Market Performance Report
March 2017

May 11, 2017

ISO Market Quality and Renewable Integration

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Executive Summary[1]

The market performance in March 2017 is summarized below.

CAISO area performance,

- Peak loads for ISO were below 30,000 MW in March.
- In the integrated forward market (IFM), SDG&E DLAP prices were elevated in a couple of days due to transmission congestion. In the fifteen-minute market (FMM) and real-time market (RTD), SDG&E DLAP prices were also elevated in a few days due to transmission congestion.
- Congestion rents for interties rose to $13.01 million from $5.83 million in February. Majority of the congestion rents in March accrued on MALIN500 (63 percent) intertie and NOB (33 percent) intertie.
- In the congestion revenue rights market, revenue adequacy increased to 81.50 percent from 69.87 percent in February. The nomogram 7820_TL23040_IV_SPS_NG contributed largely to the revenue shortfall. This nomogram was enforced to avoid overload in the underlying parallel 230 kV lines and cross tripping.
- The monthly average ancillary service cost to load edged down to $0.73/MWh from $0.75/MWh in February. There were three ancillary service scarcity events this month.
- The cleared virtual supply was well above cleared demand throughout March. The profits from convergence bidding dropped to $0.83 million from $2.21 million in February.
- The bid cost recovery increased to $7.21 million from $6.05 million in February.
- The real-time energy offset rose to $4.25 million from $2.55 million in February. The real-time congestion offset cost inched up to $0.86 million from $0.71 million in February.
- The volume of exceptional dispatch dropped to 48,963 MWh from 49,894 MWh in February, largely driven by operating procedure number and constraint, voltage support, and planned transmission outage and constraint. The monthly average of total exceptional dispatch volume as a percentage of load decreased to 0.29 percent from 0.31 percent in February.

[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 price in the NEVP area was elevated due to generation outage. In the RTD market, the prices for NEVP were also relatively high on March 6-10 when the administrative pricing applies to Nevada due to market interruption in Nevada.
- Bid cost recovery, real-time imbalance energy offset, and real-rime congestion offset costs for EIM entities (PACE, PACW, NEVP, AZPS, and PSEI) were $1.03 million, $1.25 million and -$1.29 million respectively.

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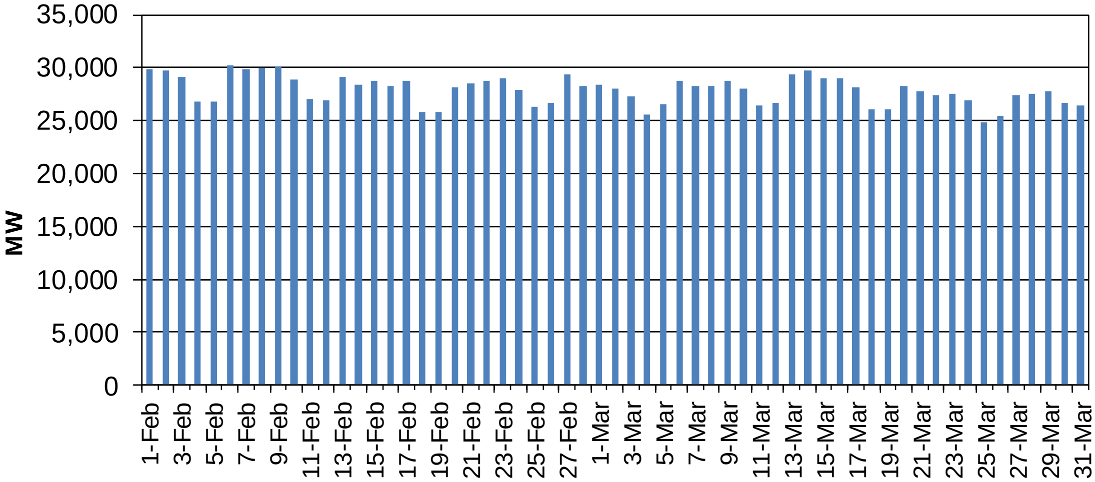
Market Characteristics

Loads

Peak loads for ISO were below 30,000 MW in March.

Figure 1: System Peak Load



Direct Market Performance Metrics

Energy

Day-Ahead Prices

Figure 2 shows daily prices of four default load aggregate points (DLAPs). Table 1 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)

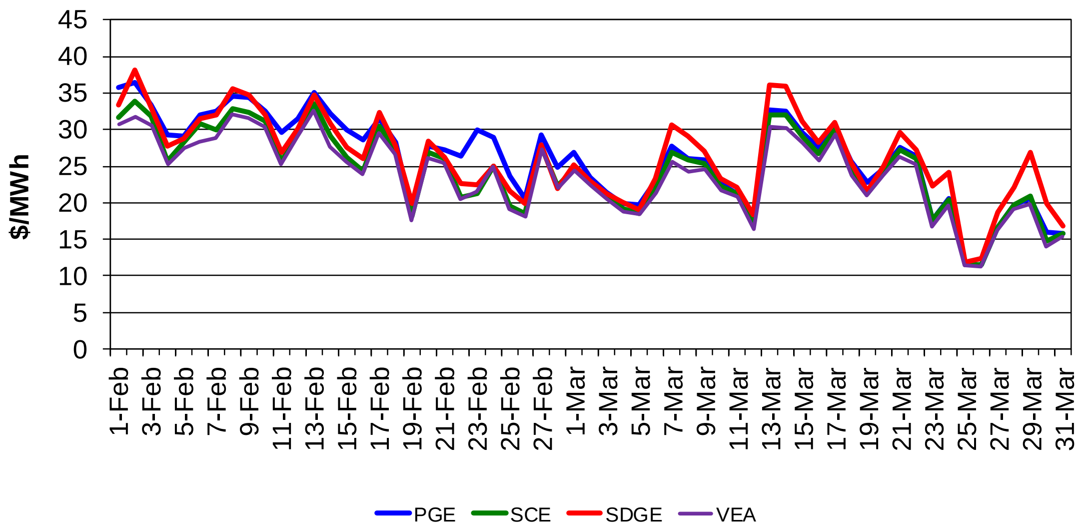


Table 1: Day-Ahead Transmission Constraints

DLAP	Date	Transmission Constraint
SG&E	March 7, 23, 24, 29, 30	7820_TL23040_IV_SPS_NG
SG&E	March 8, 13	SYCA TP1-SYCAMORE-230kV line
SG&E	March 14	7820_TL23040_IV_SPS_NG, SYCA TP1-SYCAMORE-230kV line

Real-Time Prices

FMM daily prices of the four DLAPs are shown in Figure 3. Table 2 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)

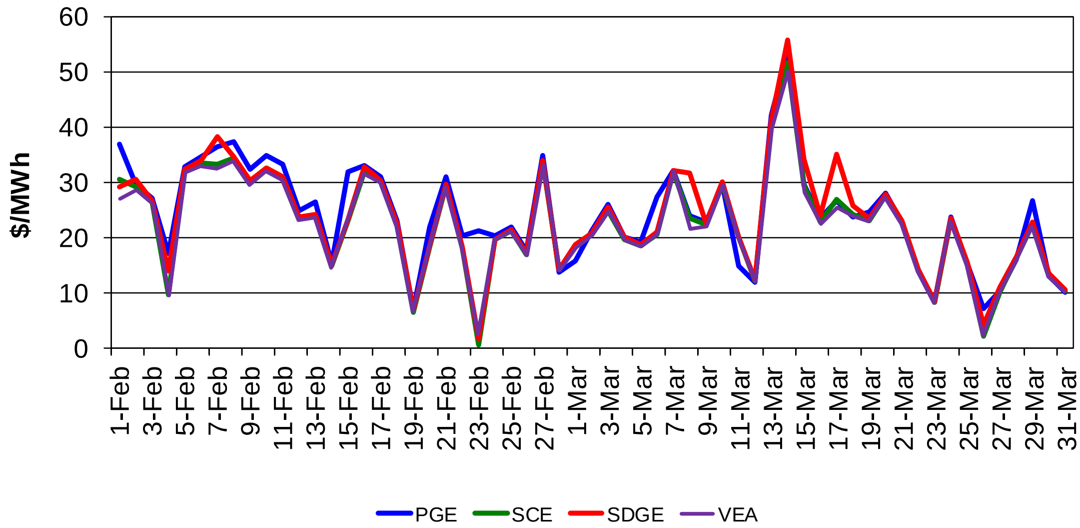
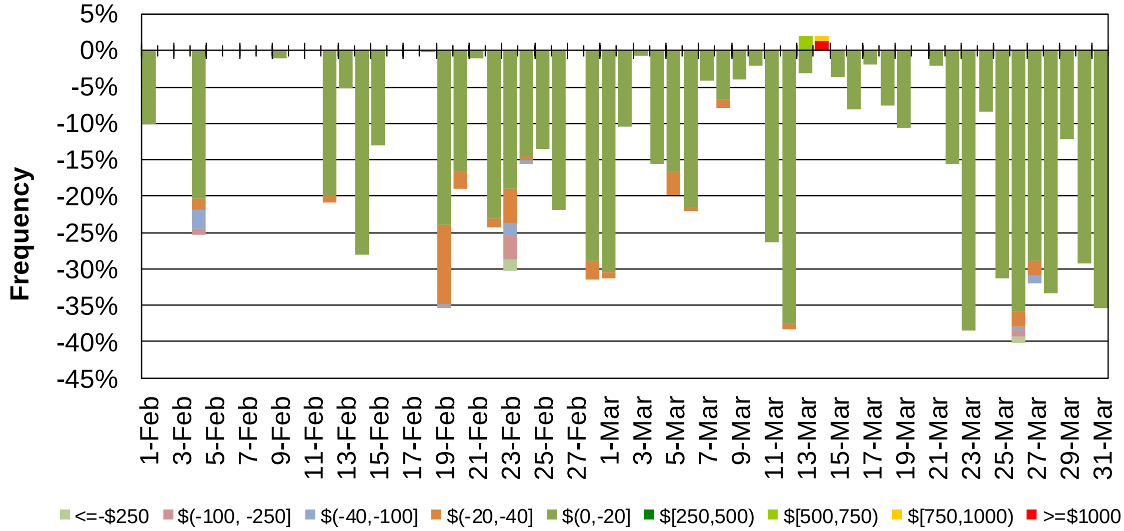


Table 2: FMM Transmission Constraints

DLAP	Date	Transmission Constraint
SDG&E	March 8	SYCA TP1-SYCAMORE-230kV line, 7820_TL 230S_OVERLOAD_NG
SDG&E	March 17	7820_TL 230S_OVERLOAD_NG
SCE, SDG&E, VEA	March 26	PATH15_S-N

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 0.13 percent in March from 0 percent in February. The cumulative frequency of negative prices increased to 15.96 percent in March from 10.58 percent in February.

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 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 5: RTD Simple Average LAP Prices (All Hours)

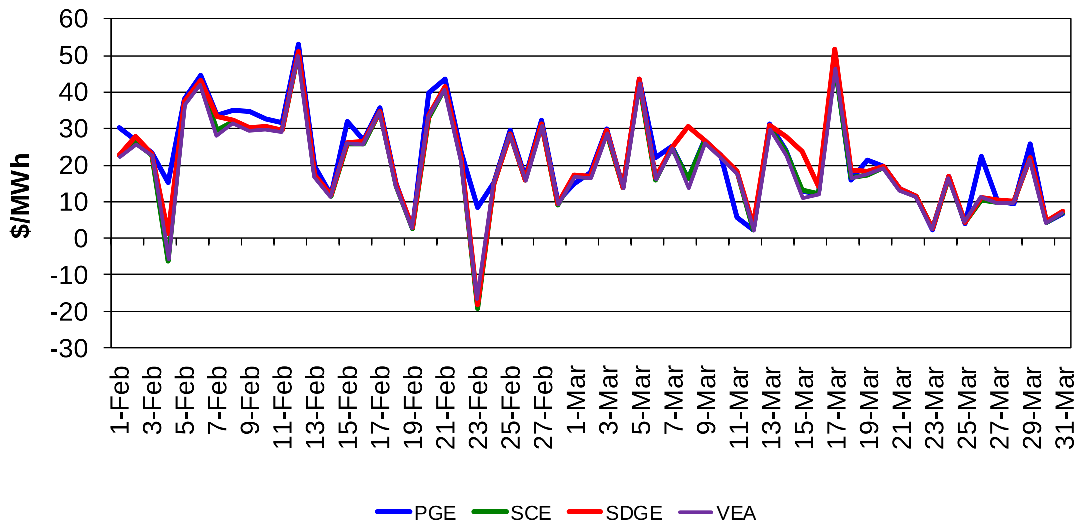
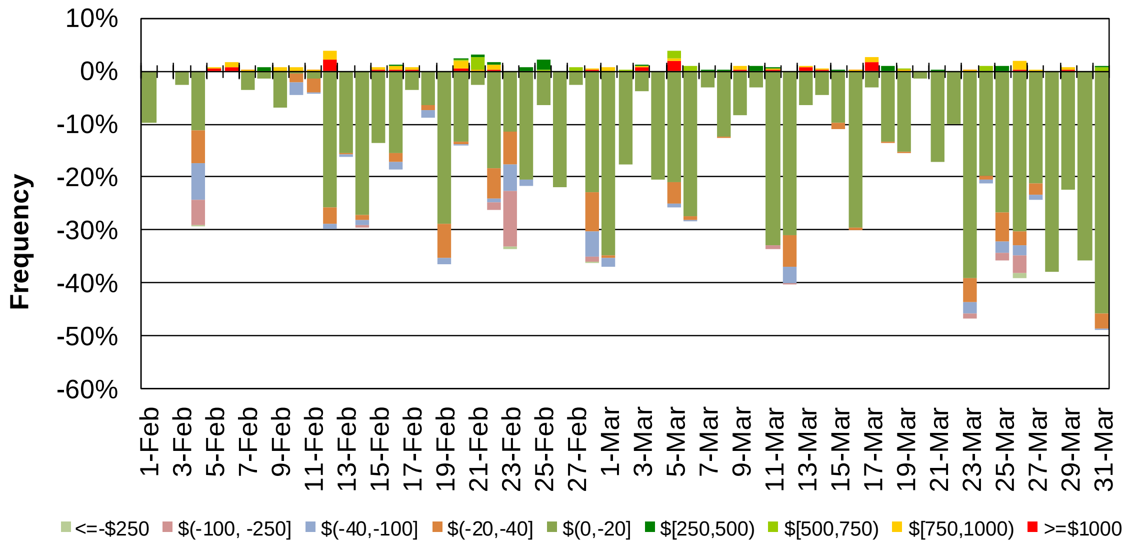


Table 3: RTD Transmission Constraints

DLAP	Date	Transmission Constraint
SDG&E	March 8, 15	7820_TL 230S_OVERLOAD_NG
SDG&E	March 14	SYCA TP1-SYCAMORE-230kV line
SCE, SDG&E, VEA	March 26	PATH15_S-N

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 0.76 percent in March from 0. 84 percent in February. The cumulative frequency of negative prices rose to 21.19 percent in March from 13.67 percent in February.

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



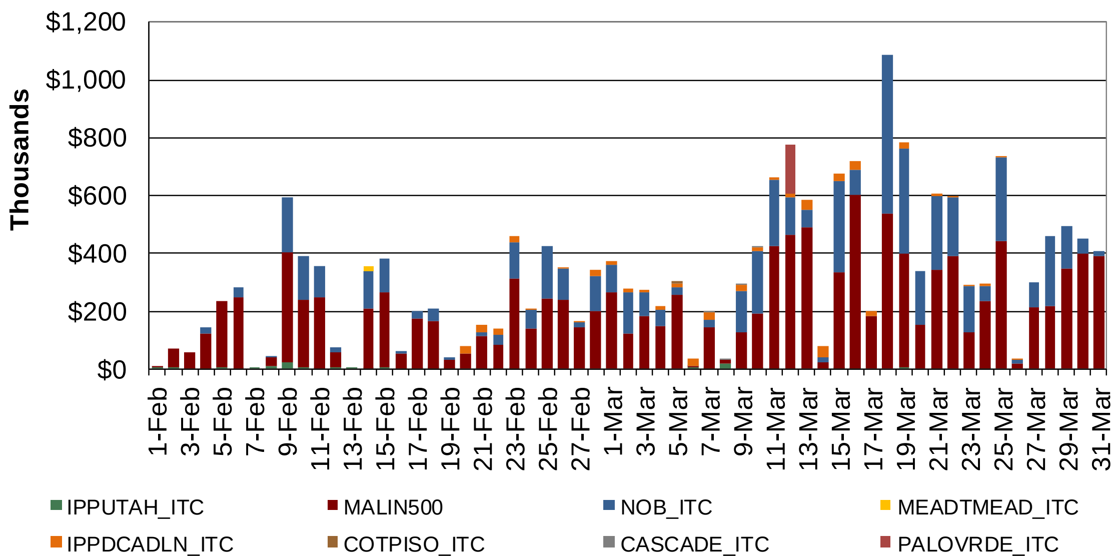
Congestion

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 March rose to $13.01 million from $5.83 million in February. Majority of the congestion rents in March accrued on MALIN500 (63 percent) intertie and NOB (33 percent) intertie.

The congestion rent on MALIN500 increased to $8.16 million in March from $4.07 million in February. MALIN500 was derated this month due to various outages including the outage of Malin-Round Mountain #1 500 kV line and Wautoma-Rock Creek #1 500 kV line. The congestion rent on NOB increased to $4.26 million in March from $1.53 million in February. NOB was derated this month due to various outages including the outage of Round Mountain-Table Mountain #2 500 kV line and the outage of Sylmar station.

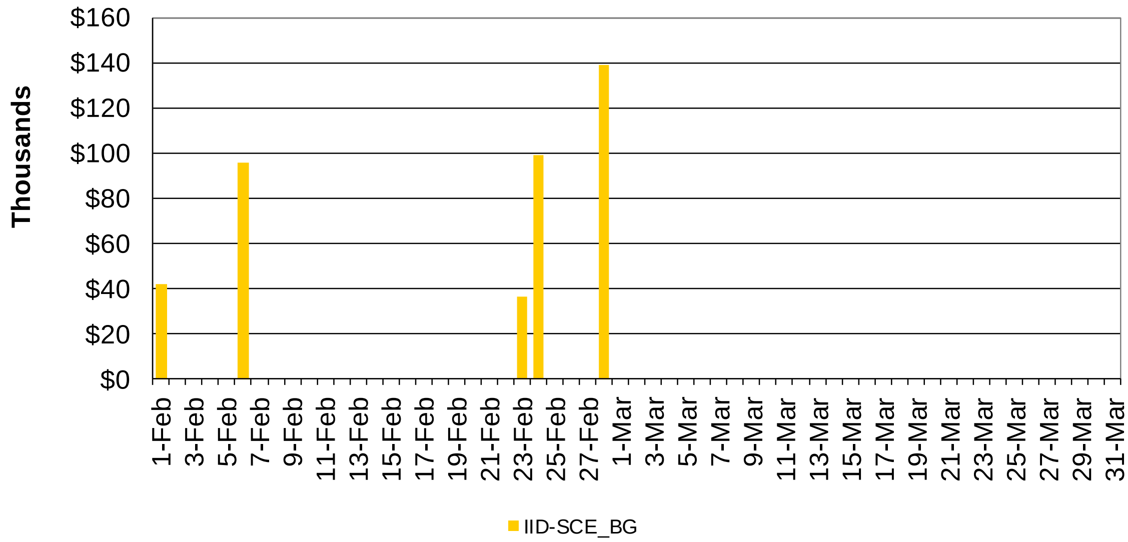
Figure 7: IFM Congestion Rents by Interties (Import)



Congestion Rents on Branch Groups

Figure 8 illustrates the IFM congestion rents on selected branch groups. Total congestion rents for branch groups dropped to $0 in March from $0.41 million in February.

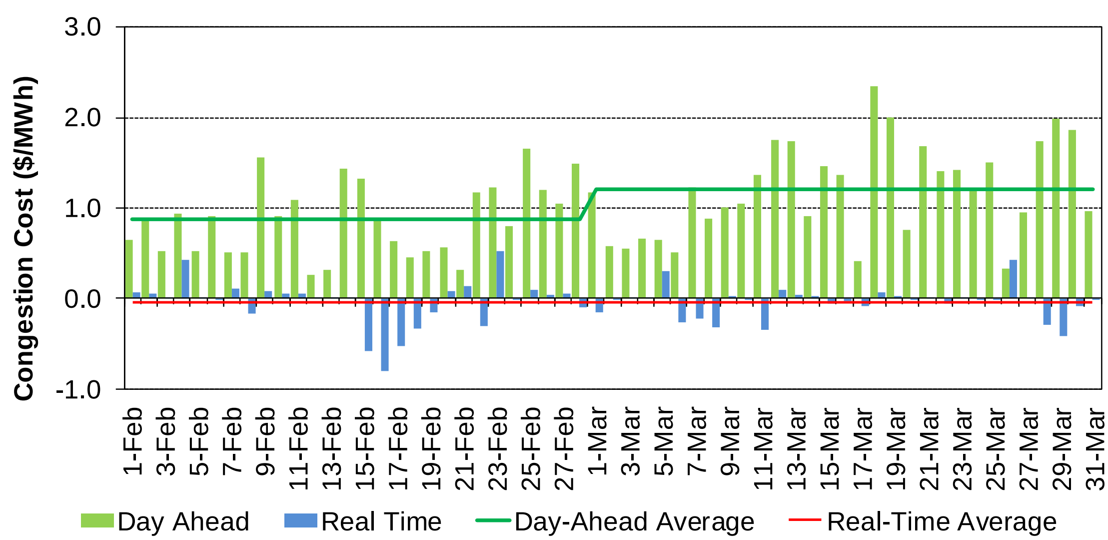
Figure 8: IFM Congestion Rents by Branch Group



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

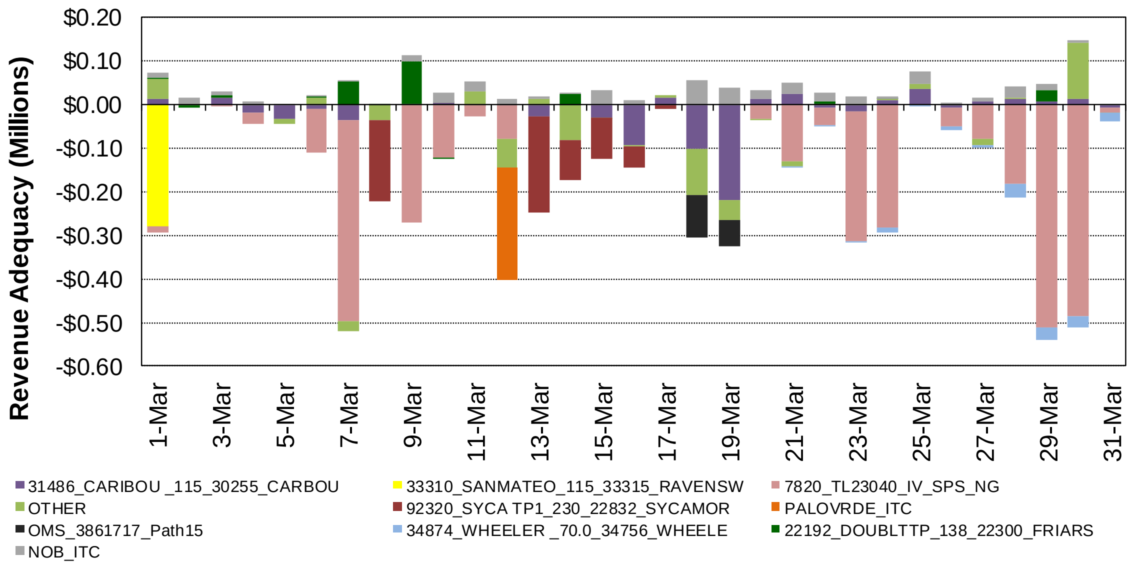


The average congestion cost per MWh of load served in the integrated forward market increased to $1.20/MWh in March from $0.87/MWh in February. The average congestion cost per load served in the real-time market went to -$0.05/MWh in March from $0.04/MWh in February.

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 March declined to $151,980 from the average revenue deficit of $214,188 in February.

Figure 10: Daily Revenue Adequacy of Congestion Revenue Rights

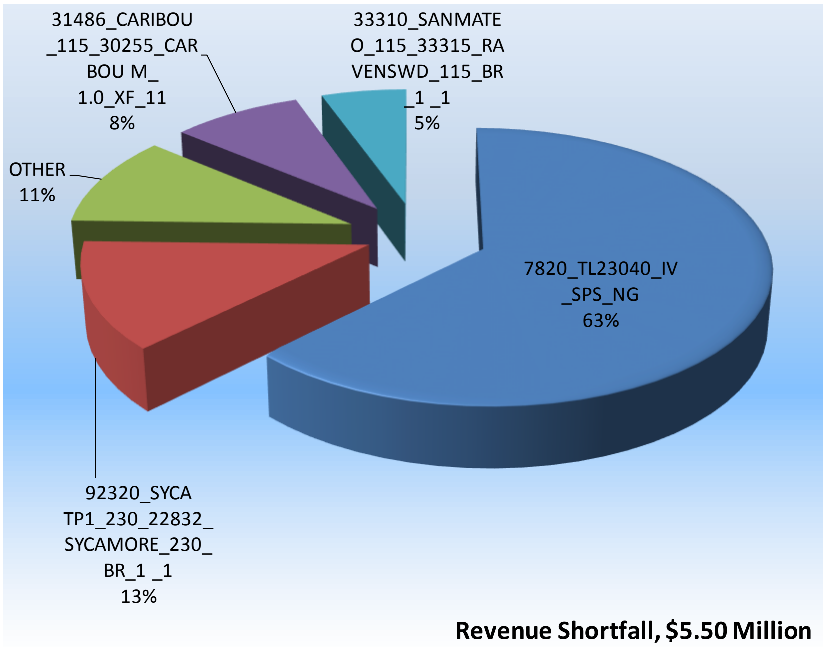


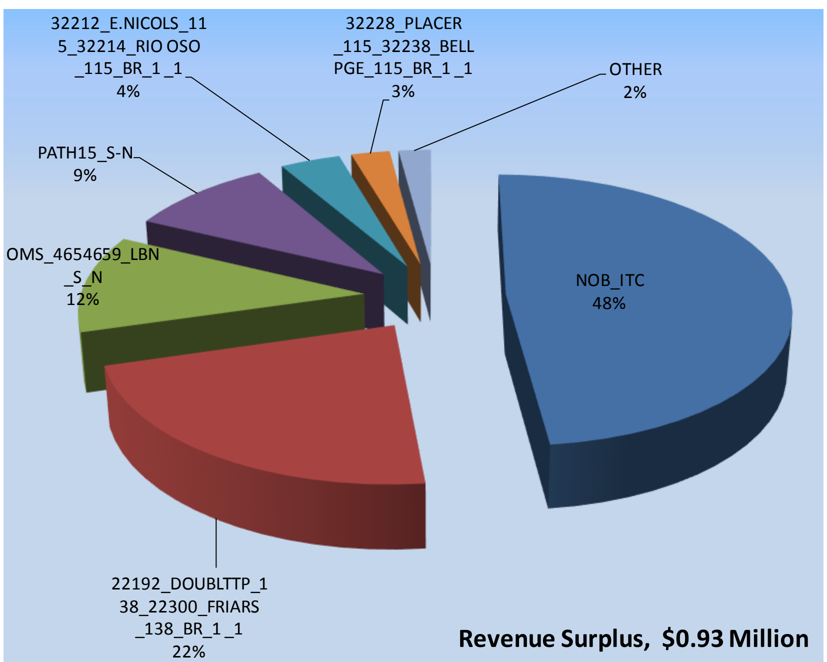
Overall, March experienced a CRR revenue deficit. Revenue shortfalls were observed in most days of this month. The main reasons are shown below.

- The nomogram 7820_TL23040_IV_SPS_NG was binding in 21 days of this month, resulting in revenue shortfall of $3.19 million. This nomogram was enforced to avoid overload in the underlying parallel 230 kV lines and cross tripping.
- NOB intertie was binding in most days of March, resulting in revenue shortfall of $0.45 million.

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 4.

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 81.50 percent in March. Out of the total congestion rents, 4.68 percent was used to cover the cost of existing right exemptions. Net total congestion revenues in March were in deficit by $4.71 million, compared to the deficit of $5.99 million in February. The auction revenues credited to the balancing account for March were $6.85 million. As a result, the balancing account for March had a surplus of approximately $2.17 million, which will be allocated to measured demand.

Table 4: CRR Revenue Adequacy Statistics

IFM Congestion Rents	$21,775,052.76
Existing Right Exemptions	-$1,019,574.25
Available Congestion Revenues	$20,755,478.51
CRR Payments	$25,466,859.70
CRR Revenue Adequacy	-$4,711,381.19
Revenue Adequacy Ratio	81.50%
Annual Auction Revenues	$3,643,474.15
Monthly Auction Revenues	$3,202,807.51
CRR Settlement Rule	$30,978.72
Allocation to Measured Demand	$2,165,879.19

Ancillary Services

IFM (Day-Ahead) Average Price

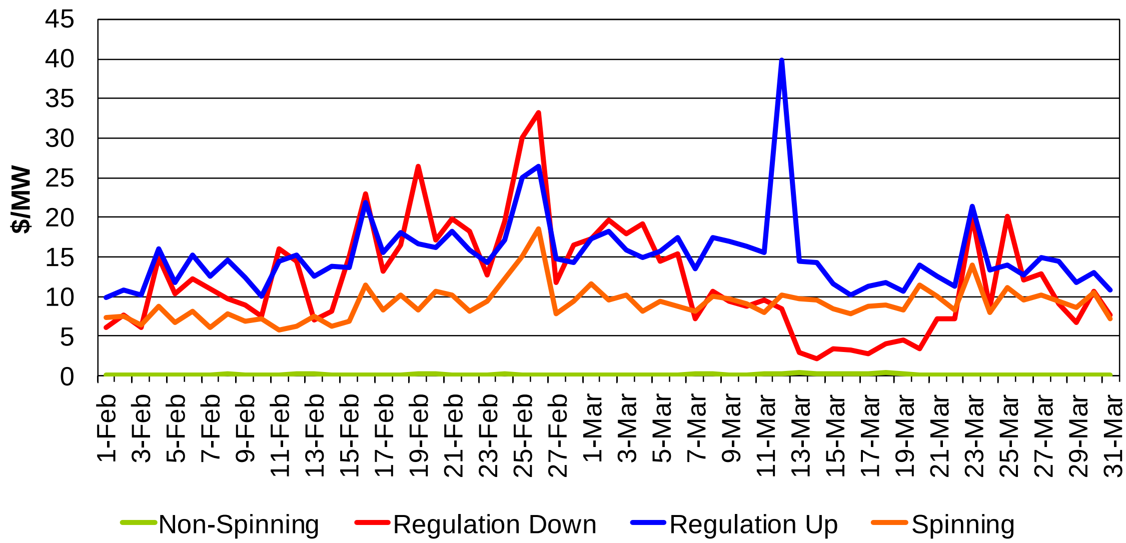
Table 5 shows the monthly IFM average ancillary service procurements and the monthly average prices. In March the monthly average procurement decreased for regulation up, regulation down, and spinning reserve.

Table 5: 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
Mar-17	311	369	712	713	$15.06	$9.90	$9.42	$0.15
Feb-17	322	380	715	708	$15.25	$14.75	$8.74	$0.11
Percent Change	-3.29%	-2.91%	-0.46%	0.74%	-1.21%	-32.87%	7.88%	37.94%

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

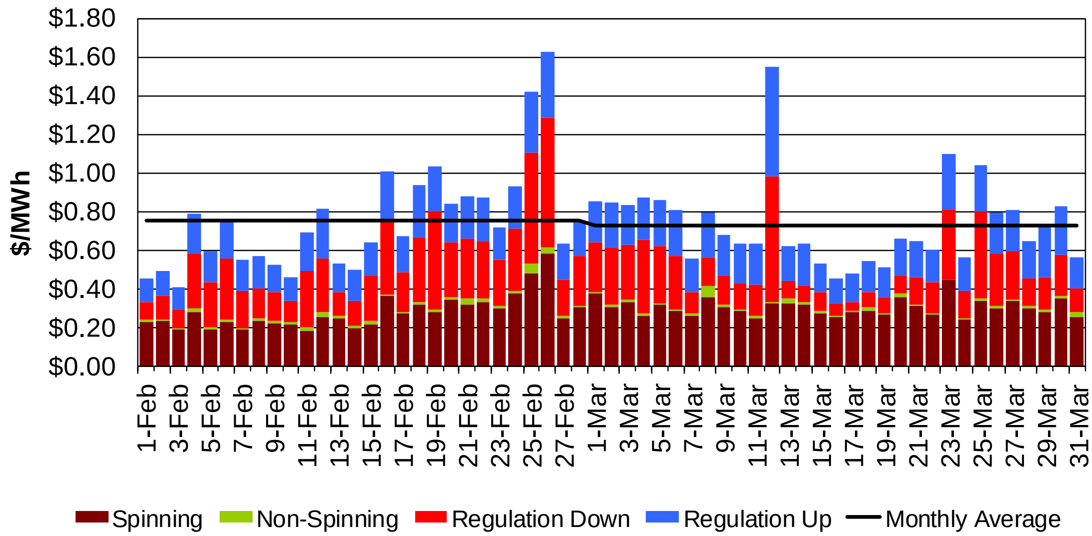
Figure 12: IFM (Day-Ahead) Ancillary Service Average Price



Ancillary Service Cost to Load

The monthly average cost to load edged down to $0.73/MWh in March from $0.75/MWh in February. The average cost was high on March 12, driven by high regulation up and regulation down prices in day-ahead market.

Figure 13: System (Day-Ahead and Real-Time) Average Cost to Load



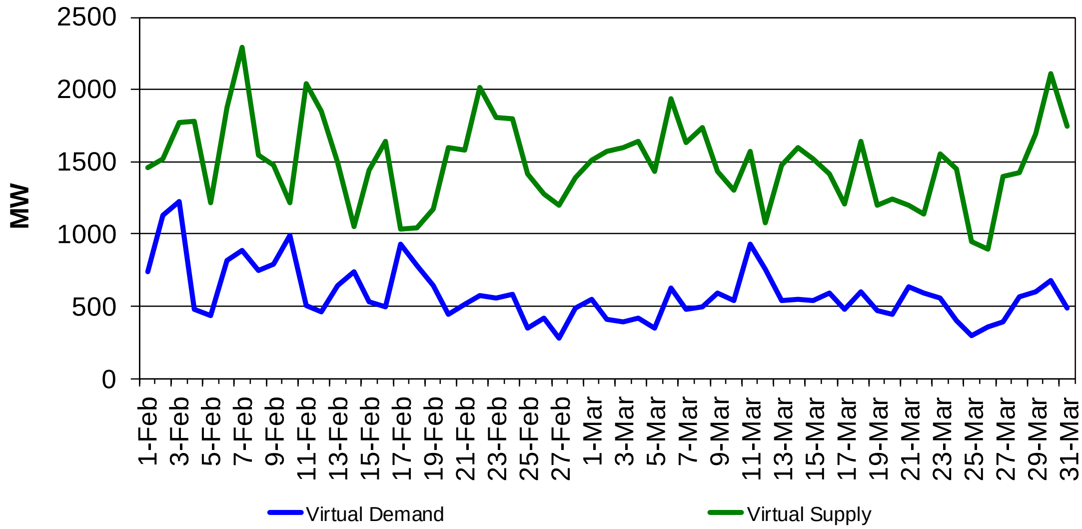
Scarcity Events

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 March 24, 2017, a regulation up scarcity occurred in the 15-minute market run for hour ending 13, interval 4 in the California ISO expanded system region. The procurement shortfall was 2.33 MW or 0.8% of the target procurement quantity. On March 30, 2017, a regulation down scarcity occurred in the 15-minute market run for hour ending 11, interval 4 in the ISO expanded system region. The procurement shortfall was 0.58 MW or 0.1% of the target procurement quantity. On March 31, 2017, a spinning reserve scarcity occurred in the 15-minute market run for hour ending 11, intervals 3 and 4 in the SP26 region. The procurement shortfall was 15 MW or 12% 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 was well above cleared demand throughout this month.

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

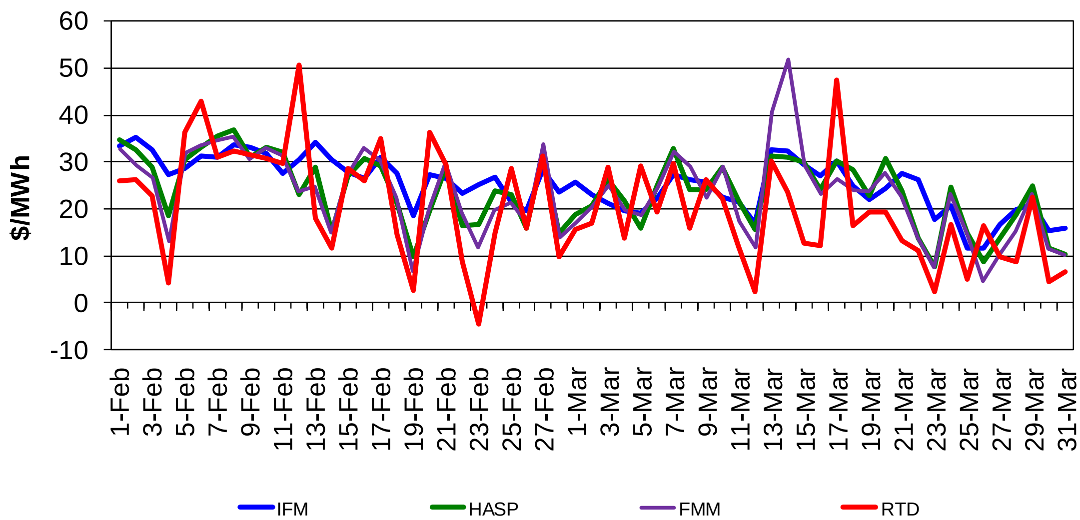
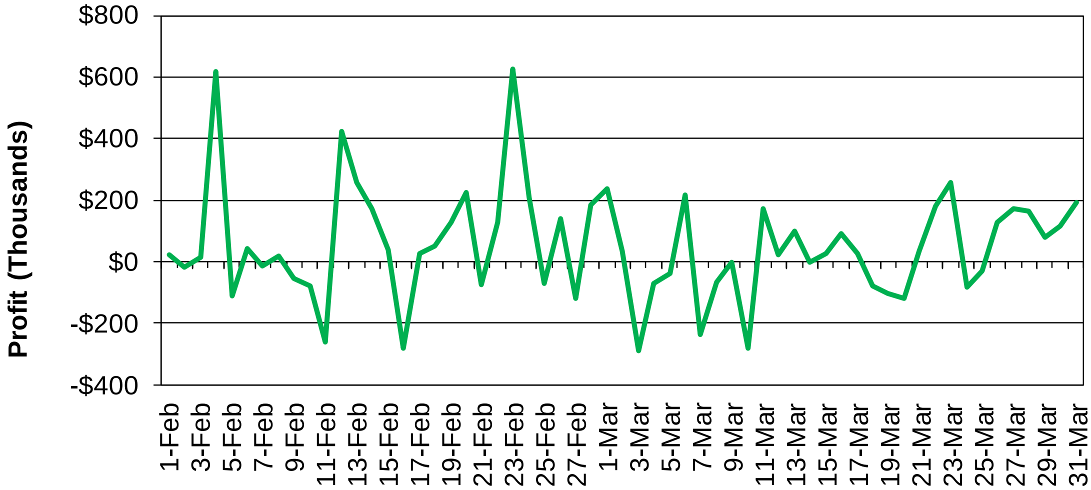


Figure 16 shows the profits that convergence bidders receive from convergence bidding. The total profits from convergence bidding dropped to $0.83 million in March from $2.21 million in February.

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 rose in March. The majority of the curtailments was economic.

Figure 17: Renewable Curtailment by Reason

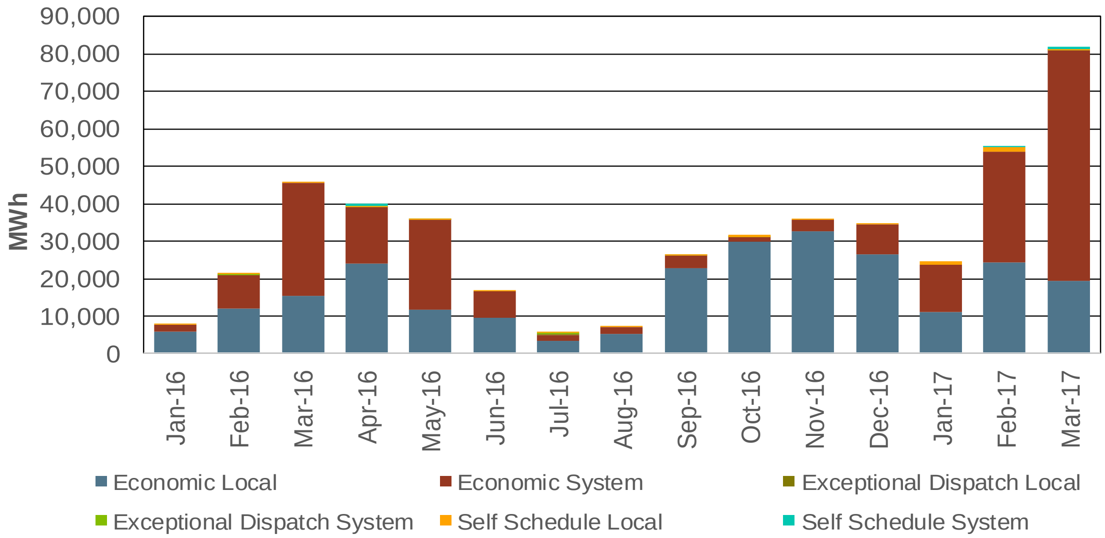
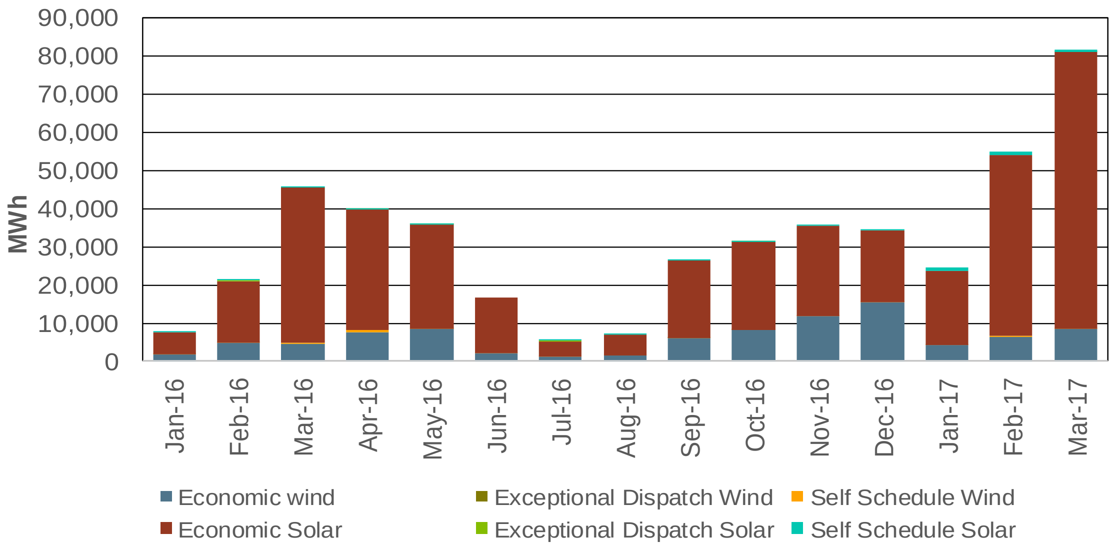


Figure 18: Renewable Curtailment by Resource Type



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 increased to $1.63 million in March from $1.13 Million in February. Flexible ramping down uncertainty payment increased to $0.29 million in March from $0.21 Million in February.

Figure 19: Flexible Ramping Up/down Uncertainty Payment

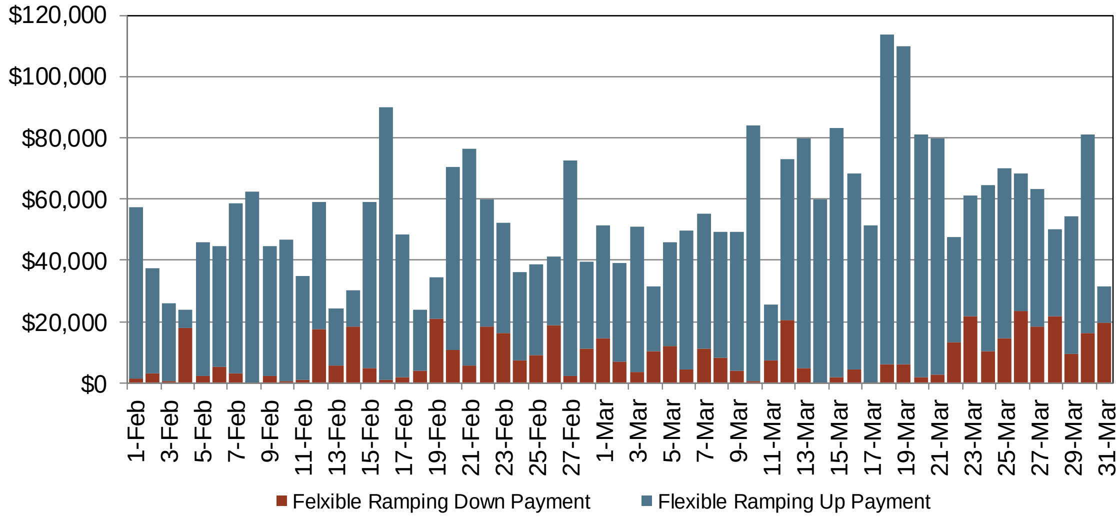
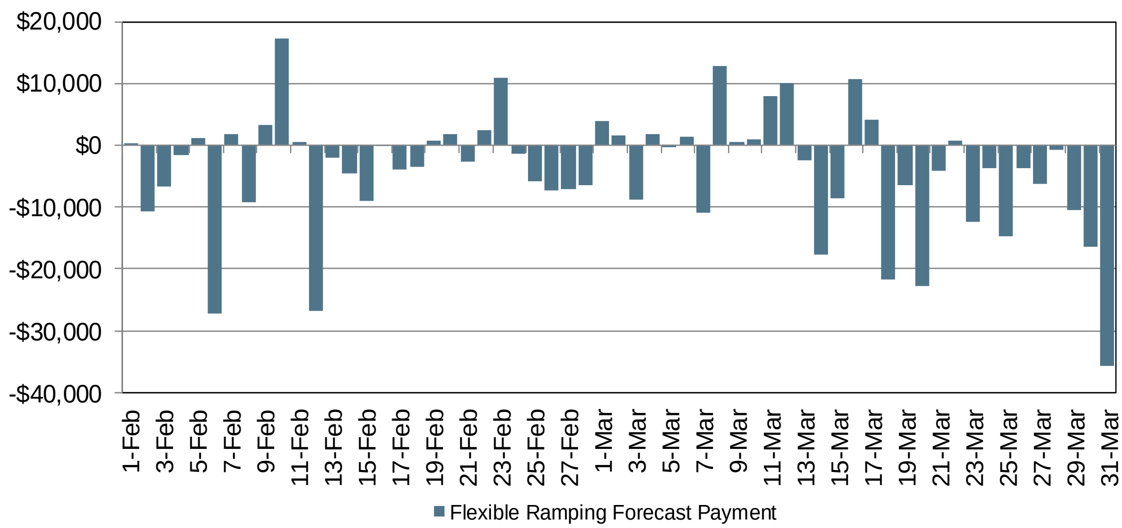


Figure 20 shows the flexible ramping forecast payment. Flexible ramping forecast payment fell to -$0.15 million this month from $-0.10 in February.

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 March inched up to $80,355 from $75,489 in February.

Figure 21: Exceptional Dispatch Uplift Costs

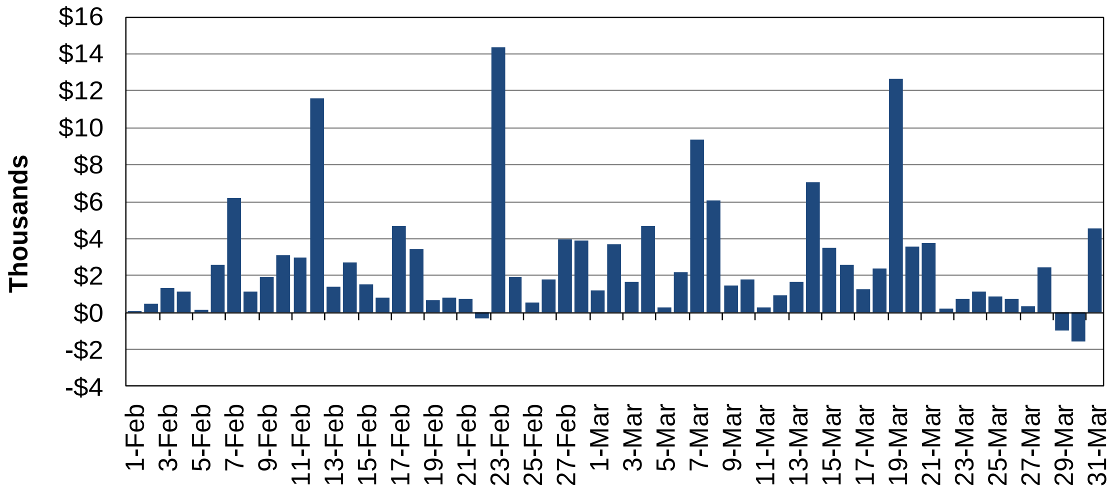


Figure 22 shows the allocation of bid cost recovery payment in the IFM, real-time unit commitment (RUC) and RTM markets. The total bid cost recovery for March increased to $7.21 million from $6.05 million in February. Out of the total monthly bid cost recovery payment for the three markets in March, the IFM market contributed 23 percent, RTM contributed 38 percent, and RUC contributed 39 percent of the total bid cost recovery payment.

Figure 22: Bid Cost Recovery Allocation

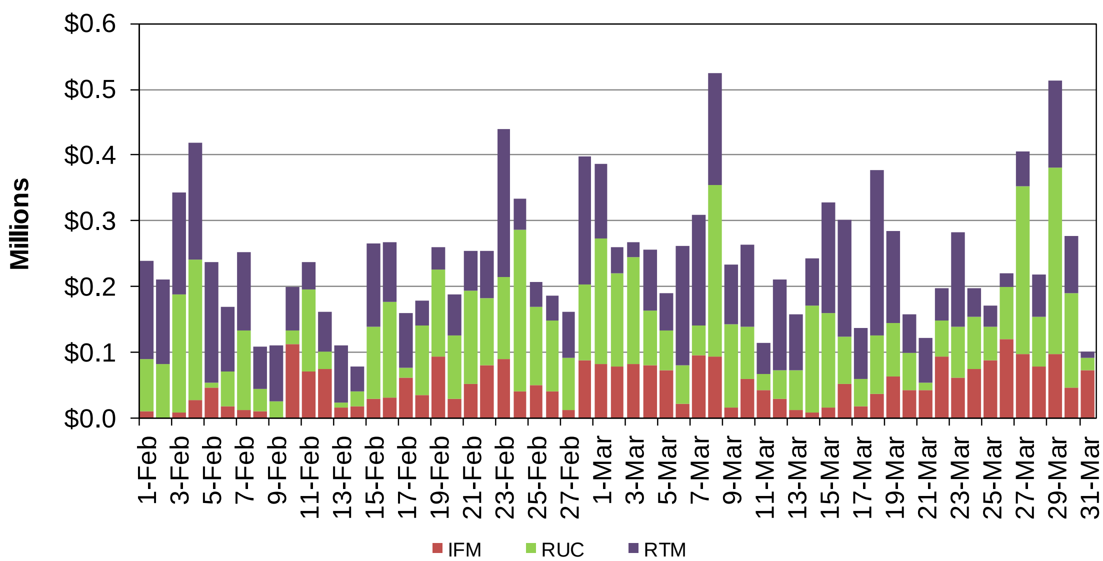


Figure 23 and Figure 24 show the daily and monthly BCR cost by local capacity requirement area (LCR) respectively.

Figure 23: Bid Cost Recovery Allocation by LCR

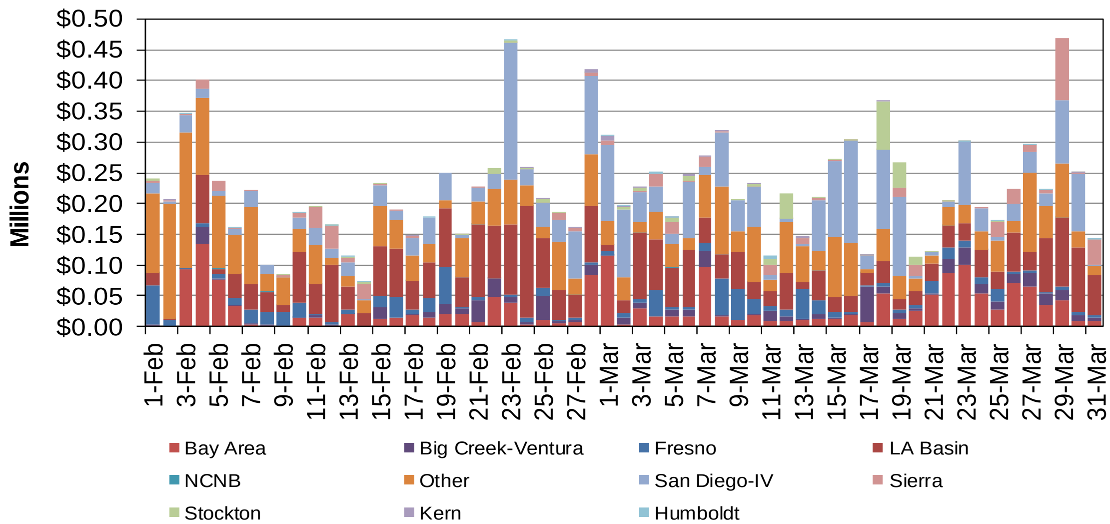


Figure 24: Monthly Bid Cost Recovery Allocation by LCR

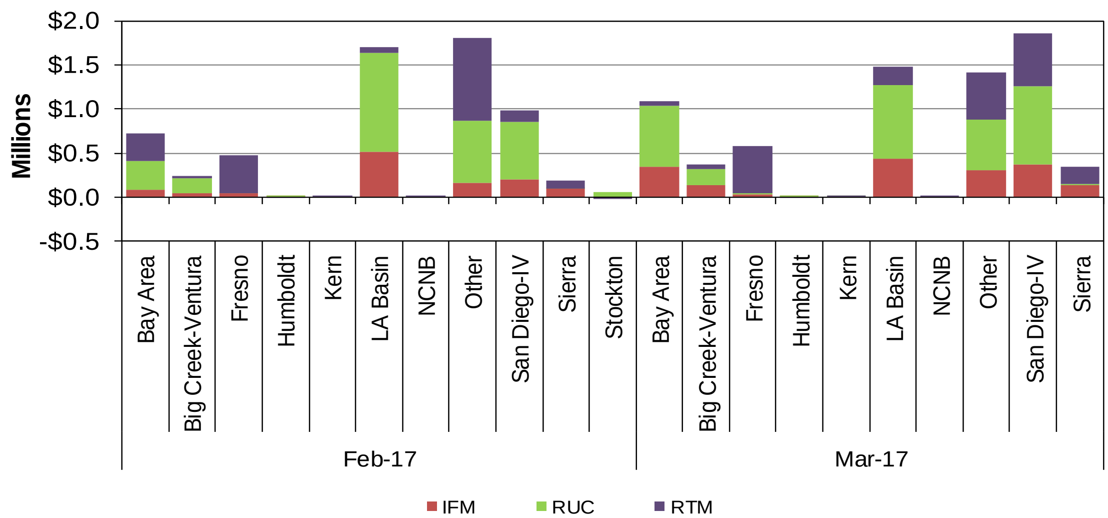


Figure 25 and Figure 26 show the daily and monthly BCR cost by utility distribution company (UDC) respectively.

Figure 25: Bid Cost Recovery Allocation by UDC

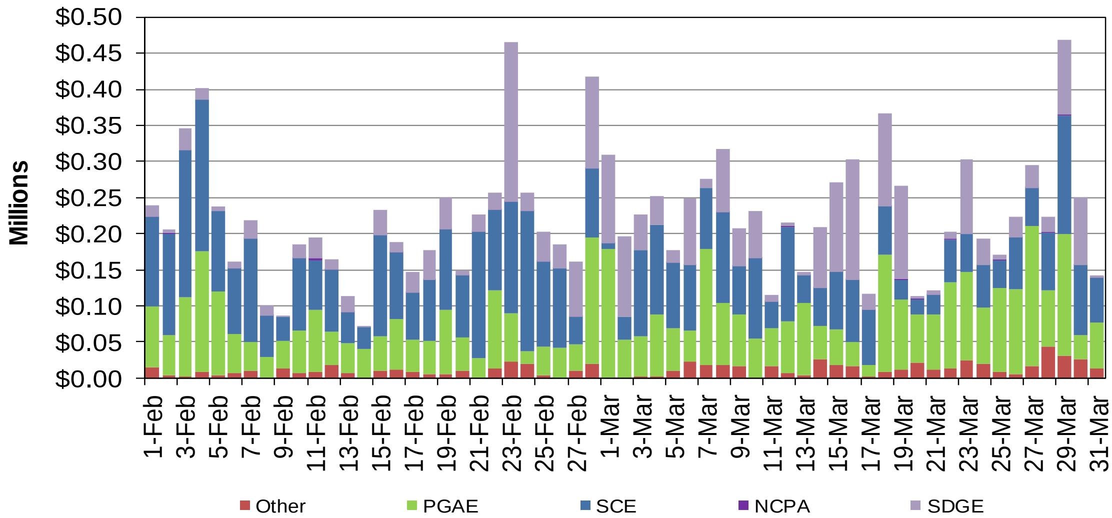


Figure 26: Monthly Bid Cost Recovery Allocation by UDC

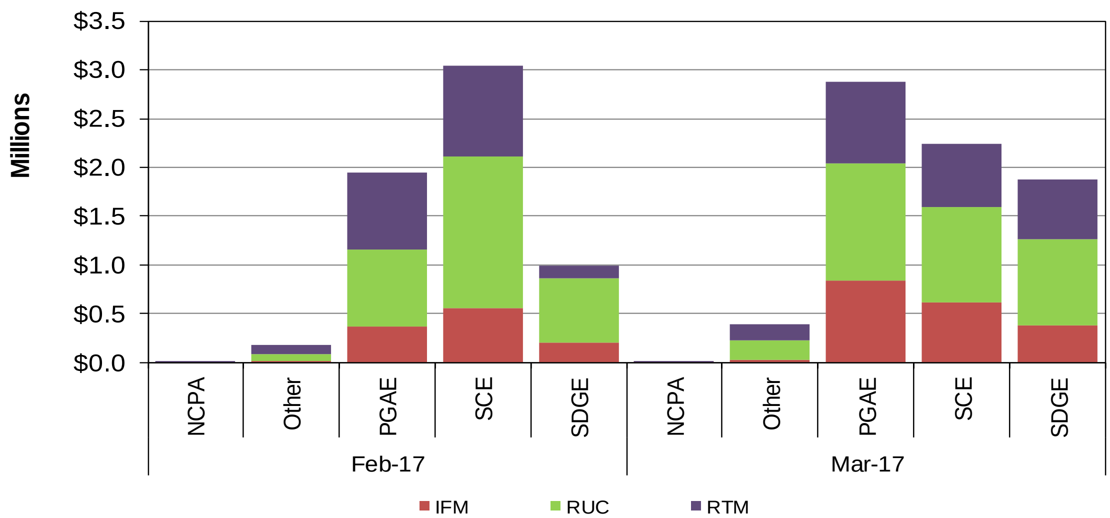


Figure 27 shows the cost related to BCR by cost type in RUC, which in March was mainly driven by minimum load cost (MLC) and start-up cost (SUC).

Figure 27: Cost in RUC

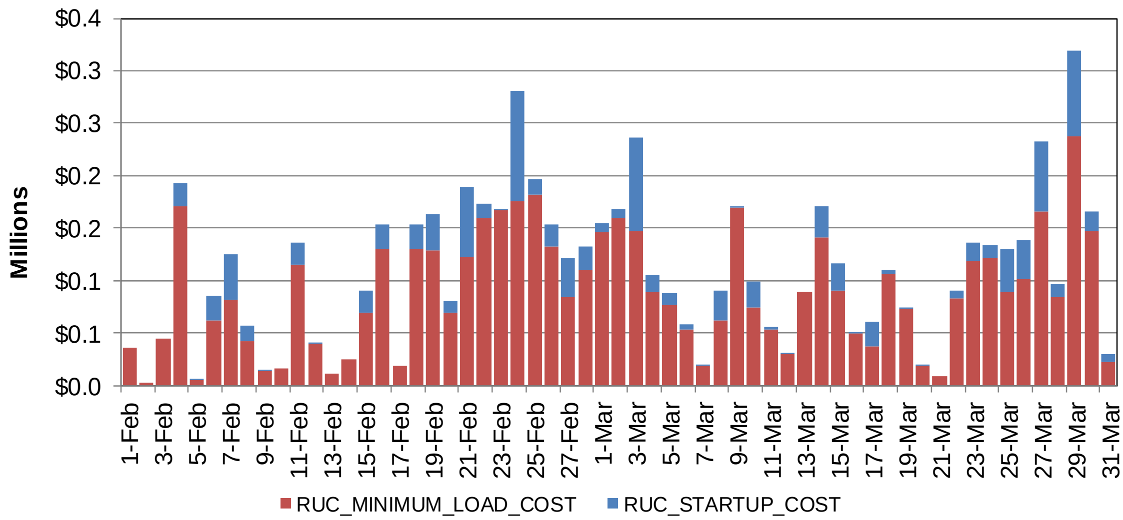


Figure 28 and Figure 29 show the daily and monthly cost related to BCR by type and LCR in RUC respectively.

Figure 28: Cost in RUC by LCR

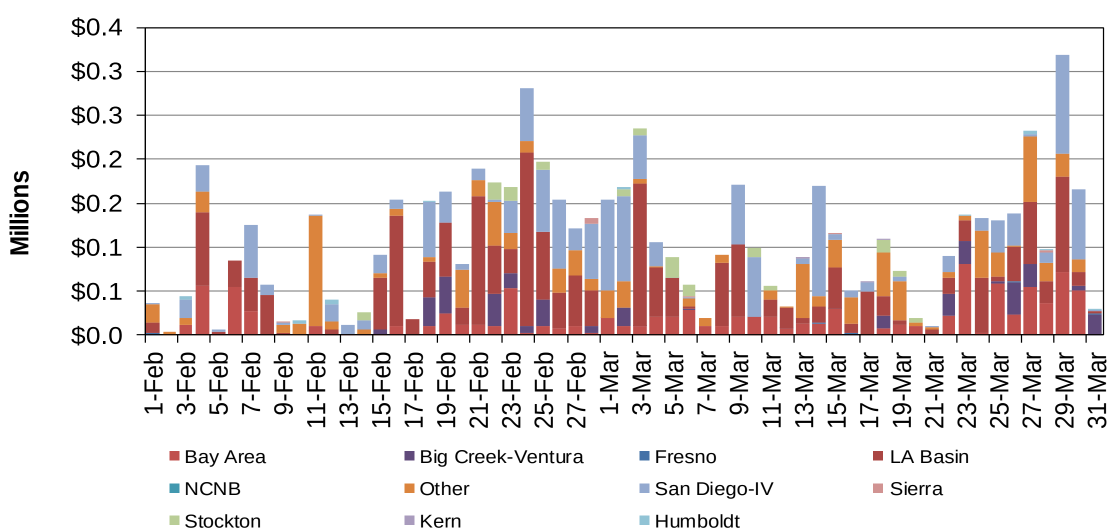


Figure 29: Monthly Cost in RUC by LCR

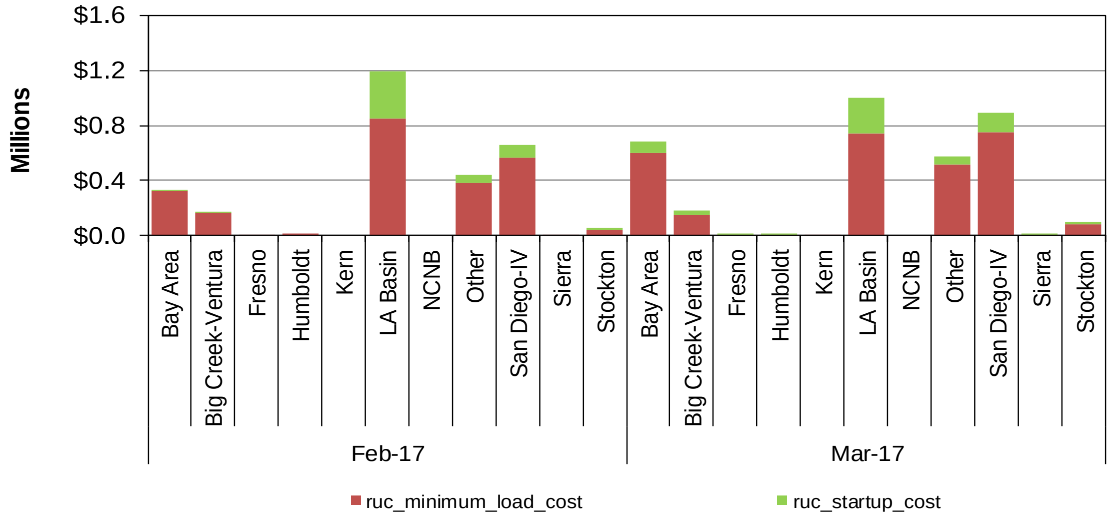


Figure 30 and Figure 31 show the daily and monthly cost related to BCR by type and UDC in RUC respectively.

Figure 30: Cost in RUC by UDC

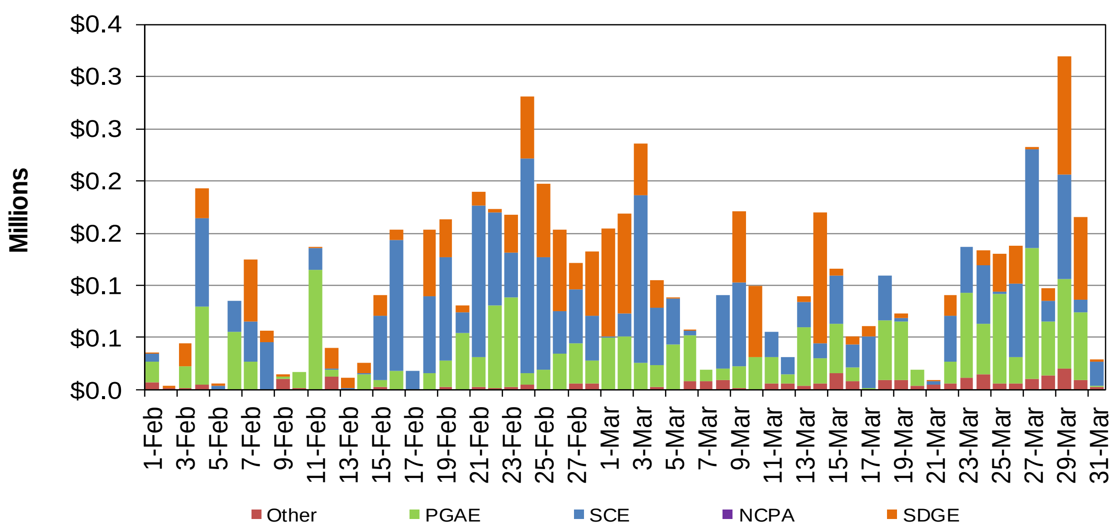


Figure 31: Monthly Cost in RUC by UDC

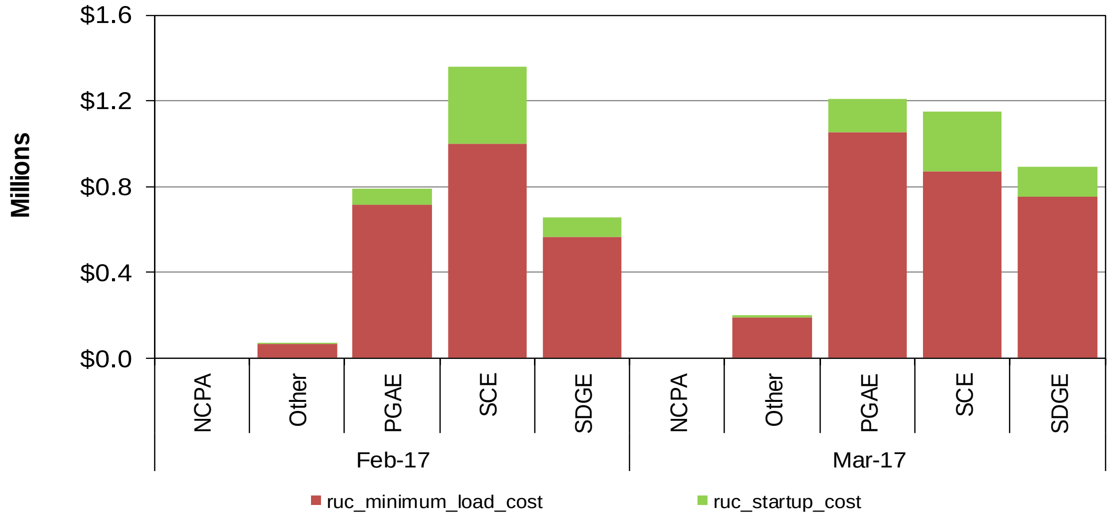


Figure 32 shows the cost related to BCR in real time by cost type. Minimum load cost contributed mostly to the real time cost in March.

Figure 32: Cost in Real Time

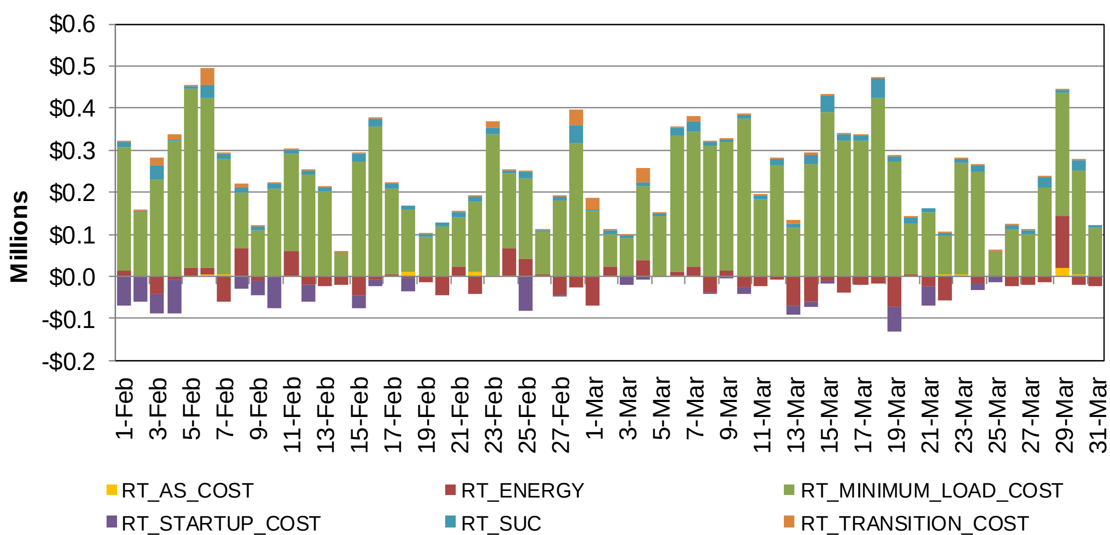


Figure 33 and Figure 34 show the daily and monthly cost related to BCR by type and LCR in real time respectively.

Figure 33: Cost in Real Time by LCR

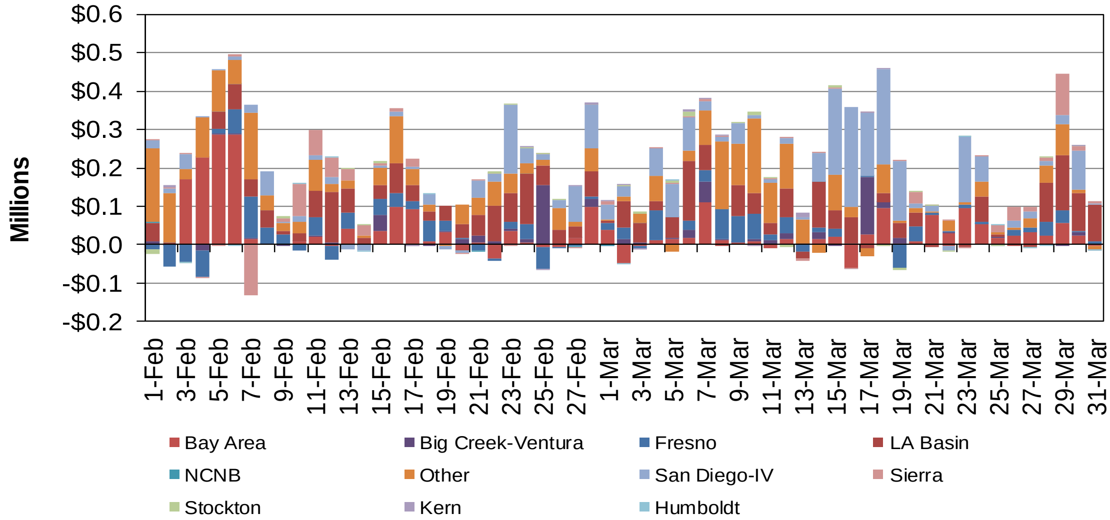


Figure 34: Monthly Cost in Real Time by LCR

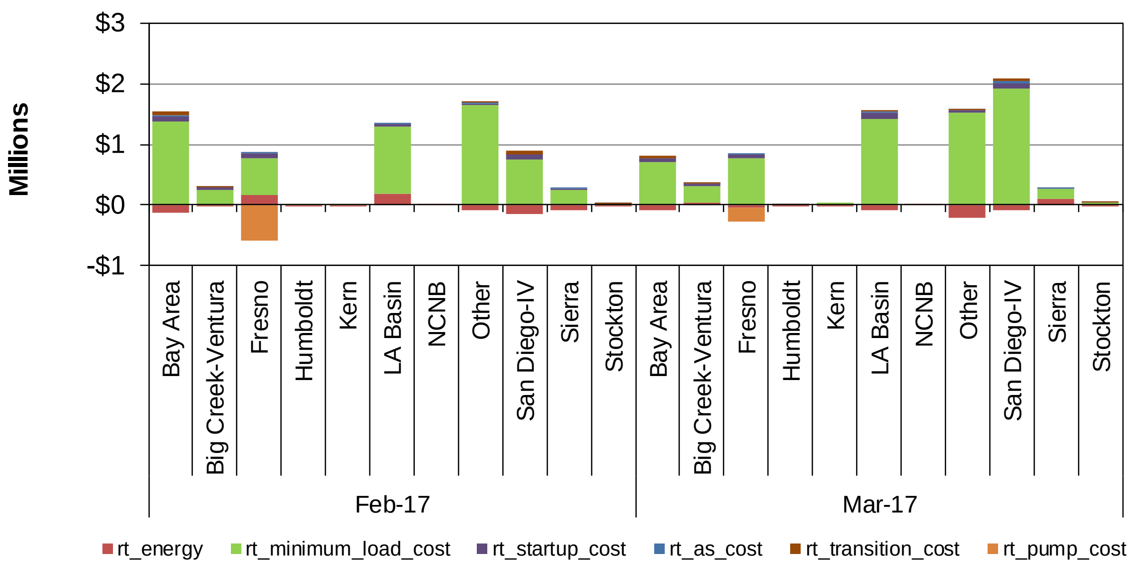


Figure 35 and Figure 36 show the daily and monthly cost related to BCR by type and UDC in Real Time respectively.

Figure 35: Cost in Real Time by UDC

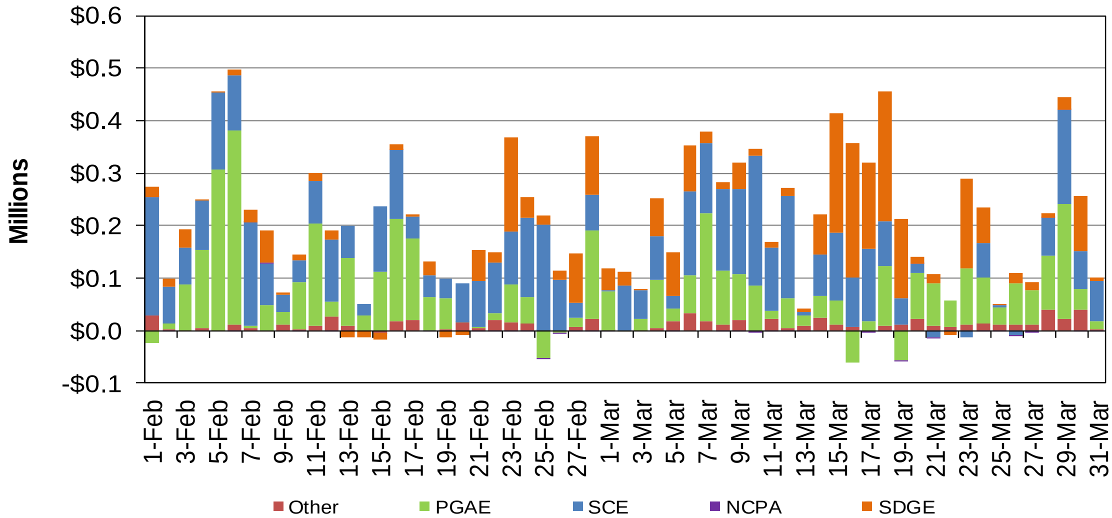


Figure 36: Monthly Cost in Real Time by UDC

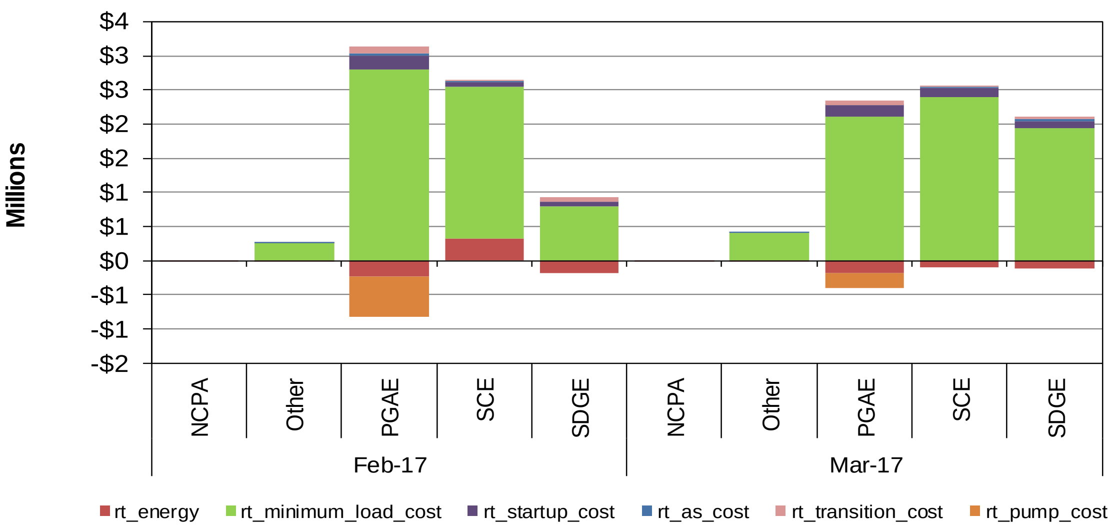


Figure 37 shows the cost related to BCR in IFM by cost type. Minimum Load cost and energy cost contributed largely to the cost in IFM in March.

Figure 37: Cost in IFM

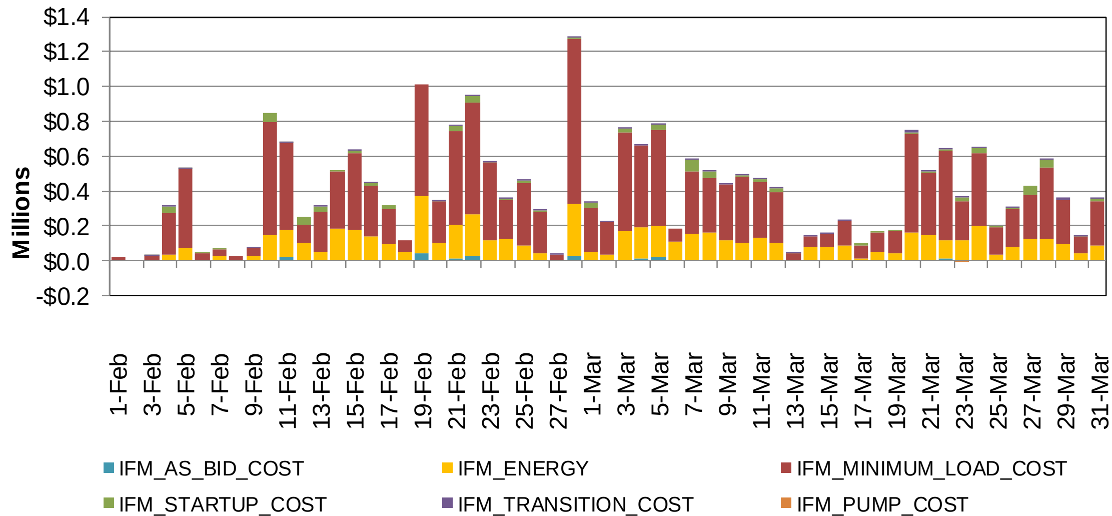


Figure 38 and Figure 39 show the daily and monthly cost related to BCR by type and location in IFM respectively.

Figure 38: Cost in IFM by LCR

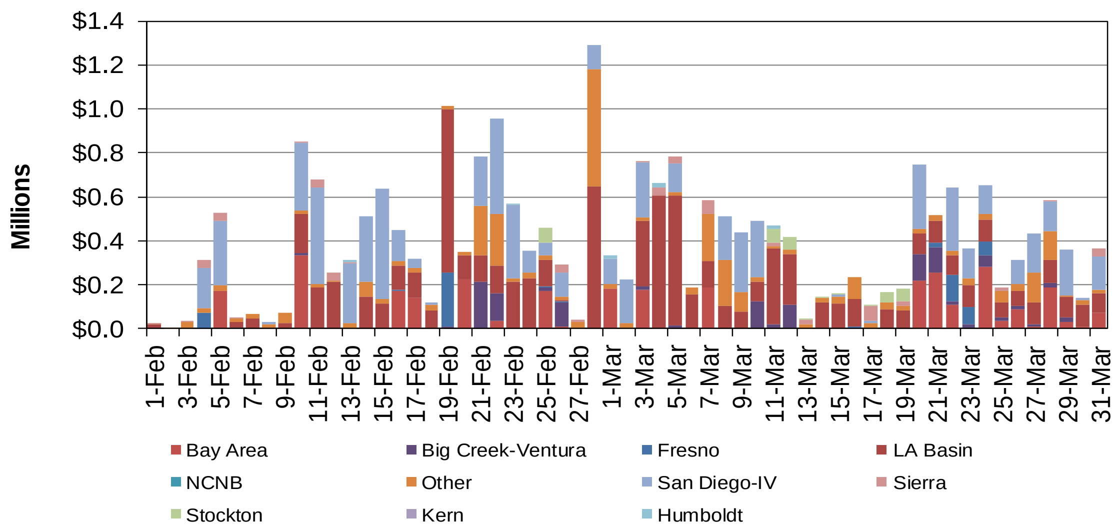


Figure 39: Monthly Cost in IFM by LCR

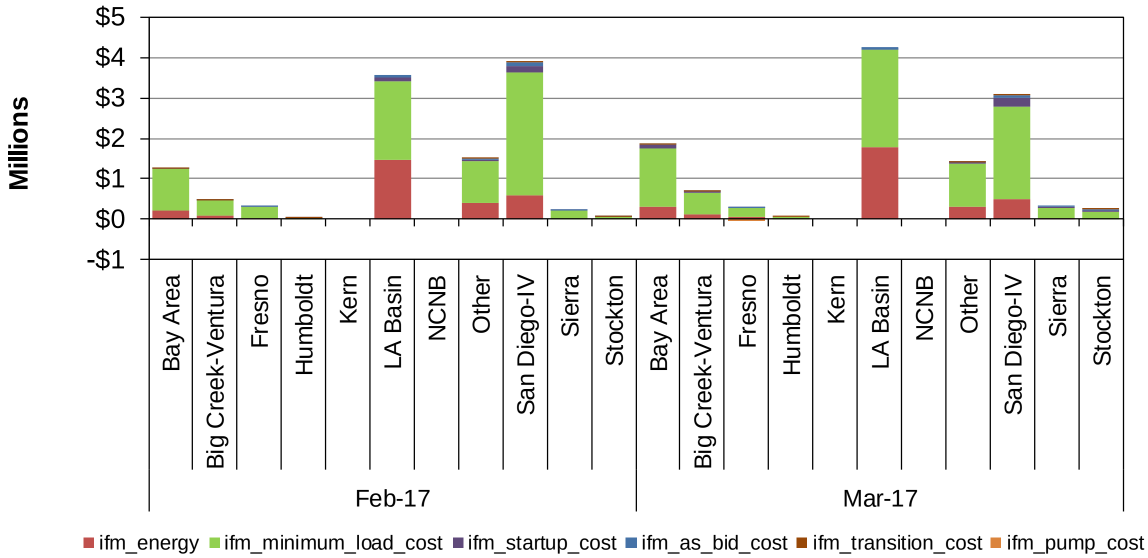


Figure 40 and Figure 41 show the daily and monthly cost related to BCR by type and UDC in IFM respectively.

Figure 40: Cost in IFM by UDC

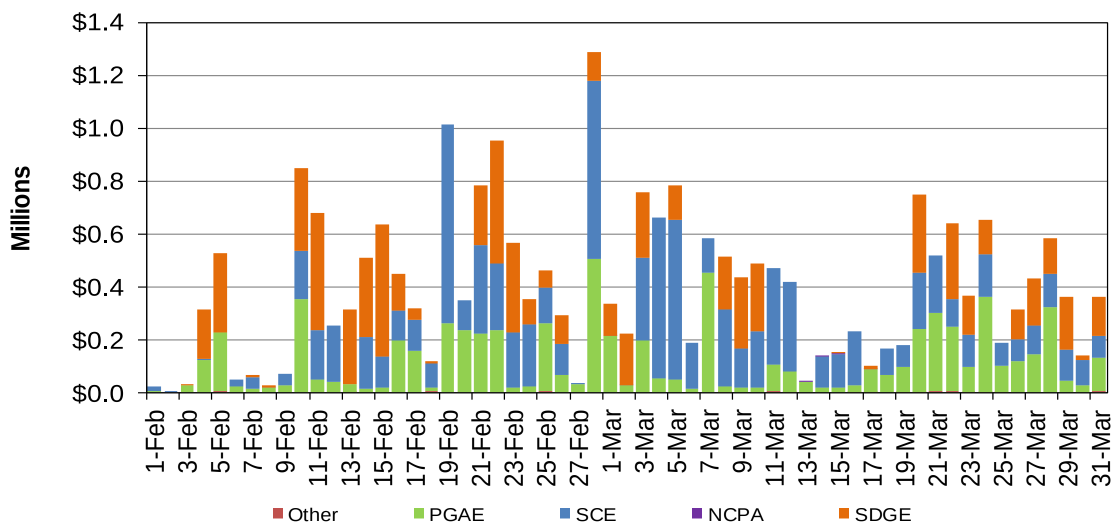
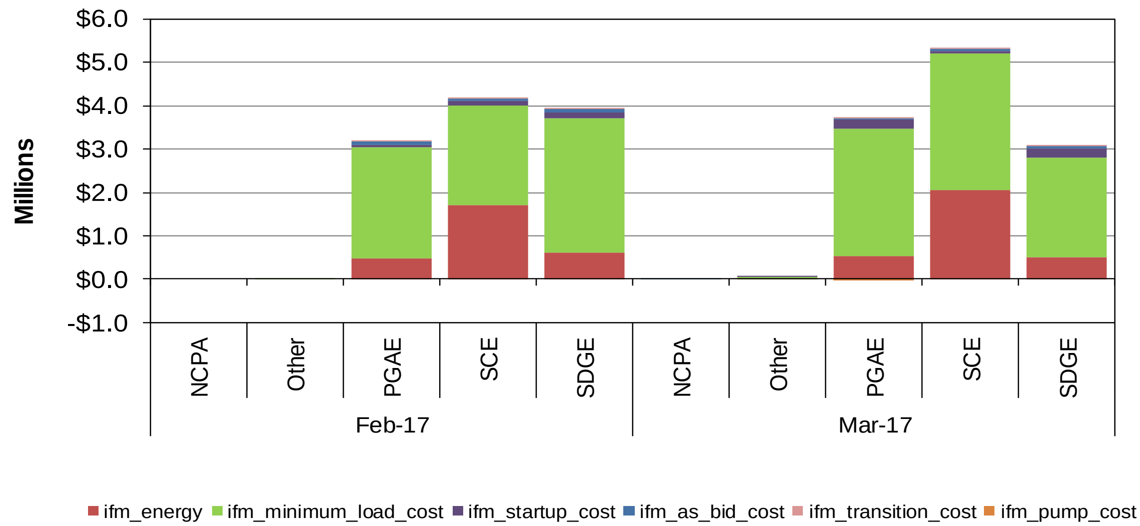


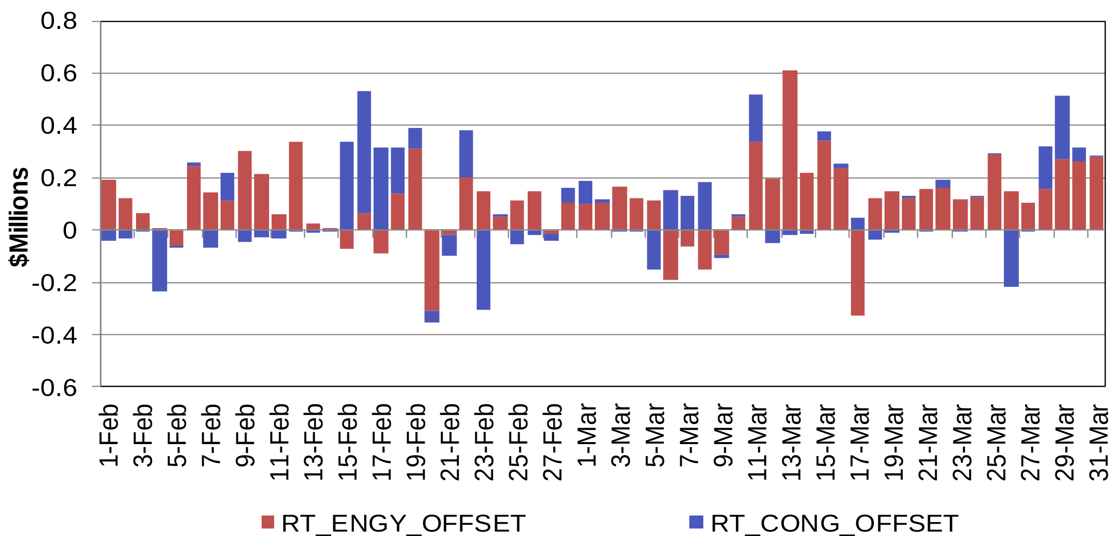
Figure 41: Monthly Cost in IFM by UDC



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 $4.25 million in March from $2.55 million in February. Real-time congestion offset cost inched up to $0.86 million in March from $0.71 million in February.

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.[2] 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 82 market disruptions in March. Table 6 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.

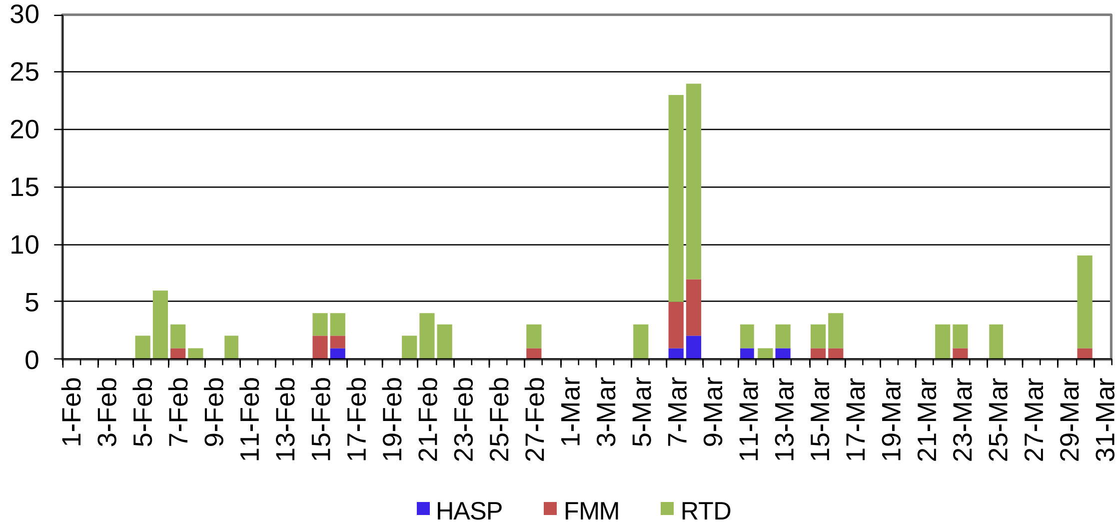
Table 6: Summary of Market Disruption

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	5	0
FMM Interval 3	2	0
FMM Interval 4	8	0
Real-Time Dispatch	64	0

Figure 43 shows the frequency of IFM, HASP (FMM interval 2), FMM (intervals 1, 3 and 4), and RTD failures. On March 7, one HASP disruption, four FMM, and 18 RTD disruptions occurred due to application problem. On March 8, two HASP disruptions, five FMM, and 17 RTD disruptions occurred due to application problem.

[2] 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 March dropped to 48,963 MWh from 49,894 MWh in February.

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

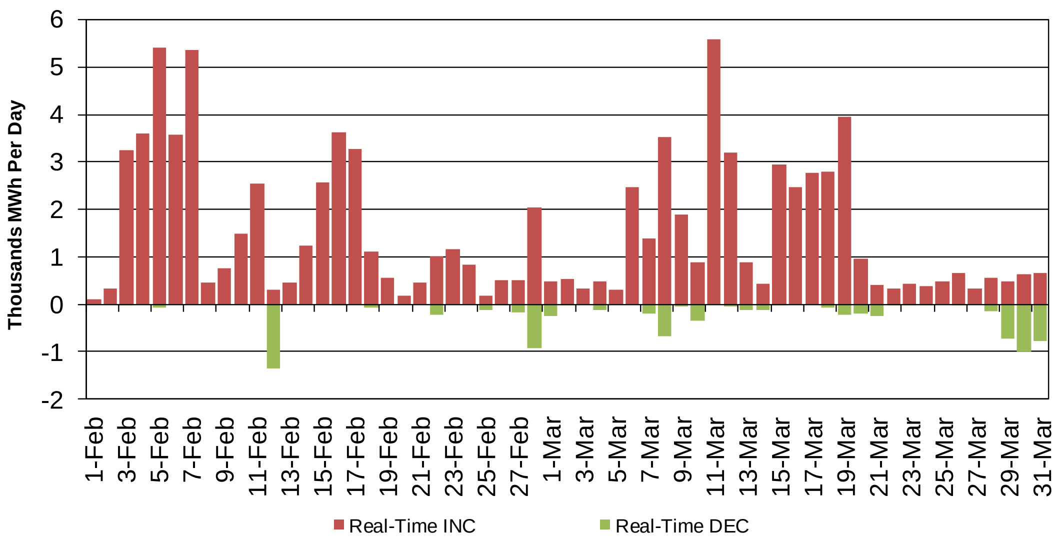


Figure 45 shows the volume of the exceptional dispatch broken out by reason.[3] The majority of the exceptional dispatch volumes in March were driven by operating procedure number and constraint (28 percent), voltage support (24 percent), and planned transmission outage and constraint (23 percent).

[3] 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

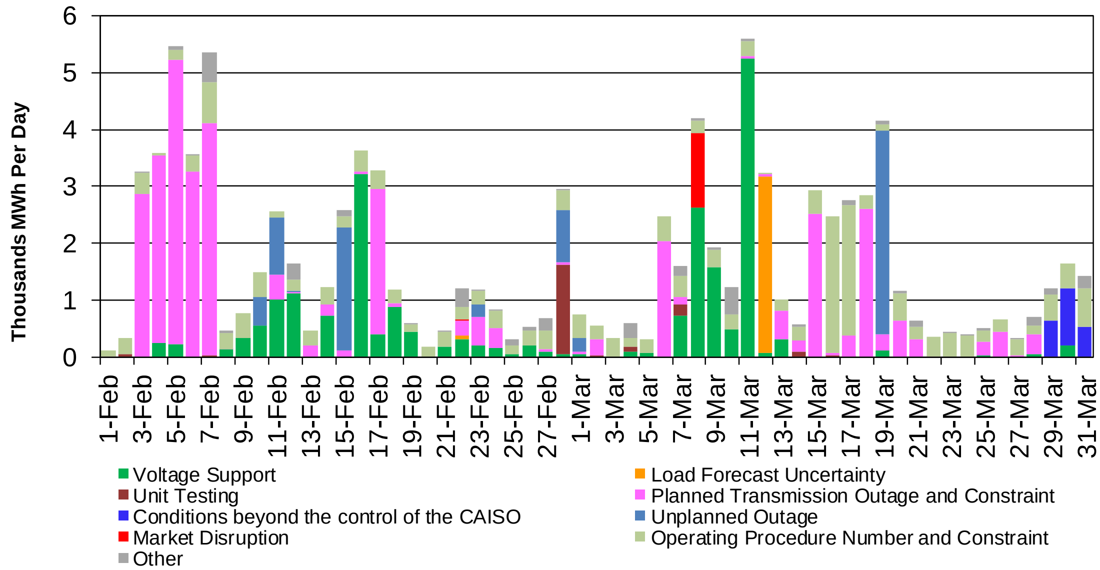
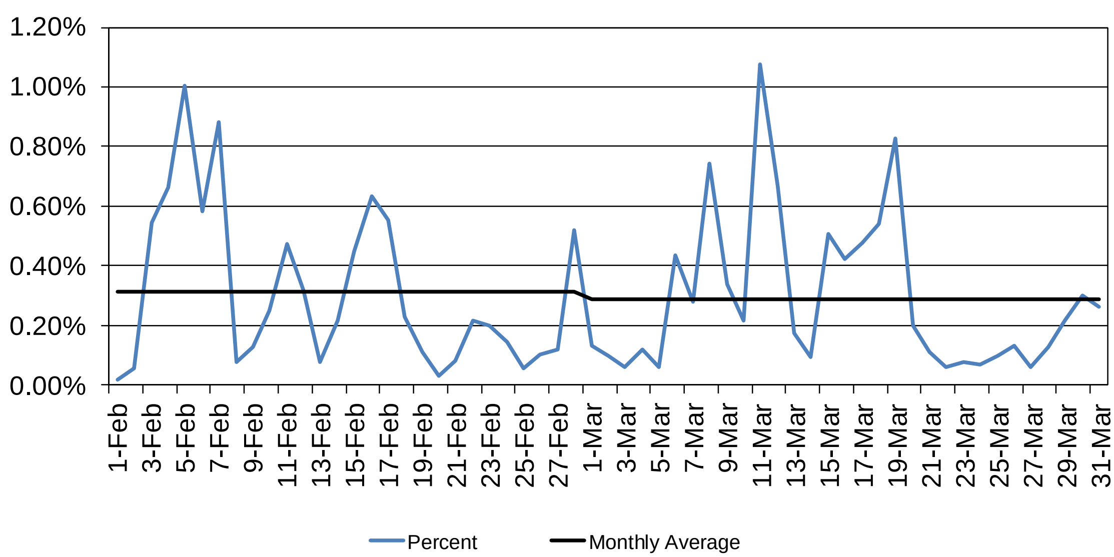


Figure 46 shows the total exceptional dispatch volume as a percent of load, along with the monthly average. The monthly average percentage decreased to 0.29 percent in March from 0.31 percent in February.

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 March 14, the price for NEVP was elevated, driven by generation outage.

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

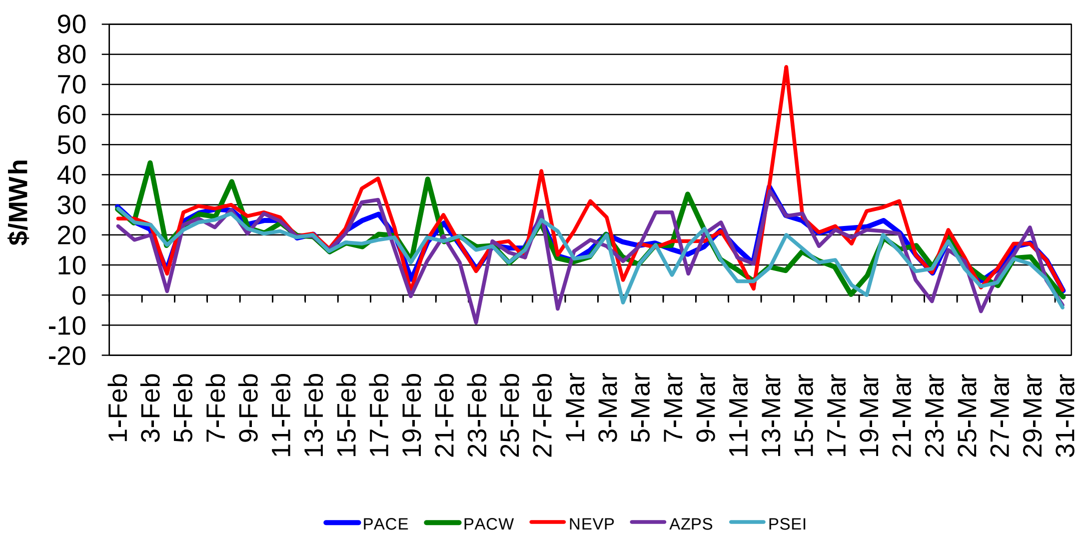


Figure 48 shows daily simple average ELAP prices for PACE, PACW, NEVP, AZPS and PSEI for all hours in RTD. The ISO declared an interruption of the

Nevada Energy Balancing Area Authority (BAA) on March 6 starting in Hour ending 18 due to transmission outage that is separating Nevada north and south areas. The market interruption ended on March 10 in HE 18. The administrative pricing applies to Nevada during the time period, resulting in relatively high prices for NEVP on March 6-10. On March 14, the price for NEVP was elevated, driven by generation outage.

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

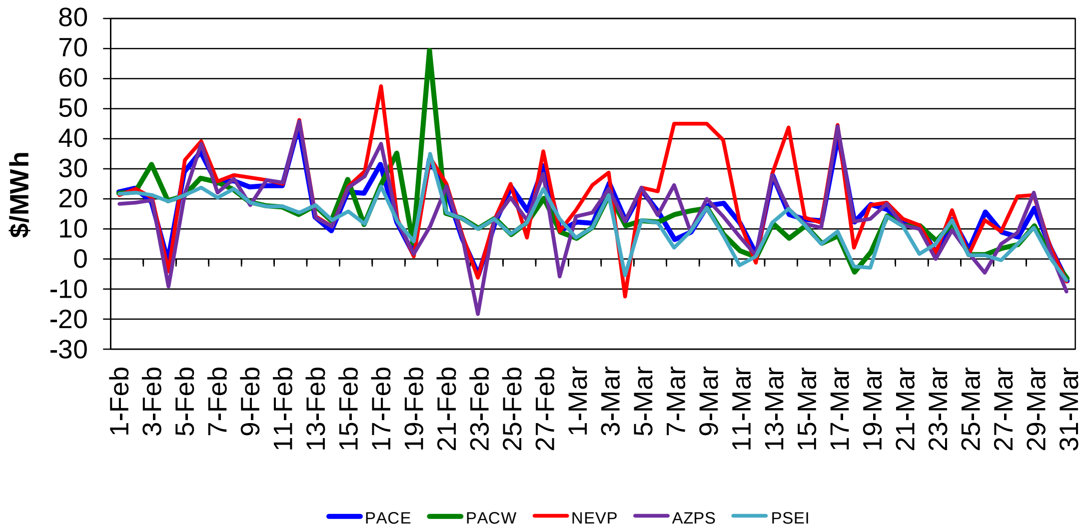


Figure 49 shows the daily price frequency for prices above $250/MWh and negative prices in FMM for PACE, PACW, NEVP, AZPS and PSEI. The cumulative frequency of prices above $250/MWh increased to 0.15 percent in March from 0.07 percent in February. The cumulative frequency of negative prices rose to 18.82 percent in March from 9.05 percent in February.

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

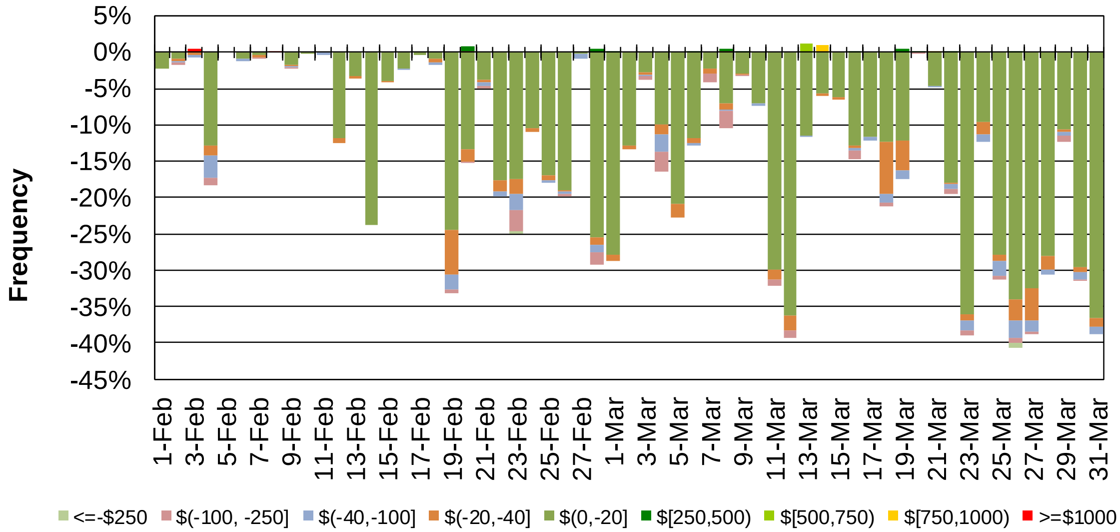


Figure 50 shows the daily price frequency for prices above $250/MWh and negative prices in RTD for PACE, PACW, NEVP, AZPS and PSEI. The cumulative frequency of prices above $250/MWh decreased to 0.44 percent in March from 0.51 percent in February. The cumulative frequency of negative prices rose to 23.87 percent in March from 11.57 percent in February.

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

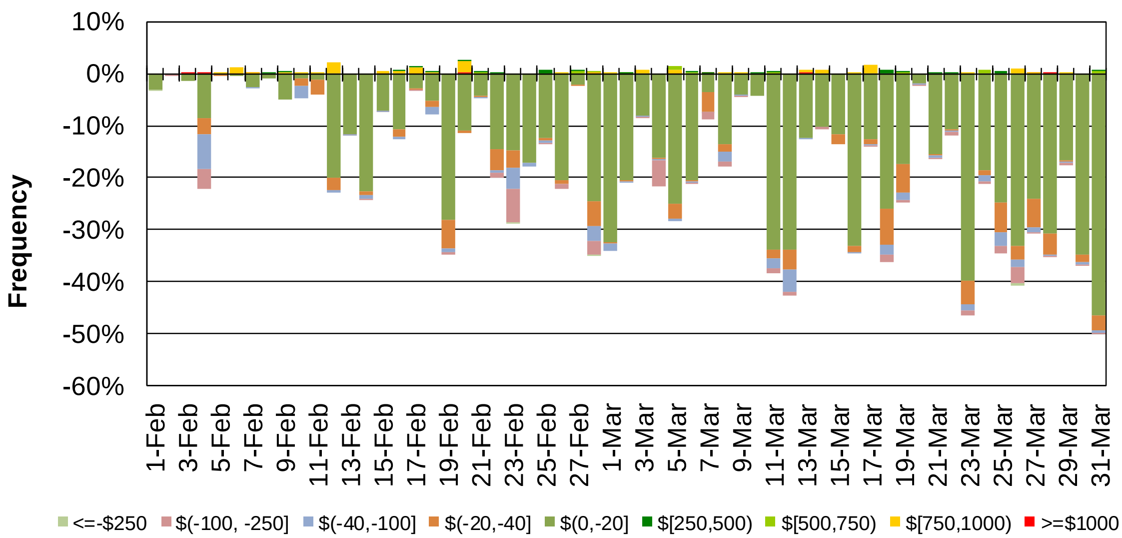


Figure 51 shows the daily volume of EIM transfer between ISO and PacifiCorp in FMM. Figure 52 shows the daily volume of EIM transfer between PACE and PACW in FMM.

Figure 51: EIM Transfer between CAISO and PAC in FMM

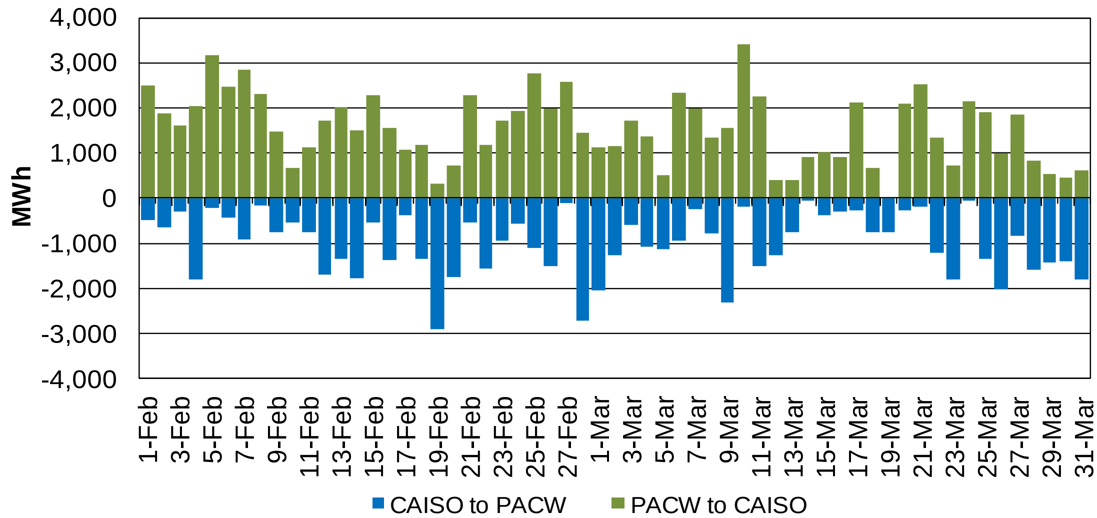


Figure 52: EIM Transfer between PACE and PACW in FMM

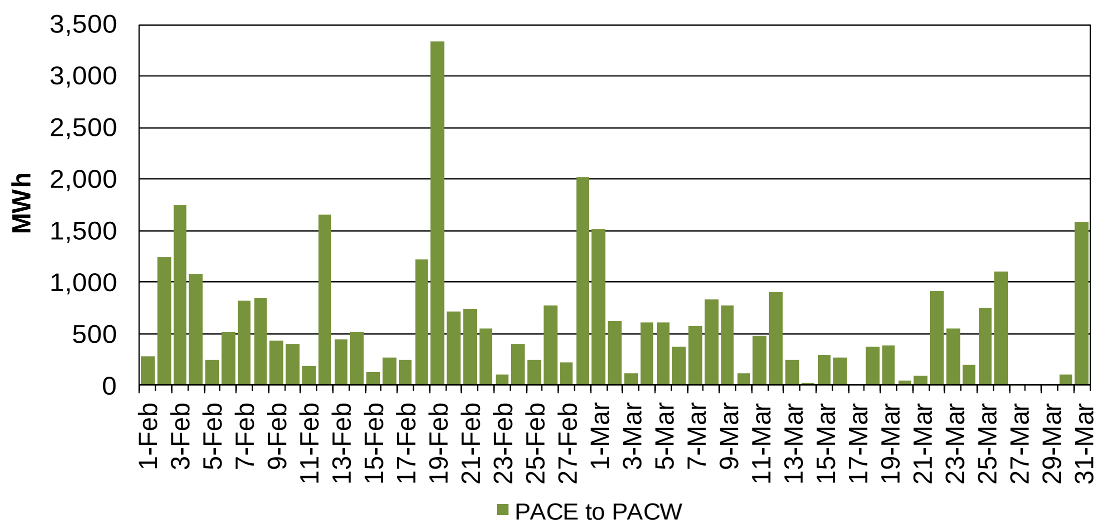


Figure 53 shows the daily volume of EIM transfer between CAISO and NEVP in FMM. The EIM transfer from NEVP to ISO decreased in March compared with February. The EIM transfer from ISO to NEVP trended upward in March. Figure 54 shows the daily volume of EIM transfer between PACE and NEVP in FMM.

Figure 53: EIM Transfer between CAISO and NEVP in FMM

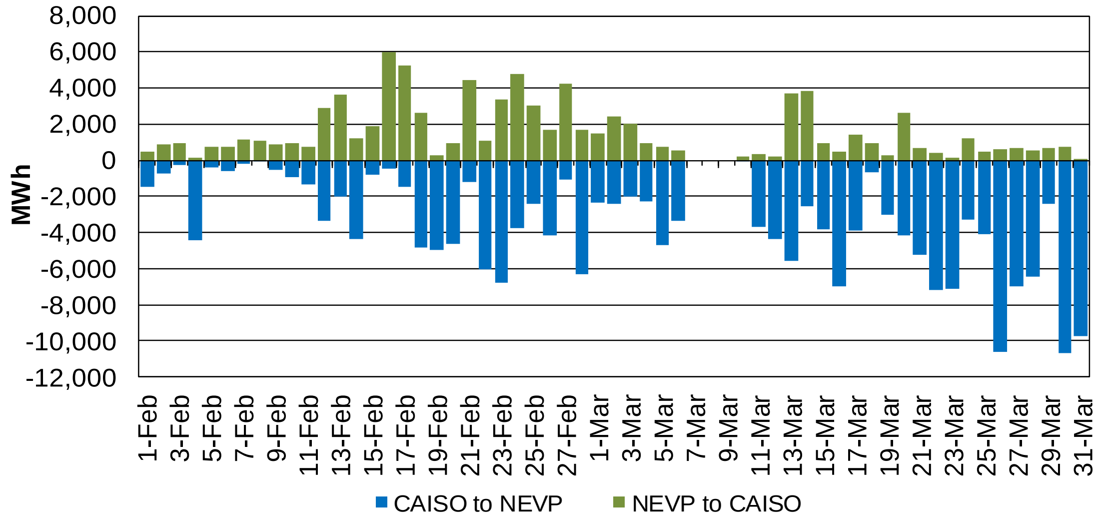


Figure 54: EIM Transfer between PACE and NEVP in FMM

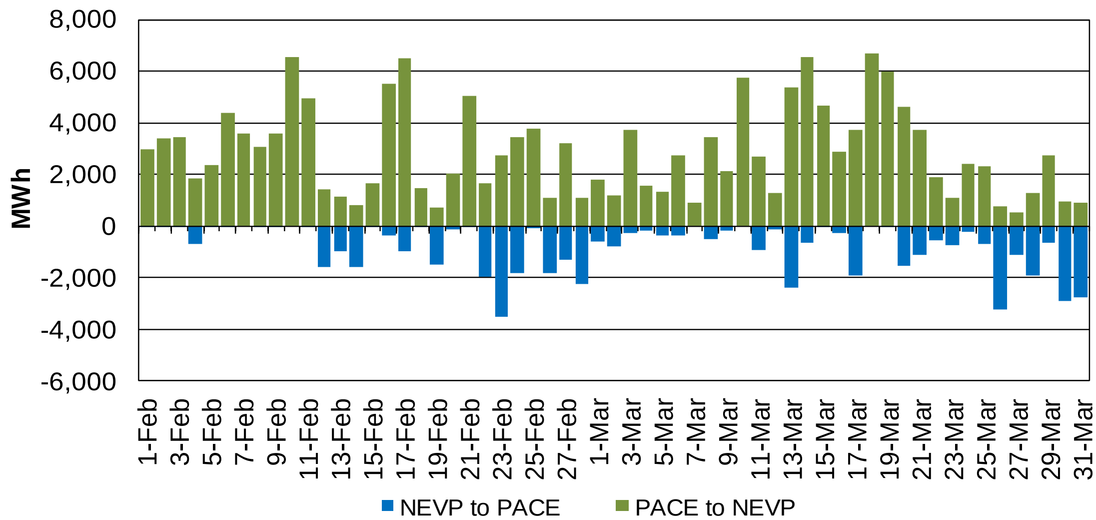


Figure 55 shows the daily volume of EIM transfer between ISO and AZPS in FMM. The EIM transfer from AZPS to ISO decreased in March compared with February. Figure 56 shows the daily volume of EIM transfer between PACE and AZPS in FMM.

Figure 55: EIM Transfer between CAISO and AZPS in FMM

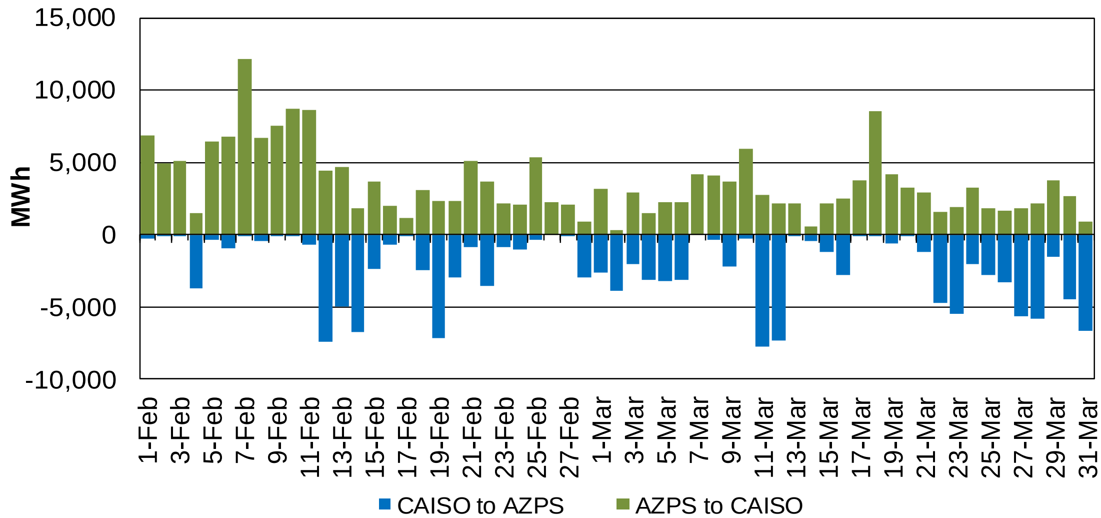


Figure 56: EIM Transfer between PACE and AZPS in FMM

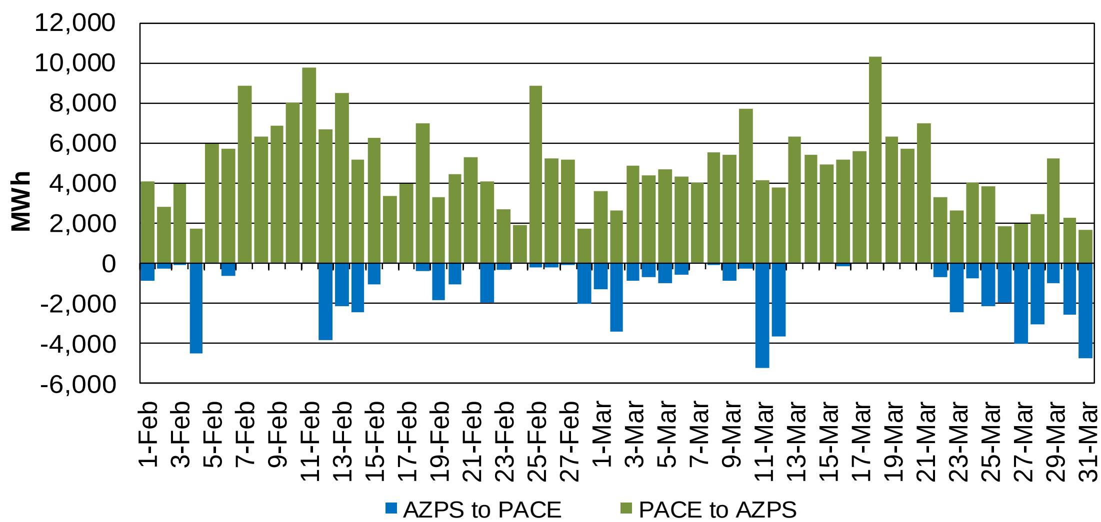


Figure 57 shows the daily volume of EIM transfer between PACW and PSEI in FMM.

Figure 57: EIM Transfer between PACW and PSEI in FMM

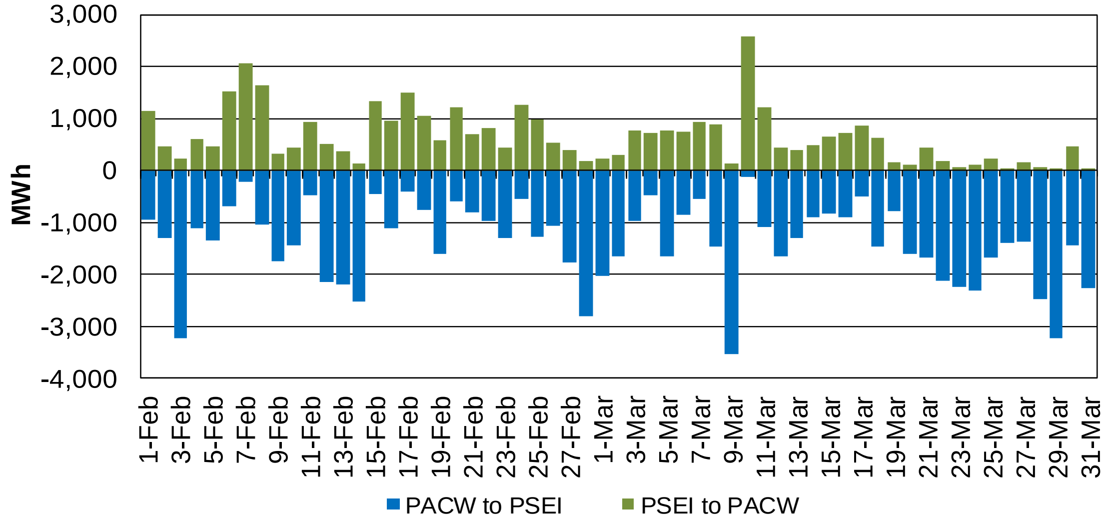


Figure 58 shows the daily volume of EIM transfer between ISO and PacifiCorp in RTD. Figure 59 shows the daily volume of EIM transfer between PACE and PACW in RTD. The EIM transfer from PACE to PACW dropped this month compared with February.

Figure 58: EIM Transfer between CAISO and PAC in RTD

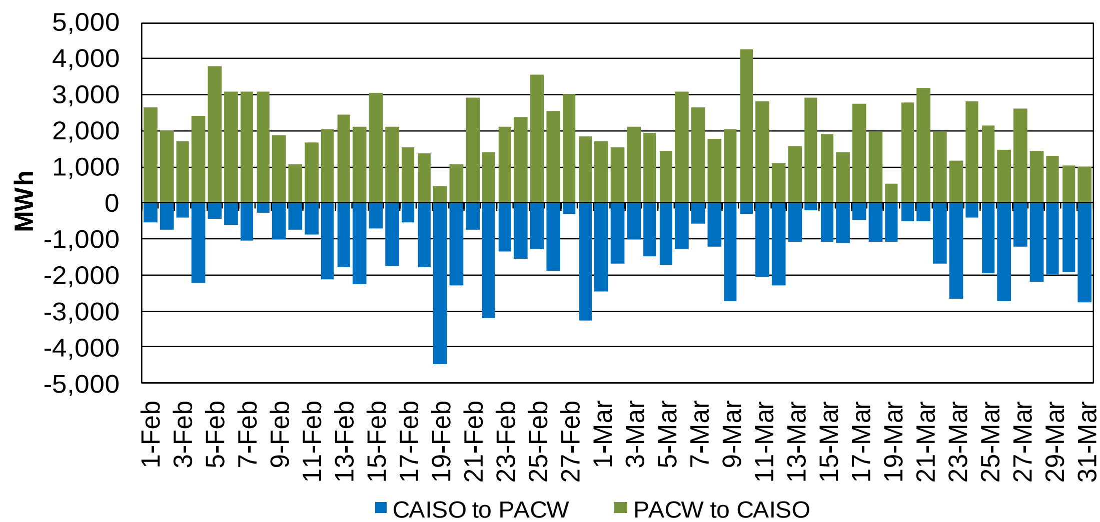


Figure 59: EIM Transfer between PACE and PACW in RTD

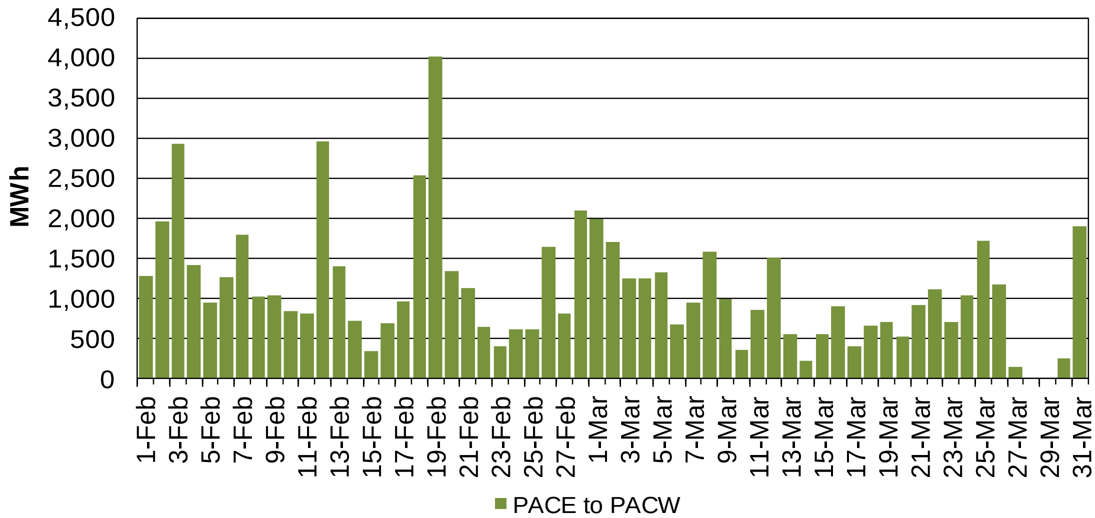


Figure 60 shows the daily EIM transfer volume between ISO and NEVP in RTD. The EIM transfer from NEVP to CAISO decreased this month compared with February. The EIM transfer from CAISO to NEVP increased this month. Figure 61 shows the daily volume EIM transfer between PACE and NEVP in RTD.

Figure 60: EIM Transfer between CAISO and NEVP in RTD

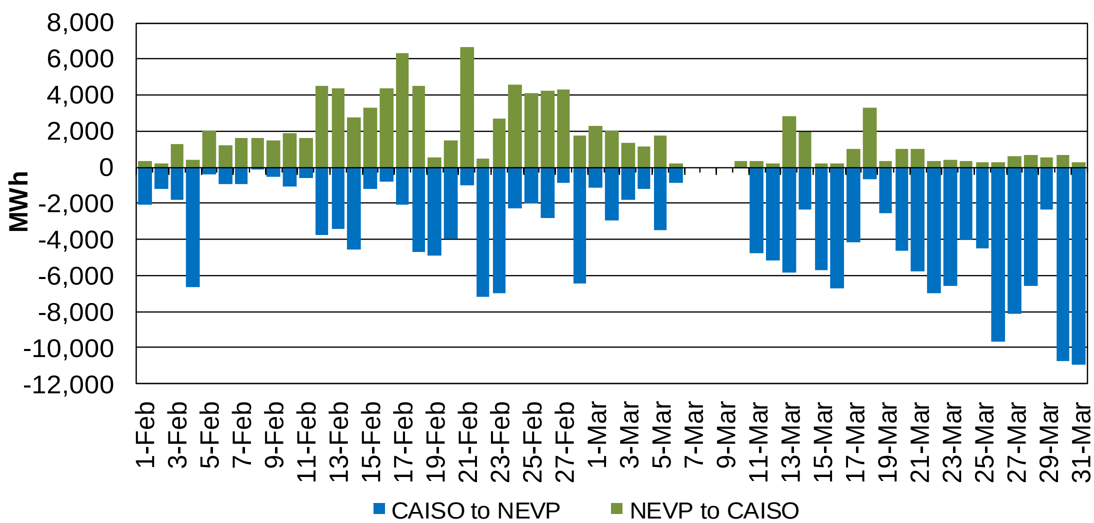


Figure 61: EIM Transfer between PACE and NEVP in RTD

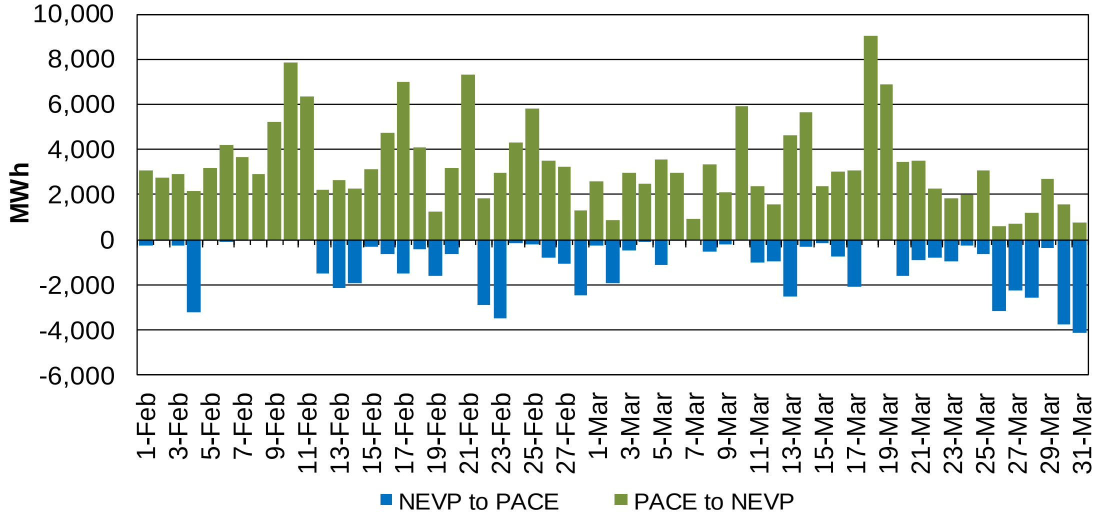


Figure 62 shows the daily volume EIM transfer between the ISO and AZPS in RTD. Figure 63 shows the daily volume EIM transfer between the PACE and AZPS in RTD.

Figure 62: EIM Transfer between CAISO and AZPS in RTD

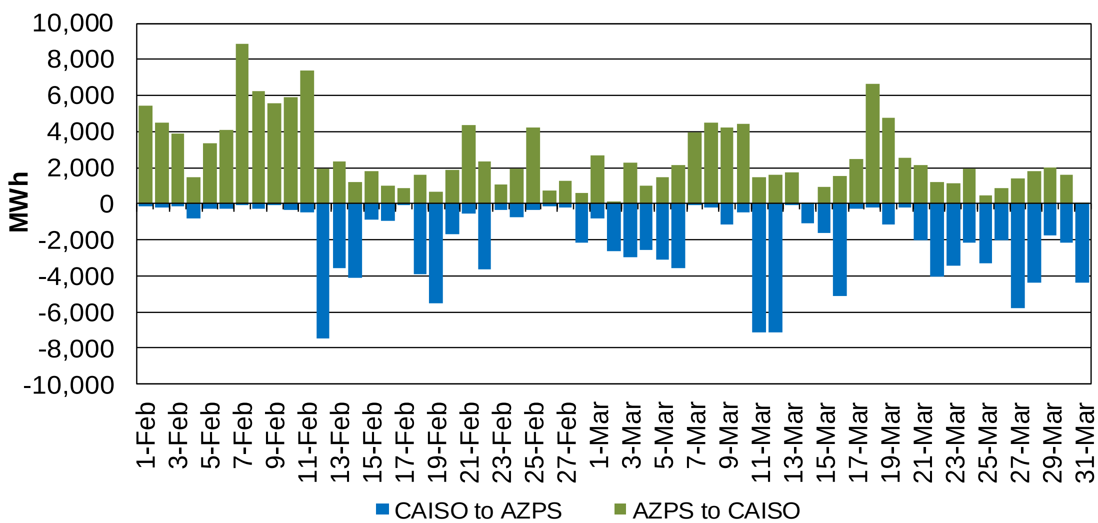


Figure 63: EIM Transfer between PACE and AZPS in RTD

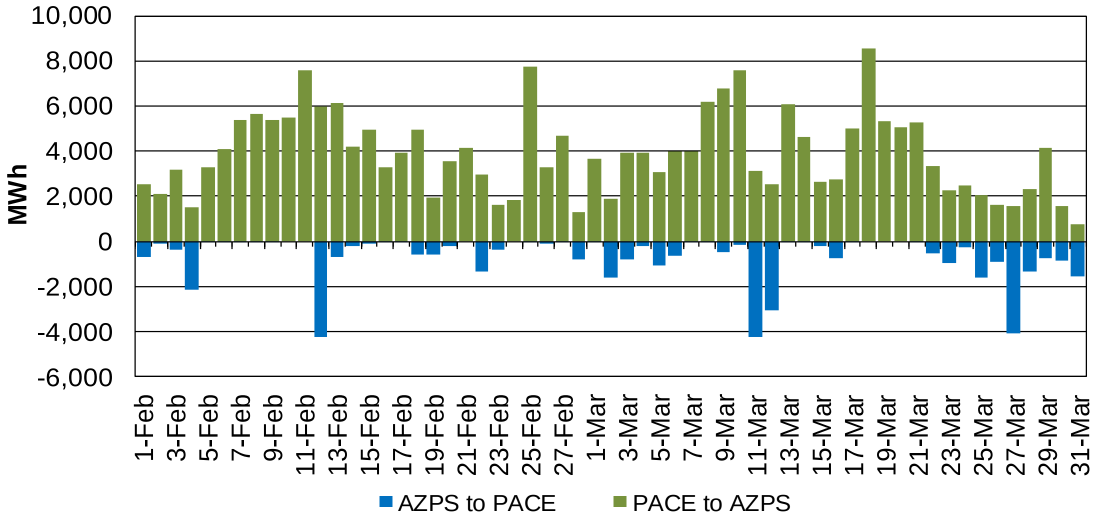


Figure 64 shows the daily volume EIM transfer between the PACW and PSEI in RTD. The EIM transfer from PSEI to PACW decreased this month.

Figure 64: EIM Transfer between PACW and PSEI in RTD

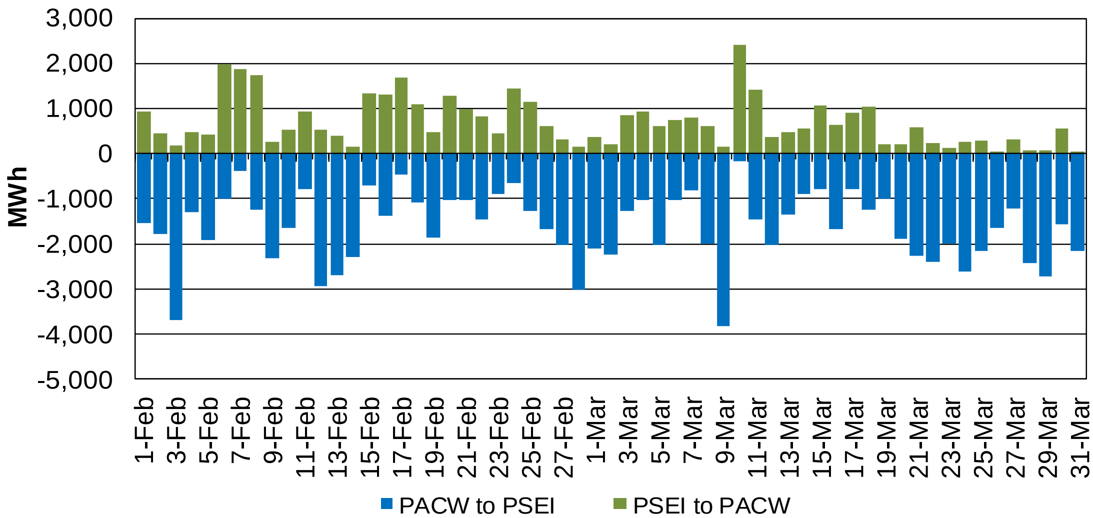


Figure 65 shows daily real-time imbalance energy offset cost (RTIEO) for PACE, PACW, NEVP, AZPS and PSEI respectively. Total RTIEO was $1.25 million in March, increasing from -$0.08 million in February.

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

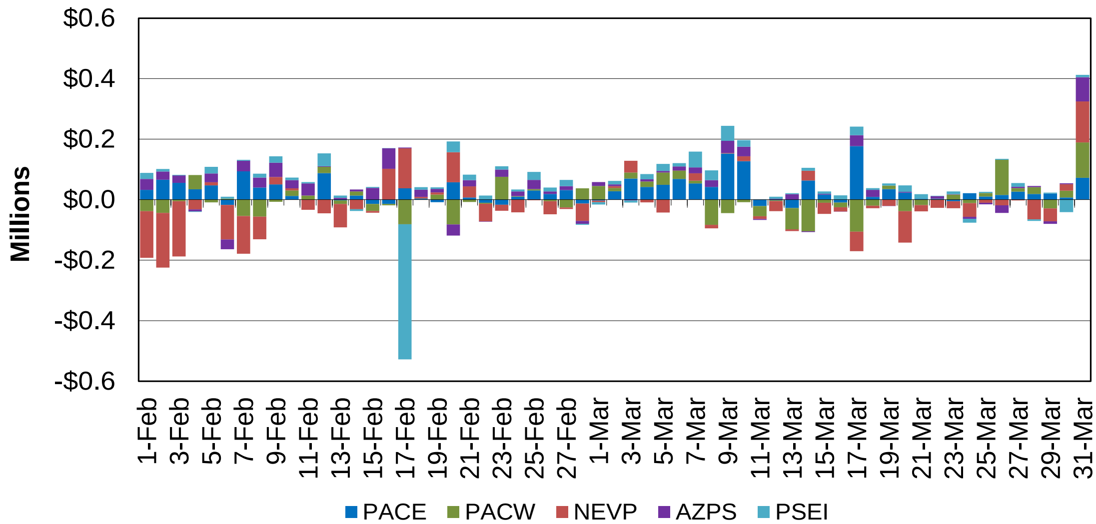


Figure 66 shows daily real-time congestion offset cost (RTCO) for PACE, PACW, NEVP, AZPS and PSEI respectively. Total RTCO fell to -$1.29 million in March from -$1.14 million in February.

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

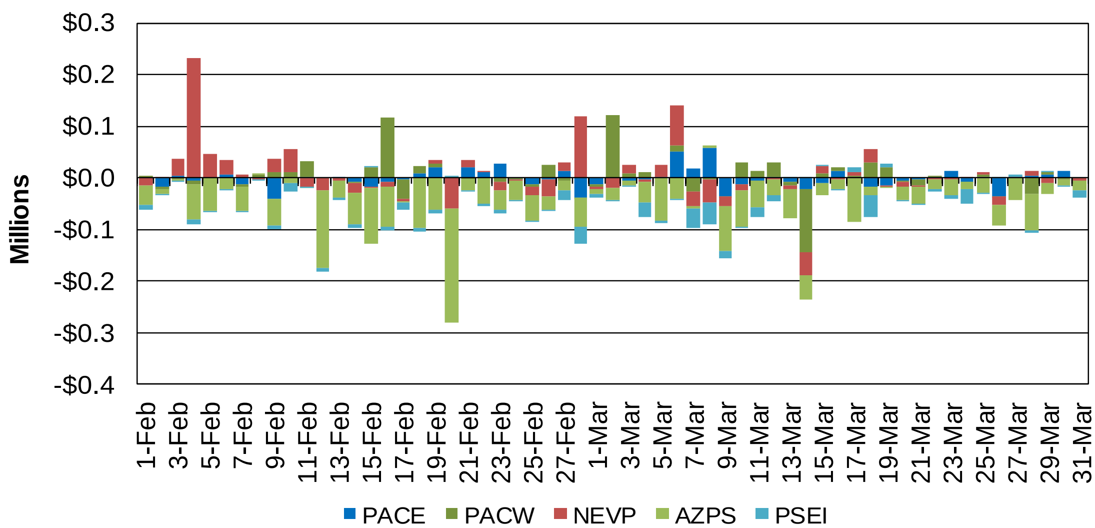


Figure 67 shows daily bid cost recovery for PACE, PACW, NEVP, AZPS and PSEI respectively. Total BCR rose to $1.03 million in March from $0.67 million in February.

Figure 67: EIM Bid Cost Recovery by Area

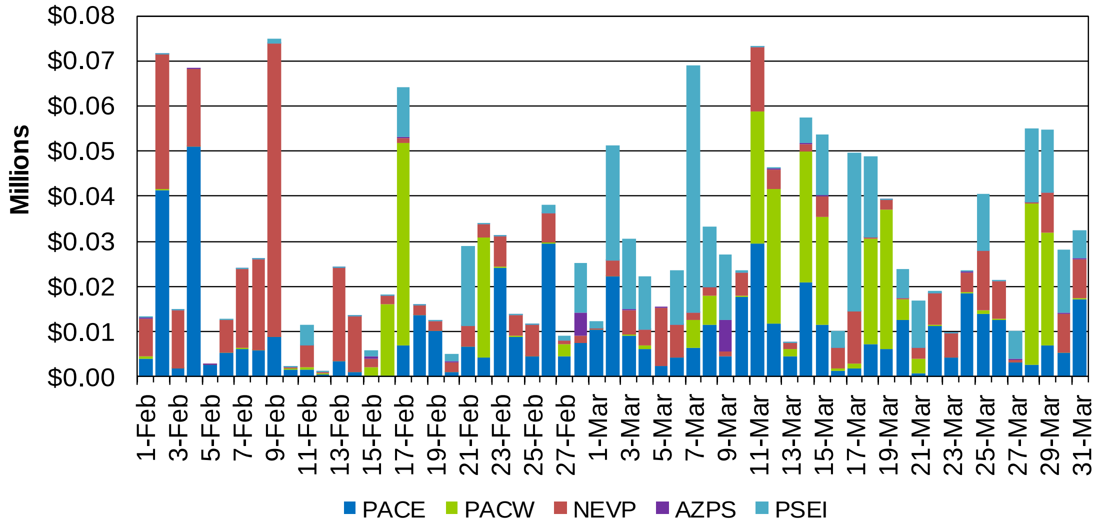


Figure 68 shows the flexible ramping up uncertainty payment for PACE, PACW, NEVP, AZPS, and PSEI respectively. Total flexible ramping up uncertainty payment in March increased to $1.52 million from $1.11 million in February.

Figure 68: Flexible Ramping Up Uncertainty Payment

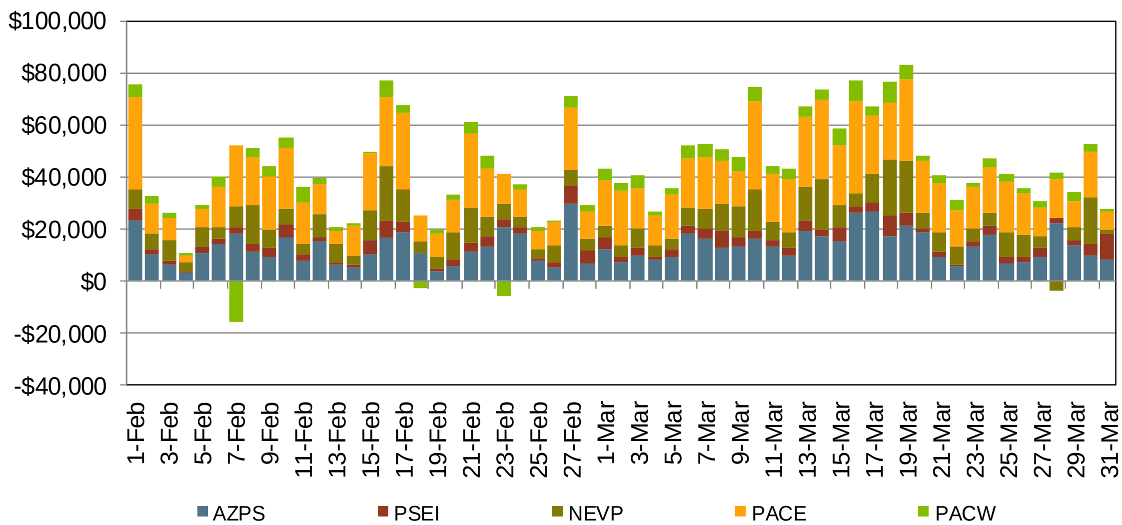


Figure 69 shows the flexible ramping down uncertainty payment for PACE, PACW, NEVP, AZPS, and PSEI respectively. Total flexible ramping down uncertainty payment in March increased to $0.34 million from $0.22 million in February.

Figure 69: Flexible Ramping Down Uncertainty Payment

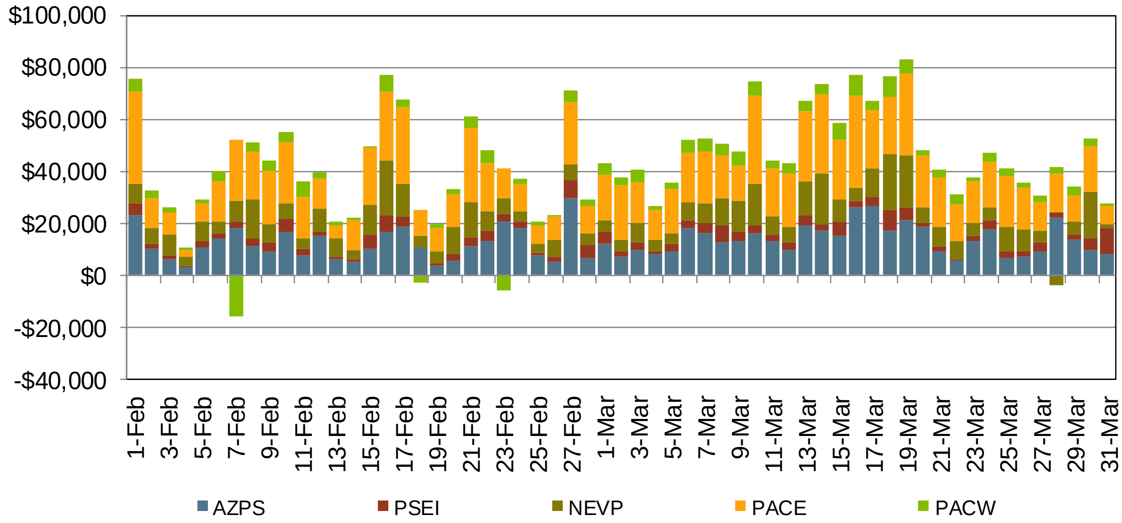
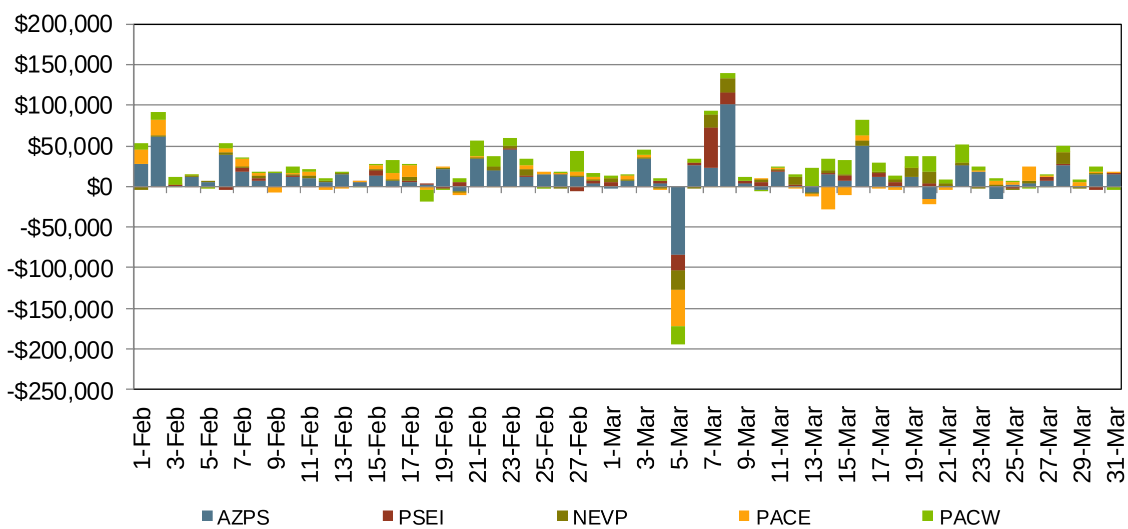


Figure 70 shows the flexible ramping forecast payment for PACE, PACW, NEVP, AZPS, and PSEI respectively. Total forecast payment in March edged down to $0.60 million from $0. 72 million in February.

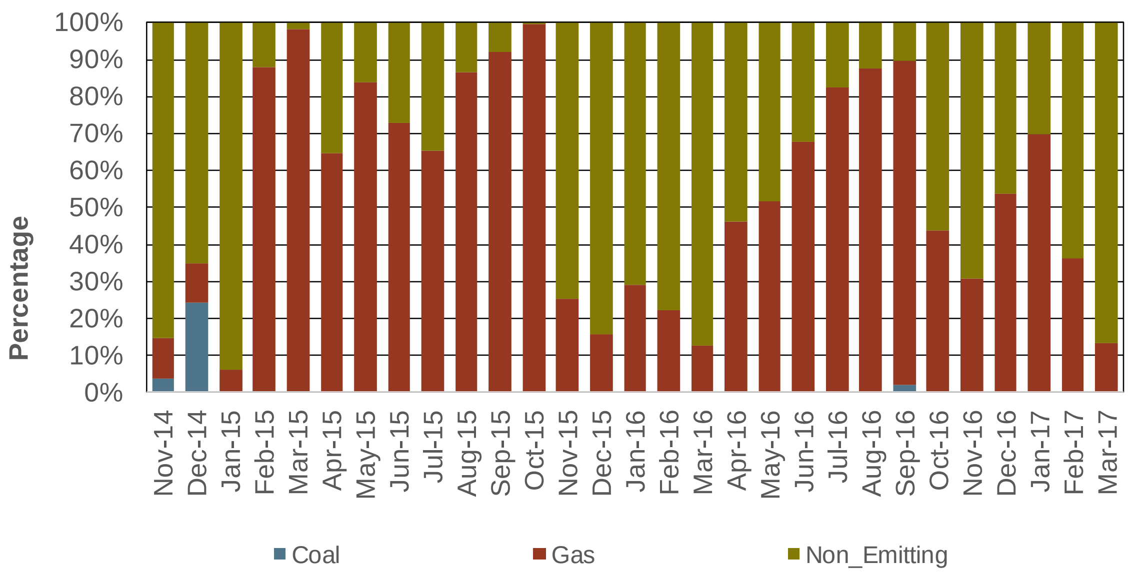
Figure 70: Flexible Ramping Forecast Payment



The ISO's Energy Imbalance Market Business Practice Manual[4] 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[5].

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 March 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 7 below.

Figure 71: Percentage of EIM Transfer into ISO by Fuel Type



[4] 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.

[5] A submitted bid may reflect that a resource is not available to support EIM transfers to California.

Table 7: 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%