Market Performance Metric Catalog

Version 1.2

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CAISO
151 Blue Ravine Road
Folsom, California 95630
(916) 351-4400

ISO Market Services

VERSION HISTORY

Date	Version	Description	Author
5/28/2009	1.0	Creation of document	Market Performance Group
6/25/2009	1.1	Document for May	Market Performance Group
7/27/2009	1.2	Document for June	Market Performance Group

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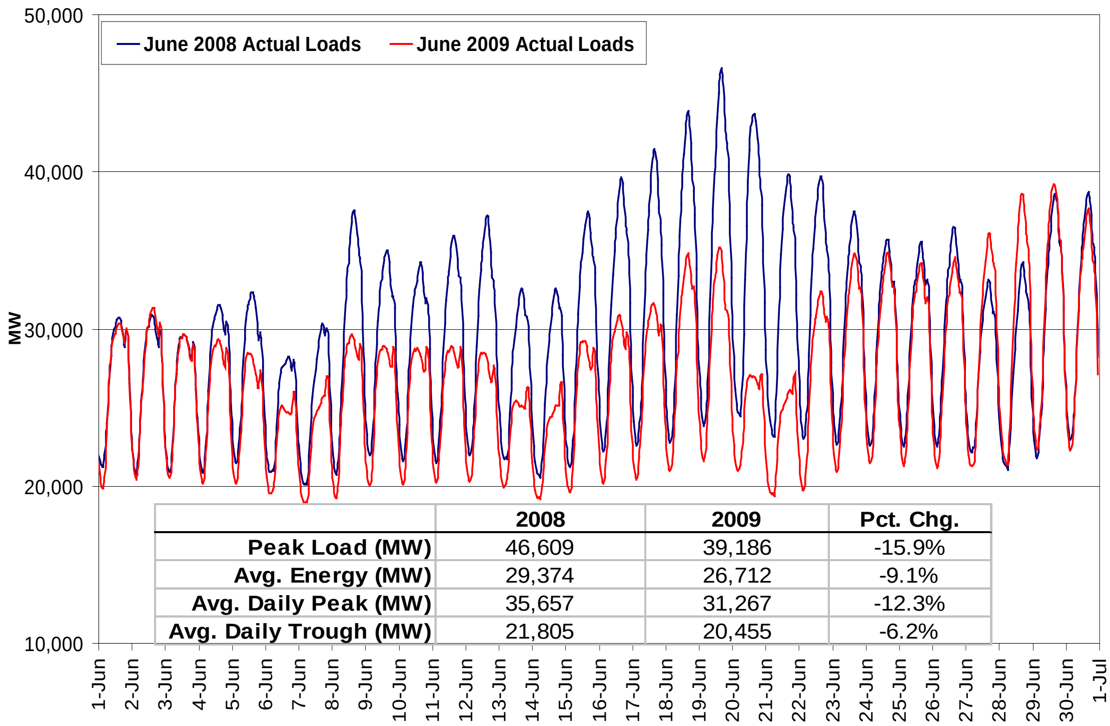
Market Characteristics

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

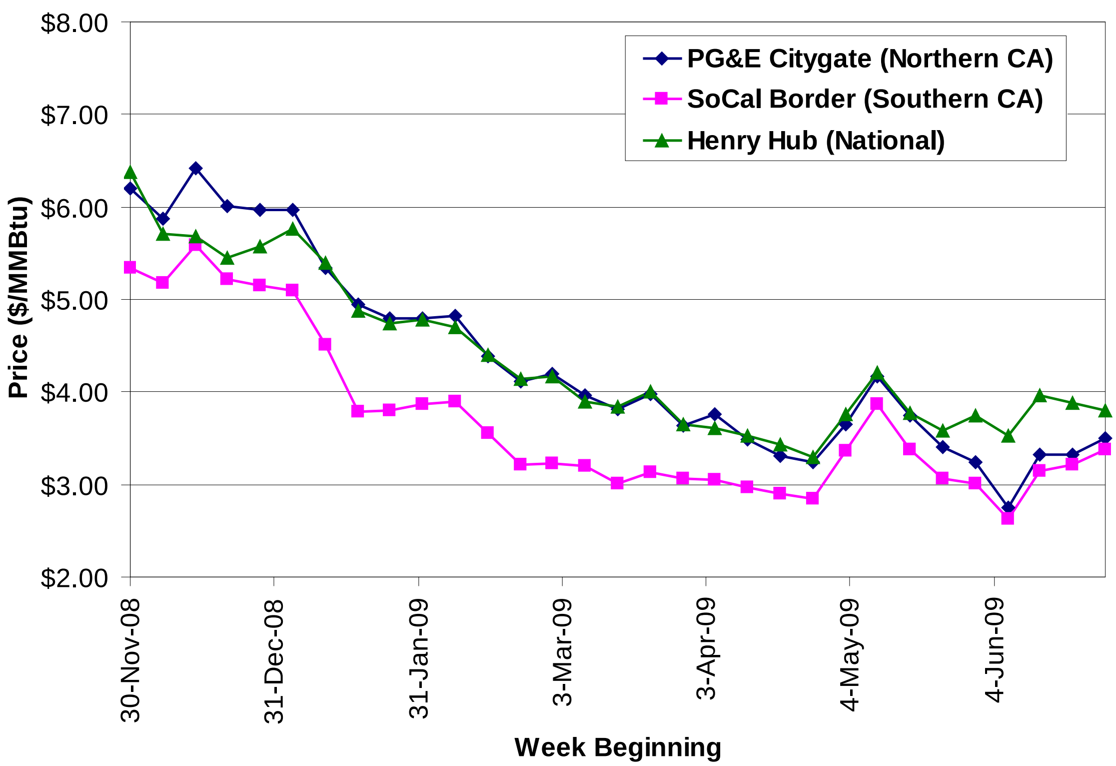


	2008	2009	Pct. Chg.
Peak Load (MW)	46,609	39,186	-15.9%
Avg. Energy (MW)	29,374	26,712	-9.1%
Avg. Daily Peak (MW)	35,657	31,267	-12.3%
Avg. Daily Trough (MW)	21,805	20,455	-6.2%

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.

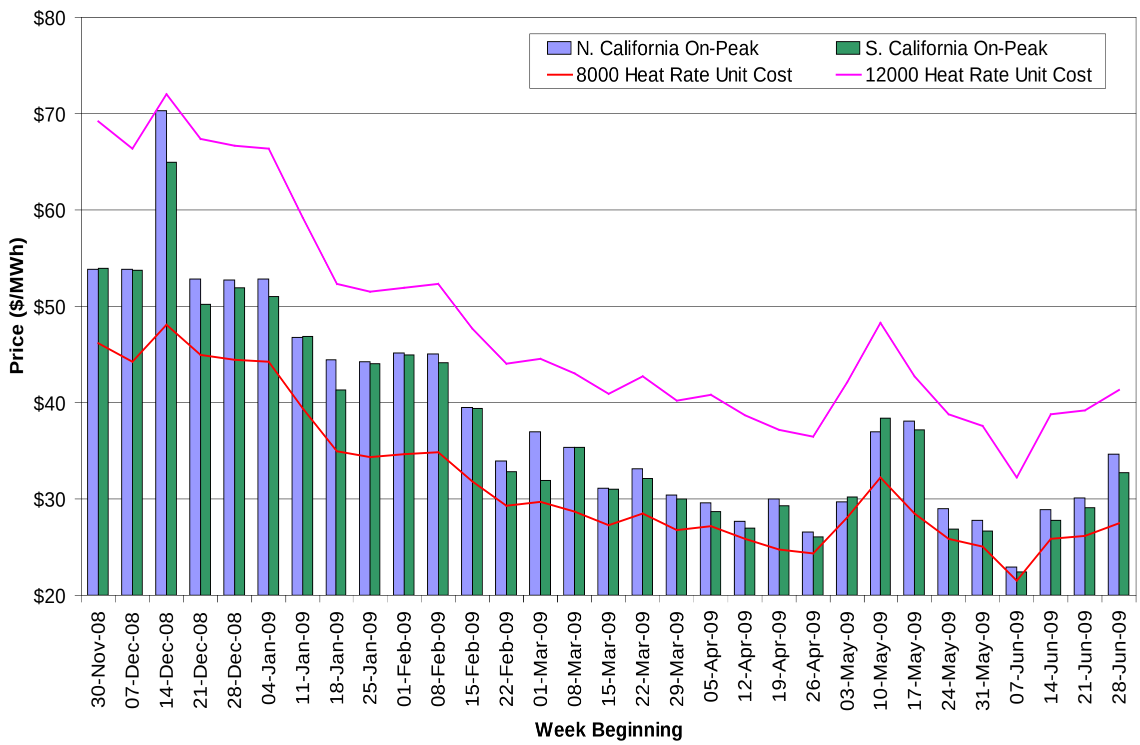
Figure 2: Weekly Average Natural Gas Spot Prices – December 2008 to June 2009



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



Market Performance Metrics

Energy

Day-Ahead Prices

Figure 4, Figure 45 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:

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

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. $SCHE\_MW_j$ is the scheduled energy in hour j for LAP i.

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

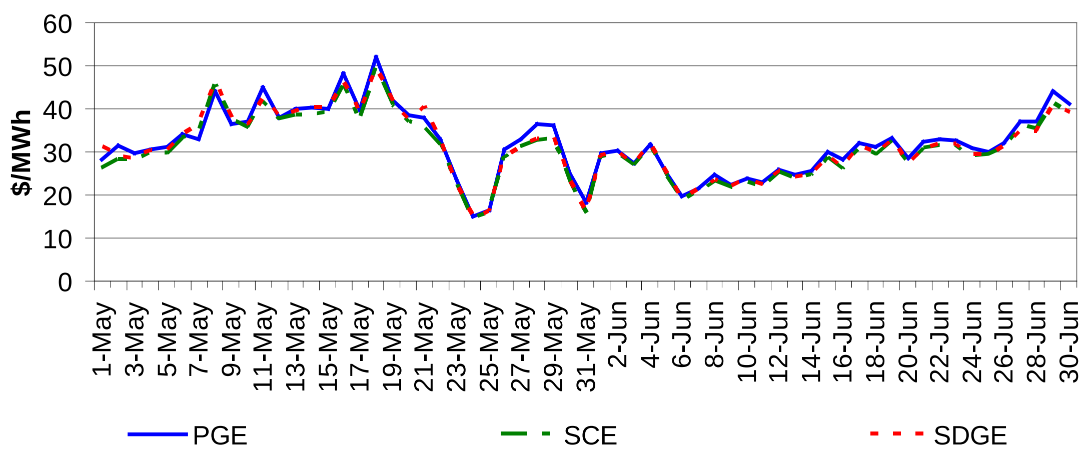


Figure 5: Day-Ahead Weighted Average Off-Peak LAP Prices

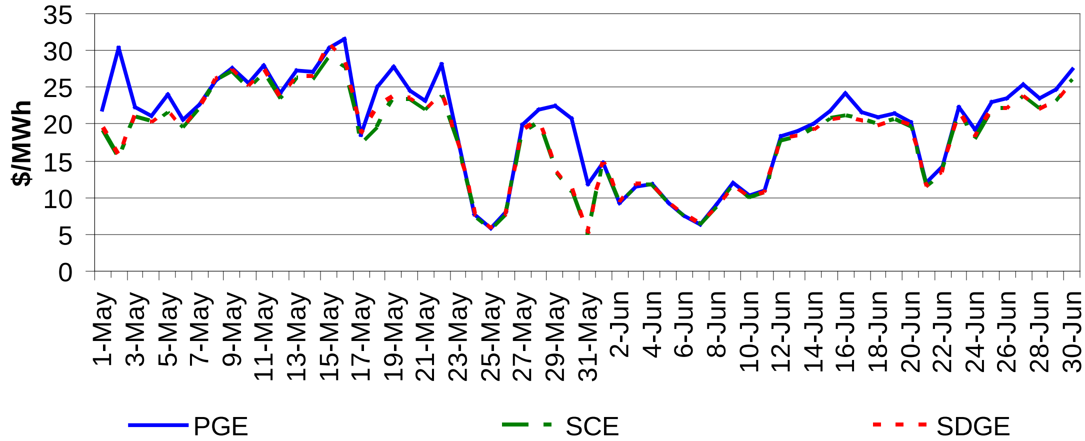
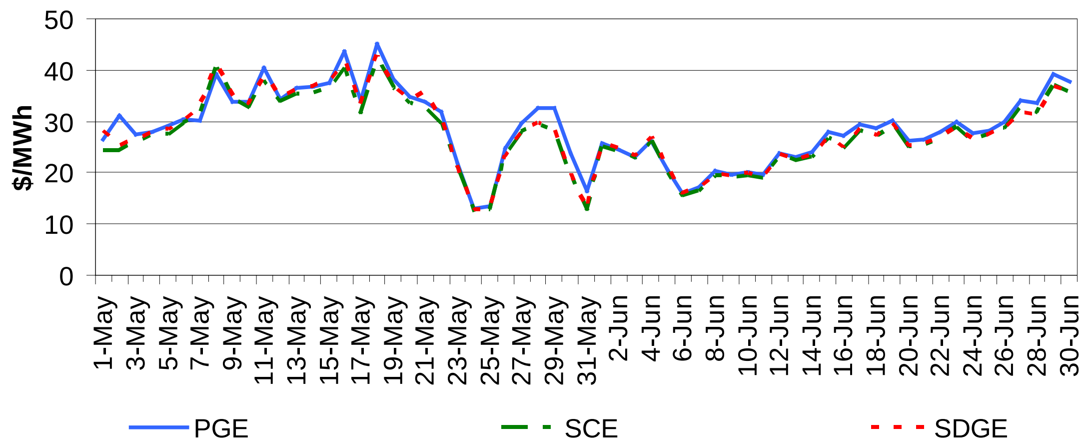


Figure 6: Day-Ahead Weighted Average LAP Prices (All Hours)



Real Time Prices

Figure 7, Figure 8 and Figure 9 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:

$$P_i = \sum_j \frac{\sum_h LMP_{ijh} * SCHE\_MW_{ijh}}{\sum_j \sum_h SCHE\_MW_{ijh}}$$ i= PGE, SCE, 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 7: RTD Weighted Average On-Peak LAP Prices

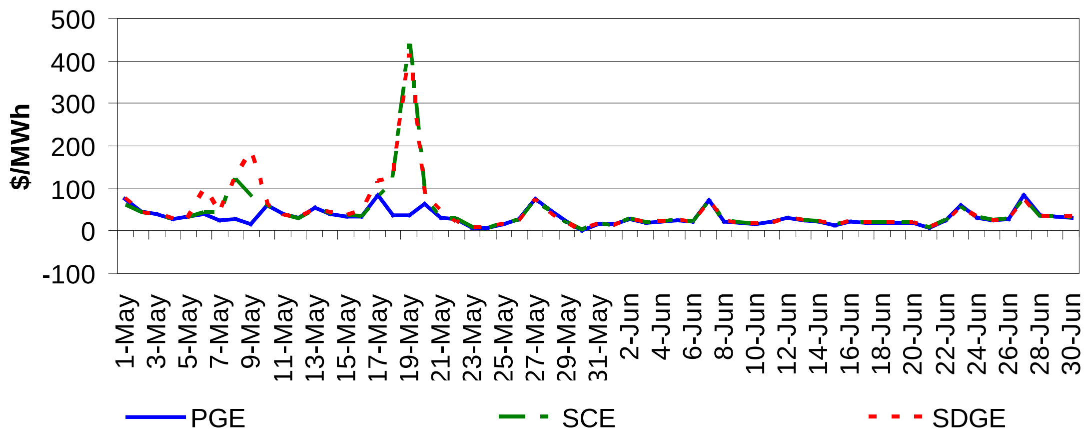


Figure 8: RTD Weighted Average Off-Peak LAP Prices

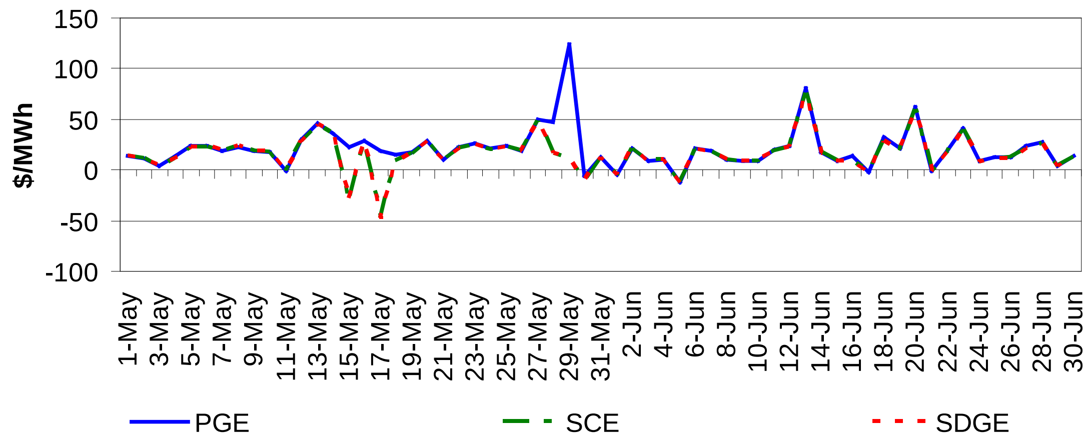


Figure 9: RTD Weighted Average LAP Prices (All Hours)

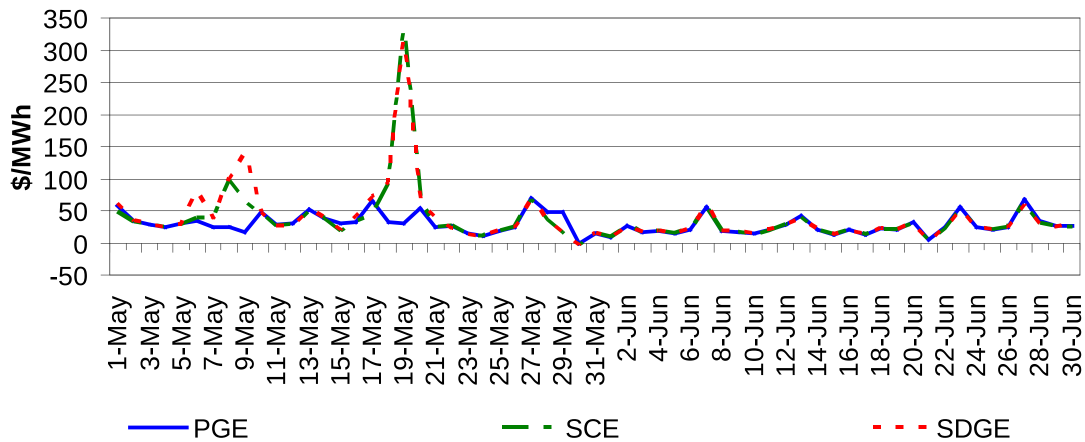


Table 1 summarizes the monthly average prices and volumes in Day-Ahead and Real-Time markets.

Table 1: Summary of Prices and Volumes

	Day-Ahead			Real-Time		
	Peak	Offpeak	All	Peak	Offpeak	All
Average Price ($)	29.51	16.96	26.14	27.75	17.23	24.86
Volume (MWh)	12,817,613	4,716,297	17,533,910	12,617,877	4,780,917	17,398,795
Percentage	73.10%	26.90%	100.00%	72.52%	27.48%	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 10 below illustrates the IFM congestion rents on inter-ties. The congestion rent 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 10: IFM (Day-Ahead) Congestion Rents by Inter-Tie (Import)

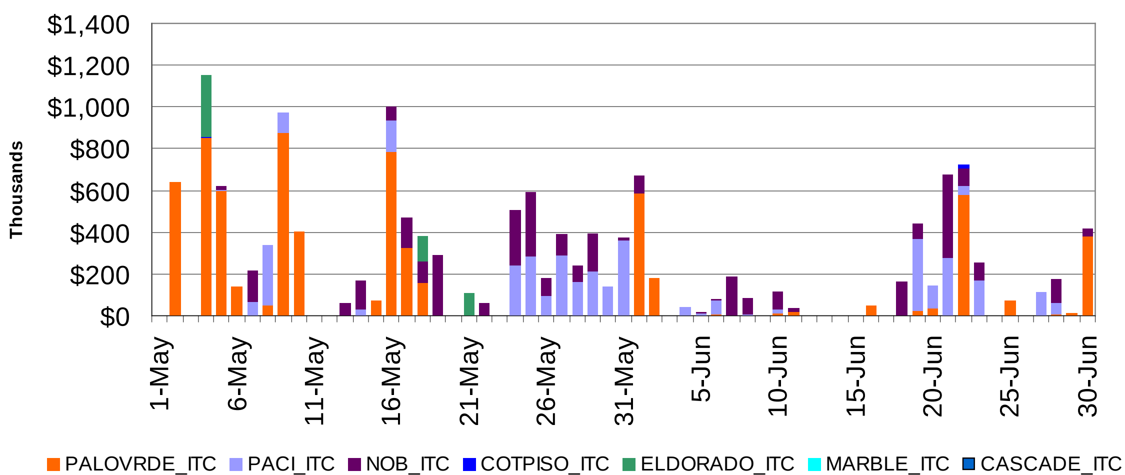


Table 2: IFM (Day-Ahead) Congestion Statistics by Inter-Tie (Import)

Inter-Tie	Average Cleared Value (MW)	Shadow Price ($/MWh)	Number of Congested Hours
COTPISO_ITC	24	60	12
NOB_ITC	1488	9	115
PACI_ITC	2697	5	88
PALOVRDE_ITC	2497	11	79

Congestion Rents on Branch Groups

Figure 11 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 11: IFM (Day-Ahead) Daily Congestion Rents by Branch Group

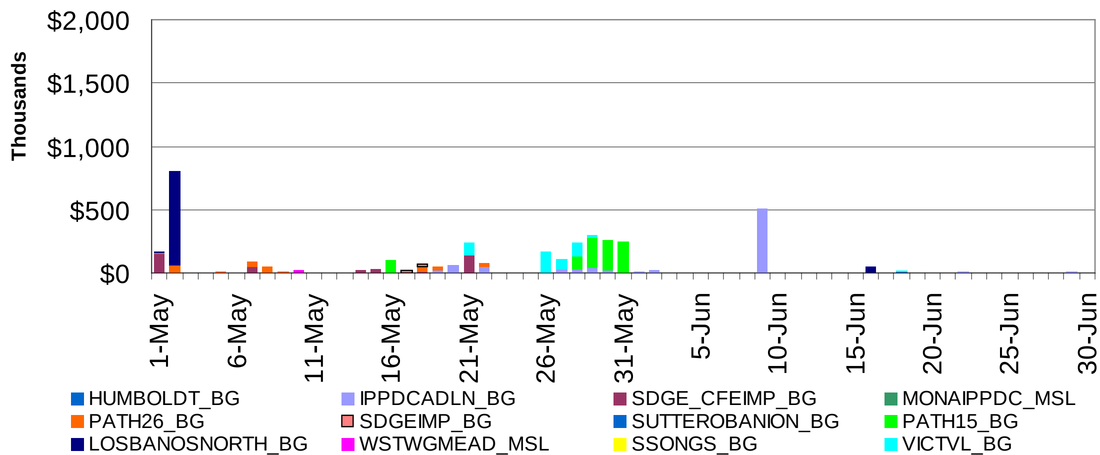


Table 3: IFM (Day-Ahead) Congestion Statistics by Branch Group

Branch Group	Average Cleared Value (MW)	Shadow Price ($/MWh)	Number of Congested Hours
HUMBOLDT_BG	43	14	10
IPPDCADLN_BG	549	27	49
LOSBANOSNORTH_BG	1964	3	9
SDGEIMP_BG	2550	0	1
VICTVL_BG	2400	1	1
WSTWGMEAD_MSL	186	1	1

Congestion Rents on Transmission Lines and Transformers

Figure 12 illustrates IFM congestion rents by transmission lines and transformers. The congestion rent is calculated as the shadow price ($/MWh) of the constraint multiplied by the flow limit (MW).

Figure 12: IFM (Day-Ahead) Congestion Rents by Transmission Lines and Transformers

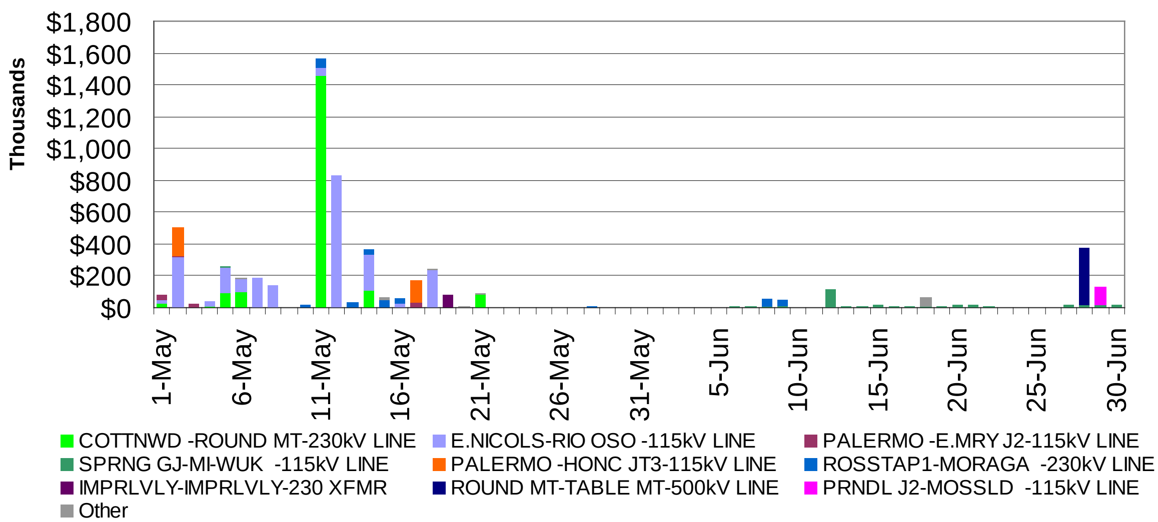


Table 4 provides a breakout of the IFM cleared value (MW), the average shadow price ($/MWh) and the number of congested hours by branch groups. Please note this table contains the cleared values for only those instances when the constraint was binding.

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

Branch Group	Average Cleared Value (MW)	Shadow Price ($/MWh)	Number of Congested Hours
LCIENEGA-LA FRESA-230kV LINE	697	5	17
PRNDL J2-MOSSLD -115kV LINE	122	500	2
ROSSTAP1-MORAGA -230kV LINE	379	13	18
ROUND MT-TABLE MT-500kV LINE	1892	21	9
SOBRANTE-SOBRANTE-115 XFMR	373	6	2
SPRNG GJ-MI-WUK -115kV LINE	96	8	446

Congestion Rents on Nomograms

Figure 13 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 13 : IFM (Day-Ahead) Daily Congestion Rents by Nomogram

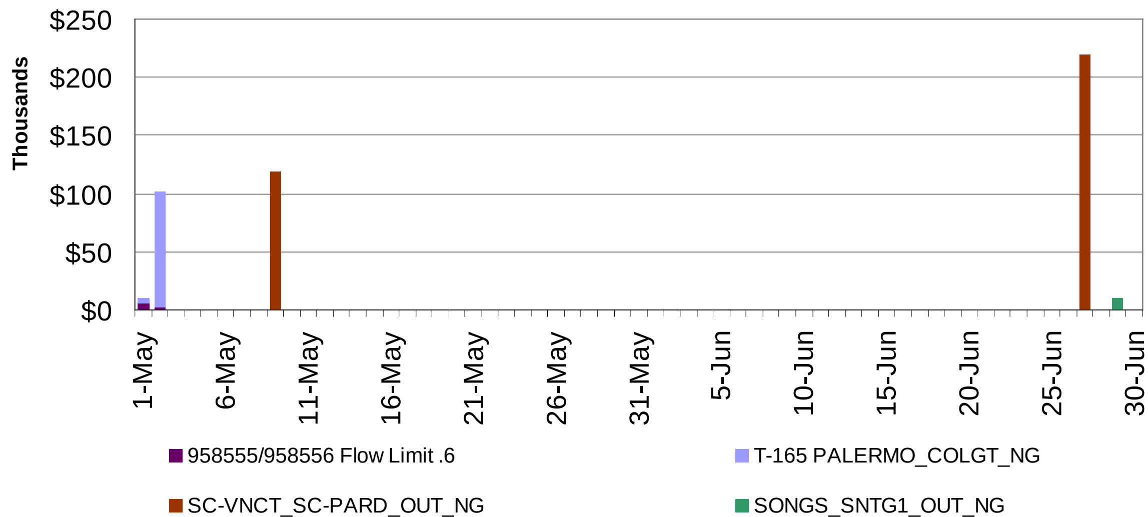


Table 5 provides a breakout of the IFM Cleared Value (MW), the average shadow price ($/MWh) and the number of congested hours by branch groups. Please note this table contains the cleared values for only those instances when the constraint was binding.

Table 5: IFM Congestion Statistics by Nomogram

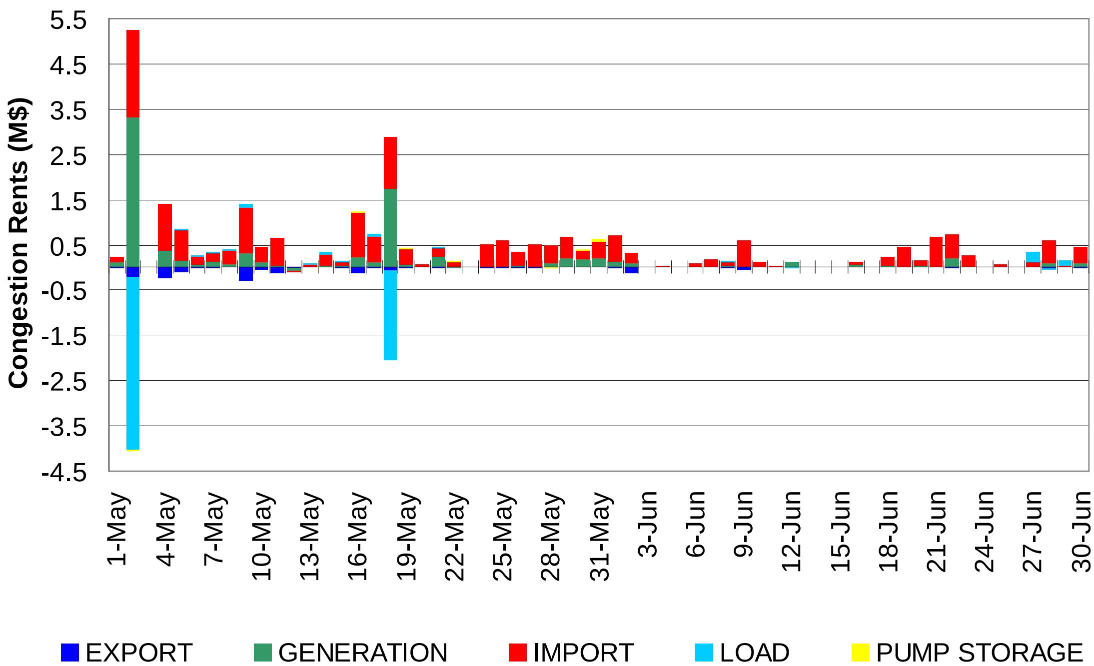
Nomogram	Average Cleared Value (MW)	Shadow Price ($/MWh)	Number of Congested Hours
SC-VNCT_SC-PARD_OUT_NG	525	417	1
SONGS_SNTG1_OUT_NG	1004	3	3

Congestion Rents by Resources

Figure 14 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 14: DA Congestion Rents by Market Resource

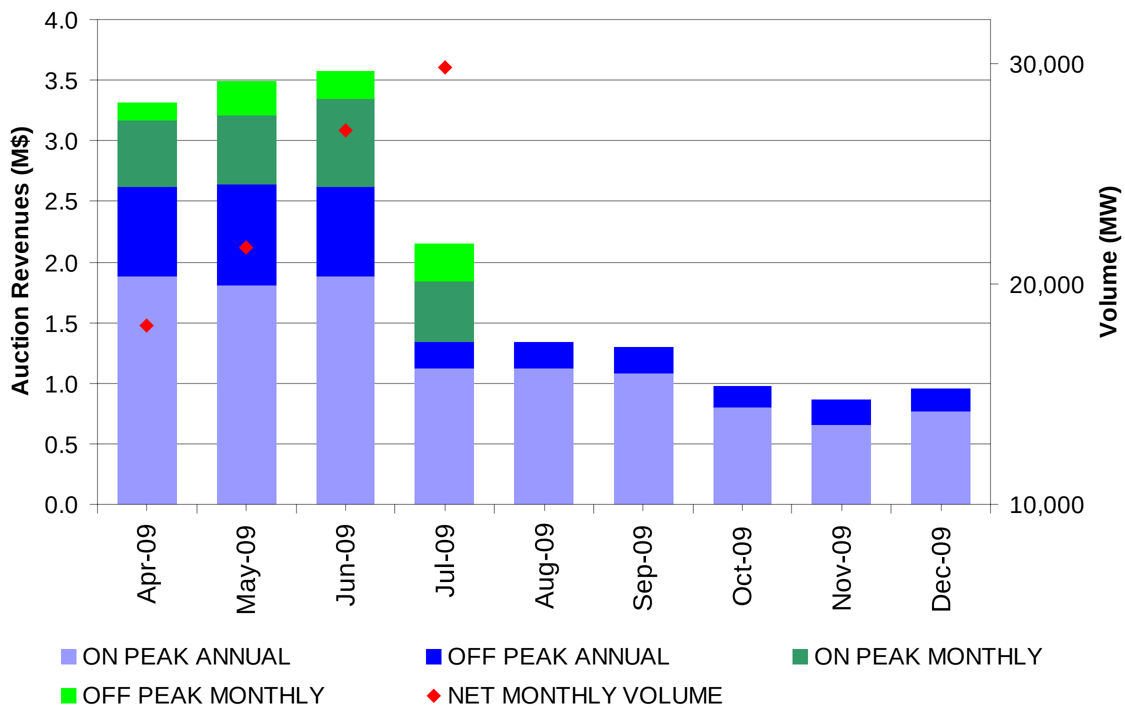


Congestion Revenue Rights

Auction Revenues

Figure 15 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 15: Revenues and Award Volumes in Monthly CRR Auctions



Monthly Volumes

Figure 16 through Figure 18 show the CRR volumes released in the monthly CRR processes. Both allocation and auctions for both times of uses are depicted. Figure 16 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 16: Monthly Volumes of CRR Awards –Allocation and Auction

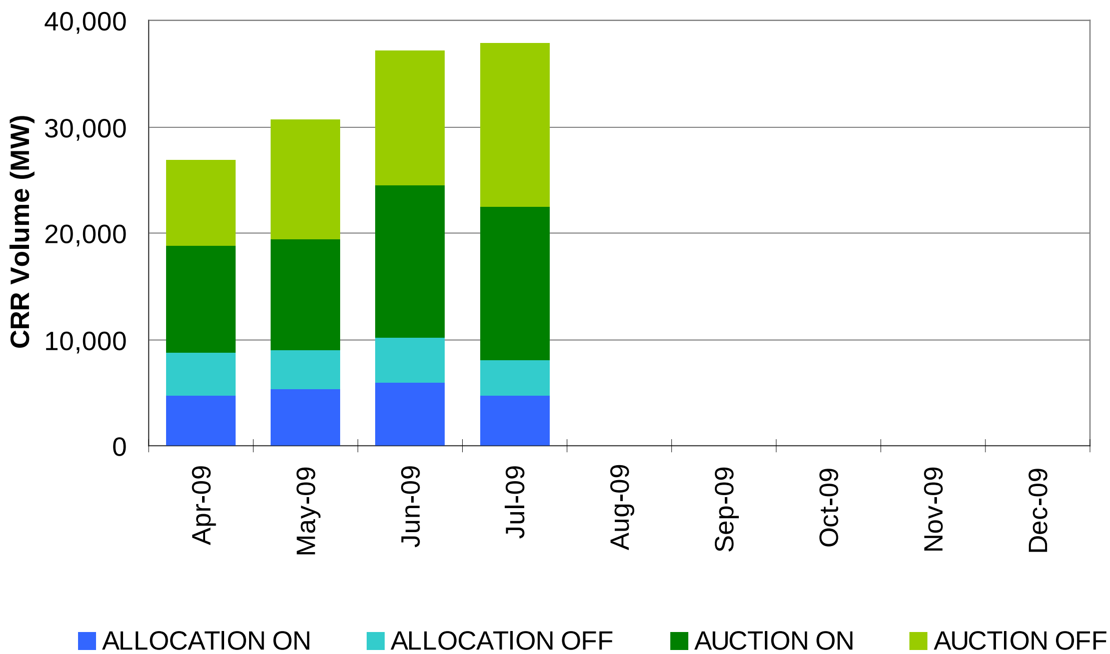


Figure 17 and Figure 18 compare the volume nominated and bid against the volumes allocated and awarded in the allocation and auction processes, respectively. It also includes the percentage of the volumes that were actually released in the monthly processes. These figures give a compact reference over time and also between allocation and auctions.

Figure 17: Volumes of Monthly CRR Allocations

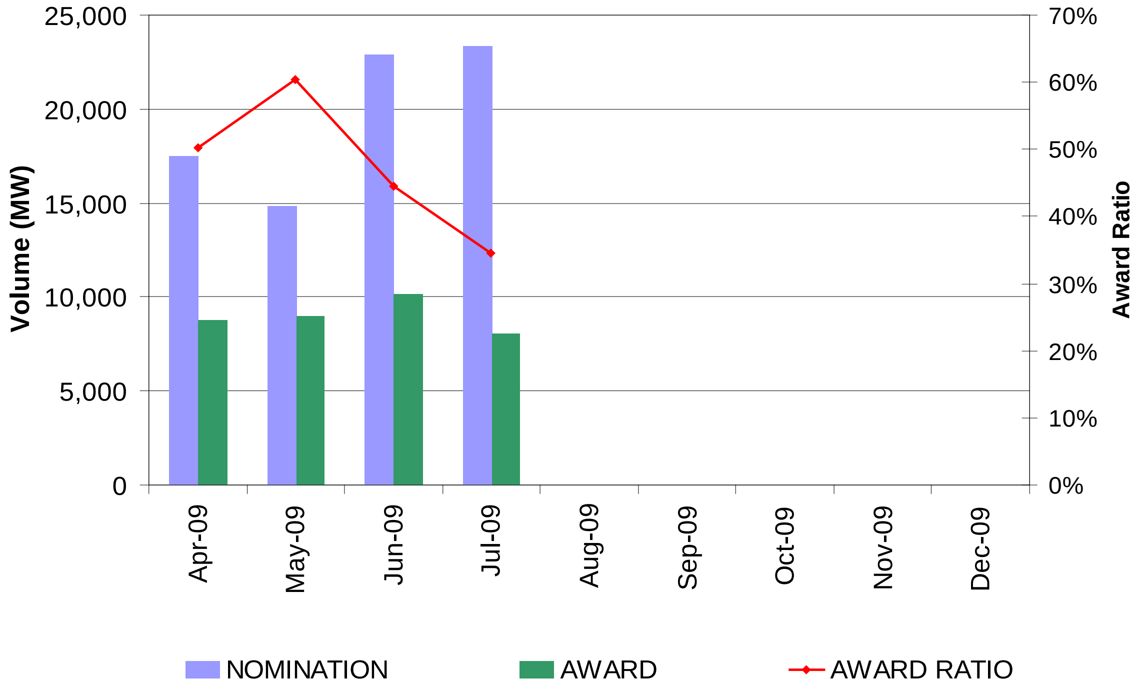
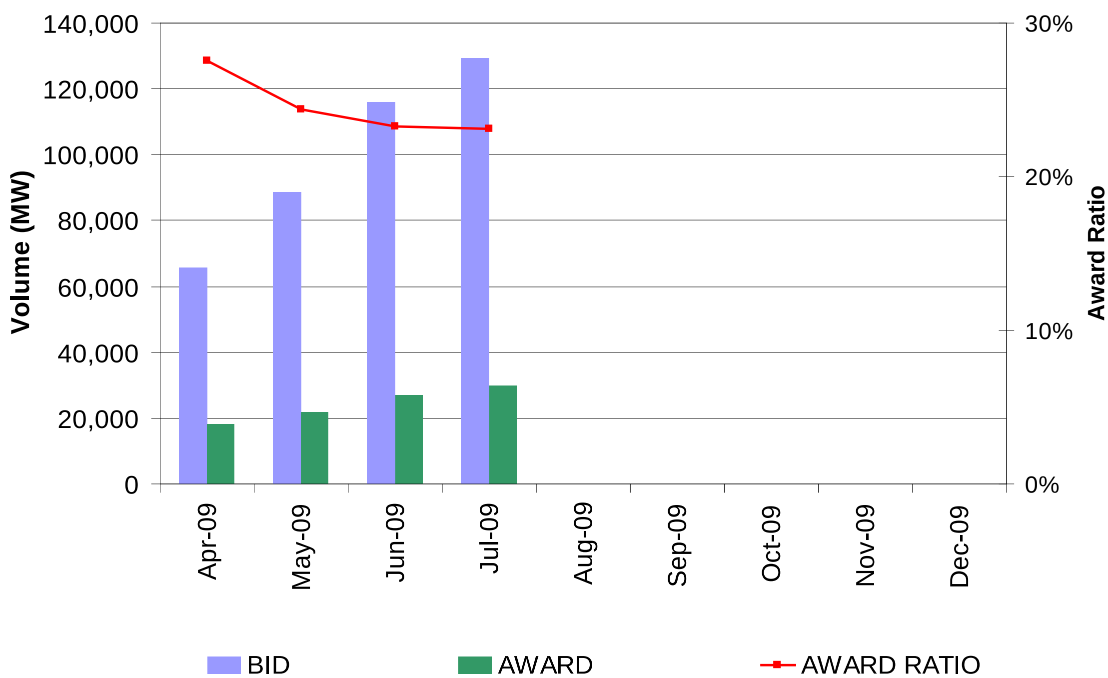


Figure 18: Volumes of Monthly CRR Auctions



Auction Prices

Figure 19 and Figure 20 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 19: Price Frequency of Monthly CRR auctions – On Peak

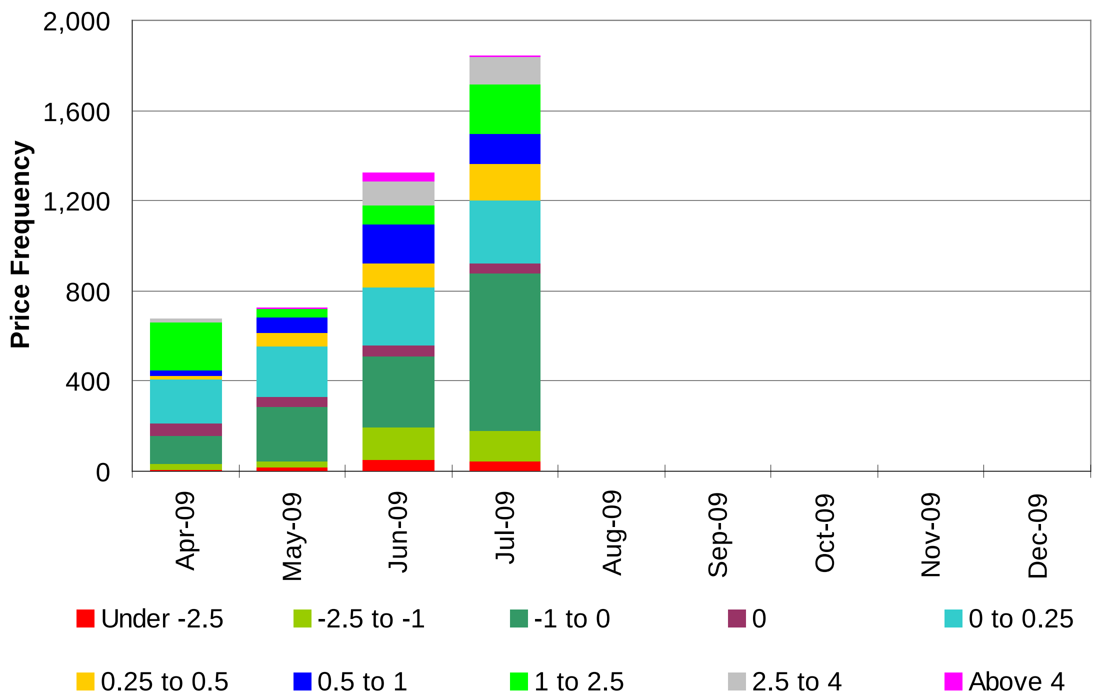
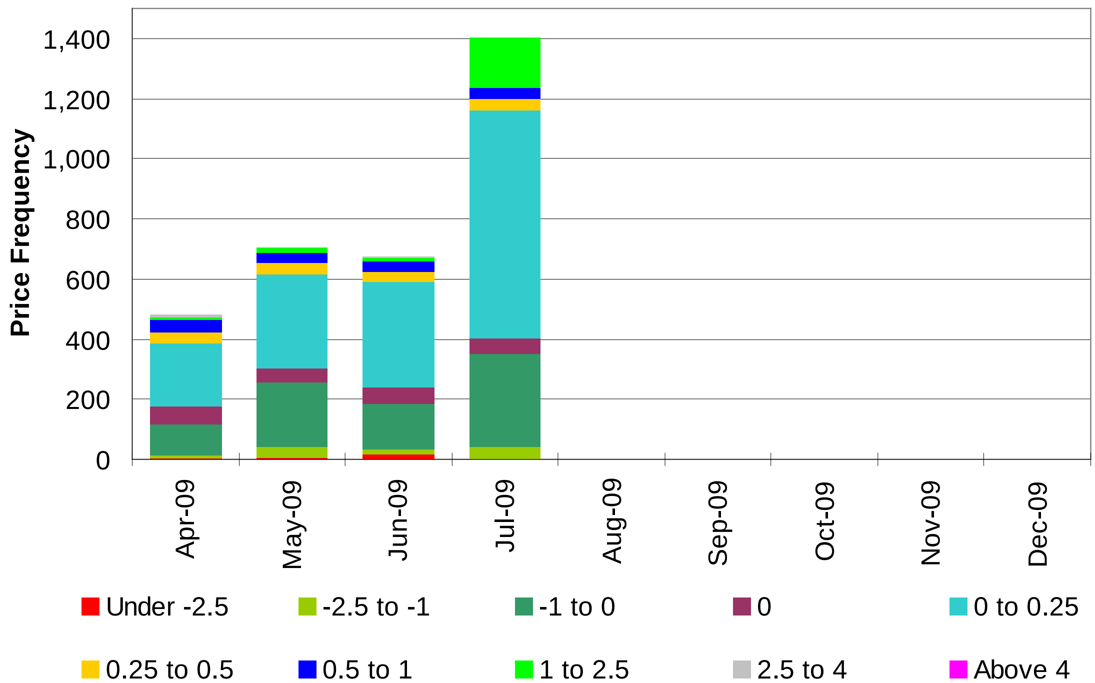


Figure 20: Price distribution of CRR Monthly Auctions – OFF Peak



Monthly Revenue Adequacy

Figure 21 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.* For settlement purposes, the hourly CRR revenue adequacy amounts (net congestion revenues minus net payments to CRR holders) are aggregated across all hours of each month and 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, in accordance with

* 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.

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.

Figure 21: Daily Revenue Adequacy of Congestion Revenue Rights

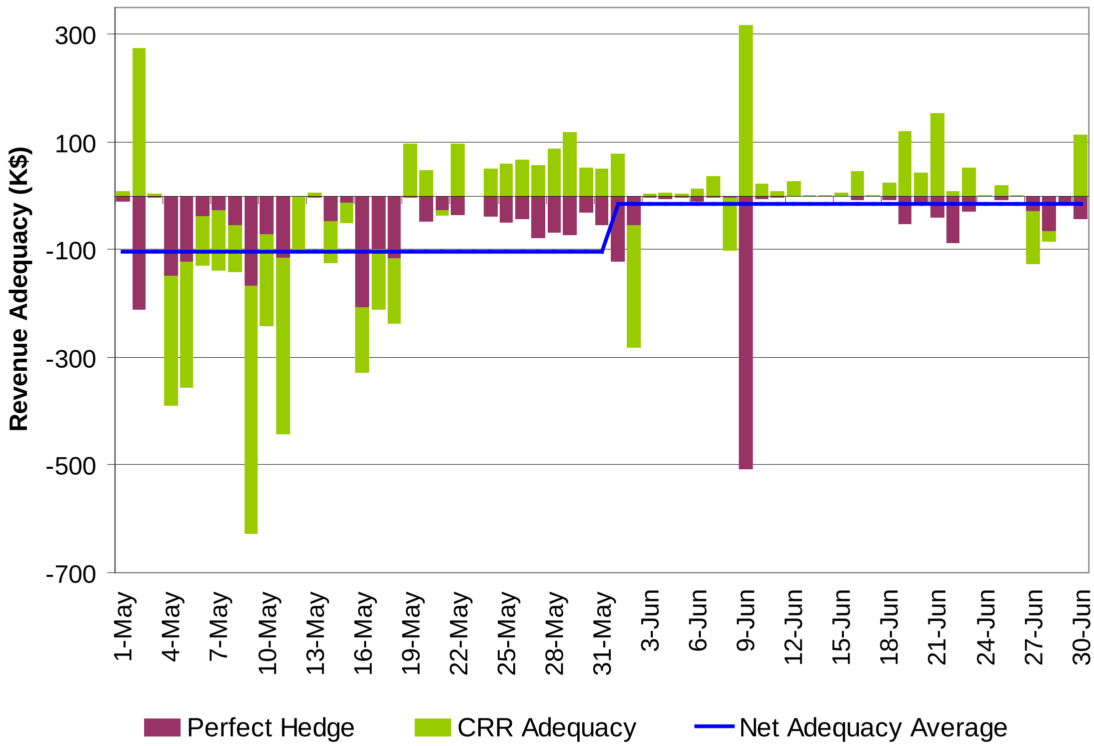


Table 6 provides a summary of the main statistics for CRRs for the current month. Definitions for the Concepts listed in Table 6 are as follows:

- *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 June

Concept	Amount
IFM Congestion Rents	$6,442,759.92
CRR Payments	$5,772,604.08
CRR Adequacy	$670,155.84
Perfect Hedge	-$1,119,271.10
Net Revenue Adequacy	-$449,115.26
Revenue Adequacy Ratio	93.48%
Annual Auction Revenues	$2,614,840.36
Monthly Auction Revenues	$955,471.16
Monthly Net Balance	$3,121,196.26

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 metered demand excluding metered demand associated with valid and balanced portions of ETCs/TORs. Figure 22 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 22: Cost of the Perfect Hedge for Post Day-Ahead ETCs/TORs

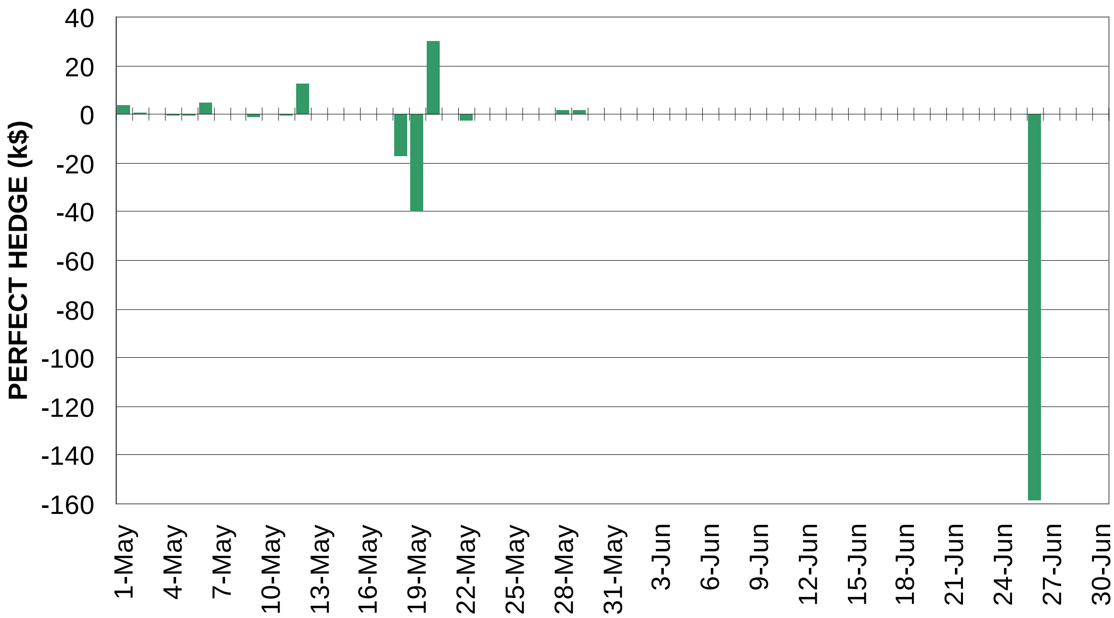


Table 7 list the monthly summary of the post Day-Ahead (HASP/RT) congestion rents and perfect hedge. A positive value of the congestion rents is a surplus; a negative value is a shortfall. Any surplus or shortfall is allocated to metered demand, excluding demand associated with ETCs/TORs. The percentage 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

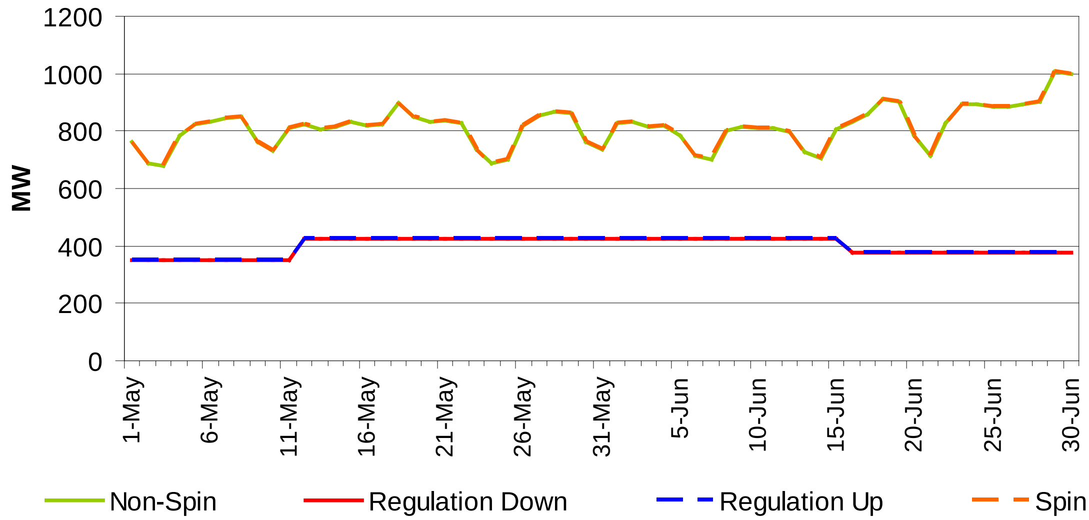
Month	Congestion Rents	Perfect Hedge	Percentage
MAY	-$11,843,743.05	-$5,599.06	0.047%
JUNE	-$1,174,233.21	-$158,629.84	13.509%

Ancillary Services

Requirements

Figure 23 illustrates the IFM (Day-Ahead) daily average Ancillary Service requirement for Regulation Up, Regulation Down, Spin and Non-Spin.

Figure 23: IFM (Day-Ahead) Ancillary Services Average Requirement



Procurements

Figure 24 illustrates the IFM Daily average procurement of Regulation Up, Spin and Non-Spin Ancillary Services.

Figure 24: IFM (Day-Ahead) Upward Ancillary Services Procurement

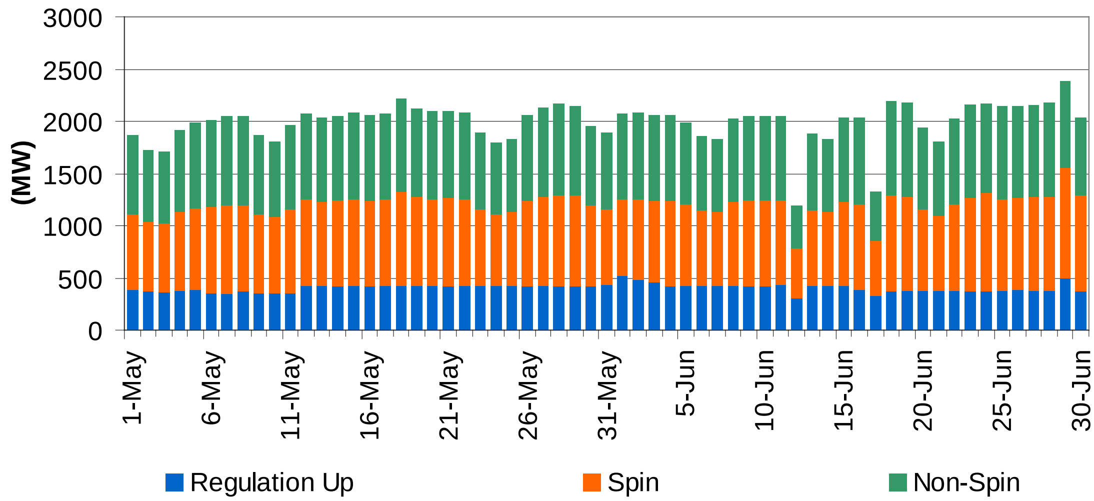


Figure 25 illustrates the IFM daily average procurement of Regulation Down.

Figure 25: IFM (Day-Ahead) Regulation Down Procured

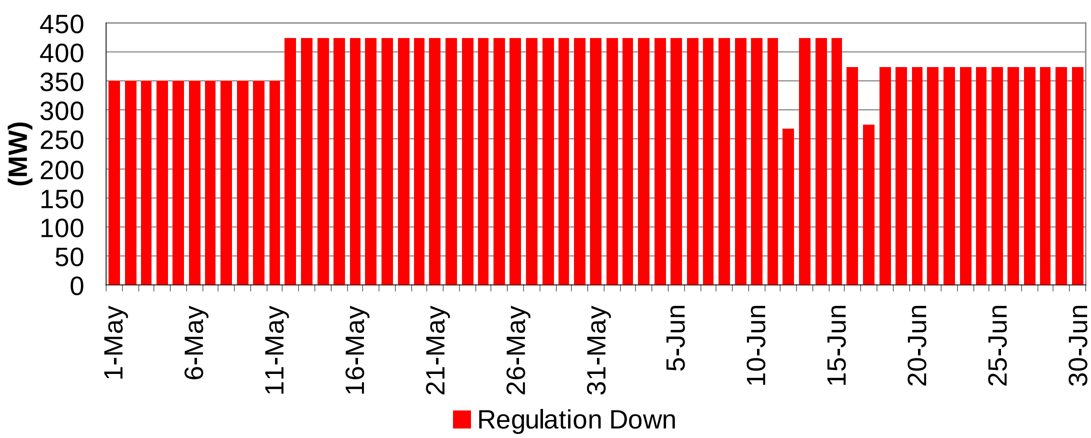


Figure 26 illustrates the RTPD Daily average procurement of Regulation Up, Spin and Non-Spin Ancillary Services.

Figure 26: RTPD (Real-Time) Upward Ancillary Services Procurement

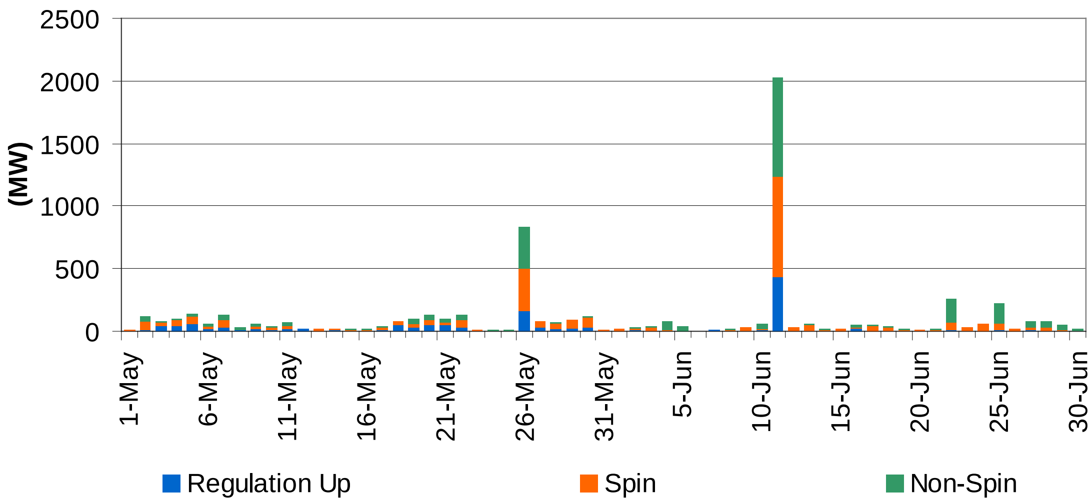
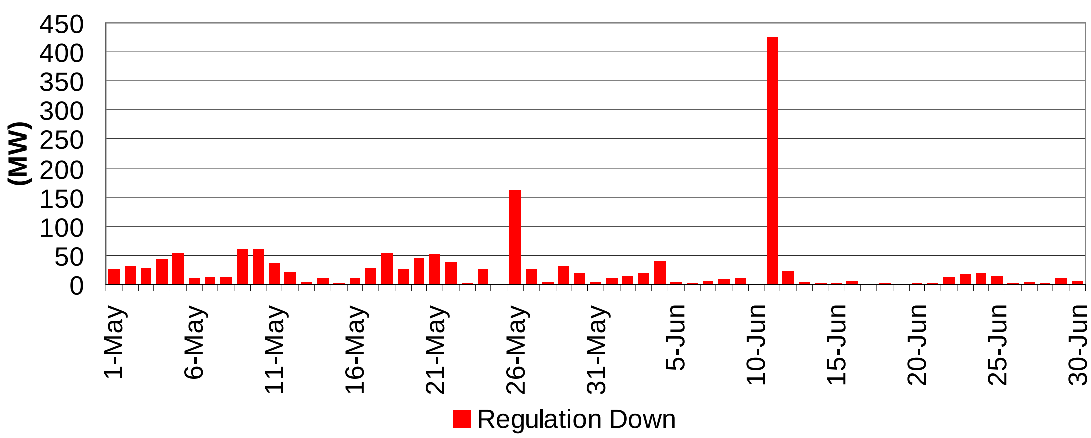


Figure 27 illustrates the RTPD daily average procurement of Regulation Down.

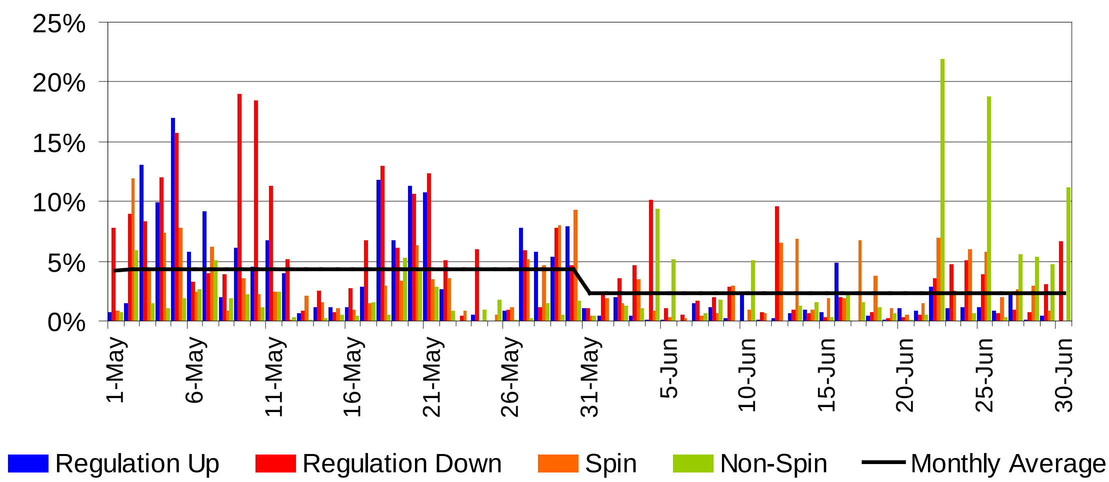
Figure 27: RTPD (Real-Time) Regulation Down Procured



The CAISO procures 100 percent of its Ancillary Services requirements in the IFM 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 market is unable to provide that service in Real-Time. The market will procure additional services to replace that service.

Figure 28 displays the percentage of RTPD procurement with respect to the IFM procurement for all four types of Ancillary Services. The percentage for each type of Ancillary Service is calculated as: (hourly average of RTPD procurement in 15 minute intervals) / (hourly IFM procurement).

Figure 28: Proportion of Real-Time Procurement as Percentage of Day-Ahead Requirement.



IFM (Day-Ahead) Average Prices

Figure 29 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 Service is calculated as: Sum (Non-Self Scheduled AS MW * Ancillary Service Marginal Price $/MW (ASMP)) / Sum (Non-Self Scheduled AS MW).

Figure 29: IFM (Day-Ahead) Ancillary Service Average Price

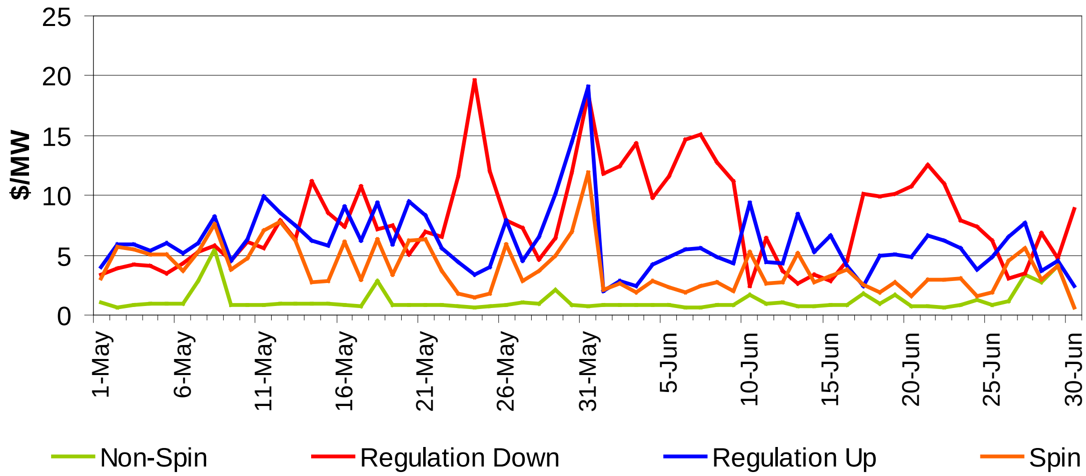
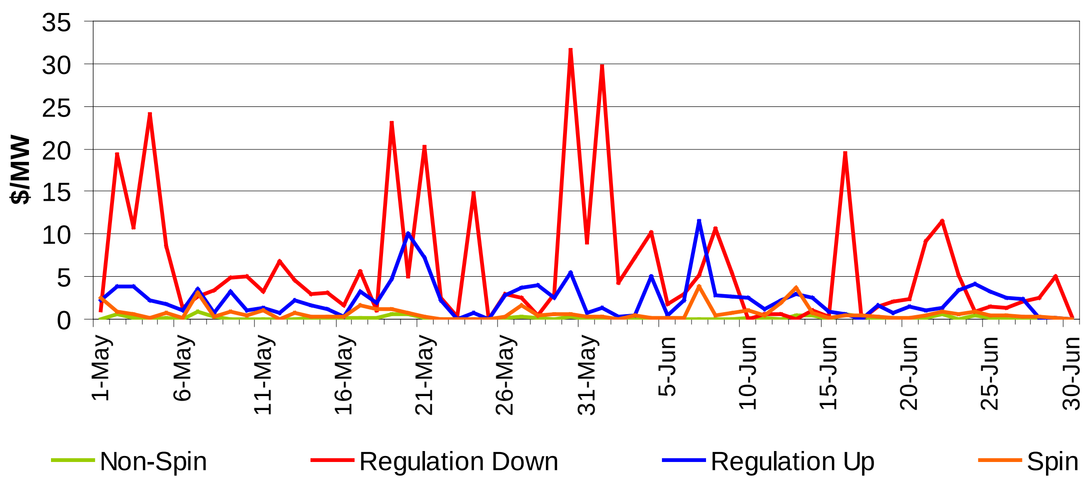


Figure 30 illustrates the RTPD daily average price for Regulation Up, Regulation Down, Spin and Non-Spin Ancillary Services. The average price for each type of Ancillary Service is calculated as: Hourly average of [Sum (Non-Self Scheduled AS MW * Ancillary Services Marginal Price $/MW (ASMP)) / Sum (Non-Self Scheduled AS MW)] for each of the 15 minute intervals.

Figure 30: RTPD (Real-Time) Ancillary Service Average Price



Average Regional Ancillary Service Shadow Prices

Figure 21 through Figure 34 display the IFM Daily Average Regional Ancillary Service Shadow Prices (RASSPs) for Regulation Up, Spin, Non-Spin and Regulation Down.

Figure 31: IFM (Day-Ahead) Regulation Up (RASSP)

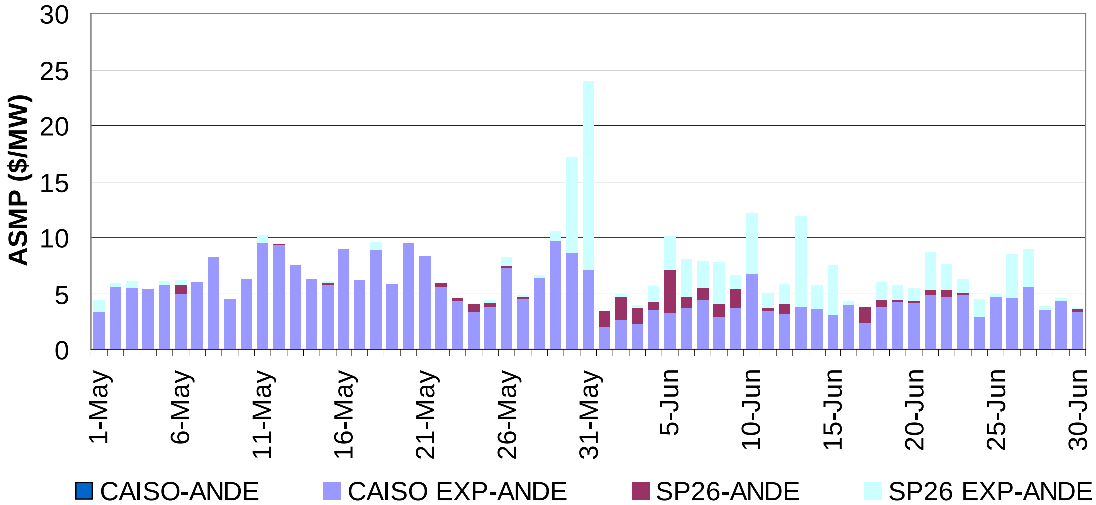


Figure 32: IFM (Day-Ahead) Spin (RASSP)

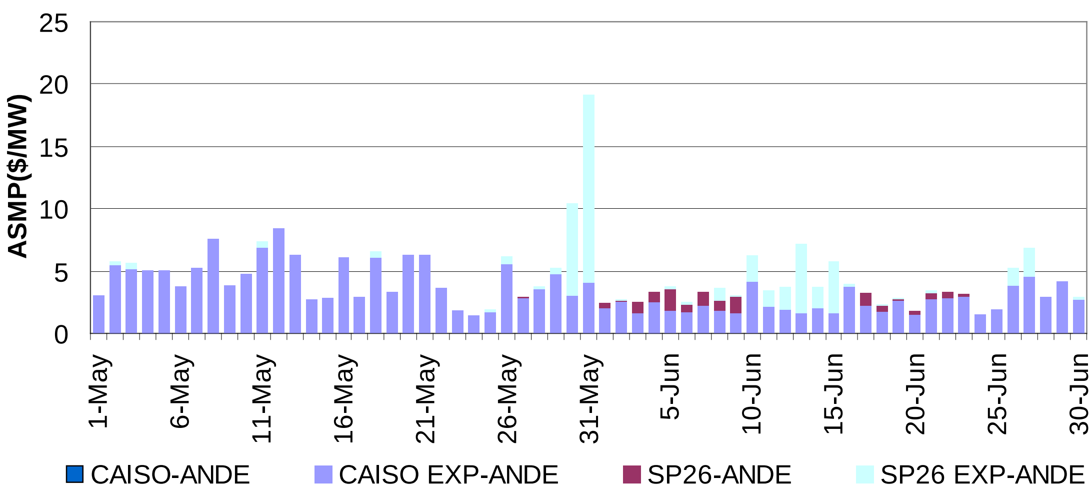


Figure 33: IFM (Day-Ahead) Non-Spin (RASSP)

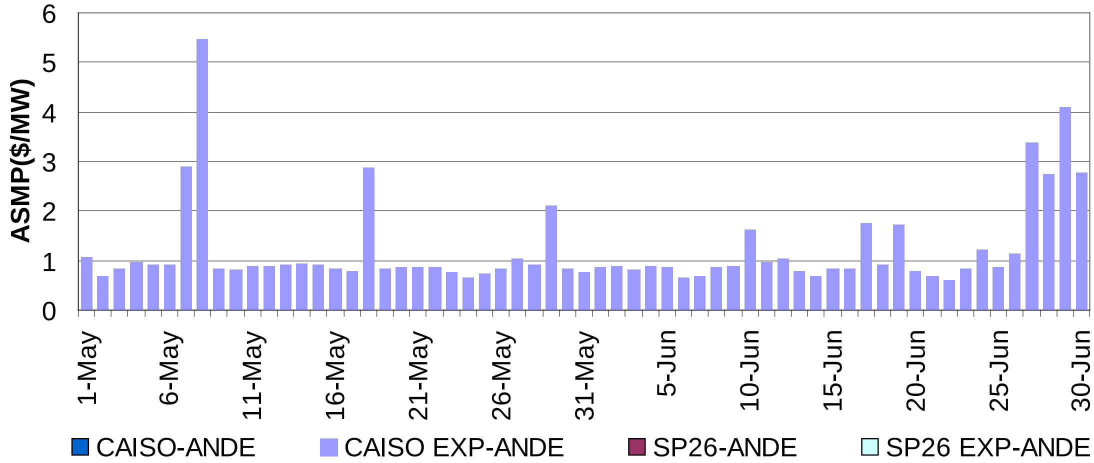
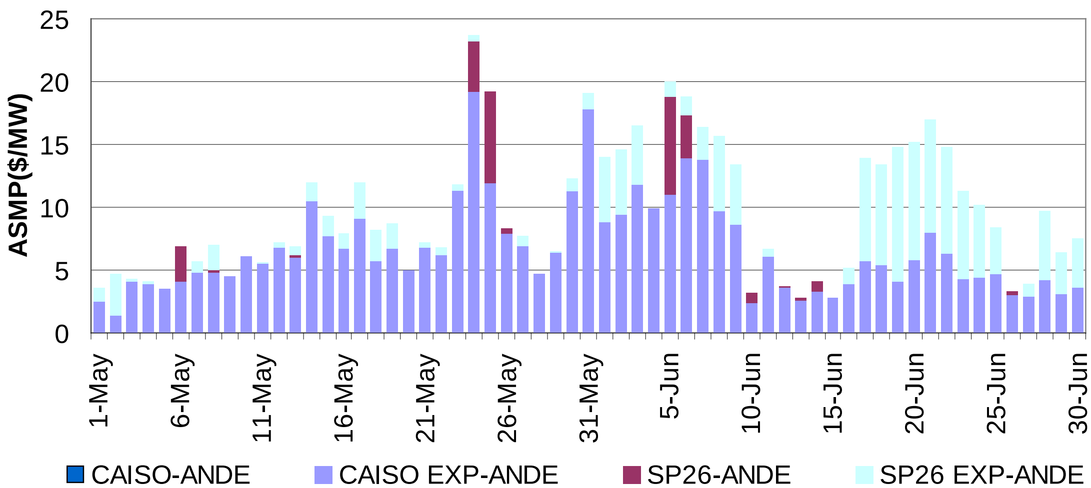


Figure 34: IFM (Day-Ahead) Regulation Down (RASSP)



Average Cost to Load

Figure 35 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 each type of Ancillary services) / (Total hourly CAISO Load)).

Figure 35: IFM (Day-Ahead) Average Cost to Load

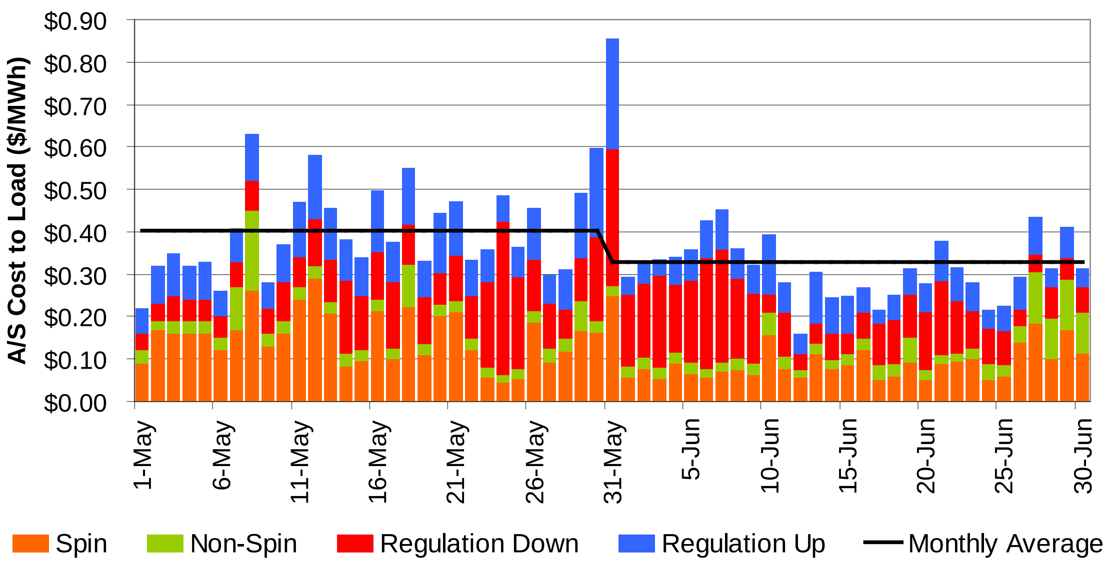
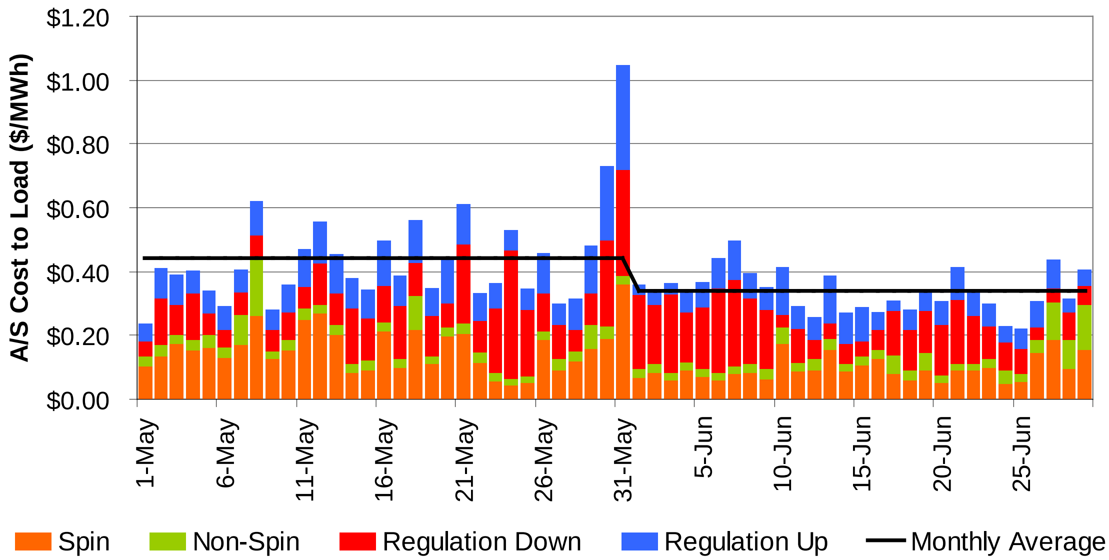


Figure 36 below shows the total system (Day-Ahead and Real-Time) average cost to load for Ancillary Services procurement in the IFM market. The average cost to load is calculated as: average ((total hourly cost of procurement for all four Ancillary services) / (Total hourly CAISO Load)).

Figure 36: System (Day-Ahead and Real-Time) Average Cost to Load



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 37. The hourly deviation of the RUC schedule from the IFM schedule is presented in Figure 38. 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 37: Daily Deviation of RUC Schedule from IFM Schedule

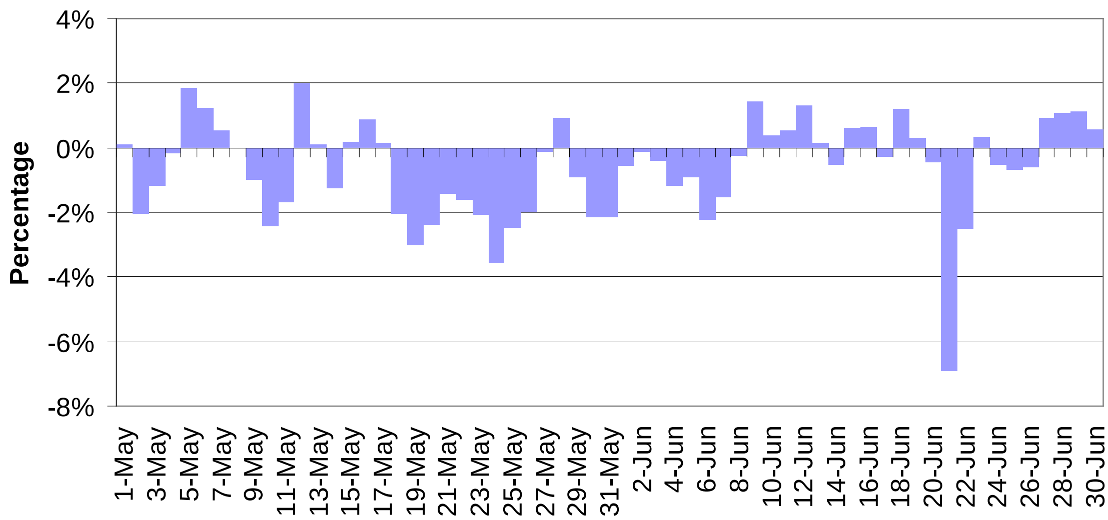
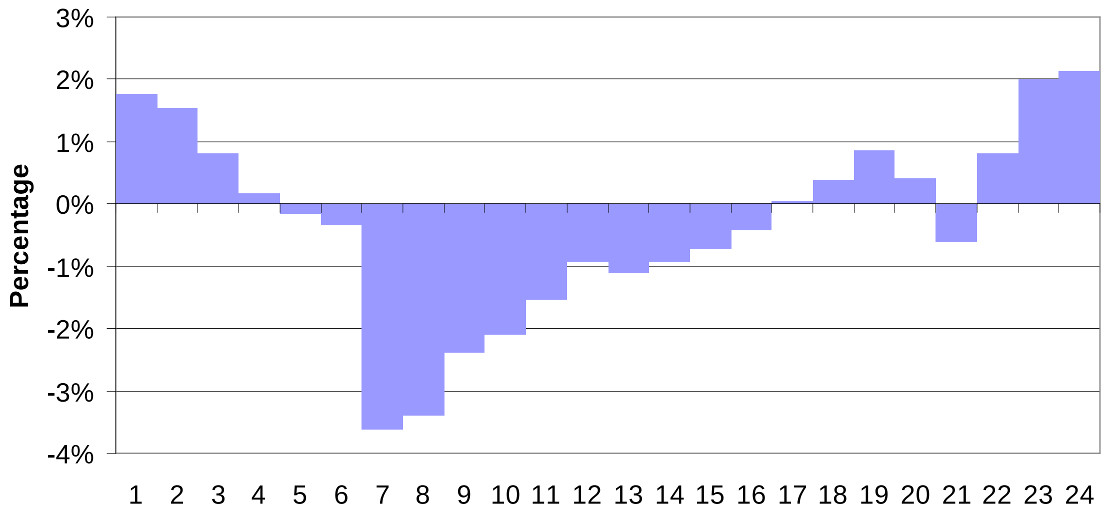


Figure 38: Hourly Deviation of RUC Schedule from IFM Schedule



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 39, Figure 40 and Figure 41 show the daily average RA/RMR RUC capacity and RUC award.

Figure 39: On-Peak RA/RMR RUC Capacity vs. RUC Award

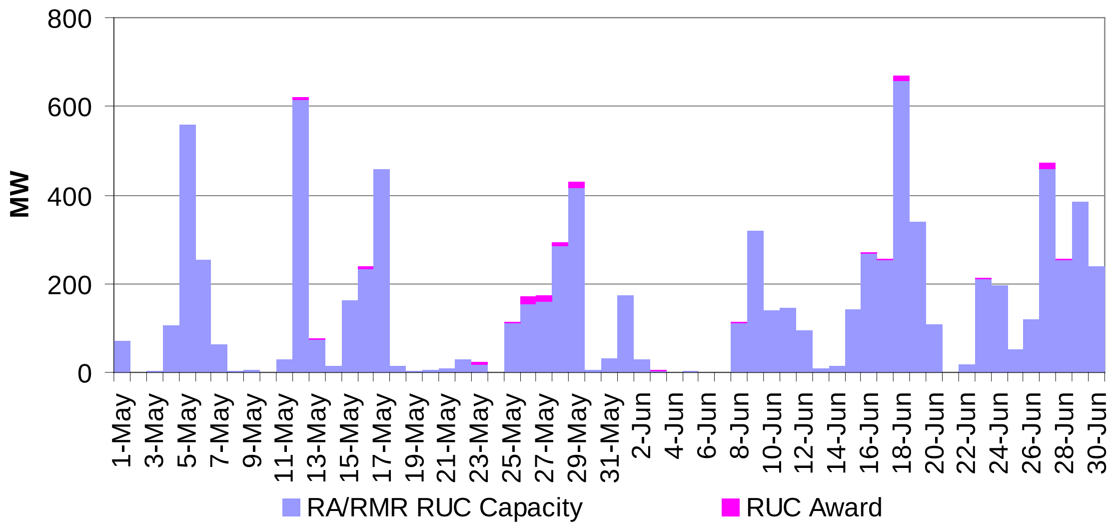


Figure 40: Off-Peak RA/RMR RUC Capacity vs. RUC Award

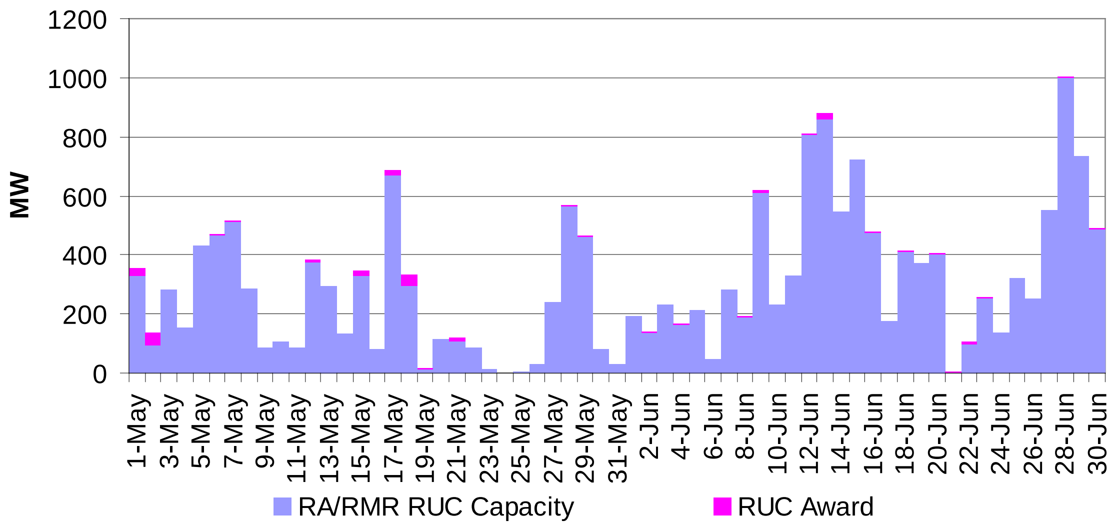
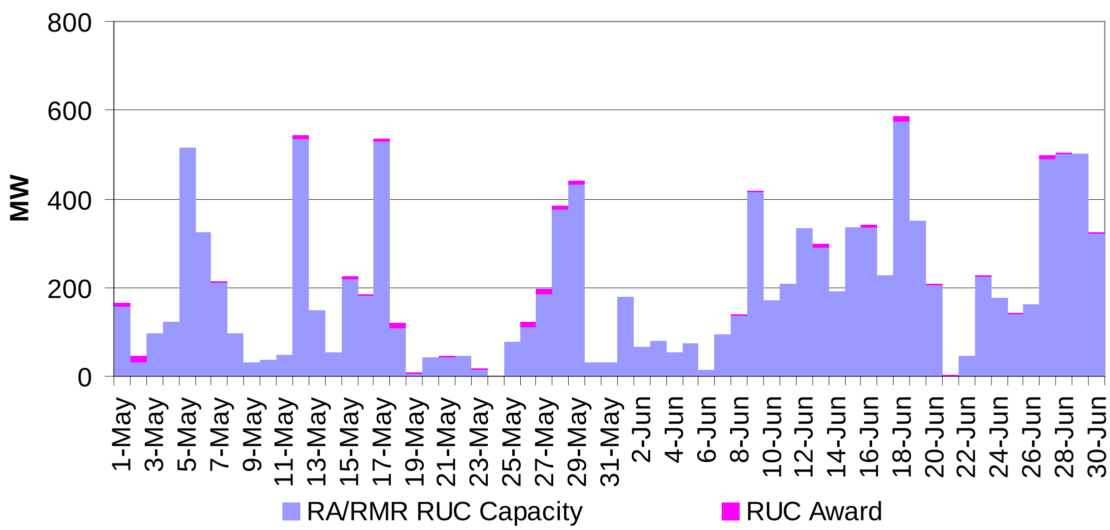


Figure 41: RA/RMR RUC Capacity vs. RUC Award (All Hours)



RUC Award

The daily RUC award and the weighted average RUC LMP are represented in Figure 42 , Figure 43 and Figure 44 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 42: Daily On-Peak RUC Award and LMP

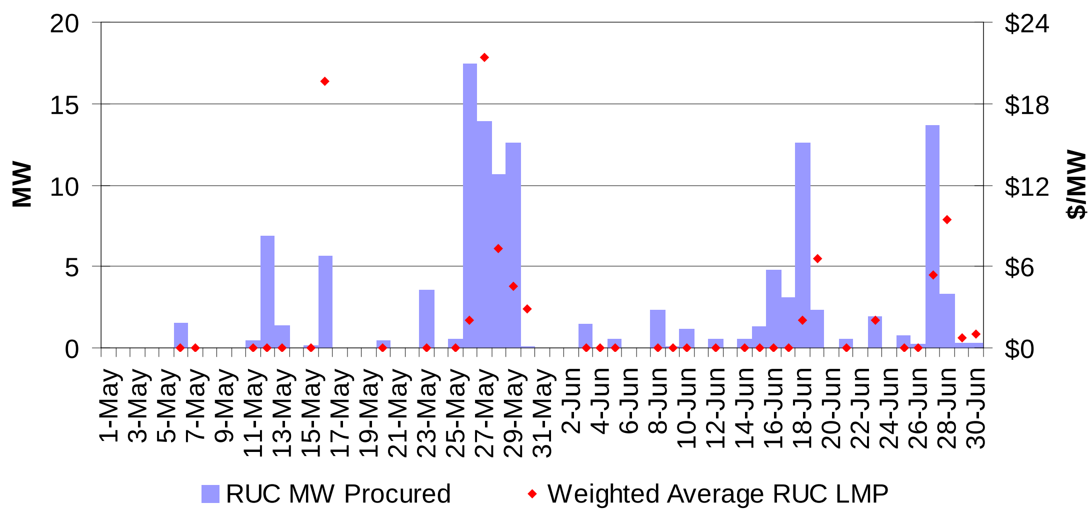


Figure 43: Daily Off-Peak RUC Award and LMP

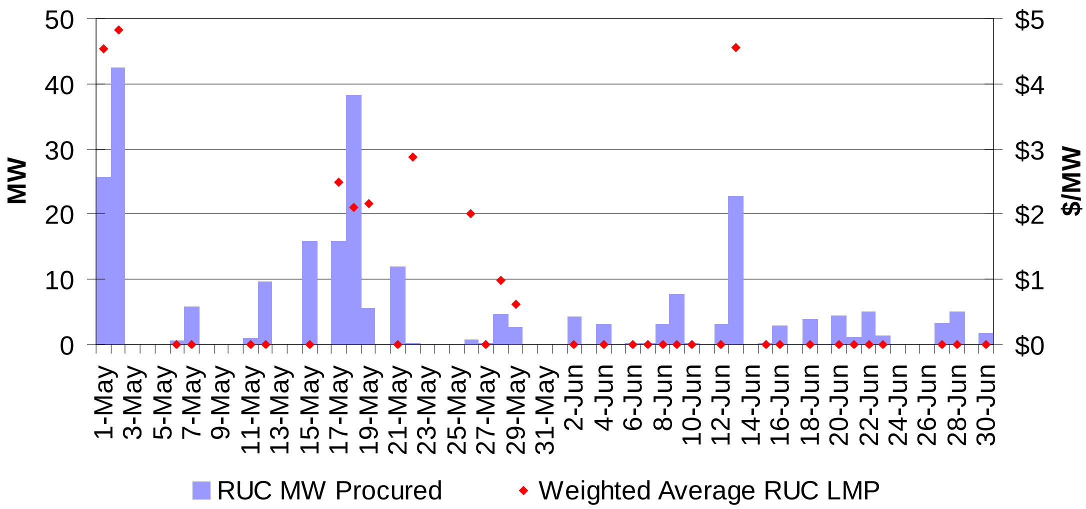
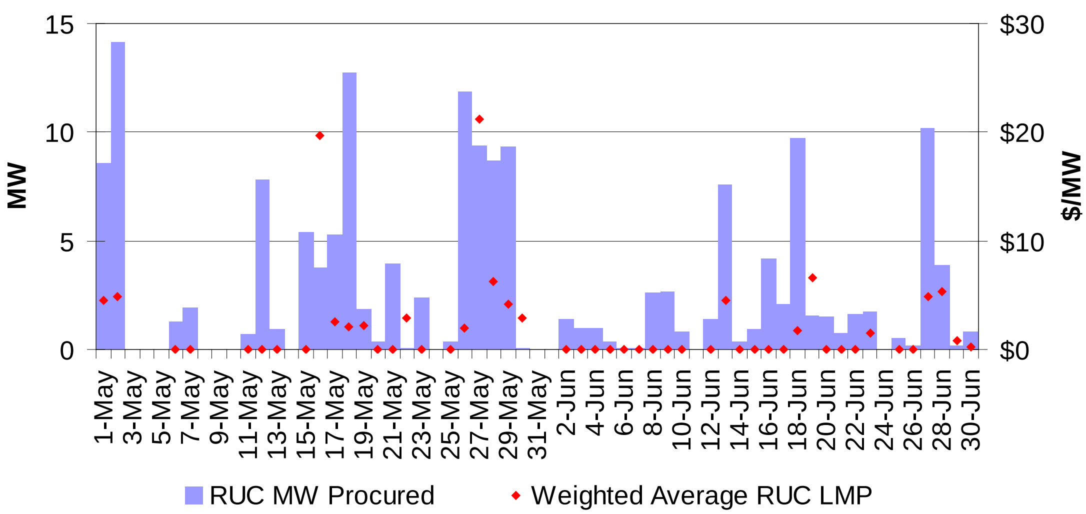


Figure 44: Daily RUC Award and LMP (All Hours)



Average RUC Price

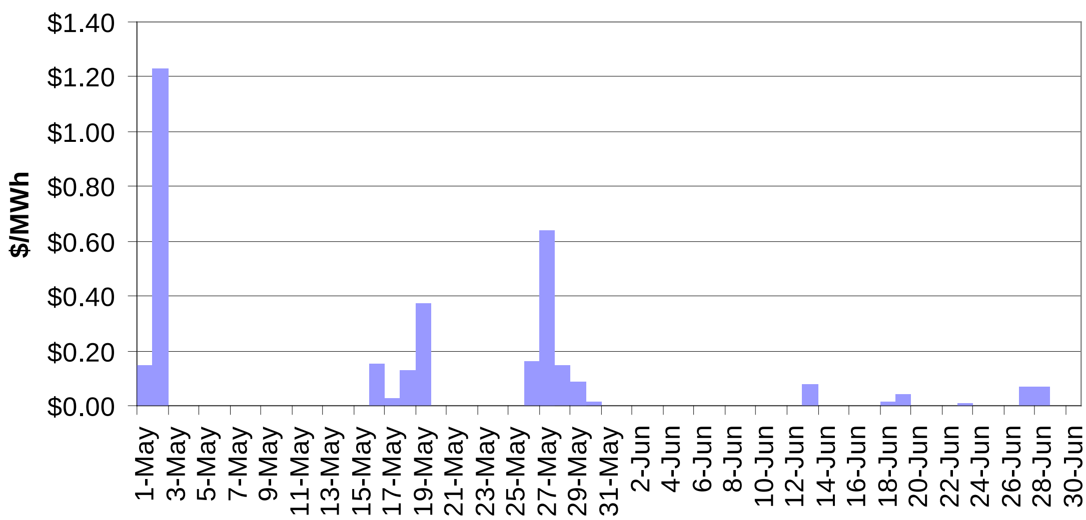
Figure 45 shows the daily average RUC price and Figure 46 shows the total RUC cost.

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

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.

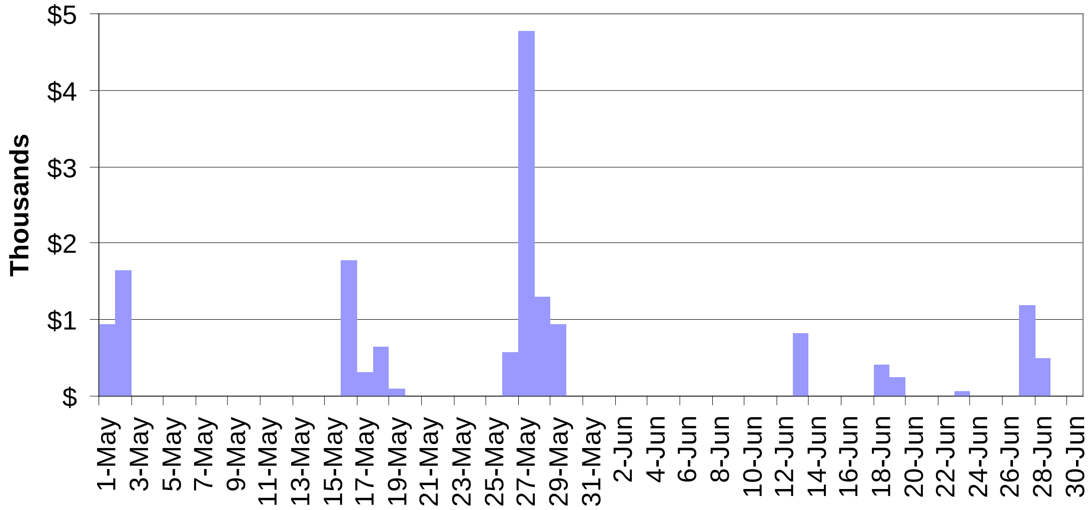
Figure 45: Average RUC Price



Total RUC Cost

Figure 46 shows the daily cumulative total RUC cost.

Figure 46: Total RUC Cost



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*, and to address other modeling or software limitations. Figure 47 shows the frequency of Exceptional Dispatches broken out by Commitment Type.

Figure 47: Exceptional Dispatch Frequency (Unit Commitment vs. Real-Time Dispatch)

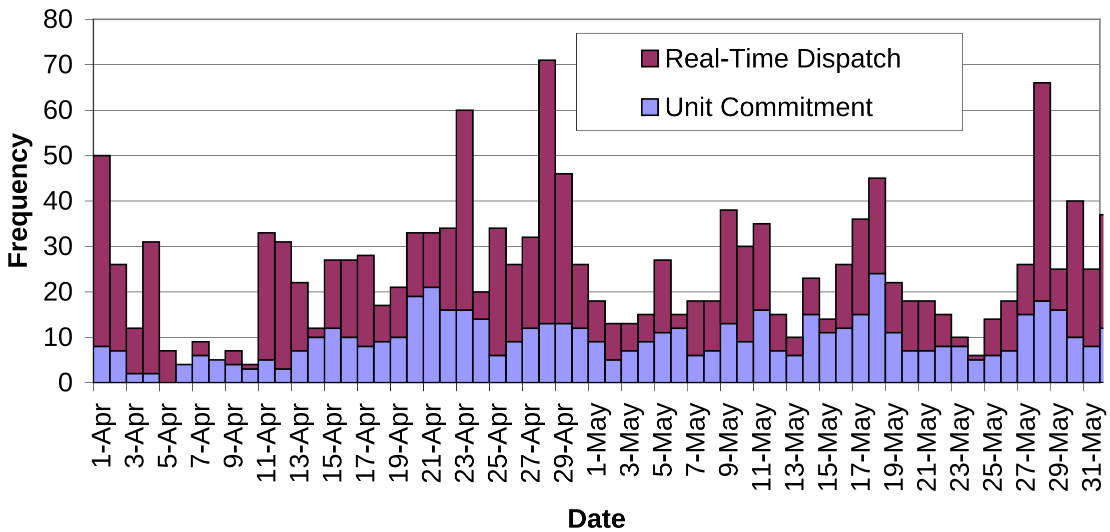


Figure 48 shows the total MW volume of Exceptional Dispatches per trade date broken out by incremental and decremental dispatches. This includes both the MW volume of unit commitments to pmin that would otherwise not be participating in the market on a given day, and changes to the Desired Operating 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.

* 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.

Peak L
Avg. Ene
Avg. Daily P
Avg. Daily Tro

Figure 48: Total Exceptional Dispatch MWh Volume