Memorandum

To: ISO Board of Governors

From: Eric Hildebrandt, Executive Director, Market Monitoring

Date: July 19, 2019

Re: **Department of Market Monitoring update**

This memorandum does not require Board action.

EXECUTIVE SUMMARY

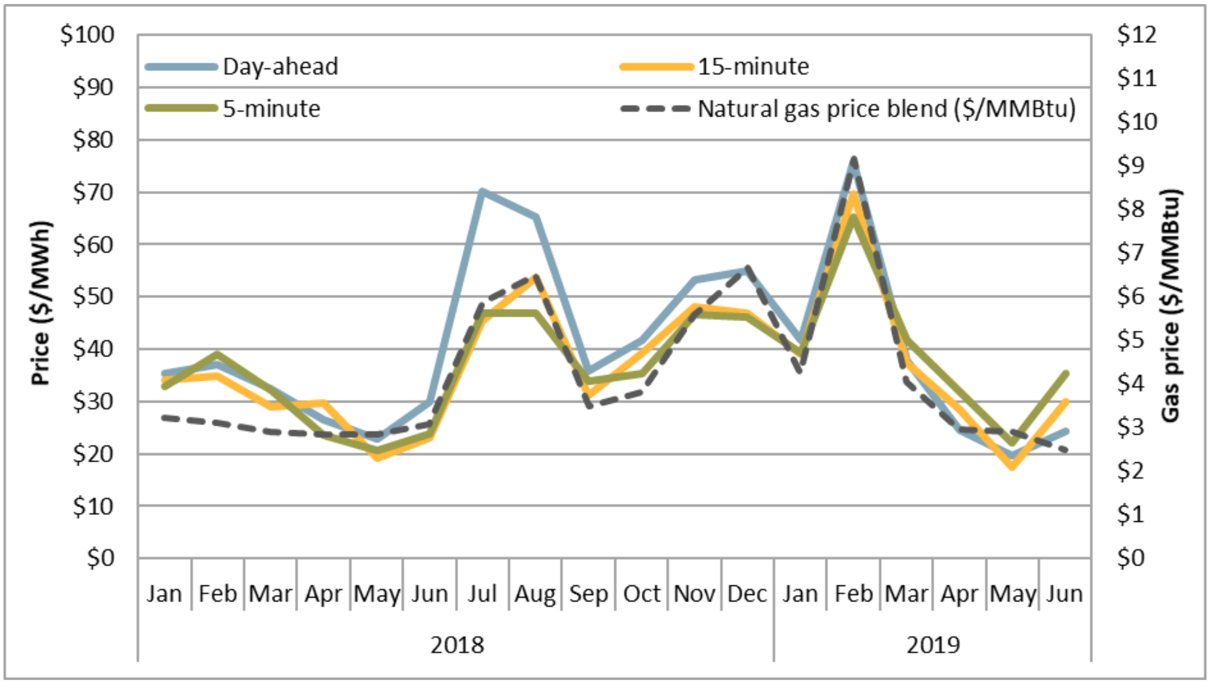
This memo provides highlights of market performance in the first half of 2019.

- Energy prices in the first quarter of 2019 driven were higher by a significant increase in gas prices during February. In the second quarter, prices dropped to about the same level as in the second quarter of 2018. Lower prices in Q2 were driven by low gas prices and an increase in hydroelectric, wind, and solar production.
- In the first quarter, prices in the day-ahead market remained higher then real-time prices, continuing a trend that has persisted during most months since June 2017. However, this pattern changed in April and June, as average day-ahead prices were lower than real-time prices.
- Reduction in wind and solar generation increased significantly compared to previous years, particularly in the second quarter. Almost all of the downward dispatch of wind and solar resources was based on bid prices submitted by these resources. Curtailment of self-scheduled wind and solar resources also increased, but remained very low.
- During the first half of 2019, congestion revenue rights auction revenues collected from non-load-serving entities have been $8 million less than payments made to entities purchasing these rights. This value is down from $61 million in losses incurred in the first half of 2018 and $31 million in the first half of 2017.
- Payments to financial entities purchasing congestion revenue rights in the first half of 2019 exceeded auction revenues by over $13 million. However, generation owners and energy marketers paid over $5 million more in auction revenues than the payments they received from these congestion revenue rights.
- The drop in overall losses to transmission ratepayers from congestion revenue rights sold in the auction result from changes made in the ISO's market rules taking effect in 2019, along with relatively low congestion compared to prior years.

MONTHLY ENERGY MARKET PRICES

As shown in Figure 1, energy prices in the first quarter were higher than both the previous quarter and the first quarter of last year. This was largely due to an increase in gas prices both in the ISO area as well as in the Pacific Northwest. In the second quarter, prices were significantly lower than the first quarter and about the same as prices in the second quarter of 2018. The trend in the second quarter was due to lower gas prices and an increase in hydroelectric, wind, and solar production.

Figure 1. Average monthly system marginal energy and natural gas prices



GAS PRICES

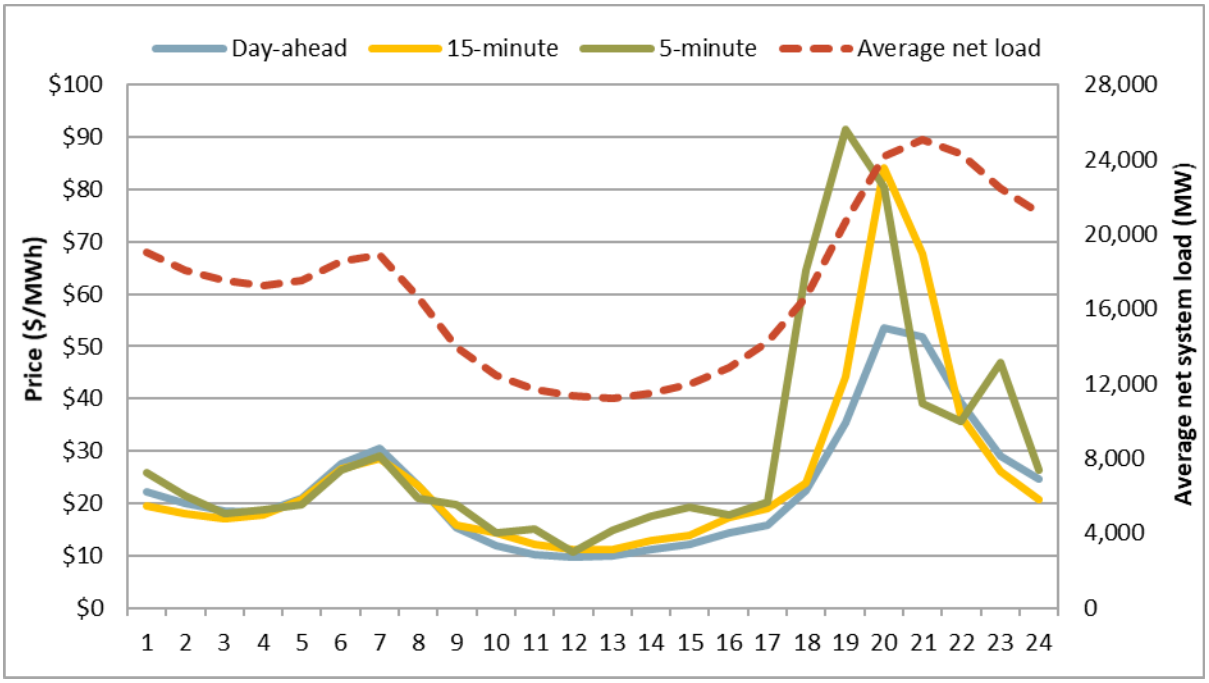
In the first quarter of 2019, natural gas prices increased significantly across major gas trading hubs in the west compared to the same quarter in 2018. High natural gas prices in February 2019, at SoCal, PG&E Citygate, and in the Pacific Northwest were the main driver of high system marginal energy prices across the ISO footprint.

The main factors contributing to the gas prices in February were high heating demand amid cold weather and limited regional gas supply. These factors also led SoCalGas and PG&E to issue electric power generation curtailment orders and withdraw gas from the Aliso Canyon storage facility throughout February. On most days in February, a low operational flow order was in effect, which might also have had an impact on the prices due to the anticipation of non-compliance penalty charges. In the second quarter, temperatures were more moderate, and gas prices dropped reflecting fewer gas supply limitations.

HOURLY ENERGY MARKET PRICES

As shown in Figure 2, on an average hourly basis, prices continue to follow the net load curve in all markets, peaking in hours ending 19 and 20. In the second quarter, prices in the day-ahead market were lower than real-time prices for most hours of the day. Average prices in the day-ahead market have tended to be higher than real-time prices during most months since June 2017.

Figure 2. Average hourly system marginal energy prices (April - June 2019)



GENERATION BY FUEL TYPE

Figure 3 shows generation by fuel type over the day. Nuclear, bio-based resources, and geothermal resources remain constant, comprising about 4,300 MW of inflexible base generation. In hours ending 18 through 21, as solar ramps down, the resources primarily being used to meet the evening peak include hydro, natural gas, and imports.

Figure 4 more clearly shows how resources of each of these fuel groups varied in the second quarter with solar production. Of all of the resource groups, generation from imports varied most over the day. During the peak, gas resources produced the most energy of any resource type. Hydroelectric generation also varied, though less than imports and natural gas. Finally, wind generation on average mirrors solar production, generating more in the early morning and late evening, and less in the middle of the day. There is little variability from other resources on an hourly basis.

Figure 3. Average hourly generation by fuel type (April - June 2019)

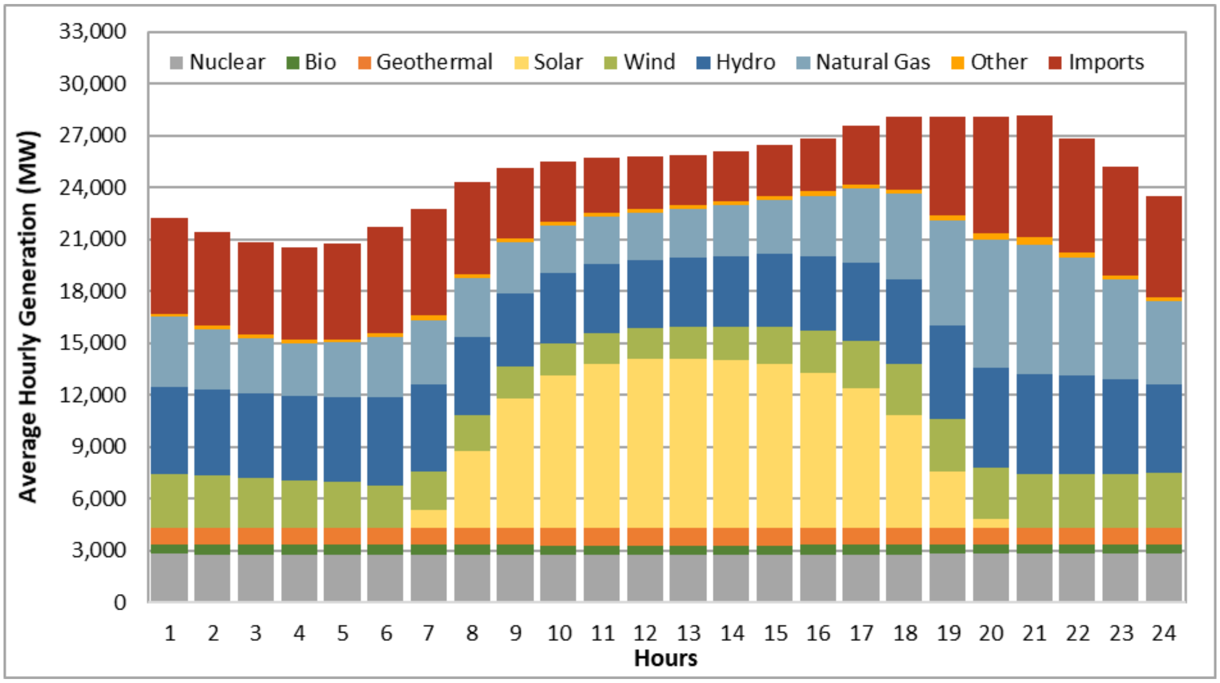
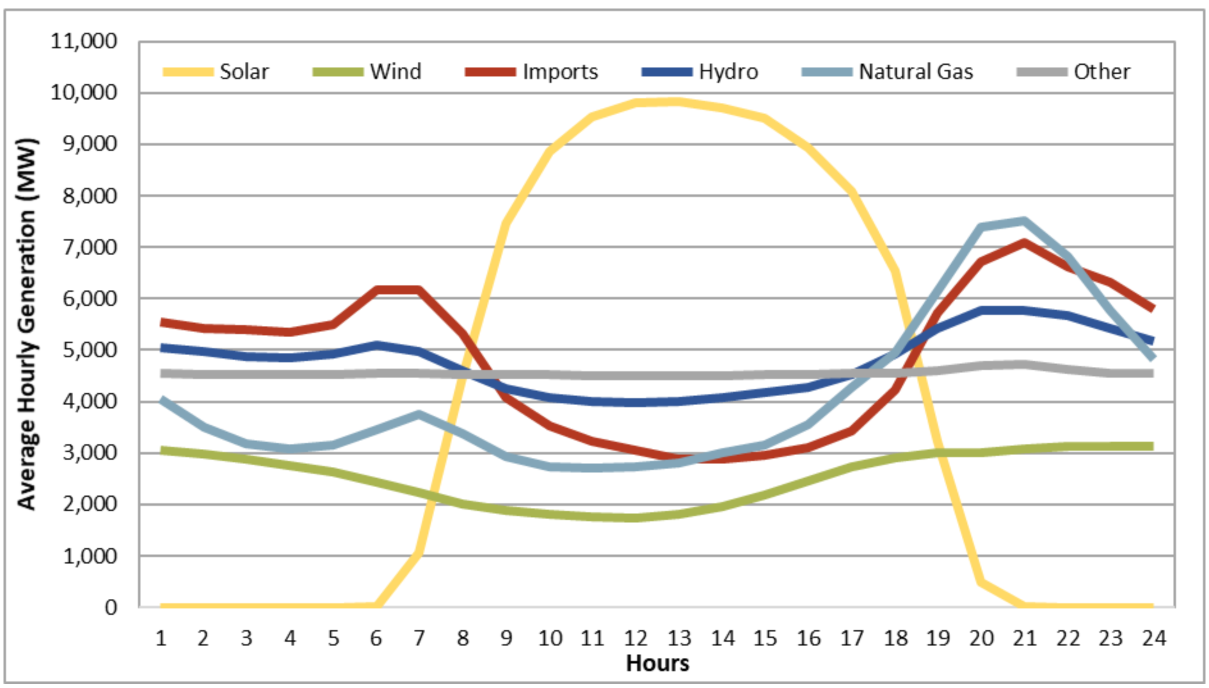


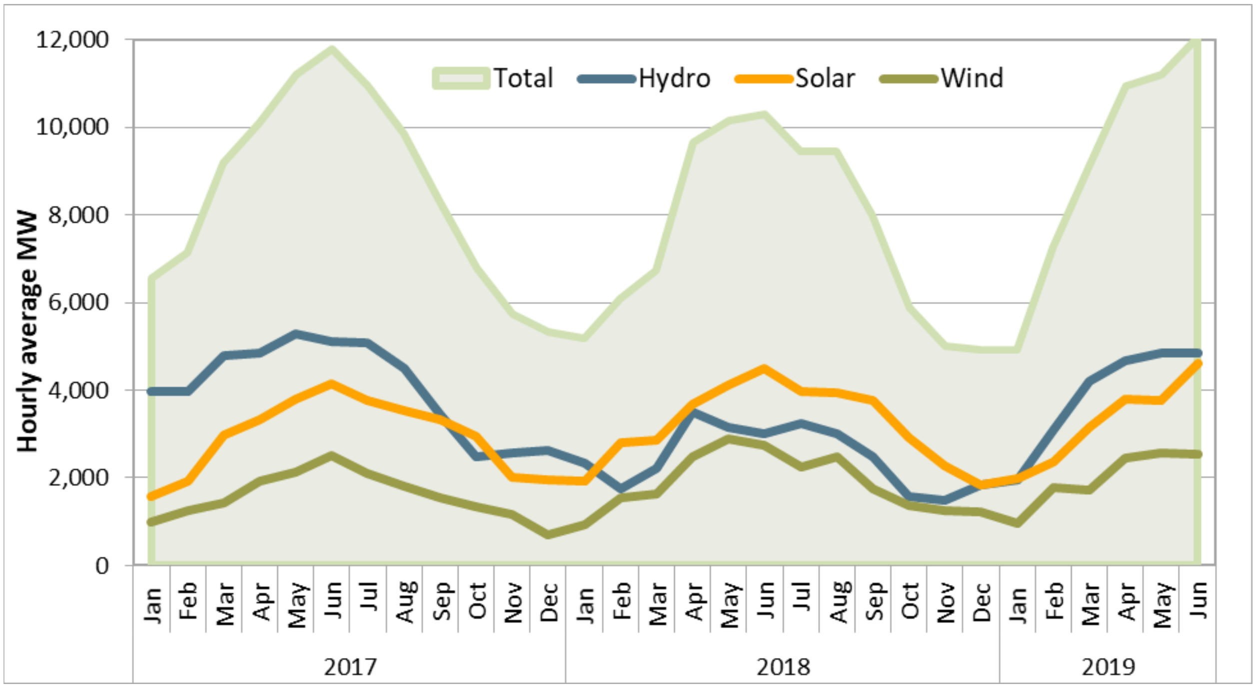
Figure 4. Average hourly generation by fuel type (April - June 2019)



MONTHLY HYDRO, WIND, AND SOLAR GENERATION

As show in Figure 5, hydroelectric production increased by about 47 percent compared to the first and second quarters of 2018. Solar and wind were slightly lower (about 1 percent) in the first half of 2019 despite increases in installed capacity. Compared to the previous quarter, all three resource types increased by more than 50 percent. Generation from these resources typically peaks in the second quarter.

Figure 5. Hydro, solar, and wind generation by month (2017-2019)



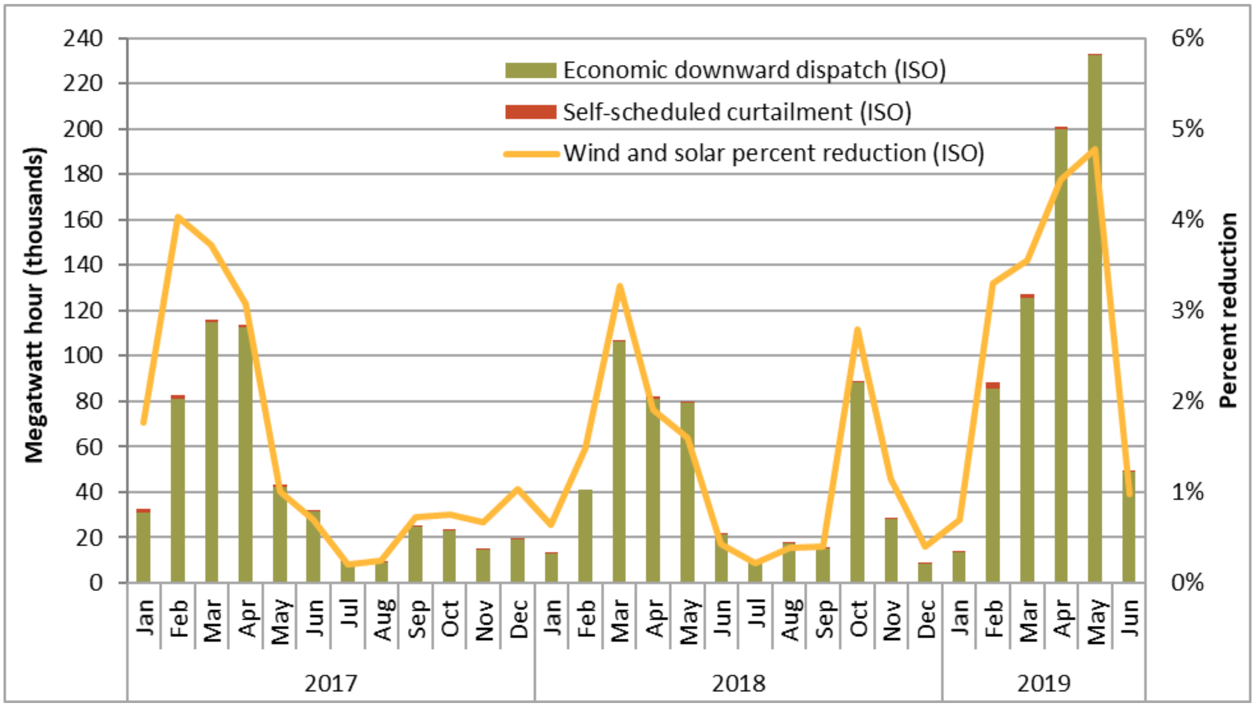
REDUCTIONS IN WIND AND SOLAR GENERATION

As shown in Figure 6, reductions in wind and solar generation as a result of economic downward dispatch and self-schedule curtailment increased significantly compared to previous years, particularly in the second quarter. Reduction in wind and solar generation can be explained by a combination of factors including negative prices, availability of hydroelectric resources, load conditions, export capability, and the amount of wind and solar bidding economically into the ISO market.

In 2019, hydroelectric production was high, similar to production in 2017. Wind and solar production decreased despite greater amounts of installed solar and wind capacity on the system. The percent of wind and solar reduction as a percent of total possible production increased slightly, as shown in Figure 6. Average loads for March, April, and May were lower than the same months in 2017 and 2018 and the ISO system saw some of the lowest net loads ever observed. There were a high frequency of negative prices.

Curtailment of self-schedules (shown in red on Figure 6) remains very low relative to the amount of economic downward dispatch. Most or all curtailments of self-scheduled wind and solar energy is due to localized congestion.

Figure 6. Reduction in wind and solar generation by month (2017-2019)



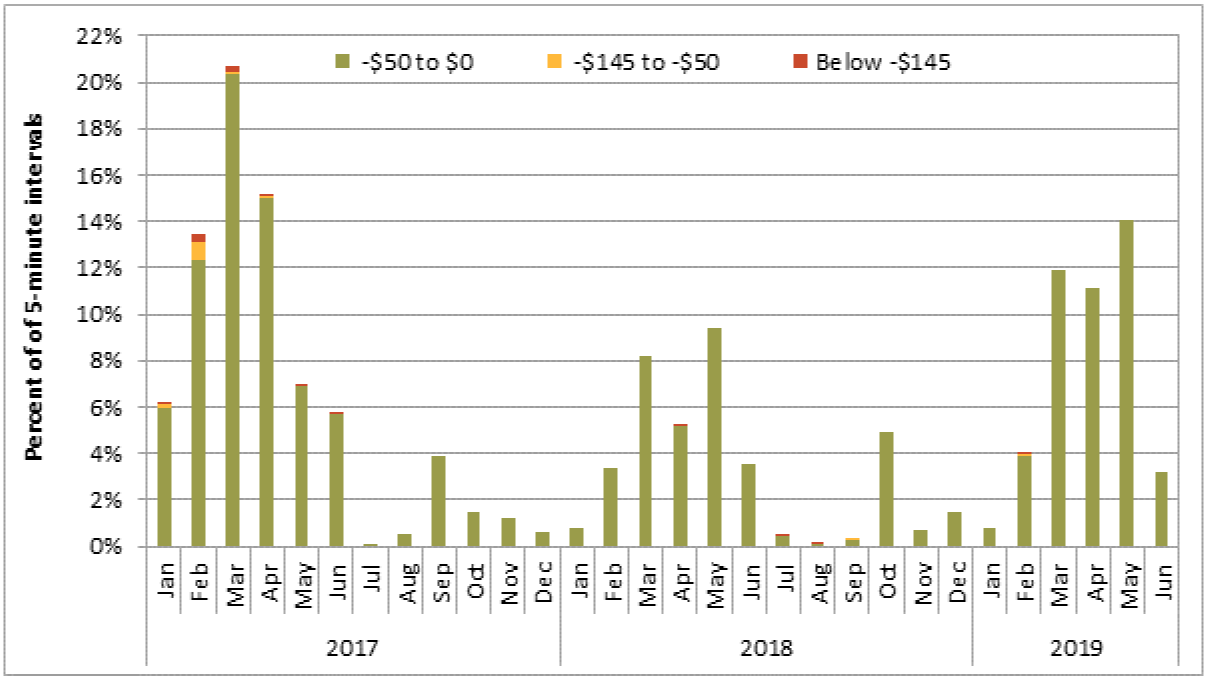
NEGATIVE ENERGY PRICES

The frequency of negative prices is one important factor connected with the reduction in wind and solar generation by economic downwards dispatch. Increased availability of hydroelectric, wind and solar resources is correlated with relatively low prices, and these resources often submit negatively priced bids reflecting their relatively low marginal costs.

Figure 7 shows that the frequency of negative prices in the 5-minute market increased in March, April, and May relative to previous months. Negative prices during April and May occurred during around 10 percent of 15-minute intervals and 13 percent of 5-minute intervals. It is important to note that the majority of negative prices were between negative \$50 and \$0.

Negative prices typically occur in the spring time when hydroelectric generation is greatest, and between hours ending 9 and 17 when net loads are lowest.

Figure 7. Frequency of negative 5-minute prices by month



CONGESTION REVENUE RIGHTS

The profitability of auctioned congestion revenue rights – or losses to transmission ratepayers – are calculated as the difference in payments received by buyers of auctioned rights less the auction price paid for these congestion revenue rights . With the settlement changes implemented in 2019 under the ISO's Track 1B initiative, payments to entities purchasing congestion revenue rights in the auction are reduced by offsets now charged to auctioned congestion revenue rights.[1]

During the first half of 2019, congestion revenue rights auction revenues collected from non-load-serving entities have been $8 million less than payments made to entities purchasing these rights (see Figure 8). These losses from the auction are down from $61 million in losses incurred in the first half of 2018 and $31 million in the first half of 2017.

[1] *Q1 Report on Market Issues and Performance,* Department of Market Monitoring, June 28, 2019, p.38. http://www.caiso.com/Documents/2019FirstQuarterReportOnMarketIssuesAndPerformance.pdf

Also see *FERC Order on Tariff Amendment - Congestion Revenue Rights Auction Efficiency Track 1B,* November 9, 2018, http://www.caiso.com/Documents/Nov9-2018-OrderAcceptingTariffRevisions-CRRTrack1BModification-ER19-26.pdf

Figure 8. Auction revenues compared to payments for auctioned CRRs

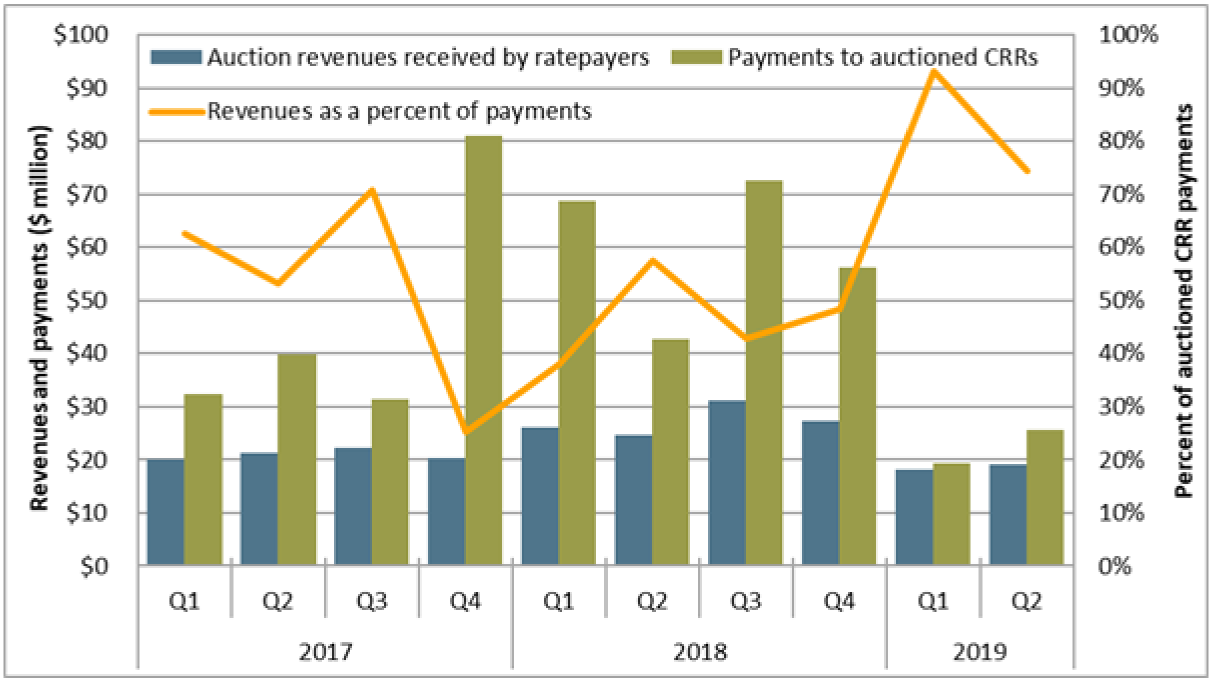


Table 1. Auction revenues compared to payments for auctioned CRRs

Participant Type	Auction revenues	CRR payments	Revenue offsets	Net CRR payments	Profit for participant	Auction revenue / payments
Financial	$19.4	$40.5	($7.8)	$32.7	$13.3	$0.59
Marketer	$9.8	$11.9	($4.3)	$7.5	($2.2)	$1.29
Generator	$8.0	$7.2	($2.4)	$4.8	($3.2)	$1.65
Total	$37.20	$59.60	($14.50)	$45.00	$7.90	$0.62

As shown in Table 1, payments to financial entities purchasing congestion revenue rights in the first half of 2019 exceeded auction revenues by over $13 million. However, generation owners and energy marketers paid about $5.4 million more in auction revenues than the payments they received from these congestion revenue rights.

The decrease in losses to transmission ratepayers from sales of congestion revenue rights is due in part to changes to the auction implemented by the ISO in 2019 which limit the source and sink of congestion revenue rights that can be purchased in the auction (Track 1A). In addition, DMM estimates that offset charges made under settlement changes implemented in 2019 under the ISO's Track 1B initiative reduced losses from auctioned revenue rights by over $14 million over the first has of 2019 (see Table 1).

The decrease in losses to transmission ratepayers from sales of congestion revenue rights was also likely driven in part by a drop in the impact and direction of congestion on day-ahead prices compared to the same period in 2018, as shown in Figure 9.

Figure 9. Impact of congestion on day-ahead market prices by load area