Market Performance Metric Catalog

Version 1.36

April 2019

ISO Market Services

VERSION HISTORY

Date	Version	Description	Author
5/28/2009	1.0	Creation of document	Market Performance Group
6/25/2009	1.1	Document for May	Market Performance Group
7/25/2009	1.2	Document for June	Market Performance Group
8/24/2009	1.3	Document for July	Market Performance Group
9/25/2009	1.4	Document for August	Market Performance Group
10/26/2009	1.5	Document for October	Market Performance Group
12/2/2009	1.6	Added a section on energy price convergence. Revised the exceptional dispatch section.	Market Performance Group
12/22/2009	1.7	Added the Market Intervention section, under which the market disruption. Added a section on intertie blocking. Added IFM hourly average regulation requirements and hourly average ancillary service price charts in the ancillary service section.	Market Performance Group
01/25/2010	1.8	Added a subsection on Blocking of Commitment Instructions.	Market Performance Group
02/25/2010	1.9	Added a subsection of transmission constraint adjustments to the section of Market Intervention. Modified language of perfect hedge to be characterized now as transmission right exemption. Added weekly average price convergence and changed the calculation formula of daily and hourly average prices for default LAPs and interties.	Market Performance Group
03/24/2010	1.10	Added a subsection of congestion cost per megawatt of load served. Added the subsection of market implied heat rate under the Market Characteristics section. Added the subsection of imbalance offset costs. Added the subsection of bid cost recovery. Reorganize the structure of the whole	Market Performance Group

Date	Version	Description	Author
		document.	
04/26/2010	1.11	Added a subsection of blocking of real-time dispatch. Reorganized the metrics in the section of CRR Revenue Adequacy	Market Performance Group
5/26/2010	1.12	Modified the charts for real-time upward ancillary services procurement, proportion of real-time procurement as percentage of day-ahead requirement, real-time ancillary service average price and system average cost to load, to include the metrics for the spinning and non-spinning ancillary services in the HASP. Remove the appendix of imbalance offset cost from the market performance report to the metric catalog. Added a section of Regulatory Requirement. Added a section of day-ahead scheduled hydro volume.	Market Performance Group
6/28/2010	1.13	Added a daily profile of transmission bias volume. Modified the plot of uplift costs. Added the section of Other Metrics, which includes the subsection of bilateral transfers of Existing Contract Import Capability. Added sections of losses for both day-ahead and real-time markets.	Market Performance Group
7/26/2010	1.14	Added the subsection of Make Whole Payment. Added the section of Net Interchange. Added the subsection of comparison of IFM congestion and RTD congestion.	Market Performance Group
9/24/2010	1.15	Added the subsection of New Market Functionalities.	Market Performance Group
10/26/2010	1.16	Added the subsection of Generation by Fuel.	Market Performance Group
12/21/2010	1.17	Added the subsection of System Parameter Excursion. Added the subsection of Analysis of Minimum Online Capacity.	Market Performance Group
1/28/2011	1.18	Added the subsections of Multi-Stage Generation and Contingent/Non Contingent Ancillary Service	Market Performance Group
2/23/2011	1.19	Added the subsection of Hourly Inter-Tie Ramping	Market Performance Group

Date	Version	Description	Author
3/30/2011	1.20	Added the subsection of Convergence Bidding	Market Performance Group
5/27/2011	1.21	Added the plot of AS hydro volume awarded in the day-ahead market. Removed the subsection of Compensating Injection. Removed the subsection of Multi-Stage Generation. Removed the subsection of Hourly Inter-Tie Ramping. Modified the plot of uplift costs.	Market Performance Group
6/28/2011	1.22	Added the plot of abandoned runs in real-time market.	Market Performance Group
2/29/2012	1.23	Removed the plot of abandoned runs in real-time market. Removed the plots of convergence bidding for interties.	Market Performance Group
4/28/2012	1.24	Replaced the Chart "Market Short Falls and Bid Cost Recovery" with the Chart "Bid Cost Recovery Allocation".	Market Performance Group
7/30/2012	1.25	Added 3 charts showing BCR allocation in RUC, IFM and RT.	Market Performance Group
7/3/2013	1.26	Removed natural gas prices and bilateral electricity prices.	Market Performance Group
2/25/2014	1.27	Added natural gas prices and implied heat rate	Market Development and Analysis
6/30/2014	1.28	Added the plots of FMM DLAP prices and price volatility. Removed weekly price convergence. Added FMM losses and loss prices. Added real-time energy offset and congestion imbalance offset chart.	Market Development and Analysis
7/31/2014	1.29	Added the plots of BCR by local capacity area and utility distribution company.	Market Development and Analysis
12/31/2014	1.30	Added EIM section	Market Development and Analysis
2/1/2016	1.31	Added renewable resource section and NV Energy to the EIM section	Market Development and Analysis
8/10/2016	1.32	Removed contingent/non-contingent ancillary services	Market Development and Analysis
10/7/2016	1.33	Removed compensating injection section. Removed Figures for total EIM BCR, RTCO, and RTIEO.	Market Analysis
12/15/2016	1.34	Added EIM transfer charts for new EIM entities, AZPS and PSEI.	Market Analysis
4/7/2017	1.35	Added flexible ramping product for ISO and EIM entities	Market Validation and Analysis

Date	Version	Description	Author
5/312017	1.36	Added resource adequacy availability incentive mechanism section	Market Validation and Analysis

TABLE OF CONTENTS

Regulatory Requirement

This section states three sets of metrics which the ISO promised to make publicly to the market participants.

The first set of metrics is about the cost of the existing rights exemptions.[1] Figure 62 shows the net cost of the existing right exemptions for schedule changes of ETCs/TORs for both day-ahead and real-time markets. Table 7 lists the monthly summary of exemptions for existing transmission rights in the day-ahead and real-time markets.

The second set of regulatory metrics is about the adjustment of the transmission constraints.[2] Figure 139 shows the frequency and average of adjustment of transmission constraints by market for the current month.

[1] As required by FERC's Order Accepting Compliance Filing issued on October 22, 2006 (*California Indep. Sys. Operator, Corp.*, 116 FERC ¶ 61,281, (2006)), the ISO maintains a record of the redispatch costs associated with honoring existing rights and charged to non-existing-rights loads and makes this information publicly available to market participants on the ISO website in the monthly market performance metric catalog: http://www.caiso.com/2424/2424d14d4a200.html

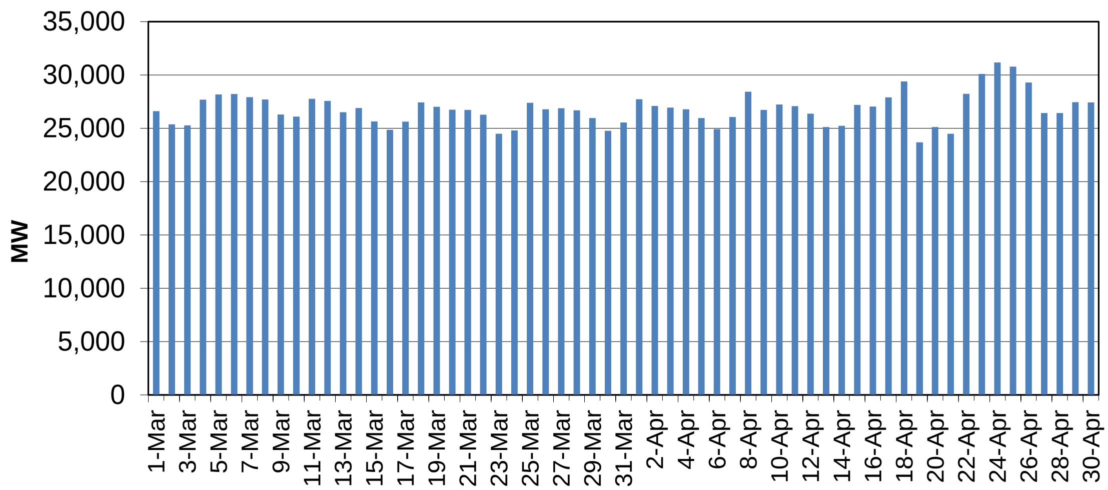
[2] As required by FERC's Order Conditionally Accepting Tariff Revisions issued on October 2, 2009 (California Indep. Sys. Operator, Corp., 129 FERC ¶ 61,009 (2009)), the ISO convenes a stakeholder process with an aim to address concerns raised by parties in that proceeding regarding what additional transparency and visibility can be provided with respect to the ISO's transmission constraint enforcement practices to account for system conditions in managing the limits of the transmission system. As an outcome of this process, the ISO provides metrics of transmission adjustments applied in the various markets to add transparency of the ISO practices for transmission constraints.

Market Characteristics

Loads

Figure 1 shows system peak load.

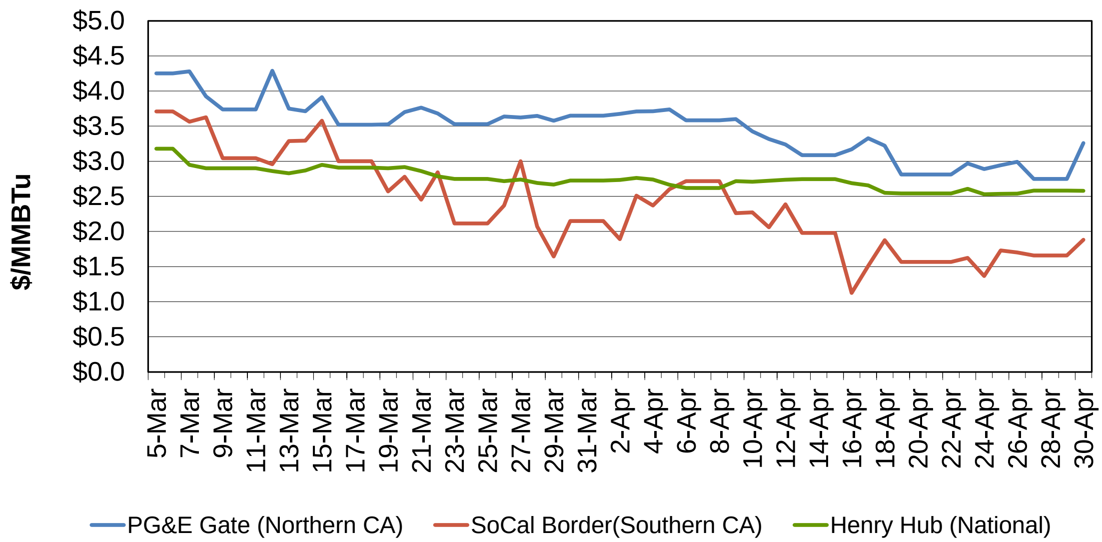
Figure 1: System Peak Load



Natural Gas Prices

Figure 2 displays the daily natural gas spot prices for three selected trading hubs: PG&E Citygate as a proxy for Northern California, So Cal Border as a proxy for Southern California, and Henry Hub as a proxy for the rest of the U.S. Natural gas prices are important to the market as much of the capacity in the West – especially the newer units – is gas-fired. These units are also often marginal, meaning that they set the price levels in bilateral markets.

Figure 2: Daily Average Natural Gas Spot Prices



Market Implied Heat Rate

The term “heat rate” refers to the power plant efficiency in converting fuel to electricity. Heat rate is expressed as the number of thousand British thermal units (MBtu) required to convert a megawatt hour (MWh) of electricity. Lower heat rates are associated with more efficient power generating plants. The market implied heat rate is calculated as shown below. The daily average market implied heat rate is an indicator of the heat rate of the marginal unit in the integrated forward market (IFM).

$$DLAP\_Market\_Implied\_Heat\_Rate_l = \frac{DLAP\_LMP_l}{Daily\_Avg\_NGI_p}$$

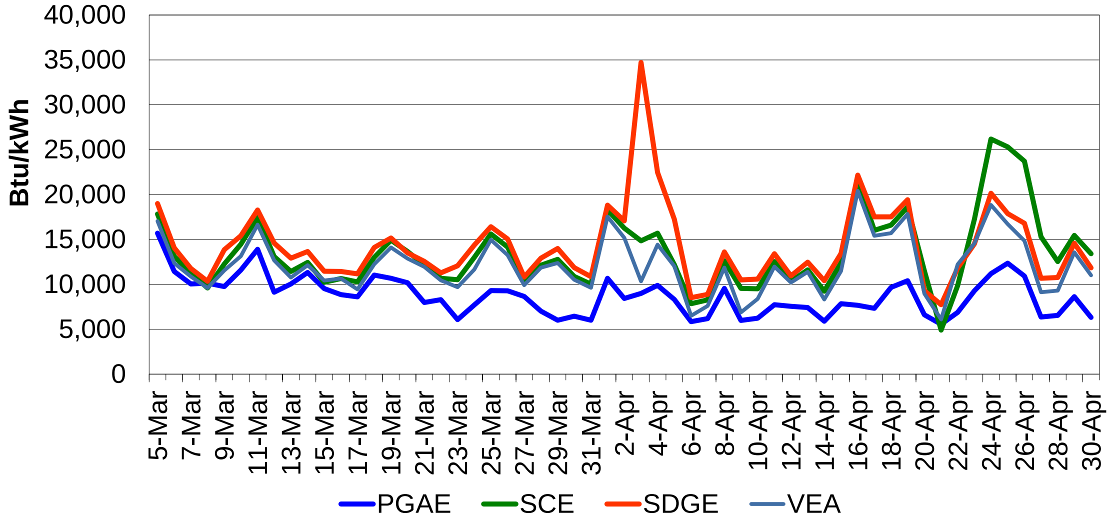
$$DLAP\_LMP_l = \frac{\sum_h^H \mathrm{LMP}_{h,l} * \mathrm{Sched}_{h,l}}{\sum_h^H \mathrm{Sched}_{h,l}}$$

Where

$l \in L$	L is set of default load aggregation points (DLAPs); which include PG&E, SCE and SDG&E.
$h \in H$	H is set of hours for trading day.
$\mathrm{Sched}_{h,l}$	Energy schedule for the hour h for DLAP l
$\mathrm{LMP}_{h,l}$	LMP for the hour h for DLAP l
$DLAP\_LMP_l$	Daily energy weighted default LMP for LAP l
$p \in P$	P is set of all natural gas pricing points. There are two pricing points for California: PG&E city gate and Southern California Border. Note that for the PG&E DLAP, PG&E city gate gas price is used. For the SCE and SDG&E DLAPs, the Southern California Border gas price is used.
$Daily\_Avg\_NGI_p$	Daily average natural gas price index for a pricing point p

Figure 3 shows the daily IFM average default LAP market implied heat rate.

Figure 3: Daily IFM Default LAP Market Implied Heat Rate



Day-Ahead Scheduled Hydro Volume

Figure 4 shows the daily average of the scheduled hydro volume in day-ahead market for the ISO control area.

Figure 4: Day-Ahead Scheduled Hydro Volume

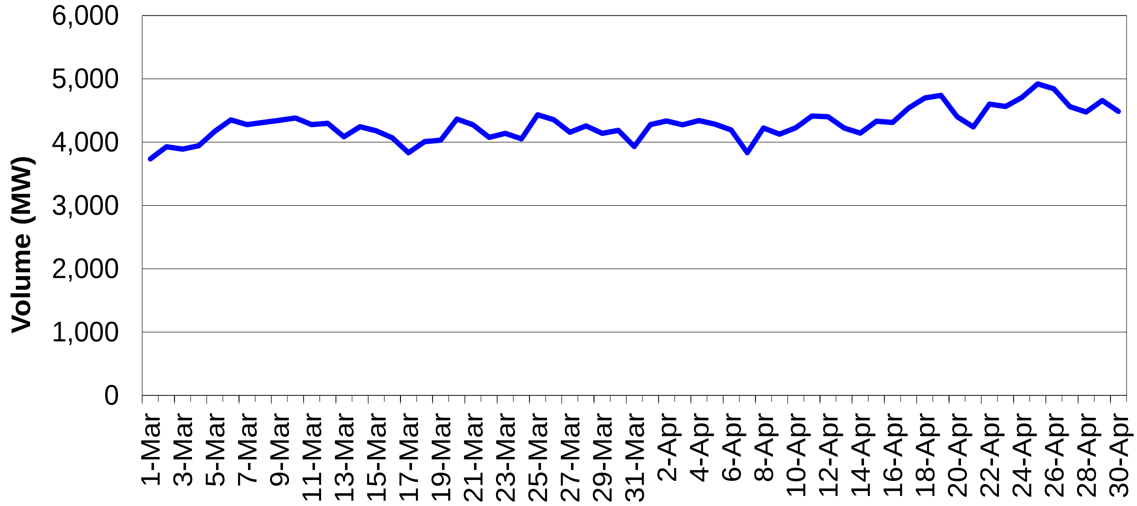
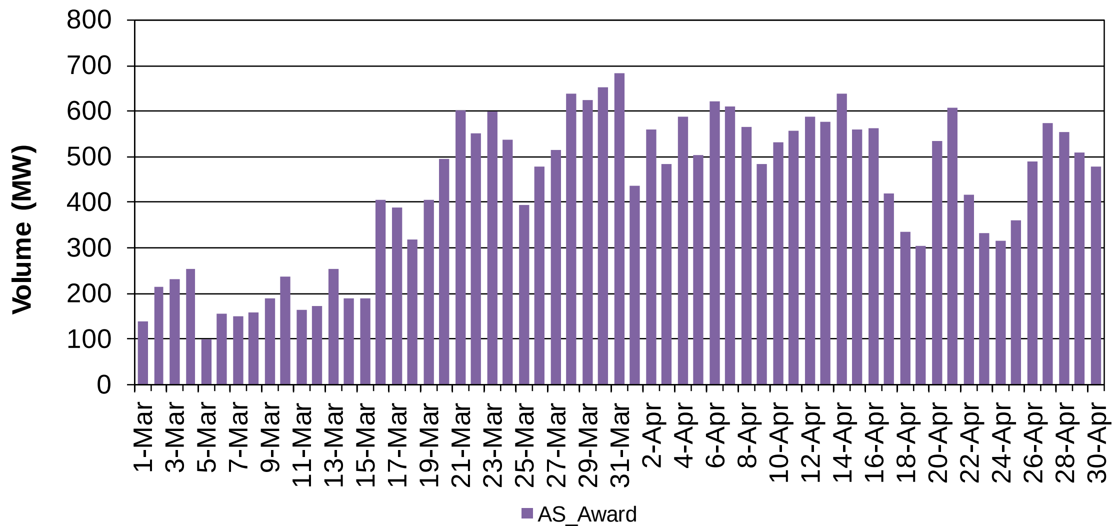


Figure 5 shows the daily average of the AS hydro volume awarded in day-ahead market.

Figure 5: AS Hydro Volume Awarded in Day-Ahead Market



Net Interchange

Figure 6 shows the net interchange in the integrated forward market, broken out by intertie. The daily values are simple averages, and the net interchange is obtained as imports less exports. Figure 7 shows the daily profile of net interchange across the various markets, namely, the integrated forward market, the hour-ahead scheduling process and the real-time dispatch.

Figure 6: Daily Average Volume of Net Interchange in IFM

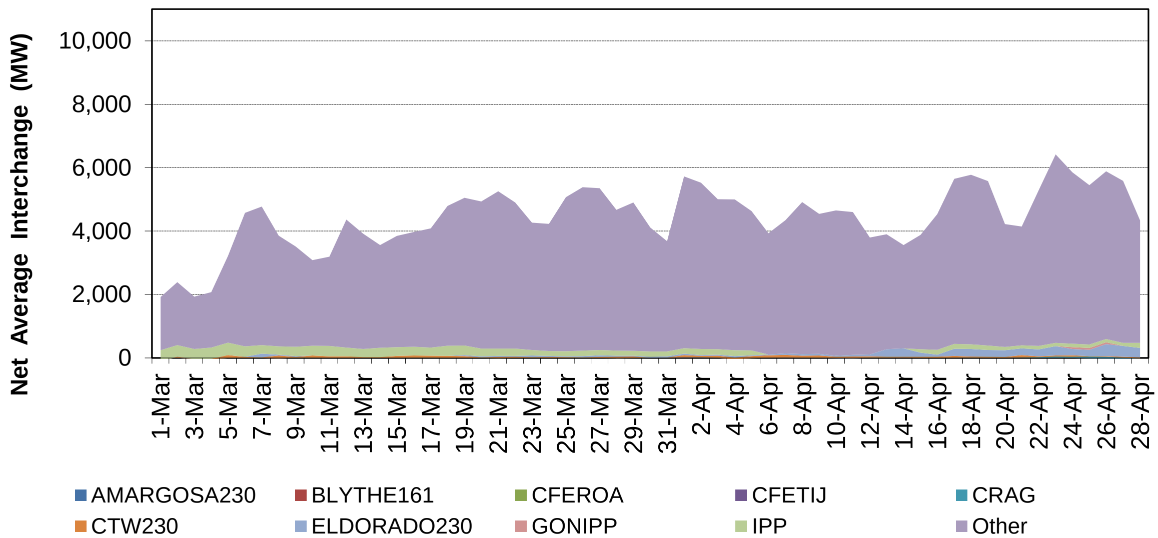
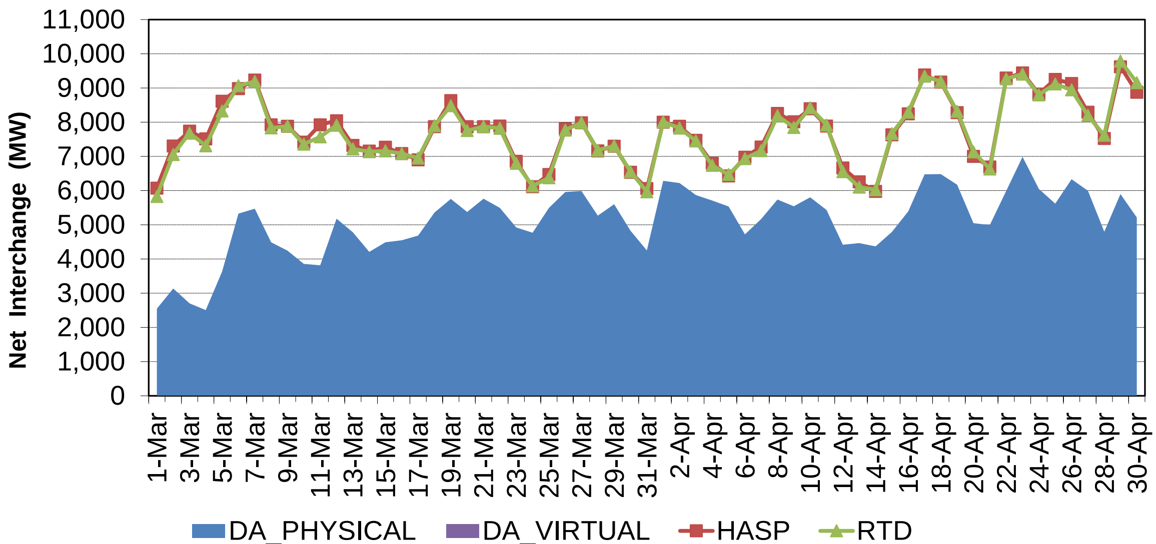


Figure 7: Daily Average Volume of Net Interchange per Market



Market Performance Metrics

Energy

Day-Ahead Prices

Figure 8, Figure 9 and Figure 10 show the daily simple average load-aggregation points (LAP) prices for each of the four default LAPs (PG&E, SCE, SDG&E, and VEA) for peak hours, off-peak hours, and all hours respectively in the day-ahead market.

Figure 8: Day-Ahead Simple Average LAP Prices (On-Peak Hours)

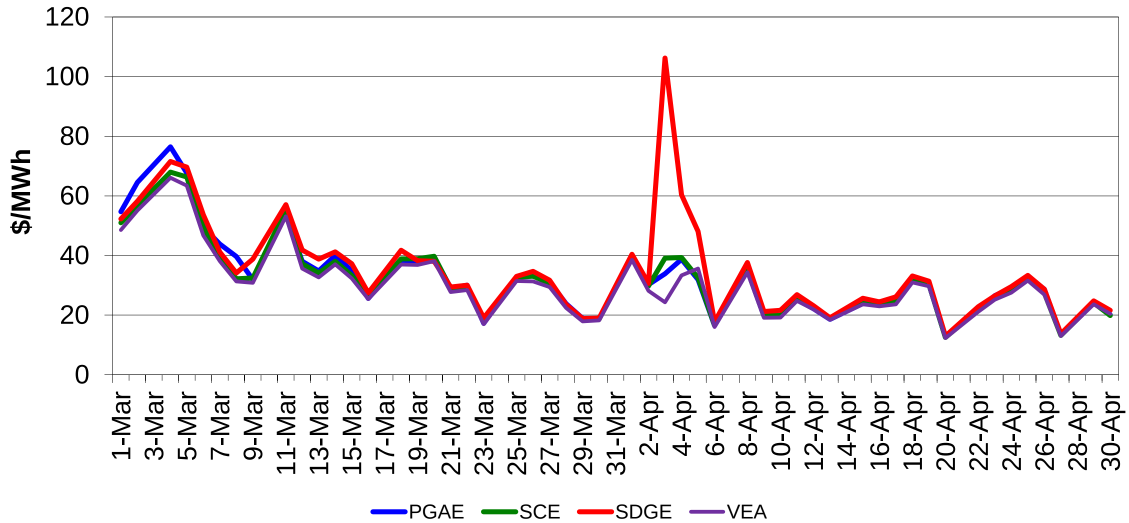


Figure 9: Day-Ahead Simple Average LAP Prices (Off-Peak Hours)

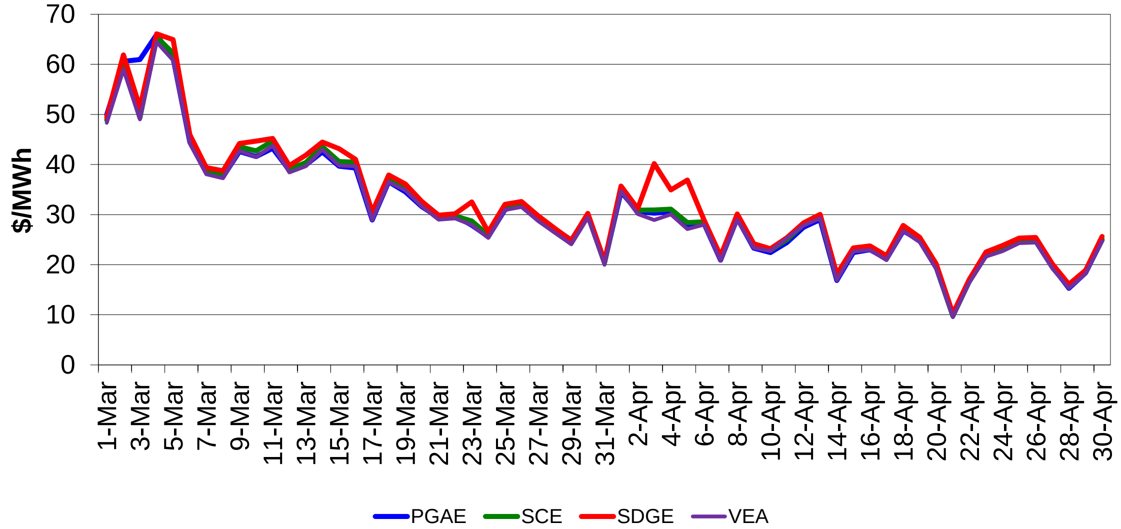


Figure 10: Day-Ahead Simple Average LAP Prices (All Hours)

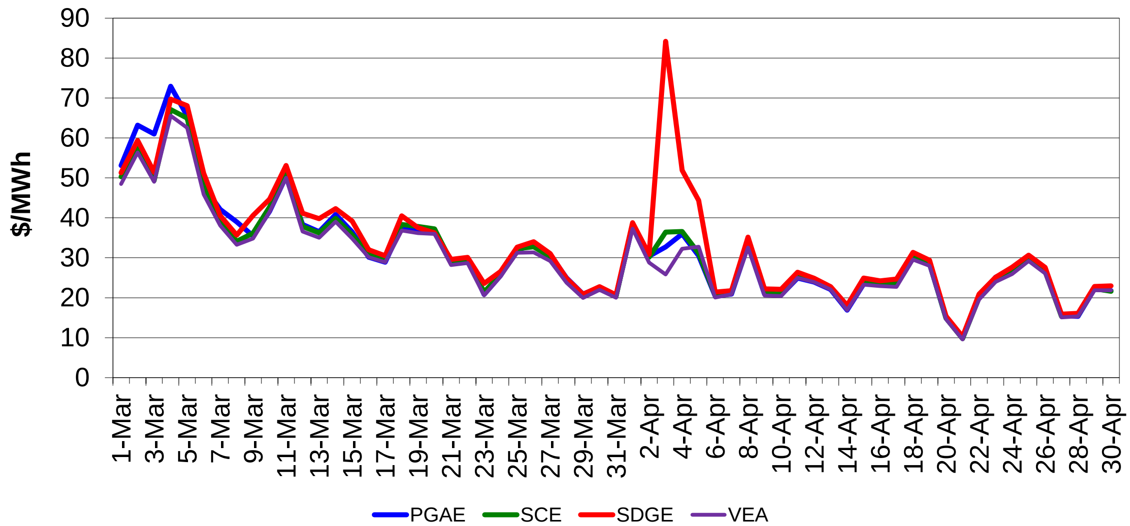
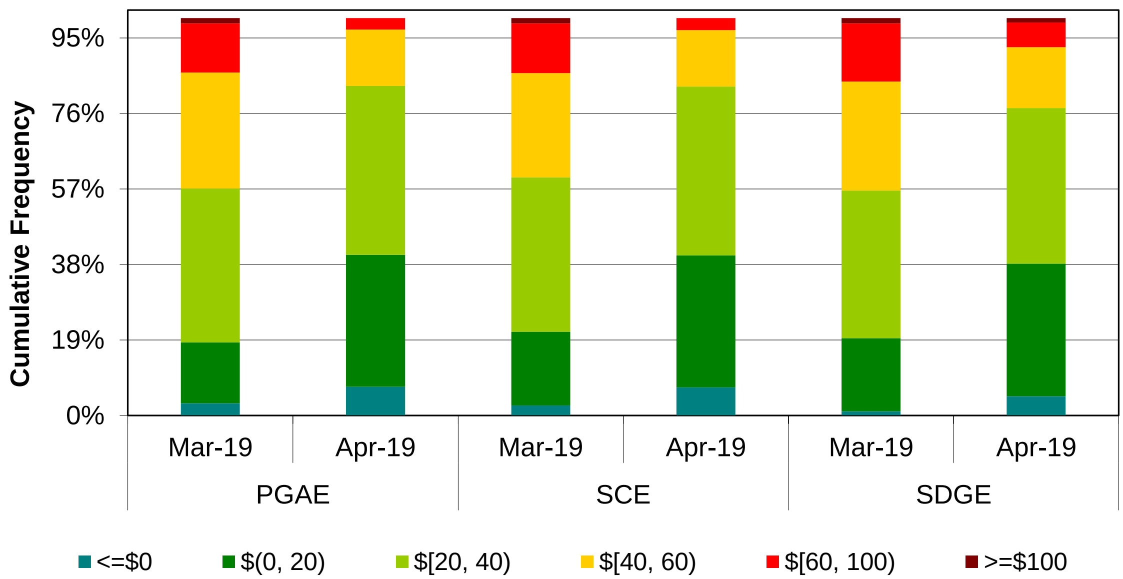


Figure 11 shows the frequency of prices of the default LAP prices in the integrated forward market (IFM). Prices are grouped in several bins. This frequency includes both time of uses, on- and off-peak. For each price bin, the price range is defined by an interval of lower and upper price; in these ranges, the parenthesis means the price range does not include the upper limit value, while the square bracket means the price range does include the lower limit.

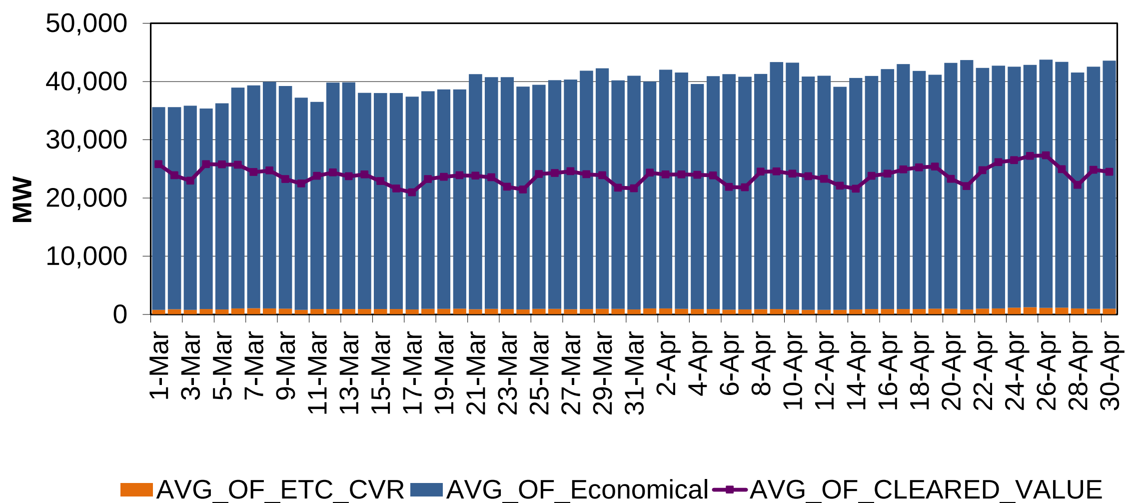
Figure 11: Frequency of Day-Ahead LAP Prices (All hours)



IFM Bid Stack

Figure 12 shows the daily average IFM bid volume classified into various types of self-schedules and economical bids. It also depicts the daily average cleared generation and imports. In the IFM, sum of cleared generation and imports is equal to the sum of cleared demand, pump schedule, loss and exports. There are three types of self-schedules bidding into the IFM which are classified based on priority. Transmission ownership right (TOR), existing transmission contract (ETC) and converted rights (CVR) self schedules have the highest priority. Reliability must take has a lower priority and the price taker has the lowest priority among all self-schedules.

Figure 12: IFM Bid Stack and Cleared Generation and Imports



Day-Ahead Volumes

Figure 13 below shows the daily average scheduling deviation percentage in the IFM and the daily average cleared load in the IFM. The average scheduling deviation percentage is calculated as

Percent Over/Under Schedule =

$$\frac{(\text{Daily\_Average\_Forecast} - \text{Daily\_Average\_Cleared\_load})}{\text{Daily\_Average\_Forecast}}$$

Figure 13: IFM Scheduling Deviation and Cleared Load

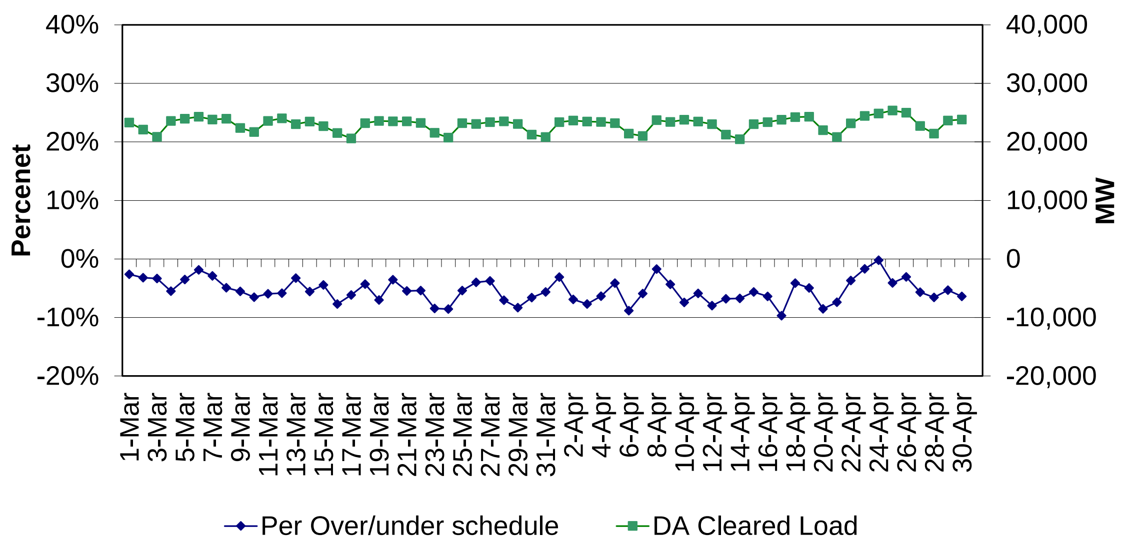
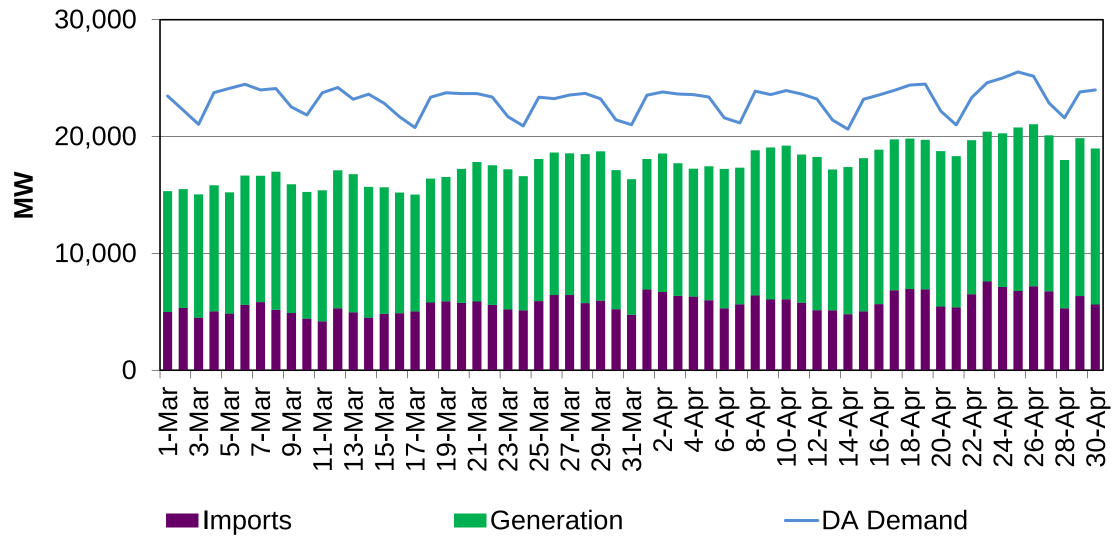


Figure 14 below shows the daily average day-ahead cleared imports, day-ahead generation (within California) and day-ahead cleared demand in the IFM. The day-ahead cleared demand includes day-ahead losses, but excludes exports.

Figure 14: Day-Ahead Cleared Quantity



Real-Time Prices

Figure 15, Figure 16 and Figure 17 show daily simple average LAP prices for all the default LAPs for peak hours, off-peak hours, and all hours respectively in FMM. Figure 18, Figure 19 and Figure 20 show daily simple average LAP prices for each of the four default LAPs for peak hours, off-peak hours, and all hours respectively in RTD.

Figure 15: FMM Simple Average LAP Prices (On-Peak Hours)

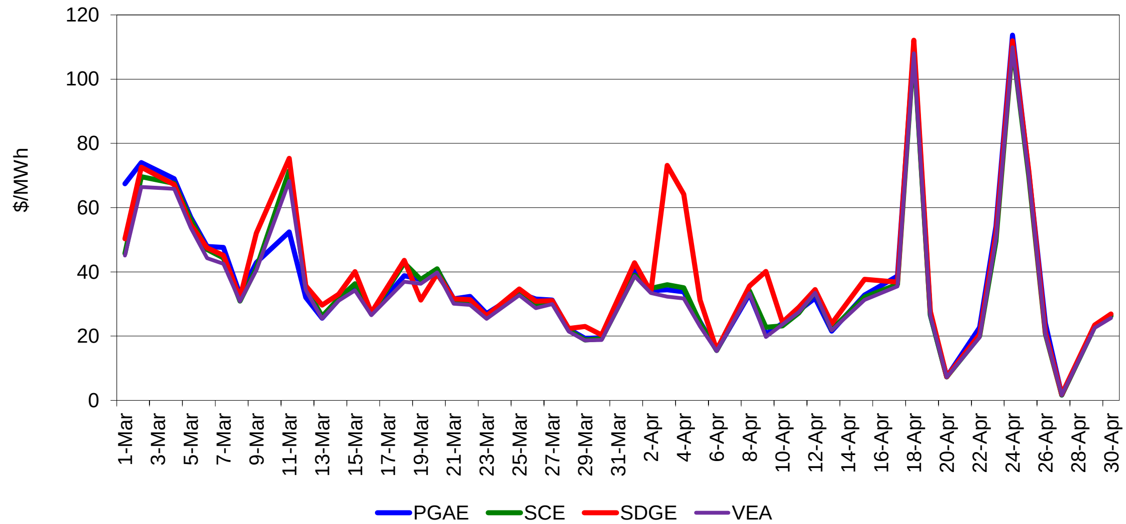


Figure 16: FMM Simple Average LAP Prices (Off-Peak Hours)

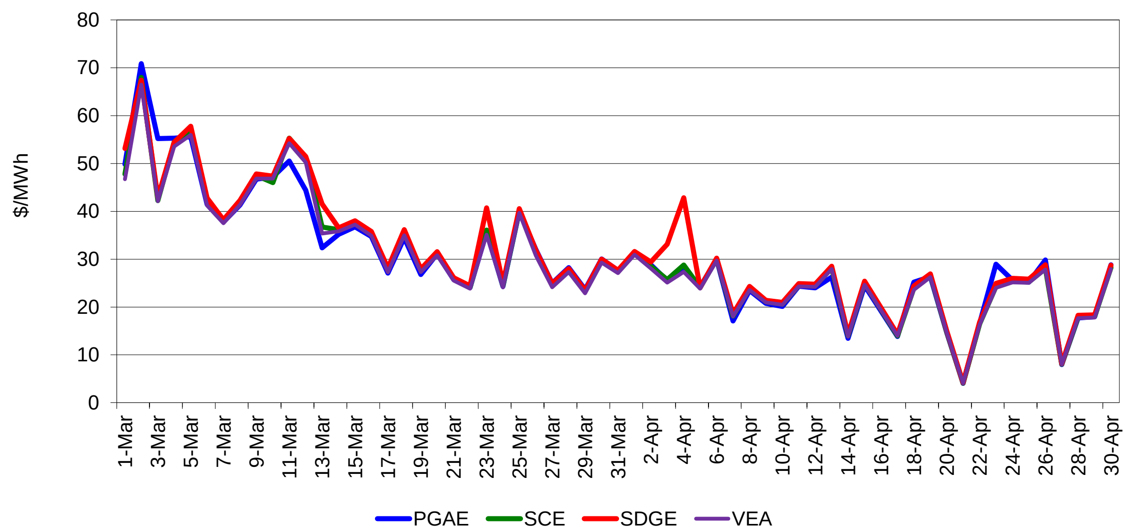


Figure 17: FMM Simple Average LAP Prices (All Hours)

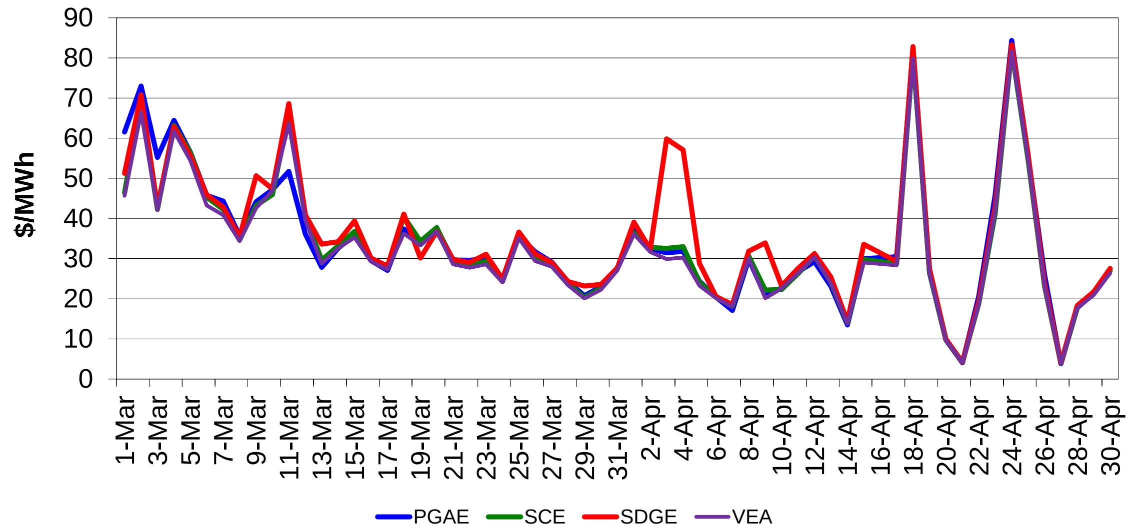


Figure 18: RTD Simple Average LAP Prices (On-Peak Hours)

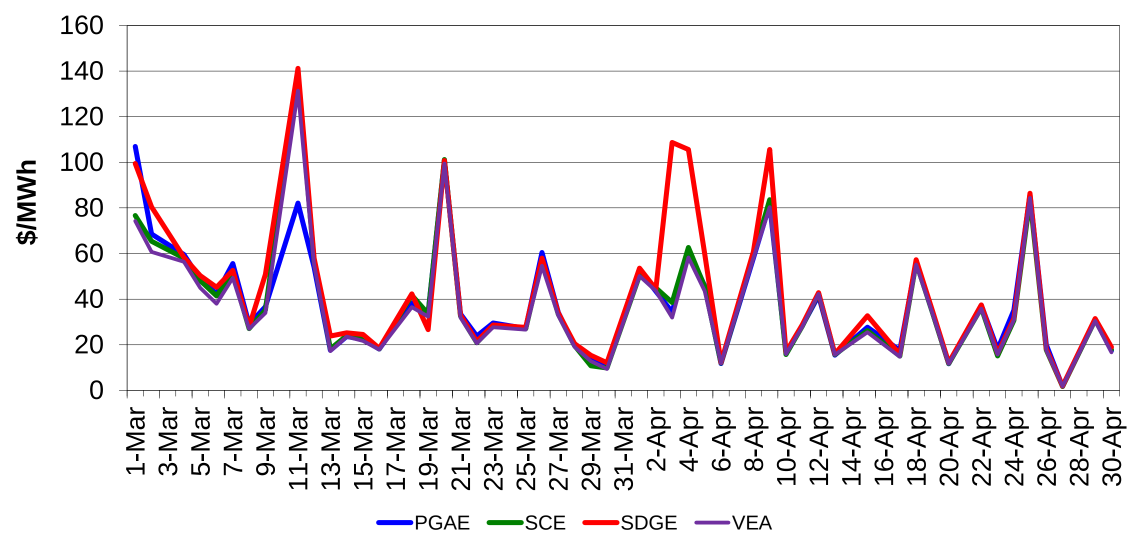


Figure 19: RTD Simple Average LAP Prices (Off-Peak Hours)

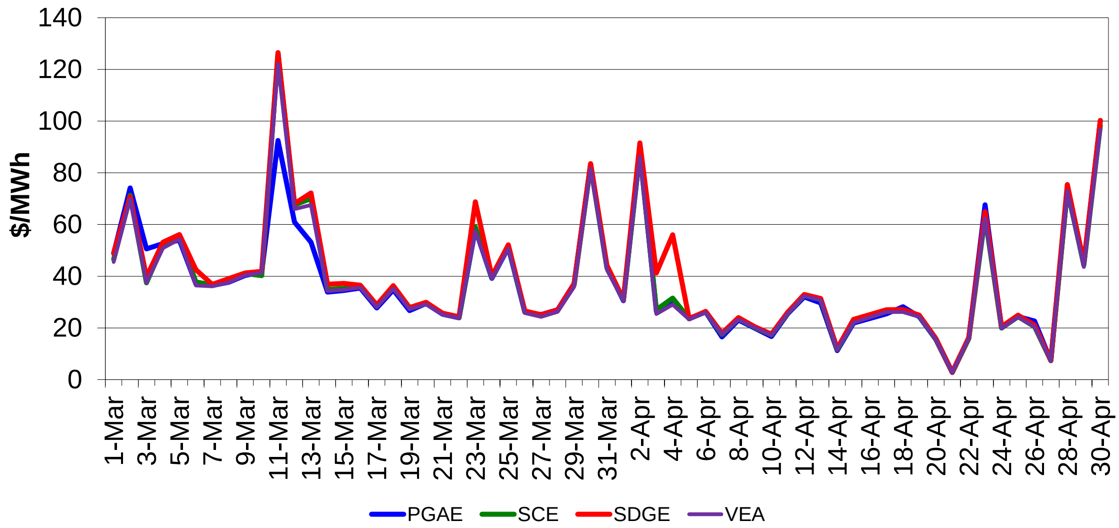
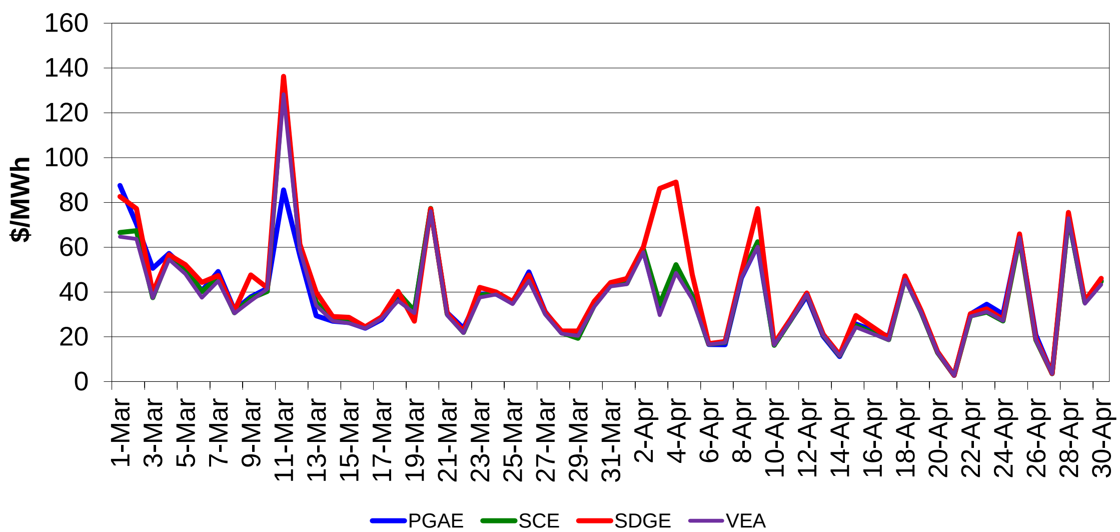


Figure 20: **RTD Simple Average LAP Prices (All Hours)**



Real-Time Price Volatility

Figure 21 shows the daily price frequency for prices above $250/MWh and below $0/MWh in FMM. Prices are for all default LAPs. The graph may provide a trend of price spikes over time.

Figure 21: Daily Frequency of FMM LAP Positive Price Spikes and Negative Prices

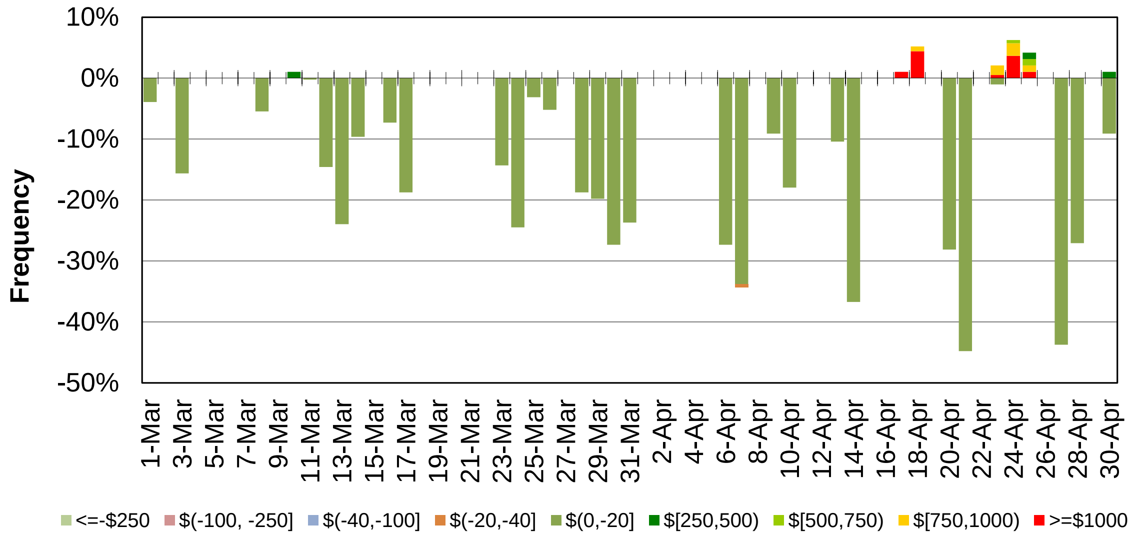


Figure 22 shows the frequency of prices of the default LAP prices in the real-time market. Prices are grouped in several bins. This plot provides a reference of the frequency of prices that fall below -30/MWh and above $250/MWh. This frequency includes both time of uses, on-peak and off-peak, and is aggregated by default LAP on a monthly basis.

Figure 22: Frequency of RTD LAP Prices (All Hours)

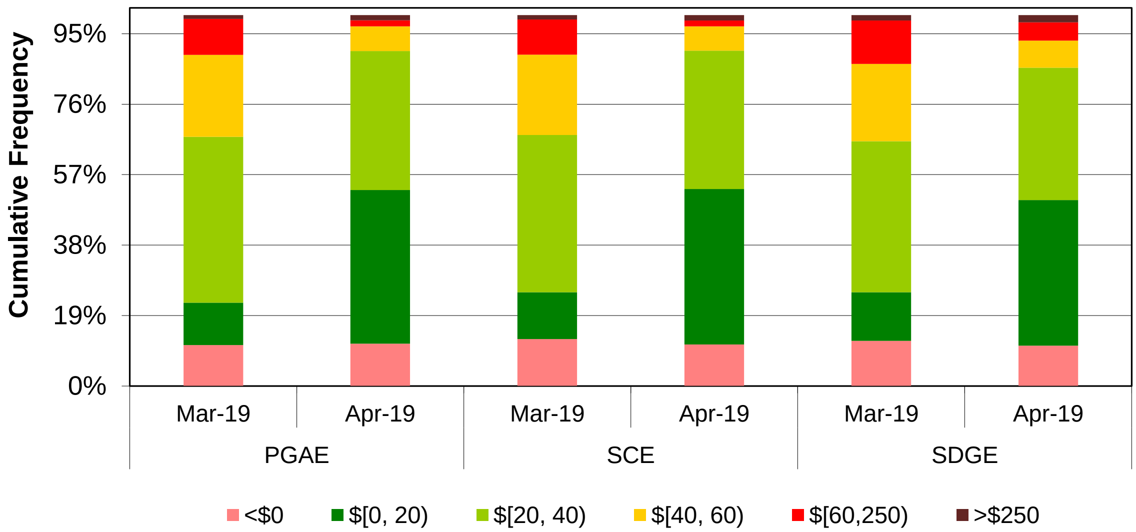


Figure 23 shows the monthly frequency of spikes for RTD default LAP prices that are above $250/MWh, and also negative prices. The prices are aggregated in a monthly basis for each default LAP.

Figure 23: Frequency of RTD LAP Price Spikes and Negative Prices

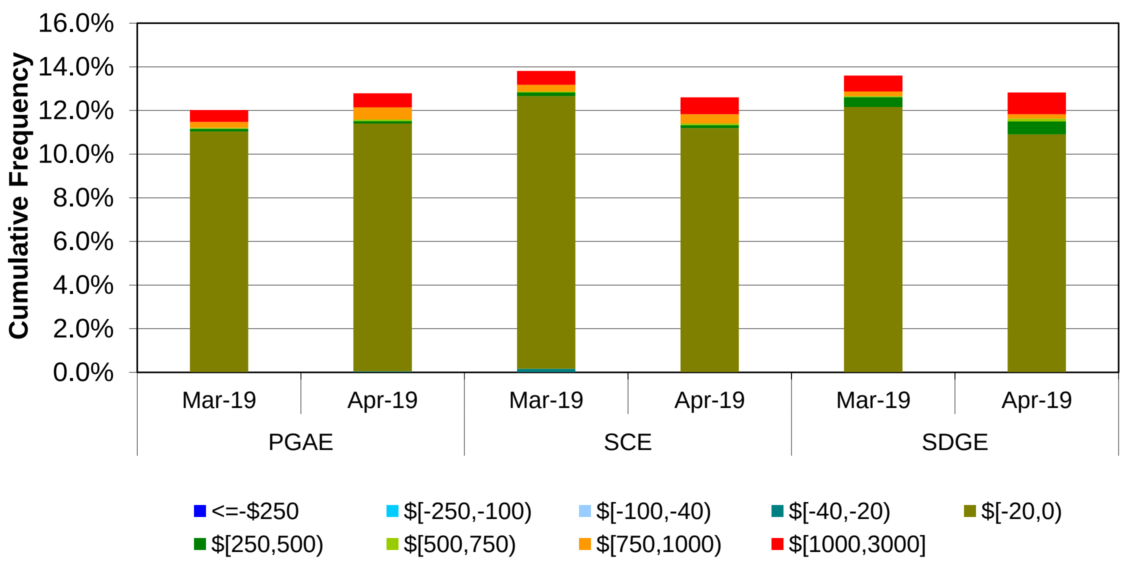
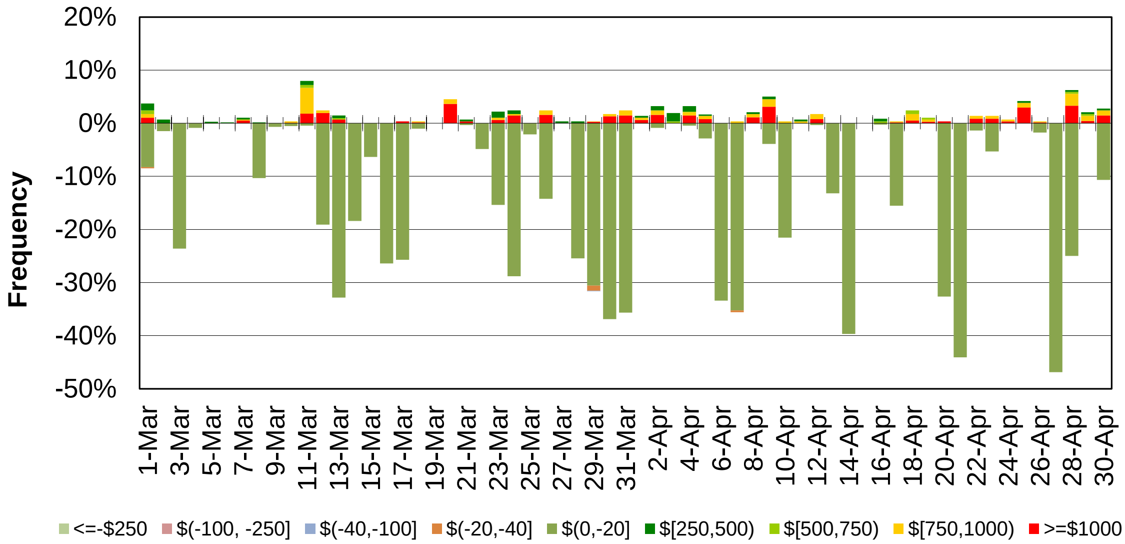


Figure 24 show the daily price frequency for prices above $250/MWh and below $0/MWh. Prices are for all four default LAPs. The graph may provide a trend of price spikes over time.

Figure 24: Daily Frequency of RTD LAP Positive Price Spikes and Negative Prices



Price Convergence

Price convergence is measured by the difference between day-ahead (DA), hour-ahead scheduling process (HASP), and real-time dispatch (RTD) prices. Generally speaking, the smaller the difference between the prices, the more convergent the prices are. Figure 25, Figure 26, and Figure 27 show the difference between DA daily average price and RTD daily average price for three default LAPs in all hours, peak hours, and off-peak hours respectively.

DA daily simple average price for each of the three default LAPs is calculated as the following:

$P_i = \sum_j LMP_{ij} / K$ i= PG&E, SCE, and SDG&E

P_i is the daily average price for LAP i while j represents the hour (peak, off-peak, or all). K is the count of the hours in one day.

The formula for RTD DLAP daily average price is:

$P_i = \sum_j \sum_h LMP_{ijh} / N$ i= PG&E, SCE, and SDG&E

P_i is the daily average price for LAP i while j represents the hour (peak, off-peak, or all) and h represents 5-minute interval. N is the count of the intervals in one day. The similar methods are applied to calculate the DA and RTD weekly average prices for default LAPs.

Figure 28, Figure 29, and Figure 30 show the difference between DA daily average price and RTD daily average price for three trading hubs (NP15, SP15, and ZP26) in all hours, peak hours, and off-peak hours respectively.

DA daily average price for each of the three trading hubs is calculated as below:

$P_i = \sum_j LMP_{ij} / K$ i= NP15, SP15, and ZP26

P_i is the daily average price for hub i while j represents the hour (peak, off-peak, or all). K is the count of the hours in one day.

The formula for RTD hub daily average price is:

$P_i = \sum_j \sum_h LMP_{ijh} / N$ i= NP15, SP15, and ZP26

P_i is the daily average price for hub i while j represents the hour (peak, off-peak, or all) and h represents 5-minute interval. N is the count of the intervals in one day. The similar methods are applied to calculate the DA and RTD weekly average prices for trading hubs.

Figure 31, Figure 32, and Figure 33 show the difference between DA daily average price and HASP daily average price for three selected interties (Malin, Palo Verde, and Sylmar) in all hours, peak hours, and off-peak hours respectively

DA daily simple average price for each of the three selected is calculated as the following:

$P_i = \sum_j LMP_{ij} / K$ i= Malin, Palo Verde, and Sylmar

P_i is the daily average price for intertie i while j represents the hour (peak, off-peak, or all). K is the count of the hours in one day.

The formula for HASP intertie daily average price is:

$P_i = \sum_j \sum_h LMP_{ijh} / N$ i= Malin, Palo Verde, and Sylmar

P_i is the daily average price for intertie i while j represents the hour (peak, off-peak, or all) and h represents 15-minute interval. N is the count of the intervals in one day. The similar methods are applied to calculate the DA and HASP weekly average prices for interties.

Table 1, Table 2, and Table 3 show the statistics of the difference between hourly average prices for default LAPs, trading hubs, and three selected interties respectively. RTD hourly simple average price for each of the three default LAPs is calculated as the following:

$P_i = \sum_h LMP_{ijh} / N$ i= PG&E, SCE, and SDG&E

P_{ij} is the hourly average price for LAP i in hour j while j represents the hour (peak, off-peak, or all) and h represents 5-minute interval. N is the count of the intervals in one hour.

RTD hourly average price for each of the three trading hubs (NP15, SP15, and ZP26) is calculated as below:

$P_{ij} = \sum_h LMP_{ijh} / N$ i= NP15, SP15, and ZP26

P_{ij} is the hourly average price for hub i in hour j while j represents the hour (peak, off-peak, or all) and h represents 5-minute interval. N is the count of the intervals in one hour.

HASP hourly average price for each of the three selected is calculated as the following:

$P_{ij} = \sum_h LMP_{ijh} /N$ i=Malin, Palo Verde, and Sylmar

P_{ij} is the hourly average price for intertie i in hour j while j represents the hour (peak, off-peak, or all) and h represents 5-minute interval. N is the count of the intervals in one hour.

In the following figures and tables, the notation "PGAE_RT_DA" means the PG&E RTD average price minus DA average price. "PGAE_RT_DA_abs" represents the absolute value of the difference between RTD and DA average prices for PG&E. The same rule applies to other default LAPs, hubs, and interties. In the summary tables, "N" is the count of the observations for current month. "MIN" and "MAX" are the minimum and maximum of the difference. "MEAN" and "STD" are mean and standard deviation of the price difference.

Figure 25: Daily LAP Price Difference (All Hours)

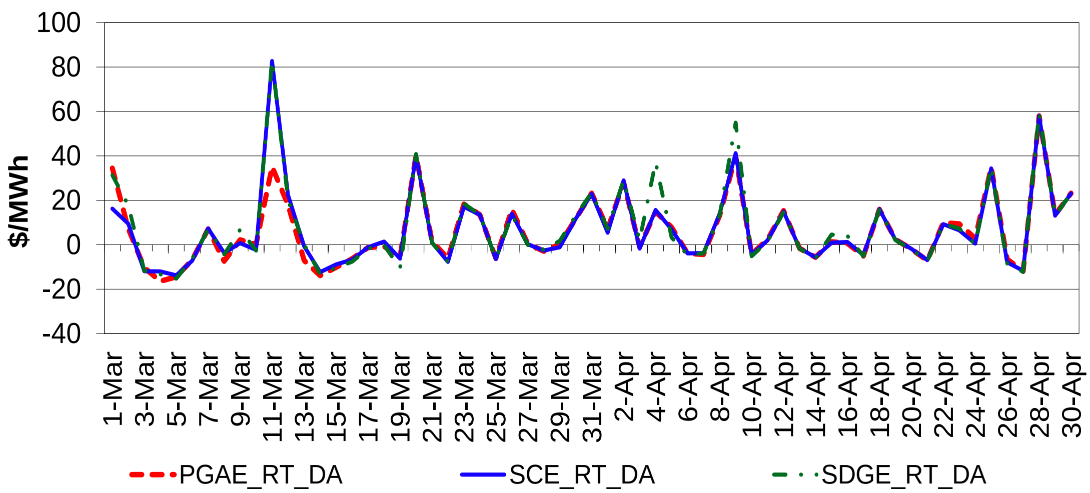


Figure 26: Daily LAP Price Difference (On-Peak Hours)

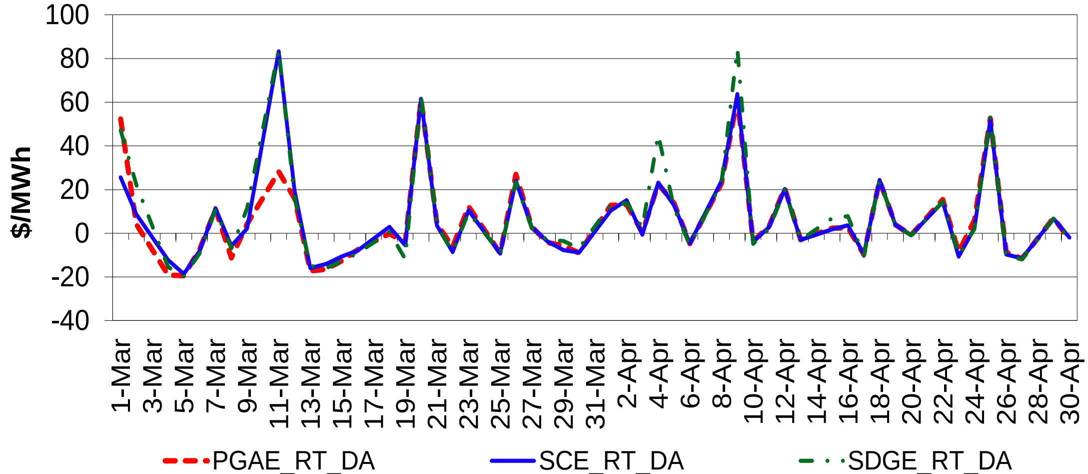


Figure 27: Daily LAP Price Difference (Off-Peak Hours)

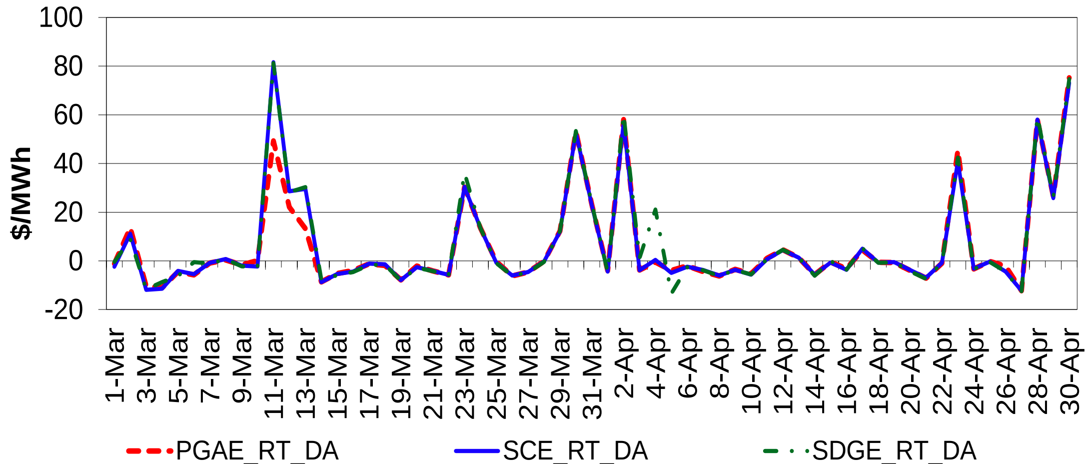


Table 1: **Summary for DLAP Hourly Average Price Difference (All Hours)**

Month	Price Difference	N	MIN	MAX	MEAN	STD
4	PGAE_RT_DA	720	-50.51	629.51	8.28	63.20
4	SCE_RT_DA	720	-51.02	634.03	8.03	62.83
4	SDGE_RT_DA	720	-97.39	629.81	9.39	66.50
4	PGAE_RT_DA_abs	720	0.00	629.51	19.95	60.54
4	SCE_RT_DA_abs	720	0.00	634.03	19.94	60.11
4	SDGE_RT_DA_abs	720	0.00	629.81	23.32	62.98

Figure 28: Daily Trading Hub Price Difference (All Hours)

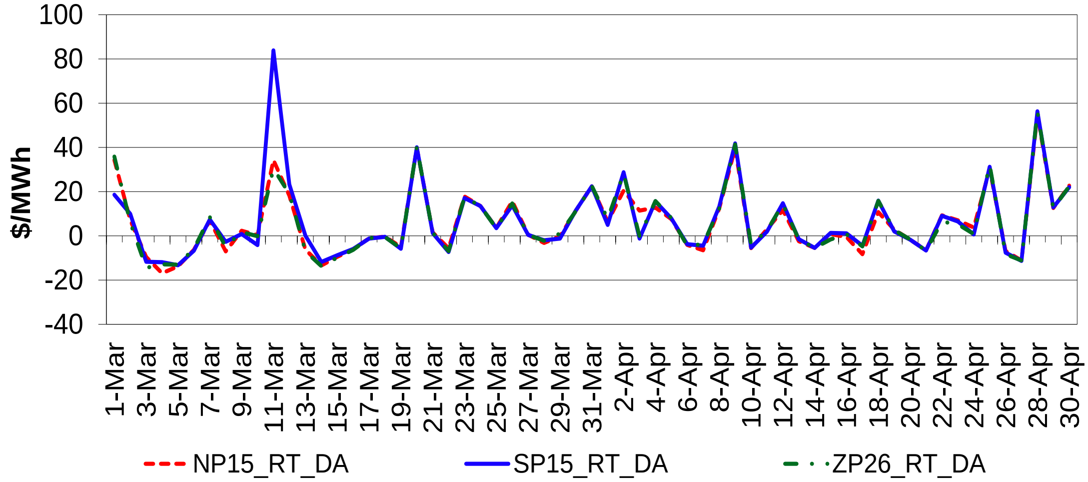


Figure 29: Daily Trading Hub Difference (On-Peak Hours)

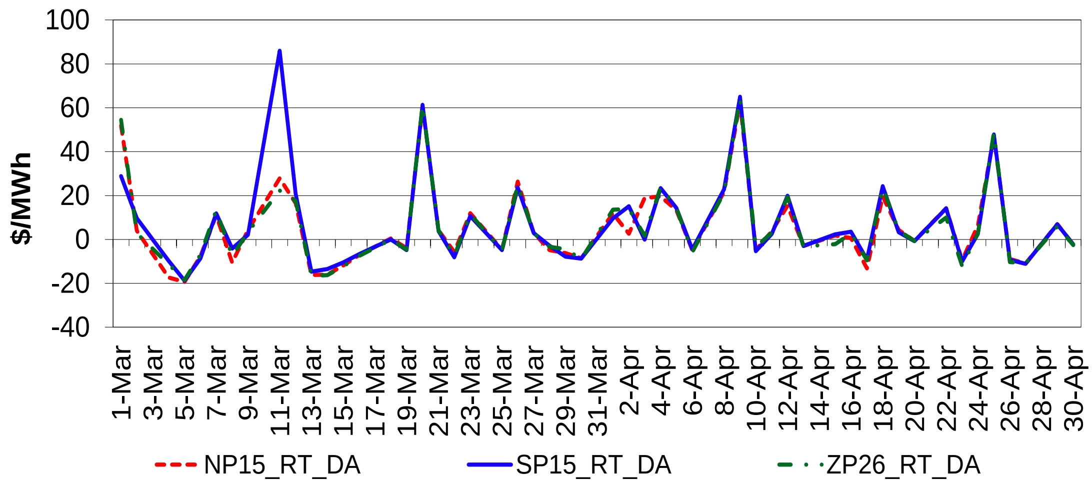


Figure 30: Daily Trading Hub Difference (Off-Peak Hours)

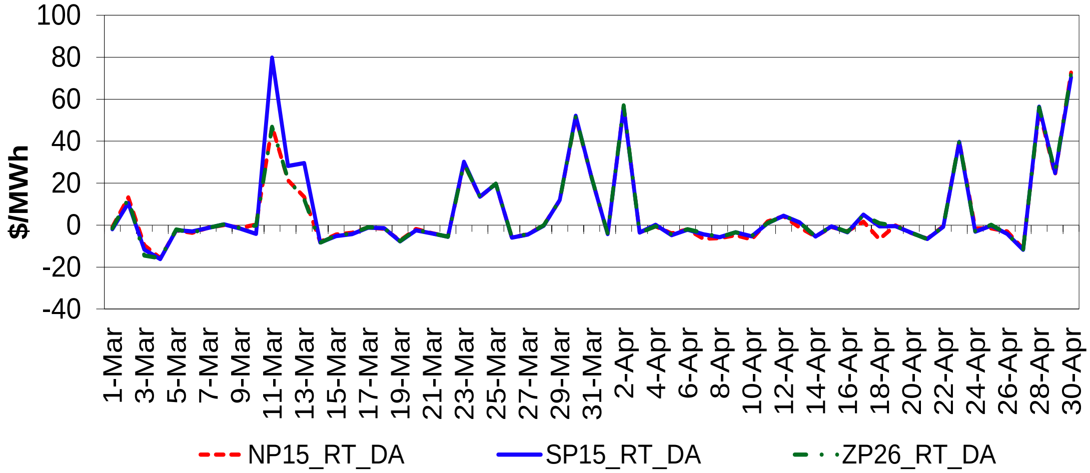


Table 2: Summary for Trading Hub Hourly Average Price Difference (All Hours)

Month	Price Difference	N	MIN	MAX	MEAN	STD
4	NP15_RT_DA	720	-47.75	626.49	7.44	60.86
4	SP15_RT_DA	720	-49.51	631.90	7.88	61.17
4	ZP26_RT_DA	720	-49.39	632.35	7.75	61.44
4	NP15_RT_DA_abs	720	0.00	626.49	19.95	57.98
4	SP15_RT_DA_abs	720	0.00	631.90	19.38	58.55
4	ZP26_RT_DA_abs	720	0.01	632.35	19.38	58.81

Figure 31: Daily Intertie Price Difference (All Hours)

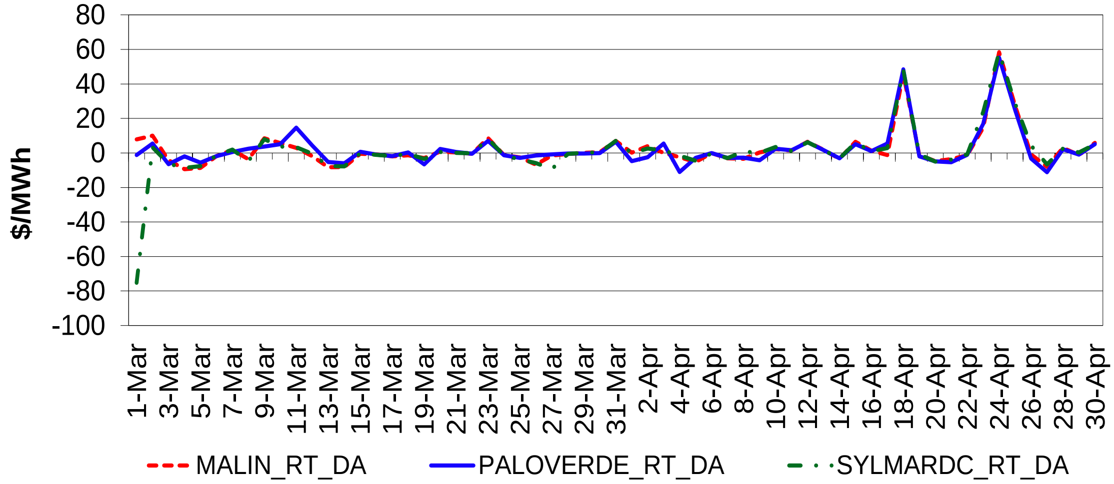


Figure 32: Daily Intertie Price Difference (On-Peak Hours)

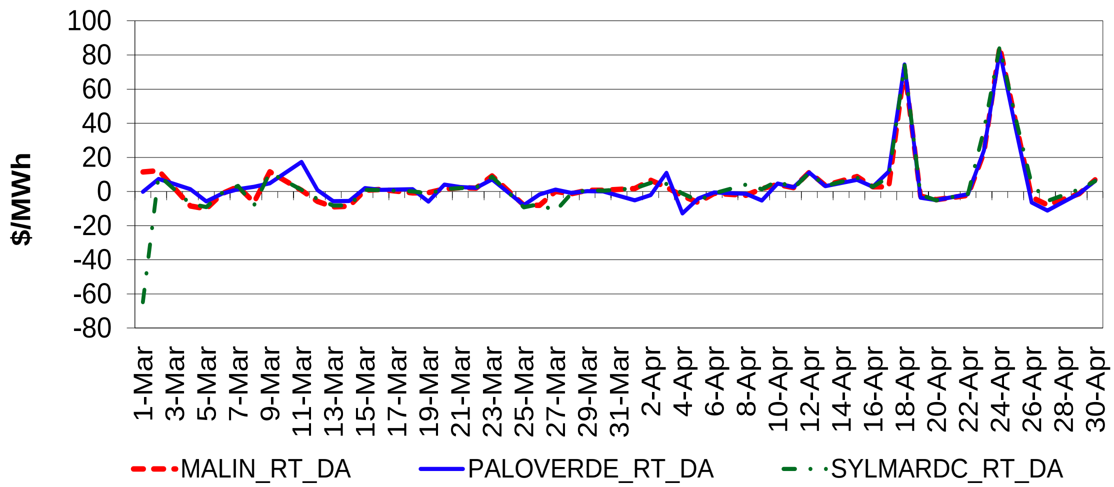


Figure 33: Daily Intertie Price Difference (Off-Peak Hours)

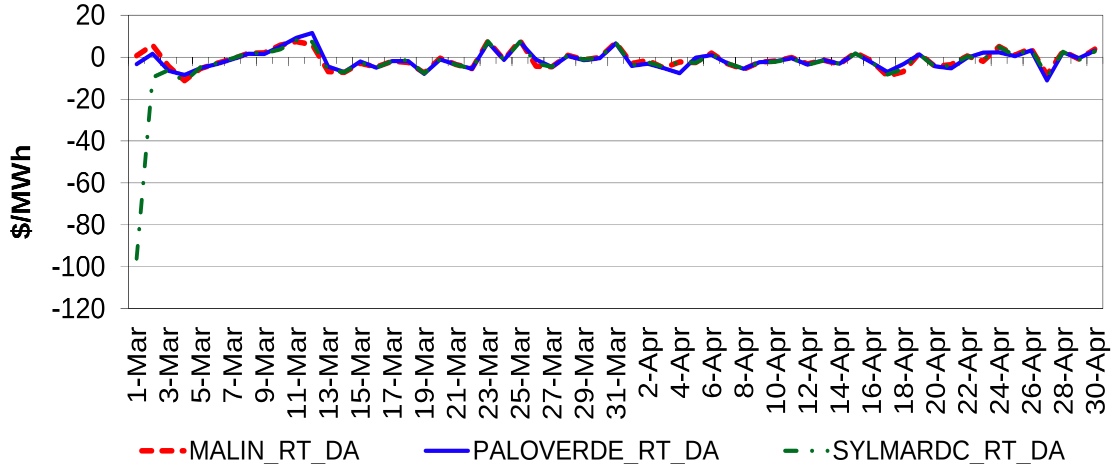


Table 3: Summary for Intertie Hourly Average Price Difference (All Hours)

Month	Price Difference	N	MIN	MAX	MEAN	STD
4	MALIN_RT_DA	720	-33.19	666.30	4.65	49.98
4	PALOVRDE_RT_DA	720	-52.49	677.37	3.96	50.34
4	SYLMARDC_RT_DA	720	-26.67	700.80	5.59	51.83
4	MALIN_RT_DA_abs	720	0.00	666.30	10.79	49.02
4	PALOVRDE_RT_DA_abs	720	0.00	677.37	11.04	49.28
4	SYLMARDC_RT_DA_abs	720	0.00	700.80	11.04	50.95

Congestion

Congestion occurs when available, least-cost energy cannot be delivered to some loads because transmission facilities do not have sufficient capacity to deliver the energy. When the least-cost, available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load. The result is the price of energy in the constrained area will be higher than in the unconstrained area because of the combination of transmission limitations and the costs of local generation.

Congestion Rents on Interties

Figure 34 below illustrates the IFM congestion costs on interties. The congestion cost is calculated as shadow price ($/MWh) of the intertie constraint multiplied by the flow (MW) on the intertie.

Figure 34: IFM (Day-Ahead) Congestion Rents by Intertie (Import)

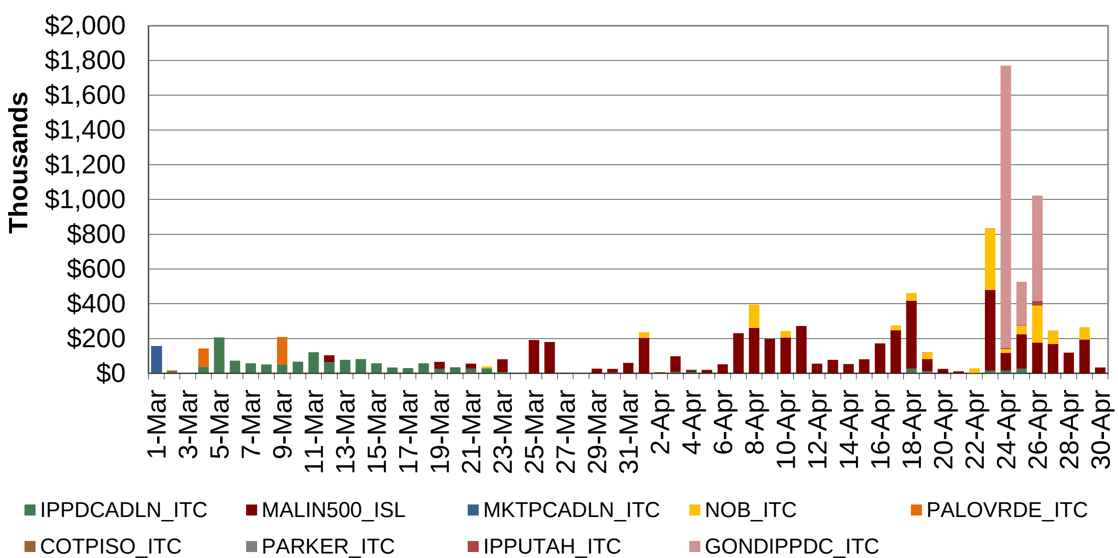


Table 4 provides a breakout of the IFM cleared value (MW), the average shadow price ($/MWh) and the number of congested hours by intertie.

Table 4: IFM (Day-Ahead) Congestion Statistics by Intertie (Import)

Intertie	Average Cleared Value (MW)	Shadow Price ($/MWh)	Number of Congested Hours
COTPISO_ITC	19.00	10.65	14
GONDIPPDC_ITC	59.01	666.53	63
IPPDCADLN_ITC	404.63	10.96	27
IPPUTAH_ITC	181.13	6.97	32
MALIN500_ISL	1325.07	11.89	269
NOB_ITC	1622.00	15.88	44
PALOVRDE_ITC	2857.00	0.61	1
PARKER_ITC	89.00	15.65	2
0	0.00	0.00	0
0	0.00	0.00	0

Congestion Rents on Branch Groups

Figure 35 illustrates IFM congestion rents by branch group. The congestion rent is calculated as the shadow price ($/MWh) of the branch group or market scheduling limit constraint multiplied by the flow limit (MW) on the branch group.

Figure 35: IFM (Day-Ahead) Daily Congestion Rents by Branch Group

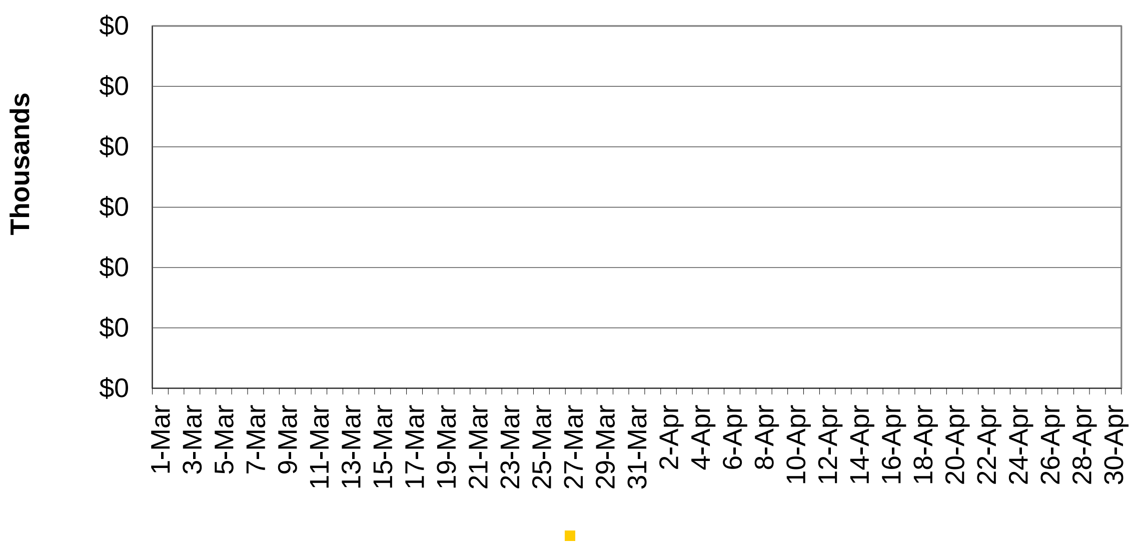


Table 5 provides a breakout of the IFM cleared value (MW), the average shadow price ($/MWh) and the number of congested hours by branch groups.

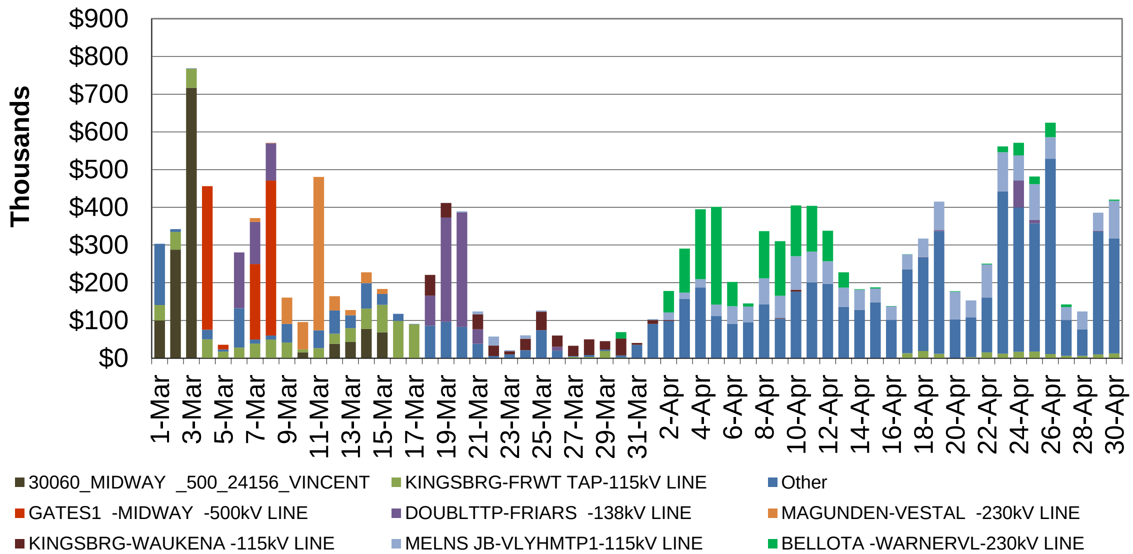
Table 5: IFM (Day-Ahead) Congestion Statistics by Branch Group

Branch Group/Market Scheduling Limit	Average Cleared Value (MW)	Shadow Price ($/MWh)	Number of Congested Hours
0	0.00	0.00	0
0	0.00	0.00	0
0	0.00	0.00	0
0	0.00	0.00	0
0	0.00	0.00	0
0	0.00	0.00	0
0	0.00	0.00	0
0	0.00	0.00	0
0	0.00	0.00	0

Congestion Rents on Transmission Lines and Transformers

Figure 36 illustrates IFM congestion rents by transmission lines and transformers. The congestion cost is calculated as the shadow price ($/MWh) of the constraint multiplied by the flow limit (MW).

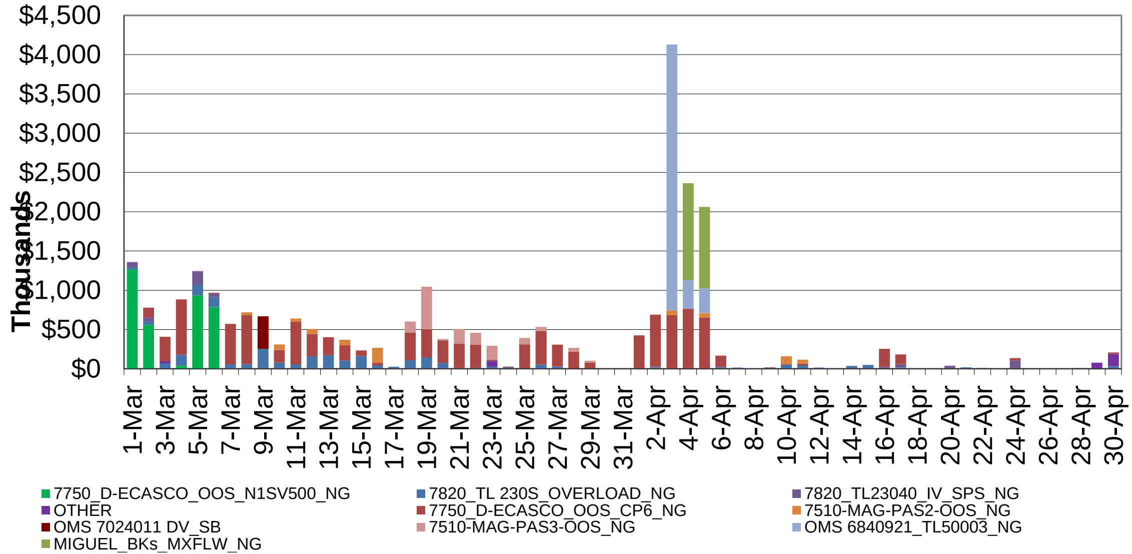
Figure 36: IFM (Day-Ahead) Congestion Rents by Transmission Lines and Transformers



Congestion Rents on Nomograms

Figure 37 illustrates IFM congestion rents by nomogram. The congestion rent is calculated as the shadow price ($/MWh) of the constraint multiplied by the flow limit (MW).

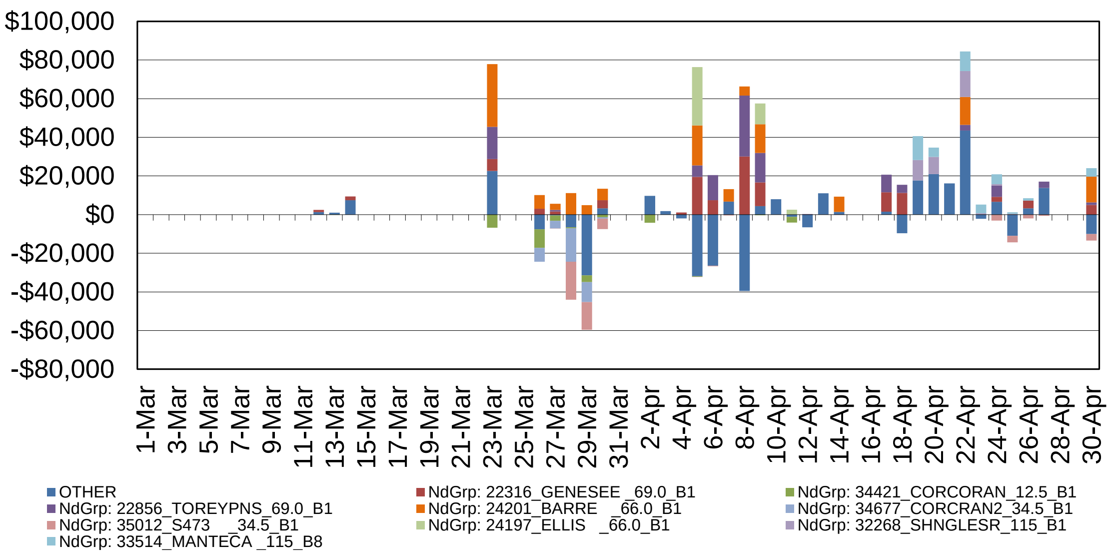
Figure 37: IFM (Day-Ahead) Daily Congestion Rents by Nomogram



Congestion Rents on Nodal Group Constraints

Figure 38 illustrates IFM congestion rents by nodal group constraints. The congestion rent is calculated as the shadow price ($/MWh) of the constraint multiplied by the flow limit (MW).

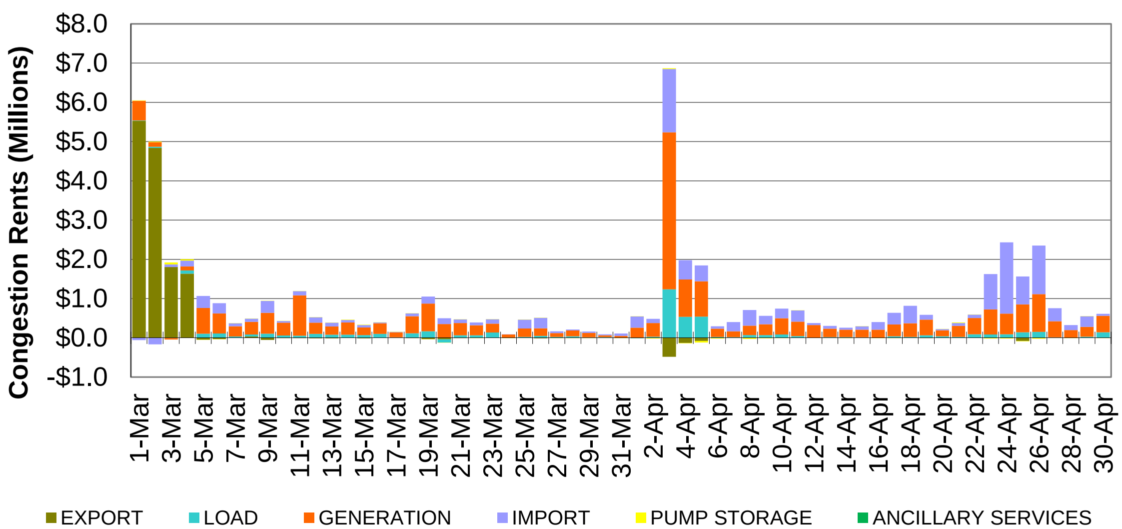
Figure 38: IFM (Day-Ahead) Daily Congestion Rents by Nodal Group Constraints



Congestion Rents by Type of Resources

Figure 39 shows the DA congestion rents grouped by type of market resource. If congestion arises, power is priced accordingly through a marginal congestion component (MCC). For any given hour of the day-ahead market, demand is charged the scheduled MW times the MCC, and supply is paid the scheduled MW times the MCC. The MCC is at the applicable PNodes, APNodes and scheduling points. The net money surplus collected by the ISO is the congestion rents. The hourly congestion rents are then summed up across all hours of the day. A positive value of congestion rents indicates a payment to the ISO (surplus). Congestion rents may also arise from provision of ancillary services over the interties. Due to the dual nature of pump storage units, they can be treated as supply or demand within the computation of congestion rents.

Figure 39: DA Congestion Rents by Type of Market Resource

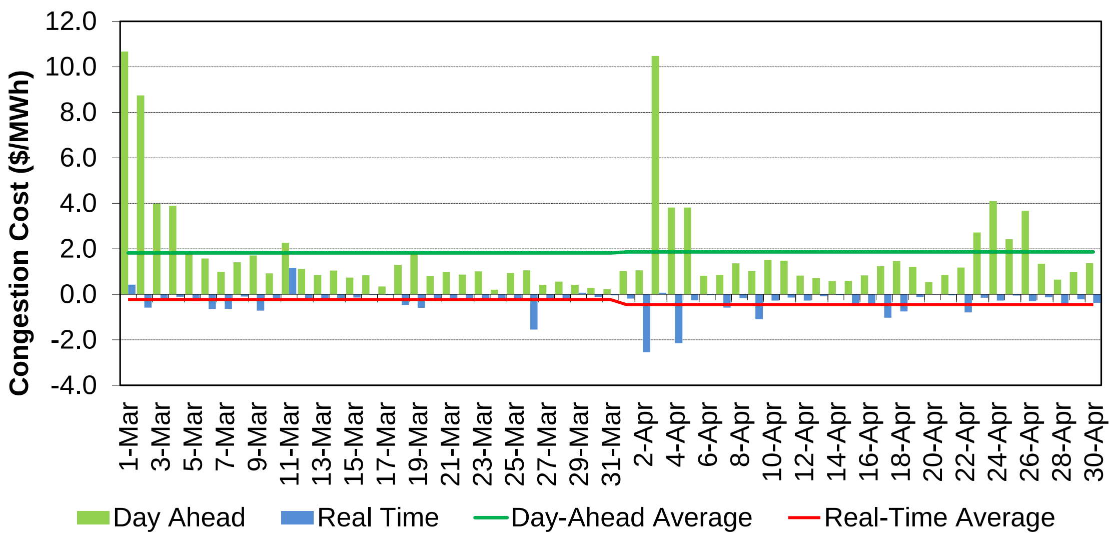


Average Congestion Cost per Load Served

This metric quantifies on average the congestion cost for serving a megawatt of load in the ISO system. The congestion rents of both the integrated forward market and the real-time market are calculated for every hour. These rents are determined by multiplying the energy schedules by the corresponding marginal congestion components. Day-ahead rents are for the full schedules, while real-time rents are just for the difference of the schedules between the day-ahead and real-time markets. Congestion rents associated with existing transmission rights (ETC, TOR and CVR) are discounted from the congestion rents because the schedules related to existing rights are exempt from congestion charges.

The total measured demand applicable to each hour is then used as a reference of load. Furthermore, the served load associated with existing rights is deducted because such load is exempted from congestion charges. Based on the hourly values for served load, and hourly day-ahead and real-time congestion rents, the weighted average congestion cost to served load is computed as the ratio of daily congestion rents (day-ahead and real-time) to total load served in each day. Similarly, a monthly weighted average cost is estimated. The daily and monthly averages for the day-ahead and real-time markets are depicted with bars and lines, respectively, in Figure 40.

Figure 40: Average Congestion Cost per Megawatt of Served Load

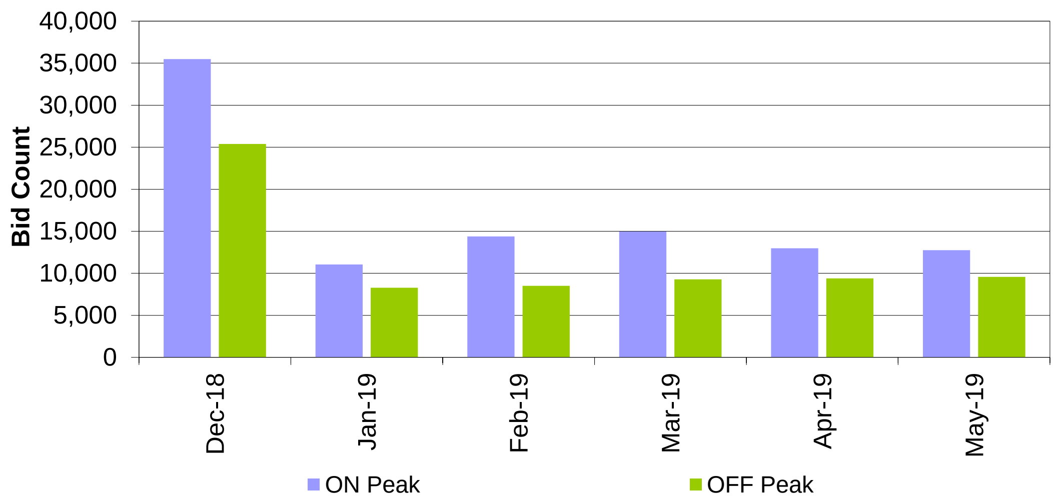


Congestion Revenue Rights

Auction Bids

Figure 41 shows the count of bids submitted in the last six monthly congestion revenue right (CRR) auctions. The count is grouped by time of use. The count is for each individual bid submitted to the auction even if they are not awarded, and regardless of the number of bid segments.

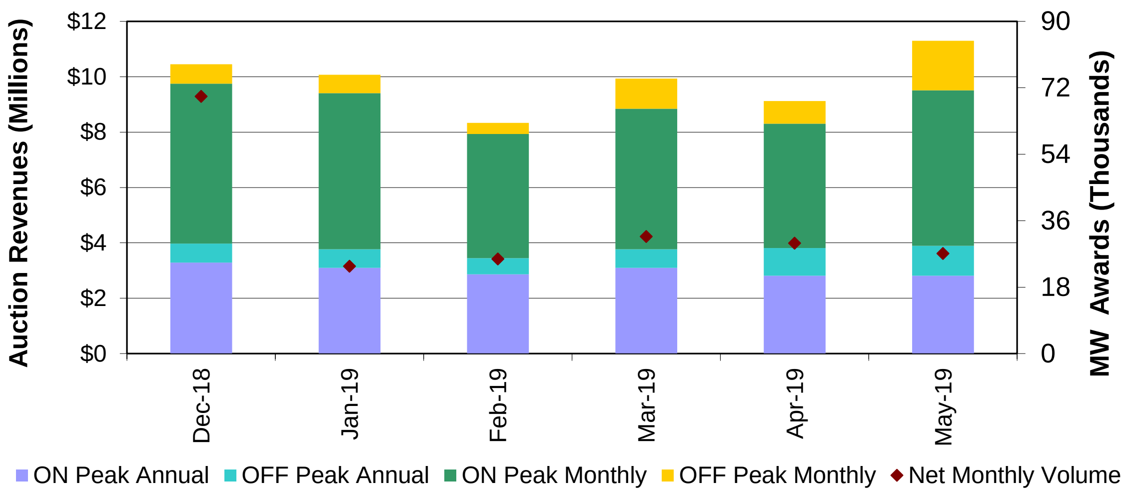
Figure 41: Bid Count for Monthly CRR Auctions



Auction Revenues

Figure 42 shows the monthly revenues with the corresponding net volume awards from CRR auctions. Revenues are from seasonal and monthly auctions and are grouped by time of use. Revenues from annual auctions are spread pro-rata to each month of a season, based on the number of – on-peak or off-peak – hours of each month. The net MW volume is based only on the allocations and awards of the last six monthly processes. This graph provides trends of auctions over time.

Figure 42: Revenues and Award Volumes in Monthly CRR Auctions



Monthly Volumes

Figure 43 through Figure 45 show the CRR volumes released in the last six monthly CRR processes. Both allocation and auctions for both times of use are depicted. Figure 43 illustrates the trends of CRR volumes awarded over time and offers an easy reference for comparison of volumes released in allocations versus auctions. This graph can also help visualize the evolution of the monthly processes over time.

Figure 43: Monthly Volumes of CRR Awards –Allocation and Auction

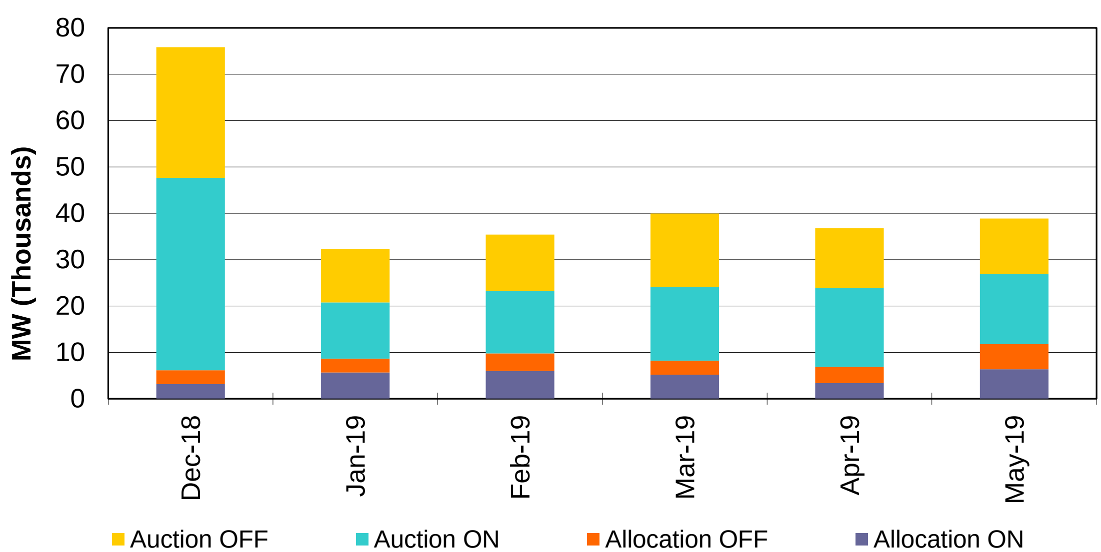


Figure 44 and Figure 45 compare the volume nominated and bid against the volumes allocated and awarded in the allocation and auction processes over the last six months, respectively. It also includes the percentage of the volumes that were actually released in the monthly processes. These figures give a compact reference over time and also between allocation and auction.

Figure 44: Volumes of Monthly CRR Allocations

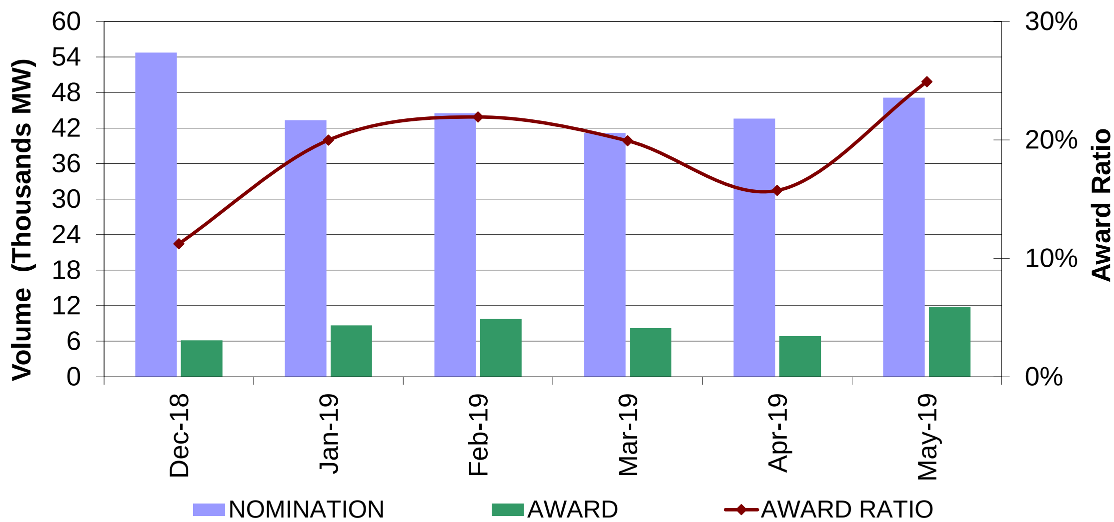
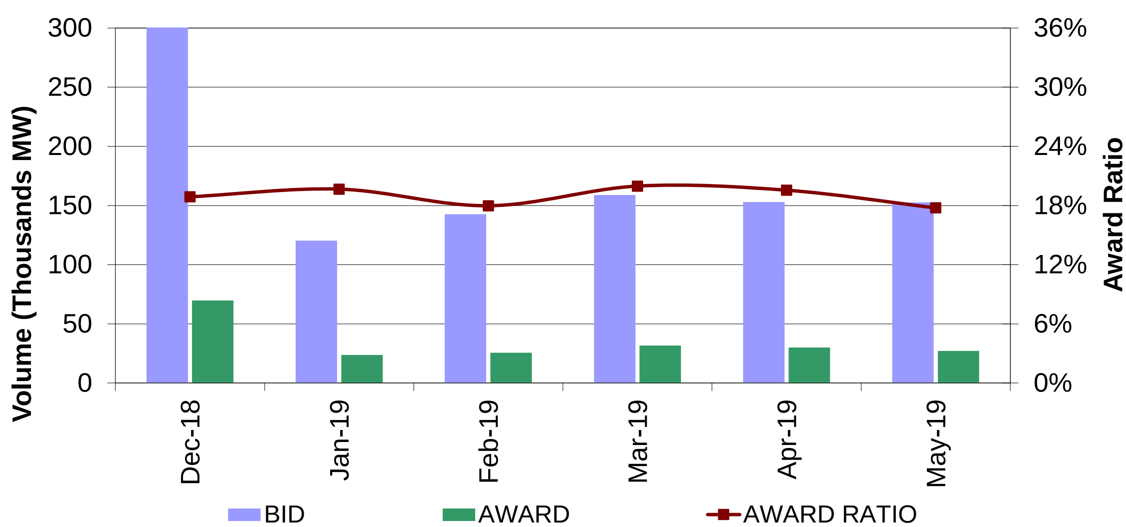


Figure 45: Volumes of Monthly CRR Auctions



Auction Prices

Figure 46 and Figure 47 show price distribution trends of the last six monthly CRR auctions. The distributions are given for each time of use. The vertical axis shows the count of prices only for CRRs that have an award greater than zero. The prices are computed as the auction prices divided by the number of hours for the corresponding time of use and month. Therefore, prices are on an hourly basis ($/MWh).

Figure 46: Price Distribution of Monthly CRR Auctions – On-Peak

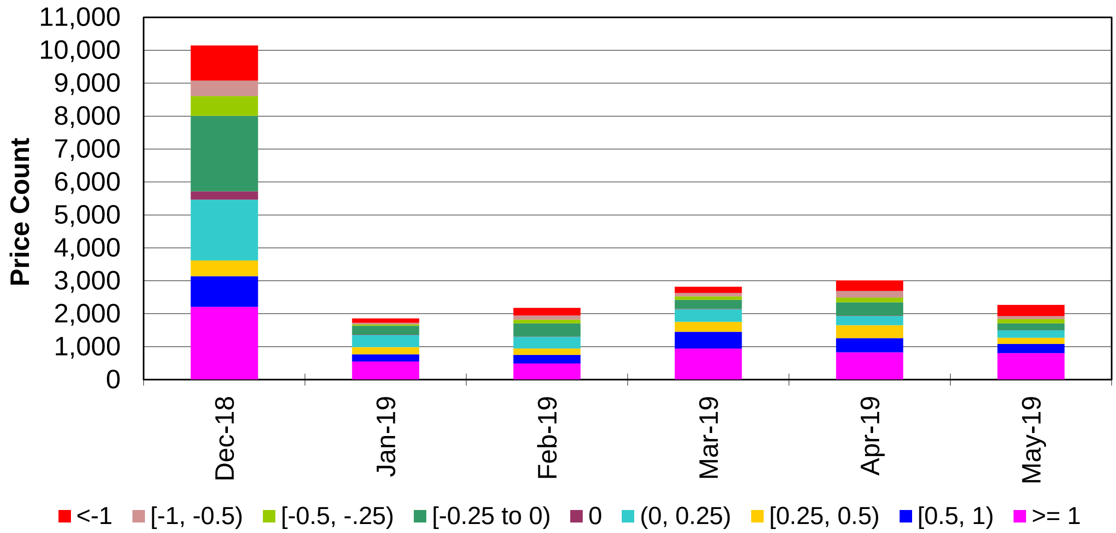
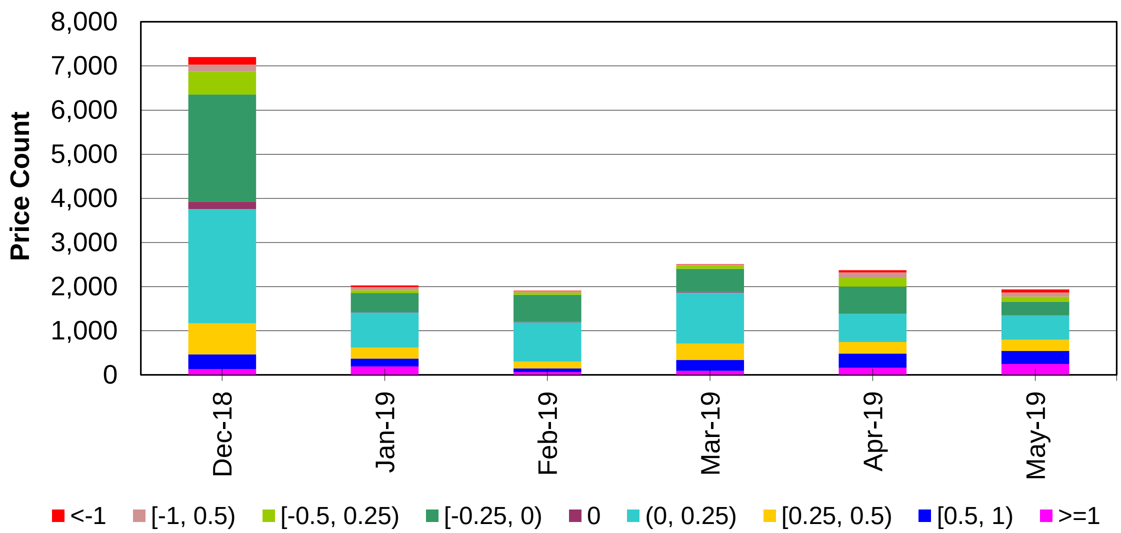


Figure 47: Price Distribution of CRR Monthly Auctions – OFF-Peak

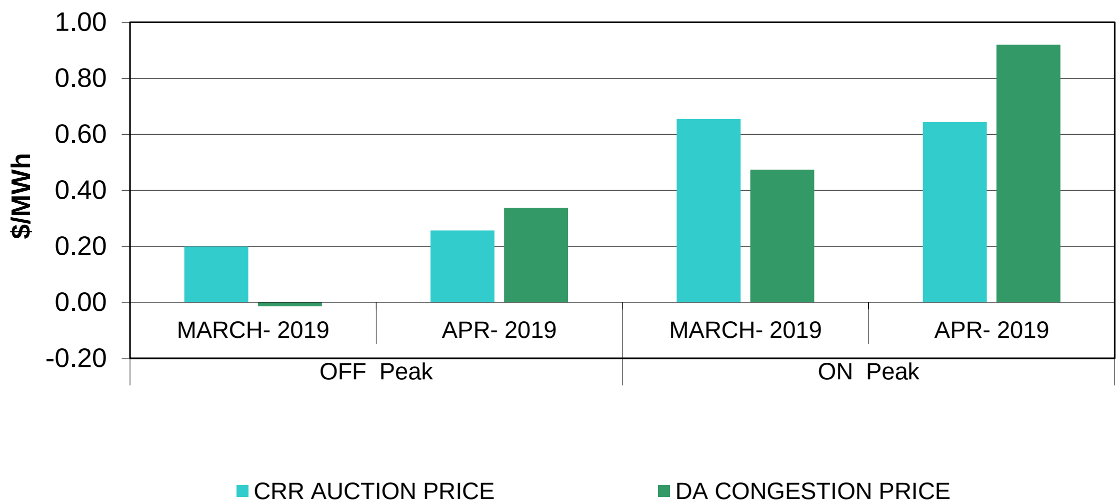


Price Convergence

Figure 48 shows the price comparison between CRR auction prices and day-ahead (IFM) prices. For the CRR auction prices, both seasonal and monthly awarded CRRs are included, and grouped by time of use. This price comparison is useful to estimate the price convergence. Over time, in a healthy market, price convergence should be observed, accounting for the fact that there may be a risk premium associated with acquiring CRRs. Each CRR may have associated a different price; in order to have all CRRs on the same basis, the metrics shown in these plots are computed as weighted average prices. The main steps to obtain such weighted prices are as follows:

1. Obtain all CRRs with awards greater than zero and their associated auction prices and quantities.
2. Divide the CRR prices by their corresponding number of hours for each time of use and season/month to have prices on an hourly basis.
3. Associate the corresponding IFM congestion component prices (sink minus source) to each CRR for each hour by time of use.
4. Obtain the total MW awarded by time of use and month and use it to obtain the weighting factors for each CRR. Multiply both the CRR auction prices and the IFM CRR (congestion) prices by their corresponding factors.
5. Sum all CRR prices by time of use and month to obtain both weighted CRR auction prices and weighted DA (IFM) congestion prices.

Figure 48: Convergence of CRR Prices towards DA Congestion Prices



The value of the auction CRR price indicates how much CRR holders pay to acquire CRRs, while the DA congestion price indicates how much the CRR holders were paid due to the CRR entitlements. A case where the DA congestion price is higher than the auction CRR price means that CRR holders profited from holding CRRs.

Monthly CRR Revenue

Figure 49 illustrates the daily CRR notional value in the corresponding month for the various transmission elements that experienced congestion during the month. CRR notional value is calculated as the product of CRR implied flow and constraint shadow price in each hour per constraint and CRR.

Figure 49: Daily CRR Notional Value by Transmission Element

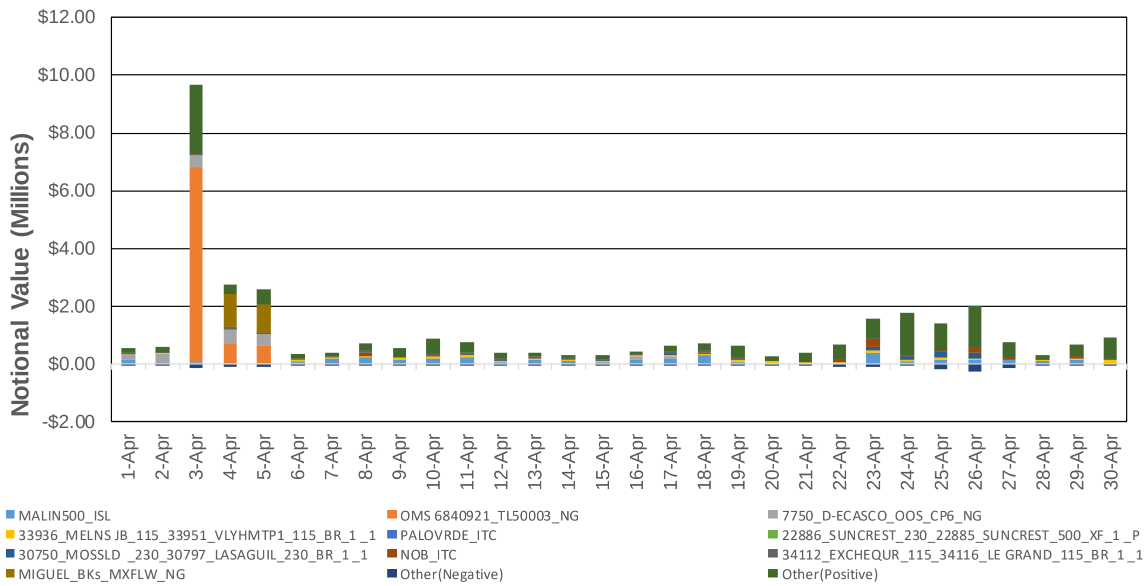
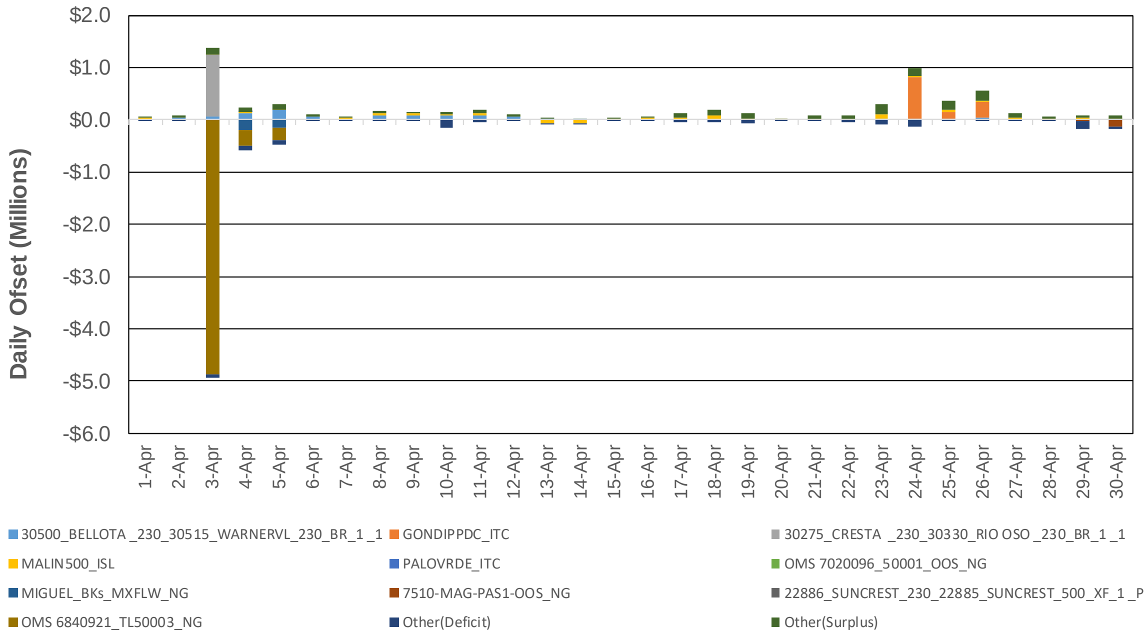


Figure 50 illustrates the daily CRR offset value in the corresponding month for the transmission elements that experienced congestion during the month. CRR offset value is the difference between the revenue collected from the congestion and CRR notional value. It is also calculated in each hour per constraint and CRR. A positive CRR offset value represents surplus and a negative CRR offset value represents shortfall.

Figure 50: Daily CRR Offset Value by Transmission Element



Furthermore, Figure 51 shows the monthly CRR deficit in the month broken out by transmission elements and Figure 52 shows the monthly CRR surplus in the month broken out by transmission elements.

Figure 51: CRR Deficit by Transmission Element

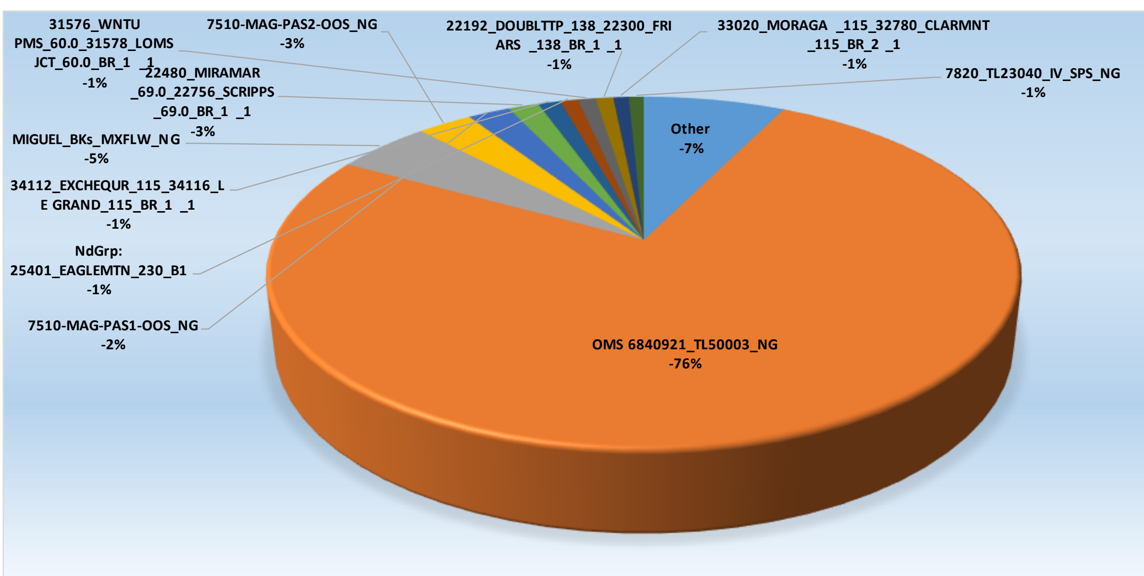


Figure 52: CRR Surplus by Transmission Element

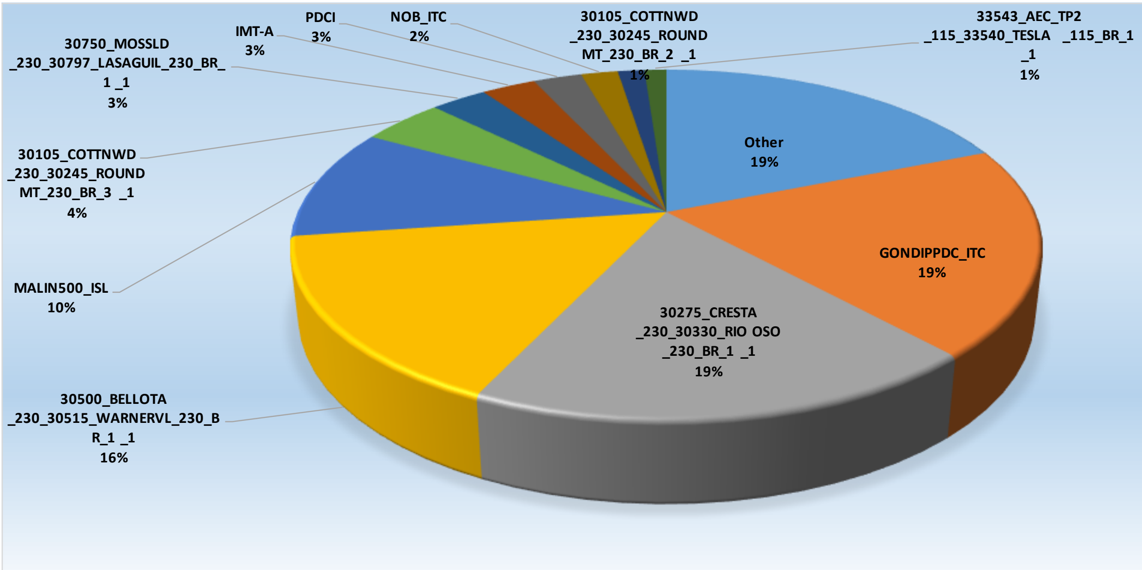


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Figure 53 shows the monthly CRR payment in the month broken out by transmission elements.

Figure 53: CRR Payment by Transmission Element

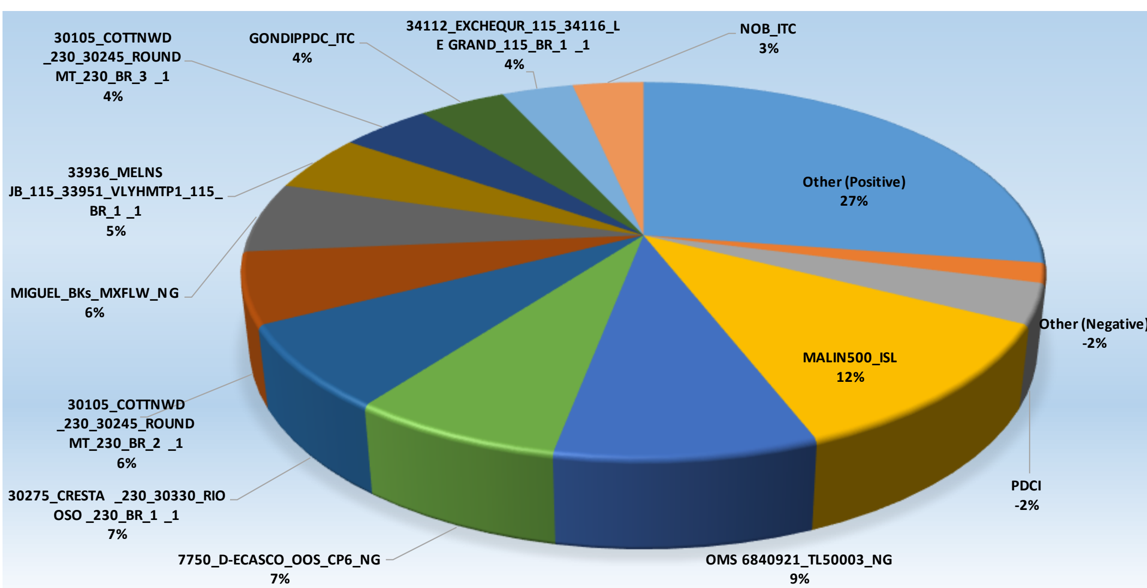


Table 6 provides a summary of the main statistics for CRRs for the current month. Definitions for the concepts listed in Table 6 are as follows:

- ***CRR Notional value*** is the product of CRR implied flow and constraint shadow price. The CRR holders are funded up to notional value,
  For each aggregated CRR, the Constraint-specific Notional CRR Value for each hour shall be calculated. The basic formula is:
  Constraint-specific Notional CRR Value = CRR Implied Flow X Constraint Shadow Price,
- ***CRR Deficit*** is the monthly negative CRR offset amount
- ***CRR Settlement Rule*** is put in place to recapture - where warranted – the increase in CRR revenues to CRR holders that are attributable to convergence bidding.
- ***CRR Adjusted Payment*** is the money paid to holders of CRRs due to the CRR entitlements,
  - it is the summation of the CRR notional value + (CRR deficit amount plus any surpluses on one constraint in one hour that can offset deficits on the same constraint in another hour over the course of the month) + CRR settlement rule,
- ***CRR Surplus*** is the monthly positive CRR offset amount minus any distributed surpluses that are used to offset the deficits on the same constraint over the course of the month
- ***Monthly Auction Revenues*** is the money obtained from the corresponding monthly auction.
- ***Annual Auction Revenues*** is the pro-rata portion of the annual auction that applies to the corresponding month,
- ***CRR Daily Balancing Account*** is CRR settlement value based on the results of constraint-based calculation. It includes CRR annual and monthly auction revenues ,
- ***Net Monthly Balancing Surplus*** is the net CRR surplus, which is the sum of the monthly CRR surplus and daily balancing account excluding CRR annual and monthly auction revenues,
- ***Allocation to Measured Demand*** is the sum of CRR annual and monthly auction revenues and CRR surplus and represents the money available in the CRR balancing account, which is distributed to measured demand.

Table 6: CRR Revenue Statistics

Row	Description	Formula	Amount
1	CRR Notional Value		$32,885,781
2	CRR Deficit		-$7,135,779
3	CRR Settlement Rule		-$116,199
4	CRR Adjusted Payment		$25,633,804
5	CRR Surplus		$6,189,810
6	Monthly Auction Revenue		$2,856,808
7	Annual Auction Revenue		$2,176,017
8	CRR Daily Balancing Account		$3,830,696
9	Net Monthly Balancing Surplus	row 5 + row 8 - (row 6 + row 7)	$4,987,681
10	Allocation to Measured Demand	row 6 + row 7 + row9	$10,020,506

Although auction revenues can be used to offset any CRR revenue deficiency that results from the IFM, the intention of the ISO's CRR release process is that proceeds from the IFM will be sufficient to cover net CRR payments over the course of each month. The annual and monthly processes to release CRRs through allocations and auctions are built upon this concept. In addition, transmission capacity is set aside in the release processes in order to account for the perfect hedge congestion payment reversal for existing transmission rights.

Existing Right Exemptions

The ISO collects congestion rents in both the day-ahead and real-time markets as determined by the charges to demand and payments to supply for schedules in the day-ahead and real-time markets. Depending on contract provisions, some holders of existing rights may utilize their rights to submit day-ahead schedules and real-time adjustments with respect to their accepted day-ahead self-schedules.[3] As required by the ISO tariff, these schedules are not subject to congestion charges. This provision applies in both the day-ahead and the real-time markets, and the real-time is independent of any settlement of the day-ahead market. The remaining real-time market congestion rents –surplus or deficit– are allocated to measured demand excluding measured demand associated with valid and balanced portions of existing rights. The real-time congestion rents and the existing rights exemption costs do not impact the settlements of congestion revenue rights, and the ISO accounts for these in real-time funds through a separate real-time mechanism (i.e., the real-time congestion off-set) instead of the CRR balancing account.

[3] Converted rights are only eligible for the existing rights exemption in association with accepted self-schedules in the integrated forward market.

Figure 54 shows the net cost of the existing right exemptions for schedule changes of ETCs/TORs for both day-ahead and real-time markets. A negative value of the existing rights exemption indicates a net payment from the ISO to existing right holders to reverse the corresponding congestion charge, i.e., a credit. A positive value of the existing rights exemption indicates a net charge to existing right holders to reverse the corresponding congestion payment.

Figure 54: Cost of Existing Right Exemptions

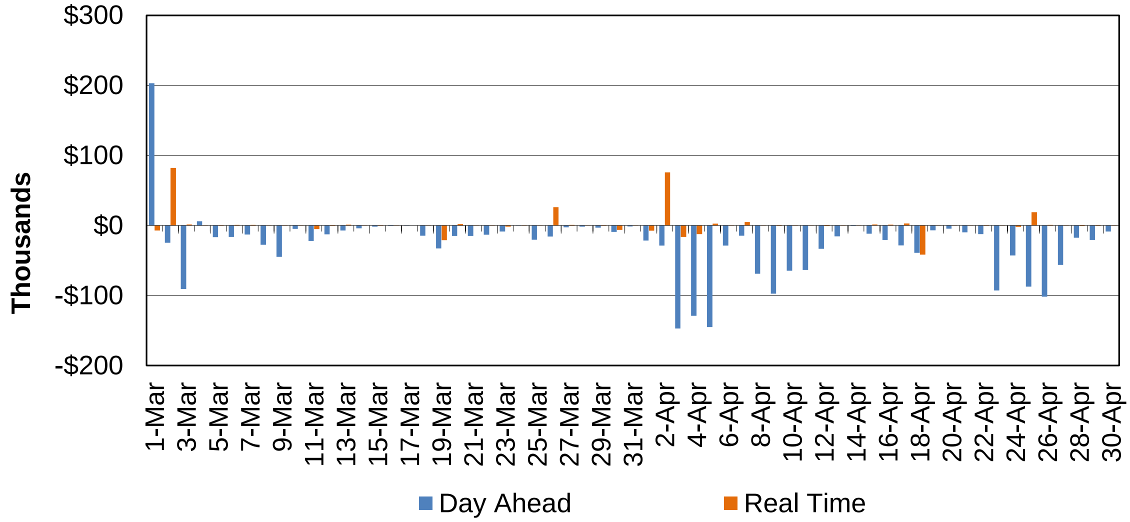


Table 7 lists the monthly summary of exemptions for existing transmission rights in the day-ahead and real-time markets. A positive value of the congestion rents is a surplus; a negative value is a shortfall. Any surplus or shortfall is allocated to measured demand, excluding demand associated with ETCs/TORs. The percentage is the ratio of the exemptions to the congestion rents. This provides a reference of the extent of the cost charged to non-ETC demand to honor the exemptions in comparison to the overall congestion rents.

Table 7: Summary of the Existing Right Exemptions

	Day Ahead Market			Real Time Market		
	Congestion Rents	Existing Right Exemptions	Percentage	Congestion Rents	Existing Right Exemptions	Percentage
MARCH	$31,073,001.99	($230,294.14)	-1%	($4,018,355.71)	$77,178.06	2%
APRIL	$32,273,338.58	($1,417,489.17)	-4%	($7,481,458.77)	$26,992.02	0%

Losses

The energy markets at the ISO are settled with locational marginal prices (LMP), which consist of three components: energy, congestion, and losses. The marginal cost of losses may be positive or negative depending on whether a power injection at that node marginally increases or decreases losses. Incorporating the marginal cost of losses in the LMP is important both for assuring least-cost dispatch and for establishing nodal prices that accurately reflect the cost of supplying the load at each node. This section provides daily trends of marginal losses prices for DLAPs and trading hubs for both the day-ahead and real-time markets.

Day-ahead Prices

Figure 55 shows the daily schedule-weighted average LAP losses prices for each of the three default LAPs (PG&E, SCE, and SDG&E) in the day-ahead market. The formula for weighted average price is:

$$P_i = \sum_j MLC_{ij} \frac{SCHE\_MW_{ij}}{\sum_j SCHE\_MW_{ij}} \qquad \text{i= PG\&E, SCE, and SDG\&E}$$

P_i is the daily average losses price for LAP i, while j represents the hour. MLC_{ij} is the marginal losses component of the LMP for LAP i in hour j. $SCHE\_MW_j$ is the scheduled energy in hour j for LAP i. The daily simple-average losses (in MW) are also shown in the plot.

Similarly, daily prices for trading hubs (NP15, SP15 and ZP26) are presented in Figure 56. These daily values, however, are obtained as the simple average of hourly prices.

Figure 55: Day-Ahead Weighted Average LAP Prices for Losses

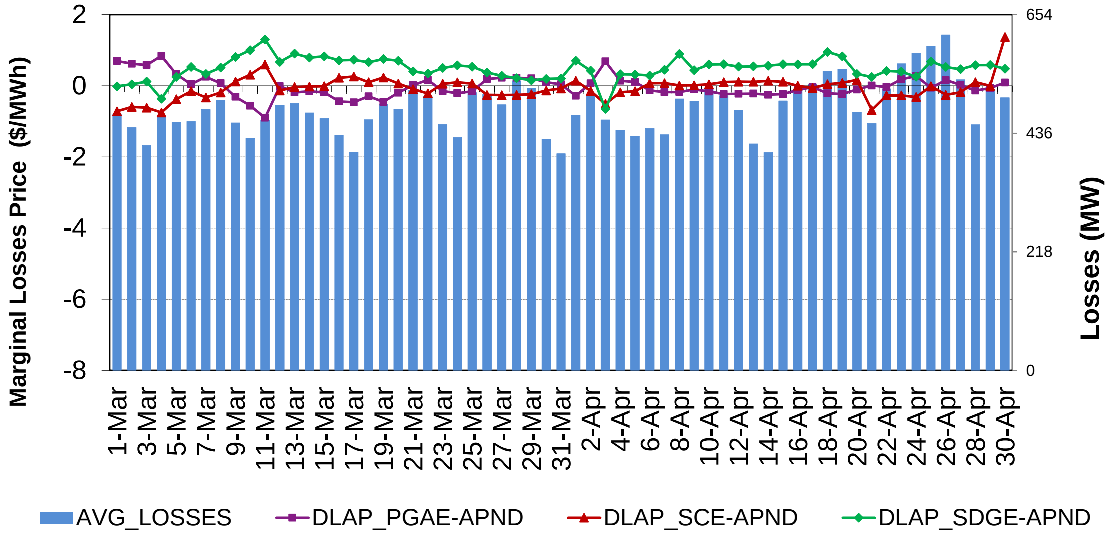
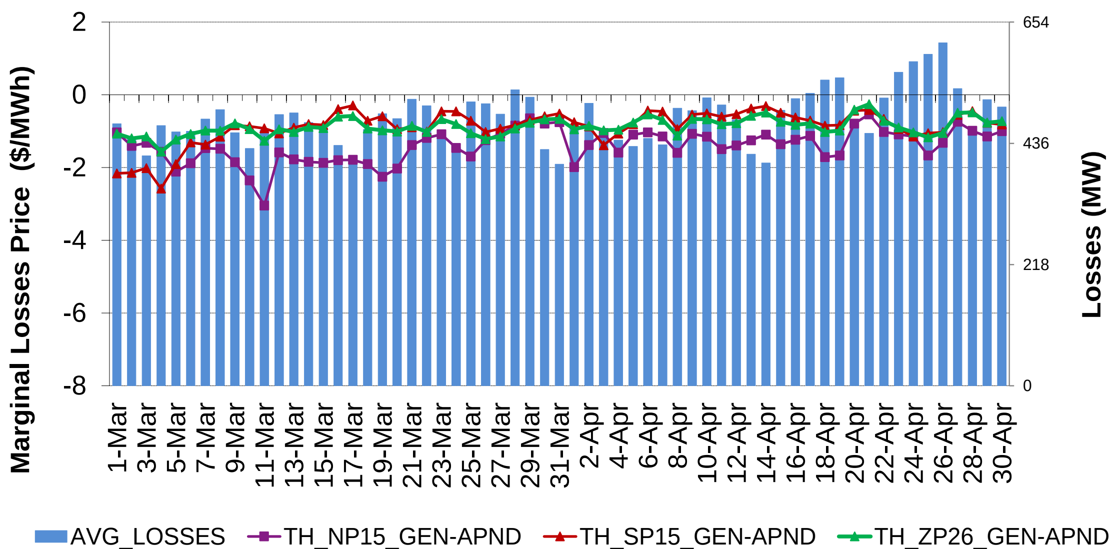


Figure 56: Day-Ahead Simple Average TH Prices for Losses



Real-Time Prices

Similar to the day-ahead section, Figure 57 and Figure 58 show the daily average prices for losses in RTD for both DLAPs and THs. Figure 59 and Figure 60 show the daily average prices for losses in the fifteen minute market (FMM) for both DLAPs and THs. These prices are computed with the same logic as those of the day-ahead market. Average losses are based on real-time (RTD and FMM) losses in this case.

Figure 57: RTD Weighted Average LAP Prices for Losses

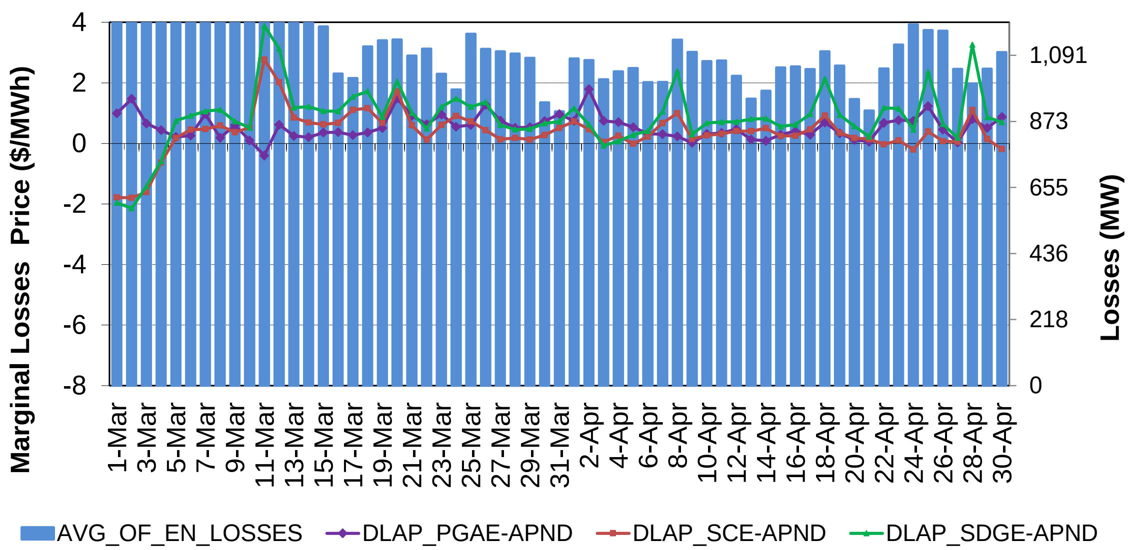


Figure 58: RTD Simple Average TH Prices for Losses

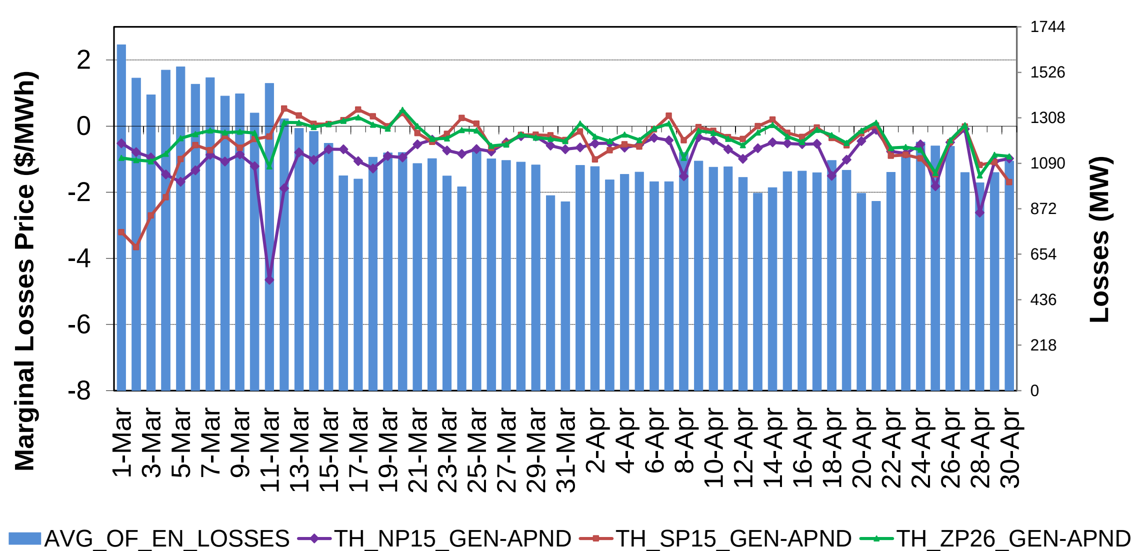


Figure 59: FMM Weighted Average LAP Prices for Losses

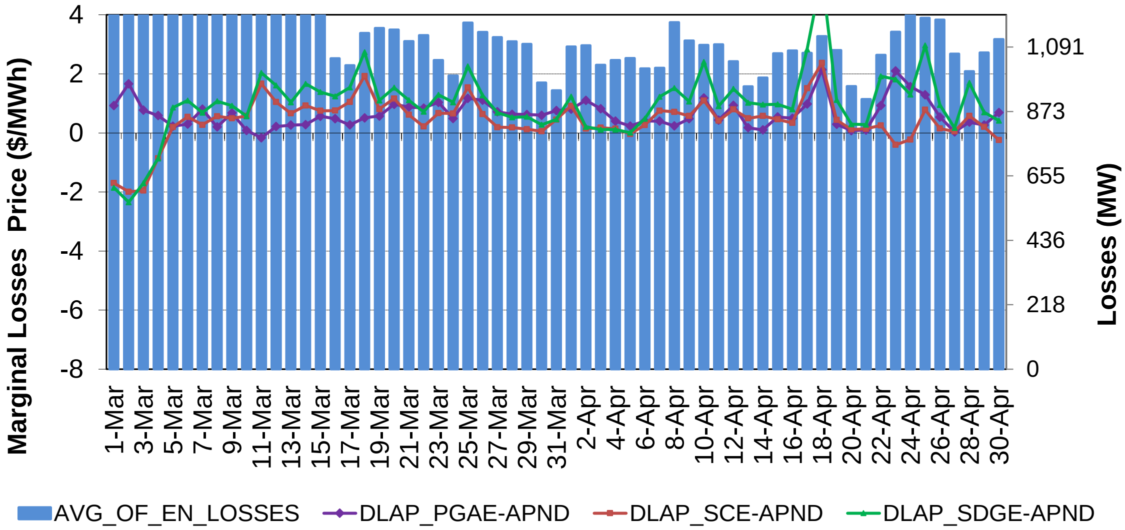
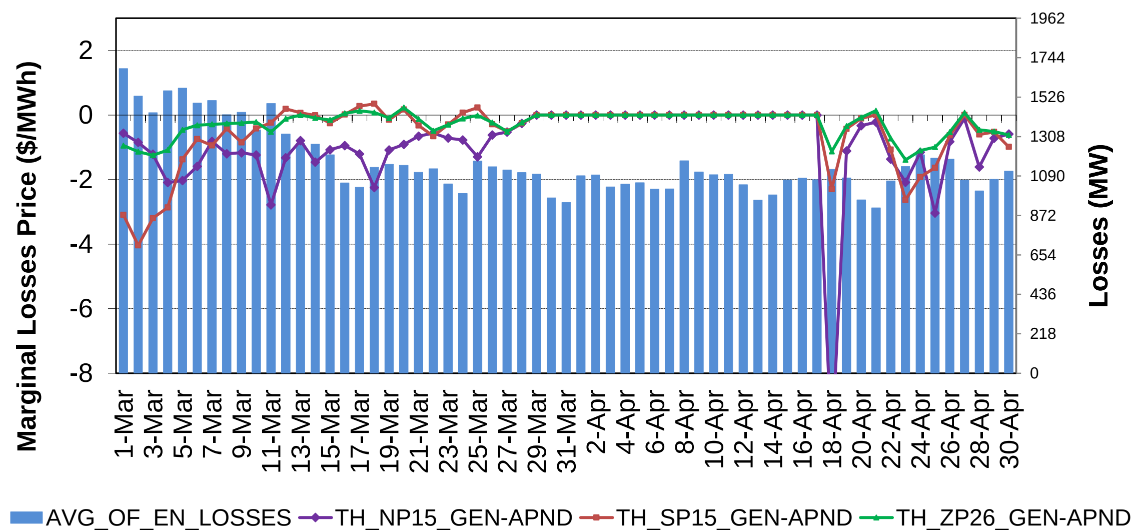


Figure 60: FMM Simple Average TH Prices for Losses

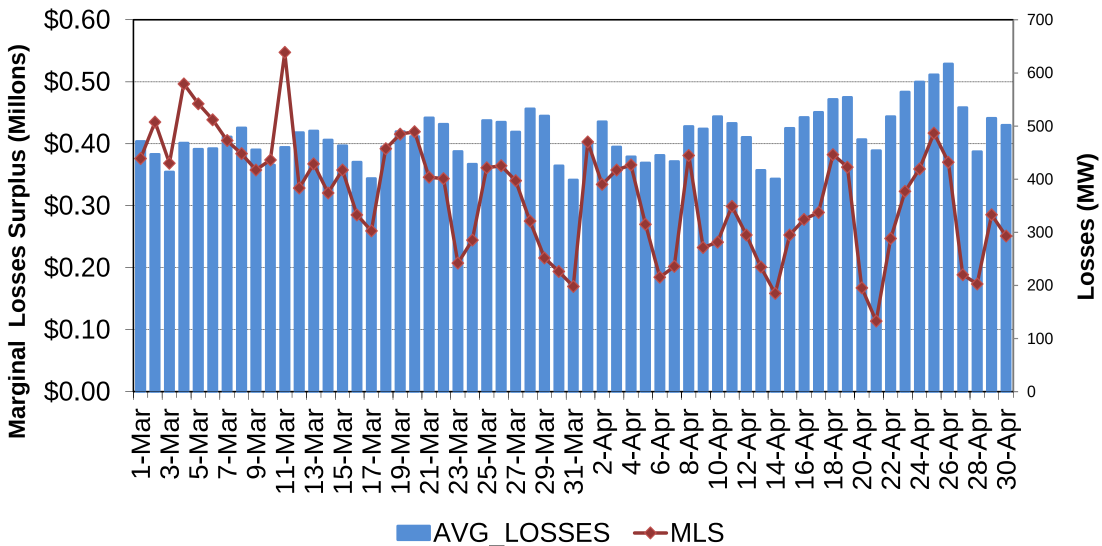


Marginal Losses Surplus

The integrated forward market is settled at LMPs, which consist of three components: energy, congestion, and losses. The marginal cost of losses may be positive or negative depending on whether a power injection at that node marginally increases or decreases losses. Incorporating the marginal cost of losses in the LMP is important both for assuring least-cost dispatch and for establishing nodal prices that accurately reflect the cost of supplying the load at each node. Because marginal losses rise quadratically with the transmission power flows, marginal losses will exceed average losses roughly by a factor of two, resulting in surplus collection for losses.

For every trading hour of the IFM, the ISO marginal losses surplus (MLS) is computed as the ISO total net hourly energy charge minus the ISO total IFM congestion charge exclusive of congestion credits for ETC/TOR/CVR and contract Loss credits to TOR holders. The MLS amount, if any, is then allocated pro-rata to the different SCs based on their measured demand in the ISO control area, excluding TOR demand quantity for which IFM and RTM loss credits were provided. The total daily MLS is shown in Figure 61.

Figure 61: Daily Marginal Losses Surplus Credit Allocation for the IFM



Ancillary Services

Requirements

Figure 62 illustrates the IFM daily average ancillary service requirement for regulation up, regulation down, spinning and non-spinning. Figure 63 shows the IFM hourly average ancillary service requirement for regulation up and regulation down.

Figure 62: IFM (Day-Ahead) Ancillary Services Average Requirement

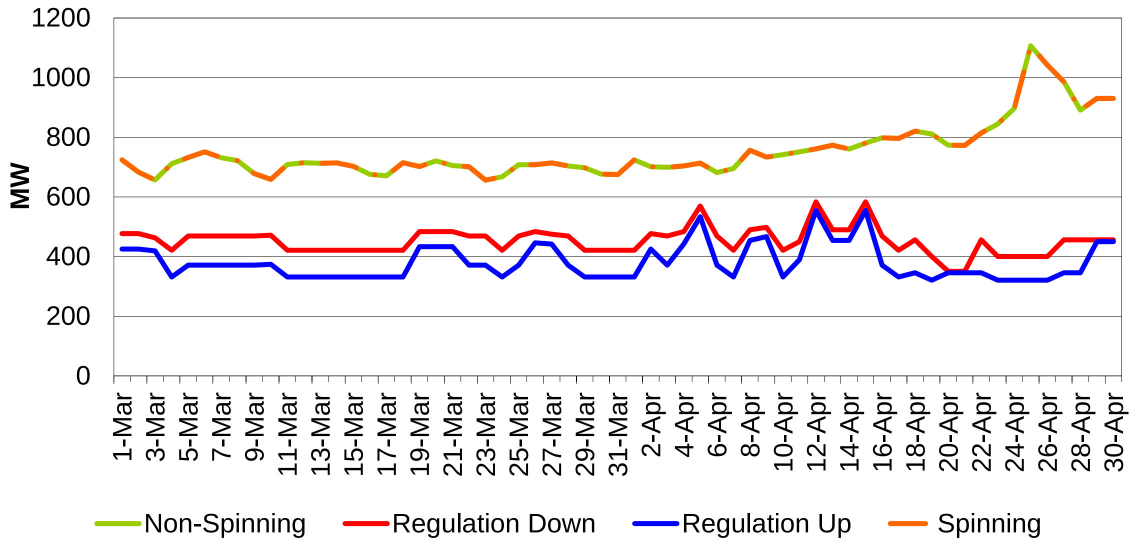
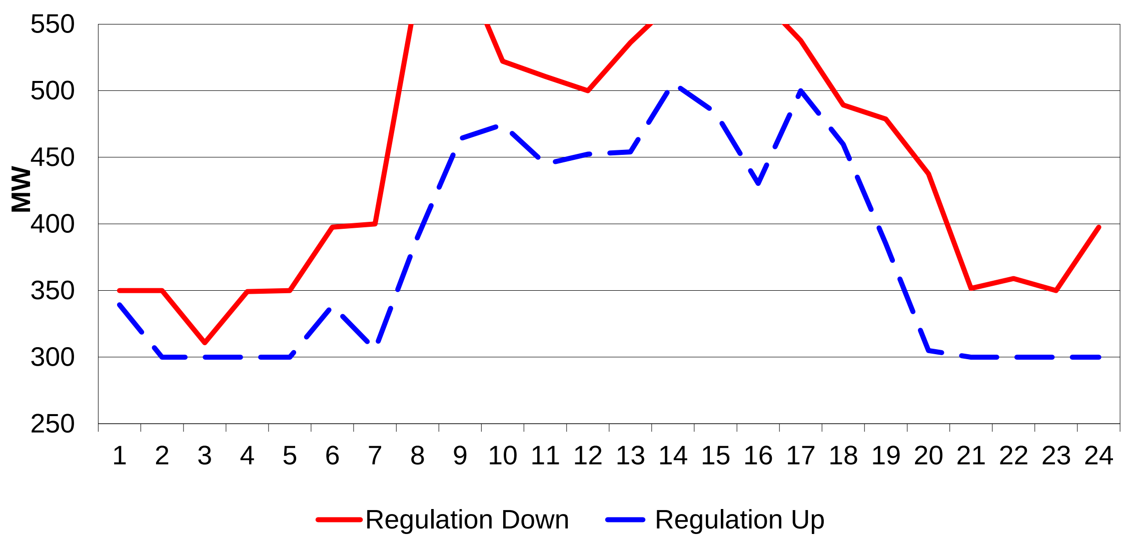


Figure 63: IFM (Day-Ahead) Hourly Average Regulation Requirement



Procurements

Figure 64 illustrates the IFM daily average procurement of regulation up, spinning and non-spinning ancillary services.

Figure 64: IFM (Day-Ahead) Upward Ancillary Services Procurement

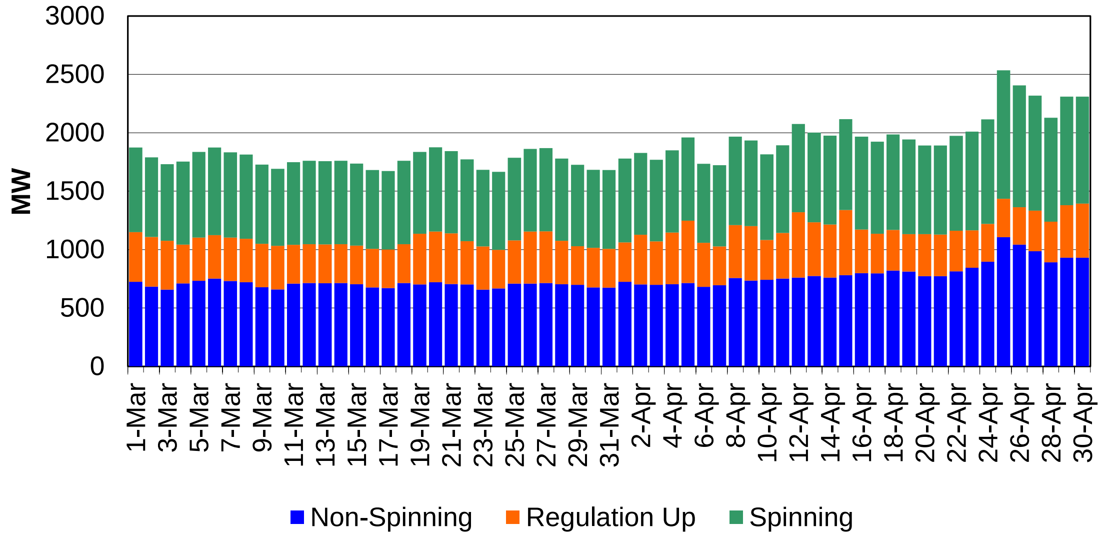


Figure 65: IFM (Day-Ahead) Regulation Down Procurement

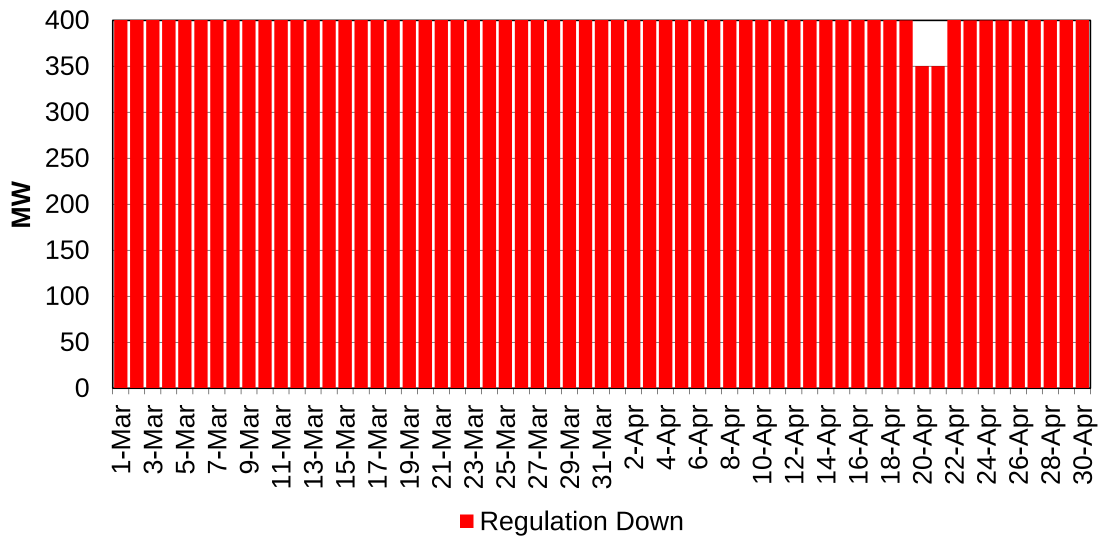


Figure 66 illustrates the real-time daily average procurement of upward ancillary services. It includes regulation up and regulation down procured in real-time unit commitment (RTUC), and spinning and non-spinning procured in both RTUC and HASP.

Figure 66: Real-Time Upward Ancillary Services Procurement

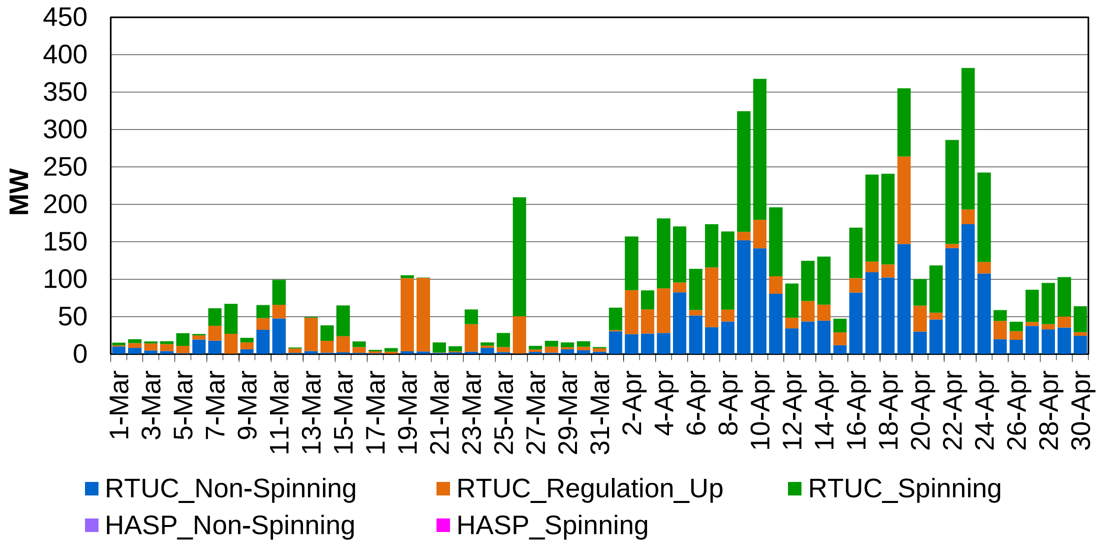
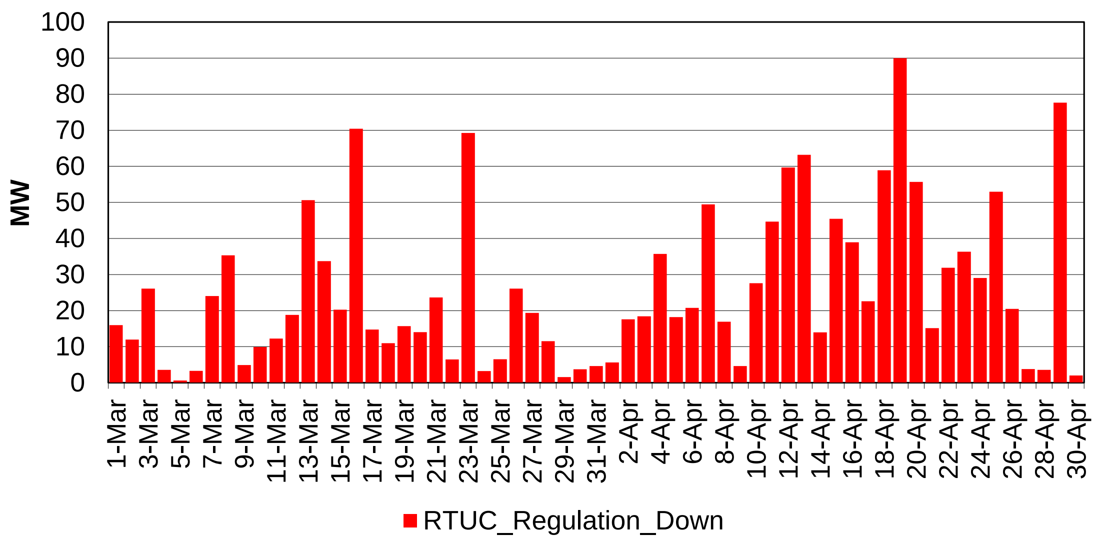


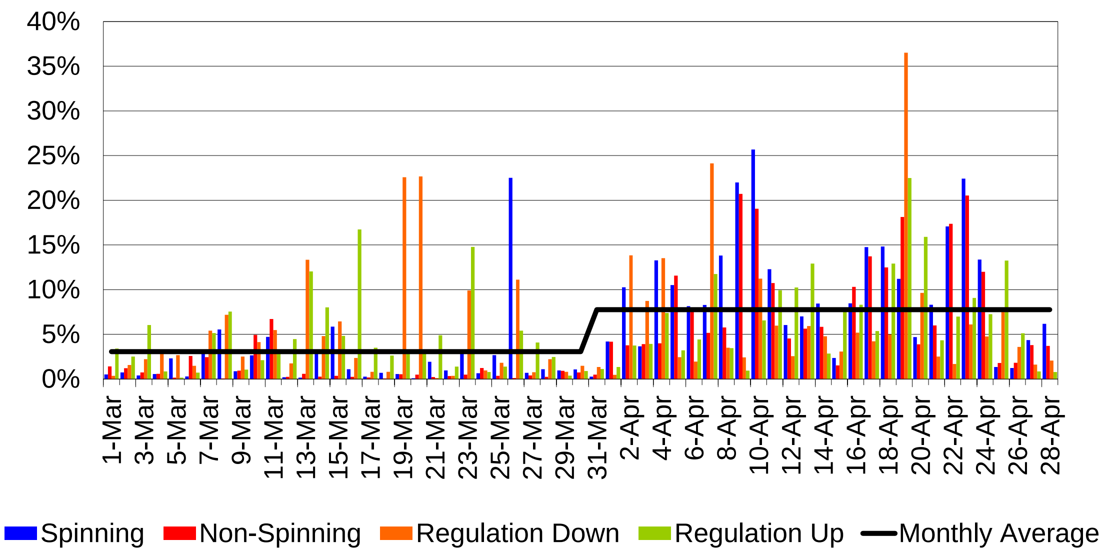
Figure 67 illustrates the RTUC daily average procurement of regulation down.

Figure 67: RTUC Regulation Down Procurement



The ISO procures 100 percent of its ancillary services requirements in the IFM (day-ahead) based on the IFM load forecast. Incremental procurements in the real-time market occurs under two scenarios. First, ancillary services requirements have changed in real-time market motivated by a change in the real-time load forecast. Second, if a unit which was awarded an ancillary service in IFM (day-ahead) is unable to provide that service in real-time. The market will automatically procure additional services to replace that service. Figure 68 displays the percentage of real-time procurement with respect to the IFM (day-ahead) procurement for all four types of ancillary services. The real-time procurement of regulation down and regulation up is actually the procurement in RTUC, while the real-time procurement of spinning and non-spinning is the sum of procurement in both RTUC and HASP. The percentage for each type of ancillary service is calculated as: (hourly average of real-time (RTUC and HASP) procurement in 15 minute intervals) / (hourly IFM (day-ahead) procurement). .

Figure 68: Proportion of Real-Time Procurement as Percentage of Day-Ahead Requirement



IFM (Day-Ahead) Average Prices

Table 8 shows the monthly IFM average procurements and prices for regulation up, regulation down, spinning and non-spinning ancillary services. Figure 69 and Figure 70 illustrate the IFM daily and hourly average price for regulation up, regulation down, spinning and non-spinning ancillary services. The average price for each type of ancillary services is calculated as: sum (non-self scheduled AS MW * ancillary services marginal price $/MW (ASMP)) / sum (non-self scheduled AS MW).

Table 8: IFM (Day-Ahead) Monthly Ancillary Service Average Procurement and Price

	Average Procurred				Average Price			
	Reg Up	Reg Dn	Spinning	Non-Spinning	Reg Up	Reg Dn	Spinning	Non-Spinning
Apr-19	395	454	803	806	$18.28	$19.88	$8.87	$0.16
Mar-19	370	450	699	700	$16.83	$18.72	$7.12	$0.35
Percent Change	6.54%	0.99%	14.81%	15.23%	8.60%	6.17%	24.61%	-53.89%

Figure 69: IFM (Day-Ahead) Ancillary Service Average Price

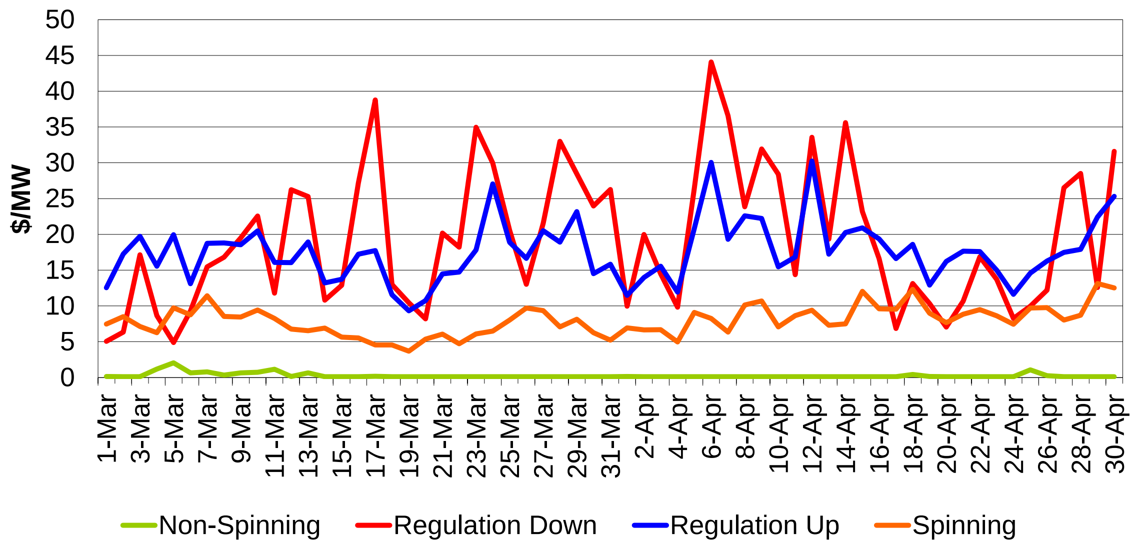


Figure 70: IFM (Day-Ahead) Hourly Average Ancillary Service Price

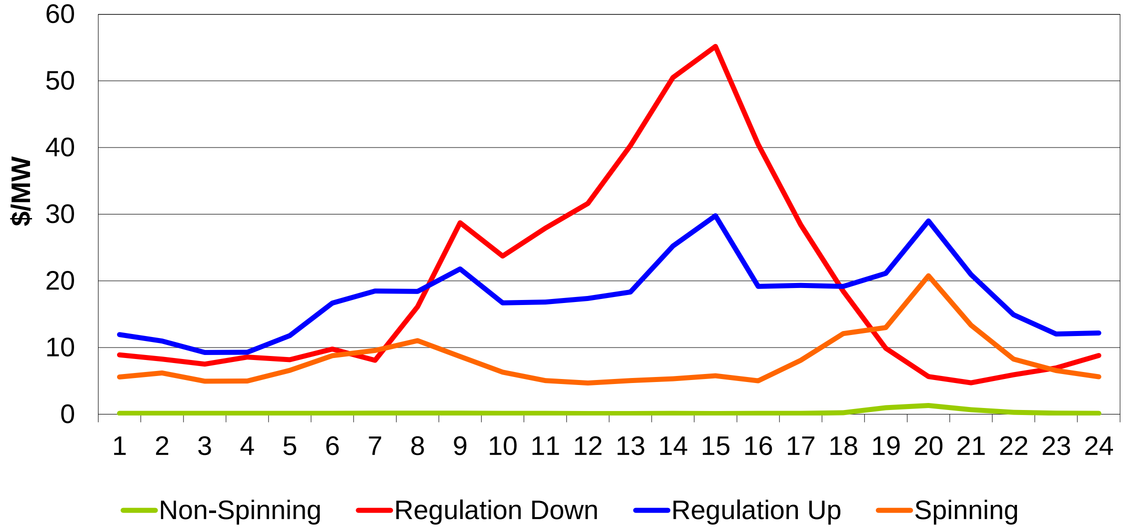
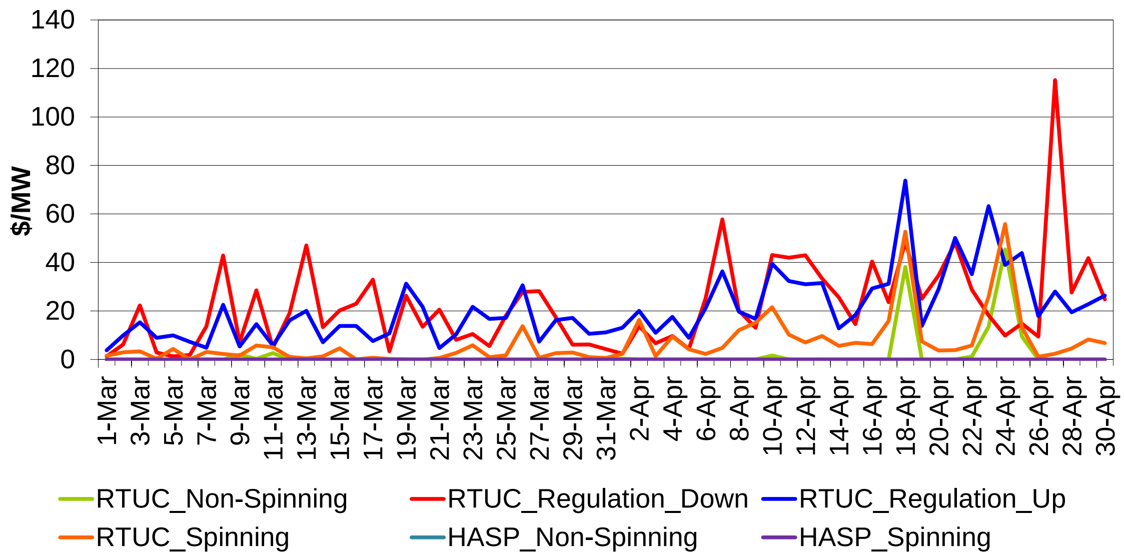


Figure 71 illustrates the real-time daily average price for ancillary services, including the average price for regulation up and regulation down procured in RTUC, and the average price for spinning and non-spinning procured in both RTUC and HASP. The average price for each type of ancillary services is calculated as: hourly average of [sum (non-self scheduled AS MW * ancillary services marginal price $/MW (ASMP)) / sum (non-self scheduled AS MW)] for each of the 15 minute intervals.

Figure 71: FMM (Real-Time) Ancillary Service Average Price



Average Regional Ancillary Service Shadow Prices

Figure 72 through Figure 75 display the IFM daily average regional ancillary service shadow prices (RASSPs) for regulation up, spinning, non-spinning and regulation down.

Figure 72: IFM (Day-Ahead) Regulation Up (RASSP)

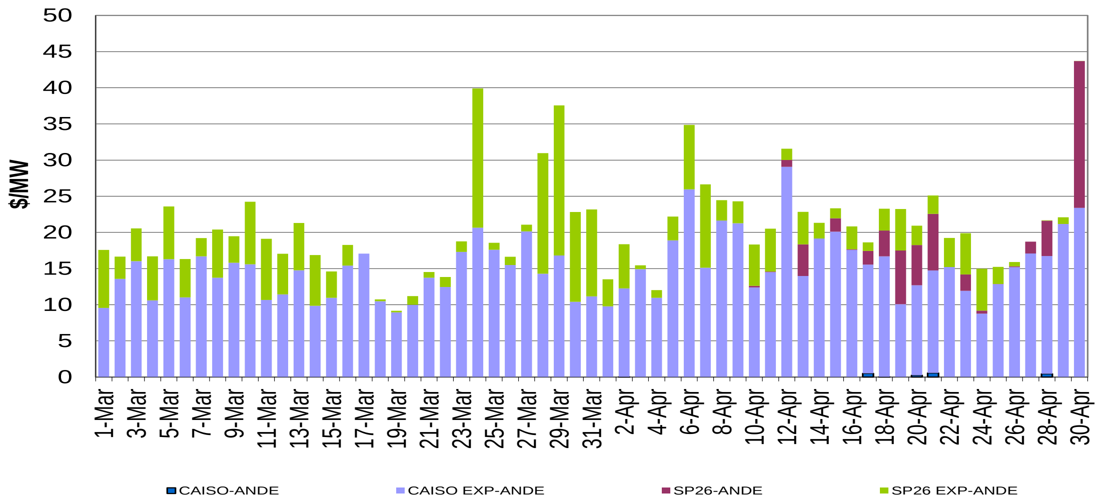


Figure 73: IFM (Day-Ahead) Spinning (RASSP)

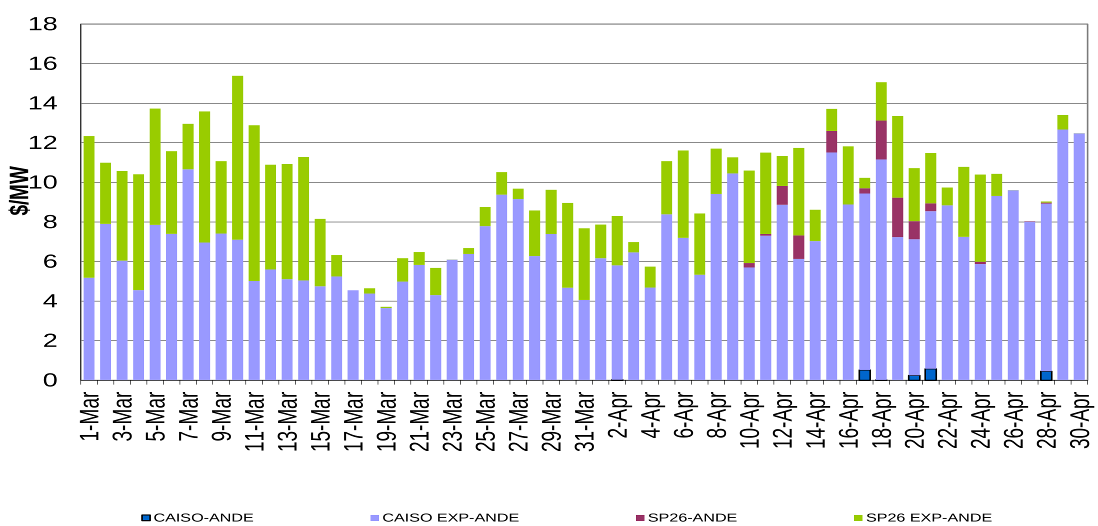


Figure 74: IFM (Day-Ahead) Non-Spinning (RASSP)

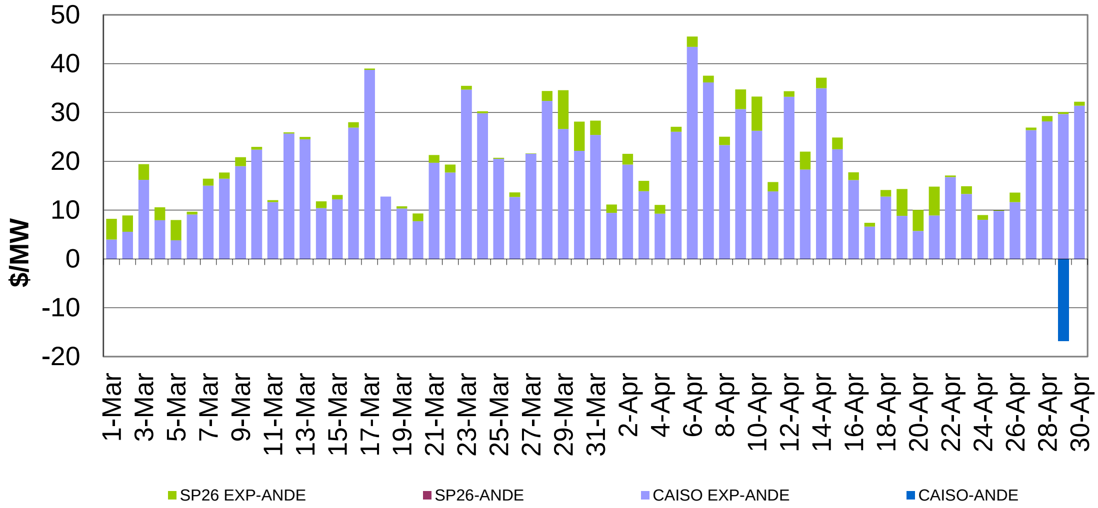
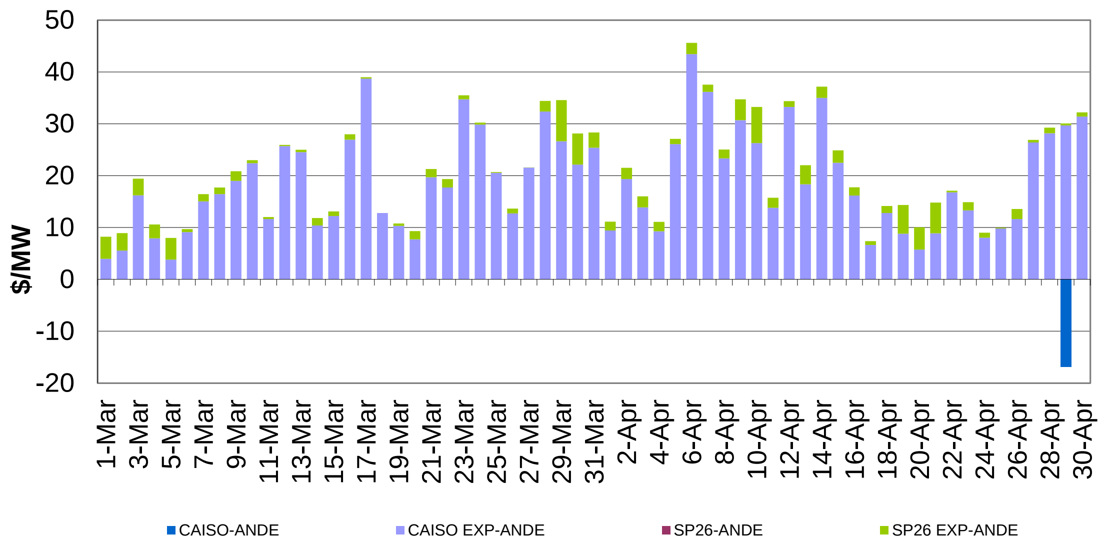


Figure 75: IFM (Day-Ahead) Regulation Down (RASSP)



Average Cost to Load

Figure 76 below shows IFM average cost to load for ancillary services procurement in the IFM market. The average cost to load is calculated as: average ((total hourly cost of procurement for all four ancillary services) / (total hourly ISO load)).

Figure 76: IFM (Day-Ahead) Average Cost to Load

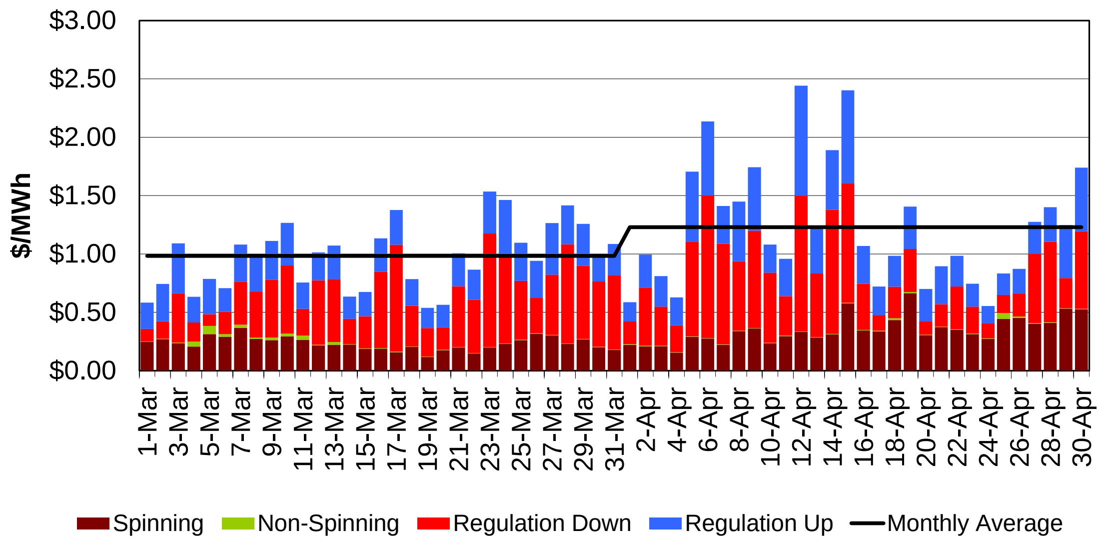
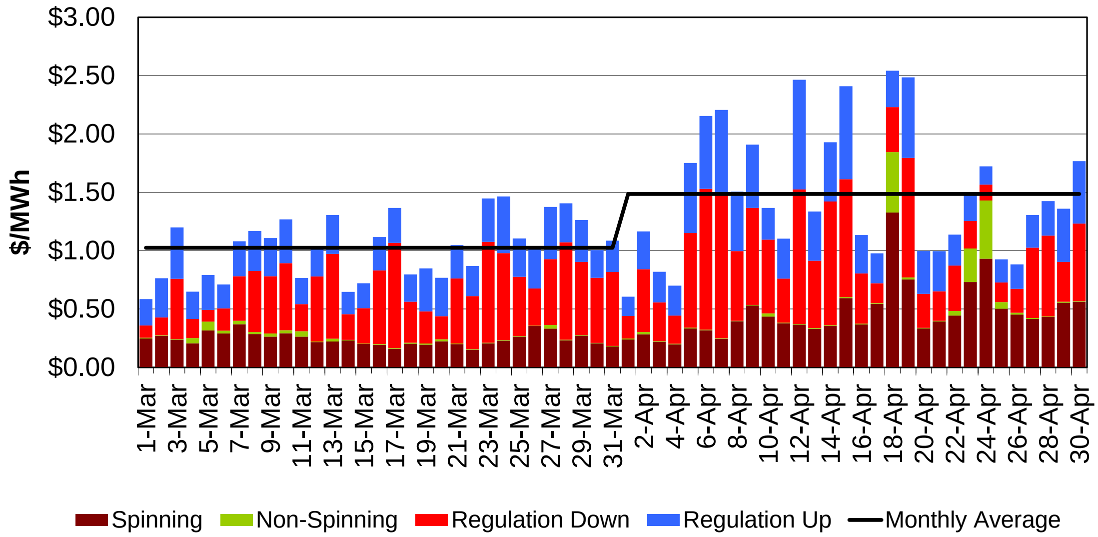


Figure 77 below shows the total system (IFM, HASP and RTUC) average cost to load for ancillary services procurement in the market. The average cost to load is calculated as: average ((total hourly cost of procurement for all four ancillary services) / (total hourly ISO load)).

Figure 77: System (Day-Ahead and Real-Time) Average Cost to Load



Residual Unit Commitment

Residual unit commitment (RUC) is a reliability function for committing resources and procuring RUC capacity not scheduled in the IFM as energy or ancillary service capacity. RUC capacity is procured in order to meet the difference between the ISO forecast of ISO demand – including locational differences and adjustments – and the demand scheduled in the IFM for each trading hour of the trading day.

Deviations of RUC schedule from IFM schedule

The RUC schedule is the total hourly capacity committed by RUC, including the capacity committed in the day-ahead schedule. The daily deviation of the RUC schedule from the IFM schedule is presented in Figure 78. The hourly deviation of the RUC schedule from the IFM schedule is presented in Figure 79. Positive deviations indicate that RUC capacity was procured, while negative deviations indicate there was over-scheduling in the IFM compared with the ISO forecast of ISO demand. If there is a positive deviation in any trade hour then RUC capacity was procured in that hour. However, if there are any negative deviations in other trade hours, the daily average deviation might be negative.

$$\text{Daily Deviation}_j = \text{Avg}\left(\frac{\text{RUC\_Schedule}_{ij} - \text{IFM\_Schedule}_{ij}}{\text{RUC\_Schedule}_{ij}}\right)$$

Here i indicates trading hour and j indicates trading day. The average is taken across 24 hours for each trading day.

$$\text{Hourly Deviation}_i = \text{Avg}\left(\frac{\text{RUC\_Schedule}_{ij} - \text{IFM\_Schedule}_{ij}}{\text{RUC\_Schedule}_{ij}}\right)$$

Here i indicates trading hour and j indicates trading day. The average is taken across all the trading days in this month for each trading hour.

Figure 78: Daily Deviation of RUC Schedule from IFM Schedule

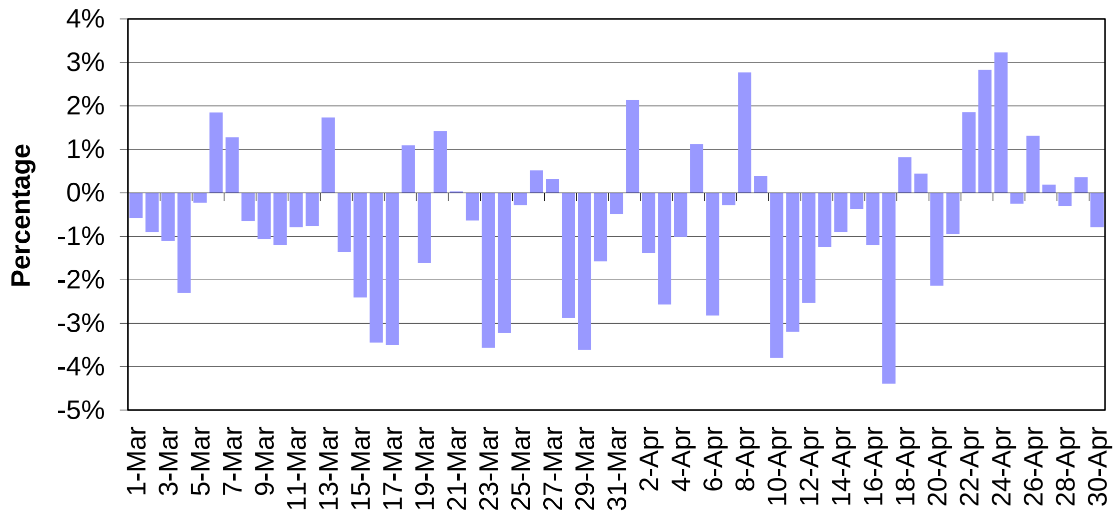
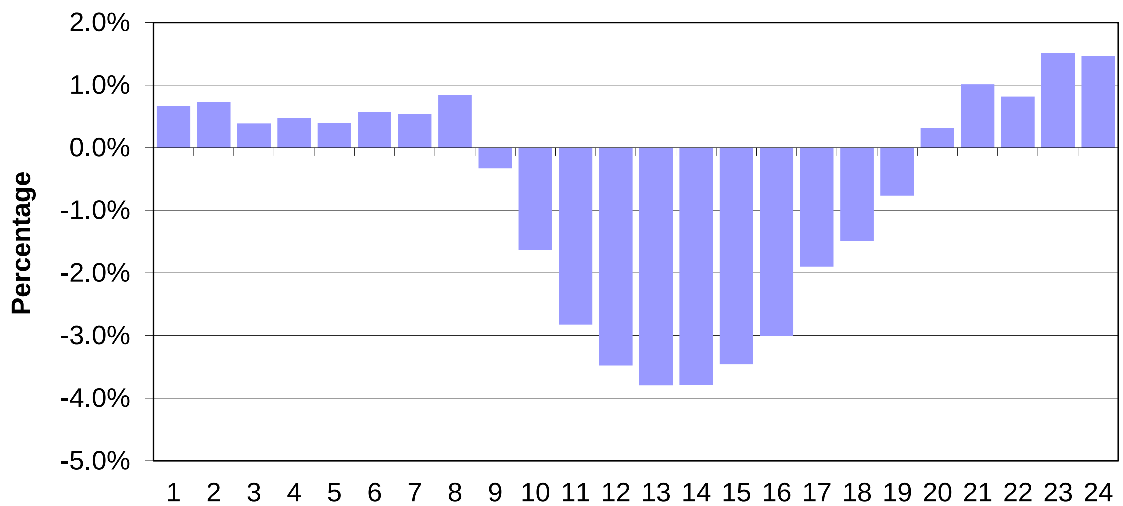


Figure 79: Hourly Deviation of RUC Schedule from IFM Schedule



RA/RMR RUC Capacity vs. RUC Award

RUC capacity is the positive difference between the RUC schedule and the greater of the IFM schedule and the minimum load level of a resource. The RUC award is the portion of RUC capacity in excess of reliability must-run (RMR) capacity or the resource adequacy (RA) RUC obligation. All RUC awards are paid the RUC LMP. RA and RMR units do not receive additional payments for their RUC capacity because they are already compensated through their RMR or RA contracts. Figure 80, Figure 81 and Figure 82 show the daily average RA/RMR RUC capacity and RUC award.

Figure 80: RA/RMR RUC Capacity vs. RUC Award (On-Peak Hours)

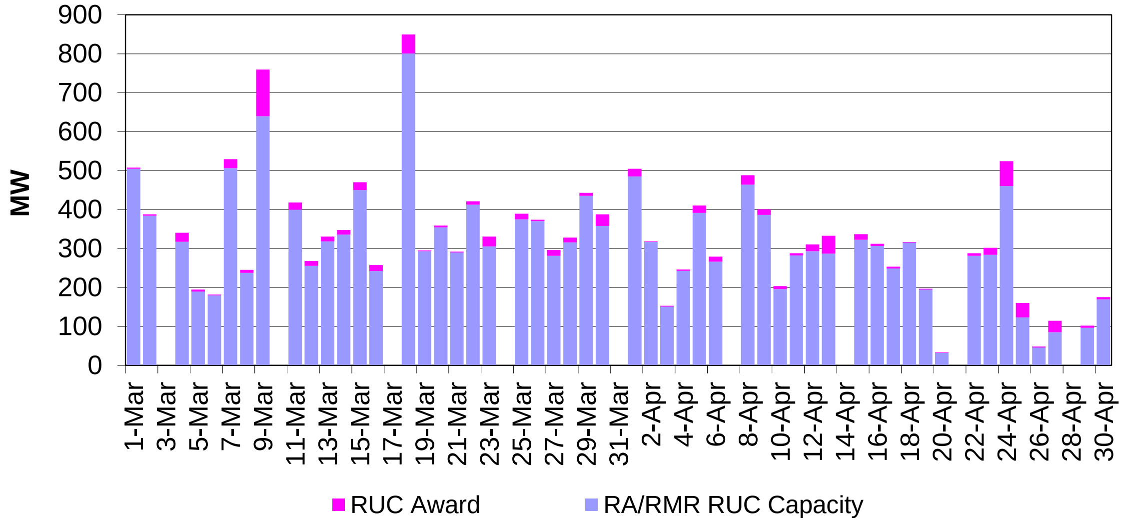


Figure 81: RA/RMR RUC Capacity vs. RUC Award (Off-Peak Hours)

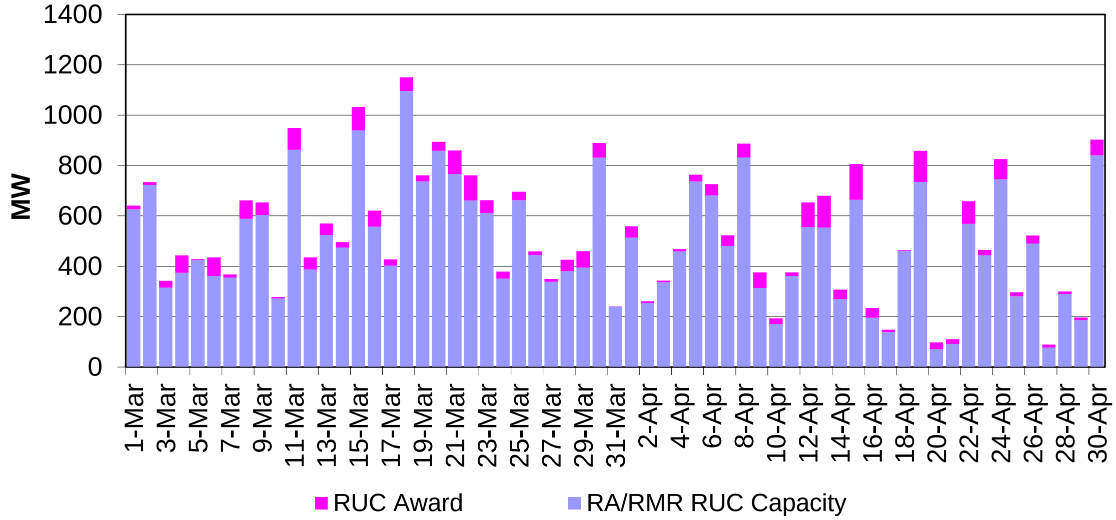
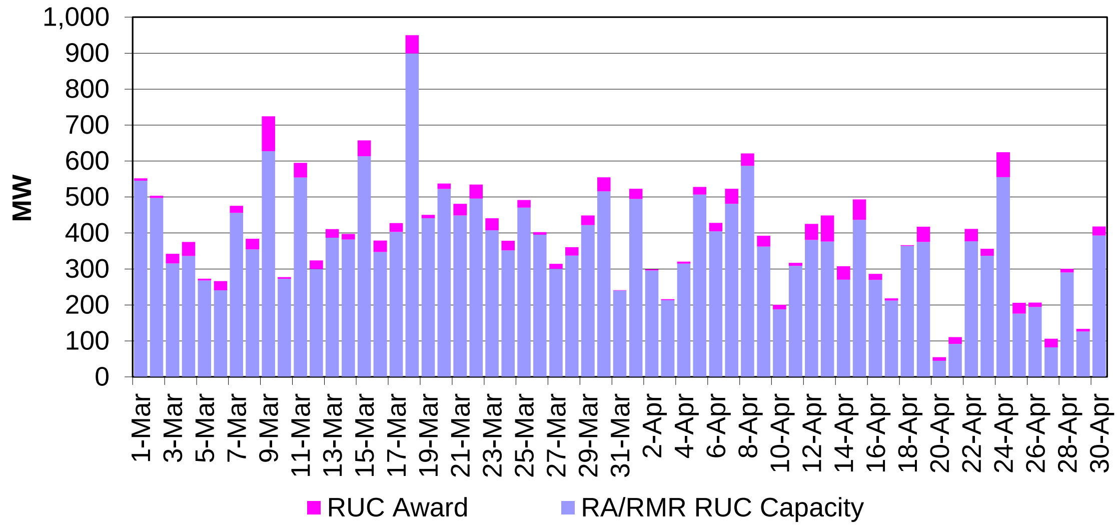


Figure 82: RA/RMR RUC Capacity vs. RUC Award (All Hours)



RUC Award

The daily RUC award and the weighted average RUC LMP are represented in Figure 83, Figure 84 and Figure 85 for on-peak, off-peak and all hours. The weighted RUC LMP will not be specified if there was no RUC award in a particular day.

$$\text{Weighted\_RUC\_LMP} = \frac{\sum_j \sum_i (\text{RUC\_LMP}_{ij} \times \text{RUC\_Award}_{ij})}{\sum_j \sum_i \text{RUC\_Award}_{ij}}$$

Here i indicates individual resource and j indicates trading hour (from 1 to 24).

Figure 83: Daily RUC Award and LMP (On-Peak Hours)

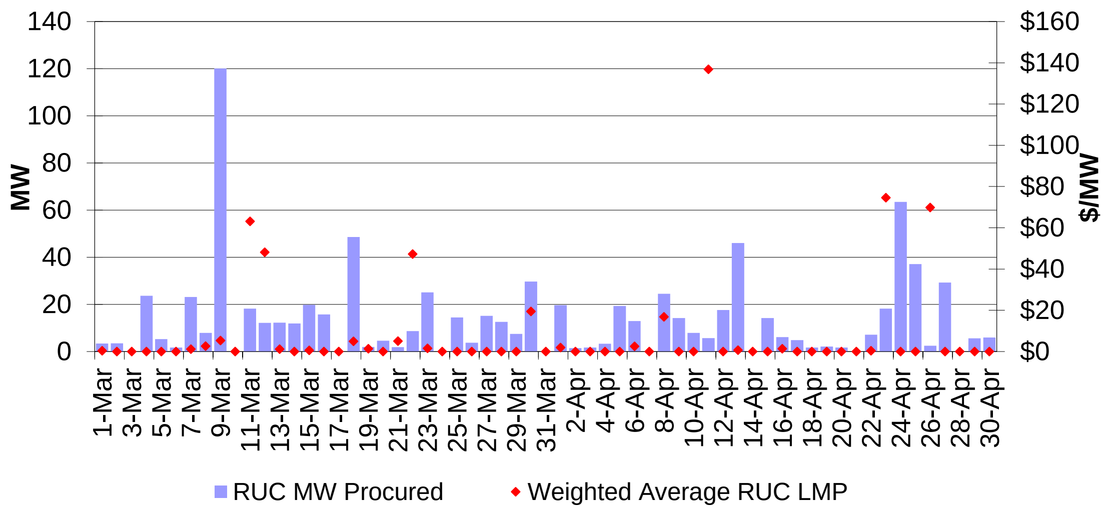


Figure 84: Daily RUC Award and LMP (Off-Peak Hours)

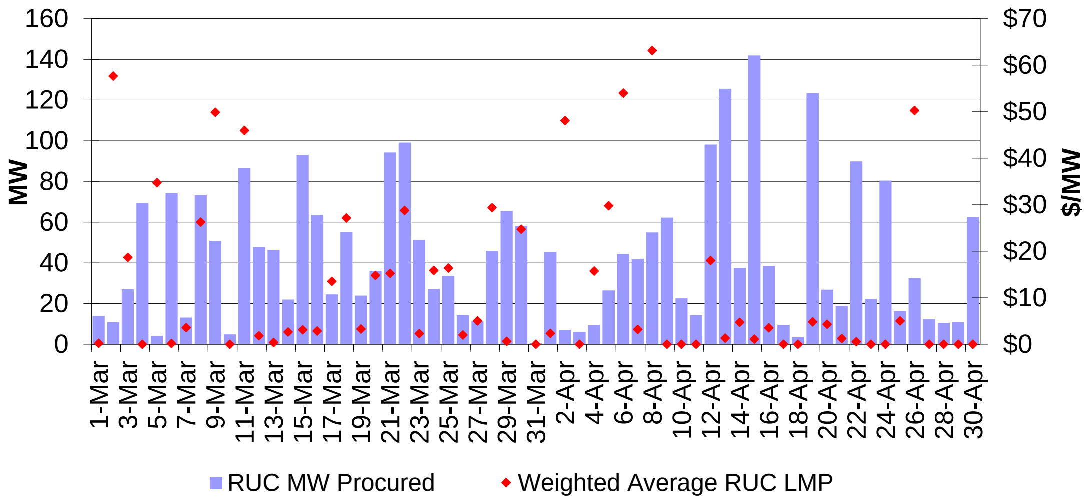
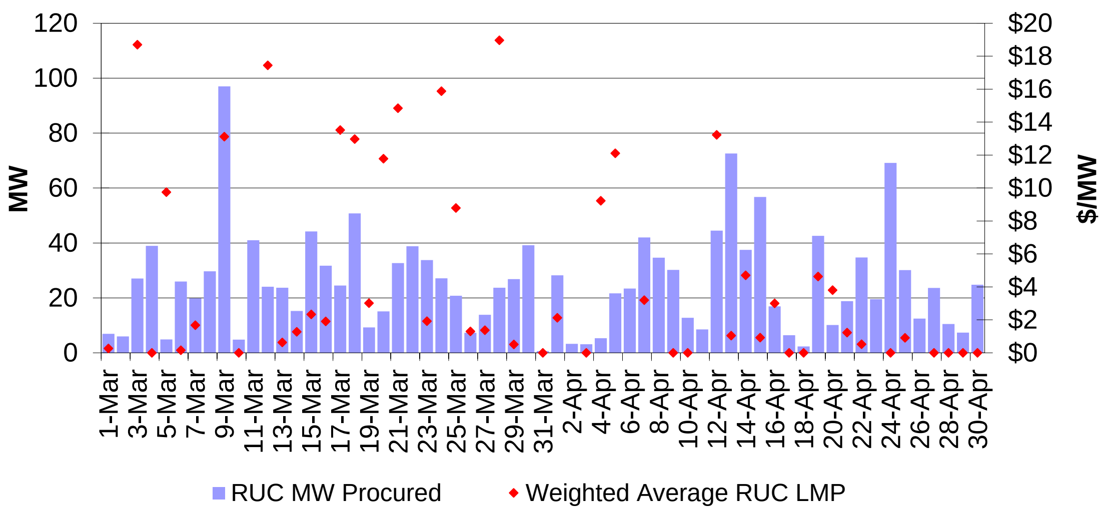


Figure 85: Daily RUC Award and LMP (All Hours)



Average RUC Price

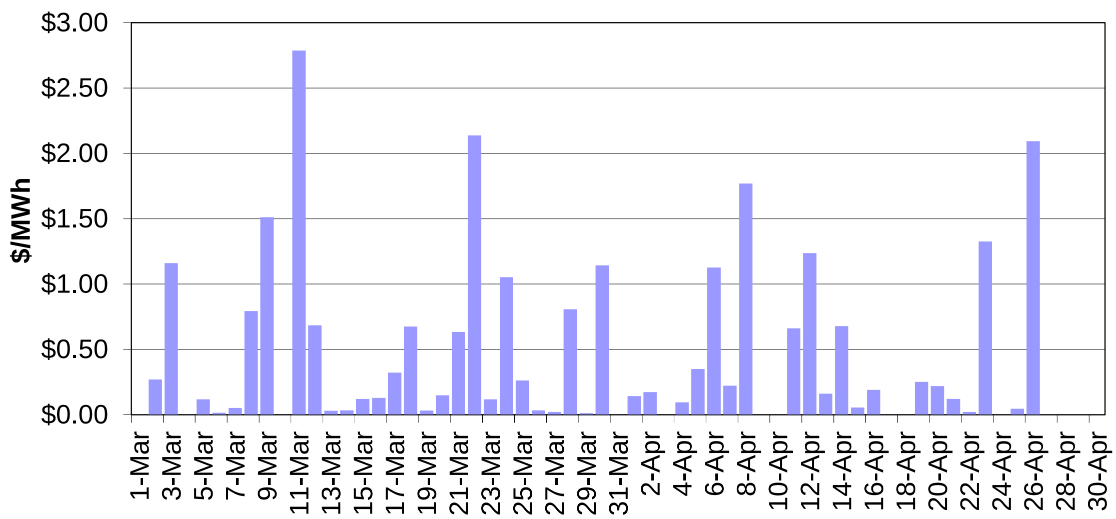
Figure 86 shows the daily average RUC price and Figure 87 shows the total RUC cost.

$$\text{RUC\_Price} = \text{Avg}\left(\frac{\sum_i (\text{RUC\_LMP}_{ij} \times \text{RUC\_Award}_{ij})}{\sum_i \text{RUC\_Capacity}_{ij}}\right)$$

Here i indicates individual resource and j indicates trading hour (from 1 to 24). The average is taken across all trading hours for each trading day.

The average RUC price will be positive only when there was a RUC award and the weighted average RUC LMP was greater than $0. If there was no RUC award or there was some RUC award but the weighted average RUC LMP was $0, average RUC price is $0 for that trading day.

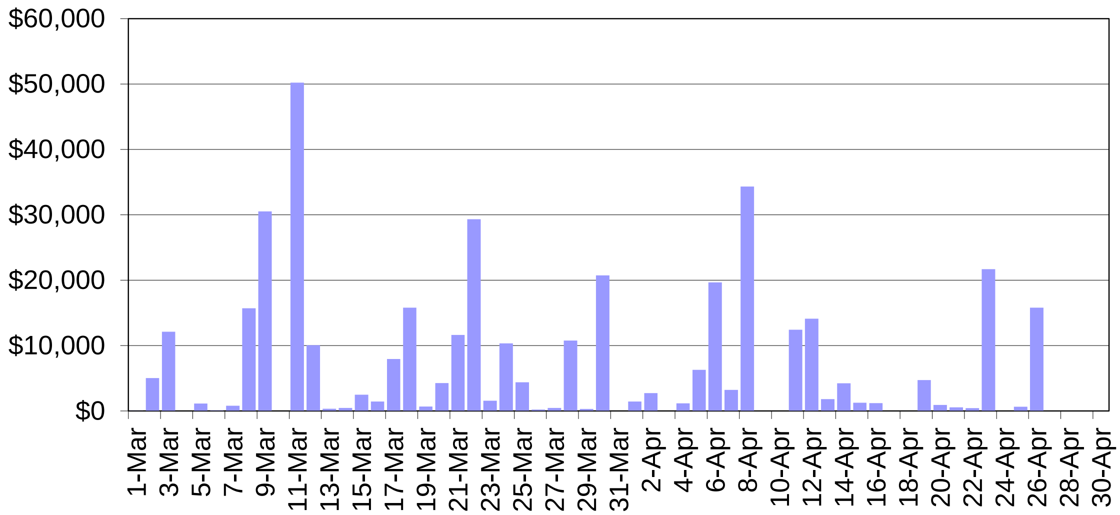
Figure 86: Average RUC Price



Total RUC Cost

Figure 87 shows the daily cumulative total RUC cost.

Figure 87: Total RUC Cost



Convergence Bidding

On February 1, 2011 the CAISO implemented convergence bidding in its software systems. Convergence bidding is an important market enhancement that enables market prices between the DA and RT markets to converge. This ultimately leads to better price discovery and more efficient dispatch of physical resources. Convergence bidding involves placing purely financial bids, at particular pricing nodes in the day-ahead market. If these bids are cleared in the day-ahead market, they are then liquidated in the opposite direction in the real-time market. The market participant thus earns or is charged the difference between the day-ahead price and the real-time price at the location of the bid. Convergence bids are cleared in the IFM. They are not part of the RUC process that commits additional capacity, if necessary, to meet the next day's demand forecast. Convergence bids are not part of any dispatch in real-time market processes.

In the CAISO's implementation there are effectively two markets for convergence bidding, namely the intertie market and the internal market. Both of these markets use the DAM as the original pricing mechanism, but the intertie market settles against the HASP run, whereas the internal market settles against the five-minute RTD run. As of November 28, 2011, The ISO removed the ability to submit convergence bids at intertie scheduling points.

Figure 88 shows the daily average volume of submitted virtual bids in the ISO market for virtual supply and virtual demand. Figure 89 shows the daily average volume of cleared virtual bids in IFM for virtual supply and virtual demand. Figure 90 shows the ratio of cleared virtual bids to submitted bids for virtual supply and virtual demand.

Figure 88: Submitted Virtual Bids

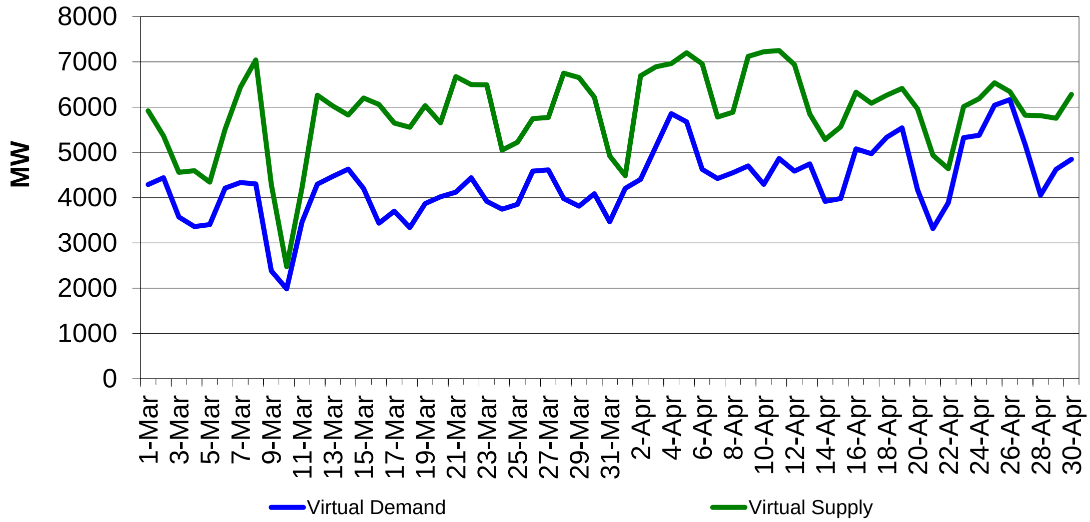


Figure 89: Cleared Virtual Bids

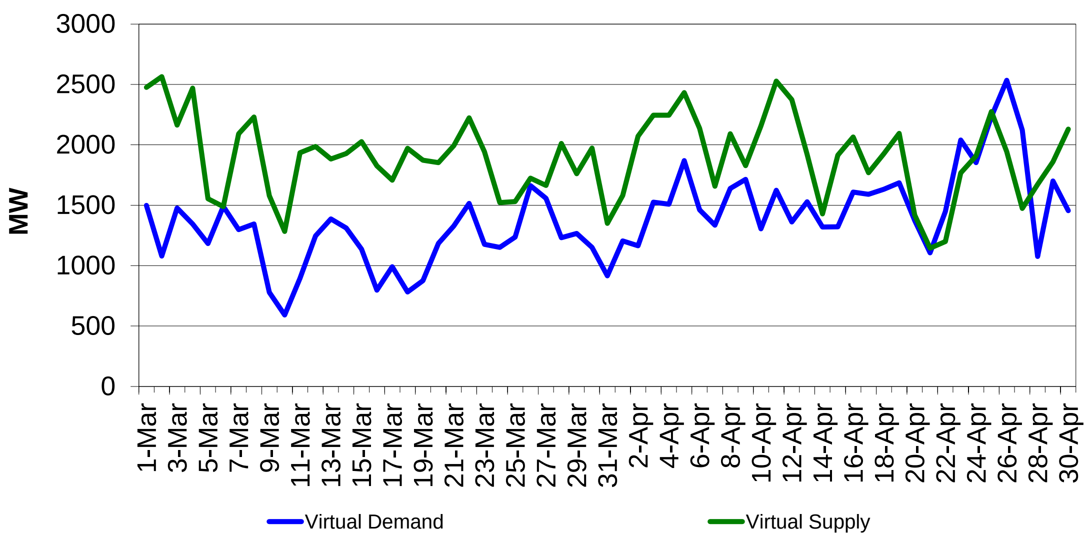


Figure 90: Ratio of Cleared Virtual Bids to Submitted Virtual Bids

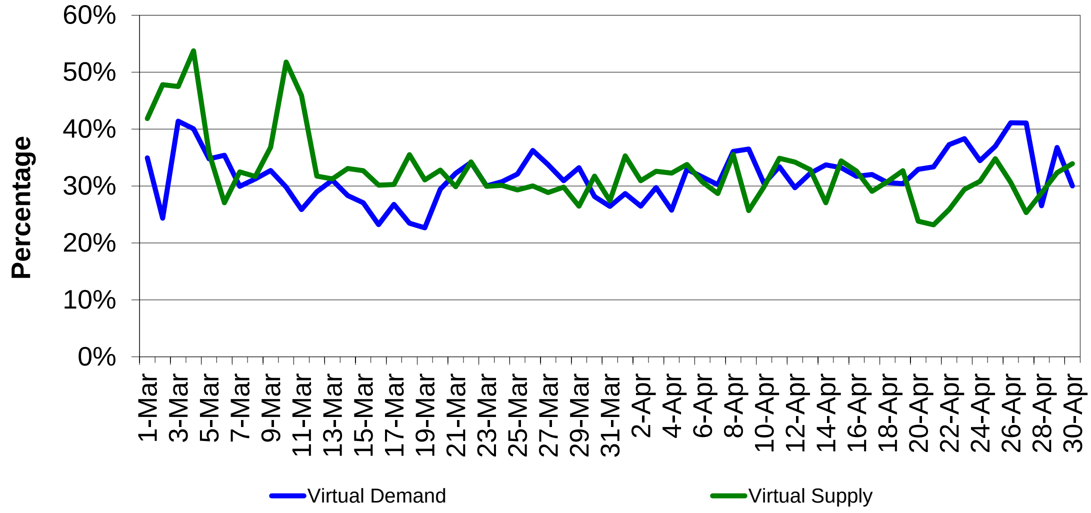


Figure 91 shows the daily average volume of submitted virtual bids for internal nodes (or internal market). Figure 92 shows the daily average volume of cleared virtual bids for internal nodes. Figure 93 shows the ratio of cleared virtual bids to submitted bids for internal nodes.

Figure 91: Submitted Virtual Bids for Internal Node

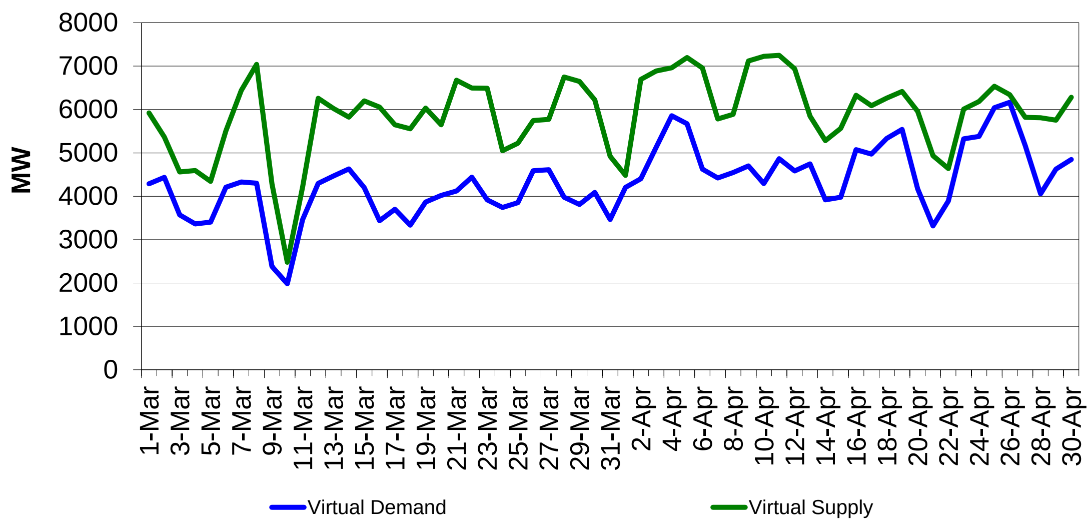


Figure 92: Cleared Virtual Bids for Internal Node

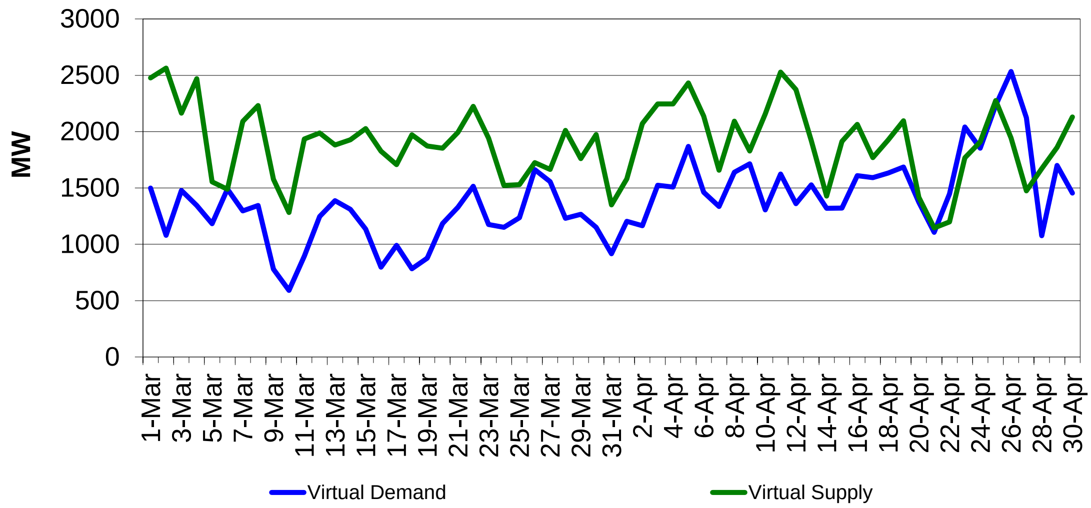
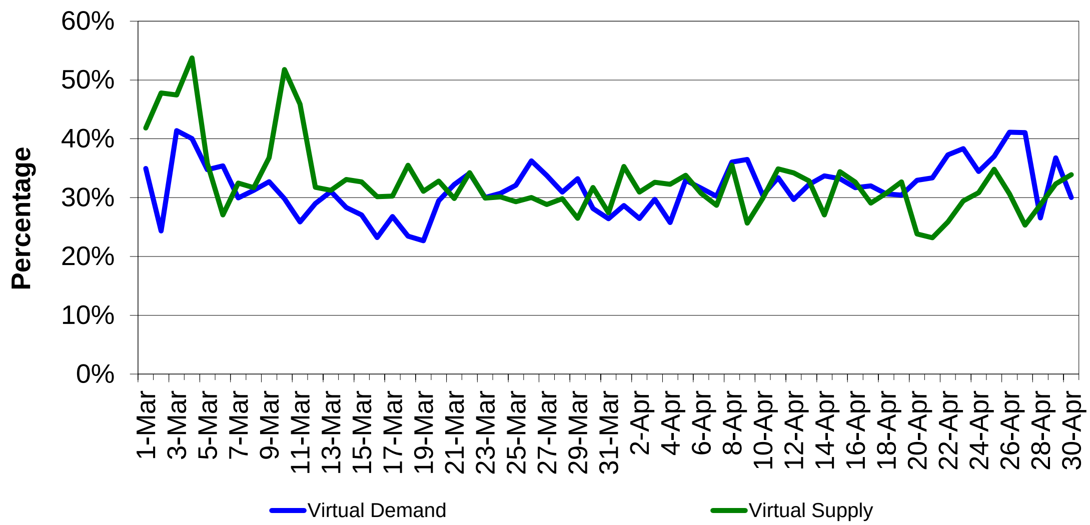


Figure 93: Ratio of Cleared Virtual Bids to Submitted Virtual Bids for Internal Node



Nodal MW injection/withdrawal limits were enforced to ensure a feasible Alternate-Current (AC) power flow solution with convergence bidding in IFM. Figure 94 shows the daily count of binding nodal constraints in IFM.

Figure 94: Binding Nodal Constraints

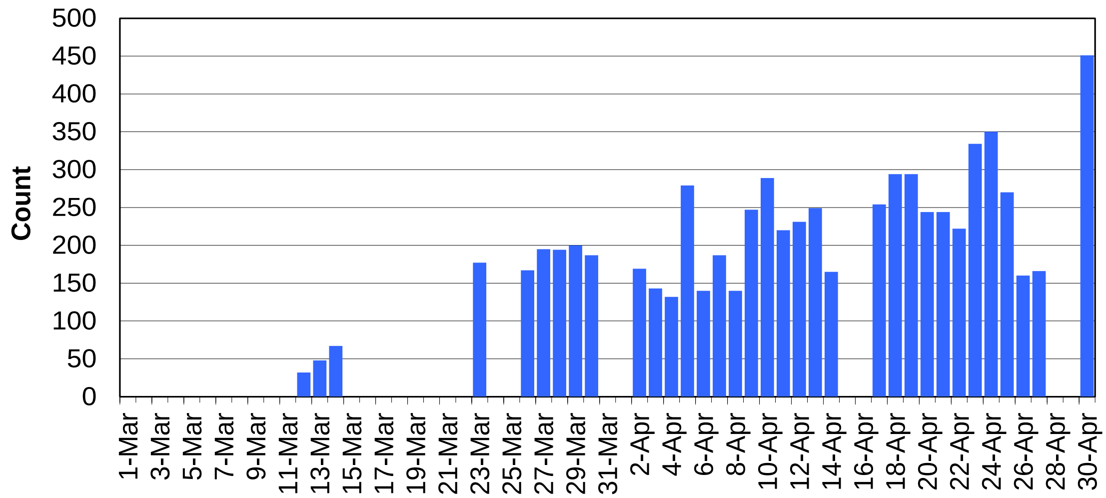
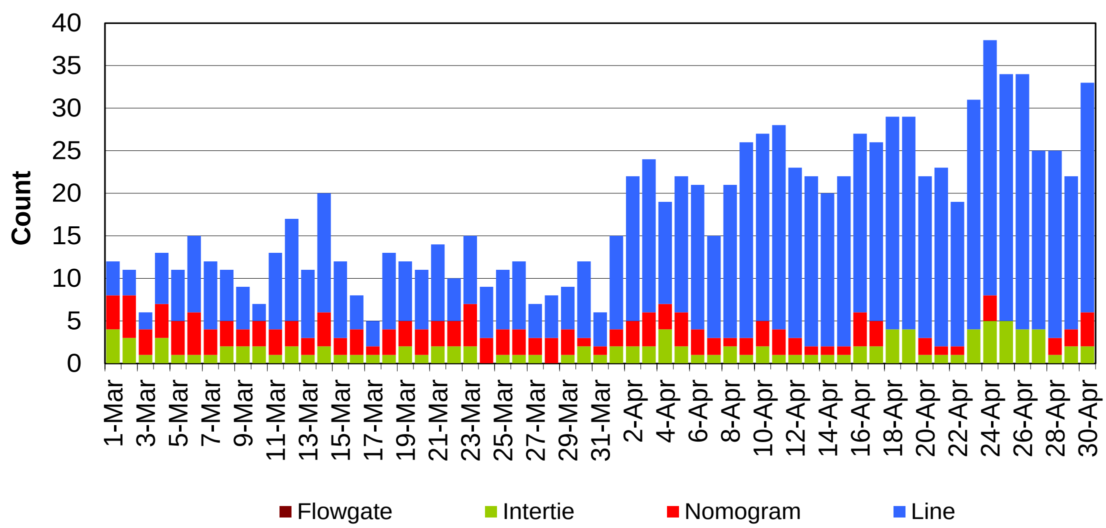


Figure 95 shows the daily count of the binding transmission constraints in IFM.

Figure 95: Binding Transmission Constraints



Convergence bidding tends to cause the day-ahead market and real-time market prices to move closer together, or “converge”. Figure 96 shows the energy prices (namely the energy component of the LMP) in IFM, HASP, FMM, and RTD. Figure 97 shows the difference between the IFM, HASP, FMM, and RTD energy prices.

Figure 96: IFM, HASP, FMM, and RTD Prices

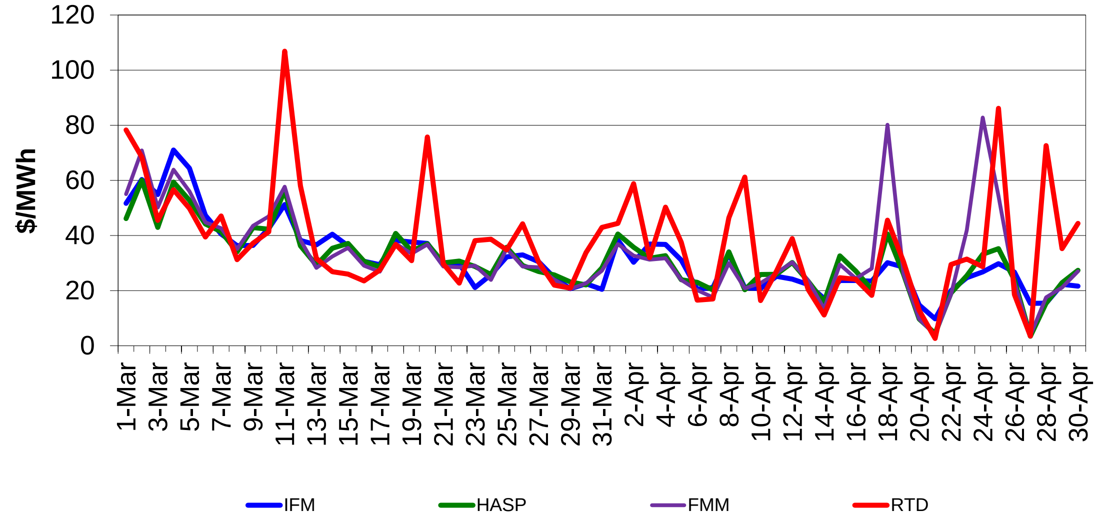


Figure 97: Difference between IFM, HASP, FMM, and RTD Prices

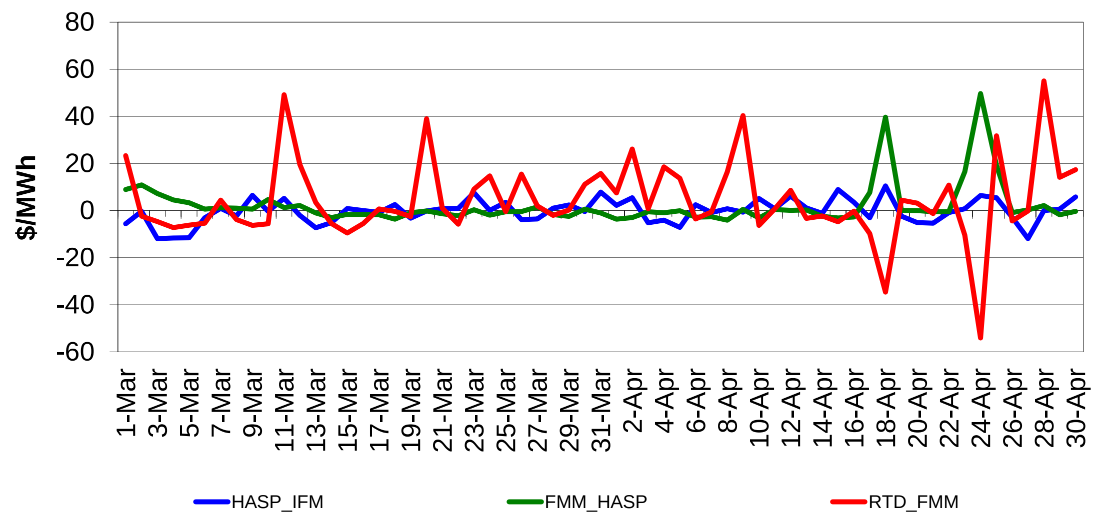
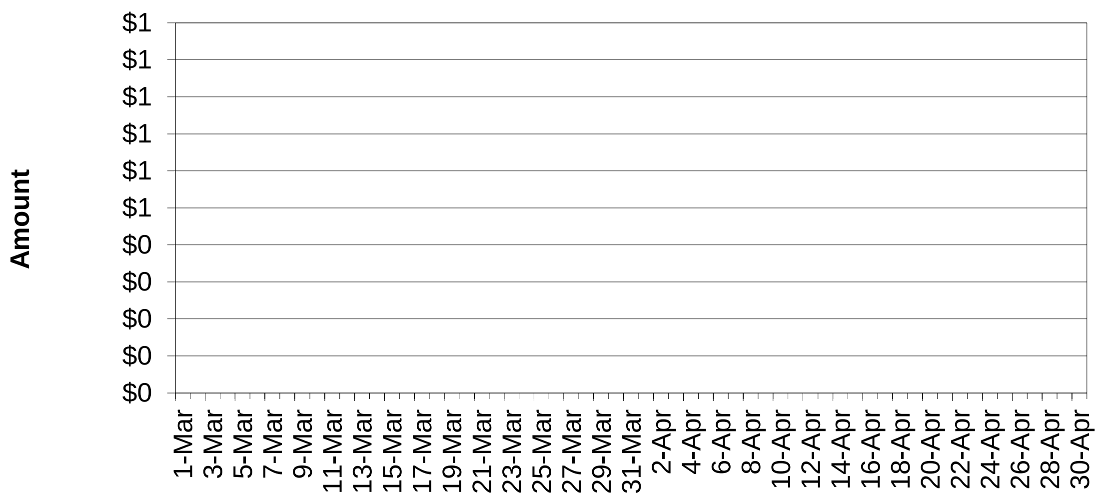


Figure 98 shows the profits which convergence bidders receive from convergence bidding. It is the sum of three settlement charge codes (CC6013, CC6053, and CC6473).

Figure 98: Convergence Bidding Profits

The congestion revenue rights (CRR) settlement rule provides a targeted way of limiting CRR payments in cases when the CRR holders' convergence bids may increase their CRR payments. This rule addresses concerns that market participants might attempt to use convergence bids to manipulate the market prices at locations where they hold CRRs and thereby increase the profitability of their CRR holdings. Figure 99 shows the CRR settlement rule payment amount when CRR settlement rule applies. It is a reversal of the increase in CRR revenues attributable to convergence bidding.

Figure 99: CRR Settlement Rule Payment



Renewable Resource

Renewable Generation Curtailment

Figure 100 shows the monthly wind and solar VERs (variable energy resource) curtailment due to system wide condition or local congestion in RTD. Figure 101 shows the monthly wind and solar VERs (variable energy resource) curtailment by resource type respectively 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 economic bid, generation outage, ramping capacity, and etc. Self-schedule curtailment is defined as the resource's self-schedule minus its RTD schedule when RTD schedule is smaller 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.

Figure 100: Renewable Curtailment by Reason

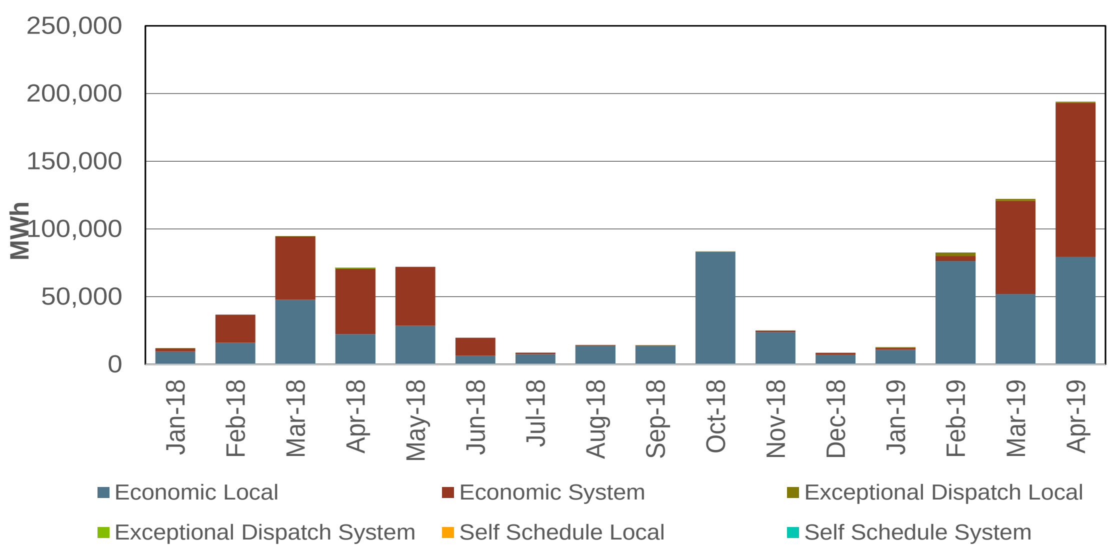
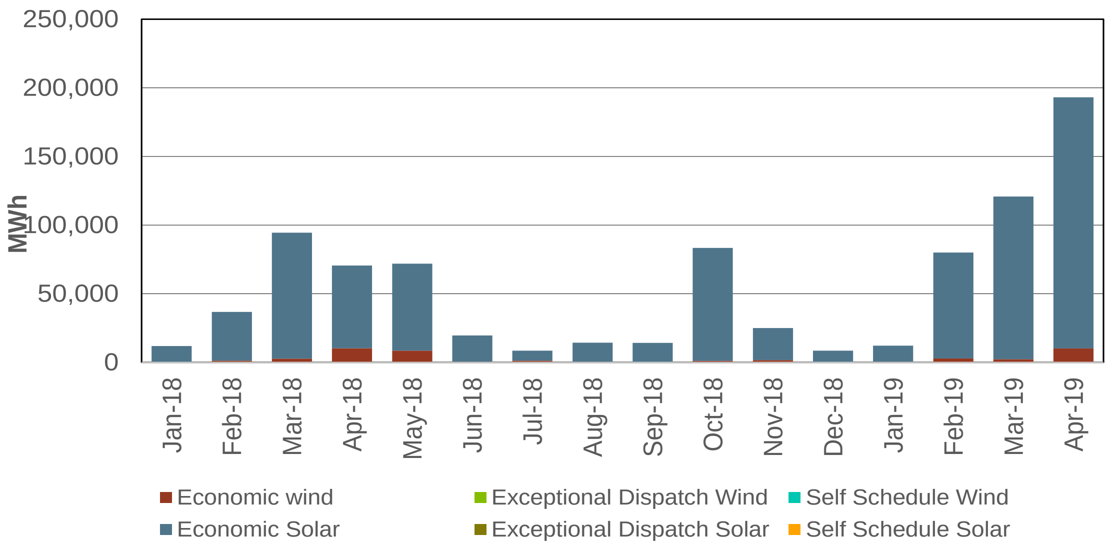


Figure 101: Renewable Curtailment by Resource Type



Flexible Ramping Product

On November 1, 2016 the ISO implemented two market products in the 15-minute and 5-minute markets: Flexible Ramp Up and Flexible Ramp 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 102 shows the flexible ramping up and down uncertainty payments. Figure 103 shows the flexible ramping forecast payment.

Figure 102: Flexible Ramping Up/down Uncertainty Payment

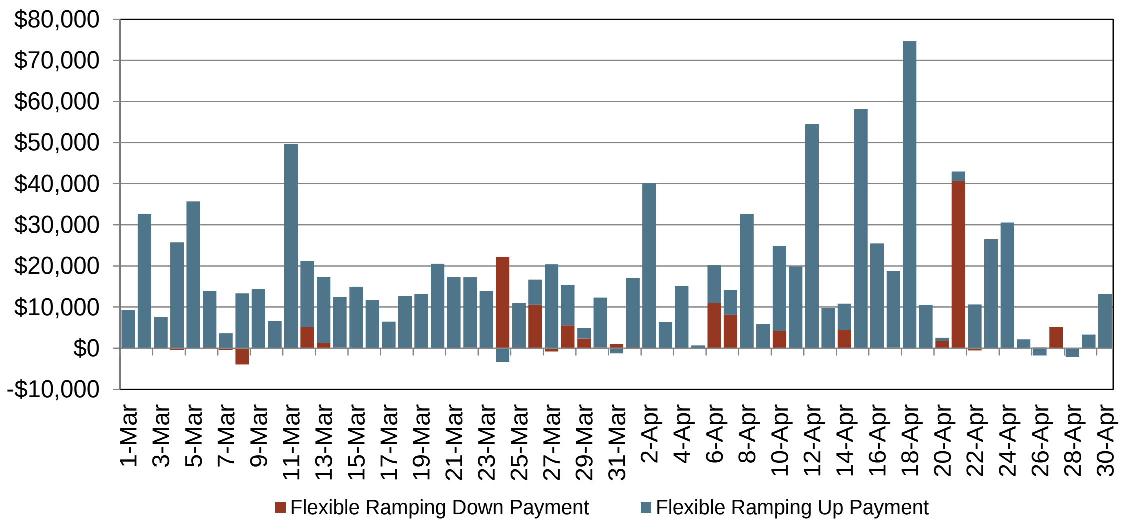
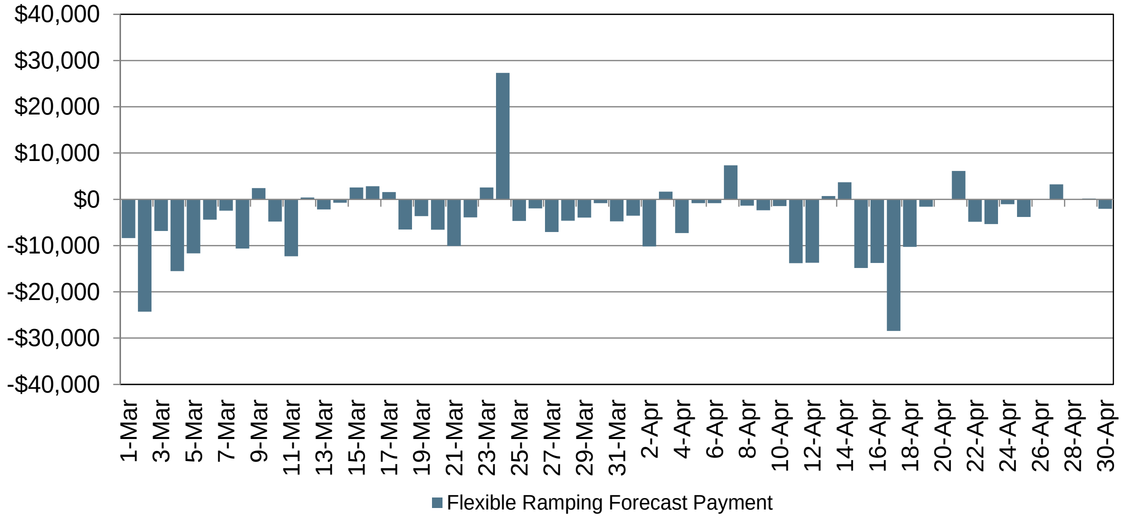


Figure 103: Flexible Ramping Forecast Payment



Indirect Market Performance Metrics

Cost Allocation Metrics

The two cost allocation metrics in this section are allocations whereby the preferred outcome would be for the allocation to be exactly zero. This is not always possible given the nature of the market systems; however, to the extent that they converge to a mean of zero the performance of the market is improved.

Imbalance Offset Costs[4]

The imbalance offset consists of three elements, namely the real-time congestion offset, real-time loss offset and the real-time energy offset.

1. The real-time congestion offset is defined as the real-time congestion fund net of the real-time congestion credit calculated as provided in tariff section 11.5.7. [5] In other words, the real-time congestion offset amount is the difference between the total congestion revenue collected from the real-time market and the total congestion revenue paid out in the real-time market for both energy and ancillary services. The real-time market includes both the hour-ahead scheduling process (HASP) and RTD market. The real-time congestion offset (CC 6774) is allocated to all scheduling coordinators based on measured demand, excluding demand associated with existing transmission rights (ETC), transmission ownership rights (TOR) or converted rights (CVR) self-schedules for which IFM and RTM congestion credits were provided.
2. The real-time loss offset is the difference between loss revenue collected in the real-time market and the loss revenue paid out in the real-time market. This real-time loss offset is allocated to all scheduling coordinators based on measured demand, excluding demand associated with TOR self-schedules.
3. The real-time energy offset is a residual calculation. The settlement amounts for the instructed imbalance energy (IIE), uninstructed imbalance energy (UIE), and unaccounted for energy (UFE) are summed up; this value represents the real-time imbalance revenue. The real-time congestion offset and the real-time loss offset are both subtracted from the real-time imbalance revenue; and the resultant residual value is known as the real-time imbalance energy offset. The real-time imbalance energy offset is allocated to all scheduling coordinators based on a pro rata share of their measured demand excluding demand quantity for the valid and balanced portion of TOR contract and self-schedules in real-time. The

[4] An appendix is provided with detailed explanations about this section.

[5] For further information regarding real-time congestion offset, please refer to the following BPM published on the California Independent System Operator Corporation website: CC 6774 Real Time Congestion Offset.doc

real-time imbalance energy offset allocation is the same as the real-time loss offset allocation.

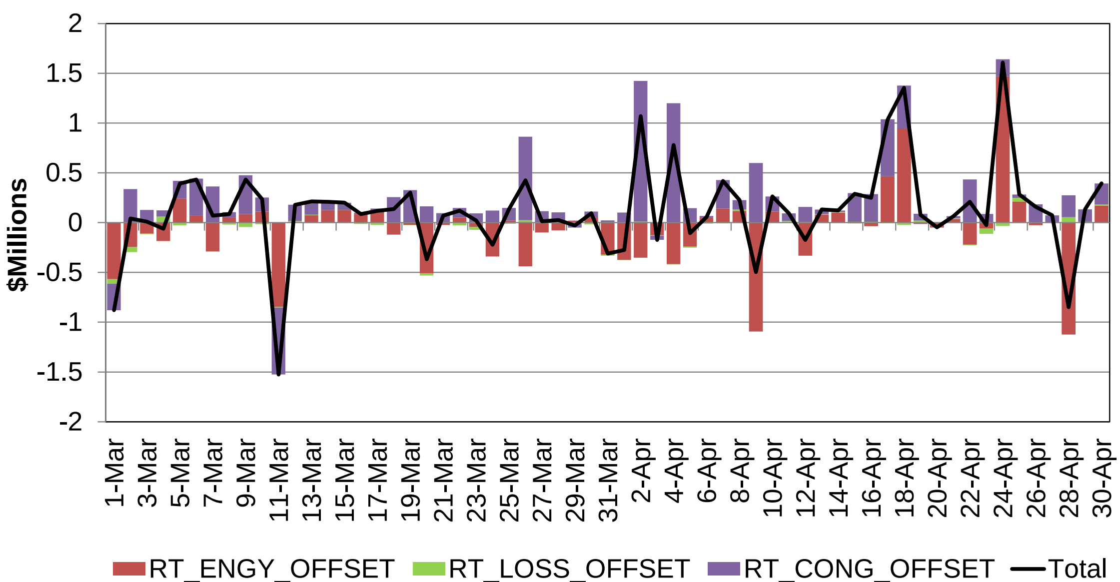
The imbalance offset amount can either be a net charge or a net payment to demand. Since the implementation of the new market, the imbalance offset amount has been a charge to measured demand. This settlement amount is mainly driven by the price divergence between the HASP and the RTD market and the use of average hourly price for the RT demand imbalance energy settlement.[6]

Figure 104 shows the daily real-time loss offset, real-time congestion offset, real-time imbalance energy offset costs and the net real-time imbalance offset cost. A positive value indicates a charge to measured demand and a negative value indicates a payment to measured demand. Table 9 below shows the monthly total real-time congestion offset, real-time loss offset and the real-time imbalance energy offset.

Table 9: Monthly Imbalance Offset Costs

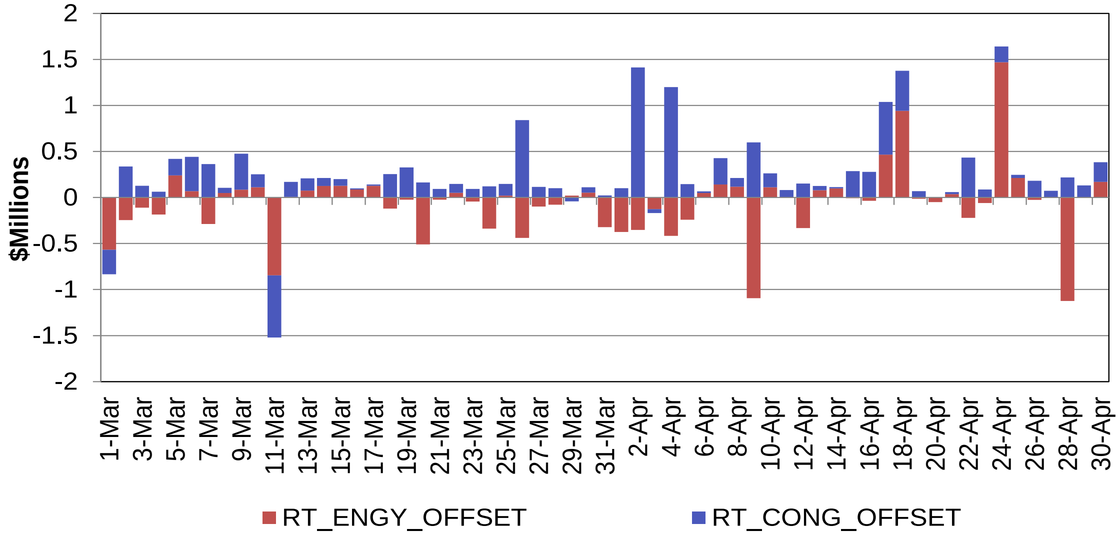
Month	RT ENGY OFFSET	RT LOSS OFFSET	RT CONG OFFSET
March-19	-$2,992,547	-$295,926	$3,941,178
April-19	-$577,455	$54,447	$7,454,467

Figure 104: Daily Real-Time Offset Allocation



[6] The root cause of real-time imbalance energy offset costs are explained in the issue paper “Analysis of Real-Time Imbalance Energy Offset” published on the ISO website at “http://www.caiso.com/2416/2416e7a84a9b0.pdf”

Figure 105: Real-Time Energy and Congestion Imbalance Offset



Bid Cost Recovery

Bid cost recovery (BCR) is the process by which the ISO ensures scheduling coordinators (SCs) are able to recover start-up costs (SUC), minimum load costs (MLC), and incremental energy bid costs.[7] The payment resulting from the ISO BCR process is known as a BCR payment which is paid through the settlements charge code 6620. The BCR payment is also known as the uplift payment or the make-whole payment in other LMP based energy markets. In order to recover SUC and MLC, a generator, pumped-storage unit, or resource-specific system resource must be committed by the ISO.

Bid cost recovery is paid to a generator when its market revenue is not sufficient to recover its bid-in costs; this condition is mainly driven by two reasons. First, when there are integer choices in the unit commitment and dispatch optimization software for the day-ahead and real-time market, there is an inherent potential for the optimization to select a solution which is optimal given the choice of these zero-one variables, but is not the globally optimal solution. In the day-ahead and real-time software there are a number of such integer choices, involving unit commitment state, the ability of the resource to provide particular ancillary services, and the unit's ramp range. As a result, there are a number of instances in which the solution is not globally optimal, and instances in which the dispatch is not optimal given the unit commitment. Second, there may be instances when certain constraints are not modeled in the day-ahead and real-time markets and operators have to manually dispatch a unit for reliability purposes. This manual dispatch, at times, distorts the clearing prices. Thus the mixed integer issue and the use of exceptional dispatch are the primary reasons for bid cost recovery payments

For each resource, the total SUC, MLC, bid costs, and market revenues from IFM, RUC, and RTM are netted together for each settlement Interval. If the difference between total costs and market revenues is positive in the relevant market, then the net amount represents a shortfall. If the difference is negative in the relevant market, the net amount represents a surplus. For each resource, the RUC and RTM shortfalls and surpluses are then netted over all hours of a trading day. As a result, surpluses from any of the ISO markets offset any shortfalls from the other markets over the entire trading day. If the net trading day amount is positive (a shortfall), then the resource receives a BCR payment equal to the net trading day amount. If a resource has shortfall in IFM, then it also receives BCR payment equals to its IFM shortfall.

[7] For more information regarding settlements calculation of bid cost recovery please refer to the following BPMs posted on the ISO website: CC 6620 Bid Cost Recovery Settlement.doc**,** IFM Net Amount.doc, RTM Net Amount.doc and RUC Net Amount.doc

A conceptual formula for BCR is shown below.

$$BCR_r = Max\left(0, \sum_h^H \sum_i^I IFM\_NET_r + \sum_h^H \sum_i^I RUC\_NET_r + \sum_h^H \sum_i^I RTM\_NET_r\right)$$

Where

H	Total number of hours in day
I	Total number interval in an hour
BCR_r	Bid cost recovery for each resource
IFM_NET_r	IFM net revenue for each resource
RUC_NET_r	RUC net revenue for each resource
RTM_NET_r	RTM net revenue for each resource

And

$$IFM\_NET_r = (IFM\_Bid\_Cost_r - IFM\_Revenue\_amount_r)$$

$$RUC\_NET_r = (RUC\_Bid\_Cost_r - RUC\_Revenue\_amount_r)$$

$$RTM\_NET_r = (RTM\_Bid\_Cost_r - RTM\_Revenue\_amount_r)$$

A generator also receives an uplift payment if it was dispatched manually, in other words, a resource also receives an uplift payment if it was dispatched through the exceptional dispatch process. A resource is compensated for its start up and minimum load cost through the BCR process, however, if the resource is dispatched above its Pmin in the real-time market by the exceptional dispatch process, then it receives a payment through the settlements exceptional dispatch charge codes (CC6482, CC6488, and CC6470). [8]

[8] For more information regarding settlements calculation of exceptional dispatch please refer to the following BPMs posted on the ISO website: CC 6488 Exceptional Dispatch Uplift Settlement.doc and CC 6482 Real Time Excess Cost for Instructed En.doc

Figure 106 shows the daily BCR exceptional dispatch payments which include the sum of the charge codes 6482, 6488, and 6470.

Figure 106: Daily Exceptional Dispatch Uplift Costs

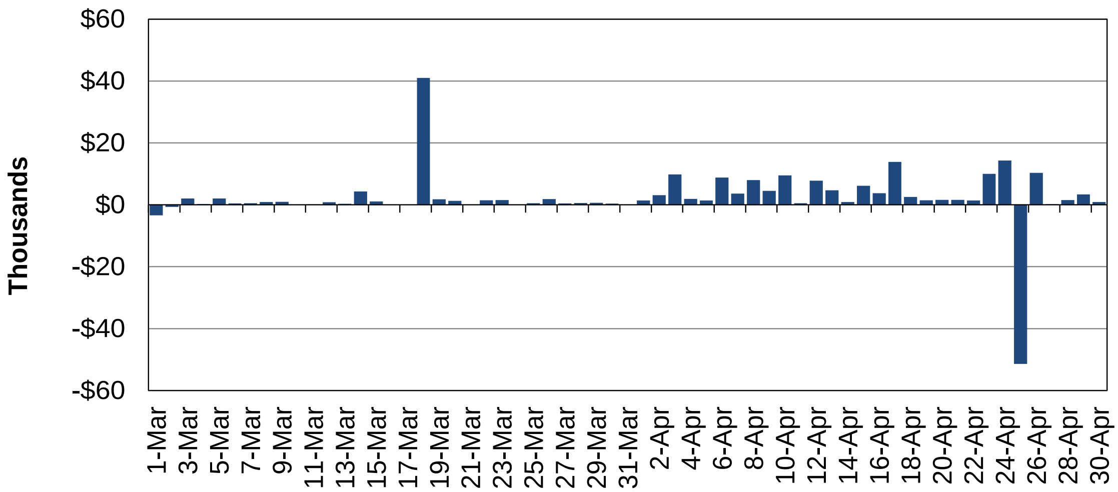


Figure 107 shows BCR allocation in the IFM, RUC and RTM markets. Figure 108 shows daily BCR allocation in the IFM, RUC and RTM markets by local capacity requirement area (LCR). Figure 109 shows monthly BCR allocation in the IFM, RUC and RTM markets by LCR. Figure 110 shows daily BCR allocation in the IFM, RUC and RTM markets by utility distribution company (UDC). Figure 111 shows monthly BCR allocation in the IFM, RUC and RTM markets by UDC.

Figure 107: Bid Cost Recovery Allocation

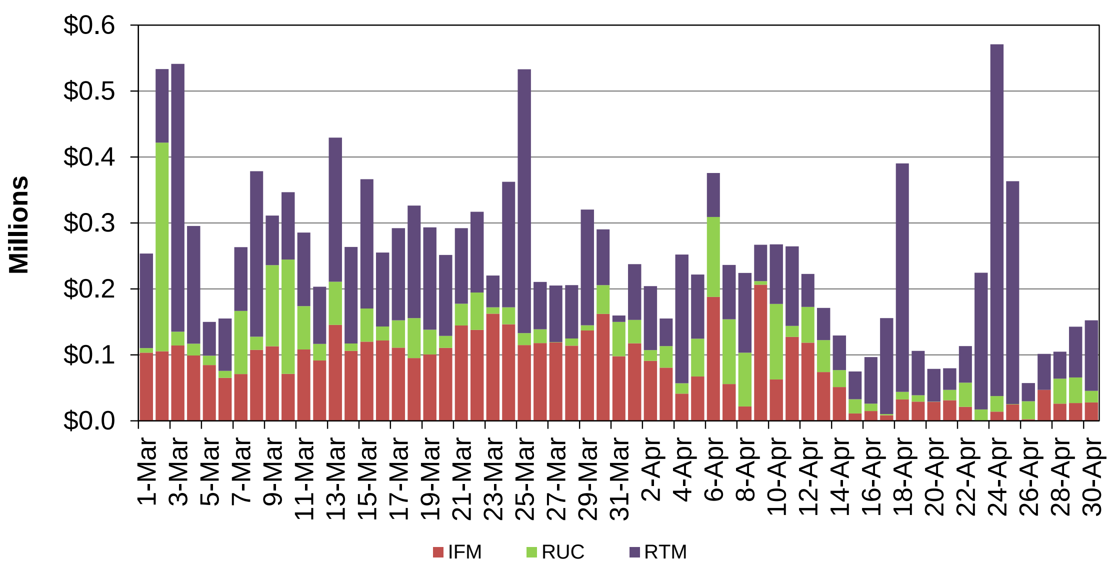


Figure 108: Bid Cost Recovery Allocation by LCR

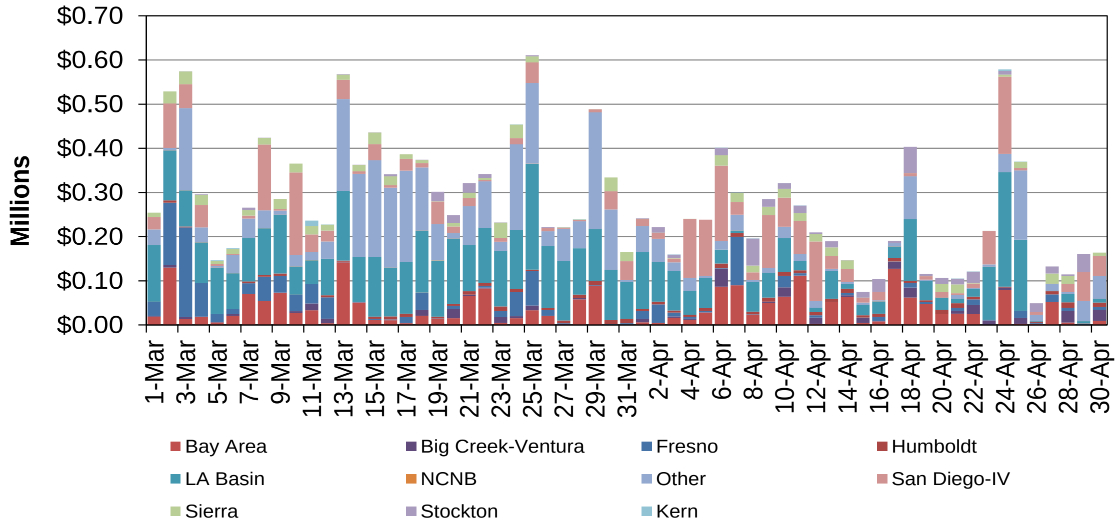


Figure 109: Monthly Bid Cost Recovery Allocation by LCR

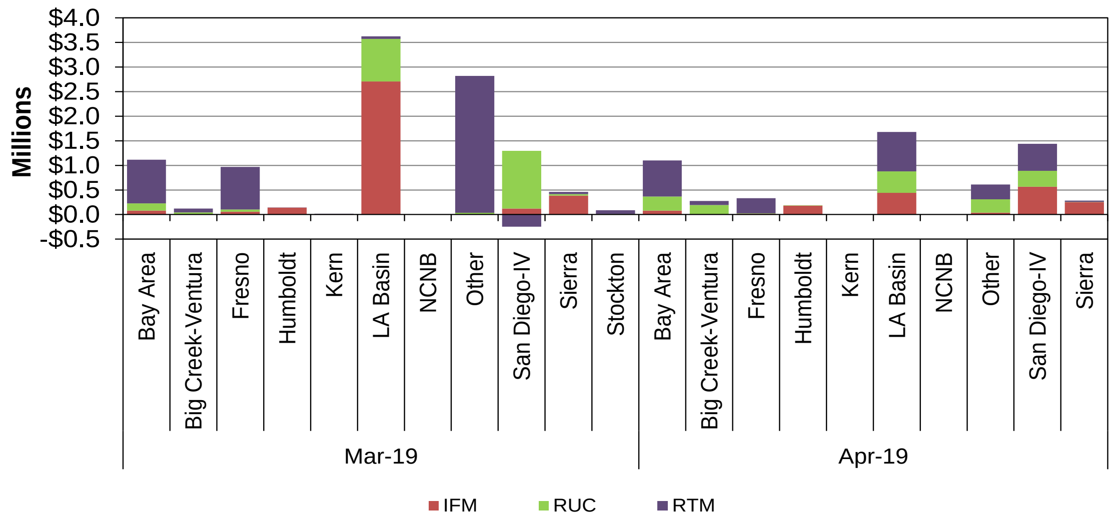


Figure 110: Bid Cost Recovery Allocation by UDC

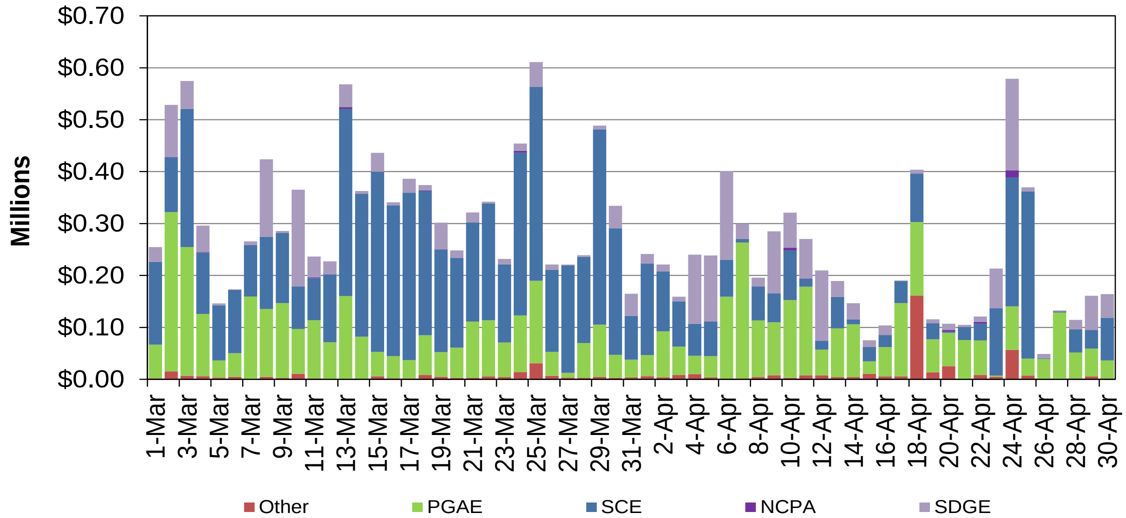


Figure 111: Monthly Bid Cost Recovery Allocation by UDC

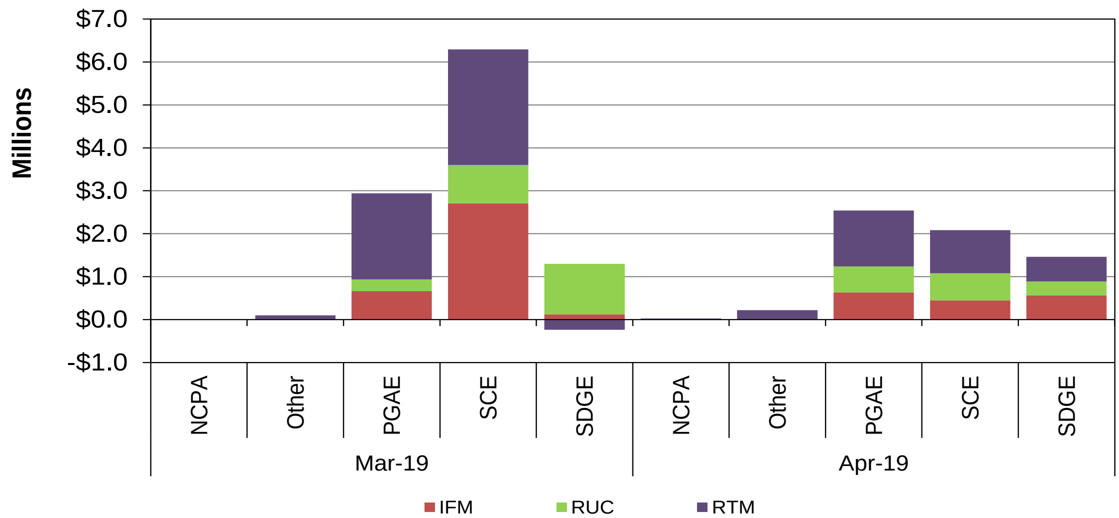


Figure 112 shows the bid cost recovery allocation in RUC by Minimum Load Cost (MLC), Capacity Cost (CAP), and Startup Cost (SUC). Figure 113 shows daily BCR allocation in RUC by cost components and LCR. Figure 114 shows monthly BCR allocation in RUC by cost components and LCR. Figure 115 shows daily BCR allocation in RUC by cost components and UDC. Figure 116 shows monthly BCR allocation in RUC by cost components and UDC.

Figure 112: Cost in RUC

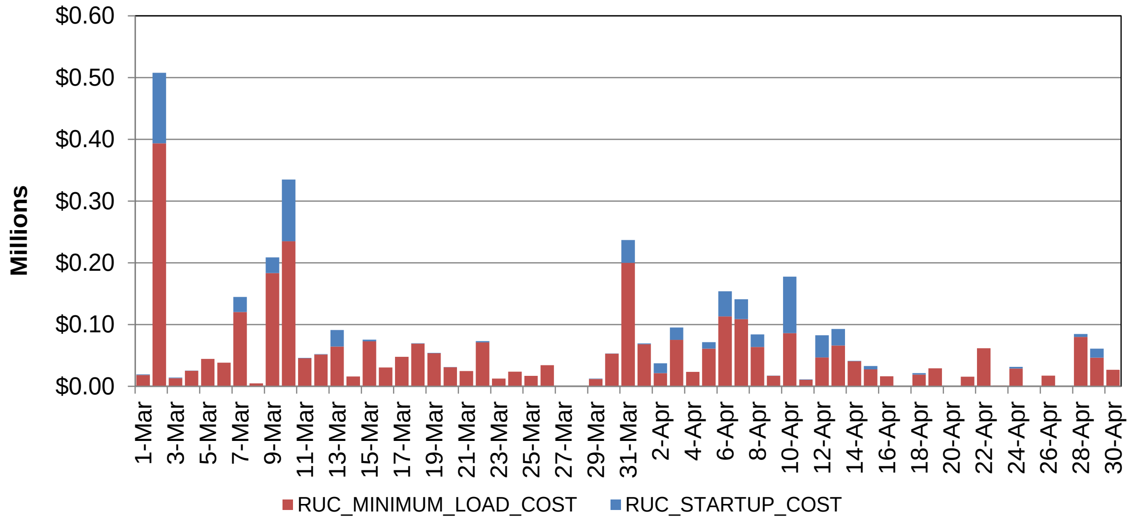


Figure 113: Cost in RUC by LCR

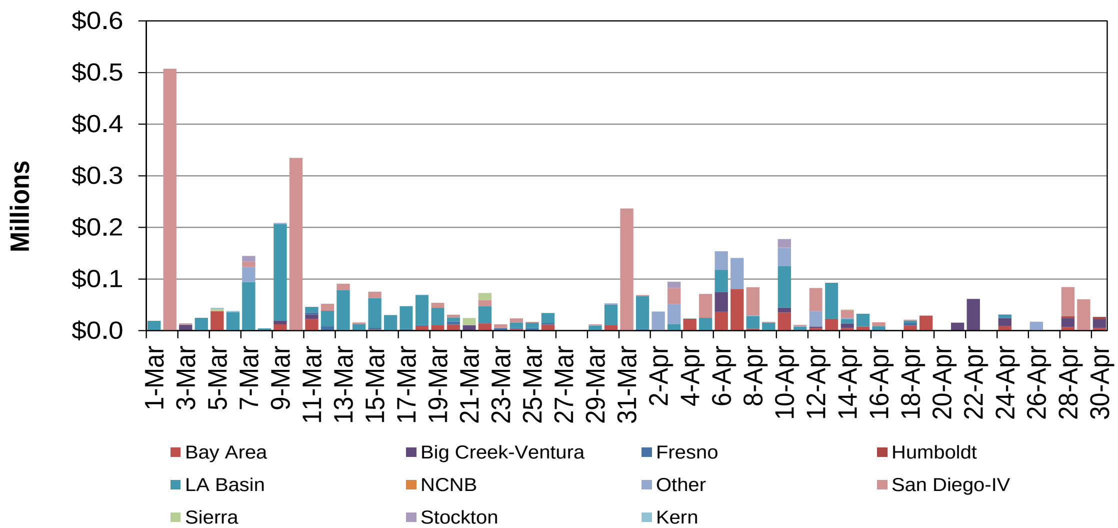


Figure 114: Monthly Cost in RUC by LCR

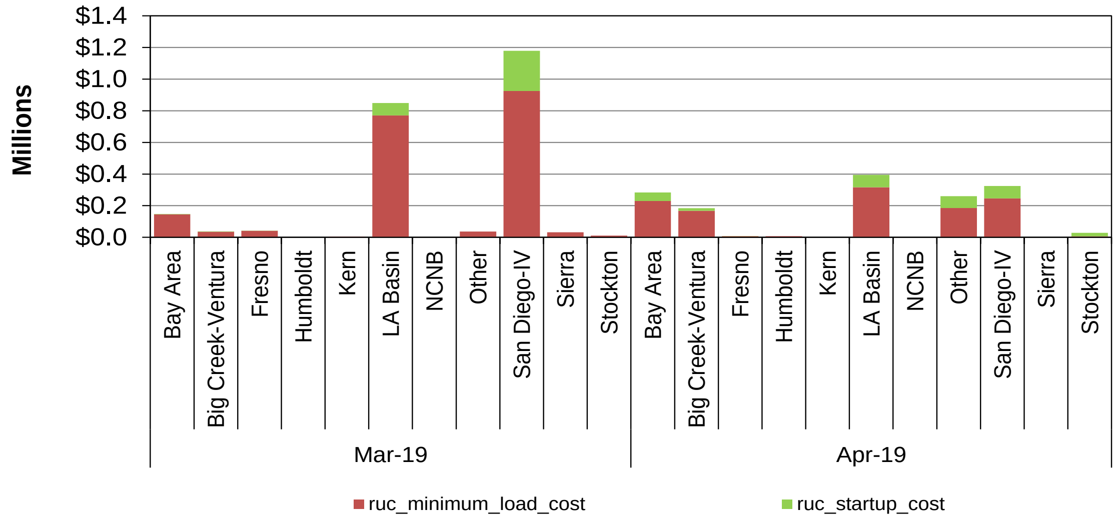


Figure 115: Cost in RUC by UDC

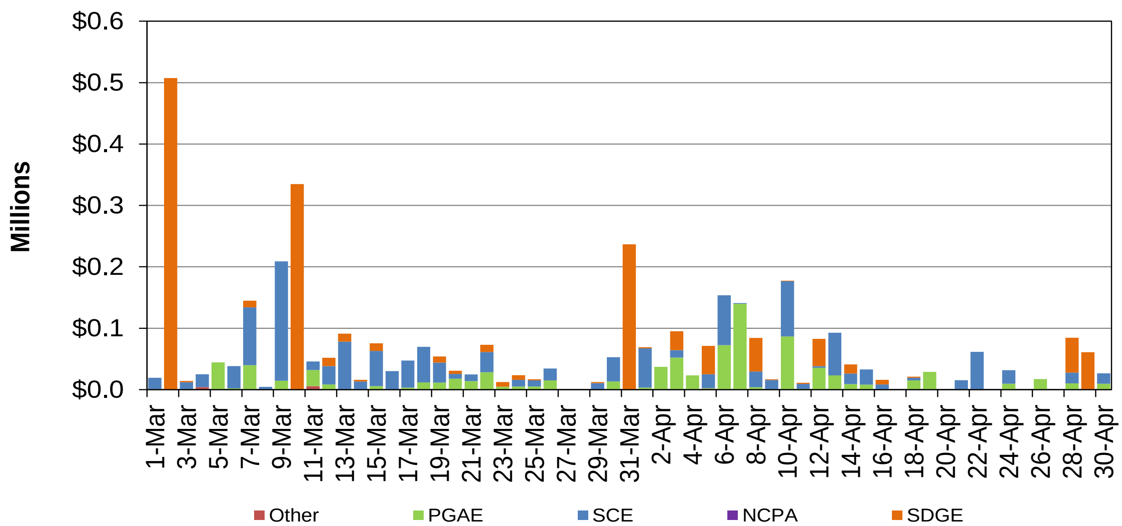


Figure 116: Monthly Cost in RUC by UDC

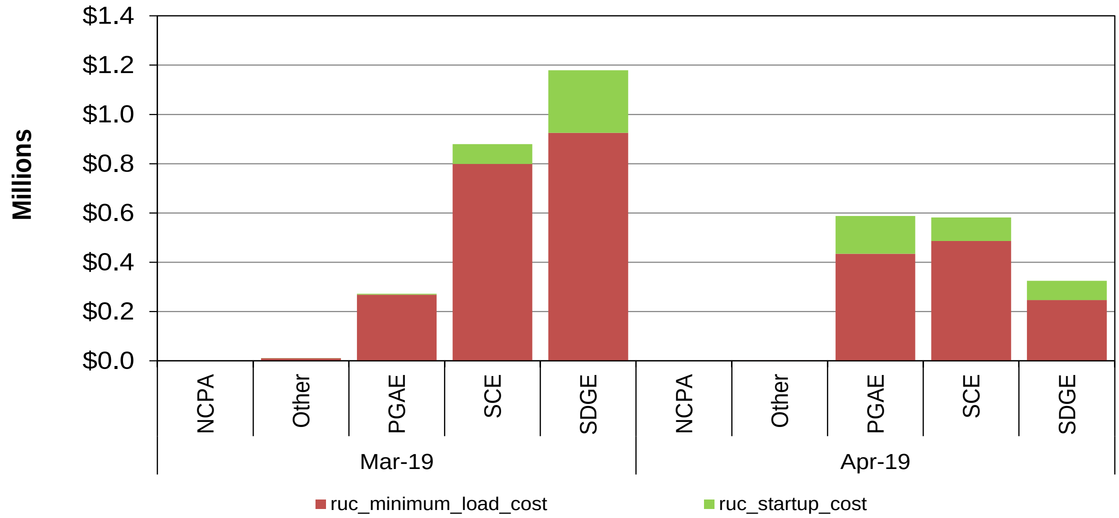


Figure 117 shows the bid cost recovery allocation in RT by Ancillary Service (AS), Energy, Minimum Load Cost (MLC), Startup cost (SUC), and Transition Cost. Figure 118 shows daily BCR allocation in RT by cost components and LCR. Figure 119 shows monthly BCR allocation in RT by cost components and LCR. Figure 120 shows daily BCR allocation in RT by cost components and UDC. Figure 121 shows monthly BCR allocation in RT by cost components and UDC.

Figure 117: Cost in RT

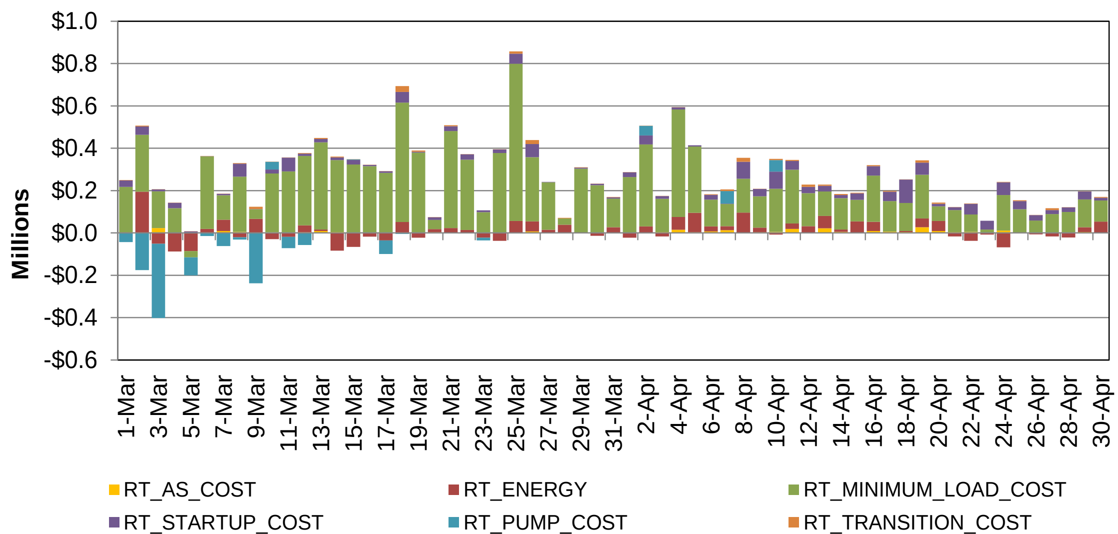


Figure 118: Cost in RT by LCR

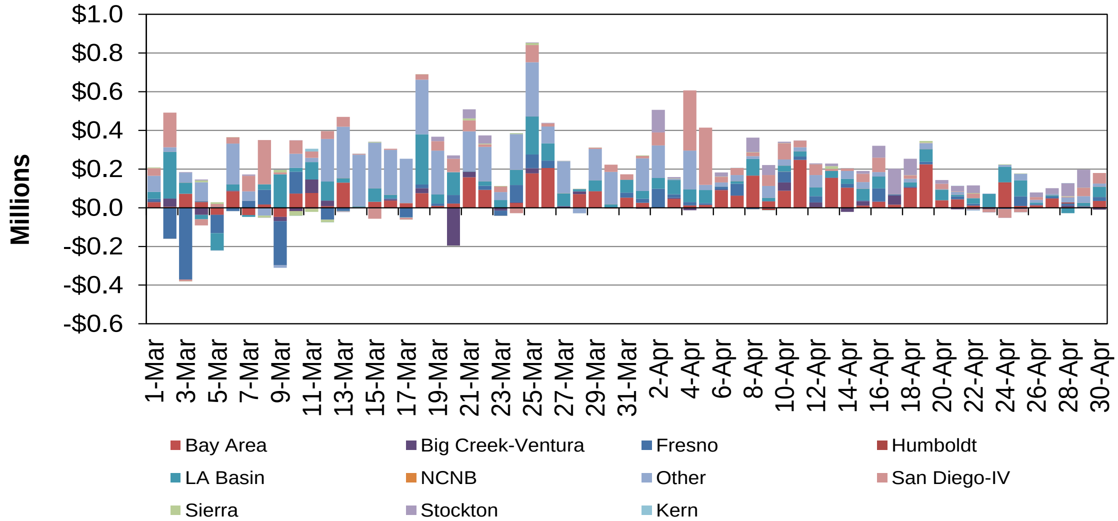


Figure 119: Monthly Cost in RT by LCR

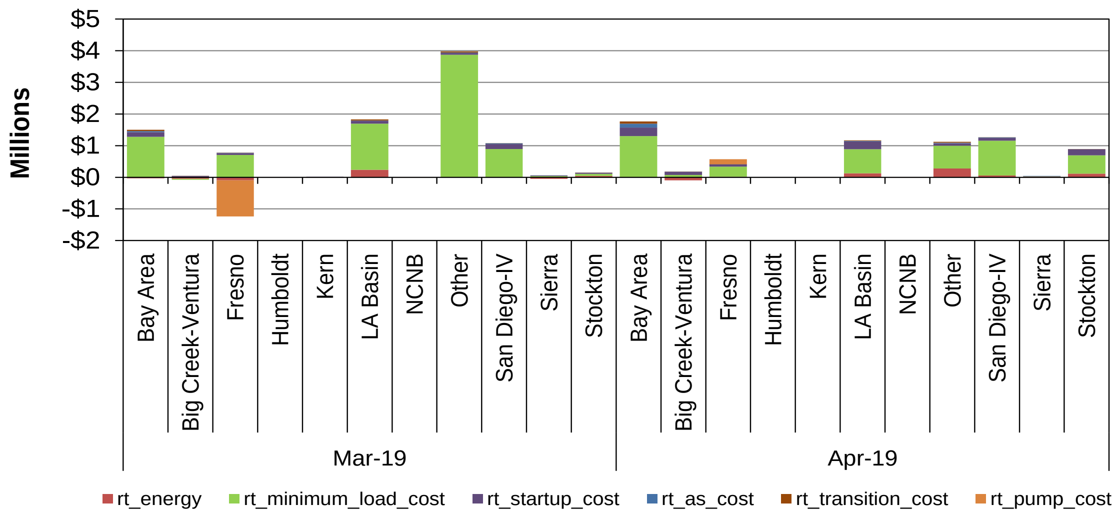


Figure 120: Cost in RT by UDC

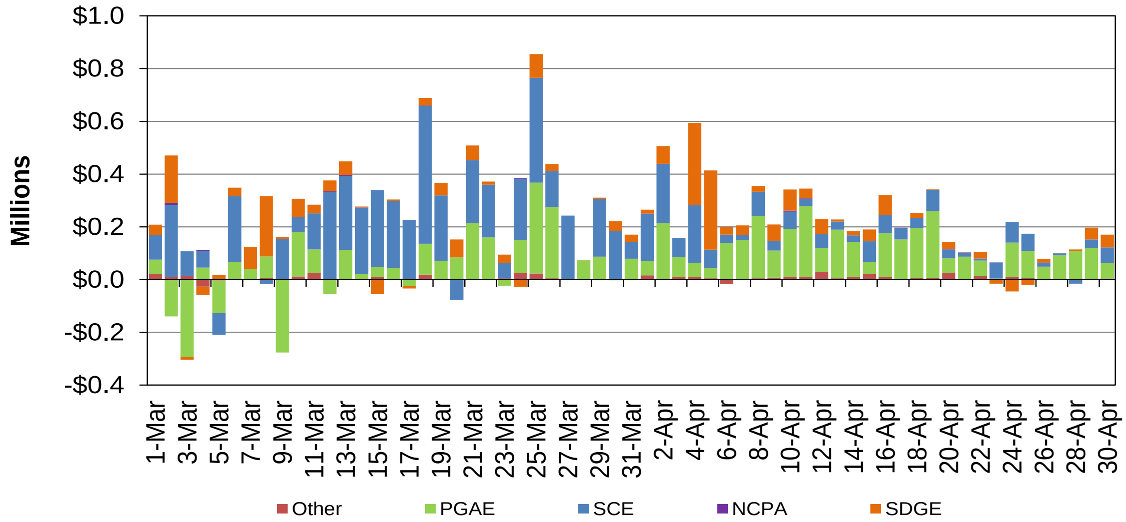


Figure 121: Monthly Cost in RT by UDC

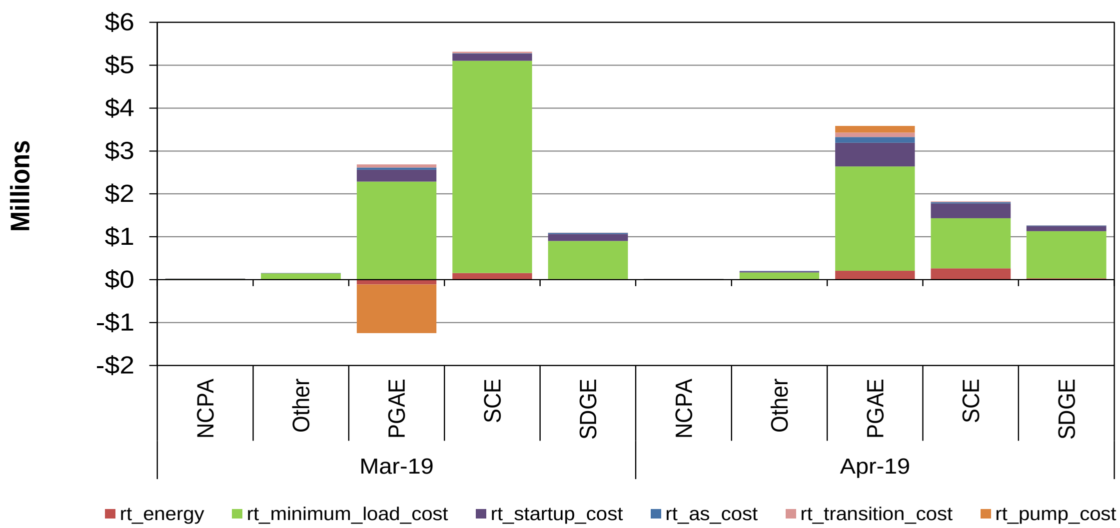


Figure 122 shows the bid cost recovery allocation in IFM by Ancillary Service Bid Cost, Energy, Minimum Load Cost (MLC), Startup cost, and Transition Cost. Figure 123 shows daily BCR allocation in IFM by cost components and LCR. Figure 124 shows monthly BCR allocation in IFM by cost components and LCR. Figure 125 shows daily BCR allocation in IFM by cost components and UDC. Figure 126 shows monthly BCR allocation in IFM by cost components and UDC.

Figure 122: Cost in IFM

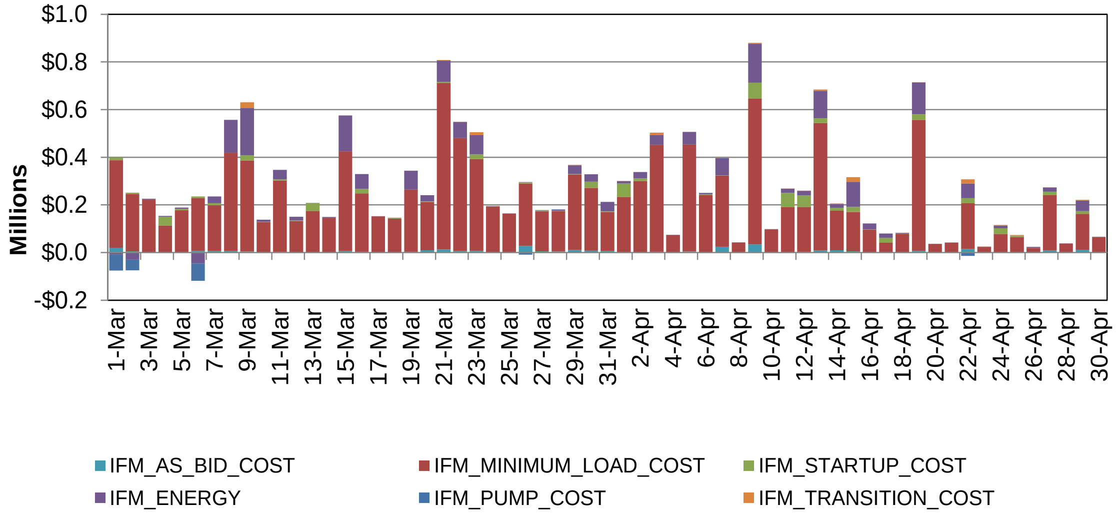


Figure 123: Cost in IFM by LCR

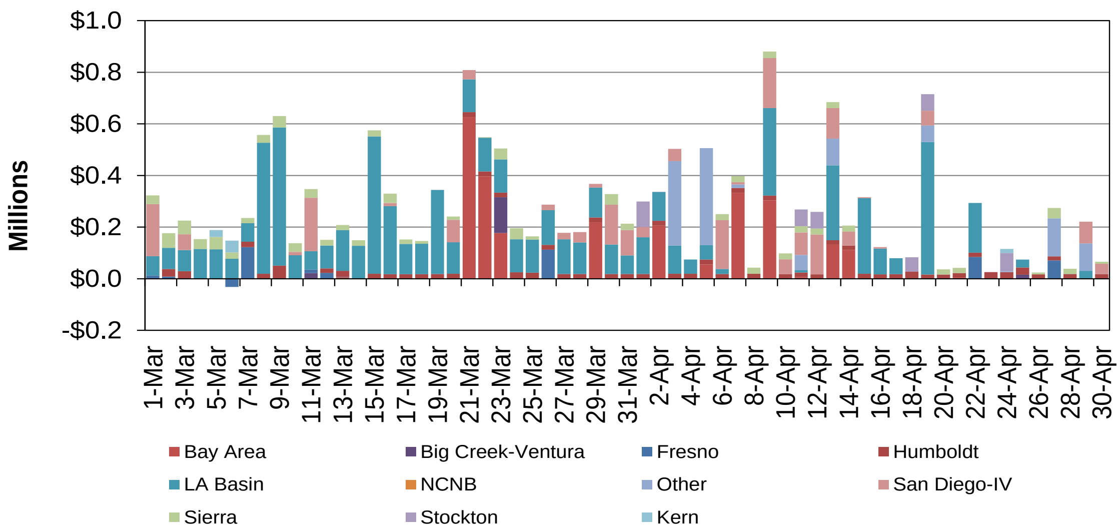


Figure 124: Monthly Cost in IFM by LCR

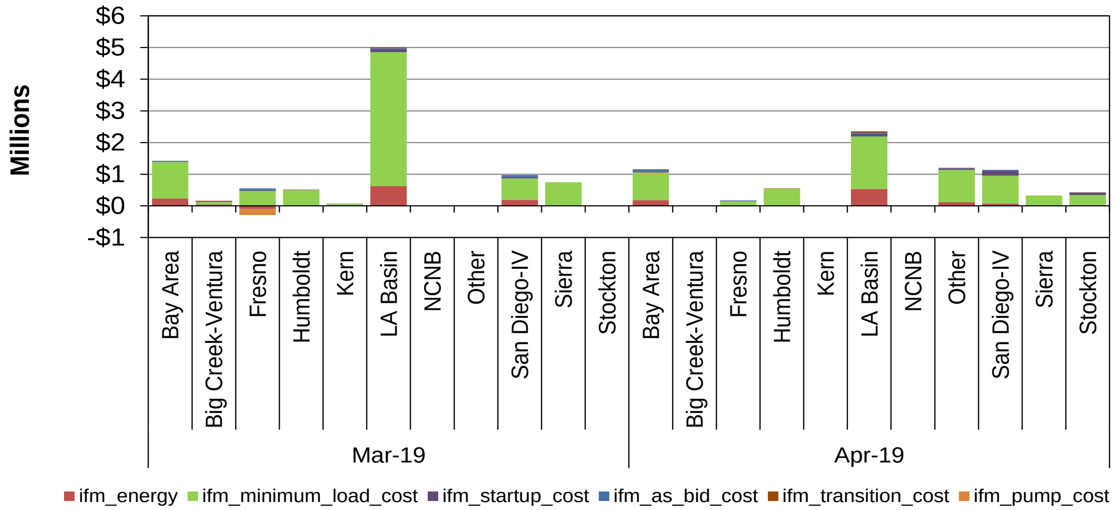


Figure 125: Cost in IFM by UDC

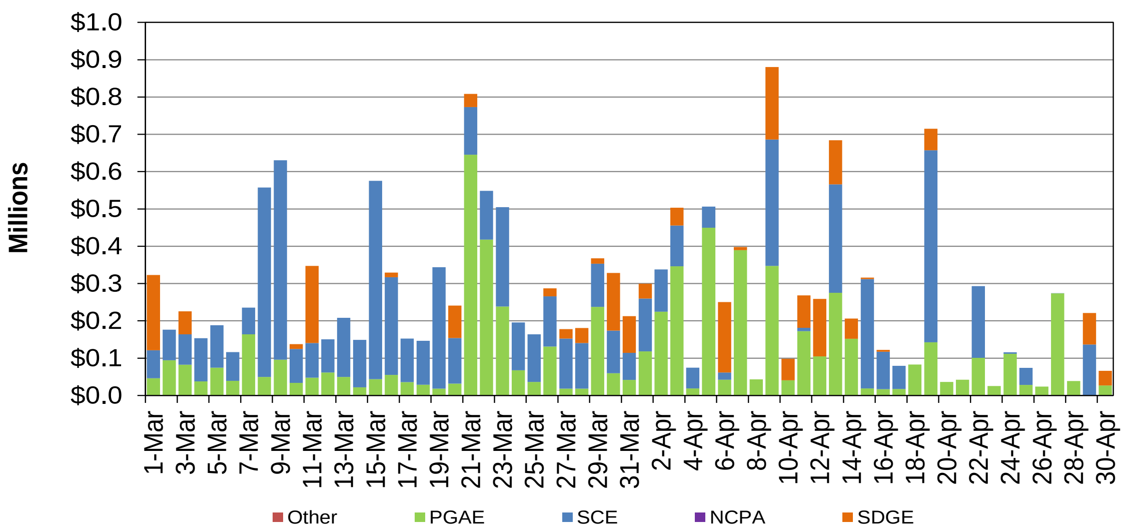
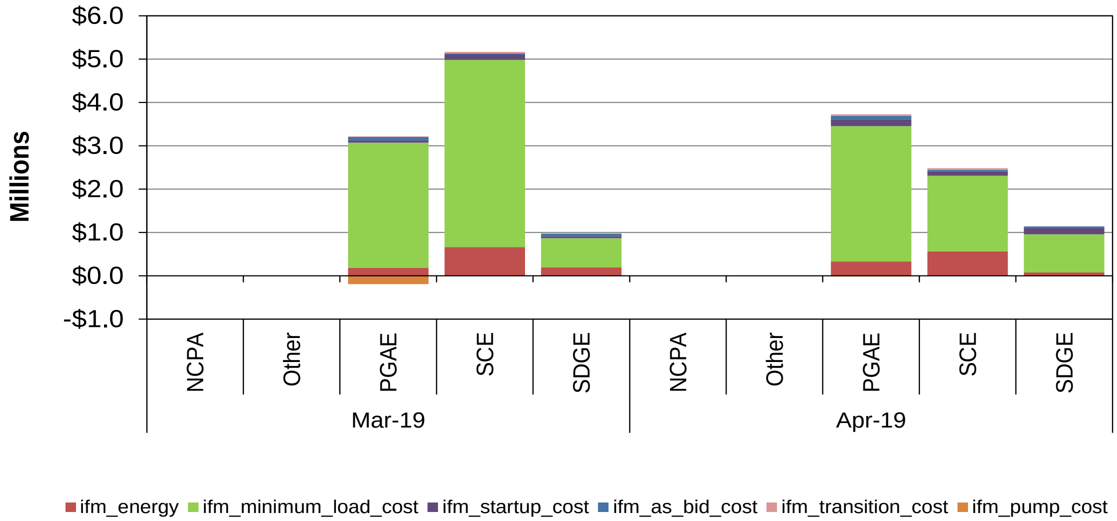


Figure 126: Monthly Cost in IFM by UDC



Make Whole Payment

The "make whole" payment mechanism applies to day-ahead demand and exports and HASP exports. It is designed to compensate market participants (demand and export) for adverse financial impacts if ex post price corrections have led to instances in which demand bids that were cleared in the market are no longer economic when evaluated against the corrected price. If the LMP correction is made in the upward direction that impacts demand in the day-ahead market or HASP such that a market participant's demand or export bid curve becomes uneconomic, then the ISO will calculate the make whole payment on an hourly basis. The make whole payment amount is calculated as the sum of MWhs in each of the cleared bid segments in the day-ahead schedule or HASP intertie schedule for the affected resource, multiplied by the maximum of zero or the corrected LMP minus the bid segment price. Table 10 shows the summary of make whole payments in both day-ahead and real-time markets.

Table 10: Summary of Make Whole Payment

Month	Market Type	Make Whole Payment
April	DA	$0
April	FMM	$0

Market Software Metrics

Market performance is obviously confounded by software issues, which vary in importance levels, however amongst these various measures the failure of a market run is the most obvious failure.

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 .[9] Pursuant to section 7.7.15 of the ISO tariff, the ISO can take one or more of a number of specified actions in the event of a market disruption, to prevent a market disruption, or to minimize the extent of a market disruption.

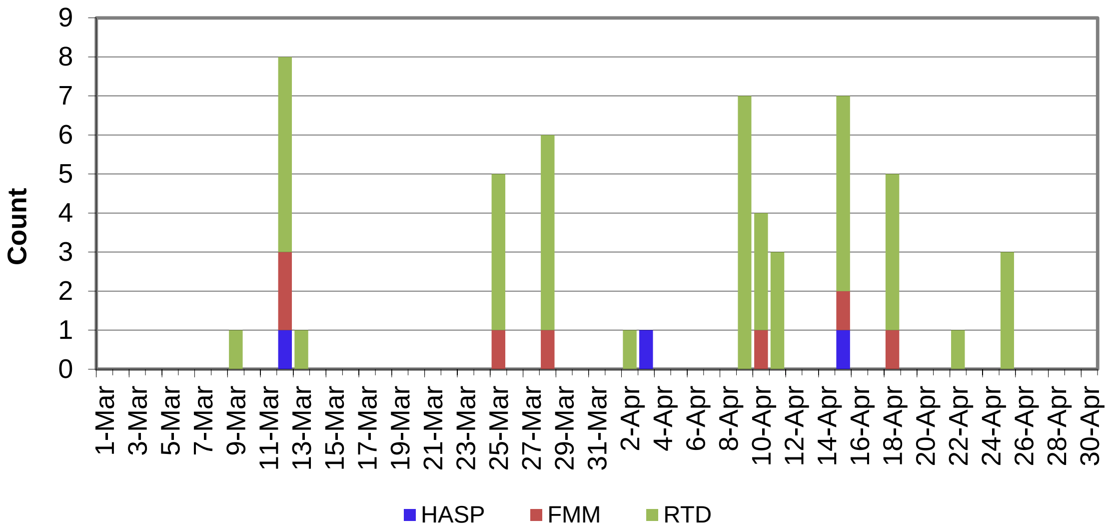
For each of the ISO markets, Table 11 lists the number of market disruptions and the number of times that the ISO removed bids (including self-schedules) during the time period covered by this report. Figure 127 shows the frequency of HASP, RTUC, and RTD failures in the current month.

Table 11: Summary of Market Disruption

Type of CAISO Market	Market Disruption or Reportable Events	Removal of Bids (including Self-Schedules)
Day-Ahead		
IFM	0	0
RUC	0	0
Real-Time		
FMM Interval 1	3	0
FMM Interval 2	2	0
FMM Interval 3	0	0
FMM Interval 4	0	0
Real-Time Dispatch	27	0

[9] These system operation issues or system emergencies are referred to in sections 7.6 and 7.7, respectively, of the CAISO tariff. CAISO tariff, appendix A, definition of market disruption. Capitalized terms not otherwise defined herein have the meanings set forth in the CAISO tariff.

Figure 127: Frequency of Market Disruption



System Parameter Excursion

The power balance constraint is one of the requirements that is enforced in the market all the time to ensure the balance between electricity generation and demand. The tendency for 5-minute real-time prices to exceed hour-ahead prices is driven in large part by extreme price spikes in the real-time market when the market software meets the system-wide power balance constraint with small and temporary amounts of regulation resources rather than with energy resources. When this relaxation occurs, the system imposes a penalty price, which then affects the energy prices in the pricing run. This constraint can occur in two different ways:

- When the market software dispatches regulation up as supply to meet projected demand, this represents a "shortage" constraint that causes prices to spike upwards to the $750/MWh bid cap.

- When the market software dispatches regulation down to balance supply with projected demand, this represents an "excess" constraint that causes prices to spike downwards to the -$30/MWh bid floor.

Figure 128 presents how often the power balance constraint is relaxed by day and by class of shortage during the real-time dispatch. Figure 129 how often the power balance constraint is relaxed by day and by class of excess during the real-time dispatch.

Figure 128: Frequency and Average MW of Shortage

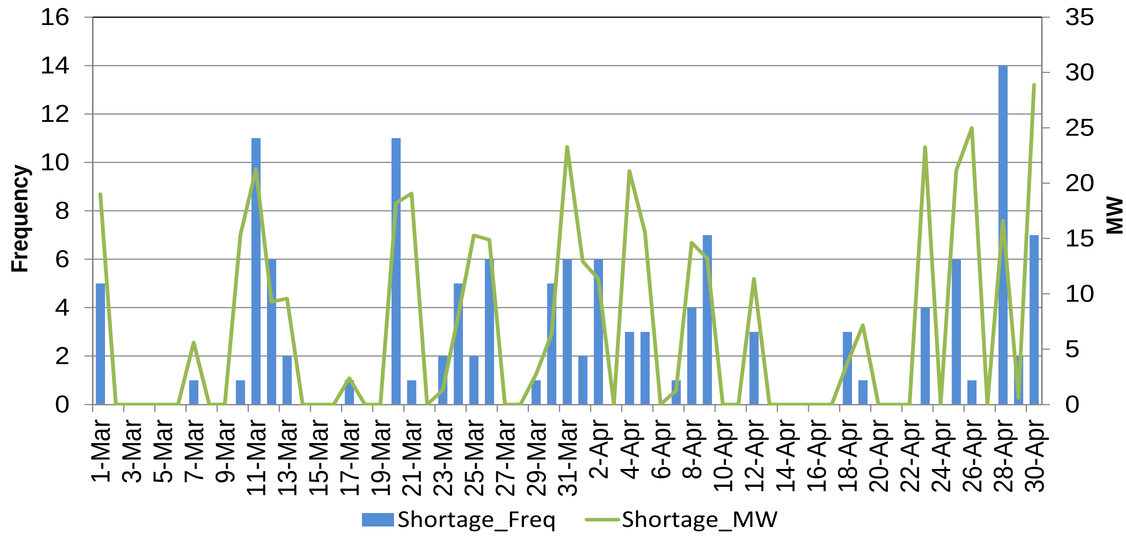
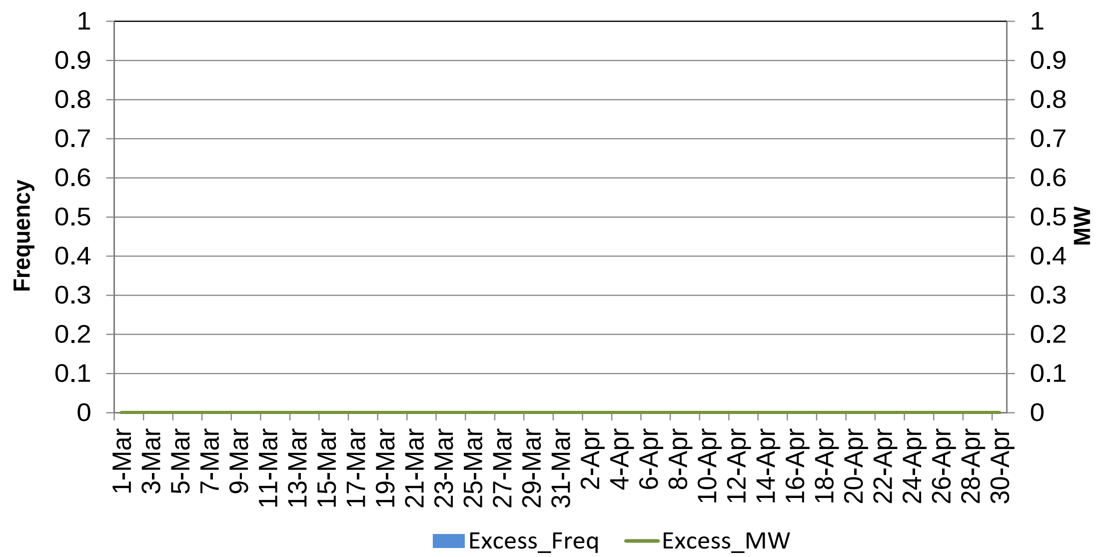


Figure 129: Frequency and Average MW of Excess

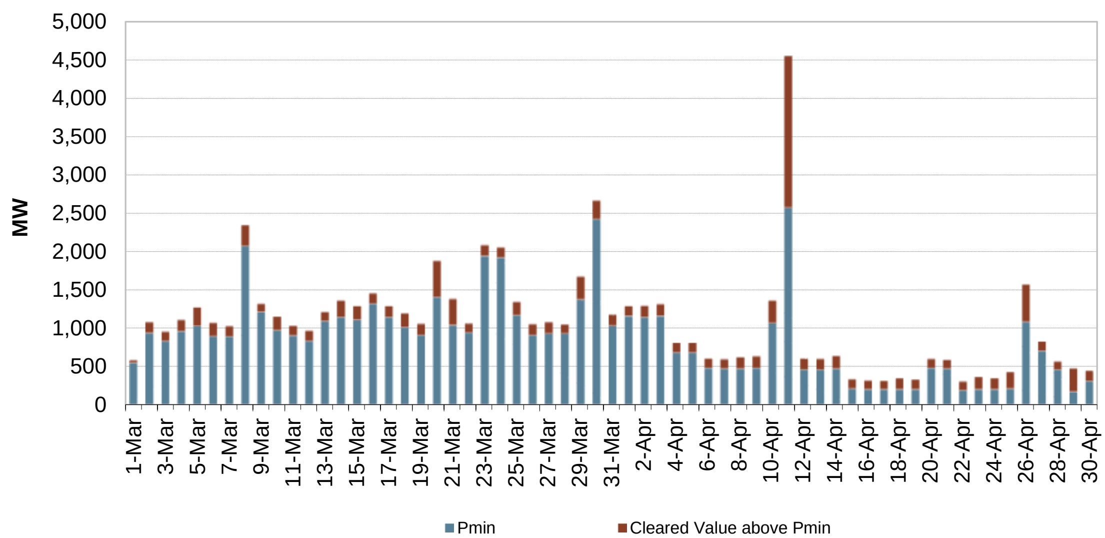


Analysis of Minimum Online Capacity

The ISO utilizes the minimum online capacity (MOC) constraint to address the operational needs of certain operating procedures that require a minimum quantity of committed online resources in order to maintain reliability[10.] MOC was deployed into the software systems with the expectation that it would commit an appropriate set of resources that were previously satisfied by either exceptional dispatch or nomogram enforcement in RUC, thus reducing the potential for over-commitment in RUC. This section studies the unit commitments driven by MOC constraint in IFM for the reporting period.

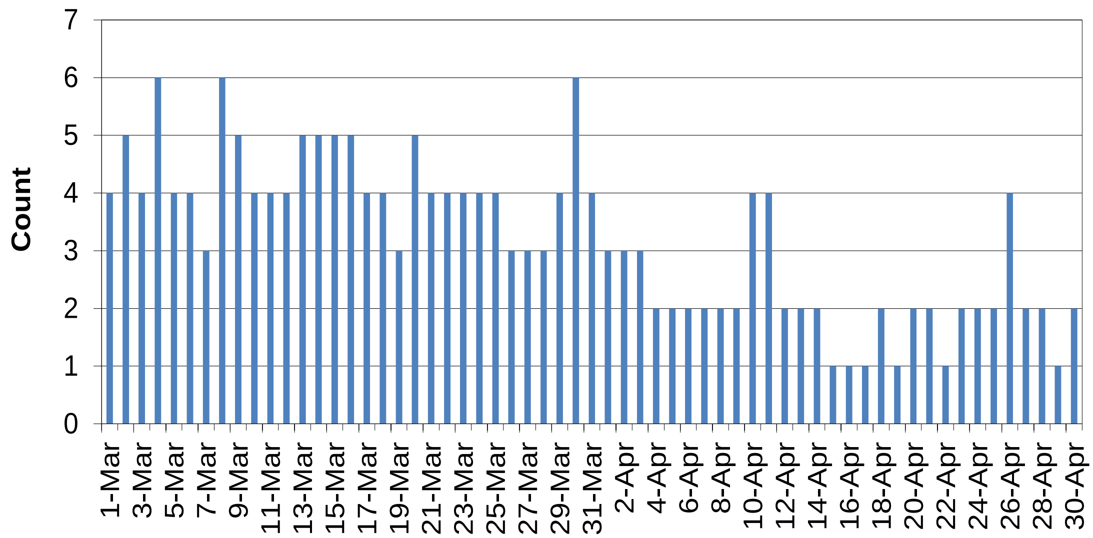
Figure 130 below shows total Pmin and cleared value of the MOC units in the market. Figure 131 summarizes the number of MOC units.

Figure 130: MOC Unit Commitment and Dispatch



[10] For more details, please refer to the technical bulletin at **http://www.caiso.com/271d/271dedc860760.pdf**.

Figure 131: Daily Count of MOC Units



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 12 below shows the monthly average actual availability, total non-availability charge, and total availability incentive payment. Starting from May 2018, the ISO reports the system RA average actual availability and flexible RA average actual availability separately.

Table 12: Resource Adequacy Availability and Payment

Jan18	$921,031	-$921,031	97.67%		
Feb18	$1,945,971	-$1,793,865	95.83%		
Mar18	$3,151,376	-$1,589,703	93.27%		
Apr18	$2,913,679	-$1,608,256	93.01%		
May18	$5,621,558	-$2,346,666		92.79%	91.75%
Jun18	$4,750,039	-$2,622,844		95.08%	92.79%
Jul18	$2,707,179	-$2,892,873		94.56%	96.58%
Aug18	$3,916,827	-$2,812,434		91.29%	96.91%
Sep18	$1,438,373	-$3,186,317		98.08%	97.38%
Oct18	$2,446,741	-$2,253,949		95.33%	96.34%
Nov18	$1,482,568	-$2,031,607		97.27%	96.94%
Dec18	$1,352,580	-$2,092,658		97.68%	96.77%
Jan19	$1,430,981	-$1,430,981		98.25%	96.70%
Feb19	$1,845,678	-$1,836,610		95.76%	97.27%
Mar19	$2,343,144	-$2,163,512		96.57%	95.25%
Apr19	$3,787,853	-$2,033,788		93.77%	93.53%

Manual Market Adjustment

Exceptional Dispatch

Broadly speaking there are two types of exceptional dispatch, namely commitments and energy dispatches. Although commitments can commit a unit on or off, generally most of the exceptional dispatch commitments are "on" commitments and "off" commitments are rare. Likewise regarding energy dispatches the dispatch can either be incremental or decremental. Incremental dispatches are the most common, and decremental dispatches are infrequent but not rare. Regarding the timing of these dispatches, the ISO can issue exceptional dispatch instructions for a resource as a pre day-ahead market unit commitment, a post day-ahead market unit commitment or a real-time energy dispatch. A pre day-ahead market unit commitment is an exceptional dispatch instruction committing a resource at or above its physical minimum (Pmin) operating level prior to any of the day-ahead market runs. A post-day-ahead market unit commitment is an exceptional dispatch instruction committing a resource at or above its Pmin operating level in the real-time market.

A real-time exceptional dispatch instructs a resource to operate at or above its physical minimum operating point. For the purposes of this report, a real-time exceptional energy dispatch above the resource's day-ahead award is considered an incremental exceptional dispatch instruction and a real-time exceptional energy dispatch below the day-ahead award is considered a decremental dispatch instruction. The ISO issues exceptional dispatch instructions primarily to manage constraints that are not modeled in the market software. In addition to constraints, the ISO also issues exceptional dispatch instructions relating to reliability requirements and, on occasion for software limitations and software failures. Reliability requirements are calculated for both local area and the system wide needs, and are classified into various requirements including local generation, transmission management, non-modeled transmission outages, and transmission management due to fires, ramping requirements and intertie emergency assistance. Whenever the ISO issues an exceptional dispatch instruction, these instructions are logged by the operators into the scheduling and logging system (SLIC), including an associated reason for each exceptional dispatch instruction.

Figure 132 below shows exceptional dispatch volume by market type: day-ahead, and real-time. All post-day-ahead exceptional dispatches are classified as real-time because those exceptional dispatches are settled in the real-time market. The total volume is calculated as sum of physical minimum of the resource, uneconomical incremental exceptional dispatch or uneconomical decremental exceptional dispatch. For instance, if resource A is exceptionally dispatched in the day-ahead market at its Pmin of 20 MW from 1:00AM till 5:00 AM, then its exceptional dispatch volume is 80 MWh. In another example consider that resource B is exceptionally dispatched in real-time market at its Pmin of 20MW from 1:00 AM till 5:00AM, and again exceptionally dispatched to 60 MW from 3:00 till 5:00 AM. However, it is economical at 60MW from 4:00 AM till 5:00 AM, then the total exceptional dispatch volume of this resource is sum of 80 MWh (20 MW* 4hrs at minimum load) and 40 MWh ((60-20)MW * 1 hr of incremental dispatch), which is equal to 120 MWh. Note that even though this resource was exceptionally dispatched to 60 MW for 2 hours, it is uneconomical for only one hour, so only those MWh are shown in the graph.

Figure 132: Total Exceptional Dispatch Volume (MWh) by Market Type

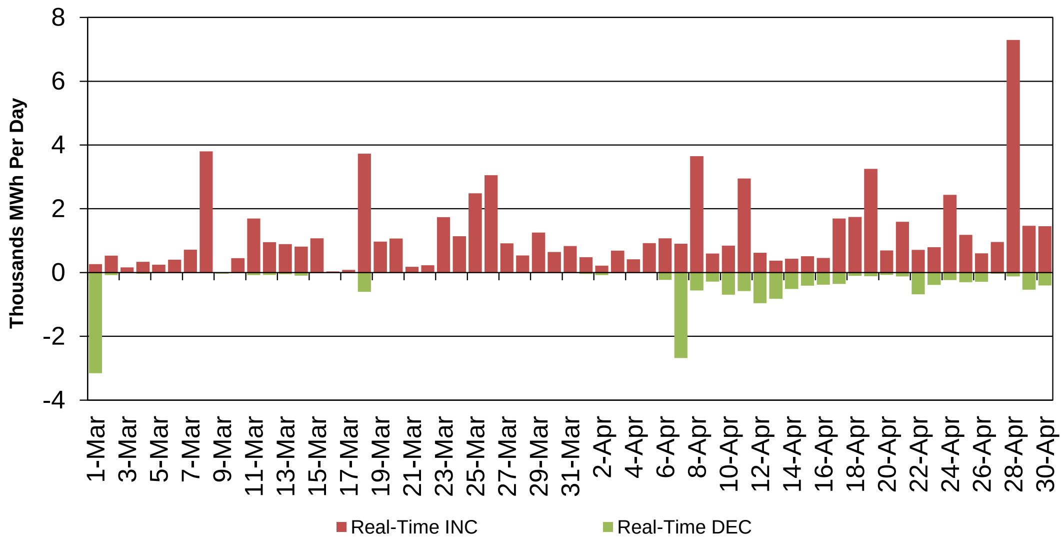


Figure 133 below shows the exceptional dispatch volume by reason.

Figure 133: Total Exceptional Dispatch Volume (MWh) by Reason

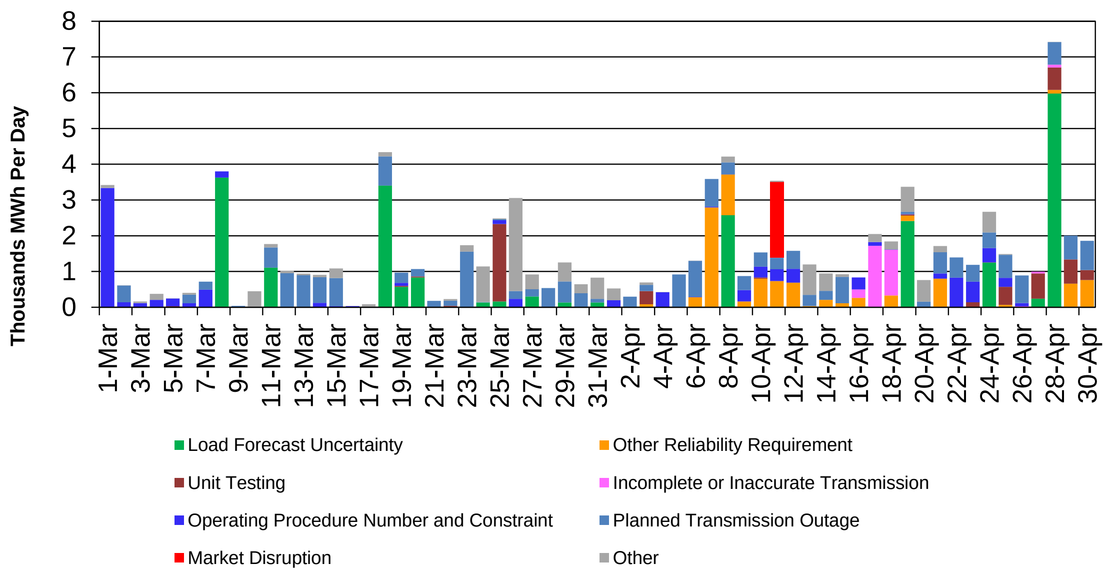
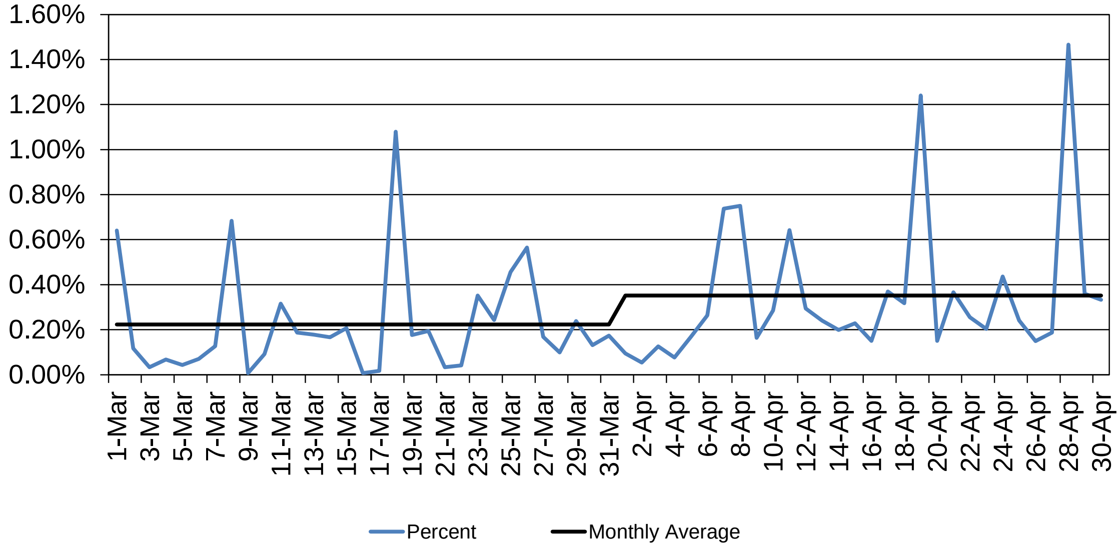


Figure 134 shows the total MWh quantity of exceptional dispatch as a percentage of the total load, where the total load is equal to internal generation plus imports minus exports. The horizontal lines in the figure identify the monthly averages for each month.

Figure 134: Exceptional Dispatch Percent of Total Load



Blocking of Intertie Schedules

Intertie blocking is the process of blocking the HASP schedule for interties and reverting their schedules to day-ahead awards. Usually intertie blocking is required for reliability reasons. Intertie blocking can occur at three different levels: i) full block of interties, in which all intertie schedules from HASP are blocked, ii) partial blocking, in which operators can selectively block certain interties, and iii) resource blocking, in which specific resources that belong to an intertie can be blocked. When an intertie is blocked, all resources belonging to it are consequently blocked. In HASP, intertie schedules may vary with respect to day-ahead awards, and there may be resources that have no changes between their DA awards and their HASP schedules; in such instances, intertie blocking has no impact on these resources. The metrics developed for intertie blocking of this section are based only on resources that have a change in their HASP schedules with respect to their DA awards.

The volume of blocking interties is estimated separately for imports (I) and exports (E) to avoid netting. First, the total incremental and decremental volumes of blocking interties is computed separately for each hour, intertie and direction, by summing up all the differences between DA awards and HASP schedules of all resources that have their schedules blocked; i.e.,

$$\Delta_{i,t}^{d+} = \sum_{r \in R_i} \left(p_{i,t}^{RT,d} - p_{i,t}^{DA,d} \right) \quad if \;\; p_{i,t}^{RT,d} > p_{i,t}^{DA,d}, \quad \forall i \in I, \quad t \in T, \quad d = \{E, I\}$$

and

$$\Delta_{i,t}^{d-} = \sum_{r \in R_i} \left(p_{i,t}^{RT,d} - p_{i,t}^{DA,d} \right) \quad if \;\; p_{i,t}^{RT,d} < p_{i,t}^{DA,d}, \quad \forall i \in I, \quad t \in T, \quad d = \{E, I\}$$

where indices *i, t, r* and *d* stand for intertie, hour, resource and direction of flow, respectively, and they belong to the sets *I*, *T*, {*E,I*}. The set $R_{i.}$ contains only blocked elements. The summation of differences is only with resources having blocked schedules that belong to a given intertie; i.e., resources in the set $R_{i.}$. The super-indices RT and DA stand for the HASP and DA references. The symbol $p_{i,t}^{RT,d}$ is the HASP schedule. A difference $\Delta_{i,t}^{d}$ can be either positive or negative. A positive difference $\Delta_{i,t}^{d+}$ means that the HASP schedule is greater than the corresponding DA award; i.e., an increase volume was blocked. It is worthwhile to mention that these metrics are based only on resources which are blocked and have a delta between DA awards and HASP schedules. In instances where the whole intertie was blocked, some resources may not have any difference between DA awards and HASP schedules and, therefore, the blocking has no impact on such resources. If that is the case, such resources are no included in the metrics and statistics for tie blocking.
The incremental and decremental volumes for a given day are then computed separately as the sum of the corresponding hourly volumes to avoid netting.

$$\Delta_i^{d+} = \sum_t \Delta_{i,t}^{d+} \quad , \quad \forall i \in I, \quad d = \{E, I\}$$

and

$$\Delta_i^{d+} = \sum_t \Delta_{i,t}^{d-} \quad , \quad \forall i \in I, \quad d = \{E, I\}$$

By doing so, in any given day there may be one incremental volume and one decremental volume per intertie, which are separately applied to exports and imports. These volumes are then organized in two charts, one for exports and one for imports, as shown in the following figures. Only interties with the top nine volumes are individually depicted, while the rest is gathered in the group of *other*.

Figure 135: Daily Volume of Blocking Imports on Interties

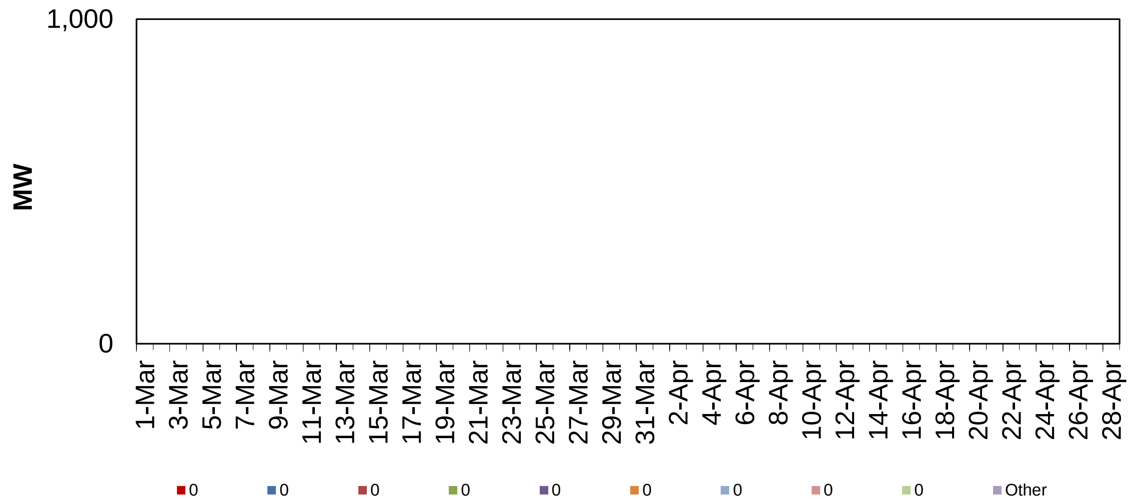
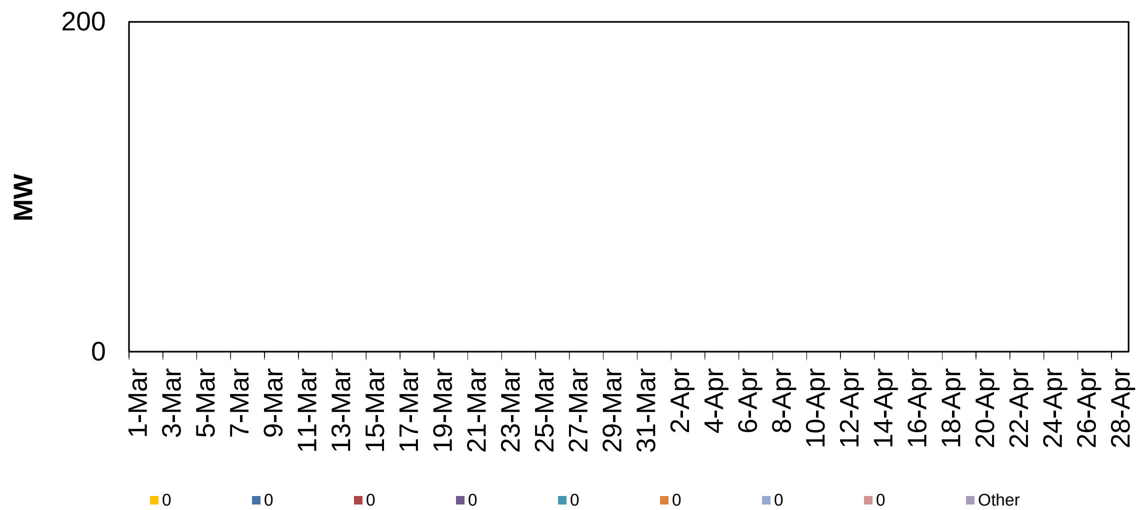


Figure 136: Daily Volume of Blocking Exports on Interties



The statistics of the extent and frequency of intertie blocking is also presented in the following table. The trade day and hour in which intertie blocking occurred are listed by export and import direction. The number of interties and individual schedules that are affected by blocking are shown as well. Finally, the total volume (incremental plus absolute decremental) from intertie blocking is provided.

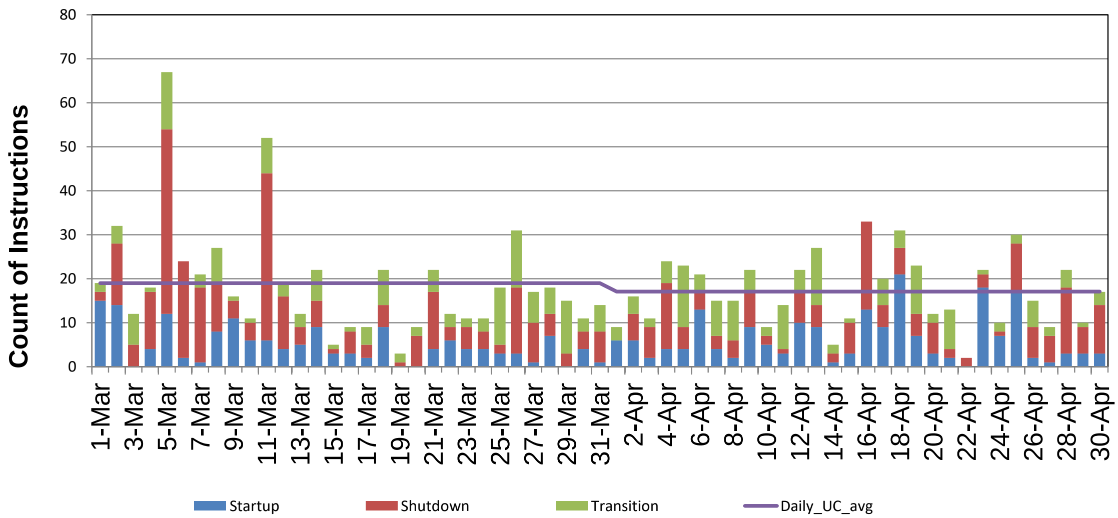
Table 13: Statistics for Hourly Intertie Blocking

Trade Date	Trade Hour	Direction	Number of Ties	Number of Schedules	Net Volume (MWh)

Blocking of Commitment Instructions

Figure 137 shows the count of commitment instructions that were blocked in any of the four RTUC runs for the corresponding month; the instructions are grouped by startups and shutdowns. This also containts a daily average per month, which is computed as the toal number of instructions blocked in a month divided by the number of days in the month.

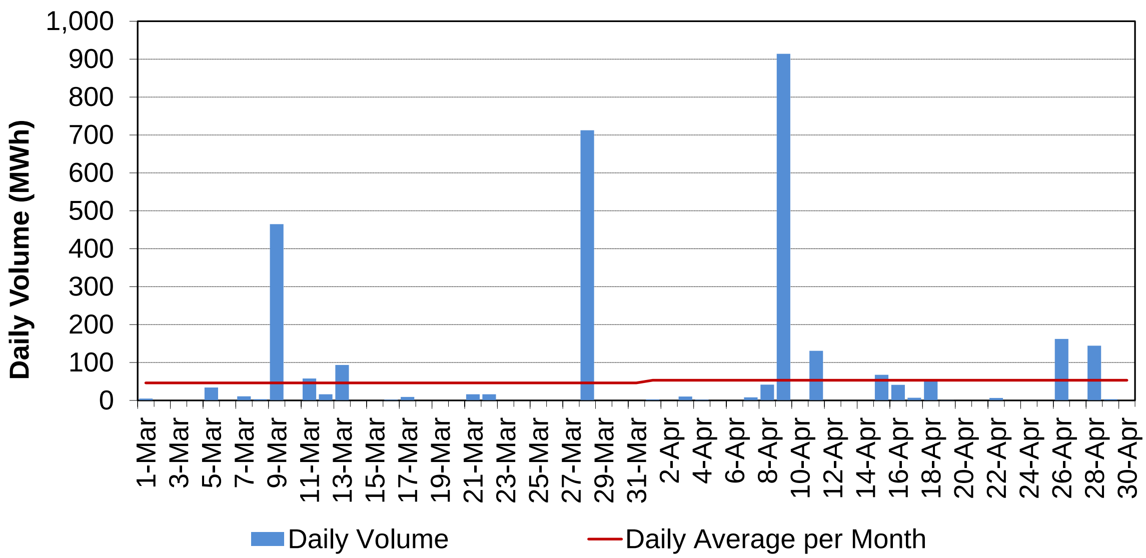
Figure 137: Daily Count of Commitment Instructions Blocked in RTUC



Blocking of Real-Time Dispatch

Figure 138 shows the daily volume in MWh of dispatches blocked in the real-time five-minute dispatch. First, the difference between the previous dispatch and the current dispatch that is being blocked is estimated. These differences are then converted into MWh by mutiplying the differences by a factor of 1/12, and summing across all intervals of each day. These values are represented in blue bars. The daiy average is also represented with a red line; this is obtained as the total volume in the month divided by the number of days of the month.

Figure 138: Daily Volume of Dispatches Blocked in RTD



Adjustments of Transmission Constraints[11]

In operating the markets the ISO, under certain circumstances, will adjust operating limits for selected flowgates (also known as transmission interface) constraints that become binding consistently in the day-ahead and real-time markets. This is done to ensure that measurable or predictable differences between actual and market-calculated flows are accounted for and adequate operating margins are maintained such that reliability of the grid is not adversely impacted.

Adjusting transmission constraints to maintain adequate operating margins is a prudent operating practice that was also used by the ISO prior to the launch of the new markets. With the implementation of the new markets based on locational marginal pricing (LMP), the market optimization tools used in conjunction with the full network model (FNM) in the day-ahead and real-time markets now perform congestion management through automated processes that calculate locational energy prices that reflect the costs of congestion at such locations. The new markets have not, however, eliminated the occurrence of measurable and often predictable differences between actual and market-calculated flows. The process of adjustments is, therefore, a necessary operational tool for ensuring that the markets result in schedules and real-time dispatches that more accurately reflect expected real-time flows, respect actual flow limits and fully support reliable grid operation. Note that adjustments are not applied to scheduling limits; they are applied only to market operating limits for certain branch groups (flow gates/transmission interfaces), as necessary. The key reasons for adjusting operating limits in the day-ahead and real-time markets are:

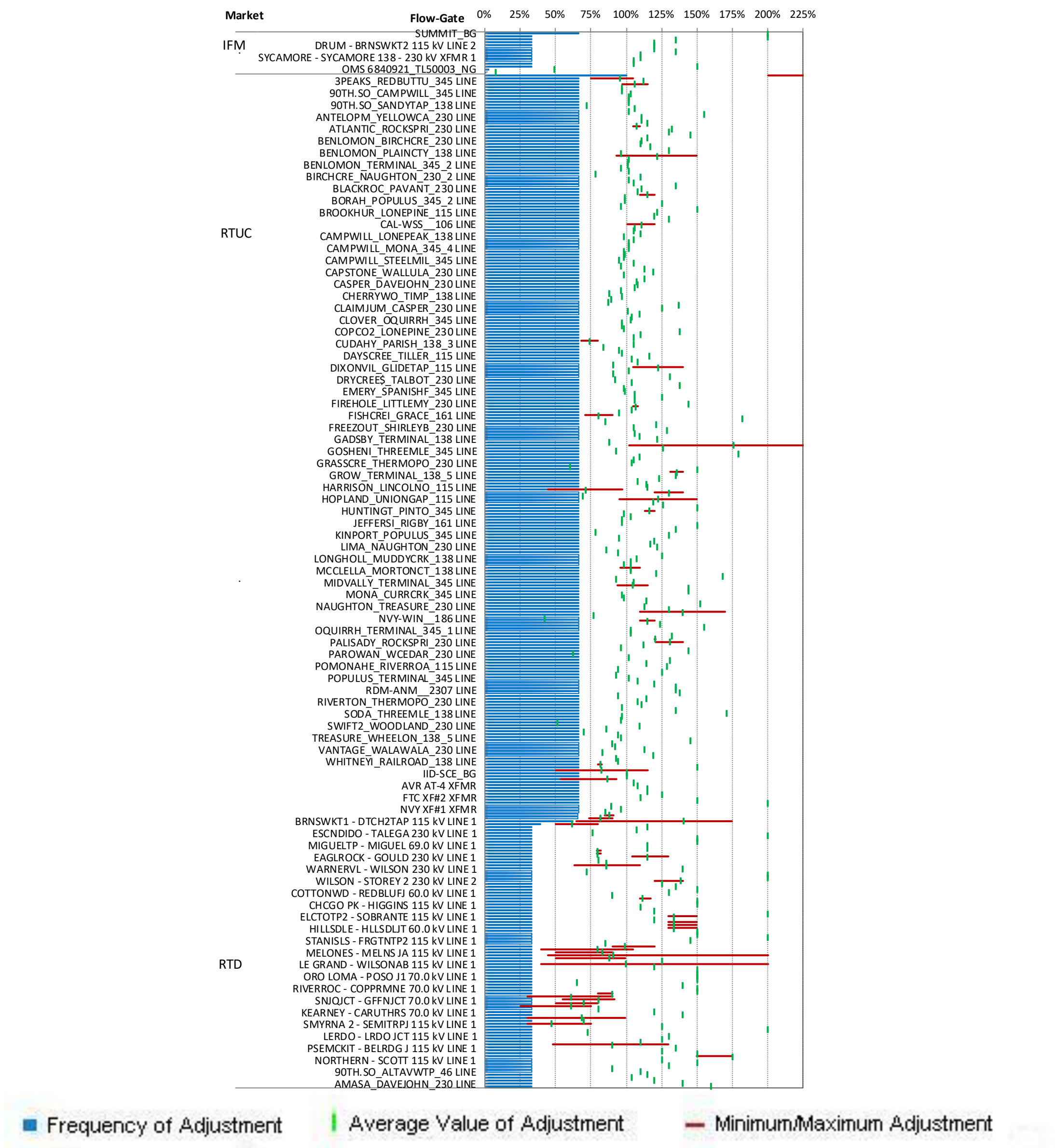
A. To align calculated market flows with measurable or predictable actual flows;
B. To accommodate mismatch due to inherent design differences of day-ahead market, real-time unit commitment and the real-time dispatch runs;
C. To allow reliability margins for certain flowgates; and
D. To adjust margins for flowgates impacted by telemetry issues.

Figure 139 shows the transmission adjustment for the given month. This plot has three different metrics.

1. The bars in blue show the frequency of limit adjustments that were applied to the various flow-gates in either the integrated forward market, real-time unit conmmitment or real-time dispatch. This frequency only counts the time in which limits were adjusted while they were being enforced in the markets. The reference time for this frequency is based on all time intervals in the month even if the the transmission constraint was not enforced all the time.

[11] A detailed description of transmission adjustments is available at http://www.caiso.com/23ea/23eae8aef980.pdf

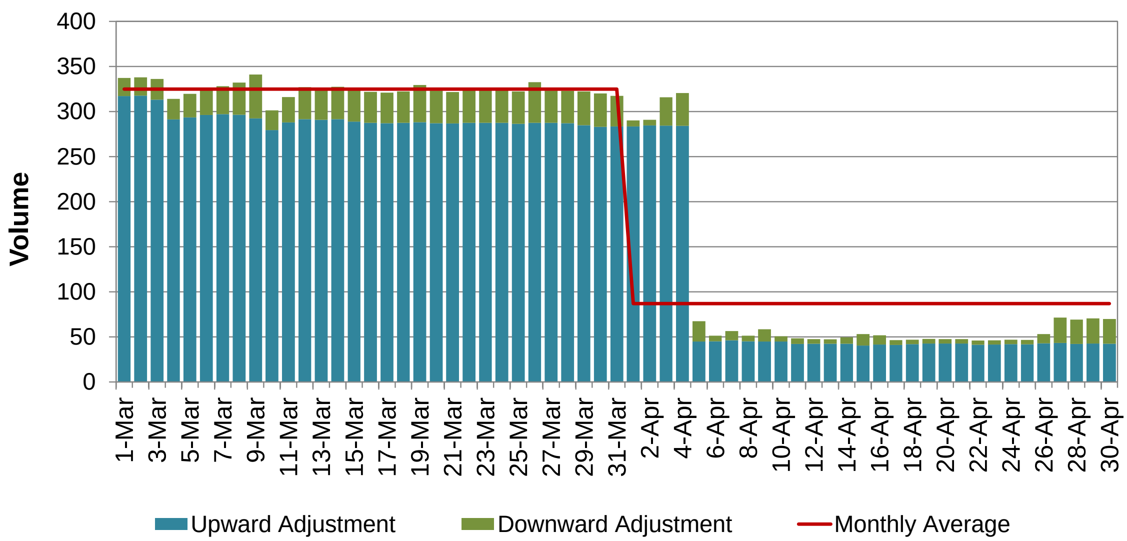
Figure 139: Frequency and Average of Adjustments to Transmission Constraints by Market



2. The second metric is represented by markers in green and it shows the average adjusted percent of limits applied to the various constraints during the corresponding month; the average adjusted percent is based only on the ajusted values different to 100 percent that were applied to the constraints while there were enforced in the markets.
3. The third metric is given with lines in red; the ends of the lines in red indicates the minimum (left end) and maximum (right end) percent of the adjusted limits. The length of the line indicates, therefore, the range of adjusted percent of limits. In some cases, there is no red line, which indicates that the adjusted percent applied to transmission limits was always at one single value, such as the case for the adjustments applied to transmission limits in the integrated forward market.

Figure 140 shows the daily profile of transmission adjustments for the last two months. Adjustments are grouped by direction: upward and downward. This metric shows the total daily volume (in terms of transmission capacity) of adjustment that acrrued on all transmission elements in all three markets (IFM, RTUC and RTD). Identifying the transmission adjusmtents in all markets, the volume of transmission adjustment (in MVA) is estimated for each transmission element as the difference between the normal limit and the adjusted limit; this is done on a five-minute basis. Then, all adjustments are summed for all transmission elements for all intervals for all markets for each day. The total volume is then divided by a factor of 12 to obtain volume in MVAh. This is further divided by a factor of 1000 to represent the metric in Gigas. The monthly average is obtained by dividing the total volume in a month by the number of days in the month.

Figure 140: Volume of Transmission Adjustments



Energy Imbalance Market

On November 1, 2014, the California Independent System Operator Corporation (CAISO) and Portland based PacifiCorp fully activated the Energy Imbalance Market (EIM). This real-time market is the first of its kind in the West. The Energy Imbalance Market allows balancing authorities outside of the CAISO balancing authority area to voluntarily take part in the imbalance energy portion of the CAISO locational marginal price-based real-time market. PacifiCorp, the CAISO, and market participants participated in market simulations prior to the start of the Energy Imbalance Market on November 1, including parallel production from October 1 to November 1.

The EIM uses state-of-the-art software to analyze regional grid needs and make available low-cost generation to meet demand every five minutes. It can bring many benefits to the West such as cost savings, improving the efficiency of dispatching resources, facilitating the renewable integration, more reliability, etc.

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.

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.

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. 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 (IPCO) and Powerex of Vancouver (BCHA), British Columbia successfully entered the EIM, 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.

On April 3, 2019, Sacramento Municipal Utility District (SMUD), part of the Balancing Authority of Northern California (BANC), successfully began full participation in the Western EIM, becoming the first publicly owned agency to be an EIM entity in the Western EIM.

Figure 141, Figure 142, and Figure 143 show daily simple average ELAP prices for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, BCHA, and BANCSMUD for peak hours, off-peak hours, and all hours respectively in FMM.

Figure 141: EIM Simple Average LAP Prices (On-Peak Hours) in FMM

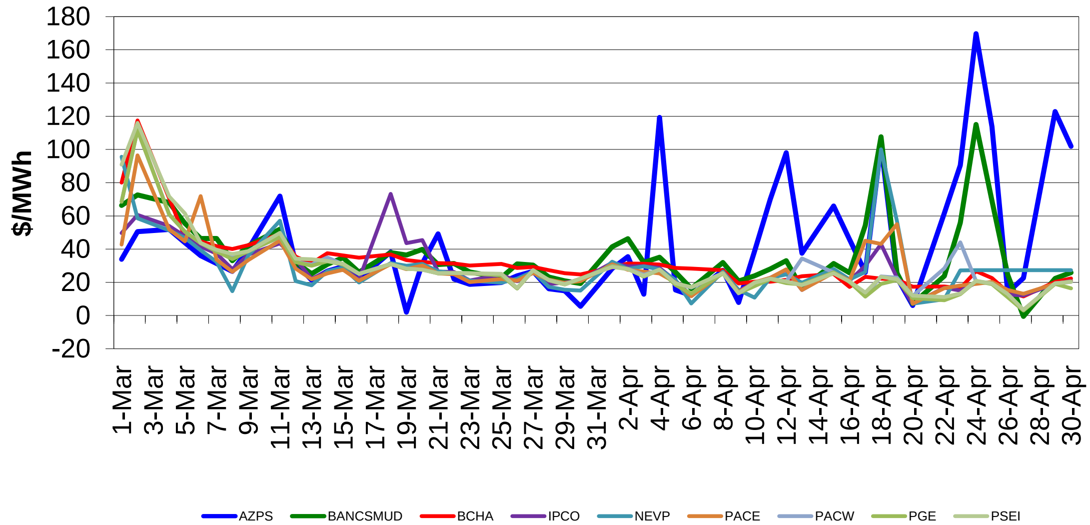


Figure 142: EIM Simple Average LAP Prices (Off-Peak Hours) in FMM

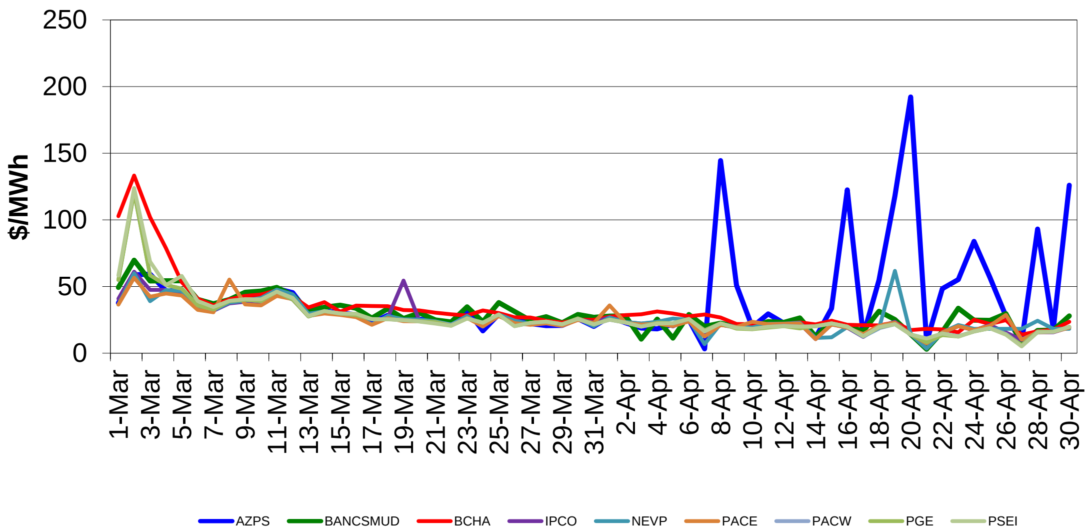


Figure 143: EIM Simple Average LAP Prices (All Hours) in FMM

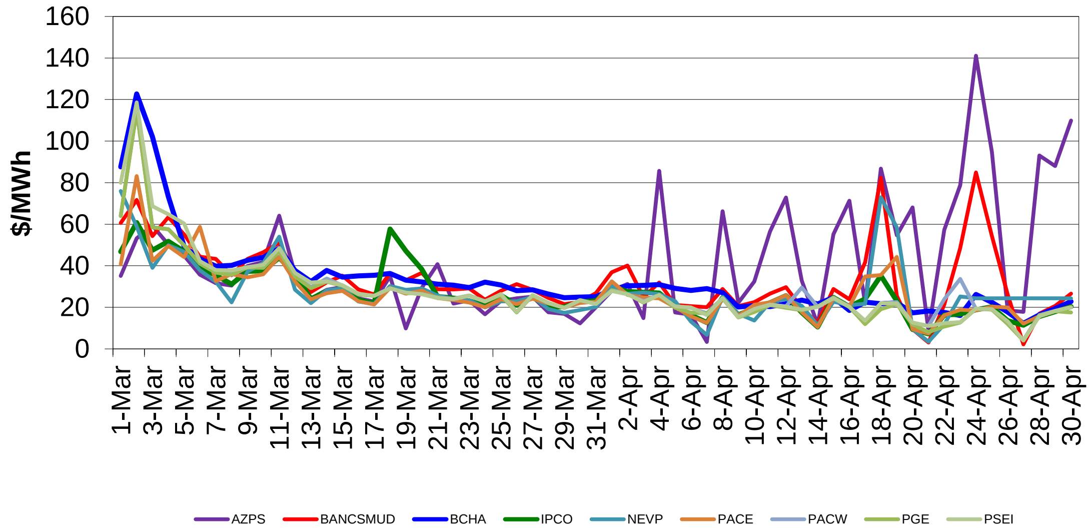


Figure 144, Figure 145, and Figure 146 show daily simple average ELAP prices for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, BCHA, and BANCSMUD for peak hours, off-peak hours, and all hours respectively in RTD.

Figure 144: EIM Simple Average LAP Prices (On-Peak Hours) in RTD

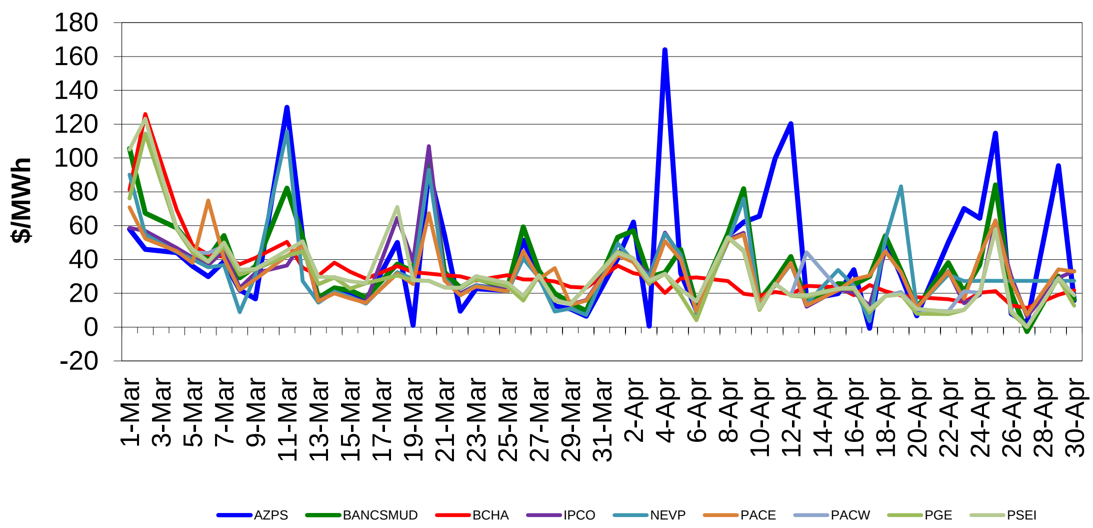


Figure 145: EIM Simple Average LAP Prices (Off-Peak Hours) in RTD

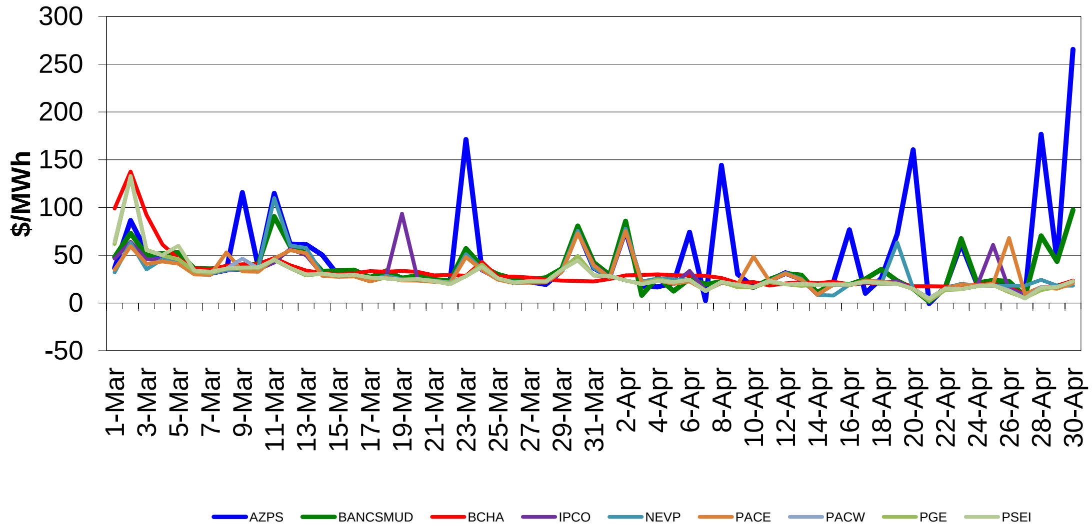


Figure 146: EIM Simple Average LAP Prices (All Hours) in RTD

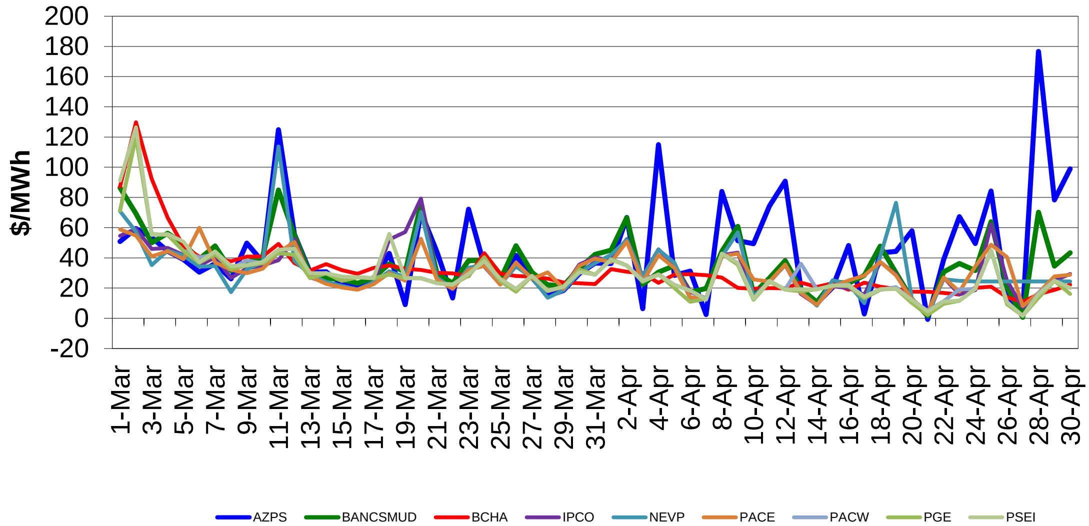


Figure 147 shows the daily price frequency for prices above $250/MWh and below $0/MWh in FMM. Prices are for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, BCHA, and BANCSMUD ELAPs. The graph may provide a trend of price spikes over time.

Figure 147: Daily Frequency of EIM LAP Positive Price Spikes and Negative Prices in FMM

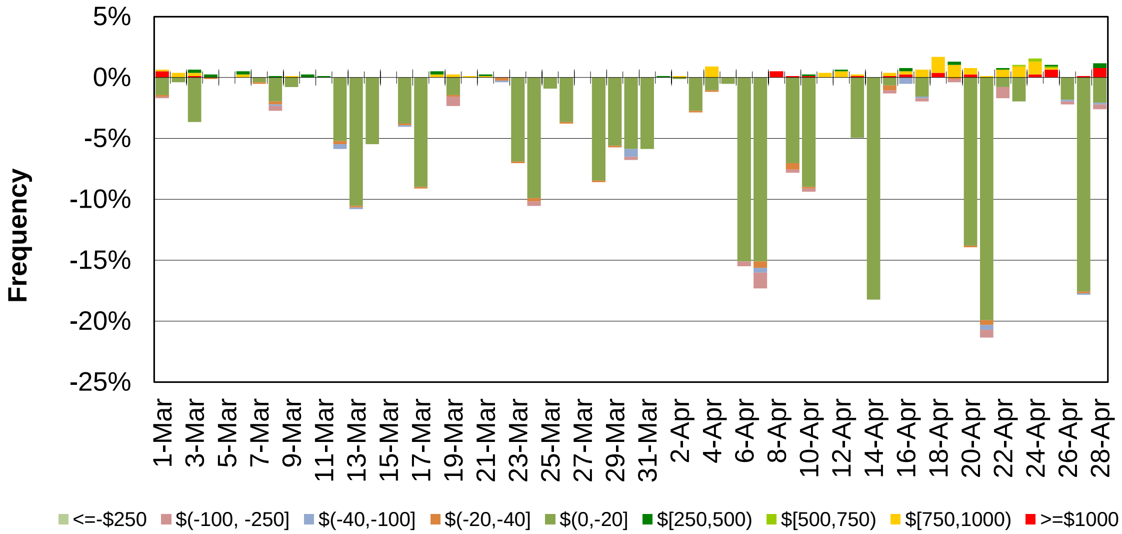


Figure 148 shows the daily price frequency for prices above $250/MWh and below $0/MWh in RTD. Prices are for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, BCHA, and BANCSMUD ELAPs. The graph may provide a trend of price spikes over time.

Figure 148: Daily Frequency of EIM LAP Positive Price Spikes and Negative Prices in RTD

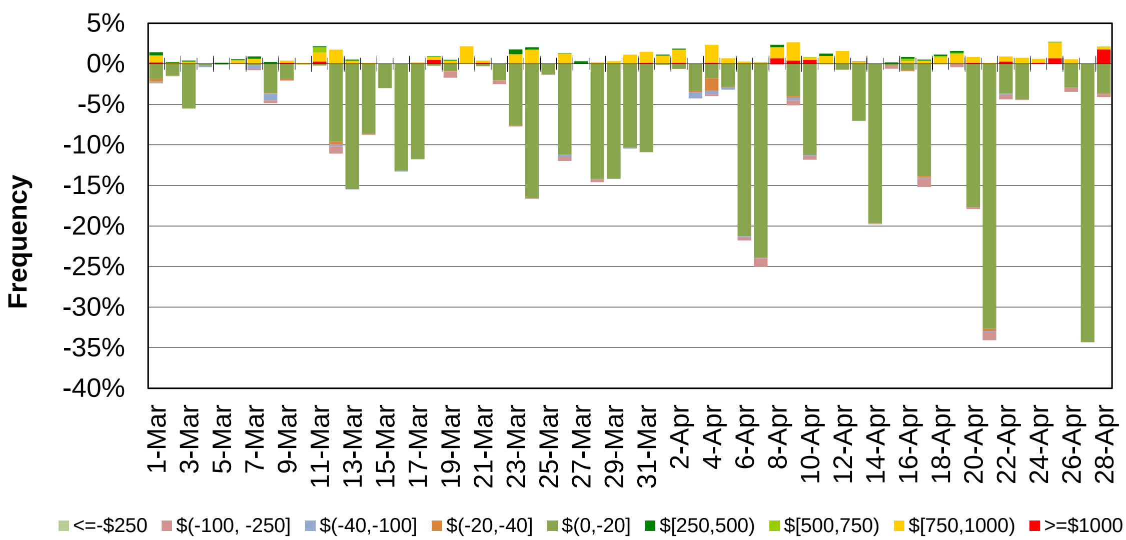


Figure 149 shows the daily volume of EIM transfer for CAISO in FMM. "Import" represents the total EIM transfer from other BAs into CAISO. "Export" represents the total EIM transfer out of CAISO to other BAs in FMM. Figure 150 shows the daily volume of EIM transfer for PACE. Figure 148 shows the daily volume of EIM transfer for PACW in FMM. Figure 151 shows the daily volume of EIM transfer for PACW in FMM. Figure 152 shows the daily volume of EIM transfer for NEVP in FMM. Figure 153 shows the daily volume of EIM transfer for AZPS in FMM. Figure 154 shows the daily volume of EIM transfer for PSEI in FMM. Figure 155 shows the daily volume of EIM transfer for PGE in FMM. Figure 156 shows the daily volume of EIM transfer for BCHA in FMM. Figure 157 shows the daily volume of EIM transfer for IPCO in FMM. Figure 158 shows the daily volume of EIM transfer for BANCSMUD in FMM.

Figure 149: EIM Transfer for CAISO in FMM

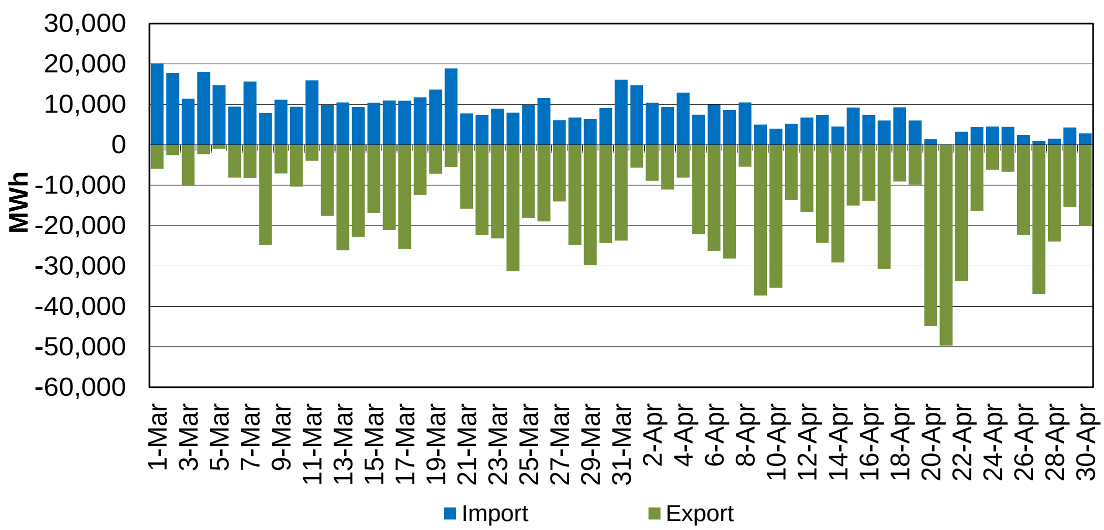


Figure 150: EIM Transfer for PACE in FMM

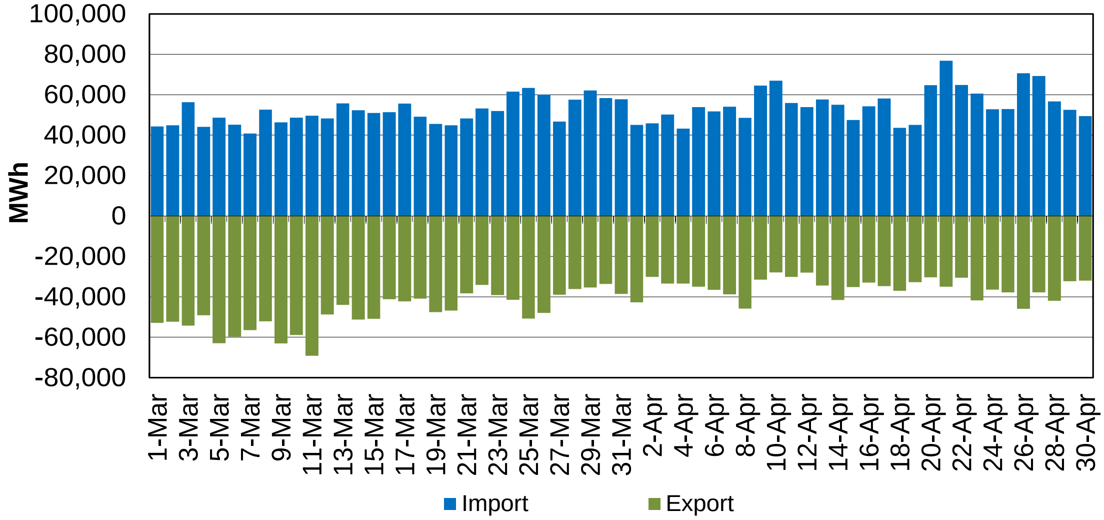


Figure 151: EIM Transfer for PACW in FMM

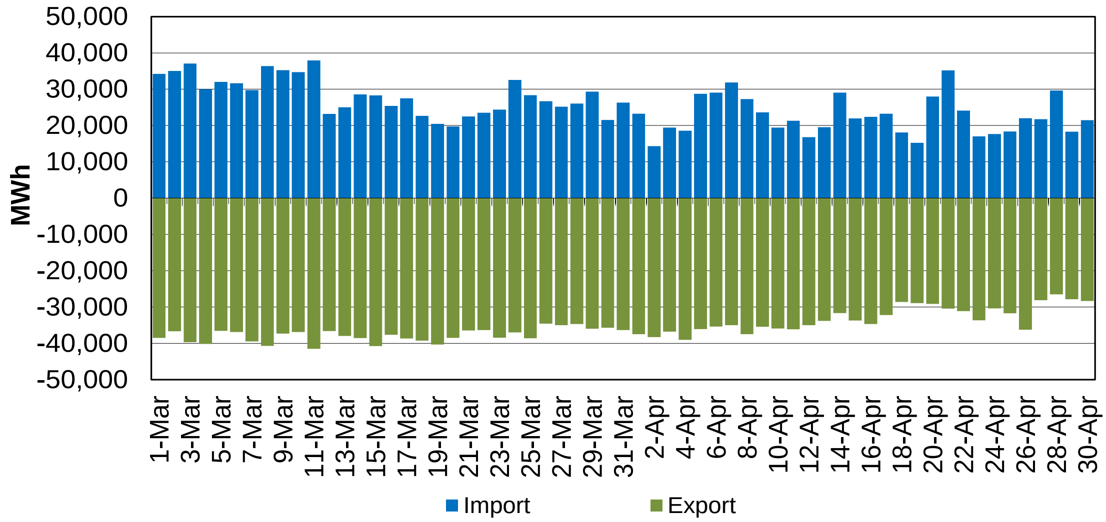


Figure 152: EIM Transfer for NEVP in FMM

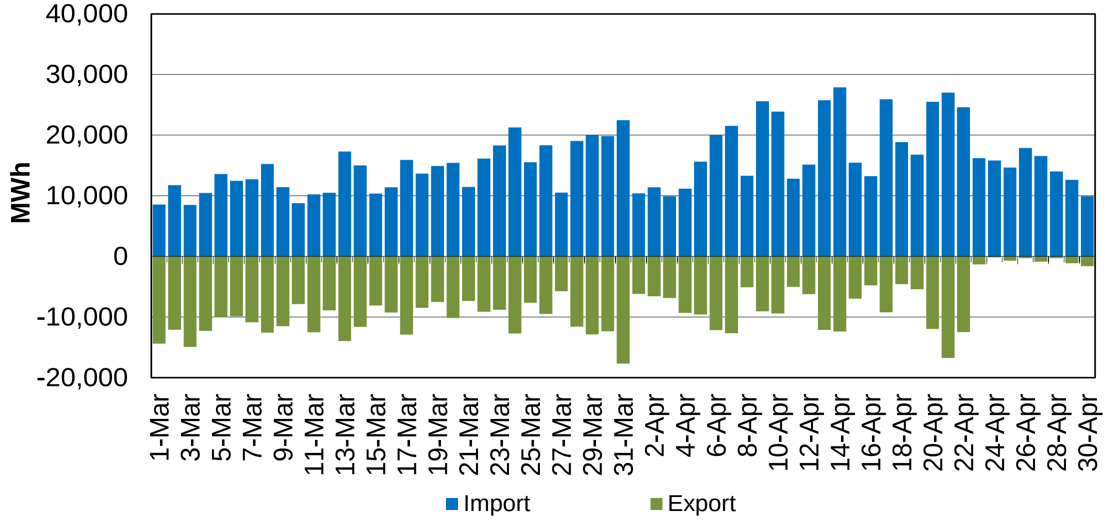


Figure 153: EIM Transfer for AZPS in FMM

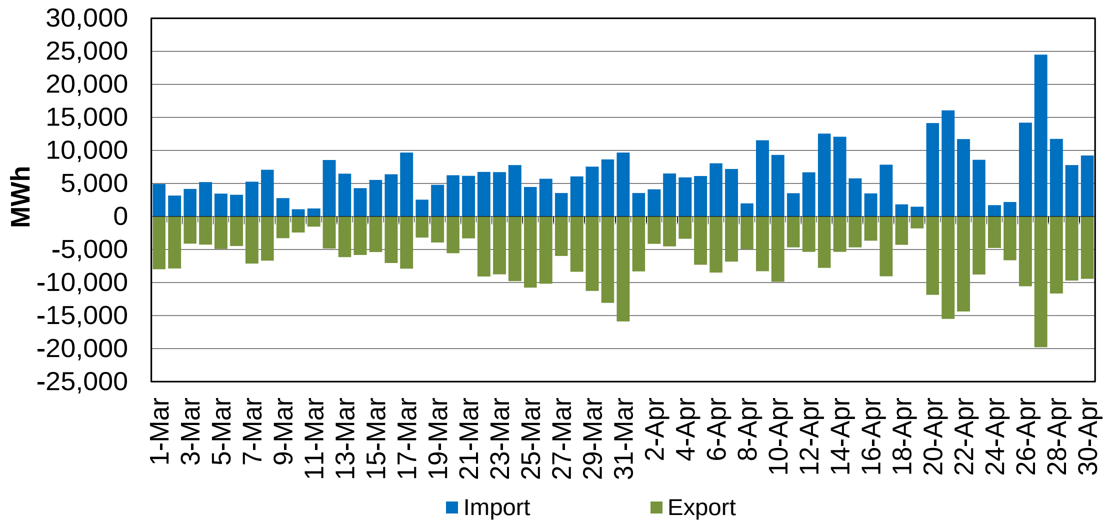


Figure 154: EIM Transfer for PSEI in FMM

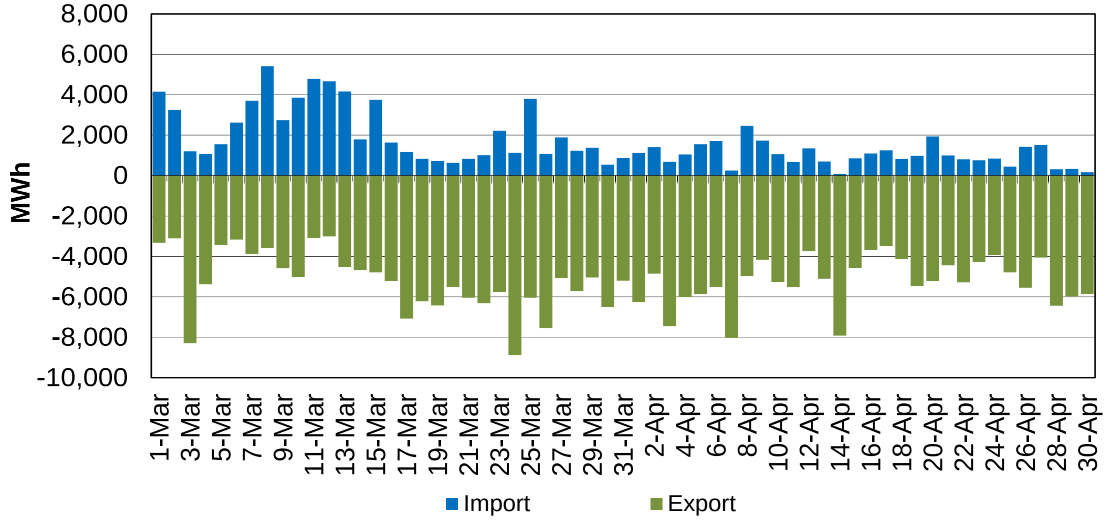


Figure 155: EIM Transfer for PGE in FMM

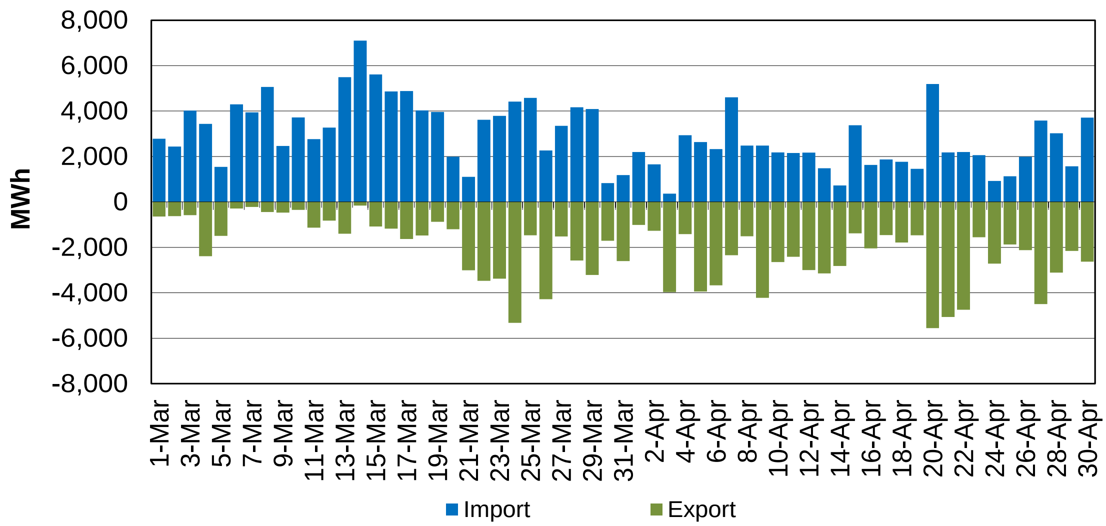


Figure 156: EIM Transfer for BCHA in FMM

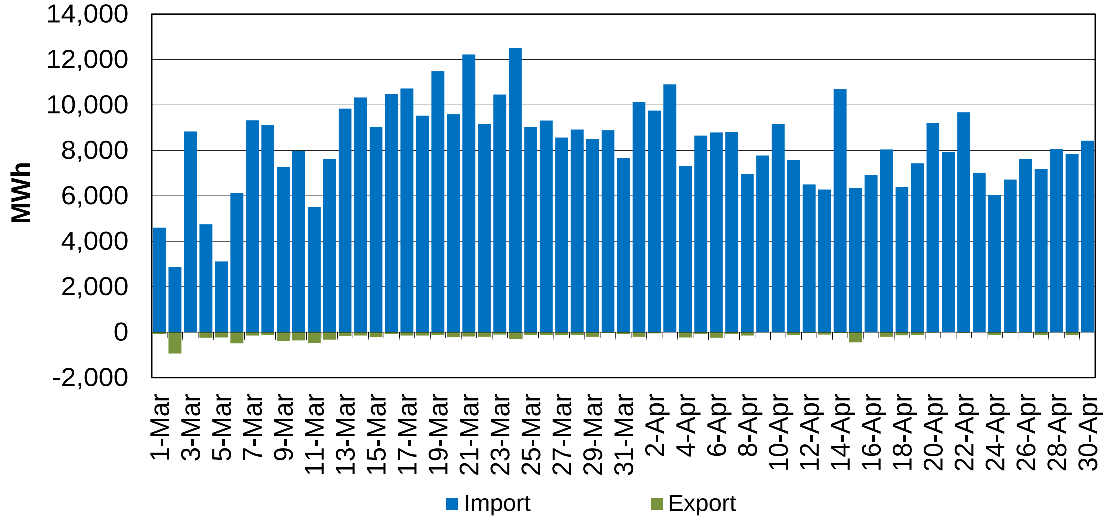


Figure 157: EIM Transfer for IPCO in FMM

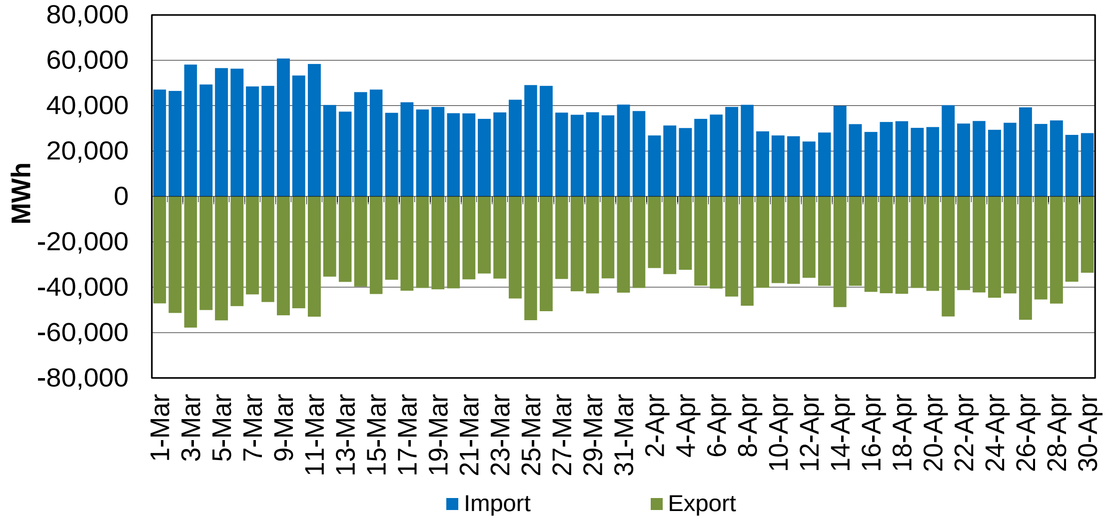


Figure 158: EIM Transfer for BANCSMUD in FMM

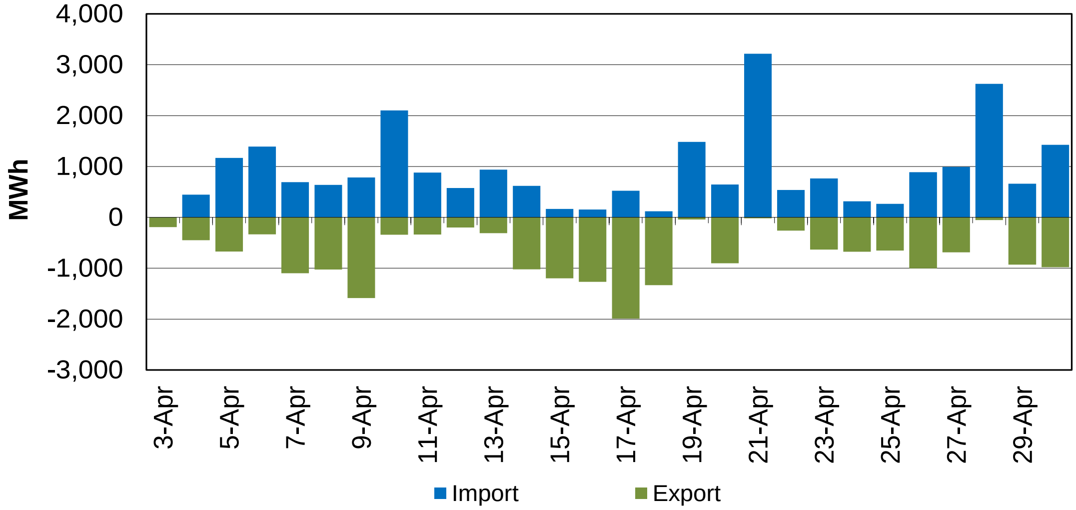


Figure 159 shows the daily volume of EIM transfer for CAISO in RTD. Figure 160 shows the daily volume of EIM transfer for PACE in RTD. Figure 161 shows the daily volume of EIM transfer for PACW in RTD. Figure 162 shows the daily volume of EIM transfer for NEVP in RTD. Figure 163 shows the daily volume of EIM transfer for AZPS in RTD. Figure 164 shows the daily volume of EIM transfer for PSEI in RTD. Figure 165 shows the daily volume of EIM transfer for PGE in RTD. Figure 166 shows the daily volume of EIM transfer for BCHA in RTD. Figure 167 shows the daily volume of EIM transfer for IPCO in RTD.

Figure 168 shows the daily volume of EIM transfer for BANCSMUD in RTD.

Figure 159: EIM Transfer for CAISO in RTD

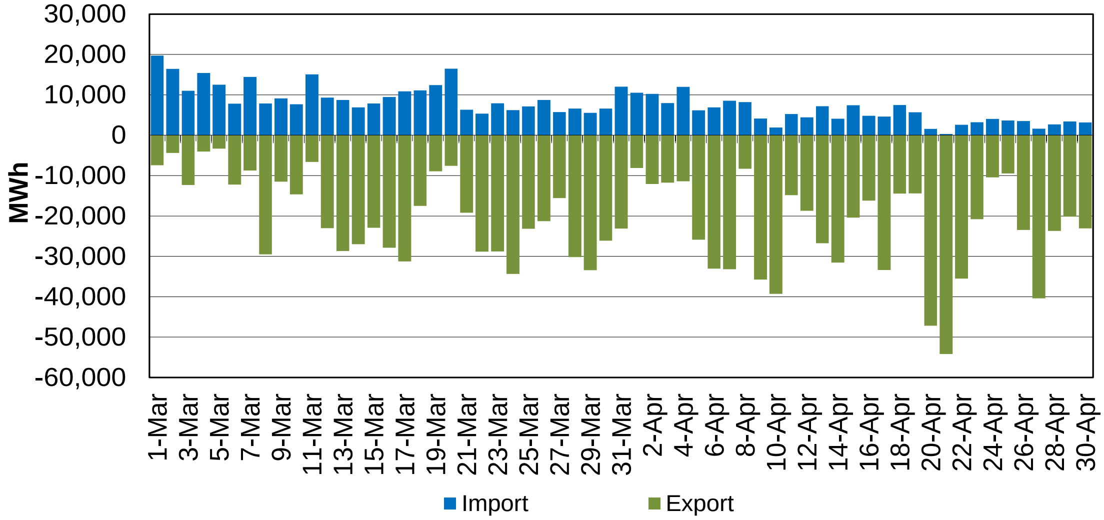


Figure 160: EIM Transfer for PACE in RTD

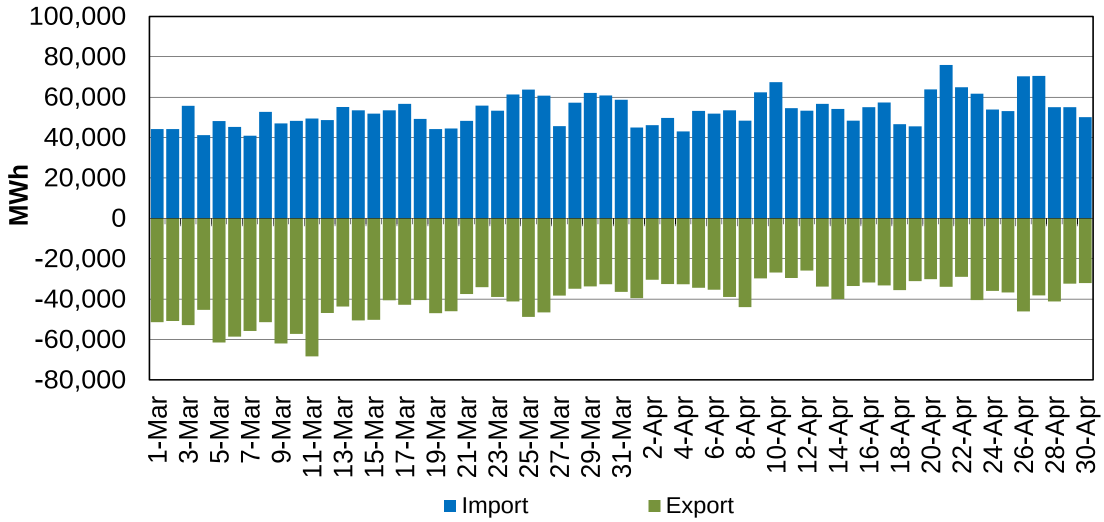


Figure 161: EIM Transfer for PACW in RTD

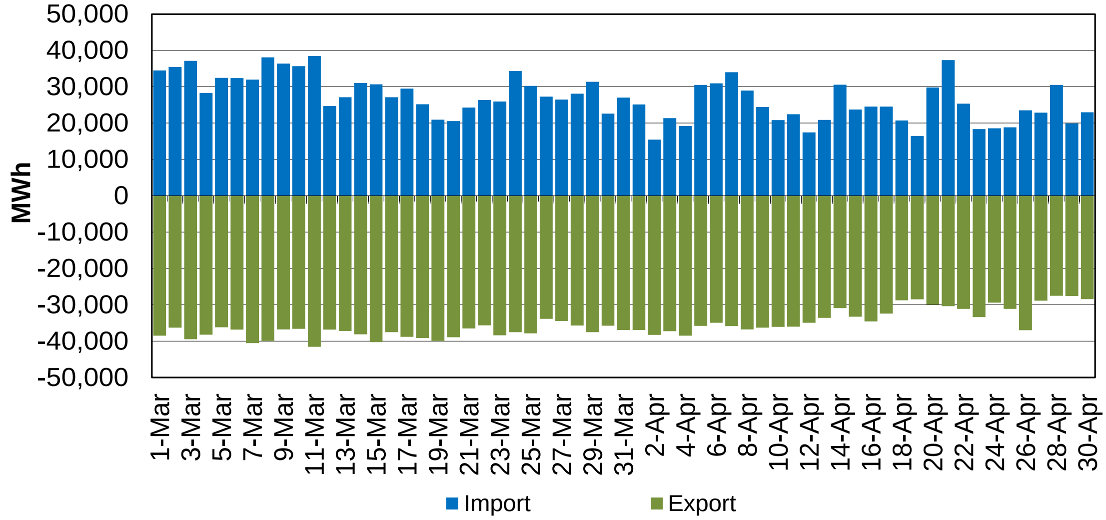


Figure 162: EIM Transfer for NEVP in RTD

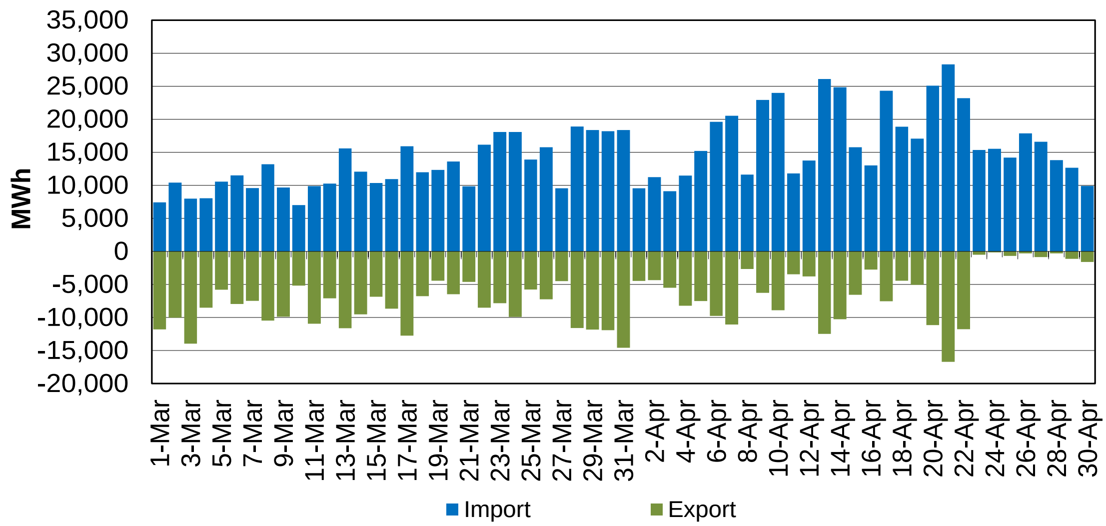


Figure 163: EIM Transfer for AZPS in RTD

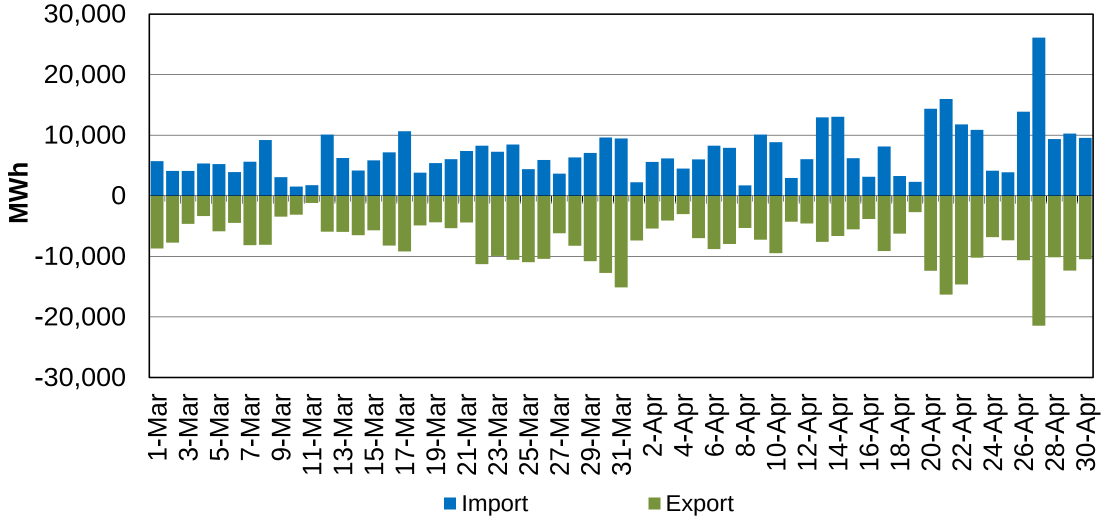


Figure 164: EIM Transfer for PSEI in RTD

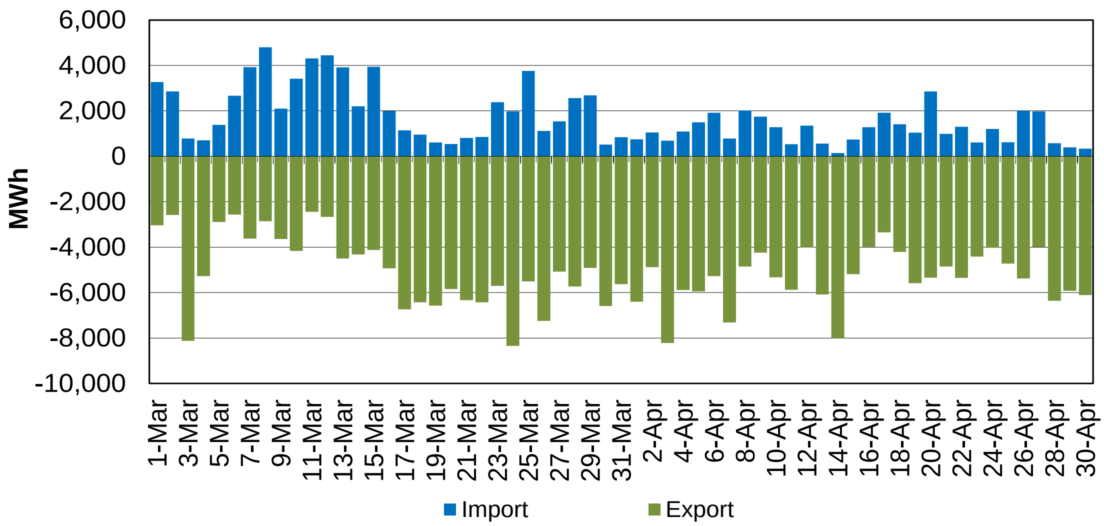


Figure 165: EIM Transfer for PGE in RTD

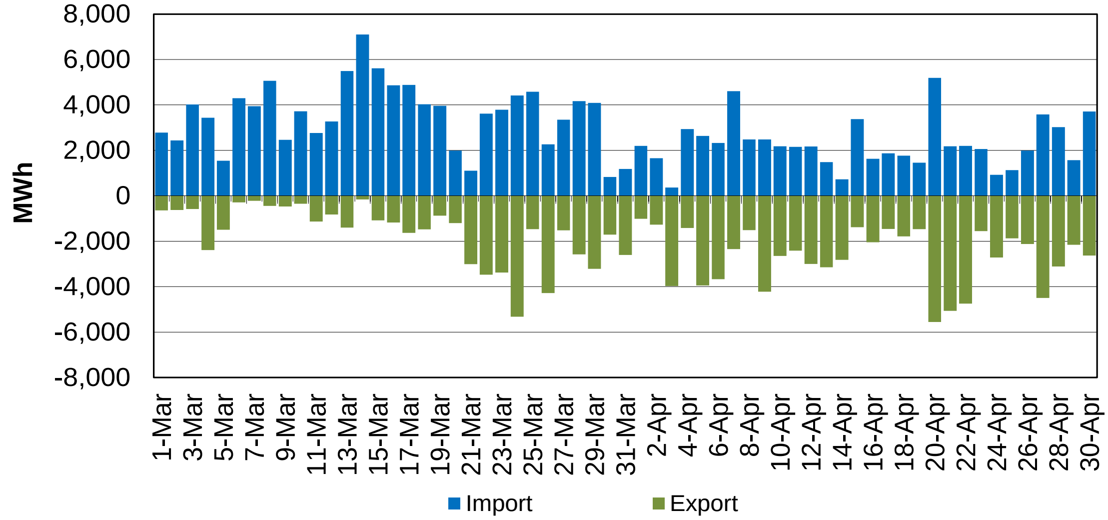


Figure 166: EIM Transfer for BCHA in RTD

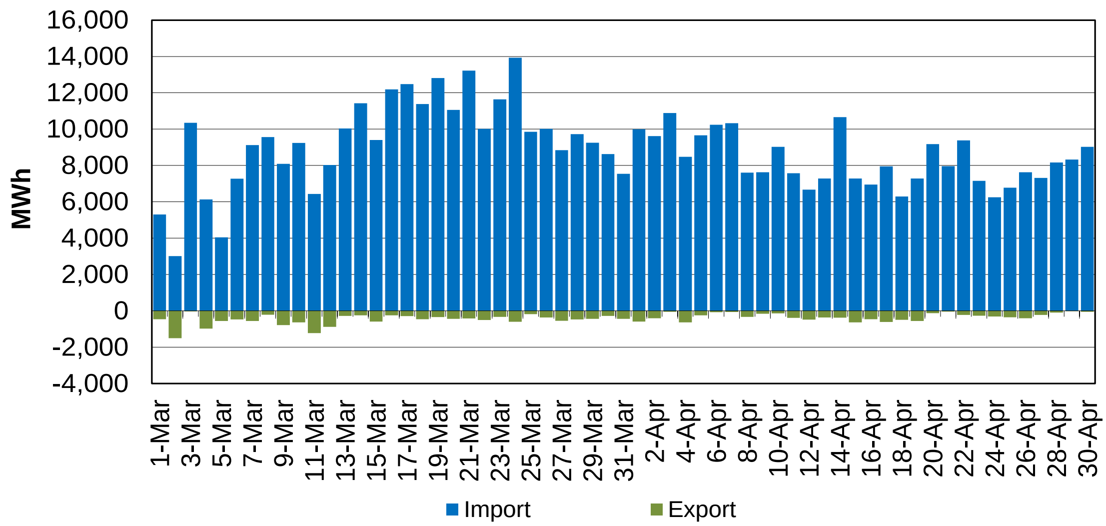


Figure 167: EIM Transfer for IPCO in RTD

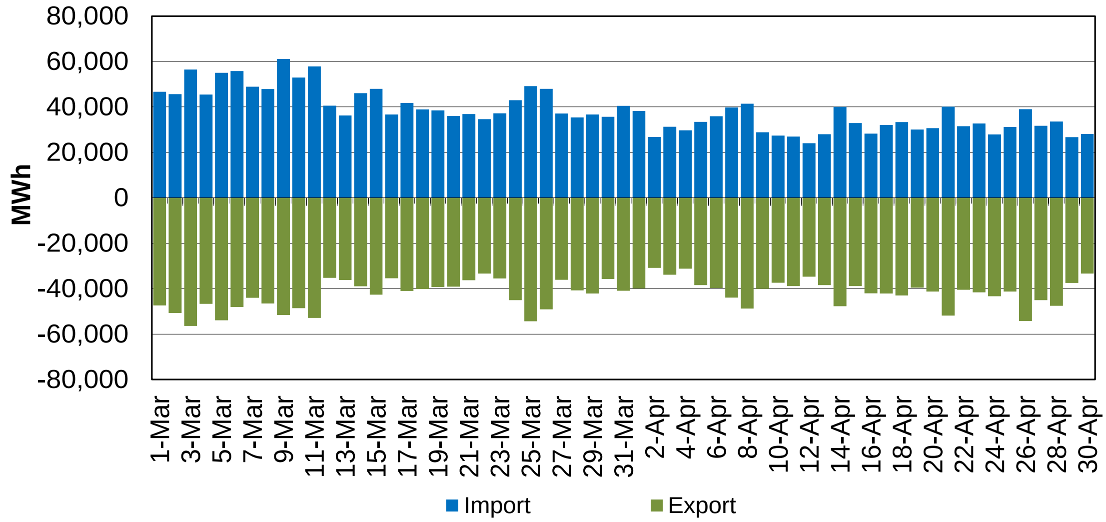


Figure 168: EIM Transfer for BANCSMUD in RTD

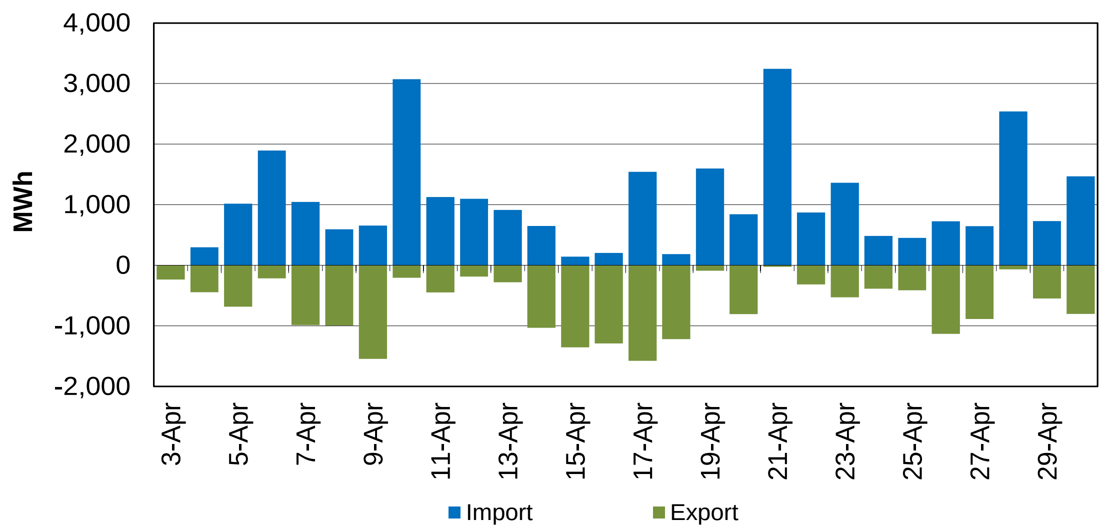


Figure 169 shows daily real-time imbalance energy offset cost for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, BCHA, and BANCSMUD respectively.

Figure 169: EIM Real-Time Imbalance Energy Offset by Area

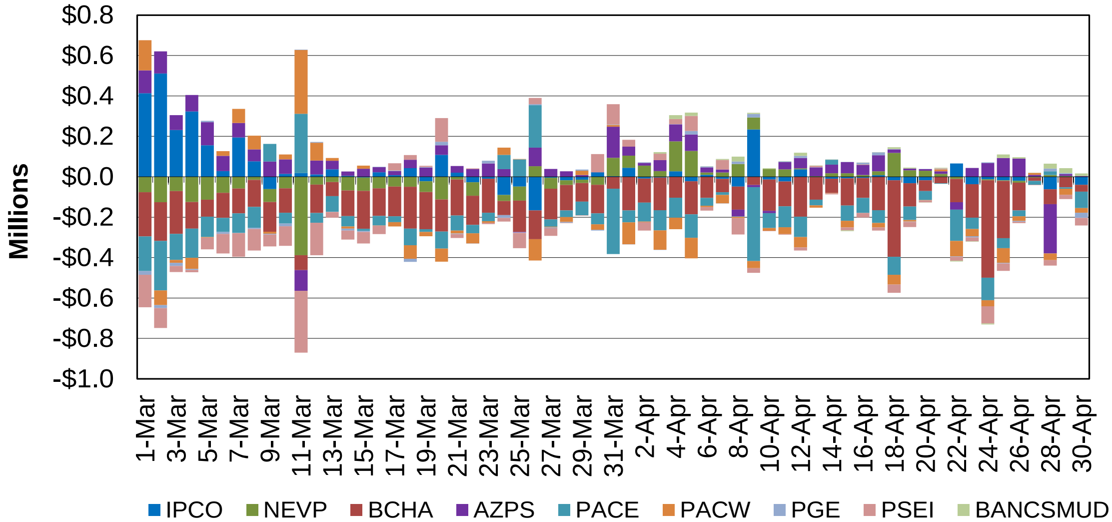


Figure 170 shows daily real-time congestion offset cost for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, BCHA, and BANCSMUD respectively.

Figure 170: EIM Real-Time Congestion Imbalance Offset by Area

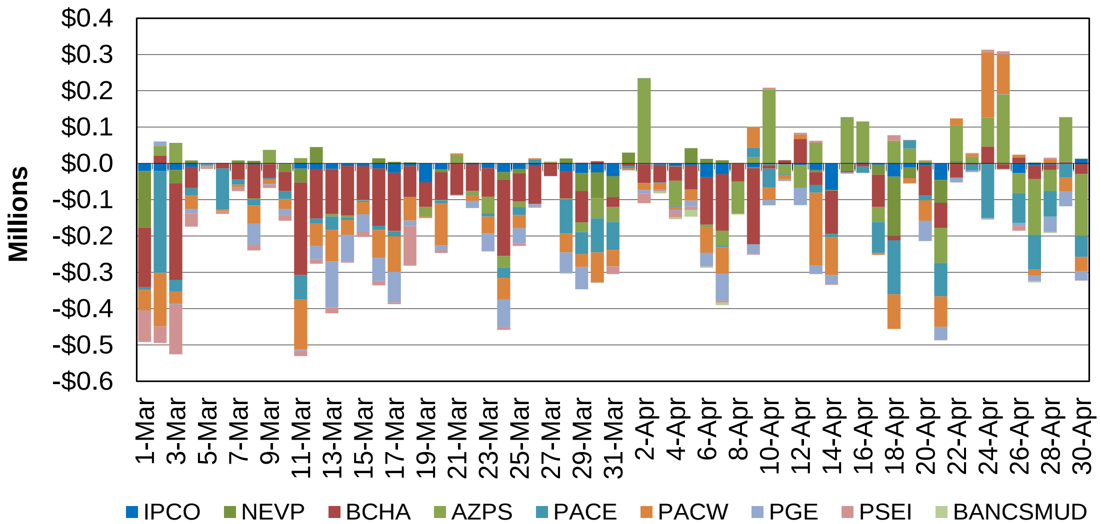


Figure 171 shows daily bid cost recovery for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, BCHA, and BANCSMUD respectively.

Figure 171: EIM Bid Cost Recovery by Area

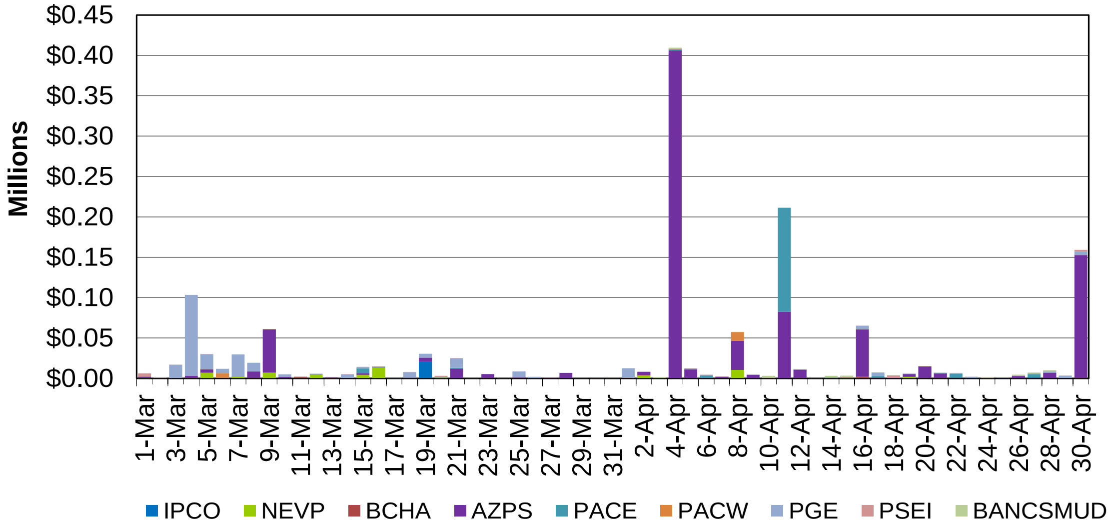


Figure 172 shows the flexible ramping up uncertainty payment PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO BCHA, and BANCSMUD respectively. Figure 173 shows the flexible ramping down uncertainty payment PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO BCHA, BANCSMUD respectively. Figure 174 shows the flexible ramping forecast payment PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, BCHA, and BANCSMUD respectively.

Figure 172: Flexible Ramping Up Uncertainty Payment

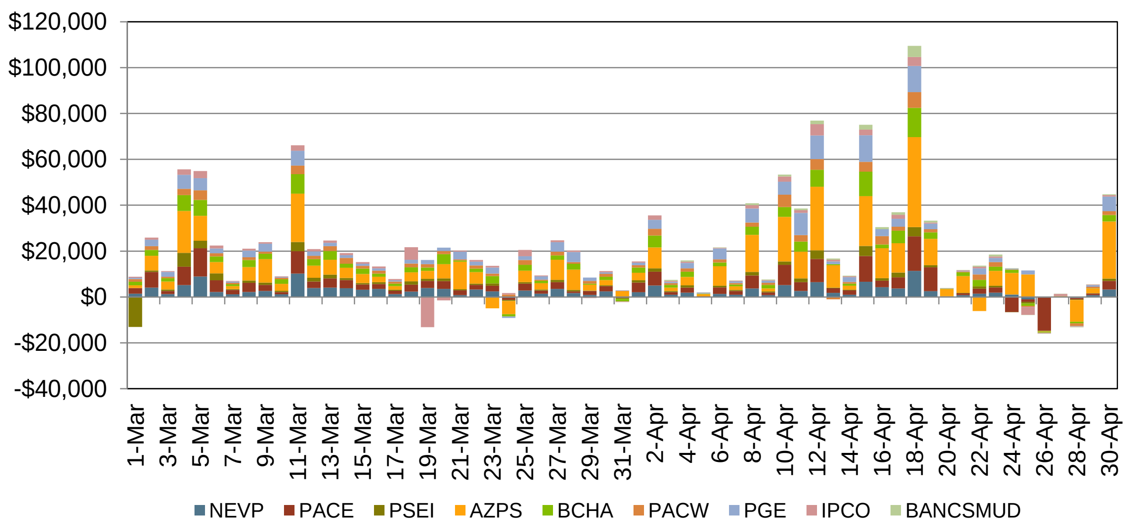


Figure 173: Flexible Ramping Down Uncertainty Payment

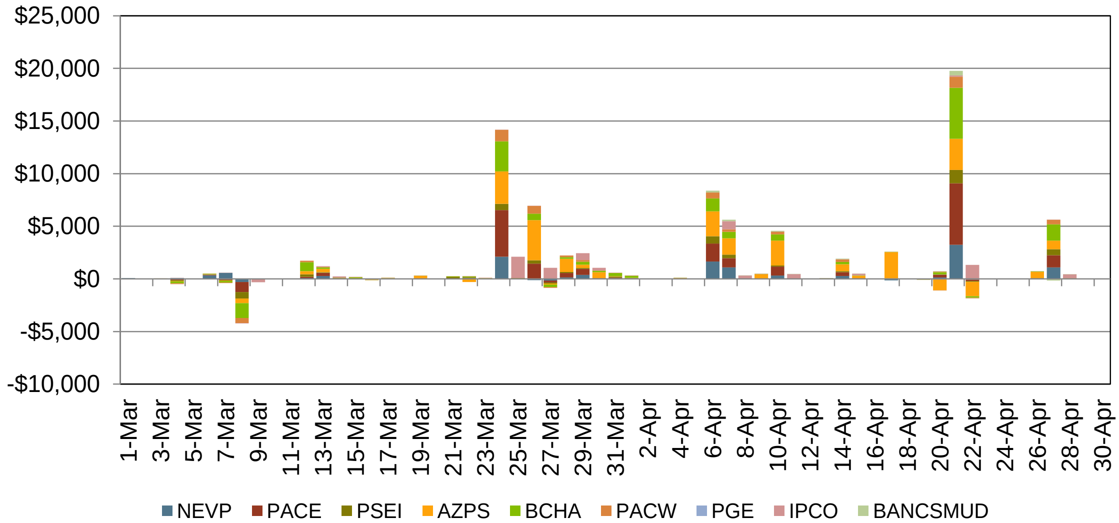
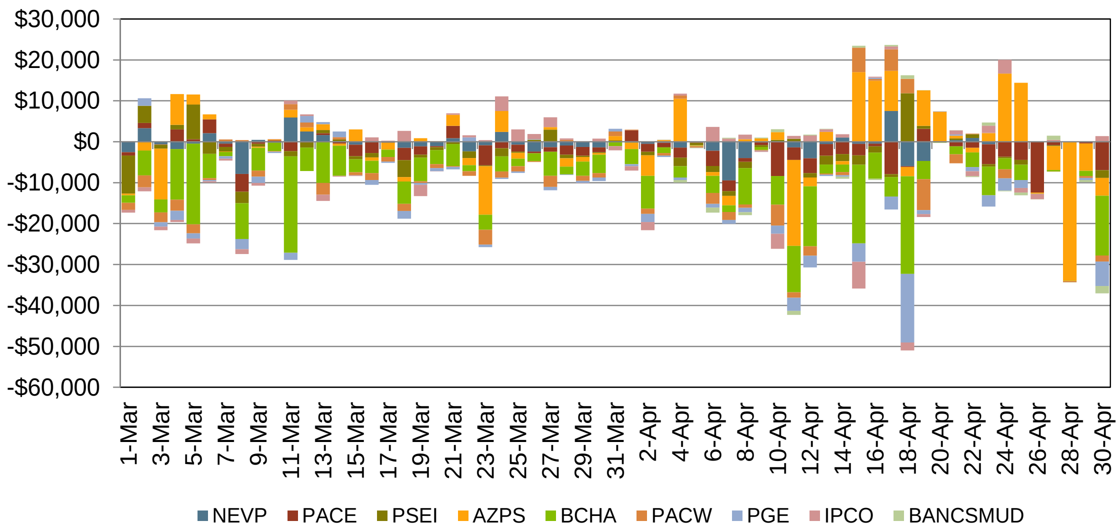


Figure 174: Flexible Ramping Forecast Payment



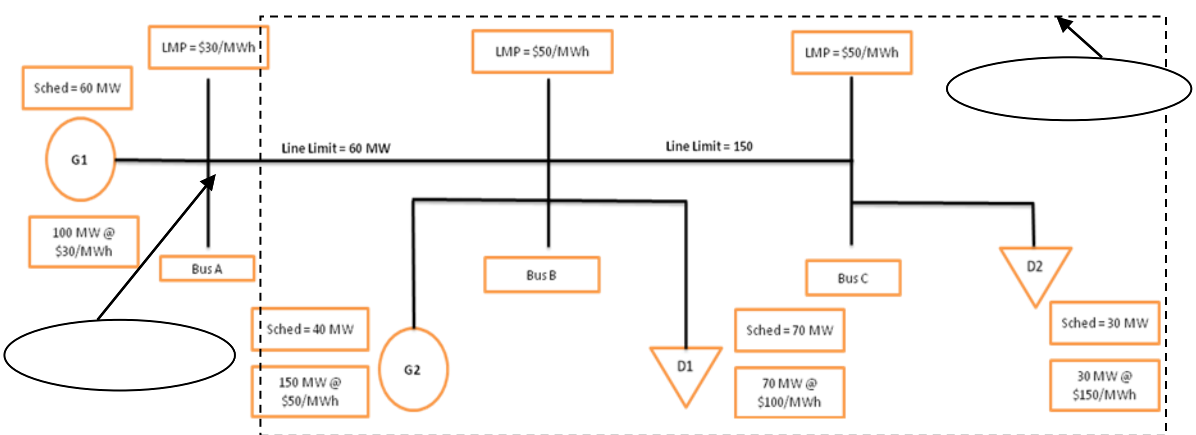
Appendix: Imbalance Offset Costs

The daily imbalance offset cost in the real-time market is the difference between the daily revenue paid in the real-time market and the revenue collected from the real-time market. In a nodal market, the revenue collected from the load is higher than the revenue paid out to the generator whenever there is congestion in the system. However, since the launch of the new market, the total revenue collected in the real-time market on a daily basis is insufficient to cover the payment made in the real-time market. This is contrary to the general expectation. This phenomenon is explained with the example of a three bus system in this document; as mentioned previously, the ISO has already published a paper which explains the root cause of this issue.

Example 1

Consider a three bus system as shown in Figure 175 below. The system under consideration is a lossless system which implies that no losses occur in the transmission system. This example consists of three buses: A, B and C. Generator G1 is connected to bus A; generator G2 and load D1 is connected to bus B; and load D2 is connected to bus C. Busses B and C are within the ISO system and bus A is a tie point. The bid for each resource at each of the location is represented as a MW-price pair. Figure 175 also shows the outcome of the day-ahead market. The schedule for each resource and the LMP at each bus location are shown below.

Figure 175: Day-Ahead Market Example 1



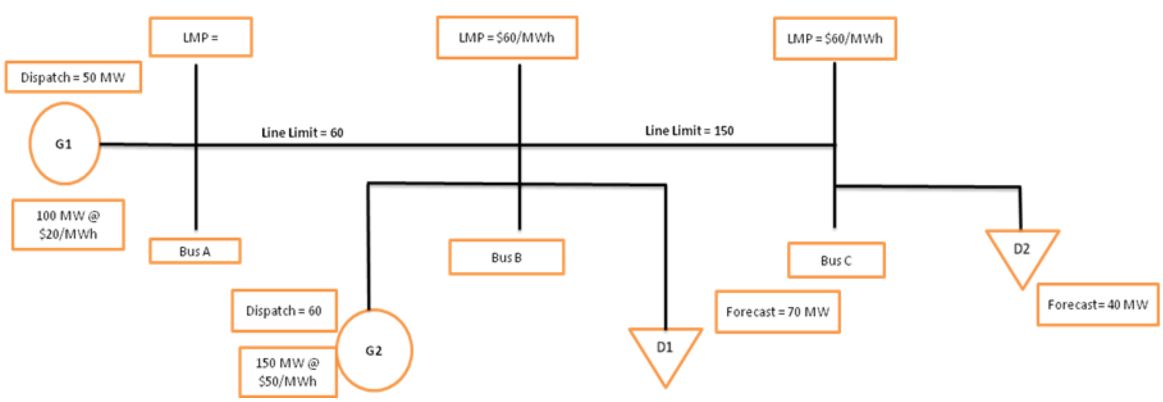
The day-ahead results are summarized in Table 14. The settlements sign convention is used to characterize the information in Table 14. A generation quantity is represented by a negative sign, whereas, load by positive. Also, a payment is shown with a negative sign and a charge with a positive sign. From Table 14, it is observed that the total payment made to generators G1 and G2 based on the LMPs at their nodes is $3,800, and the total charge collected from load D1 and D2 is $5,000. Due to the congestion on the intertie conecting bus A to bus B, the difference between the total charge and the total payment is $1,200. This surplus collected by the ISO would be a day-ahead offset, which is used to pay the CRR holders.

Table 14: Summary of Day-Ahead Market for Example 1

Resource Name	Schedule	LMP ($/MWh)	Revenue ($)	Energy Compnent ($/MWh)	Congestion Component ($/MWh)	Congestion Revenue
G1	-60.00	30.00	-1800.00	50.00	-20.00	1200.00
G2	-40.00	50.00	-2000.00	50.00	0.00	0.00
D1	70.00	50.00	3500.00	50.00	0.00	0.00
D2	30.00	50.00	1500.00	50.00	0.00	0.00

Figure 176 below shows the real-time market; this is the continuation of the day-ahead market discussed above. This figure shows the dispatch quantites in the real-time market. Note that, only generators bid into the real-time market, clearing against the real-time forecast. Table 15 shows the summary of dispatches and prices from the real-time market. In a multi-settlement system, like the ISO's new market which was implemented on April 1, 2010, the real-time price (LMP) is settled at the difference between the metered quantity and the day-ahead schedule. In this example the generators dispatch quantities are assumed to be the same as their metered quantities; similarly, the load forecast quantities are assumed to be the same as their metered quantities.

Figure 176: Real-Time Market Example 1.



As seen from Table 15, the generator G1 has a net decrement of 10 MW, that is, its output in the real-time is reduced from 60 MW to 50 MW. A net decrement for a generator results in a positive quantity which is equivalent to a demand.

Similarly, imbalance energy quantities are calculated for generator G2, load D1 and D2.

Based on the real-time dispatch results, as shown in Table 15, the total revenue collected is $800 ($200 from G1 and $600 form D2); but, the revenue paid is $1200 (to generator G2). Clearly, there is a revenue shortfall of $400 in the real-time market. This revenue shortfall represents the real-time offset quantity.

Table 15: Summary of Real-Time Market Dispatch for Example 1.

Resource Name	DA Sched (MWh)	RT Dispatch (MWh)	Imbalance (MWh)	LMP ($/MWh)	Market Revenue ($)	Energy Component ($/MWh)	Congestion Component ($/MWh)	Energy Component Revenue ($)	Congestion Revenue ($)
G1	-60	-50	10	20	200	20	0	200	0
G2	-40	-60	-20	60	-1200	60	0	-1200	0
D1	70	70	0	60	0	60	0	0	0
D2	30	40	10	60	600	60	0	600	0

Root Cause for Revenue Deficiency in Example 1

There is a revenue deficiency in the real-time market in example 1; this condition occurs because the dispatch in this example is inconsistent with the bid-in quantities. Resource G1, an hourly system resource connected to tie point A, is the cheapest unit. This unit has a net decrement in the real-time market even though it is the least priced unit, whereas, the resource G2 has a net increment in real-time even though it's more expensive. Such situations occur in the ISO real-time markets mainly because the HASP market, which is settled at an hourly price, is run 75 minute before the actual trade interval. However, the real-time interval dispatch market, which is settled at the five-minute interval price, is run seven minutes before the trading interval. Sometimes, it happens that the HASP market observes a load forecast which is much lower than the real-time five minute market; so, the market application creates a net decrement on interties. However, as the system approaches the actual five minute interval, the load forecast is significantly higher compared to what is seen by the HASP market. Thus, the market application creates a dispatch which results in a net increment. If there is a significant difference between the price from the HASP market and the price from the real-time five minute interval market, the system will experience an imbalance offset, as seen in example 1.

Example 2

The decomposition of imbalance offset costs into imbalance energy offset cost and imbalance congestion offset cost is presented in this example. The imbalance loss offset cost is excluded from this example for simplicity. Figure 177 below shows a similar three bus system to what was used in example 1. Except that in this example, a generator G3 is added to bus C; in addition, the bid-in quantities for both generators and load are modified. Figure 177 also shows the outcome of the day-ahead market run for example 2.

Figure 177: Day-Ahead Market for Example 2

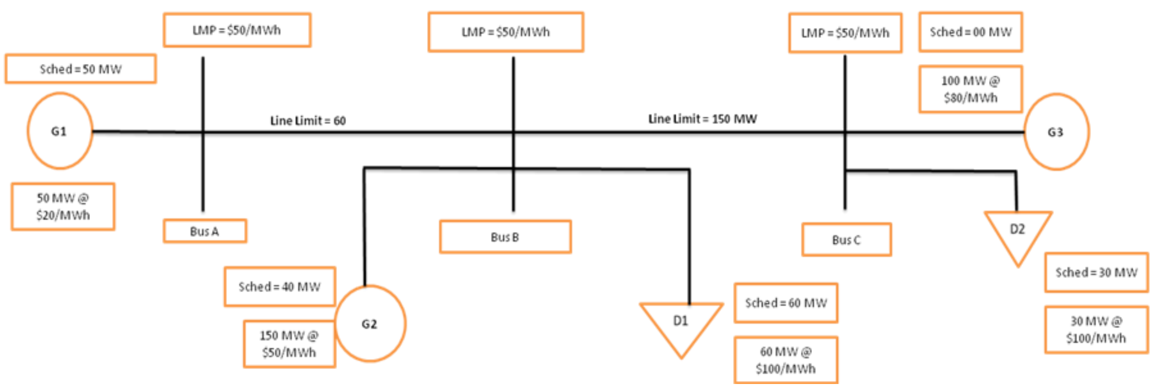


Table 16 below shows the summary of the day-ahead market for example 2. From the data shown in the table, there is no congestion in the day-ahead market in example 2. Also, the generator G3 has no award in the day-ahead market as it is the most expensive unit.

Table 16: Summary of Day-Ahead Market for Example 2

Resource Name	Schedule	LMP ($/MWh)	Revenue ($)	Energy Compnent ($/MWh)	Congestion Component ($/MWh)	Congestion Revenue	Revenue Energy Component	Revenue Congestion Component
G1	-60	50	-3000	50	0	0	-3000	0
G2	-40	50	-2000	50	0	0	-2000	0
G3	0	50	0	50	0	0	0	0
D1	70	50	3500	50	0	0	3500	0
D2	30	50	1500	50	0	0	1500	0

Figure 178 below shows the real-time market; this is the continuation of the day-ahead market discussed in example 2. This figure also shows the dispatch quantites in the real-time market. Table 17 shows the summary of the real-time market dispatch for example 2. As mentioned previously, geneator G1 is connected to bus A which is a tie point. The dispatch and price at this node is settled by the hourly HASP process. In this real-time example the line connecting the bus A to bus B is congested in HASP. In the real-time five minute market, the line connecting bus B to bus C is derated to 30 MW and it is also congested. Because of congestion on these two lines, the LMPs in both HASP and five-minute interval market have a congestion compoent as shown in Table 17.

Figure 178: Summary of Real-Time Market Dispatch for Example 2

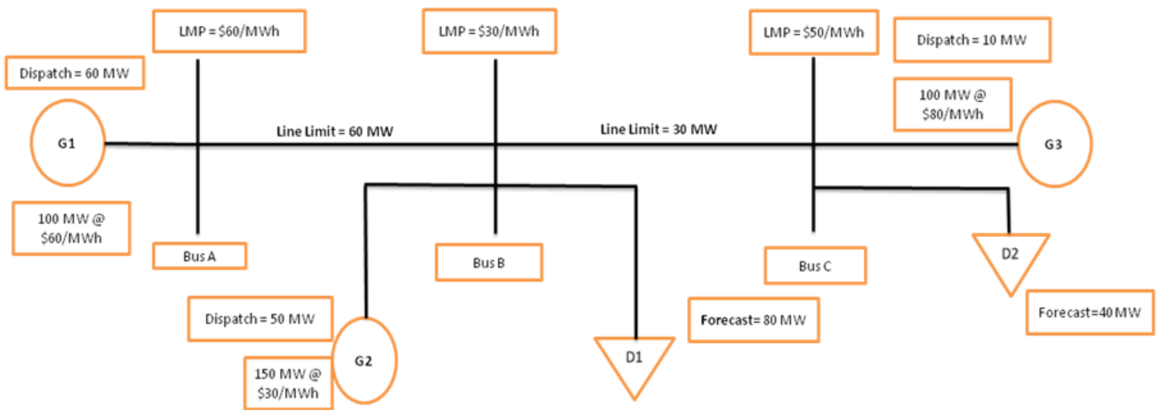


Table 17: Summary of Real-Time Market Dispatch for Example 1.

Resource Name	DA Sched (MW)	RT Dispatch (MW)	Imbalance (MW)	LMP ($/MWh)	Market Revenue ($)	Energy Component ($/MWh)	Congestion Component ($/MWh)	Energy Component Revenue($)	Congestion Revenue ($)
G1	-50	-60	-10	60	-600	65	-5	-650	50
G2	-40	-50	-10	30	-300	50	-20	-500	200
G3	0	-10	-10	50	-500	50	0	-500	0
D1	60	80	20	30	600	50	-20	1000	-400
D2	30	40	10	50	500	50	0	500	0

In this real-time example, payments are made to generators G1, G2 and G3; the total payment made to these generators is $1,400. However, the total revenue collected from load D1 and D2 is only $ 1,100. Thus, there is a revenue shortfall of $300 which is the imbalance offset. This imbalance offset is decomposed into the energy imbalance offset and the congestion imbalance offset. From Table 17 the imbalance energy offset is a shortfall of $150 and the imbalance congestion offset is a shortfall of $150.

Root Cause for Revenue Deficiency in Example 2

As explained in example 2, the imbalance offset is mainly driven by the difference in the HASP and the real-time five minute market results. In this example, the HASP market expects a higher load forecast and hence the generator connected at the tie point A is dispatched at a $60 bid. However, the real-time market observes a lower forecast and hence the real-time LMPs are lower than the HASP results.

The divergence between the HASP and the RTD energy prices occurs due to various other reasons: over-scheduling in the day-ahead market, under-scheduling in the IFM and under forecasting in RUC and matching supply to demand variation in real-time. These reasons are explained in the document published by the ISO on its website at **http://www.caiso.com/2416/2416e7a84a9b0.pdf**