Market Performance Report
June 2017

August 15, 2017

ISO Market Quality and Renewable Integration

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Executive Summary[1]

The market performance in June 2017 is summarized below.

CAISO area performance,

- Peak loads for ISO exceeded 40,000 MW in five days due to high temperature.
- In the integrated forward market (IFM), SDG&E DLAP prices were elevated in a few days due to transmission congestion. In the fifteen-minute market (FMM) all four DLAP prices were elevated by renewable deviation and generation outages. In the real-time market (RTD), SDG&E DLAP prices were elevated in a few days driven by transmission congestion.
- Congestion rents for interties edged up to $20.22 million from $19.75 million in May. Majority of the congestion rents in June accrued on MALIN500 (54 percent) intertie and NOB (44 percent) intertie.
- In the congestion revenue rights market, revenue adequacy was 86.12 percent, decreasing from 94.71 percent in May. The line 30005_ROUND MT_500_30015_TABLE M contributed largely to the revenue shortfall.
- The monthly average ancillary service cost to load increased to $0.85/MWh from $0.64/MWh in May. There were 14 ancillary service scarcity events this month.
- The cleared virtual supply moved close to the cleared demand in the middle of June. The profits from convergence bidding increased to $2.52 million from $1.02 million in May.
- The bid cost recovery slid to $8.53 million from $9.07 million in May.
- The real-time energy offset inched up to $4.87 million in June from $4.28 million in May. The real-time congestion offset cost increased to $4.41 million in June from $4.01 million in May.
- The volume of exceptional dispatch decreased to 85,249 MWh from 126,430 MWh in May, largely driven by load forecast uncertainty and planned transmission outage and constraint. The monthly average of total exceptional dispatch volume as a percentage of load fell to 0.42 percent in June from 0.67 percent in May.

[1] This report contains the highlights of the reporting period. For a more detailed explanation of the technical characteristics of the metrics included in this report please download the Market Performance Metric Catalog, which is available on the CAISO web site at **http://www.caiso.com/market/Pages/ReportsBulletins/Default.aspx**.

Energy Imbalance market (EIM) performance,

- In the FMM, the prices in the NEVP area were elevated on June 19 and 20 due to upward load adjustment, renewable deviation, net import reduction, and generation outage. In the RTD market, the prices for NEVP were elevated on June 19 and 20 due to upward load adjustment and renewable deviation.
- Bid cost recovery, real-time imbalance energy offset, and real-rime congestion offset costs for EIM entities (PACE, PACW, NEVP, AZPS, and PSEI) were $0.92 million, -$2.24 million and -$4.67 million respectively.

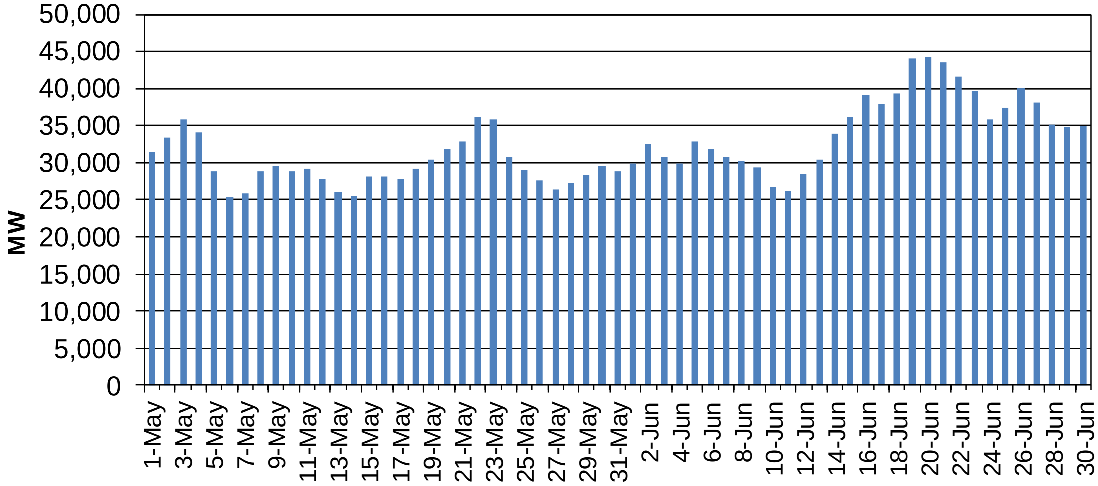
TABLE OF CONTENTS

Market Characteristics

Loads

Peak loads for ISO increased in June due to high temperature, exceeding 40,000 MW in five days.

Figure 1: System Peak Load



Resource Adequacy Available Incentive Mechanism

Resource Adequacy Availability Incentive Mechanism (RAAIM) was activated on November 1, 2016 to track the performance of Resource Adequacy (RA) Resources. RAAIM is used to determine the availability of resources providing local and/or system Resource Adequacy Capacity and Flexible RA Capacity each month and then assess the resultant Availability Incentive Payments and Non-Availability Charges through the CAISO's settlements process. Table 1 below shows the monthly average actual availability, total non-availability charge, and total availability incentive payment.[2]

Table 1: Resource Adequacy Availability and Payment

	Average Actual Availability	Total Non-availbility Charge	Total Availability Incentive Payment
Nov-16	91.70%	$4,109,333	-$1,535,968
Dec-16	96.11%	$1,872,061	-$1,872,061
Jan-17	95.64%	$2,866,734	-$2,013,269
Feb-17	92.28%	$3,262,889	-$1,875,649
Mar-17	91.94%	$3,046,829	-$1,550,469
Apr-17	89.43%	$4,096,806	-$1,543,647
May-17	95.41%	$1,842,755	-$1,238,302
Jun-17	95.12%	$2,456,737	-$1,417,349

[2] On June 21, 2017, the ISO indicated in the market notice that it intended to file a petition with the FERC for a limited tariff waiver on section 40.9.6 to forego assessing any Resource Adequacy Availability Incentive Mechanism (RAAIM) charges for the period April 1, 2017 through December 31, 2017 due to identified implementation issues. This waiver includes April, 2017 and May 2017. The ISO is currently estimating the penalties reflected in the charge code 8830 to be zero pursuant to tariff section 11.29.10.5.

Direct Market Performance Metrics

Energy

Day-Ahead Prices

Figure 2 shows daily prices of four default load aggregate points (DLAPs). Table 2 below lists the binding constraints along with the associated DLAP locations and the occurrence dates when the binding constraints resulted in relatively high or low DLAP prices. All four DLAP prices were high on June 21 driven by high load and tight supply.

Figure 2: Day-Ahead Simple Average LAP Prices (All Hours)

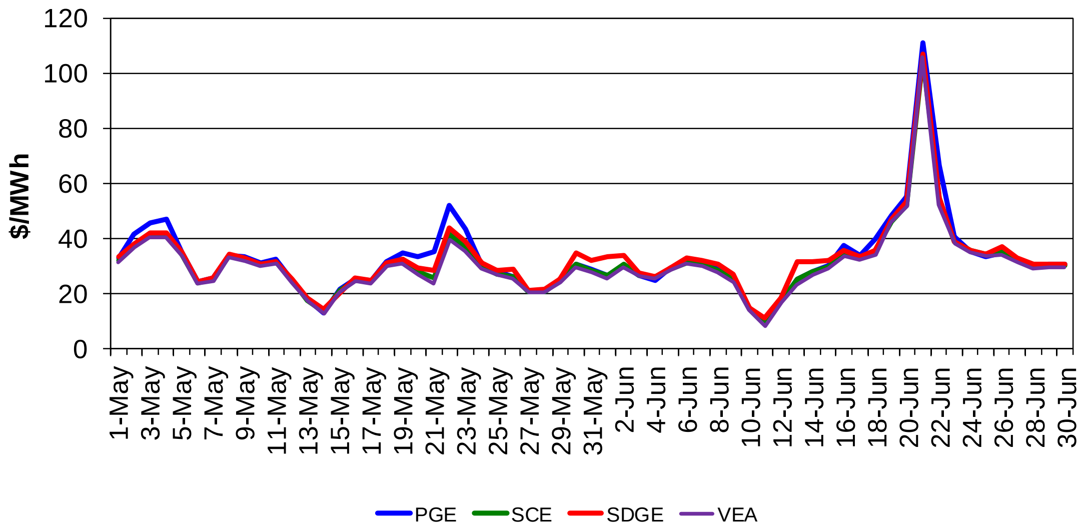


Table 2: Day-Ahead Transmission Constraints

DLAP	Date	Transmission Constraint
SDG&E	June 1	7820_TL 230S_TL50001OUT_NG, SUNCREST-SUNC TP1-230kV line, SYCAMORE-SYCAMORE-138 XFMR
SDG&E	June 2	7820_TL 230S_TL50001OUT_NG, SUNCREST-SUNC TP1-230kV line
SDG&E	June 13	SYCAMORE-SYCAMORE-138 XFMR
SDG&E	June 14	7820_TL23040_IV_SPS_NG

Real-Time Prices

FMM daily prices of the four DLAPs are shown in Figure 3. Table 3 lists the binding constraints along with the associated DLAP locations and the occurrence dates when the binding constraints resulted in relatively high or low DLAP prices. On June 21, all four DLAP prices were high, driven by renewable deviation and generation outages.

Figure 3: FMM Simple Average LAP Prices (All Hours)

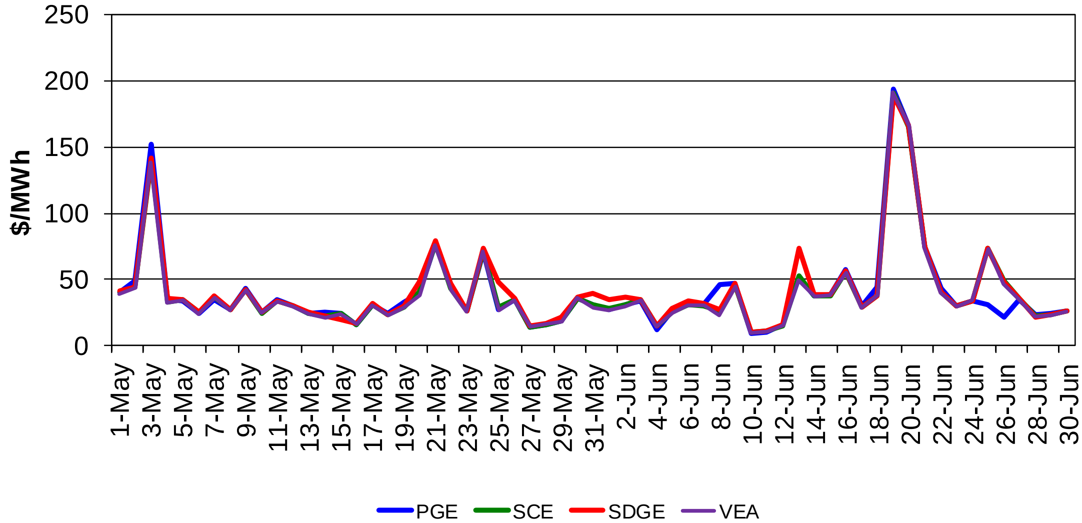
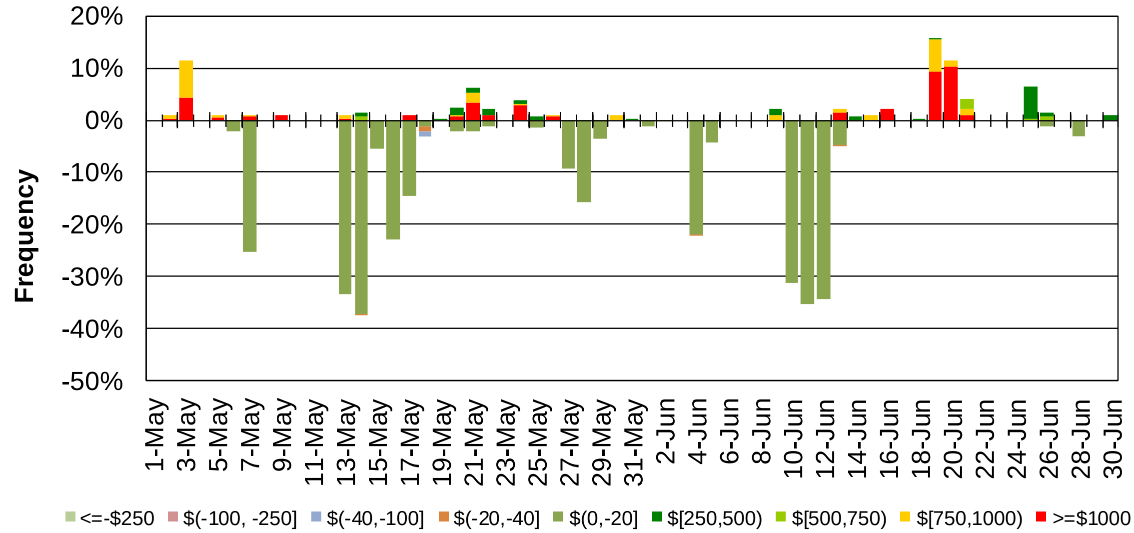


Table 3: FMM Transmission Constraints

DLAP	Date	Transmission Constraint
PG&E	June 8	NEWARK -NWK DIST-230kV line, NWK DIST-LS ESTRS-230kV line, LASAGUIL-PANOCHE -230kV line
SDG&E	June 31	SYCA TP1-SYCAMORE-230kV line, SYCAMORE-SYCAMORE-138 XFMR, 7820_TL 230S_OVERLOAD_NG

Figure 4 below shows the daily frequency of positive price spikes and negative prices by price range for the default LAPs in the FMM. The cumulative frequency of prices above $250/MWh increased to 1.63 percent in June from 1.20 percent in May. The cumulative frequency of negative prices decreased to 4.60 percent in June from 5.79 percent in May.

Figure 4: Daily Frequency of FMM LAP Positive Price Spikes and Negative Prices



RTD daily prices of the four DLAPs are shown in Figure 5. Table 4 lists the binding constraints along with the associated DLAP locations and the occurrence dates when the binding constraints resulted in relatively high or low DLAP prices.

Figure 5: RTD Simple Average LAP Prices (All Hours)

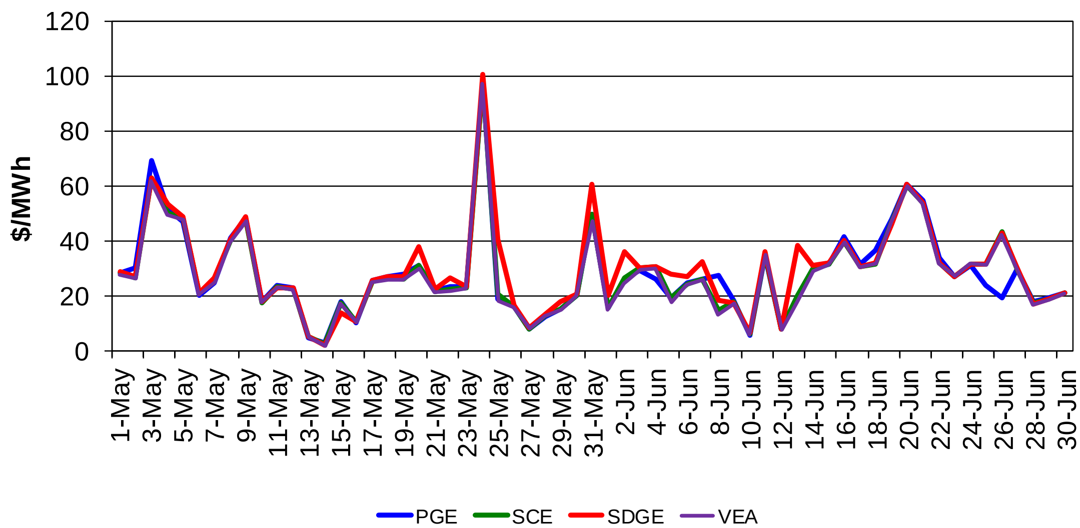
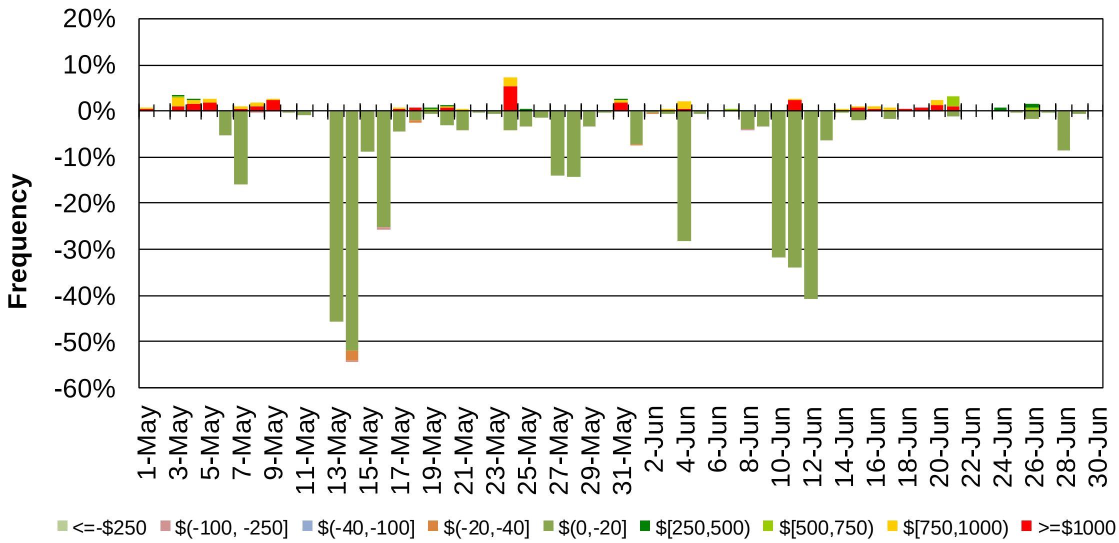


Table 4: RTD Transmission Constraints

DLAP	Date	Transmission Constraint
SDG&E	June 2	7820_TL 230S_TL50001OUT_NG
SDG&E	June 5	7820_TL 230S_OVERLOAD_NG
SDG&E	June 7	OMS 4602677 50002_OOS_TDM
SDG&E	June 13	SYCAMORE-SYCAMORE-138 XFMR, 7820_TL 230S_OVERLOAD_NG
PG&E	June 26	MIDWAY -VINCENT -500kV line

Figure 6 below shows the daily frequency of positive price spikes and negative prices by price range for the default LAPs in RTD. The cumulative frequency of prices above $250/MWh edged down to 0.59 percent in June from 0.93 percent in May. The cumulative frequency of negative prices inched down to 5.82 percent in June from 6.93 percent in May.

Figure 6: Daily Frequency of RTD LAP Positive Price Spikes and Negative Price



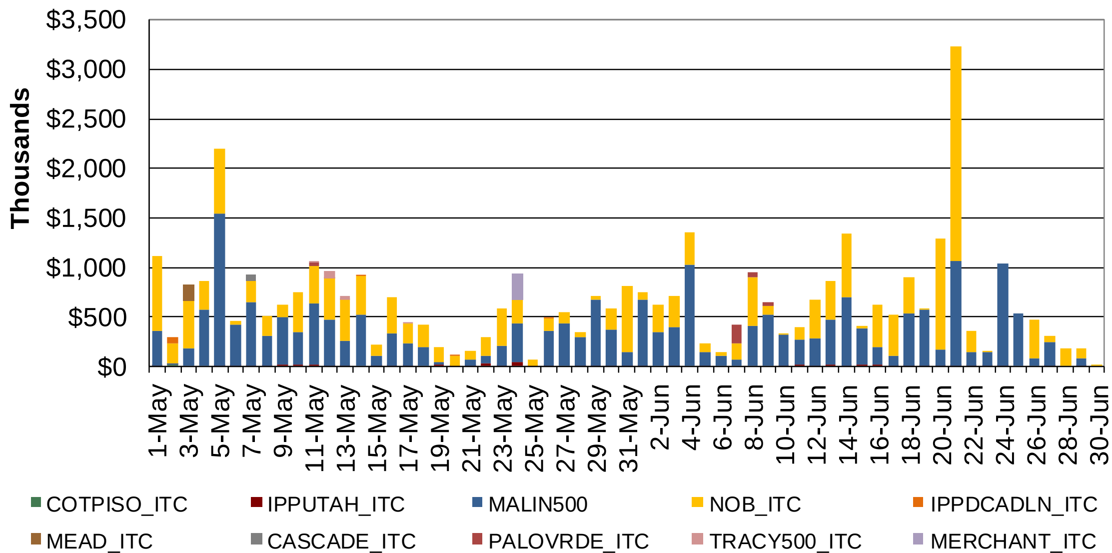
Congestion

Congestion Rents on Interties

Figure 7 below illustrates the daily integrated forward market congestion rents by interties. The cumulative total congestion rent for interties in June edged up to $20.22 million from $19.75 million in May. Majority of the congestion rents in June accrued on MALIN500 (54 percent) intertie and NOB (44 percent) intertie.

The congestion rent on MALIN500 increased slightly to $10.91 million in June from $10.58 million in May. MALIN500 was derated this month due to various outages including the outage of Malin-Round Mountain #2 500 kV line, Round Mountain-Table Mountain #2 500 kV line, and Buckley – Marion #1 500 kV line. The congestion rent on NOB inched up to $8.96 million in June from $8.26 million in May.

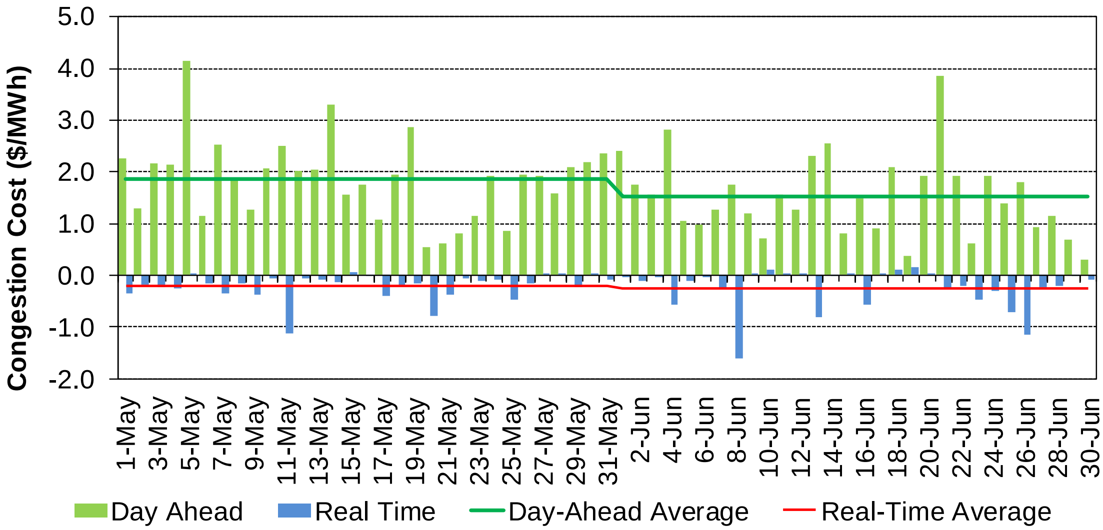
Figure 7: IFM Congestion Rents by Interties (Import)



Average Congestion Cost per Load Served

This metric quantifies the average congestion cost for serving one megawatt of load in the ISO system. Figure 8 shows the daily and monthly averages for the day-ahead and real-time markets respectively.

Figure 8: Average Congestion Cost per Megawatt of Served Load

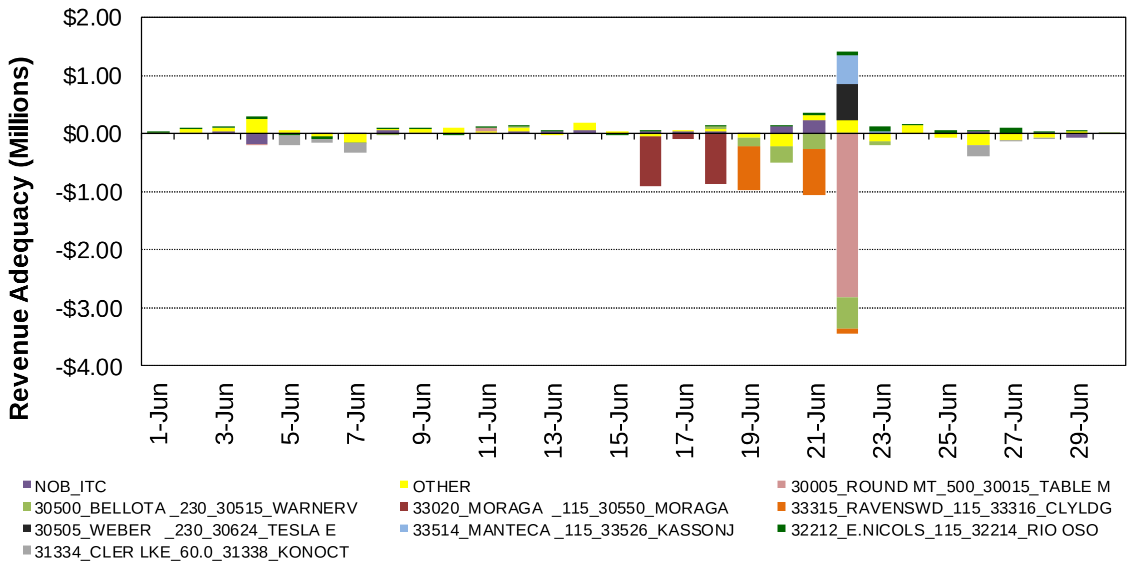


The average congestion cost per MWh of load served in the integrated forward market decreased to $1.52/MWh in June from $1.85/MWh in May. The average congestion cost per load served in the real-time market went to -$0.24/MWh in June from -$0.21/MWh in May.

Congestion Revenue Rights

Figure 9 illustrates the daily revenue adequacy for congestion revenue rights (CRRs) broken out by transmission element. The average CRR revenue deficit in June rose to $168,715 from the average revenue deficit of $62,382 in May.

Figure 9: Daily Revenue Adequacy of Congestion Revenue Rights

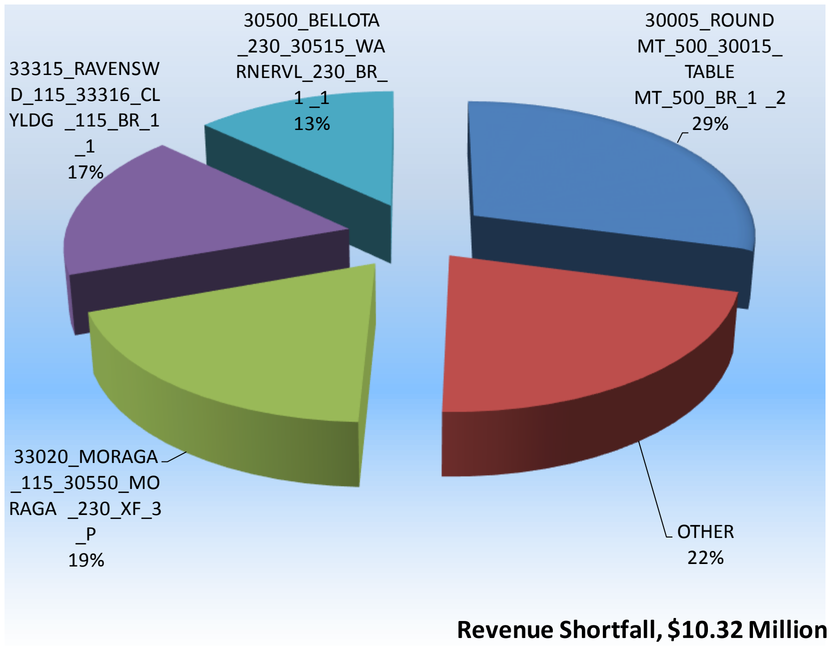


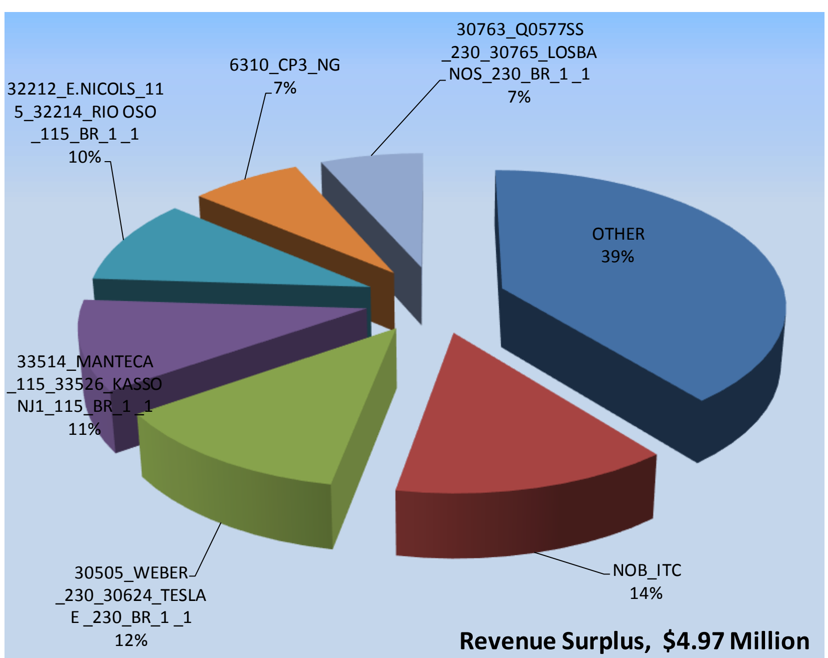
Overall, June experienced a CRR revenue deficit. Revenue shortfalls were observed in 15 days this month. The main reasons are shown below.

- The line 30005_ROUND MT_500_30015_TABLE M was binding in three days of this month, resulting in revenue shortfall of $2.76 million.
- The line 33020_MORAGA _115_30550_MORAGA was binding in three days of this month, resulting in revenue shortfall of $1.80 million.
- The line 33315_RAVENSWD_115_33316_CLYLDG was binding in three days of this month, resulting in revenue shortfall of $1.65 million.

The shares of the revenue surplus and deficit accruing on various congested transmission elements for the reporting period are shown in Figure 10 and the monthly summary for CRR revenue adequacy is provided in Table 5.

Figure 10: CRR Revenue Adequacy by Transmission Element





Overall, the total amount collected from the IFM was not sufficient to cover the net payments to congestion revenue right holders and the cost of the exemption for existing rights. The revenue adequacy level was 86.12 percent in June. Out of the total congestion rents, 11.74 percent was used to cover the cost of existing right exemptions. Net total congestion revenues in June were in deficit by $5.06 million, compared to the deficit of $1.93 million in May. The auction revenues credited to the balancing account for June were $6.17 million. As a result, the balancing account for June had a surplus of approximately $1.50 million, which will be allocated to measured demand.

Table 5: CRR Revenue Adequacy Statistics

IFM Congestion Rents	$35,574,753.75
Existing Right Exemptions	-$4,177,286.90
Available Congestion Revenues	$31,397,466.85
CRR Payments	$36,458,931.13
CRR Revenue Adequacy	-$5,061,464.28
Revenue Adequacy Ratio	86.12%
Annual Auction Revenues	$2,879,148.47
Monthly Auction Revenues	$3,294,276.78
CRR Settlement Rule	$385,335.46
Allocation to Measured Demand	$1,497,296.43

Ancillary Services

IFM (Day-Ahead) Average Price

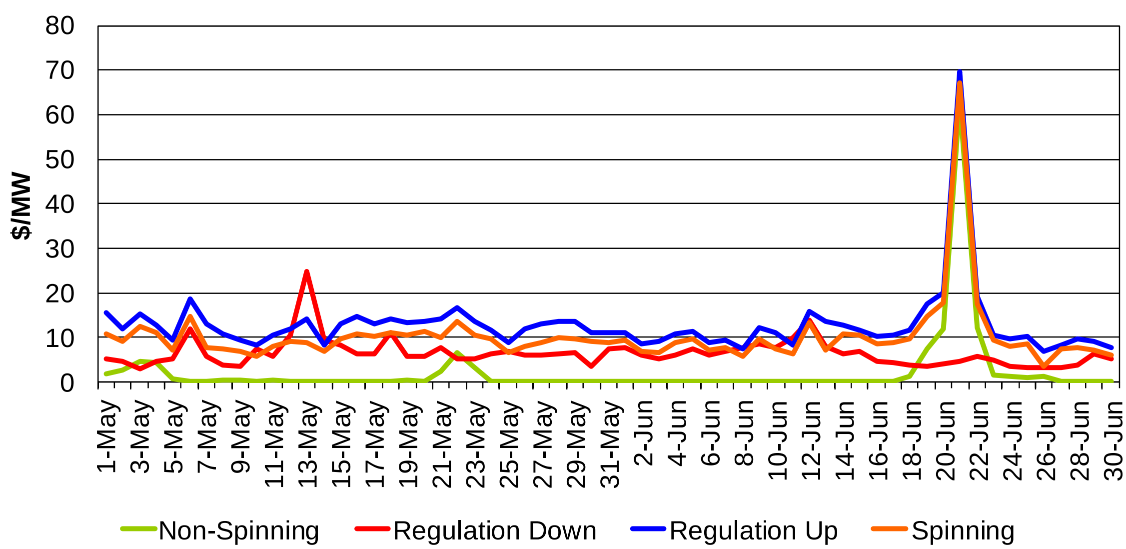
Table 6 shows the monthly IFM average ancillary service procurements and the monthly average prices. In June the monthly average procurement increased for spinning and non-spinning reserves. Following the NERC study of a large solar tripping event, starting from June 14, 2017 the ISO temporarily increased its daily procurement of operating reserves in both DA and RT markets to mitigate reliability risk against potential loss of solar resources which are susceptible to tripping due to faults on the transmission system. This resulted in the increase of monthly average procurements of spinning and non-spinning reserves.

Table 6: IFM (Day-Ahead) Monthly Average Ancillary Service Procurement

	Average Procured				Average Price			
	Reg Up	Reg Dn	Spinning	Non-Spinning	Reg Up	Reg Dn	Spinning	Non-Spinning
Jun-17	310	317	947	944	$13.09	$5.95	$10.96	$3.44
May-17	345	345	754	754	$12.61	$6.97	$9.50	$0.97
Percent Change	-9.96%	-8.09%	25.46%	25.17%	3.83%	-14.68%	15.42%	253.61%

The monthly average prices increased for regulation up, spinning, and non-spinning reserve in June. Figure 11 shows the daily IFM average ancillary service prices. Regulation up, spinning, and non-spinning prices were relatively high on June 19-22 due to high opportunity cost of energy.

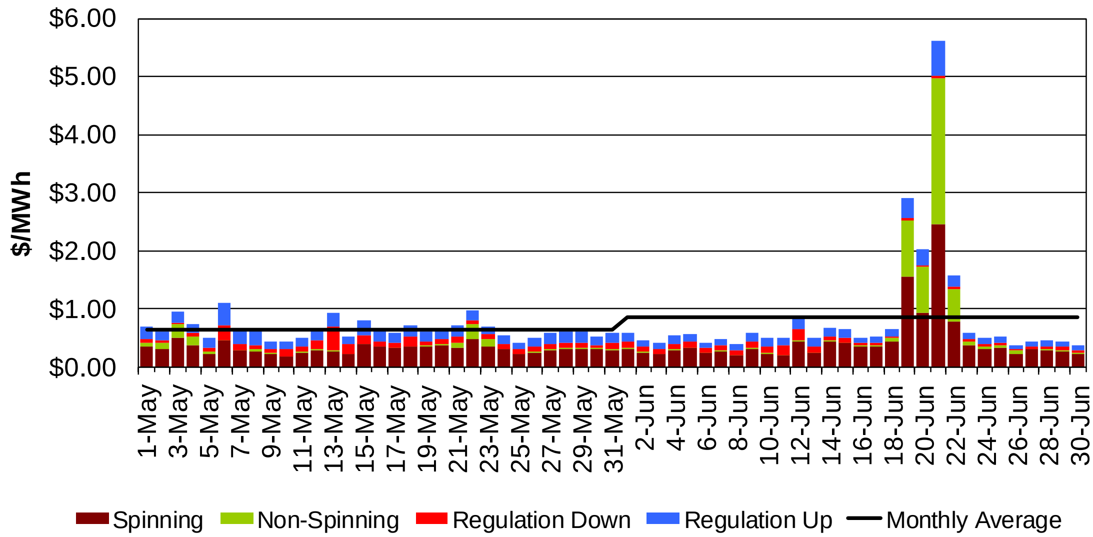
Figure 11: IFM (Day-Ahead) Ancillary Service Average Price



Ancillary Service Cost to Load

The monthly average cost to load increased to $0.85/MWh in June from $0.64/MWh in May. The average cost to load was relatively high on June 19-22, driven by high spinning and non-spinning prices.

Figure 12: System (Day-Ahead and Real-Time) Average Cost to Load



Scarcity Events

The ancillary services scarcity pricing mechanism is triggered when the ISO is not able to procure the target quantity of one or more ancillary services in the IFM and real-time market runs. On June 19, 20 and 21, 2017, regulation up and non-spinning reserve scarcities occurred in the 15-minute market run in the CAISO expanded system region for the following quantities.

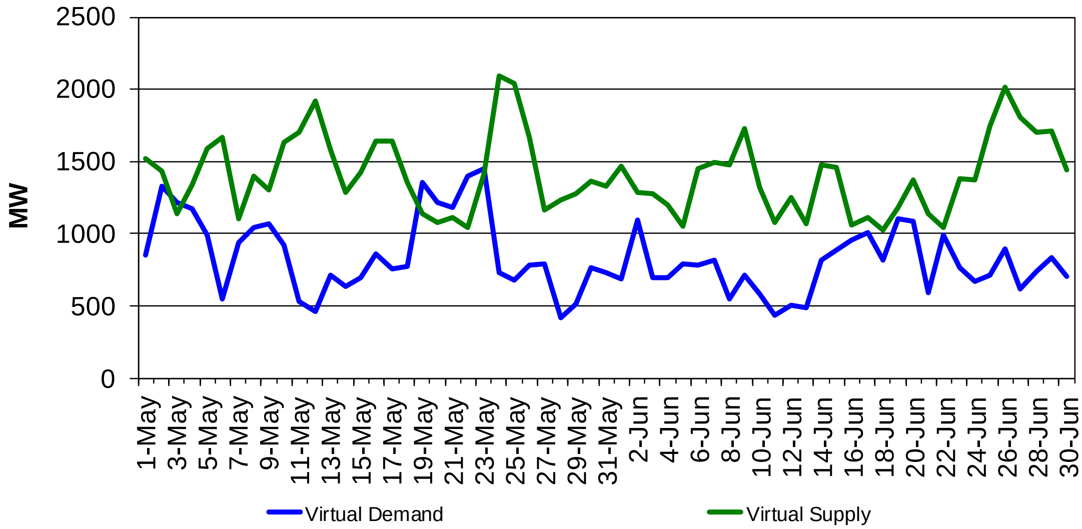
Trade Date	Hour Ending	Interval	Ancillary Service	Region	Shortfall (MW)	Percentage of Requirement
6/19/17	19	3	Reg Up	CAISO_EXP	5.99	2%
6/19/17	19	3	Non-Spin	CAISO_EXP	538.3	42%
6/19/17	19	4	Non-Spin	CAISO_EXP	608.9	48%
6/19/17	20	1	Non-Spin	CAISO_EXP	309.3	25%
6/19/17	20	2	Non-Spin	CAISO_EXP	524.7	43%
6/19/17	20	3	Non-Spin	CAISO_EXP	394.9	32%
6/20/17	19	2	Non-Spin	CAISO_EXP	308.4	24%
6/20/17	19	3	Non-Spin	CAISO_EXP	284.2	22%

6/20/17	19	4	Non-Spin	CAISO_EXP	247.7	19%
6/20/17	20	1	Non-Spin	CAISO_EXP	222.5	18%
6/20/17	20	2	Non-Spin	CAISO_EXP	502.8	40%
6/20/17	20	3	Non-Spin	CAISO_EXP	654.9	54%
6/20/17	20	4	Non-Spin	CAISO_EXP	504.1	41%
6/21/17	19	4	Non-Spin	CAISO_EXP	25.4	2%

Convergence Bidding

Figure 13 below shows the daily average volume of cleared virtual bids in IFM for virtual supply and virtual demand. The cleared virtual supply moved close to the cleared demand in the middle of June.

Figure 13: Cleared Virtual Bids



Convergence bidding tends to cause the day-ahead market and real-time market prices to move closer together, or “converge”. Figure 14 shows the energy prices (namely the energy component of the LMP) in IFM, hour ahead scheduling process (HASP), FMM, and RTD.

Figure 14: IFM, HASP, FMM, and RTD Prices

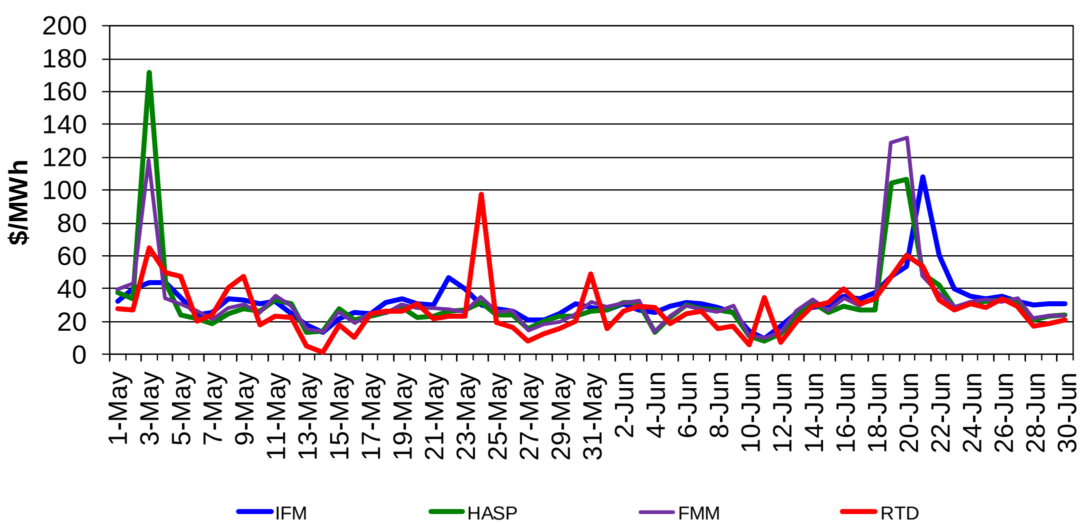
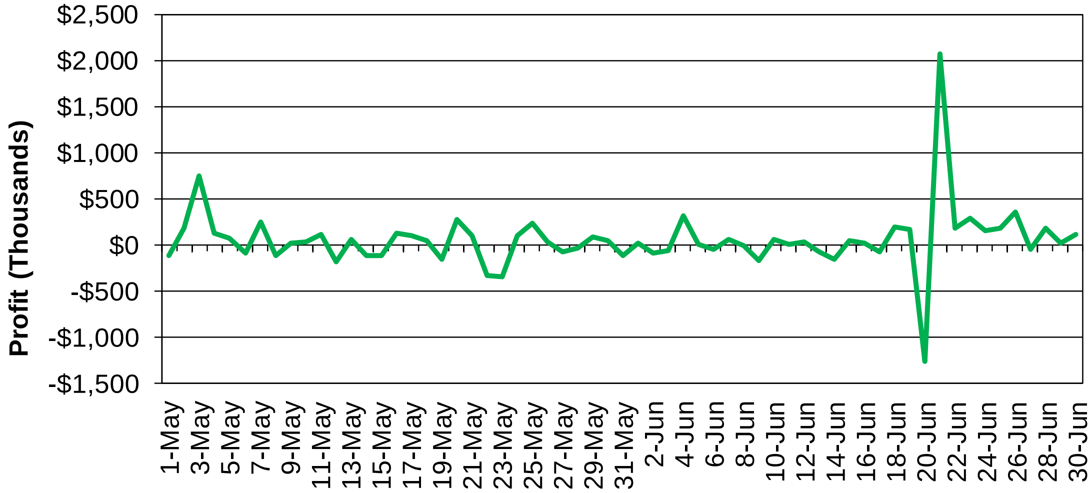


Figure 15 shows the profits that convergence bidders receive from convergence bidding. The total profits from convergence bidding increased to $2.52 million in June from $1.02 million in May.

Figure 15: Convergence Bidding Profits



Renewable Generation Curtailment

Figure 16 below shows the monthly wind and solar VERs (variable energy resource) curtailment due to system wide condition or local congestion in RTD. Figure 17 shows the monthly wind and solar VERs (variable energy resource) curtailment by resource type in RTD. Economic curtailment is defined as the resource's dispatch upper limit minus its RTD schedule when the resource has an economic bid. Dispatch upper limit is the maximum level the resource can be dispatched to when various factors are take into account such as forecast, maximum economic bid, generation outage, and ramping capacity. Self-schedule curtailment is defined as the resource's self-schedule minus its RTD schedule when RTD schedule is lower than self-schedule. When a VER resource is exceptionally dispatched, then exceptional dispatch curtailment is defined as the dispatch upper limit minus the exceptional dispatch value.

As Figure 16 and Figure 17 below indicate, the renewable curtailment declined since April. The majority of the curtailments was economic.

Figure 16: Renewable Curtailment by Reason

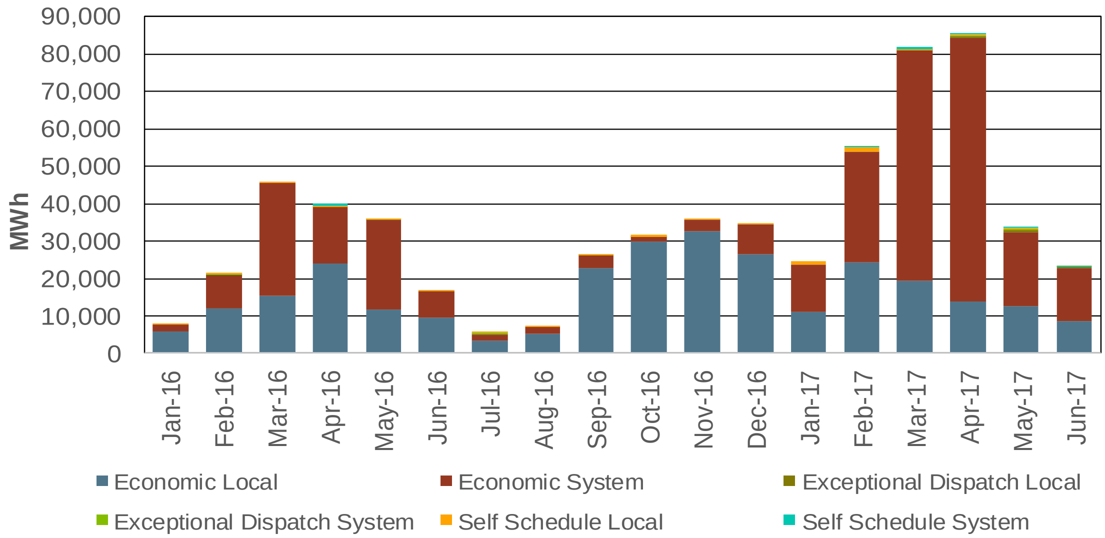
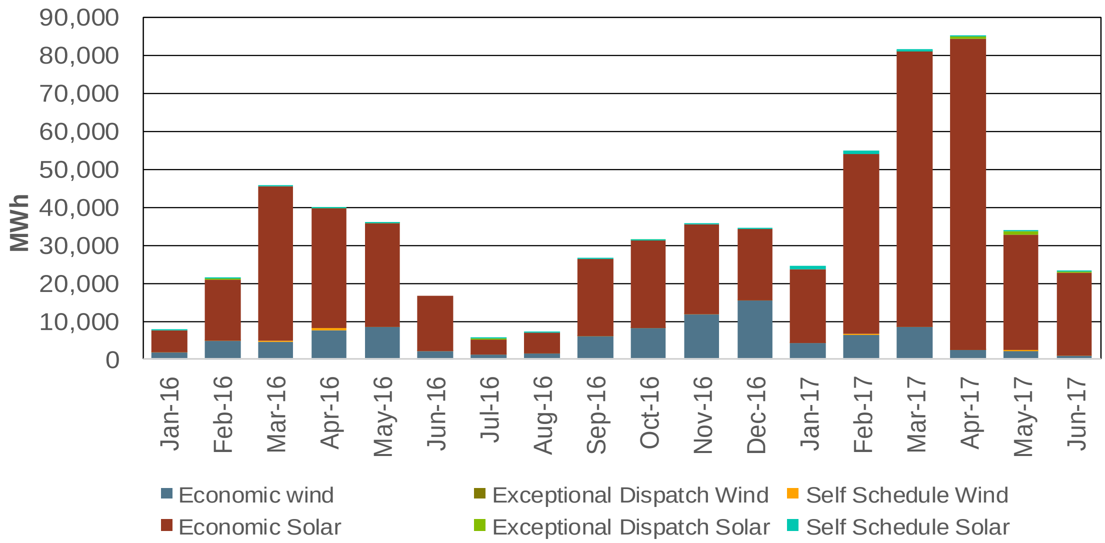


Figure 17: Renewable Curtailment by Resource Type



Flexible Ramping Product

On November 1, 2016 the ISO implemented two market products in the 15-minute and 5-minute markets: Flexible Ramping Up and Flexible Ramping Down uncertainty awards. These products provide additional upward and downward flexible ramping capability to account for uncertainty due to demand and renewable forecasting errors. In addition, the existing flexible ramping sufficiency test was extended to ensure feasible ramping capacity for real-time interchange schedules.

Flexible Ramping Product Payment

Figure 18 shows the flexible ramping up and down uncertainty payments. Flexible ramping up uncertainty payment decreased to $0.84 million in June from $1.29 Million in May. Flexible ramping down uncertainty payment declined to $0.05 million in June from $0.10 Million in May.

Figure 18: Flexible Ramping Up/down Uncertainty Payment

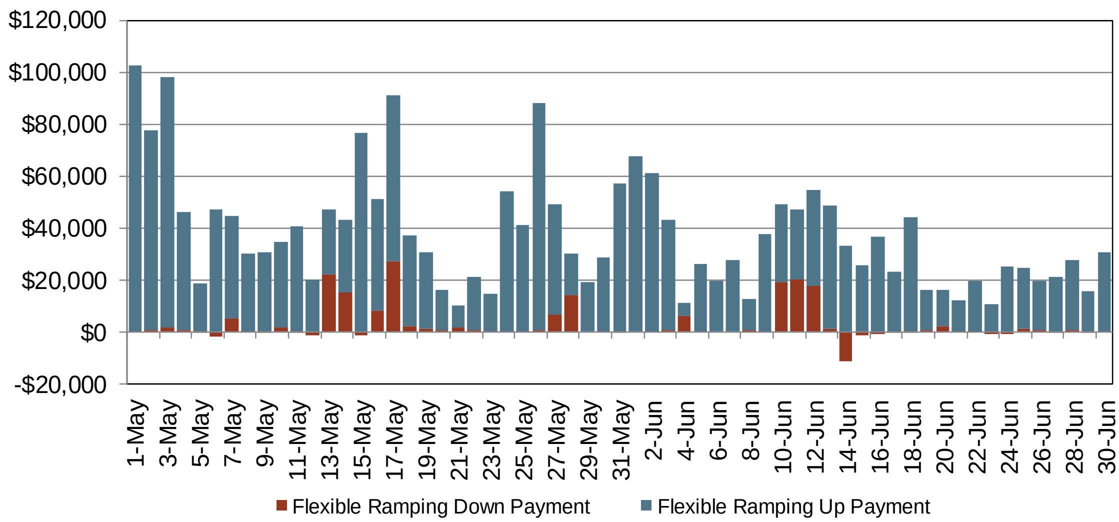
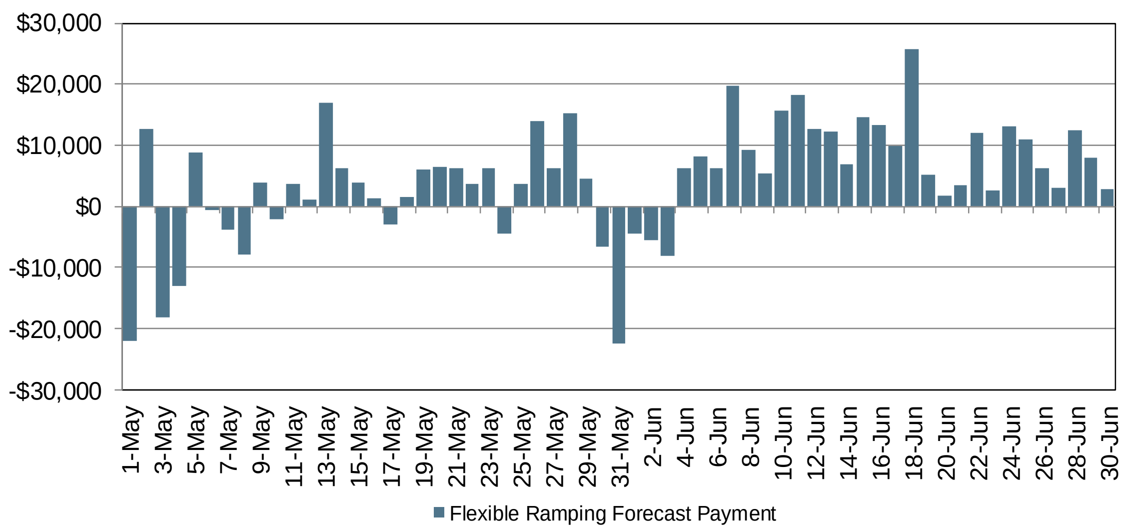


Figure 19 shows the flexible ramping forecast payment. Flexible ramping forecast payment rose to $0.25 million this month from $0.03 million in May.

Figure 19: Flexible Ramping Forecast Payment



Indirect Market Performance Metrics

Bid Cost Recovery

Figure 20 shows the daily uplift costs due to exceptional dispatch payments. The monthly uplift costs in June skidded to $596,152 from $983,861 in May.

Figure 20: Exceptional Dispatch Uplift Costs

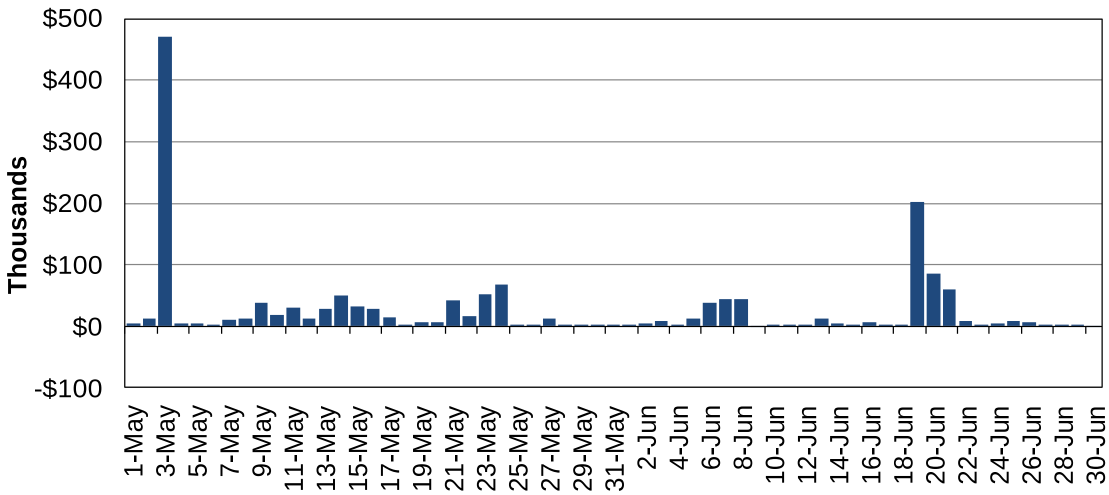


Figure 21 shows the allocation of bid cost recovery payment in the IFM, residual unit commitment (RUC) and RTM markets. The total bid cost recovery for June slid to $8.53 million from $9.07 million in May. Out of the total monthly bid cost recovery payment for the three markets in June, the IFM market contributed 11 percent, RTM contributed 63 percent, and RUC contributed 26 percent of the total bid cost recovery payment.

Figure 21: Bid Cost Recovery Allocation

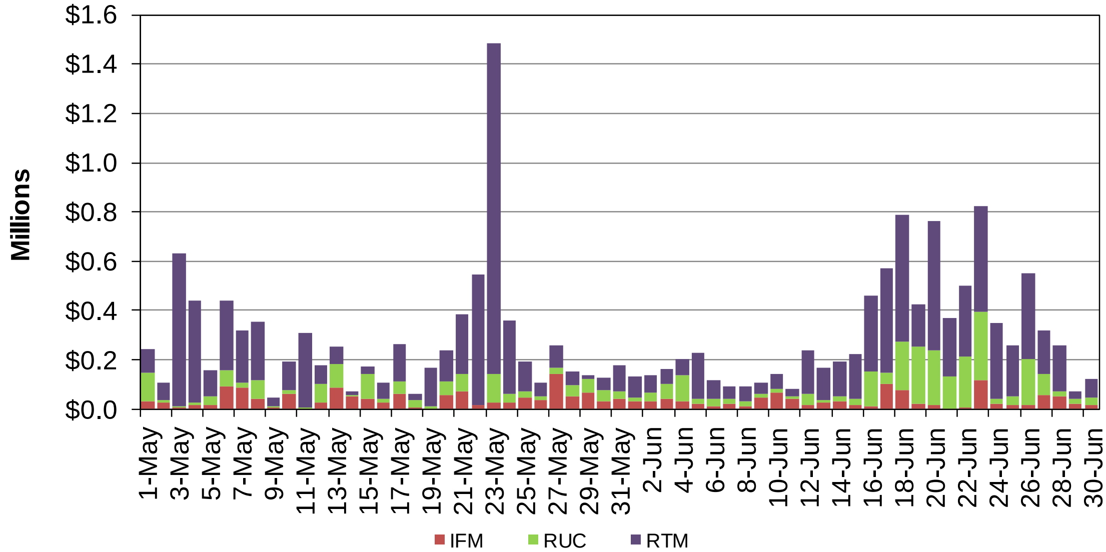


Figure 22 and Figure 23 show the daily and monthly BCR cost by local capacity requirement area (LCR) respectively.

Figure 22: Bid Cost Recovery Allocation by LCR

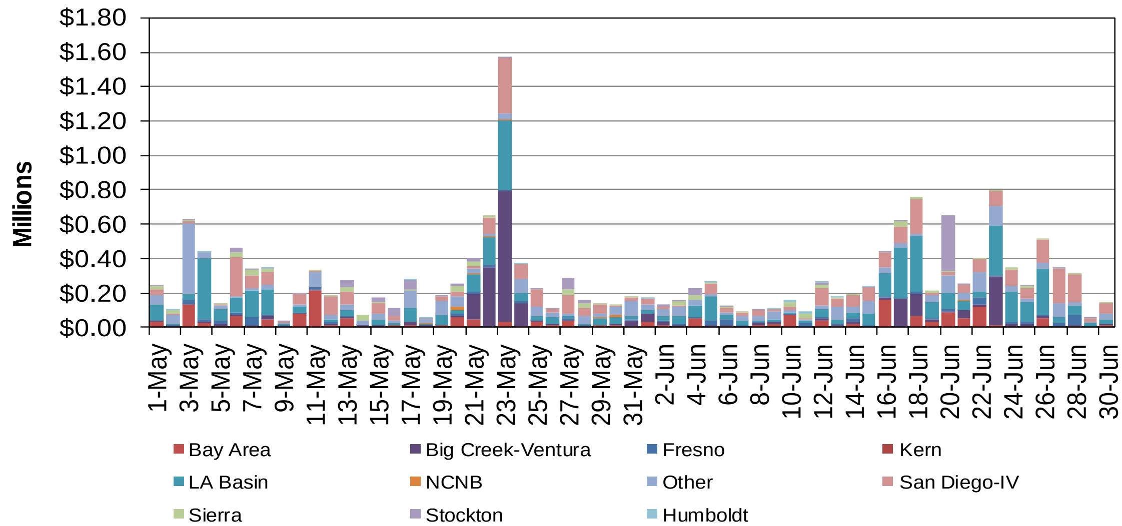


Figure 23: Monthly Bid Cost Recovery Allocation by LCR

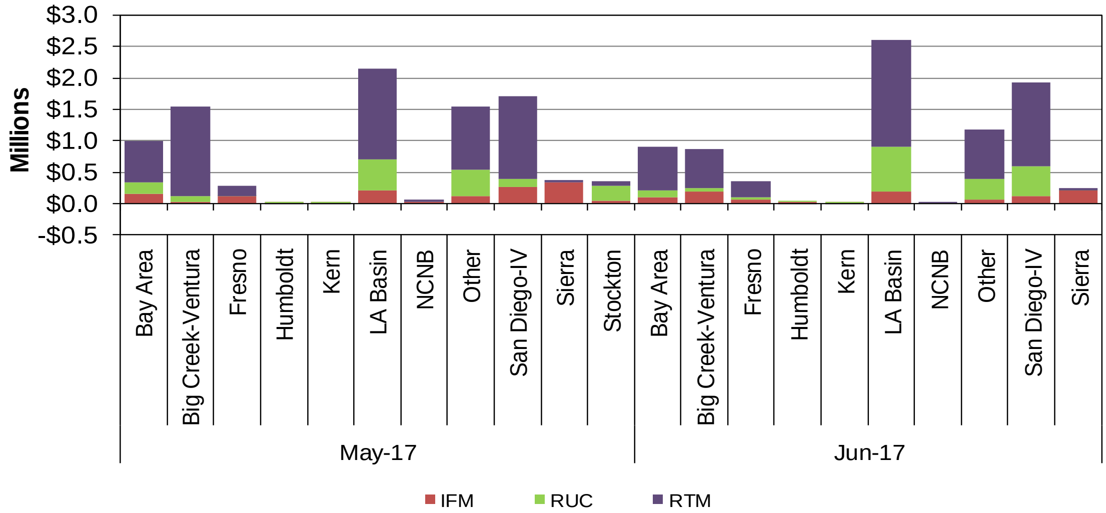


Figure 24 and Figure 25 show the daily and monthly BCR cost by utility distribution company (UDC) respectively.

Figure 24: Bid Cost Recovery Allocation by UDC

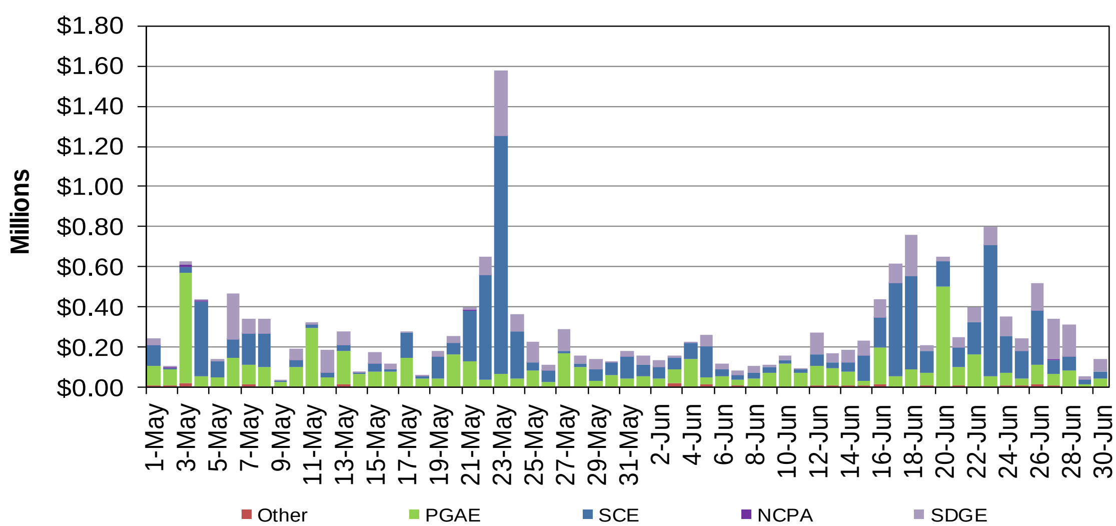


Figure 25: Monthly Bid Cost Recovery Allocation by UDC

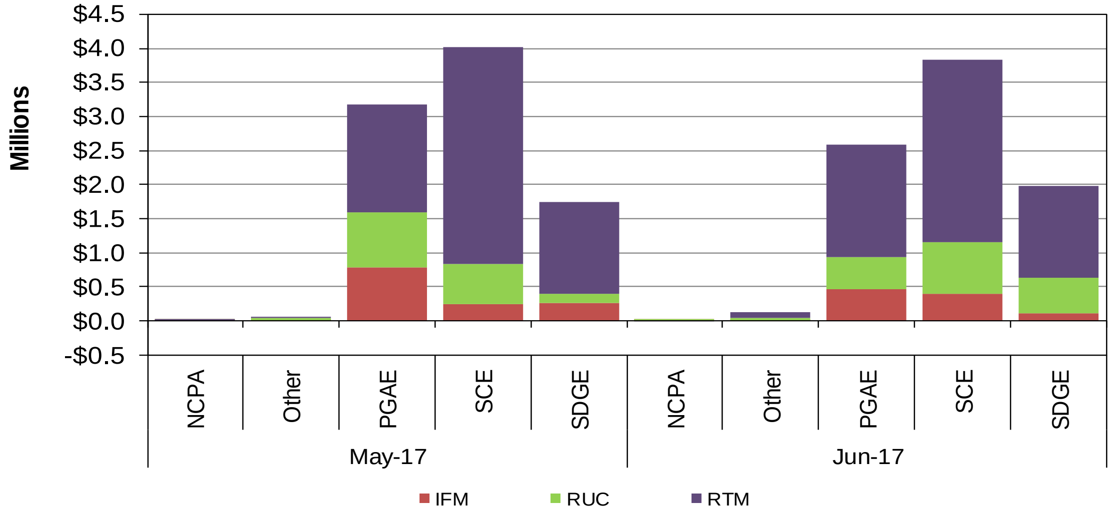


Figure 26 shows the cost related to BCR by cost type in RUC, which in June was mainly driven by minimum load cost (MLC) and start-up cost (SUC).

Figure 26: Cost in RUC

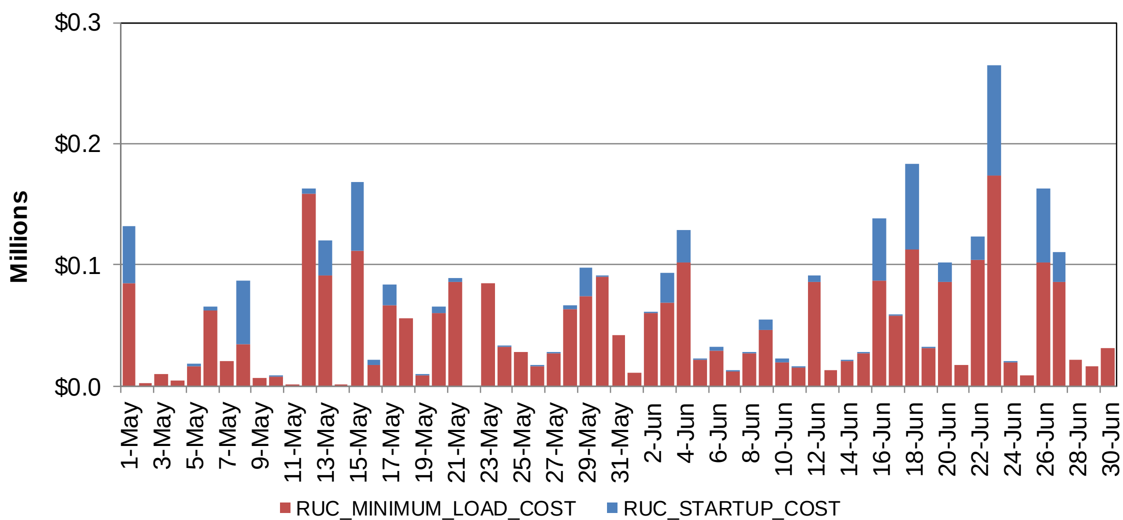


Figure 27 and Figure 28 show the daily and monthly cost related to BCR by type and LCR in RUC respectively.

Figure 27: Cost in RUC by LCR

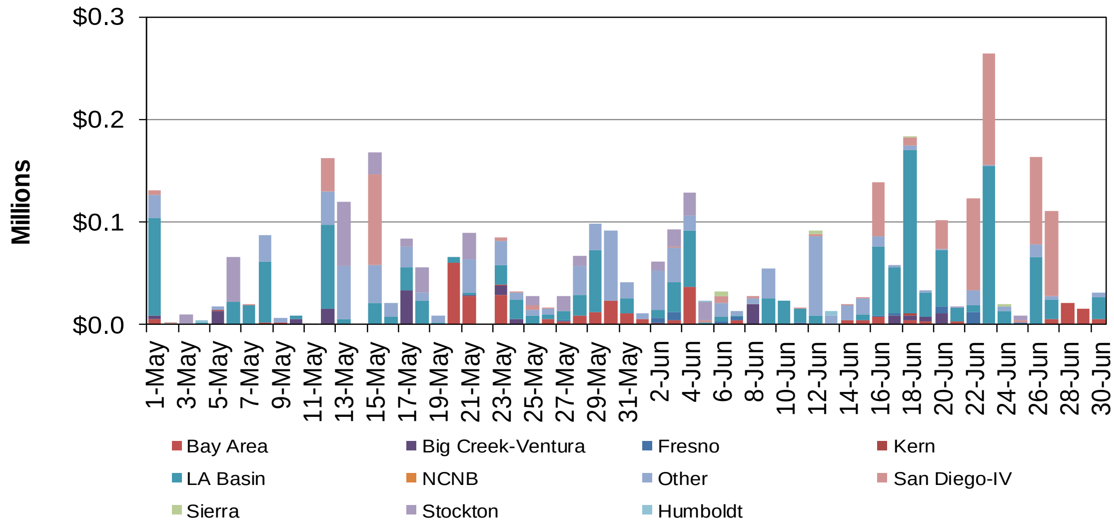


Figure 28: Monthly Cost in RUC by LCR

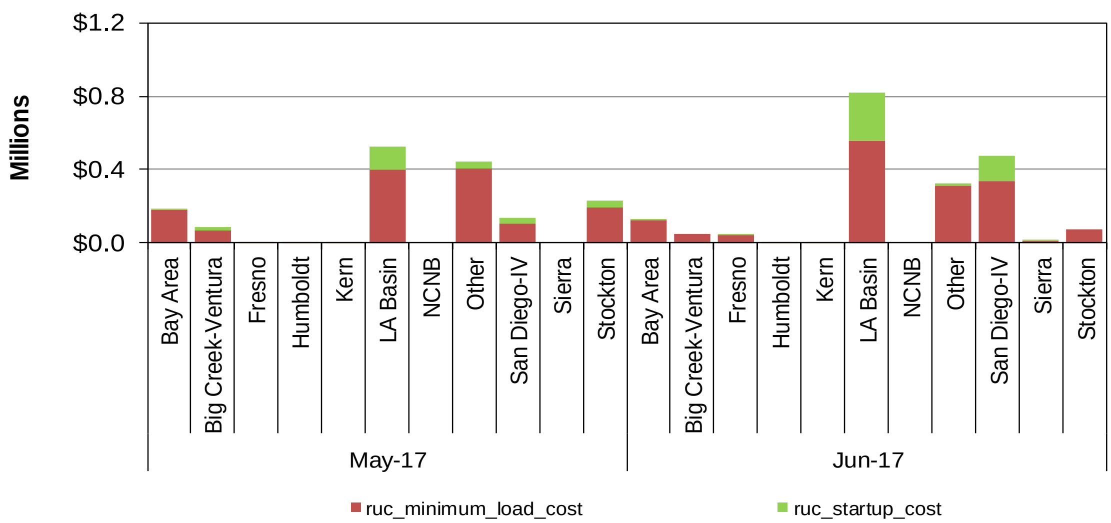


Figure 29 and Figure 30 show the daily and monthly cost related to BCR by type and UDC in RUC respectively.

Figure 29: Cost in RUC by UDC

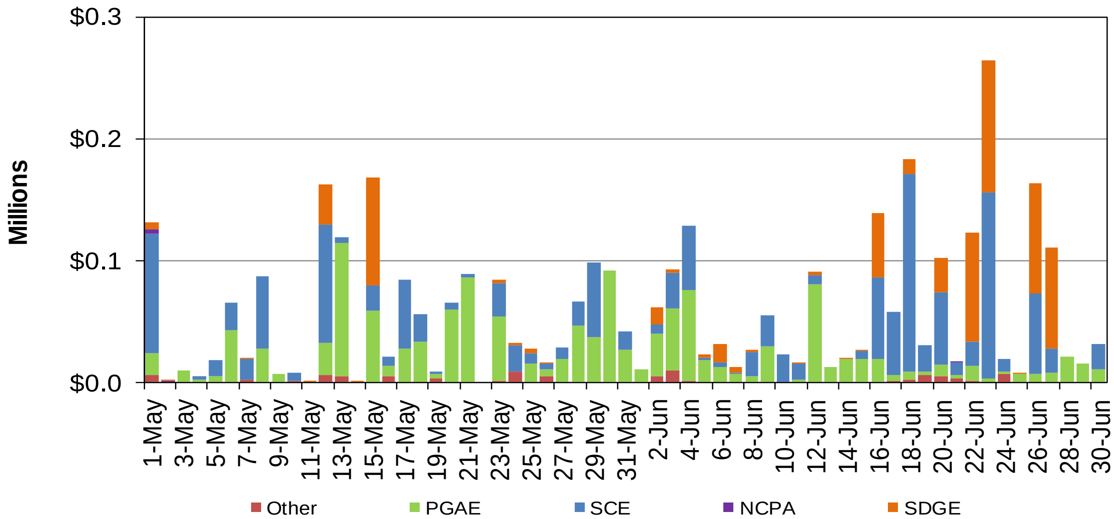


Figure 30: Monthly Cost in RUC by UDC

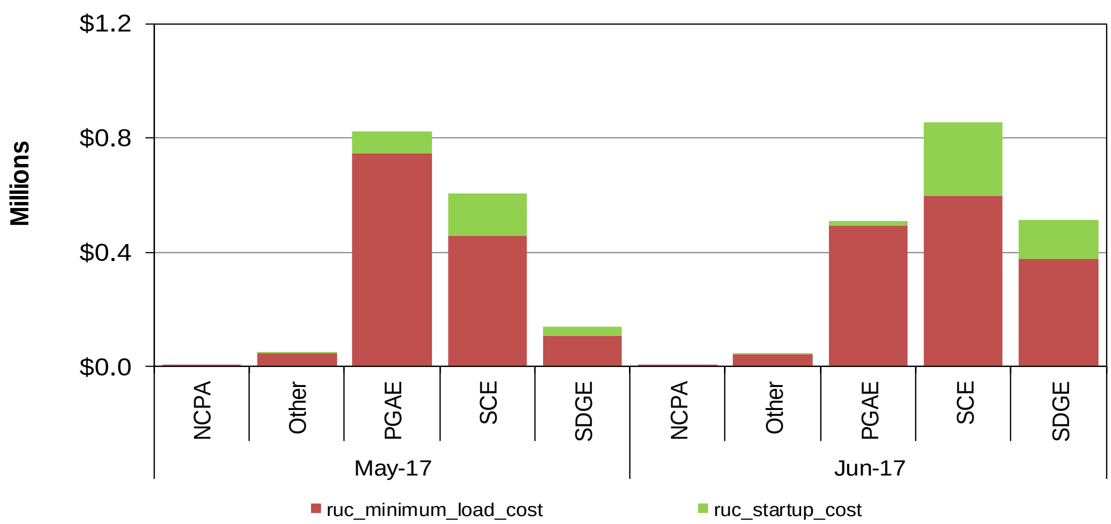


Figure 31 shows the cost related to BCR in real time by cost type. Minimum load cost and energy cost contributed mostly to the real time cost in June.

Figure 31: Cost in Real Time

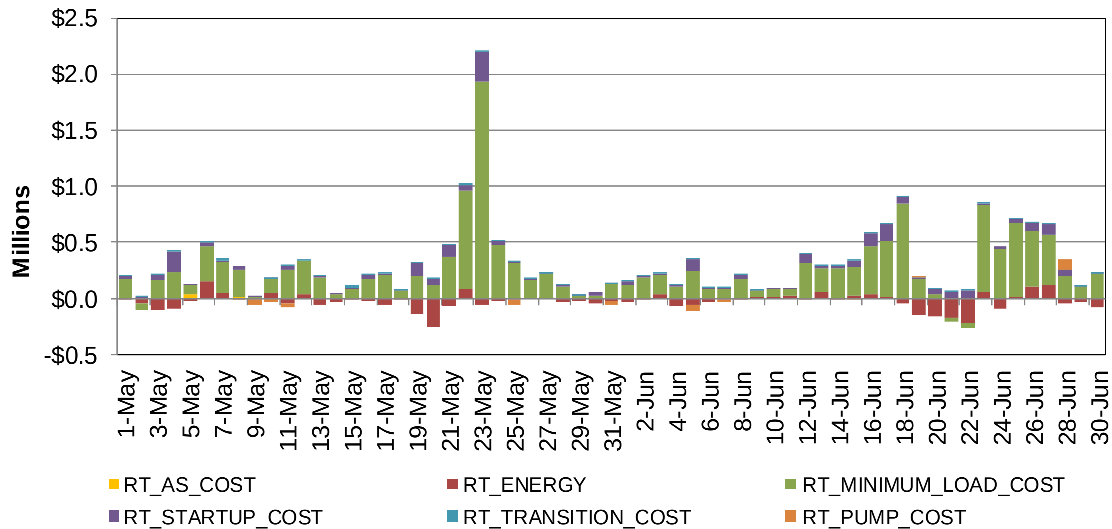


Figure 32 and Figure 33 show the daily and monthly cost related to BCR by type and LCR in real time respectively.

Figure 32: Cost in Real Time by LCR

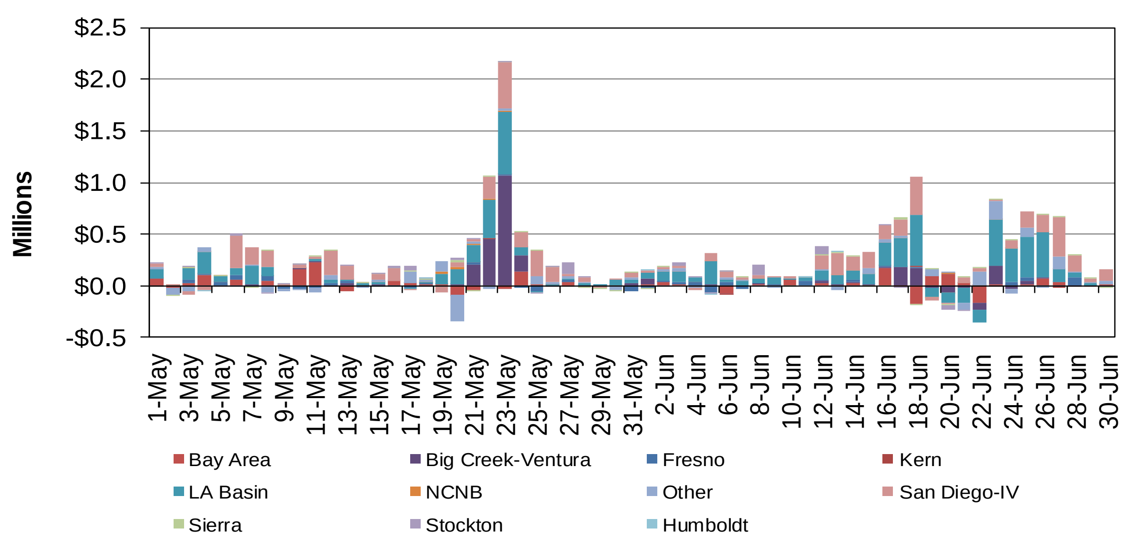


Figure 33: Monthly Cost in Real Time by LCR

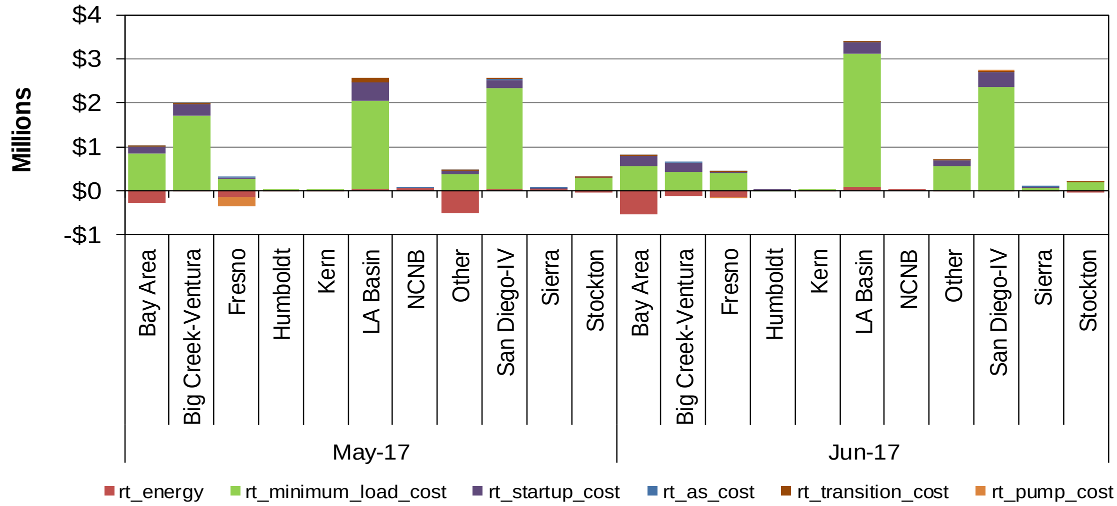


Figure 34 and Figure 35 show the daily and monthly cost related to BCR by type and UDC in Real Time respectively.

Figure 34: Cost in Real Time by UDC

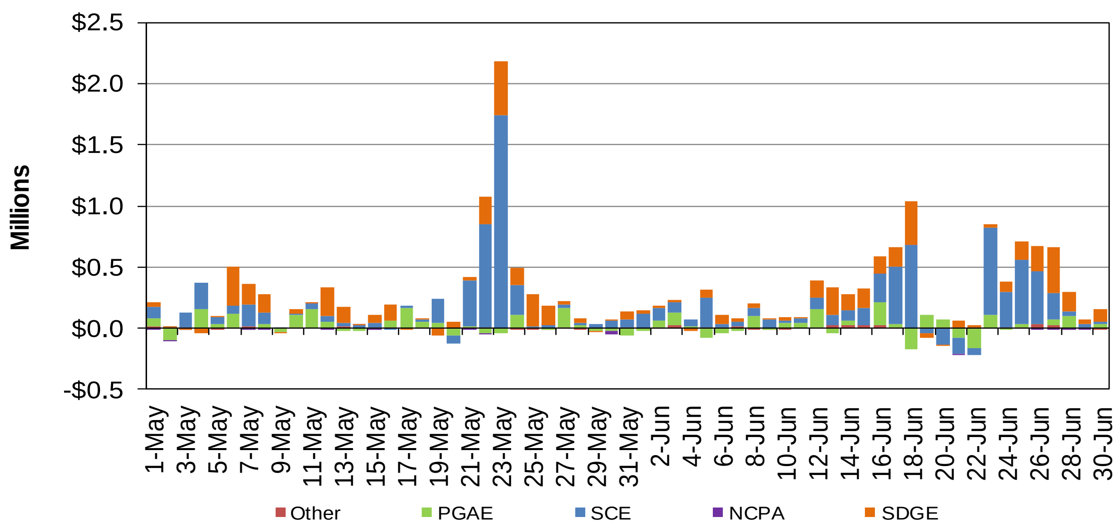


Figure 35: Monthly Cost in Real Time by UDC

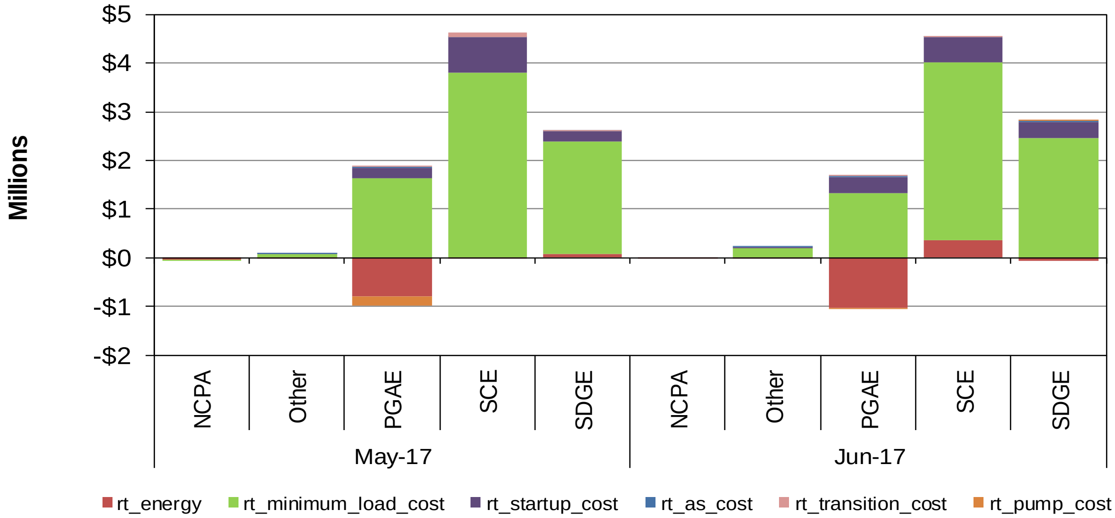


Figure 36 shows the cost related to BCR in IFM by cost type. Minimum Load cost and energy cost contributed largely to the cost in IFM in June.

Figure 36: Cost in IFM

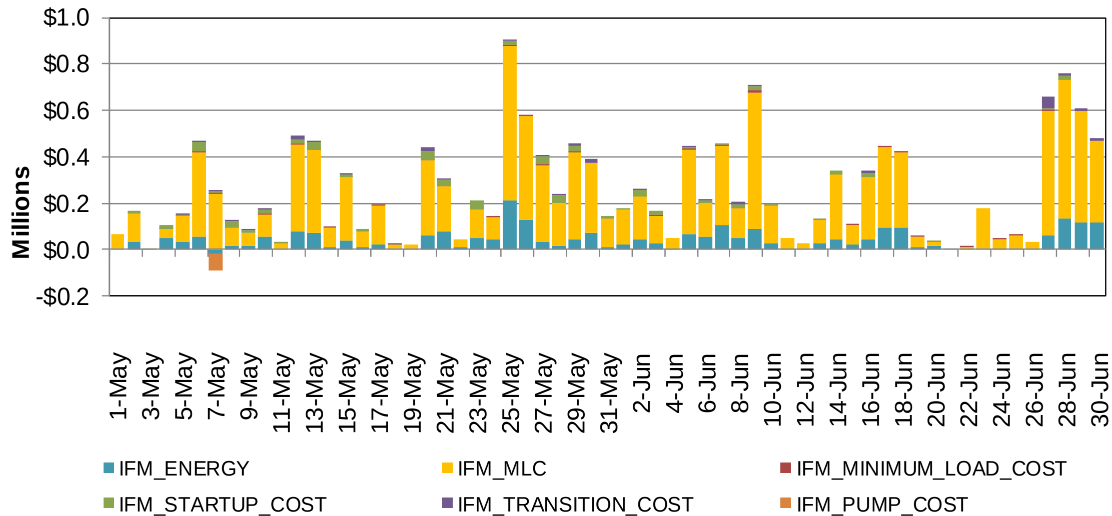


Figure 37 and Figure 38 show the daily and monthly cost related to BCR by type and location in IFM respectively.

Figure 37: Cost in IFM by LCR

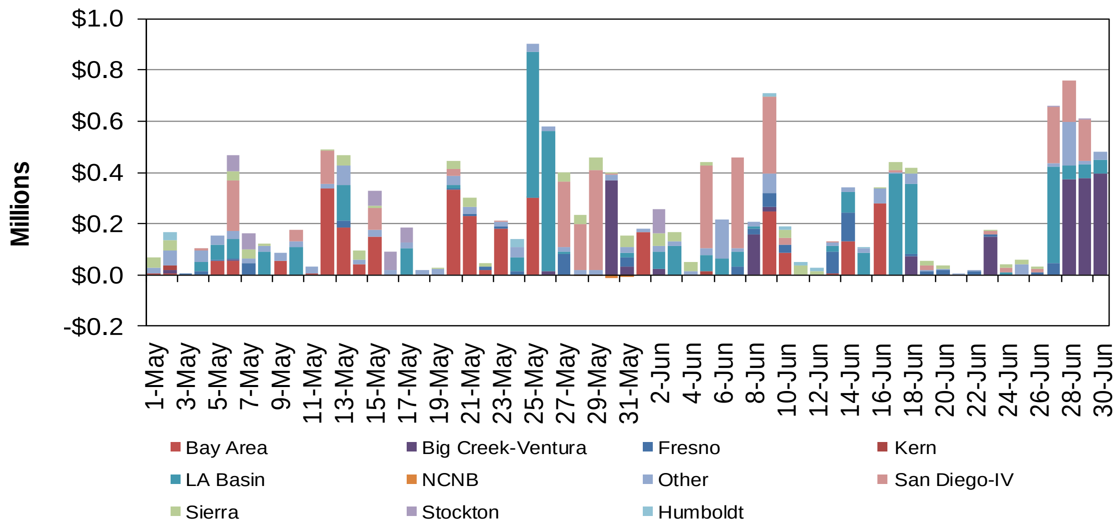


Figure 38: Monthly Cost in IFM by LCR

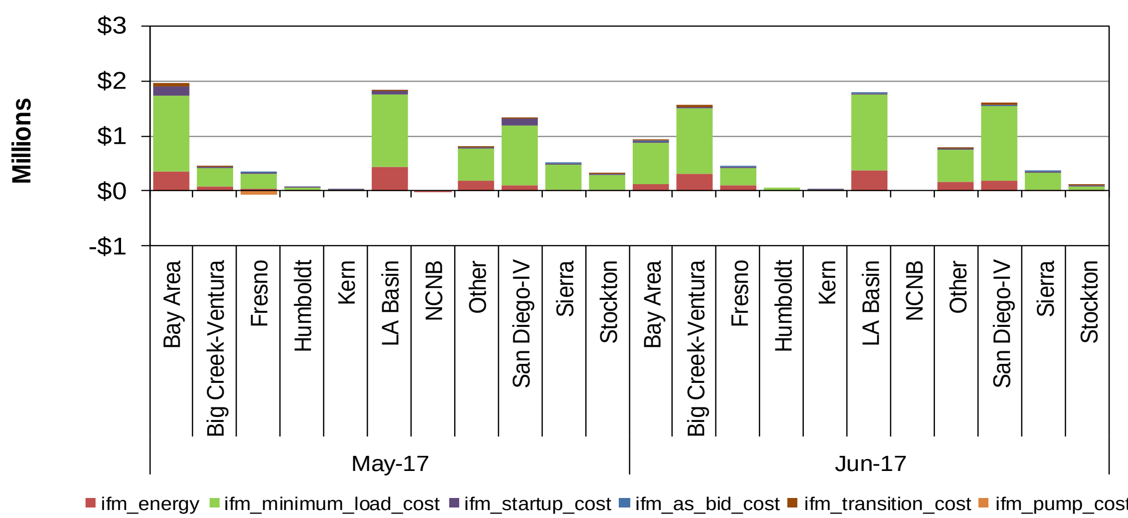


Figure 39 and Figure 40 show the daily and monthly cost related to BCR by type and UDC in IFM respectively.

Figure 39: Cost in IFM by UDC

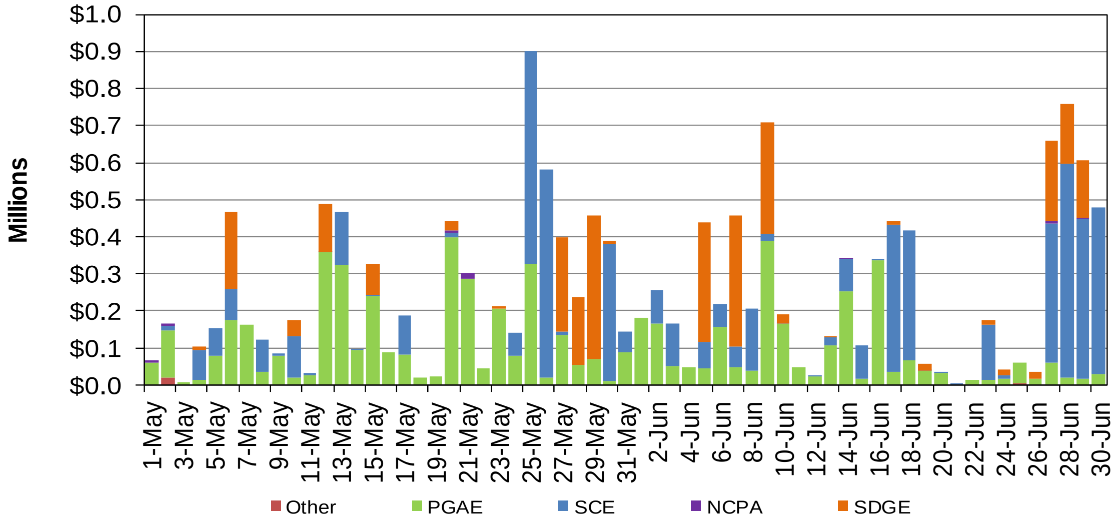
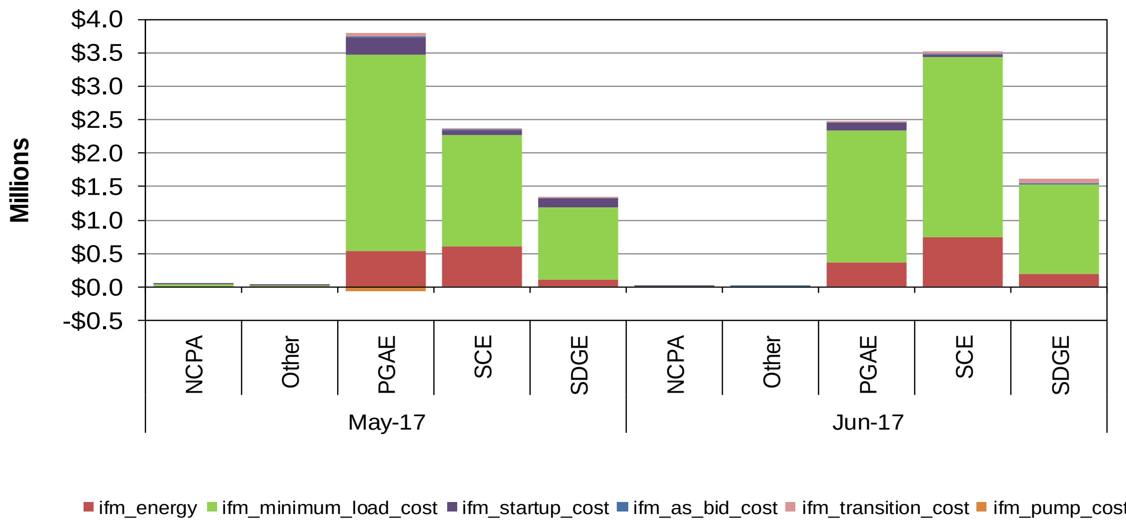


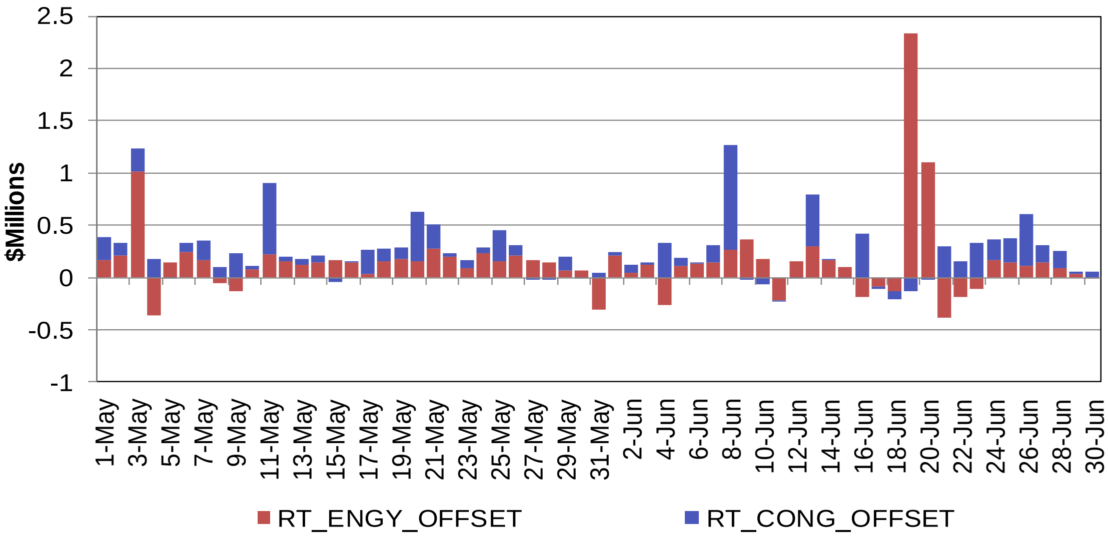
Figure 40: Monthly Cost in IFM by UDC



Real-time Imbalance Offset Costs

Figure 41 shows the daily real-time energy and congestion imbalance offset costs. Real-time energy offset cost inched up to $4.87 million in June from $4.28 million in May. Real-time congestion offset cost increased to $4.41 million in June from $4.01 million in May.

Figure 41: Real-Time Energy and Congestion Imbalance Offset



Market Software Metrics

Market performance can be confounded by software issues, which vary in severity levels with the failure of a market run being the most severe.

Market Disruption

A market disruption is an action or event that causes a failure of an ISO market, related to system operation issues or system emergencies.[3] Pursuant to section 7.7.15 of the ISO tariff, the ISO can take one or more of a number of specified actions to prevent a market disruption, or to minimize the extent of a market disruption.

There were a total of 37 market disruptions in June. Table 7 lists the number of market disruptions and the number of times that the ISO removed bids (including self-schedules) in any of the following markets in this month. The ISO markets include IFM, RUC, FMM and RTD processes.

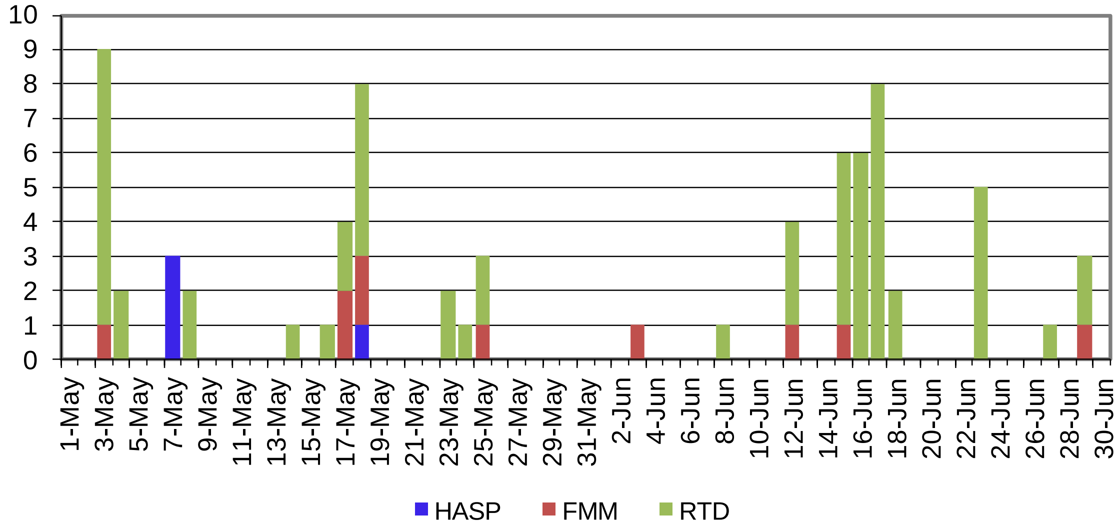
Table 7: Summary of Market Disruption

Type of CAISO Market	Market Disruption or Reportable	Removal of Bids (including Self-Schedules)
Day-Ahead		
IFM	0	0
RUC	0	0
Real-Time		
FMM Interval 1	0	0
FMM Interval 2	0	0
FMM Interval 3	1	0
FMM Interval 4	3	0
Real-Time Dispatch	33	0

Figure 42 shows the frequency of IFM, HASP (FMM interval 2), FMM (intervals 1, 3 and 4), and RTD failures. On June 17, eight RTD disruptions occurred due to application problem.

[3] These system operation issues or system emergencies are referred to in Sections 7.6 and 7.7, respectively, of the ISO tariff.

Figure 42: Frequency of Market Disruption



Manual Market Adjustment

Exceptional Dispatch

Figure 43 shows the daily volume of exceptional dispatches, broken out by market type: day-ahead, real-time incremental dispatch and real-time decremental dispatch. Generally, all day-ahead exceptional dispatches are unit commitments at the resource physical minimum. The real-time exceptional dispatches are among one of the following types: a unit commitment at physical minimum; an incremental dispatch above the day-ahead schedule and a decremental dispatch below the day-ahead schedule.

The total volume of exceptional dispatch in June decreased to 85,249 MWh from 126,430 MWh in May.

Figure 43: Total Exceptional Dispatch Volume (MWh) by Market Type

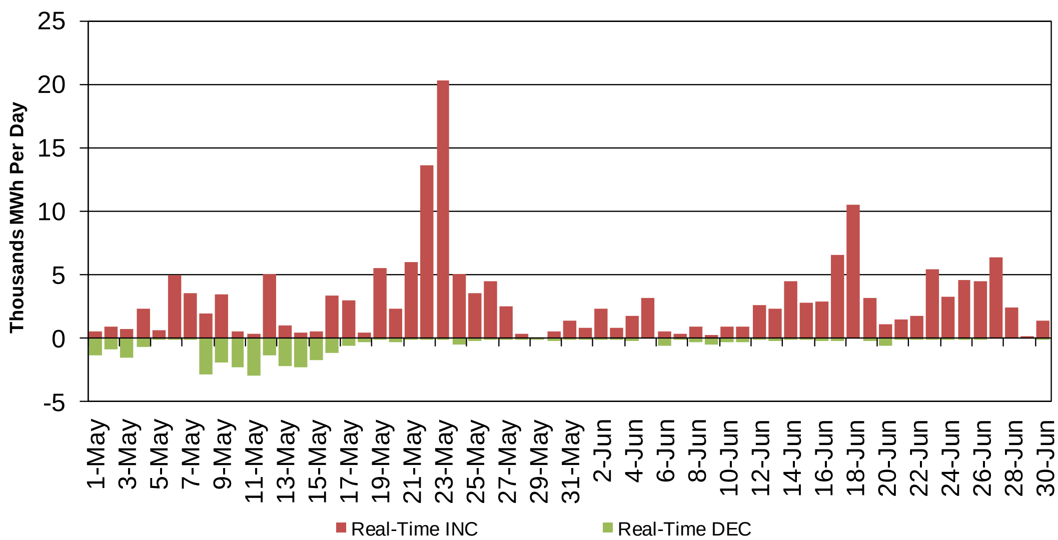


Figure 44 shows the volume of the exceptional dispatch broken out by reason.[4] The majority of the exceptional dispatch volumes in June were driven by load forecast uncertainty (47 percent), planned transmission outage and constraint (17 percent), and load pull (11 percent).

[4] For details regarding the reasons for exceptional dispatch please read the white paper at this link: **http://www.caiso.com/1c89/1c89d76950e00.html**.

Figure 44: Total Exceptional Dispatch Volume (MWh) by Reason

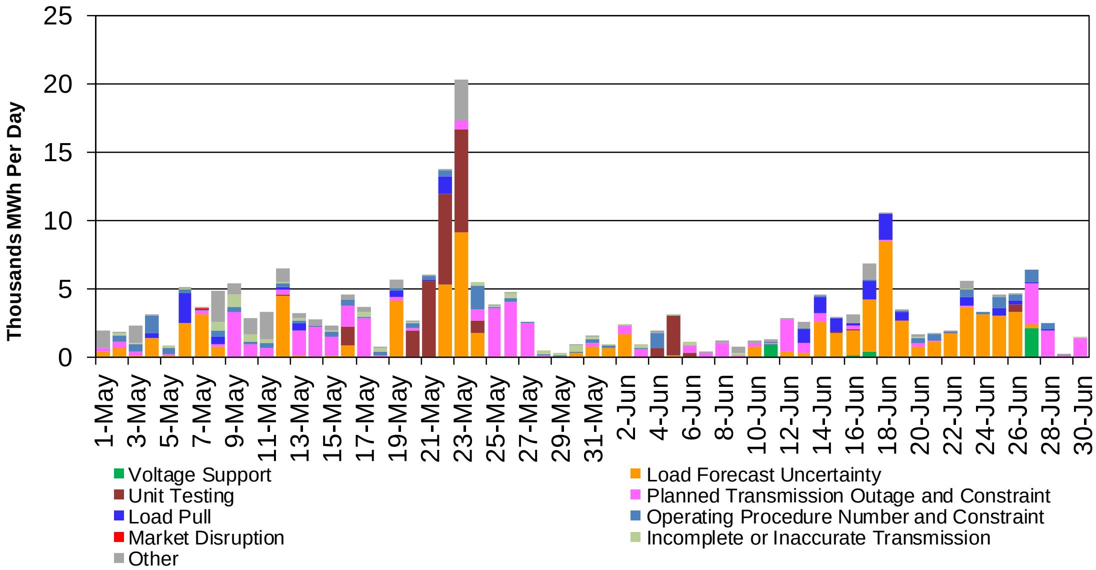
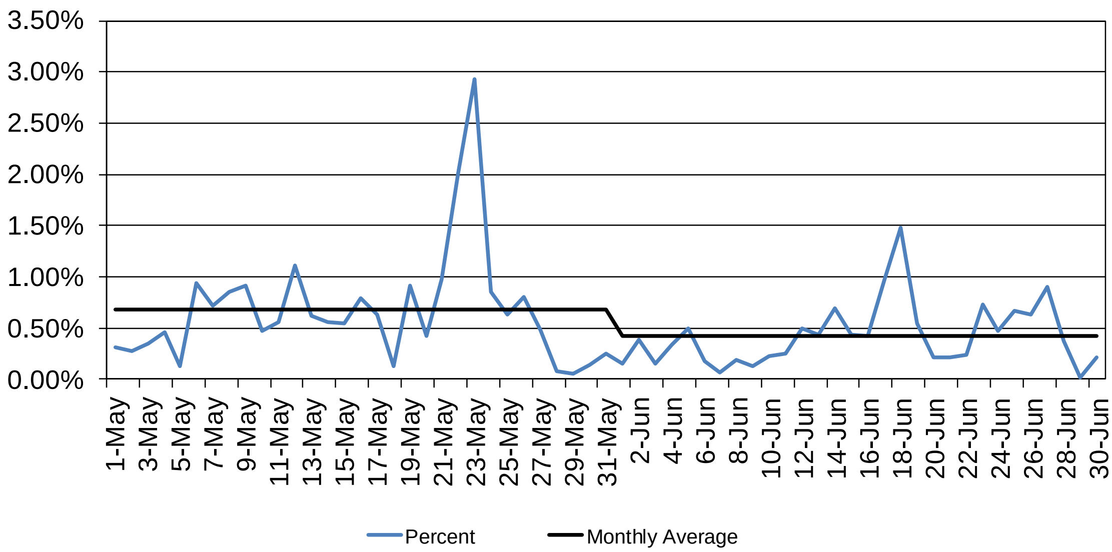


Figure 45 shows the total exceptional dispatch volume as a percent of load, along with the monthly average. The monthly average percentage fell to 0.42 percent in June from 0.67 percent in May.

Figure 45: Total Exceptional Dispatch as Percent of Load



Energy Imbalance Market

On November 1, 2014, the California Independent System Operator Corporation (ISO) and Portland-based PacifiCorp fully activated the Energy Imbalance Market (EIM). This real-time market is the first of its kind in the West. EIM covers six western states: California, Oregon, Washington, Utah, Idaho and Wyoming.

On December 1, 2015, NV Energy, the Nevada-based utility successfully began participating in the western Energy Imbalance Market (EIM). With the addition of NV Energy, the EIM expands into Nevada, where the utility serves 2.4 million customers. The ISO real-time market is now in seven states, saving millions of dollars for consumers. The newly expanded marketplace enables the ISO and participants to incorporate thousands of megawatts of variable generating resources, such as wind and solar, into the power grid while reducing greenhouse emissions, and improving grid resiliency and reliability.

On October 1, 2016, Phoenix-based Arizona Public Service (AZPS) and Puget Sound Energy (PSEI) of Washington State successfully began full participation in the western Energy Imbalance Market. With the addition of Arizona Public Service and Puget Sound Energy, The EIM is serving over 5 million consumers in California, Washington, Oregon, Arizona, Idaho, Wyoming, Nevada and Utah.

Figure 46 shows daily simple average ELAP prices for PacifiCorp east (PACE), PacifiCorp West (PACW), NV Energy (NEVP), Arizona Public Service (AZPS) and Puget Sound Energy (PSEI) for all hours in FMM. On June 19, the prices for AZPS, NEVP and PACE were elevated due to upward load adjustment, renewable deviation, and generation outage. On June 20, the price for NEVP was elevated due to net import reduction, renewable deviation, and upward load adjustment.

Figure 46: EIM Simple Average LAP Prices (All Hours) in FMM

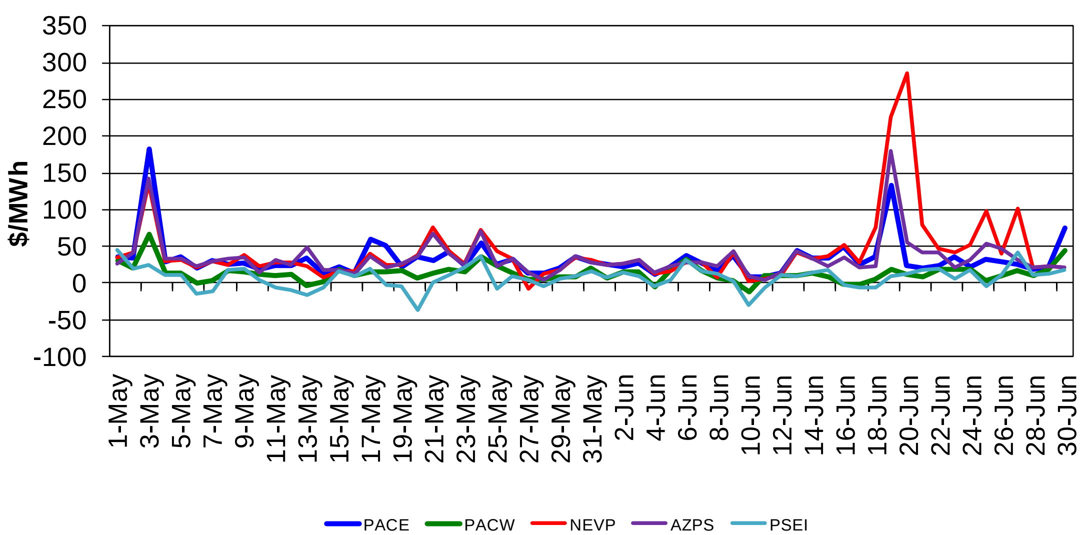


Figure 47 shows daily simple average ELAP prices for PACE, PACW, NEVP, AZPS and PSEI for all hours in RTD. On June 19 and 20, the prices for NEVP were elevated driven by upward load adjustment and renewable deviation.

Figure 47: EIM Simple Average LAP Prices (All Hours) in RTD

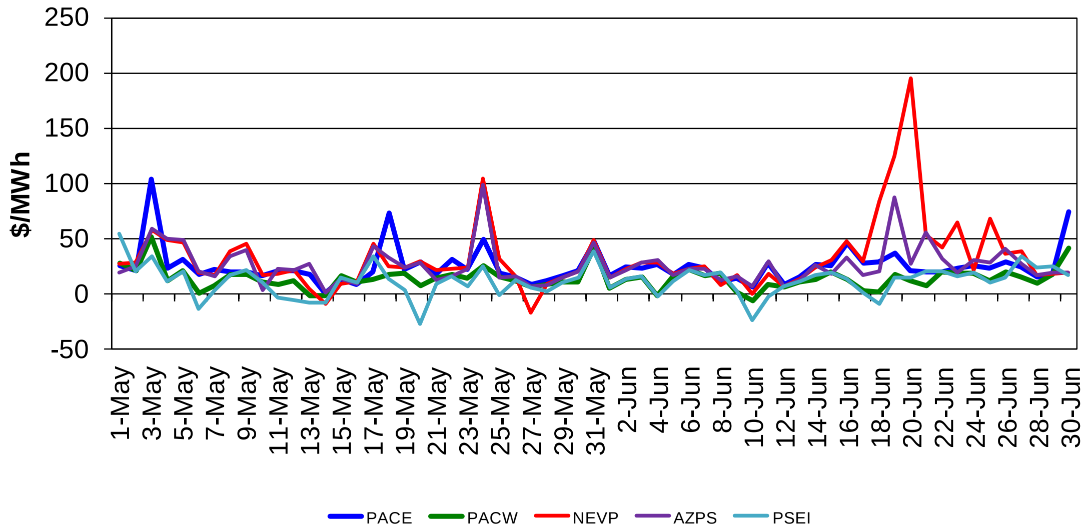


Figure 48 shows the daily price frequency for prices above $250/MWh and negative prices in FMM for PACE, PACW, NEVP, AZPS and PSEI. The cumulative frequency of prices above $250/MWh increased to 1.17 percent in June from 0.89 percent in May. The cumulative frequency of negative prices increased to 12.39 percent in June from 10.80 percent in May.

Figure 48: Daily Frequency of EIM LAP Positive Price Spikes and Negative Prices in FMM

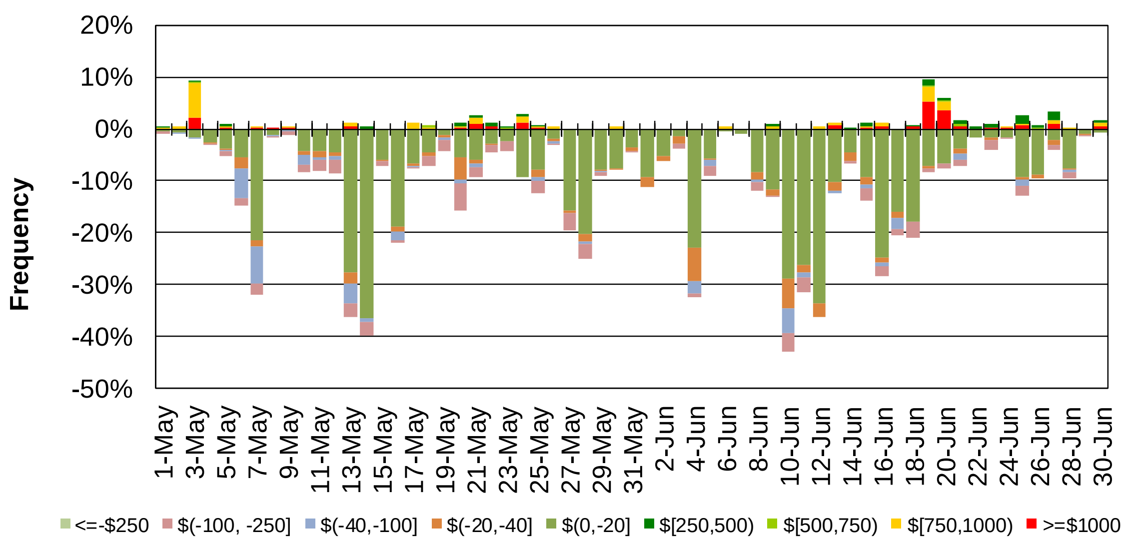


Figure 49 shows the daily price frequency for prices above $250/MWh and negative prices in RTD for PACE, PACW, NEVP, AZPS and PSEI. The cumulative frequency of prices above $250/MWh edged up to 0.88 percent in June from to 0.80 percent in May. The cumulative frequency of negative prices rose to 12.63 percent in June from 11.64 percent in May.

Figure 49: Daily Frequency of EIM LAP Positive Price Spikes and Negative Prices in RTD

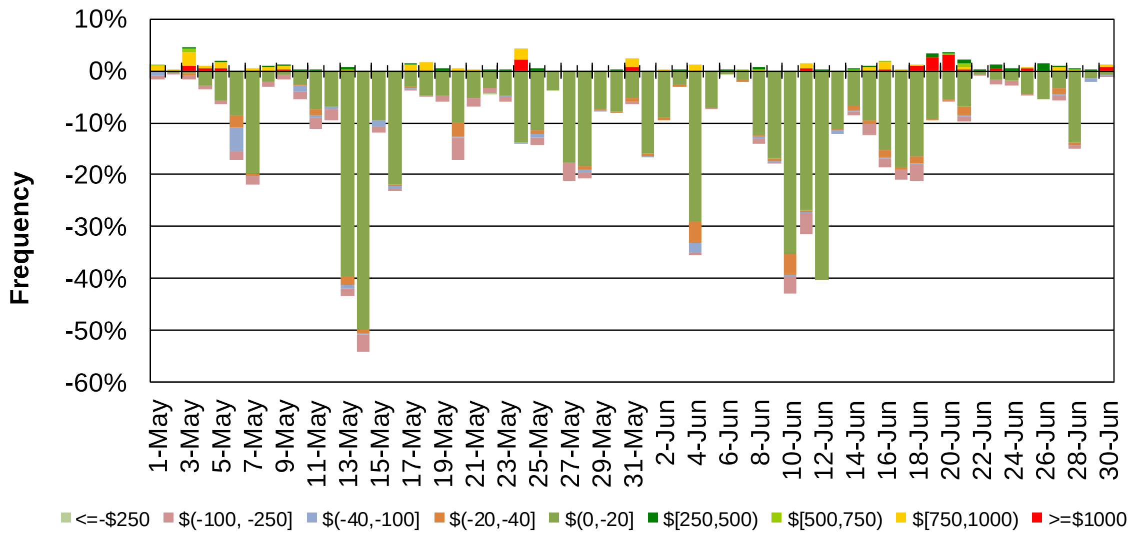


Figure 50 shows the daily volume of EIM transfer between ISO and PacifiCorp in FMM. Figure 51 shows the daily volume of EIM transfer between PACE and PACW in FMM. The EIM transfer from PACE to PACW trended upward in June

Figure 50: EIM Transfer between CAISO and PAC in FMM

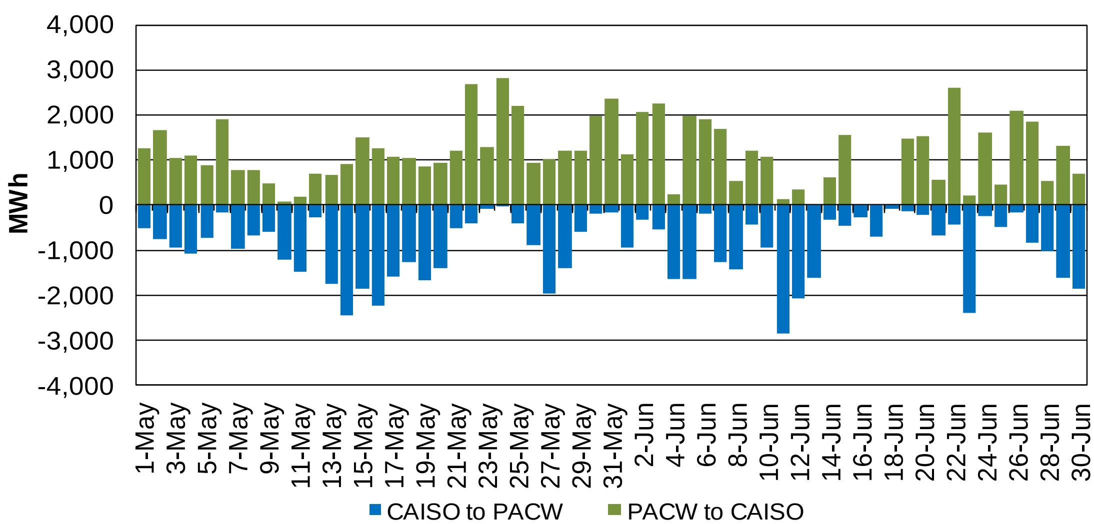


Figure 51: EIM Transfer between PACE and PACW in FMM

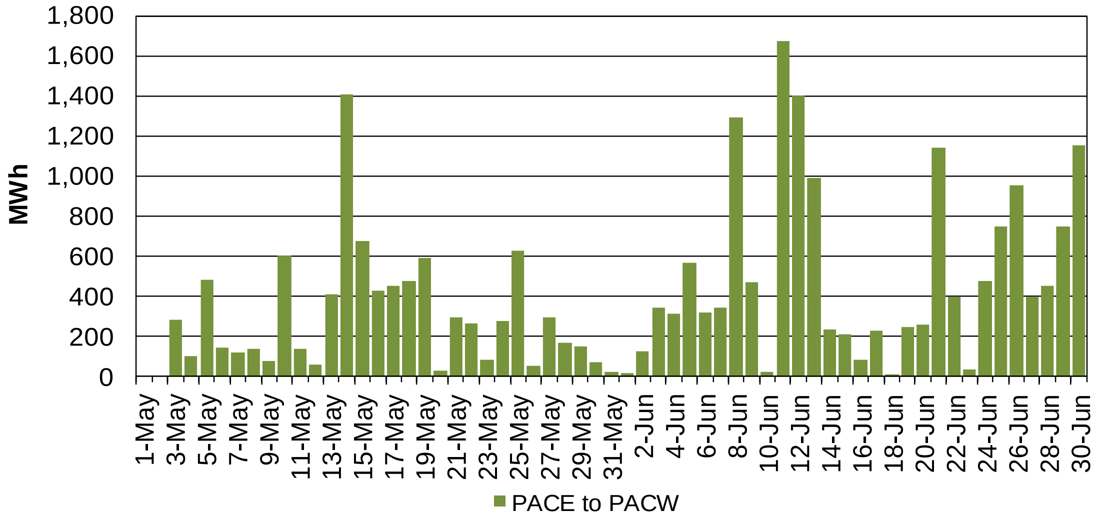


Figure 52 shows the daily volume of EIM transfer between CAISO and NEVP in FMM. Figure 53 shows the daily volume of EIM transfer between PACE and NEVP in FMM. The EIM transfer from PACE to NEVP increased in the first half of June and then fell in the second half of June.

Figure 52: EIM Transfer between CAISO and NEVP in FMM

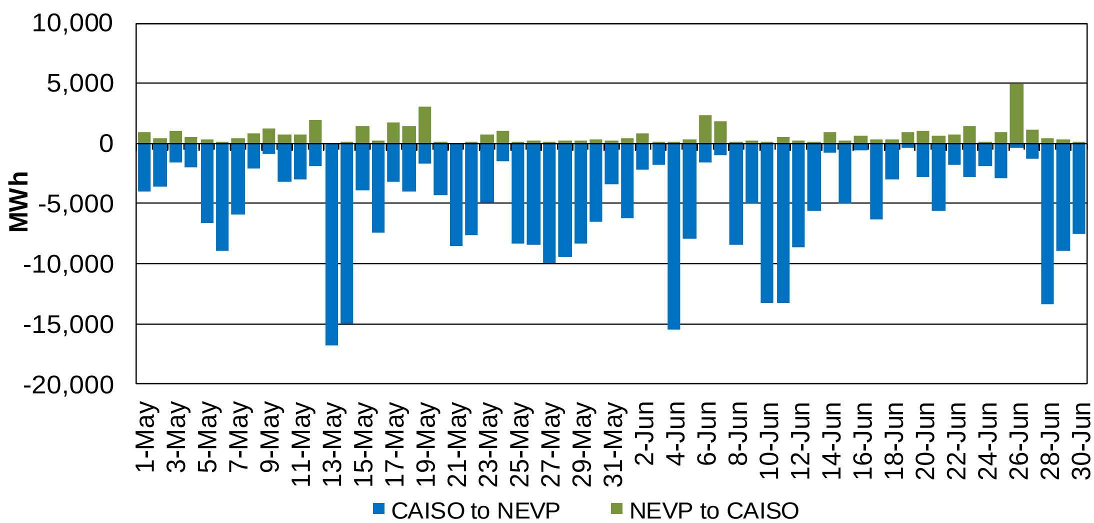


Figure 53: EIM Transfer between PACE and NEVP in FMM

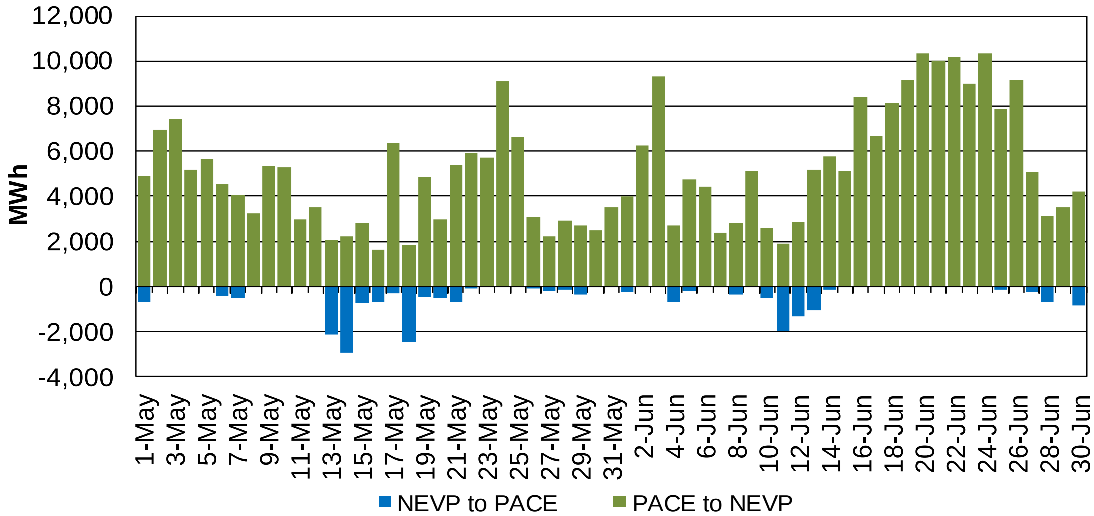


Figure 54 shows the daily volume of EIM transfer between ISO and AZPS in FMM. Figure 55 shows the daily volume of EIM transfer between PACE and AZPS in FMM.

Figure 54: EIM Transfer between CAISO and AZPS in FMM

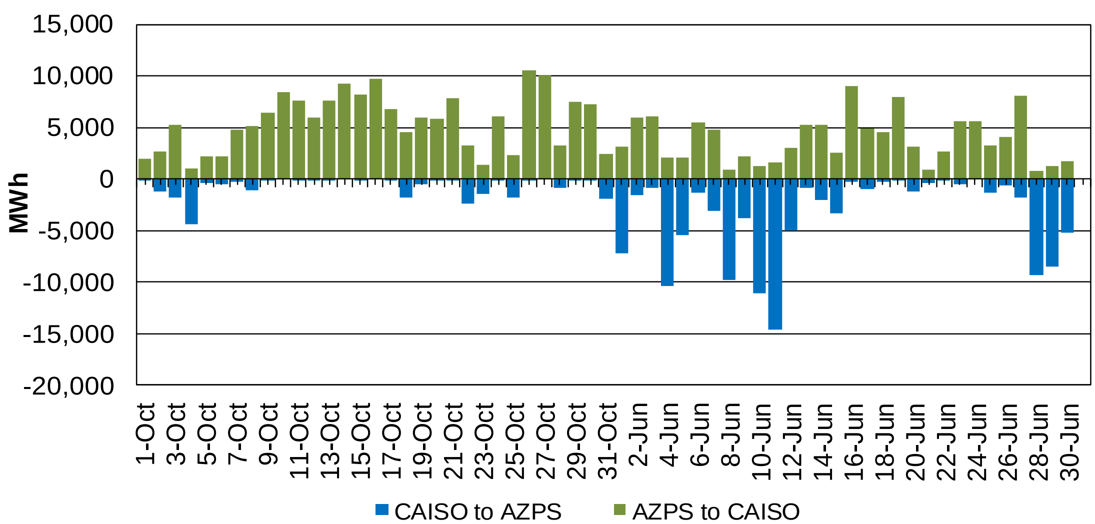


Figure 55: EIM Transfer between PACE and AZPS in FMM

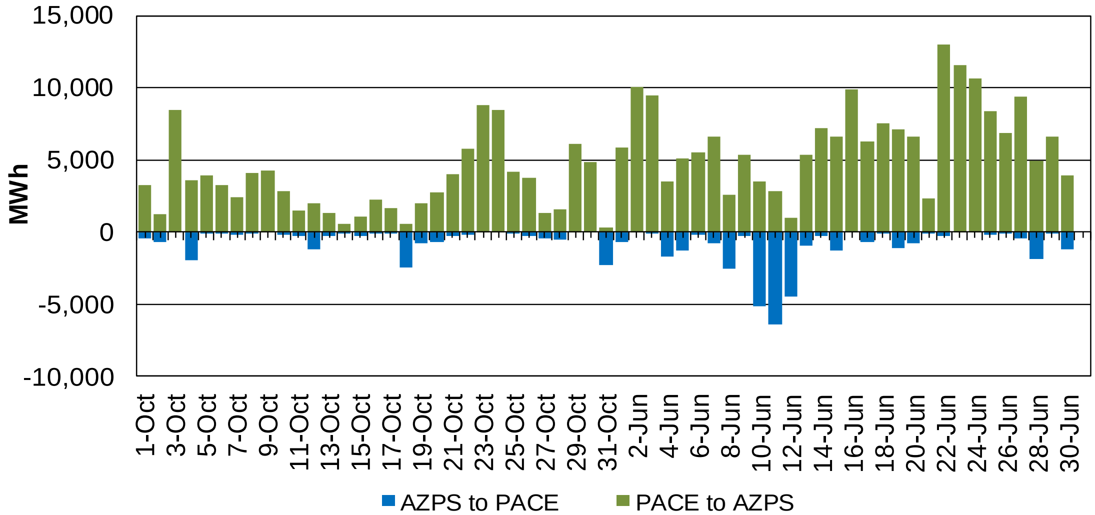


Figure 56 shows the daily volume of EIM transfer between PACW and PSEI in FMM.

Figure 56: EIM Transfer between PACW and PSEI in FMM

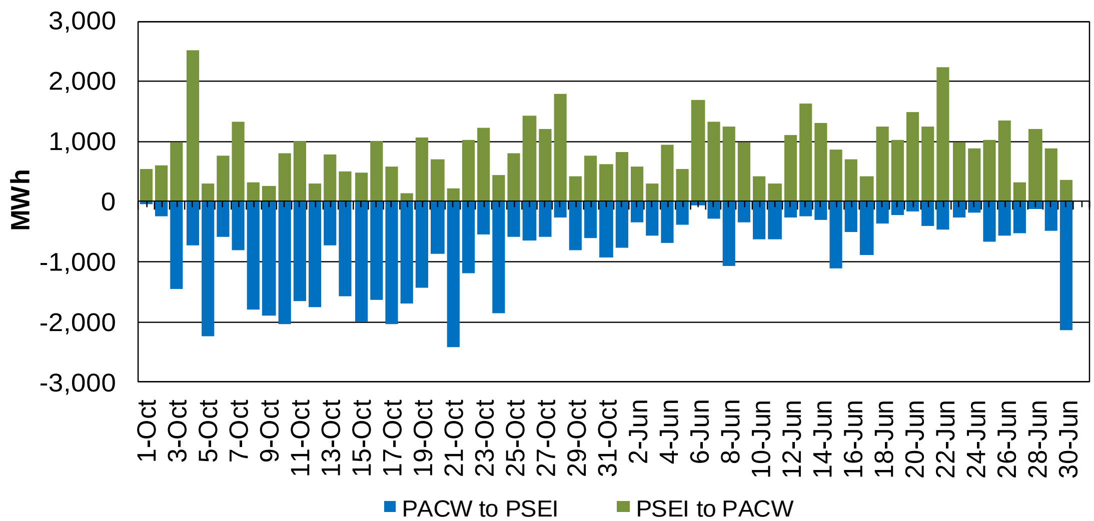


Figure 57 shows the daily volume of EIM transfer between ISO and PacifiCorp in RTD. Figure 58 shows the daily volume of EIM transfer between PACE and PACW in RTD.

Figure 57: EIM Transfer between CAISO and PAC in RTD

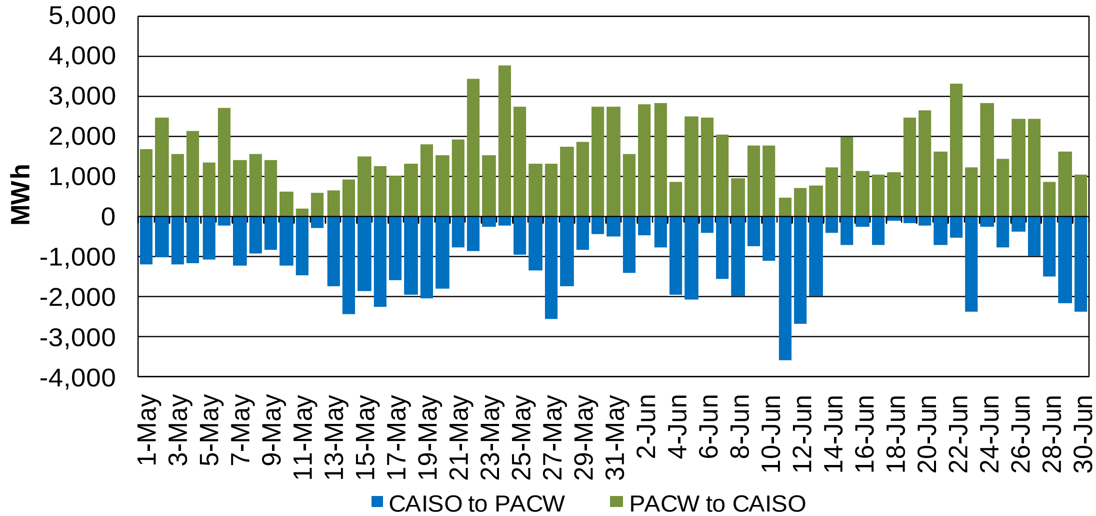


Figure 58: EIM Transfer between PACE and PACW in RTD

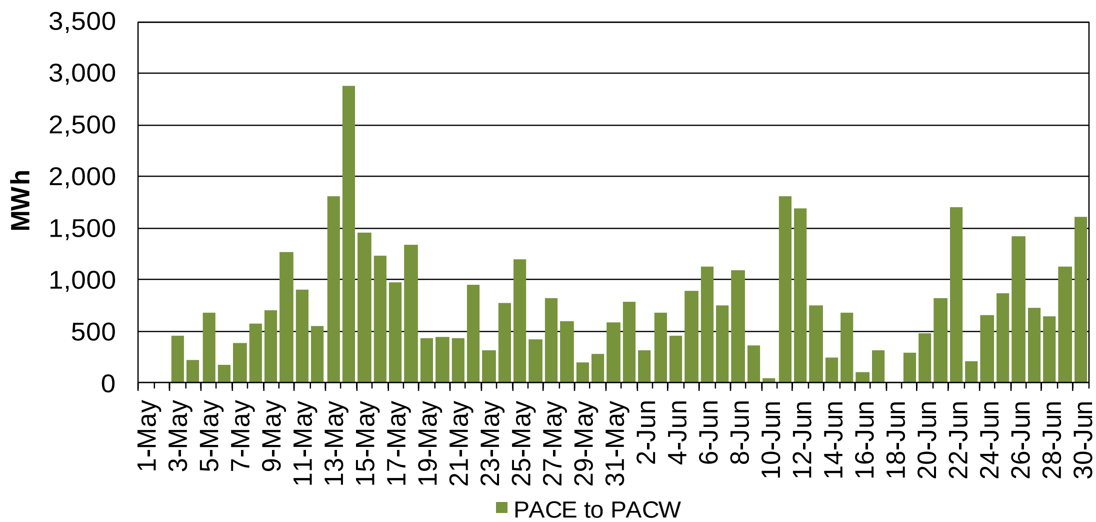


Figure 59 shows the daily EIM transfer volume between ISO and NEVP in RTD. Figure 60 shows the daily EIM transfer volume between PACE and NEVP in RTD. The EIM transfer from PACE to NEVP rose in the first half of June and then declined in the second half of June.

Figure 59: EIM Transfer between CAISO and NEVP in RTD

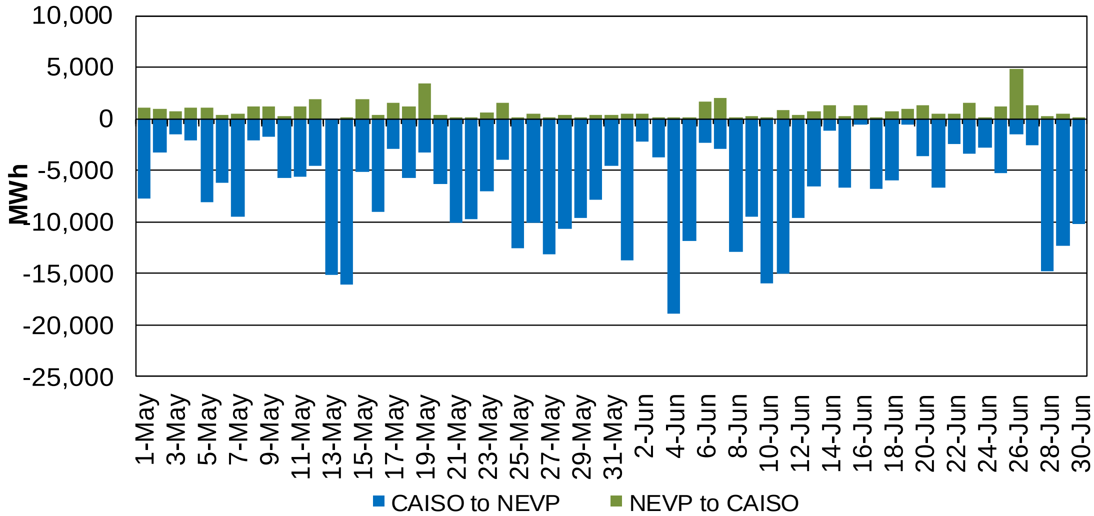


Figure 60: EIM Transfer between PACE and NEVP in RTD

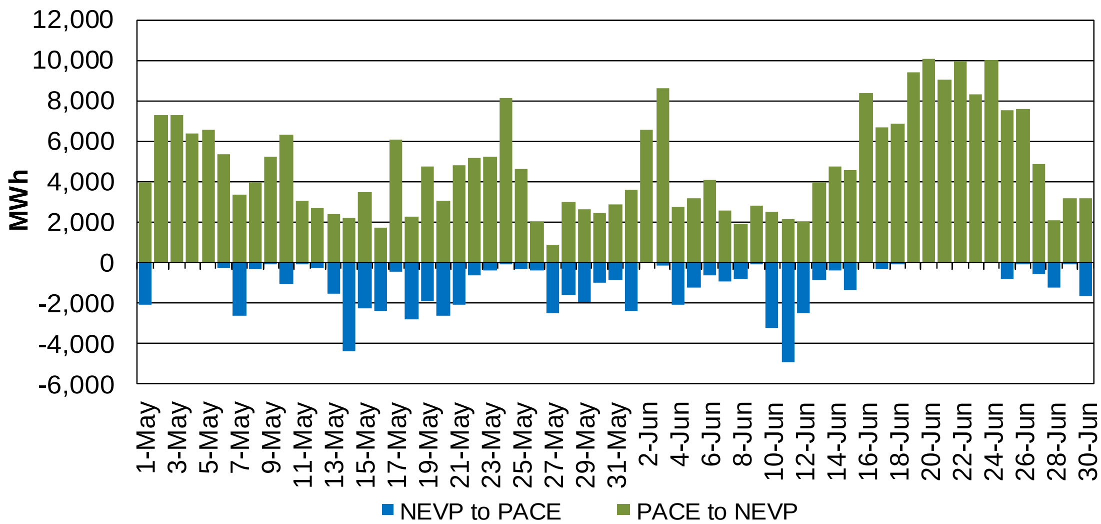


Figure 61 shows the daily volume EIM transfer between the ISO and AZPS in RTD. Figure 62 shows the daily volume EIM transfer between the PACE and AZPS in RTD.

Figure 61: EIM Transfer between CAISO and AZPS in RTD

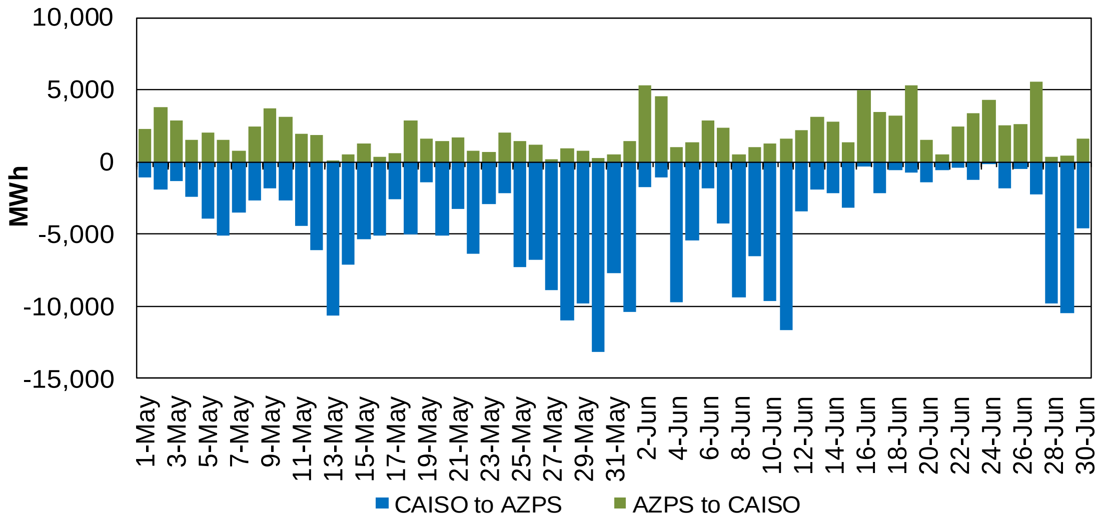


Figure 62: EIM Transfer between PACE and AZPS in RTD

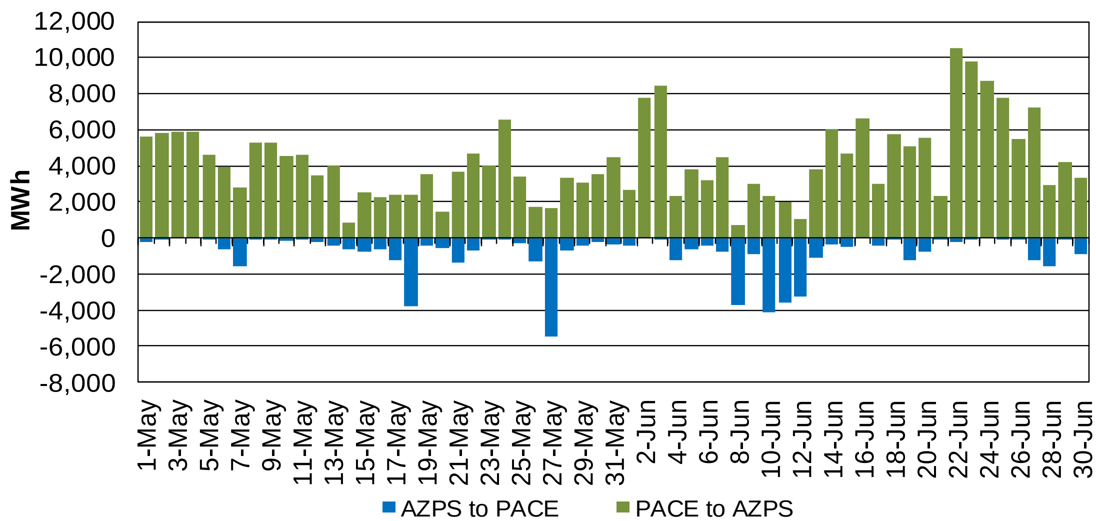


Figure 63 shows the daily volume EIM transfer between PACW and PSEI in RTD.

Figure 63: EIM Transfer between PACW and PSEI in RTD

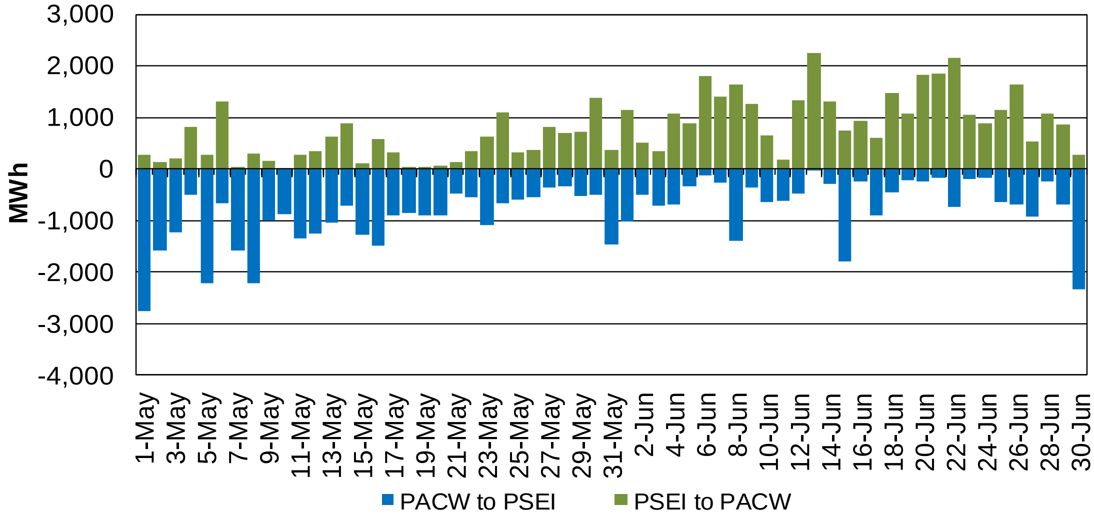


Figure 64 shows daily real-time imbalance energy offset cost (RTIEO) for PACE, PACW, NEVP, AZPS and PSEI respectively. Total RTIEO was -$2.24 million in June, decreasing from -$0.36 million in May.

Figure 64: EIM Real-Time Imbalance Energy Offset by Area

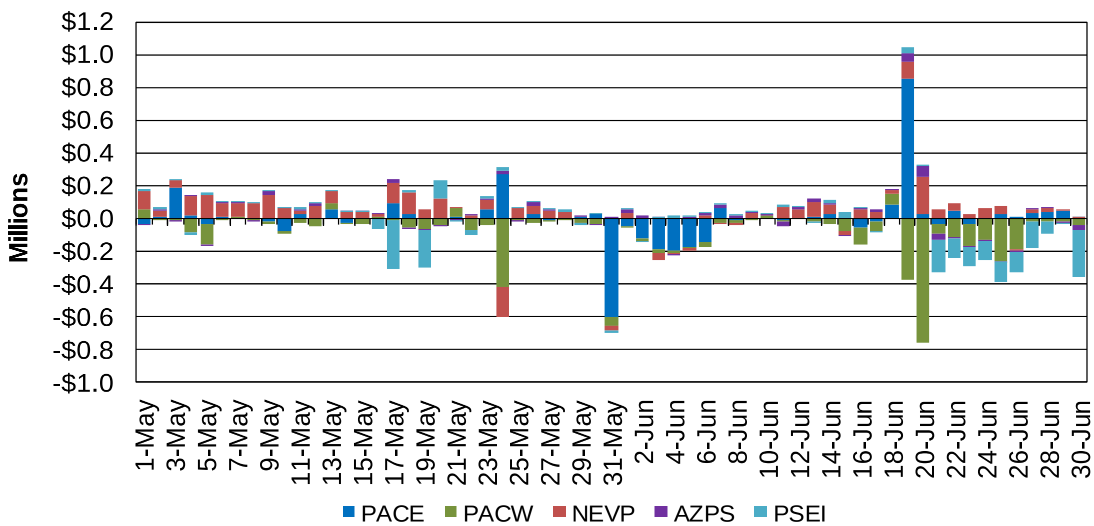


Figure 65 shows daily real-time congestion offset cost (RTCO) for PACE, PACW, NEVP, AZPS and PSEI respectively. Total RTCO skidded to -$4.67 million in June from -$0.82 million in May.

Figure 65: EIM Real-Time Congestion Imbalance Offset by Area

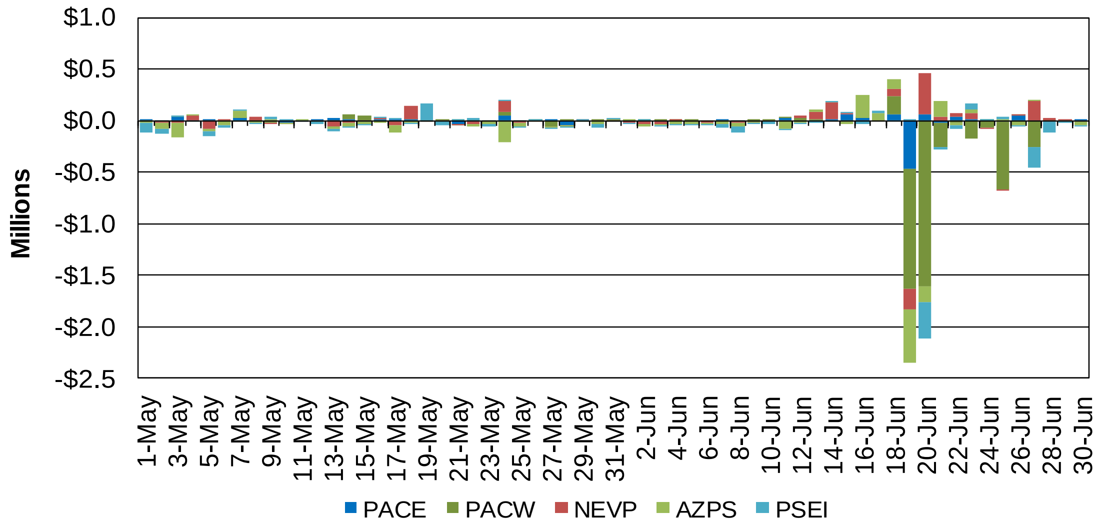


Figure 66 shows daily bid cost recovery for PACE, PACW, NEVP, AZPS and PSEI respectively. Total BCR dropped to $0.92 million in June from $1.27 million in May.

Figure 66: EIM Bid Cost Recovery by Area

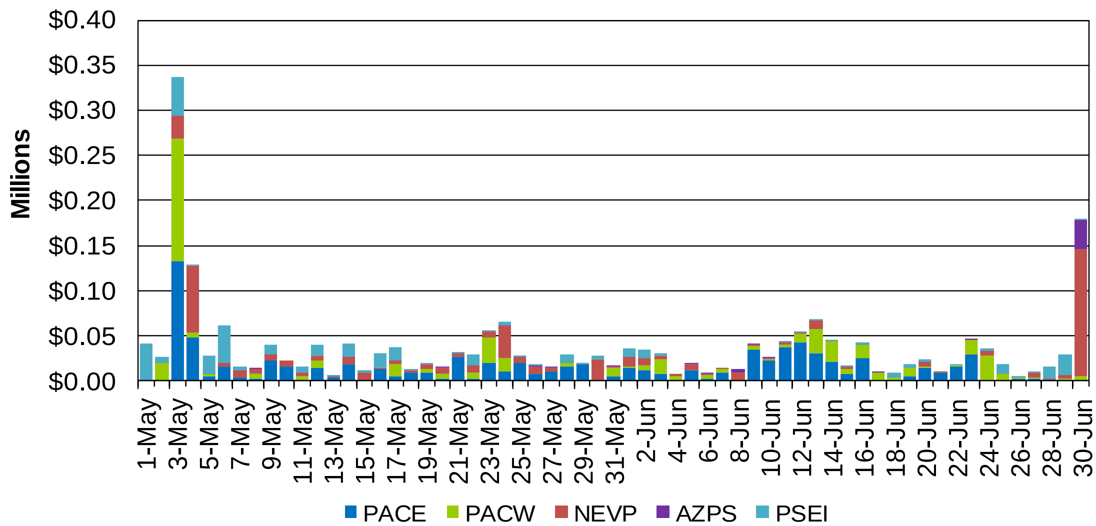


Figure 67 shows the flexible ramping up uncertainty payment for PACE, PACW, NEVP, AZPS, and PSEI respectively. Total flexible ramping up uncertainty payment in June decreased to $0.65 million from $1.14 million in May.

Figure 67: Flexible Ramping Up Uncertainty Payment

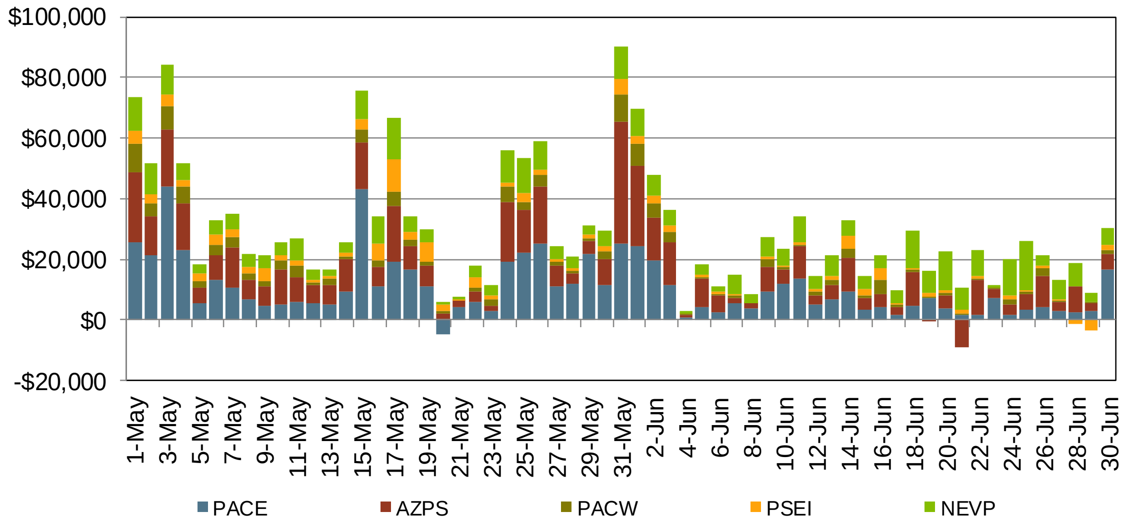


Figure 68 shows the flexible ramping down uncertainty payment for PACE, PACW, NEVP, AZPS, and PSEI respectively. Total flexible ramping down uncertainty payment in June decreased to $0.03 million from $0.08 million in May.

Figure 68: Flexible Ramping Down Uncertainty Payment

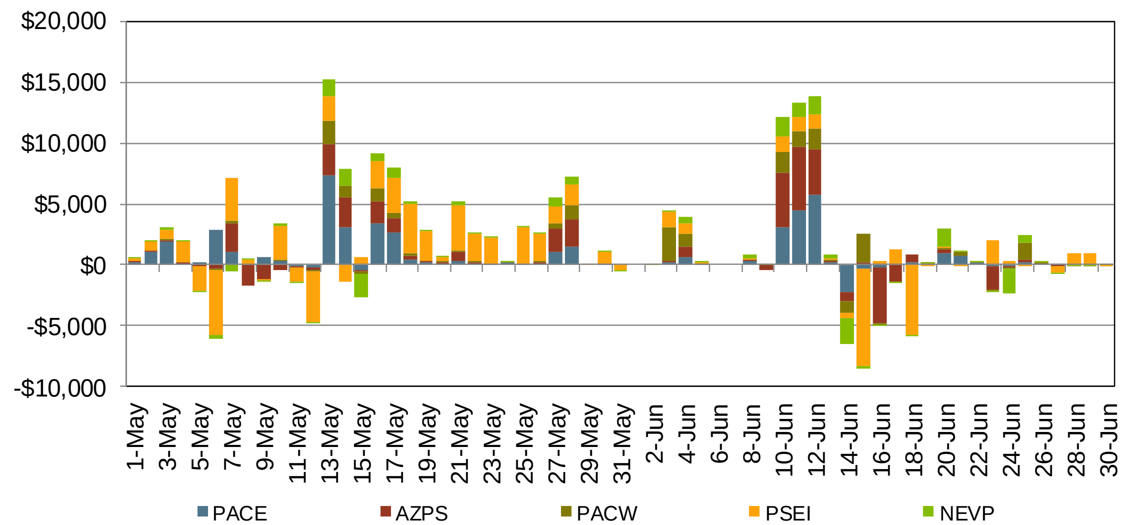
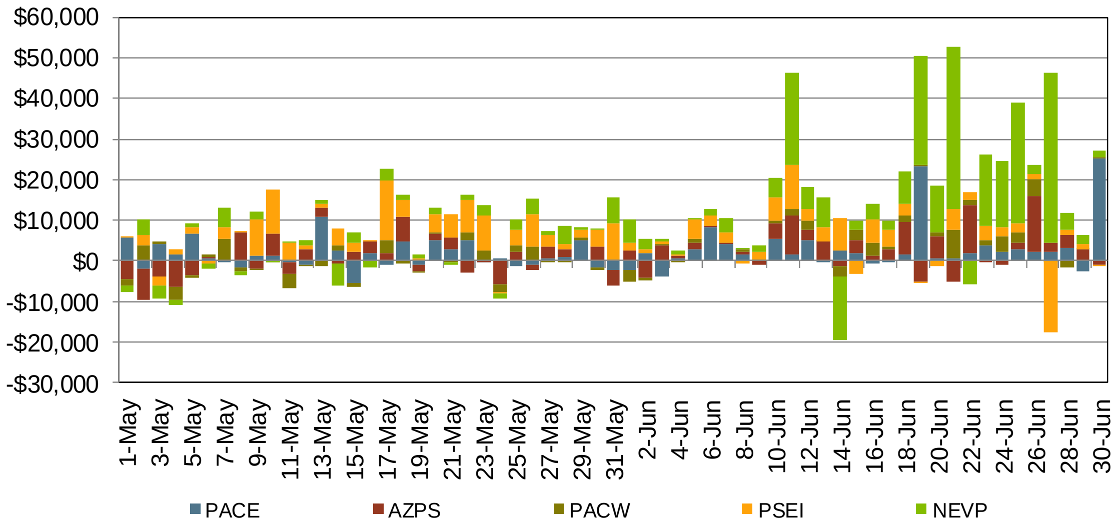


Figure 69 shows the flexible ramping forecast payment for PACE, PACW, NEVP, AZPS, and PSEI respectively. Total forecast payment in June increased to $0.46 million from $0.20 million in May.

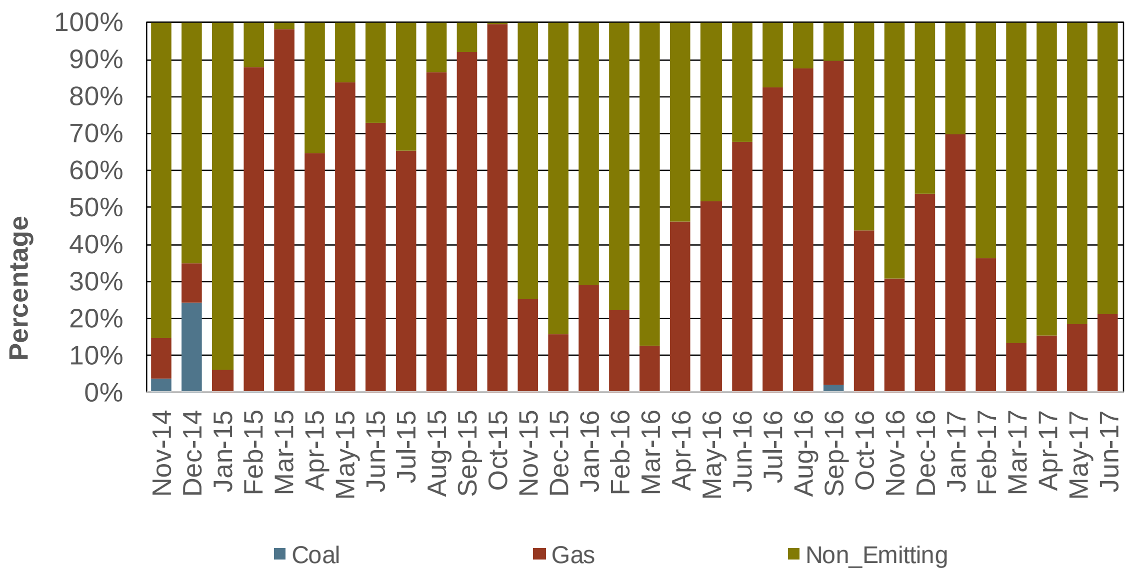
Figure 69: Flexible Ramping Forecast Payment



The ISO's Energy Imbalance Market Business Practice Manual[5] describes the methodology for determining whether an EIM participating resource is dispatched to support transfers to serve California load. The methodology ensures that the dispatch considers the combined energy and associated marginal greenhouse gas (GHG) compliance cost based on submitted bids[6].

In the first two months of EIM operations (November and December 2014), EIM startup issues related to processing GHG bid adder resulted in the dispatch of coal generation to support transfers into California. Once the adders were properly accounted for, beginning in June 2015, almost all of the EIM dispatches to support transfers into the ISO were from resources other than coal, as documented in Figure 70 and Table 8 below.

Figure 70: Percentage of EIM Transfer into ISO by Fuel Type



[5] See the Energy Imbalance Market Business Practice Manual for a description of the methodology for making this determination, which begins on page 42 -- http://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Energy Imbalance Market.
[6] A submitted bid June reflect that a resource is not available to support EIM transfers to California.

Table 8: EIM Transfer into ISO by Fuel Type

Month	Coal (%)	Gas (%)	Non-Emitting (%)	Total
Nov-14	3.66%	11.12%	85.22%	100%
Dec-14	24.18%	10.78%	65.04%	100%
Jan-15	0.07%	6.22%	93.71%	100%
Feb-15	0.32%	87.72%	11.96%	100%
Mar-15	0.48%	97.94%	1.58%	100%
Apr-15	0.12%	64.56%	35.32%	100%
May-15	0.00%	83.83%	16.17%	100%
Jun-15	0.00%	72.88%	27.12%	100%
Jul-15	0.00%	65.41%	34.59%	100%
Aug-15	0.02%	86.51%	13.48%	100%
Sep-15	0.00%	92.13%	7.87%	100%
Oct-15	0.10%	99.70%	0.20%	100%
Nov-15	0.00%	25.25%	74.75%	100%
Dec-15	0.00%	15.79%	84.21%	100%
Jan-16	0.00%	28.96%	71.04%	100%
Feb-16	0.00%	22.21%	77.79%	100%
Mar-16	0.00%	12.72%	87.28%	100%
Apr-16	0.00%	46.26%	53.74%	100%
May-16	0.00%	51.63%	48.37%	100%
Jun-16	0.00%	67.89%	32.11%	100%
Jul-16	0.00%	82.42%	17.58%	100%
Aug-16	0.00%	87.59%	12.41%	100%
Sep-16	1.98%	87.68%	10.34%	100%
Oct-16	0.00%	43.82%	56.18%	100%
Nov-16	0.00%	30.74%	69.26%	100%
Dec-16	0.00%	53.77%	46.23%	100%
Jan-17	0.00%	69.88%	30.12%	100%
Feb-17	0.00%	36.42%	63.58%	100%
Mar-17	0.00%	13.37%	86.63%	100%
Apr-17	0.00%	15.47%	84.53%	100%
May-17	0.00%	18.47%	81.53%	100%
Jun-17	0.00%	21.33%	78.67%	100%