California Public Utilities Commission

The 2013 – 2014 Resource Adequacy Report

ENERGY DIVISION

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2013 & 2014 Resource Adequacy Report

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Table of Acronyms

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

2013 & 2014 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 15% 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 2013 and 2014 RA compliance years. While this report does not make explicit policy recommendations, it is intended to provide information relevant to the currently open RA rulemaking (R.14-10-010) 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 that they have procured 90% of their System RA obligation for the five summer months. For the Local showing, LSEs are required to demonstrate that 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 2013 and 2014, the RA program successfully provided sufficient resources to meet peak load. 2013 peak demand (for CPUC jurisdictional LSEs) was forecasted to occur in August 2013 at 44,738 MW.[2] The forward procurement obligation/RA obligation to meet peak demand in August totaled 51,449 MW[3] and LSEs collectively procured 53,395 MW[4] to meet expected system needs (which included a 15% reserve margin). Actual peak load for 2013 (for CPUC and non-CPUC jurisdictional LSEs) occurred on July 1 at 48,478 MW.

In 2014, peak demand (for CPUC jurisdictional LSEs) was forecasted to occur in August at 49,791 MW.[5] The forward procurement obligation/RA obligation to meet peak demand in August totaled 52,659 MW and LSEs collectively procured 52,740 MW to meet expected system need (which included a 15% reserve margin). Actual peak load for 2014 (for CPUC and non-CPUC jurisdictional LSEs) occurred on September 16 at 44,994 MW.

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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 3.

3 Ibid.

4 Ibid.

[5] See Figure 4.

CPUC jurisdictional LSEs fulfilled their Local RA obligations during the 2013 and 2014 compliance years. 2013 Local RA procurement obligations for CPUC-jurisdictional LSEs totaled 23,021 MW; these obligations were met with a monthly minimum of 26,728 MW. In 2014, Local RA procurement obligations for CPUC-jurisdictional LSEs totaled 24,029 MW; these obligations were met with a monthly minimum of 26,728 MW. The Local obligations were met with Physical resources, Cost Allocation Mechanism (CAM) resources, Reliability Must-Run (RMR) resources and Demand Response (DR) resources.[6]

A key to establishing accurate RA procurement targets is the review of LSE demand forecasts. The California Energy Commission (CEC) assesses the reasonableness of LSE demand forecasts and makes monthly plausibility adjustments.[7] In 2013 and 2014, the CEC made positive plausibility adjustments for all months of the year, except September 2013 and August 2013 and 2014. For 2013 and 2014, the monthly plausibility adjustments as a percentage of the month's aggregated year-ahead forecast ranged from -2.2% to 0.6% and -0.3% to 0.3%.[8]

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 with costs passed through to customers through distribution charges. In 2013, CAM, RMR and DR procurement comprised 14.4% of the overall RA requirement. In 2014, this number increased to 15.4%. In general, overall CAM procurement has continued to increase since 2011 whereas the RMR procurement declined to one resource in 2011 and has remained there since. DR procurement remained relatively stable from 2011 to 2014.[9]

In late 2014, Energy Division staff issued a data request to all CPUC jurisdictional LSEs requesting monthly capacity prices paid by (or to) LSEs for every RA capacity contract covering the 2013 – 2017 compliance years. A total of 3,556 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 dataset is $3.23 kW-month.[10] The weighted average capacity price for capacity South of Path 26 is about 35% higher than the weighted average capacity price of North of Path 26 capacity. As expected, capacity prices are highest during the months of July through September and in the following locally constrained areas: San Diego, LA Basin, and Big Creek-Ventura. The price of capacity varies significantly between month, local area, and zone.

[6] See Table 8 and Table 9

[7] To correct LSE estimations of customer retention, the CEC prepares a plausibility adjustment that estimates customer retention by certain LSEs.

[8] See Table 3

[9] See Figure 11

[10] See Table 11

In 2013, 4,705 MW of new generation came online, and in 2014 an additional 2,152 MW came online. These new generation resources include both conventional and renewable generation. The new conventional resources included Wellhead Delano, Walnut Creek, El Segundo, Sentinel, Marsh Landing , and Russell City.[11] Notable renewable resources that came online include Genesis, Ivanpah, and Mojave solar thermal generators and Ocotillo and Alta wind resources. New solar PV resources included California Valley, AV Solar Ranch, Desert Sunlight, Solar Star and Topaz. Overall, 2014 set a record for the highest amount of renewables coming online. In addition, 3,414 MW of generation, including the San Onofre Nuclear Generator, retired in 2013 resulting in an incremental increase of 1,290 MW of Net Qualifying Capacity (NQC). In 2014, 883 MW of generation retired for a net increase of 1,269 MW of NQC.

Because the RA program requires LSEs to acquire capacity to meet load and reserve requirements, when LSEs do not fully comply with RA program rules,[12] the Commission issues citations or starts enforcement actions. In total, the Commission issued four citations for violations related to compliance year 2013-2014 and collected $14,600 in payments from LSEs from these citations.

[11] See Table 19 and Table 20

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

2 Changes to the RA Program for 2013-2014

Decisions (D.)12-06-025 and 13-06-024 adopted several new rules for the 2013 and 2014 compliance years, including the following:

- The coincidence adjustment factor used in determining a load serving entity's RA requirement was modified to an LSE-specific coincidence adjustment factor for annual resource adequacy requirements, and an energy service provider-composite coincidence factor for monthly resource adequacy requirements, as follows:

  - Annual Resource Adequacy Requirements – The California Energy Commission will calculate a Load Serving Entity-specific coincidence adjustment factor using Load Serving Entity hourly loads; and
  - Monthly Resource Adequacy Requirements – The California Energy Commission will calculate an Electric Service Provider-composite coincidence factor, which would be applied to each Electric Service Provider's migrating load for the month; migrating load for community choice aggregators would be treated separately.

- Dynamically scheduled resources and pseudo tie resources are now treated as if they were internal California Independent System Operator resources.

- All non-unit specific DWR contract have expired. DWR contracts are no longer used to meet RA requirements.

- The CPUC's scheduled outage replacement rule is no longer in effect starting in 2013. This rule has been replaced by the CAISO's scheduled replacement rule which became effective January 1, 2013.

- Rounding conventions were changed in the 2013 RA decision to be rounded to the 0.1 MWs for resource adequacy compliance instead of the whole MW. The 2014 RA decision reverted back to the whole MW rounding convention.

- Beginning in 2013, Load Serving Entities can count resources under construction toward meeting their year-ahead local RA obligations by specifying the replacement capacity for the resource under construction in the month-ahead RA filings.

- D.13-06-024 adopted an Interim Flexible Capacity Framework, as shown in Appendix A of that decision, for the 2014 RA compliance year. D.13-06-024 also adopted annual and monthly Flexible RA Targets (non-mandatory) for 2014.

- D.13-02-006 changed the RA filing calendar timeline from 30 days prior to the beginning of the month to 45 days prior to beginning of compliance month. The purpose of this timeline change was to align the CPUC's RA filing process with the CAISO's scheduled outage replacement rule. Beginning with the May month-ahead 2013 RA filing, LSEs are now required to submit their RA filings and RA forecasts 45 days prior to the RA compliance month.

- A new Maximum Cumulative Capacity (MCC) bucket has been created for DR resources, and the percentages used for MCC buckets has been updated to reflect a more current load shape. These updates have been implemented through the Energy Division's Resource Adequacy template. The buckets and their percentage limits are currently defined in the RA guide as follows:

Summary of Resource Categories

Category	Resources may be categorized into one of the five categories shown below, according to their planned availability as expressed in hours available to run or operate per month (hours/month):
DR	Demand Response resources available for "Greater than or equal to" 24 hours per month.
1	"Greater than or equal to" the ULR [Use Limited Resource] monthly hours as shown in the Phase 1 Workshop Report, Table "Number Hours ISO Load Greater than 90% of the Monthly Peak," p.24-25, last line of table, titled "RA Obligation," http://www.cpuc.ca.gov/word_pdf/REPORT/37456.pdf These ULR hours for May through September are, respectively: 30, 40, 40, 60, and 40, which total 210 hour and have been referred to as "the 210 hours."
2	"Greater than or equal to" 160 hours per month.
3	"Greater than or equal to" 384 hours per month.
4	All Hours (planned availability is unrestricted)

3 Load Forecast and Resource Adequacy Program Requirements

The RA program requires its jurisdictional LSEs to demonstrate through monthly and annual compliance filings that they have sufficient capacity commitments to satisfy demand at all times to ensure system reliability.

Monthly and annual system RA requirements are based on load forecast data filed annually by each LSE and adjusted by the CEC. The adopted forecast methodology is known as the "best estimate approach" and requires jurisdictional and non-jurisdictional LSEs to submit, on an annual basis, historical hourly peak load data for the preceding year and monthly energy and peak demand forecasts for the coming compliance year that are based on reasonable assumptions for load growth and customer retention. Following this annual LSE submission, the CEC makes a series of adjustments to the LSE submitted load forecasts which form the final load forecast used for year-ahead RA compliance. This process also requires LSEs to submit monthly load forecasts to the CEC that account for load migration throughout the compliance year.

In order to establish the year-ahead load forecast used to set RA requirements, the CEC first calculates each LSE's specific monthly coincident factors[13] using historic hourly load data (filed by the 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 are used to make each LSE's peak load forecast reflective of the LSE's contribution to load at the time of CAISO's peak load. The CEC then reconciles the aggregate of the jurisdictional LSEs' monthly peak load forecasts against the CEC's monthly 1-in-2, short-term, weather normalized peak-load forecast, for each IOU service area. This is done to evaluate the reasonableness of the LSEs' forecasts. As a part of the reconciliation, the CEC may adjust individual IOU service area forecasts, if the aggregate LSE forecasts are significantly inconsistent with CEC's forecasts for reasons other than load migration. The CEC also compares individual LSE forecasts to current peak demand estimates, (i.e., August month ahead forecast) and adjusts them if the difference is greater than a tolerance threshold.

Additionally, as specified in D.05-10-042, adjustments are made by the CEC to account for the impact of energy efficiency (EE), distributed generation (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. In the event that total LSEs forecasts are more than 1% divergent from the CEC's monthly weather normalized forecasts, a pro rata adjustment is made to bring it back within 1%.

The aggregated LSE forecasts are used by the CEC to create monthly load shares for each TAC area, which are then used to allocate DR, CAM, and RMR RA credits. Flexible RA targets for 2014 were calculated allocated to LSEs using 12 monthly load ratio shares. Local obligations are calculated using the load shares for August of the coming compliance year. The forecasts and the allocations together determine the System annual and monthly RA obligations.

[13] Adopted in D.12-06-025.

3.1 Yearly and Monthly Load Forecast Process

Starting in 2012, LSEs have been able to revise their April annual load forecast for load migration. The 2013 and 2014 revised annual forecasts were due on August 17, 2012 and August 19, 2013. 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 used for the 2013 process:

LSEs file historical load information	**Mar 16, 2012**
LSEs file 2013 Year-Ahead load forecast	**Apr 20, 2012**
LSEs receive 2013 Year-Ahead RA obligations	**Jul 31, 2012**
Final date to file revised forecasts for 2013	**Aug 17, 2012**
LSEs receive revised 2013 RA obligations	**Sep 17, 2012**

The following timeline was used for the 2014 process:

LSEs file historical load info	**Mar 29, 2013**
LSEs file 2014 Year-Ahead load forecast	**Apr 26, 2013**
LSEs receive 2014 Year-Ahead RA obligations	**Jul 31, 2013**
Final date to file revised forecasts for 2014	**Aug 19, 2013**
LSEs receive revised 2014 RA obligations	**Sep 17, 2013**

For 2013, CPUC staff sent initial allocations to LSEs on July 31 and final allocations to LSEs on September 18, 2012. For 2014, the initial allocations were sent August 1 and final allocations were sent September 18, 2013. 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 a secure file transfer server.

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 Guides for the 2013 and 2014 compliance years, LSEs must submit a revised forecast two months prior to each compliance filing month.[14] 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[15] 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.

[14] Annual RA Filing Guides are available on the CPUC website: http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_compliance_materials.htm

[15] http://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/FINAL_DECISION/119856.htm Ordering Paragraph 6.

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 re-calculate 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. The revised load forecasts also inform the local true-up process discussed in 3.3.2.

3.1.1 Yearly Load Forecast Results

Table 1 and Table 2 show the aggregate LSE submissions for 2013 and 2014, respectively, and the adjustments that were made by the CEC across the three IOU service areas.[16] 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 1% of the CEC's overall service area forecast. 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 2013 of 44,457 MW, which represents a 0.7% increase from the peak forecast of 44,167 MW in 2012. The August 2014 expected peak of 45,457 MW represents a 2.3% increase from the 2013 peak forecast and 2.9% increase from the 2012 peak forecast.[17]

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

[17] The 2012 RA report can be found at: http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/.

Table 1. 2013 Aggregated Load Forecast Data (MW) - Results of Energy Commission Review and Adjustment to the 2013 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)	29,375	28,547	28,629	30,284	34,308	39,374	43,833	46,327	41,582	34,747	29,832	30,974
CEC Adjustment for Plausibility/ Migrating Load	0	56	63	60	61	95	99	(985)	249	102	70	64
EE/DG Adjustment	(82)	(82)	(83)	(89)	(96)	(105)	(120)	(127)	(119)	(100)	(85)	(85)
Pro Rata Adjustment to CEC Forecast	0	51	(50)	0	0	0	0	0	0	0	0	55
Non-Coincident Peak Demand	29,292	28,572	28,560	30,255	34,273	39,363	43,813	45,215	41,712	34,749	29,818	31,008
Coincidence Adjustment	(684)	(494)	(479)	(494)	(634)	(616)	(483)	(759)	(748)	(758)	(487)	(470)
Final Load Forecast Used for Compliance	**28,608**	**28,078**	**28,081**	**29,762**	**33,639**	**38,747**	**43,330**	**44,457**	**40,963**	**33,991**	**29,331**	**30,537**

Source: CEC Staff.

Table 2. 2014 Aggregated Load Forecast Data (MW) - Results of Energy Commission Review and Adjustment to the 2014 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)	29,380	28,426	28,296	30,230	33,774	38,466	43,582	46,438	41,363	34,535	29,974	30,825
CEC Adjustment for Plausibility/ Migrating Load	61	67	69	74	77	78	81	(147)	89	88	79	71
EE/DG Adjustment	(39)	(39)	(41)	(43)	(42)	(43)	(44)	(46)	(47)	(46)	(41)	(38)
Pro Rata Adjustment to CEC Forecast	19	0	24	0	0	16	2	12	63	(0)	0	22
Non-Coincident Peak Demand	29,421	28,453	28,347	30,262	33,809	38,517	43,621	46,258	41,468	34,577	30,012	30,880
Coincidence Adjustment	(530)	(435)	(368)	(432)	(508)	(636)	(603)	(801)	(750)	(750)	(536)	(458)
Final Load Forecast Used for Compliance	**28,891**	**28,019**	**27,979**	**29,830**	**33,301**	**37,881**	**43,018**	**45,457**	**40,717**	**33,827**	**29,476**	**30,422**

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 3 below illustrates the magnitude of monthly plausibility adjustments from 2009 through 2014 compliance years and reports the monthly plausibility adjustments to the monthly year-ahead forecast as a percentage for 2013 and 2014.

In 2013 and 2014, the CEC's plausibility adjustments increased total load for all months except for January of 2013, when there was no adjustment made, and August of both years, when the CEC adjustment decreased load. While the CEC found that three of fifteen ESPs and all of the three IOUs serving load in 2013 required plausibility adjustments in at least one month of 2013, in 2014 only one of fifteen ESPs and one of three IOUs required an adjustment. In 2013, monthly plausibility adjustments as a percentage of that month's aggregated year-ahead forecast ranged from -2.2% to 0.6% and in 2014 they ranged from 0.3% to 0.3%. These adjustments to ESP forecasts reflect 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 3. CEC Plausibility Adjustments, 2009-2014 (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
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
2013 Plausibility Adjustment/ Load	0.0%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	-2.2%	0.6%	0.3%	0.2%	0.2%
2014 Plausibility Adjustment/ Load	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	-0.3%	0.2%	0.3%	0.3%	0.2%

Source: Aggregated year-ahead CEC load forecasts, 2009-2014.

Monthly load forecasts, which are adjusted for load migration, form the basis of monthly RA obligations. Table 4 and Table 5 show the monthly total load forecasts and the monthly adjustments for 2013 and 2014. 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 1.93% for January 2013. On a megawatt basis, the net monthly load migration adjustments ranged from 166 to 551 MW in 2013 and 200 to 533 MW in 2014.

Table 4. Summary of Load Migration Adjustments in 2013 (MW)

Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Forecasts , July 2012	28,608	28,078	28,081	29,762	33,639	38,747	43,330	44,457	40,963	33,991	29,331	30,537
Monthly Adjustments, 2013	551	452	166	235	228	245	313	281	359	209	507	284
Final Forecasts in Monthly RA Filings	29,159	28,530	28,247	29,997	33,867	38,992	43,643	44,738	41,322	34,200	29,838	30,821
Monthly Adjustments/ Final Load Forecast	1.93%	1.61%	0.59%	0.79%	0.68%	0.63%	0.72%	0.63%	0.88%	0.61%	1.73%	0.93%

Source: Aggregated load forecast adjustments submitted to the CEC and CPUC through 2013.

Table 5. Summary of Load Migration Adjustments in 2014 (MW)

Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Forecasts , July 2013	28,891	28,019	27,979	29,830	33,301	37,881	43,018	45,457	40,717	33,827	29,476	30,422
Monthly Adjustments, 2014	353	404	273	200	409	424	296	334	462	247	393	533
Final Forecasts in Monthly RA Filings	29,244	28,423	28,252	30,030	33,710	38,305	43,314	45,791	41,179	34,074	29,869	30,955
Monthly Adjustments/ Final Load Forecast	1.22%	1.44%	0.98%	0.67%	1.23%	1.12%	0.69%	0.73%	1.13%	0.73%	1.33%	1.75%

Source: Aggregated load forecast adjustments submitted to the CEC and CPUC through 2014.

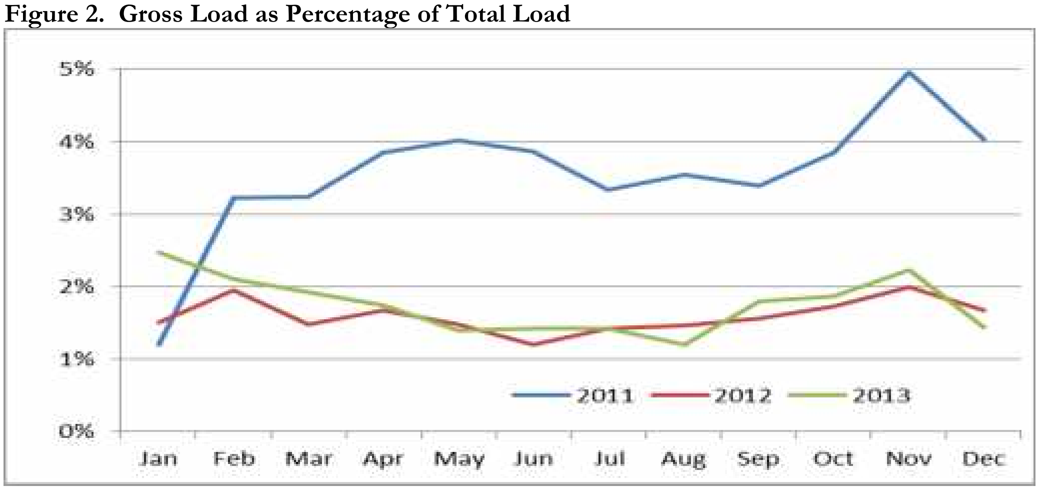
Figure 1 illustrates the gross monthly load migration between LSEs from January 2011 through 2013. The high amount of load migration in 2011 coincided with the partial reopening of direct access and the implementation of the three tranches of DA departure from bundled service throughout 2011. By 2012, the last phase had been implemented, and migration levels were much more stable.

Figure 1. Gross Load Migration adjustments per month (MW), 2011-2013

Source: Monthly forecast adjustments submitted by LSEs, 2011-2013

Gross load migration was highest in MW terms in 2011, and also high in percentage of total load. Figure 2 illustrates the relationship of gross load migration each month to the total load for the month. The chart shows the very high levels in 2011 and the much lower percentages in 2012 and 2013, and illustrates that although the MW amounts were highest in the middle of the year in 2011, the percentage of total load was highest in the last two months of the year. After 2011, load migration levels generally fell below two percent of total load.

Figure 2. Gross Load as Percentage of Total Load



Source: Monthly forecast adjustments submitted by LSEs, 2011-2013

3.2 System RA Requirements for CPUC-Jurisdictional LSEs

CPUC-jurisdictional LSEs satisfied their individual and collective system Resource Adequacy Requirements (RAR) for every month of 2013 and 2014. The total MW of RA resources procured exceeded the total System RAR by 0.2% to 6.0%, depending on the month. Table 6 and Table 7 show the total CPUC-jurisdictional RA procurement for each month of 2013 and 4014, respectively, broken down by: physical resources within the CAISO's control area, DR, CAM/RMR resources, and imports. 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.

The data represented in Table 6 and Table 7 reflect the committed RA procurement for 2013 and 2014 for all CPUC jurisdictional LSEs by contract type, and compares this procurement to the procurement obligation. In 2013, 74 to 87% of all committed RA capacity was procured from unit-specific physical resources within the CAISO control area; 5 to 10% of capacity was from imports, 3 to 7% was from DR resources and 4 to 13% was from CAM and RMR resources. In 2014, 72 to 76% of all committed RA capacity was procured from unit-specific physical resources within the CAISO control area; 6 to 9% of capacity was from imports, 3 to 6% was from DR resources and 10 to 17% was from CAM and RMR resources.

Table 6. 2013 RA Filing Summary – CPUC-Jurisdictional Entities (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
RAR without DR,CAM, & RMR	33,533	32,810	32,484	34,496	38,947	44,841	50,190	51,448	47,520	39,330	34,314	35,444
Phys. Res.	29,993	28,256	27,571	29,845	33,254	38,009	39,502	40,236	36,678	31,743	27,909	28,592
Imports	1,886	1,940	2,387	1,939	2,722	2,908	4,931	5,315	4,858	2,786	2,535	2,652
DR plus 15% PRM	1,073	1,185	1,164	1,306	2,107	3,187	3,474	3,580	3,656	2,235	1,200	1,043
CAM & RMR	1,684	1,688	1,659	1,700	1,582	3,428	3,482	4,264	4,267	4,254	4,301	4,928
Total	34,636	33,069	32,780	34,789	39,665	47,533	51,389	53,395	49,460	41,018	35,945	37,213
Total/ RAR	**103.3%**	**100.8%**	**100.9%**	**100.8%**	**101.8%**	**106.0%**	**102.4%**	**103.8%**	**104.1%**	**104.3%**	**104.8%**	**105.0%**

Source: Aggregated LSE Monthly RA Filings.

Table 7. 2014 RA Filing Summary – CPUC-Jurisdictional Entities (MW)

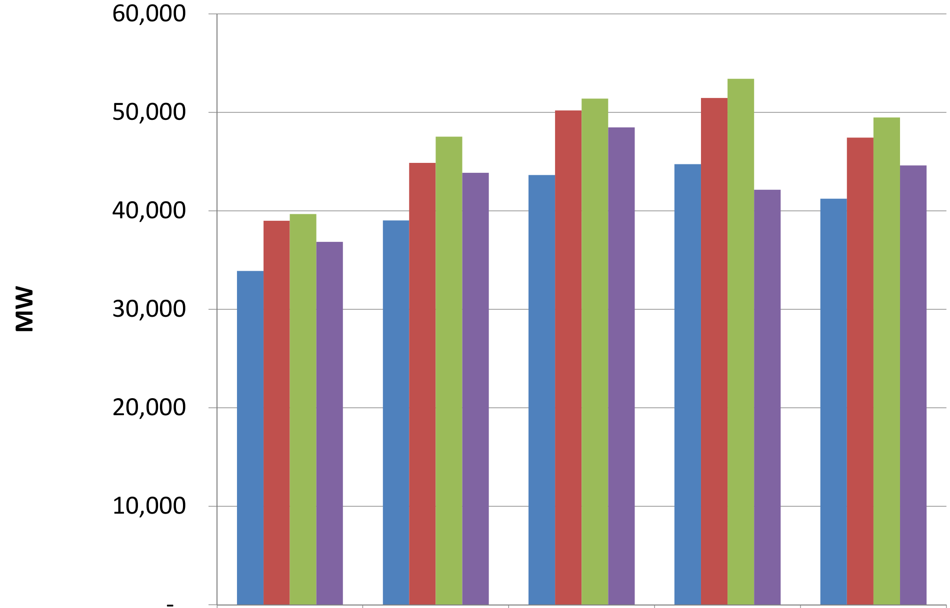
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
RAR without DR,CAM, & RMR	33,630	32,686	32,490	34,534	38,766	44,051	49,811	52,659	47,356	39,185	34,349	35,599
Phys. Res.	25,189	24,356	24,575	26,159	29,319	33,623	38,154	39,705	35,488	28,814	25,423	26,137
Imports	2,115	1,889	2,679	2,323	2,771	3,336	3,866	4,927	3,899	3,030	2,524	2,763
DR plus 15% PRM	1,161	1,166	1,231	1,316	2,230	2,452	2,590	2,644	2,622	2,287	1,287	1,207
CAM & RMR	5,505	5,489	5,477	5,410	5,472	5,500	5,460	5,464	5,481	5,415	5,532	5,611
Total	33,970	32,900	33,961	35,209	39,793	44,911	50,069	52,740	47,490	39,546	34,765	35,717
Total/ RAR	**101.0%**	**100.7%**	**104.5%**	**102.0%**	**102.6%**	**102.0%**	**100.5%**	**100.2%**	**100.3%**	**100.9%**	**101.2%**	**100.3%**

Source: Aggregated LSE Monthly RA Filings.

In 2013, committed RA resources, including DR, CAM and RMR resources, ranged from 39,665 MW in May to 53,395 MW in August. These resources enabled CPUC jurisdictional LSEs to meet between 101.8 and 104.1% of total procurement obligations in each summer month. Actual peak demand occurred on July 1, 2013 at 48,478 MW.

Figure 3 and Figure 4 reflect 2013 and 2014 total load forecast, procurement obligation (forecast plus planning reserve margin), and total committed RA for only CPUC-jurisdictional LSEs. These are compared against the actual peak load forecasts for the entire CAISO balancing area (which include both CPUC and non-CPUC jurisdictional LSEs). The difference between the red and the green bars reflect the excess amount of committed resources to meet the monthly RA requirement.

Figure 3. 2013 CPUC Load Forecast, RA Requirements, Total RA Committed Resources, and Actual peak Load (For Summer Months)

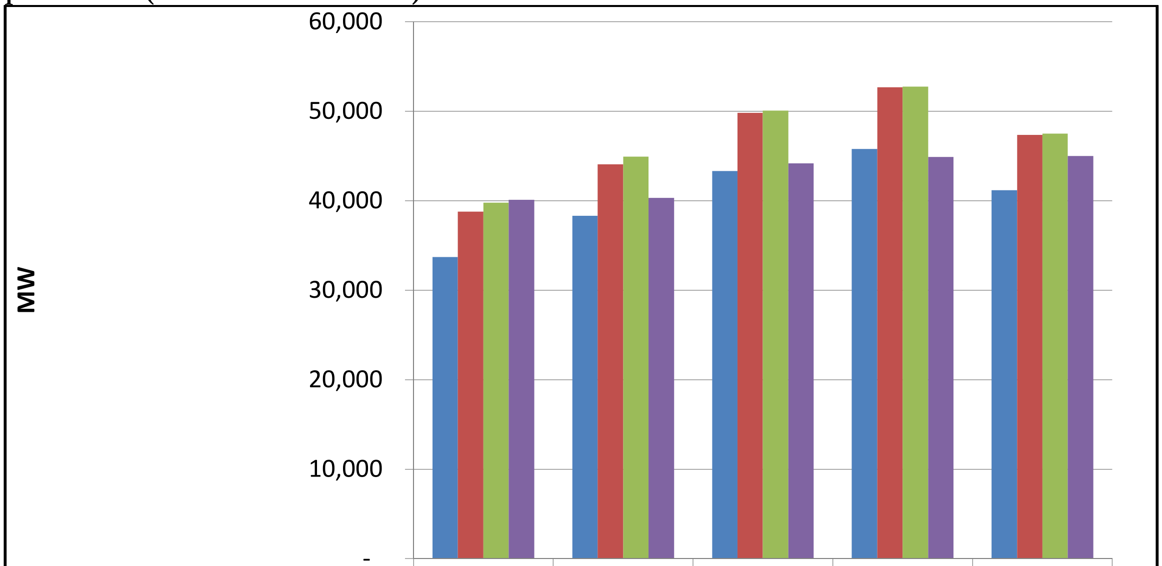


	May	Jun	Jul	Aug	Sep
Load forecast	33,896	39,022	43,643	44,738	41,231
Forward Commitment Obligation	38,980	44,875	50,189	51,449	47,416
Total RA resources Committed	39,665	47,533	51,389	53,395	49,460
Actual Peak Load	36,859	43,850	48,478	42,152	44,601

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

In 2014, committed RA resources, including DR, CAM and RMR resources, ranged from 39,793 MW in May to 52,740 MW in August. These resources enabled CPUC jurisdictional LSEs to meet between 100.2 and 102.6% of total procurement obligations in each summer month. Actual peak demand occurred on September, 2014 at 44,994 MW.

Figure 4. 2014 CPUC Load Forecast, RA Requirements, Total RA Committed Resources, and Actual peak Load (For Summer Months)



	May	Jun	Jul	Aug	Sep
Load forecast	33,710	38,305	43,314	45,791	41,179
Forward Commitment Obligation	38,766	44,051	49,811	52,659	47,356
Total RA resources Committed	39,793	44,911	50,069	52,740	47,490
Actual Peak Load	40,086	40,319	44,179	44,877	44,994

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

The CPUC RA program is 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. In past years we have included non-CPUC-jurisdictional LSEs information in this graph. However, due to insufficient data response from the CAISO we are unable to provide this for 2013 and 2014.

To give one a sense of the how much the chart would change if we had been able to include the aggregate non-CPUC-jurisdictional LSEs information we provide the August load ratios for 2013 and 2014. In 2013 and 2014, non-CPUC-jurisdictional LSEs aggregate load share for August was 9.1 and 8.5% of total CAISO load forecast.[18]

[18] These values are derived from the CEC year-ahead aggregate load forecasts used for allocating local capacity requirements to LSEs.

3.3 Local RA Program – CPUC-Jurisdictional LSEs

Beginning with the 2007 compliance year, the CPUC required LSEs to file an annual local RA filing, showing that they have met 100% of their local capacity requirement for all 12 months of the coming compliance year. Local RA requirements are developed through the CAISO's annual Local Capacity Technical Analysis. The annual study identifies the minimum local resource capacity required in each local area to meet energy needs using a 1-in-10 weather year and N-1-1 contingencies.[19] The results of the analysis are adopted in the annual RA decision and allocated to each LSE based on their August load ratio in each TAC area.

All LSEs are required to make a 12 month showing of their local requirement on or around October 31, with their system year-ahead showing.[20] In D.12-06-025 and D.13-06-024, the CPUC adopted the 2013 and 2014 Local RA obligations for the ten locally constrained areas (Big Creek/Ventura, LA Basin, San Diego, Greater Bay Area, Humboldt, North Coast/North Bay, Sierra, Stockton, Fresno, and Kern). As in previous years, the following local areas are aggregated to one area known as the "other PG&E areas": Humboldt, North Coast/North Bay, Sierra, Stockton, Fresno, and Kern.

3.3.1 Year-Ahead Local RA Procurement

CPUC-jurisdictional LSEs' overall Local RA procurements for 2013 and 2014 are summarized in Table 8 and Table 9. CPUC-jurisdictional LSE procurement exceeded local RA obligations in each of the five Local Areas by 1-29%. Aggregate minimum procurement across all Local Areas exceeded Local RA Requirements (Local RAR) by 16% in 2013 and 9% in 2014. Local requirements are allocated to LSEs net of RMR and CAM as these resources are used to reduce an LSE's Local RA obligation. The net local obligation was 19,329 MW in 2013 (23,021 MW – 3,692 MW = 19,329 MW) and 19,147 MW in 2014 (24,029 MW – 4,882 MW = 19,147 MW). Starting in 2013, DR resources RA values are reported through the RA filings, similarly to a physical resource. Historically, the local RA values associated with the DR resources were netted off the local RA requirements allocated to LSEs.

Table 8. Local RA Procurement in 2013, CPUC-Jurisdictional LSEs

Local Areas in 2013	Total LCR	CPUC-Jurisdictional Local RAR	Minimum Physical Resources per Month	Local RMR & CAM Credit	Local DR	Minimum Procurement/ Local RAR
LA Basin	10,295	9,244	5,951	2,225	1,400	104%
Big Creek/Ventura	2,241	2,012	1,803	49	286	106%
San Diego- IV	2,938	2,938	3,149	0	118	111%
Greater Bay Area	4,502	4,090	3,790	955	114	119%
Other PG&E Areas	5,213	4,736	5,396	463	231	129%
Totals	25,189	23,021	20,888	3,692	2,148	116%

[19] Local Capacity Requirement (LCR) studies and materials for 2013 and 2014 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.

Table 9. Local RA Procurement in 2014, CPUC-Jurisdictional LSEs

Local Areas in 2014	Total LCR	CPUC-Jurisdictional Local RAR	Minimum Physical Resources per Month	Local RMR & CAM Credit	Local DR	Minimum Procurement/ Local RAR
LA Basin	10,430	9,456	6,083	2,457	992	101%
Big Creek/Ventura	2,250	2,040	1,223	619	261	103%
San Diego-IV	3,605	3,605	3,580	49	84	103%
Greater Bay Area	4,423	4,043	3,523	1,303	149	123%
Other PG&E Areas	5,345	4,885	5,118	454	342	121%
Totals	26,053	24,029	19,527	4,882	1,828	109%

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 consists of two reallocations cycles. This 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.

The first allocation cycle for 2013 and 2014 began with the LSEs submission of revised August forecasts to the CEC on January 3, 2013 and January 14, 2014 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-ahead local requirements. The netted local requirement values, known as incremental local allocations, were then sent to LSEs on February 17, 2013 and February 1, 2014, 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 2013 and 2014 began with revised August forecasts filed on April 2, 2013 and March 17, 2014. Local true-up values based on these forecasts were sent out on April 15, 2013 and April 1, 2014 with the July CAM-RMR letters. These incremental values were used by the LSEs for the remainder of 2013 and 2014 (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.

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 MOO 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.

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), Capacity Procurement Mechanism (CPM) 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. Resources procured to meet reliability must go through something known as the Cost Allocation Mechanism (CAM). The CAM mechanism allows the net costs of new generation resources to be recovered from all benefiting customers in the IOU's TAC area. The RA benefits of these 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 Bilateral Transactions- RA Price Analysis

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. Prices of bilateral contracts could vary substantially depending on unit location, transmission constraints and market power.

On January 21, 2015, Energy Division issued a data request to all 20 CPUC-jurisdictional LSEs (comprised of three IOUs and 17 ESPs) asking for monthly capacity prices paid by (or to) LSEs for every RA capacity contract covering the 2013 – 2017 compliance years. The data request was confined to RA-only capacity contracts bought or sold covering the period from January 2013 – December 2017. Since RA prices can vary by month, the data request asked for specific monthly prices from each contract. QF contracts, imports and exports were excluded from the data set, as were all contracts with either a $0 or negative price value or a 0 MW value.

Of the 20 LSEs that were sent the data request, Energy Division received eleven responses (from three IOUs and eight ESPs), which consisted of a combined 3,556 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 below. The majority of the capacity in the data set is contracted for 2013 and 2014. This is as expected, since at the time that the data was collected the 2013 and 2014 RA compliance years had ended, and there had only been a year-ahead showing and a few month ahead showings for 2015 compliance year.

In an attempt to get a better understanding of the magnitude of the data set, we compared the data set to 2013 RA requirements. Keep in mind that the results include both capacity MWs bought and sold, which may result in the double counting of the same MW being used to meet the monthly RA requirement. In 2013, the sum of monthly contracted capacity represented approximately 25% of the 2013 monthly sum of RA requirements net CAM, RMR and DR allocations.[21] In 2014, the sum of monthly contracted capacity represented approximately 25% of the 2014 monthly sum of RA requirements net CAM, RMR and DR allocations. 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 25% of 2013 capacity is far from complete, it nevertheless provides important insights into overall RA pricing in that year. If we use the aggregate 2014 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 2015, the sum of monthly contracts represent about 24%, the 2016 data represents about 14% , and the 2017 data represents about 6%.

Table 10. Capacity Prices by Compliance Year, 2013-2017

	2013 Capacity	2014 Capacity	2015 Capacity	2016 Capacity	2017 Capacity
Weighted Average Price $/kW-month	$ 3.45	$ 3.41	$ 3.12	$ 2.70	$ 3.16
Average Price $/kW-month	$ 3.28	$ 3.32	$ 2.90	$ 3.29	$ 3.39
Minimum Price $/kW-month	$ 0.11	$ 0.11	$ 0.09	$ 0.27	$ 1.60
Maximum Price $/kW-month	$ 26.54	$ 26.54	$ 26.54	$ 26.54	$ 6.43
85% of MW at or below $/kW-month	$ 7.48	$ 7.81	$ 5.40	$ 3.00	$ 5.10
Sum of Contracted Capacity (MW)	104,947	96,712	91,788	54,289	24,887
Percentage of total contracted MW in data set	28.2%	26.0%	24.6%	14.6%	6.7%

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 2015 Net Qualifying Capacity list.[22] Local RA Capacity areas are described in Section 3.3 of the report.

[21] The 25% is calculated by dividing the sum of contracted capacity in 2013 (104,947 MW) by the sum of all 2013 monthly RA obligations net of CAM, RMR, and DR allocations (484,011MW). The 25% is calculated by dividing the sum of contracted capacity in 2014 (96,714 MW) by the sum of all 2014 monthly RA obligations net of CAM, RMR, and DR allocations (387,106 MW).

[22] The 2015 Net Qualifying Capacity list can be found at http://www.caiso.com/Documents/FinalNetQualifyingCapacityReport_ComplianceYear2015.xls

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 372,623 MW-months of capacity under contract. Of that capacity, 40% is located in the North of Path 26 (NP-26) Zone and 60% is located in the South of Path 26 (SP-26) Zone.[23] The data also show that 69% of the total capacity is located in Local Areas, with the remainder located in the CAISO system area. Of the Local RA capacity reported, the vast majority – 79% – is located in one of the SP-26 Local Areas; the remaining 21% is located in an NP-26 Local Area. The CAISO System RA has the opposite breakdown, with 69% of capacity located in the NP-26 Zone and only 31% of System RA capacity located in the SP-26 Zone.[24]

Table 11. Aggregated RA Contract Prices, 2013-2017

	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
Weighted Average Price ($/kW-month)	**$3.23**	$2.66	$3.60	**$3.39**	$2.44	$3.65	**$2.86**	$2.79	$3.17
Average Price ($/kW-month)	**$3.20**	$2.65	$3.61	**$3.43**	$2.88	$3.73	**$2.41**	$2.26	$2.76
Minimum Price ($/kW-month)	**$0.09**	$0.11	$0.09	**$0.09**	$0.90	$0.09	**$0.11**	$0.11	$0.14
Maximum Price ($/kW-month)	**$26.54**	$14.85	$26.54	**$26.54**	$8.62	$26.54	**$18.99**	$14.85	$18.99
85th Percentile ($/kW-month) [25]	**$5.80**	$3.50	$8.20	**$6.48**	$3.17	$8.47	**$4.49**	$4.49	$7.30
Contracted Capacity (MW)	**372,623**	148,417	224,207	**256,562**	54,590	201,972	**116,061**	93,827	22,234
Percentage of Total Capacity in Data Set	**100%**	40%	60%	**69%**	15%	54%	**31%**	25%	6%
Number of Monthly Values	**3,556**	1,516	2,040	**2,748**	956	1,792	**808**	560	248

The weighted average price for all capacity is $3.23/kW-month. This is $0.05 lower than the weighted average price reported in the 2012 RA price analysis. The weighted average price for SP-26 capacity (including Local and System RA) is $3.60/kW-month, which is about 35% higher than the NP-26 weighted average price of $2.66/kW-month. Higher prices in the SP-26 Zone are also revealed through the 85th-percentile statistics, which indicate the price under which 85% of the contracted MW values in a given category fall. In SP-26, 85% of contracted MW prices are at a price of $8.20/kW-month or less, while in NP-26, 85% of the MWs contracted are at a price of $3.50/kW-month or less.

[23] Path 26 is defined in the WECC Path Rating Catalog, viewable at http://www.wecc.biz/library/Pages/Path%20Rating%20Catalog%202013.pdf.

[24] 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.

[25] 85th percentile statistic is the price under which 85% of contract MW values, in a given category, fall.

The weighted average price of Local RA capacity is 18.5% 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 NP-26 Zone is less than the weighted average price of System RA capacity in the NP-26 Zone. This suggests that capacity prices north of Path 26 are supressed due to over supply in the northern local areas.

The price curves for RA-only contracts are shown by category in Figure 5-Figure 7. Figure 5 displays three price curves. The All Capacity price curve includes all contract 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 69% 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 5. Price Curves for RA Capacity Contracts, 2013-2017 Compliance Years

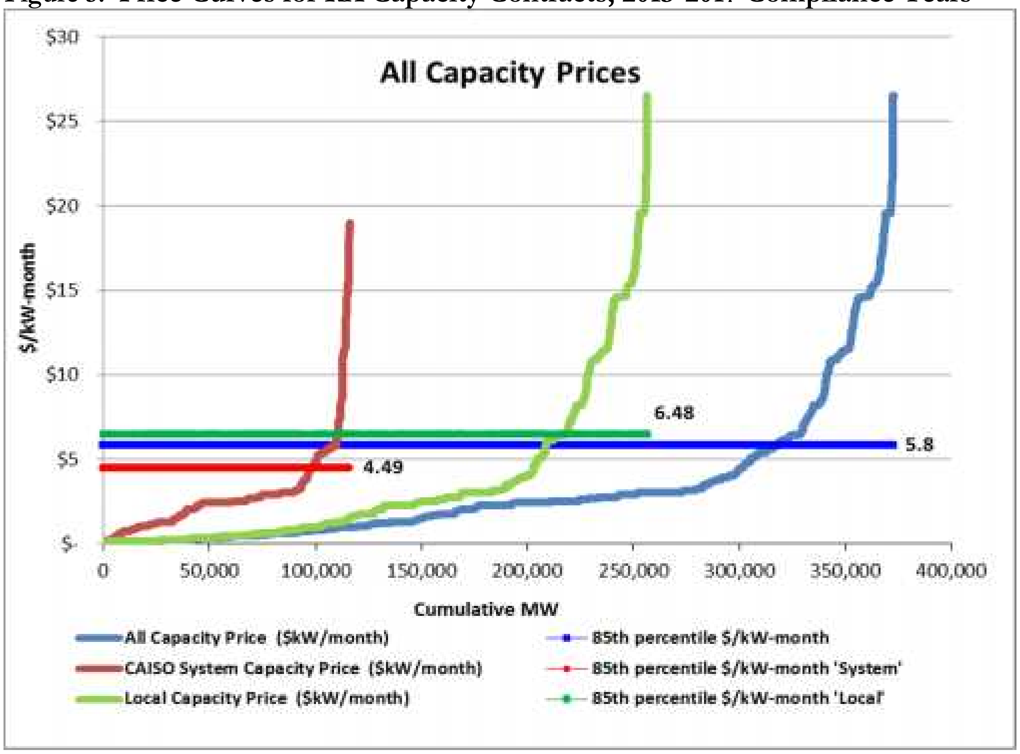


Figure 6. RA Price Curves for Resources North of Path 26, 2012- 2017

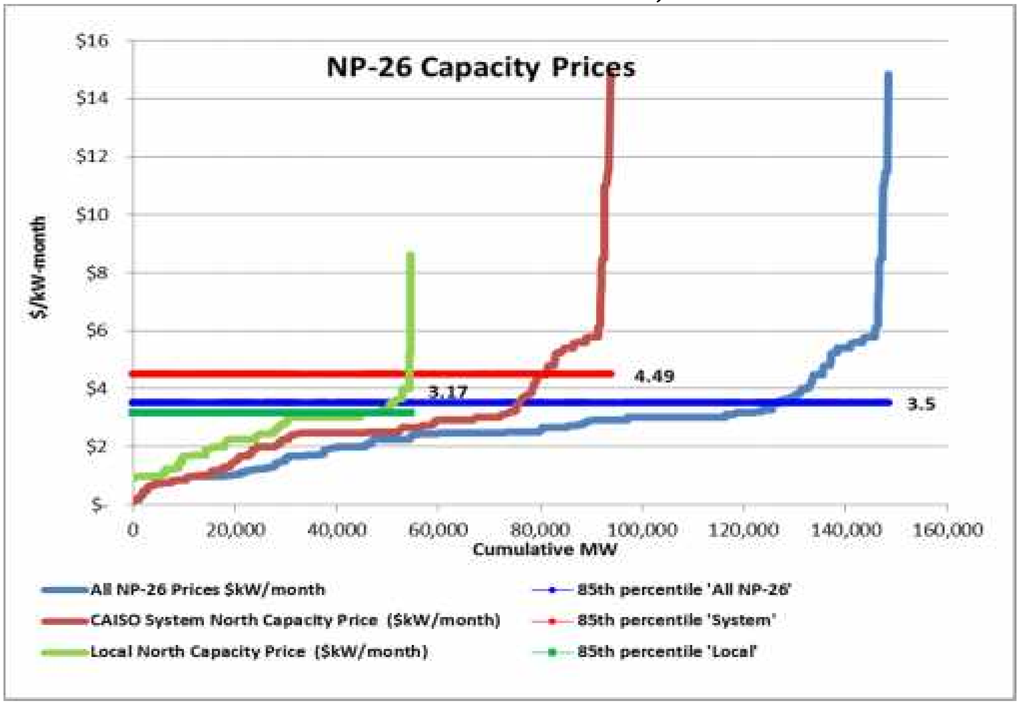


Figure 6 displays price curves for contracted capacity north of Path 26. Like Figure 5, the price curves are differentiated by Local and System RA capacity. In contrast to the statewide aggregate data, the majority of contracted capacity north of Path-26 were resources *not* located in local areas. The weighted 85th percentile contract price of System RA Capacity is about $1.32/kW-month more than for Local RA, indicating that there is generally not a premium placed on Local RA capacity north of Path 26. However, there are much higher price outliers in the System RA capacity curve than there are in the Local RA capacity curve. This is not what we would expect to see.

Figure 7 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 $1.17/kW-month more than for System RA. This is slightly lower than the difference of $1.50/kW-month reported in the 2012 RA report.

Figure 7. RA Price Curves for Resources South of Path 26, 2013-2017

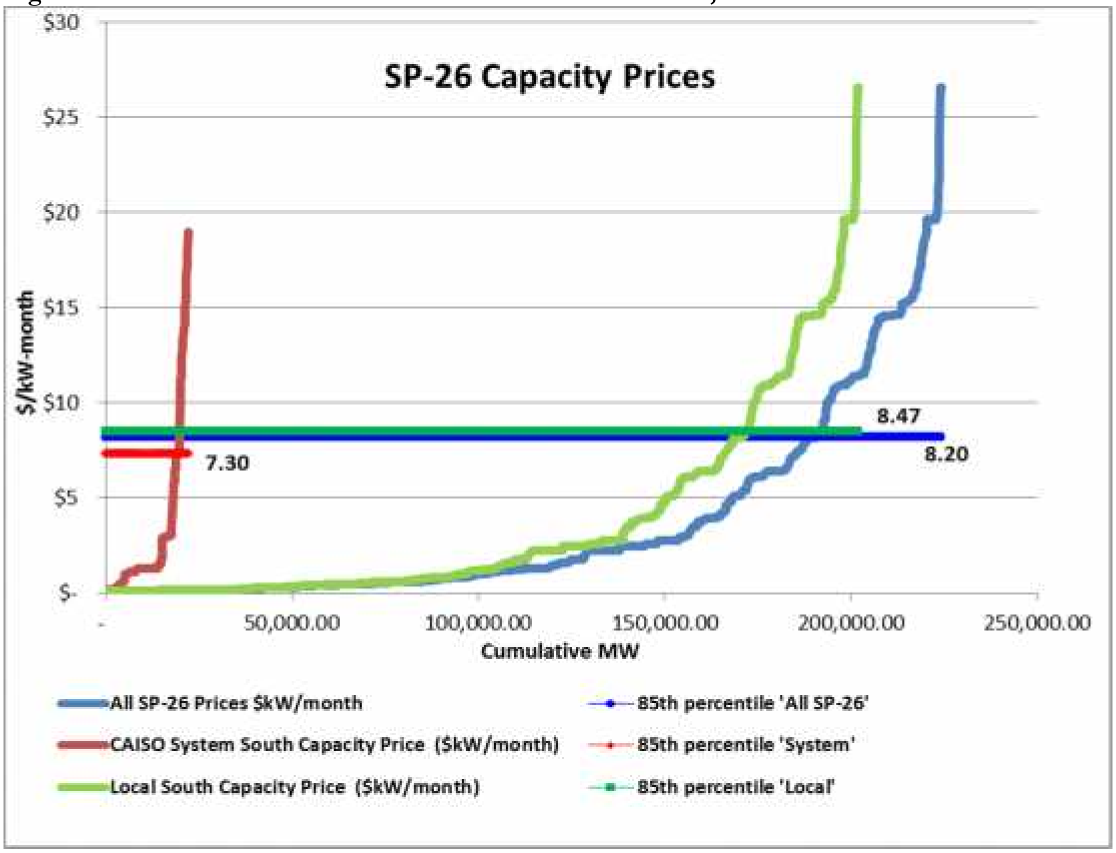


Table 12 reports capacity prices by Local Capacity Area. The San Diego Local Area has the highest weighted average price, the highest 85th percentile price and the highest maximum price. The 85th percentile price indicates that 85% of the contracted MW in the San Diego Local Area were procured at prices of $11.10/kW-month or below. According to the average weighed price and the 85th percentile price, LA Basin capacity is more expensive than Big Creek Ventura capacity, which is the opposite of what we saw in the 2012 RA resport. Looking at the 85th percentile statistic and the weighted average price of local areas in the North, the data suggest that Other PG&E area local capacity is more expensive than Bay Area local capacity. However, given the limited data available for Other PG&E Local Areas (only 5,448 MW of contracted capacity, which is a little more than one tenth of the contracted capacity in the Bay Area and only about 1.5% of the total data set), it is not possible to draw any strong conclusions.

Table 12. Capacity Prices by Local Area, 2013-2017

	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)	$3.41	$3.63	$2.37	$3.01	$4.08	$2.86
Average Price ($/kW-month)	$3.39	$3.95	$2.79	$2.97	$3.78	$2.41
Minimum Price ($/kW-month)	$0.12	$0.11	$0.90	$0.90	$0.09	$0.11
Maximum Price ($/kW-month)	$21.77	$24.26	$4.51	$8.62	$26.54	$18.99
85th percentile ($/kW-month)	$7.53	$8.58	$3.12	$3.25	$11.10	$4.49
Contracted Capacity (MW)	79,154	73,922	49,142	5,448	48,896	116,061
Percentage of Total Capacity in Data Set	21.2%	9.8%	13.2%	1.5%	13.1%	31.1%

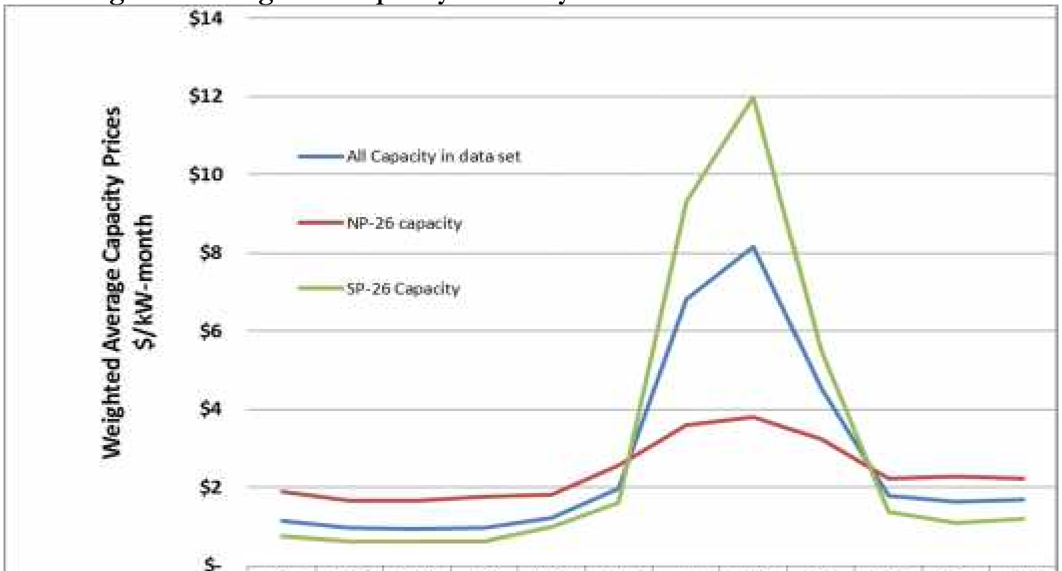
The monthly weighted average capacity prices shown in Table 13 below illustrate that capacity prices are significantly higher from July through September; the 85th percentile price in August is more than five times the 85th-percentile prices reported in the months of January through May. This is what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

Table 13. RA Capacity Prices by Month, 2013-2017

	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	$ 1.13	$ 0.19	$ 6.43	$ 2.46	26,325.12	7.1%
February	$ 0.95	$ 0.09	$ 6.43	$ 2.25	25,675.89	6.9%
March	$ 0.92	$ 0.09	$ 6.43	$ 2.50	24,832.53	6.7%
April	$ 0.97	$ 0.09	$ 6.43	$ 2.46	25,373.88	6.8%
May	$ 1.23	$ 0.16	$ 6.43	$ 2.50	29,503.41	7.9%
June	$ 1.98	$ 0.41	$ 6.43	$ 3.00	34,701.70	9.3%
July	$ 6.81	$ 0.80	$19.77	$11.86	43,003.17	11.5%
August	$ 8.16	$ 0.97	$26.54	$15.44	47,207.26	12.7%
September	$ 4.52	$ 0.97	$11.10	$ 6.66	42,822.67	11.5%
October	$ 1.78	$ 0.25	$ 6.43	$ 2.80	29,076.93	7.8%
November	$ 1.64	$ 0.28	$ 6.43	$ 2.75	22,548.09	6.1%
December	$ 1.68	$ 0.37	$ 6.43	$ 2.75	21,552.59	5.8%

Figure 8 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 8. 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	$1.13	$0.95	$0.92	$0.97	$1.23	$1.98	$6.81	$8.16	$4.52	$1.78	$1.64	$1.68
NP-26 capacity	$1.88	$1.67	$1.65	$1.76	$1.80	$2.56	$3.60	$3.79	$3.24	$2.21	$2.27	$2.23
SP-26 Capacity	$0.75	$0.61	$0.62	$0.62	$0.98	$1.61	$9.31	$11.98	$5.48	$1.36	$1.09	$1.20

Figure 9 graphs the contracted capacity by month and year. 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. Note that the data set was collected at the beginning of 2015, which means both the 2013 and 2014 RA compliance years had concluded.

Figure 9. Contracted RA Capacity by Month, 2013- 2017

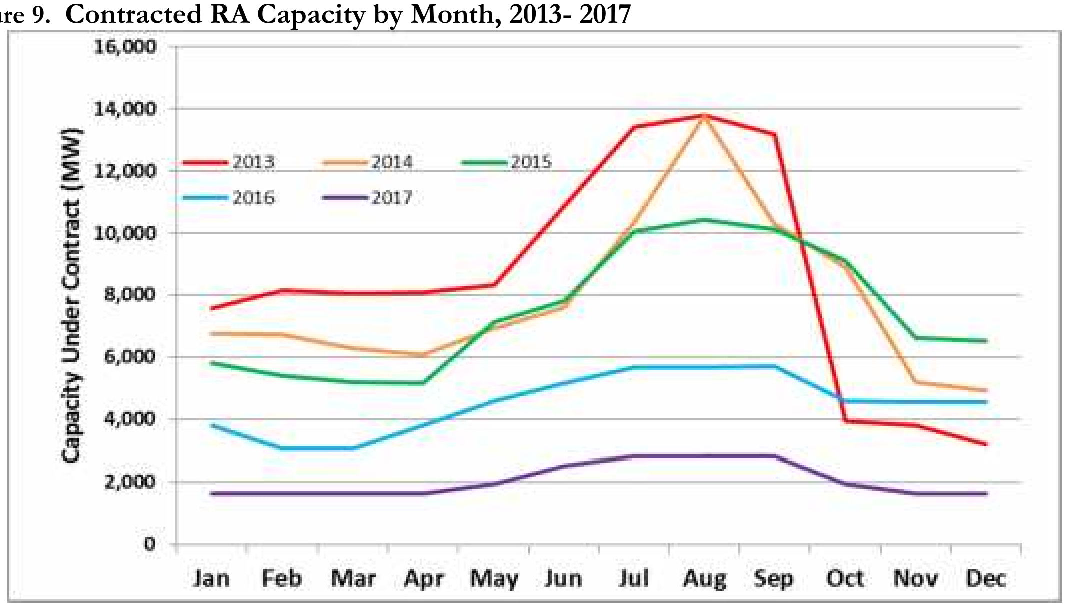


Figure 10. Weighted Average Capacity Prices by Month, 2013-2017

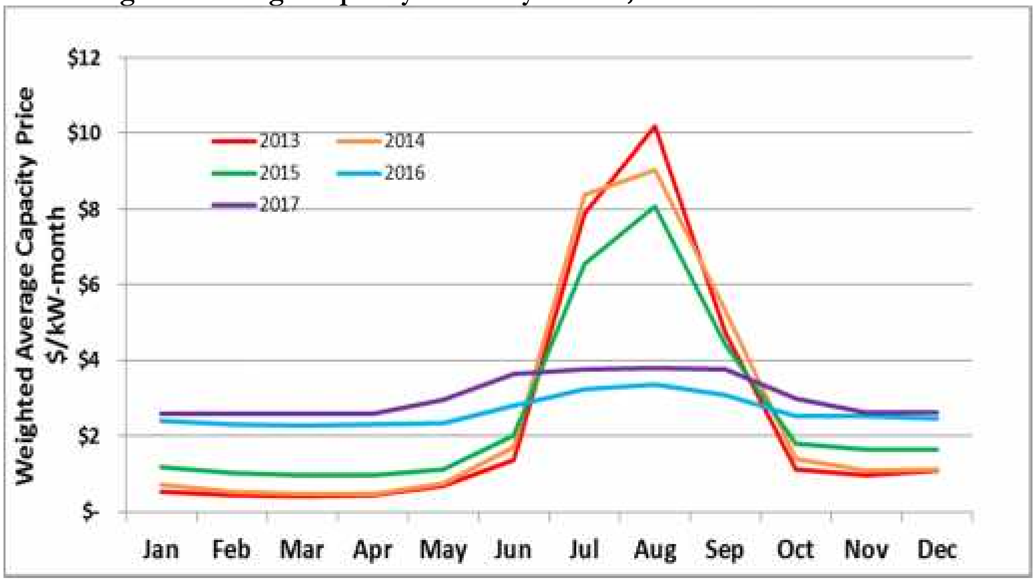


Figure 10 graphs the weighted average capacity prices by month and year. Prices are highest during the summer months for all years in the data set. The prices show a steady downward trend for June-September the farther out the contracted year is. However, in non-summer months we see the opposite trend; prices are *higher* the farther out the contracted year is. This is consistent with the trend we saw in the 2012 RA report capacity price analysis.

4.2 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,[26] 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 2014.

4.3 CAISO Out of Market Procurement – CPM Designations

CAISO implemented the Capacity Procurement Mechanism (CPM) effective April 1, 2011. The purpose of CPM is to enable the CAISO to procure capacity to maintain grid reliability if:

- LSEs fail to meet RA requirements
- RA resources are insufficient to meet local reliability constraints
- Significant event triggers procurement, and
- Through issuance of Exceptional Dispatch for non-RA, non-RMR, or non-CPM capacity.

The CPM applies to two types of circumstances: 1) procurement of capacity at-risk of retirement needed for reliability and 2) Exceptional Dispatch. Procurement for resources at risk of retirement during the current RA compliance year can occur if the resource is identified as being needed by the end of the calendar year following the current RA compliance year. If a resource at-risk of retirement qualifies under CAISO's list of criteria, the resource can be procured from a minimum commitment of 30 days to a maximum commitment of one year within the current RA compliance year. Under the Exceptional Dispatch CPM, CAISO can procure resources at an initial term of 30 days. The term can be extended beyond the initial 30 day period if CAISO determines that the circumstances leading to Exceptional Dispatch continue to exist.[27]

The price of CPM is based on the going forward fixed costs of a reference resource. It is set at the higher of the resource's actual going forward cost or $55/kW-year beginning on April 1, 2011. Effective on February 16, 2012, the CPM price was increased to $67.50/kW-year when FERC issued an order that approved the settlement in the CAISO's CPM proceeding. Effective February 16, 2014, the CPM price was increased to $70.88/kW-year. The CPM price is set to expire in February 2016. Current tariff language pending FERC approval would replace the CPM price with a CPM auction mechanism.

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

[27] CAISO Capacity Procurement Mechanism Overview Presentation, March 3, 2011, http://www.caiso.com/Documents/CapacityProcurementMechanismOverview.pdf

Table 14 shows CAISO's CPM designation from 2012 to 2014.

Table 14. CAISO CPM Designation from 2012-2014

Resource ID	MW	CPM Type	Term (in days)	Start Date	End Date	Estimated Capacity Cost
HNTGBH_7_UNIT 1	20	Exceptional Disp.	20	2/8/2012	3/8/2012	$121,810
HNTGBH_7_UNIT 1	98	Exceptional Disp.	60	3/1/2012	4/29/2012	$1,255,748
ENCINA_&_EA4	300	Exceptional Disp.	60	3/1/2012	4/29/2012	$3,844,125
HNTGBH_7_UNIT 3	225	Sig Event	30	5/11/2012	6/9/2012	$1,441,547
HNTGBH_7_UNIT 4	215	Sig Event	30	5/11/2012	6/9/2012	$1,377,478
HNTGBH_7_UNIT 3	225	Sig Event	60	6/10/2012	8/8/2012	$2,883,094
HNTGBH_7_UNIT 4	215	Sig Event	60	6/10/2012	8/8/2012	$2,754,956
HNTGBH_7_UNIT 3	225	Sig Event	84	8/9/2012	10/31/2012	$4,036,331
HNTGBH_7_UNIT 4	215	Sig Event	84	8/9/2012	10/31/2012	$3,856,939
HNTGBH_7_UNIT 1	225.75	Sig Event	30	9/5/2012	10/4/2012	$1,446,352
INLDEM_5_UNIT 2	79.99	Exceptional Disp.	60	11/4/2012	1/2/2013	
MORBAY_7_UNIT 4	50.01	Exceptional Disp.	60	2/22/2013	4/22/2013	$640,815
HNTGBH_7_UNIT 2	163	Exceptional Disp.	60	9/1//2013	10/30/2013	$2,088,642
HIDSRT_2_UNITS	181	Exceptional Disp.	30	2/6/2014	3/7/2014	$1,159,644
GWFPWR_1_UNITS	20	Exceptional Disp.	60	5/26/2014	7/24/2014	
MOSSLD_2_PSP2	490	Exceptional Disp.	60	10/2/2014	12/1/2014	$6,593,139

As Table 14 shows, there were no CPM designations due to capacity at risk of retirement. There were CPM designations due to significant event and Exceptional Dispatch. Huntington Beach Unit 3 and 4 received CPM designations due to the outage of SONGS in the summer of 2012.

4.4 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.

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

Table 15. 2013, 2014, & 2015 Resources Authorized for CAM Due to Reliability

2013 Resources Authorized for CAM Due to Reliability

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
BARRE_6_PEAKER	8/1/2007	7/31/2017	SCE	47.00
BUCKBL_2_PL1X3	8/1/2010	7/31/2020	SCE	490.00
CENTER_6_PEAKER	8/1/2007	7/31/2017	SCE	47.00
ETIWND_6_GRPLND	8/1/2007	7/31/2017	SCE	46.00
HINSON_6_LBECH1-HINSON_6_LBECH4	6/1/2007	5/31/2017	SCE	260.00
MIRLOM_6_PEAKER	8/1/2007	7/31/2017	SCE	46.00
VESTAL_2_WELLHD	2/1/2013	5/31/2022	SCE	49.00
WALCRK_2_CTG1-WALCRK_2_CTG5	6/1/2013	5/31/2023	SCE	479.32
SENTNL_2_CTG1 - SENTNL_2_CTG8	8/1/2013	7/31/2023	SCE	728.80
ELSEGN_2_UN1011 & ELSEGN_2_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

2014 Resources Authorized for CAM Due to Reliability (Incremental)

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
ESCNDO_6_PL1X2	5/1/2014	12/31/2038	SDG&E	48.71

2015 Resources Authorized for CAM Due to Reliability (Incremental)

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
MNDALY_6_MCGRTH	11/1/2014	10/31/2024	SCE	47.20

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

D.10-12-035[28] 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.[29] 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.[30]

In 2013, PG&E had 21 CHP contracts whose costs and benefits were allocated to all customers. These CHP contracts amounted to 589 MW of RA credit.[31] These RA capacity credits were allocated in the monthly CAM allocation process beginning with the January 2013 compliance month. In 2014, PG&E had 26 CHP contracts whose costs and benefits were allocated to all customers. These CHP contracts amounted to 1,006 MW of RA credit.[32] In 2014, SCE had 11 CHP contracts that received CAM treatment. These CHP contracts amounted to 757 MW of RA credit.[33] Table 16, below, lists the CHP resources whose RA capacity credits were allocated from 2013 to 2015.

Table 16. CHP Resources Allocated for CAM 2013-2015

CHP Resources that Received RA Credits in 2013

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
SARGNT_2_UNIT	4/1/2012	12/31/2016	PG&E	31.81
SALIRV_2_UNIT	4/1/2012	12/31/2016	PG&E	30.83
COLGA1_6_SHELLW	4/1/2012	12/31/2016	PG&E	35.70
MIDSET_1_UNIT 1	4/1/2012	12/31/2016	PG&E	33.14
BDGRCK_1_UNITS	7/1/2012	6/30/2015	PG&E	45.21
CHALK_1_UNIT	7/1/2012	6/30/2015	PG&E	44.58
MKTRCK_1_UNIT 1	7/1/2012	6/30/2015	PG&E	40.84
LIVOAK_1_UNIT 1	7/1/2012	6/30/2015	PG&E	44.40
UNVRSY_1_UNIT 1	8/1/2012	6/30/2015	PG&E	34.19
CONTAN_1_UNIT	8/1/2012	6/30/2015	PG&E	18.04
TEMBLR_7_WELLPT	8/1/2012	3/31/2015	PG&E	0.38

[28] http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/128624.htm
[29] CHP Program Settlement Agreement Term Sheet 13.1.2.2
http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124875.PDF
[30] 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."
[31] August NQC values are used in this calculation
[32] August NQC values are used in this calculation
[33] August NQC values are used in this calculation

DEXZEL_1_UNIT	9/2/2012	7/1/2015	PG&E	28.25
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
TXMCKT_6_UNIT	7/1/2012	9/30/2013	PG&E	3.74
TIDWTR_2_UNITS	8/1/2013	6/30/2015	PG&E	17.58

CHP Resources that Received RA Credits in 2014 (Incremental)

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
OROVIL_6_UNIT	1/1/2014	10/14/2020	PG&E	7.5
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	12/31/2017	PG&E	135.00
LGHTHP_6_QF	12/10/2012	12/31/2014	SCE	0.78
TENGEN_2_PL1X2	7/2/2012	7/1/2015	SCE	34.99
HOLGAT_1_BORAX	6/1/2012	7/1/2015	SCE	20.03
SEARLS_7_ARGUS	7/13/2013	7/1/2015	SCE	12.39
LMEC_1_PL1X3	1/1/2014	12/31/2020	SCE	135
GILROY_1_UNIT	1/1/2014	12/31/2018	SCE	52.5
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
ARCOGN_2_UNITS	10/1/2013	6/30/2015	SCE	274.89

CHP Resources that Received RA Credits in 2015 (Incremental)

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
STOILS_1_UNITS	10/1/2014	7/31/2026	PG&E	1.72
SMPRIP_1_SMPSON	4/1/2015	5/31/2018	PG&E	45.6
BEARMT_1_UNIT	5/1/2015	4/30/2022	PG&E	44.58
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	6.2
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

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

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 aggregator customers. The RA credit associated with DR is calculated using the CPUC-adopted Load Impact Protocols. On about April 1 of each year, the IOUs/DR providers submit the ex-ante load impact values associated with each DR program 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 determined to be final, the DR RA credits are posted on the CPUC's RA compliance website and then allocated to all LSEs for the coming compliance year.

Beginning in 2013,[34] the RA program implemented the adopted MCC DR bucket structure. This was done by adding an additional tab to the RA reporting template specifically for DR resources. LSEs are still sent their annual DR allocations through the year-ahead process. Once the DR allocations are sent to all benefiting LSEs in the annual allocations, the DR values are inserted into the allocation tab of the RA template which then auto-populates the DR values to the DR resource tab of the workbook. The DR values are combined with other physical resources reported in the workbook and are counted towards meeting the LSE's RA obligation verses reducing the LSE's RA obligation. LSEs can also enter additional DR resources that they have procured on this tab.

In 2013, a total of 3,114 MW of DR RA credit was allocated to benefiting LSEs to meet August RA obligations. In 2014, a total of 2,644 MW of DR RA credit was allocated to benefiting LSEs to meet August RA obligations. These DR values include an added T&D loss factor and an added 15% planning reserve margin.

Table 17 and Figure 11, below, show the DR RA credit allocation for August for 2007 through 2015. DR allocations have remained relatively steady during this period, ranging from 2,554 MW-3,114 MW. The total amount of capacity procured through DR, CAM and RMR for August 2013 was 7,393 MW. This is 14.4% of the total CPUC-jurisdictional LSE obligation for August 2013 (51,448 MW). The total amount of capacity procured through DR, CAM, and RMR for August 2014 was 8,125 MW. This is 15.4% of the total CPUC-jurisdictional LSE obligation for August 2014 (52,659 MW). Note that the DR values listed here only include event based DR programs. Non-event based DR programs are allocated to LSEs through a downward adjustment in the LSEs load forecasts used for RA compliance.

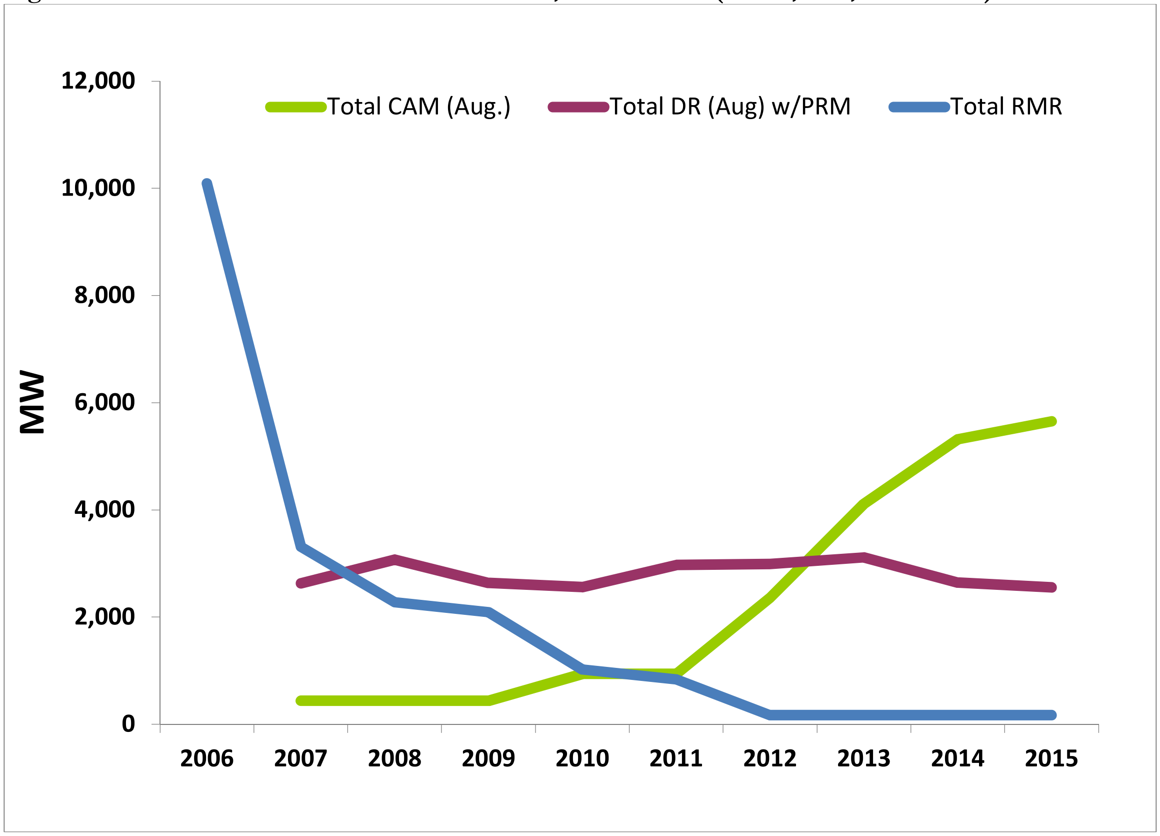
[34] (D.)12-06-025

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

	IOU	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
DR Procurement	SCE			1,705	1,616	1,613	1,838	2,067	2,195	1,615	1,626
	PG&E			1,018	912	846	888	744	783	933	807
	SDG&E			346	104	97	241	177	135	96	121
	Total DR (Aug)		**2,628**	**3,069**	**2,633**	**2,556**	**2,967**	**2,987**	**3,114**	**2,644**	**2,554**
CAM Procurement	SCE		436	436	436	936	936	1,529	2,763	3,477	3,583
	PG&E							703	1,351	1,790	2,020
	SDG&E							130		49	49
	Total CAM (Aug)		**436**	**436**	**436**	**936**	**936**	**2,362**	**4,114**	**5,316**	**5,652**
RMR Procurement	SCE	1,390									
	PG&E	6,151	1,348	1,303	1,263	709	527	165	165	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**	**165**	**165**

Figure 11 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 2015, total CAM procurement reached 5,652 MW where RMR procurement consisted of only 165 MW (CPUC jurisdictional LSEs were allocated 148.71 MW of the 165 MW in August 2014).

Figure 11. RA Procurement Credit Allocation, 2006 – 2015 (RMR, DR, and CAM)



4.5 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.

4.6 CAISO Exceptional Dispatch Analysis

Exceptional Dispatch (ExD) occurs when the CAISO manually issues dispatch instructions outside of market dispatch for a variety of reasons, including unavailability of market solutions, excessive scheduling of capacity, software failure, unit testing or generator/transmission contingencies. Beginning in 2010, the CAISO has made modifications to their market optimization with an aim to reduce reliance on ExD. The purpose of this analysis is to examine trends in ExD since that time, and to explore the main drivers underlying ExD between 2010 and 2013. Recent market developments, including the sudden retirement of the San Onofre Nuclear Generating Station (SONGS) and the growing need to integrate intermittent renewable generation, have complicated the effort to reduce reliance on ExD, but still there has been marked progress.

The ExD data used for the analysis were imported from ExD Reports on the CAISO website. Staff downloaded ExD reports for the date range between January 2011 and December 2013.[35] Data reported for each ExD event include: reason code (cause for ExD); date; MWh dispatched including ExD and regular dispatch, incremental/decremental dispatch specifically due to ExD; and costs of both regular dispatch; incremental/decremental ExD.

To facilitate staff analysis, staff consolidated the dozens of reported reason codes into broader categories. Table 18 summarizes the categories staff created to assess trends and distribution of ExD across categories of reason codes.

[35] Source: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=99D47DC1-9D55-4CA1-A900-16AC9A551493.

Table 18. ED Staff Categories of ExD

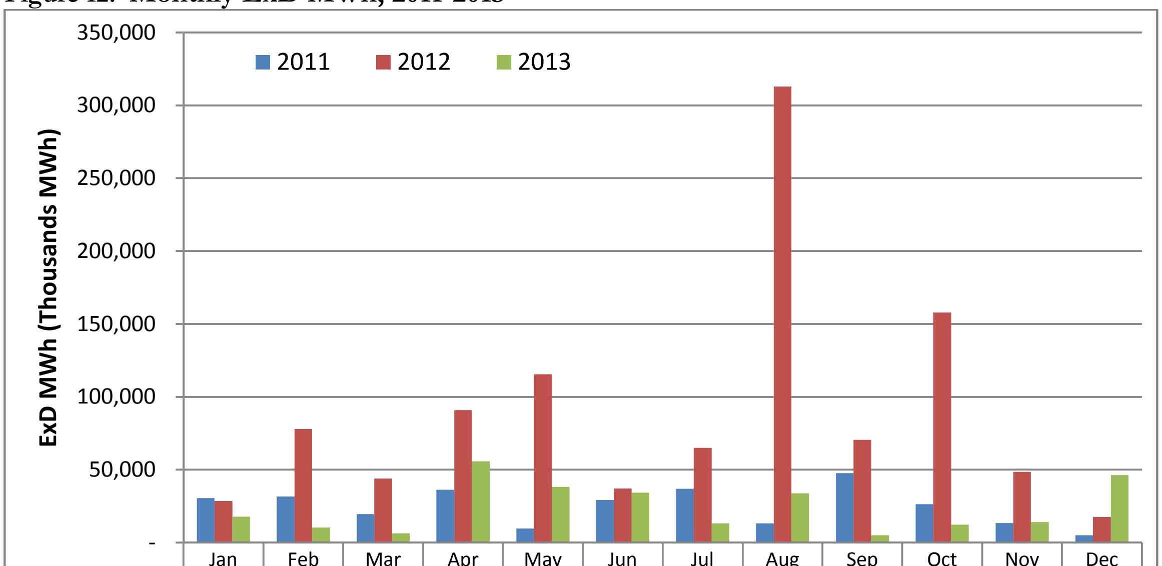
Category	Category Name	Reason Code
1	Flexibility and Ramping Re-dispatch	Recover ACE (area control error, a type of contingency reserve), Stranded AS, USF Accommodation, Over Generation, Dispatchability, Dispatch Modification, Ramp Rate, Stranded A/S or RUC, Load Pull, Reverse Commitment Instruction, Recover ACE
2	Software Issue	Software Error, Software Issue, Software Limitation, Telemetry Error, Failed Telemetry, Bad Transition, Bridging Schedules, Revenue Meter Testing, Communication Outage, Communication Failure
3	Generation Physical Contingency	SLIC Derate, Generation Outage, RAS Outage
4	Generation Related Re-dispatch	G-206, G-217, G-219, Peaker Management, Fast Start Unit Management, MSG Plant Startup
5	Transmission Physical Contingency	Transmission Outage Other, Transmission Outage PG&E, Transmission Outage SCE, Transmission Outage SDG&E, COI Limitation, InterTie Emergency Assistance, Transmission Outage
6	Transmission Related Re-dispatch	Path 15, Path 26, Path 43, Path 66, Transmission Mitigation, COI Mitigation, T-100, T-103, T-129, T-132, T-133, T-135, T-136, T-138, T-163, T-165, T-167, T-169, T-170, Voltage Control, Voltage Support, Thermal Margin, Los Banos North Mitigation, 6110, 6510, 6610, 7110, 7120, 7230, 7240, 7320, 7410, 7430, 7510, 7570, 7620, 7630, 7720, 7810, 7820, 7830, 8710,
7	Gas/Fuel	Fuel Management, Gas Supply Curtailment, Gas/Fuel Supply Limitation, SDG&E Gas Limitation, SDG&E Gas Outage, Gas/Fuel Supply Limitations
8	Forecasting Issue	Load Forecast Error, Load Forecast Uncertainty, Risk Predictor, Suspect Modeling Error
9	System Management Issue	System Capacity, System Energy, System Reliability, System Restoration, Infeasible Day Ahead Schedule, Pump Management, Unit Control, ELC Commitment, Wrong Start Time, Late Start Up, SCE Import Limit, SDG&E Import, SDG&E Import Limit, SDGE Imports, SP26 Capacity, PG&E Import Limit, Pumped-Storage, System Load, SCE SOB 204, Operating Reserve Deficiency, Reliability need cannot be met by other resources, NP26 Capacity
10	Market Management Issue	Customer Request, Missing Bids, PACI Scheduling Rights, SC Request, Market Disruption
11	Physical Contingency	Fire, Fire Test, Weather, Contingency, Conditions beyond control of the CAISO BA
12	Testing	Unit Testing

Staff created pivot tables to summarize the dataset by year and to compare annual data by month, local reliability area and reason code category. In light of the results shown below, staff further analyzed the ExD events applicable to the LA Basin area by specific reason codes. Detailed explanations and results are presented in the following section.

Total exceptional dispatch was 299.2 GWh, 1,065.9 GWh and 287.3 GWh in the years 2011, 2012 and 2013 respectively. According to CAISO's Market Performance reposts, the ExD in August 2012 (the highest ExD month in the highest ExD year) corresponds to a range 2.5% to 5%[36] of total in-state generation, indicating that ExD is a relatively small number relative to total generation, which is a notable insight, but also that ExD still creates significant costs.

As can be seen from Figure 12, the amount of ExD was generally higher in spring and summer than in autumn and winter. The MWh dispatched were particularly high in 2012, especially in the LA Basin Area as shown inFigure 13. Among all the local reliability areas, the LA Basin had the most exceptional dispatch in all three years. The amount of ExD in the LA Basin was 143 GWh, 649.8 GWh and 74.5 GWh in 2011, 2012 and 2013 respectively, which accounts for 48%, 61%, and 26% of the total ExD in each year respectively. Due to these insights, staff conducted further analysis on ExD in the LA Basin to locate primary causes and code categories to which ExD can be attributed.

Figure 12. Monthly ExD MWh, 2011-2013



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011	30,459	31,591	19,566	36,207	9,683.	29,103	36,822	13,137	47,736	26,439	13,486	5,008.
2012	28,435	77,895	43,965	90,805	115,43	37,181	64,907	312,79	70,444	157,81	48,574	17,628
2013	17,855	10,281	6,280.	55,812	38,277	34,360	13,099	33,734	4,988.	12,315	13,955	46,340

36 This figure was taken from the CAISO 2012 Market Performance Report

Figure 13. ExD MWh by Local Area, 2011-2013

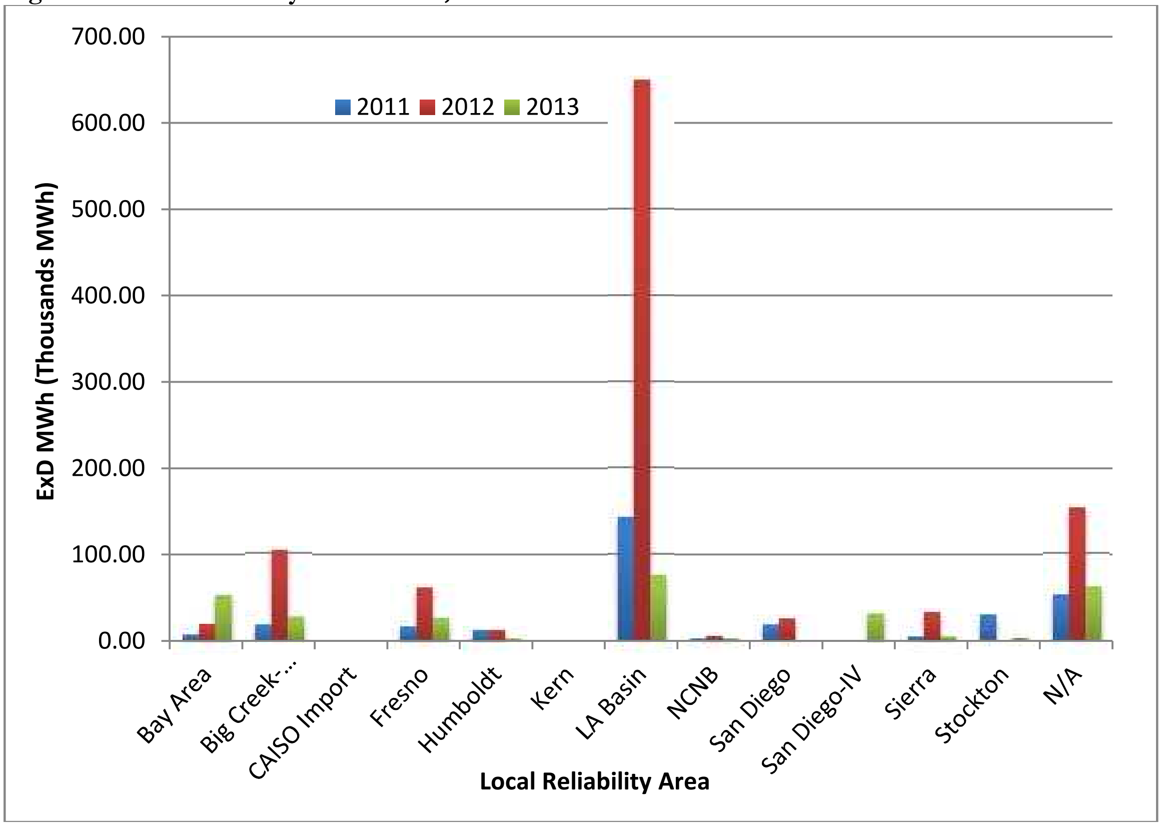
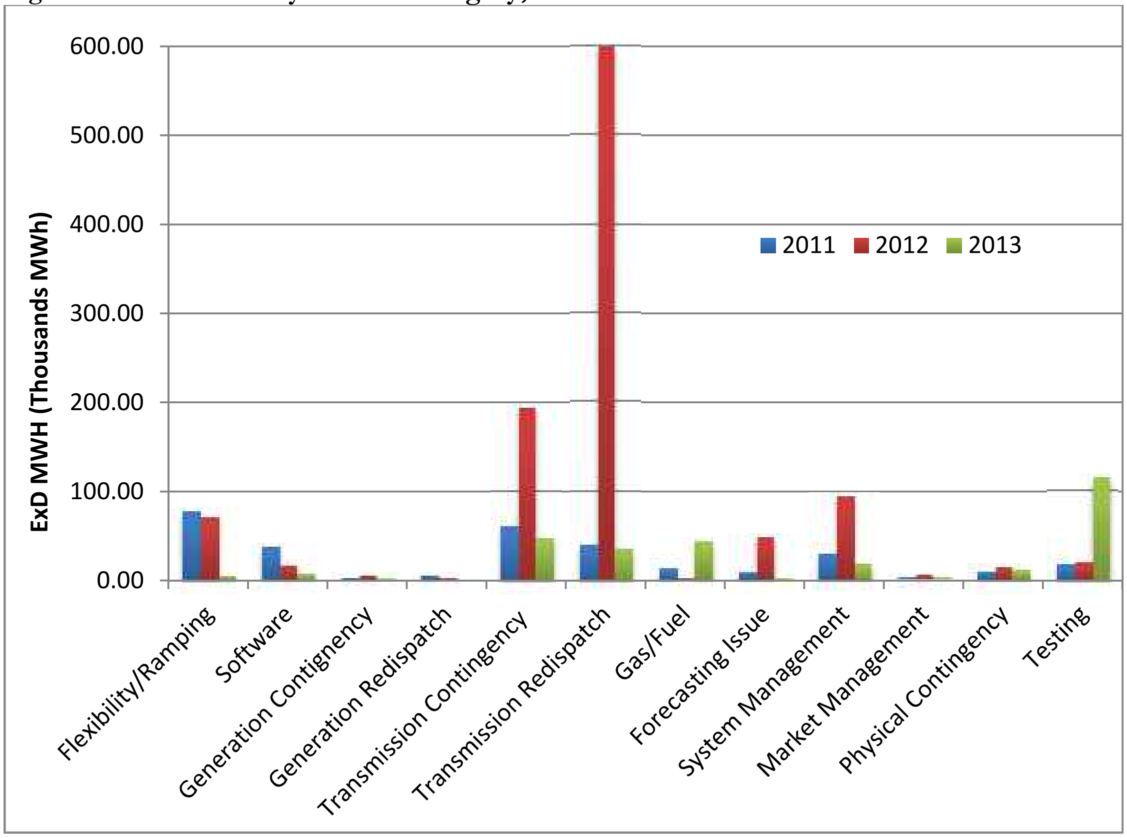


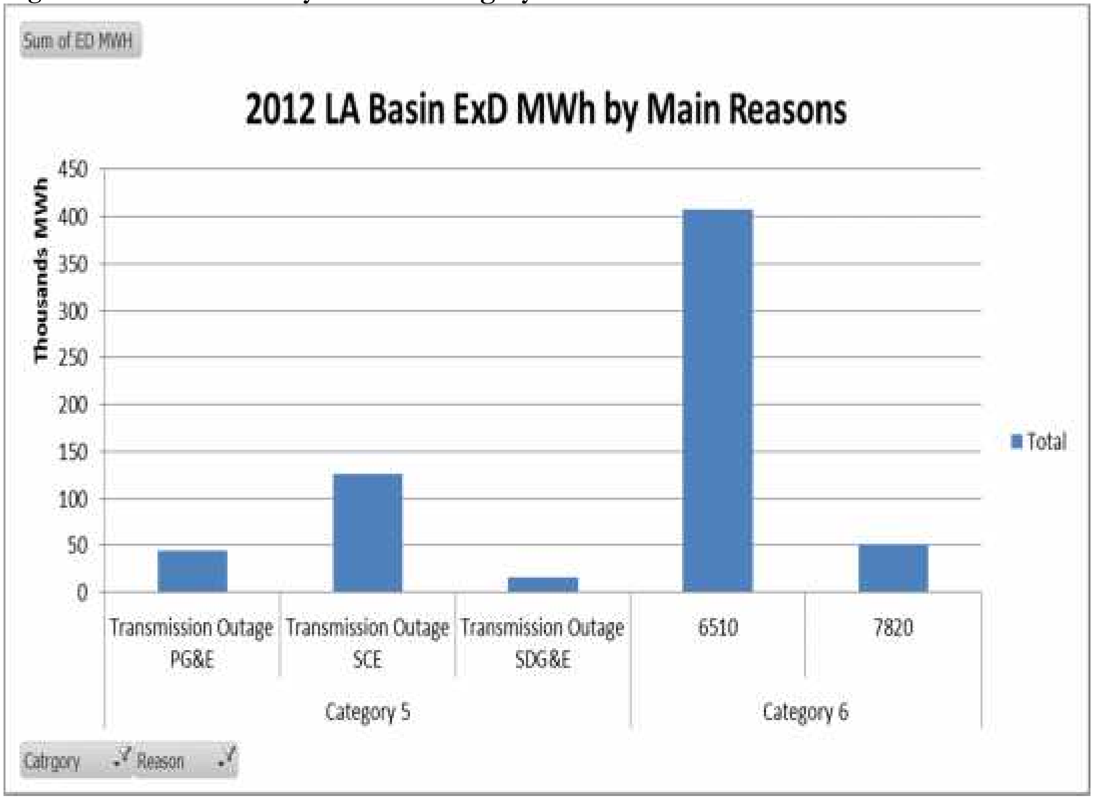
Figure 14 shows the ExD MWh by category. In 2012, the Transmission Physical Contingency category was significant and the Transmission Related Redispatch category was extremely high. As a result, CPUC staff focused further analysis of these two categories in 2012.

Figure 14. ExD MWh by Reason Category, 2011-2013



Further analysis on these two categories shows that "Transmission Outages in SCE" were the main cause in Transmission Physical Contingency category 5 and "6510" transmission procedure stood out in the Transmission Related Re-dispatch category 6 (shown in Figure 14). Around 62.7% of the total ExD MWH in 2012 was due to ExD to accommodate the "6510" transmission procedure. Figure 15 illustrates the significant impact of these two case codes and the large impact of category 6510 overall.

Figure 15. ExD in 2012 by Reason Category

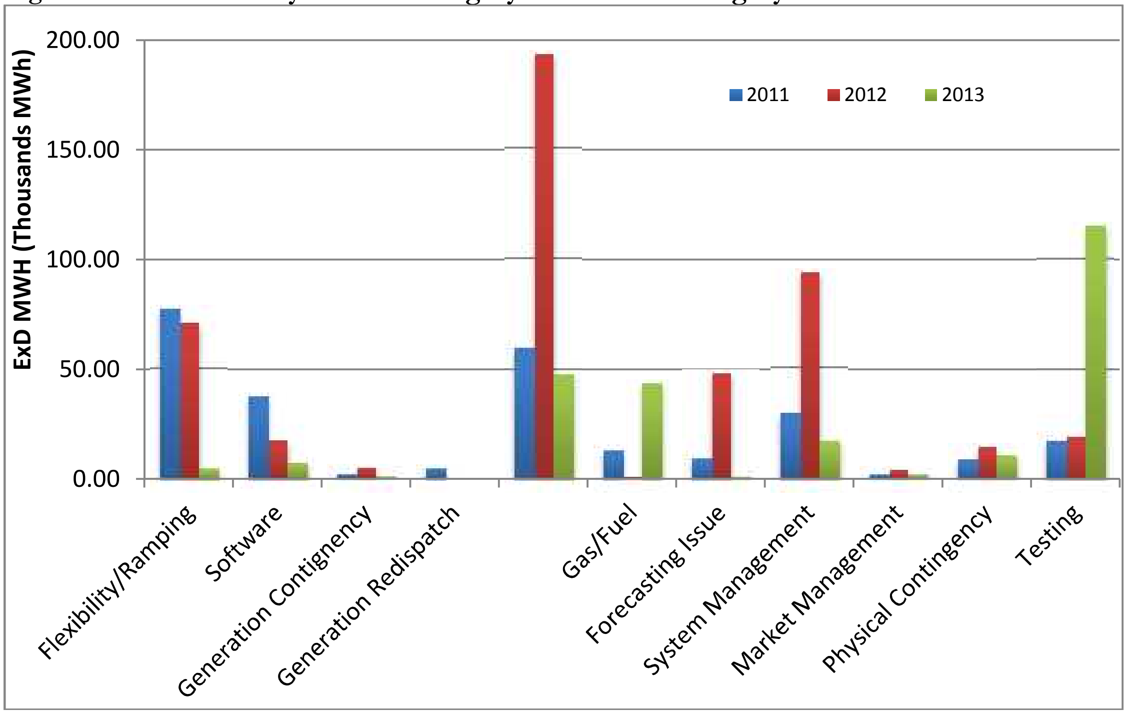


The "6510" transmission procedure, also known as Southern California Import Transmission (SCIT), is a CAISO operating procedure designed to redispatch generators in Southern California to account for imports into Southern California. Operating Procedures are explained on the CAISO website.[37] The sudden retirement of SONGS units 2 and 3 likely provided the rationale for marked increases in SCIT during 2012. The significant ExD amounts related to SCIT may be attributable to SONGS retirement, but it is possible that there was other transmission and generation contingency related redispatch in the LA Basin and San Diego in 2012 as well.

In studying the possible effects of SONGS retirement, ED staff examined other operating procedures that may also be related to SONGS. Operating procedure "7820" (San Diego Area) and "Transmission Outage SCE" were also examined and tabulated. These three reason codes total to a significant amount of ExD MWh in 2012. If the Transmission Redispatch category, containing "6510", "7820" and "Transmission Outage SCE", removed from the charts above, other reason codes stand out and the resolution of the chart is increased as reflected in Figure 16. Figure 16 reflects the following issues in more detail: Flexibility/Ramping problems in 2011, Forecasting Issue and System Management issue in 2012, and Unit Testing Issue in 2013. A significant amount of new capacity (both conventional and renewable) came online during the course of 2013, so that could explain some of the increase in unit testing but more examination might be warranted.

[37] http://www.caiso.com/rules/Pages/OperatingProcedures/Default.aspx

Figure 16. ExD MWh by Reason Category – Removed Category 6



Cost related to ExD is another significant issue. It is important to know if ExD costs were largely correlated with the MWh dispatched, and if ExD has a large economic impact. For example, since Unit Testing explained for a large amount of ExD in 2013, it is necessary to know the cost related to it. If the cost was also high, it may serve as a warning signal.

Figure 17. ExD Cost by Reason Category

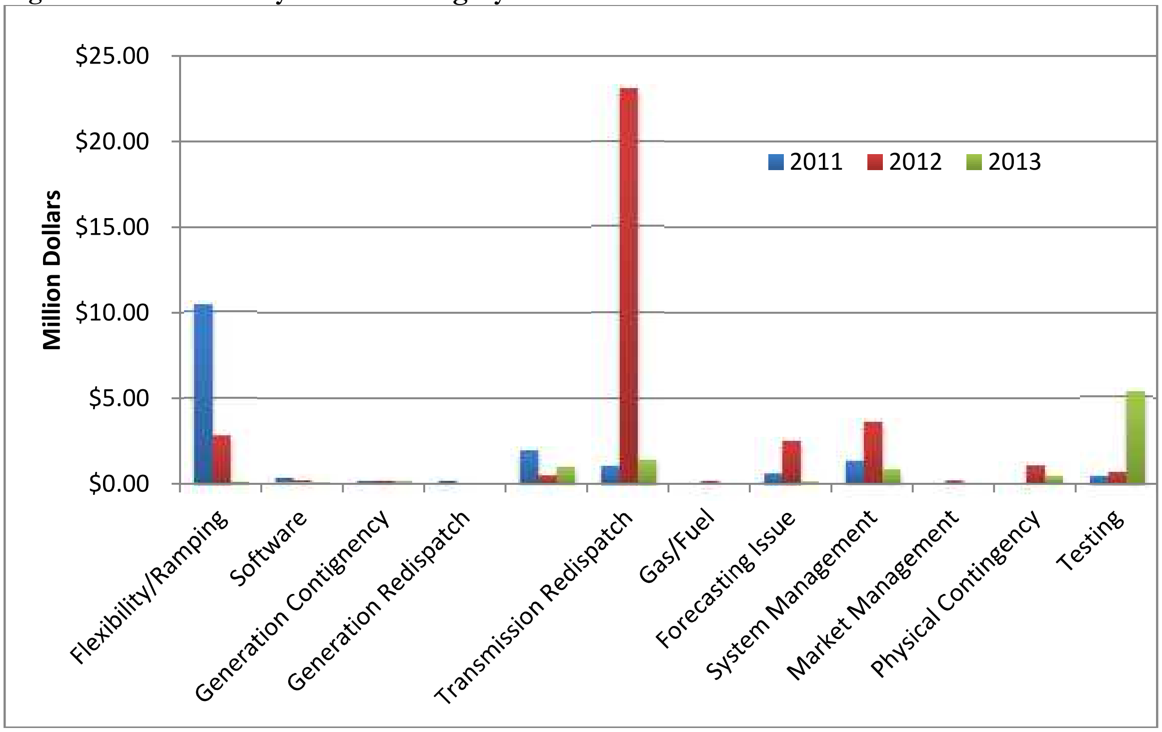
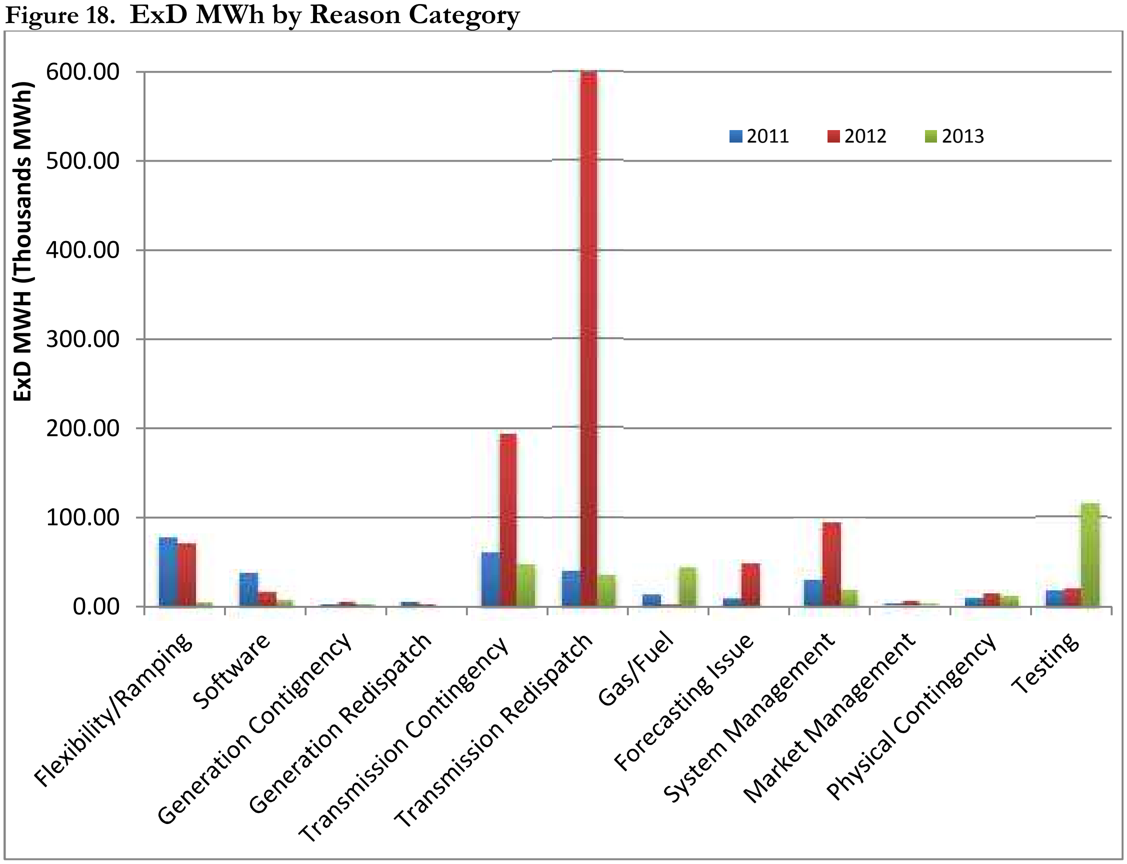


Figure 18. ExD MWh by Reason Category



According to the Exceptional Dispatch Report on CAISO website, the best estimate of the cost of ExD is to consider the following four cost categories: CC6470 INC, CC6470 DEC, CC6482 and CC6488. In this paper, CPUC staff estimated the total cost related to ExD by summing up these four costs.

As is shown in Figure 17 and

Figure 18 above, the pattern of ExD cost is consistent with the pattern of MWh distribution on the whole. The highest ExD costs related to events categorized in the Transmission Redispatch category during 2012. ExD costs related to Flexibility/Ramping in 2011 and Unit Testing in 2013 were also significant, however, Flexibility/Ramping related ExD in 2011 was not as high as indicated by the cost, meaning that the average cost of each MWh related to Flexibility/ Ramping category was higher than average costs for other categories. Transmission Contingency related average costs were very low though the MWh was relatively high, indicating that Transmission Contingency did not result in significant economic consequences. For Transmission Redispatch category, most of the cost was also related to 6510 as is shown in Figure 19.

Figure 19. 2012 ExD Costs by Reason Category

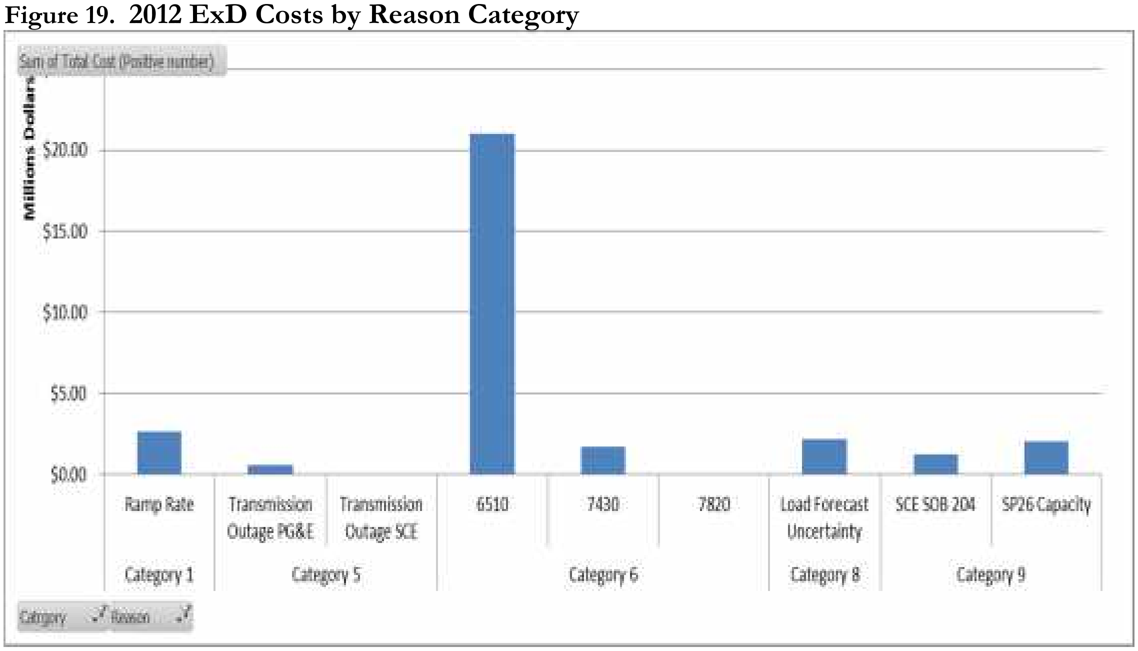
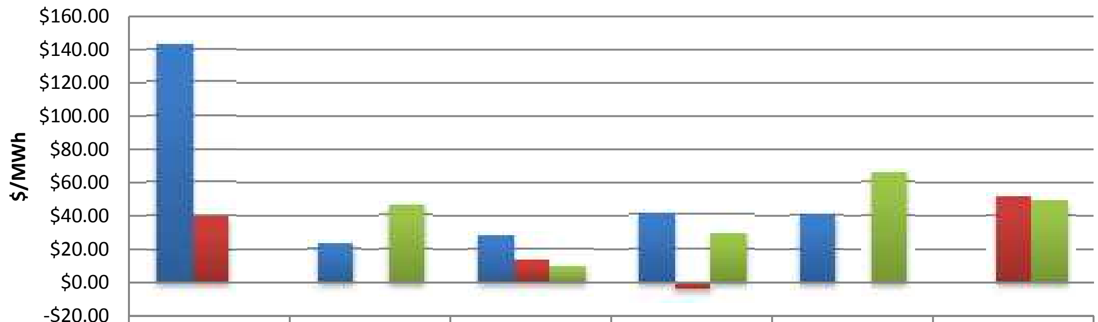


Figure 20 shows the average cost per MWh of some main key codes. The average cost of ExD related to Ramp Rate issues was $143.25/MWh in 2011, the highest among all the key reason codes; however, the cost and MWh of Ramp Rate related ExD reduced over the years.

Figure 20. Average ExD Costs per MWh



	Ramp Rate	Unit Testing	Transmission Outage PG&E	Transmission Outage SCE	Transmission Outage SDG&E	6510
2011	$143.25	$23.56	$28.14	$41.70	$41.29	
2012	$39.59		$12.81	-$3.89		$51.52
2013		$46.70	$9.57	$29.23	$66.06	$48.84

5 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.[38] The applicable data sets and data conventions are laid out in the adopted QC methodology manual, which is posted on the CPUC website.[39] 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 historical production. The CPUC executes a subpoena for settlement quality meter data from the ISO and performs 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.

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 resource's deliverable capacity, the NQC is adjusted to the deliverability capacity value. The CAISO conducts the deliverability assessment for both new and existing resources two to three times a year pursuant to the Large Generator Interconnection Procedures (LGIP).[40] 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 three 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 that the ISO list includes NQC value requests from non-CPUC jurisdictional LSEs. The CPUC NCQ values 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.[41] This NQC list includes information on the Local Area, the Zonal Area, and the deliverability of each resource. Once posted, no changes are permitted to the list except for addition of new resources and correction of clerical errors.

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[38] http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/119856.htm (QC manual adopted as Appendix B).
[39] http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_compliance_materials.htm
[40] The CAISO's deliverability assessment methodology is available at http://www.caiso.com/23d7/23d7e41c14580.pdf
[41] http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_compliance_materials.htm

5.1 New Resources and Retirements in 2013 and 2014

2013 and 2014 saw numerous additions to the fleet. In particular, many new solar resources came online including such large facilities as the 306.23 MW Ivanpah solar thermal generator (Units 1-3) and Desert Sunlight AV Solar Ranch 1, a 411.7 MW solar PV installation.[42] Additionally, several new natural gas generators such as Walnut Creek, Marsh Landing, Sentinel, El Segundo and Russell City came online during 2013. This new capacity was able to compensate for the loss of capacity from the retirement of the SONGS in 2013, as well as closures of Contra Costa Units 6 & 7, El Segundo Unit 3, and Morro Bay Units 3 & 4 in compliance with the State's phase out of once-through-cooling. Overall, 1,290.23 MW were added in calendar year 2013, with 4,704.68 MW of new capacity coming online and 3,414.45 MW retired. In total, 1,269 MW of NQC were added in 2014 with 2,151.6 MW of new capacity and 882.6 MW retired.

Table 19 and Table 20 list the new and retiring facilities for 2013 and 2014, respectively. Net dependable capacity, as determined by the ISO, is also listed for new facilities as facilities 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. For example, in 2013, the net dependable capacity of facilities that came online was over 1,000 MW greater than the assigned NQC values.

Table 19. New NQC Resources Online in 2013

Resource ID	Resource Name	Technology	NQC[43]	Net Dependable Capacity
ALPSLR_1_NTHSLR	Alpaugh North, LLC	Solar PV	16.28	20.00
ALPSLR_1_SPSSLR	Alpaugh 50 LLC	Solar PV	40.72	50.00
ALT6DN_2_WIND7	Alta 2012 Alta Wind 7	Wind	29.33	168.00
ALT6DS_2_WIND9	CPC East Alta Wind IX	Wind	23.04	132.00
ARBWD_6_QF	Wind Resource II	Wind	3.48	19.95
ATWELL_1_SOLAR	Atwell Island PV Solar Generating Facility	Solar PV	16.28	20.00
BREGGO_6_SOLAR	NRG Borrego Solar One	Solar PV	21.17	26.00
CATLNA_2_SOLAR	Catalina Solar - Phases 1 and 2	Solar PV	89.59	110.00
CAVLSR_2_BSOLAR	California Valley Solar Ranch-Phase B	Solar PV	32.57	40.00
CAVLSR_2_RSOLAR	California Valley Solar Ranch-Phase A	Solar PV	70.49	210.00
CHINO_2_JURUPA	Jurupa	Solar PV	-	1.50
CHINO_2_SASOLR	Nautilus Solar Energy	Solar PV	-	1.50
COCOPP_2_CTG1	Genon Marsh Landing Gen Station Unit 1	Combustion Turbine	191.35	204.20
COCOPP_2_CTG2	Genon Marsh Landing	Combustion	189.30	202.70

[42] NQC lists for 2013-2015 are available at: http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

[43] August NQC values are reported for facilities with NQC's that vary by month. If no NQC value is listed, that indicates an energy only facility.

	Gen Station Unit 2	Turbine		
COCOPP_2_CTG3	Genon Marsh Landing Gen Station Unit 3	Combustion Turbine	191.45	208.96
COCOPP_2_CTG4	Genon Marsh Landing Gen Station Unit 4	Combustion Turbine	191.44	204.29
CONTRL_1_CASAD1	Mammoth G1	Geothermal	2.53	10.00
CONTRL_1_CASAD3	Mammoth G3	Geothermal	7.86	14.00
CORONS_2_SOLAR	SunEdison - Corona	Solar PV	-	0.99
CPVERD_2_SOLAR	Campo Verde Solar	Solar PV	113.21	139.00
CRELMN_6_RAMON1	Ramona 1	Solar PV	1.63	2.00
CRELMN_6_RAMON2	Ramona 2	Solar PV	4.07	5.00
CSLR4S_2_SOLAR	Imperial Valley (Csolar IV)	Solar PV	105.88	130.00
DAVIS_1_SOLAR1	Grasslands 3	Solar PV	-	1.00
DAVIS_1_SOLAR2	Grasslands 4	Solar PV	-	1.00
DEVERS_1_SOLAR	Cascade Solar	Solar PV	-	18.50
DEVERS_1_SOLAR1	SEPV8	Solar PV	-	12.00
DEVERS_1_SOLAR2	SEPV9	Solar PV	-	9.00
ELSEGN_2_UN1011	El Segundo Energy Center 5/6	CCGT	263.00	263.00
ELSEGN_2_UN2021	El Segundo Energy Center 7/8	CCGT	263.68	263.68
ETIWND_2_CHMPNE	Champagne	Solar PV	-	1.00
ETIWND_2_RTS010	SPVP010 Fontana RT Solar	Solar PV	1.12	1.50
ETIWND_2_RTS015	SPVP015 Fontana RT Solar	Solar PV	2.25	3.00
ETIWND_2_RTS023	SPVP023 Fontana RT Solar	Solar PV	1.87	2.50
GATES_2_SOLAR	Gates Solar Station	Solar PV	16.28	20.00
GATES_2_WSOLAR	West Gates Solar Station	Solar PV	-	10.00
GENESI_2_STG	Genesis Station	Solar Thermal	203.61	250.00
GLDTWN_6_COLUM3	Columbia 3	Solar PV	7.49	10.00
GLDTWN_6_SOLAR	Rio Grande	Solar PV	4.07	5.00
GLOW_6_SOLAR	Antelope Power Plant	Solar PV	-	20.00
GRIDLY_6_SOLAR	Gridley Main Two	Solar PV	-	2.50
GUERNS_6_SOLAR	Guernsey Solar Station	Solar PV	16.28	20.00
IVANPA_1_UNIT1	Ivanpah 1	Solar Thermal	102.62	123.20
IVANPA_1_UNIT2	Ivanpah 2	Solar Thermal	95.29	133.00
IVANPA_1_UNIT3	Ivanpah 3	Solar Thermal	108.32	133.00
KANSAS_6_SOLAR	RE Kansas South	Solar PV	-	20.00
KNGBRG_1_KBSLR1	Kingsburg 1	Solar PV	-	1.50
KNGBRG_1_KBSLR2	Kingsburg 2	Solar PV	-	1.50
LECEF_1_UNITS	Los Esteros Energy Facility (Aggregate)	Gas Peaker	293.88	294.00
NEENCH_6_SOLAR	Alpine Solar	Solar PV	53.75	66.00
OCTILO_5_WIND	Ocotillo Wind Energy Facility	Wind	46.26	265.00
OLIVEP_1_SOLAR	White River Solar	Solar PV	16.28	20.00
PEORIA_1_SOLAR	Sonora 1	Solar PV	1.22	1.50
RSMSLR_6_SOLAR1	Rosamond One	Solar PV	-	20.00

RSMSLR_6_SOLAR2	Rosamond Two	Solar PV	-	20.00
RUSCTY_2_UNITS	Russell City Energy Center	CCGT	585.70	612.80
SBERDO_2_RTS048	SPVP048	Solar PV	-	5.00
SENTNL_2_CTG1	CPV Sentinel Unit 1	Combustion Turbine	91.00	92.09
SENTNL_2_CTG2	CPV Sentinel Unit 2	Combustion Turbine	91.00	92.40
SENTNL_2_CTG3	CPV Sentinel Unit 3	Combustion Turbine	91.00	92.36
SENTNL_2_CTG4	CPV Sentinel Unit 4	Combustion Turbine	91.00	91.98
SENTNL_2_CTG5	CPV Sentinel Unit 5	Combustion Turbine	91.00	91.83
SENTNL_2_CTG6	CPV Sentinel Unit 6	Combustion Turbine	91.00	92.16
SENTNL_2_CTG7	CPV Sentinel Unit 7	Combustion Turbine	91.00	91.84
SENTNL_2_CTG8	CPV Sentinel Unit 8	Combustion Turbine	91.00	91.56
VESTAL_2_WELLHD	Wellhead Power Delano	Combustion Turbine	49.00	49.00
VLCNTR_6_VCSLR1	Valley Center 1	Solar PV	2.04	2.50
VLCNTR_6_VCSLR2	Valley Center 2	Solar PV	4.07	5.00
WALCRK_2_CTG1	Walnut Creek Energy Park Unit 1	Combustion Turbine	96.00	96.43
WALCRK_2_CTG2	Walnut Creek Energy Park Unit 2	Combustion Turbine	96.00	96.91
WALCRK_2_CTG3	Walnut Creek Energy Park Unit 3	Combustion Turbine	96.00	96.65
WALCRK_2_CTG4	Walnut Creek Energy Park Unit 4	Combustion Turbine	96.00	96.49
WALCRK_2_CTG5	Walnut Creek Energy Park Unit 5	Combustion Turbine	96.65	96.65
WAUKNA_1_SOLAR	Corcoran Solar	Solar PV	16.28	20.00
		Total	**4704.68**	**5846.12**

Resources that Retired in 2013

Resource ID	Resource Name	Technology	NQC
CLRKRD_6_COALCN	Coal Canyon Hydro	Hydro	0.00
COCOPP_7_UNIT 6	Contra Cost Unit 6	Steam Turbine	337.00
COCOPP_7_UNIT 7	Contra Costa Unit 7	Steam Turbine	337.00
ELSEGN_7_UNIT 3	El Segundo Gen Sta. Unit 3	Steam Turbine	335.00
FAYETT_1_UNIT	Arcadian Renewable Power Corp	Wind	0.00
GWFPW1_6_UNIT	GWF Power Systems Inc. #1	CHP	16.55
GWFPW2_1_UNIT 1	GWF Power Systems Inc. #2	CHP	17.87
GWFPW3_1_UNIT 1	GWF Power Systems Inc. #3	CHP	15.95
GWFPW4_6_UNIT 1	GWF Power Systems Inc. #4	CHP	18.23
GWFPW5_6_UNIT 1	GWF Power Systems Inc. #5	CHP	18.10

JAKVAL_2_IONE	Jackson Valley Energy Ptnrs (IONE)	Biomass	0.00
JRWOOD_1_UNIT 1	San Joaquin Power Company	CHP	0.00
KALINA_2_UNIT 1	Altamont Cogeneration Corp.	CHP	0.00
KERKH1_7_UNIT 2	Kerkhoff Ph 1 Unit #2	Hydro	8.50
KRNOIL_7_TEXEXP	Texaco Exploration & Prod QF Aggregation	CHP	0.00
MARKHM_1_CATLST	San Jose Cogen	CHP	0.00
MCARTH_6_BIGVAL	Big Valley Power	Biomass	0.00
MTNPWR_7_BURNEY	Ogden Power Pacific Inc. (Burney)	Biomass	5.83
NAPA_2_UNIT	Napa Hospital	CHP	0.00
NAVY35_1_UNITS	Occidental of Elk Hills, Inc.	CHP	0.00
OAK L_7_EBMUD	East Bay M.U.D. (Oakland)	Biogas	0.66
SMPAND_7_UNIT	Wheelabrator Lassen Inc.	CHP	0.00
SONGS_7_UNIT 2	San Onofre Nuclear Unit 2	Nuclear	1122.00
SONGS_7_UNIT 3	San Onofre Nuclear Unit 3	Nuclear	1124.00
STOKCG_1_UNIT 1	Stockton Cogen Co.	Biomass	32.67
SUISUN_7_CTYFAI	City of Fairfield Generation Aggregate	CHP	0.01
UNTDQF_7_UNITS	United Airlines (Cogen)	CHP	25.08
		Total	**3414.45**

Table 20. New NQC Resources Online in 2014

Resource ID	Resource Name	Technology	NQC	Net Dependable Capacity
ADOBEE_1_SOLAR	Adobe Solar	Solar PV	14.97	20.00
ALTA6B_2_WIND11	Alta Wind 11	Wind	13.78	90.00
ALTA6E_2_WIND10	Alta Wind 10	Wind	21.13	138.00
ARVINN_6_ORION1	Orion 1 Solar	Solar PV	8.98	12.00
ARVINN_6_ORION2	Orion 2 Solar	Solar PV	5.99	8.00
AVSOLR_2_SOLAR	AV Solar Ranch 1	Solar PV	187.14	241.50
BREGGO_6_DEGRSL	Desert Green Solar Farm	Solar PV	4.72	6.50
CAMLOT_2_SOLAR2	Camelot 2	Solar PV	11.23	15.00
CAYTNO_2_VASCO	Vasco Road	Biogas	4.30	4.30
CNTNLA_2_SOLAR1	Centinela Solar Energy Facility (Phase I)	Solar PV	95.06	127.00
CNTNLA_2_SOLAR2	Centinela Solar Energy 2	Solar PV	-	45.60
COGNAT_1_UNIT	Stockton Biomass	Biomass	25.46	48.00
CORRAL_6_SJOAQN	Ameresco San Joaquin	Biogas	3.24	4.30
DSRTSN_2_SOLAR1	Desert Sunlight 300	Solar PV	224.56	300.00
DSRTSN_2_SOLAR2	Desert Sunlight 250	Solar PV	187.14	250.00
IVSLRP_2_SOLAR1	Silver Ridge Mount Signal	Solar PV	149.71	200.00
LAMONT_1_SOLAR1	Regulus Solar	Solar PV	44.91	60.00
LASSEN_6_AGV1	AGV 1	Geothermal	1.43	1.80

LEPRFD_1_KANSAS	Kansas	Solar PV	14.97	20.00
MIDWD_6_WNDLND	Windland Refresh I	Wind	1.14	7.45
MSOLAR_2_SOLAR1	Mesquite Solar 1	Solar PV	134.38	165.00
NZWIND_6_CALWND	Wind Resource I	Wind	1.23	9.00
OAKWD_6_ZEPHWD	Zephyr Park	Wind	0.54	3.50
OLDRIV_6_BIOGAS	Bidart Old River 1	Biogas	1.51	2.00
OLDRV1_6_SOLAR	Old River One	Solar PV	14.97	20.00
OLIVEP_1_SOLAR2	White River West	Solar PV	14.78	19.75
OTAY_6_LNDFL5	Otay 5	Biogas	1.47	1.50
OTAY_6_LNDFL6	Otay 6	Biogas	1.47	1.50
PUTHCR_1_SOLAR1	Putah Creek Solar Farm	Solar PV	1.48	1.98
REEDLY_6_SOLAR	Terzian	Solar PV	-	1.23
SAMPSN_6_KELCO1	CP Kelco Cogeneration Facility	CHP	0.57	25.00
SANDLT_2_SUNITS	Mojave Solar	Solar Thermal	187.14	250.00
SLSTR1_2_SOLAR1	Solar Star 1	Solar PV	172.92	285.00
SLSTR2_2_SOLAR2	Solar Star 2	Solar PV	176.29	276.00
TMPLTN_2_SOLAR	Vintner Solar	Solar PV	1.12	1.50
TOPAZ_2_SOLAR	Topaz Solar Farms	Solar PV	411.70	550.00
TRNSWD_1_QF	FPL Energy C Wind	Wind	5.97	38.97
VICTOR_1_EXSLRA	Expressway Solar A	Solar PV	-	2.00
VICTOR_1_EXSLRB	Expressway Solar B	Solar PV	-	2.00
WEBER_6_FORWRD	Forward	Biogas	4.20	4.20
		Total	**2151.60**	**3259.58**

Resources that Retired in 2014

Resource ID	Resource Name	Technology	NQC*
BLHVN_7_MENLOP	Gas Recovery Sys. (Menlo Park)	Biogas	0.88
BRDGVL_7_BAKER	Baker Station Associates, LP Hydro	Hydro	0.00
BULLRD_7_SAGNES	Saint Agnes Med. Ctr	CHP	0.03
EGATE_7_NOCITY	North City Unit (Eastgaste)	Biogas	0.26
HICKS_7_GUADLP	Gas Recovery Sys. (Guadalupe)	Biogas	1.74
HOLGAT_1_MOGEN	Mojave Cogeneration Co. LP	CHP	51.19
KEARNY_7_KY1	Kearny Gas Turbine Unit 11	Gas Peaker	16.00
LAFRES_6_QF	La Fresa QFS	Biogas	1.44
LEWSTN_7_WEBRFL	Pan Pacific (Weber Flat)	Hydro	0.00
MCGEN_1_UNIT	Ace Cogeneration	CHP	96.89
MIDWAY_1_QF	Small QF Aggregation - Bakersfield	Biogas	0.01
MORBAY_7_UNIT 3	Morro Bay Unit 3	Steam Turbine	325.00
MORBAY_7_UNIT 4	Morro Bay Unit 4	Steam Turbine	325.00
MTNLAS_6_UNIT	Ogden Power Pacific, Inc. (Mt Lassen)	Biomass	9.56
SANJOA_1_UNIT 1	San Joaquin Cogen	CHP	48.00
SMARQF_1_UNIT 1	Santa Maria Cogen	CHP	0.00

VESTAL_6_WDFIRE	Sierra Power Corporation	Biomass	6.60
		Total	**882.60**

Source: 2013-2015 NQC lists posted to the CAISO website[44]

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.[45]

5.2 Aggregate NQC Values 2010 through 2015

Table 21 shows aggregate NQC values from the CAISO NQC lists for 2010 through 2015.[46] 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 decreased 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 rather than 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.

The total 2014 NQC (as reported on the CAISO 2014 NQC list) decreased by 224 MW from the 2013 NQC list and the 2015 NQC decreased by 116 MW from the 2014 list. The NQC lists for both years saw large increases in the resources listed by the end of the year, as many new facilities became operational in 2012, 2013, and 2014. 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. There also may be 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 only partial capacity. While these adjustments in large part mitigated the retirement losses in 2013 and 2014, there was still a small decline in the 2014 and 2015 total NQC values. In addition, there has been a trend towards smaller facilities as more renewables have come online with a net increase of 156 facilities but only 656 MW between 2010 and 2015.

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

[45] http://www.energy.ca.gov/sitingcases/all_projects.html

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

Table 21. Final NQC Values for 2010 – 2015

Year	Total NQC (MW)	Total Number of Scheduling Resource IDs	Net NQC Change (MW)	Net Gain in CAISO IDs on List
2010	52,340	646		
2011	51,929	647	-411	1
2012	50,442	657	-1,487	10
2013	53,336	733	2,894	76
2014	53,112	765	-224	32
2015	52,996	802	-116	37
2010-15			**656**	**156**

Source: NQC lists from 2010 through 2015.

6 Compliance with RAR

CPUC staff continued the implementation of the RA program during 2013 and 2014 and built on experience from past years.

6.1 Overview of the RA Filing Process

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

As in previous years, Energy Division hosted two workshops in 2012 (one in August and one in September), to discuss general compliance rules as well as to highlight changes in procedures and filing rules new to the 2013 compliance year. Energy Division also hosted a workshop in July 2013 to discuss changes in procedures and filing rules new to the 2014 compliance year. During the workshops, 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 included detailed instructions tabs. The workshop, RA guide, and templates were 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 2013 filing guide and templates were made available to LSEs in October 2012. The 2013 System and Local RA filing templates and guides were very similar to those used in 2012. Slight changes were made to implement the new RA rules adopted in D.12-06-025. The final 2014 filing guide and templates were made available to LSEs in August and November 2013. More changes were made to implement the new RA rules adopted in D.13-06-024, particularly flexible capacity procurement targets. As in previous years, the CPUC required that all filings be submitted simultaneously to the CAISO and CEC.

6.2 Compliance Review

CPUC staff, in coordination with the CEC and CAISO, reviewed all compliance filings received 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 scheduling coordinators for 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 2013 and 2014, 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.

6.3 Enforcement and Compliance

The essence of the RA program is mandatory LSE acquisition of capacity to meet load and reserve requirements. The short timeframes in which the CPUC, CAISO and CEC staff must verify that adequate capacity has been procured and 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.

6.4 Enforcement Actions in the 2006 through 2014 Compliance Years

Pursuant to Commission Resolution E-4195[47] 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 22 summarizes enforcement actions and citations taken by the Commission since the inception of the RA program in 2006. From 2006 through 2014, the Commission issued 32 citations for violations and initiated 4 enforcement cases, collecting $128,600 and $847,500 respectively from LSEs. In 2013, the Commission issued five citations and took no enforcement action, ultimately collecting $26,500 from LSEs. In 2014, the Commission issued one citation and took no enforcement action, ultimately collecting $5,000 from LSEs.

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

Table 22. Enforcement Summary Pursuant to the RA Program Since 2006

Compliance Year	Citations Issued	LSEs Cited	Citation Penalties	Enforcement Cases	LSEs Enforced	Enforcement Penalties
2006	1	Commerce Energy	$1,500	0		0
2007	3	3Phases; Commerce Energy; Amer. Util. Network	$5,000	1	CNE	$107,500
2008	7	3Phases (2); Commerce Energy (2); Corona DWP; Sempra Energy; Shell Energy	$17,000	1	Calpine	$225,000
2009	4	Commerce Energy (3); CNE	$26,500	1	CNE	$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	PG&E	$215,000
2012	4	Glacial Energy of CA, Shell Energy, SDG&E, Direct Energy Business	$14,600	0		
2013	5	SDG&E, Commerce Energy, 3 Phases, Liberty Power (2)	$26,500	0		0
2014	1	3 Phases	$5,000	0		0
Total	**32**		**$128,600**	**4**		**$847,500**

Source: CPUC enforcement records.

7 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.[48]

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

7.1 Performance and Availability for RA Resources in CAISO

On January 1, 2010, the CAISO implemented the SCP provisions for conventional generation. The SCP created an availability standard that was intended to be utilized by counterparties in bilateral capacity contracting as a performance metric that they could refer to. The product defines annual and monthly availability standards that are used for evaluating the performance of RA resources. SCP also provides incentives for RA capacity to participate in the energy market and meet a resource-specific must offer obligation through rewarding high performing resources and penalizing low performing resources. The adopted provisions include:

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.

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

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.[49] 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 current SCP price is tied to the Capacity Procurement Mechanism (CPM), which is currently $70.88 per kW-year ($5.91/kW-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.[50]

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 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 23 and Table 24 below present SCP data[51] for the period from January 2013 to December 2014. These data include: availability standards, charges, incentive payments, and performance. The table shows that in 2013 on average 28,104 MW[52] of RA capacity from generators and 1,936 MW[53] of RA capacity from interties were subject to SCP rules. This is about a 13 percent increase in the number of generator MW subject to SCP and about a 68 percent increase in the number of intertie MWs subject to SCP in 2012. The monthly availability standards ranged from 94.89% to 97.02 percent during 2013; actual availability of generators averaged 97.69 percent, which is an increase of 1.29 percent from the 96.4 percent 2012 average. The actual monthly availability average for intertie resources slightly increased from 99.6 percent in 2012 to 99.68 percent in 2013.

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

[50] Ibid

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

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

[53] *Ibid.*

In 2014, on average 29,383[54] MW of RA capacity from generators and 1,821 MW[55] of RA capacity from interties were subject to SCP rules. The monthly availability standards ranged from 95.1 percent to 97.71 percent during 2014; actual availability of generators averaged 98.21, which is an increase of .54 percent from the 2013 average. The 2014 actual monthly availability average for intertie resources stayed the same from 2013 to 2014 at 99.6 percent.

Table 23. 2013 RA Availability and SCP Payments

2013 Standard Capacity Product Report

	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Monthly Availability Standards	GENERATOR	97.48%	97.70%	97.02%	95.77%	94.89%	96.30%	96.56%	95.34%	95.52%	96.34%	96.11%	97.75%
	INTERTIE	97.48%	97.70%	97.02%	95.77%	94.89%	96.30%	96.56%	95.34%	95.52%	96.34%	96.11%	97.75%
Non-Availability Charges	GENERATOR	$ 1,508,766	$ 1,867,657	$ 2,051,275	$ 1,830,424	$ 777,314	$ 3,275,020	$ 3,790,047	$ 1,213,444	$ 1,850,329	$ 1,180,237	$ 1,755,742	$ 2,052,950
	INTERTIE	$ -	$ 716	$ -	$ 60,431	$ -	$ -	$ -	$ 123,183	$ 132,255	$ 98,093	$ -	$ 8
Availability Incentive Payment	GENERATOR	$ 71,433	$ -	$ 1,567,757	$ 1,830,424	$ 777,314	$ 3,275,020	$ 2,870,126	$ 1,213,444	$ 1,850,329	$ 1,180,237	$ 1,755,742	$ -
	INTERTIE	$ -	$ -	$ -	$ 60,431	$ -	$ -	$ -	$ 123,183	$ 132,255	$ 98,093	$ -	$ -
Monthly Surplus	GENERATOR	$ 1,437,333	$ 1,867,657	$ 483,518	$ -	$ -	$ -	$ 919,921	$ -	$ -	$ -	$ -	$ 2,052,950
	INTERTIE	$ -	$ 716	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8
Average Actual Availability (%)	GENERATOR	98.11%	98.02%	97.73%	97.90%	97.93%	96.77%	96.16%	98.35%	97.47%	98.47%	97.68%	97.70%
	INTERTIE	100.00%	99.84%	99.88%	99.15%	100.00%	99.95%	100.00%	99.34%	99.17%	98.89%	100.00%	99.96%
Average RA Capacity (MW)	GENERATOR	25,439	25,630	25,914	26,483	27,904	29,446	31,997	32,461	30,609	29,226	26,428	25,716
	INTERTIE	760	1,633	1,358	1,683	1,379	1,252	3,512	3,473	3,326	1,776	1,565	1,516

Source: CAISO 2013 Standard Capacity Product Report, http://www.caiso.com/Documents/2013StandardCapacityProductAnnualReport.pdf

54 This does not include RA capacity that is grandfathered in because it predates the implementation of SCP availability standards.
55 *Ibid.*

Table 24. 2014 RA Availability and SCP Payments

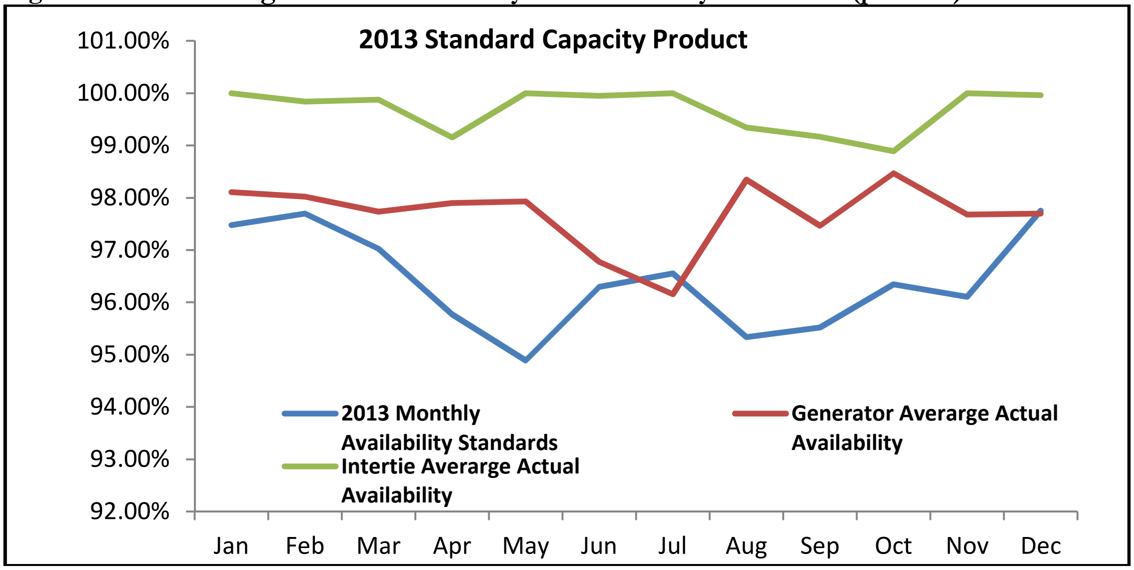
2014 Standard Capacity Product Report

	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Monthly Availability Standards	GENERATOR	97.71%	96.95%	96.77%	96.24%	95.34%	96.28%	96.87%	95.10%	95.89%	95.34%	95.90%	97.36%
	INTERTIE	97.71%	96.95%	96.77%	96.24%	95.34%	96.28%	96.87%	95.10%	95.89%	95.34%	95.90%	97.36%
Non-Availability Charges	GENERATOR	$ 1,438,763	$ 1,231,844	$ 994,933	$ 425,874	$ 1,518,447	$ 1,220,683	$ 1,118,278	$ 2,310,573	$ 1,412,093	$ 1,004,499	$ 601,062	$ 954,997
	INTERTIE	$ -	$ -	$ -	$ -	$ -	$ 19,367	$ 2,706	$ 1,667	$ 75,095	$ 100,189	$ -	$ 16,425
Availability Incentive Payments	GENERATOR	$ -	$ 1,231,844	$ 994,933	$ 425,874	$ 1,518,447	$ 1,220,683	$ 1,118,278	$ 2,310,573	$ 1,412,093	$ 1,004,499	$ 601,062	$ 460,545
	INTERTIE	$ -	$ -	$ -	$ -	$ -	$ 19,367	$ 2,706	$ 1,667	$ 75,095	$ 100,189	$ -	$ 16,425
Monthly Surplus	GENERATOR	$ 1,438,763	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 494,452
	INTERTIE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Actual Availability (%)	GENERATOR	98.38%	97.67%	98.41%	98.93%	97.88%	98.22%	98.26%	97.45%	97.90%	98.28%	98.55%	98.63%
	INTERTIE	99.65%	100.00%	100.00%	100.00%	100.00%	99.62%	99.75%	99.97%	98.91%	98.35%	100.00%	99.76%
Average RA Capacity (MW)	GENERATOR	25,205	24,787	25,084	26,723	28,004	30,574	35,462	37,200	33,997	31,312	27,327	26,914
	INTERTIE	1,586	1,673	1,661	1,429	1,679	1,780	2,150	3,159	2,163	1,640	1,479	1,448

Source: CAISO 2014 Standard Capacity Product Report,
http://www.caiso.com/Documents/2014StandardCapacityProductAnnualReport.pdf

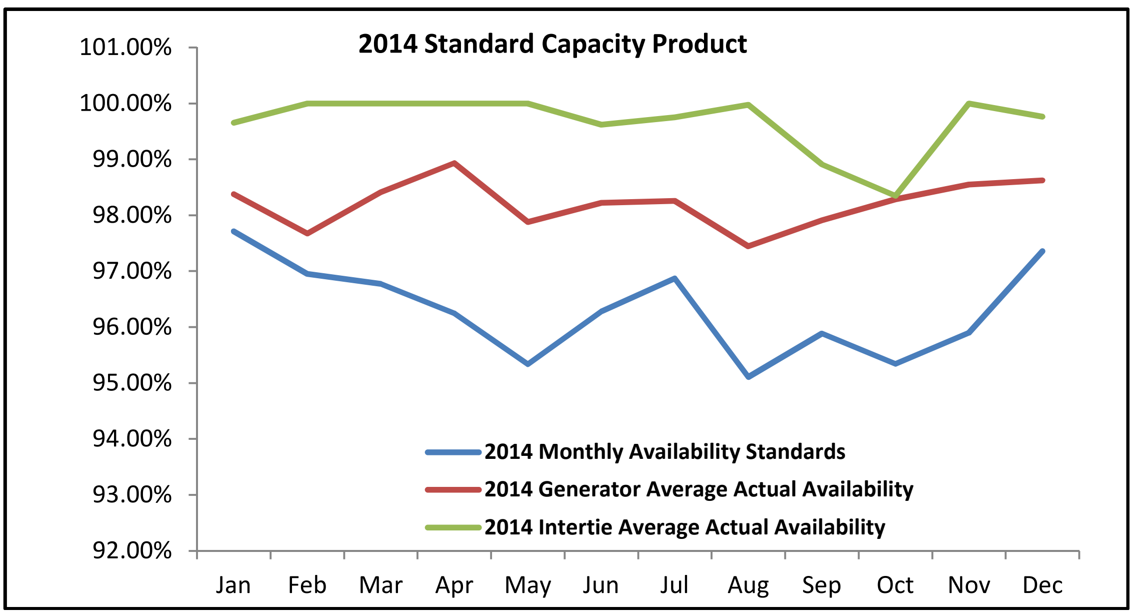
Figure 21 and Figure 22 illustrate the monthly availability standards and the average actual availability of both generators and interties in 2013 and 2014. In 2013 and 2014, interties show a higher average actual availability than the monthly availability standard for all months. This is roughly the same trend observed in the 2012 performance of interties, as shown in Figure 23. Figure 23 graphs the average monthly availability for interties and generators from 2012- 2014 compared with the annual availability standards. Generators show an improvement in their 2014 performance when compared with the 2012 and 2013 values.

Figure 21. 2013 Average Actual Availability vs. Availability Standards (percent)



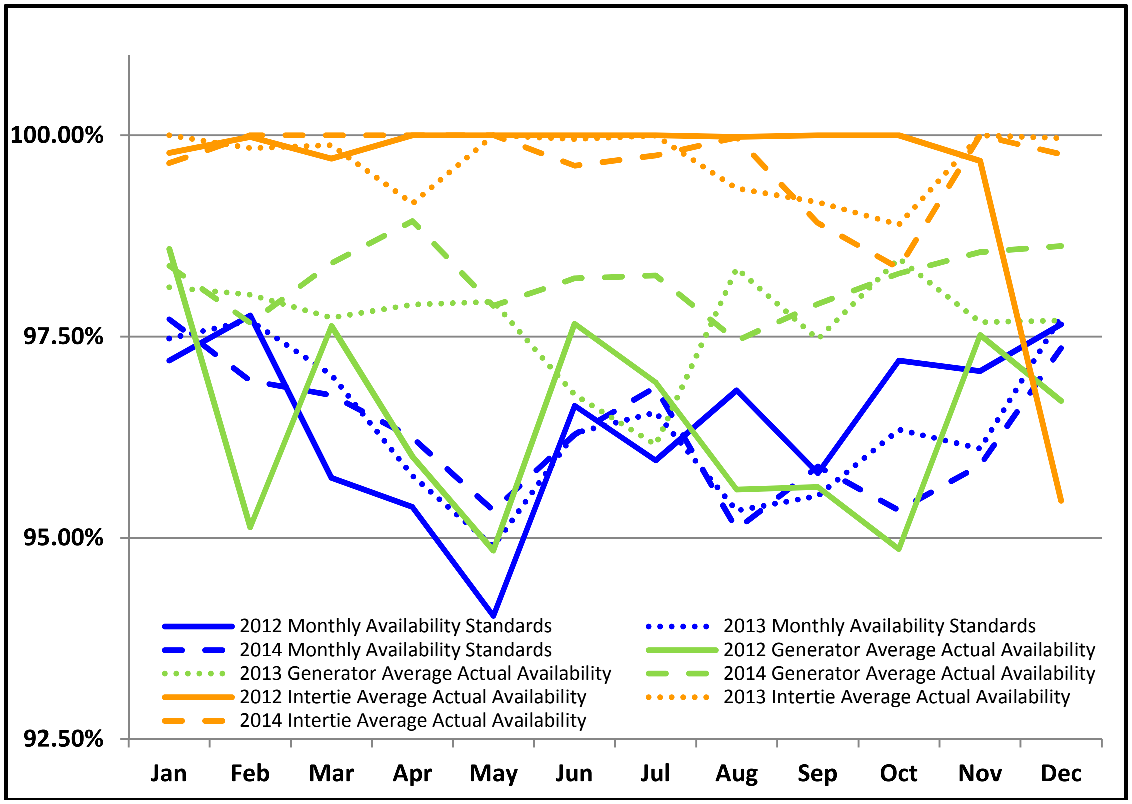
Source: 2013 Standard Capacity Product Report - http://www.caiso.com/Documents/2013StandardCapacityProductAnnualReport.pdf

Figure 22. 2014 Average Actual Availability vs. Availability Standards (percent)



Source: 2014 Standard Capacity Product Report http://www.caiso.com/Documents/2014StandardCapacityProductAnnualReport.pdf

Figure 23. 2012, 2013, and 2014 Average Actual Availability vs. Availability Standards



Source: CAISO 2012, 2013, & 2014 Standard Capacity Product Reports - http://www.caiso.com/Documents/2012StandardCapacityProductAnnualReport.pdf http://www.caiso.com/Documents/2013StandardCapacityProductAnnualReport.pdfhttp://www.caiso.com/Documents/2014StandardCapacityProductAnnualReport.pdf

In 2014, the ISO conducted a stakeholder process that reviewed the current availability incentive mechanism and specifically addressed the development of a flexible RA availability mechanism and new availability mechanism price which is set to expire February 16, 2016. The current tariff language, which is pending approval at FERC, seeks to change the mechanism so that generators are no longer evaluated based on SLIC outage information, but instead evaluated based on economic and self-scheduled bid information.

The new availability incentive mechanism will assess availability based on whether a resource is bid into the ISO energy markets consistent with their RA must-offer obligation during assessment hours. This mechanism will also be able to assess the newly functioning flexible capacity product, as well as a significant amount of capacity that is currently exempt from, and or not equitably subject to, the SCP.

Additionally, the tariff language seeks to change the current SCP price which is tied to the CPM (currently \$70.88 per kW-year or \$5.91/kW-month), to a price of \$3.79/kW-month. This price is calculated using 60% of the CPM soft offer cap price, which corresponds to a higher than average bilateral capacity price.

This new availability incentive mechanism, known as RAAIM, is currently pending FERC approval, which is expected in the fall of 2015. The new mechanism would take effect beginning in January 2016, with a 3-month advisory period.