Market Performance Report
November 2018

January 18, 2019

ISO Market Quality and Renewable Integration

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Executive Summary[1]

The market performance in November 2018 is summarized below.

CAISO area performance,

- Peak loads for ISO area stayed low in November due to cold weather.
- Across all market, such as the integrated forward market (IFM), the fifteen-minute market (FMM) and real-time market (RTD), the market observed price separation with higher prices in the SDGE area due to transmission congestion.
- Congestion rents for interties edged up to $5.89 million from $5.88 million in October. Majority of the congestion rents in November accrued on Malin (51 percent) intertie and Palo Verde (40 percent) intertie.
- In the congestion revenue rights (CRR) market, revenue adequacy was 77.11 percent, flipping into a deficit from a revenue surplus of 101.78 percent observed in October. The nomogram 7820_TL 230S_OVERLOAD_NG contributed largely to the revenue deficit.
- The monthly average ancillary service cost to load inched down to $0.50/MWh from $0.54/MWh in October. There were two scarcity events in this month.
- The cleared virtual supply was well above the cleared demand throughout this month. The profits from convergence bidding edged up to $5.17 million in November from $5.16 million in October.
- The bid cost recovery increased to $12.95 million from $7.90 million in October.
- The real-time energy offset decreased to -$8.90 million from -$5.19 million in October. The real-time congestion offset cost increased to $14.28 million from $12.33 million in October.
- The volume of exceptional dispatch increased to 116,515 MWh from 105,112 MWh in October. The main contributors to the increased monthly volume were load forecast uncertainty and planned transmission outage. The monthly average of total exceptional dispatch volume as a percentage of load percentage 0.68 percent in November, increasing from 0.56 percent in October.

[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 were generally quiet in November. In RTD, the prices for AZPS, IPCO, NEVP, and PACE were elevated on November 29 due to upward load adjustment, renewable deviation, net import reduction, and generation outage.
- The monthly average prices in FMM for EIM entities (AZPS, BCHA, IPCO, NEVP, PACE, PACW, PGE and PSEI) observed very little price separation and were $40.36, $44.10, $42.00, $37.38, $36.88, $37.83, $37.86, and $38.03 respectively.
- The monthly average prices in RTD for EIM entities (AZPS, BCHA, IPCO, NEVP, PACE, PACW, PGE and PSEI) was $29.82, $33.71, $34.39, $31.35, $29.83, $33.65, $33.13 and $33.25 respectively.
- Bid cost recovery, real-time imbalance energy offset, and real-rime congestion offset costs for EIM entities (AZPS, BCHA, IPCO, NEVP, PACE, PACW, PGE and PSEI) were $0.60 million, -$1.29 million and -$1.52 million respectively.

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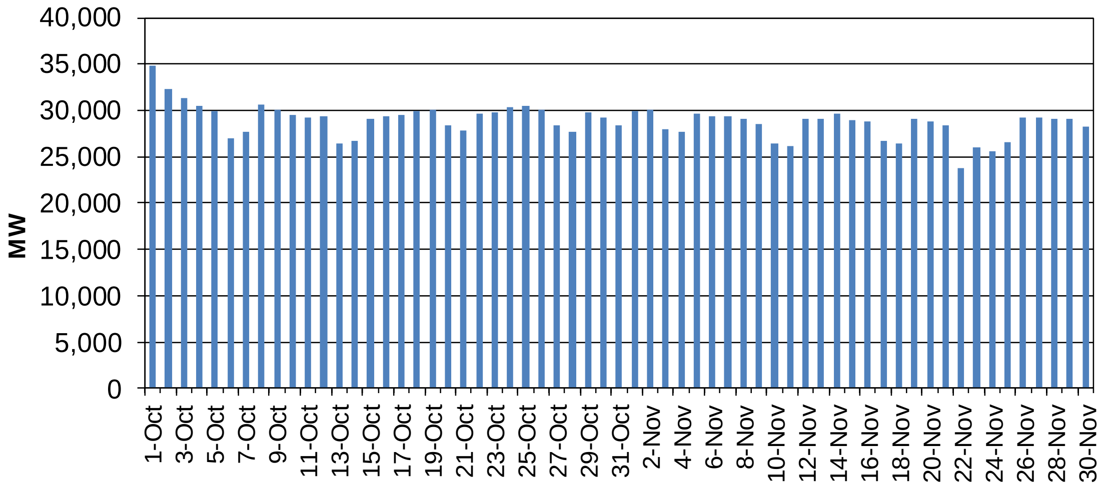
Market Characteristics

Loads

Peak loads for ISO area stayed low in November due to cold weather.

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] Starting from May 2018, the ISO reports the system RA average actual availability and flexible RA average actual availability separately.

Table 1: Resource Adequacy Availability and Payment

	Total Non-availability Charge	Total Availability Incentive Payment	Average Actual Availability	Flexible Average Actual Availability	System Average Actual Availability
Jan17	$2,265,805	-$1,844,332	95.72%		
Feb17	$3,157,590	-$2,119,905	92.52%		
Mar17	$2,975,585	-$1,789,708	92.15%		
Apr17	$3,641,392	-$1,703,556	89.75%		
May17	$1,017,191	-$1,628,646	96.55%		
Jun17	$4,058,330	-$1,502,850	94.24%		
Jul17	$3,277,858	-$1,940,268	95.20%		
Aug17	$3,691,798	-$1,544,674	95.27%		
Sep17	$934,468	-$934,468	96.82%		
Oct17	$620,818	-$620,818	97.58%		
Nov17	$1,483,755	-$1,483,755	96.29%		
Dec17	$1,502,939	-$1,502,939	96.96%		
Jan18	$921,031	-$921,031	97.66%		
Feb18	$1,945,971	-$1,793,865	95.83%		
Mar18	$3,552,921	-$1,541,456	93.06%		
Apr18	$2,917,993	-$1,599,950	93.00%		
May18	$6,004,496	-$2,254,847		92.43%	91.22%
Jun18	$5,182,422	-$2,618,787		95.08%	92.09%
Jul18	$2,085,852	-$2,692,615		94.54%	95.18%
Aug18	$3,943,252	-$2,808,202		91.28%	96.88%
Sep18	$1,456,190	-$2,905,748		98.08%	97.35%
Oct18	$2,443,889	-$2,285,277		95.42%	96.29%
Nov18	$1,471,834	-$2,020,874		97.27%	96.97%

[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)

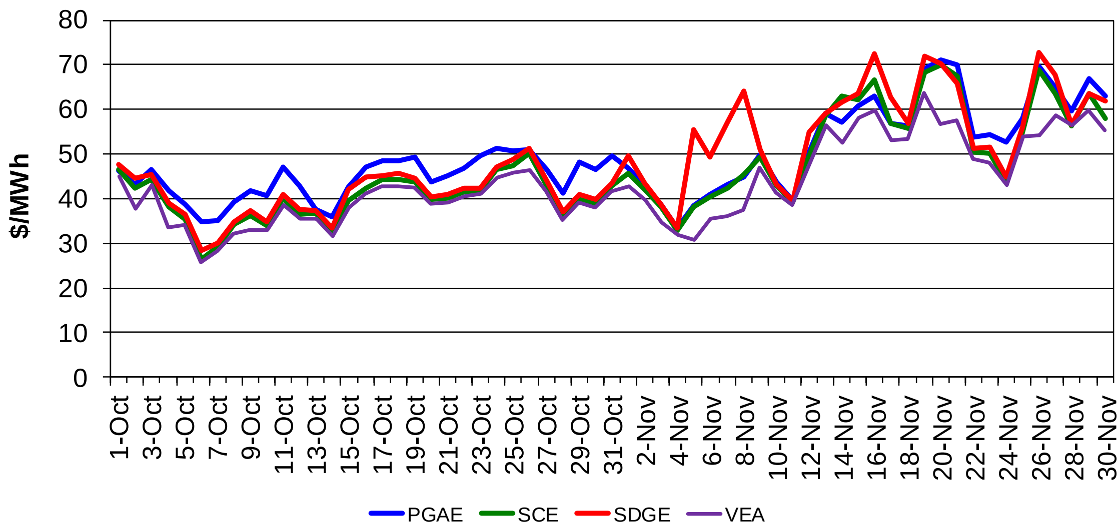


Table 2: Day-Ahead Transmission Constraints

DLAP	Date	Transmission Constraint
SDGE	November 5-8	MIGUEL_BKs_MXFLW_NG, OMS 6355712 TL50003_NG
VEA	November 20, 21	PARDEE -SYLMAR S-230kV line
VEA	November 26, 27	LUGO -VICTORVL-500kV LINE

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. The LMPs for all four DLAPs spiked on November 1 and 2 due to upward load adjustment, renewable deviation, import reduction, and generation outage.

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

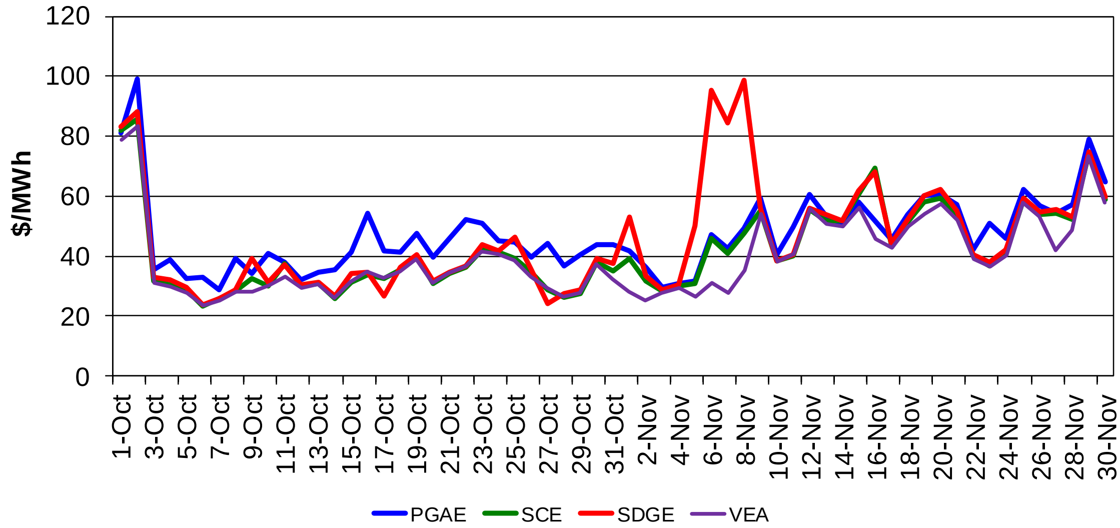
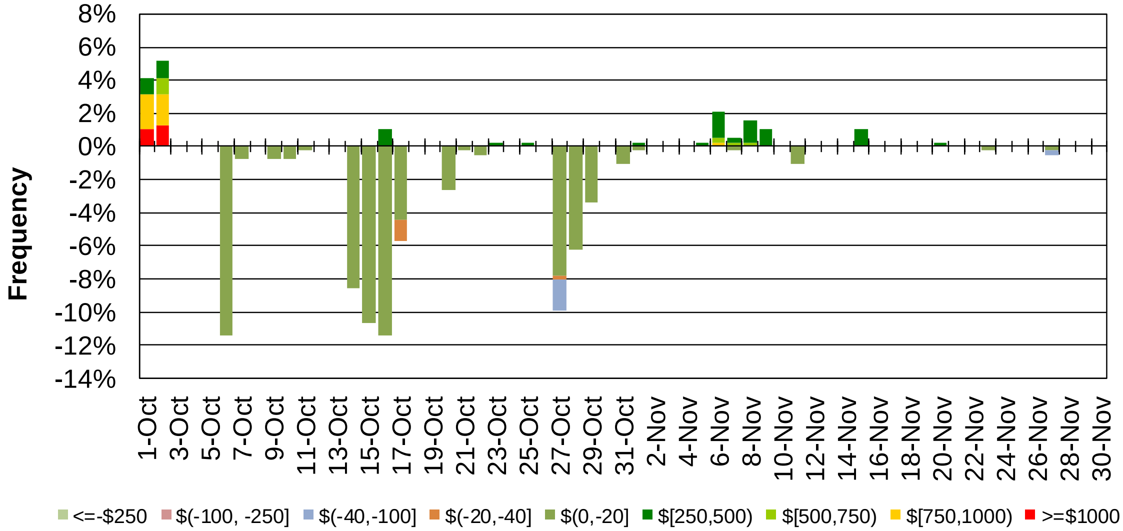


Table 3: FMM Transmission Constraints

DLAP	Date	Transmission Constraint
SDGE	November 5-8	MIGUEL_BKs_MXFLW_NG, OMS 6355729 TL50003_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 decreased to 0.23 percent in November from 0.35 percent in October. The cumulative frequency of negative prices fell to 0.08 percent in November from 2.40 percent in October.

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. On November 29, all four DLAP LMPs were elevated by upward load adjustment, renewable deviation, net import reduction, and generation outage.

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

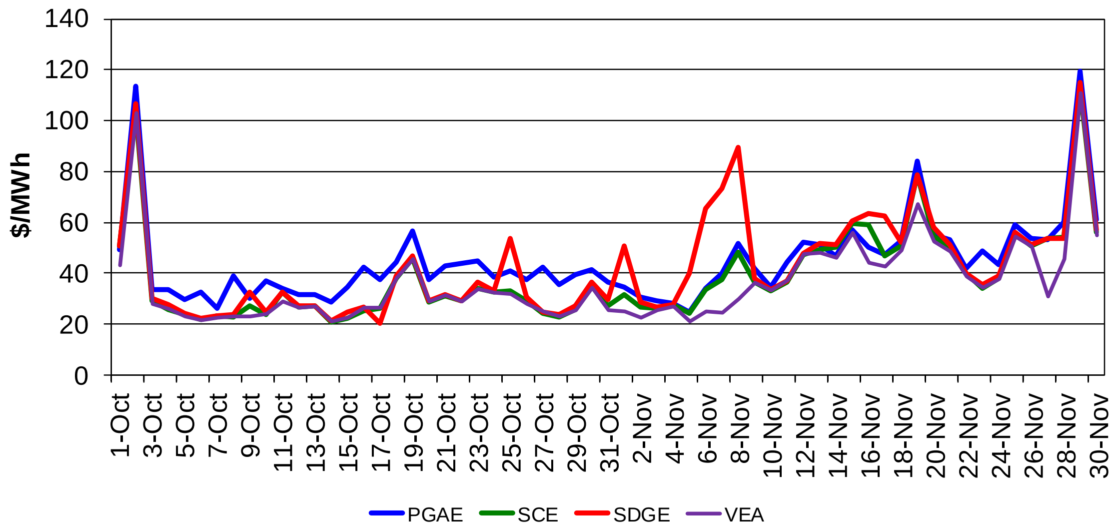
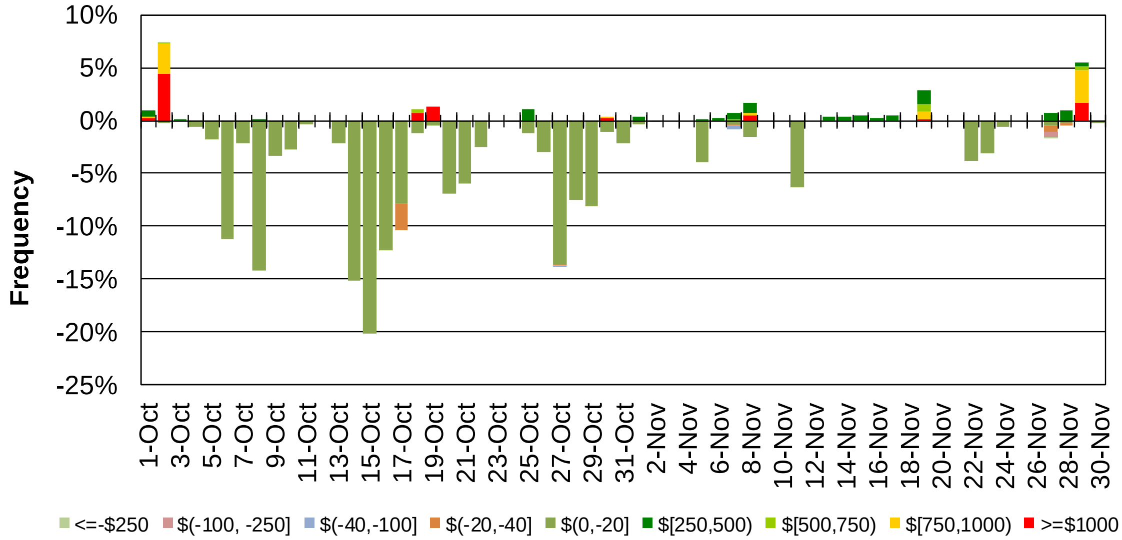


Table 4: RTD Transmission Constraints

DLAP	Date	Transmission Constraint
SDGE	November 5-8	MIGUEL_BKs_MXFLW_NG, OMS 6355729 TL50003_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 0.51 percent in November from 0. 40 percent in October. The cumulative frequency of negative prices dropped to 0.76 percent in November from 4.86 percent in October.

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



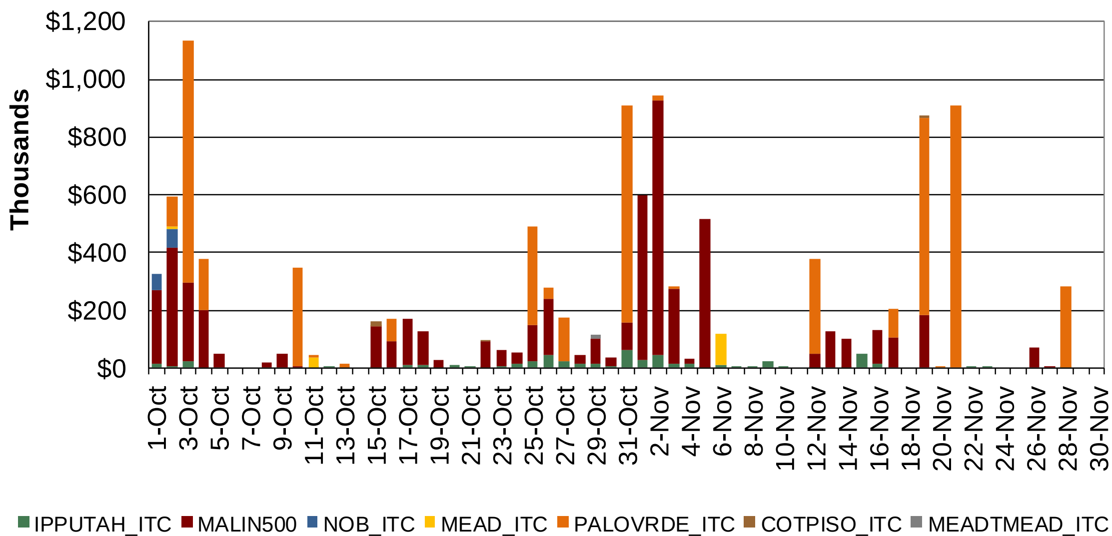
Congestion

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 November edged up to $5.89 million from $5.88 million in October. Majority of the congestion rents in November accrued on Malin (51 percent) intertie and Palo Verde (40 percent) intertie.

The congestion rent on Malin dropped to $3.00 million in November from $2.54 million in October. The congestion rent on Palo Verde reduced to $2.34 million in November from $2.85 million in October.

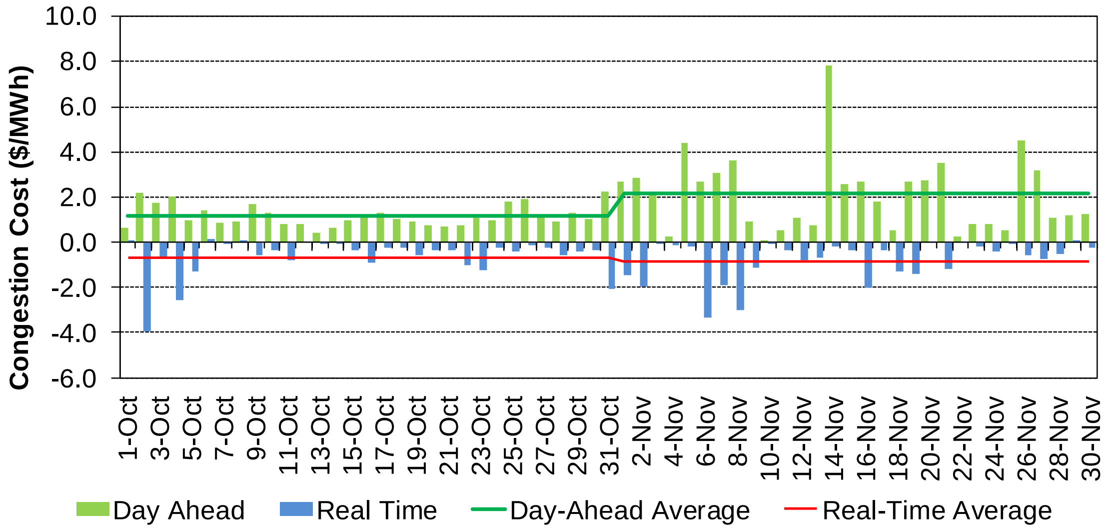
Figure 7: IFM Congestion Rents by Interties (Import)



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

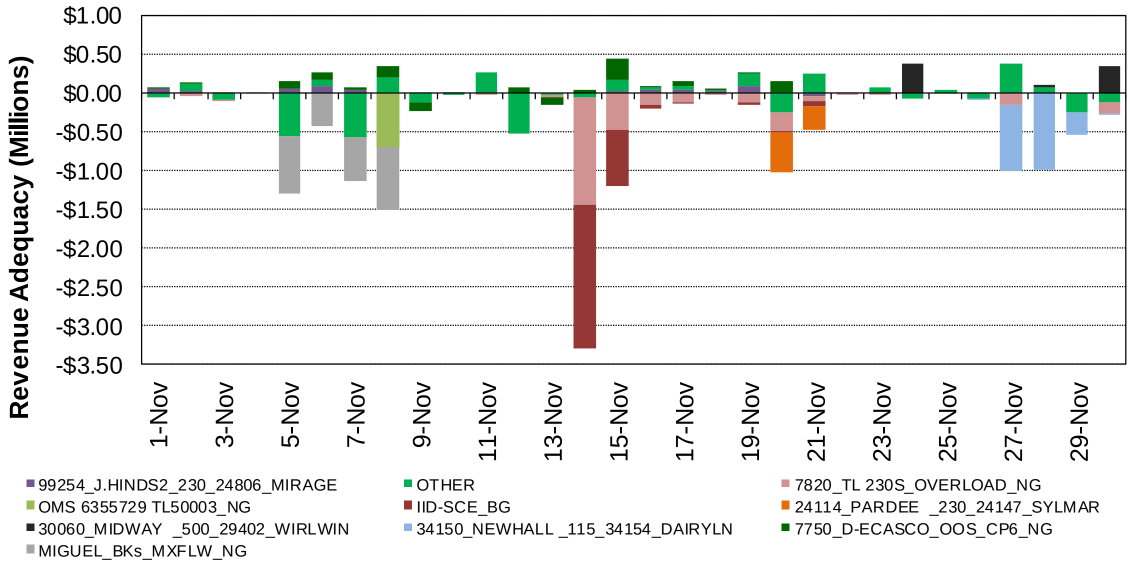


The average congestion cost per MWh of load served in the integrated forward market increased to $2.16/MWh in November from $1.19/MWh in October. The average congestion cost per load served in the real-time market decreased to -$0.83/MWh in November from -$0.66/MWh in October.

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 November was $363,395 compared with the average revenue surplus of $12,450 in October.

Figure 9: Daily Revenue Adequacy of Congestion Revenue Rights

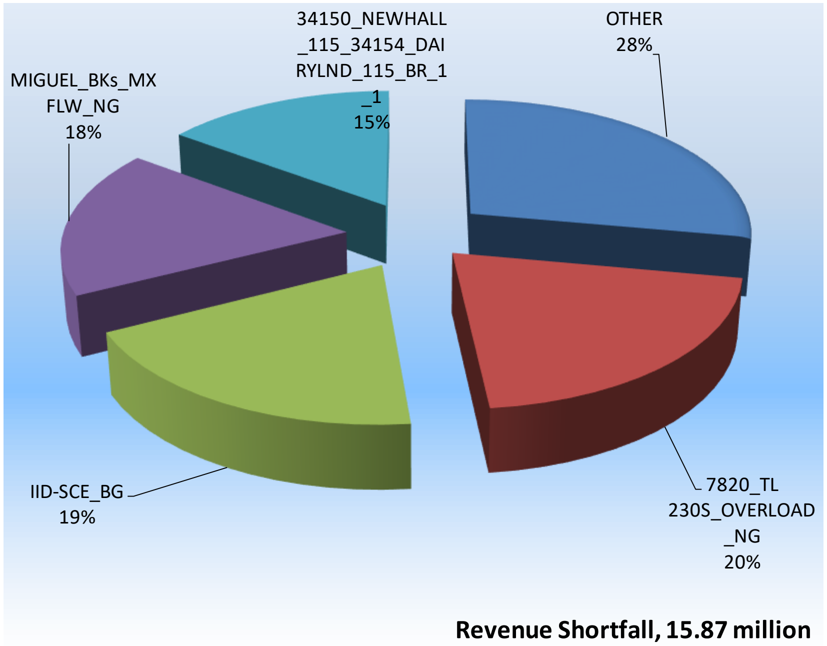


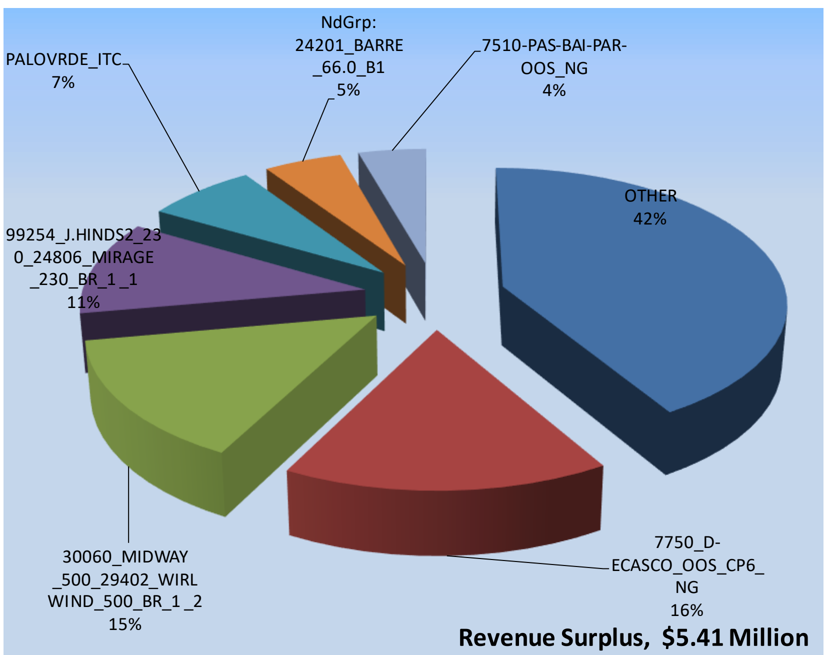
Overall, November experienced a CRR revenue surplus. Revenue deficit was observed in 17 days this month. The main reasons are

- The nomogram 7820_TL 230S_OVERLOAD_NG was binding in 17 days this month, resulting in revenue deficit of $2.95 million.
- IID-SCE_BG was binding in nine days of this month, resulting in revenue deficit of $2.75 million.
- The nomogram MIGUEL_BKs_MXFLW_NG was binding in four days of this month, resulting in revenue deficit of $2.53 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 insufficient to cover the net payments to congestion revenue right holders and the cost of the exemption for existing rights. The revenue adequacy level was 77.11 percent in November. Out of the total congestion rents, -0.63 percent was used to cover the cost of existing right exemptions. Net total congestion revenues in November were in deficit by $10.90 million, compared to the surplus of $0.39 million in October. The auction revenues credited to the balancing account for November were $7.75 million. As a result, the balancing account for November had a deficit of approximately $3.07 million, which will be allocated to measured demand.

Table 5: CRR Revenue Adequacy Statistics

IFM Congestion Rents	$36,497,473.72
Existing Right Exemptions	$230,536.43
Available Congestion Revenues	$36,728,010.15
CRR Payments	$47,629,852.46
CRR Revenue Adequacy	-$10,901,842.32
Revenue Adequacy Ratio	77.11%
Annual Auction Revenues	$3,927,913.86
Monthly Auction Revenues	$3,825,597.86
CRR Settlement Rule	$74,923.13
Allocation to Measured Demand	-$3,073,407.46

Ancillary Services

IFM (Day-Ahead) Average Price

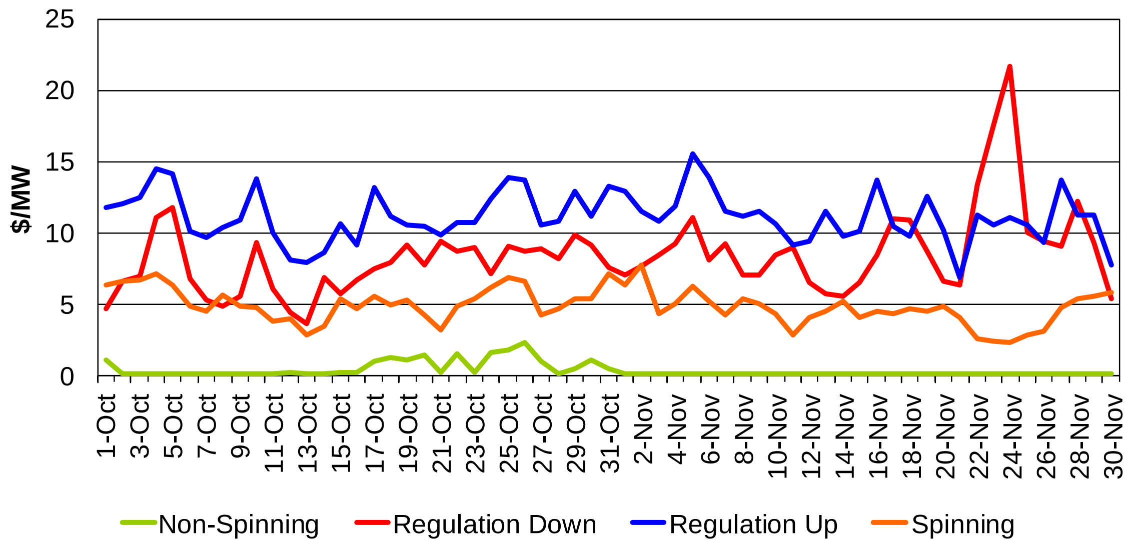
Table 6 shows the monthly IFM average ancillary service procurements and the monthly average prices. In November the monthly average procurement increased for regulation up and regulation down.

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
Nov-18	324	403	728	779	$11.07	$9.23	$4.55	$0.11
Oct-18	313	385	790	791	$11.29	$7.56	$5.23	$0.60
Percent Change	3.48%	4.89%	-7.83%	-1.51%	-1.94%	22.01%	-13.00%	-82.36%

The monthly average prices decreased for regulation up, spinning and non-spinning reserves in November. Figure 11 shows the daily IFM average ancillary service prices. The average price on November 24 was elevated due to high opportunity cost of energy.

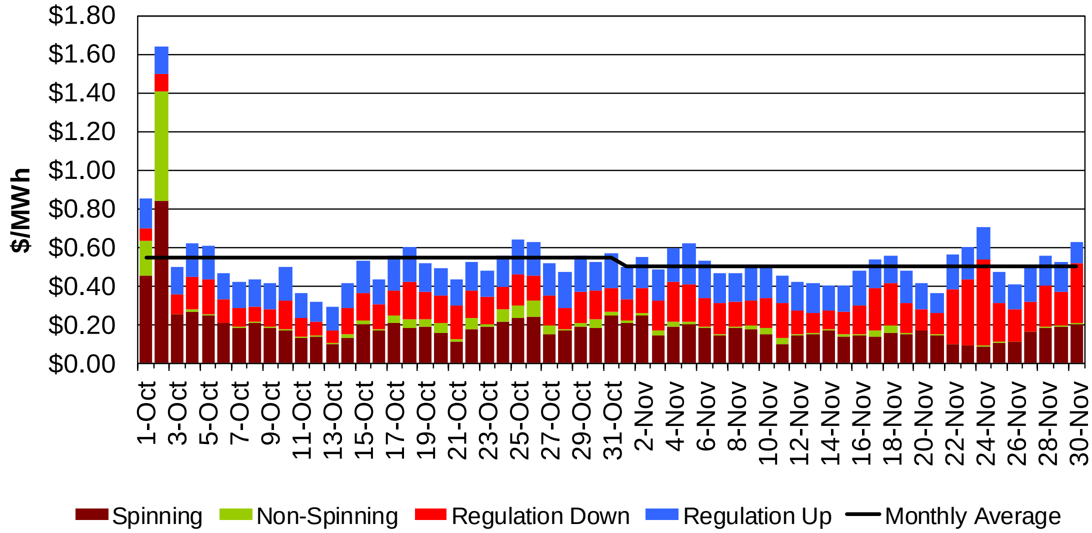
Figure 11: IFM (Day-Ahead) Ancillary Service Average Price



Ancillary Service Cost to Load

The monthly average cost to load inched down to $0.50/MWh in November from $0.54/MWh in October.

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



Scarcity Events

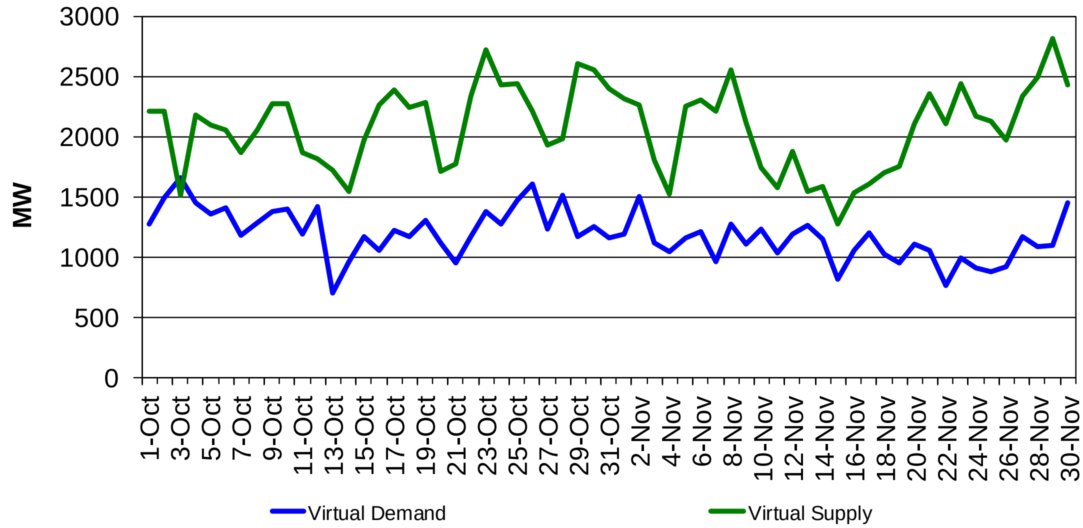
The ancillary services scarcity pricing mechanism is triggered when the ISO is not able to procure the target quantity of one or more ancillary services in the IFM and real-time market runs. The scarcity events in November are shown in the table below.

Date	Hour Ending	Interval	Ancillary Service	Region	Shortfall (MW)	Percentage of Requirement
Nov 29	12	4	Regulation Up	NP26	8.1	81%
Nov 30	21	2	Regulation Up	SP26_EXP	1.4	1%

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 was well above the cleared demand throughout this month.

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

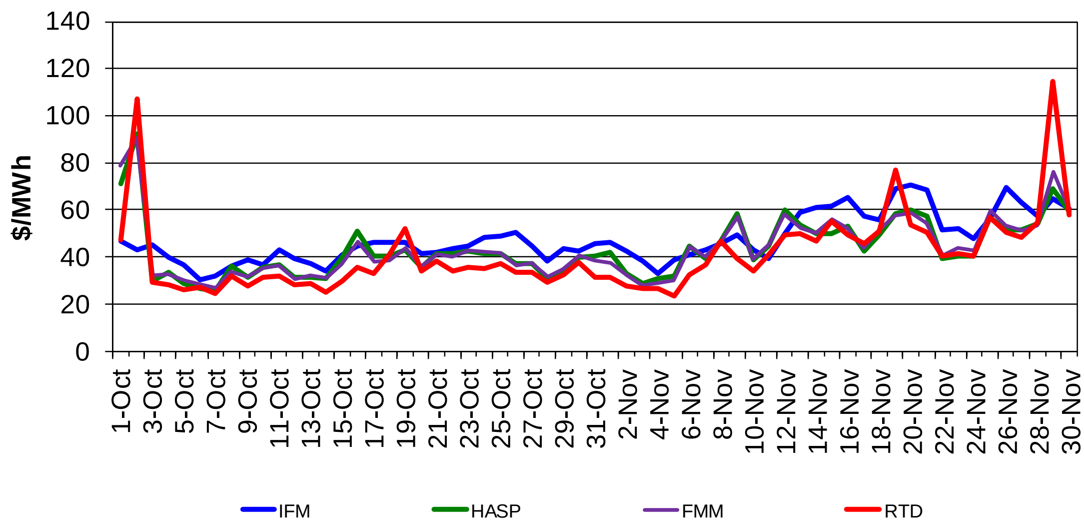
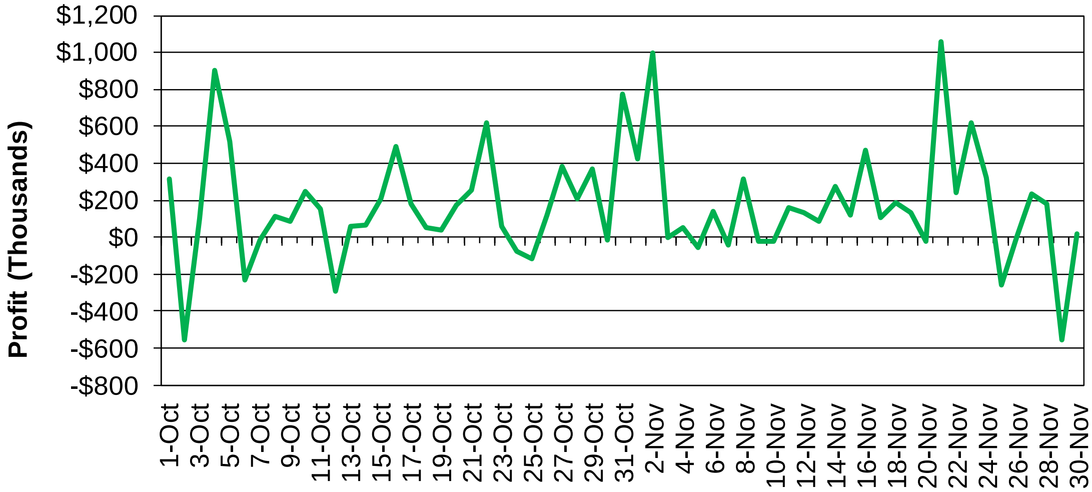


Figure 15 shows the profits that convergence bidders receive from convergence bidding. The total profits from convergence bidding edged up to $5.17 million in November from $5.16 million in October.

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 show, the renewable curtailment fell in November. The majority of the curtailments was economic and was mainly due to local congestion.

Figure 16: Renewable Curtailment by Reason

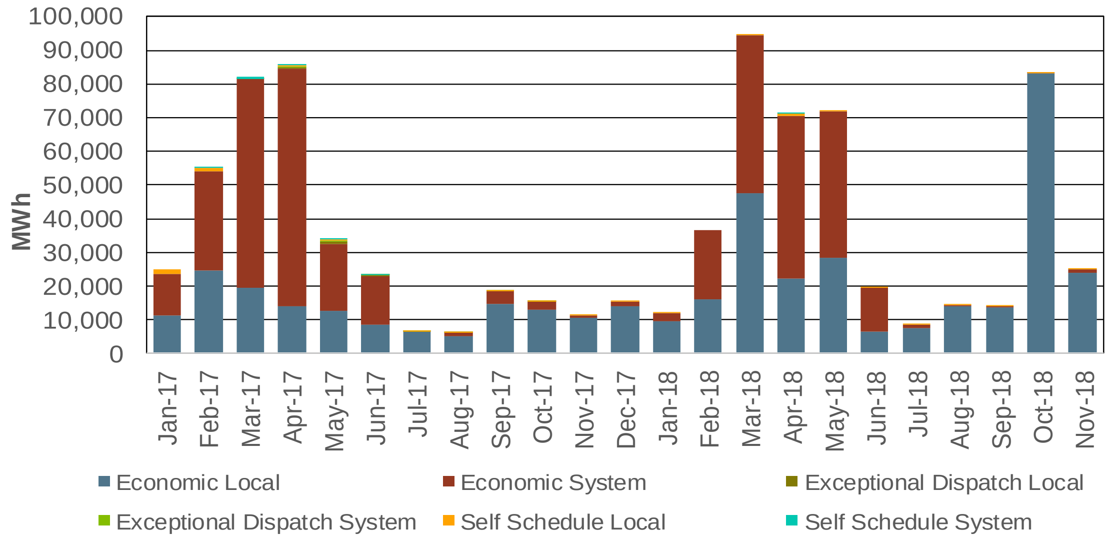
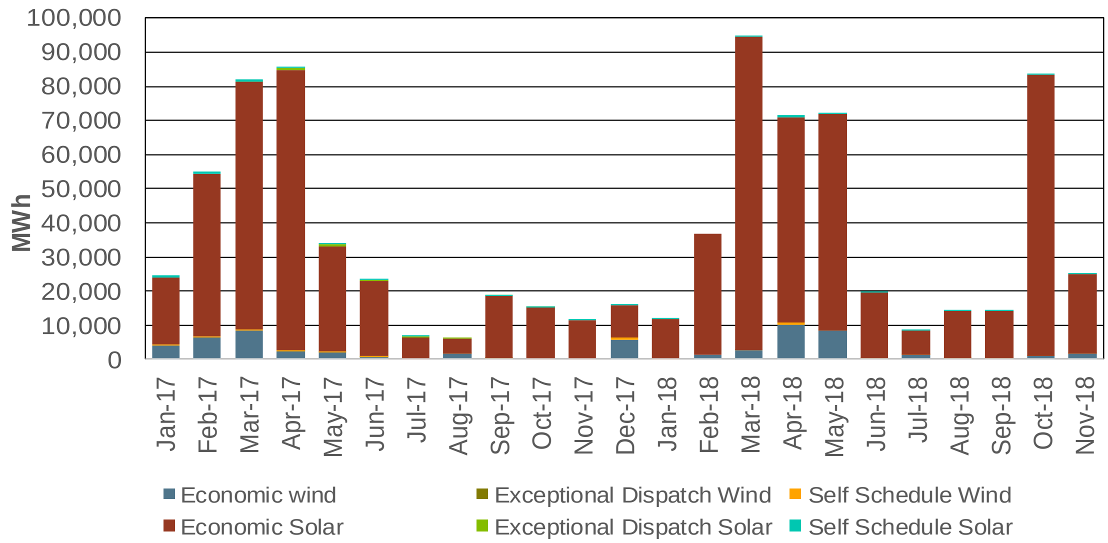


Figure 17: Renewable Curtailment by Resource Type



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 increased to $0.40 million in November from $0.29 million in October. Flexible ramping down uncertainty payment increased to -$2,368 in November from -$5,482 in October.

Figure 18: Flexible Ramping Up/down Uncertainty Payment

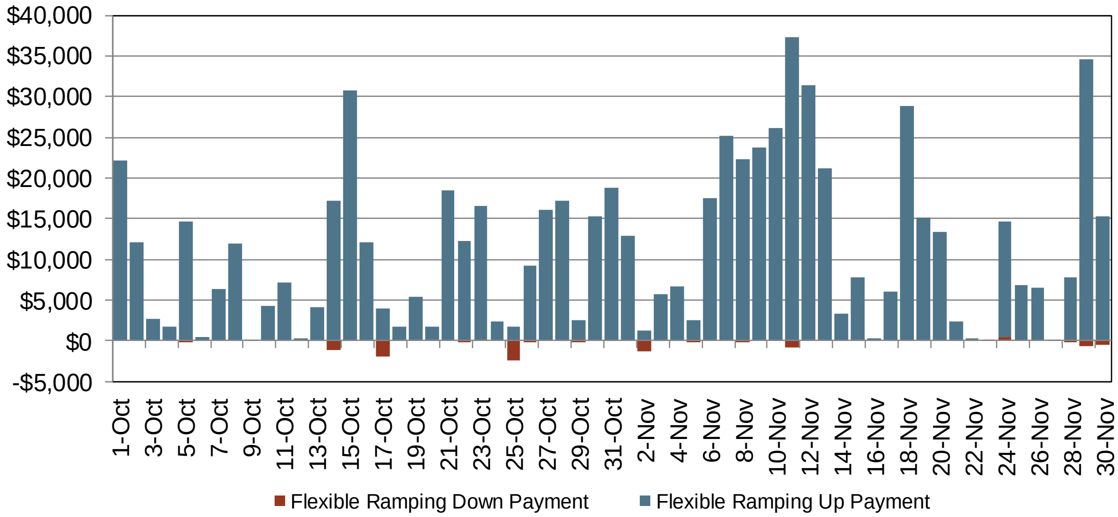
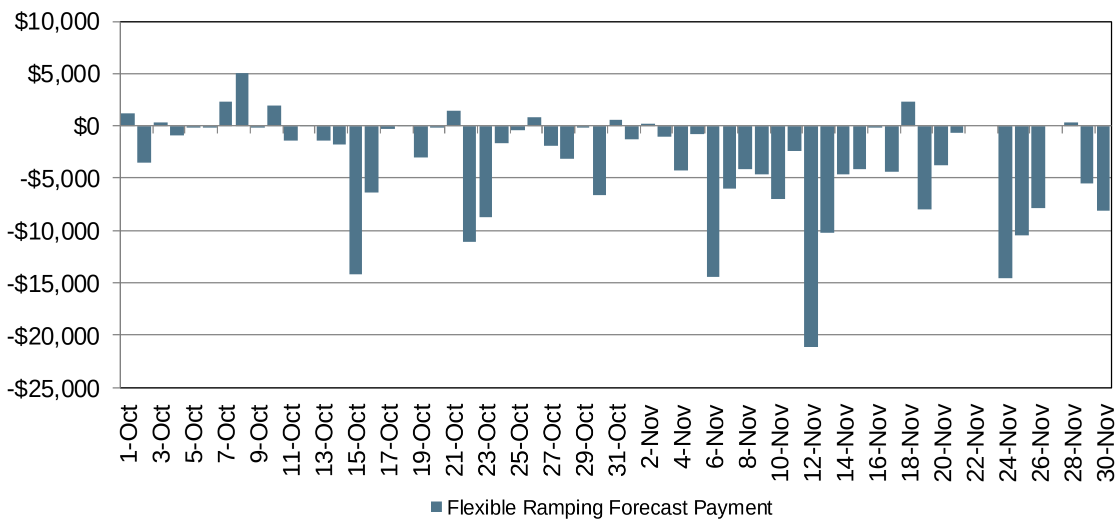


Figure 19 shows the flexible ramping forecast payment. Flexible ramping forecast payment dropped to -$0.15 million this month from -$0.05 million observed in October.

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 November rose to $1.76 million from $0.89 million in October.

Figure 20: Exceptional Dispatch Uplift Costs

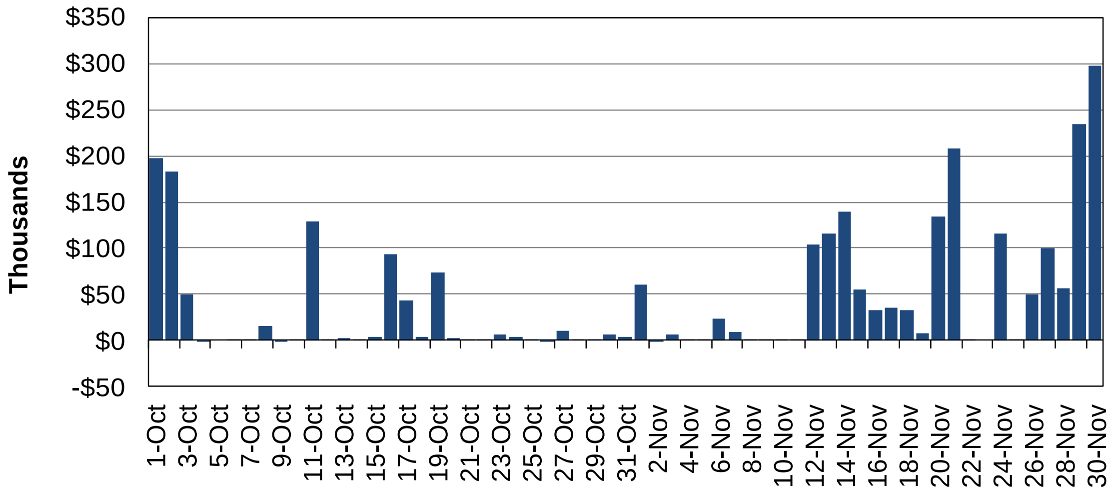


Figure 21 shows the allocation of bid cost recovery payment in the IFM, residual unit commitment (RUC) and RTM markets. The total bid cost recovery for November increased to $12.95 million from $7.90 million in October. Out of the total monthly bid cost recovery payment for the three markets in November, the IFM market contributed 19 percent, RTM contributed 70 percent, and RUC contributed 11 percent of the total bid cost recovery payment.

Figure 21: Bid Cost Recovery Allocation

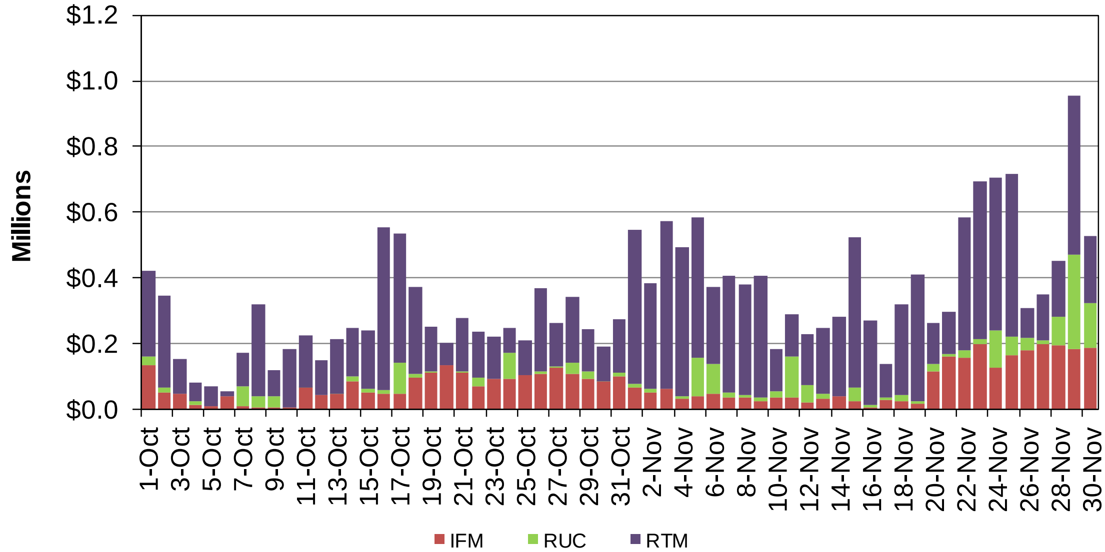


Figure 22 and Figure 23 show the daily and monthly BCR cost by local capacity requirement area (LCR) respectively.

Figure 22: Bid Cost Recovery Allocation by LCR

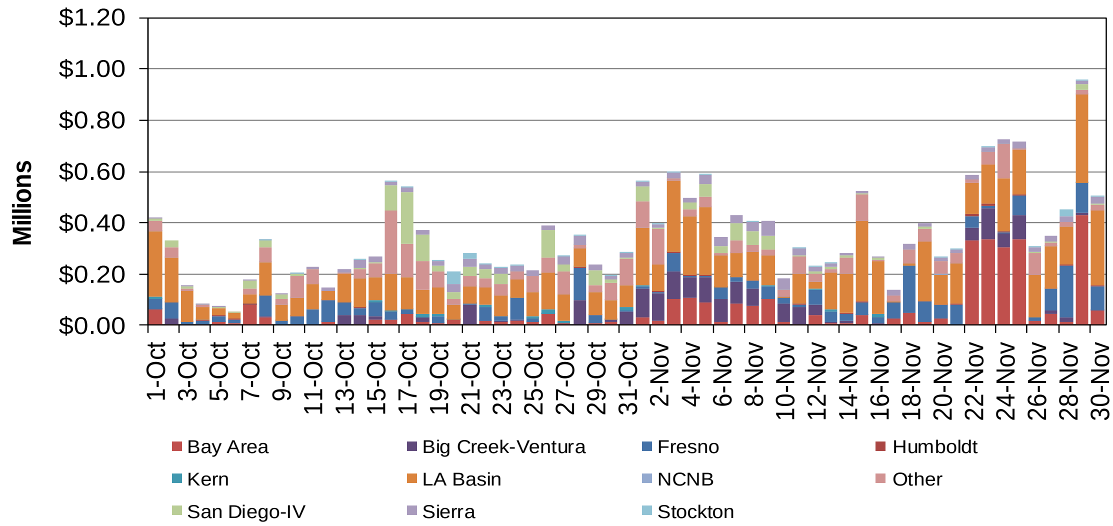


Figure 23: Monthly Bid Cost Recovery Allocation by LCR

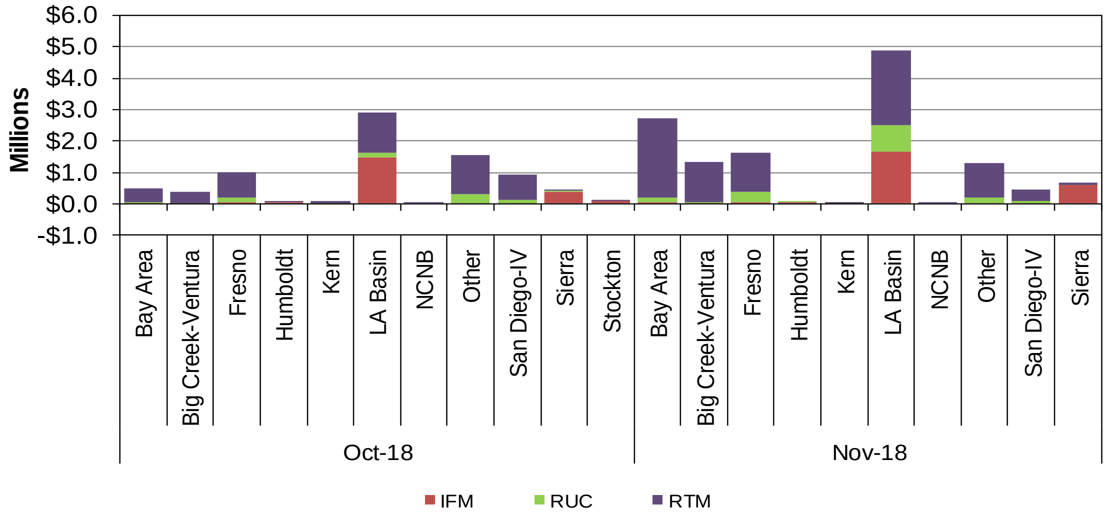


Figure 24 and Figure 25 show the daily and monthly BCR cost by utility distribution company (UDC) respectively.

Figure 24: Bid Cost Recovery Allocation by UDC

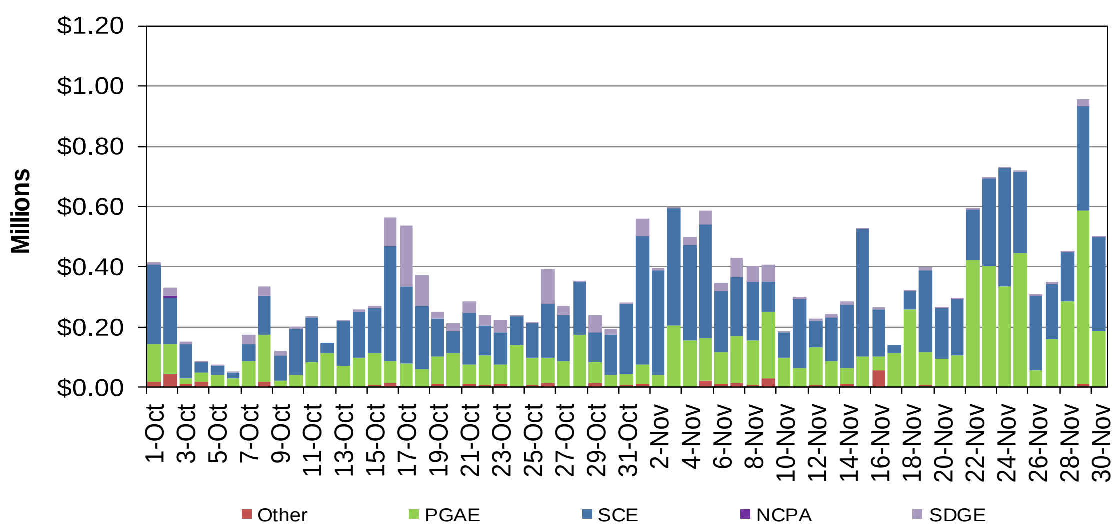


Figure 25: Monthly Bid Cost Recovery Allocation by UDC

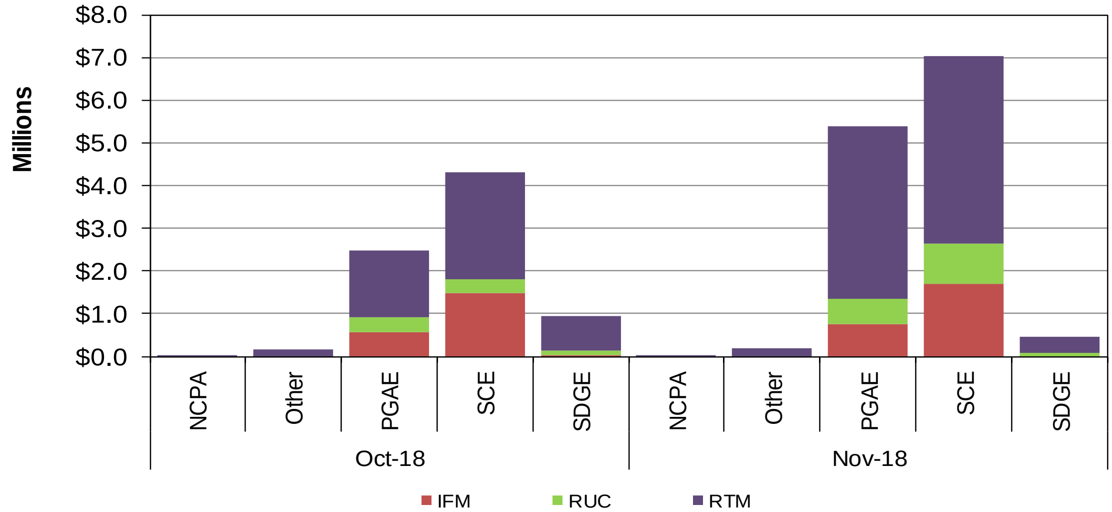


Figure 26 shows the cost related to BCR by cost type in RUC.

Figure 26: Cost in RUC

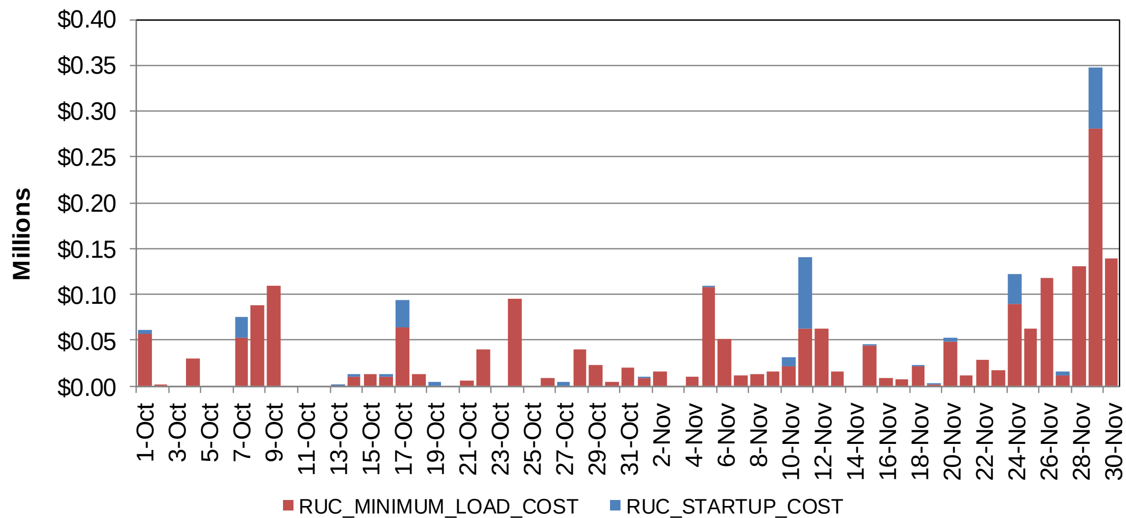


Figure 27 and Figure 28 show the daily and monthly cost related to BCR by type and LCR in RUC respectively.

Figure 27: Cost in RUC by LCR

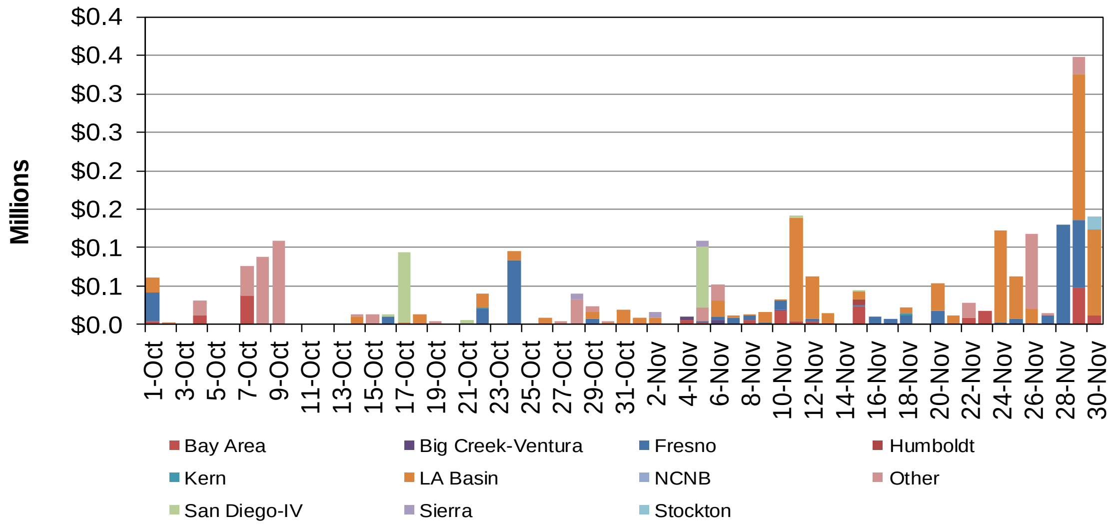


Figure 28: Monthly Cost in RUC by LCR

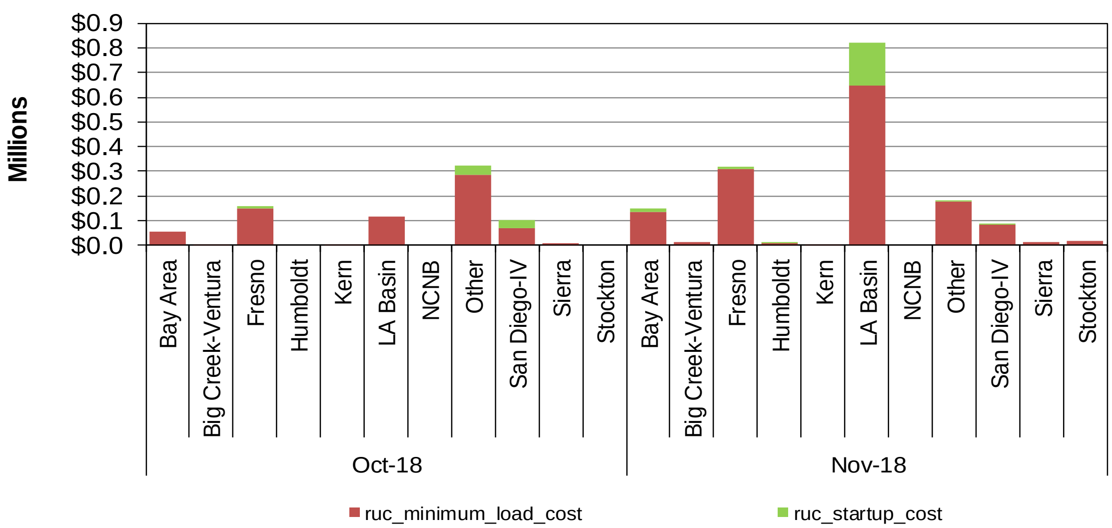


Figure 29 and Figure 30 show the daily and monthly cost related to BCR by type and UDC in RUC respectively.

Figure 29: Cost in RUC by UDC

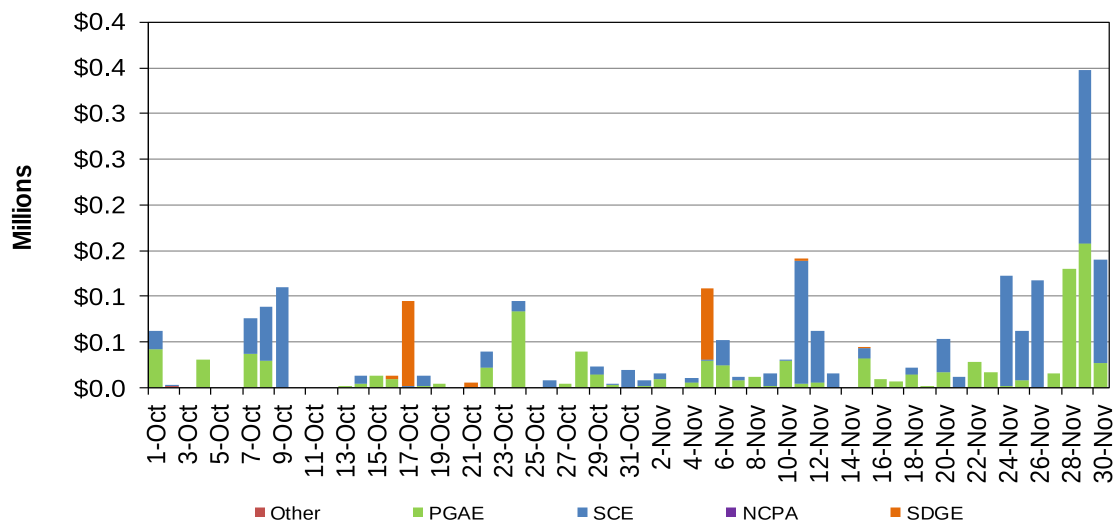


Figure 30: Monthly Cost in RUC by UDC

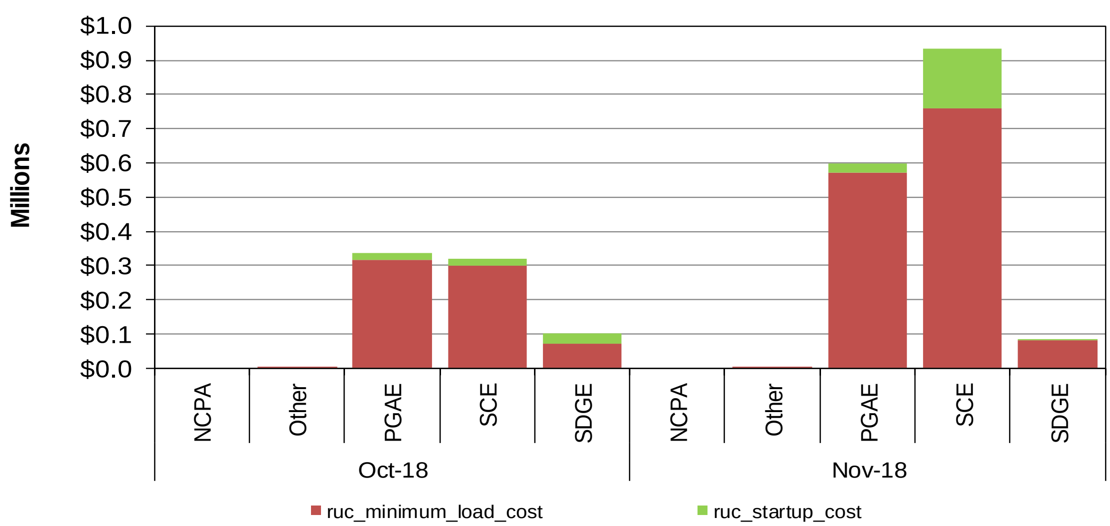


Figure 31 shows the cost related to BCR in real time by cost type. Minimum load cost contributed largely to the real time cost this month.

Figure 31: Cost in Real Time

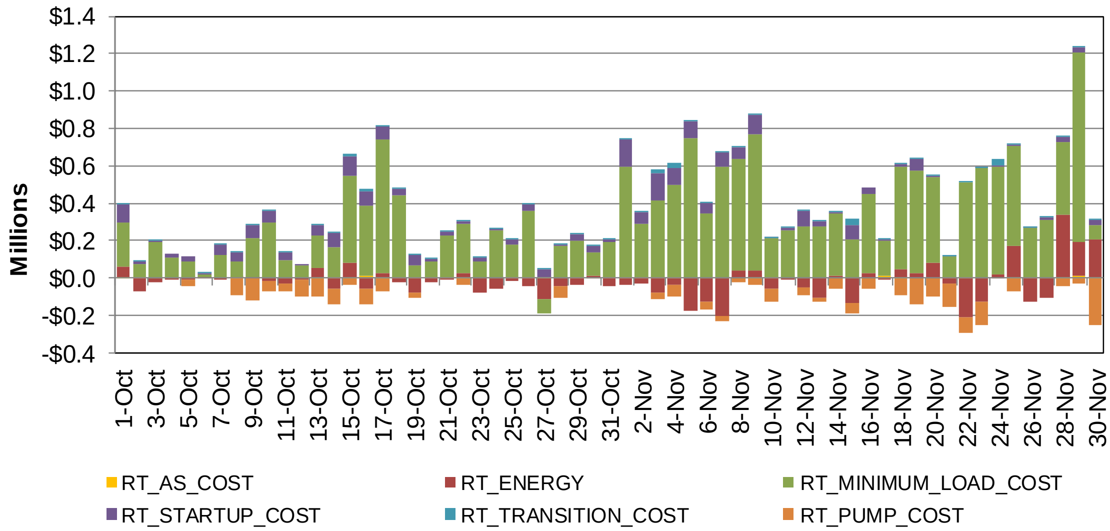


Figure 32 and Figure 33 show the daily and monthly cost related to BCR by type and LCR in real time respectively.

Figure 32: Cost in Real Time by LCR

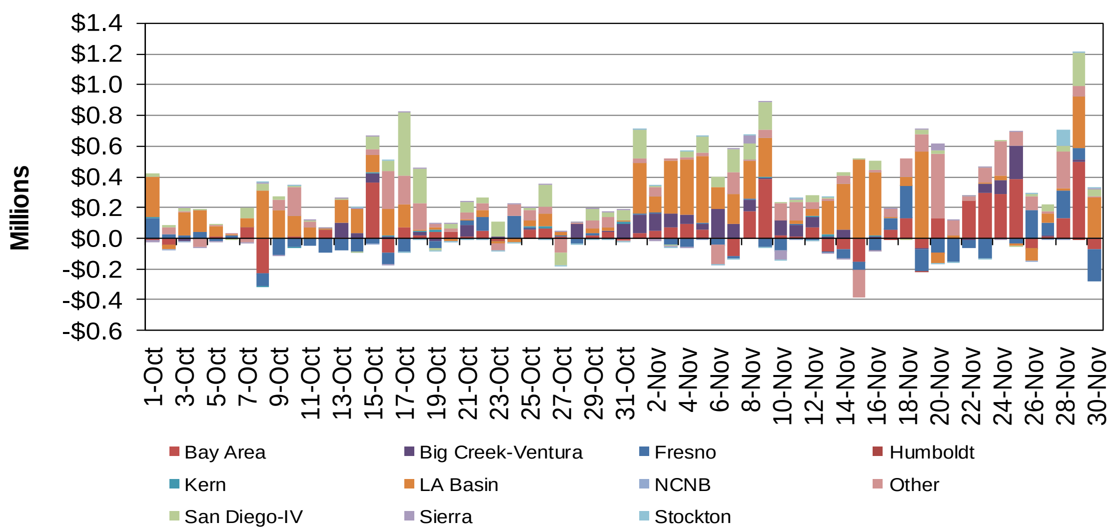


Figure 33: Monthly Cost in Real Time by LCR

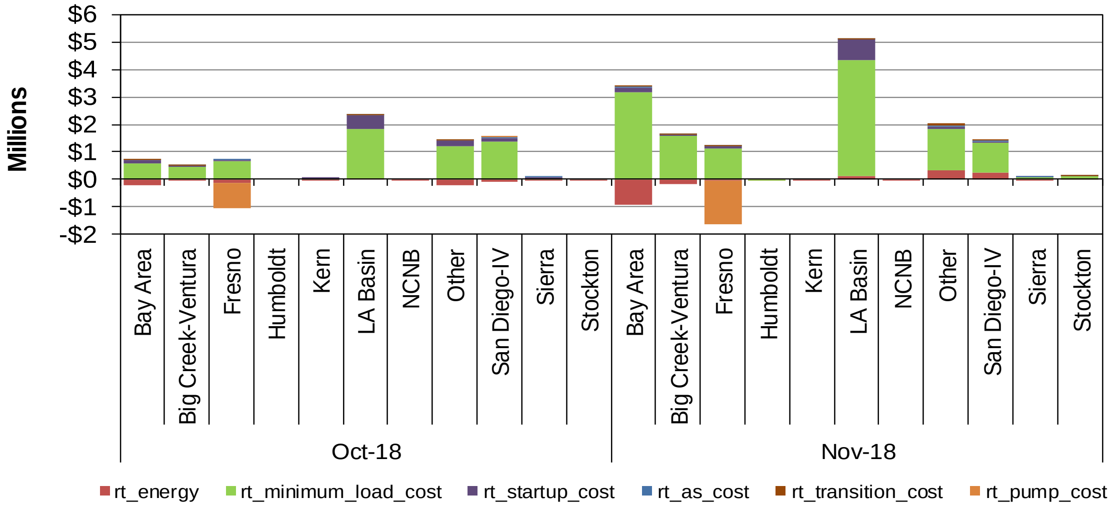


Figure 34 and Figure 35 show the daily and monthly cost related to BCR by type and UDC in Real Time respectively.

Figure 34: Cost in Real Time by UDC

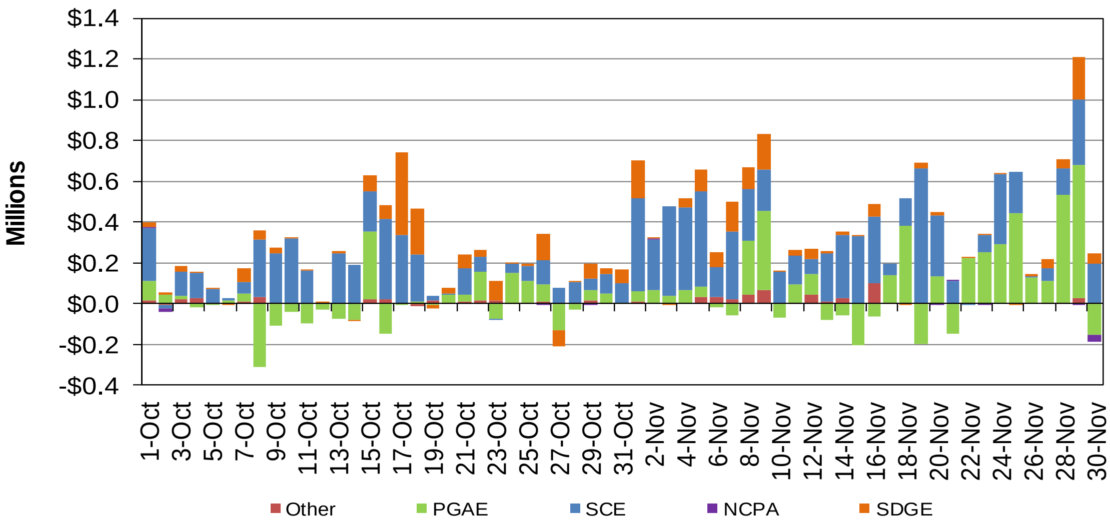


Figure 35: Monthly Cost in Real Time by UDC

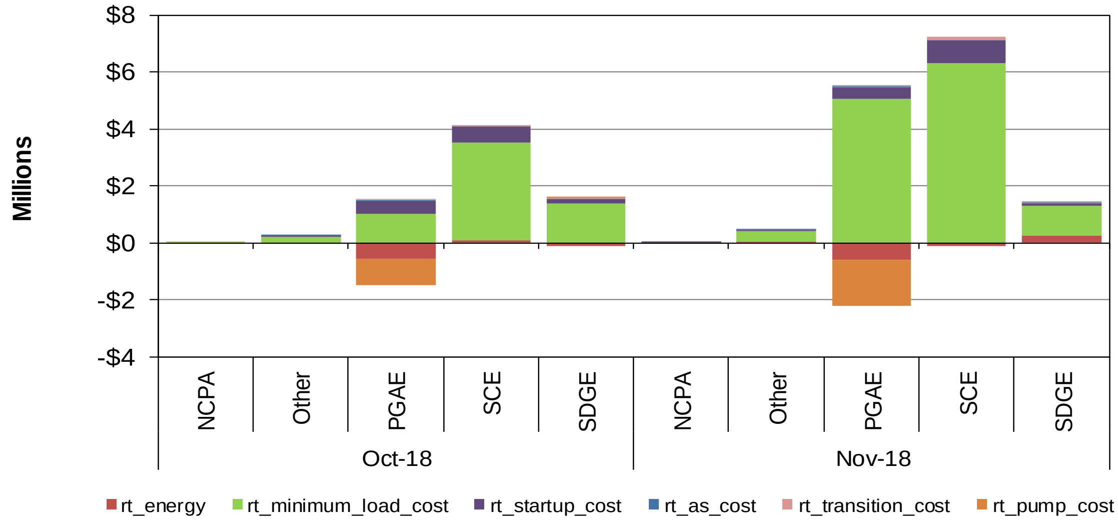


Figure 36 shows the cost related to BCR in IFM by cost type.

Figure 36: Cost in IFM

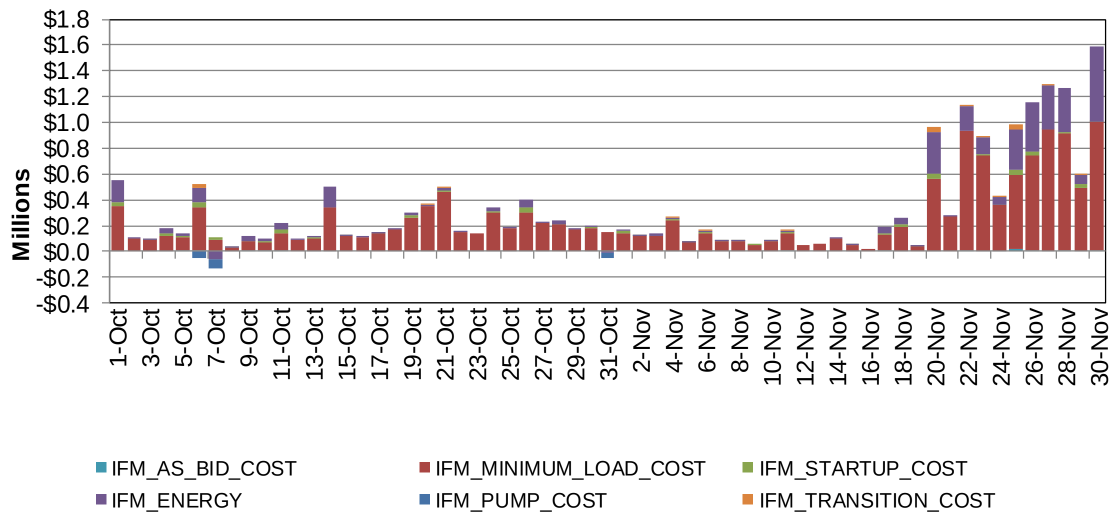


Figure 37 and Figure 38 show the daily and monthly cost related to BCR by type and location in IFM respectively.

Figure 37: Cost in IFM by LCR

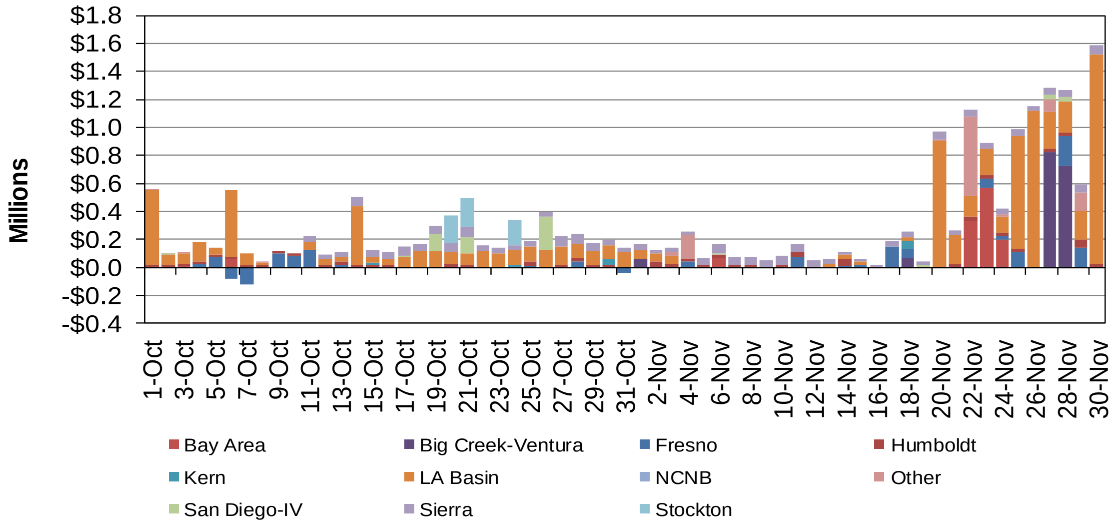


Figure 38: Monthly Cost in IFM by LCR

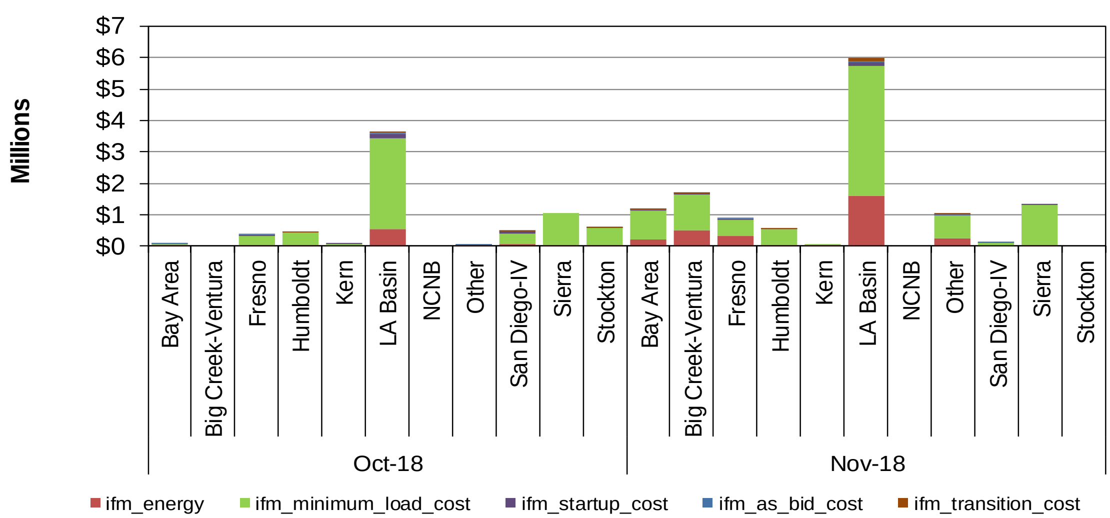


Figure 39 and Figure 40 show the daily and monthly cost related to BCR by type and UDC in IFM respectively.

Figure 39: Cost in IFM by UDC

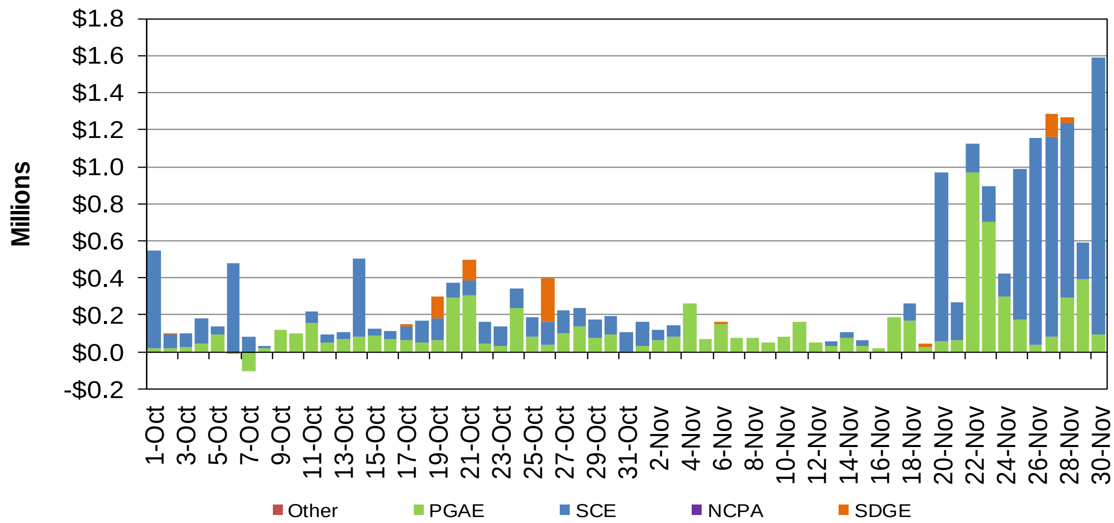
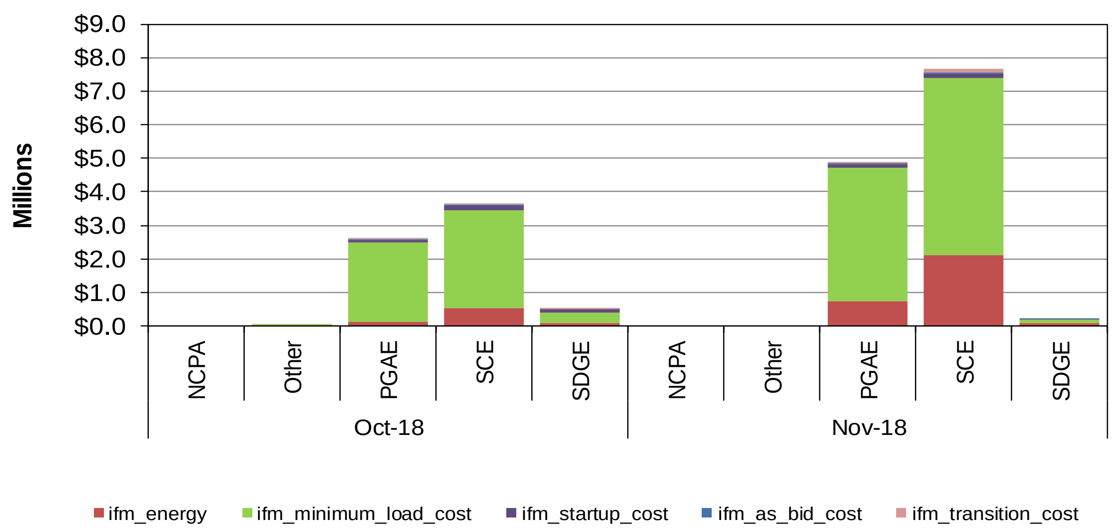


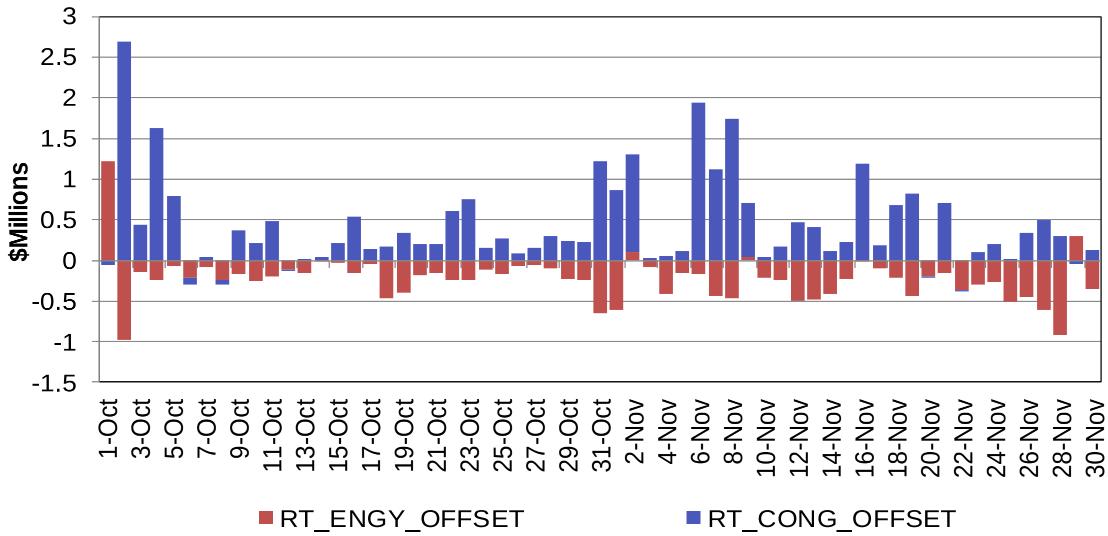
Figure 40: Monthly Cost in IFM by UDC



Real-time Imbalance Offset Costs

Figure 41 shows the daily real-time energy and congestion imbalance offset costs. Real-time energy offset cost decreased to -$8.90 million in November from -$5.19 million in October. Real-time congestion offset cost increased to $14.28 million in November from $12.33 million in October.

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 54 market disruptions this month. 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.

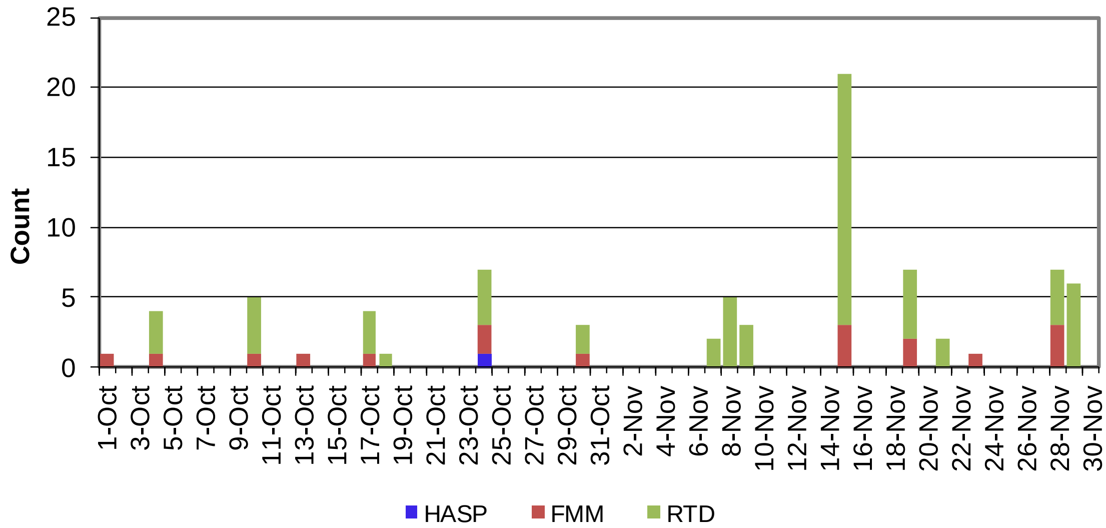
Table 7: Summary of Market Disruption

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	4	0
FMM Interval 2	0	0
FMM Interval 3	2	0
FMM Interval 4	3	0
Real-Time Dispatch	45	0

Figure 42 shows the frequency of IFM, HASP (FMM interval 2), FMM (intervals 1, 3 and 4), and RTD failures. On November 24, three FMM and 13 RTD disruptions occurred due to application problem. There were five other RTD disruptions that day due to broadcast not being successful.

[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: real-time incremental dispatch and real-time decremental dispatch. 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 November increased to 116,515 MWh from 105,112 MWh in October.

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

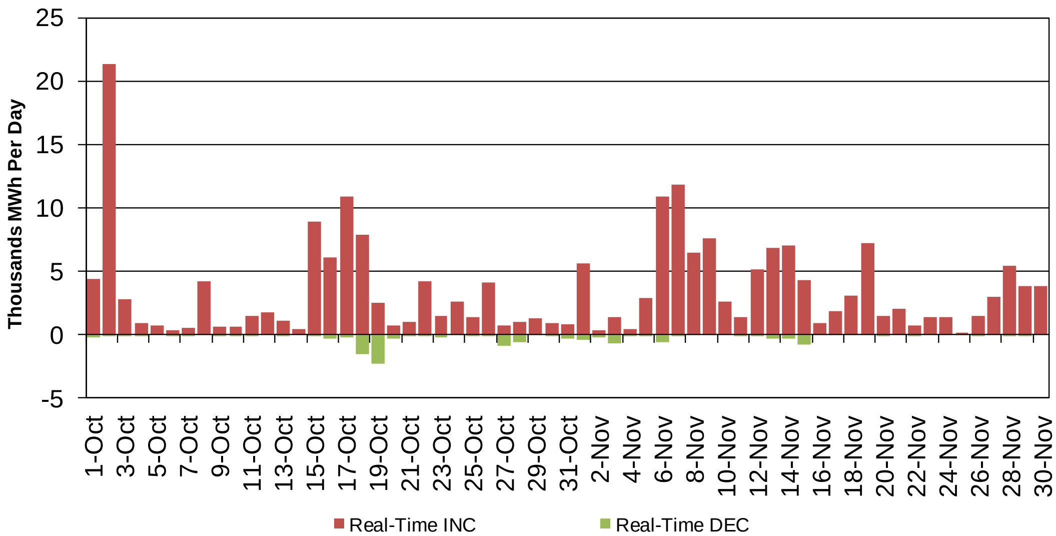


Figure 44 shows the volume of the exceptional dispatch broken out by reason.[4] The majority of the exceptional dispatch volumes in November were driven by load forecast uncertainty (24 percent) and planned transmission outage (42 percent).

[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

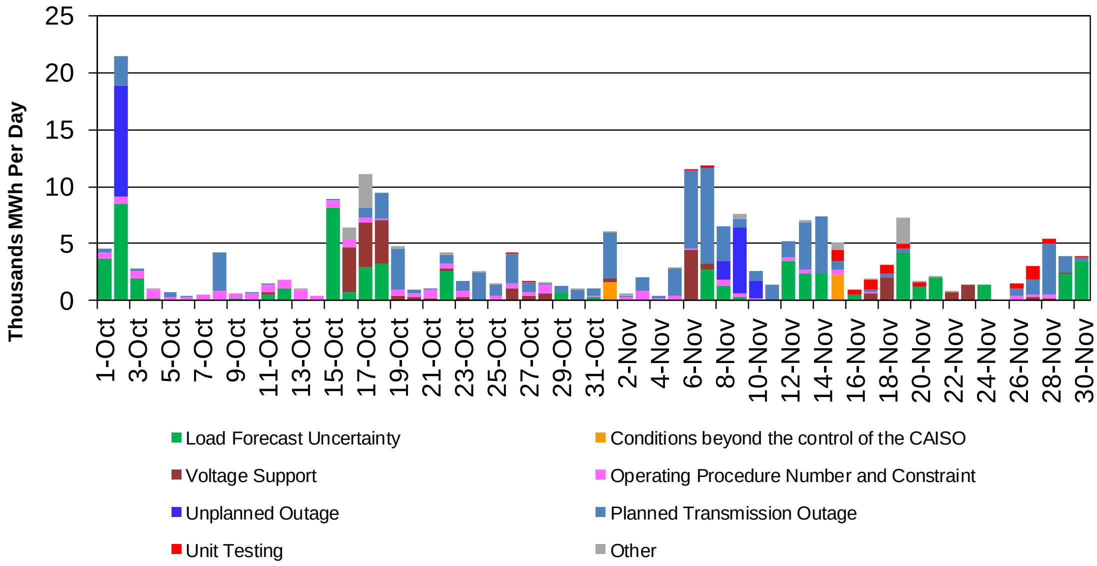
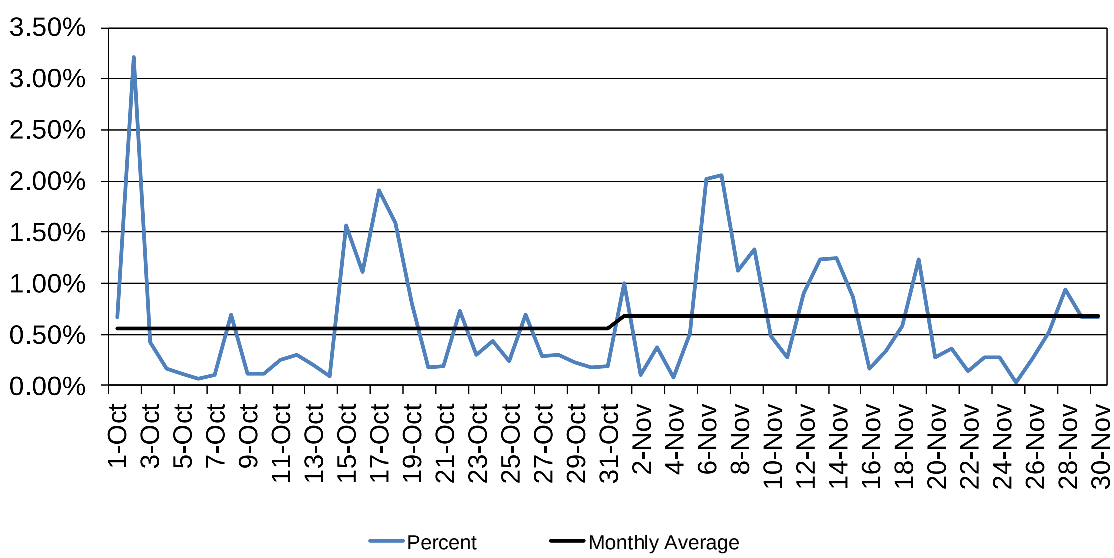


Figure 45 shows the total exceptional dispatch volume as a percent of load, along with the monthly average. The monthly average percentage was 0.68 percent in November, increasing from 0.56 percent in October.

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). 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.

On October 1, 2017, Portland General Electric Company (PGE) became the fifth western utility to successfully begin full participation in the western Energy Imbalance Market (EIM). PGE joins Arizona Public Service, Puget Sound Energy, NV Energy, PacifiCorp and the ISO, together serving over 38 million consumers in eight states: California, Arizona, Oregon, Washington, Utah, Idaho, Wyoming and Nevada.

On April 4, 2018, Boise-based Idaho Power and Powerex of Vancouver, British Columbia successfully entered the western Energy Imbalance Market (EIM) today, allowing the ISO's real-time power market to serve energy imbalances occurring within about 55 percent of the electric load in the Western Interconnection. The eight western EIM participants serve more than 42 million consumers in the power grid stretching from the border with Canada south to Arizona, and eastward to Wyoming.

Figure 46 shows daily simple average ELAP prices for PacifiCorp east (PACE), PacifiCorp West (PACW), NV Energy (NEVP), Arizona Public Service (AZPS), Puget Sound Energy (PSEI), Portland General Electric Company (PGE), Idaho Power (IPCO), and Powerex (BCHA) for all hours in FMM. The prices were generally quiet in November.

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

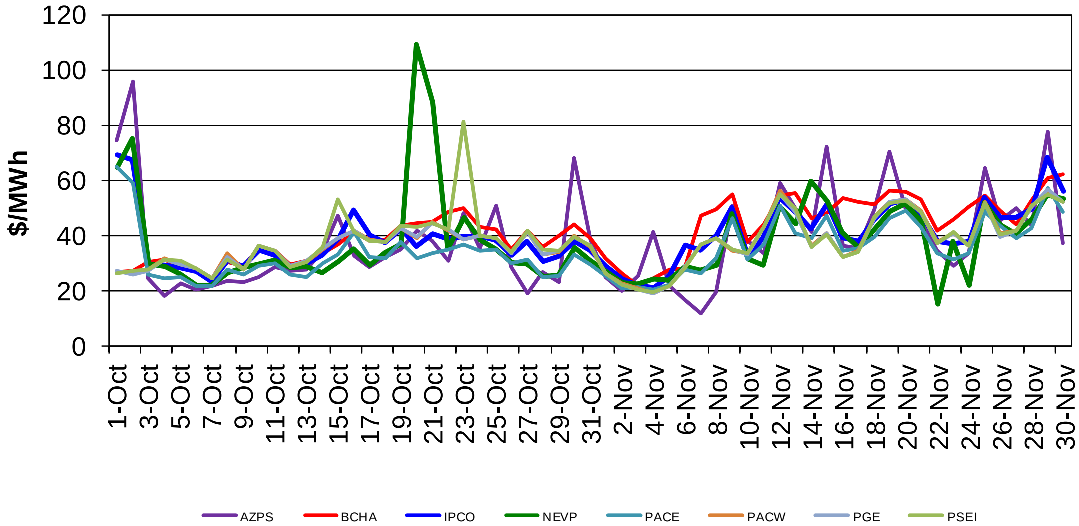


Figure 47 shows daily simple average ELAP prices for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA for all hours in RTD. The prices for AZPS, IPCO, NEVP, and PACE were elevated on November 29 due to upward load adjustment, renewable deviation, net import reduction, and generation outage.

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

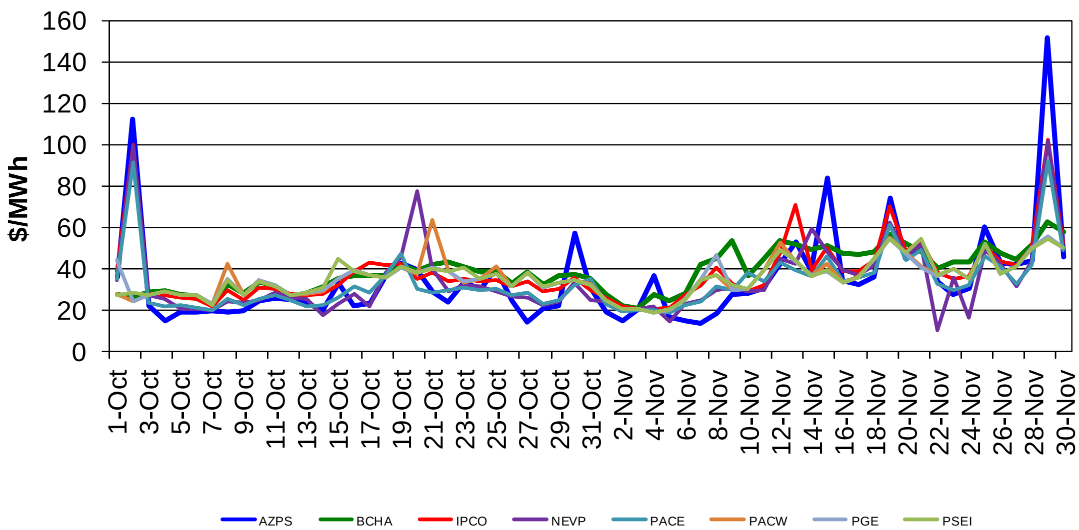


Figure 48 shows the daily price frequency for prices above $250/MWh and negative prices in FMM for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA. The cumulative frequency of prices above $250/MWh increased to 0.18 percent in November from 0.35 percent in October. The cumulative frequency of negative prices slid to 0.37 percent in November from 0.53 percent in October.

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

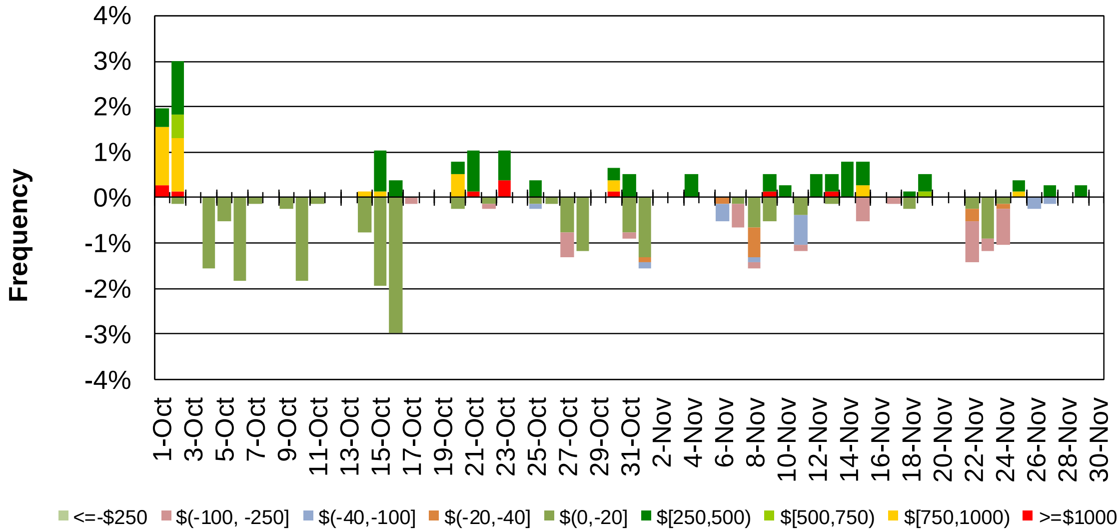


Figure 49 shows the daily price frequency for prices above $250/MWh and negative prices in RTD for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA. The cumulative frequency of prices above $250/MWh stayed at 0.30 percent in November, unchanged from October. The cumulative frequency of negative prices decreased to 0.87 percent in November from 1.07 percent in October.

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

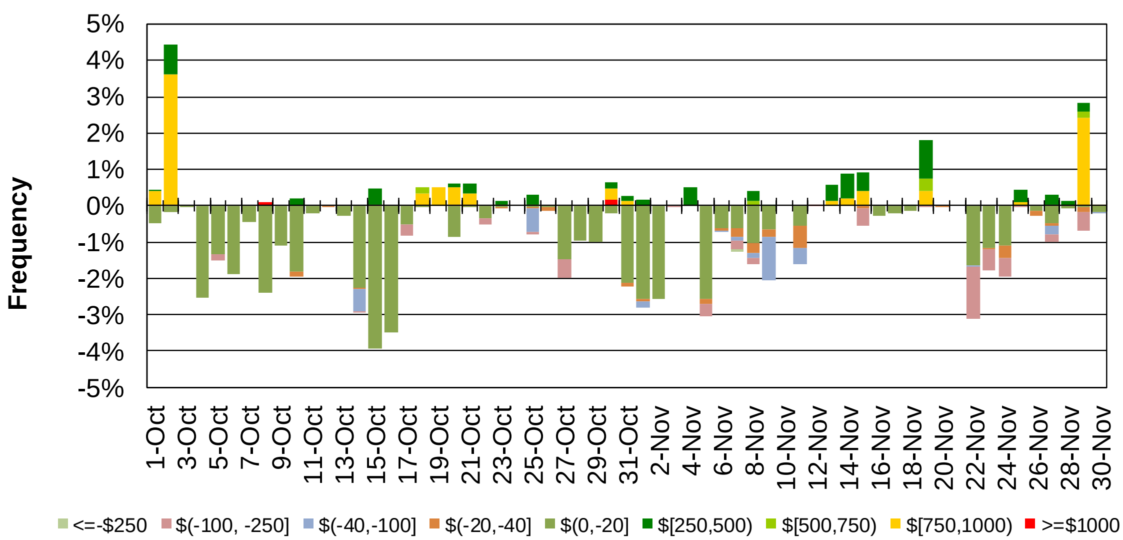


Figure 50 shows daily real-time imbalance energy offset cost (RTIEO) for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA respectively. Total RTIEO skidded to -$1.29 million in November from $1.98 million in October.

Figure 50: EIM Real-Time Imbalance Energy Offset by Area

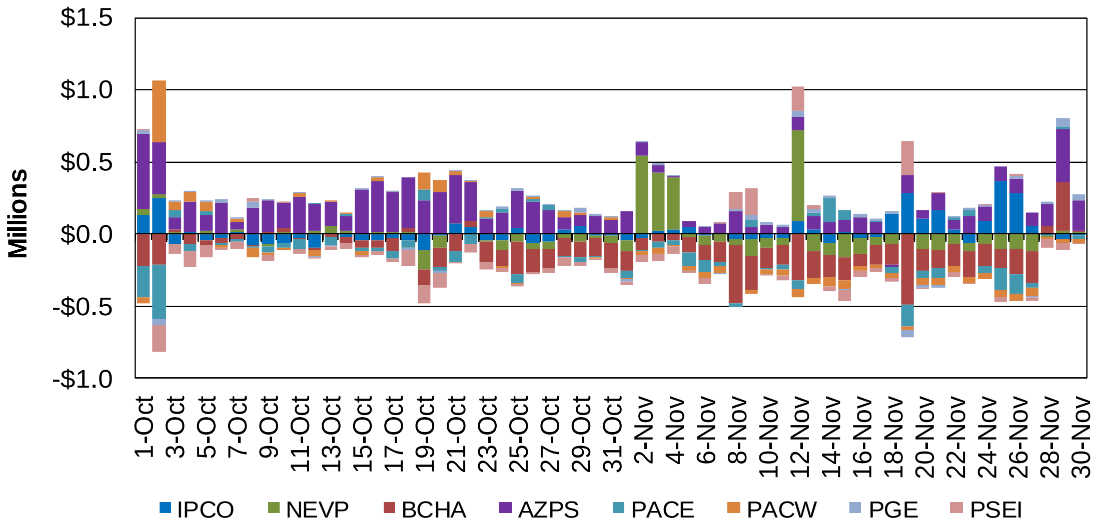


Figure 51 shows daily real-time congestion offset cost (RTCO) for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA respectively. Total RTCO declined to -$1.52 million in November from -$0.70 million in October.

Figure 51: EIM Real-Time Congestion Imbalance Offset by Area

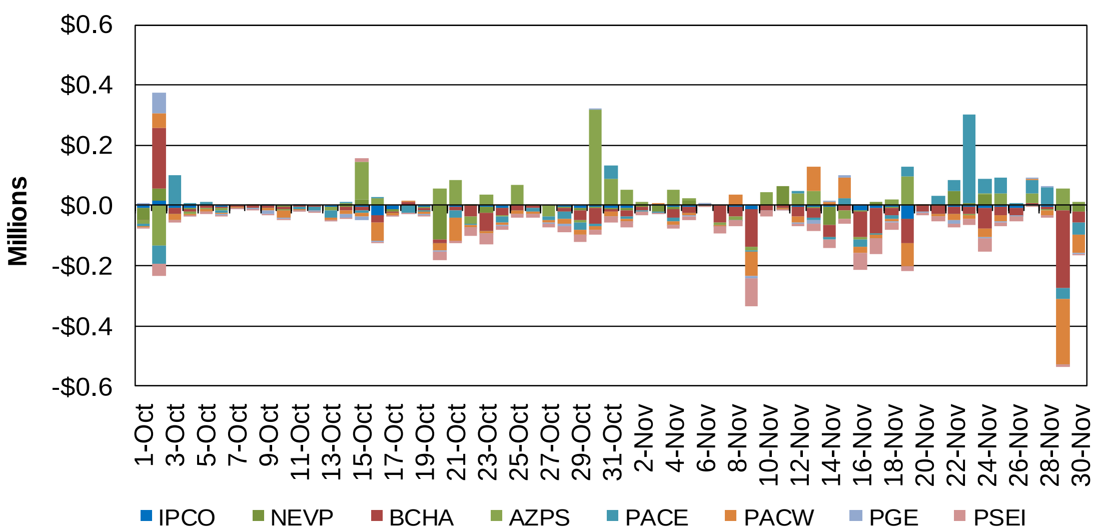


Figure 52 shows daily bid cost recovery for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA respectively. Total BCR inched up to $0.60 million in November from $0.36 million in October.

Figure 52: EIM Bid Cost Recovery by Area

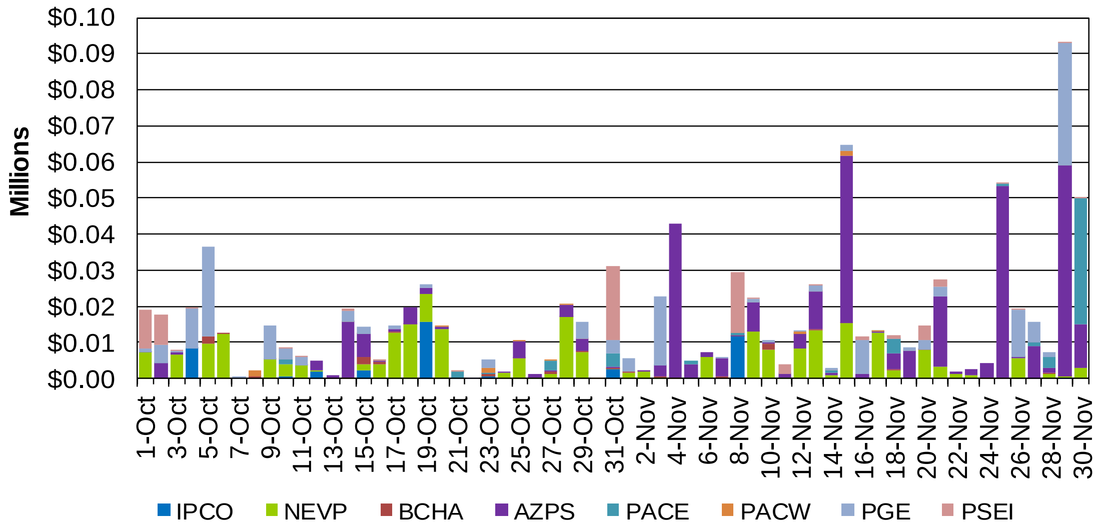


Figure 53 shows the flexible ramping up uncertainty payment for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA respectively. Total flexible ramping up uncertainty payment in November increased to $0.66 million from $0.45 million in October.

Figure 53: Flexible Ramping Up Uncertainty Payment

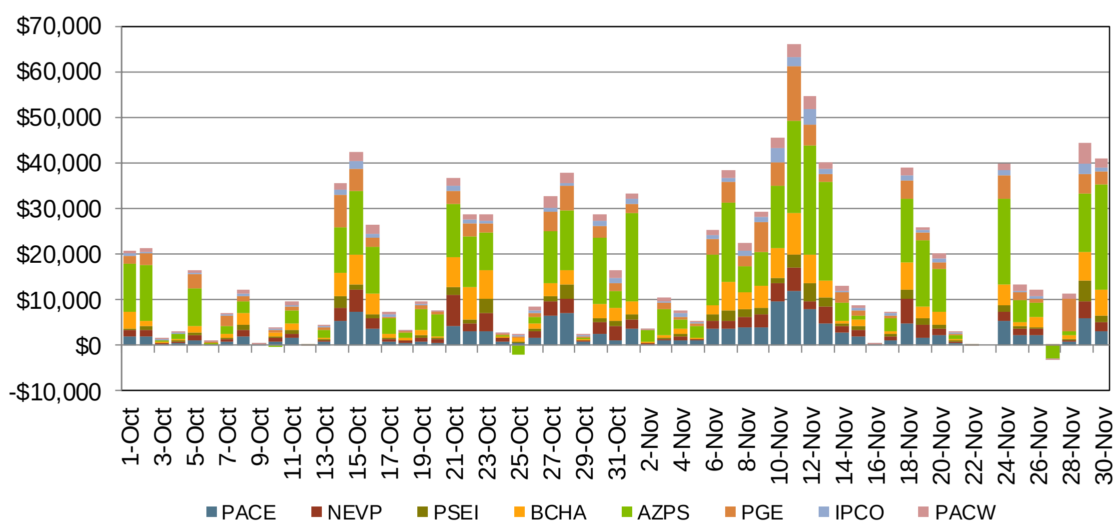


Figure 54 shows the flexible ramping down uncertainty payment for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA respectively. Total flexible ramping down uncertainty payment in November increased to -$8,432 from -$11,455 in October.

Figure 54: Flexible Ramping Down Uncertainty Payment

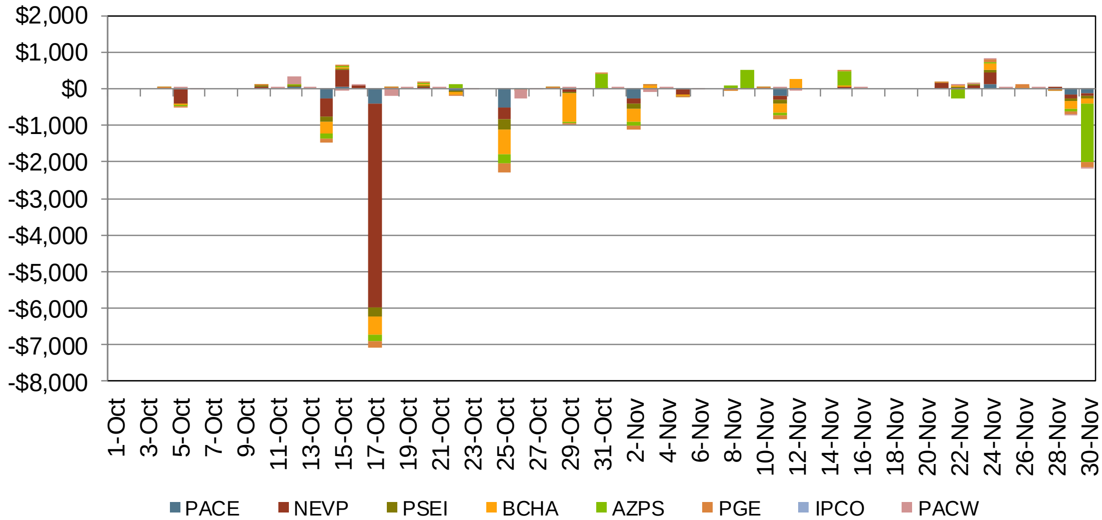
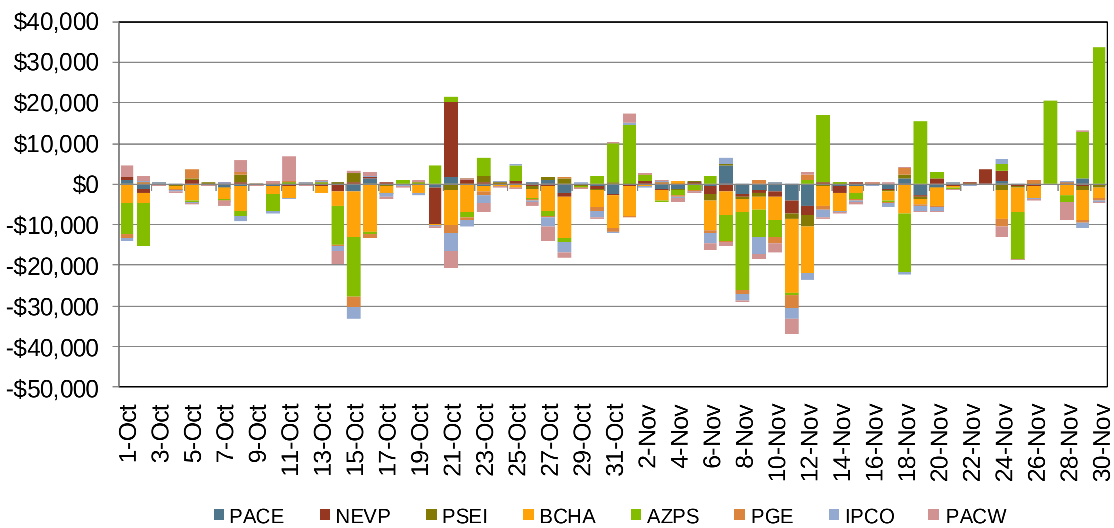


Figure 55 shows the flexible ramping forecast payment for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA respectively. Total forecast payment in November inched up to -$0.14 million from -$0.16 million in October.

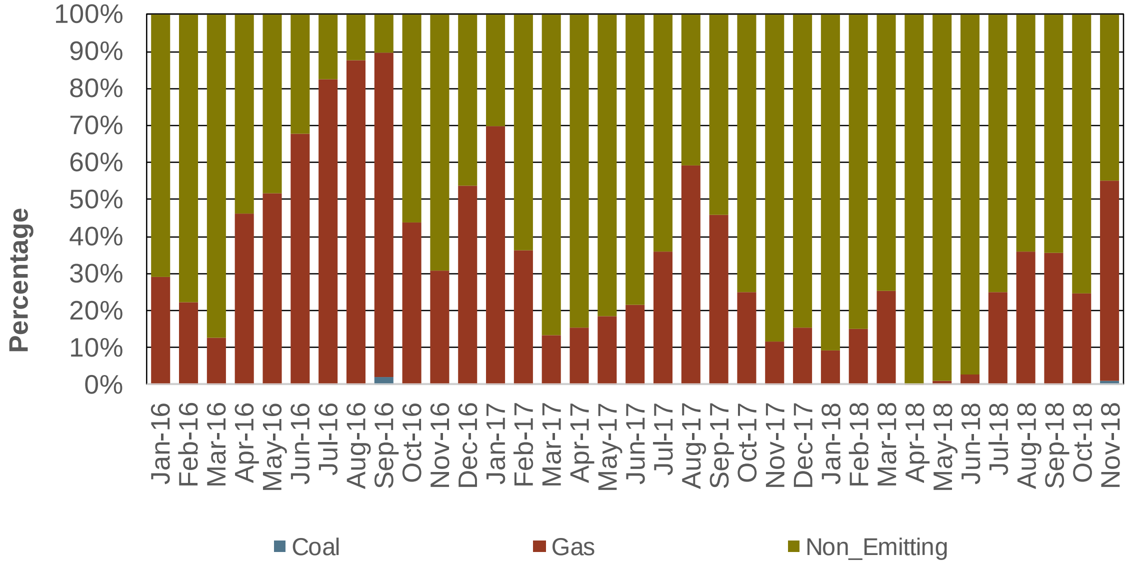
Figure 55: Flexible Ramping Forecast Payment



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].

The EIM dispatches to support transfers into the ISO were documented in Figure 56 and Table 8 below.

Figure 56: 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
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%	21.42%	78.58%	100%
Jul-17	0.00%	36.08%	63.92%	100%
Aug-17	0.00%	59.20%	40.80%	100%
Sep-17	0.00%	45.94%	54.06%	100%
Oct-17	0.00%	24.85%	75.15%	100%
Nov-17	0.00%	11.57%	88.43%	100%
Dec-17	0.00%	15.36%	84.64%	100%
Jan-18	0.00%	9.12%	90.88%	100%
Feb-18	0.00%	15.20%	84.80%	100%
Mar-18	0.16%	25.00%	74.84%	100%
Apr-18	0.00%	0.14%	99.86%	100%
May-18	0.00%	1.09%	98.91%	100%
Jun-18	0.00%	2.89%	97.11%	100%
Jul-18	0.00%	25.04%	74.96%	100%
Aug-18	0.00%	35.87%	64.13%	100%
Sep-18	0.00%	35.50%	64.50%	100%
Oct-18	0.00%	24.51%	75.49%	100%
Nov-18	1.16%	53.81%	45.03%	100%