



California ISO  
Your Link to Power

# Market Performance Metric Catalog

Version 1.3

August 24, 2009

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## ISO Market Services

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### VERSION HISTORY

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5/28/2009	1.0	Creation of document	Market Performance Group
6/25/2009	1.1	Document for May	Market Performance Group
7/25/2009	1.2	Document for June	Market Performance Group
8/24/2009	1.3	Document for July	Market Performance Group

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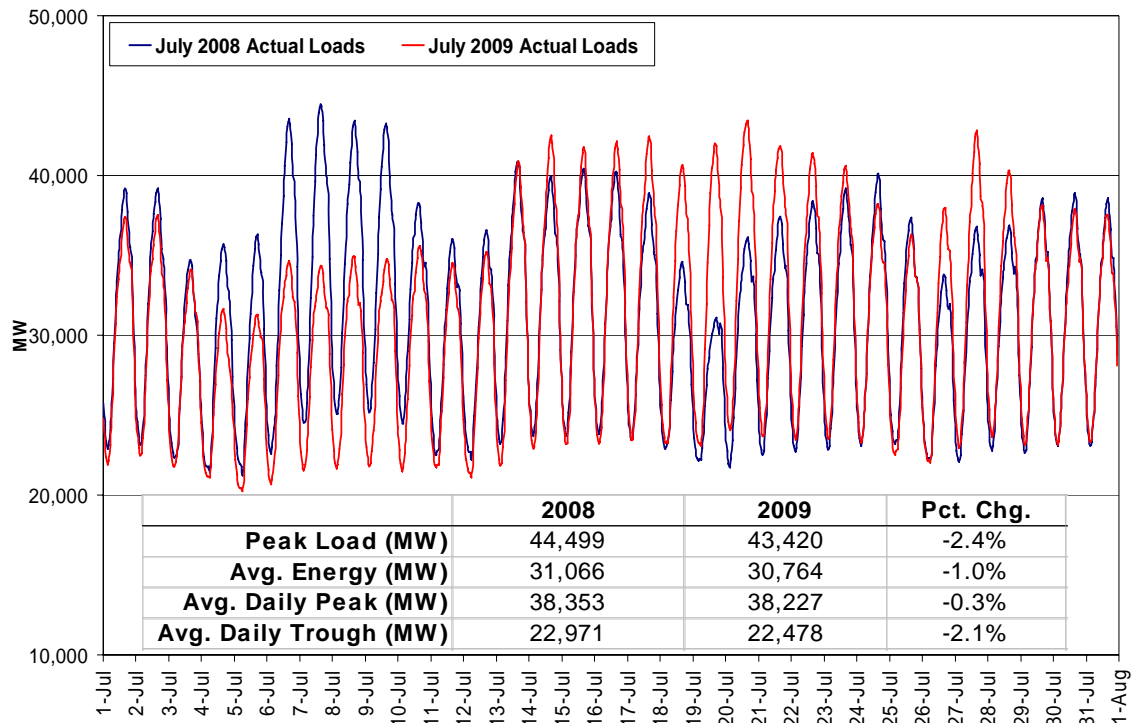
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## Market Characteristics

### Loads

Figure 1 compares total, hourly demand for the CAISO control area for the current calendar month with hourly demand for the same month in the prior year. An insert is included in the figure with summary statistics on Peak Load, Average Energy, Average Daily Peak and Average Daily Trough.

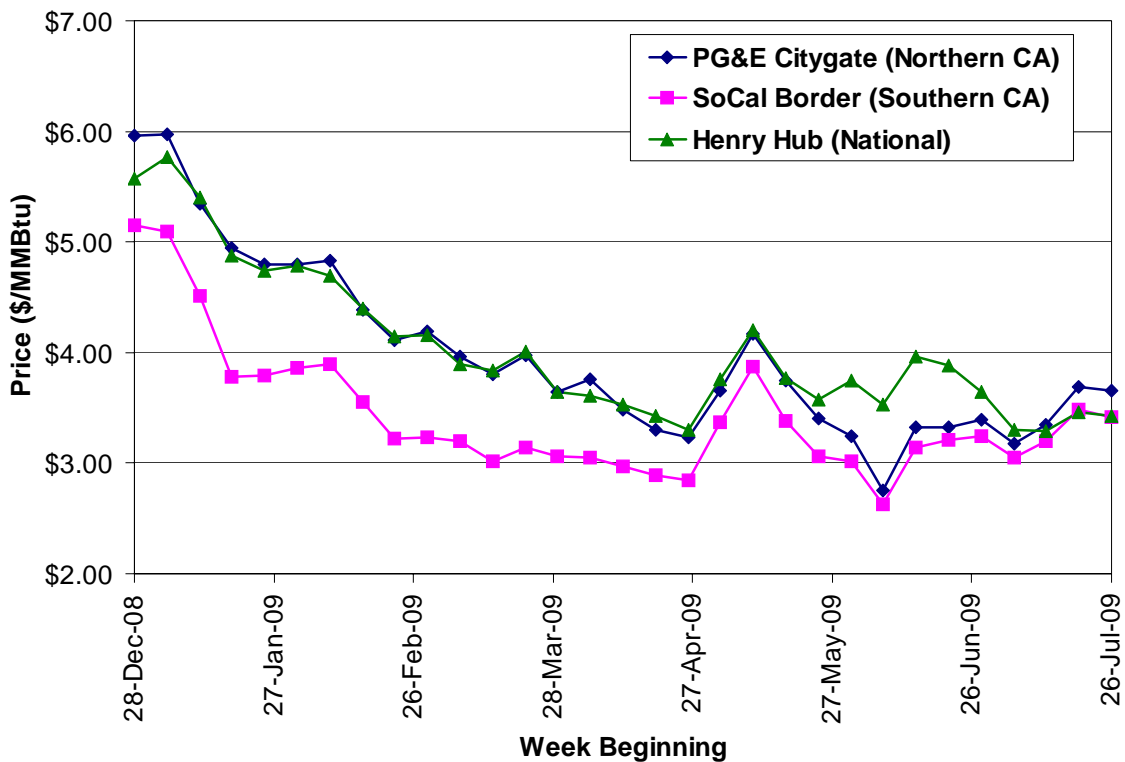
**Figure 1: System Load Comparison**



## Natural Gas Prices and Inventories

Figure 2 displays the weekly average of daily, natural gas spot prices for three selected trading hubs: PG&E Citygate as a proxy for Northern California, So Cal Border as a proxy for Southern California, and Henry Hub as a proxy for the rest of the U.S. Natural gas prices are important to the market as much of the capacity in the West – especially the newer units – is gas-fired. These units are also often marginal, meaning that they set the price levels in bilateral markets.

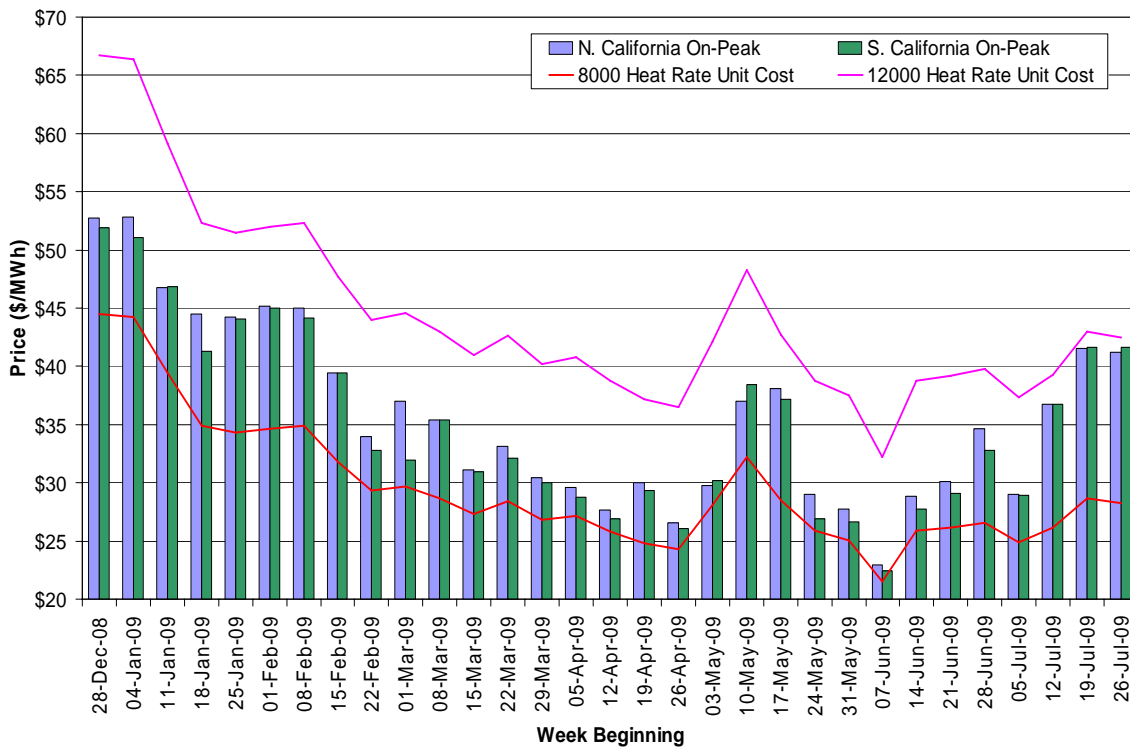
**Figure 2: Weekly Average Natural Gas Spot Prices  
– January 2008 to July 2009**



### Bilateral Electricity Prices

Figure 3 displays weekly average on-peak bilateral spot electricity price for Northern and Southern California. Bilateral electricity prices indicate the general level of prices at which electricity is being traded in California outside of the CAISO’s markets. In addition, the figure provides for reference the nominal gas costs for two assumed Combined Cycle Gas Turbines with average heat rates of 8,000 and 12,000 MMBtu per MWh, respectively. When loads are light or there is a surplus of generating capacity, spot prices should trend towards the 8,000 MMBtu cost curve reflecting that more efficient, modern gas turbines are setting the market price. Alternatively, when loads are high or generating capacity is otherwise scarce due to outages, then less efficient, higher cost turbines will become marginal and prices in Figure 3 should trend towards the 12,000 MMBtu cost curve.

**Figure 3: Daily Peak-Hour Bilateral Contract Prices – Weekly Averages**



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## Market Performance Metrics

### Energy

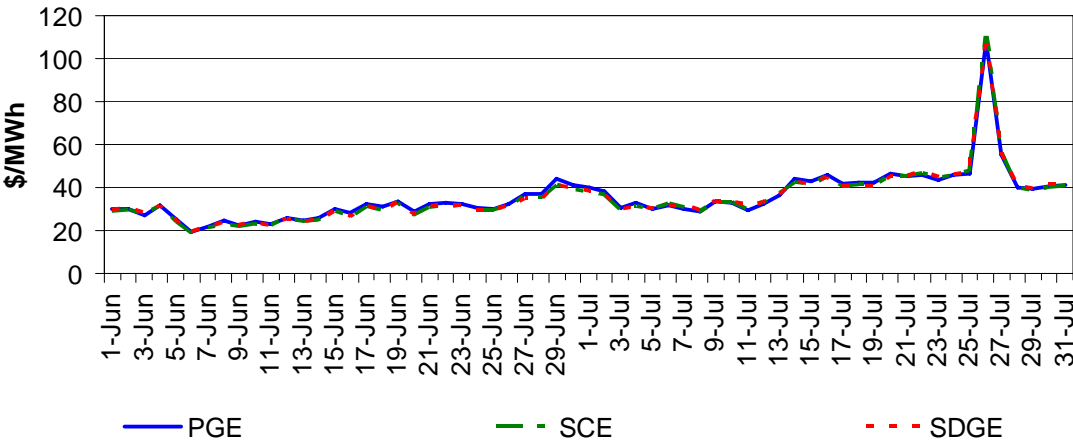
#### Day-Ahead Prices

Figure 4, Figure 5 and Figure 6 show the daily energy-weighted average LAP prices for each of the three major LAPs (PGE, SCE, and SDGE) for peak hours, off-peak hours, and all hours respectively in the day-ahead market. The formula for daily average price is:

$$P_i = \frac{\sum_j LMP_{ij} \cdot SCHE\_MW_{ij}}{\sum_j SCHE\_MW_{ij}} \quad i = \text{PGE, SCE, and SDGE}$$

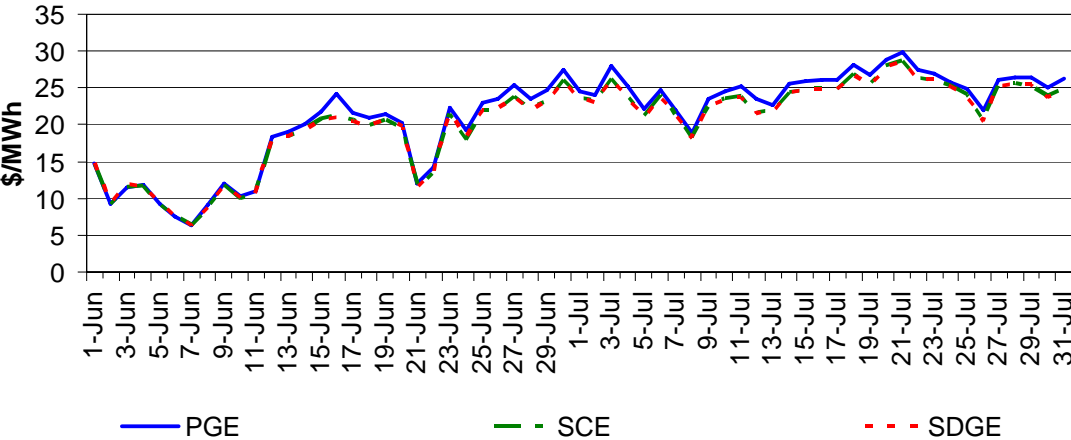
$P_i$  is the daily average price for LAP  $i$ , while  $j$  represents the hour (peak, off-peak, or all).  $LMP_{ij}$  is the LMP for LAP  $i$  in hour  $j$ .  $SCHE\_MW_{ij}$  is the scheduled energy in hour  $j$  for LAP  $i$ .

**Figure 4: Day-Ahead Weighted Average On-Peak LAP Prices**



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**Figure 5: Day-Ahead Weighted Average Off-Peak LAP Prices**



**Figure 6: Day-Ahead Weighted Average LAP Prices (All Hours)**

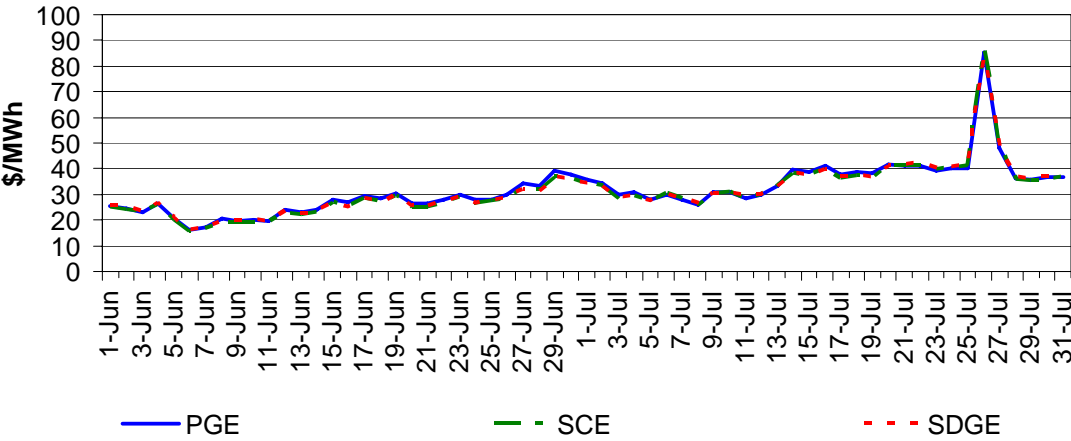
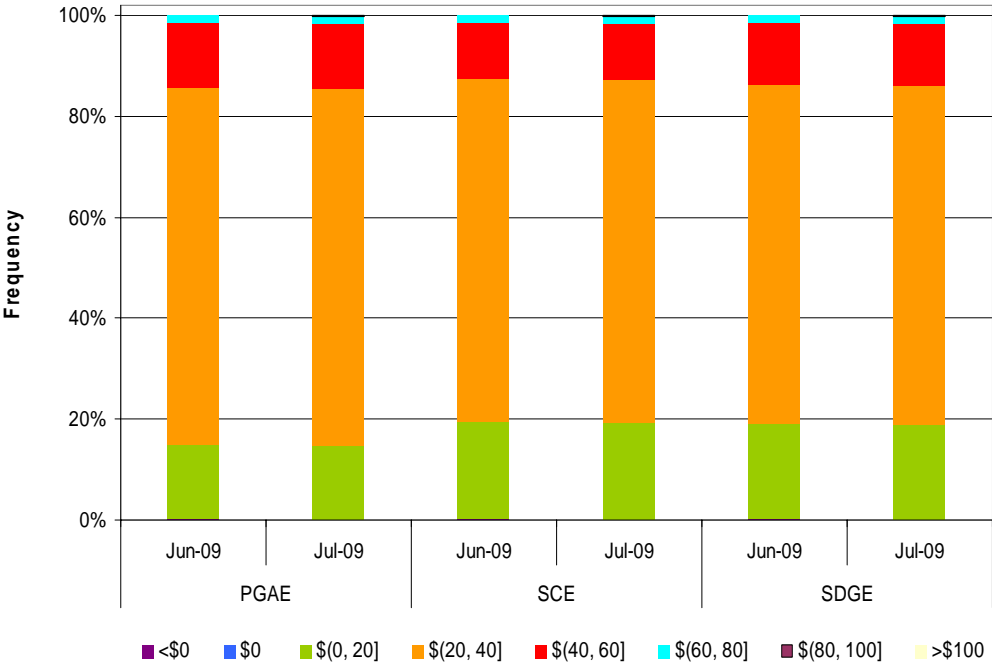


Figure 7 shows the frequency of the DLAP prices in the IFM. Prices are grouped in several bins. This frequency includes both time of uses On- and Off-peak.

**Figure 7: Frequency of Day-Ahead DLAP prices (All hours)**

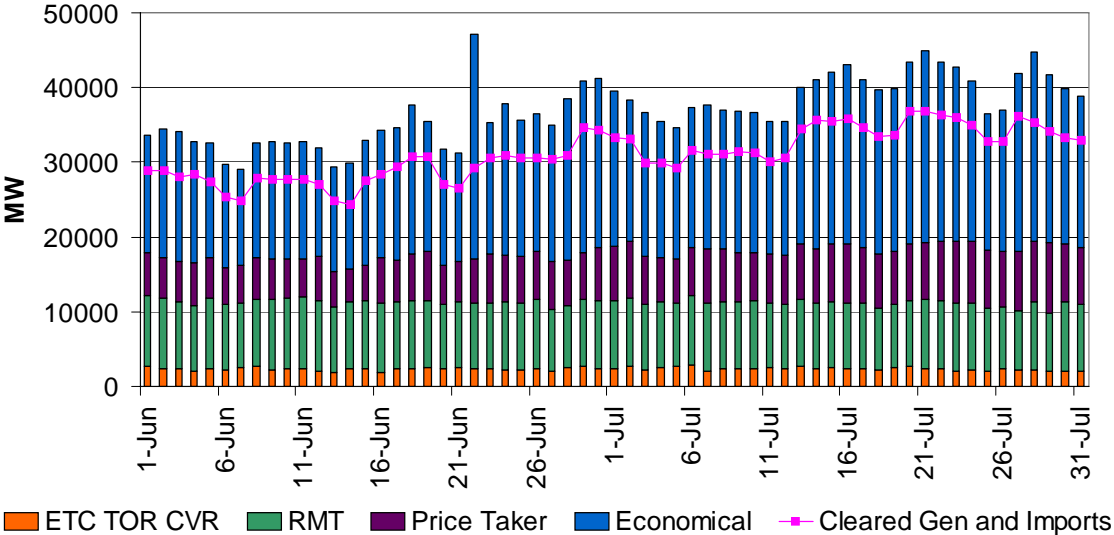


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**IFM Bid Stack**

Figure 8 shows the daily average IFM bid volume grouped into various types of self-schedules and economical bids. It also depicts the daily average cleared generation and Imports. In the IFM, sum of cleared generation and Imports is equal to the sum of cleared demand, pump schedule, loss and export. There are three types of self-schedules bid into the IFM market which are grouped based on priority<sup>1</sup>. ETC, TOR and CVR self schedule have the highest priority. RMT (regulatory must take) have a lower priority and the Price taker have the lowest priority of all self-schedules.

**Figure 8: IFM Bid Stack and Cleared Generation and Imports**



<sup>1</sup> This section is based on the CAISO Tariff Section 31.4, Uneconomic Adjustments in the IFM

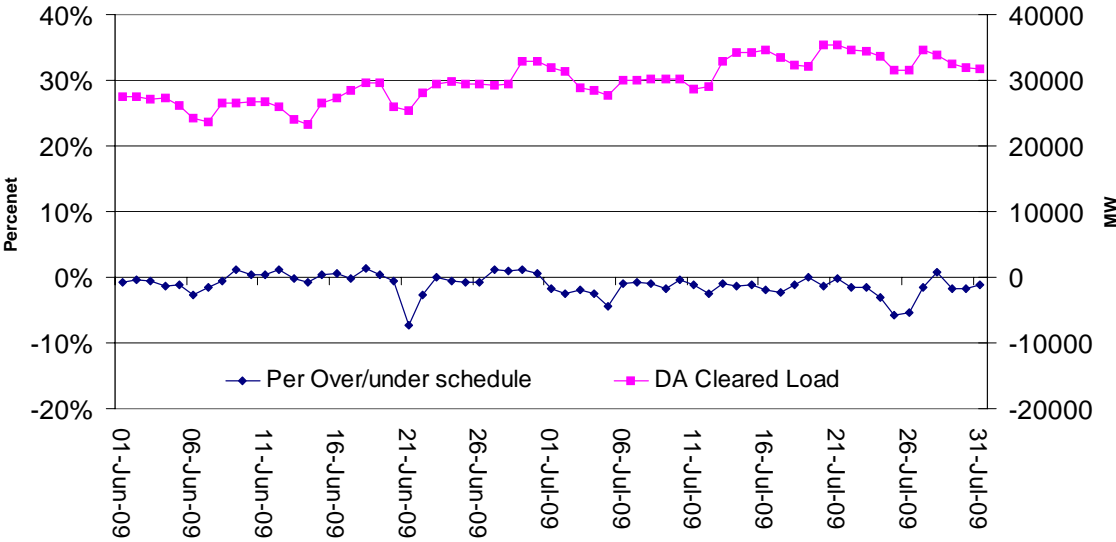
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**Day-Ahead Volumes**

Figure 9 below shows average scheduling deviation percentage in the IFM market and the daily average cleared load in the IFM market. The average scheduling deviation percentage is calculated as

$$\text{Percent Over/Under Schedule} = \frac{(\text{Daily\_Average\_Forecast} - \text{Daily\_Average\_Cleared\_load})}{\text{Daily\_Average\_Forecast}}$$

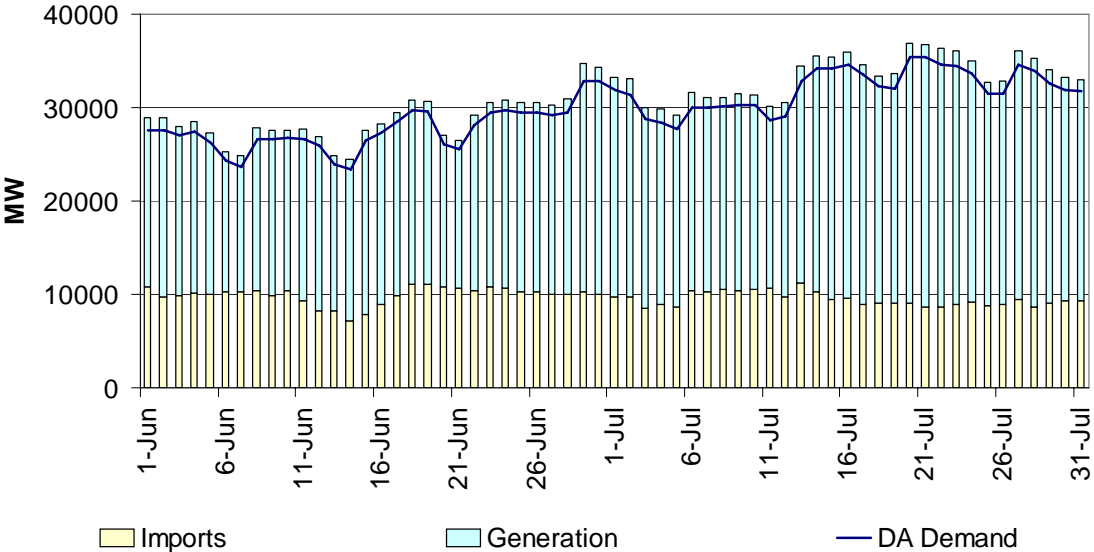
**Figure 9: IFM Scheduling Deviation and Cleared Load**



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Figure 10 below shows the daily average day-ahead cleared Imports, day-ahead generation (within the state of California) and day-ahead cleared demand in the IFM market. The day-ahead cleared demand includes day-ahead Losses, but excludes exports.

**Figure 10: Day-Ahead Cleared Quantity**



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**Real-Time Prices**

Figure 11, Figure 12 and Figure 13 show daily energy-weighted average LAP prices for each of the three major LAPs (PGE, SCE, and SDGE) for peak hours, off-peak hours, and all hours respectively in the Real-Time market. The formula for the daily average price is:

$$P_i = \sum_j \frac{\sum_h LMP_{ijh} * SCHE\_MW_{ijh}}{\sum_j \sum_h SCHE\_MW_{ijh}} \quad i= PGE, SCE, \text{ and } SDGE$$

$P_i$  is the daily average price for LAP  $i$ , while  $j$  represents the hour (peak, off-peak, or all) and  $h$  represents 5-minute interval.  $LMP_{ijh}$  is the LMP for LAP  $i$  in hour  $j$ , interval  $h$ .  $SCHE\_MW_{ijh}$  is the scheduled energy in hour  $j$ , interval  $h$  for LAP  $i$ .

**Figure 11: RTD Weighted Average On-Peak LAP Prices**

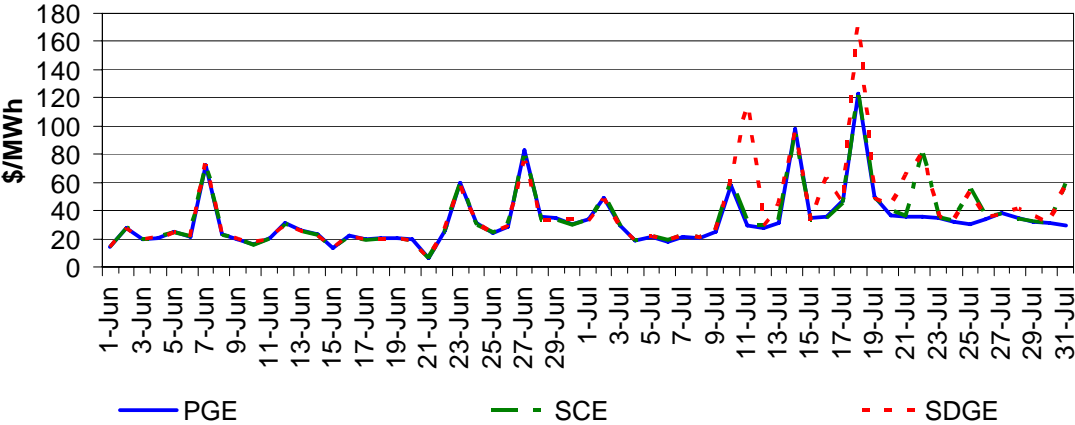


Figure 12: RTD Weighted Average Off-Peak LAP Prices

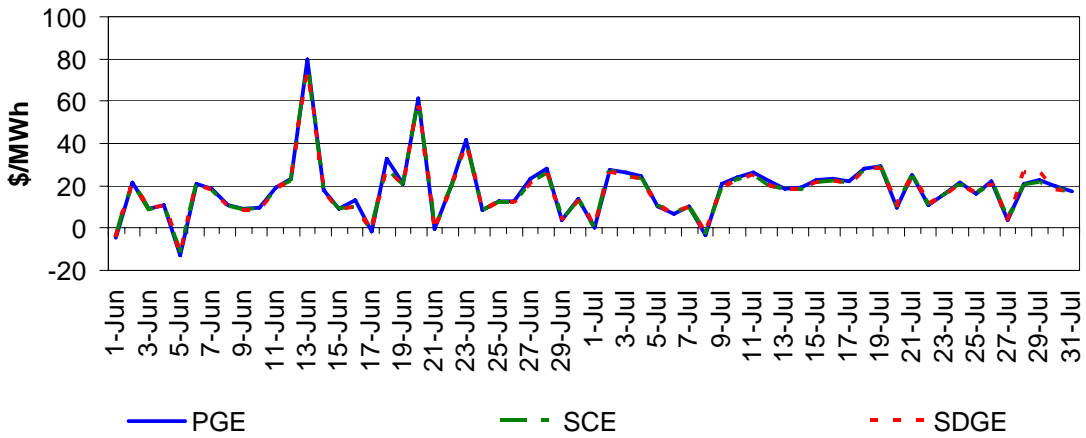
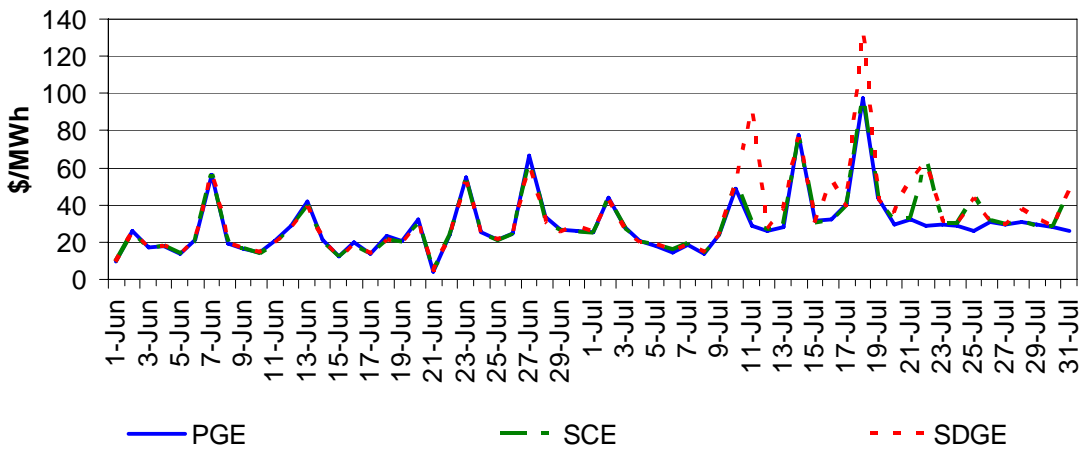


Figure 13: RTD Weighted Average LAP Prices (All Hours)



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**Real-Time Price Volatility**

Figure 14 shows the frequency of the DLAP prices in the RTM for all intervals in a month. Prices are grouped in several bins. This plot provides a reference of the frequency of prices in different ranges. This frequency includes both time of uses –On- and Off-peak – and is aggregated by DLAP in a monthly basis.

**Figure 14: Monthly Frequency of Real-Time DLAP Prices (All Intervals)**

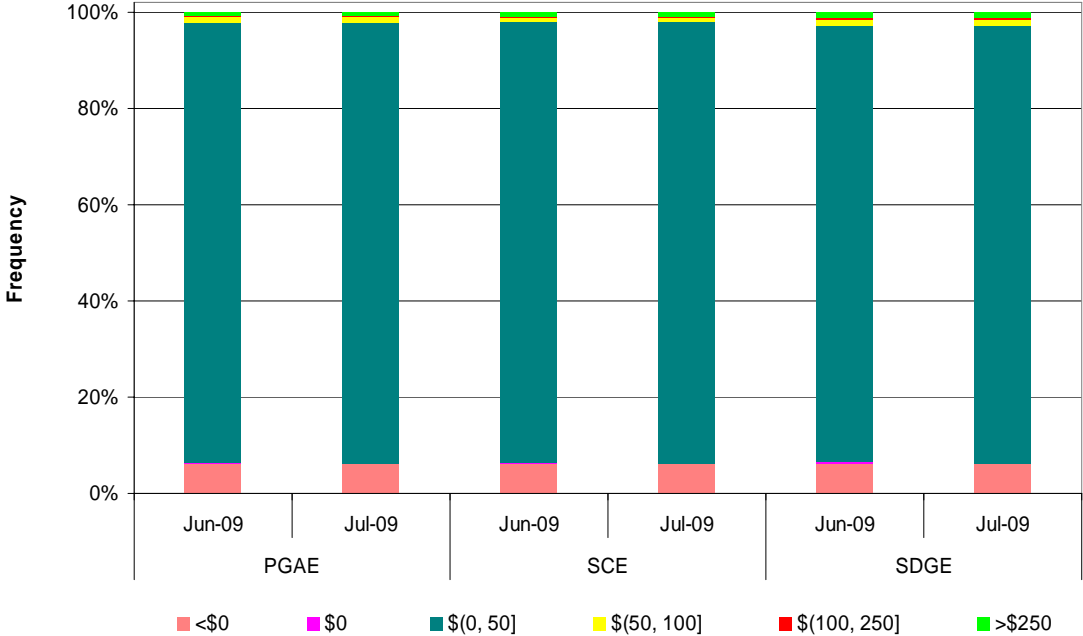


Figure 15 shows the monthly frequency of spikes, with respect to the overall number of price intervals in a month, for RTD LAP prices that are above \$250/MWh. The frequencies are aggregated in a monthly basis by DLAP.

**Figure 15: Monthly Frequency of RTD LAP Positive Price Spikes**

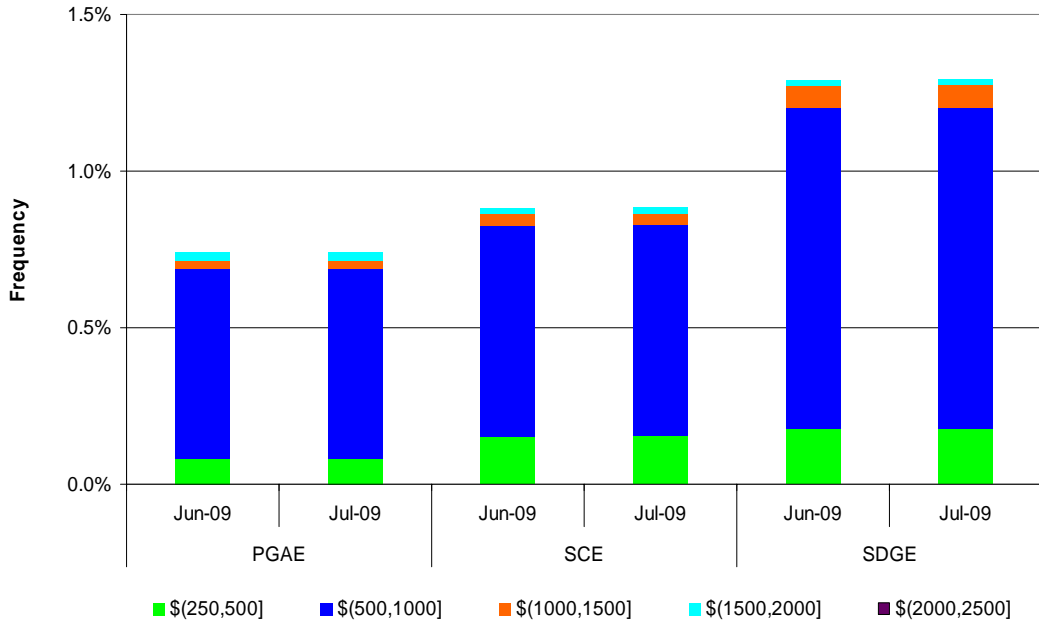
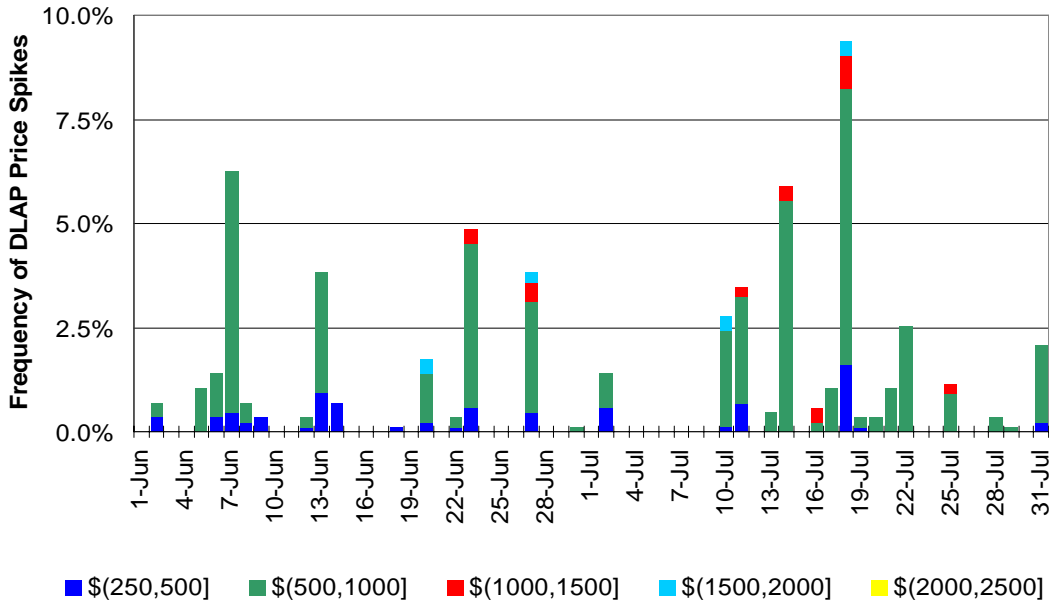


Figure 18 and Figure 19 show the daily breakdown of frequencies for prices below -30/MWh and above \$250/MWh, respectively. Prices are for all three DLAPs. These graphs may provide a trend of price spikes over time.

**Figure 16: Daily Frequency of RTD LAP Positive Price Spikes**



**Figure 17: Daily Frequency of RTD LAP Negative Price Spikes**

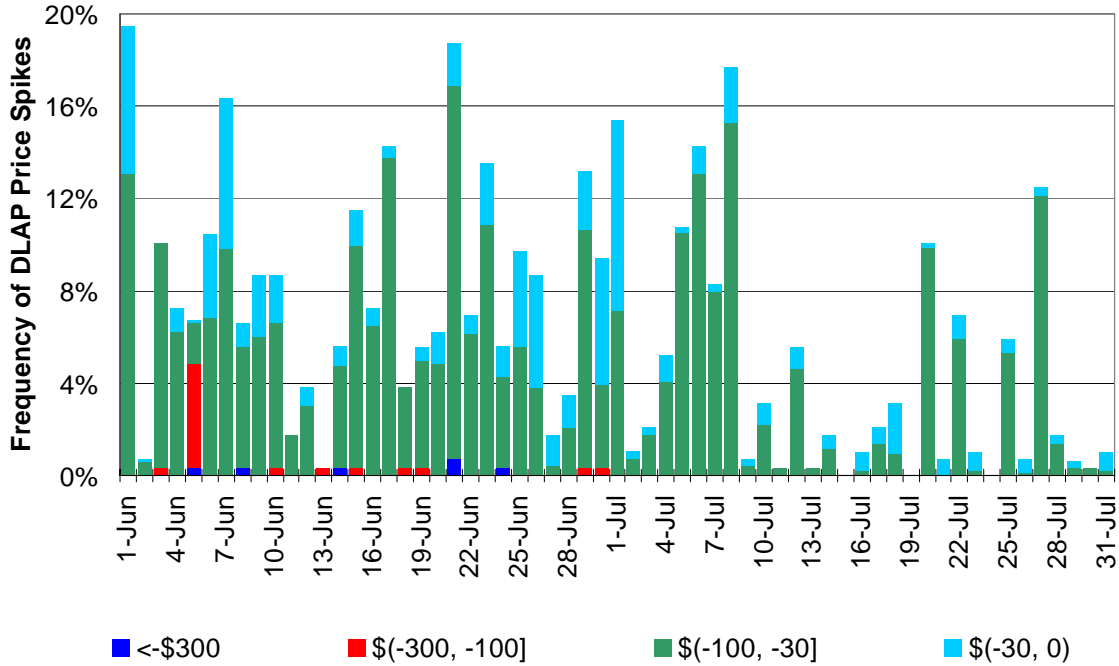


Table 1 summarizes the monthly average prices and volumes in Day-Ahead and Real-Time markets.

**Table 1: Summary of Prices and Volumes**

	Day-Ahead			Real-Time		
	Peak	Offpeak	All	Peak	Offpeak	All
Average Price (\$)	41.66	24.73	37.26	41.27	18.01	35.11
Volume (MWh)	15,589,802	5,473,487	21,063,289	15,242,775	5,487,896	20,730,672
Percentage	74.01%	25.99%	100.00%	73.53%	26.47%	100.00%

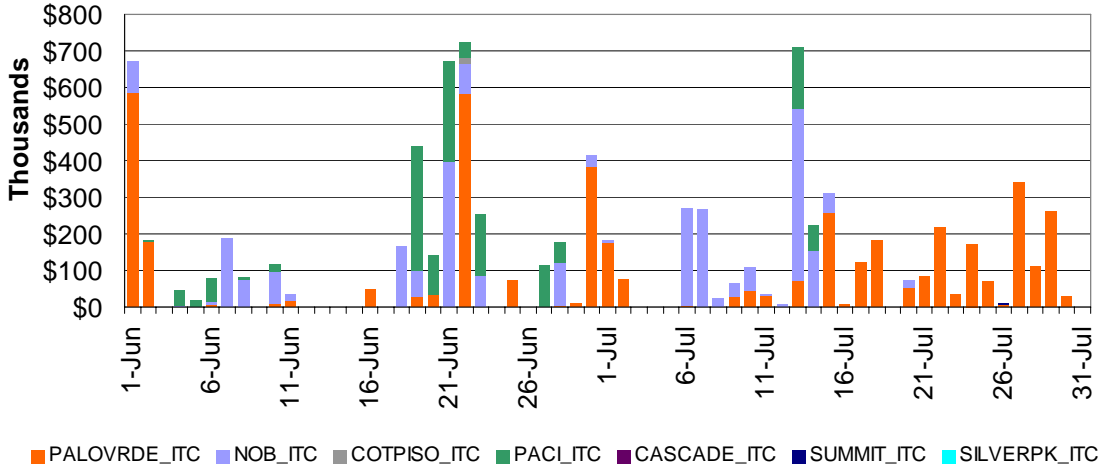
**Congestion**

Congestion occurs when available, least-cost energy cannot be delivered to some loads because transmission facilities do not have sufficient capacity to deliver the energy. When the least-cost, available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load. The result is the price of energy in the constrained area will be higher than in the unconstrained area because of the combination of transmission limitations and the costs of local generation.

**Congestion Rents on Interties**

Figure 18 below illustrates the IFM congestion costs on inter-ties. The congestion cost is calculated as shadow price (\$/MWh) of the inter-tie constraint multiplied by the flow (MW) on the inter-tie. Table 2 provides a breakout of the IFM cleared value (MW), the average shadow price (\$/MWh) and the number of congested hours by inter-tie.

**Figure 18: IFM (Day-Ahead) Congestion Rents by Inter-Tie (Import)**



**Table 2: IFM (Day-Ahead) Congestion Statistics by Inter-Tie (Import)**

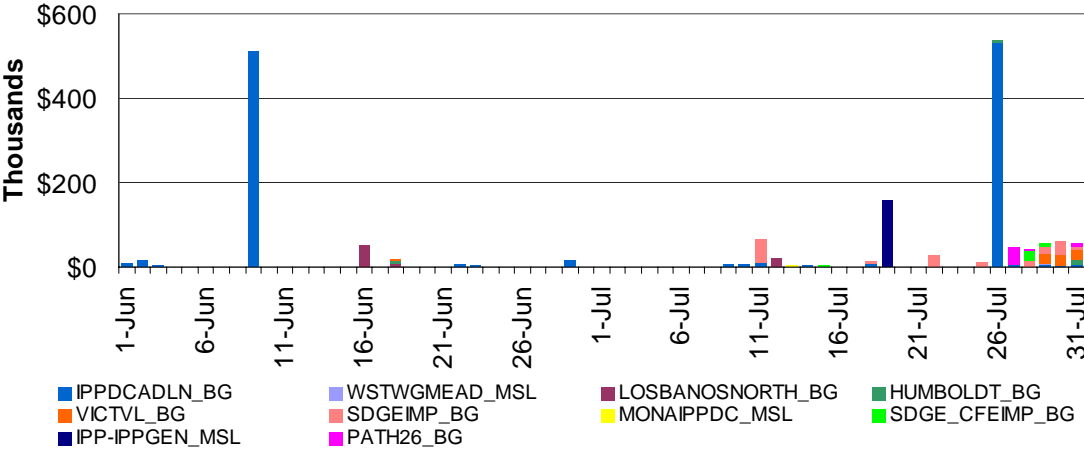
Inter-Tie	Average Cleared Value (MW)	Shadow Price (\$/MWh)	Number of Congested Hours
NOB_ITC	1525	13	72
PACI_ITC	2732	11	8
PALOVRDE_ITC	2813	5	164
SUMMIT_ITC	2	82	18

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**Congestion Rents on Branch Groups**

Figure 19 illustrates IFM congestion rents by branch group. The congestion rent is calculated as the shadow price (\$/MWh) of the branch group constraint multiplied by the flow limit (MW) on the branch group. Table 3 provides a breakout of the IFM cleared value (MW), the average shadow price (\$/MWh) and the number of congested hours by branch groups.

**Figure 19: IFM (Day-Ahead) Daily Congestion Rents by Branch Group**



**Table 3: IFM (Day-Ahead) Congestion Statistics by Branch Group**

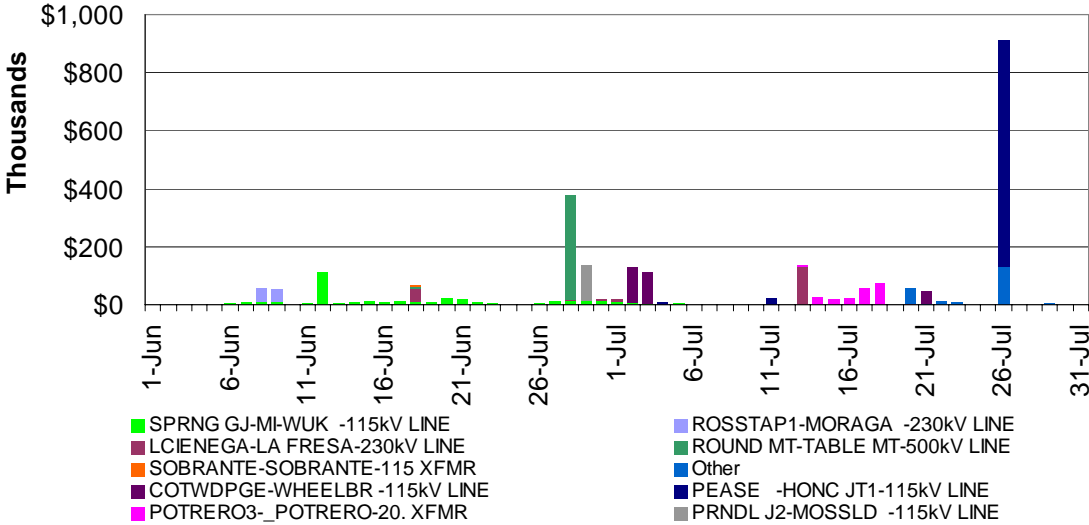
Branch Group	Average Cleared Value (MW)	Shadow Price (\$/MWh)	Number of Congested Hours
HUMBOLDT_BG	43	61	6
IPP-IPPGEN_MSL	470	21	16
IPPDCADLN_BG	647	17	52
LOSBANOSNORTH_BG	1275	17	1
MONAIPPDC_MSL	236	2	8
PATH26_BG	2700	5	4
SDGEIMP_BG	2263	3	24
SDGE_CFEIMP_BG	2073	1	11
VICTVL_BG	2640	6	5
WSTWGMEAD_MSL	181	3	13

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**Congestion Rents on Transmission Lines and Transformers**

Figure 20 illustrates IFM congestion rents by transmission lines and transformers. The congestion cost is calculated as the shadow price (\$/MWh) of the constraint multiplied by the flow limit (MW).

**Figure 20: IFM (Day-Ahead) Congestion Rents by Transmission Lines and Transformers**



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Table 4 provides a breakout of the IFM cleared value (MW), the average shadow price (\$/MWh) and the number of congested hours by branch groups. Please note this table contains the cleared values for only those instances when the constraint was binding.

**Table 4: IFM (Day-Ahead) Congestion Statistics by Transmission Line and Transformer**

Line or Transformer	Average Cleared Value (MW)	Shadow Price (\$/MWh)	Number of Congested Hours
BAYSHOR1-MARTIN C-115kV LINE	100	20	1
CARIBOU -BELDENTP-230kV LINE	221	246	1
COTWDPGE-WHEELBR -115kV LINE	83	59	57
LCIENEGA-LA FRESA-230kV LINE	699	10	21
MARTINEZ-ALHAMTP1-115kV LINE	96	16	2
MC CALL -HENTAP2 -230kV LINE	383	13	13
MIDWAY -VINCENT -500kV LINE	1496	7	1
NWARK EF-AMES BS -115kV LINE	94	21	1
PALERMO -HONC JT3-115kV LINE	81	500	2
PEASE -HONC JT1-115kV LINE	86	1339	7
POTRERO3-_POTRERO-20. XFMR	200	12	82
SAN-MAR1-MAR-SAN1-230kV LINE	251	2	1
SPRNG GJ-MI-WUK -115kV LINE	96	4	80
VINCENT -ANTELOPE-230kV LINE	477	3	1

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### Congestion Rents on Nomograms

Figure 21 illustrates IFM congestion rents by Nomogram. The congestion rent is calculated as the shadow price (\$/MWh) of the constraint multiplied by the flow limit (MW).

**Figure 21 : IFM (Day-Ahead) Daily Congestion Rents by Nomogram**

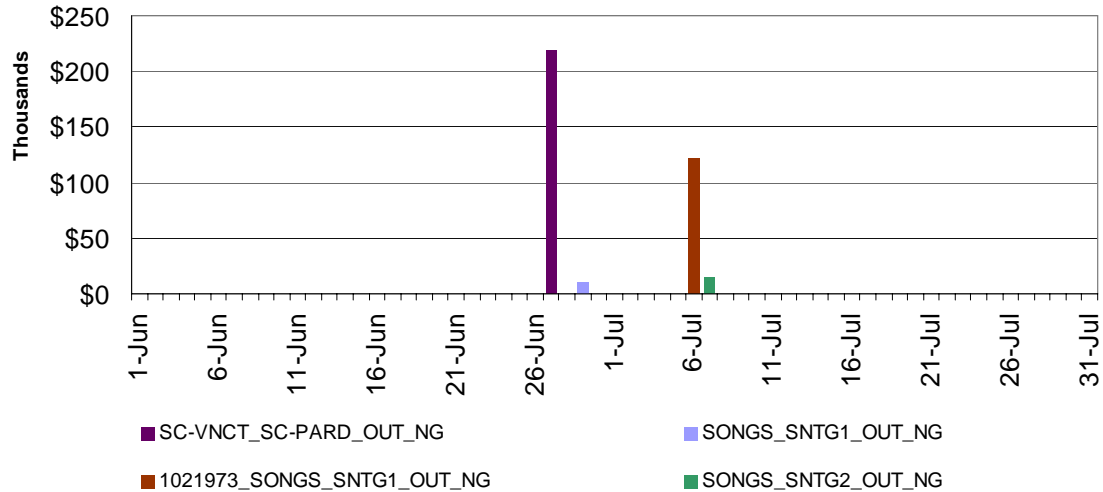


Table 5 provides a breakout of the IFM Cleared Value (MW), the average shadow price (\$/MWh) and the number of congested hours by branch groups. Please note this table contains the cleared values for only those instances when the constraint was binding.

**Table 5: IFM Congestion Statistics by Nomogram**

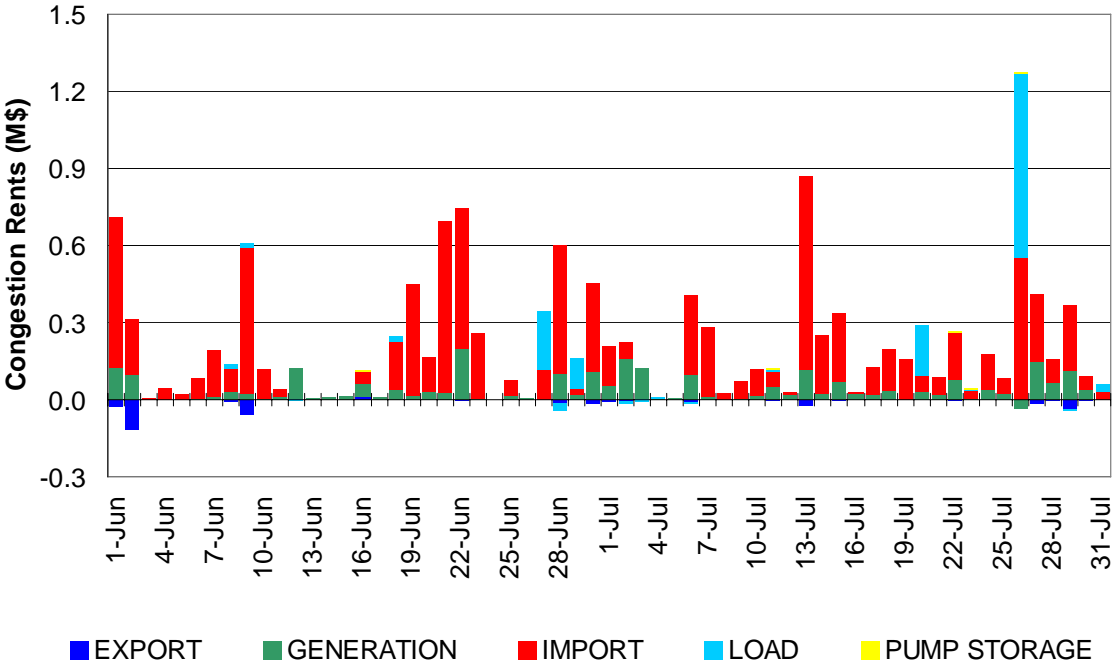
Nomogram	Average Cleared Value (MW)	Shadow Price (\$/MWh)	Number of Congested Hours
1021973_SONGS_SNTG1_OUT_NG	975	21	6
SONGS_SNTG2_OUT_NG	975	15	1
T-133 RAVENSWDSANMAT_NG_SUM	115	571	2
T-171 ANTLPE-VINCENT_NG	635	4	1

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**Congestion Rents by Resources**

Figure 22 shows the DA congestion rents grouped by type of market resource. If congestion arises, power is priced accordingly through a marginal congestion component (MCC). For any given hour of the DAM, Demand is charged the scheduled MW times the MCC, and supply is paid the scheduled MW times the MCC. The MCC is at the applicable Pnode, Apnodes and Scheduling Points. The net money surplus collected by the ISO is the congestion rents. The hourly congestion rents are then summed up across all hours of the day. A positive value of congestion rents indicates a payment to the CAISO (surplus). Congestion rents may also arise from provision of ancillary services over the interties. Due to the dual nature of Pump Storage (PS) units, they can be treated as supply or demand within the computation of congestion rents.

**Figure 22: DA Congestion Rents by Market Resource**



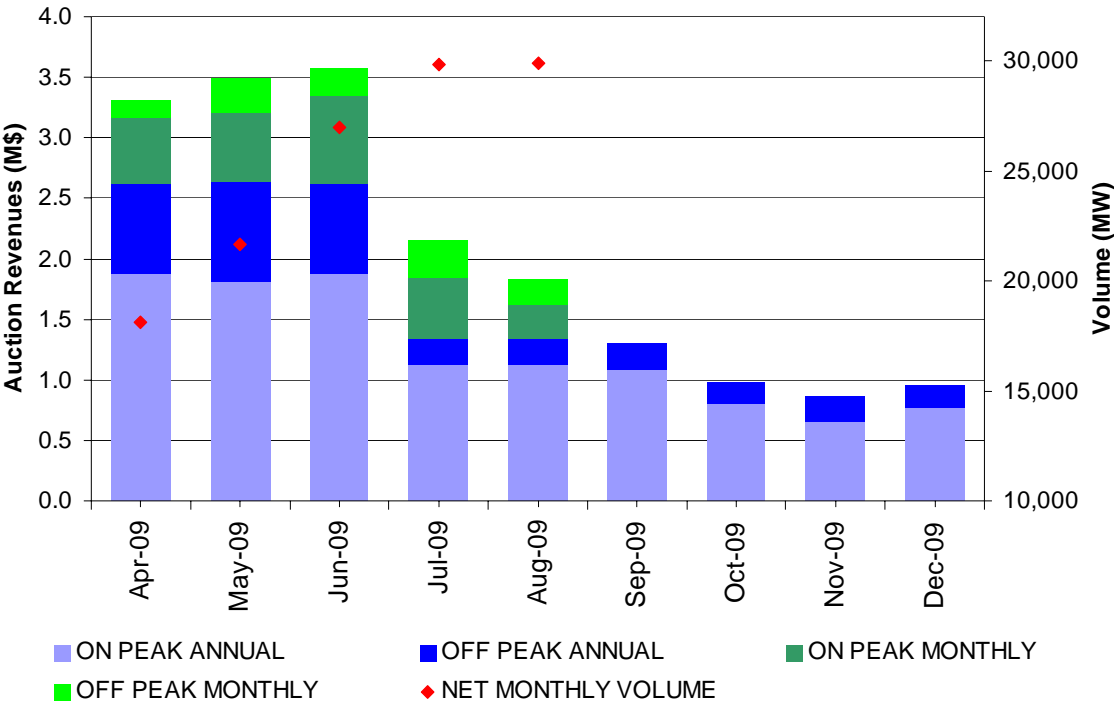
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## Congestion Revenue Rights

### Auction Revenues

Figure 23 shows the monthly revenues with the corresponding net volume awards from Congestion Revenue Rights (CRR) auctions. Revenues are from seasonal and monthly auctions and are grouped by time of use. Revenues from annual auctions are spread pro-rata to each month of a season, based on the number of –On or Off peak- hours of each month. The net MW volume is based only in the allocations and awards of the monthly process. This graph provides trends of auctions over time.

**Figure 23: Revenues and Award Volumes in Monthly CRR Auctions**



**Monthly Volumes**

Figure 24 through Figure 26 show the CRR volumes released in the monthly CRR processes. Both allocation and auctions for both times of uses are depicted. Figure 24 illustrates the trends of CRR volumes awarded over time and offers an easy reference for comparison of volumes released in allocations versus auctions. This graph can also help visualize the evolution of the monthly processes over time.

**Figure 24: Monthly Volumes of CRR Awards –Allocation and Auction**

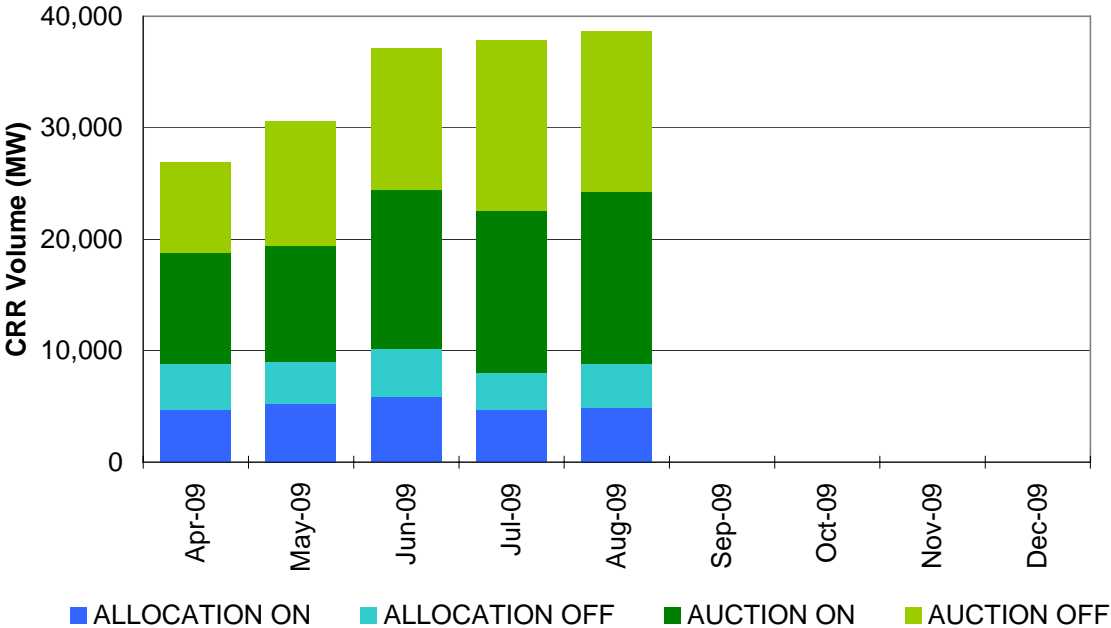
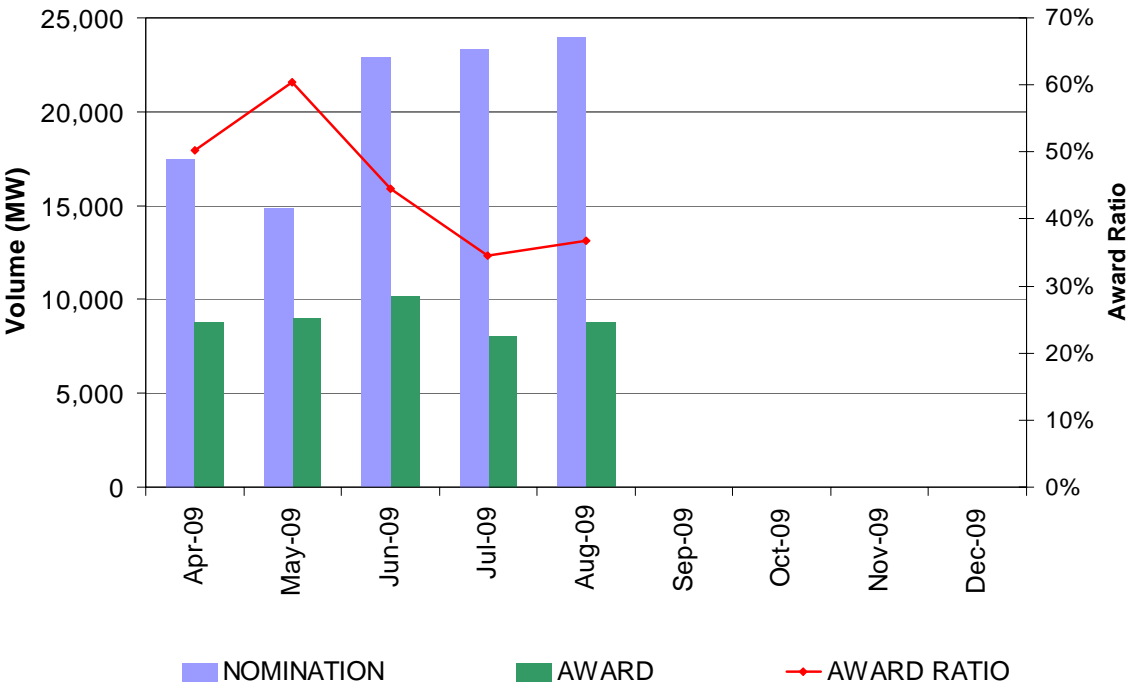


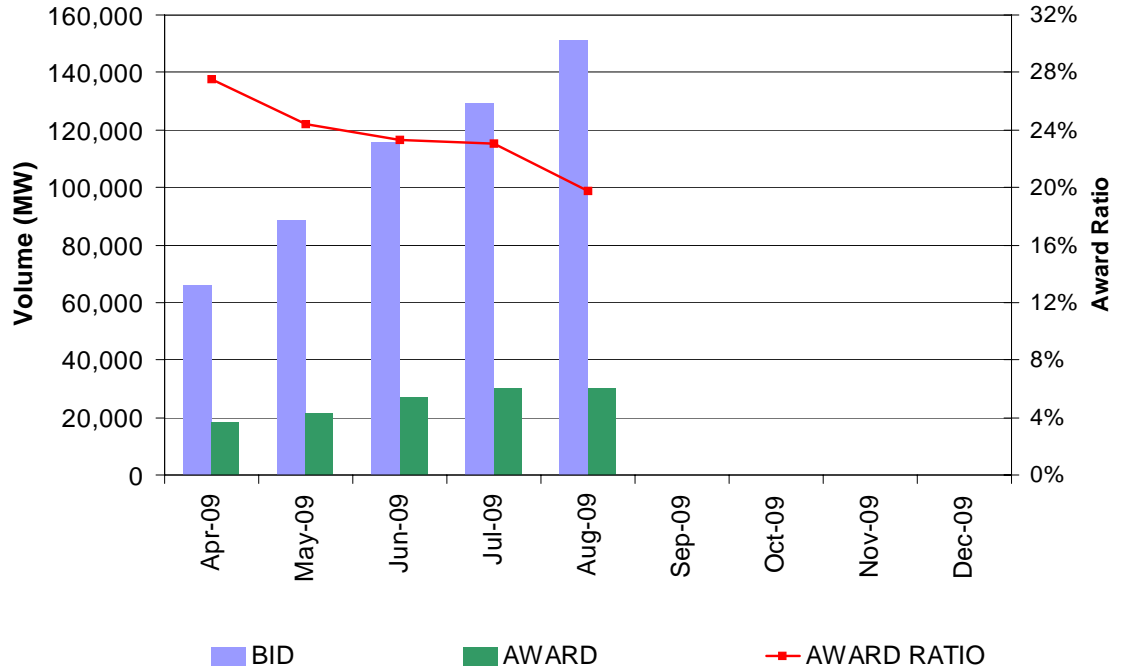
Figure 25 and Figure 26 compare the volume nominated and bid against the volumes allocated and awarded in the allocation and auction processes, respectively. It also includes the percentage of the volumes that were actually released in the monthly processes. These figures give a compact reference over time and also between allocation and auctions.

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**Figure 25: Volumes of Monthly CRR Allocations**



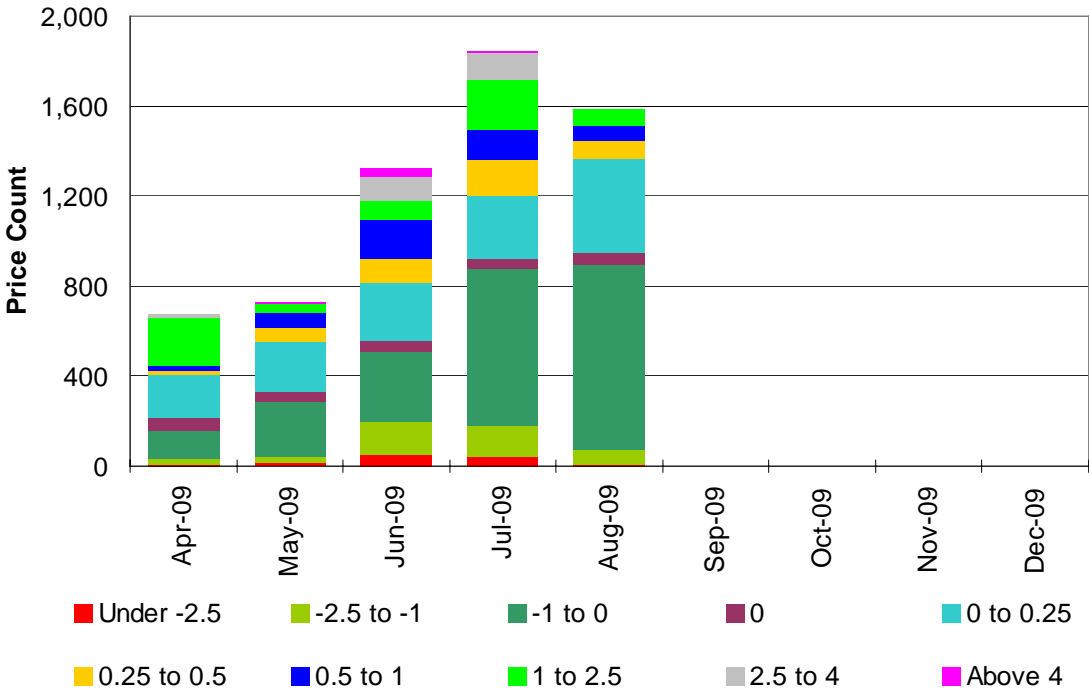
**Figure 26: Volumes of Monthly CRR Auctions**



**Auction Prices**

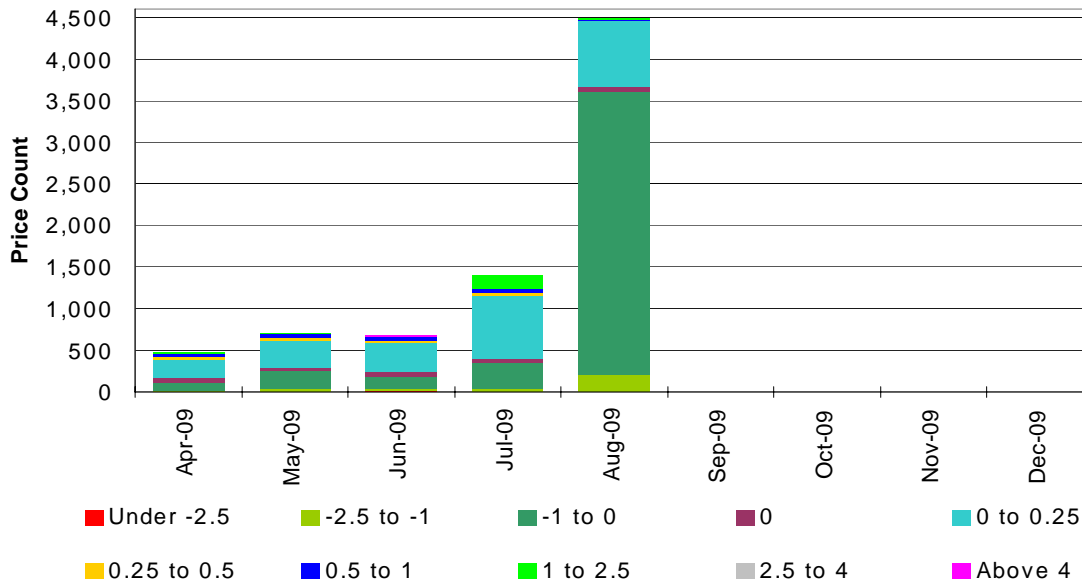
Figure 27 and Figure 28 show price distribution trends of the monthly CRR auctions over time. The distributions are given for each time of use. The vertical axis shows the count of prices only for CRRs that have an award greater than zero. The prices are computed as the auction prices divided by the number of hours for the corresponding TOU and month. Therefore, the prices are in an hourly basis (\$/MWh).

**Figure 27: Price Frequency of Monthly CRR auctions – On Peak**



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**Figure 28: Price distribution of CRR Monthly Auctions – OFF Peak**



### Price Convergence

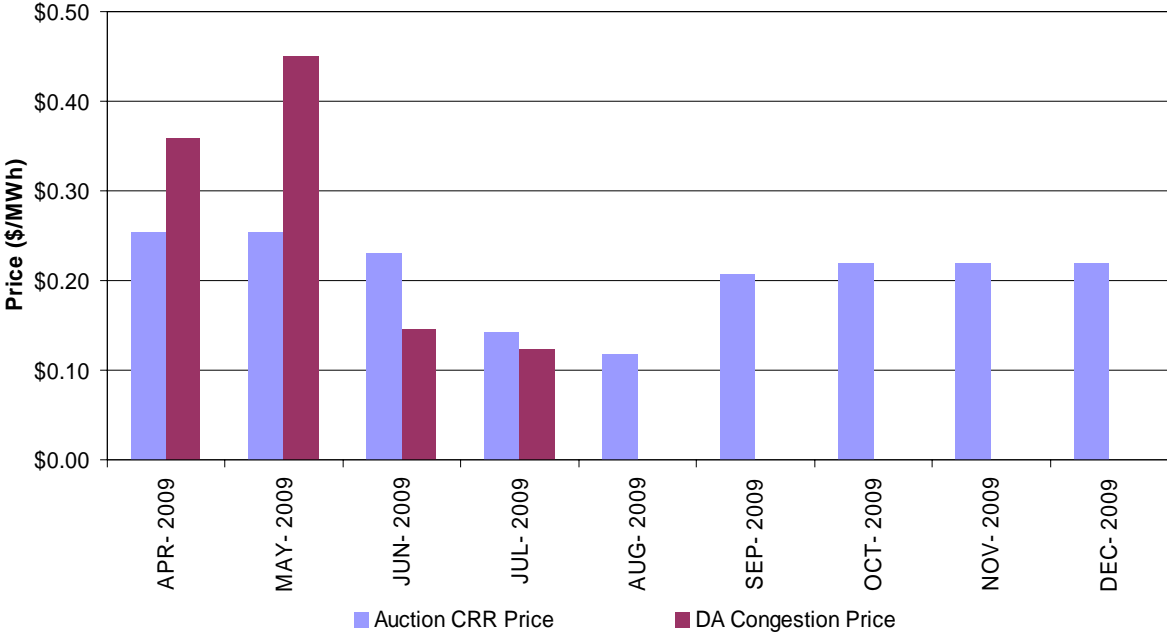
Figure 29 and Figure 30 show the price convergence between CRR auction prices and Day-Ahead (IFM) prices. For the CRR auction prices, both seasonal and monthly awarded CRRs are included, and grouped by time of use. This price comparison is useful to see any trend of price convergence. Over time, price convergence should be observed, accounting for the fact that there may be a risk premium associated with it. Because each CRR may have associated a different price, and in order to have all CRRs in a same basis, the metrics shown in these plots are computed as weighted average prices. The main steps to obtain such weighted prices are as follows:

1. Obtain all CRRs with awards greater than zero and their associated auction prices and quantities.
2. Divide CRR prices by their corresponding number of hours for each TOU and season/month to have prices in an hourly basis.
3. Associate the corresponding IFM congestion component prices (sink minus source) to each CRR for each hour by TOU.
4. Obtain the total MW awarded by TOU in each month and use it to obtain the weighting factors for each CRR. Multiply both CRR auction prices and IFM CRR (congestion) prices by their corresponding factors.
5. Sum all CRR prices by TOU and month to obtain both weighted CRR auction prices and weighted DA (IFM) congestion prices.

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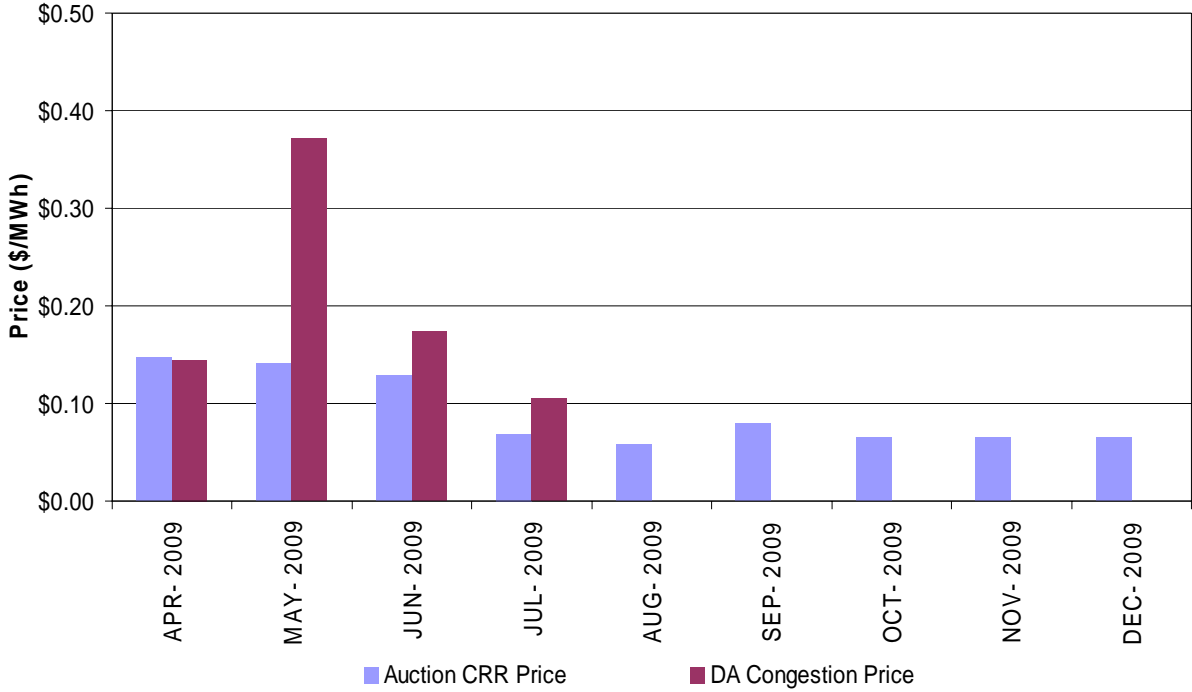
The value of the Auction CRR price indicates how much CRR holders pay to acquire CRRs, while the CA congestion Price indicates much the CRR holders were paid due to the CRR entitlements. A case where the DA congestion price is higher than the Auction CRR price means that CRR holders profited from holding CRRs.

**Figure 29: Convergence between CRR Prices and IFM  
Congestion Prices –ON Peak**



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**Figure 30: Convergence between CRR Prices and IFM  
Congestion Prices –OFF Peak**

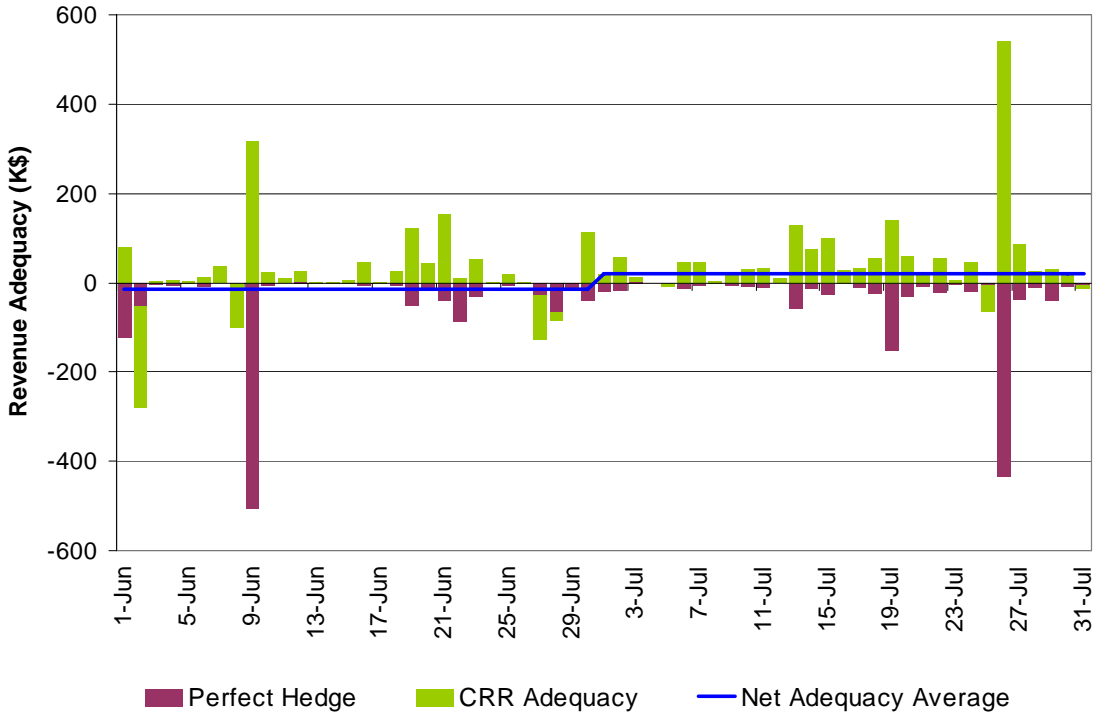


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**Monthly Revenue Adequacy**

Figure 31 illustrates the Revenue Adequacy for CRRs in the corresponding month, without including the offsetting effect of the CRR auction revenues. Net positive values indicate that there is a surplus and net negative values indicate there is a shortfall. Revenue adequacy for CRRs reflects the extent to which the hourly net congestion revenues collected from the IFM are sufficient to cover the hourly net payments to CRR holders.<sup>2</sup> The cost of the perfect hedge is explicitly depicted with red bars. For illustration purposes, the CRR revenue adequacy amounts (net congestion revenues minus net payments to CRR holders) are computed hourly and then aggregated across all hours of each day; they are represented in green bars. In addition, the net revenue adequacy (IFM rents minus CRR payments minus perfect hedge) are computed for each month and then a daily average is estimated and represented with the blue line.

**Figure 31: Daily Revenue Adequacy of Congestion Revenue Rights**



<sup>2</sup> On an hourly basis another factor affecting CRR revenue adequacy is the fact that holders of existing rights (TOR, ETC. CVR) are exempt from IFM congestion charges in accordance with the perfect hedge provisions of the ISO tariff. The perfect hedge reduces the net IFM congestion revenues available for paying CRR holders, and therefore the expected impact of the perfect hedge on CRR revenue adequacy is taken into account by the ISO in the process for releasing CRRs.

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The net revenue adequacy in a month is supplemented by the net CRR auction revenues collected by the CAISO for the month through the mechanism of the CRR Balancing Account. The net surplus or deficit in the CRR Balancing Account at the end of each month is then allocated to all measured demand in accordance with the ISO tariff. Thus, following the principle of full funding of CRRs, any deficit in the CRR Balancing Account at the end of a month does not adversely affect the payments to CRR holders.

Table 6 provides a summary of the main statistics for CRRs for the current month. Definitions for the Concepts listed in Table 6 are as follows:

- *IFM Congestion Rents* are the net monthly rents from IFM congestion,
- *CRR Payments* are the moneys used to honor the CRR entitlements,
- *CRR Adequacy* is the difference between IFM Congestion Rents and CRR Payments,
- *Perfect Hedge* quantifies the cost of the reversal payment to holders of existing transmission contracts,
- *Net Revenue Adequacy* is the sum of both the Perfect Hedge and the CRR Revenue Adequacy,
- *Revenue Adequacy Ratio* is the proportion of the money collected from the IFM to the money paid to both the CRR entitlements and the Perfect Hedge,
- *Annual Auction Revenues* is the pro-rata portion of the annual auction that applies to the corresponding month,
- *Monthly Auction Revenues* is the money obtained from the corresponding monthly auction. These auction revenues are then added to the net revenue adequacy, to obtain the Net Monthly Balance.
- *Net Monthly Balance* is the sum of Monthly Auction Revenue and Net Revenue Adequacy

**Table 6: CRR Adequacy Statistics for July**

Concept	Amount
IFM Congestion Rents	\$6,750,872.85
CRR Payments	\$5,098,371.85
CRR Adequacy	\$1,652,500.99
Perfect Hedge	-\$1,014,300.48
Net Revenue Adequacy	\$638,200.51
Revenue Adequacy Ratio	110.44%
Annual Auction Revenues	\$1,344,248.42
Monthly Auction Revenues	\$808,482.31
Monthly Net Balance	\$2,790,931.24

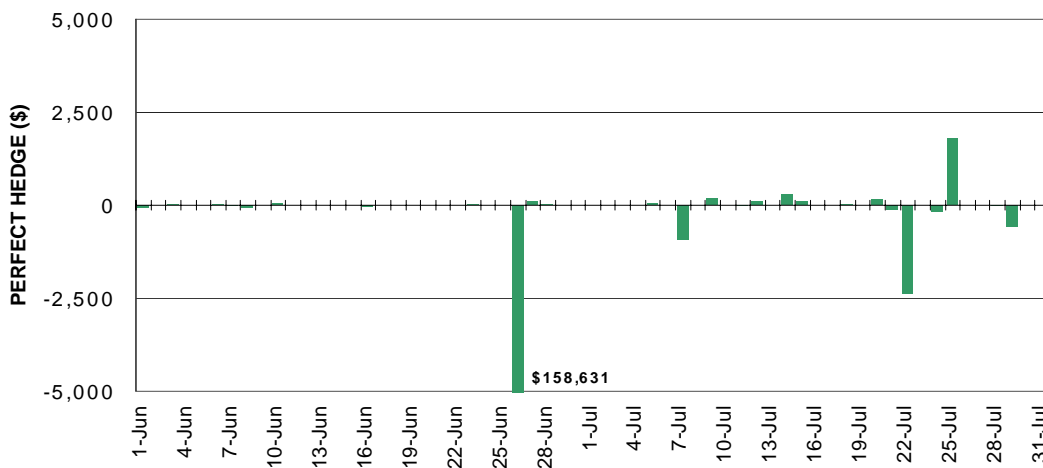
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Although auction revenues can be used to offset any CRR revenue deficiency that results from the IFM, the intention of the ISO's CRR release process is that proceeds from the IFM will be sufficient to cover net CRR payments over the course of each month. The annual and monthly processes to release CRRs through allocations and auctions are built upon this concept. In addition, transmission capacity is set aside in the release processes in order to account for the perfect hedge congestion payment reversal for existing transmission rights.

### Post Day-Ahead Perfect Hedge

Similar to the day-ahead market, CAISO collects congestion rents determined by the charges to demand and payments to supply for schedule deviations, and imports of Ancillary Services through inter-ties. Holders of ETCs and TORs can submit post day ahead, i.e. in the HASP/RT time frame, schedules changes. As per tariff requirements, these schedules are exempt from congestion charges and, thus, congestion charges are reversed through the mechanism of the perfect hedge. This is in addition to any settlement of the day-ahead market. The remaining congestion rents –surplus or deficit- will be allocated to measured demand excluding measured demand associated with valid and balanced portions of ETCs/TORs. Figure 32 shows the net cost per day of honoring the perfect hedge of post day-ahead schedule changes of ETCs/TORs. A negative value of the perfect hedge indicates a net payment from CAISO to the ETC/TOR holders to reverse the post day-ahead congestion charge, i.e., a credit. A positive value of the perfect hedge indicates a net charge to the ETC/TOR holders to reverse the post day-ahead congestion payment.

**Figure 32: Cost of the Perfect Hedge for Post Day-Ahead ETCs/TORs**



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Table 7 list the monthly summary of the post Day-Ahead (HASP/RT) congestion rents and perfect hedge. A positive value of the congestion rents is a surplus; a negative value is a shortfall. Any surplus or shortfall is allocated to metered demand, excluding demand associated with ETCs/TORs. The percentage is the absolute-value ratio of the perfect hedge to the congestion rents. This provides a reference of the extent of the cost charged to non-ETC demand to honor the perfect hedge in comparison to the overall congestion cost of the post Day-Ahead markets.

**Table 7: Summary of the Post Day-Ahead Perfect Hedge**

Month	Congestion Rents	Perfect Hedge	Percentage
JUNE	-\$1,174,233.21	-\$158,629.84	13.509%
JULY	-\$1,693,689.52	-\$1,592.08	0.094%

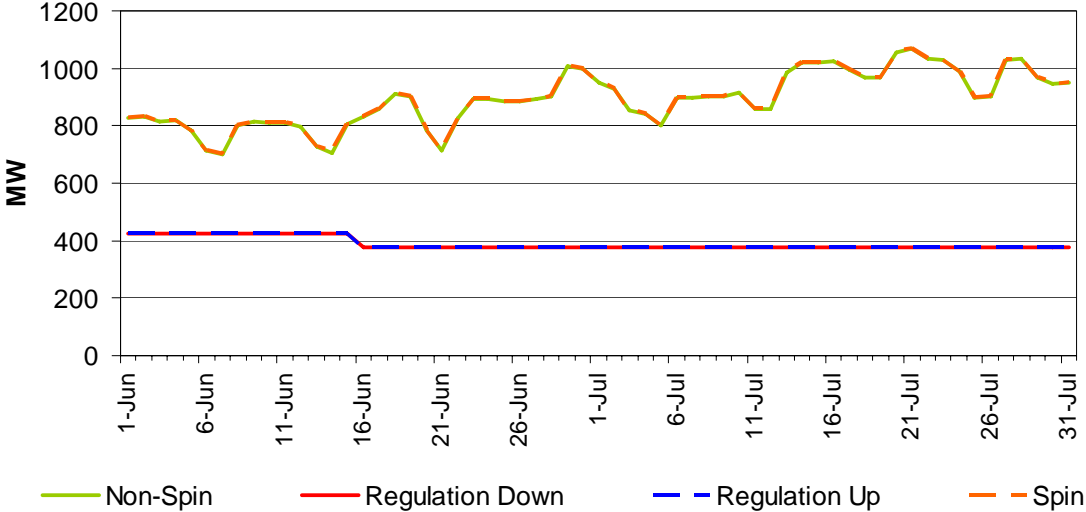
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**Ancillary Services**

**Requirements**

Figure 33 illustrates the IFM daily average Ancillary Service requirement for Regulation Up, Regulation Down, Spin and Non-Spin.

**Figure 33: IFM (day-ahead) Ancillary Services Average Requirement**



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**Procurements**

Figure 34 illustrates the IFM Daily average procurement of Regulation Up, Spin and Non-Spin Ancillary Services.

**Figure 34: IFM (day-ahead) Upward Ancillary Services Procurement**

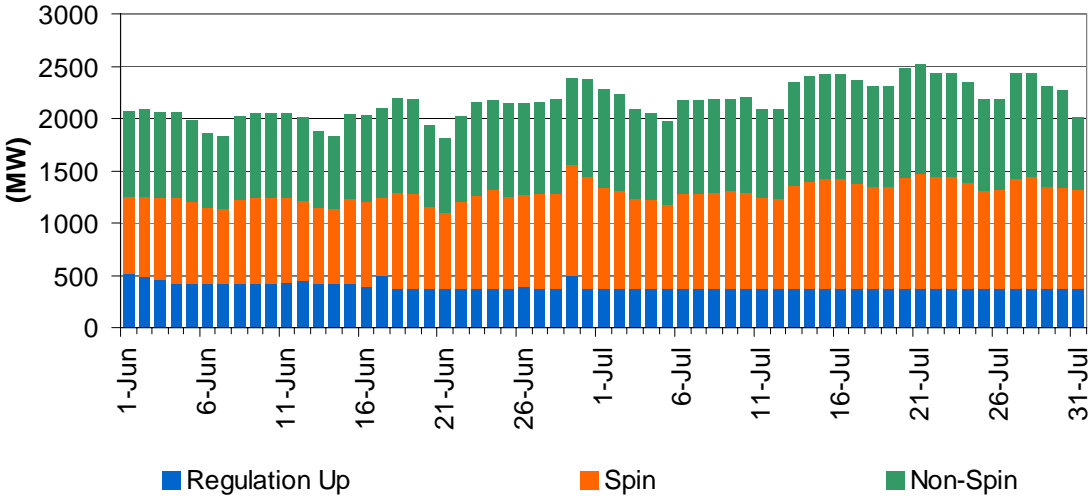
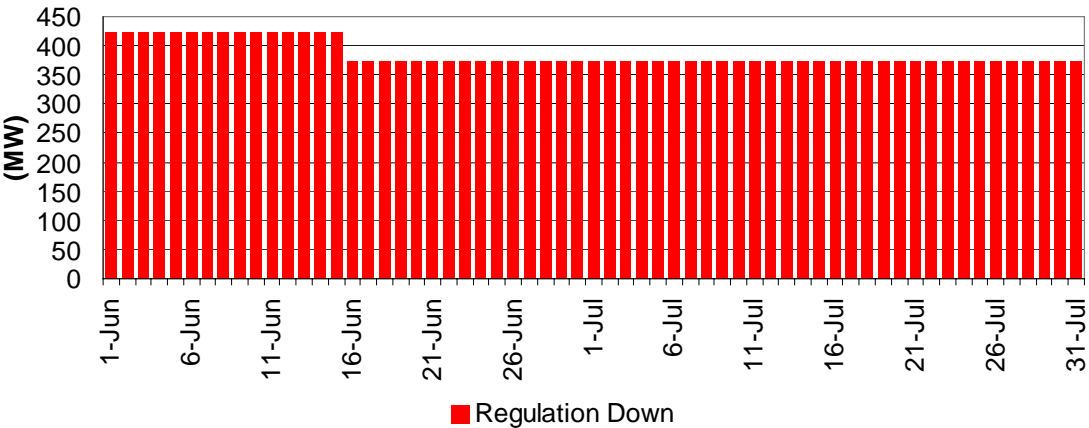


Figure 35 illustrates the IFM daily average procurement of Regulation Down.

**Figure 35: IFM (day-ahead) Regulation Down Procured**



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Figure 36 illustrates the RTPD Daily average procurement of Regulation Up, Spin and Non-Spin Ancillary Services.

**Figure 36: RTPD (real-time) Upward Ancillary Services Procurement**

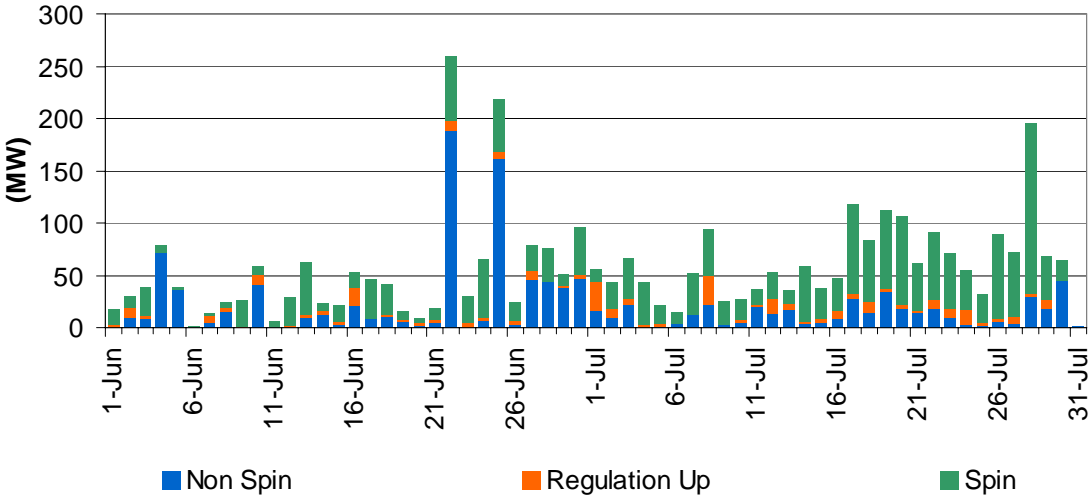
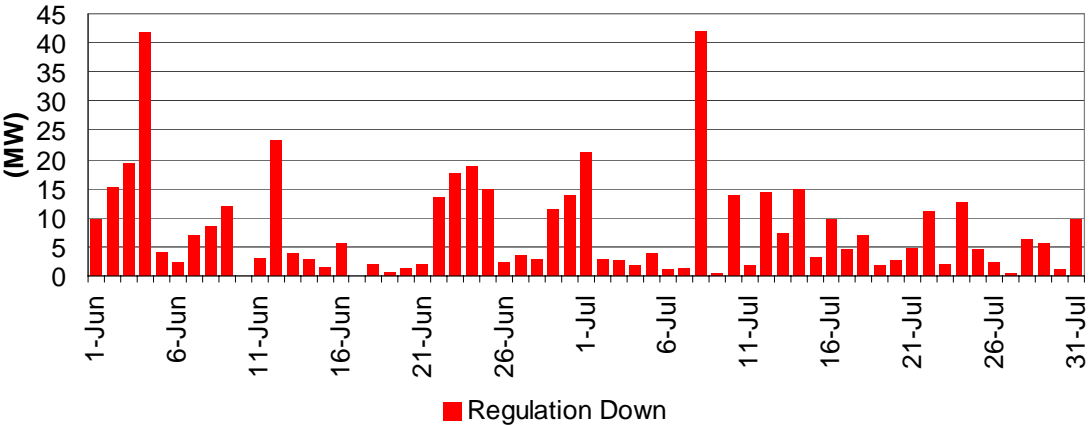


Figure 37 illustrates the RTPD daily average procurement of Regulation Down.

**Figure 37: RTPD (real-time) Regulation Down Procured**

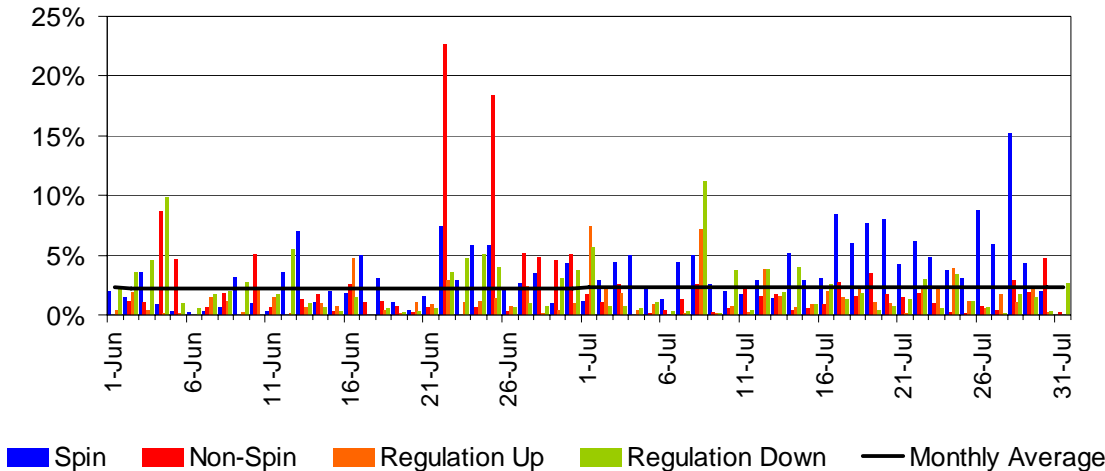


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The CAISO procures 100 percent of its Ancillary Services requirements in the IFM (Day-Ahead) market based on the IFM load forecast. Incremental procurements in the Real-Time market occurs under two scenarios. First, Ancillary Services requirements have changed in Real-Time market motivated by a change in the Real-Time load forecast. Second, if a unit which was awarded an Ancillary Service in IFM (Day-Ahead) market is unable to provide that service in Real-Time. The market will automatically procure additional services to replace that service.

Figure 38 displays the percentage of RTPD (Real-Time) procurement with respect to the IFM (Day-Ahead) procurement for all four types of Ancillary Services. The percentage for each type of Ancillary Service is calculated as: (hourly average of RTPD (Real-Time) procurement in 15 minute intervals) / (hourly IFM (Day-Ahead) procurement).

**Figure 38: Proportion of Real-Time procurement as Percentage of Day-Ahead requirement.**



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**IFM (Day-Ahead) Average Prices**

Figure 39 illustrates the IFM daily average price for Regulation Up, Regulation Down, Spin and Non-Spin Ancillary Services. The average price for each type of Ancillary Services is calculated as:  $\text{Sum (Non-Self Scheduled AS MW * Ancillary Services Marginal Price \$/MW (ASMP)) / Sum (Non-Self Scheduled AS MW)}$ .

**Figure 39: IFM (day-ahead) Ancillary Service Average Price**

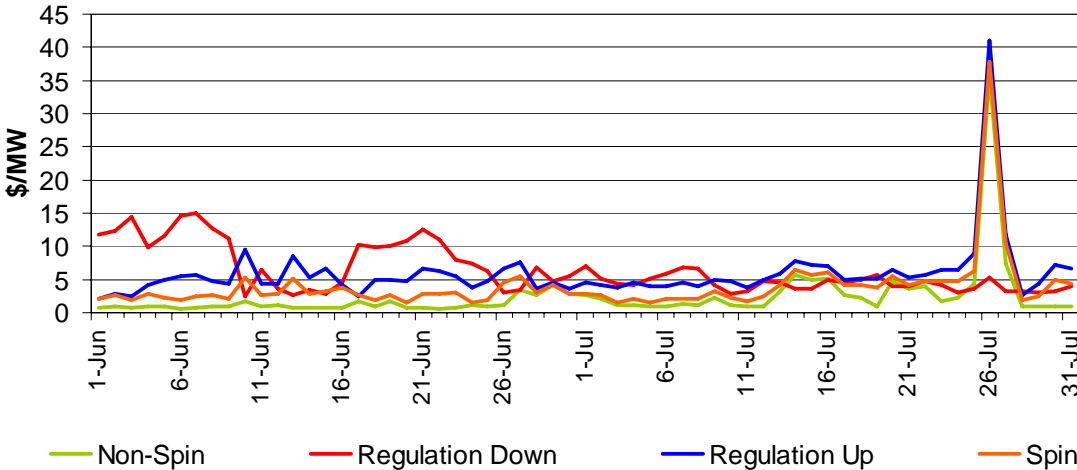
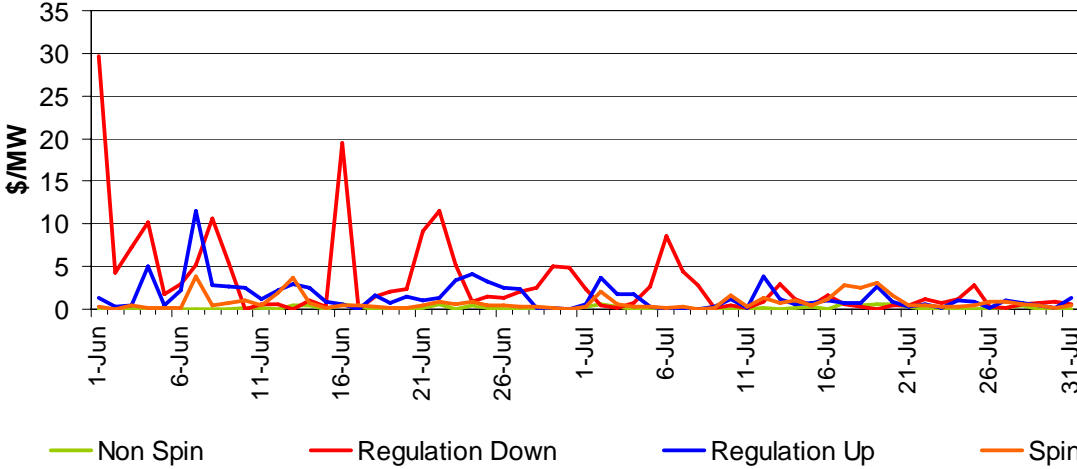


Figure 40 illustrates the RTPD daily average price for Regulation Up, Regulation Down, Spin and Non-Spin Ancillary Services. The average price for each type of Ancillary Services is calculated as:

Hourly average of  $[\text{Sum (Non-Self Scheduled AS MW * Ancillary Services Marginal Price \$/MW (ASMP)) / Sum (Non-Self Scheduled AS MW)}]$  for each of the 15 minute intervals.

**Figure 40: RTPD (real-time) Ancillary Service Average Price**

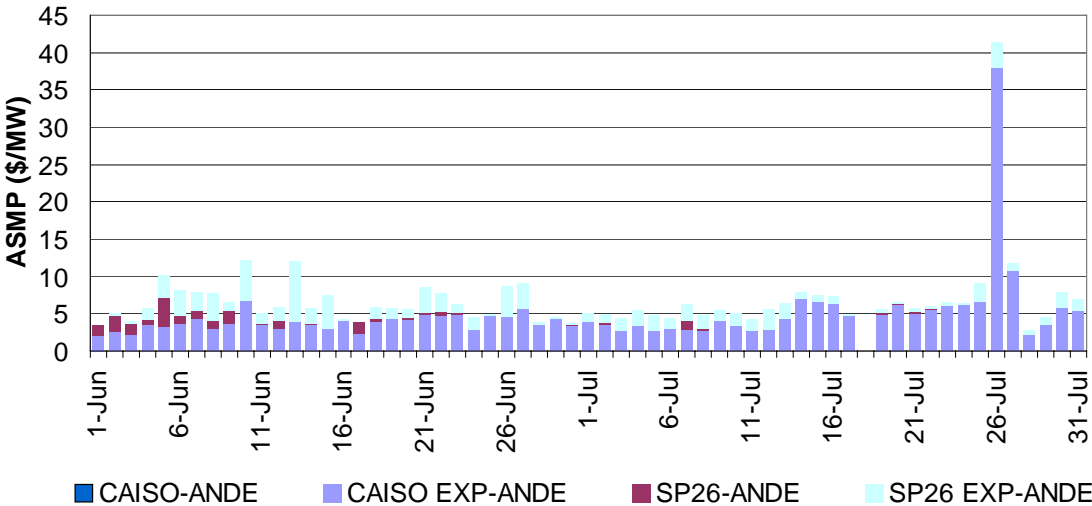


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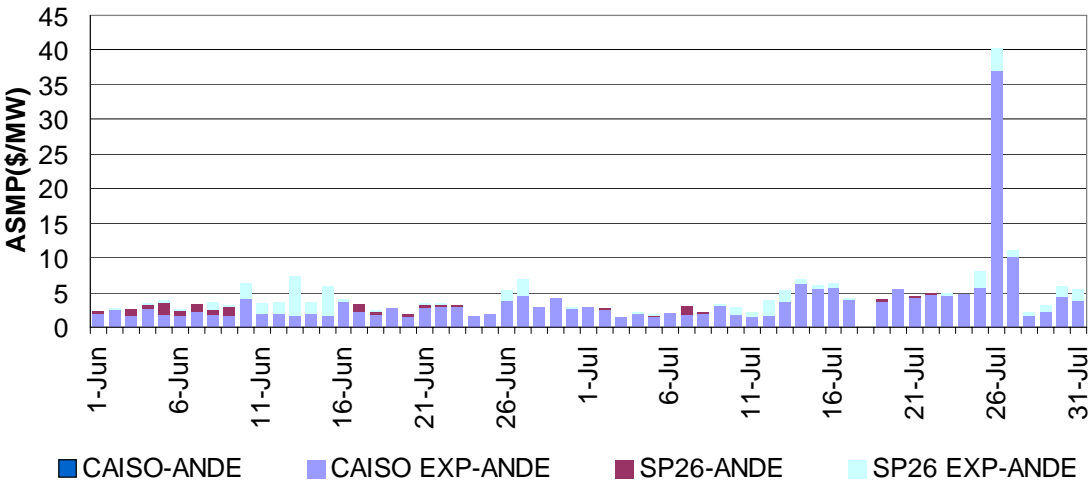
**Average Regional Ancillary Service Shadow Prices**

Figure 41 through Figure 44 displays the IFM daily average Regional Ancillary Service Shadow prices (RASSPs) for Regulation Up, Spin, Non-Spin and Regulation Down.

**Figure 41: IFM (day-ahead) Regulation Up (RASSP)**

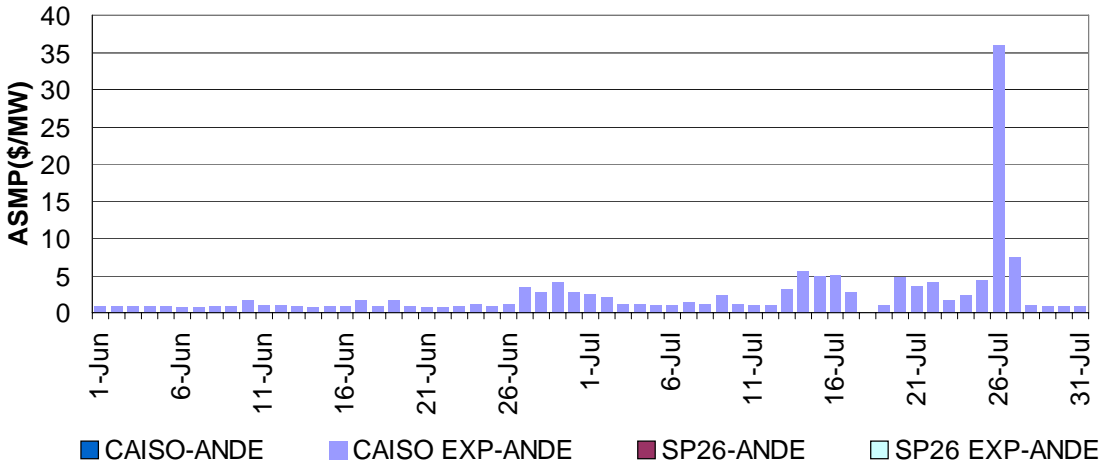


**Figure 42: IFM (day-ahead) Spin (RASSP)**

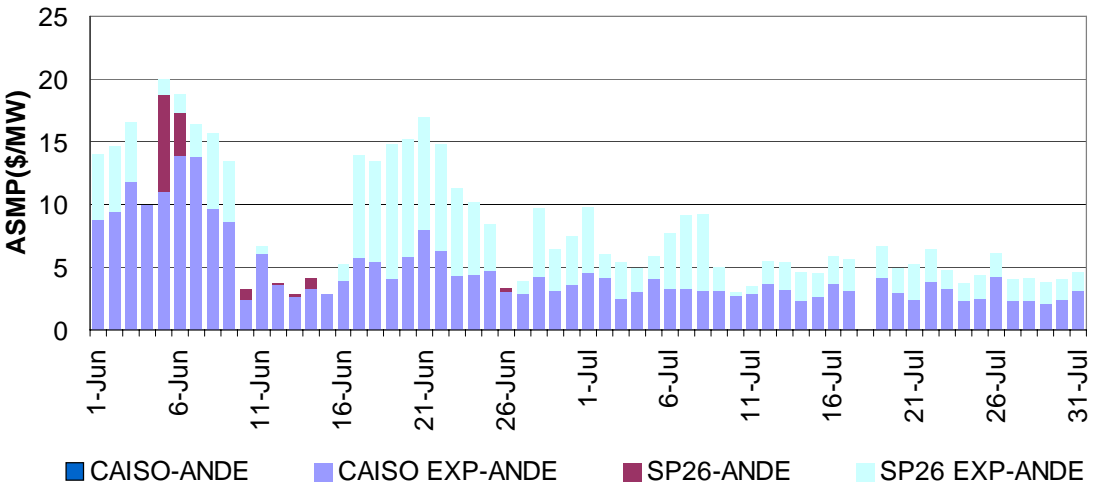


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**Figure 43: IFM (day-ahead) Non-Spin (RASSP)**



**Figure 44: IFM (day-ahead) Regulation Down (RASSP)**

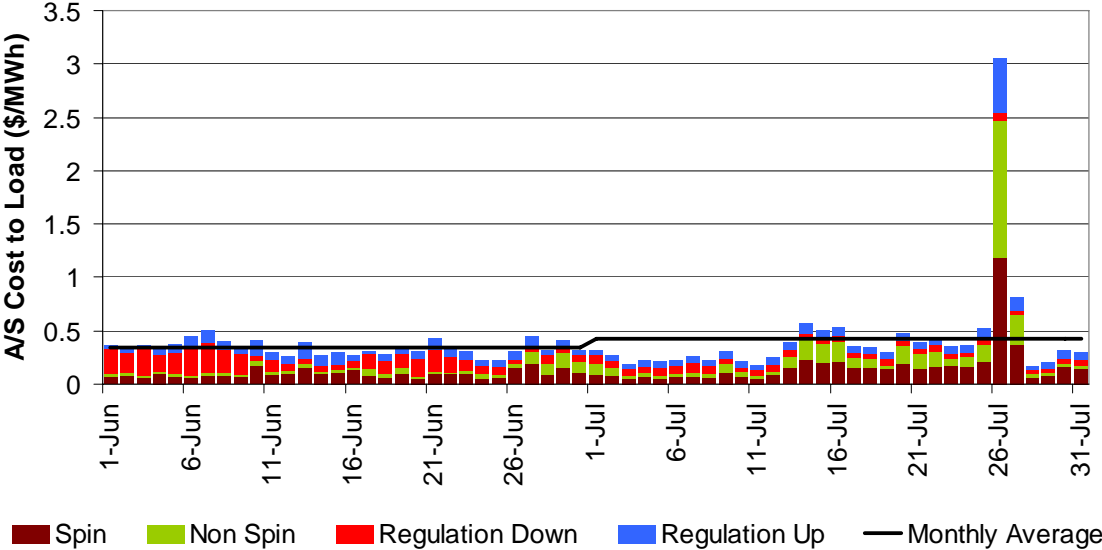


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**Average Cost to Load**

Figure 45 below shows IFM average cost to load for Ancillary Services procurement in the IFM market. The average cost to load is calculated as: average ((total hourly cost of procurement for all four Ancillary services) / (Total hourly CAISO Load)).

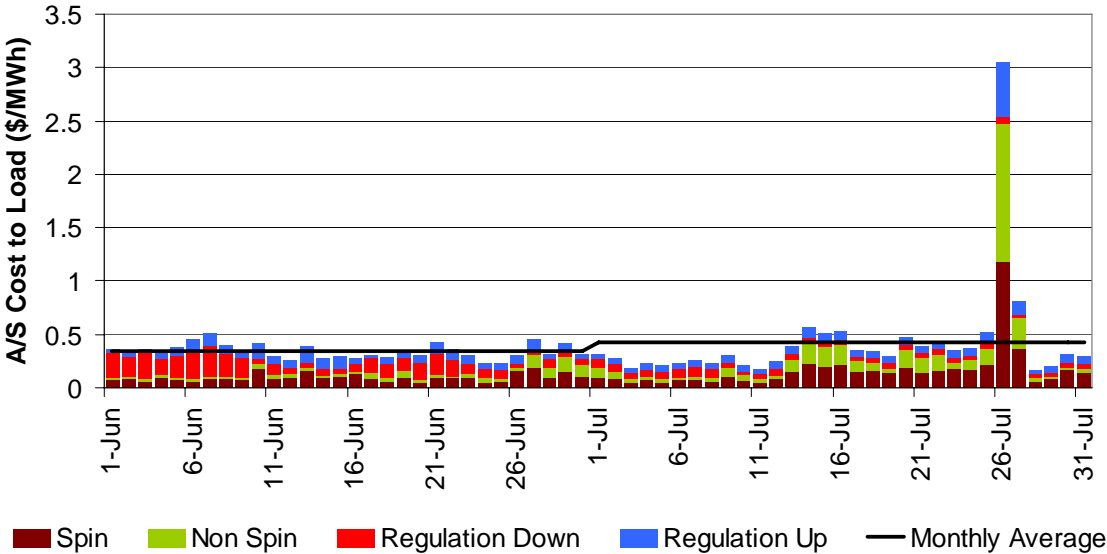
**Figure 45: IFM (day-ahead) Average Cost to Load**



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Figure 46 below shows the total system (day-ahead and real-time) average cost to load for Ancillary Services procurement in the IFM market. The average cost to load is calculated as: average ((total hourly cost of procurement for all four Ancillary services) / (Total hourly CAISO Load)).

**Figure 46: System (day-ahead and real-time) Average Cost to Load**



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## Residual Unit Commitment

Residual Unit Commitment (RUC) is a reliability function for committing resources and procuring RUC capacity not scheduled in the IFM as Energy or Ancillary Service (AS) capacity. RUC capacity is procured in order to meet the difference between the CAISO Forecast of CAISO Demand (CFCD) – including locational differences and adjustments – and the demand scheduled in the IFM for each trading hour of the trading day.

### Deviations of RUC schedule from IFM schedule

The RUC schedule is the total hourly capacity committed by RUC, including the capacity committed in the day-ahead schedule. The daily deviation of the RUC schedule from the IFM schedule is presented in Figure 47. The hourly deviation of the RUC schedule from the IFM schedule is presented in Figure 48. Positive deviations indicate that RUC capacity was procured, while negative deviations indicate there was over-scheduling in the IFM compared with the CFCD. If there is a positive deviation in any trade hour then RUC capacity was procured in that hour. However, if there are any negative deviations in other trade hours, the daily average deviation might be negative.

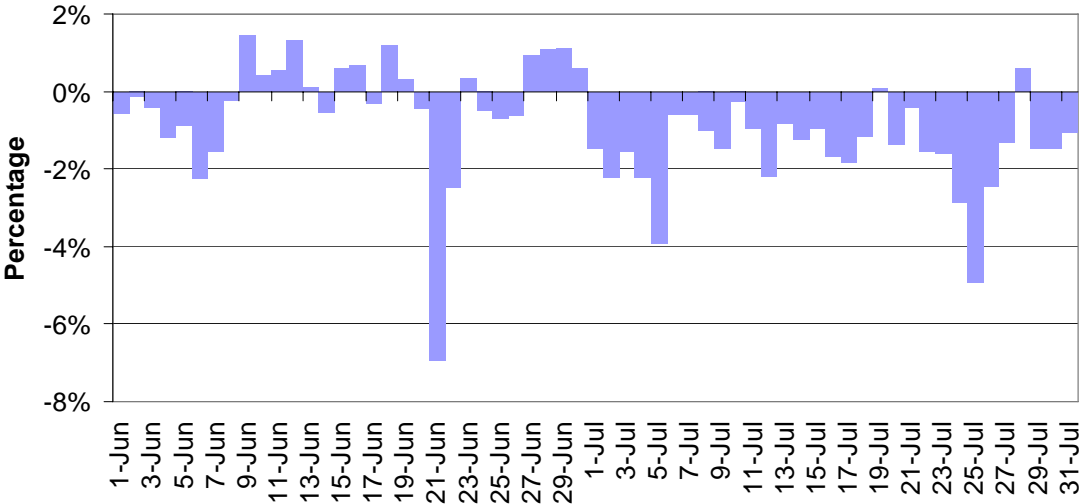
$$\text{Daily Deviation}_j = \text{Avg}\left(\frac{\text{RUC\_Schedule}_{ij} - \text{IFM\_Schedule}_{ij}}{\text{RUC\_Schedule}_{ij}}\right)$$

Here *i* indicates trading hour and *j* indicates trading day. The average is taken across 24 hours for each trading day.

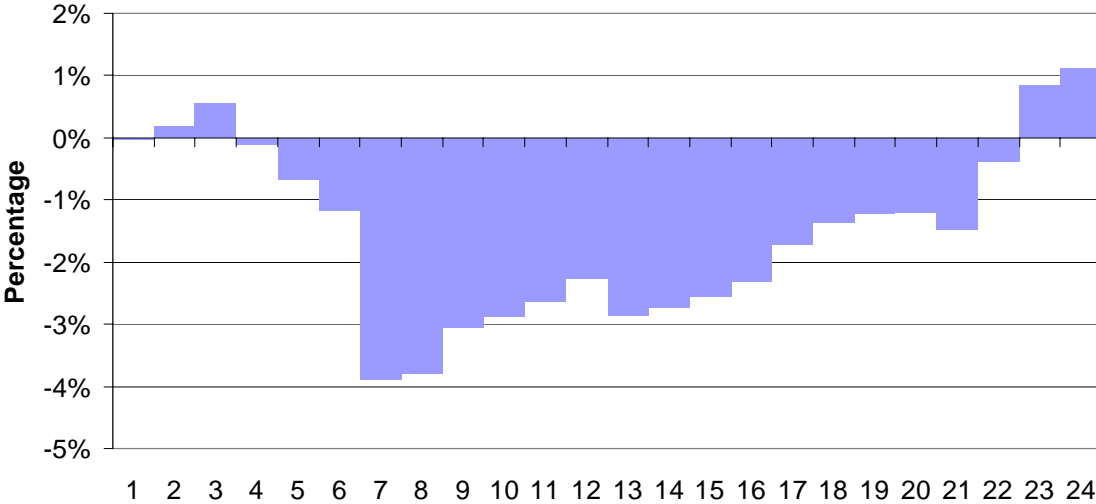
$$\text{Hourly Deviation}_i = \text{Avg}\left(\frac{\text{RUC\_Schedule}_{ij} - \text{IFM\_Schedule}_{ij}}{\text{RUC\_Schedule}_{ij}}\right)$$

Here *i* indicates trading hour and *j* indicates trading day. The average is taken across all the trading days in this month for each trading hour.

**Figure 47: Daily Deviation of RUC Schedule from IFM Schedule**



**Figure 48: Hourly Deviation of RUC Schedule from IFM Schedule**

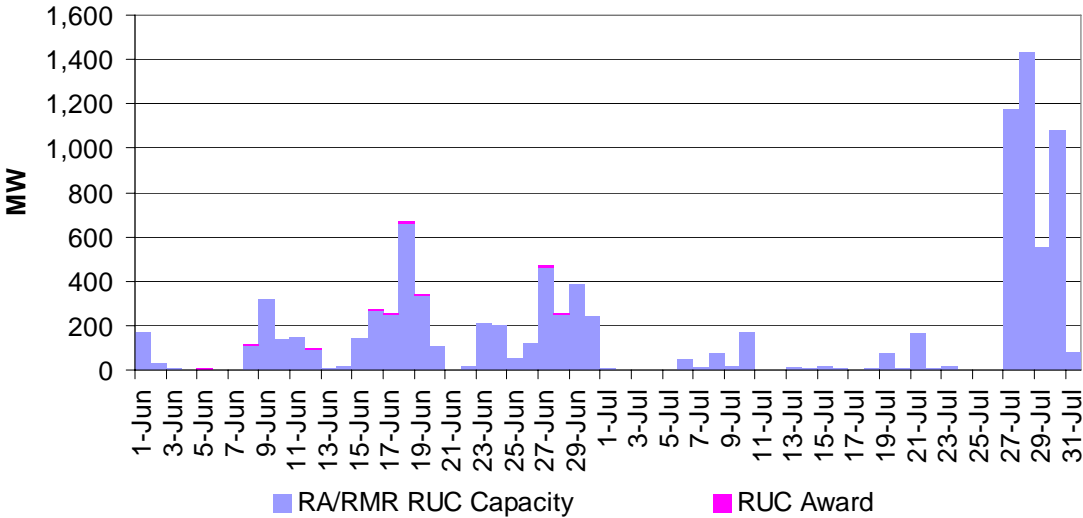


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**RA/RMR RUC Capacity vs. RUC Award**

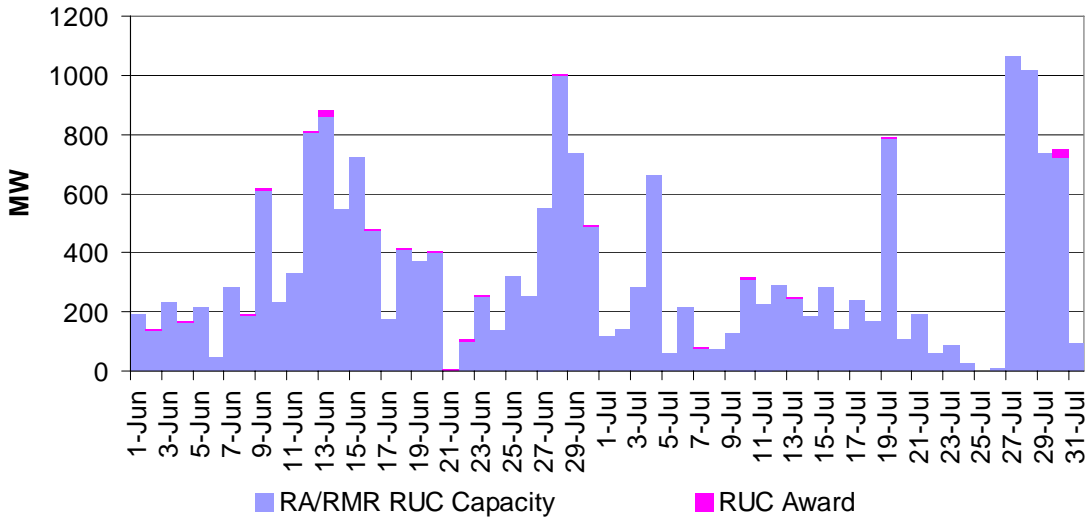
RUC capacity is the positive difference between the RUC schedule and the greater of the IFM schedule and the minimum load level of a resource. The RUC award is the portion of RUC capacity in excess of RMR capacity or the RA RUC obligation. All RUC awards are paid the RUC LMP. RA and RMR units do not receive additional pays for their RUC capacity because they are already compensated through their RMR or RA contracts. Figure 49, Figure 50 and Figure 51 show the daily average RA/RMR RUC capacity and RUC award.

**Figure 49: On-Peak RA/RMR RUC Capacity vs. RUC Award**

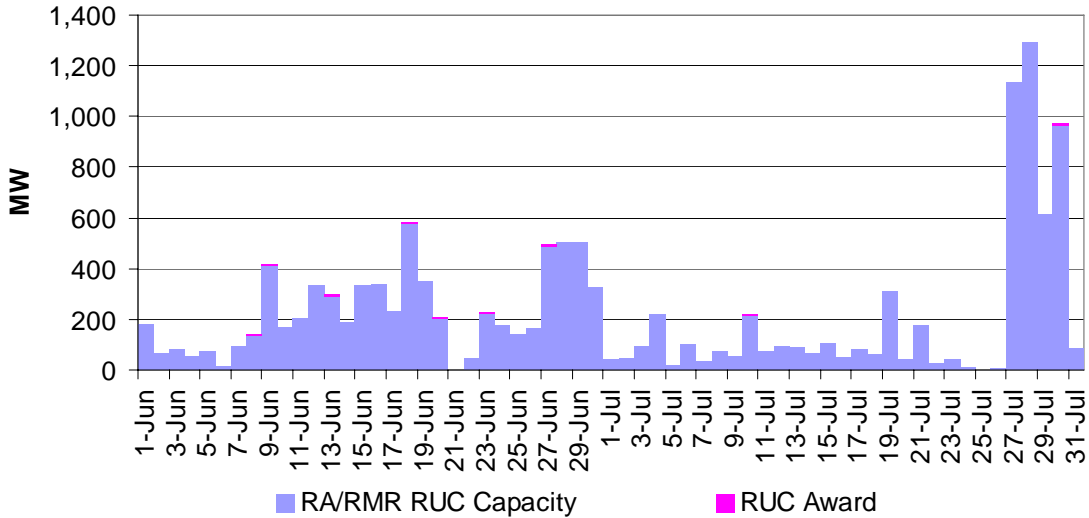


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**Figure 50: Off-Peak RA/RMR RUC Capacity vs. RUC Award**



**Figure 51: RA/RMR RUC Capacity vs. RUC Award (All Hours)**



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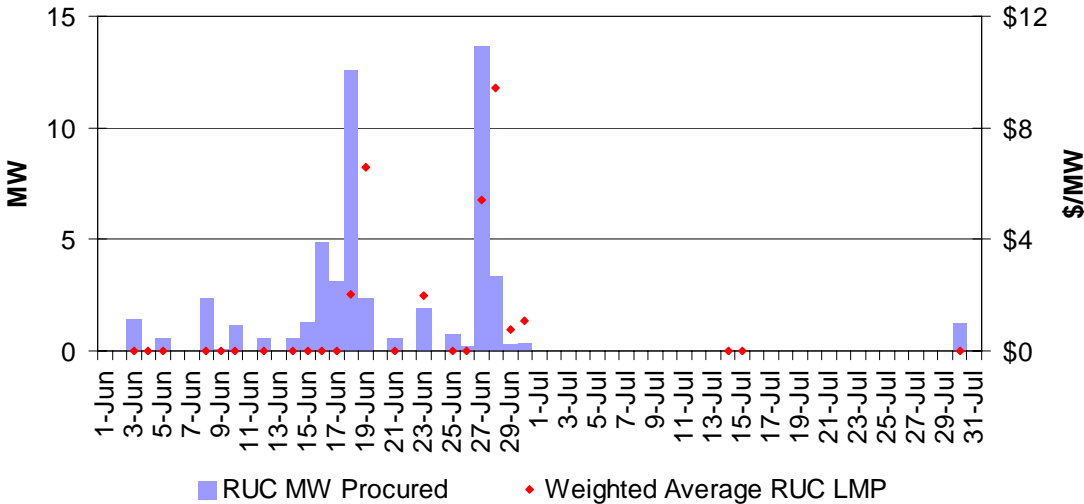
**RUC Award**

The daily RUC award and the weighted average RUC LMP are represented in Figure 52 , Figure 53 and Figure 54 for on-peak, off-peak and all hours. The weighted RUC LMP will not be specified if there was no RUC award in a particular day.

$$\text{Weighted\_RUC\_LMP} = \frac{\sum_j \sum_i (\text{RUC\_LMP}_{ij} \times \text{RUC\_Award}_{ij})}{\sum_j \sum_i \text{RUC\_Award}_{ij}}$$

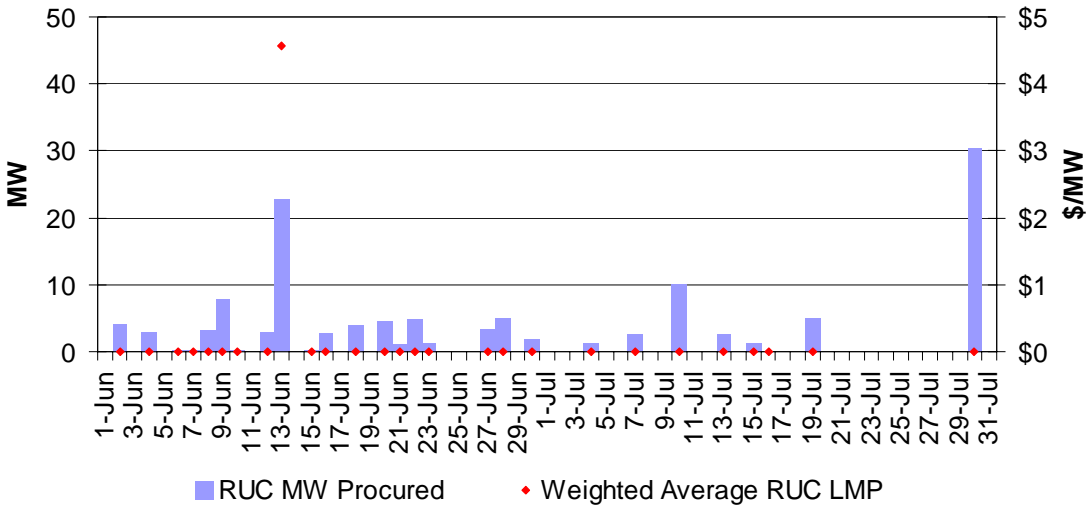
Here i indicates individual resource and j indicates trading hour (from 1 to 24).

**Figure 52: Daily On-Peak RUC Award and LMP**

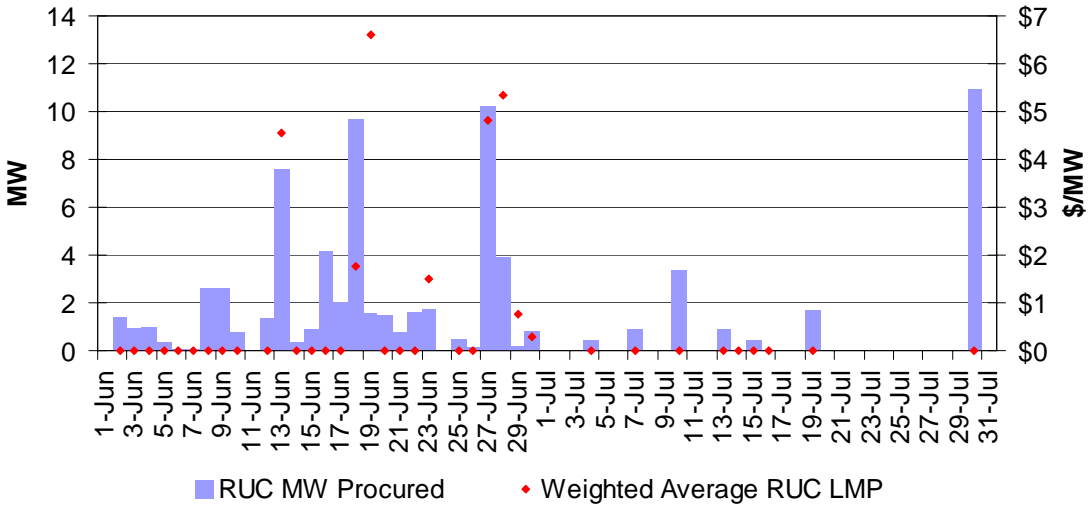


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**Figure 53: Daily Off-Peak RUC Award and LMP**



**Figure 54: Daily RUC Award and LMP (All Hours)**



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**Average RUC Price**

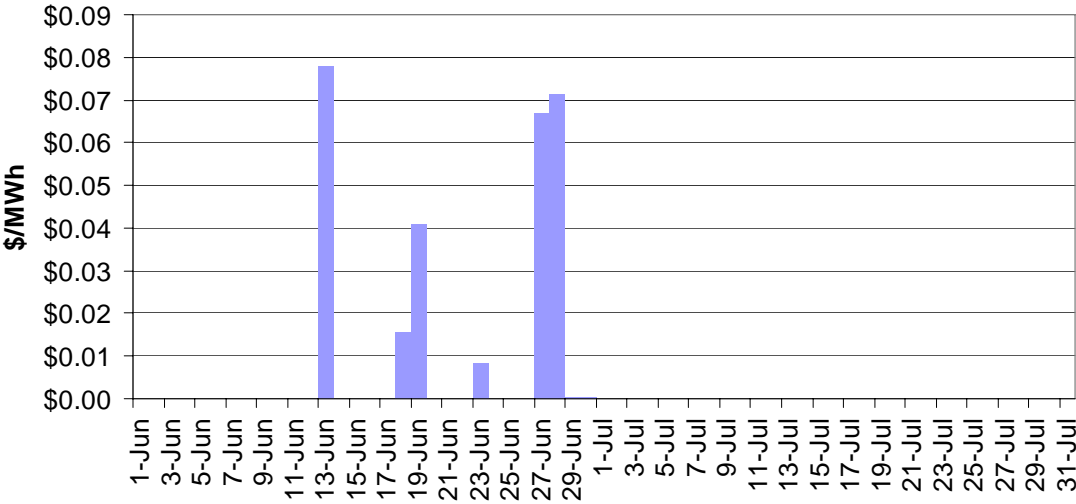
Figure 55 shows the daily average RUC price and Figure 56 shows the total RUC cost.

$$RUC\_Price = Avg\left( \frac{\sum_i (RUC\_LMP_{ij} \times RUC\_Award_{ij})}{\sum_i RUC\_Capacity_{ij}} \right)$$

Here i indicates individual resource and j indicates trading hour (from 1 to 24). The average is taken across all trading hours for each trading day.

The average RUC price will be positive only when there was a RUC award and the weighted average RUC LMP was greater than \$0. If there was no RUC award or there was some RUC award but the weighted average RUC LMP was \$0, average RUC price is \$0 for that trading day.

**Figure 55: Average RUC Price**

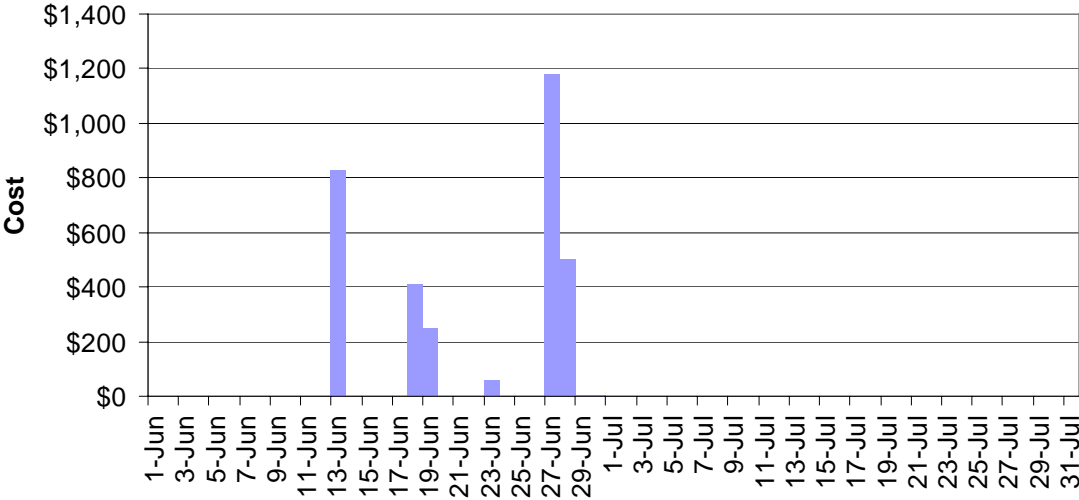


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**Total RUC Cost**

Figure 56 shows the daily cumulative total RUC cost.

**Figure 56: Total RUC Cost**

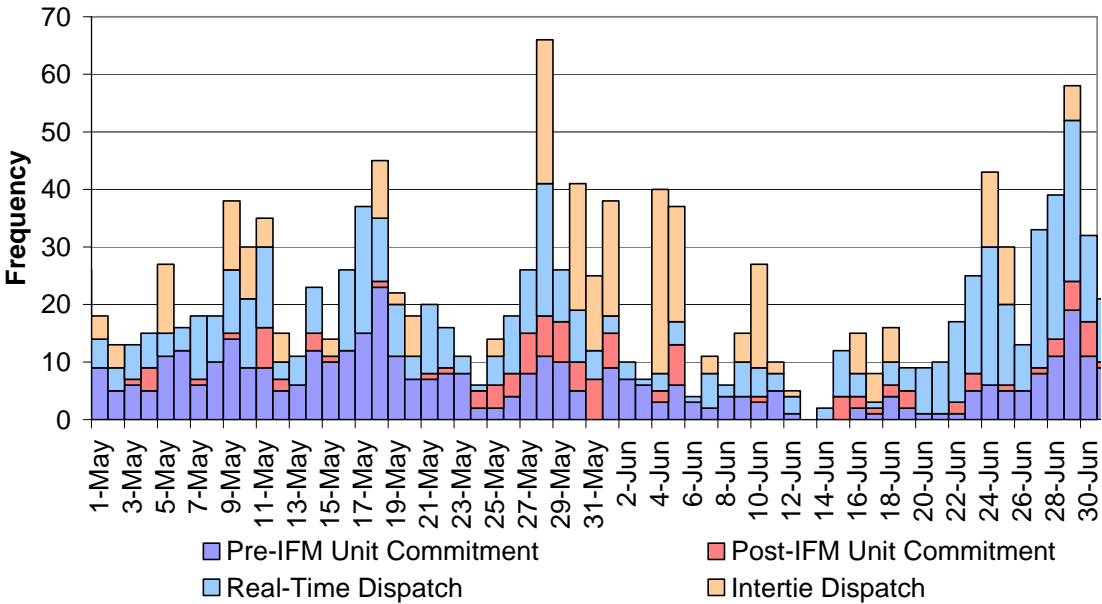


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### Exceptional Dispatch

Exceptional Dispatch refers generally to a subset of manual commitment or dispatch instructions that are not determined as result of the market software in the IFM, RUC or RTM. As a result, Exceptional Dispatches are not used to establish the LMP at the applicable PNode. Most frequently, Exceptional Dispatches occur when operators commit generators in the IFM (day-ahead) to address transmission or other operating constraints that are not included in the Full Network Model. Exceptional Dispatch may also be employed to prevent or manage System Emergencies and other Market Disruptions<sup>3</sup>, and to address other modeling or software limitations. Figure 57 shows the frequency of Exceptional Dispatch broken out by: (1) unit commitments made prior the Integrated Forward Market (“IFM”); (2) unit commitments made after the close of the IFM; (3) Instructed Imbalance Energy Dispatches made in Real-Time (dispatches above a units minimum operating level); and (4) Real-Time dispatches on interties (including HASP dispatches).

**Figure 57: Exceptional Dispatch Frequency**

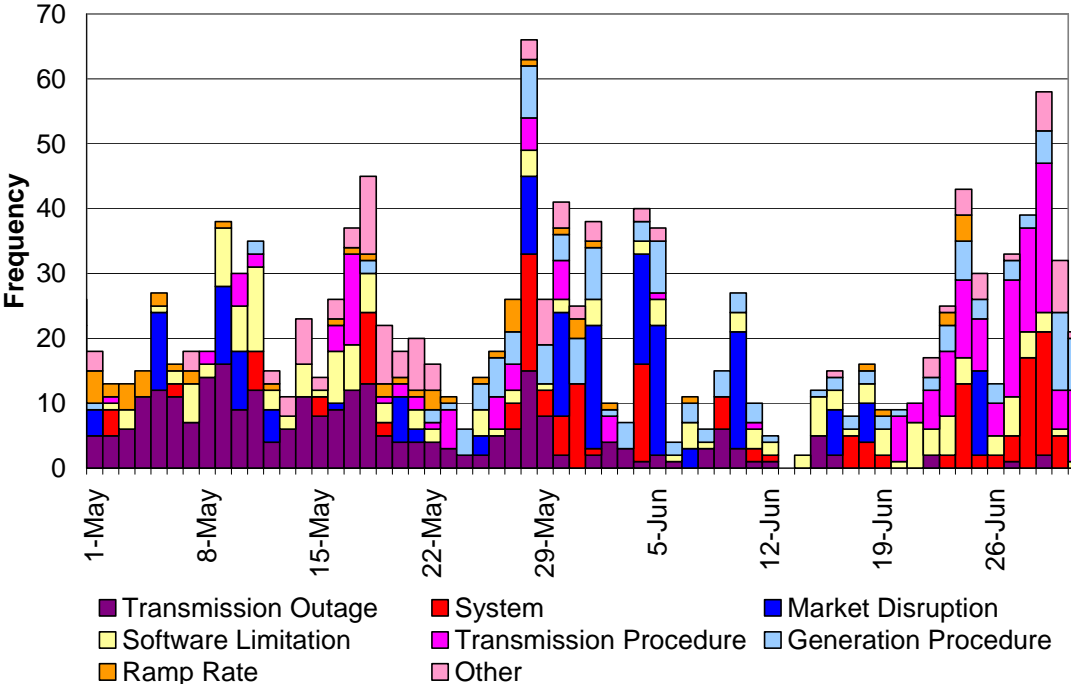


<sup>3</sup> A Market Disruption is defined as an action or event that causes a failure of a CAISO Market related to system operations or System Emergencies.

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Figure 58 summarizes Exceptional Dispatches by general reason where System includes System Energy on interties and other System Capacity requirements in the ISO Balancing Authority Area and Market Disruption includes HASP Failures.

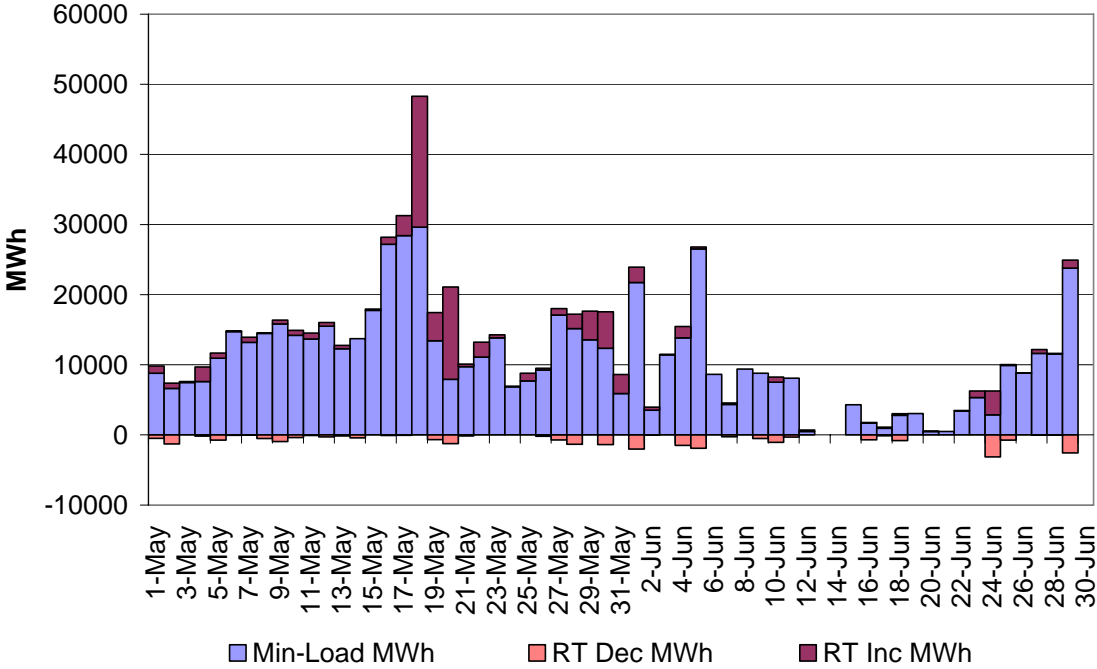
**Figure 58: Summary of Exceptional Dispatch Frequency by Reason**



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Figure 59 shows the total MWh volume of Exceptional Dispatches per trade date broken out by incremental and decremental dispatches. This includes both the MWh volume of unit commitments to pmin that would otherwise not be participating in the market on a given day, and changes to the Desired Operating Point (DOP) of units that are participating in the market. Note that decremental dispatches – which occur much less frequently than incremental dispatches – are represented as negative volumes.

**Figure 59: Total Exceptional Dispatch MWh Volume**



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.Figure 60 shows the total MWh quantity of Exceptional Dispatch as a percentage of total load, where total load is equal to internal generation plus imports minus exports. The horizontal lines in the Figure identify the monthly averages for each month

**Figure 60: Exceptional Dispatch Percent of Total Load**

