in 2010, the Commission adopted a true-up mechanism to adjust each LSE's Local RA obligation to account for load migration in D.10-03-022. The true-up process worked but proved cumbersome, and in D.10-12-038 the process was modified for the 2011 compliance year and beyond.

The new local true-up process requires LSEs to file revised load forecasts for August's peak load twice during the compliance year. The CEC uses these revised August load forecasts to update each LSE's load share, which is then used to revise each LSE's local capacity requirements. The difference between the original allocations and the new requirements is allocated to LSEs as an incremental Local RA requirement, which the LSEs must meet in their monthly filings.

In 2012, LSEs submitted revised August forecasts to the CEC on January 31st along with their 60 day-ahead (April) load forecasts. 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 netted from the individual LSE year-

[21] http://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/FINAL_DECISION/138375.htm

ahead local requirements. The netted local requirement values, known as incremental local allocations, were then sent to LSEs on February 17th in the May CAM-RMR allocation letters. LSEs were instructed to incorporate these incremental local allocations into their May and June RA month-ahead (MA) compliance filings. Through its review, Energy Division staff verified that each LSE met its reallocated local requirement for May and June using these values.

The second reallocation process for the 2012 compliance year began with revised August forecasts filed on April 2nd. Local true-up values based on these forecasts were sent out on April 12th with the July CAM-RMR letters. These incremental values were used by the LSEs for the remainder of 2012 (July to December MA filings). Energy Division also used these incremental values to verify that each LSE met its revised Local RA requirement in the July-December MA filings.

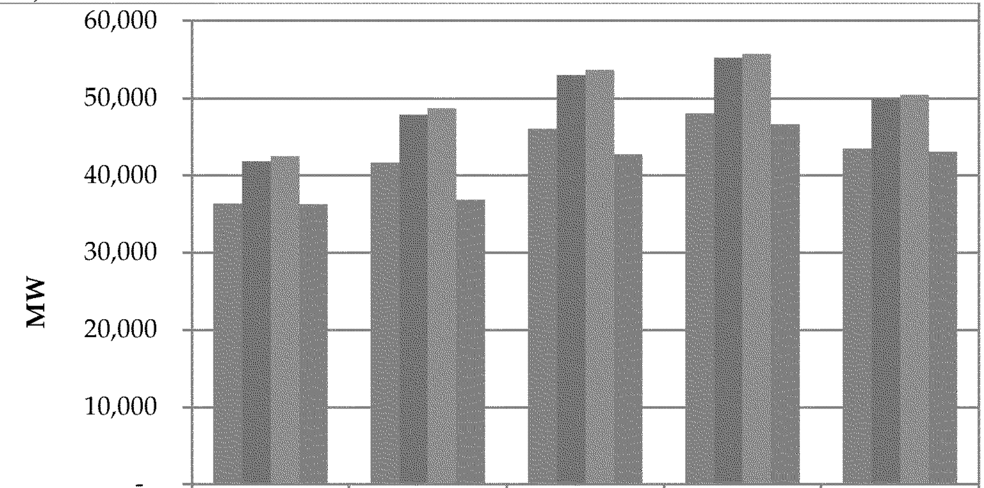
3.4 Total RA Resources Available to the CAISO

The CPUC RA program is closely coordinated with the CAISO's reliability requirements. In addition to receiving RA plans from CPUC-jurisdictional LSEs, the CAISO also receives resource adequacy filings from non-CPUC-jurisdictional LSEs.

Figure 2 shows the total load forecast for both CPUC-jurisdictional and non-jurisdictional LSEs, the total procurement obligation (forecast plus planning reserve margin), total committed RA, and actual peak load in the summer months of 2012.

Committed RA resources, including DR, CAM and RMR resources, ranged from 42,501 MW in May to 55,803 MW in August. These resources enabled LSEs to meet between 101 and 101.8 percent of total procurement obligations in each summer month. In all summer months, the capacity available to the CAISO exceeded the actual monthly peak load. The total peak load was forecasted to be 48,075 MW in August, which is when the actual system peak occurred at 46,682 MW. Committed RA resources procured by all LSEs, including both CPUC-jurisdictional and non-CPUC-jurisdictional, totaled 55,803 MW for that month.

Figure 2. Summer 2012 Demand Forecast, RA Obligation, Procurement, Actual Peak Demand (MW)



	May	Jun	Jul	Aug	Sep
Load forecast	36,371	41,659	46,083	48,075	43,434
Forward Commitment Obligation	41,801	47,877	52,975	55,267	49,933
Total RA resources Committed	42,501	48,719	53,673	55,803	50,461
Actual Peak Load	36,327	36,810	42,780	46,682	43,020

Source: Aggregated data compiled from Monthly CPUC and non-CPUC RA Filings, CEC load forecasts, and CAISO OASIS.

The data represented in Figure 2 is derived from Appendix 1, which illustrates total committed RA procurement for the summer of 2012 for all LSEs (both CPUC and non-CPUC jurisdictional) by contract type, and compares this procurement to the procurement obligation.[22] In the summer of 2012 78 to 88 percent of all committed RA capacity was procured from unit-specific physical resources within the CAISO control area; 3 to 12 percent of capacity was from imports, and about 1 percent was from non-DWR Liquidated Damages contracts listed by the POUs for May and June.

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 the 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

[22] These data come from the ISO Reliability Requirement (IRR) application, implemented beginning in January 2012. The IRR application is an online application that validates, maintains, and reports RA information. LSEs upload RA plans into the IRR and scheduling coordinators (SC) upload supply plans. The CAISO performs a series of checks that cross-validate the RA plans against the supply plans. This cross-validation output is then sent to the CPUC for compliance purposes.

for dispatch. In other words, the MOO commits these RA resources to CAISO market (MRTU) mechanisms.

The CAISO utilizes these committed resources through its Day Ahead Market, Real Time Market, and Residual Unit Commitment (RUC). The CAISO also relies on out-of-market commitments (e.g. Exceptional Dispatch (ExD), Interim Capacity Procurement Mechanism (ICPM) and Reliability Must Run (RMR) contracts) to meet reliability needs that are not satisfied by the Day Ahead, Real Time and RUC market mechanisms.

To ensure funding for new generation needed for grid reliability, the CPUC began authorizing IOUs, in the LTPP, to procure new generation resources to meet reliability needs (both system and local) beginning in 2007. The RA benefits of new generation resources are applied as a credit towards RA requirements (the Local credit is applied to the overall Local RA obligation and the System credit is allocated monthly). These CAM resources carry the same must offer obligation as all other RA resources.

4.1 Resource Adequacy Procurement Mechanism

4.1.1 Bilateral Transactions

The bilateral RA transactions in combination with other market opportunities provide generation owners and developers the opportunity to obtain revenue to cover their fixed costs and help enable new projects to secure financing needed for new construction. Prices of bilateral contracts could vary substantially depending on unit location, transmission constraints and market power.

4.1.2 CAISO Out of Market Procurement- RMR Designations

The CAISO performs an annual RMR study to identify which generator resources are needed on-line in order to reliably serve the local area load. 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 during the relevant compliance year. RMR resources are placed into two classes: Condition 1 contracts are allowed to operate in the energy market even if not dispatched by the CAISO for reliability purposes, and Condition 2 units are generally not allowed to operate in the energy market but are under the full dispatch of the CAISO for reliability purposes. Both types of RMR contracts are paid for by all customers in the transmission area.

Condition 1 units are able to competitively earn revenue in the energy market in addition to the capacity payments under the RMR Agreement. In D.06-06-064, the CPUC ordered that capacity from Condition 1 RMR contracts be allocated to LSEs to count towards the LSEs' Local RA obligations only, while Condition 2 RMR units may be counted towards both the 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,[23] Local RA requirements began to supplant RMR contracting for the 2007 compliance year, and a significant decline in 2007 RMR designations occurred. That trend continued through the 2011 compliance year, with only one remaining RMR contract (with the Oakland Power Plant) and no change in RMR designations from 2011 to 2012.

Table 6 provides a summary of the CAISO's 2009-2012 RMR designations, RMR allocations and the year-over-year decreases.

Table 6. RMR Designations and RMR Allocations for 2009-2012

Year		PG&E	SCE	SDG&E	Total
2009	Compliance year CAISO Board of Governors	1,263	0	979	2,242
	Compliance year RMR allocations	709	0	132	841
	Net change in designations from previous year	1,263	0	979	2,242
2010	Compliance year CAISO Board of Governors	709	0	311	1,020
	Compliance year RMR allocations	709	0	311	1,020
	Net change in designations from previous year	-554	0	-668	-1,222
2011	Compliance year CAISO Board of Governors	527	0	311	838
	Compliance year RMR allocations	527	0	311	838
	Net change in designations from previous year	-182	0	0	-182
2012	Compliance year CAISO Board of Governors	165	0	0	165
	Compliance year RMR allocations	165	0	0	165
	Net change in designations from previous year	-362	0	-311	-673

Source: CAISO Board of governors meetings for 10/29/08, and 10/21/09, and 10/26/10.

4.1.3 IOU Procurement for System Reliability and Other Policy Goals

D.06-07-029 adopted a process known as the CAM, which allows the Commission to designate IOUs to procure new generation within an IOU's distribution service territory, with the costs and benefits to be allocated to all benefiting customers, including bundled utility customers, Direct Access customers and Community Choice Aggregator customers. The LSEs serving these customers are allocated the rights to the capacity in each service territory, which are applied towards meeting the LSE's RA requirement. The LSEs receiving a portion of the CAM capacity pay only for the net cost of the capacity, which is the net of the total cost of the power purchase contract price minus the energy revenues associated with the dispatch of the contract.

[23] D.06-06-064, Section 3.3.7.1.

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

Table 7 shows which conventional generation resources qualify for CAM and provides the scheduling resource ID, the contract dates that the CAM was approved to cover, and the authorized IOU. The list includes all conventional generation resources subject to the CAM mechanism since its inception.

Table 7. 2012 Resources Authorized for CAM Due to Reliability

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU
BARRE_6_PEAKER	8/1/2007	7/31/2017	SCE
BUCKBL_2_PL1X3	8/1/2010	7/31/2020	SCE
CENTER_6_PEAKER	8/1/2007	7/31/2017	SCE
ETIWND_6_GRPLND	8/1/2007	7/31/2017	SCE
HINSON_6_LBECH1	6/1/2007	5/31/2017	SCE
HINSON_6_LBECH2	6/1/2007	5/31/2017	SCE
HINSON_6_LBECH3	6/1/2007	5/31/2017	SCE
HINSON_6_LBECH4	6/1/2007	5/31/2017	SCE
MIRLOM_6_PEAKER	8/1/2007	7/31/2017	SCE
VESTAL_2_WELLHD	2/1/2013	5/31/2022	SCE
WALCRK_2_CTG1	6/1/2013	5/31/2023	SCE
WALCRK_2_CTG2	6/1/2013	5/31/2023	SCE
WALCRK_2_CTG3	6/1/2013	5/31/2023	SCE
WALCRK_2_CTG4	6/1/2013	5/31/2023	SCE
WALCRK_2_CTG5	6/1/2013	5/31/2023	SCE
ELSEGN_2_UN1011	8/1/2013	7/31/2023	SCE
ELSEGN_2_UN2021	8/1/2013	7/31/2023	SCE
SENTNL_2_CTG1	8/1/2013	7/31/2023	SCE
SENTNL_2_CTG2	8/1/2013	7/31/2023	SCE
SENTNL_2_CTG3	8/1/2013	7/31/2023	SCE
SENTNL_2_CTG4	8/1/2013	7/31/2023	SCE
SENTNL_2_CTG5	8/1/2013	7/31/2023	SCE
SENTNL_2_CTG6	8/1/2013	7/31/2023	SCE
SENTNL_2_CTG7	8/1/2013	7/31/2023	SCE
SENTNL_2_CTG8	8/1/2013	7/31/2023	SCE
COCOPP_2_CTG1	7/1/2013	4/30/2023	PG&E
COCOPP_2_CTG2	7/1/2013	4/30/2023	PG&E
COCOPP_2_CTG3	7/1/2013	4/30/2023	PG&E
COCOPP_2_CTG4	7/1/2013	4/30/2023	PG&E
SUTTER_2_PL1X3	7/1/2012	12/31/2012	PG&E, SCE, SDG&E
HNTGBH_7_UNIT 3	8/1/2012	10/31/2012	SCE, SDG&E
HNTGBH_7_UNIT 4	8/1/2012	10/31/2012	SCE, SDG&E

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 have the IOUs reduce the GHG emissions consistent with the ARB climate change scoping plan. 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 what was adopted in the 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, DA, and CCA customers. The RA benefits associated with the CHP contract are also allocated to all customers paying the net capacity costs.[26]

In 2012, PG&E procured several CHP contracts whose costs and benefits were allocated to all customers. These CHP contracts amounted to approximately 500 MW of RA credit. These RA capacity credits were allocated in the monthly CAM allocation process beginning with the May 2012 compliance month. Table 8 below lists the CHP resources whose RA capacity credits were allocated in 2012. The table does not include CHP resources whose RA capacity credits were allocated in 2013, although 2013 allocations are shown in Figure 3.

Table 8. CHP Resources Allocated for CAM

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU
KERNFT_1_UNITS	4/1/2012	11/30/2020	PG&E
SIERRA_1_UNITS	4/1/2012	11/30/2020	PG&E
DOUBLC_1_UNITS	4/1/2012	11/30/2020	PG&E
SARGNT_2_UNIT	4/1/2012	12/31/2016	PG&E
SALIRV_2_UNIT	4/1/2012	12/31/2016	PG&E
COLGA1_6_SHELLW	4/1/2012	12/31/2016	PG&E
MIDSET_1_UNIT 1	4/1/2012	12/31/2016	PG&E
BDGRCK_1_UNITS	7/1/2012	6/30/2015	PG&E
CHALK_1_UNIT	7/1/2012	6/30/2015	PG&E
MKTRCK_1_UNIT 1	7/1/2012	6/30/2015	PG&E
LIVOAK_1_UNIT 1	7/1/2012	6/30/2015	PG&E
UNVRSY_1_UNIT 1	8/1/2012	6/30/2015	PG&E
CONTAN_1_UNIT	8/1/2012	6/30/2015	PG&E
TEMBLR_7_WELLPT	8/1/2012	3/31/2015	PG&E
DEXZEL_1_UNIT	9/2/2012	7/1/2015	PG&E
TANHIL_6_SOLART	10/1/2012	9/30/2019	PG&E
FRITO_1_LAY	10/1/2012	9/30/2019	PG&E

[24] http://docs.cpuc.ca.gov/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
[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
KERNRG_1_UNITS	10/1/2012	9/30/2019	PG&E
CALPIN_1_AGNEW	11/1/2012	4/18/2021	PG&E
TXMCKT_6_UNIT	7/1/2012	12/31/2012	PG&E

Event based DR resources are also treated as an RA credit towards meeting RA obligations. The costs for most DR programs are allocated through the distribution charge which means that most DR programs, other than SCE's Save Power Day (SPD) and Critical Peak Pricing (CPP) programs, are paid for by bundled, direct access, and community choice aggregate customers. The RA credit associated with DR is calculated using the CPUC adopted Load Impact Protocols. On about April 1st of each year the IOUs/DR providers submit the forecasted load impact values associated with each event based DR program for the coming RA compliance year. Energy Division verifies that the load impact values are plausible given their ex post performance and forecasted assumptions. When the values are determined to be final, the RA credits are allocated to all benefiting customers for the coming compliance year.

In 2012, a total of 2,598 MW of DR RA credit was allocated to benefiting LSEs to meet August RA obligations. Table 9 and Figure 4 below shows the DR RA credit allocation for August for 2007 through 2013. DR allocations have remained relatively steady during this period, ranging from 2,286 MW- 2,669 MW. The total amount of capacity procured through DR, CAM and RMR for August 2012 was 5,124 MW. This is approximately 10% of the total CPUC-Jurisdictional LSE obligation for August 2012 (51,226 MW). The total DR included in the tables below does not include the 15% PRM that is added to it for compliance purposes.

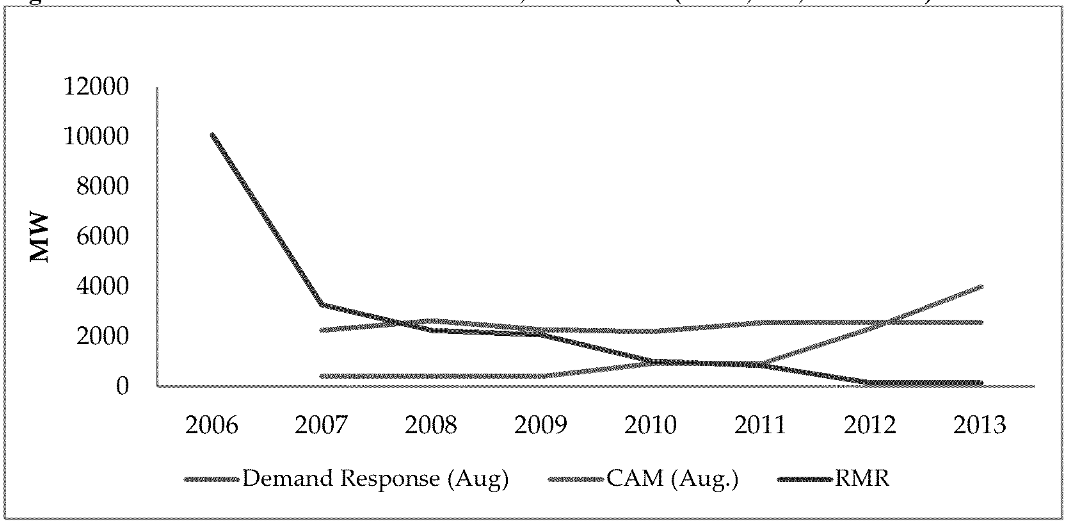
Table 9. DR, CAM, and RMR Allocations (MW)

		2006	2007	2008	2009	2010	2011	2012	2013
DR Procurement	SCE			1,483	1,406	1,403	1,599	1,797	1,859
	PG&E			885	793	736	772	647	606
	SDG&E			301	91	85	210	154	118
	Total DR (Aug)		2,286	2,669	2,290	2,223	2,580	2,598	2,582
CAM Procurement	SCE		436	436	436	936	936	1,529	2,742
	PG&E		0	0	0	0	0	703	1278
	SDG&E		0	0	0	0	0	130	0
	Total CAM (Aug.)		436	436	436	936	936	2,362	4,021
RMR Procurement	SCE	1,390	-	-	-	-	-	-	
	PG&E	6,151	1,348	1,303	1,263	709	527	165	165
	SDG&E	2,549	1,961	973	828	311	311	-	
	Total RMR	10,090	3,309	2,276	2,091	1,020	838	165	165

Figure 3. illustrates the amount and type of procurement credit that has been allocated since the beginning of the RA program. The graph reflects the decline in RMR units and the increase in CAM units. DR RA credits have remained relatively steady since 2007.

In August 2013 total CAM procurement reached 4,021 MW where RMR procurement consisted of only 165 MW.

Figure 3. RA Procurement Credit Allocation, 2006 – 2013 (RMR, DR, and CAM)



4.2 RA Resource Commitments into CAISOs Markets—RA Capacity Bidding and Scheduling Obligations

The scheduling coordinators for the RA capacity procured by the LSE have an obligation to make the capacity listed in the monthly supply plan available to the ISO. The manner in which this occurs depends on the resource type. However, the general requirement for RA generation units is that they submit economic bids or self-schedule into the Intergraded Forward Market (IFM) /Day Ahead Market (DAM). They must also submit $0/MW RUC availability bids for all hours for the month the resource is available. Any RA capacity that does not submit a bid in the IFM or RUC mechanism must submit an economic bid or self-schedule into the real time market. If the SC fails to submit a bid for the resource through these mechanisms the ISO will generate one for them.

5 RA Price Analysis

On October 28th, 2013, Energy Division issued a data request to all 18 CPUC-jurisdictional LSEs (comprised of three IOUs and 15 ESPs) requesting monthly capacity prices paid by (or to) LSEs for every RA capacity contract covering the 2012 – 2016 compliance years. The data request was confined to RA-only capacity contracts bought or sold covering the period from January 2012 – December 2016. Since RA prices can vary by month, the data request asked for specific monthly prices from each contract. QF and RPS contracts were included if they were for RA capacity only (no energy). Imports and exports were excluded from the data set, as were all contracts with either a $0 price value or a 0 MW value.

In an attempt to collect a larger data set, the data request included contracts bought and sold by LSEs.[27] Because both purchased and sold RA contracts are included in the data set it is hard to compare the magnitude of MWs in a given period to the RA requirement of the same period. For example, say LSE A purchases 500 MW of System RA capacity, and sells 75 MW to LSE B, 50 MW to LSE C, and 25 MW to a third party that ultimately resells the capacity to LSE B. If LSE A and B both report their full contract data, but LSE C does not, then the data set will include 500 MW purchased by LSE A, 150 MW sold by LSE A, and 100 MW purchased by LSE B. The result would be an apparent 750 MW of RA capacity, despite only 500 MW of physical resource that can count towards meeting an RA requirement. Because this section of the RA Report aims to provide as complete a picture as possible of the overall RA market, the full contracted capacity is included in the data set, regardless of the physical resource it represents.

Of the 18 LSEs that were sent the data request, Energy Division received eight responses (from three IOUs and five ESPs), which consisted of a combined 3,463 monthly contract values; these values collectively form the data set used in this price analysis. Key statistics characterizing the reported capacity contracted in each year are shown in Table 10. The majority of the capacity in the data set is contracted for 2012 and 2013. This is as expected, since the 2012 and 2013 RA compliance years have ended, and there is not yet an obligation to procure for 2015 or 2016.

In an attempt to better understanding the magnitude of the data set we compare the data set to 2012 RA requirements. Keep in mind that this results in either the inclusion of RA contracts ultimately used to meet the RA obligations of non-reporting LSEs (in the case of RA capacity sold to a third party that then sold the contract to a non-reporting LSE), or in the inclusion of more than one contract for a given MW of physical RA capacity (in the case of RA capacity sold either directly or indirectly to another reporting LSE). In 2012, the sum of monthly contracted capacity represents approximately 33% of the 2012 monthly sum of RA requirements net of CAM, RMR and DR allocations.[28] The remainder of RA capacity for that year either was not reported because it was not procured via an RA-only capacity contract, or was procured by an LSE that did not respond to the Energy Division's data request.

While the data set coverage of 33% of 2012 capacity is far from complete, it nevertheless provides important insights into overall RA pricing in that year. If we use the aggregate 2012 monthly capacity requirements as a proxy to determine how much data in each year is representative of the total monthly RA requirements, it appears that for 2013 the sum of monthly contracts represent about 25% of the 2012 RA requirements, the 2014 data

[27] Due to reporting both bought and sold contracts there are nine contracts that are duplicative, meaning they are reported by both the buyer and the seller of the contract, in the data set. The nine contracts represent 1,400 MW with a weighted average of $3.94/kW-month. Of the 1,400 MW, 600 MW are located in the System North zone and have a total weighted average of $4.00/kW-month covering the compliance periods of July and August 2012. The remaining 800 MW are located in Local South areas and have a weighted average of $3.91/kW-month covering the compliance periods of July and August 2012 and August and September 2013.

[28] The 33% is calculated by dividing the sum of contracted capacity in 2012 (141,566 MW) by the sum of all 2012 monthly RA obligations net of CAM, RMR, and DR allocations (426,735 MW).

represents about 19% of the 2012 RA requirements, the 2015 data represents about 15% of the 2012 RA requirements, and 2016 represents about 7% of the RA requirements. These values appear to be very similar to the percentages of total capacity in data set values by year. This is because the total MW value of the data set is very close to the 2012 monthly sum of RA requirements net CAM, RMR, and DR allocations.

Table 10. Capacity Prices by Compliance Year, 2012-2016

	2012 Capacity	2013 Capacity	2014 Capacity	2015 Capacity	2016 Capacity
Weighted Average Price ($/kW-month)	$ 3.18	$ 3.42	$ 3.46	$ 3.21	$ 2.95
Average Price ($/kW-month)	$ 3.21	$ 3.29	$ 3.59	$ 3.70	$ 3.76
Minimum Price ($/kW-month)	$ 0.10	$ 0.11	$ 0.08	$ 0.08	$ 0.08
Maximum Price ($/kW-month)	$ 24.49	$ 26.54	$ 26.54	$ 26.54	$ 26.54
85th percentile ($/kW-month)[29]	$ 7.85	$ 7.30	$ 7.34	$ 6.10	$ 4.01
Contracted Capacity (MW)	141,566	108,058	80,129	64,043	29,522
Percentage of Total Capacity in Data Set	33.4%	25.5%	18.9%	15.1%	7.0%

Energy Division staff aggregated the contracts across all compliance years, sorted them into the categories shown in Table 11 below, and performed a statistical analysis of each category. Local and System RA contracts are differentiated by the unit's location, which is taken from the 2014 NQC list.[30] Local RA Capacity areas are described in Section 3.3 of the report. Table 11 below presents the summary statistics from the data set. All prices are in units of nominal dollars per kW-month.

The data set represents 423,318 MW-months of capacity under contract. Of that capacity, 34% is located in the North of Path 26 (NP-26) Zone and 66% is located in the South of Path 26 (SP-26) Zone;[31] in other words, there is roughly twice as much RA capacity under contract in the SP-26 Zone as there is in the NP-26 Zone. The data also show that 70% of the total capacity is located in Local Areas, with the remainder located in the CAISO balancing area. Of the Local RA capacity reported, the vast majority – 86% – is located in one of the SP-26 Local Areas; the remaining 14% is located in an NP-26 Local Area. The CAISO System RA has the opposite breakdown, with 74% of capacity located in the NP-26 Zone and only 26% of System RA capacity located in the SP-26 Zone.[32]

[29] 85th percentile statistic is the price under which 85% of contract MW values, in a given category, fall.
[30] The 2014 NQC list can be found at http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_compliance_materials.htm.
[31] Path 26 is defined in the WECC Path Rating Catalog, viewable at http://www.wecc.biz/library/Pages/Path%20Rating%20Catalog%202013.pdf.
[32] The CAISO System RA category is applied to contracts with resources that are not located in Local Capacity Areas. It can be further divided into NP-26 and SP-26 sub-categories, which indicate whether those contracts are north or south of Path 26.

Table 11. Aggregated RA Contract Prices, 2012-2016

	All RA Capacity			Local RA Capacity			CAISO System RA Capacity		
	Total	NP-26	SP-26	**Subtotal**	NP-26	SP-26	**Subtotal**	NP-26	SP-26
Weighted Average Price ($/kW-month)	$ 3.28	$ 2.74	$ 3.57	$ 3.45	$ 2.82	$ 3.55	$ 2.90	$ 2.71	$ 3.68
Average Price ($/kW-month)	$ 3.37	$ 2.87	$ 3.65	$ 3.55	$ 3.26	$ 3.64	$ 2.74	$ 2.41	$ 3.68
Minimum Price ($/kW-month)	$ 0.08	$ 0.10	$ 0.08	$ 0.08	$ 0.18	$ 0.08	$ 0.10	$ 0.10	$ 0.14
Maximum Price ($/kW-month)	$ 26.54	$ 23.62	$ 26.54	$ 6.54	$ 23.62	$ 6.54	$ 18.99	$ 15.93	$ 18.99
85th Percentile ($/kW-month) [33]	$ 6.46	$ 4.00	$ 9.80	$ 8.10	$ 3.92	$ 9.84	$ 4.79	$ 4.20	$ 8.34
Contracted Capacity (MW)	423,318	144,655	278,663	295,736	41,747	253,989	127,582	102,908	24,674
Percentage of Total Capacity in Data Set	100%	34%	66%	70%	10%	60%	30%	24%	6%
Number of Monthly Values	3,463	1,227	2,236	2,719	677	2,042	744	550	194

The weighted average price for all capacity is $3.28/kW-month. The weighted average price for SP-26 capacity (including Local and System RA) is $3.57/kW-month, which is about 30% higher than the NP-26 weighted average price of $2.74/kW-month. Higher prices in the SP-26 Zone are also revealed through the 85th-percentile statistics, which indicate the price under which 85 percent of the contracted MW values in a given category fall. In SP-26, 85% of contracted MW prices are at a price of $9.80/kW-month or less, while in NP-26, 85% of the contracted MWs cost $4.00/kW-month or less.

The weighted average price of Local RA capacity is 19% higher than the weighted average price of System RA capacity. This is expected, as Local RA is a more constrained product. However, the weighted average price of Local RA capacity in the SP-26 Zone is less than the weighted average price of System RA capacity in the SP-26 Zone, whereas the 85th-percentile price is in fact about $1.50/kW-month *higher* for SP-26 Local RA as compared to SP-26 System RA. This suggest prices between the 50th pecentile and the 85th percentile are much higher in the SP-26 Local area then they are in SP-26 System area. Conversely, the weighted average price of Local RA capacity in the NP-26 Zone is greater than the weighted average price of System RA capacity in the NP-26 Zone, whereas the 85th-percentile price is in fact about $0.28/kW-month *lower* for NP-26 Local RA as compared to NP-26 System RA. It is important to note that the data set is weighted with much more SP-26 Local than NP-26 Local and much more NP-26 System than SP-26 System. The weighting of the data set suggests that the limited data available may not reveal a complete picture.

The price curves for RA-only contracts are shown by category in Figures 4-6, below. Figure 4 displays three price curves. The All Capacity price curve includes all contract

[33] 85th percentile statistic is the price under which 85% of contract MW values, in a given category, fall.

prices in the data set plotted as a price curve along a cumulative MW x-axis. The other two price curves show either Local or System RA capacity contracts only. Because 70% of the capacity in the data set is Local RA, the overall price curve more closely matches Local RA prices than System RA prices.

Figure 4. Price Curves for RA Capacity Contracts, 2012-2016 Compliance Years

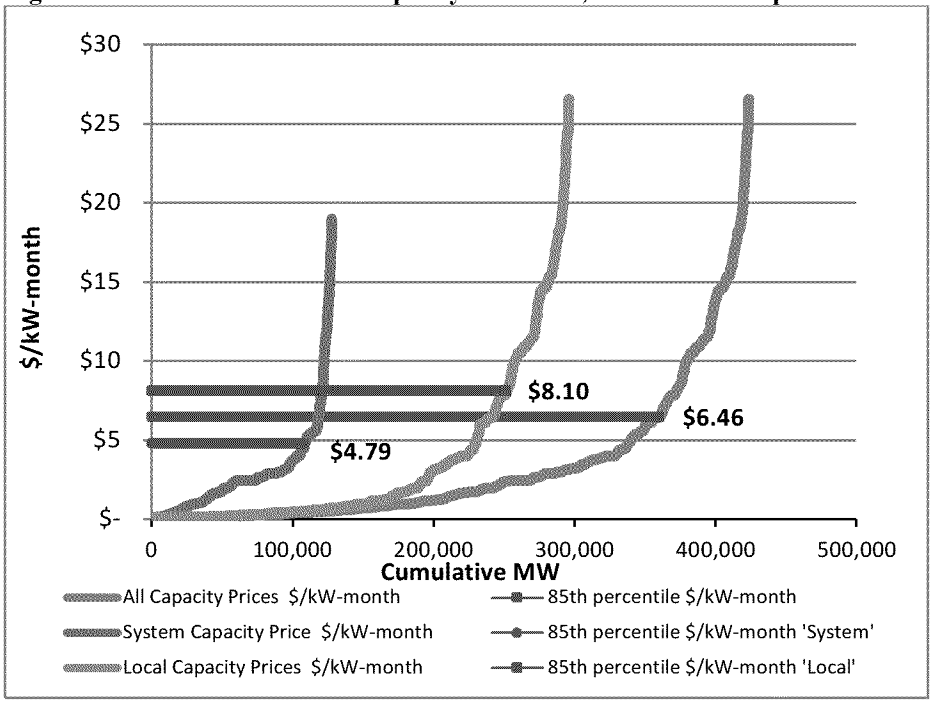


Figure 5. RA Price Curves for Resources North of Path 26, 2012-2016

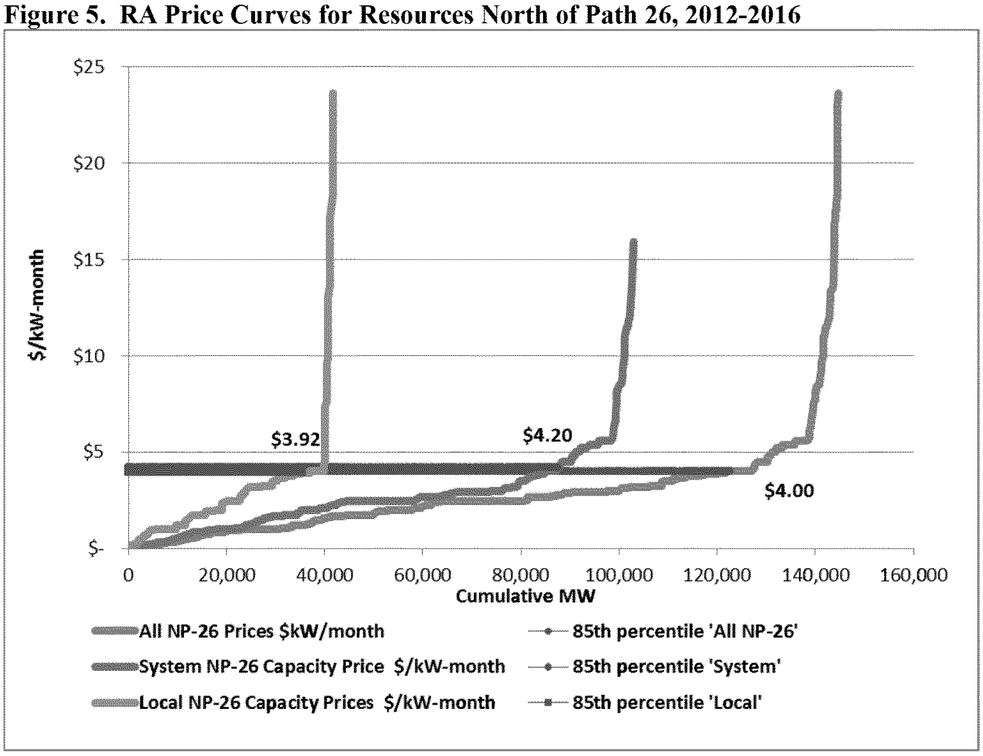


Figure 5 displays price curves for contracted capacity north of Path 26. Like Figure 4, the price curves are differentiated by Local and System RA capacity. In contrast to the statewide aggregate data, the majority of contracted capacity north of Path-26 is with resources *not* located in local areas. The weighted 85th-percentile contract price of System RA Capacity is about $0.30/kW-month more than for Local RA, indicating that there is generally not a significant premium placed on Local RA capacity north of Path 26. However, there are much higher price outliers in the Local RA capacity curve than there are in the System RA capacity curve. This is to be expected; it may be particularly difficult to procure Local RA in highly constrained areas, while System RA does not have such local constraints.

Figure 6 displays price curves of contracted capacity south of Path 26. The vast majority of contracted capacity in the SP-26 Zone is with resources located in Local Areas. The weighted 85th-percentile price for Local RA capacity is about $1.50/kW-month more than for System RA.

Figure 6. RA Price Curves for Resources South of Path 26, 2012-2016

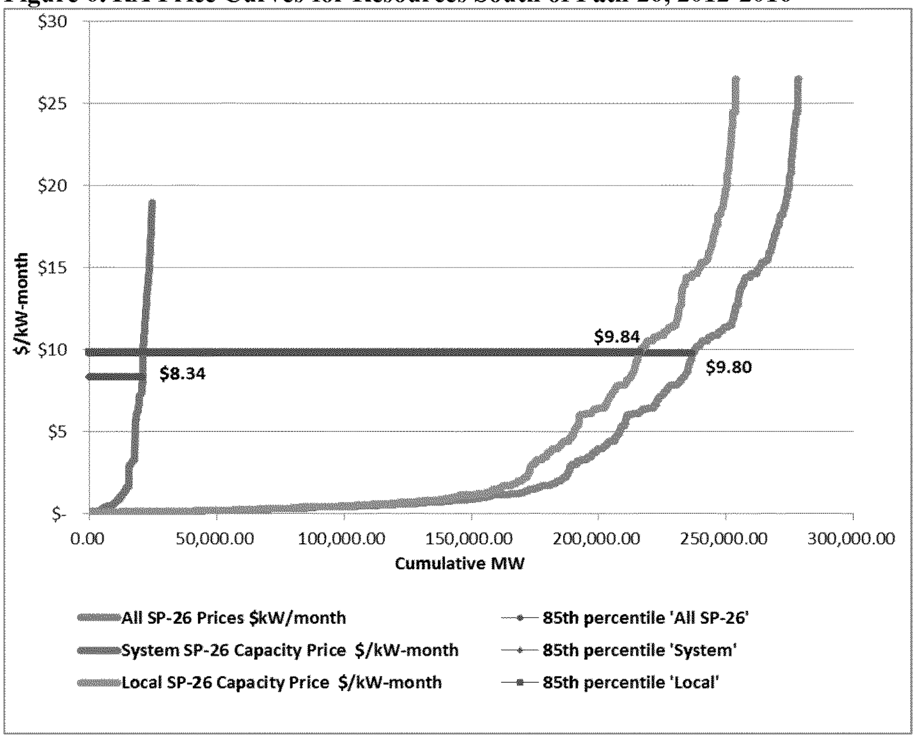


Table 12 reports capacity prices by Local Capacity Area. The San Diego Local Area has the highest weighted average price, the highest 85th-percentile price and the highest maximum price. The 85th-percentile price indicates that 85 percent of the contracted MW in the San Diego Local Area were procured at prices of $10.24/kW-month or below. According to the average weighed price and the 85th percentile price Big Creek Ventura capacity is more expensive than LA Basin capacity. Looking at the 85th percentile statistic of local areas in the North, the data suggest that Bay Area capacity is typically more expensive than capacity in the other PG&E Local Areas, however, the weighted average price suggest the opposite; Other PG&E Local Areas is more expensive than Bay Area. Given the limited data available for Other PG&E Local Areas (only 3,552 MW of

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contracted capacity, which is less than one tenth of the contracted capacity in the Bay Area), it is not possible to draw any strong conclusions.

Table 12. Capacity Prices by Local Area, 2012-2016

	Big Creek-Ventura	LA Basin	Bay Area	Other PG&E Local Areas	San Diego - IV	CAISO System (no Local Area)
Weighted Average Price ($/kW-month)	$ 3.55	$ 3.27	$ 2.79	$ 3.10	$ 4.39	$ 2.90
Average Price ($/kW-month)	$ 3.41	$ 3.57	$ 3.48	$ 2.93	$ 3.92	$ 2.74
Minimum Price ($/kW-month)	$ 0.08	$ 0.10	$ 0.18	$ 1.24	$ 0.09	$ 0.10
Maximum Price ($/kW-month)	$ 23.67	$ 24.26	$ 23.62	$ 8.62	$ 26.54	$ 18.99
85th percentile ($/kW-month)	$ 9.90	$ 8.58	$ 3.92	$ 3.25	$ 10.24	$ 4.79
Contracted Capacity (MW)	106,764	109,105	38,195	3,552	38,120	127,582
Percentage of Total Capacity in Data Set	25.2%	25.8%	9.0%	0.8%	9.0%	30.1%

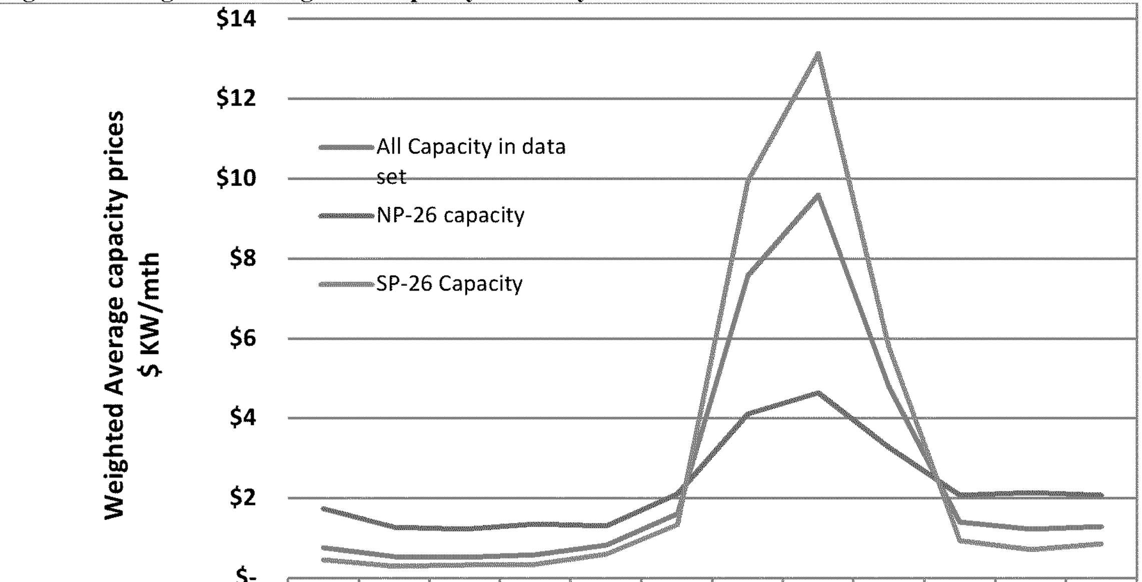
The monthly weighted average capacity prices shown in Table 13 below, illustrate that capacity prices are significantly higher from July through September; the 85th-percentile price in August is more than six times the 85th-percentile prices reported in the months of October through June. This is what we would expect to see, given the high demand in the summer months.

Table 13. System-wide RA Capacity Prices by Month, 2012-2016

	Weighted Average Price ($/kW-month)	Minimum Price ($/kW-month)	Maximum Price ($/kW-month)	85th Percentile ($/kW-month)	Contracted Capacity (MW)	Percentage of Total Capacity in Data Set
January	$ 0.76	$ 0.17	$ 6.43	$ 1.71	28,073	6.6%
February	$ 0.55	$ 0.08	$ 6.43	$ 1.20	29,149	6.9%
March	$ 0.53	$ 0.08	$ 6.43	$ 0.97	27,983	6.6%
April	$ 0.58	$ 0.08	$ 6.43	$ 0.97	29,151	6.9%
May	$ 0.83	$ 0.12	$ 6.43	$ 1.24	35,276	8.3%
June	$ 1.61	$ 0.31	$ 6.43	$ 2.00	39,710	9.4%
July	$ 7.58	$ 0.97	$ 19.77	$ 12.78	50,708	12.0%
August	$ 9.60	$ 0.97	$ 26.54	$ 17.15	52,354	12.4%
September	$ 4.80	$ 0.95	$ 11.10	$ 7.24	48,309	11.4%
October	$ 1.41	$ 0.19	$ 6.43	$ 2.67	31,068	7.3%
November	$ 1.23	$ 0.25	$ 6.43	$ 2.46	25,989	6.1%
December	$ 1.29	$ 0.33	$ 6.43	$ 2.46	25,549	6.0%

Figure 7 graphs the weighted average capacity prices by month and zone, revealing the large difference in prices for capacity in the north and in the south during summer months. The higher prices in the south may reflect lower supply levels, accompanied by higher demands during summer. They may also reflect the more constrained Local Capacity Areas in Southern California.

Figure 7. Weighted Average RA Capacity Prices by Month and Zone



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
All Capacity in data set	$0.76	$0.55	$0.53	$0.58	$0.83	$1.61	$7.58	$9.60	$4.80	$1.41	$1.23	$1.29
NP-26 capacity	$1.74	$1.28	$1.23	$1.35	$1.32	$2.11	$4.12	$4.64	$3.29	$2.08	$2.14	$2.08
SP-26 Capacity	$0.46	$0.30	$0.33	$0.34	$0.61	$1.34	$9.95	$13.1	$5.80	$0.93	$0.72	$0.87

Figure 8 graphs the contracted capacity by months and year. This chart does not include any RPS contracted capacity, utility owned generation, hydro facilities, or much of the capacity procured by ESPs and CCAs; thus Figure 8 is not totally inclusive. As expected, there is a downward trend in total capacity contracted each summer, for future years. Because there is more capacity contracted in each year for July-September, there is more contracted capacity overall in the nearer-term than in later years.

Figure 8. Contracted RA Capacity by Month, 2012- 2016

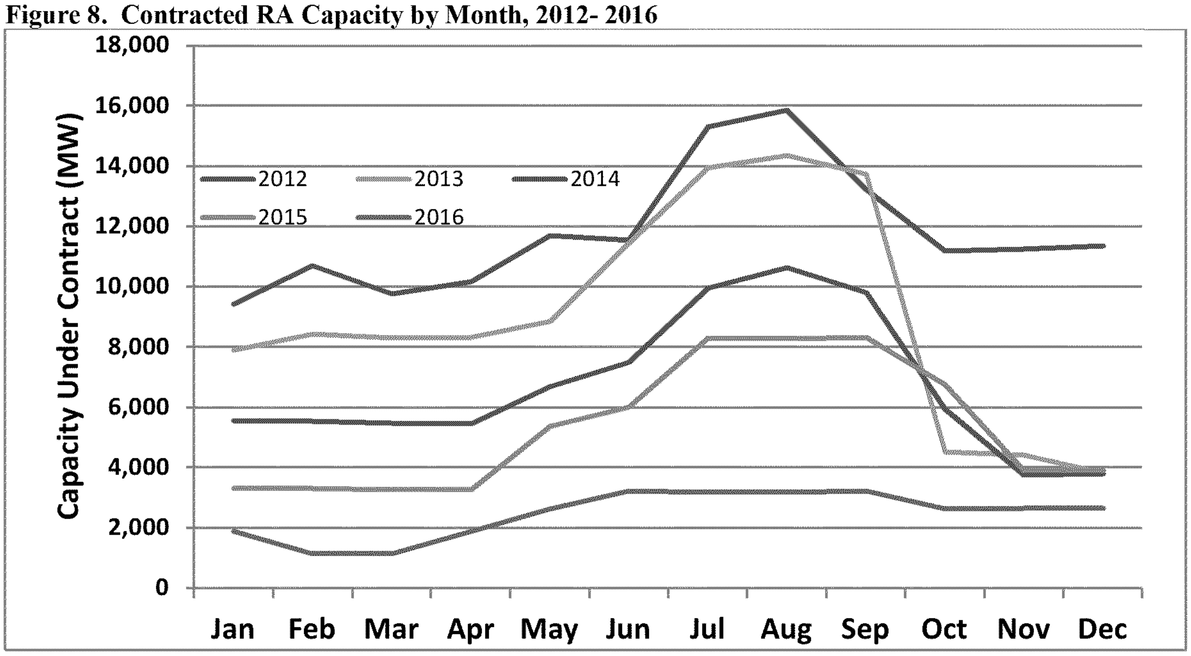


Figure 9. Weighted Average Capacity Prices by Month, 2012-2016

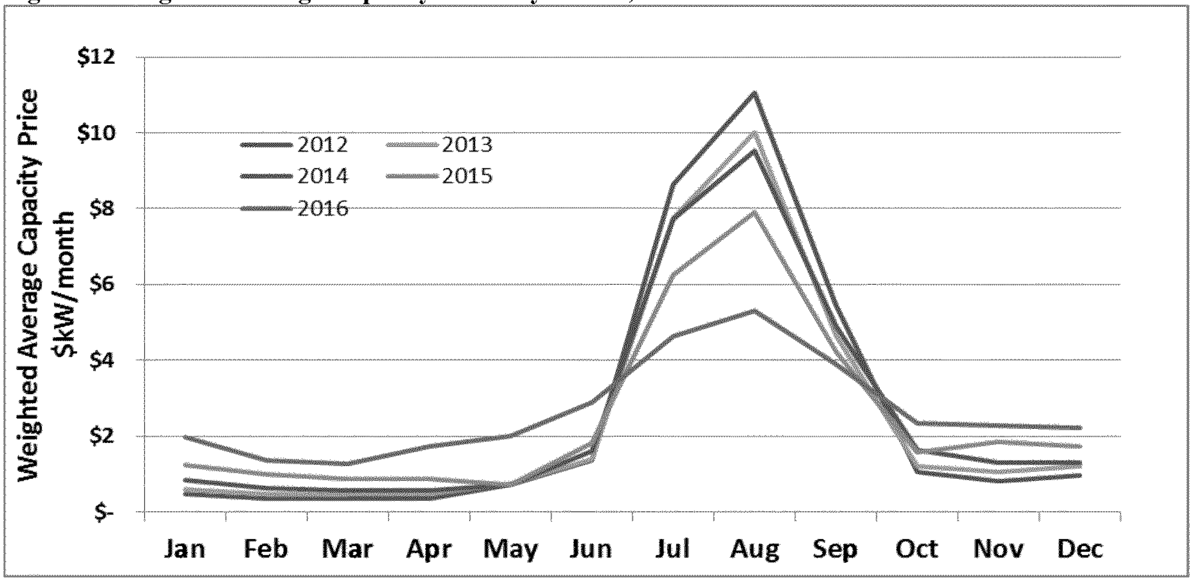


Figure 9 graphs the weighted average capacity prices by month and year. Prices are highest during the summer months for all years in the data set. The prices show a steady downward trend for June- September the farther out the contracted year is. However, in non-summer months we see the opposite trend; prices are *higher* the farther out the contracted year is.

6 Process for Determining the NQC of RA Resources

Qualifying Capacity (QC) represents the maximum capacity eligible to be counted for meeting the CPUC's RA Requirement prior to assessing the deliverability of the resource. The CPUC adopted the current QC counting conventions, which are computed based on the applicable resource type, in D.10-06-036.[34] The applicable data sets and data conventions are laid out in the adopted QC methodology manual, which is posted on the CPUC website.[35] For dispatchable resources, the QC is based on the most recent Pmax test. The Pmax test is kept in the ISO's master file. For wind, solar, and non-dispatchable resources, the QC methodology is based on a historical data calculation. The CPUC executes a subpoena for settlement quality meter data from the ISO and performs the QC calculations for non-dispatchable resources annually. After the QC values are determined, the CAISO conducts a deliverability assessment to produce the NQC value of each resource.

Deliverability is the ability of the output from generating resource to be delivered to an aggregate load. The difference between the QC and the NQC is the deliverability of the resource to aggregate California ISO load. When the QC for a resource exceeds the resources deliverable capacity, the NQC is adjusted to the deliverability capacity value. The CAISO conducts the deliverability assessment for both new and existing resources

[34] http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/119856.htm (QC manual adopted as Appendix B).
[35] http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_compliance_materials.htm

two to three times a year pursuant to the Large Generator Interconnection Procedures (LGIP). The ability of the output from a new or existing generation project to be delivered to aggregate load within CAISO is evaluated using the ISO's deliverability assessment methodology.[36] The August deliverability study is used to determine the annual NQC of a resource.

After the CAISO has completed the August deliverability study, a draft NQC list is posted and generators are typically given 3 weeks to file comments with the CAISO regarding the proposed NQC values. After the comment period, the values are updated, if needed, and a final NQC list is posted. Both the CPUC and the ISO publish a version of the list. The only difference between the two lists is NQC value requests from non-CPUC jurisdictional LSEs. The CPUC NCQ values on its list are used for RA compliance and represent the capacity that can be counted in RA compliance filings. Energy Division posts the final NQC list to the CPUC website prior to the year-ahead filing process.[37] This NQC list includes information on the Local Area, the Zonal Area, and the deliverability for each resource. Once posted, no changes are permitted to the list except to add new resources or correct clerical errors.

The total 2012 NQC (as reported on the CPUC 2012 NQC list) increased by 956.62 MW from the 2011 NQC list. The 2013 NQC list saw a large increase in the resources listed by the end of the year, as many new facilities became operational in 2013. While there have been some very significant retirements and additions this year, This decrease is attributable to retirements and changes in resource performance from one year to the next. For resources whose NQC is based on performance, such as wind and solar resources, each year new data replaces a portion of the old data, causing some year-to-year variation.

6.1 New Resources and Retirements in 2012

There were numerous additions to the overall fleet in 2012, as well as a few retirements,[38] after publishing the 2012 NQC list. It is worth noting that the San Onofre Nuclear Generating Station (SONGS) stopped generating in 2012 but did not actually retire until 2013, so it does not appear in the list of 2012 retirements. It is also worth noting that the Sunrise Powerlink became operational in 2012 adding to the south grid reliability and renewable resource additions. Overall in 2012 there was a net gain of 956.62 MWs of NQC after netting 1,124 MWs of online additions with 166.91MW of retirements.

[36] http://www.caiso.com/23d7/23d7e41c14580.pdf
[37] http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_compliance_materials.htm
[38] The 2012 compliance year NQC list is posted to the CPUC website: http://www.caiso.com/1796/179688b22c970.html

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Table 14. New Resources Online in 2012

Resource ID	Resource Name	Technology	NQC[39]
AGUCAL_5_SOLAR1	Agua Caliente Solar	Solar	25.17
ALTA3A_2_CPCE8	Alta Wind VIII	Wind	24.98
ALTA4B_2_CPCW6	Mustang Hills LLC	Wind	24.98
BLAST_1_WIND	Mountain View IV Project	Wind	8.16
BRDSLD_2_MTZUM2	Montezuma II Wind Project	Wind	13.02
BRDSLD_2_SHLO3B	Shiloh IV Wind Project	Wind	16.65
BRODIE_2_WIND	Coram Brodie Wind	Wind	16.98
BUCKWD_1NPALM1	North Palm Springs 1A	Solar	2.10
BUCKWIND_1_QF	Buckwind (QF conversion & repowering, capacity reduction)	Wind	2.75
CANTUA_1_SOLAR	Cantua Solar Station	Solar	16.78
COPMT2_2_SOLAR2	Copper Mountain Solar 2	Solar	28.52
DELAMO_2_SOLRC1	Golden Springs Building C1	Solar	0.98
DELAMO_2_SOLRD	Golden Springs Building D	Solar	1.17
DEVERS1_SEPV05	SEPV 5	Solar	1.68
ETIWIND_2_RTS018	SPVP018	Solar	1.26
GARNET_1_SOLAR	North Palm Springs 4A	Solar	3.46
GARNET_1_WINDS	Garnet Winds (QF conversion & repowering; aggregation of Triad, Carter, and Aldrich Wind Re-powering Projects)	Wind	3.75
GARNET_1_WT3WND	WKN Wagner	Wind	1.00
GIFFEN_6_SOLAR	Giffen Solar Station	Solar	8.39
HURON_1_SOLAR	Huron Solar Station	Solar	16.78
JAWBNE_2_NSRWND	North Sky River Wind Project	Wind	49.45
KELSO_2_UNITS	Mariposa	Simple Cycle	183.81
LAKHDG_6_UNIT2	Lake Hodges Pump Station Unit 2	Pumped Hydro	20.00
LITLRK_6_SEPV01	SEPV 1	Solar	1.68
LODIEC_2_PL1X2	Lodi Energy Center	CCGT[40]	280.00
MANZNA_2_WIND	Manzana Wind Project	Wind	31.47

[39] August NQC is reported for NQCs that vary by month. Solar NQC is calculated as 83.89% of nameplate capacity. Wind NQC is calculated as 16.65% of nameplate capacity. Other facilities' 2013 NQC values are shown, as detailed in http://www.cpuc.ca.gov/NR/rdonlyres/83CB4D22-B52A-4EE1-B499-2119B14FF2E1/0/CPUCFinalNetQualifyingCapacityList2013.xlsx. **[[Why are we discussing 2013? Also, I don't quite understand how these are distinguishable?]]**
[40] Combined Cycle Gas Turbine.

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Resource ID	Resource Name	Technology	NQC[39]
MNDALY_6_MCGRTH	McGrath Peaker	Peaker	47.13
OAKL_1_GTG1	EBMUD Wastewater Treatment GT Expansion	Gas Turbine	0.66
OLINDA_2_LNDFL2	Brea Power II	CCGT	28.10
PANSEA_1_PANARO	Mesa Wind (QF conversion; came out of DEVERS_1_QF aggregate)	Wind	5.00
RENWD_1_QF	Renwind (QF conversion & repowering, capacity resulting)	Wind	1.75
ROSMDW_2_WIND1	Pacific Wind, LLC Phase 1	Wind	23.31
SANWD_1_QF	Whitewater Wind (QF conversion; came out of DEVERS_1_QF aggregate)	Wind	5.00
SBERDO_2_RTS005	SPVP005	Solar	2.1
SBERDO_2_RTS007	SPVP007	Solar	2.1
SCHLTE_1_PL1X3	GWF Tracy Expansion	CCGT	327.70
TANHIL_6_SOLART	Berry Petroleum Cogen 18 Aggregate	CHP	10.35
TWISSL_6_SOLAR	Nickel 1 Solar	Solar	1.26
USWNDR_2_SMUD2	Solano Wind Phase 3	Wind	21.23
USWPJR_2_UNITS	Green Ridge Power (Jackson) (QF conversion & repowering)	Wind	13.02
VESTAL_2_RTS042	SPVP042	Solar	4.19
WFRESN_1_SOLAR	Joya Del Sol	Solar	1.26
Total			**1123.53**

Resources that Retired in 2012

Resource Name	Resource ID	Technology	NQC
Tracy Unit 1 Peaking Project	SCHLTE_1_UNITA1	Gas Peaker	83.56
Tracy Unit 2 Peaking Project	SCHLTE_1_UNITA2	Gas Peaker	82.88
San Marcos Landfill Bio-Gas	SMRCOS_6_LNDFIL	Biogas	0.47
Total			**166.91**

Source: 2012 and 2013 NQC lists posted to the CAISO website[41]

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, can be found on the CEC website.[42]

6.2 Aggregate NQC Values 2006 through 2012

Table 15 shows aggregate NQC values from the CAISO NQC list for 2006 through 2012. While many large resources have become available over the previous few years, the total NQC has not grown accordingly, partially due to resources retiring and the effect of new CPUC QC counting conventions that decrease the NQC of many intermittent resources. This change is in part attributable the gradual increase in the number of resources that receive a monthly NQC value instead of an annual value. In addition to those resources that now receive a monthly value pursuant to changes in QC counting conventions adopted by the Commission (most notably, cogeneration and hydro resources are now provided monthly values), several larger thermal resources have begun to voluntarily supply information to support monthly NQC values in light of performance due to differing ambient weather conditions. Accounting for decreases in performance at higher temperatures can result in lower August NQC values, and thus a decrease in the aggregate reported NQC over time. For those facilities that were given monthly NQC values, this table shows August NQC values.

Table 15. NQC for 2006 – 2012

Year	Total NQC (MW)	Total Number of Scheduling Resource IDs	Net NQC Change (MW)	Net Gain in CAISO IDs on List
2006	46,687	563		
2007	46,504	572	(183)	9
2008	48,056	600	1,552	30
2009	48,899	613	843	13

[41] http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx and http://www.caiso.com/planning/Pages/ReliabilityRequirements/ReliabilityRequirementsArchive.aspx
[42] http://www.energy.ca.gov/sitingcases/all_projects.html

2010	51,790	646	2,891	33
2011	51,895	649	105	3
2012	50,173	667	(453)	18

Source: NQC lists from 2006 through 2012

7 Allocation of Import Capacity for RA

The CAISO allocates available import capacity to CPUC-jurisdictional and non-CPUC jurisdictional LSEs annually to ensure that California is not relying on more imports than could be accommodated by the current transmission system. The CPUC worked closely with the CAISO on the development of this process for use in the CPUC RA program. The CAISO has a 13 step process in the CAISO tariff to perform this allocation.[43] The steps of the process are summarized in the CPUC RA Guide for 2012 and the results of selected steps are summarized in Table 16.

Table 16. 2012 Import Allocation Process

Selected Results of Allocation Process	MW
Step 1: **Maximum Imports for 2012 compliance year Step 1**	15,819
Total ETC for outside the control area loads	3,384
Available Import Capability (for loads in the control area) Step 2	12,436
Existing Contract Import Capability (ETC inside loads)	2,342
Total Pre-RA Import Commitments Step 3	5,399
Total Pre-RA Import Commitments & ETC Step 4a	6,994
Remaining Import Capability after Step 4	5,442
Assigned Remaining Import Capability	4,551
Remaining Import Capability after Step 10	891
Assigned Remaining Import Capability	375
Remaining Import Capability after Step 12	516
Remaining Import Capability after Step 13 (Aug 2011)	486

Source: Aggregate CAISO import allocations posted at
http://www.caiso.com/Documents/2012Assigned_UnassignedRAImportCapability_BranchGroups-AfterStep6.pdf

Over the course of the summer of 2012, the CAISO allocated 12,436 MW out of 15,819 MW of import capacity to LSEs, and 3,384 MW to Existing Transmission Contracts (ETCs) outside the CAISO control area. Table 17 below summarizes 2012 Import Allocations and the use of Import Allocations in RA filings. The CPUC jurisdictional LSEs in CAISO territory reported between zero and 6,145 MW of total imports. CPUC jurisdictional LSEs used between nine and 56 percent of their monthly import allocations during the summer of 2012. The NA's below are values that were shown to the CAISO by municipals and other non-CPUC jurisdictional LSEs. Imports represented between 3 and 12 percent of monthly RA capacity during the summer months.[44] This percent would be higher if we had obtained the non-CPUC jurisdictional information.

[43] CAISO tariff section 40.5.2.2.
[44] Appendix A

Table 17. 2012 Import Allocations and Usage (MW)

Element	May	June	July	August	September
Import Allocations provided to LSEs for use in RA filings (Step 2)	12,436	12,436	12,436	12,436	12,436
Imports shown by CPUC jurisdictional LSEs	1,165	2,365	6,145	6,932	4,036
Imports shown by non-CPUC jurisdictional LSEs	NA	NA	NA	NA	NA
Total Imports shown	1,165	2,365	6,145	6,932	4,036
Allocations not used in RA Filings:	11,271	10,071	6,291	5,504	8,400
Percentage used of allocated (line 4/Line 1)	9%	19%	49%	56%	32%

Source: Import Allocation information posted on the CAISO website as well as aggregate RA filing information

8 Compliance with RAR

CPUC staff continued the implementation of the RA program during 2012 and built on experience from past years.

8.1 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 in July 2011 to discuss general compliance rules as well as to highlight changes in procedures and filing rules new to the 2012 compliance year. During the workshop, Energy Division reviewed the process of filling out the compliance templates and provided suggestions to help avoid errors that could lead to non-compliance. The templates also include detailed instructions tabs. The workshop, RA guide, and templates are all designed to assist LSEs in showing compliance with the RA program and to clarify any confusion that could lead to errors leading to non-compliance.

The final 2012 filing guide and templates were made available to LSEs in August 2011. The 2012 System and Local RA filing templates and guides were very similar to those used in 2011. Slight changes were made to implement the new RA rules adopted in D.11-10-023. As in previous years, the CPUC required that all filings be submitted simultaneously to the CAISO and CEC.

8.2 Compliance Review

CPUC staff, in coordination with the CEC and CAISO, reviewed all compliance filings received to date in accordance with comprehensive procedures that include: verifying timely arrival of the filings, matching resources listed against those of the NQC list, confirming compliance with Local 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 generators; the CAISO then helps Energy Division match these supply plans to the LSE filings. Energy Division verifies compliance, approves filings, and sends an approval letter to each LSE.

In 2011 and 2012, CPUC staff continued to work closely with LSEs to resolve any questions regarding the RA filing process and templates. CPUC staff answered numerous questions raised by LSEs with special or unique circumstances. CPUC staff expects that working with the LSEs to reconcile differences and make revisions will continue to lead to fewer questions in the future and make the RA filing process smoother. Due to the administrative obligations of the RA Program, Energy Division staff attempts to continually simplify and streamline filing procedures including, for example, removal of the preliminary local filing requirement.

8.3 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 complete backstop procurement if necessary creates a need for filings to arrive on time and be accurate. Non-compliance occurs if an LSE files with a procurement deficiency (i.e., it did not 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. Although the CAISO has not yet needed to engage in backstop procurement for CPUC-jurisdictional LSE procurement deficiencies, this could occur if compliance is not strictly enforced.

8.3.1 Enforcement Actions in the 2006 through 2012 Compliance Years

Pursuant to Commission Resolution E-4195[45] and D.11-06-022, Energy Division refers potential violations to the CPUC's Safety and Enforcement Division (SED), which pursues enforcement cases related to the RA program on behalf of the Commission.

Table 18 summarizes enforcement actions and citations taken by the Commission since the inception of the RA program in 2006. From 2006 through 2012, the Commission issued 26 citations for violations and initiated 4 enforcement cases, collecting $97,100 and $847,500 respectively from LSEs. In 2012, the Commission issued two citations and took one enforcement action, ultimately collecting $14,600 and $215,000 respectively from LSEs.

An enforcement action taken against Constellation New Energy in 2007 for failure to comply with the 2007 Year-Ahead Local RA obligation was settled in Resolution L-350 for $107,500. In 2008, the Commission took enforcement action against Calpine Power America-CA, LLC related to the 2008 System and Local RA filings and subsequently settled for $225,000 in I.09-01-017. In 2009 a Commission enforcement action against Constellation New Energy for under procurement related to 2009 compliance year filings reached a settlement for $300,000 in I.10-04-010 in March 2010. The 2011 Commission

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

enforcement case against PG&E for failure to comply with the month-ahead RA obligations reached a settlement of $215,000 in D.12-02-030 in OII.11-0-011.

Table 18. Enforcement Summary Pursuant to the RA Program Since 2006

Compliance Year	Citations Issued	LSEs Cited	Citation Penalties	Enforcement Cases	Enforcement Penalties
2006	1	Commerce Energy	$1,500	0	0
2007	3	3Phases; Commerce Energy; Amer. Util. Network	$5,000	1	$107,500
2008	7	3Phases (2); Commerce Energy (2); Corona DWP; Sempra Energy; Shell Energy	$17,000	1	$225,000
2009	4	Commerce Energy (3); CNE	$26,500	1	$300,000
2010	5	Commerce Energy; Pilot Power (2); Dir. Energy Bus.; SDG&E	$25,500	0	0
2011	2	Liberty Power; Tiger Nat Gas	$7,000	1	$215,000
2012	4	Glacial Energy of CA, Shell Energy, SDG&E, Direct Energy Business	$14,600	0	
Total	**26**		**$97,100**	**4**	**$847,500**

Source: CPUC enforcement records.

In 2012 there was an increase in minor errors leading to citations. Errors are largely due to the outage counting protocol, load migration and mismatches in supply plans. There is also the continued need to monitor administrative issues such as filing dates and filing procedures.

9 Generator Performance and Availability

To facilitate and ensure that generators perform in accordance with their RA capacity contracts, and are available as per agreement, the CAISO introduced Standard Capacity Product (SCP) provisions in 2010. The SCP provisions monitor and penalize generators' Scheduling Coordinators (SCs) based on performance and availability. SCP penalties apply to generation confirmed as an RA resource for the month, whether or not it is located within CAISO territory. SCP reporting information is posted to the CAISO website.[46]

To better understand and benchmark power plant performance, availability, and reliability, the North American Electric Reliability Corporation (NERC) also tracks, records, and measures generator performance data via the Generator Availability Data System (GADS) application. In 2011, GADS reporting became mandatory and electronic filing procedures were developed. General Order 167 requires large generating facilities

[46] SCP tariff and implementation information posted to the CAISO website at http://www.caiso.com/1796/179688b22c970.html#2406b60b7570

in California to submit data to GADS, and a process is underway at NERC to extend this mandatory reporting requirement to smaller generators.

9.1 Performance and Availability for RA Resources in CAISO

On January 1, 2010, the CAISO implemented newly developed Standard Capacity Product (SCP) provisions for all conventional resources. These provisions:

1.) Establish a standard product definition for Resource Adequacy (RA) capacity, to facilitate selling, buying, and trading capacity to meet RA requirements;

2.) Create a standard method to incent high performance from RA resources using performance incentives and non-availability charges;

3.) Create a Must Offer Obligation (MOO) for Ancillary Services (A/S) for all certified products on RA resources subject to an energy MOO;

4.) Create an annual process to review prequalification requests for units to be used in Real-Time Market (RTM) Pre-approved Unit Substitution Process; and

5.) Create a process to review requests for unit substitution that are not prequalified in the annual process

For 2010 certain resources were exempt from SCP; these included DR and resources with QC values based on historical values. Beginning in 2011, resources with QC values based on historical values were added to SCP provisions, while DR remained exempt. Currently, DR resources continue to remain exempt.

The monitoring of the SCP entails a monthly review by the CAISO of all RA resources to determine whether the resource's monthly availability met the monthly availability standard. When an RA resource's availability exceeds the monthly availability standard by 2.5% or more, the resource becomes eligible for an availability incentive payment. When an RA resource's availability falls to 2.5% below the monthly availability standard, the resource becomes subject to a non-availability charge.[47] To maintain a revenue-neutral program, the performance payments for a particular month are drawn from the pool of performance penalties paid for the same month.

The CAISO calculates the monthly availability standard using the historical forced outages of RA resources over the range of availability assessment hours for each month of the year for the past three years. The CAISO publishes these values annually on about July 1st, to be used for the coming compliance year.[48]

The CAISO calculates individual resource availability by summing the total RA capacity reported as available in SLIC for each availability assessment hour of the month, and dividing that value by the product of the facility's NQC and the number of availability

[47] CAISO posts SCP information to the CAISO website here: http://www.caiso.com/Documents/2012MonthlyResourceAdequacyAvailabilityStandards.pdf

[48] Ibid

assessment hours in the month. A resource is considered 100% available if the resource has no forced outages or temperature related ambient derates that reduce the available RA capacity during the availability assessment hours.

In contrast, non-resource specific (NRS) System Resource availability (intertie availability) is not based on outages in SLIC. The availability of a NRS System Resource is measured by its hourly offers (e.g. Economic Bids or Self-Schedules) to provide energy, per CAISO Tariff Section 40.9.7.2, *Availability Calculation for Non-Resource-Specific System Resources Providing Resource Adequacy Capacity*.

Table 19 below presents SCP data[49] for the period from January to December 2012. This data includes: availability standards, charges, incentive payments, and performance. The table shows that in 2012 on average 24,906 MW[50] of RA capacity from generators and 1,153 MW[51] of RA capacity from interties were subject to SCP rules. The monthly availability standards ranged from 94 percent to 97.8 percent during 2012; actual availability of generators averaged 96.4 percent, while intertie resources had an average actual availability of 99.6 percent.

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[49] Data in Table 15 does not reflect adjustments made after publication on the ISO website.

[50] This does not include RA capacity that is grandfathered in because it predates the implementation of SCP availability standards.

[51] *Ibid.*

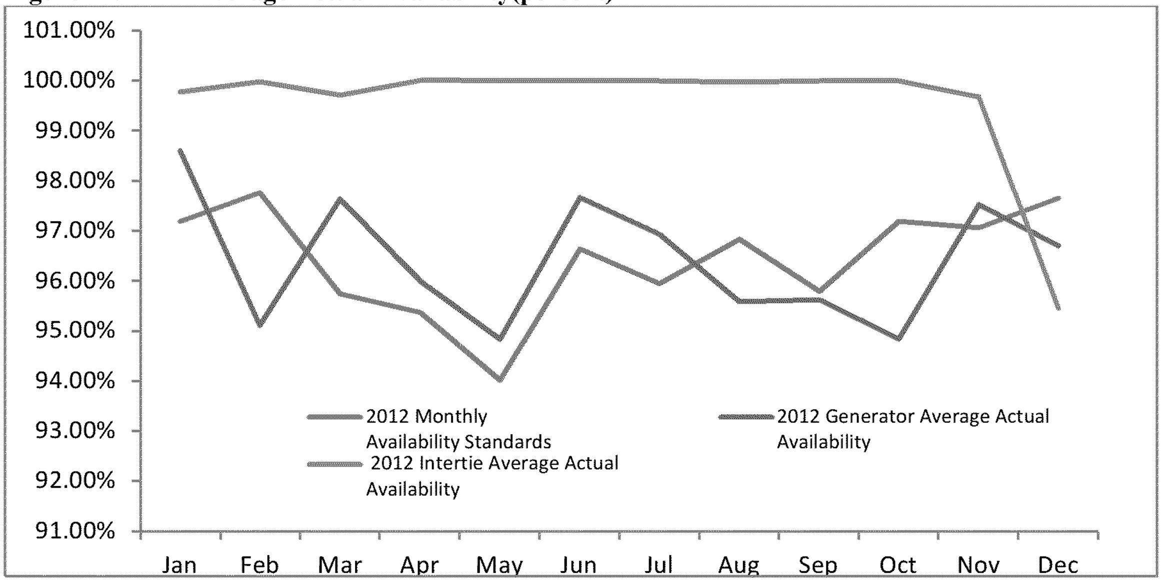
Table 19. 2012 RA Availability and SCP Payments

	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Monthly Availability Standards	GENERATOR	97.20%	97.76%	95.74%	95.38%	94.03%	96.64%	95.96%	96.83%	95.80%	97.20%	97.07%	97.65%
	INTERTIE	97.20%	97.76%	95.74%	95.38%	94.03%	96.64%	95.96%	96.83%	95.80%	97.20%	97.07%	97.65%
Non-Availability Charges	GENERATOR	$484,068	$4,470,627	$1,842,078	$2,841,563	$4,273,631	$2,586,646	$3,009,920	$4,721,653	$4,813,277	$4,961,694	$1,536,027	$2,069,665
	INTERTIE	$ -	$ -	$4,181	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$16,529	$281,250
Availability Incentive Payments	GENERATOR	$484,068	$ -	$1,842,078	$2,841,563	$4,273,631	$2,586,646	$3,009,920	$1,969,619	$4,813,277	$655,398	$1,082,038	$ -
	INTERTIE	$ -	$ -	$4,181	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$16,529	$ -
Monthly Surplus	GENERATOR	$ -	$4,470,627	$ -	$ -	$ -	$ -	$ -	$2,752,034	$ -	$4,306,296	$453,988	$2,069,665
	INTERTIE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$281,250
Average Actual Availability (%)	GENERATOR	98.59%	95.13%	97.63%	96.01%	94.84%	97.66%	96.93%	95.60%	95.63%	94.86%	97.52%	96.70%
	INTERTIE	99.78%	99.98%	99.71%	100.00%	100.00%	100.00%	100.00%	99.98%	100.00%	100.00%	99.68%	95.46%
Average RA Capacity (MW)	GENERATOR	21,331	20,891	20,836	21,358	24,447	27,443	30,129	30,915	29,086	25,052	24,189	23,192
	INTERTIE	344	342	481	384	458	458	3,157	3,713	1,412	936	1,050	1,101

Source: CAISO 2012 Standard Capacity Product Report,
http://www.caiso.com/Documents/2012StandardCapacityProductAnnualReport.pdf

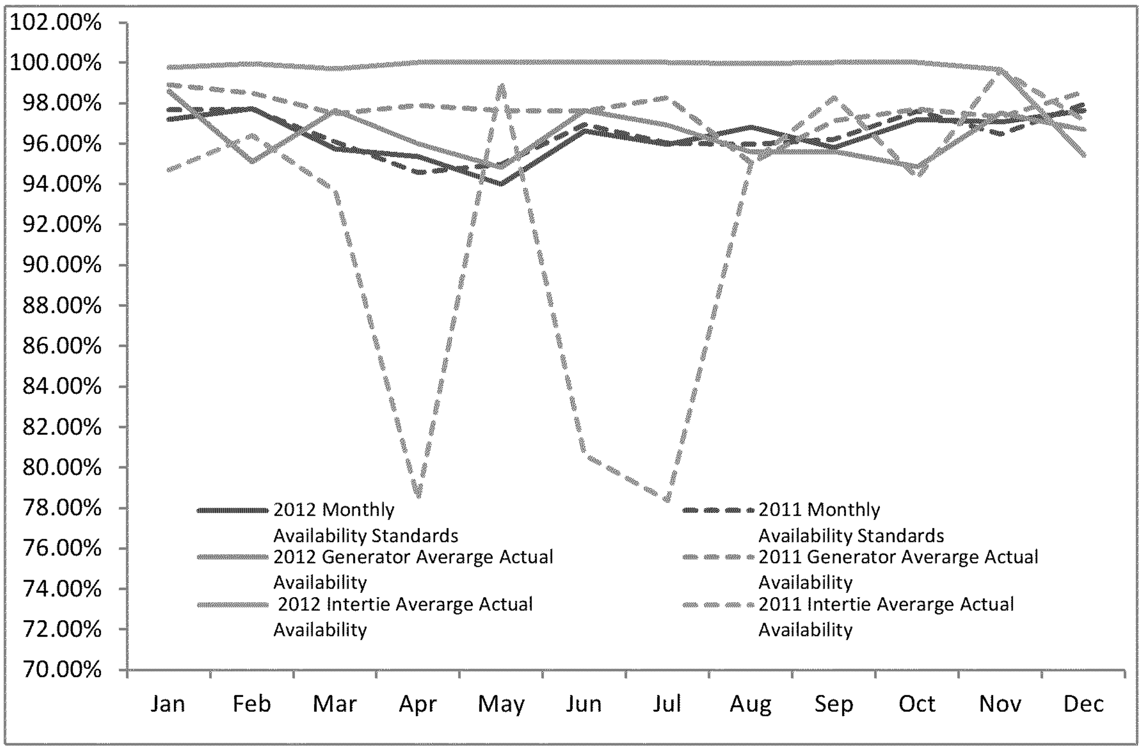
Figure 10 illustrates the monthly availability standards and the average actual availability of both generators and interties in 2012, as shown in Table 19. Interties show a lower average actual availability than the monthly availability standard for only one month of 2012. For five of the months they show 100% actual availability, which means RA intertie capacity had no forced outages or temperature-related ambient derates that impacted the committed RA capacity during the availability assessment hours. This is a considerable improvement from 2011, where interties showed lower average monthly actuals than their availability standards for nine of the 12 months. This improvement is reflected in Figure 10, which compares the 2011 SCP report values to the 2012 SCP values. The opposite trend occurs for generators. In 2012, generators showed a slightly lower monthly average actual availability than their monthly availability standard for six of twelve months, whereas in 2011 this was the case for only one of 12 months.

Figure 10. 2012 Average Actual Availability(percent)



Source: 2012 Standard Capacity Product Report - http://www.caiso.com/Documents/2012StandardCapacityProductAnnualReport.pdf

Figure 11. 2011 v. 2012 Average Actual Availability



Source: CAISO 2011 and 2012 Standard Capacity Product Report - http://www.caiso.com/Documents/2012StandardCapacityProductAnnualReport.pdf

Appendix 1 - Total CAISO LSE Procurement as a Percentage of Total Obligation

Table 20. Total LSE (CPUC-Jurisdictional and Non-Jurisdictional) Procurement as a Percentage of Total Obligation (MW)

2012	Type of LSE	Peak Demand Forecast	Forward Commitment Obligation	Physical Resources in ISO Control Area	DWR Contracts	Total Imports	Dispatchable DR and Participating Load + PRM	Liquidated Damages Contracts	CAM & RMR	Total RA Capacity	RA Capacity/ Obligation
May	CPUC LSEs	33,843	38,919	34,607	298	1,165	2,070	-	1,274	39,414	101.3%
	Non-CPUC LSEs	2,528	2,881	2,629		NA	18	425	14	3,087	107.1%
	Total RA capacity	36,371	41,801	37,236	298	1,165	2,089	425	1,288	42,501	101.7%
	% of Total Capacity			88%	1%	3%	5%	1%	3%	100%	
Jun	CPUC LSEs	38,632	44,427	38,038	595	2,365	2,745	-	1,274	45,018	101.3%
	Non-CPUC LSEs	3,027	3,450	3,157		NA	18	511	14	3,701	107.3%
	Total RA capacity	41,659	47,877	41,195	595	2,365	2,763	511	1,288	48,719	101.8%
	% of Total Capacity			85%	1%	5%	6%	1%	3%	100%	
Jul	CPUC LSEs	42,491	48,865	38,162	-	6,145	3,055	-	2,020	49,384	101.1%
	Non-CPUC LSEs	3,592	4,111	3,642		NA	18	615	14	4,290	104.4%
	Total RA capacity	46,083	52,975	41,804	-	6,145	3,074	615	2,034	53,673	101.3%
	% of Total capacity			78%	0%	11%	6%	1%	4%	100%	
Aug	CPUC LSEs	44,544	51,226	39,165		6,932	2,987		2,513	51,597	131.7%
	Non-CPUC LSEs	3,531	4,041	3,593		NA	18	581	14	4,206	104.1%
	Total RA capacity	48,075	55,267	42,758	-	6,932	3,006	581	2,527	55,803	101.0%
	% of Total Capacity			77%	0%	12%	5%	1%	5%	100%	
Sep	CPUC LSEs	40,151	46,174	36,976	-	4,036	2,951	-	2,491	46,455	100.6%
	Non-CPUC LSEs	3,282	3,759	3,440		NA	18	534	14	4,006	106.6%
	Total RA capacity	43,434	49,933	40,417	-	4,036	2,970	534	2,505	50,461	101.1%
	% of Total Capacity			80%	0%	8%	6%	1%	5%	100%	

Source: Aggregated RA data collected by the CPUC along with Non-CPUC jurisdictional data from the CAISO