Market Performance Report April 2017

June 27, 2017

ISO Market Quality and Renewable Integration

CAISO
250 Outcropping Way
Folsom, California 95630
(916) 351-4400

Executive Summary[1]

The market performance in April 2017 is summarized below.

CAISO area performance,

- Peak loads for ISO stayed below 30,000 MW in April.
- In the integrated forward market (IFM), PG&E DLAP prices were depressed in a few days due to transmission congestion. In the fifteen-minute market (FMM) and real-time market (RTD), PG&E DLAP prices were also depressed in a few days due to the same transmission congestion.
- Congestion rents for interties increased to $15.48 million from $13.01 million in March. Majority of the congestion rents in April accrued on MALIN500 (46 percent) intertie and NOB (51 percent) intertie.
- In the congestion revenue rights market, revenue adequacy rose to 90.16 percent from 81.50 percent in March. The nomogram 6410_CP5_NG contributed largely to the revenue shortfall. This nomogram was enforced in the energy market due to transmission outage.
- The monthly average ancillary service cost to load inched up to $0.78/MWh from $0.73/MWh in March. There were 16 ancillary service scarcity events this month.
- The cleared virtual supply moved closer to the cleared demand this month compared with March. The profits from convergence bidding fell to $0.59 million from $0.83 million in March.
- The bid cost recovery inched down to $6.86 million from $7.20 million in March.
- The real-time energy offset increased to $6.85 million from $4.22 million in March. The real-time congestion offset cost rose to $4.96 million from $0.78 million in March.
- The volume of exceptional dispatch dropped to 45,040 MWh from 49,309 MWh in March, largely driven by operating procedure number and constraint and planned transmission outage and constraint. The monthly average of total exceptional dispatch volume as a percentage of load declined to 0.27 percent in April from 0.29 percent in March.

[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 and RTD market, the prices in the AZPS area were depressed in a couple of days due to limited export, low load, renewable deviation, and generation outage.
- Bid cost recovery, real-time imbalance energy offset, and real-rime congestion offset costs for EIM entities (PACE, PACW, NEVP, AZPS, and PSEI) were $1.31 million, -$2.22 million and -$0.97 million respectively.

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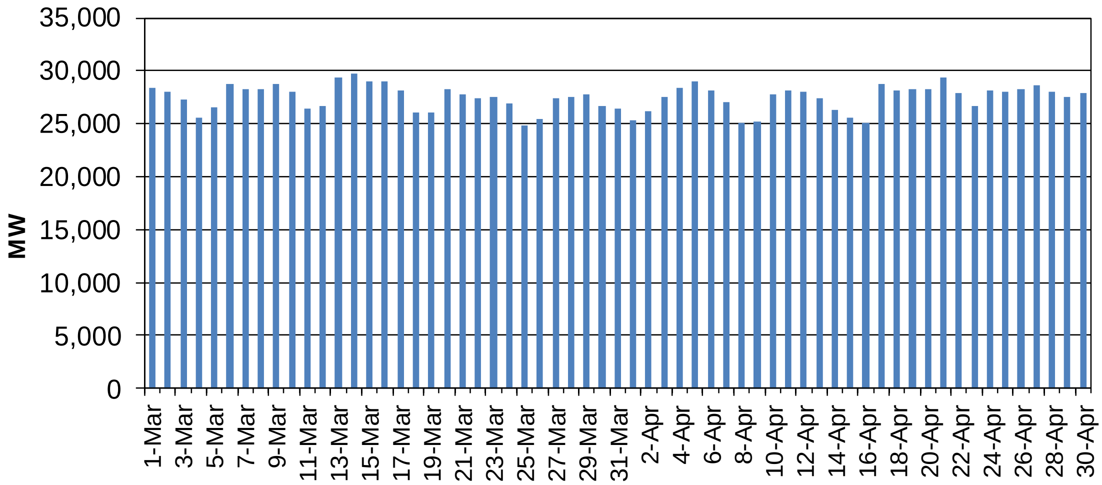
Market Characteristics

Loads

Peak loads for ISO stayed low in April.

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	91.66%	4,696,312	1,891,988
Apr-17	89.26%	4,586,987	1,539,030
May-17	95.37%	1,930,528	1,231,709

[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.

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

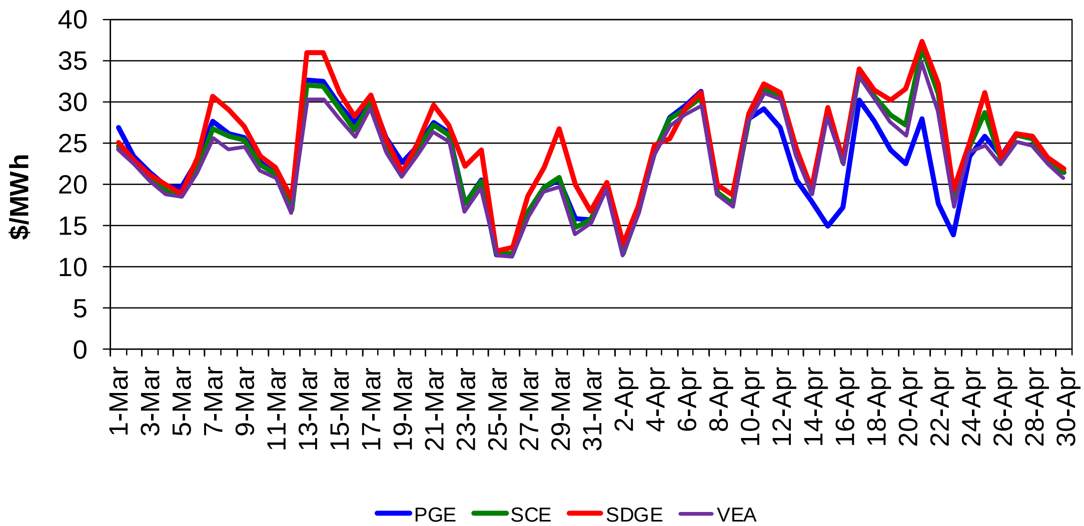


Table 2: Day-Ahead Transmission Constraints

DLAP	Date	Transmission Constraint
PG&E	April 12- 23	6410_CP5_NG
SDG&E	April 20	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.

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

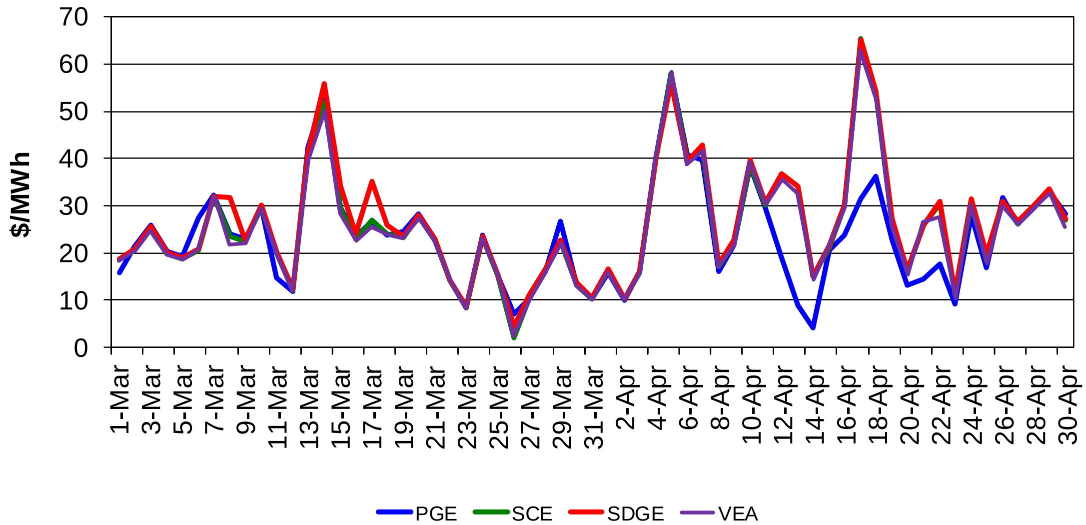
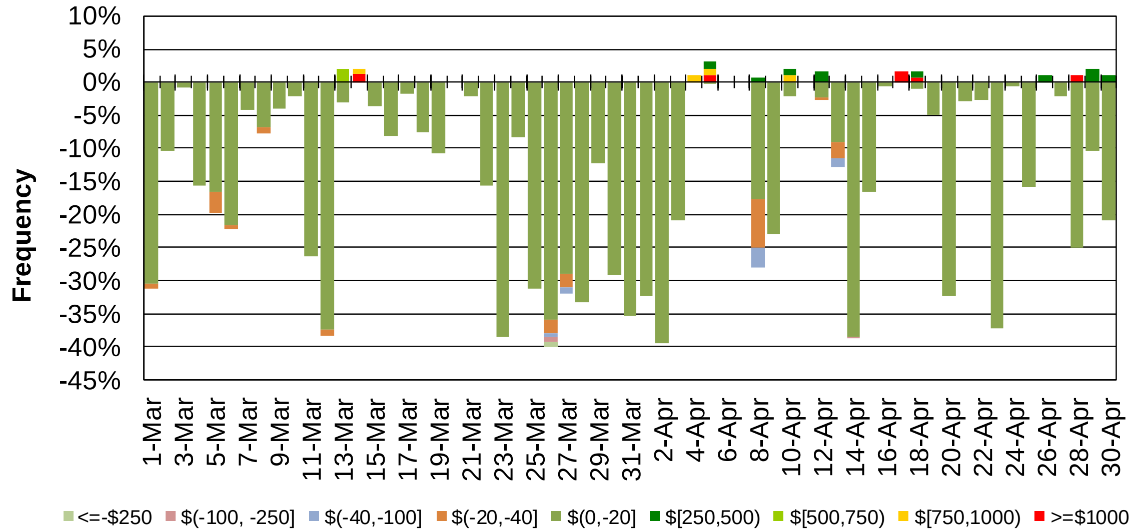


Table 3: FMM Transmission Constraints

DLAP	Date	Transmission Constraint
PG&E	April 12-14, 16-22	6410_CP5_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 edged up to 0.56 percent in April from 0.13 percent in March. The cumulative frequency of negative prices decreased to 12.44 percent in April from 15.96 percent in March.

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)

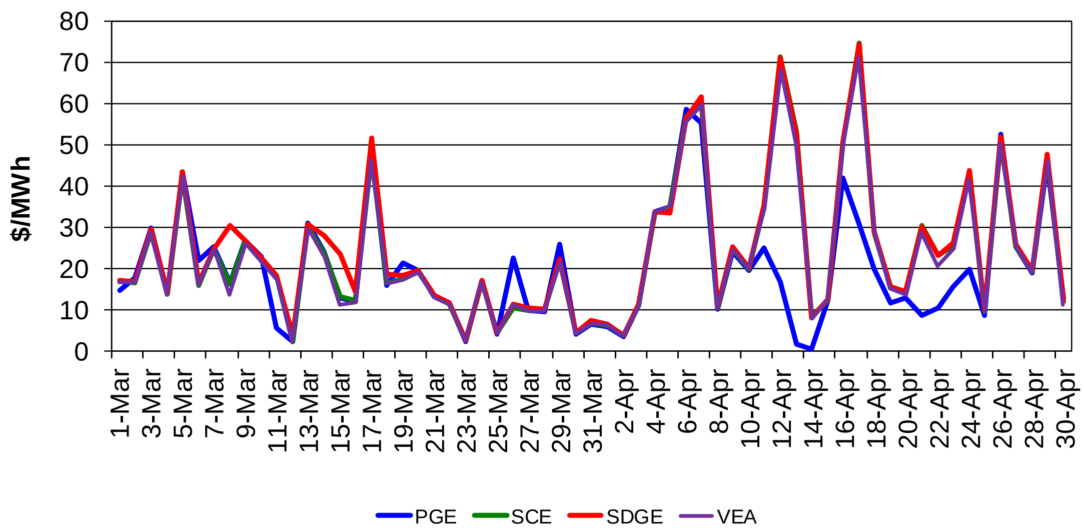
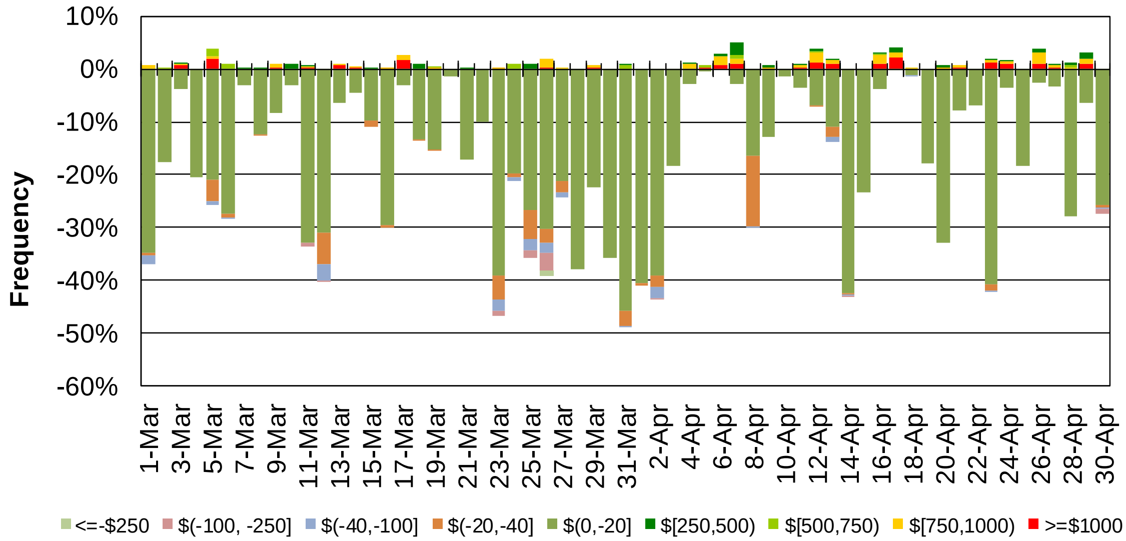


Table 4: RTD Transmission Constraints

DLAP	Date	Transmission Constraint
PG&E	April 11-14, 16-24	6410_CP5_NG

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 increased to 1.33 percent in April from 0.76 percent in March. The cumulative frequency of negative prices fell to 14.86 percent in April from 21.19 percent in March.

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



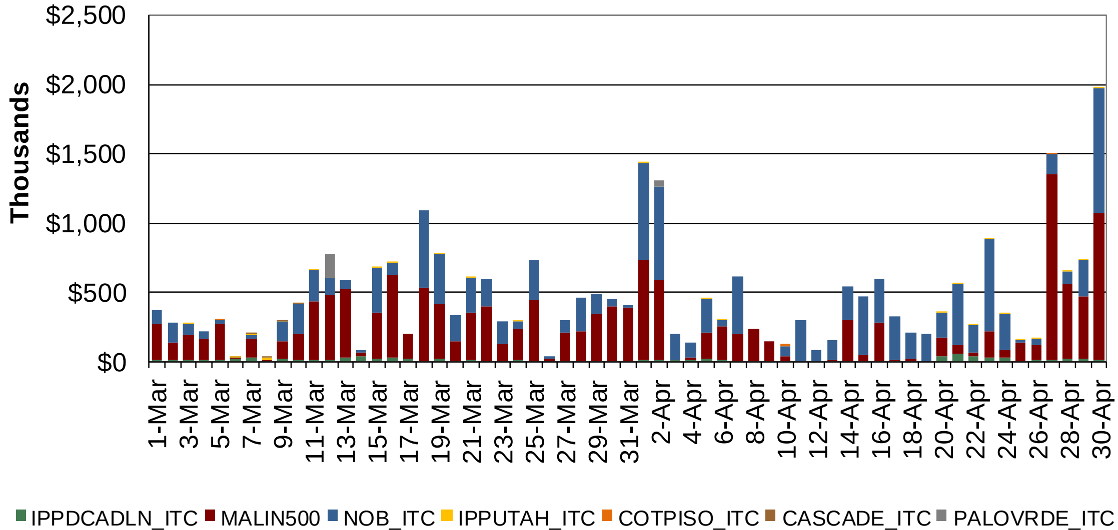
Congestion

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 April rose to $15.48 million from $13.01 million in March. Majority of the congestion rents in April accrued on MALIN500 (46 percent) intertie and NOB (51 percent) intertie.

The congestion rent on MALIN500 decreased to $7.13 million in April from $8.16 million in March. MALIN500 was derated this month due to various outages including the outage of Malin-Round Mountain #1 500 kV line and Malin-Round Mountain #2 500kV line. The congestion rent on NOB increased to $7.87 million in April from $4.26 million in March.

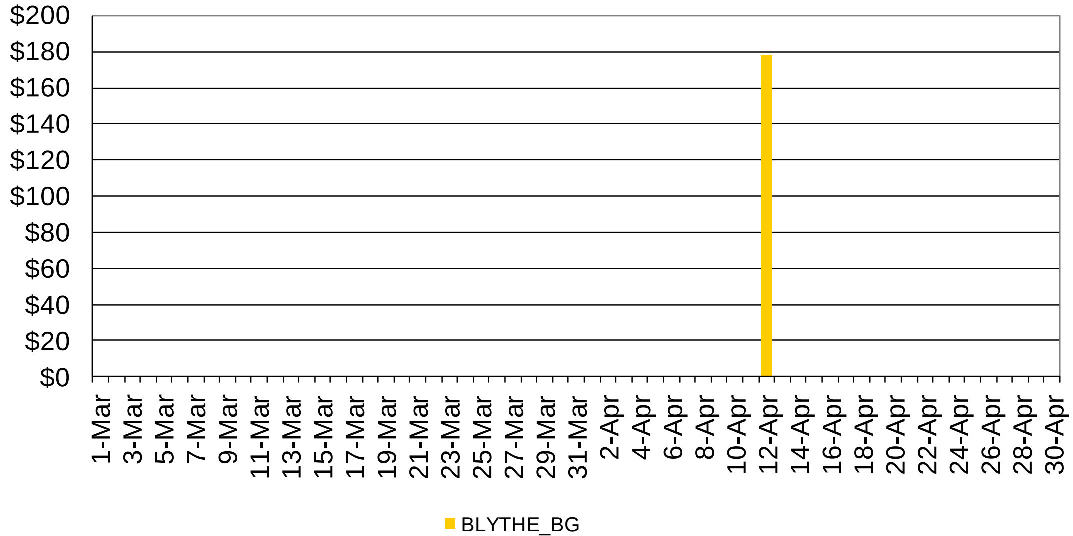
Figure 7: IFM Congestion Rents by Interties (Import)



Congestion Rents on Branch Groups

Figure 8 illustrates the IFM congestion rents on selected branch groups. Total congestion rents for branch groups edged up to $178 in April from $0 in March.

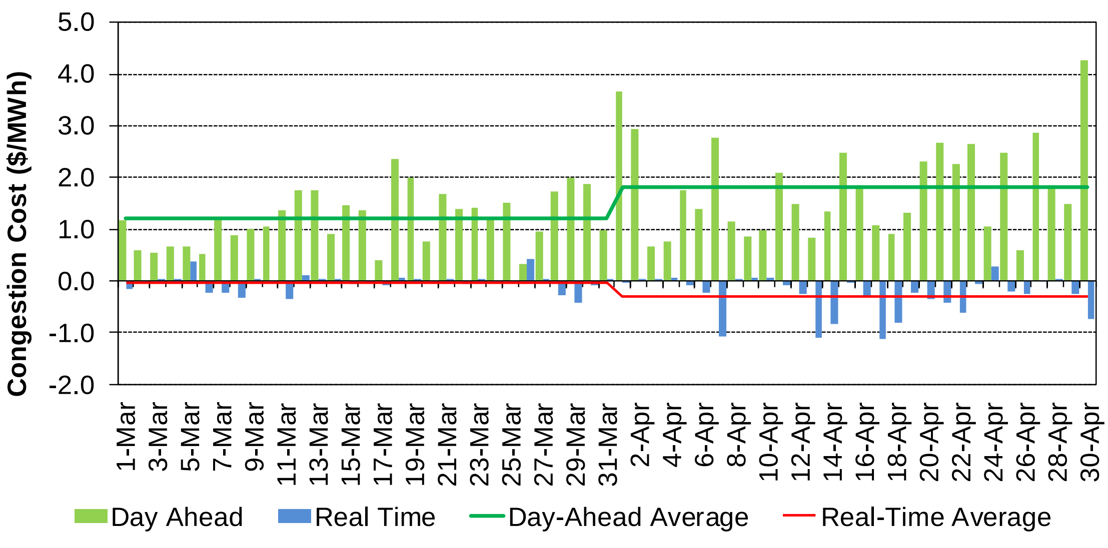
Figure 8: IFM Congestion Rents by Branch Group



Average Congestion Cost per Load Served

This metric quantifies the average congestion cost for serving one megawatt of load in the ISO system. Figure 9 shows the daily and monthly averages for the day-ahead and real-time markets respectively.

Figure 9: Average Congestion Cost per Megawatt of Served Load

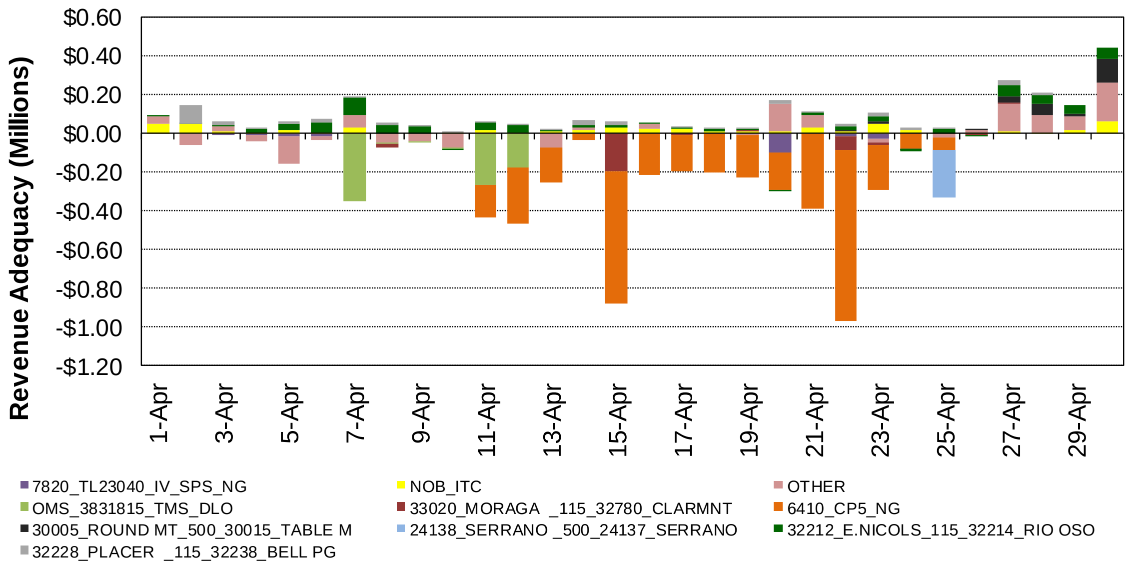


The average congestion cost per MWh of load served in the integrated forward market increased to $1.81/MWh in April from $1.20/MWh in March. The average congestion cost per load served in the real-time market went to -$0.30/MWh in April from -$0.05/MWh in March.

Congestion Revenue Rights

Figure 10 illustrates the daily revenue adequacy for congestion revenue rights (CRRs) broken out by transmission element. The average CRR revenue deficit in April dropped to $110,422 from the average revenue deficit of $151,981 in March.

Figure 10: Daily Revenue Adequacy of Congestion Revenue Rights

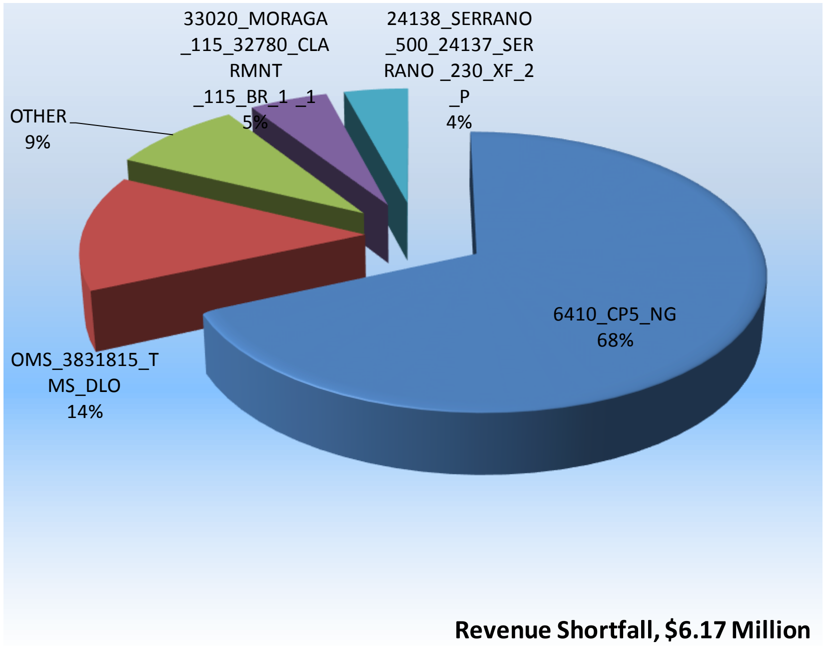


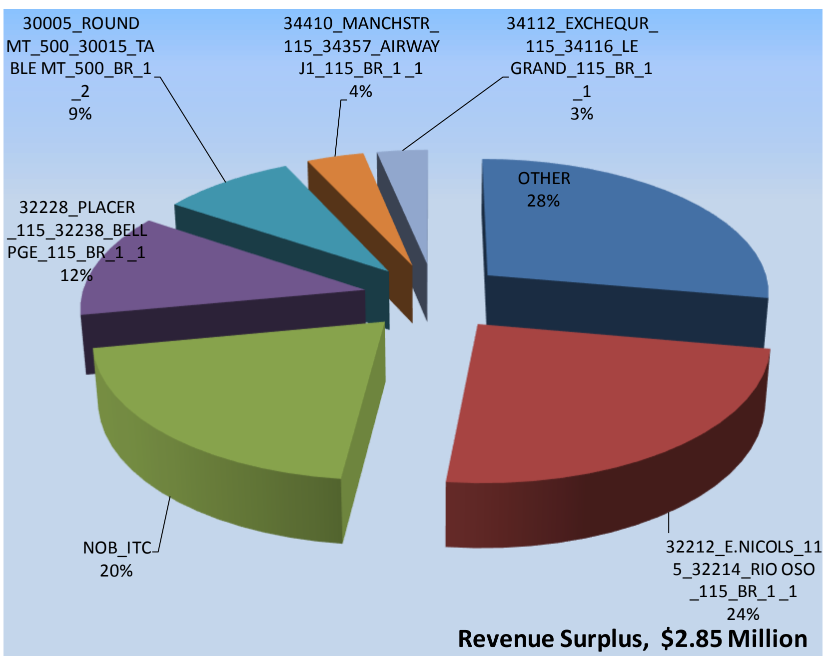
Overall, April experienced a CRR revenue deficit. Revenue shortfalls were observed in 20 days this month. The main reasons are shown below.

- The nomogram 6410_CP5_NG was binding in 15 days of this month, resulting in revenue shortfall of $4.02 million. This nomogram was enforced due to transmission outage.
- The nomogram OMS_3831815_TMS_DLO was binding in six days of this month, resulting in revenue shortfall of $0.81 million. This nomogram was enforced for transmission outage.

The shares of the revenue surplus and deficit accruing on various congested transmission elements for the reporting period are shown in Figure 11 and the monthly summary for CRR revenue adequacy is provided in Table 5.

Figure 11: 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 90.16 percent in April. Out of the total congestion rents, 4.25 percent was used to cover the cost of existing right exemptions. Net total congestion revenues in April were in deficit by $3.31 million, compared to the deficit of $4.71 million in March. The auction revenues credited to the balancing account for April were $5.77 million. As a result, the balancing account for April had a surplus of approximately $4.34 million, which will be allocated to measured demand.

Table 5: CRR Revenue Adequacy Statistics

IFM Congestion Rents	$31,689,081.21
Existing Right Exemptions	-$1,347,885.57
Available Congestion Revenues	$30,341,195.63
CRR Payments	$33,653,858.93
CRR Revenue Adequacy	-$3,312,663.29
Revenue Adequacy Ratio	90.16%
Annual Auction Revenues	$2,829,828.58
Monthly Auction Revenues	$2,939,835.95
CRR Settlement Rule	$1,886,598.03
Allocation to Measured Demand	$4,343,599.27

Ancillary Services

IFM (Day-Ahead) Average Price

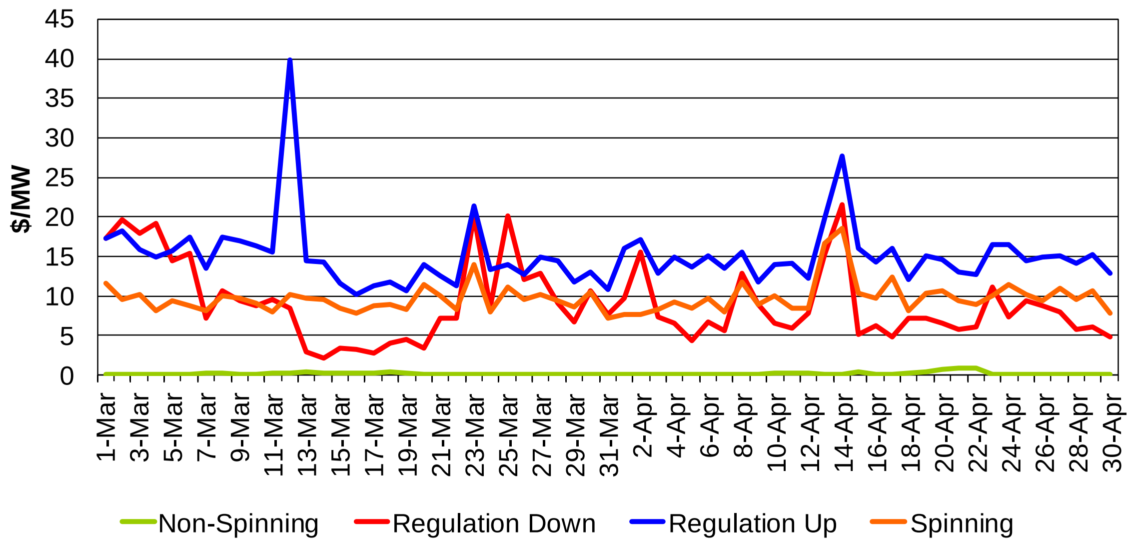
Table 6 shows the monthly IFM average ancillary service procurements and the monthly average prices. In April the monthly average procurement decreased for regulation down, spinning, and non-spinning reserve.

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
Apr-17	383	358	705	705	$15.07	$8.14	$10.04	$0.20
Mar-17	311	369	712	713	$15.06	$9.90	$9.42	$0.15
Percent Change	23.06%	-3.06%	-1.07%	-1.19%	0.05%	-17.72%	6.58%	31.22%

The monthly average prices increased for regulation up, spinning and non-spinning reserve in April. Figure 12 shows the daily IFM average ancillary service prices. Regulation up, regulation down and spinning reserve prices were relatively high on April 13-14 due to high opportunity cost of energy.

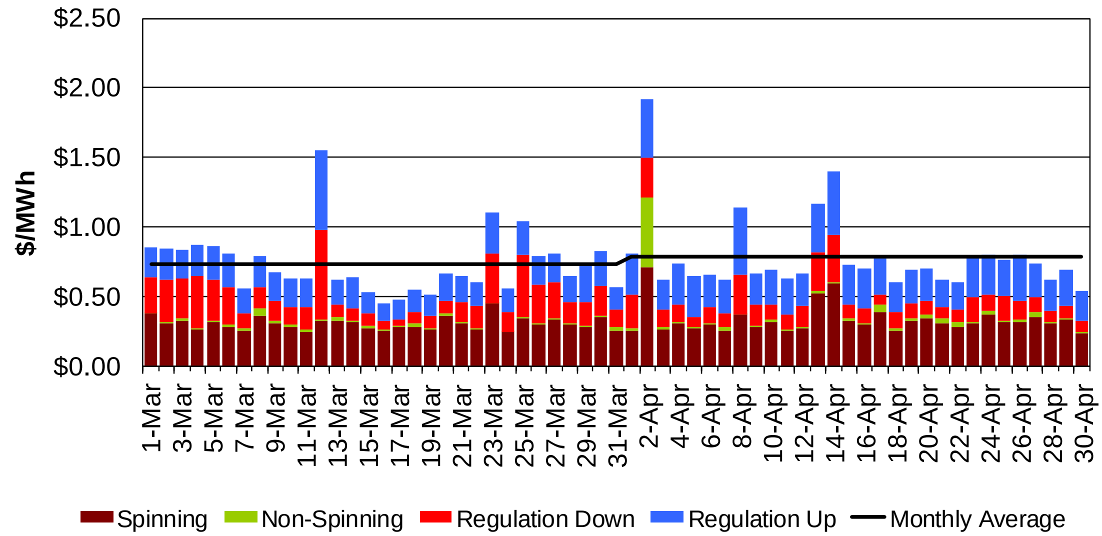
Figure 12: IFM (Day-Ahead) Ancillary Service Average Price



Ancillary Service Cost to Load

The monthly average cost to load inched up to $0.78/MWh in April from $0.73/MWh in March. The average cost was high on April 2, driven by high regulation up, spinning and non-spinning prices in real-time market.

Figure 13: 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 April 2, 2017, a regulation down scarcity occurred in the 15-minute market run for hour ending 10, intervals 1-4 in the SP26 expanded system region. The procurement shortfall was 3.18 MW or 2% of the target procurement quantity in intervals 1-3 and 2.7 MW or 1.7% of the target procurement quantity in interval 4. On April 3, 2017, a regulation up scarcity occurred in the 15-minute market run for hour ending 11, interval 1, hour ending 13, interval 1 and hour ending 15, interval 1 in the ISO expanded system region where the procurement shortfall was between 1.4 to 4.6 MW or 0.4% to 1.3% of the target procurement quantity in these intervals.

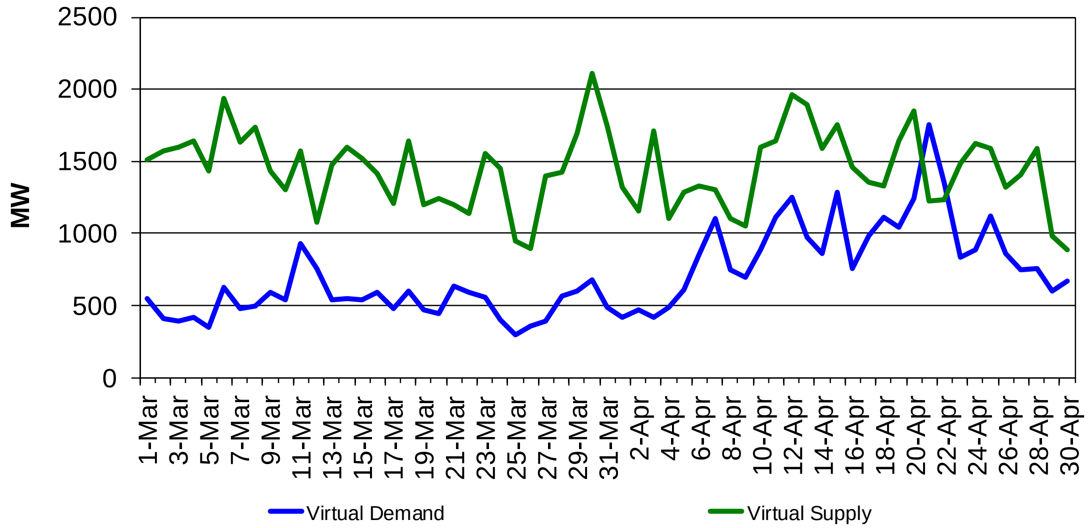
On April 4, 2017, a regulation up scarcity occurred in the 15-minute market run for hour ending 10, intervals 3-4 in the CAISO expanded system region. The procurement shortfall was 0.62 MW or 0.2% of the target procurement quantity in hour ending 10. On the same day, a regulation up scarcity occurred in the 15-minute market run for hour ending 15, interval 4 and hour ending 20, interval 3 in the SP26 expanded system region. The procurement shortfall was 13.62 MW or 11% of the target procurement quantity in hour ending 15 and 55 MW or 45% of the target procurement quantity in hour ending 20.

On April 5, 2017, a regulation up scarcity occurred in the 15-minute market run for hour ending 20, interval 2 in the CAISO expanded system region where the procurement shortfall was 0.3 MW or 0.1% of the target procurement quantity. On April 9, 2017, a regulation down scarcity occurred in the 15-minute market run for hour ending 6, intervals 1-4 in the SP26 region where the procurement shortfall was 3.05 MW or 30% of the target procurement quantity in each interval.

Convergence Bidding

Figure 14 below shows the daily average volume of cleared virtual bids in IFM for virtual supply and virtual demand. The cleared virtual supply moved closer to the cleared demand this month compared with March.

Figure 14: Cleared Virtual Bids



Convergence bidding tends to cause the day-ahead market and real-time market prices to move closer together, or “converge”. Figure 15 shows the energy prices (namely the energy component of the LMP) in IFM, hour ahead scheduling process (HASP), FMM, and RTD.

Figure 15: IFM, HASP, FMM, and RTD Prices

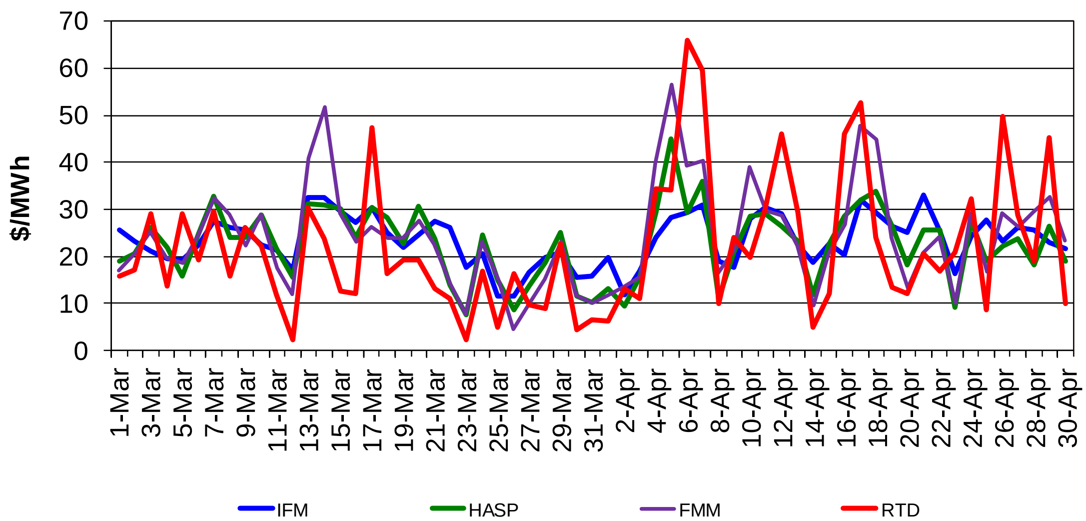
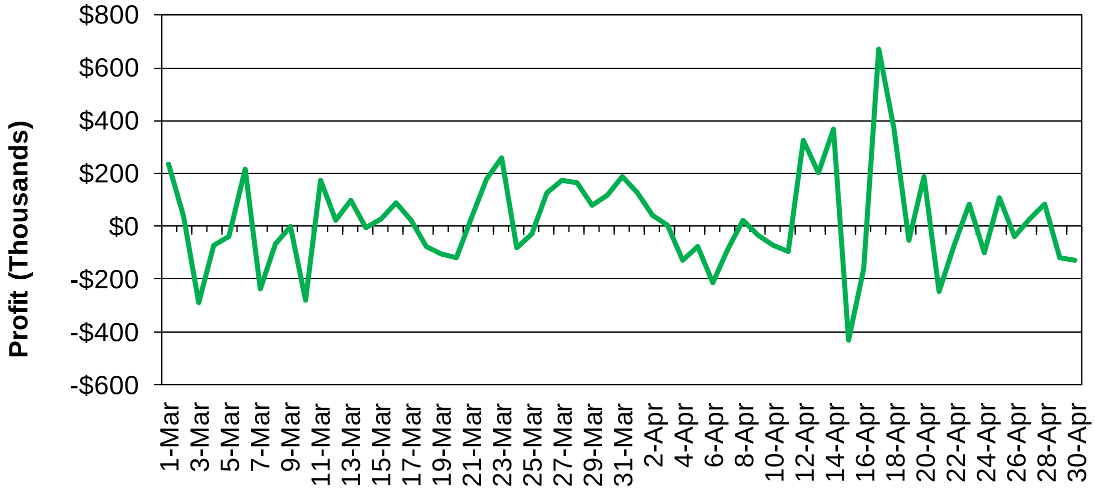


Figure 16 shows the profits that convergence bidders receive from convergence bidding. The total profits from convergence bidding fell to $0.59 million in April from $0.83 million in March.

Figure 16: Convergence Bidding Profits



Renewable Generation Curtailment

Figure 17 below shows the monthly wind and solar VERs (variable energy resource) curtailment due to system wide condition or local congestion in RTD. Figure 18 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 17 and Figure 18 below indicate, the renewable curtailment continued to increase in April. The majority of the curtailments was economic.

Figure 17: Renewable Curtailment by Reason

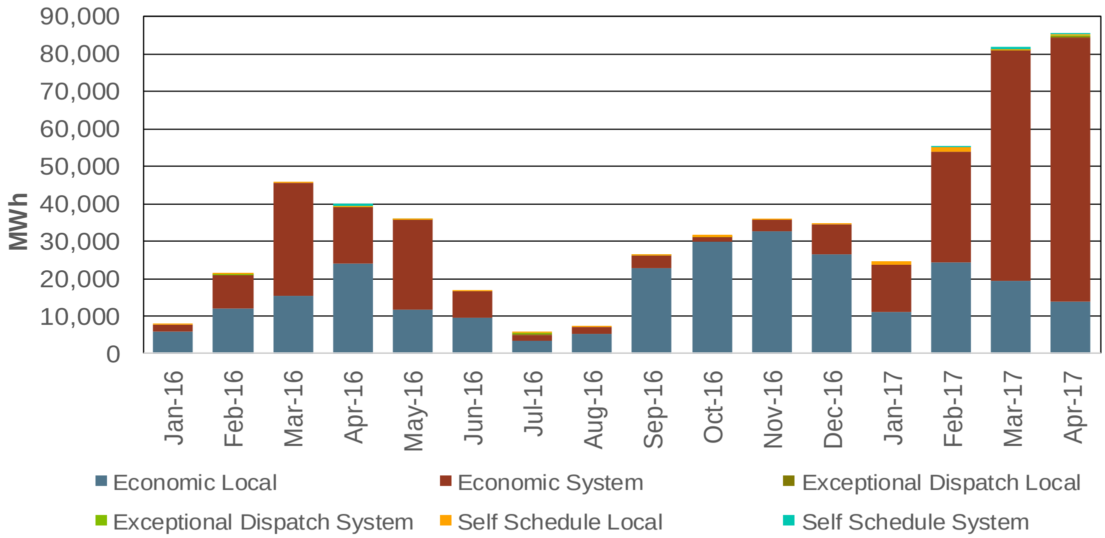
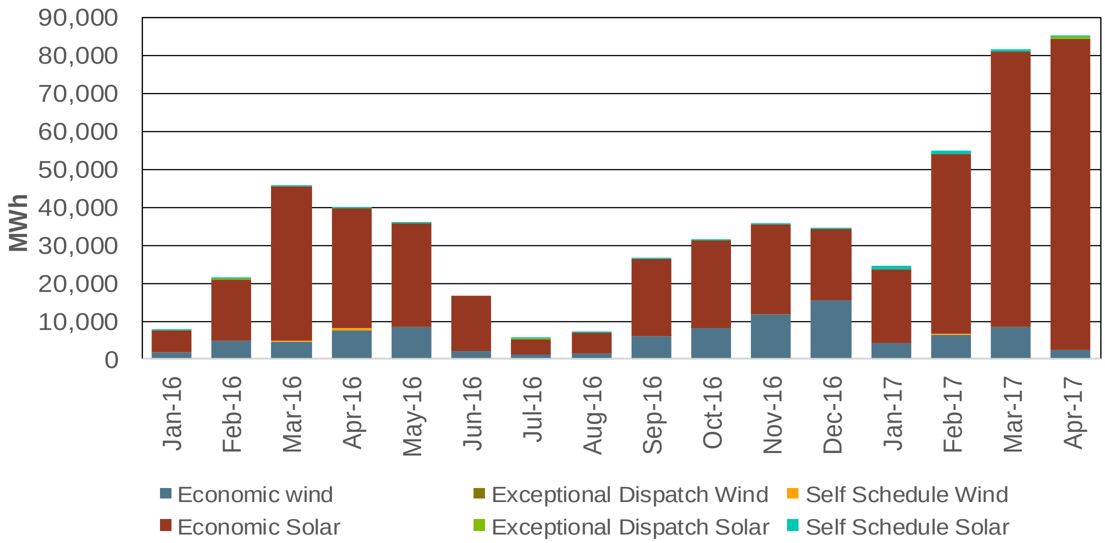


Figure 18: Renewable Curtailment by Resource Type



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 19 shows the flexible ramping up and down uncertainty payments. Flexible ramping up uncertainty payment decreased to $1.43 million in April from $1.66 Million in March. Flexible ramping down uncertainty payment declined to $0.24 million in April from $0.31 Million in March.

Figure 19: Flexible Ramping Up/down Uncertainty Payment

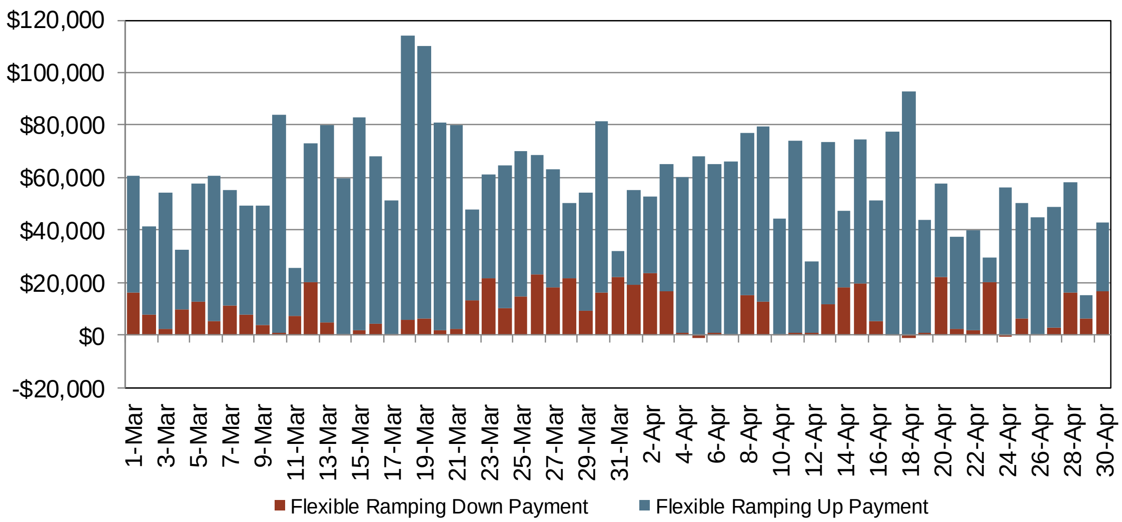
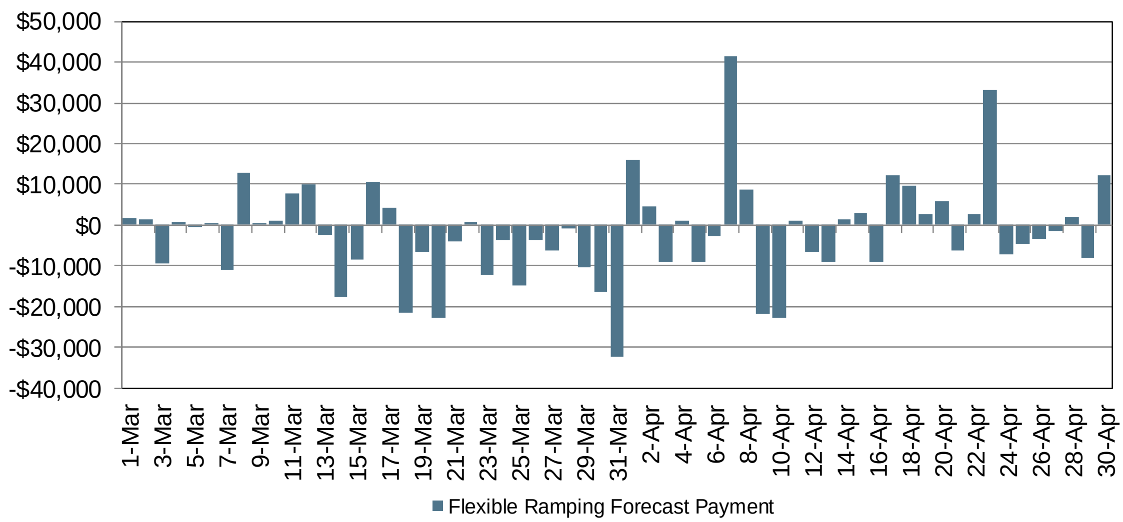


Figure 20 shows the flexible ramping forecast payment. Flexible ramping forecast payment increased to $0.04 million this month from -$0.15 in March.

Figure 20: Flexible Ramping Forecast Payment



Indirect Market Performance Metrics

Bid Cost Recovery

Figure 21 shows the daily uplift costs due to exceptional dispatch payments. The monthly uplift costs in April rose to $258,134 from $81,581 in March. The cost was relatively high on April 4-8 driven by the exceptional dispatch issued for planned transmission outage and constraint and the conditions beyond the control of the CAISO.

Figure 21: Exceptional Dispatch Uplift Costs

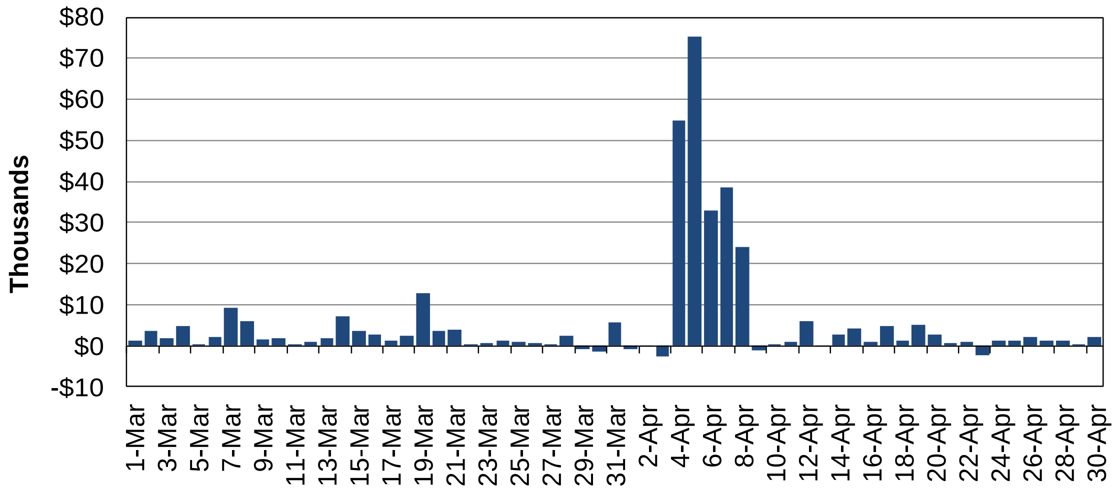


Figure 22 shows the allocation of bid cost recovery payment in the IFM, residual unit commitment (RUC) and RTM markets. The total bid cost recovery for April inched down to $6.86 million from $7.20 million in March. Out of the total monthly bid cost recovery payment for the three markets in April, the IFM market contributed 28 percent, RTM contributed 49 percent, and RUC contributed 23 percent of the total bid cost recovery payment.

Figure 22: Bid Cost Recovery Allocation

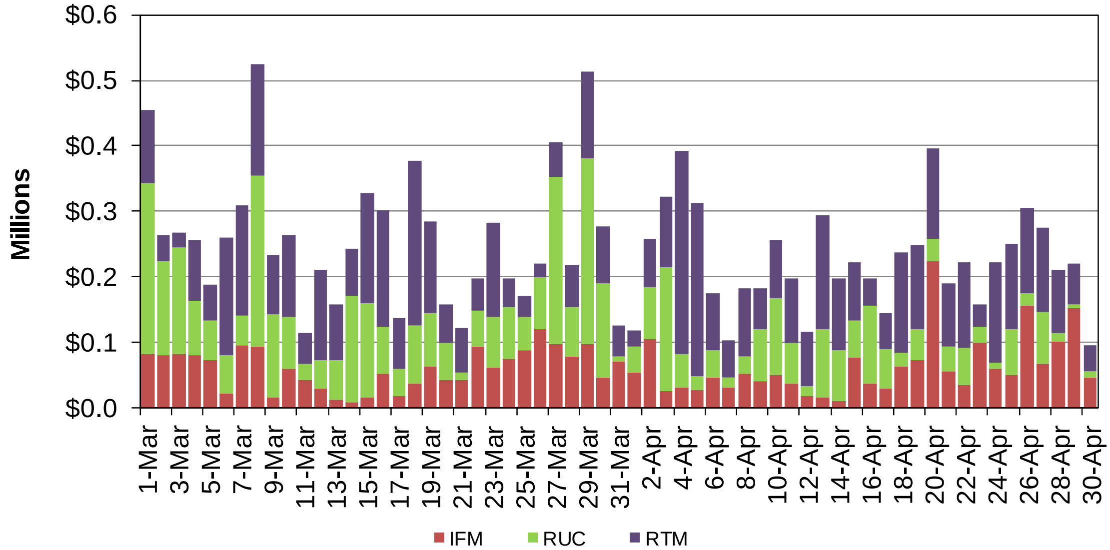


Figure 23 and Figure 24 show the daily and monthly BCR cost by local capacity requirement area (LCR) respectively.

Figure 23: Bid Cost Recovery Allocation by LCR

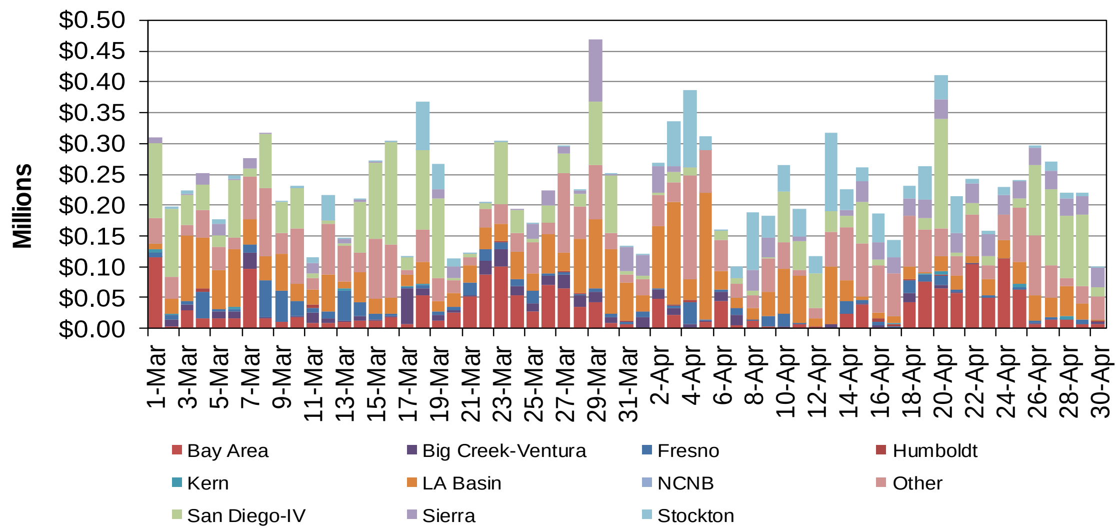


Figure 24: Monthly Bid Cost Recovery Allocation by LCR

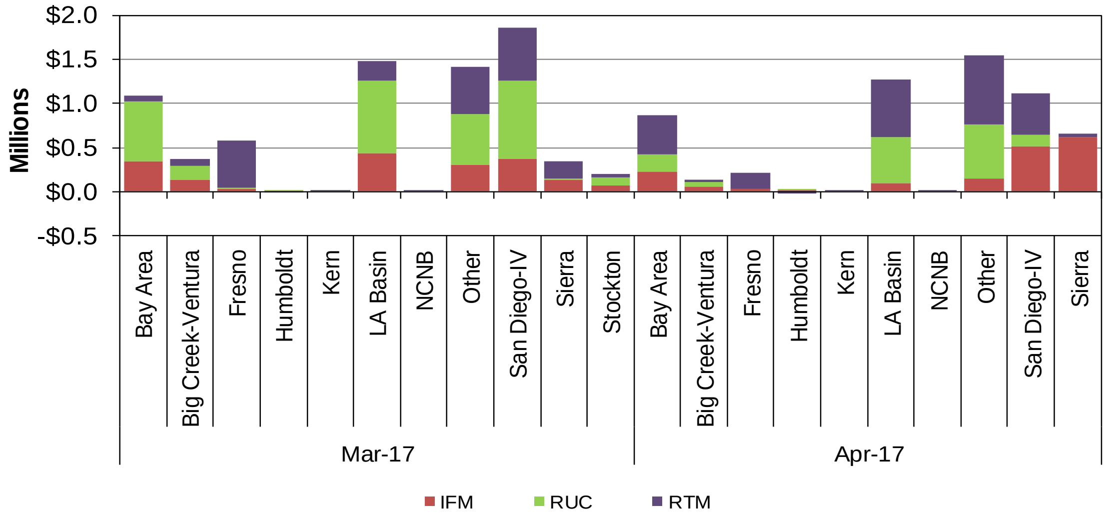


Figure 25 and Figure 26 show the daily and monthly BCR cost by utility distribution company (UDC) respectively.

Figure 25: Bid Cost Recovery Allocation by UDC

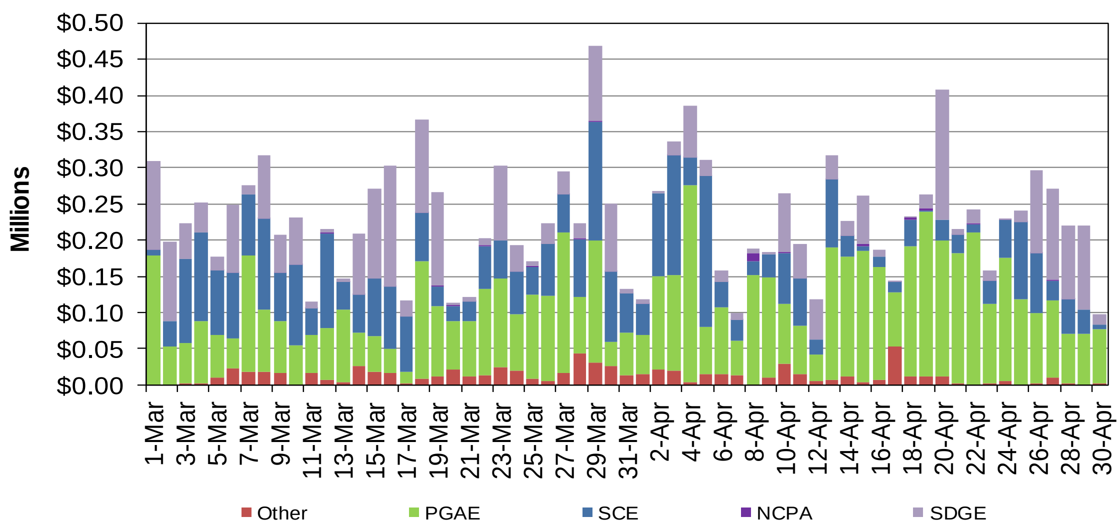


Figure 26: Monthly Bid Cost Recovery Allocation by UDC

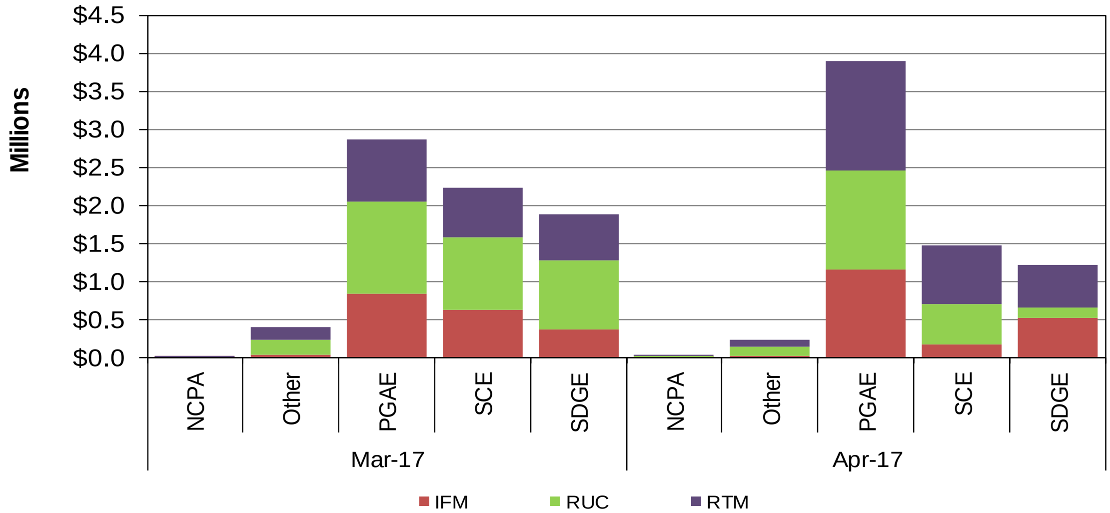


Figure 27 shows the cost related to BCR by cost type in RUC, which in April was mainly driven by minimum load cost (MLC) and start-up cost (SUC).

Figure 27: Cost in RUC

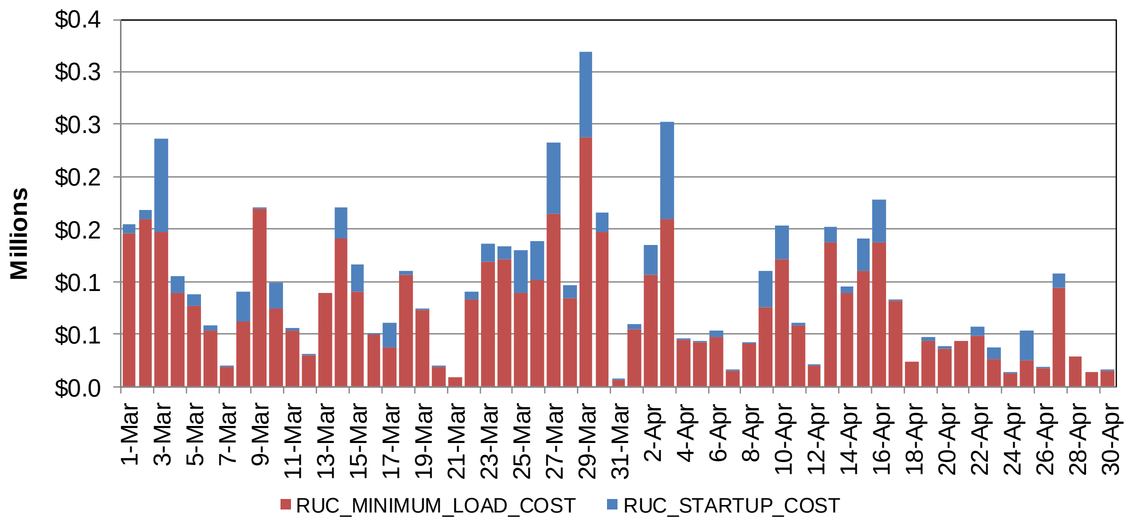


Figure 28 and Figure 29 show the daily and monthly cost related to BCR by type and LCR in RUC respectively.

Figure 28: Cost in RUC by LCR

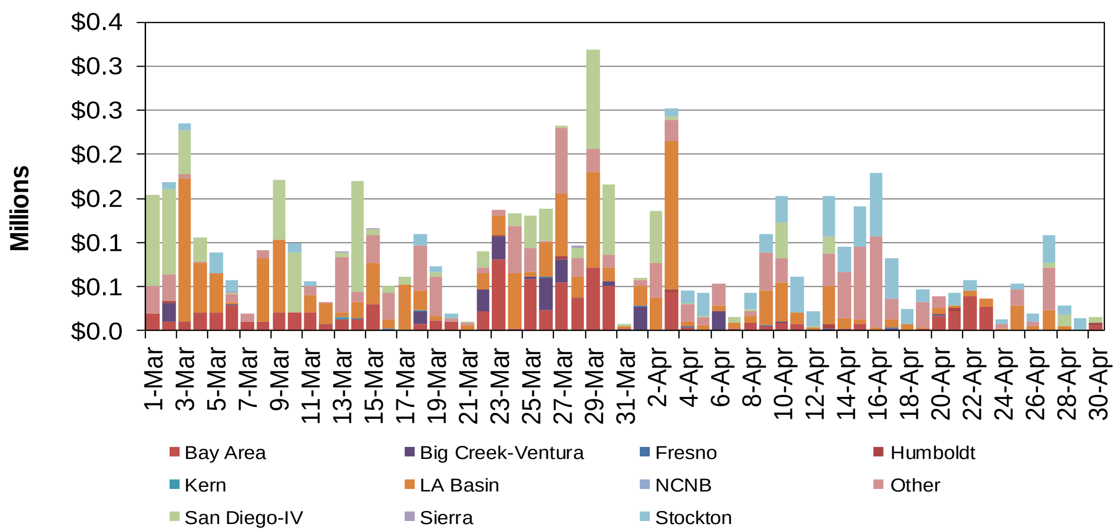


Figure 29: Monthly Cost in RUC by LCR

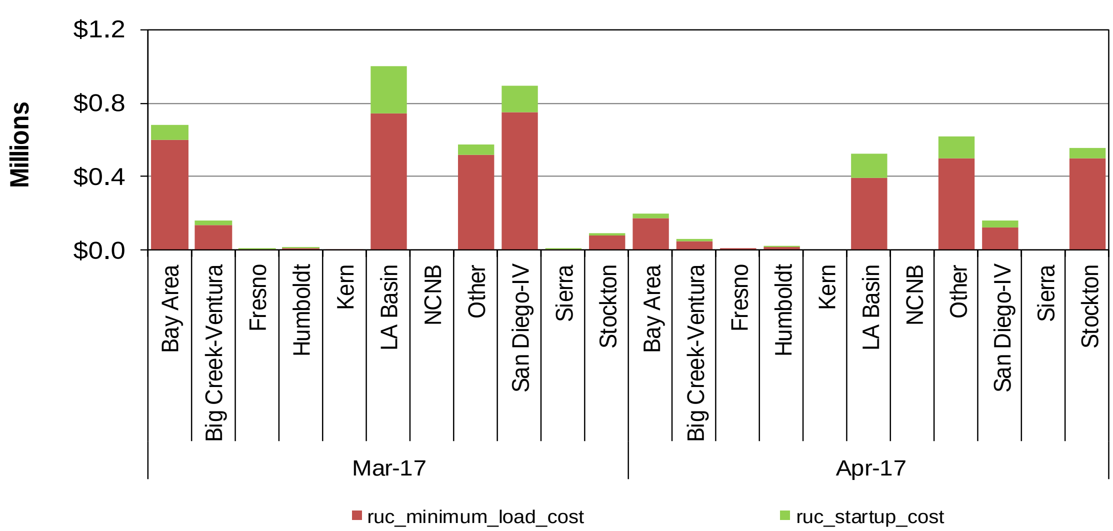


Figure 30 and Figure 31 show the daily and monthly cost related to BCR by type and UDC in RUC respectively.

Figure 30: Cost in RUC by UDC

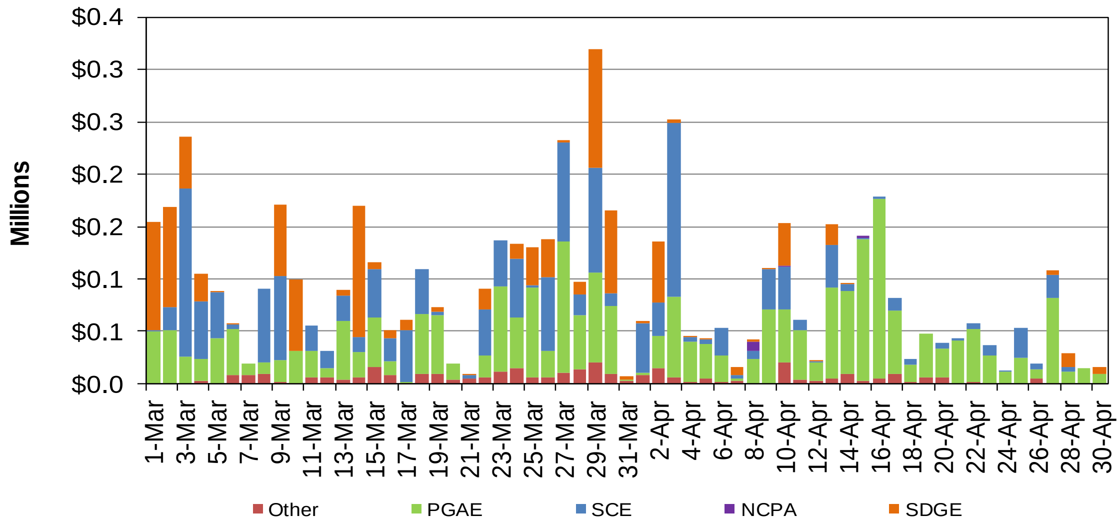


Figure 31: Monthly Cost in RUC by UDC

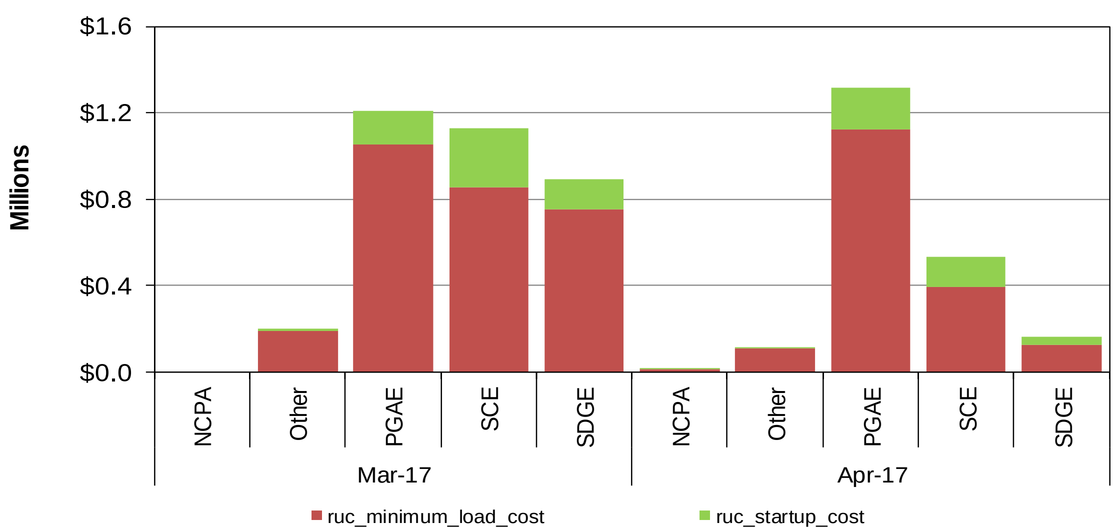


Figure 32 shows the cost related to BCR in real time by cost type. Minimum load cost and energy cost contributed mostly to the real time cost in April.

Figure 32: Cost in Real Time

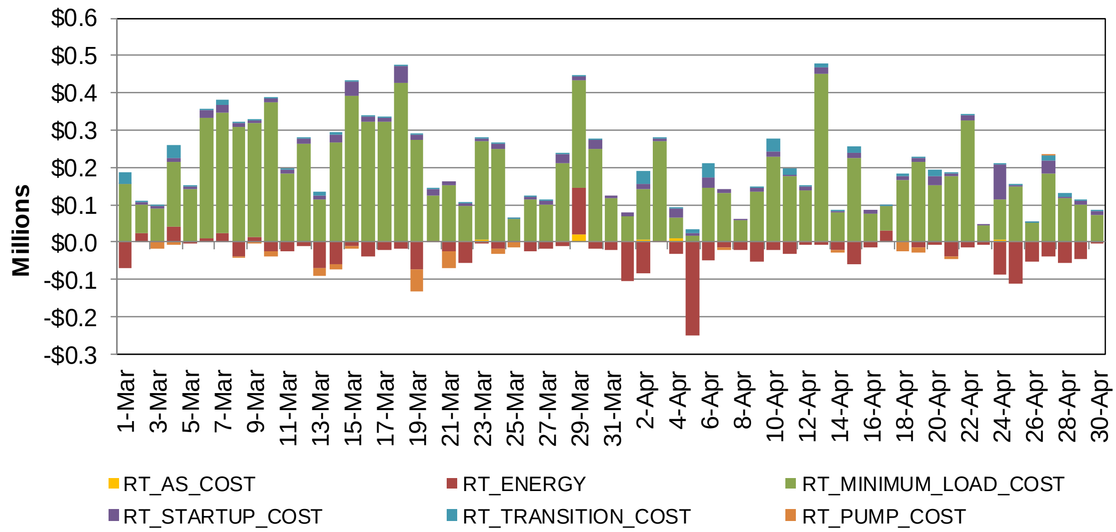


Figure 33 and Figure 34 show the daily and monthly cost related to BCR by type and LCR in real time respectively.

Figure 33: Cost in Real Time by LCR

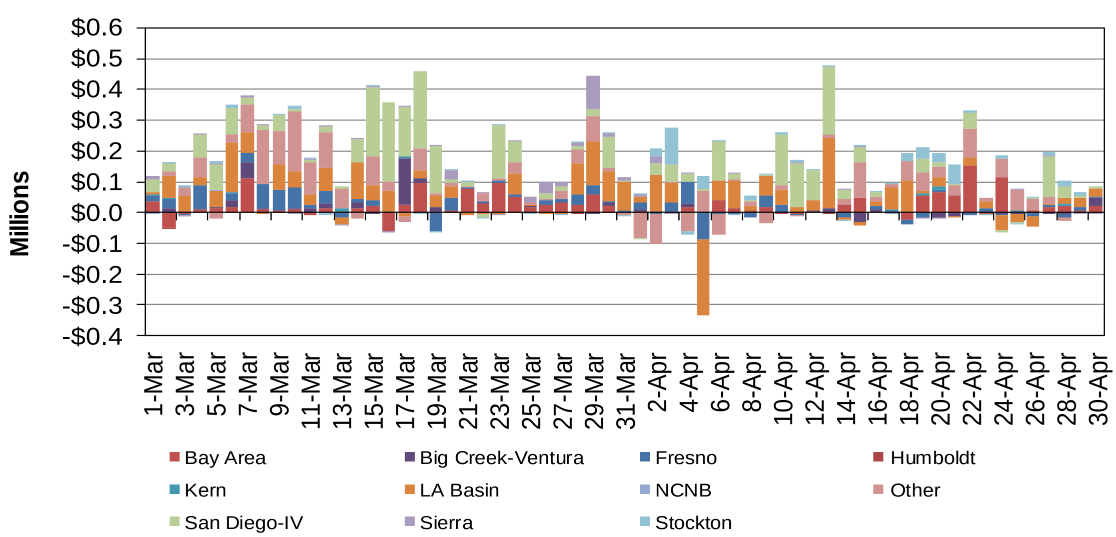


Figure 34: Monthly Cost in Real Time by LCR

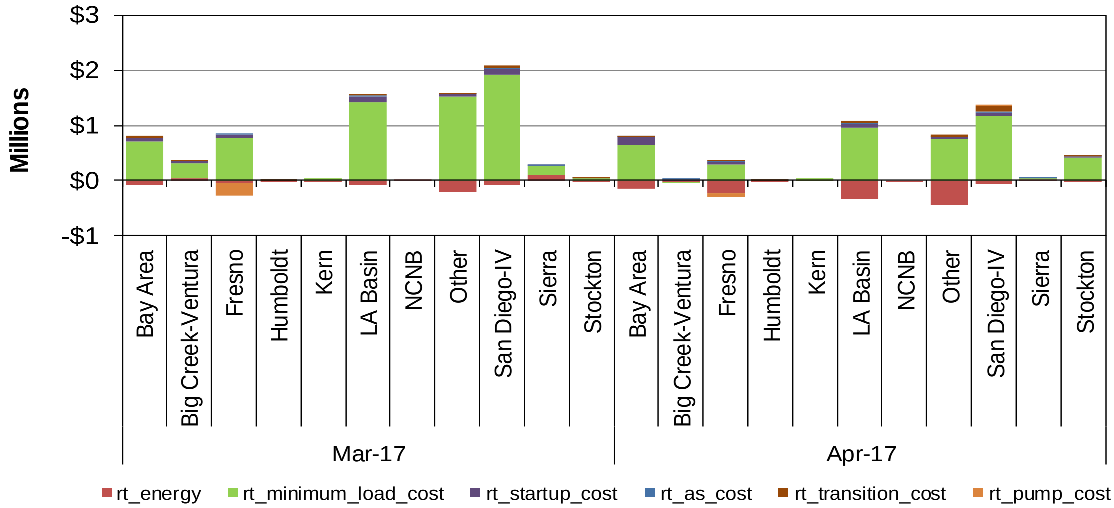


Figure 35 and Figure 36 show the daily and monthly cost related to BCR by type and UDC in Real Time respectively.

Figure 35: Cost in Real Time by UDC

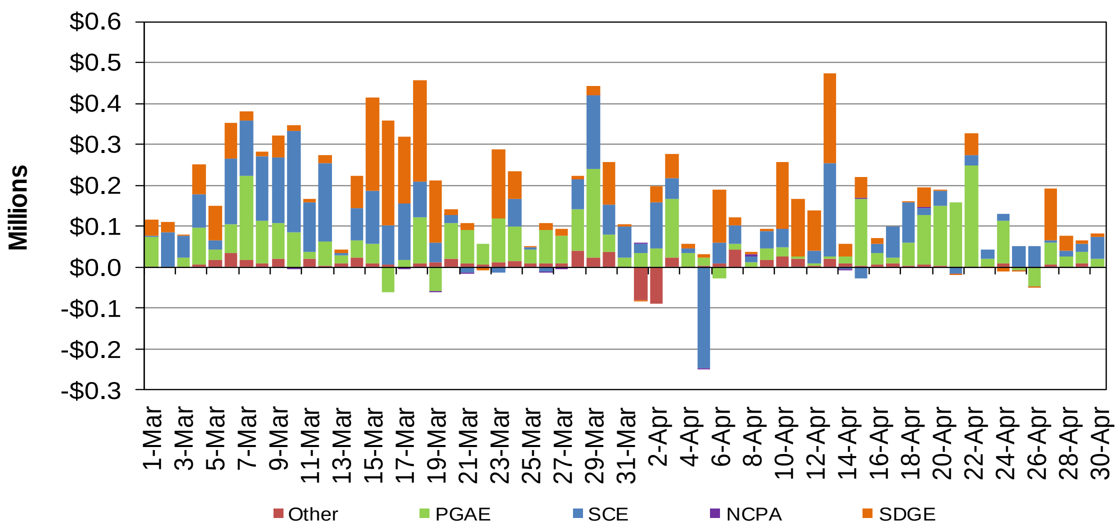


Figure 36: Monthly Cost in Real Time by UDC

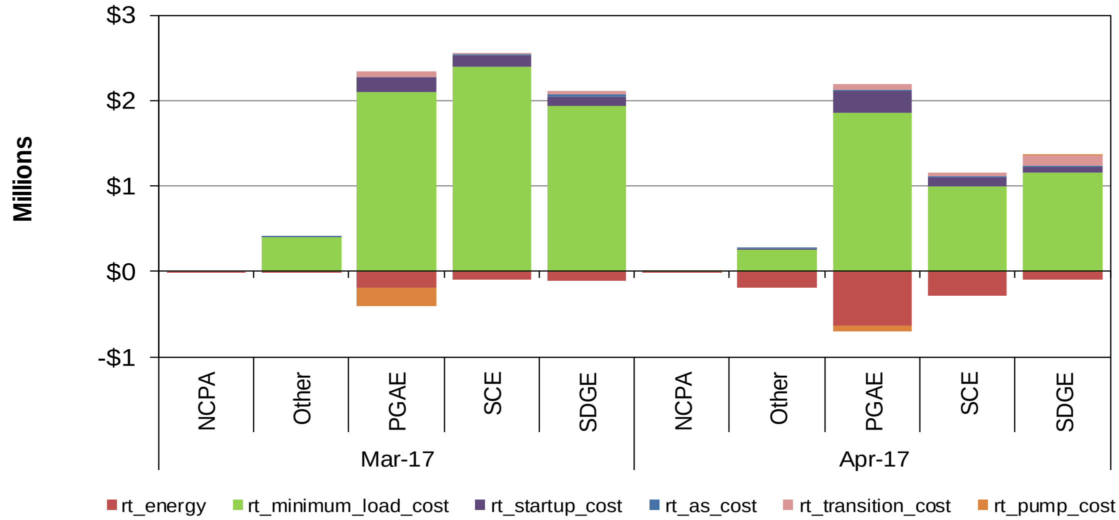


Figure 37 shows the cost related to BCR in IFM by cost type. Minimum Load cost and energy cost contributed largely to the cost in IFM in April.

Figure 37: Cost in IFM

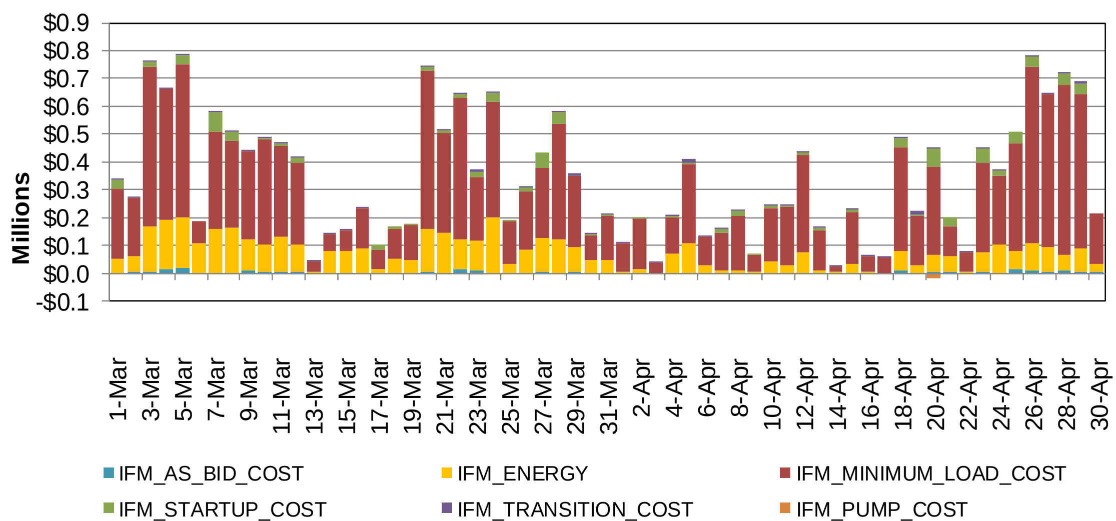


Figure 38 and Figure 39 show the daily and monthly cost related to BCR by type and location in IFM respectively.

Figure 38: Cost in IFM by LCR

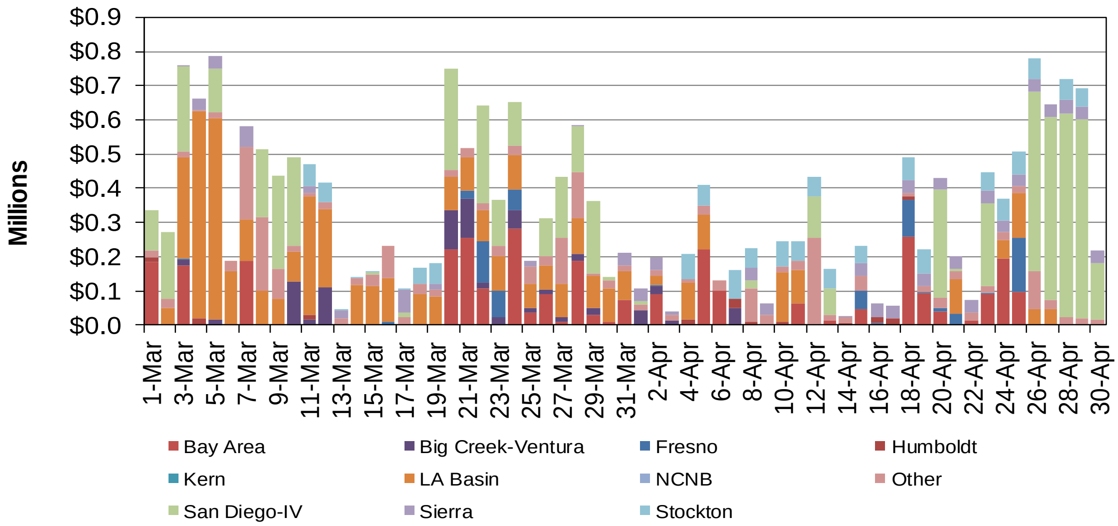


Figure 39: Monthly Cost in IFM by LCR

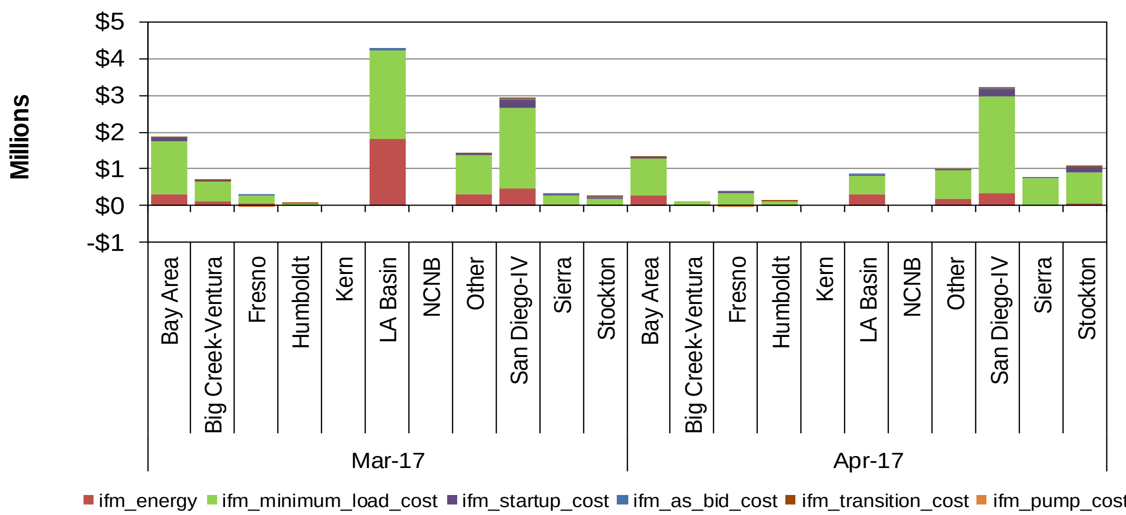


Figure 40 and Figure 41 show the daily and monthly cost related to BCR by type and UDC in IFM respectively.

Figure 40: Cost in IFM by UDC

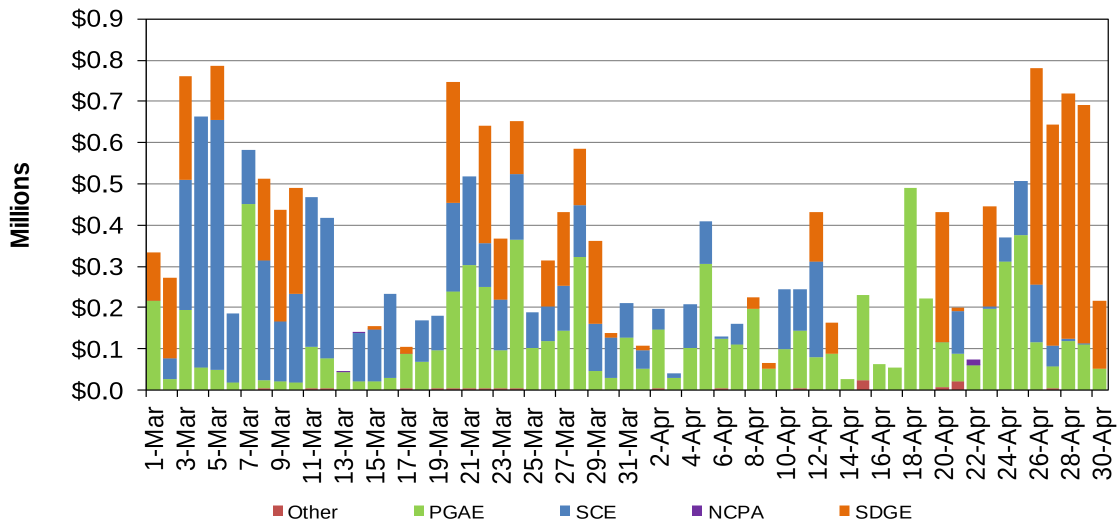
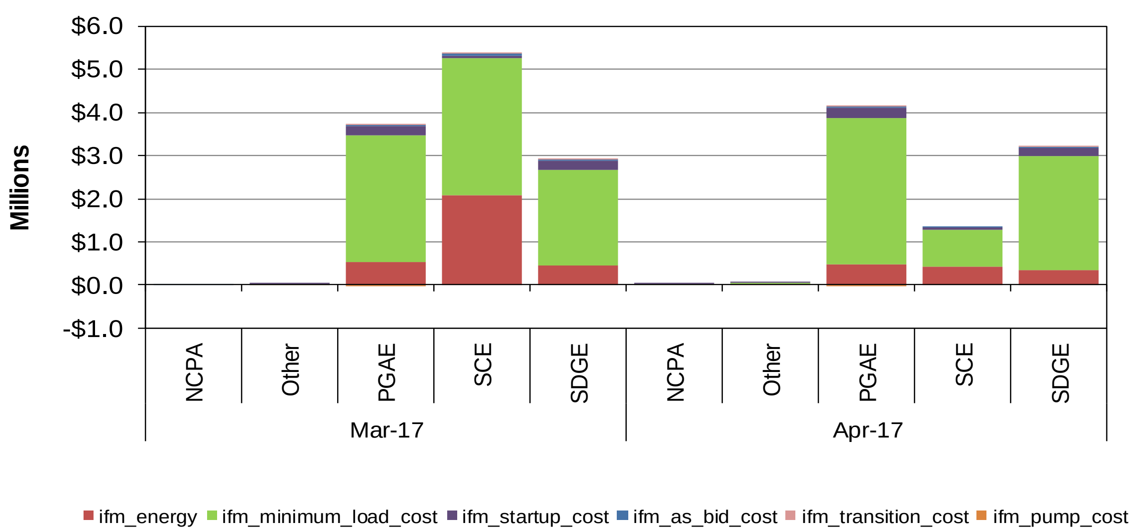


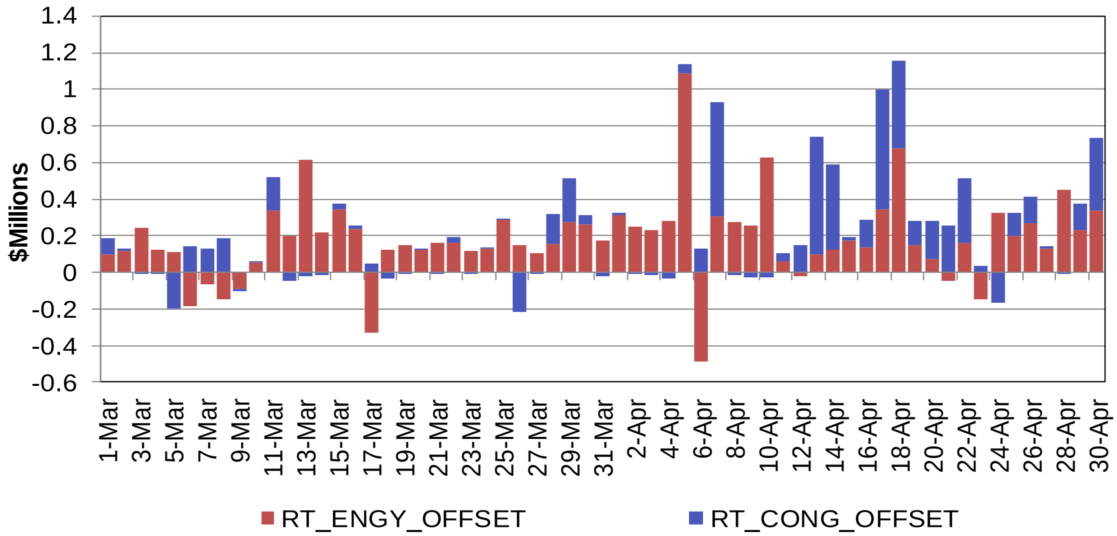
Figure 41: Monthly Cost in IFM by UDC



Real-time Imbalance Offset Costs

Figure 42 shows the daily real-time energy and congestion imbalance offset costs. Real-time energy offset cost rose to $6.85 million in April from $4.22 million in March. Real-time congestion offset cost increased to $4.96 million in April from $0.78 million in March.

Figure 42: 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 63 market disruptions in April. 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.

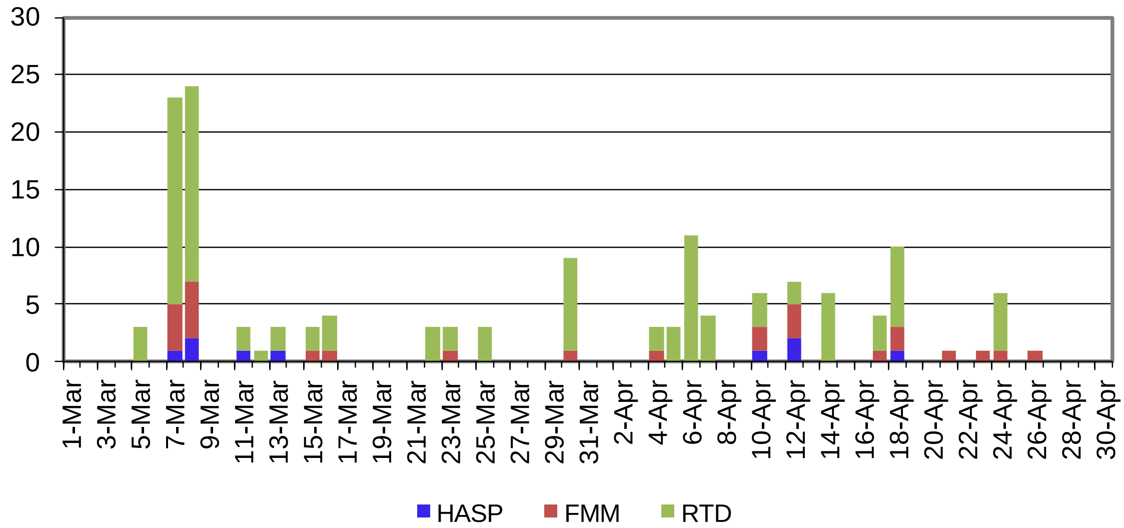
Table 7: Summary of Market Disruption

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	3	0
FMM Interval 2	4	0
FMM Interval 3	3	0
FMM Interval 4	7	0
Real-Time Dispatch	46	0

Figure 43 shows the frequency of IFM, HASP (FMM interval 2), FMM (intervals 1, 3 and 4), and RTD failures. On April 6, six RTD disruptions occurred due to application problem and five other RTD disruptions occurred due to market results being blocked. On April 18, one HASP disruption, two FMM, and seven 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 43: Frequency of Market Disruption



Manual Market Adjustment

Exceptional Dispatch

Figure 44 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 April dropped to 45,040 MWh from 49,309 MWh in March.

Figure 44: Total Exceptional Dispatch Volume (MWh) by Market Type

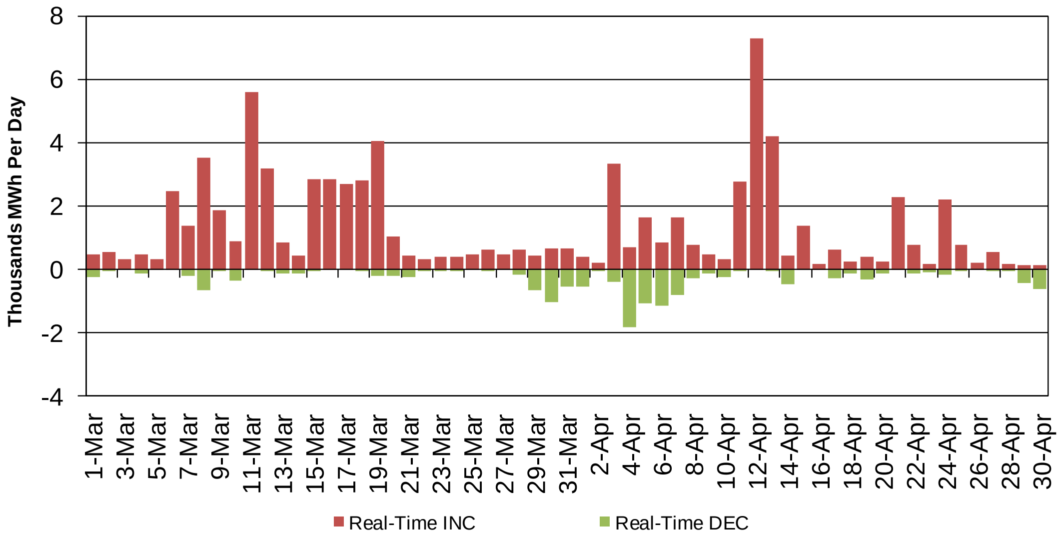


Figure 45 shows the volume of the exceptional dispatch broken out by reason.[4] The majority of the exceptional dispatch volumes in April were driven by operating procedure number and constraint (34 percent), planned transmission outage and constraint (20 percent), other reliability requirement (15 percent), and voltage support (11percent).

[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 45: Total Exceptional Dispatch Volume (MWh) by Reason

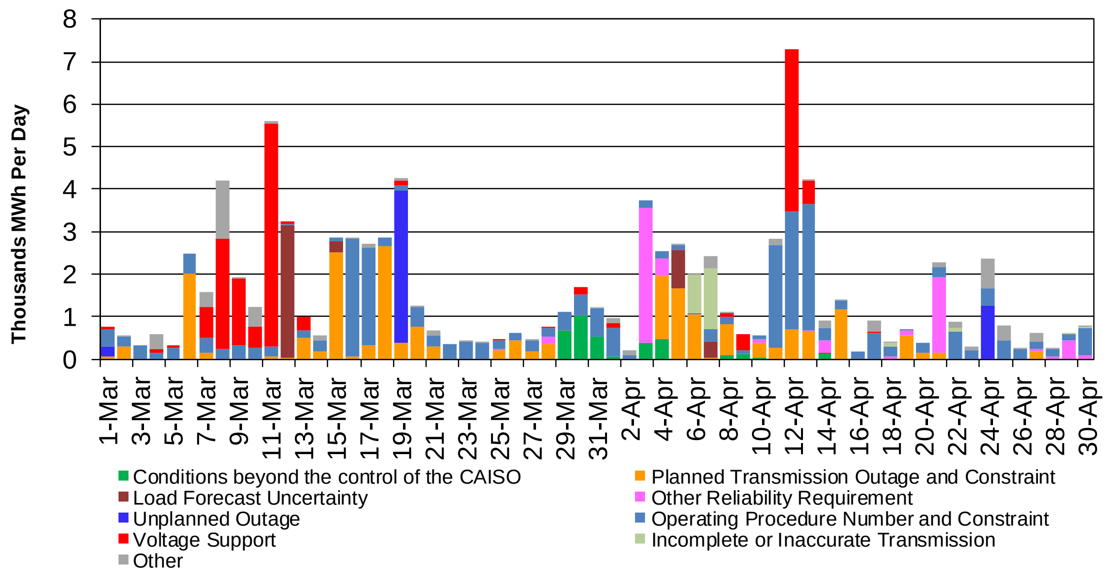
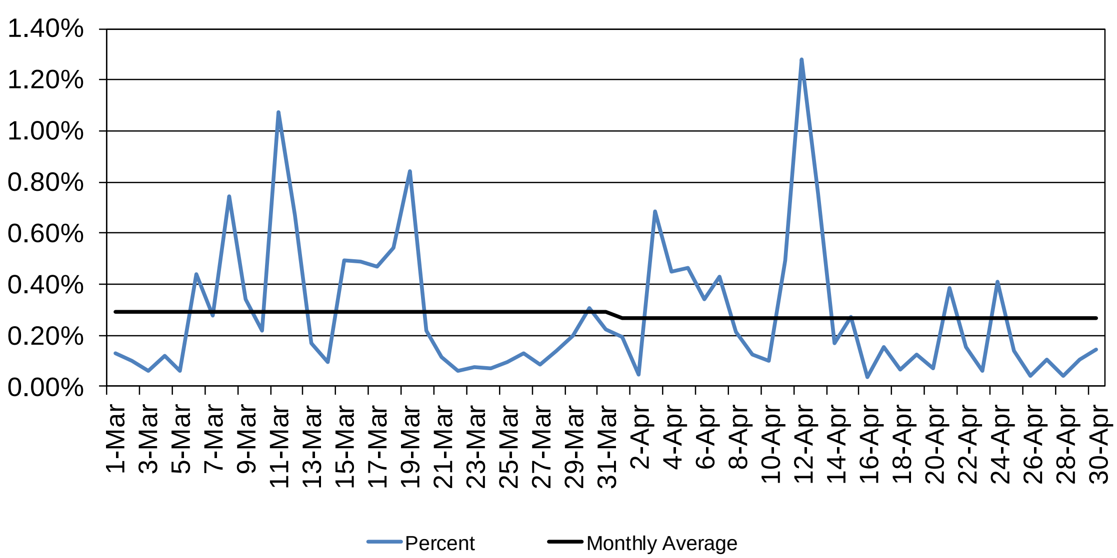


Figure 46 shows the total exceptional dispatch volume as a percent of load, along with the monthly average. The monthly average percentage decreased to 0.27 percent in April from 0.29 percent in March.

Figure 46: 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 47 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 April 1-3 and 29-30, the price for AZPS were depressed due to limited export, low load, renewable deviation, and generation outage.

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

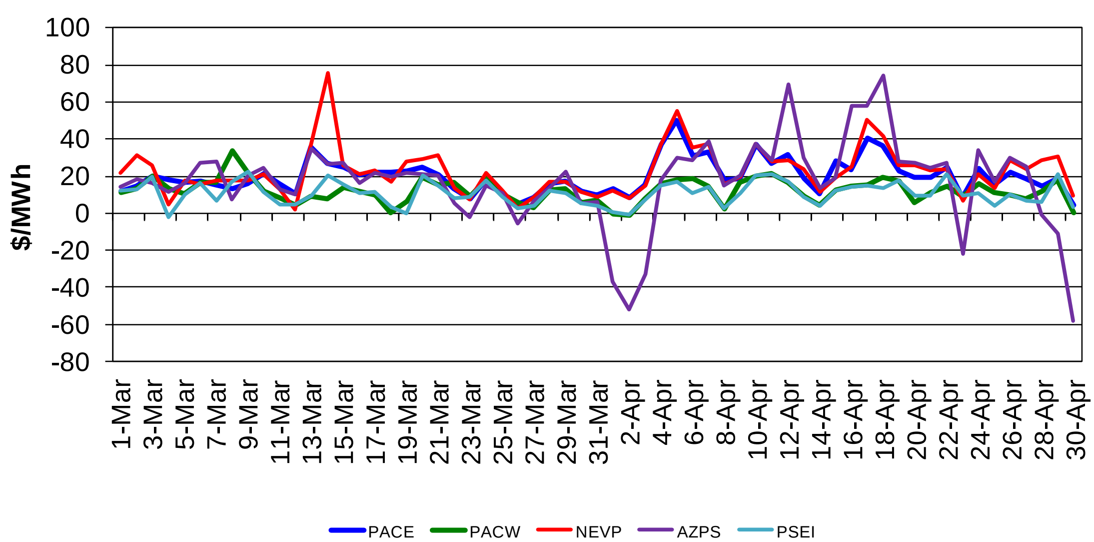


Figure 48 shows daily simple average ELAP prices for PACE, PACW, NEVP, AZPS and PSEI for all hours in RTD. On April 1-3 and 29-30, the prices for AZPS were depressed due to limited export, low load, renewable deviation, and generation outage.

Figure 48: EIM Simple Average LAP Prices (All Hours) in RTD

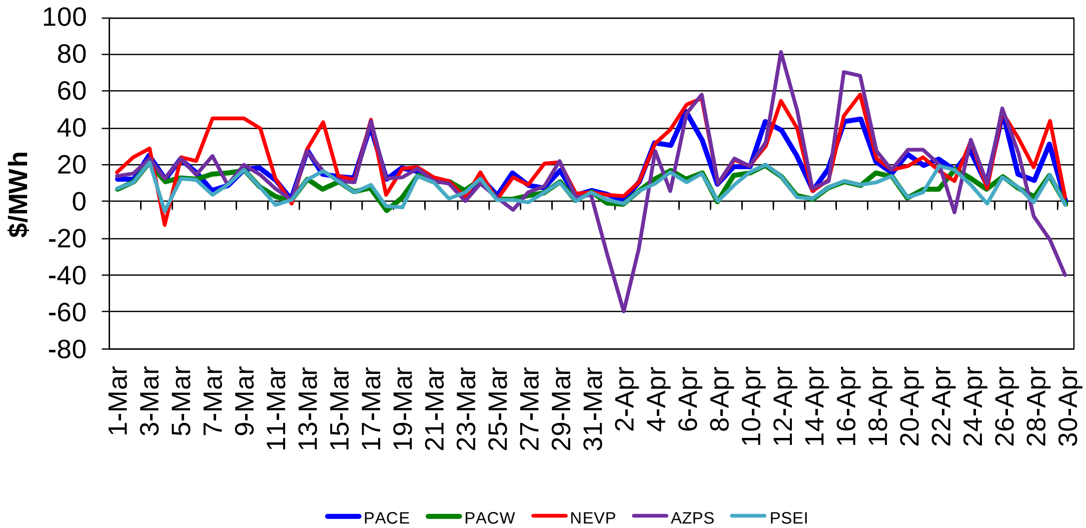


Figure 49 shows the daily price frequency for prices above $250/MWh and negative prices in FMM for PACE, PACW, NEVP, AZPS and PSEI. The cumulative frequency of prices above $250/MWh increased to 0.51 percent in April from 0.15 percent in March. The cumulative frequency of negative prices dropped to 13.85 percent in April from 18.84 percent in March.

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

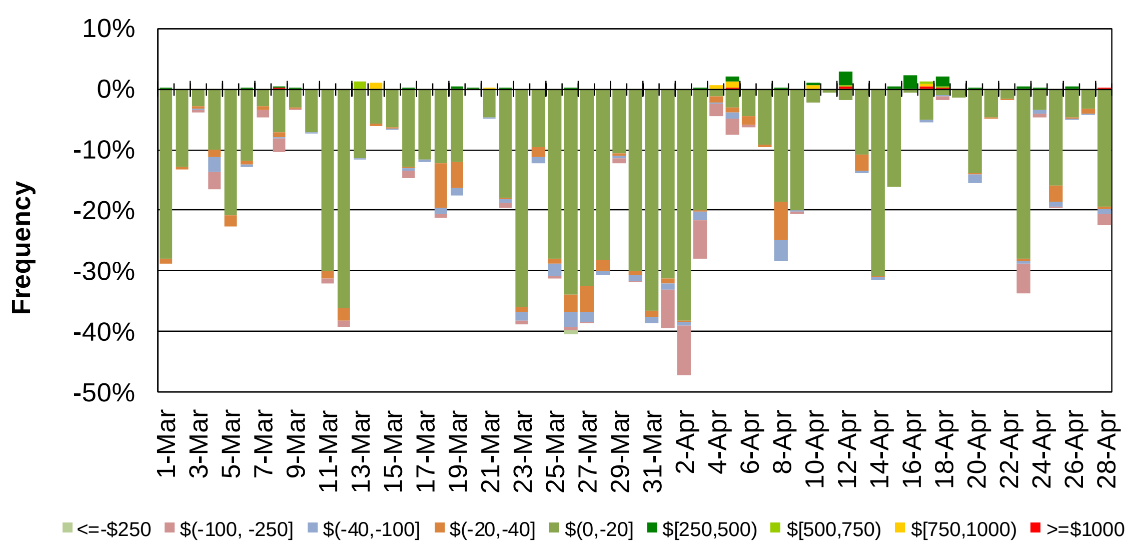


Figure 50 shows the daily price frequency for prices above $250/MWh and negative prices in RTD for PACE, PACW, NEVP, AZPS and PSEI. The cumulative frequency of prices above $250/MWh inched up to 0.95 percent in April from 0.44 percent in March. The cumulative frequency of negative prices fell to 15.68 percent in April from 23.87 percent in March.

Figure 50: Daily Frequency of EIM LAP Positive Price Spikes and Negative Prices in RTD

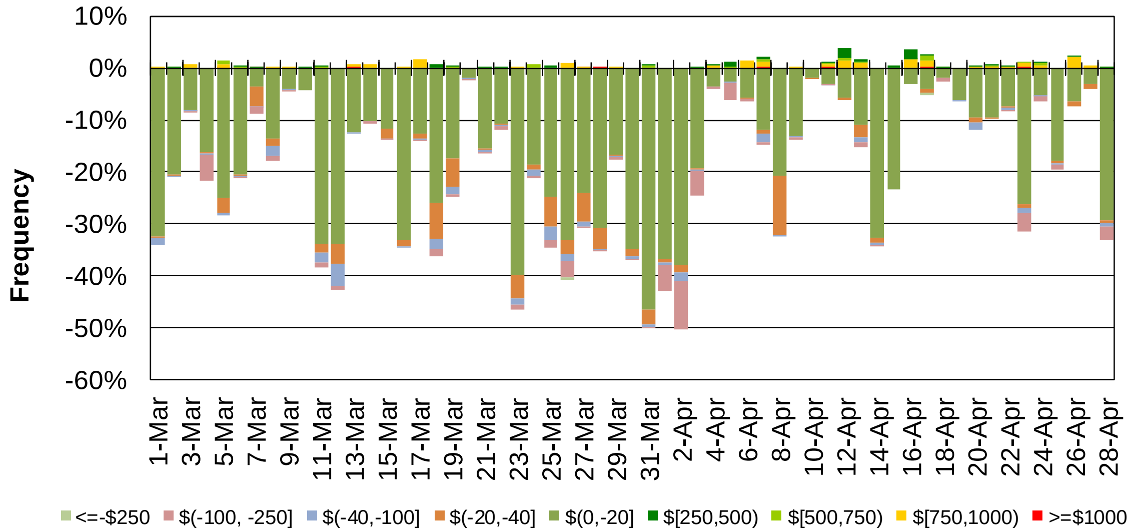


Figure 51 shows the daily volume of EIM transfer between ISO and PacifiCorp in FMM. Figure 52 shows the daily volume of EIM transfer between PACE and PACW in FMM.

Figure 51: EIM Transfer between CAISO and PAC in FMM

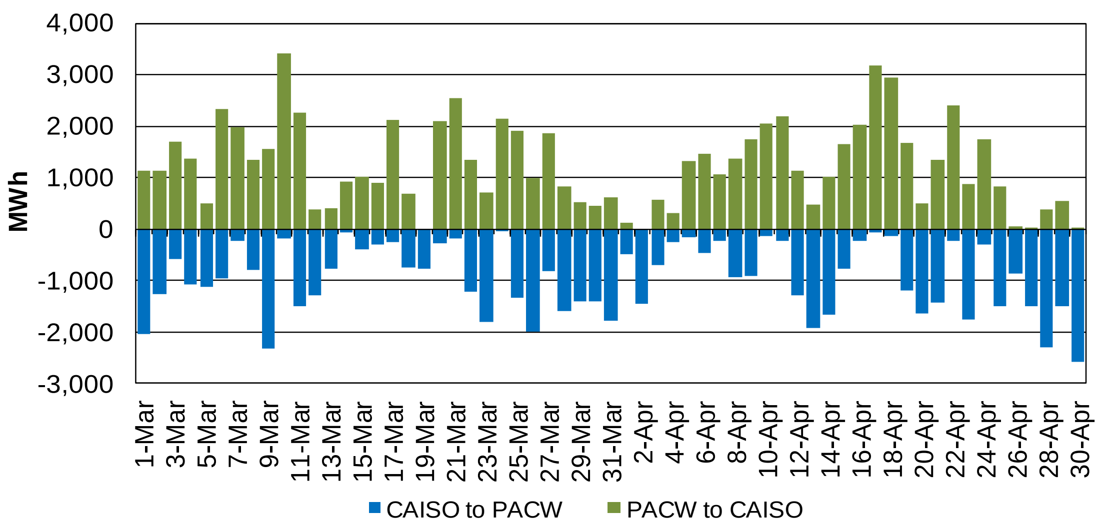


Figure 52: EIM Transfer between PACE and PACW in FMM

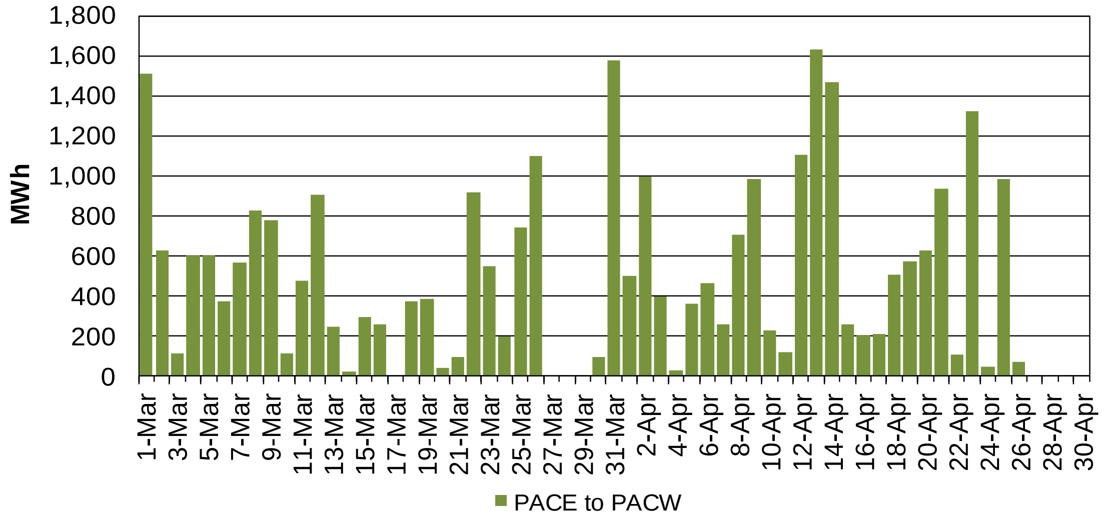


Figure 53 shows the daily volume of EIM transfer between CAISO and NEVP in FMM. Figure 54 shows the daily volume of EIM transfer between PACE and NEVP in FMM. The EIM transfer from PACE to NEVP increased in April compared with March.

Figure 53: EIM Transfer between CAISO and NEVP in FMM

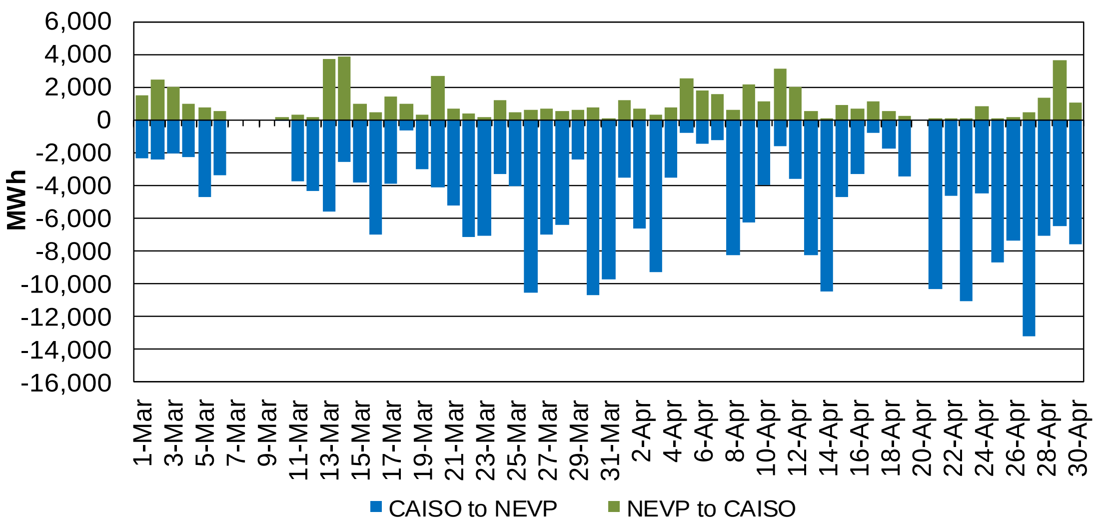


Figure 54: EIM Transfer between PACE and NEVP in FMM

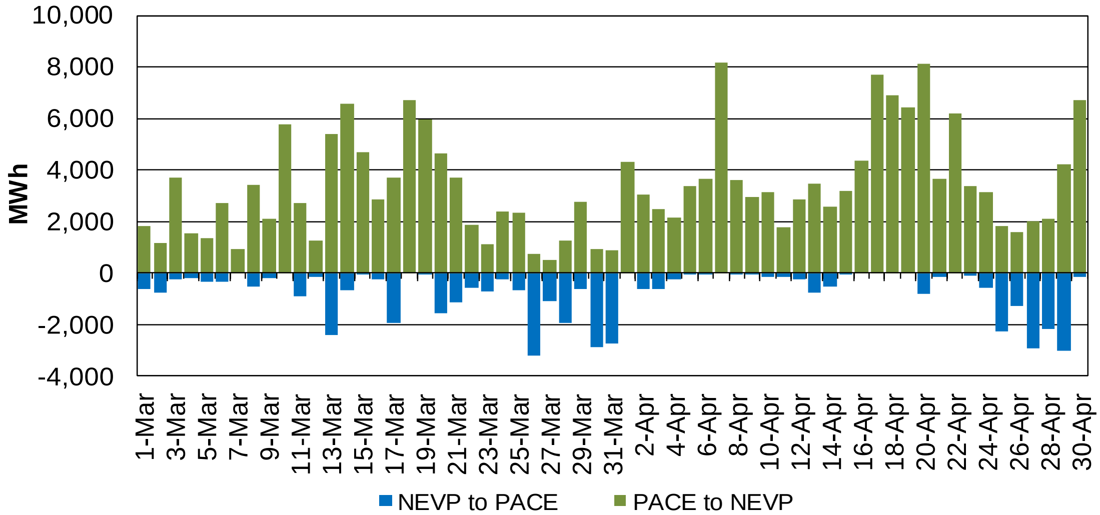


Figure 55 shows the daily volume of EIM transfer between ISO and AZPS in FMM. The EIM transfer from ISO to AZPS increased in the first half of April and then decreased in the second half of this month. Figure 56 shows the daily volume of EIM transfer between PACE and AZPS in FMM. The EIM transfer from PACE to AZPS trended downward in April.

Figure 55: EIM Transfer between CAISO and AZPS in FMM

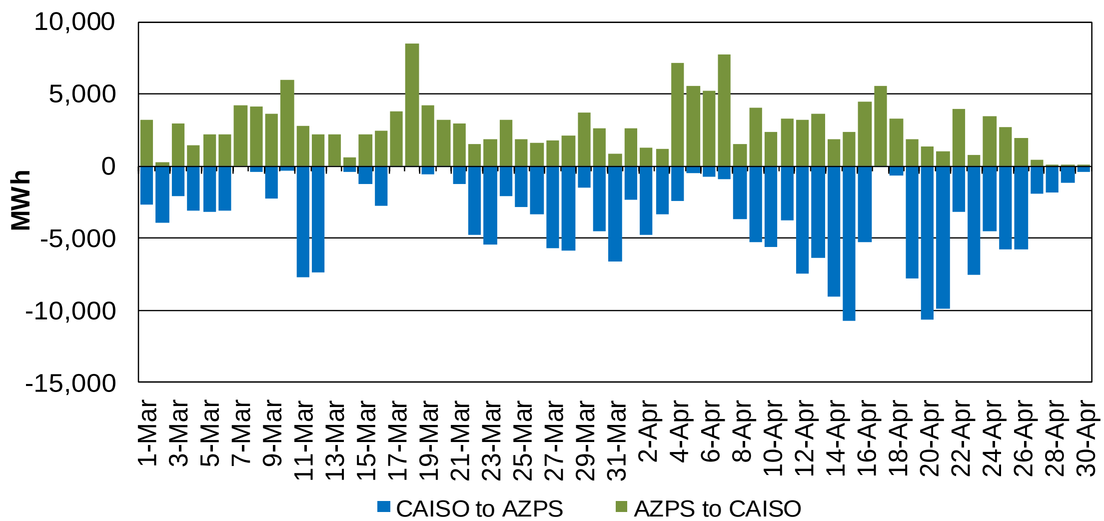


Figure 56: EIM Transfer between PACE and AZPS in FMM

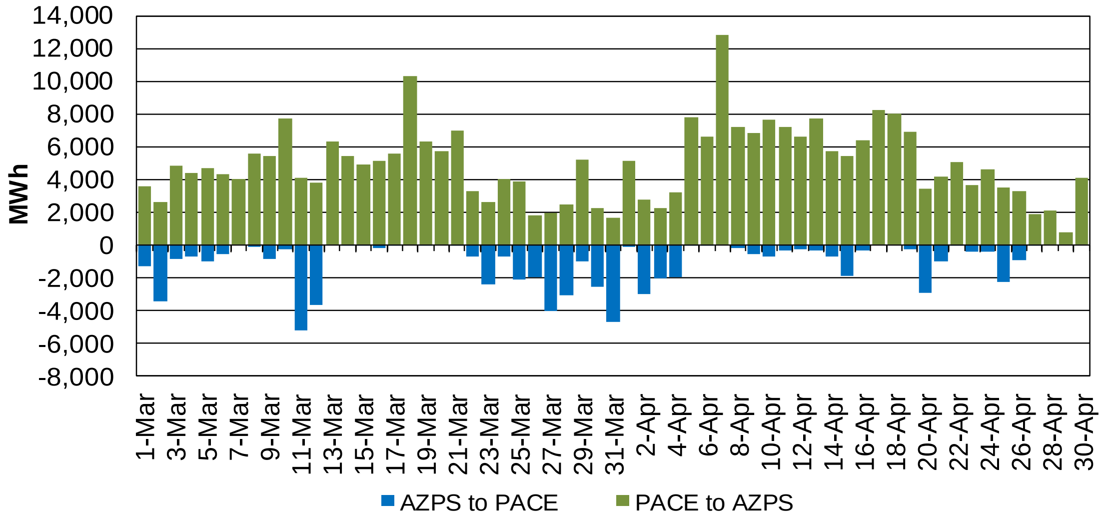


Figure 57 shows the daily volume of EIM transfer between PACW and PSEI in FMM.

Figure 57: EIM Transfer between PACW and PSEI in FMM

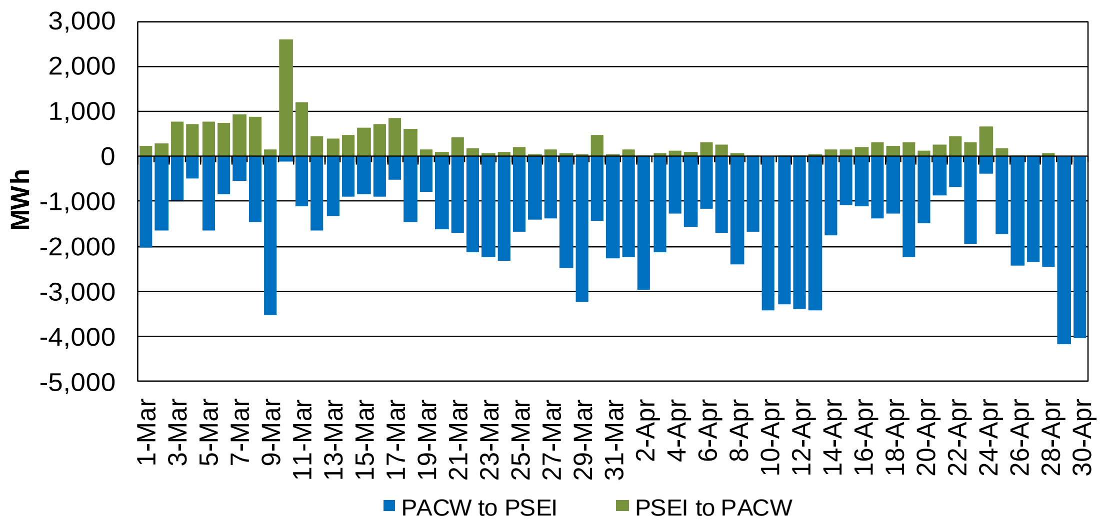


Figure 58 shows the daily volume of EIM transfer between ISO and PacifiCorp in RTD. The EIM transfer from ISO to PACW decreased in the second half of April. Figure 59 shows the daily volume of EIM transfer between PACE and PACW in RTD.

Figure 58: EIM Transfer between CAISO and PAC in RTD

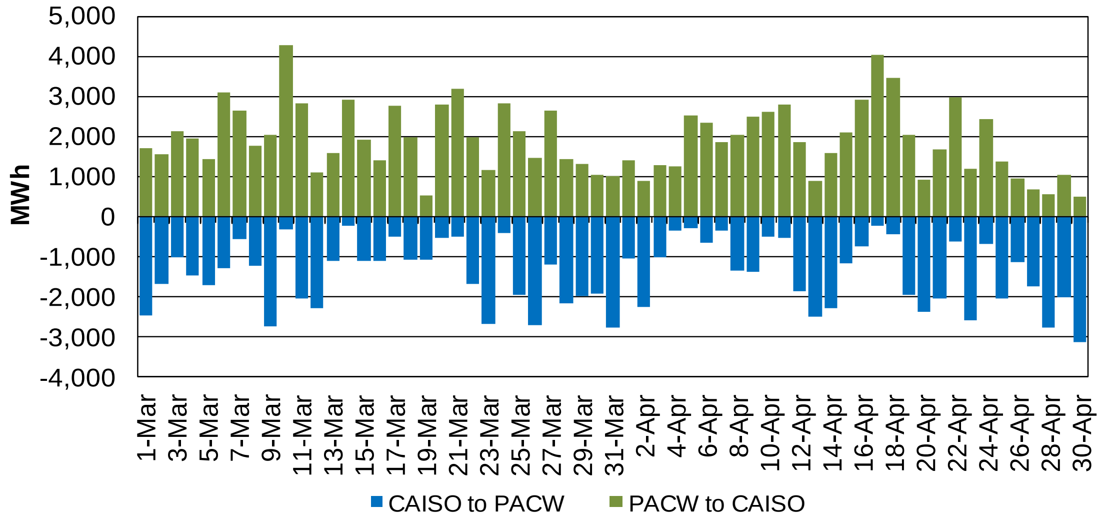


Figure 59: EIM Transfer between PACE and PACW in RTD

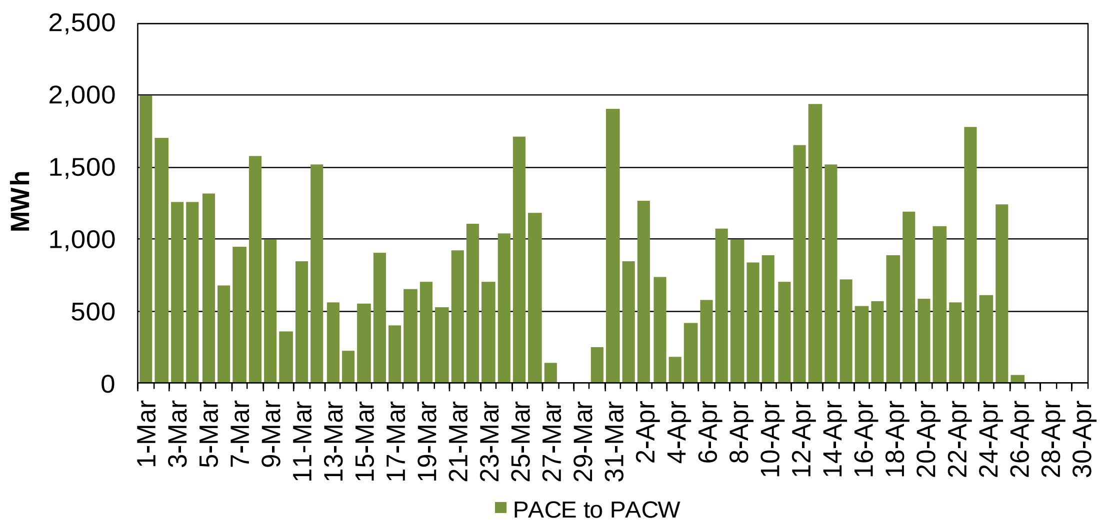


Figure 60 shows the daily EIM transfer volume between ISO and NEVP in RTD. The EIM transfer from CAISO to NEVP increased this month. Figure 61 shows the daily EIM transfer volume between PACE and NEVP in RTD.

Figure 60: EIM Transfer between CAISO and NEVP in RTD

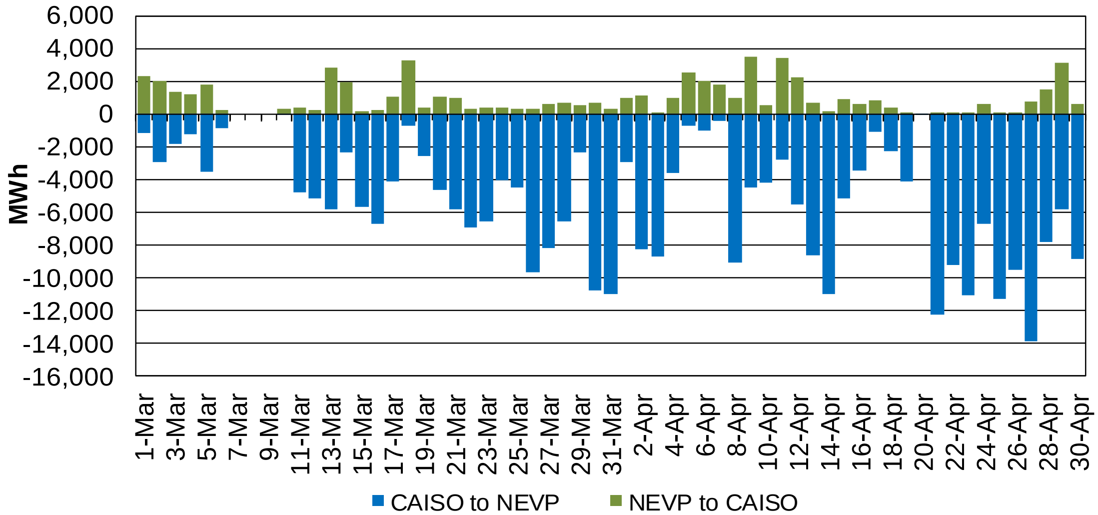


Figure 61: EIM Transfer between PACE and NEVP in RTD

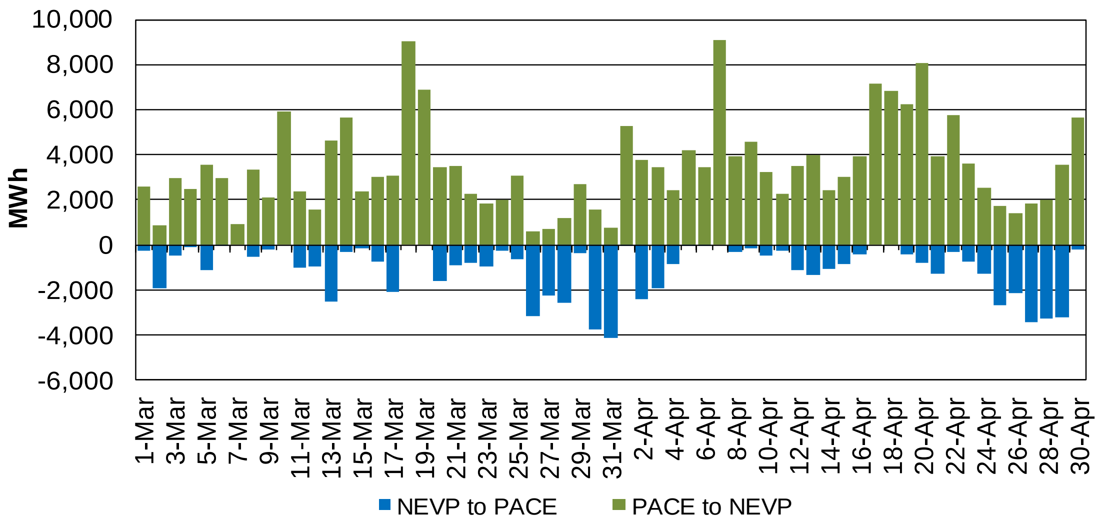


Figure 62 shows the daily volume EIM transfer between the ISO and AZPS in RTD. Figure 63 shows the daily volume EIM transfer between the PACE and AZPS in RTD.

Figure 62: EIM Transfer between CAISO and AZPS in RTD

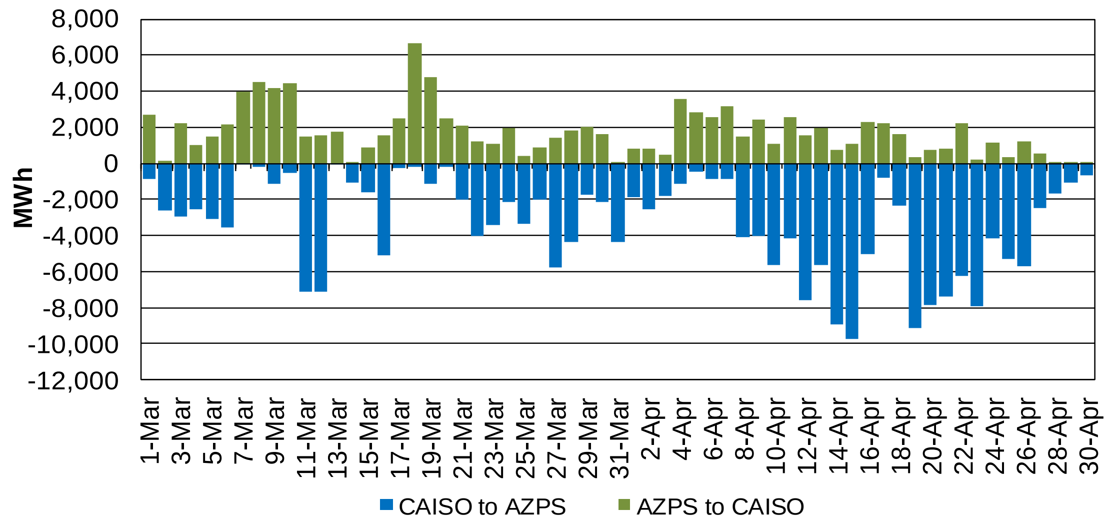


Figure 63: EIM Transfer between PACE and AZPS in RTD

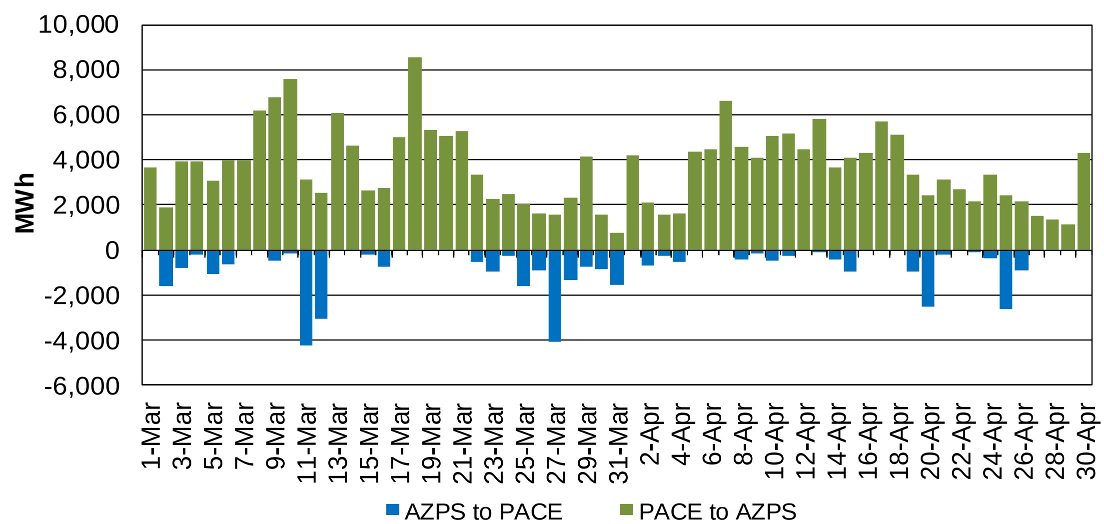


Figure 64 shows the daily volume EIM transfer between the PACW and PSEI in RTD.

Figure 64: EIM Transfer between PACW and PSEI in RTD

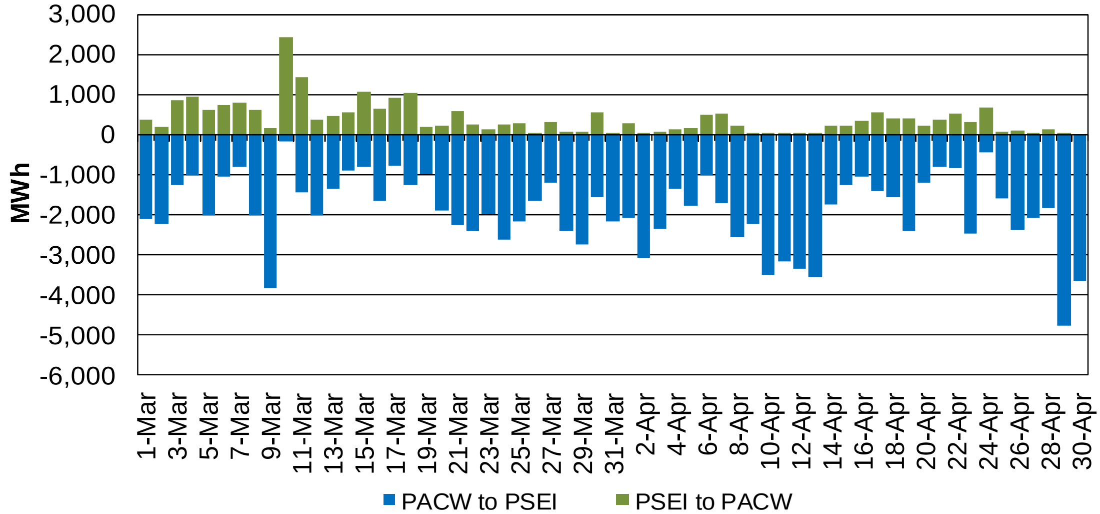


Figure 65 shows daily real-time imbalance energy offset cost (RTIEO) for PACE, PACW, NEVP, AZPS and PSEI respectively. Total RTIEO was -$2.22 million in April, decreasing from $0.49 million in March.

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

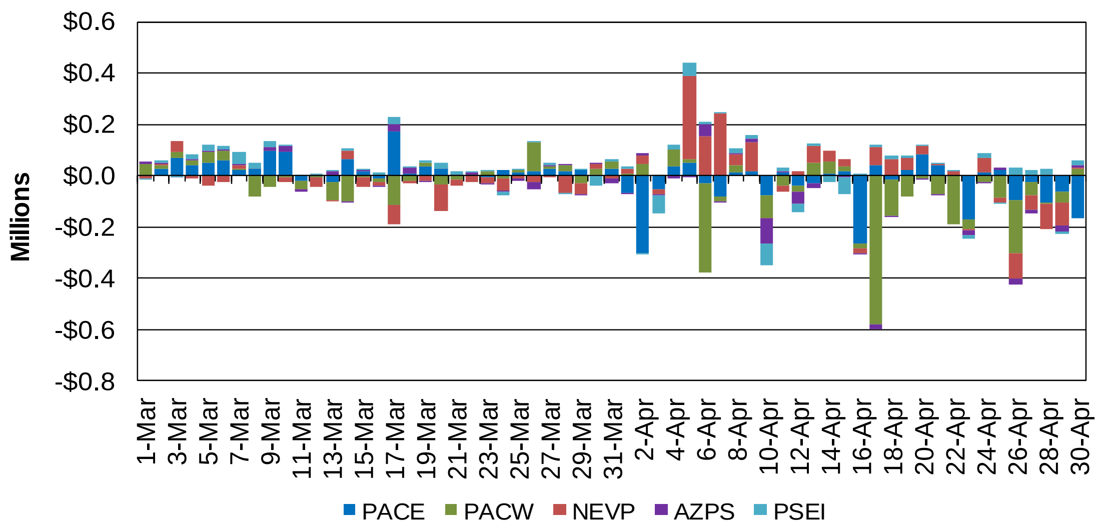


Figure 66 shows daily real-time congestion offset cost (RTCO) for PACE, PACW, NEVP, AZPS and PSEI respectively. Total RTCO increased to -$0.97 million in April from -$1.31 million in March.

Figure 66: EIM Real-Time Congestion Imbalance Offset by Area

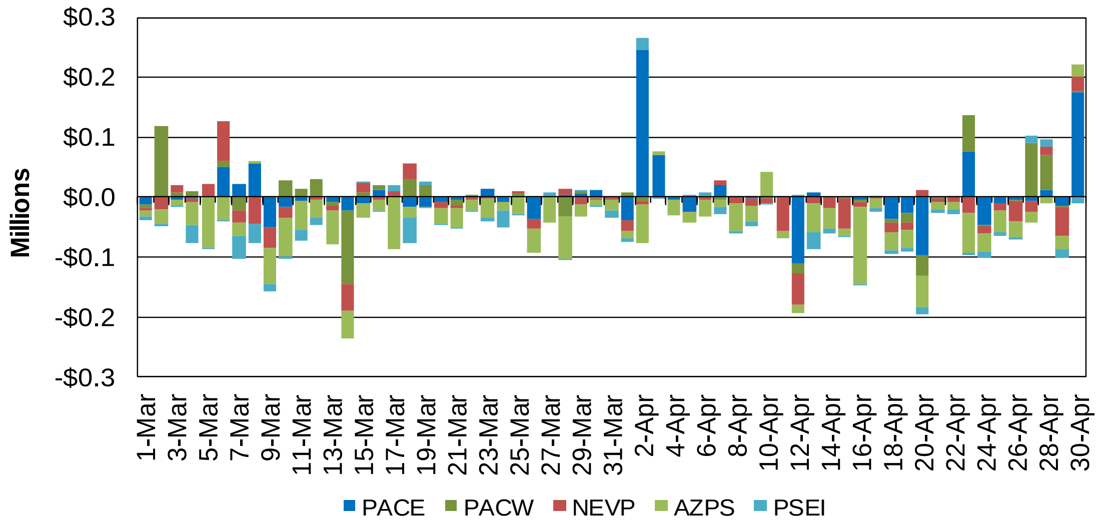


Figure 67 shows daily bid cost recovery for PACE, PACW, NEVP, AZPS and PSEI respectively. Total BCR rose to $1.31 million in April from $1.03 million in March.

Figure 67: EIM Bid Cost Recovery by Area

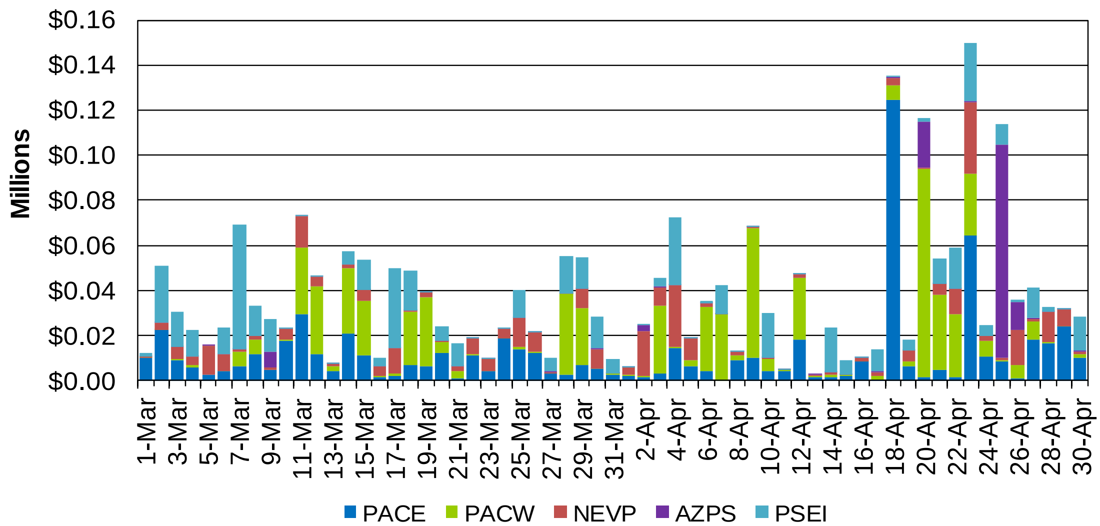


Figure 68 shows the flexible ramping up uncertainty payment for PACE, PACW, NEVP, AZPS, and PSEI respectively. Total flexible ramping up uncertainty payment in April decreased to $1.42 million from $1.48 million in March.

Figure 68: Flexible Ramping Up Uncertainty Payment

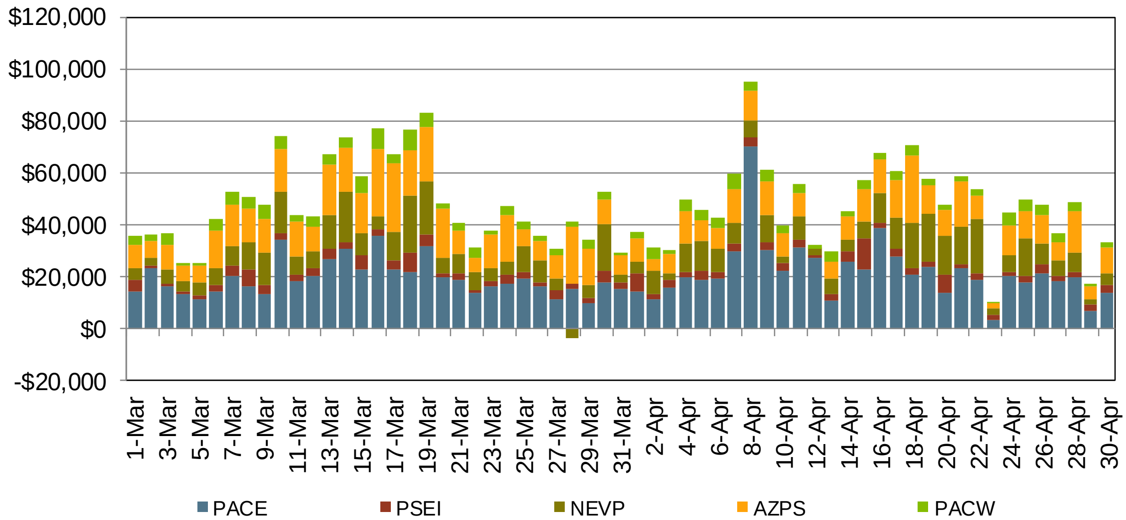


Figure 69 shows the flexible ramping down uncertainty payment for PACE, PACW, NEVP, AZPS, and PSEI respectively. Total flexible ramping down uncertainty payment in April inched down to $0.21 million from $0.34 million in March.

Figure 69: Flexible Ramping Down Uncertainty Payment

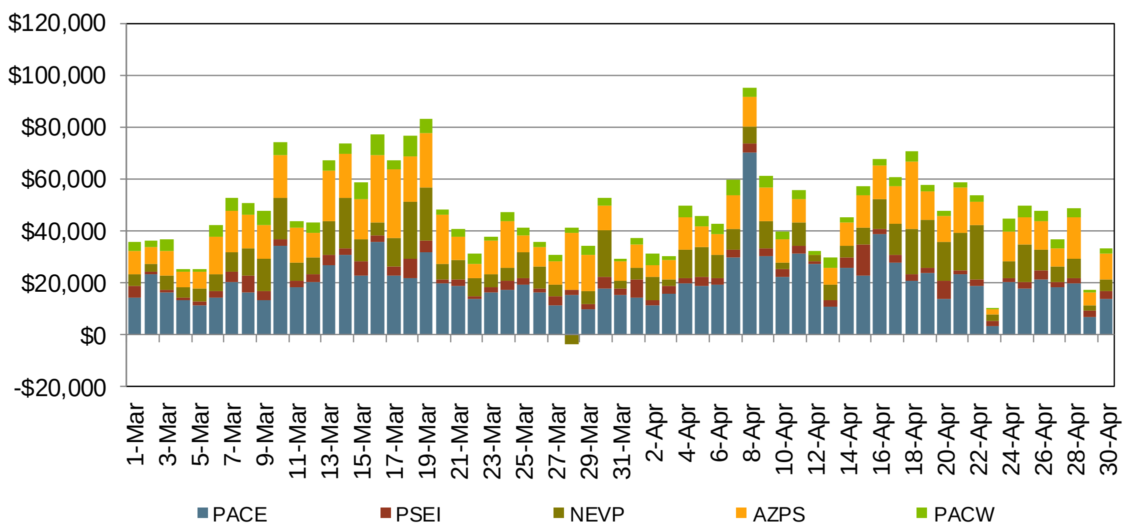
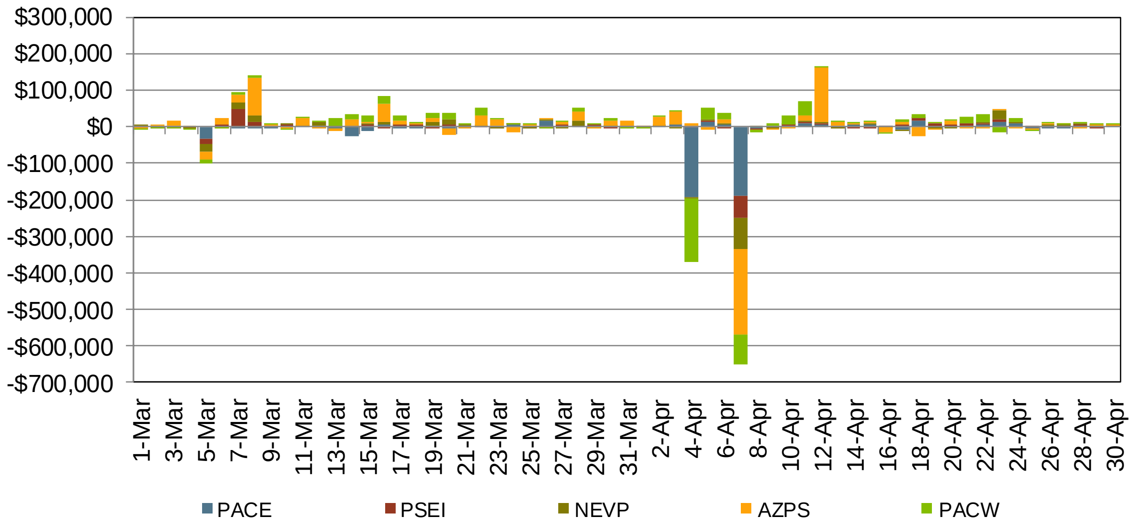


Figure 70 shows the flexible ramping forecast payment for PACE, PACW, NEVP, AZPS, and PSEI respectively. Total forecast payment in April dropped to -$0.40 million from $0.62 million in March.

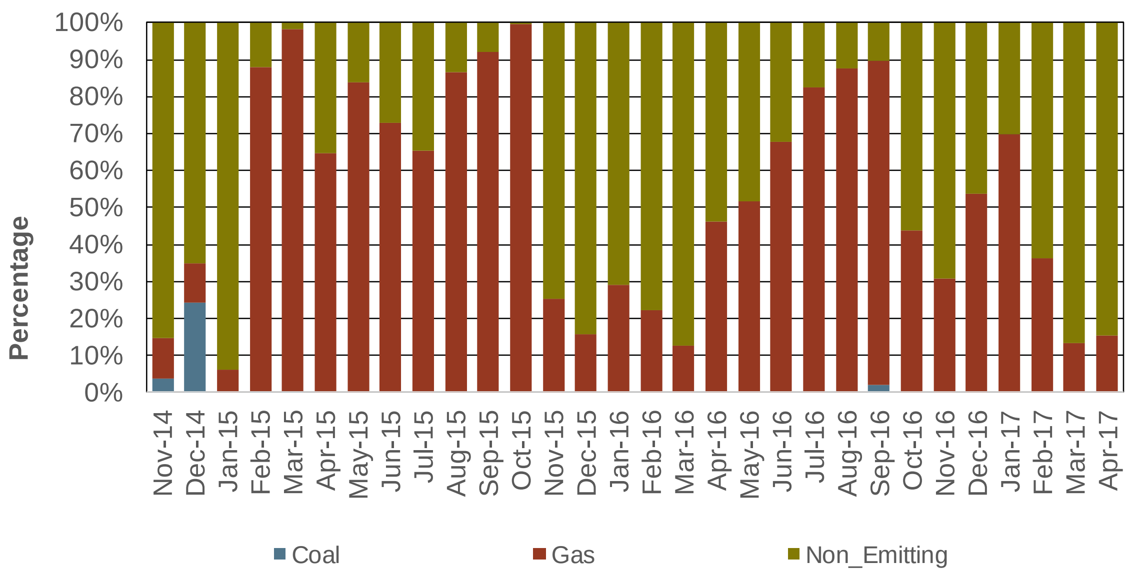
Figure 70: Flexible Ramping Forecast Payment



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 April 2015, almost all of the EIM dispatches to support transfers into the ISO were from resources other than coal, as documented in Figure 71 and Table 8 below.

Figure 71: 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 may 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%