California ISO

Q3 Report on Market Issues and Performance

December 5, 2019

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California Independent System Operator

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Executive summary

This report covers market performance during the third quarter of 2019 (July – September). Key highlights during this quarter include the following:

- Market prices were lower and highly competitive in the third quarter due to a combination of favorable market and system conditions, including low and stable gas prices, low loads, high hydroelectric supplies and limited generation and transmission outages.
- The total estimated wholesale cost of serving load in the third quarter of 2019 was about $2.5 billion or about $39/MWh. The third quarter cost is a 44 percent ($33.12/MWh) decrease compared to the third quarter of 2018.
- Natural gas prices dropped by about 45 percent and were much more stable in Q3 compared to 2018. After adjusting for natural gas costs and changes in greenhouse gas prices, wholesale electric costs decreased by about 14 percent to $42/MWh from $49/MWh.
- Lower load conditions contributed to lower wholesale energy costs. This summer the instantaneous peak load was 44,301 MW — the lowest load peak since 2003. This summer's peak is about 5 percent lower than the ISO's 1-in-2 year load forecast (46,511 MW) and about 10 percent lower than the 1-in-10 year forecast (48,979 MW).
- Day-ahead, 15-minute and 5-minute prices were closely aligned, averaging $35/MWh, $35/MWh, and $34/MWh, respectively (Figure E.1).
- The increase in load forecast adjustments by grid operators during the morning and evening net load ramp periods which began in 2017 continued into the third quarter of 2019. Load adjustments averaged almost 1,200 MW in both hour-ahead and 15-minute markets for peak net load hours. Operator adjustments to day-ahead residual unit commitment requirements averaged 686 MW.
- In the day-ahead market, the overall net impact and frequency of congestion was very low relative to the same quarter in 2018 and slightly higher than in the second quarter of 2019. Similar to previous quarters, the frequency of congestion was highest in SDG&E.
- During the third quarter of 2019, congestion revenue rights auction revenues were $4.1 million less than payments made to non-load-serving entities purchasing these rights (Figure E.2). Payments to financial entities and energy marketers purchasing congestion revenue rights exceeded auction revenues by about $4.4 million and $2.2 million, respectively. However, generators paid about $2.3 million more in auction revenues than the revenues they received from these congestion revenue rights.
- The $4.1 million loss this quarter is 23 million less than losses to transmission ratepayers from sales of congestion revenue rights, relative to $27.4 million loss in the third quarter of 2018. The reduced loss is due in part to changes to the auction and settlement of CRRs implemented by the ISO in 2019. Losses from sales of congestion revenue rights are also down due to lower congestion in the day-ahead market.

Figure E.1 Average monthly system marginal energy prices (all hours)

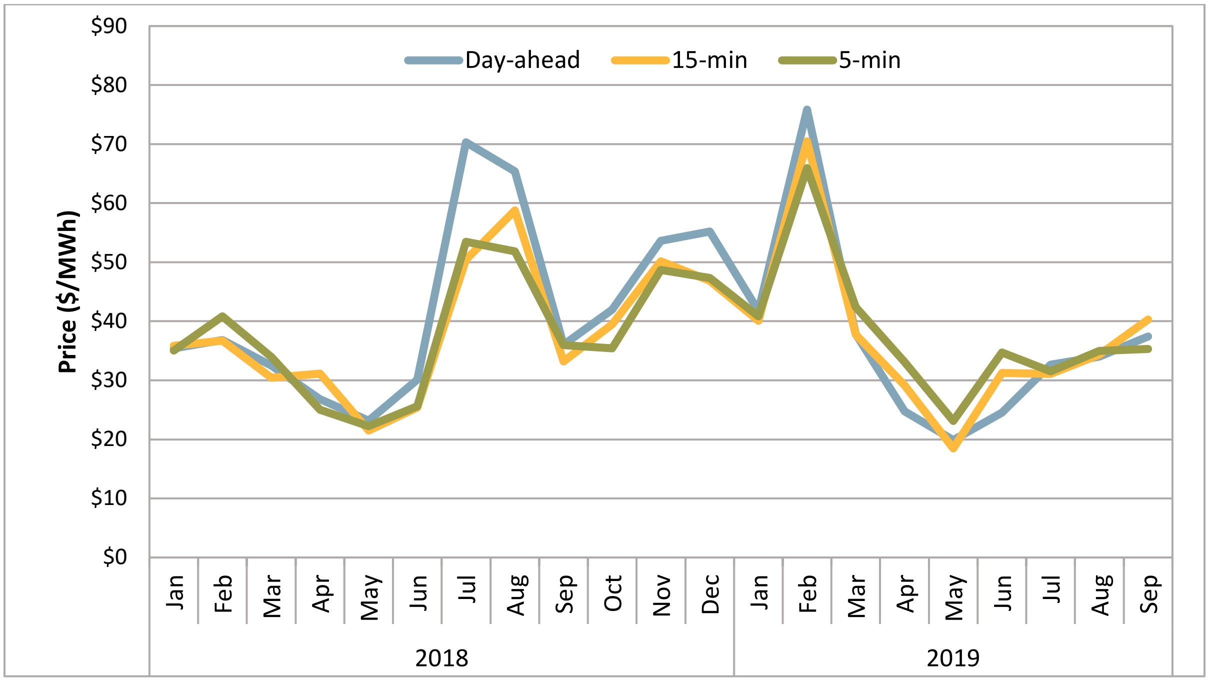
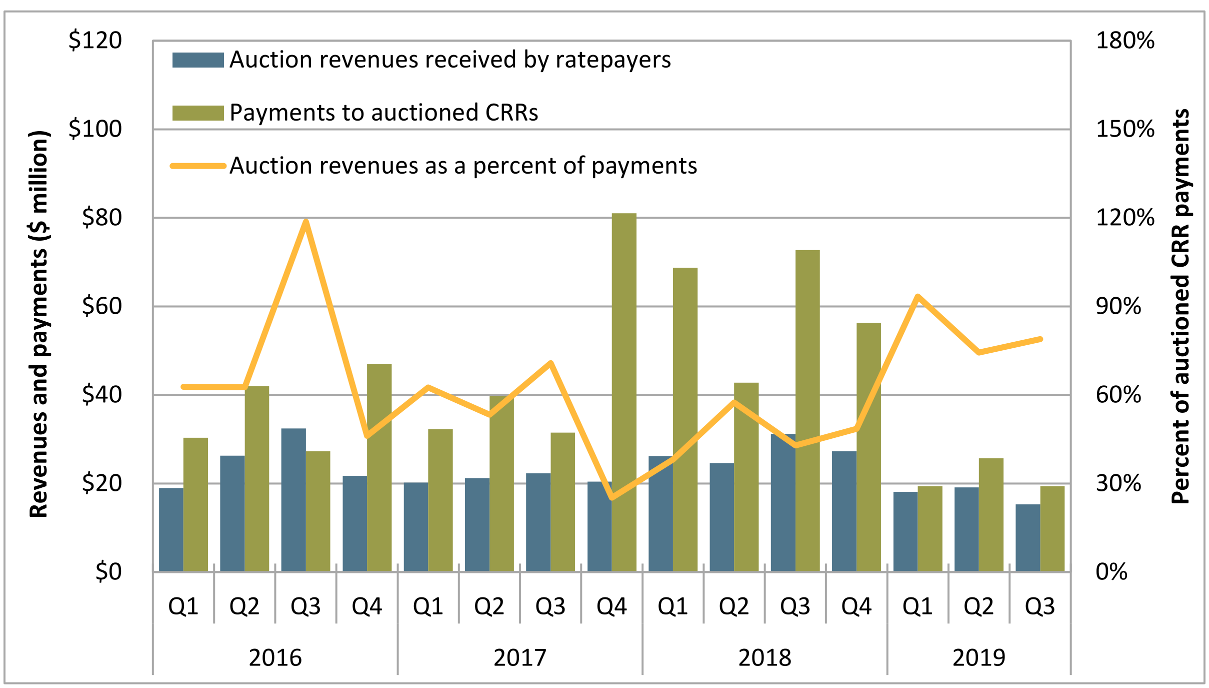


Figure E.2 Auction revenues and payments to non-load-serving entities



- Costs for ancillary services decreased during the third quarter to about $29 million, compared to about $58 million in the previous quarter and $78 million during the same quarter in 2018. In addition to lower energy costs, reduced operating reserve requirements contributed to this reduction.
- Estimated bid cost recovery payments for the third quarter of 2019 totaled about $48 million. This amount was $20 million higher than the total amount of bid cost recovery in the previous quarter and about $40 million lower than the third quarter of 2018.
- Net revenues for convergence bidders, before accounting for bid cost recovery charges, were about $7.2 million – with about $1.4 million in profits to virtual supply and $5.9 million to virtual demand. Net profits for virtual bidders were about $5.8 million after including about $1.4 million of virtual bidding bid cost recovery charges.
- Imbalance offset charges totaled $26 million, the sum of $15 million congestion offset charges, $10 million energy offset, and $1 million loss offset. Congestion offset charges were associated with network model changes and reductions in constraint limits in the 15-minute market from the day-ahead market.

Energy imbalance market

- The ISO implemented an enhancement in May 2019 which evaluates sufficiency test results and potentially limits transfers on a 15-minute interval basis rather than for the entire hour. This enhancement has decreased the frequency in which EIM areas failed the upward or downward sufficiency test.
- Another enhancement implemented in February 2019 significantly reduced the frequency in which the conformance limiter triggered for under-supply conditions for NV Energy during the third quarter. Instead, prices for this area were often set at the $1,000/MWh penalty parameter in these instances.
- During peak system load hours, prices in the Northwest region including PacifiCorp West, Puget Sound Energy, Portland General Electric, and Powerex were regularly lower than those in the ISO and other balancing areas because of limited transfer capability out of this region.
- Export transmission capacity from Powerex and Portland General Electric toward the ISO continued to be limited in many hours in both the 15-minute and 5-minute markets.

Special issues

Flexible ramping product

- Flexible ramping prices were frequently zero in both the 15-minute and 5-minute markets in both the upward and downward directions. In these intervals, flexible ramping capacity was readily available relative to the need for it so that no cost is associated with the level of procurement. However, much of this capacity was not available when needed due to it being released, resource characteristics, transmission constraints and other issues.

- Total uncertainty payments to generators for providing flexible ramping capacity during the third quarter were around $0.6 million, compared to around $2.1 million in the previous quarter.
- For the year ending September 2019, 44 percent of payments for flexible ramping capacity have been to resources internal to the ISO while 43 percent of payments for flexible ramping capacity have been to areas in the Northwest region that includes PacifiCorp West, Puget Sound Energy, Portland General Electric, and Powerex. About 53 percent of payments have been to hydroelectric generators and 32 percent to gas resources, while around 6 percent have been to each of coal and proxy demand response units.
- A recent ISO report highlighted several issues with current flexible ramping product design and implementation including procurement of flexible ramping capacity from resources that are not able to meet system uncertainty either because of resource characteristics or congestion.[1] This can reduce the effectiveness of the flexible ramping product to manage net load volatility and prevent power balance violations.
- Uncertainty over load and the future availability of resources to meet that load contributes to operators needing to enter systematic and large imbalance conformance adjustments, as described in Section 1.14 of this report. The ISO could reduce the need for manual load adjustments and more efficiently integrate distributed and variable energy resources by designing a real-time flexible ramping product that could procure and price the appropriate amount of ramping capability to account for uncertainty over longer time horizons (e.g., 2 or 3 hours) than the 15-minute and 5-minute time horizons that the current design considers.

Batteries

- Energy bids from battery storage resources appeared to be more economic in the second and third quarters of 2019 than in prior quarters. However, there has not been a significant increase in energy schedules for battery storage resources compared to regulation capacity schedules in 2019.

Demand response resource adequacy

- Analysis of 2019 market data suggests that the aggregate demand response capacity that proxy demand response (PDR) resources have shown on resource adequacy supply plans exceeds both bids in the day-ahead market in some hours and appears to exceed the total capability of this resource fleet. This means that PDR resource adequacy capacity bid into the ISO was frequently in excess of the actual load reduction capability from these resources.

Exceptional dispatch

- Total energy resulting from all types of exceptional dispatch accounted for almost 1 percent of system load, comparable to the same quarter in 2018.

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1 *CAISO Energy Markets Price Performance Report*, California ISO, September 23, 2019: http://www.caiso.com/Documents/FinalReport-PricePerformanceAnalysis.pdf

Flexible Ramping Product Refinements Issue Paper and Straw Proposal, California ISO, November 14, 2019: http://www.caiso.com/Documents/IssuePaper-StrawProposal-FlexibleRampingProductRefinements.pdf

- In the third quarter, out-of-sequence energy costs were $8.1 million, while commitment costs for exceptional dispatch paid through bid cost recovery were $9.3 million.
- In the third quarter, mitigation of exceptional dispatches should reduce total exceptional dispatch costs by about $15.4 million. Almost all of this reduction was due to mitigation of exceptional dispatches to ramp units up to a minimum dispatchable level. The ISO's settlement system did not apply mitigation to exceptional dispatches prior to mid-2019, so the ISO will apply mitigation retroactively through settlement corrections.
- Many exceptional dispatches were issued to commit and start slower ramping gas units during the evening ramping hours in the third quarter. Most of these exceptional dispatches were issued to slow ramping gas generating resources located in the Los Angeles basin. These exceptional dispatches were issued to increase the amount of ramping capacity available to meet the evening net load ramp and to respond to other uncertainties in real-time, the same issues that the flexible ramping product is designed to address.
- Exceptional dispatches to RA Max are not subject to energy bid mitigation, and are paid the higher of the unit's energy bid or the market price.[2] The total unmitigated RA Max exceptional dispatch energy costs were around $5.2 million, about $3.3 million above market prices in the third quarter.
- DMM is recommending that RA Max exceptional dispatch energy should be subject to mitigation as there is a strong potential for suppliers to exercise market power and raise bids substantially over marginal cost.

System market power

- In 2019, the residual supply index, with the three largest suppliers removed (RSI_3), was less than one during 95 hours, and the index was less than one during 33 hours with the two largest suppliers removed (RSI_2). There have been no hours so far in 2019 with the index less than one and only the largest single supplier removed. A reduction in potentially non-competitive hours in 2019 relative to the previous two years is the result of factors supporting competitive conditions including lower loads and high rates of low cost renewable production.
- For the first three quarters of 2019, the average price-cost markup was about $0.73 or about 2 percent. This slight positive markup indicates that prices have been very competitive, overall, for the year.
- In the last few years, market power has had a very limited effect on system market prices even during hours when the ISO system was structurally uncompetitive. However, DMM has expressed concern that market conditions may evolve in a way that will increase the potential for system-level market power.
- DMM supports the ISO's proposal to continue with an initiative to design system market power mitigation and looks forward to working with the ISO throughout that process.
- DMM continues to recommend several other market design changes that may help mitigate system market power beyond the bid mitigation options being examined as part of this initiative. These

2 Exceptional dispatches referred to as *RA Max* exceptional dispatches by the ISO operators are exceptional dispatches to a resource adequacy contract value, which is typically at or near the unit's maximum capacity.

include consideration of options that would increase the supply and availability of energy from resource adequacy imports beyond the day-ahead market into real-time. DMM also continues to recommend that the ISO's plan for implementing FERC Order No. 831 include provisions to (1) ensure that import bids over $1,000/MWh are subject to ex ante cost justification and (2) avoid setting penalty prices at $2,000/MWh except when needed to implement the provisions of the order.

1 Market performance

This section highlights key indicators of market performance in the third quarter.

- Market prices were lower and highly competitive in the third quarter due to a combination of favorable market and system conditions, including low and stable gas prices, low loads, high hydroelectric supplies and limited generation and transmission outages.
- The total estimated wholesale cost of serving load in the third quarter of 2019 was about $2.5 billion or about $39/MWh. This represents a 44 percent decrease compared to the third quarter of 2018 when the wholesale cost was $4.6 billion or $69/MWh. After adjusting for natural gas costs and changes in greenhouse gas prices, wholesale electric costs decreased by about 14 percent to $42/MWh from $49/MWh.
- This summer the instantaneous peak load was 44,301 MW which is the lowest load peak since 2003. This year's summer peak is about 5 percent lower than the ISO's 1-in-2 year load forecast (46,511 MW) and about 10 percent lower than the 1-in-10 year forecast (48,979 MW). Lower load conditions contributed to lower wholesale energy costs.
- During the third quarter of 2019, natural gas prices remained low across major gas trading hubs in the west. Compared to the same quarter in 2018, the average SoCal Citygate price dropped by 60 percent. Lower gas prices also contributed to lower wholesale energy costs.
- Increased renewable production also contributed to lower costs than the same quarter in 2018. Hydroelectric production increased by roughly 34 percent. Solar and wind production increased by about 10 percent and 6 percent, respectively. The change is likely due to increases in installed capacity from the previous year.
- Prices in the day-ahead market were close to prices in both real-time markets on a monthly average basis. Average day-ahead prices were just below $35/MWh, slightly lower than 15-minute prices just above $35/MWh, and slightly above average 5-minute prices, $34/MWh. Hourly average prices were also closely aligned, with the exception of hour ending 19, when 15-minute average hourly prices exceeded day-ahead and 5-minute prices by about $8/MWh, and hour 20, when both day-ahead and 15-minute market average prices exceeded 5-minute prices by more than $12/MWh.
- Estimated bid cost recovery payments for the third quarter of 2019 totaled about $48 million. This amount was $20 million higher than the total amount of bid cost recovery in the previous quarter and about $40 million lower than the third quarter of 2018.
- The overall net impact and frequency of congestion was very low relative to the same quarter in 2018 and slightly higher when compared to the second quarter of 2019 in the day-ahead market. Similar to previous quarters, the frequency of congestion was highest in SDG&E.
- During the third quarter of 2019, congestion revenue rights auction revenues were $4.1 million less than payments made to non-load-serving entities purchasing these rights. Payments to financial entities and energy marketers purchasing congestion revenue rights exceeded auction revenues by about $4.4 million and $2.2 million, respectively. However, generators paid about $2.3 million more in auction revenues than the revenues they received from these congestion revenue rights.

- Costs for ancillary services decreased during the third quarter to about $29 million, compared to about $58 million in the previous quarter and $78 million during the same quarter in 2018.
- The dramatic increase in load forecast adjustments during the steep morning and evening net load ramp periods in the ISO's hour-ahead and 15-minute markets in 2017 continued throughout 2018 and into the third quarter of 2019, with hourly average adjustments of almost 1,200 MW in both markets for peak net load hours.

1.1 Load conditions

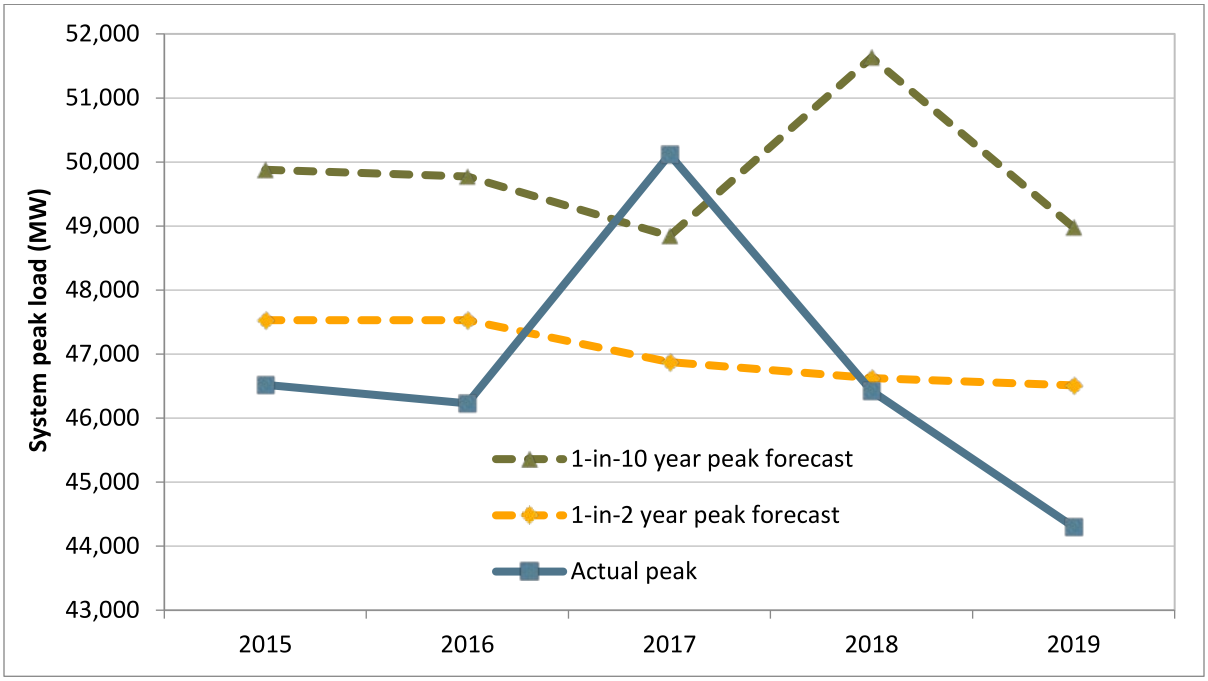
System demand during the single highest load hour often varies substantially year-to-year due to variation in summer heat wave weather conditions. This variation continues to create challenges to maintain operational reliability. Because demand in the ISO balancing area is primarily driven by temperature, peak loads usually occur during the third quarter.

This summer the instantaneous peak load was 44,301 MW and occurred on August 15, which is the lowest load peak since 2003 when the peak was 42,689 MW.[3] This year's peak is about 5 percent lower than the peak in 2018 and about 12 percent lower than the peak in 2017. Low load conditions were largely related to moderate temperatures across California along with greater penetration of behind-the-meter solar and energy efficiency.

The ISO works with the California Public Utilities Commission (CPUC) and other local regulatory authorities to set reliability planning requirements. System level resource adequacy requirements are based on the 1-in-2 year (or median year) forecast of peak demand. Resource adequacy requirements for local areas are based on the 1-in-10 year (or 90th percentile year) peak forecast for each area. As shown in Figure 1.1, the peak load this summer was about 5 percent lower than the ISO's 1-in-2 year load forecast (46,511 MW) and about 10 percent lower than the 1-in-10 year forecast (48,979 MW).

3 This value represents year-to-date peak loads.

Figure 1.1 Actual load compared to planning forecasts



1.2 Supply conditions

Natural gas prices

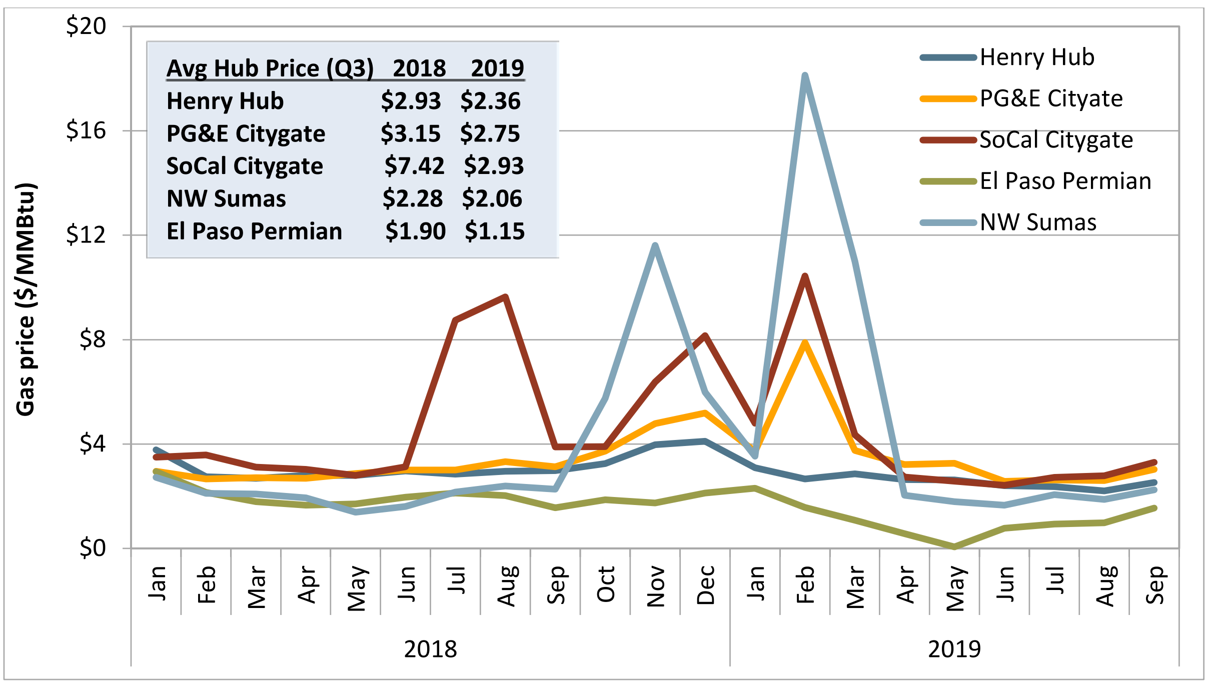
Electricity prices in western states typically follow natural gas price trends because natural gas units are often the marginal source of generation in the ISO and other regional markets. During the third quarter of 2019, natural gas prices remained low across major gas trading hubs in the west. Compared to the same quarter in 2018, the average SoCal Citygate price fell by 60 percent. Lower natural gas prices coupled with low load and increased renewable energy production led to low overall system marginal energy prices across the ISO footprint.

Figure 1.2 shows monthly average natural gas prices at key delivery points across the west including PG&E Citygate, SoCal Citygate, Northwest Sumas, El Paso Permian as well as for the Henry Hub trading point, which acts as a point of reference for the national market for natural gas. As shown in the figure, natural gas prices continued to remain steady in the third quarter of 2019 for all the hubs.

Prices at the SoCal Citygate gas hub averaged $2.93/MMBtu compared to $7.42/MMBtu in the third quarter of 2018. Prices remained low throughout the quarter because of relatively low gas demand in the SoCal area. Beginning June 1, 2019, the CPUC approved capping the Stage 4 and Stage 5 operational flow order (OFO) non-compliance penalties from $25/dth to $5/dth. This penalty structure was in place through September 30, 2019. During this period, the SoCalGas Company did not declare any low OFO's exceeding Stage 1. Beginning October 1 through May 31, 2020, an alternate tiered structure will be in place, which expands the OFO stages from 5 to 8.[4] On October 14, SoCalGas announced the completion of the Line 235-2 maintenance and its return to service at reduced pressure. This line has been out of service since October 2, 2017, causing significant supply constraints, which increased SoCal Citygate gas prices. SoCal Citygate prices often impact overall electric system prices because 1) there are large numbers of natural gas resources in the south, and 2) these resources can set system prices in the absence of congestion.

PG&E Citygate and Northwest Sumas gas prices have also remained low, and were trending below SoCal Citygate gas prices during the third quarter. After remaining low and sometimes negative throughout much of the second quarter of 2019, Permian basin prices started to rise because a new pipeline entered into service. The new pipeline provided additional take-away capacity, which was previously short due to a force majeure on El Paso Natural Gas's pipeline.

Figure 1.2 Monthly average natural gas prices



Generation by fuel type

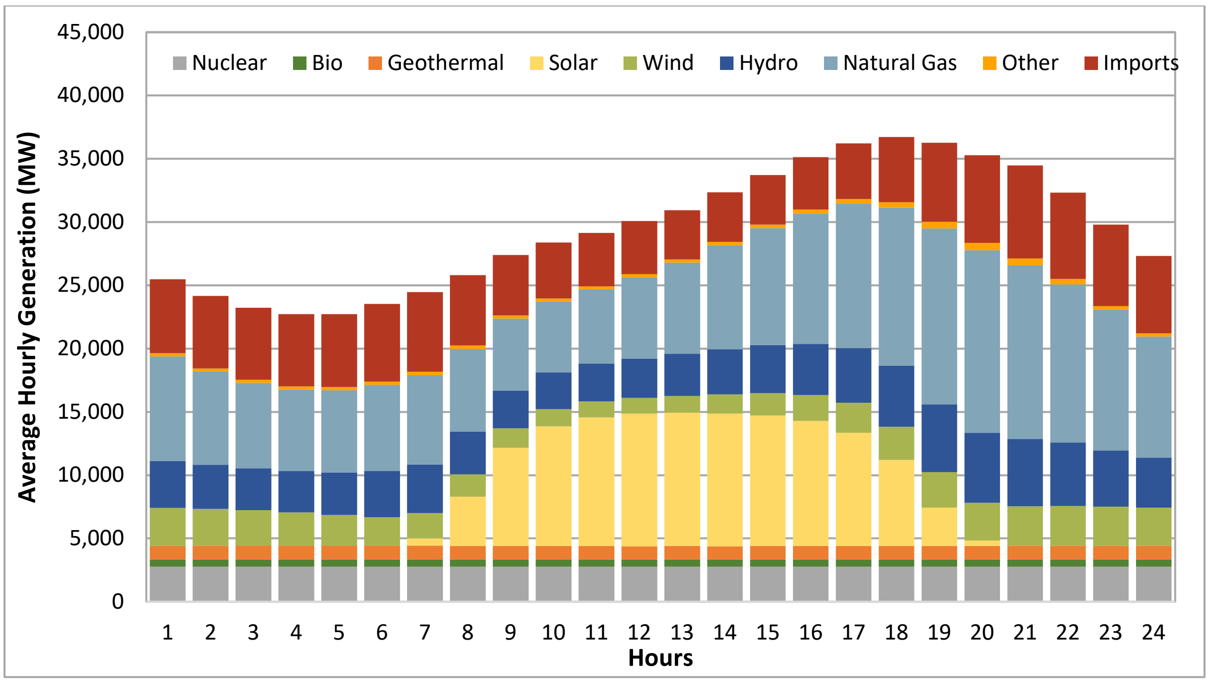
Figure 1.3 shows average hourly generation for the quarter by fuel type. In the third quarter, higher loads and lower wind and hydroelectric generation resulted in significantly more production from natural gas relative to the prior quarter, particularly in the evening hours. Generation from imports also increased compared to the previous quarter, especially during the middle of the day and during the peak. Nuclear, bio-based resources, and geothermal resources increased slightly compared to the previous quarter, comprising about 4,400 MW of inflexible base generation. Generation from 'other'

4 CPUC's Proposed Decision Granting In Part and Denying In Part for Modification Filed by SCE & Southern CA Generation Coalition of Commission, pp 31-32, April 29,2019: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M285/K085/285085989.PDF

resources, including coal, battery storage, demand response, and additional non-gas technologies, increased in this quarter, but it continues to be a small share of generation.

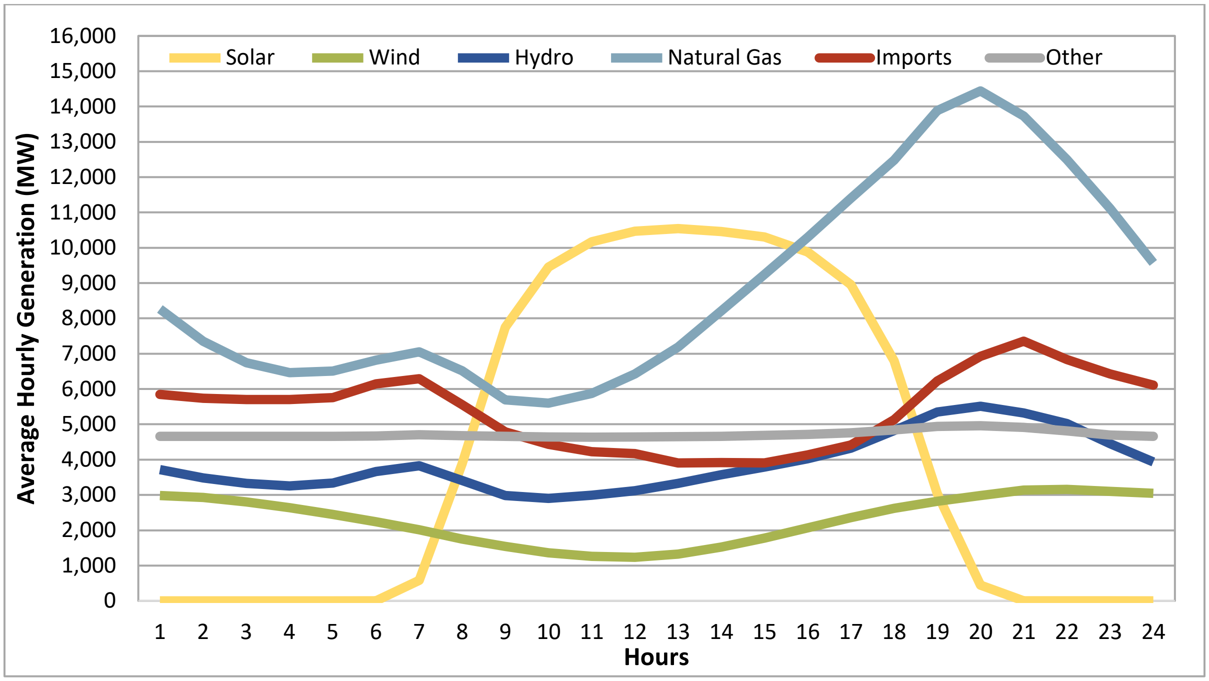
Figure 1.4 shows hourly variation of generation by fuel group, driven by hourly variation of solar production. In the third quarter, natural gas varied most over the day and produced significantly more than any resource during the peak net load hours. Net imports and hydroelectric generation also varied over the day, ramping up for the morning and evening net load peaks, and backing down when solar is producing. Conversely, there is little variability from other resources on an hourly basis.[5] Wind generation typically complements solar production, by generating more in the early morning and late evening, and less in the middle of the day.

Figure 1.3 Average hourly generation by fuel type (Q3 2019)



5 In this figure, the 'Other' category contains nuclear, geothermal, bio-based resources, coal, battery storage, demand response, and additional resources of unique technologies.

Figure 1.4 Hourly variation in generation by fuel type (Q3 2019)



Monthly variation in hydroelectric, wind, and solar

In the third quarter, total generation from hydroelectric, solar, and wind resources decreased when compared to the previous quarter. Generation from these resources tends to peak in the second quarter. Compared to the same quarter in 2018, generation increased due to greater availability of hydroelectric resources and continued capacity additions of wind and solar.

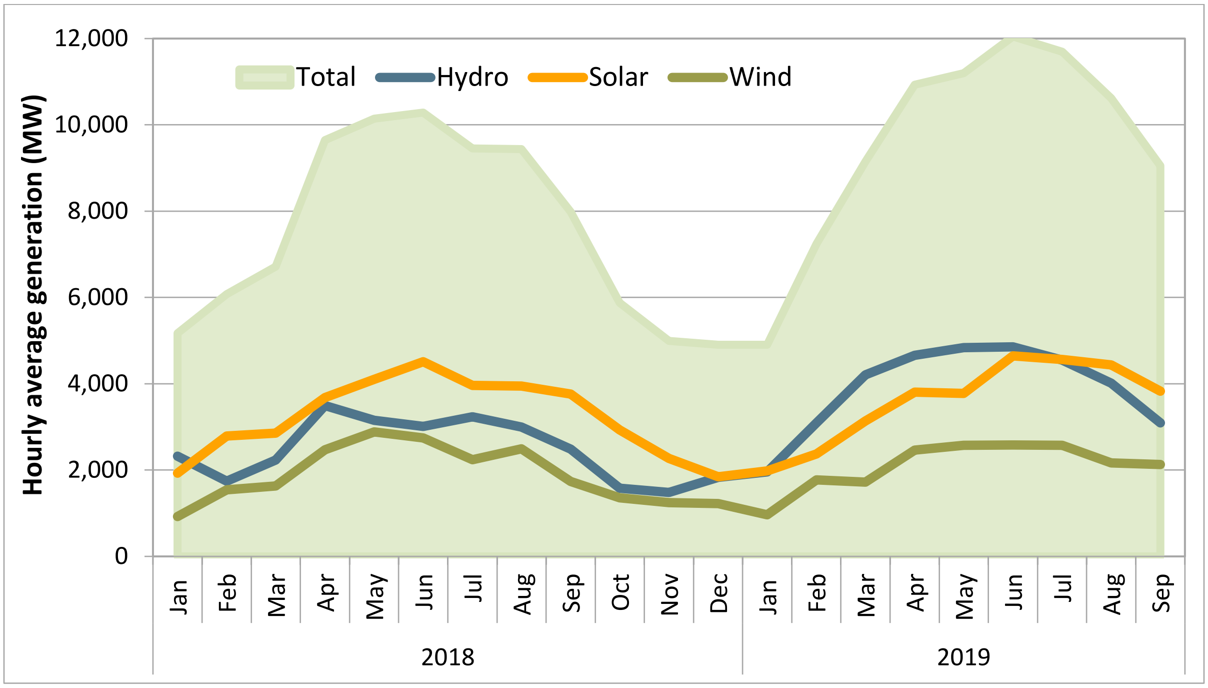
Compared to 2018, hydroelectric production in the third quarter increased by roughly 34 percent. As of April 1, the statewide weighted average snowpack in California was 175 percent of normal compared to 58 percent of normal on April 1, 2018.[6] Compared to the previous quarter, generation decreased 19 percent.

Compared to the third quarter of 2018, solar and wind production rose by about 10 percent and 6 percent, likely due to increases in installed capacity from the previous year. Compared to the second quarter of 2019, solar production increased, while wind production decreased. While generation from these resources typically peak in the second quarter, the increase in solar production was in part due to a large amount of economic downward dispatch in the second quarter. In April and May 2019, solar downward dispatch reached record levels of roughly 200,000.

The availability of variable resources contributes to patterns in prices both seasonally and hourly. Compared to the previous quarter, the decrease in production from these resources contributed to higher wholesale electricity prices due to their low marginal cost relative to other resources. The 19 percent increase in hydroelectric output is one contributing factor to this trend.

6 For snowpack information, please see California Cooperative Snow Survey's Snow Course Measurements on the California Department of Water Resources website: https://cdec.water.ca.gov/snow/current/snow/.

Figure 1.5 Average hourly hydroelectric, wind, and solar generation by month

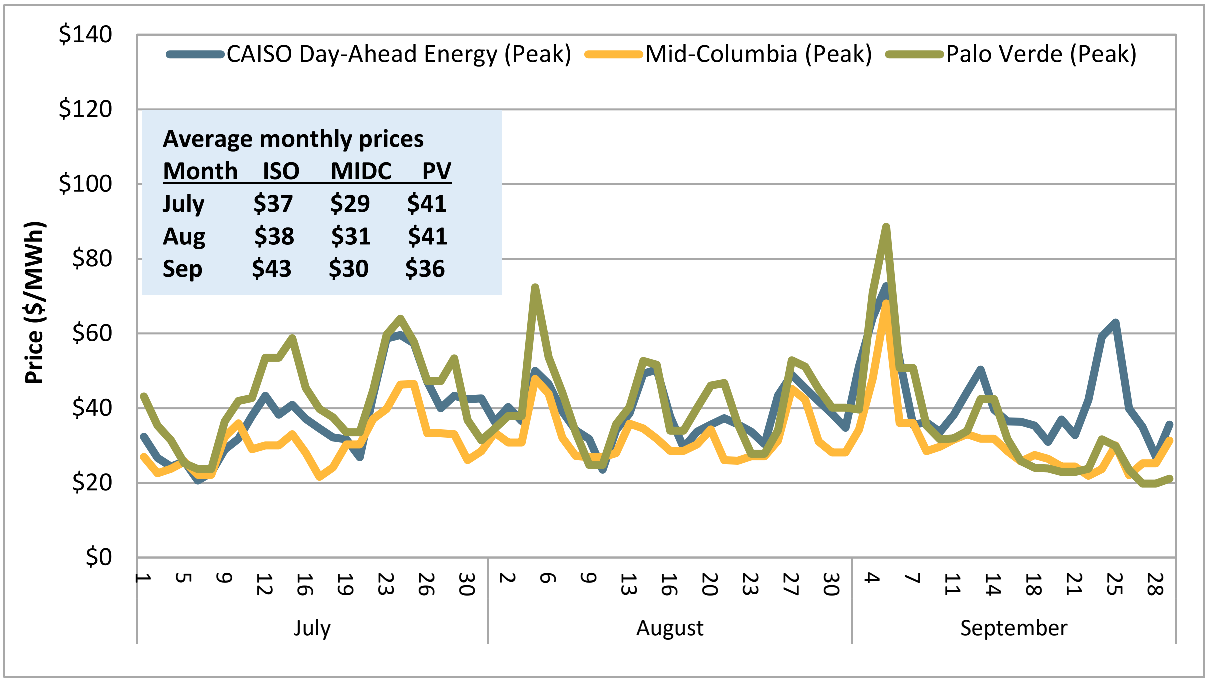


1.3 Comparison to bilateral market prices

Bilateral price comparison

Figure 1.6 shows day-ahead weighted average prices across the three largest load aggregation points (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric) in the ISO, as well as average peak energy prices at the Palo Verde and Mid-Columbia hubs outside of the ISO market in the third quarter.

Figure 1.6 Daily system and bilateral market prices (July – Sept)



Average prices in the ISO and trade hubs were calculated during peak hours (hours ending 7 through 22) for all days excluding Sundays and holidays. Daily energy prices at Palo Verde tended to be higher than ISO prices about 60 percent of the time, while Mid-Columbia prices were higher than ISO prices about 8 percent of the time during the quarter.

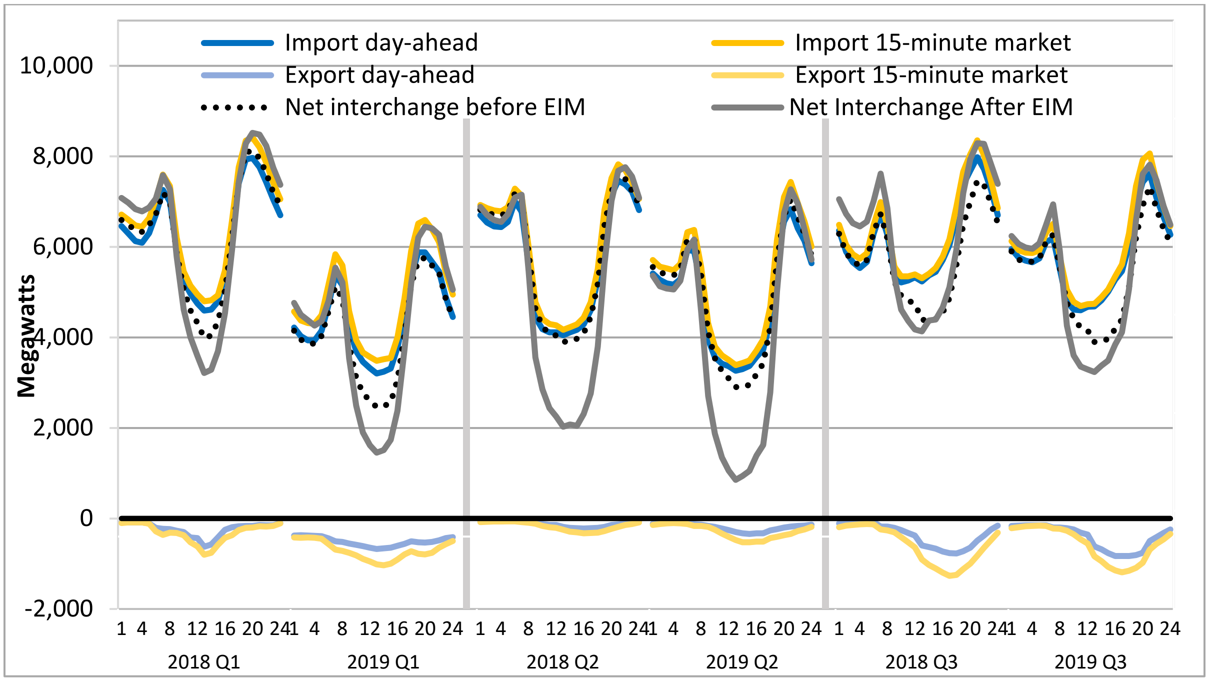
Average day-ahead prices in the ISO were also compared to hourly energy prices traded at Mid-Columbia and Palo Verde hubs for all hours of the quarter using data published by Powerdex. Average prices in the ISO, across all hours in the third quarter, were greater on average than prices in Mid-Columbia and Palo Verde by $8.56/MWh and $2.85/MWh, respectively.

Imports and exports

As shown in Figure 1.7, average hourly cleared imports (shown in dark blue and dark yellow) peaked at the same time and approximately the same volumes as the same quarter from the previous year. At peak imports in the day-ahead (dark blue line) decreased from about 8,000 MW in the previous quarter to 7,600 MW. Peak 15-minute cleared imports also decreased from about 8,400 MW to 8,100 MW.

The greatest import transfer into the ISO from the EIM occurred in hour ending 20 at about 700 MW. Exports (shown as negative numbers below the horizontal axis in pale blue and yellow), increased slightly from the same quarter in 2018, peaking at about 830 MW in hour ending 16 through 18. The average net interchange, excluding EIM transfers (shown in dashes), is based on meter data and averaged by hour and quarter. The solid grey line adds incremental EIM interchange, which reached a low point of about 3,300 MW in hour ending 15 and 14.

Figure 1.7 Average hourly net interchange by quarter



1.4 Energy market performance

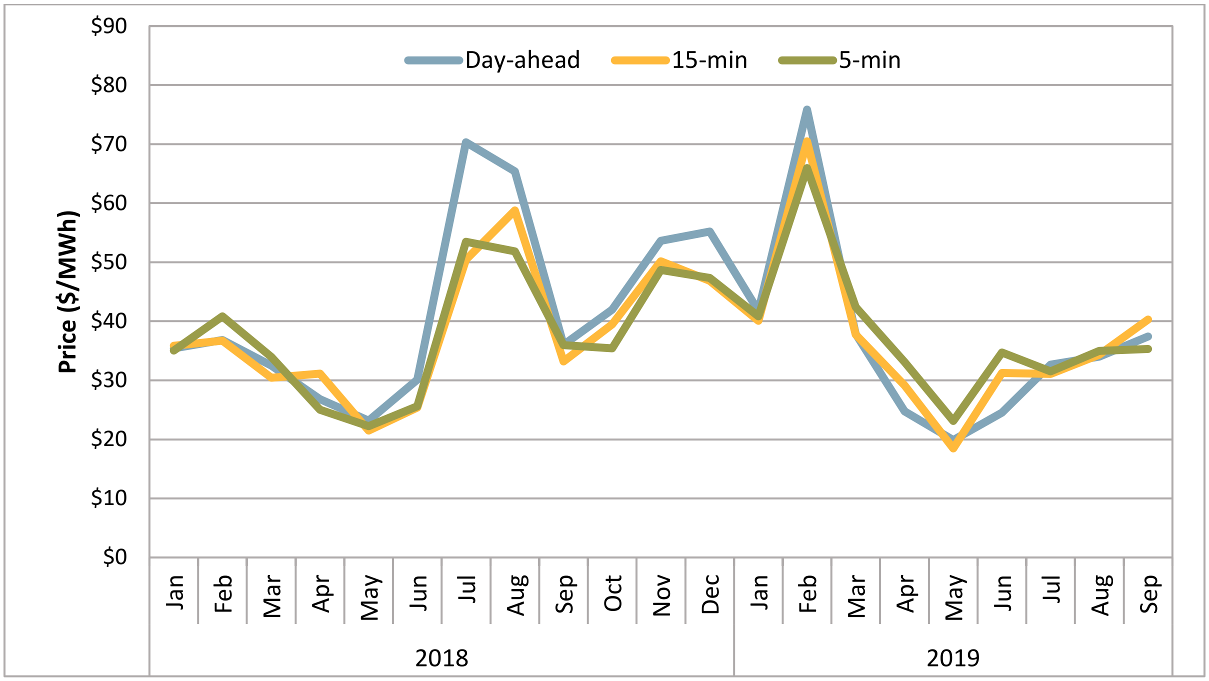
Energy market prices

This section assesses energy market efficiency based on an analysis of day-ahead and real-time market prices. Price convergence between these markets may help promote efficient commitment of internal and external generating resources.

Figure 1.8 shows load-weighted average monthly energy prices during all hours across the three largest load aggregation points in the ISO (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric).[7] Average prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) from January 2018 to June 2019.

[7] DMM typically weights prices at load aggregation points by schedules in each market. Due to data issues, however, prices reported here are weighted by actual load measurements at load aggregation points.

Figure 1.8 Average monthly system marginal energy prices (all hours)



Prices increased moderately from the second quarter to the third quarter of 2019. Average day-ahead prices increased by 51 percent, 15-minute prices increased by 34 percent, and 5-minute prices increased by 12 percent. Similar to the second quarter, these lower third quarter prices were driven by low gas prices as well as an increase in production from renewable resources when compared to the first quarter. Energy prices were lower than the third quarter of 2018 when system prices were affected by high natural gas prices in SoCal Citygate.[8]

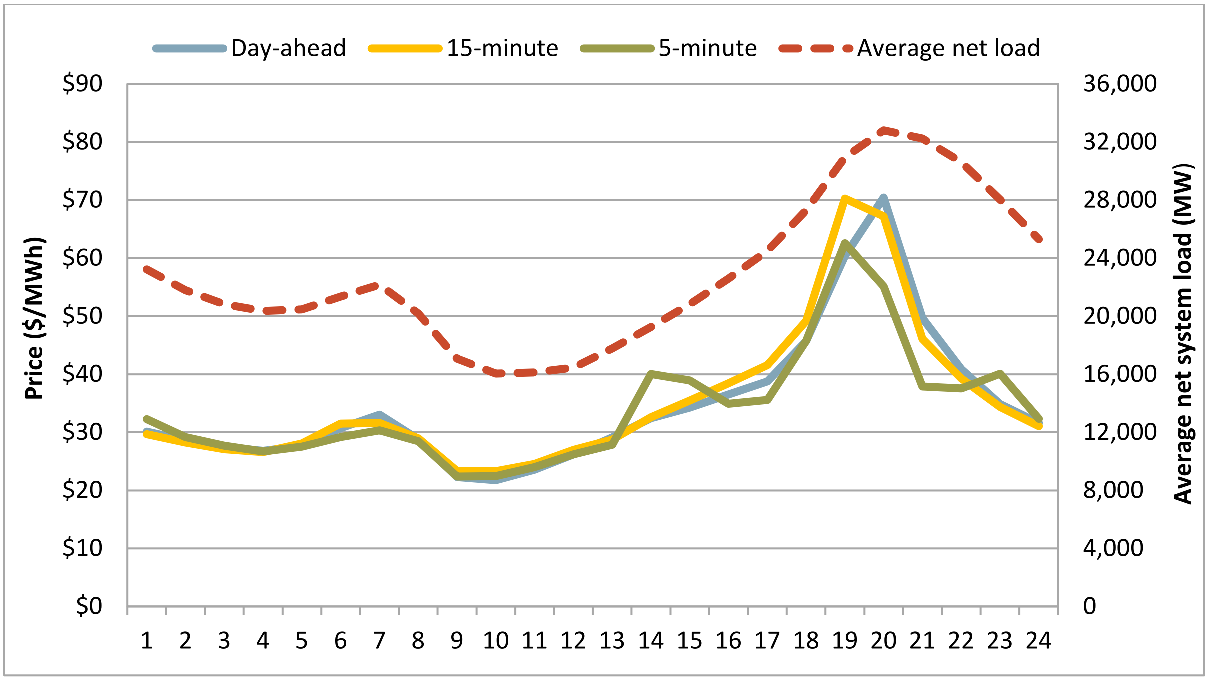
Average day-ahead prices were in between the 15-minute and 5-minute prices during the third quarter of 2019. Day-ahead prices averaged just below $35/MWh while 15-minute prices averaged just over $35/MWh and 5-minute prices averaged about $34/MWh. Since 2014, day-ahead prices have typically been higher than real-time prices, however, this pattern has changed in the second and third quarters of 2019.

Figure 1.9 illustrates load-weighted average energy prices on an hourly basis in the third quarter compared to average hourly net load.[9] Average hourly prices are shown for the day-ahead (blue line), 15-minute (gold line), and 5-minute (green line) and are measured by the left axis while average hourly net load (red dashed line) is measured by the right axis.

8 For more information, refer to DMM's *Q3 2018 Report on Market Issues and Performance*.

9 Net load is calculated by subtracting the generation produced by wind and solar that is directly connected to the ISO grid from actual load.

Figure 1.9 Hourly load-weighted average marginal energy prices



Average hourly prices in the third quarter continue to follow the net load pattern with the highest energy prices during the morning and evening peak net load hours and peak prices in hours ending 19 and 20. These hours had the greatest price divergence between the markets. In hour ending 19, 15-minute average hourly prices exceeded day-ahead and 5-minute prices by about $8/MWh, while in hour 20, both day-ahead and 15-minute market average prices exceeded 5-minute prices by more than $12/MWh. Despite the divergence in market prices during the evening peak hours, these prices were more consistent in the third quarter than in the second quarter of 2019 when large spikes in the 15-minute and 5-minute markets were associated with a large number of power balance constraint violations.

1.5 Wholesale energy cost

Total wholesale cost to serve load in the ISO market during the third quarter of 2019 was about $2.5 billion, compared to about $4.6 billion in the same quarter of 2018. The average cost per megawatt-hour of load decreased 44 percent to about $39/MWh for the third quarter from $69/MWh in the same quarter of 2018 (nominal costs shown in blue bars in Figure 1.10).

The decrease in average wholesale electric prices is primarily from a 43 percent decrease in natural gas prices compared to the same quarter in 2018. Volume-weighted gas prices decreased to about $3.80/MMBtu, a 43 percent decrease from about $6.63/MMBtu in the same quarter of 2018. When normalizing for changes in natural gas and greenhouse gas costs using the 2010 gas price as a reference year, the gold bar in Figure 1.10 shows the wholesale energy costs to serve load decreased by 14 percent to about $42/MWh from about $49/MWh in the same quarter of 2018. In addition to lower natural gas costs, low load, increased production from hydroelectric and solar resources, and low rates of congestion contributed to reduced wholesale energy costs this quarter.

Figure 1.10 Total quarterly wholesale costs per MWh of load

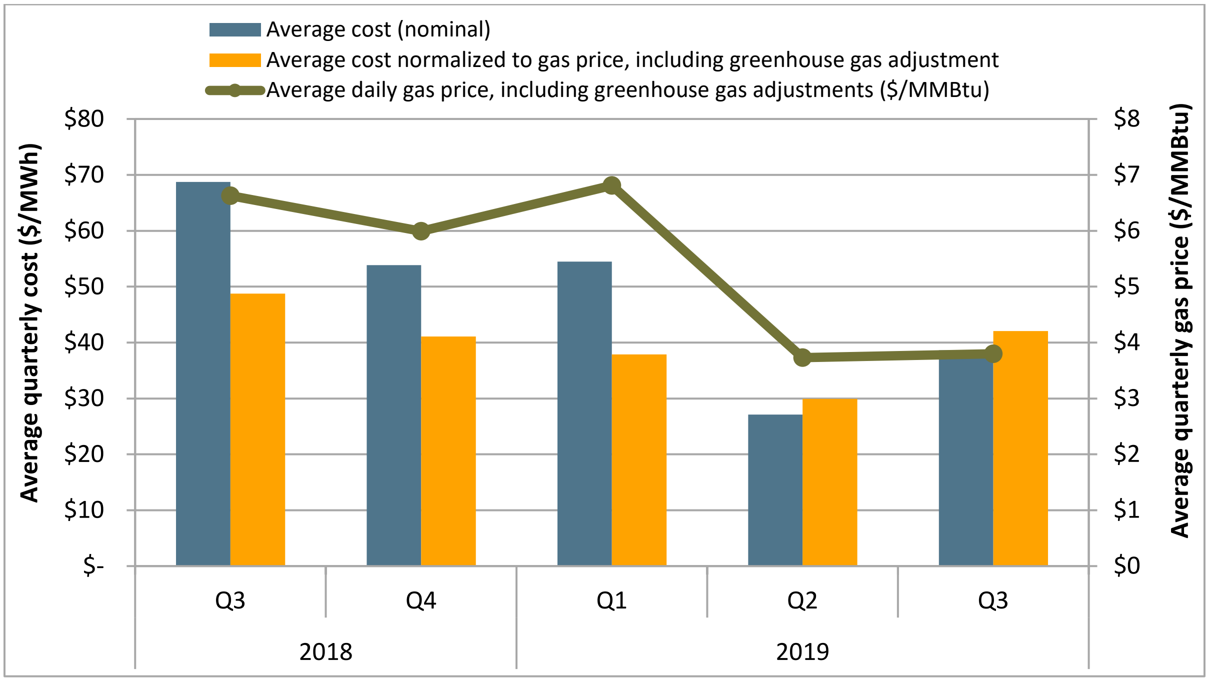


Table 1.1 provides quarterly summaries of nominal total wholesale costs by category. Costs for energy procured in the day-ahead market continued to make up a majority (93 percent) of the total cost to deliver energy to the market, similar to the third quarter of 2018 but an increase from 88 percent in the previous quarter. Real-time market costs increased to 2.5 percent of the total cost from about 1 percent in the same quarter of 2018 but decreased compared to 4.5 percent in the second quarter of 2019. Bid cost recovery costs were about 1.8 percent of total cost, about the same as both the previous quarter and the same quarter of 2018. Costs for reliability remained low at about 0.1 percent, and reserve costs decreased slightly to about 1.2 percent of total costs.

Table 1.1 Estimated average wholesale energy costs per MWh

	Q3 2018	Q4 2018	Q1 2019	Q2 2019	Q3 2019	Change Q3 2018-Q3 2019
Day-ahead energy costs	$ 64.52	$ 51.46	$ 52.24	$ 23.73	$ 36.01	$ (28.51)
Real-time energy costs (incl. flex ramp)	$ 0.69	$ 0.01	$ 0.25	$ 1.22	$ 0.95	$ 0.26
Grid management charge	$ 0.46	$ 0.48	$ 0.46	$ 0.46	$ 0.45	$ (0.01)
Bid cost recovery costs	$ 1.27	$ 0.48	$ 0.56	$ 0.49	$ 0.72	$ (0.56)
Reliability costs (RMR and CPM)	$ 0.63	$ 0.90	$ 0.06	$ 0.06	$ 0.04	$ (0.58)
Average total energy costs	**$ 67.57**	**$ 53.32**	**$ 53.56**	**$ 25.96**	**$ 38.17**	**$ (29.40)**
Reserve costs (AS and RUC)	$ 1.19	$ 0.53	$ 0.94	$ 1.14	$ 0.46	$ (0.72)
Average total costs of energy and reserve	**$ 68.76**	**$ 53.85**	**$ 54.50**	**$ 27.09**	**$ 38.64**	**$ (30.12)**

1.6 Day-ahead price variability

High prices

Figure 1.11 shows the frequency of day-ahead market prices in various high priced ranges from July 2018 to September 2019. There was a slight increase in the frequency of hours with high day-ahead prices between the second and third quarter of 2019. Prices greater than $100/MWh occurred during 1 percent of hours in the third quarter of 2019 compared to 0.1 percent of hours in the second quarter.

The frequency of high day-ahead price spikes in the third quarter of 2019 was significantly lower than the prices that occurred during the same quarter of the previous year. Day-ahead prices spiked in the third quarter of 2018 largely due to high demand and limited natural gas supply during extreme temperatures across the West. The ISO's system did not experience the same high temperature conditions during the third quarter of 2019 and, consequently, load and supply conditions did not cause as many high day-ahead prices.

Negative prices

Figure 1.12 shows the frequency of day-ahead market prices in various low priced ranges from July 2018 to September 2019. Unlike the first two quarters of 2019, there were no negative day-ahead prices in the third quarter, even during the mid-day hours when generation from solar was at its peak with relatively low loads. This result is similar to the frequency of negative day-ahead prices from the same quarter of the previous year.

Figure 1.11 Frequency of high day-ahead prices (MWh) by month

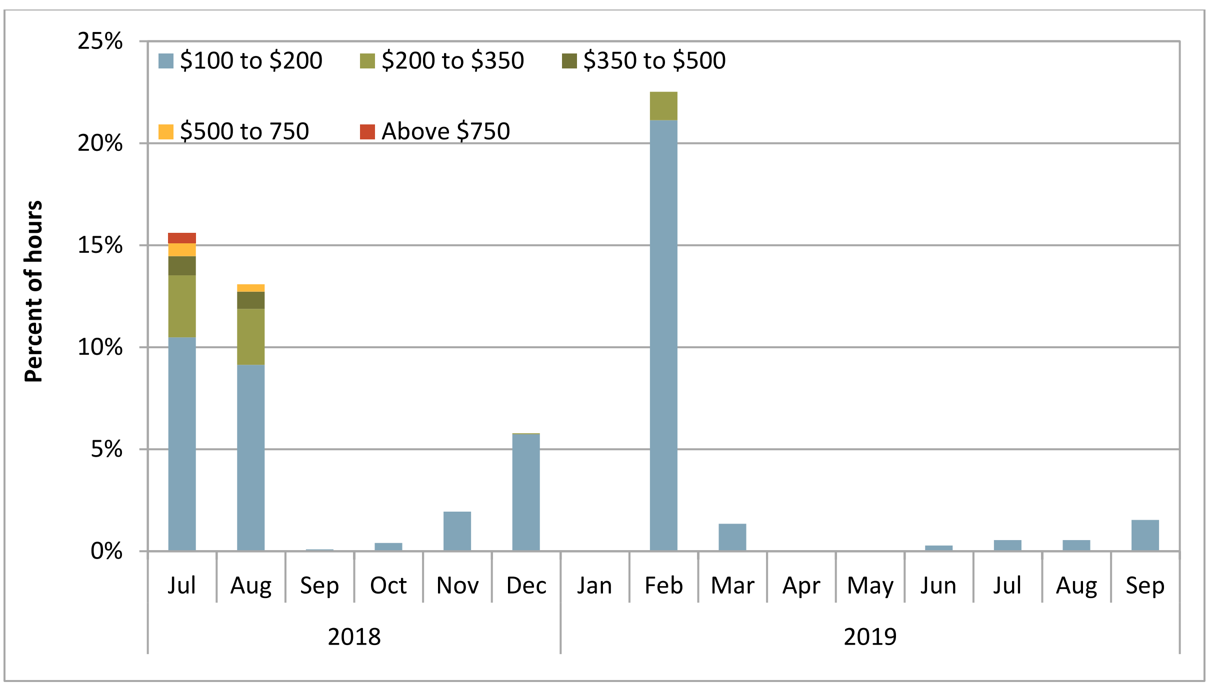
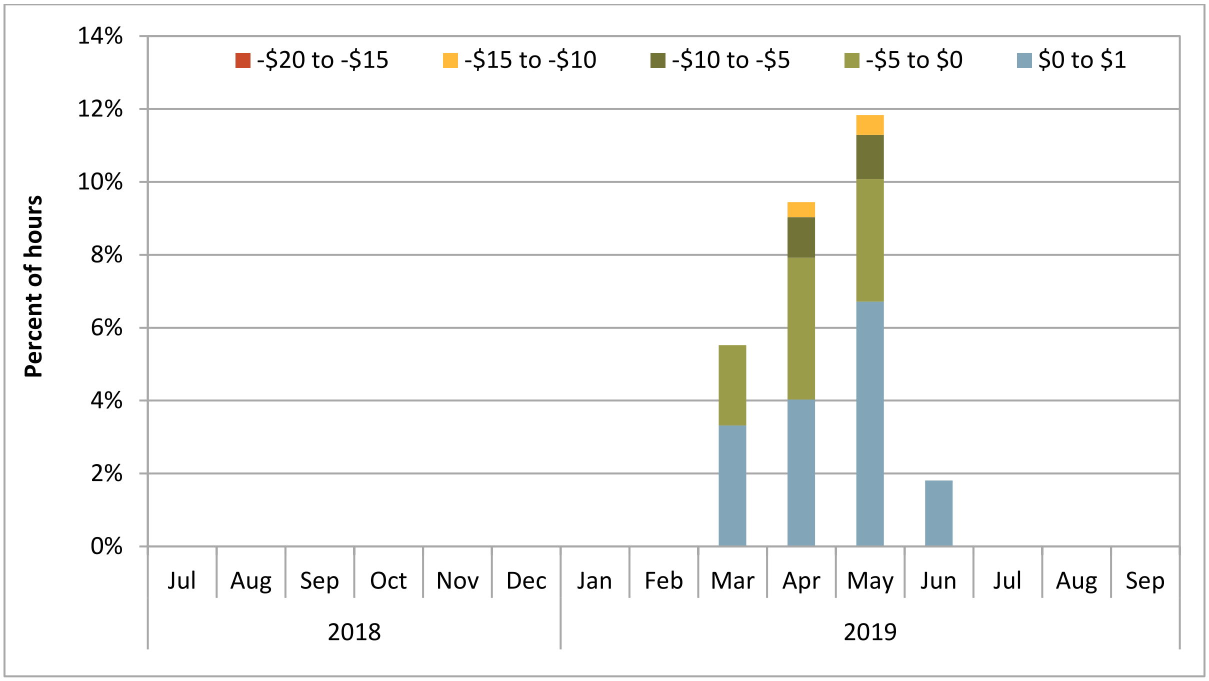


Figure 1.12 Frequency of negative day-ahead prices (MWh) by month



1.7 Real-time price variability

Real-time market prices can be volatile with periods of extreme positive or negative prices. Even a short period of extremely high or low prices can significantly impact average prices. During the third quarter of 2019, the frequency of high real-time prices was significantly lower than both the previous quarter and the third quarter of 2018.

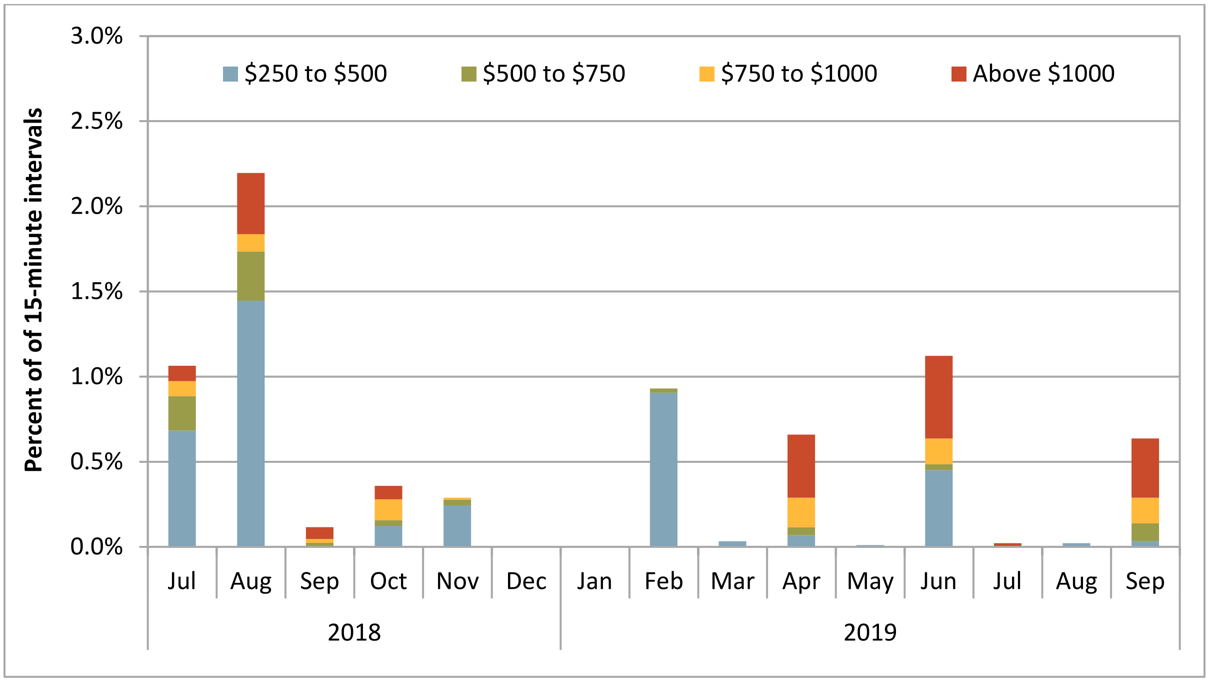
High prices

Figure 1.13 and Figure 1.14 show the frequency of prices above $250/MWh across the three largest load aggregation points (LAP) in the ISO. As shown in Figure 1.13, the occurrence of high prices in the 15-minute market greater than $250/MWh was almost entirely exclusive to September for the quarter. During September, high 15-minute market prices greater than $250/MWh were mostly concentrated between hours 18 and 20. The majority of these prices were set by under-supply infeasibilities.

Figure 1.14 shows the frequency of high prices in the 5-minute market. The frequency of price spikes greater than $250/MWh in the 5-minute market decreased significantly during the quarter, to less than 0.5 percent of intervals. This was the lowest quarterly frequency of high 5-minute market prices across the three largest LAP areas since 2015.

Figure 1.15 shows the corresponding frequency of under-supply infeasibilities in the 5-minute market. Valid under-supply infeasibilities were infrequent in the third quarter, occurring during less than 0.1 percent of 5-minute market and 15-minute market intervals. Infeasibilities resolved by the load conformance limiter continued to be very infrequent, a trend that began in the first quarter with the implementation of the enhancement to the limiter at the end of February.[10] However, the changes to the load conformance limiter did not have a significant impact on prices in the ISO. This is because in most intervals when the limiter triggers in the ISO, the highest priced bids dispatched are often at or near the $1,000/MWh bid cap such that the resulting price is often very similar with or without the limiter.

Figure 1.13 Frequency of high 15-minute prices by month (ISO LAP areas)



10 With the enhancement, the load conformance limiter triggers by a measure based on the change in load adjustment from one interval to the next, rather than the total level of load adjustment. For more information on the load conformance limiter enhancement, see Section 2.4.

Figure 1.14 Frequency of high 5-minute prices by month (ISO LAP areas)

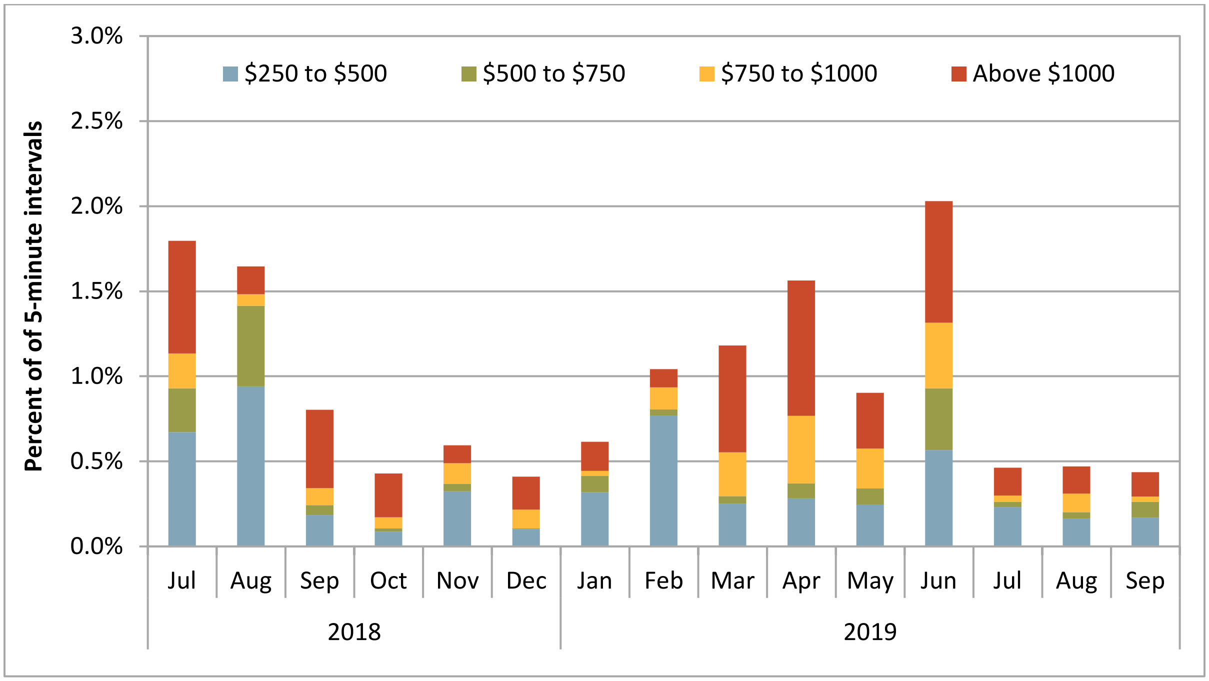
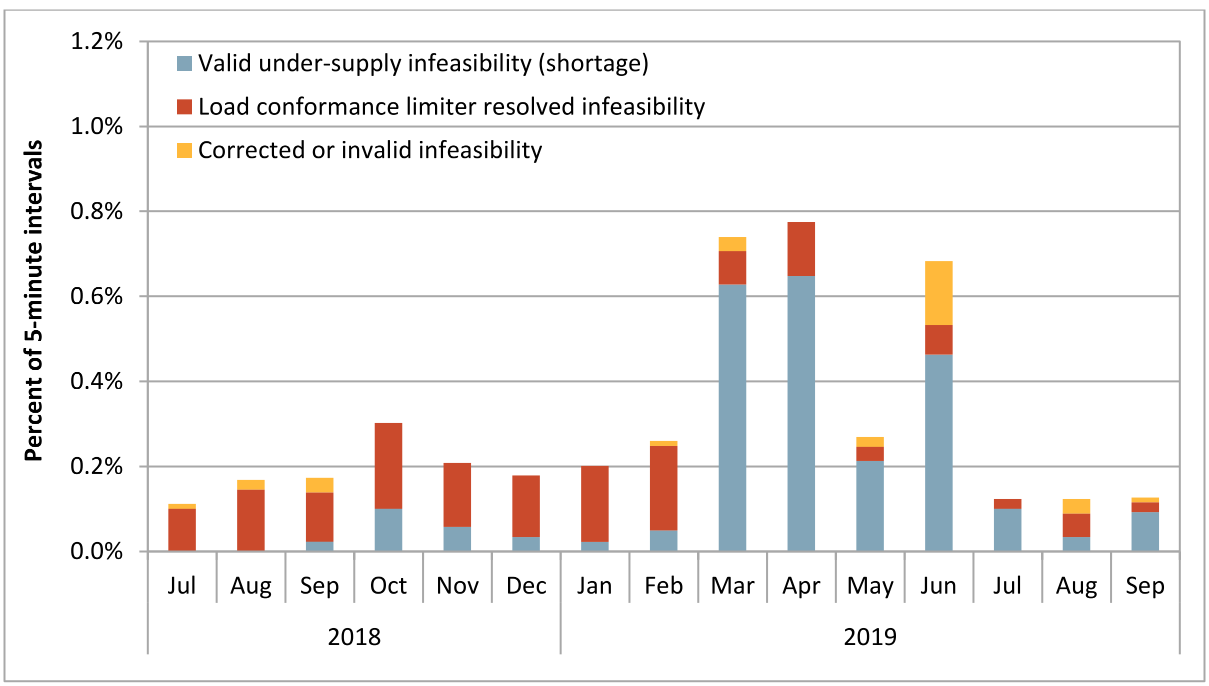


Figure 1.15 Frequency of under-supply power balance constraint infeasibilities (5-minute market)

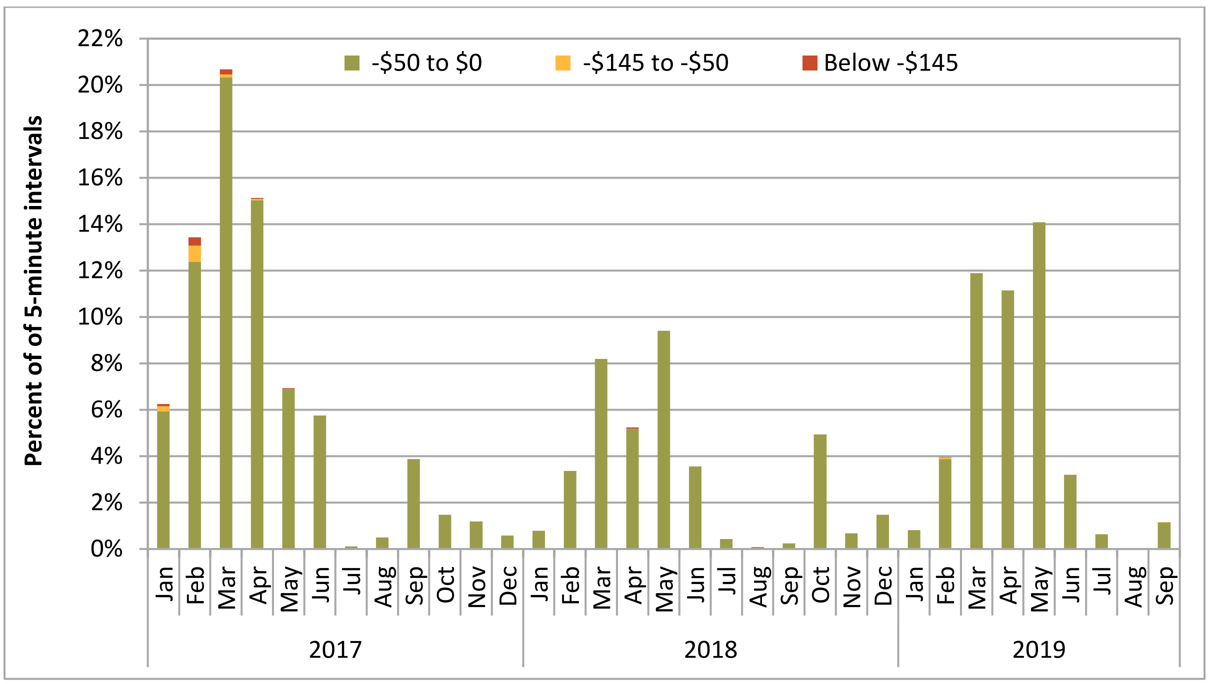


Negative prices

Figure 1.16 shows the frequency of negative prices in the 5-minute market by month across the three largest load aggregation points in the ISO.[11] The frequency of negative prices in the 15-minute and 5-minute markets was very low during the third quarter of 2019, occurring during less than 1 percent of intervals. There were no intervals when the power balance constraint was relaxed because of excess energy during the quarter.

Instead, negative prices were typically set by economic bids from wind and solar resources reflecting their relatively low marginal costs. During the third quarter, this was most frequent between hours ending 9 and 17 when loads, net of wind and solar, were lowest.

Figure 1.16 Frequency of negative 5-minute prices by month (ISO LAP areas)



1.8 Convergence bidding

Overall convergence bidding was profitable for both virtual demand and virtual supply for the third quarter. Virtual demand generated revenues of about $5.9 million while, before accounting for bid cost recovery charges, virtual supply generated net revenues of $1.4 million. Combined net revenues for virtual supply and demand fell to about $5.8 million after including about $1.4 million of virtual bidding bid cost recovery charges.

11 Corresponding values for the 15-minute market show a similar pattern but at a lower frequency.

1.8.1 Convergence bidding trends

Average hourly cleared volumes were about 3,400 MW, a decrease of about 100 MW from the previous quarter. Average hourly virtual supply remained similar to the previous quarter at about 2,000 MW. Virtual demand averaged around 1,400 MW during each hour of the quarter, a 100 MW decrease from the previous quarter. On average, about 30 percent of virtual supply and demand bids offered into the market cleared in the quarter, similar to the previous quarter.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 540 MW on average, an increase from 460 MW of net virtual supply in the previous quarter. On average for the quarter, net cleared virtual demand only exceeded net cleared virtual supply between hours ending 17 and 20. In the remaining 20 hours, net cleared virtual supply exceeded net cleared virtual demand. Similar to the previous quarter, cleared virtual supply exceeded virtual demand by 1,000 MW during hours ending 22 through 24.

Convergence bidding is designed to align day-ahead and real-time prices when the net market virtual position is directionally consistent (and profitable) with the price difference between the two markets. For the quarter, net convergence bidding volumes were consistent with average price differences between the day-ahead and real-time markets during 17 of 24 hours. The majority of the inconsistent volumes occurred between hours ending 9, 10, 11, 16, 17 and 20.

Offsetting virtual supply and demand bids

Market participants can hedge congestion costs or earn revenues associated with differences in congestion between different points within the ISO system by placing virtual demand and supply bids at different locations during the same hour. These virtual demand and supply bids offset each other in terms of system energy and are not exposed to bid cost recovery settlement charges. When virtual supply and demand bids are paired in this way, one of these bids may be unprofitable independently, but the combined bids may break even or be profitable because of congestion differences between the day-ahead and real-time markets.

Offsetting virtual positions accounted for an average of about 835 MW of virtual demand offset by 835 MW of virtual supply in each hour of the quarter. These offsetting bids represented about 50 percent of all cleared virtual bids in the third quarter, about the same as the previous quarter.

1.8.2 Convergence bidding revenues

Participants engaged in convergence bidding in the third quarter were profitable overall. Net revenues for convergence bidders, before accounting for bid cost recovery charges, were about $7.2 million. Net revenues for virtual supply and demand fell to about $5.8 million after including about $1.4 million of virtual bidding bid cost recovery charges.[12] This decline is due primarily to bid cost recovery charges associated with virtual supply.

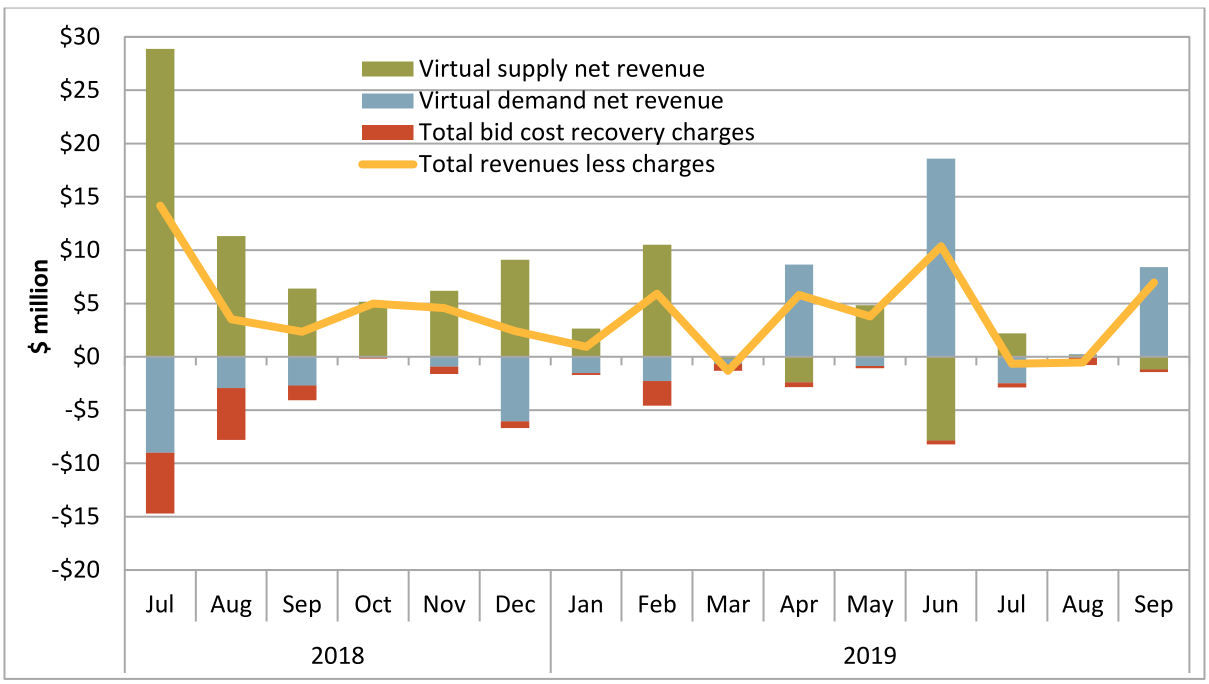
12 For more information on how bid cost recovery charges are allocated please refer to the *Q3 2017 Report on Market Issues and Performance*, December 2017, pp. 40-41: http://www.caiso.com/Documents/2017ThirdQuarterReport-MarketIssuesandPerformance-December2017.pdf.

Figure 1.17 shows total monthly net revenues for virtual supply (green bars), total net revenues for virtual demand (blue bars), the total amount paid for bid cost recovery charges (red bars), and the total payments for all convergence bidding inclusive of bid cost recovery charges (gold line).

Before accounting for bid cost recovery charges:

- Total market revenues were positive during all months of the quarter. Net revenues during the third quarter totaled about $7.2 million, compared to about $31 million during the same quarter in 2018, and about $21 million during the previous quarter.
- Virtual demand net revenues were slightly negative in July and August and positive in September. In total, virtual demand generated positive net revenues of about $6 million for the quarter. As with the previous quarter, virtual demand revenues were positive for the quarter almost exclusively due to large positive net virtual demand revenues on a small number of hours, September 3 and September 4, 2019.
- Virtual supply net revenues were positive in July and August while negative in September. In September, virtual supply generated negative net revenues of nearly $1.4 million. This was primarily due to virtual supply losses on September 3 and September 4, 2019.

Figure 1.17 Convergence bidding revenues and bid cost recovery charges



Convergence bidders received about $7.2 million before subtracting bid cost recovery charges of about $1.4 million for the quarter.[13,14] Bid cost recovery charges were about $0.4 million in July, $0.8 million in August and $0.3 million in September.

Net revenues and volumes by participant type

Figure 1.18 compares the distribution of convergence bidding cleared volumes and net revenues, in millions of dollars, among different groups of convergence bidding participants in the quarter.[15] As with the previous quarter, financial entities represented the largest segment of the virtual bidding market, accounting for about 70 percent of volume and 60 percent of settlement revenue. Marketers represented about 28 percent of the trading volumes and about 26 percent of settlement revenue. Generation owners and load-serving entities represented a smaller segment of the virtual market in terms of both volumes and settlement revenue, at about 4 percent and 5 percent respectively. Generation owners and load-serving entities accounted for around $0.4 million of net revenues in the market.

Figure 1.18 Convergence bidding volumes and revenues by participant type

Trading entities	Average hourly megawatts			Revenues\Losses ($ million)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	913	1,327	2,240	$3.84	$1.12	$4.96
Marketer	423	516	939	$1.64	$0.26	$1.90
Physical load	38	40	78	$0.38	-$0.05	$0.33
Physical generation	0	39	39	$0.00	$0.05	$0.05
Total	**1,374**	**1,921**	**3,295**	**$5.9**	**$1.4**	**$7.2**

1.9 Residual unit commitment

The purpose of the residual unit commitment market is to ensure that there is sufficient capacity on-line or reserved to meet actual load in real time. The residual unit commitment market runs immediately after the day-ahead market and procures capacity sufficient to bridge the gap between the amount of

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13 Further detail on bid cost recovery and convergence bidding can be found here, p.25: http://www.caiso.com/Documents/DMM_Q1_2015_Report_Final.pdf.

14 Business Practice Manual configuration guide has been updated for CC 6806, day-ahead residual unit commitment tier 1 allocation, to ensure that the residual unit commitment obligations do not receive excess residual unit commitment tier 1 charges or payments. For additional information on how this allocation may impact bid cost recovery, refer to page 3: BPM Change Management Proposed Revision Request.

15 DMM has defined financial entities as participants who own no physical power and participate in the convergence bidding and congestion revenue rights markets only. Physical generation and load are represented by participants that primarily participate in the ISO markets as physical generators and load-serving entities, respectively. Marketers include participants on the interties and participants whose portfolios are not primarily focused on physical or financial participation in the ISO market.

load cleared in the day-ahead market and the day-ahead forecast load. ISO operators are able to increase residual unit commitment requirements. Use of this tool increased in the third quarter of 2019.

As illustrated in Figure 1.19, residual unit commitment procurement appears to be driven in large part by the need to replace cleared net virtual supply bids, which can offset physical supply in the day-ahead market run. On average, cleared virtual supply (green bar) was about 48 percent lower in the third quarter of 2019 than in the same quarter of 2018.

ISO operators were able to increase the amount of residual unit commitment requirements primarily to account for load forecast errors from one day to the next. This tool, noted as operator adjustments (red bar) in the figure, was used frequently in the third quarter of 2019 averaging about 686 MW per hour compared to about 983 MW per hour in the same quarter of 2018.

The day-ahead forecasted load versus cleared day-ahead capacity (blue bar) represents the difference in cleared supply (both physical and virtual) compared to the ISO's load forecast. On average, this factor contributed towards increased residual unit commitment requirements in the third quarter of 2019, particularly in August.

Residual unit commitment also includes an automatic adjustment to account for differences between the day-ahead schedules of bid in variable energy resources and the forecast output of these renewable resources. This intermittent resource adjustment reduces residual unit commitment procurement targets by the estimated under-scheduling of renewable resources in the day-ahead market. It is represented by the yellow bar in Figure 1.19.

Figure 1.19 Determinants of residual unit commitment procurement

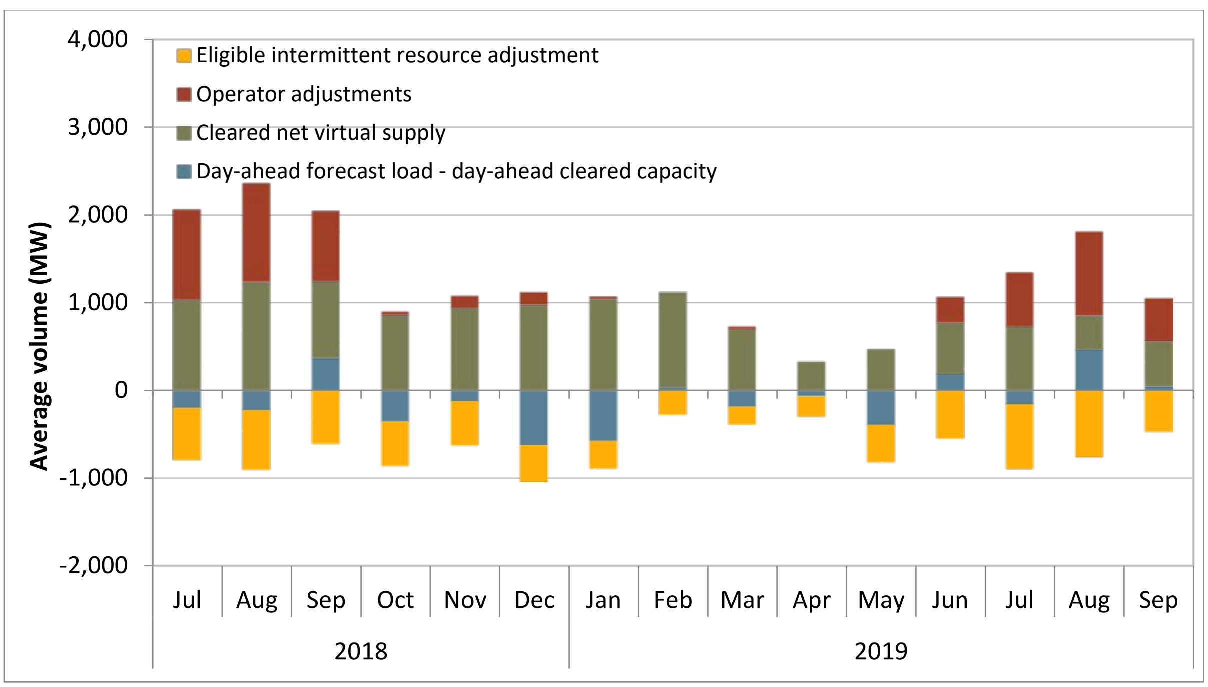
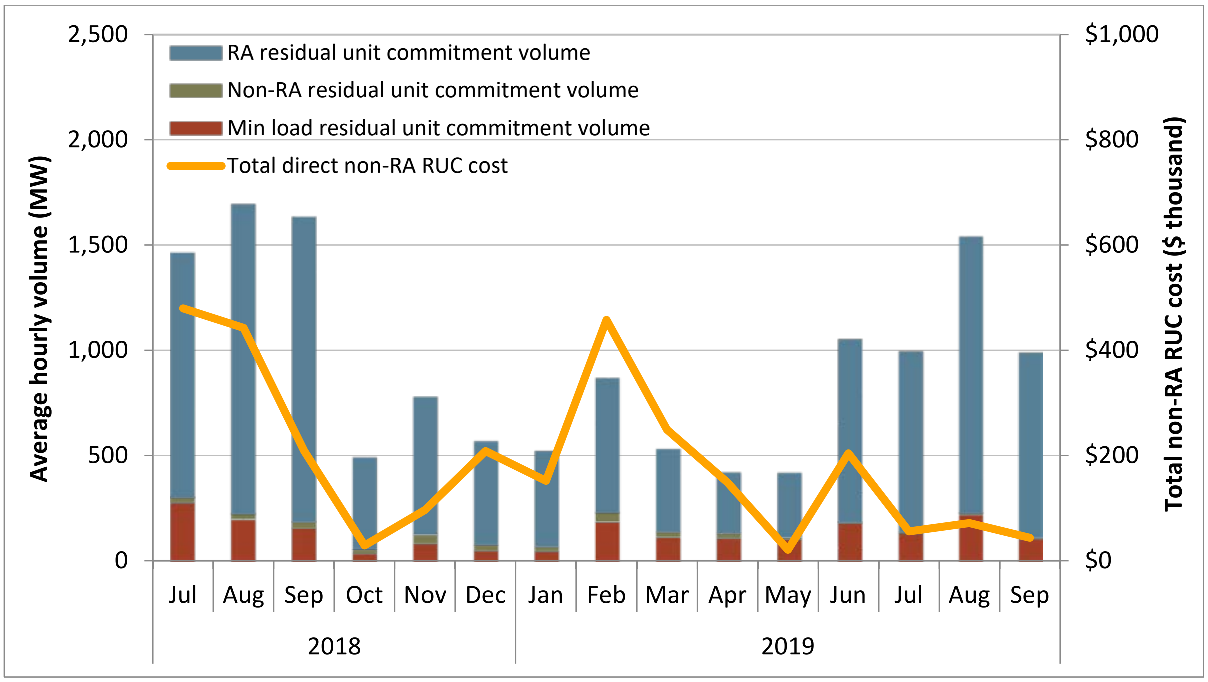


Figure 1.20 shows monthly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. Total residual unit commitment procurement

decreased to about 1,176 MW per hour in the third quarter of 2019 from an average of 1,600 MW in the same quarter of 2018. Of the 1,176 MW per hour capacity, the capacity committed to operate at minimum load averaged about 151 MW each hour compared to 207 MW in the third quarter of 2018.

Most of the capacity procured in the residual unit commitment market does not incur any direct costs from residual unit capacity payments because only non-resource adequacy units committed in this process receive capacity payments.[16] The total direct cost of non-resource adequacy residual unit commitment is represented by the gold line in Figure 1.20. In the third quarter of 2019, these costs decreased to $0.17 million when compared to about $1.1 million in the same quarter of 2018.

Figure 1.20 Residual unit commitment costs and volume



1.10 Bid cost recovery

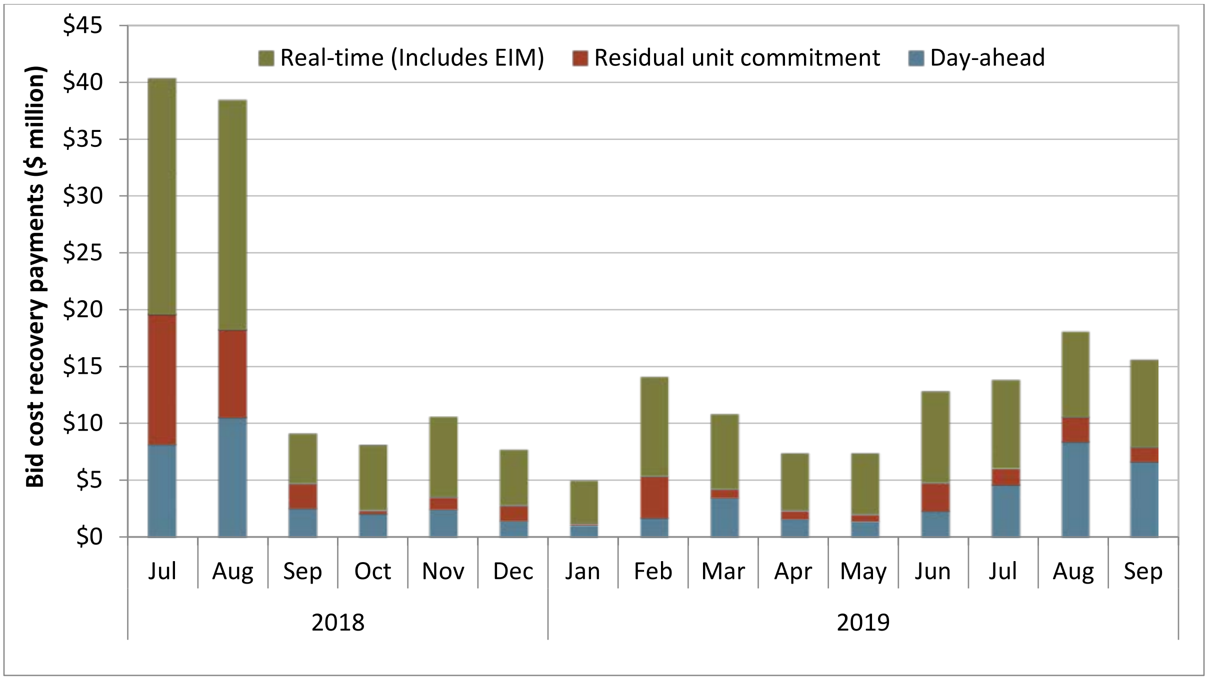
Estimated bid cost recovery payments for the third quarter of 2019 totaled about $48 million. This amount was $20 million higher than the total amount of bid cost recovery in the previous quarter and about $40 million lower than the third quarter of 2018. The significant decrease can be attributed to relatively lower loads and lower gas prices in this quarter.

Bid cost recovery attributed to the day-ahead market totaled about $20 million, about $15 million higher than the prior quarter. Bid cost recovery payments for residual unit commitment during the quarter totaled about $5 million, compared to $4 million in the prior quarter. Bid cost recovery attributed to the real-time market totaled about $23 million, or about $22 million lower than payments in the third quarter of 2018 and $4.5 million higher than payments in the second quarter of 2019.

16 If committed, resource adequacy units may receive bid cost recovery payments in addition to resource adequacy payments.

Although bid cost recovery costs decreased relative to the same quarter of 2018, their share of total wholesale energy cost increased slightly from 1.85 to 1.86 percent.

Figure 1.21 Monthly bid cost recovery payments



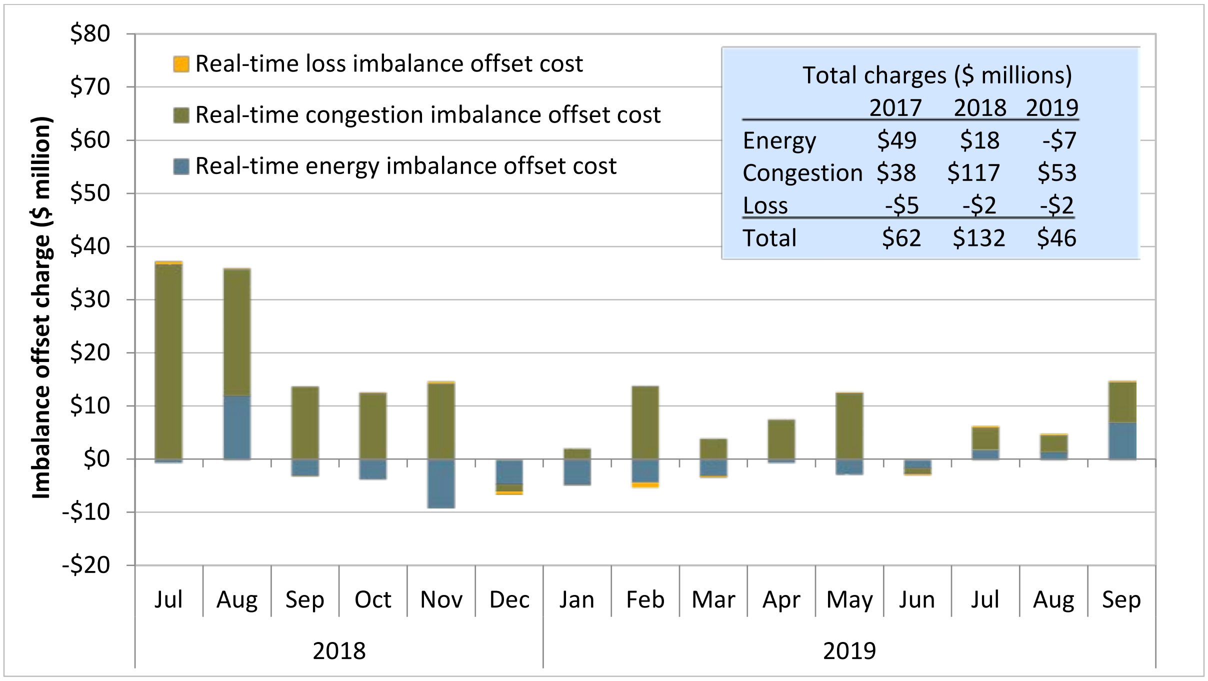
1.11 Real-time imbalance offset costs

Third quarter imbalance offset charges totaled $26 million, the sum of $15 million congestion offset charges, $10 million energy offset, and $1 million loss offset. Congestion offset charges were associated with network model changes and reductions in constraint limits in the 15-minute market from the day-ahead market.

The real-time imbalance offset charge consists of three components. Any revenue imbalance from the energy components of real-time energy settlement prices is collected through the real-time imbalance energy offset charge (RTIEO). Any revenue imbalance from the congestion component of these real-time energy settlement prices is recovered through the real-time congestion imbalance offset charge (RTCIO). Any revenue imbalance from the loss component of real-time energy settlement prices is collected through the real-time loss imbalance offset charge.

The real-time imbalance offset cost is the difference between the total money paid out by the ISO and the total money collected by the ISO for energy settled in the real-time energy markets. Historically, this included energy settled at hour-ahead and 5-minute prices. The ISO implemented market changes related to FERC Order No. 764 in May 2014, which included a financially binding 15-minute market. Following this change, real-time imbalance offsets include energy settled at 15-minute and 5-minute prices. Within the ISO system, the charge is allocated as an uplift to measured demand (i.e., physical load plus exports).

Figure 1.22 Real-time imbalance offset costs



1.12 Congestion

This section provides an assessment of the frequency and impact of congestion on prices in the day-ahead and 15-minute markets. It assesses both the impact of congestion on local areas in the ISO (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric) as well as on EIM entities.

Congestion in a nodal energy market occurs when the market model determines that flows have reached or exceeded the limit of a transmission constraint. Within areas where flows are constrained by limited transmission, higher cost generation is dispatched to meet demand. Outside of these transmission constrained areas, demand is met by lower cost generation. This results in higher prices within congested regions and lower prices in unconstrained regions.

The impact of congestion on each pricing node in the ISO system is calculated by summing the product of the shadow price of that constraint and the shift factor for that node relative to the congested constraint. This calculation works for individual nodes, as well as for groups of nodes that represent different load aggregation points or local capacity areas.[17]

Color shading is used in the tables to help distinguish patterns in the impacts of constraints. Orange indicates a positive impact to prices, while blue represents a negative impact. The stronger the color of the shading, the greater the impact in either the positive or negative direction.

[17] This approach does not include price differences that result from transmission losses.

1.12.1 Congestion in the day-ahead market

In the day-ahead market, congestion frequency is typically higher than in the 15-minute market, but price impacts tend to be lower. The congestion pattern in this quarter reflects this overall trend.

Impact of congestion to overall prices in each load area

Figure 1.23 shows the overall impact of congestion on day-ahead prices in each load area for each quarter in 2018 and 2019.[18] Figure 1.24 shows the frequency of congestion. Highlights for this quarter include:

- The overall net impact to price separation as well as the frequency of congestion was very low relative to the same quarter in 2018 and slightly higher than in the second quarter of 2019. Similar to previous quarters, the frequency of congestion was highest in SDG&E.
- Congestion resulted in a net increase to SCE and SDG&E prices by $0.05/MWh (1.5 percent) and $2/MWh (4 percent), respectively, and a net decrease to prices in PG&E by $0.70/MWh (0.5 percent).
- Congestion primarily decreased PG&E prices while congestion primarily increased prices in SCE and SDG&E. There was little “offsetting” congestion in the south-to-north direction throughout the quarter.
- The primary constraints impacting price separation in the day-ahead market were the Imperial Valley nomogram, the Barre-Lewis 500 kV line, and the Midway-Whirlwind 500 kV line.

Additional information regarding the impact of congestion from individual constraints and the cause of congestion for constraints that had the largest impact on price separation is below.

18 The values in the figure represent the net impact of constraints on prices. Congestion sometimes increased and sometimes decreased values in each of the areas.

Figure 1.23 Overall impact of congestion on price separation in the day-ahead market

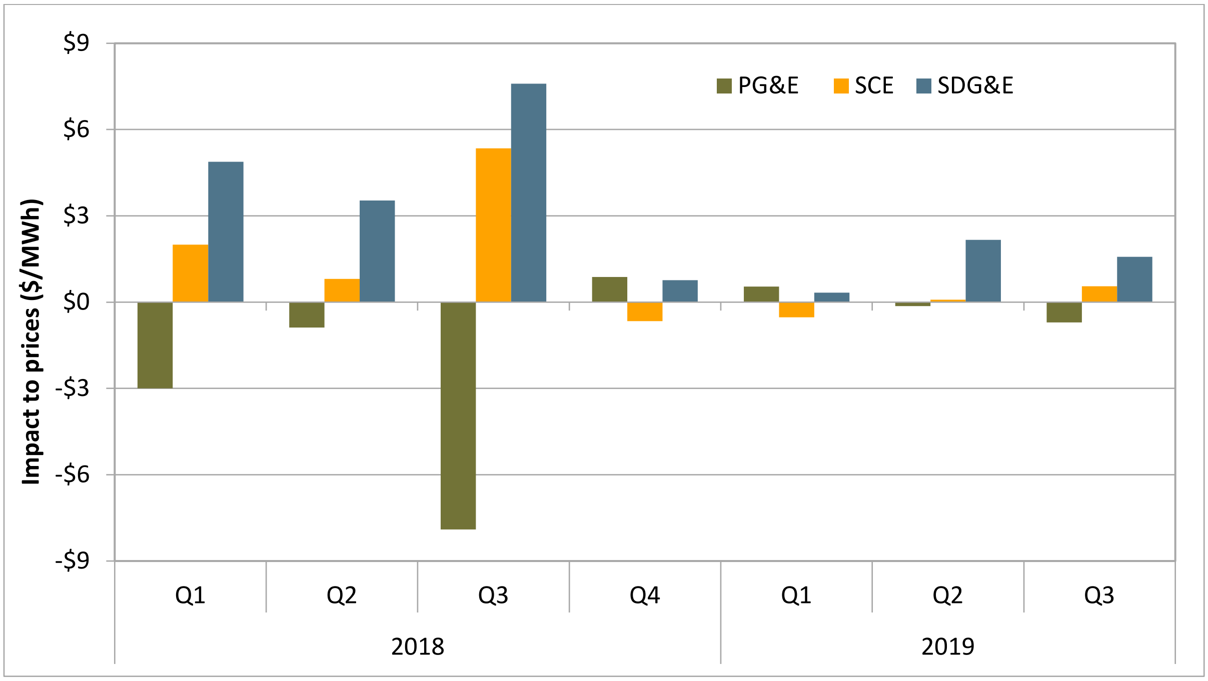


Figure 1.24 Percent of hours with congestion impacting day-ahead prices by load area (>$0.05/MWh)

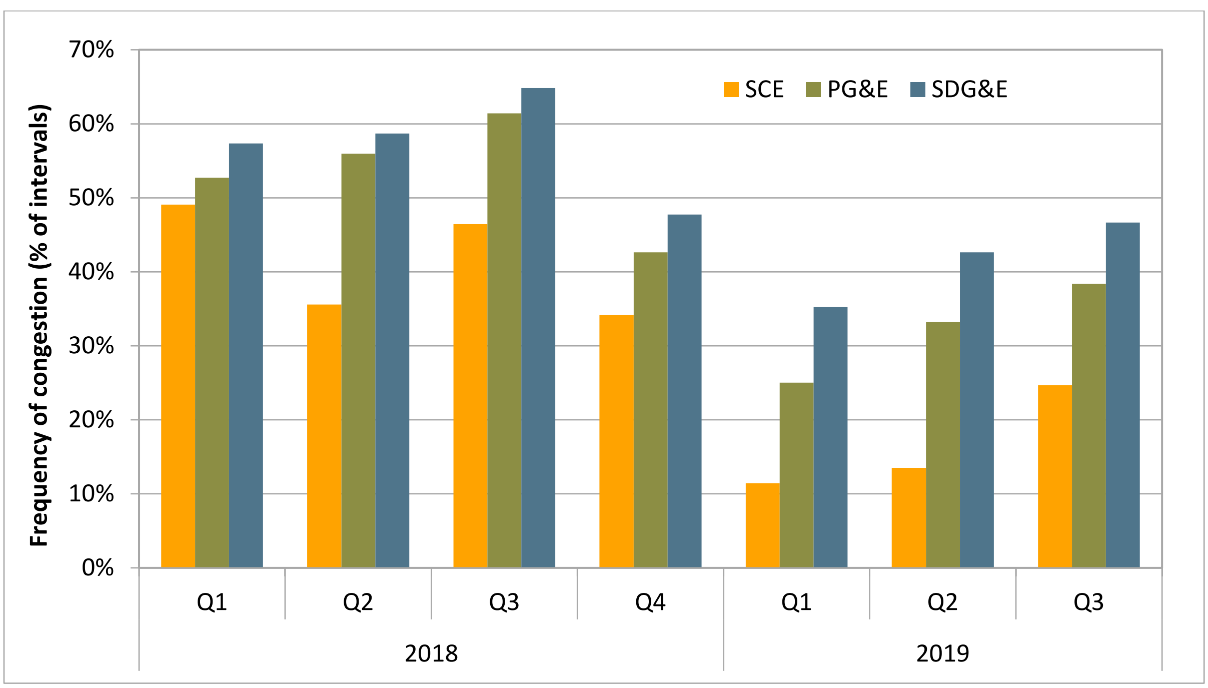
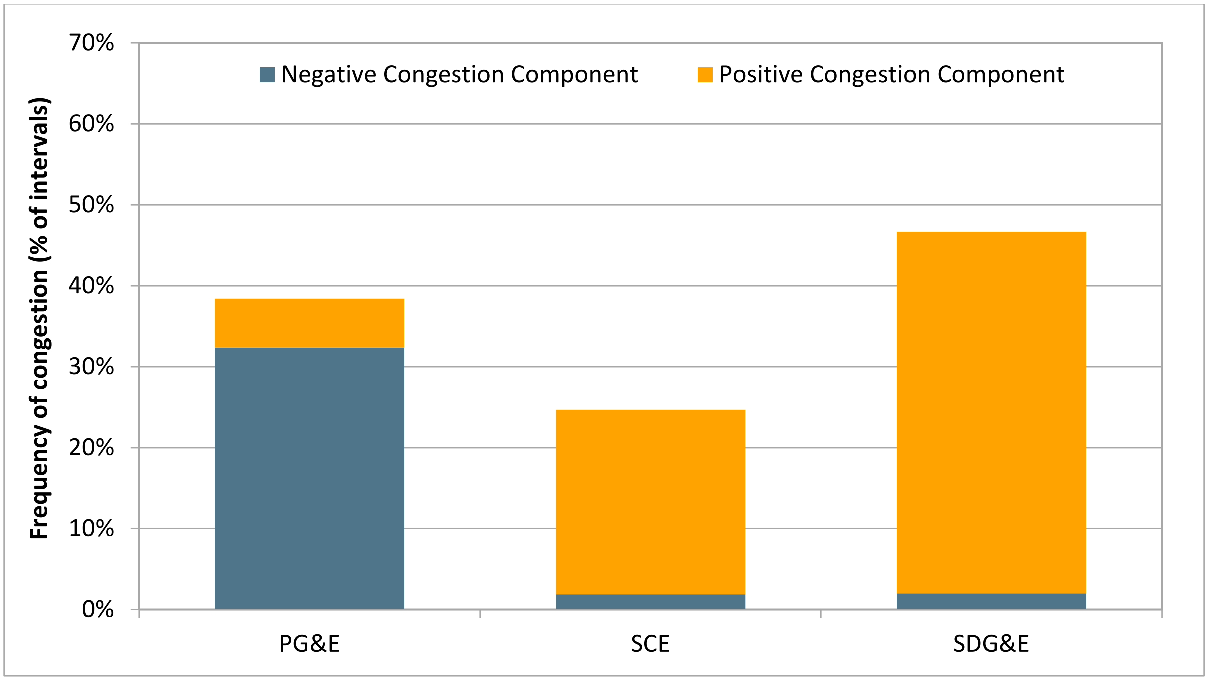


Figure 1.25 Percent of hours with congestion increasing versus decreasing day-ahead prices in the third quarter (>$0.05/MWh)



Impact of congestion from individual constraints

Table 1.2 breaks down the impact to price separation in the quarter by constraint.[19] Table 1.3 shows the impact of congestion from each constraint only during congested intervals, where the number of congested intervals is presented separately as frequency. The constraints with the greatest impact on price separation for the quarter were the Imperial Valley nomogram, the Barre-Lewis 500 kV line, and the Midway-Whirlwind 500 kV line.

Imperial Valley nomogram

The Imperial Valley nomogram (7820_TL 230S_OVERLOAD_NG) bound frequently in the quarter, during 15 percent of hours. When binding, it increased SDG&E prices by about $3/MWh and decreased PG&E prices slightly by about $0.25/MWh. Over the entire quarter, it increased SDG&E prices by about $0.44/MWh (1.2 percent) and decreased PG&E prices $0.04/MWh (0.11 percent). The nomogram is enforced to mitigate for the loss of the Imperial Valley-North Gila 500 kV line. In the 2017-2018 transmission planning cycle, an upgrade to the Imperial Valley-El Centro 230 kV S-Line was approved. The project, which is planned to be complete in 2021, will help to alleviate congestion in this area.

Barre-Lewis 230 kV line

The Barre-Lewis 500 kV line (24016_BARRE _230_25201_LEWIS _230_BR_1 _1) bound frequently in about 15 percent of hours. When binding, it increased prices in SDG&E and SCE by about $1/MWh and decreased prices in PG&E by about $1/MWh. Overall for the quarter, the constraint increased prices in SCE and SDG&E by about $0.23/MWh (0.7 percent) and $0.09/MWh (0.2 percent), respectively, and

[19] Details on constraints with shift factors less than 2 percent have been grouped in the 'other' category.

decreased PG&E prices by about $0.20/MWh (0.6 percent). This constraint is used to mitigate the loss of the Barre-Villa Park 230 kV line.

Midway-Whirlwind 500 kV line

In the PG&E area, congestion on the Midway-Whirlwind 500 kV line (30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2) bound infrequently in about 2.6 percent of hours. When binding, it increased prices in SDG&E and SCE by about $5/MWh and decreased prices in PG&E by about $8/MWh. Overall for the quarter, the constraint increased prices in SCE and SDG&E by about $0.13/MWh (0.4 percent) and decreased PG&E prices by about $0.19/MWh (0.6 percent). This constraint primarily bound due to normal flow conditions and was not a result of outages.

Table 1.2 Impact of congestion on overall day-ahead prices

Constraint Location	Constraint	PG&E		SCE		SDG&E	
		$ per MWh	Percent	$ per MWh	Percent	$ per MWh	Percent
PG&E	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _3	$0.02	0.05%	-$0.01	-0.04%	-$0.01	-0.03%
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	-$0.04	-0.10%	$0.02	0.07%	$0.02	0.06%
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.11	-0.33%	$0.08	0.23%	$0.08	0.21%
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	-$0.19	-0.58%	$0.14	0.38%	$0.12	0.33%
SCE	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.20	-0.59%	$0.23	0.67%	$0.09	0.24%
	24156_VINCENT _500_24155_VINCENT _230_XF_3	-$0.05	-0.16%	$0.04	0.11%	$0.02	0.05%
	25201_LEWIS _230_24137_SERRANO _230_BR_2 _1	-$0.04	-0.13%	$0.04	0.10%	$0.00	0.00%
	6410_CP1_NG	-$0.01	-0.02%	$0.01	0.02%	$0.01	0.02%
	24091_MESA CAL_230_24126_RIOHONDO_230_BR_1 _1	-$0.01	-0.02%	$0.01	0.01%	$0.01	0.01%
	24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1	-$0.04	-0.13%	$0.00	0.01%	$0.00	0.00%
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	$0.00	-0.01%	$0.00	0.01%	$0.00	0.01%
	24092_MIRALOMA_500_24093_MIRALOM _230_XF_1 _P	-$0.01	-0.01%	$0.00	0.01%	$0.01	0.01%
SDG&E	7820_TL 230S_OVERLOAD_NG	-$0.04	-0.11%	$0.00	0.00%	$0.44	1.20%
	22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.15	0.41%
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.15	0.40%
	22592_OLD TOWN_69.0_22873_VINE SUB_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.09	0.24%
	7820_TL23040_IV_SPS_NG	$0.00	-0.01%	$0.00	0.00%	$0.09	0.23%
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	-$0.01	-0.03%	$0.00	0.00%	$0.08	0.21%
	22596_OLD TOWN_230_22504_MISSION _230_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.06	0.17%
	22873_VINE SUB_69.0_22380_KETTNER _69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.05	0.13%
	OMS 7333672 ML_BK80_NG	$0.00	0.00%	$0.00	0.00%	$0.04	0.11%
	22592_OLD TOWN_69.0_22660_POINTLMA_69.0_BR_2 _1	$0.00	0.00%	$0.00	0.00%	$0.04	0.10%
	22597_OLDTWNTP_230_22504_MISSION _230_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.03	0.07%
	22592_OLD TOWN_69.0_22596_OLD TOWN_230_XF_1	$0.00	0.00%	$0.00	0.00%	$0.02	0.06%
	22480_MIRAMAR _69.0_22756_SCRIPPS _69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.02	0.06%
	22476_MIGUELTP_69.0_22456_MIGUEL _69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.02	0.04%
	22357_IV PFC1 _230_22358_IV PFC _230_PS_1	$0.00	0.00%	$0.00	0.00%	$0.01	0.04%
	7820_TL 230S_TL50001OUT_NG	$0.00	0.00%	$0.00	0.00%	$0.01	0.03%
	22592_OLD TOWN_69.0_22660_POINTLMA_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	$0.01	0.03%
	7750_D-VISTA1_OOS_N1SV500_NG	$0.00	0.01%	$0.00	-0.01%	$0.00	-0.01%
	7750_D-VISTA1_OOS_CP6_NG	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.01%
	22710_SNLSRYSC_230_22504_MISSION _230_BR_1 _1	$0.00	0.00%	$0.00	0.00%	-$0.01	-0.02%
	24804_DEVERS _230_24901_VSTA _230_BR_2 _2	$0.00	0.00%	$0.00	0.00%	-$0.04	-0.10%
	22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1	$0.00	0.00%	$0.00	0.00%	-$0.09	-0.24%
Other		$0.03	0.07%	$0.00	0.01%	$0.08	0.22%
Total		**-$0.70**	**-2.10%**	**$0.55**	**1.56%**	**$1.57**	**4.25%**

Table 1.3 Impact of congestion on day-ahead prices during congested hours[20]

Constraint Location	Constraint	Frequency	PG&E	SCE	SDG&E
PG&E	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	2.9%	-$3.74	$2.73	$2.60
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	2.6%	-$7.50	$5.23	$4.76
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	0.5%	-$6.97	$4.62	$4.25
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _3	0.4%	$4.30	-$3.16	-$2.90
SCE	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	15.1%	-$1.32	$1.55	$0.84
	24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1	3.4%	-$1.32	$0.90	$0.00
	24156_VINCENT _500_24155_VINCENT _230_XF_3	1.1%	-$4.97	$3.43	$1.71
	25201_LEWIS _230_24137_SERRANO _230_BR_2 _1	1.0%	-$4.67	$3.71	$0.00
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	0.5%	-$0.79	$0.89	$0.53
	6410_CP1_NG	0.4%	-$2.04	$1.50	$1.49
	24092_MIRALOMA_500_24093_MIRALOM _230_XF_1 _P	0.3%	-$1.49	$1.01	$1.60
SDG&E	7820_TL 230S_OVERLOAD_NG	15.2%	-$0.25	$0.00	$2.93
	22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1	5.1%	$0.00	$0.00	$3.01
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	3.6%	$0.00	$0.00	$4.07
	22592_OLD TOWN_69.0_22873_VINE SUB_69.0_BR_1 _1	3.6%	$0.00	$0.00	$2.48
	22873_VINE SUB_69.0_22380_KETTNER _69.0_BR_1 _1	3.6%	$0.00	$0.00	$1.30
	22592_OLD TOWN_69.0_22660_POINTLMA_69.0_BR_2 _1	1.9%	$0.00	$0.00	$1.95
	7820_TL23040_IV_SPS_NG	1.7%	-$0.26	$0.00	$4.95
	7750_D-VISTA1_OOS_CP6_NG	1.2%	$0.64	-$0.66	-$0.57
	24804_DEVERS _230_24901_VSTA _230_BR_2 _2	1.1%	$0.00	$0.00	-$3.12
	22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1	1.0%	$0.00	$0.00	-$9.03
	22480_MIRAMAR _69.0_22756_SCRIPPS _69.0_BR_1 _1	0.8%	$0.00	$0.00	$2.62
	22476_MIGUELTP_69.0_22456_MIGUEL _69.0_BR_1 _1	0.8%	$0.00	$0.00	$1.96
	OMS 7333672 ML_BK80_NG	0.7%	-$0.28	$0.00	$5.73
	22596_OLD TOWN_230_22504_MISSION _230_BR_1 _1	0.6%	$0.00	$0.00	$10.58
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	0.4%	-$2.54	$0.00	$19.25
	7750_D-VISTA1_OOS_N1SV500_NG	0.4%	$0.77	-$0.74	-$0.78
	7820_TL 230S_TL50001OUT_NG	0.4%	-$0.24	$0.00	$2.58
	22597_OLDTWNTP_230_22504_MISSION _230_BR_1 _1	0.3%	$0.00	$0.00	$8.45

1.12.2 Congestion in the 15-minute market

In the 15-minute market, congestion frequency is typically lower than in the day-ahead market, but price impacts tend to be higher. The congestion pattern in this quarter reflects this overall trend.

Impact of congestion to overall prices in each load area

Figure 1.26 shows the overall impact of congestion on 15-minute prices in each load area for each quarter of 2018 and 2019. Figure 1.27 shows the frequency of congestion. Highlights for this quarter include:

20 This table shows impacts on load aggregation point prices for constraints binding during more than 0.3 percent of the intervals during the quarter.

- The overall net impact to price separation of congestion was significantly lower in the third quarter of 2019 compared to the same quarter of 2018. Congestion resulted in a net increase to SCE, SDG&E, NEVP, and AZPS prices by about $4/MWh on average, and a net decrease to prices in PG&E, BANC, PACE, IPCO, PACW, PGE, PSEI, and PWRX by about $2/MWh on average.
- The frequency of congestion in this quarter was lower compared to all prior quarters of 2018 and 2019, unlike the day-ahead market where congestion frequency has increased throughout each quarter of 2019. This is largely due to the decrease in the frequency of congestion primarily in EIM load areas.
- Congestion continued to impact prices in both the positive and negative direction, often offsetting the impact of congestion over the quarter. The frequency of congestion was highest in Powerex (36 percent of intervals), where congestion sometimes increased prices (18 percent of intervals) and sometimes decreased prices (19 percent of intervals).
- The primary constraints impacting price separation in the 15-minute market were the Imperial Valley nomogram, the Midway-Vincent 500 kV lines, and the Vincent transformer 3.

Additional information regarding the impact of congestion from individual constraints and the cause of congestion for constraints that had the largest impact on price separation is below.

Figure 1.26 Overall impact of congestion on price separation in the 15-minute market

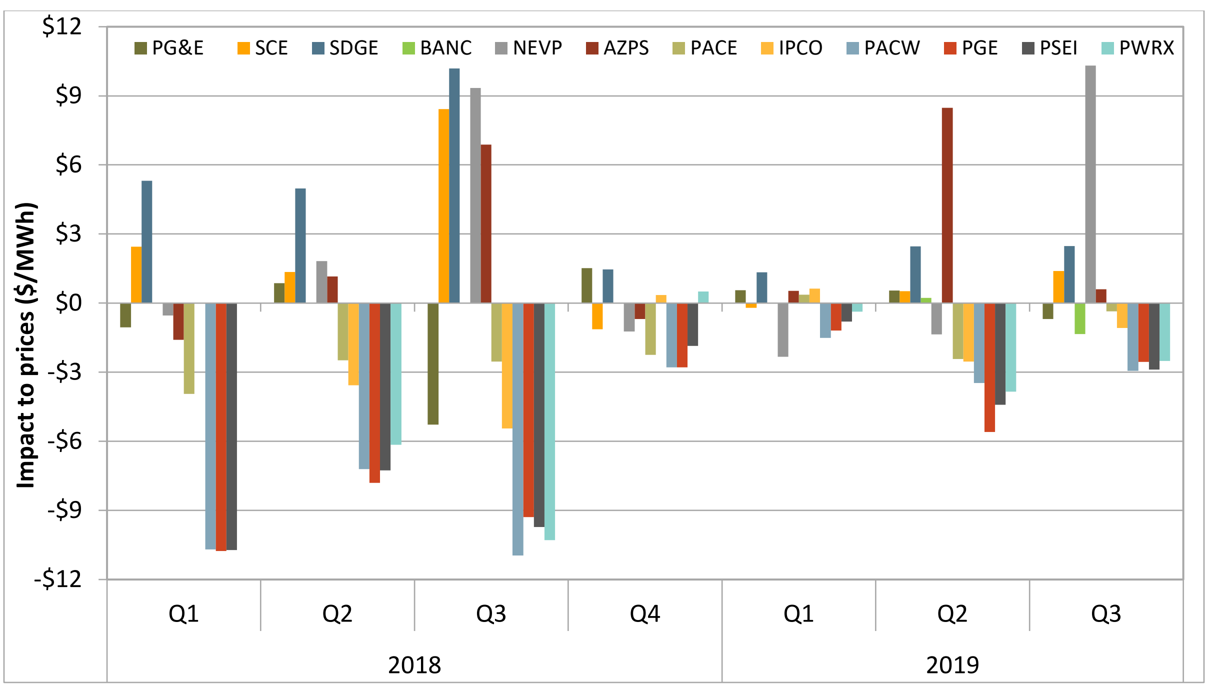


Figure 1.27 Percent of intervals with congestion increasing versus decreasing fifteen-minute prices in the third quarter (>$0.05/MWh)

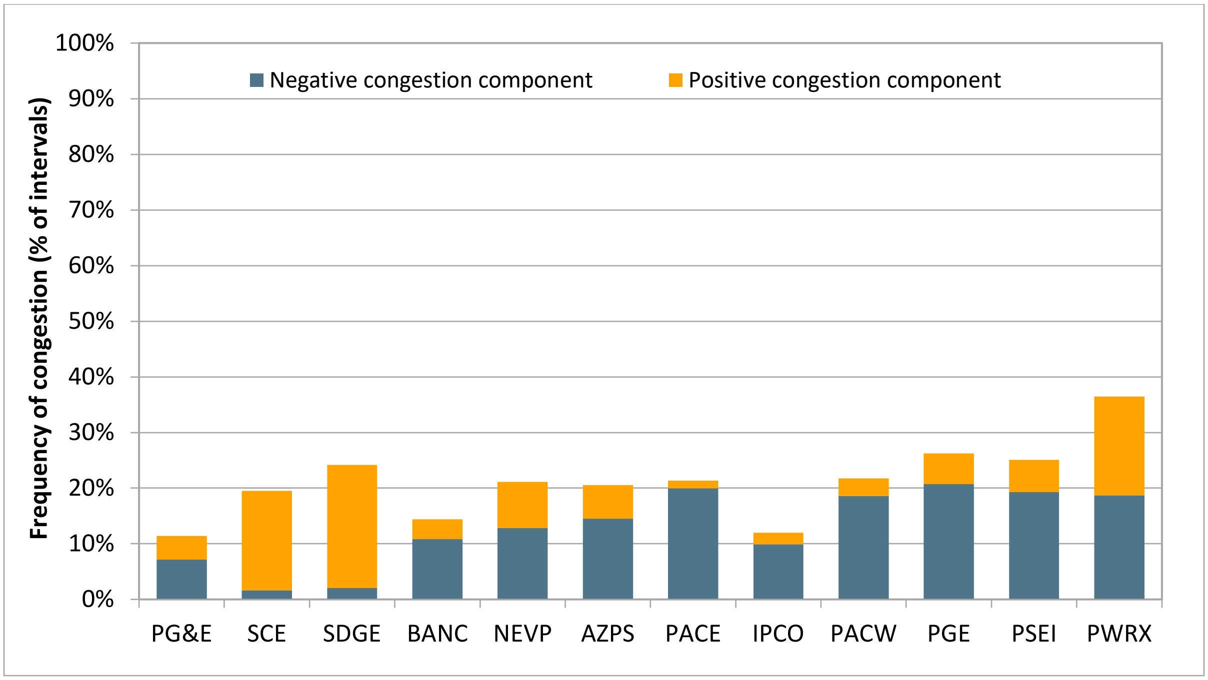
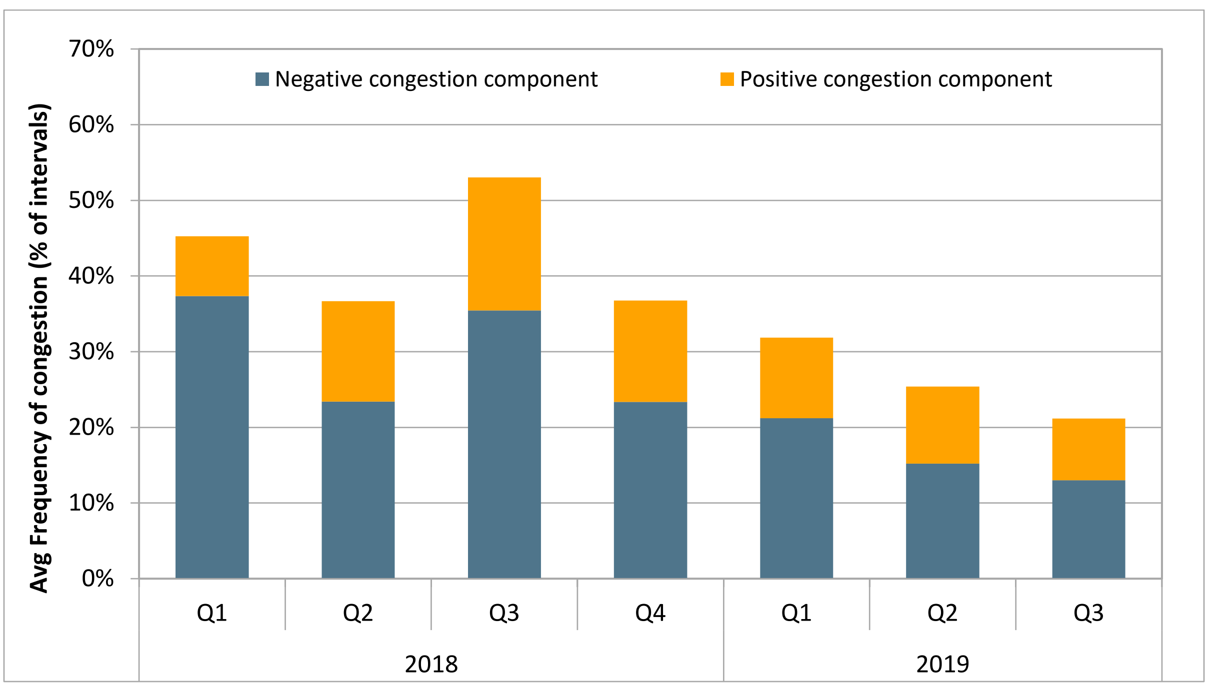


Figure 1.28 Percent of intervals with congestion impacting 15-minute prices (quarterly average of load areas)



Impact of congestion from individual constraints

Table 1.4 shows the overall impact (during all intervals) of congestion on average 15-minute prices in each load area. Table 1.5 shows the impact of congestion from each constraint only during congested intervals, where the number of congested intervals is presented separately as frequency. The color scales in the table below apply only to the individual constraints (excludes “other” in Table 1.4). The category labeled “other” includes the impact of EIM transfer constraints and power balance constraint (PBC) violations, which often have the greatest impact on price separation for EIM areas. Transfer constraints and PBC violations are discussed in greater depth in Chapter 2. This section will focus on the individual flow-based constraints.

The constraints that had the greatest impact on price separation in the 15-minute market were the Imperial Valley nomogram, the Midway-Vincent 500 kV lines, and the Vincent transformer 3.

Imperial Valley nomogram

The Imperial Valley nomogram (7820_TL 230S_OVERLOAD_NG) bound frequently in the quarter, during 7 percent of intervals. When binding, it increased prices in SDG&E by about $12/MWh and decreased prices in all EIM areas by about $0.60/MWh on average. Over the entire quarter, it increased SDG&E prices by about $0.79/MWh and decreased EIM area prices by about $0.03/MWh. The nomogram is enforced to mitigate for the loss of the Imperial Valley-North Gila 500 kV line. In the 2017-2018 transmission planning cycle, an upgrade to the Imperial Valley-El Centro 230 kV S-Line was approved. The project, which is planned to be complete in 2021, will help to alleviate congestion in this area.

Midway-Vincent 500 kV lines

The Midway-Vincent 500 kV lines (30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3 and 30060_MIDWAY _500_24156_VINCENT _500_BR_2 _1) bound infrequently in the quarter, during 2 percent and 1 percent of intervals, respectively. When binding, they increased prices in SCE, SDG&E, NEVP, and AZPS by about $10/MWh on average and decreased prices throughout the rest of the west by about $8/MWh on average. Overall for the quarter, the nomogram increased prices in SCE, SDG&E, NEVP, and AZPS by about $0.1/MWh on average and decreased prices throughout the rest of the west by about $0.13/MWh on average. This constraint was binding in part due to a planned outage of the Whirlwind 500 kV line series capacitor.

Vincent Transformer 3

The Vincent transformer 3 (24156_VINCENT _500_24155_VINCENT _230_XF_3) bound infrequently in the quarter, during 1 percent of intervals. When binding, it increased prices in SCE and SDG&E by about $20/MWh on average and decreased prices throughout the rest of the west by about $13/MWh on average. Congestion due to the transformer did not impact prices in Nevada and Arizona. Overall for the quarter, the nomogram increased prices in SCE and SDG&E by about $0.2/MWh on average and decreased prices throughout the rest of the west (except NEVP and AZPS) by about $0.13/MWh on average. This constraint bound as a result of using emergency ratings to mitigate overloading.

Table 1.4 Impact of congestion on overall 15-minute prices

Constr. Location	Constraint	PG&E	SCE	SDGE	BANC	NEVP	AZPS	PACE	IPCO	PACW	PGE	PSEI	PWRX
NEVP	HA-RE_345KV		$0.00	$0.00		$0.00	$0.00	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00
PACE	WYOMING_EXPORT							-$0.04					
PG&E	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.22	$0.20	$0.19	-$0.21	$0.11	$0.17	$0.00	-$0.09	-$0.15	-$0.15	-$0.15	-$0.15
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _1	-$0.19	$0.19	$0.18	-$0.18	$0.10	$0.16		-$0.07	-$0.13	-$0.13	-$0.13	-$0.13
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	-$0.12	$0.10	$0.09	-$0.11	$0.05	$0.08	$0.00	-$0.05	-$0.08	-$0.08	-$0.08	-$0.08
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	-$0.11	$0.10	$0.09	-$0.10	$0.05	$0.08		-$0.04	-$0.07	-$0.08	-$0.08	-$0.08
	RM_TM12_NG	$0.06	$0.03	$0.03	$0.04		$0.02	-$0.04	-$0.07	-$0.10	-$0.10	-$0.10	-$0.10
	30735_METCALF _230_30042_METCALF _500_XF_12	$0.04	-$0.02	-$0.02		-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02
	40687_MALIN _500_30005_ROUND MT_500_BR_1 _3	$0.01	$0.01	$0.01	$0.01		$0.00	-$0.01	-$0.01	-$0.02	-$0.02	-$0.02	-$0.02
	37563_MELONES _230_30800_WILSON _230_BR_1 _1				-$0.14								
	24156_VINCENT _500_24155_VINCENT _230_XF_2 _P	-$0.01	$0.02	$0.01	-$0.01			-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	30515_WARNERVL_230_30800_WILSON _230_BR_1 _1				-$0.08								
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	$0.01	-$0.01	-$0.01	$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.00	-$0.01	-$0.01	$0.01	$0.00	-$0.01		$0.00	$0.01	$0.01	$0.01	$0.01
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _3	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00
	30500_BELLOTA _230_30515_WARNERVL_230_BR_1 _1				$0.03								
	SUMMIT1-DRUM					$0.03							
	30050_LOSBANOS_500_30056_GATES2 _500_BR_2 _1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00
	30622_EIGHT MI_230_30624_TESLA E _230_BR_1 _1				-$0.02								
	6310_CP6_NG	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00
SCE	24156_VINCENT _500_24155_VINCENT _230_XF_3	-$0.12	$0.22	$0.14	-$0.12			-$0.09	-$0.12	-$0.12	-$0.12	-$0.12	-$0.12
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.02	$0.18	$0.12	-$0.02	-$0.06	-$0.04	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02
	6410_CP1_NG	-$0.04	$0.04	$0.04	-$0.04	$0.02	$0.03		-$0.02	-$0.03	-$0.03	-$0.03	-$0.03
	24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1		$0.13	$0.12									
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	$0.00	$0.06	$0.04	$0.00	-$0.03	-$0.03	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00
	24092_MIRALOMA_500_24093_MIRALOM _230_XF_1 _P	-$0.01	$0.03	$0.04	-$0.01	-$0.01		-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	OP-6610_ELD-LUGO	$0.01	$0.02	$0.01	$0.01	-$0.05	-$0.04	-$0.02	-$0.01				
	24025_CHINO _230_24093_MIRALOM _230_BR_3 _1	$0.00	$0.01	$0.03	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	24091_MESA CAL_230_24126_RIOHONDO_230_BR_1 _1	$0.00	$0.00	$0.00	$0.00			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SDG&E	7820_TL 230S_OVERLOAD_NG		$0.05	$0.79	$0.00	-$0.06	-$0.18	-$0.07	$0.00	$0.00	$0.00	$0.00	$0.00
	25201_LEWIS _230_24137_SERRANO _230_BR_2 _1	-$0.02	$0.05	$0.02	-$0.02	-$0.03	-$0.04	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P			$0.14		-$0.01	-$0.04						
	22464_MIGUEL _230_22468_MIGUEL _500_XF_81			$0.12			-$0.04						
	24804_DEVERS _230_24901_VSTA _230_BR_2 _2						-$0.15						
	22886_SUNCREST_230_22885_SUNCREST_500_XF_1 _P			$0.08		-$0.01	-$0.03						
	24132_SANBRDNO_230_24804_DEVERS _230_BR_1 _1						-$0.11						
	7750_D-VISTA1_OOS_CP6_NG	$0.01		$0.00	$0.00	$0.00	-$0.06	-$0.01		$0.00	$0.00	$0.00	$0.00
	OMS 7333672 ML_BK80_NG			$0.07			-$0.02						
	22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1			-$0.08									
	OMS 7649801_50001_OOS_NG			$0.06			-$0.01						
	22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1			$0.06									
	22592_OLD TOWN_69.0_22873_VINE SUB_69.0_BR_1 _1			$0.03									
	22832_SYCAMORE_230_22652_PENSQTOS_230_BR_1 _1			$0.02			-$0.01						
	7820_TL23040_IV_SPS_NG			$0.02			$0.00						
Other		$0.03	$0.00	$0.06	-$0.40	$10.23	$0.90	$0.04	-$0.52	-$2.17	-$1.77	-$2.11	-$1.74
Total		**-$0.69**	**$1.40**	**$2.47**	**-$1.34**	**$10.32**	**$0.61**	**-$0.35**	**-$1.08**	**-$2.94**	**-$2.55**	**-$2.88**	**-$2.51**

Table 1.5 Impact of congestion on 15-minute prices in the ISO during congested intervals[21]

Constraint Location	Constraint	Freq.	PG&E	SCE	SDGE	BANC	NEVP	AZPS	PACE	IPCO	PACW	PGE	PSEI	PWRX
PACE	WYOMING_EXPORT	10.2%							-$0.43					
PG&E	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	2.0%	-$10.87	$9.83	$9.39	-$10.29	$5.33	$8.23	-$0.35	-$4.18	-$7.46	-$7.48	-$7.48	-$7.48
	37563_MELONES _230_30800_WILSON _230_BR_1 _1	1.9%				-$7.19								
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	1.7%	-$6.33	$5.80	$5.32	-$5.99	$3.10	$4.65		-$2.58	-$4.33	-$4.34	-$4.34	-$4.34
	30515_WARNERVL_230_30800_WILSON _230_BR_1 _1	1.7%				-$4.88								
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _1	1.3%	-$14.18	$13.86	$13.14	-$13.37	$7.19	$11.65		-$5.27	-$9.68	-$9.64	-$9.64	-$9.64
	RM_TM12_NG	0.8%	$7.55	$4.09	$3.51	$5.32		$2.49	-$5.53	-$9.38	-$12.73	-$12.80	-$12.80	-$12.80
	30500_BELLOTA _230_30515_WARNERVL_230_BR_1 _1	0.7%				$4.43								
	30735_METCALF _230_30042_METCALF _500_XF_12	0.6%	$7.24	-$2.93	-$2.93		-$2.93	-$2.93	-$2.93	-$2.93	-$2.93	-$2.93	-$2.93	-$2.93
	30622_EIGHT MI_230_30624_TESLA E _230_BR_1 _1	0.4%				-$3.76								
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	0.4%	-$29.74	$25.87	$23.73	-$28.29	$13.47	$20.63	-$0.99	-$12.28	-$21.06	-$21.15	-$21.15	-$21.15
SCE	24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1	2.4%		$5.64	$5.46									
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	2.1%	-$3.24	$8.53	$5.85	-$3.24	-$4.24	-$3.82	-$3.24	-$3.24	-$3.24	-$3.24	-$3.24	-$3.24
	24156_VINCENT _500_24155_VINCENT _230_XF_3	0.9%	-$13.27	$24.40	$15.12	-$13.27			-$10.47	-$13.26	-$13.27	-$13.27	-$13.27	-$13.27
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	0.5%	-$3.61	$11.39	$7.12	-$3.61	-$5.64	-$6.05	-$4.06	-$3.61	-$3.61	-$3.61	-$3.61	-$3.61
	OP-6610_ELD-LUGO	0.5%	$2.60	$3.12	$1.61	$1.98	-$10.41	-$7.49	-$4.72	-$1.54				
	6410_CP1_NG	0.3%	-$12.21	$11.45	$11.39	-$11.53	$6.39	$10.04		-$4.63	-$8.17	-$8.23	-$8.23	-$8.23
SDG&E	7820_TL 230S_OVERLOAD_NG	6.6%		$0.79	$12.01	-$0.06	-$0.86	-$2.70	-$1.01	-$0.22	-$0.06	-$0.06	-$0.06	-$0.06
	24804_DEVERS _230_24901_VSTA _230_BR_2 _2	1.2%						-$13.22						
	22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1	1.1%			$5.12									
	7750_D-VISTA1_OOS_CP6_NG	1.1%	$1.08		-$1.10	$1.30	-$0.56	-$5.06	-$1.40		$0.63	$0.55	$0.55	$0.55
	24132_SANBRDNO_230_24804_DEVERS _230_BR_1 _1	1.1%						-$10.66						
	22464_MIGUEL _230_22468_MIGUEL _500_XF_81	0.6%			$21.19			-$6.62						
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	0.5%			$28.87		-$2.39	-$8.62						
	22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1	0.5%			-$16.85									
	25201_LEWIS _230_24137_SERRANO _230_BR_2 _1	0.5%	-$3.87	$11.07	$3.87	-$3.87	-$6.90	-$7.30	-$3.92	-$3.87	-$3.87	-$3.87	-$3.87	-$3.87
	22832_SYCAMORE_230_22652_PENSQTOS_230_BR_1 _1	0.3%			$5.88			-$3.78						

1.12.3 Congestion on interties

Figure 1.29 shows total import congestion charges in the day-ahead market for 2018 and 2019. Figure 1.30 shows the frequency of congestion on five major interties for the first three quarters of 2019. Table 1.6 provides a detailed summary of this data over a broader set of interties.

The total import congestion charges reported are the products of the shadow prices times the binding limit for the intertie constraint. For a supplier or load-serving entity trying to import power over a congested intertie, the congestion price represents a decrease in the price for imports into the ISO. This congestion charge also represents the amount paid to owners of congestion revenue rights that are sourced outside of the ISO at points corresponding to these interties.

The charts and table highlight the following:

- Total import congestion charges for the first three quarters of 2019 were about $73 million compared to $82 million in the first three quarters of 2018.
- In the third quarter of 2019, the congestion on the major interties decreased significantly in day-ahead market compared to the same quarter of 2018, and decreased slightly compared to the second quarter of 2019.

[21] Details on constraints binding in less than 0.3 percent of the intervals have not been reported.

- The frequency of congestion in the third quarter decreased overall, though increased on some major ties and decreased on others compared to the second quarter of 2019.
- The frequency of congestion and magnitude of congestion charges tends to be highest on PACI/Malin 500, NOB, Palo Verde, and the IPP Utah interties. Congestion on other interties continue to remain relatively low relative to these top constraints.

Figure 1.29 Summary of import congestion in day-ahead market

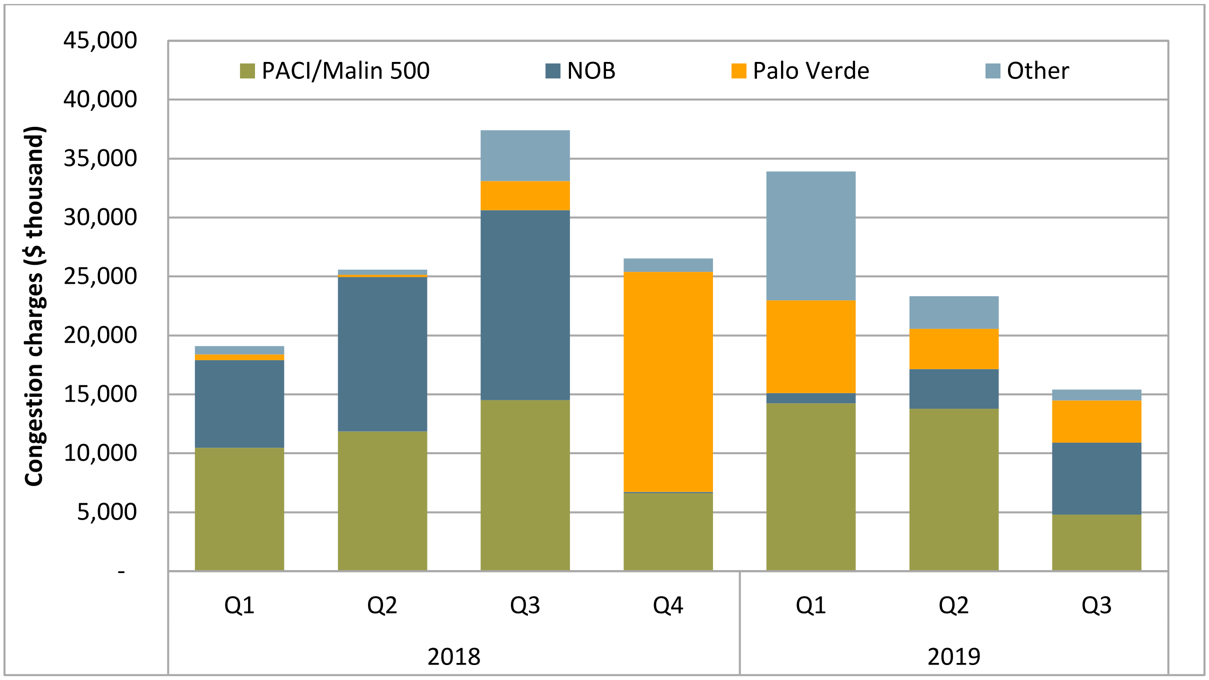


Figure 1.30 Frequency of import congestion on major interties in the day-ahead market (2019)

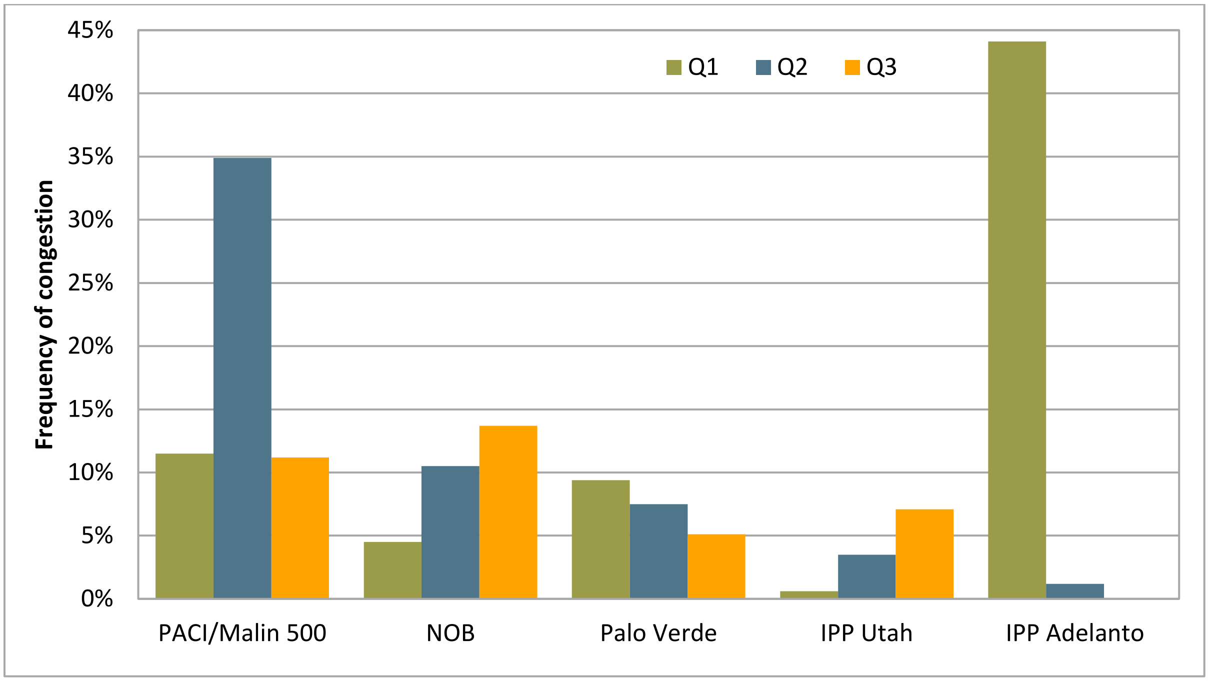


Table 1.6 Summary of import congestion in day-ahead market (2018-2019)

Area	Intertie	Frequency of import congestion							Import congestion charges ($ thousand)						
		2018				2019			2018				2019		
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q1	Q2	Q3	Q4	Q1	Q2	Q3
Northwest	PACI/Malin 500	24%	20%	21%	13%	12%	35%	11%	10,467	11,860	14,500	6,607	14,246	13,773	4,787
	NOB	32%	36%	18%	1%	5%	11%	14%	7,445	13,095	16,136	123	858	3,380	6,128
	COTPISO	2%	3%	1%	1%	0%	3%		33	51	23	29	4	20	
	Cascade	0%	1%				1%	2%	3	12	0			30	162
Southwest	Palo Verde	1%	1%	2%	20%	9%	8%	5%	487	201	2,463	18,650	7,864	3,409	3,579
	IPP Adelanto	1%	2%	2%		44%	1%		46	150	394		10,028	120	
	IPP Utah	17%	10%	26%	15%	1%	4%	7%	385	220	1,018	517	13	99	186
	Gonder IPP Utah						3%							2,477	
	CFE			0%				0%			1,844				55
	Mead			0%	1%	1%		0%			18	223	306		238
	Marketplace Adelanto	0%				1%			59				477		
	MeadTMead			0%	0%						424	13			
	IID-SDGE			0%							283				197
	IID-SCE	1%							158		283				
	Westwing Mead				3%	2%		1%				157	127		21
	Adelanto				1%							223			
Other	Other										33	0		21	63

1.13 Ancillary services

1.13.1 Ancillary service requirements

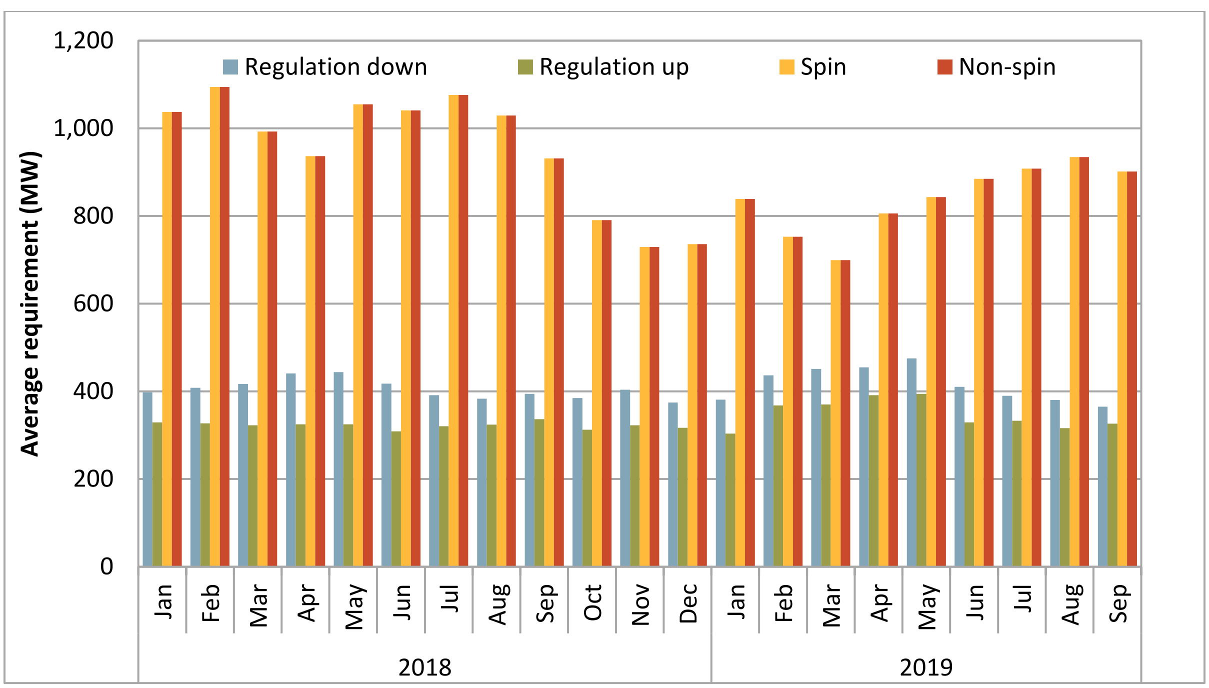
The ISO procures four ancillary services in the day-ahead and real-time markets: spinning reserves, non-spinning reserves, regulation up, and regulation down. Ancillary service procurement requirements are set for each ancillary service to meet or exceed Western Electricity Coordinating Council's (WECC) minimum operating reliability criteria and North American Electric Reliability Corporation's (NERC) control performance standards.

The ISO can procure ancillary services in the day-ahead and real-time markets from the internal system region, expanded system region, four internal sub-regions, and four corresponding expanded sub-regions. The expanded regions are identical to the corresponding internal regions but include interties. Each of these regions can have minimum requirements set for procurement of ancillary services where the internal sub-regions are nested within the system and corresponding expanded regions. Therefore, ancillary services procured in an inward region also count toward meeting the minimum requirement of the outer region. Both internal resources and imports then meet ancillary service requirements, where imports are indirectly limited by the minimum requirements from the internal regions.

Operating reserve requirements in the day-ahead market are typically set by the maximum of (1) 6.3 percent of the load forecast, (2) the most severe single contingency and (3) 15 percent of forecasted solar production. Operating reserve requirements in real-time are calculated similarly except using 3 percent of the load forecast and 3 percent of generation instead of 6.3 percent of the load forecast. Projected schedules on the Pacific DC intertie that sink in the ISO balancing area (which can include a higher volume than the share that sinks directly in the ISO) often serve as the most severe single contingency.

Figure 1.31 shows monthly average ancillary service requirements for the expanded system region in the day-ahead market. As shown in the figure, average spinning and non-spinning operating reserve requirements increased during the third quarter, mostly due to higher seasonal loads. In addition, Pacific DC intertie schedules frequently set the operating reserve requirement during the morning hours as the most severe single contingency.

Figure 1.31 Average monthly day-ahead ancillary service requirements

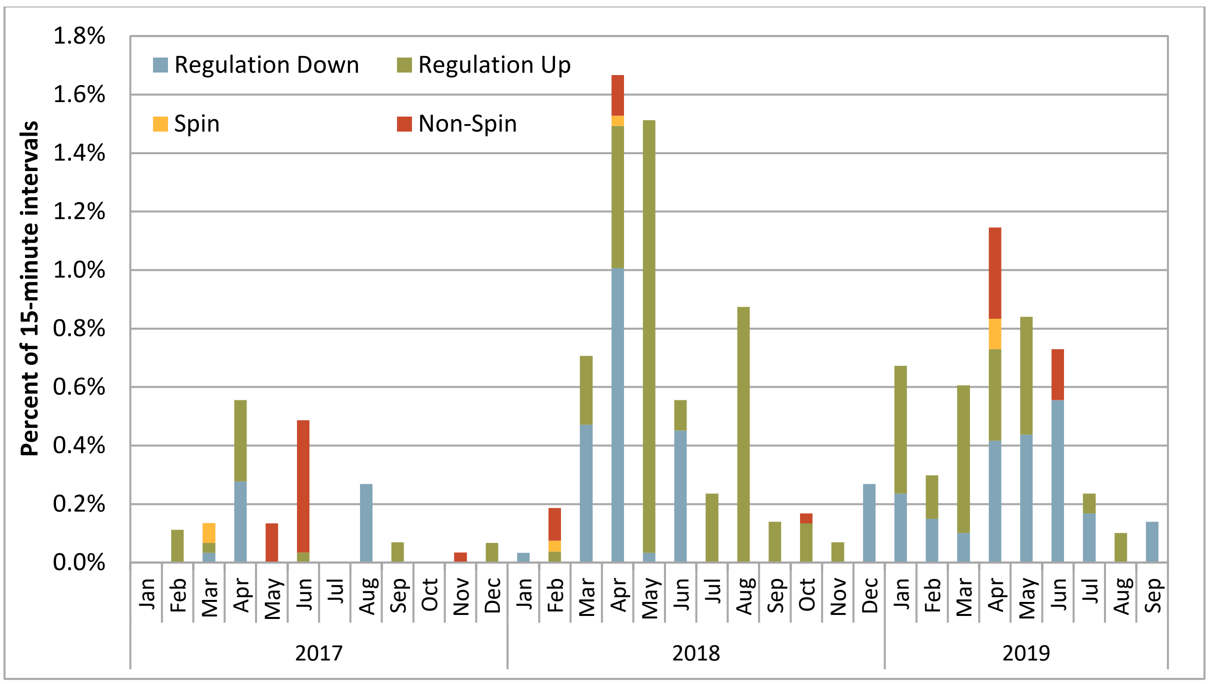


1.13.2 Ancillary service scarcity

Scarcity pricing of ancillary services occurs when there is insufficient supply to meet reserve requirements. Under the ancillary service scarcity price mechanism, implemented in December 2010, the ISO pays a pre-determined scarcity price for ancillary services procured during scarcity events. The scarcity prices are determined by a scarcity demand curve, such that the scarcity price is higher when the procurement shortfall is larger.

As shown in Figure 1.32 the number of intervals with scarcity pricing decreased during the third quarter. During the third quarter of 2019, around 79 percent of the scarcity intervals occurred in the expanded South of Path 26 region, and the remaining 21 percent in the expanded North of Path 26 region.

Figure 1.32 Frequency of ancillary service scarcities (15-minute market)

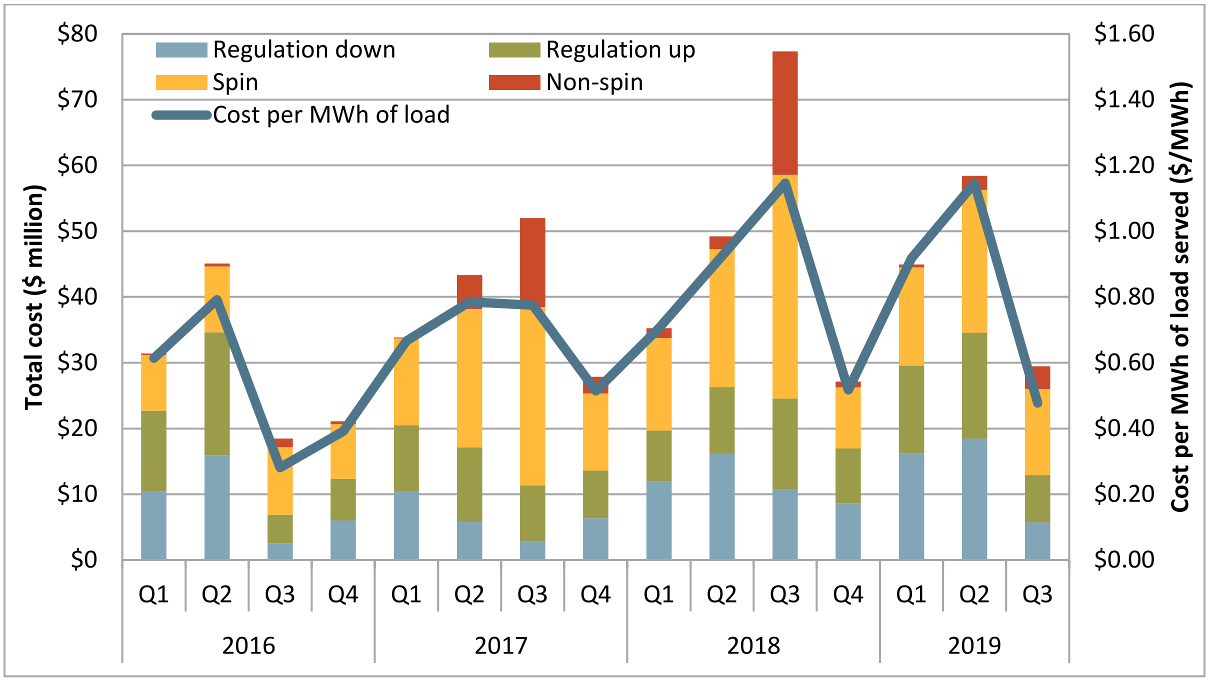


1.13.3 Ancillary service costs

Costs for ancillary services decreased during the third quarter to about $29 million, compared to about $58 million in the previous quarter and $78 million during the same quarter in 2018.

Figure 1.33 shows the total cost of procuring ancillary service products by quarter and the total ancillary service cost for each megawatt-hour of load served. In particular, total payments associated with regulation down and regulation up decreased by around $13 million and $9 million, respectively, from the previous quarter.

Figure 1.33 Ancillary service cost by product



1.14 Load forecast adjustments

Load forecast adjustments

Operators in the ISO and EIM can manually modify load forecasts used in the market through a load adjustment. Load adjustments are sometimes referred to as load bias or load conformance. The ISO uses the term imbalance conformance to describe these adjustments. Load forecast adjustments are used to account for potential modeling inconsistencies and inaccuracies. Specifically, operators listed multiple reasons for use of load adjustments including managing load and generation deviations, automatic time error corrections, scheduled interchange variations, reliability events, and software issues.[22] DMM will continue to use the terms load forecast adjustment and load bias limiter for consistency with prior reports.

Frequency and size of load adjustments, generation/import prices and imports

The dramatic increase in load forecast adjustments during the steep morning and evening net load ramp periods in the ISO's hour-ahead and 15-minute markets in 2017 appears to have continued throughout 2018 and into the third quarter of 2019. For this same period, mid-day adjustments also increased on average for all markets from a neutral/slightly negative adjustment to slightly positive. As with the previous quarter, load forecast adjustments for the 5-minute market increased throughout most of the

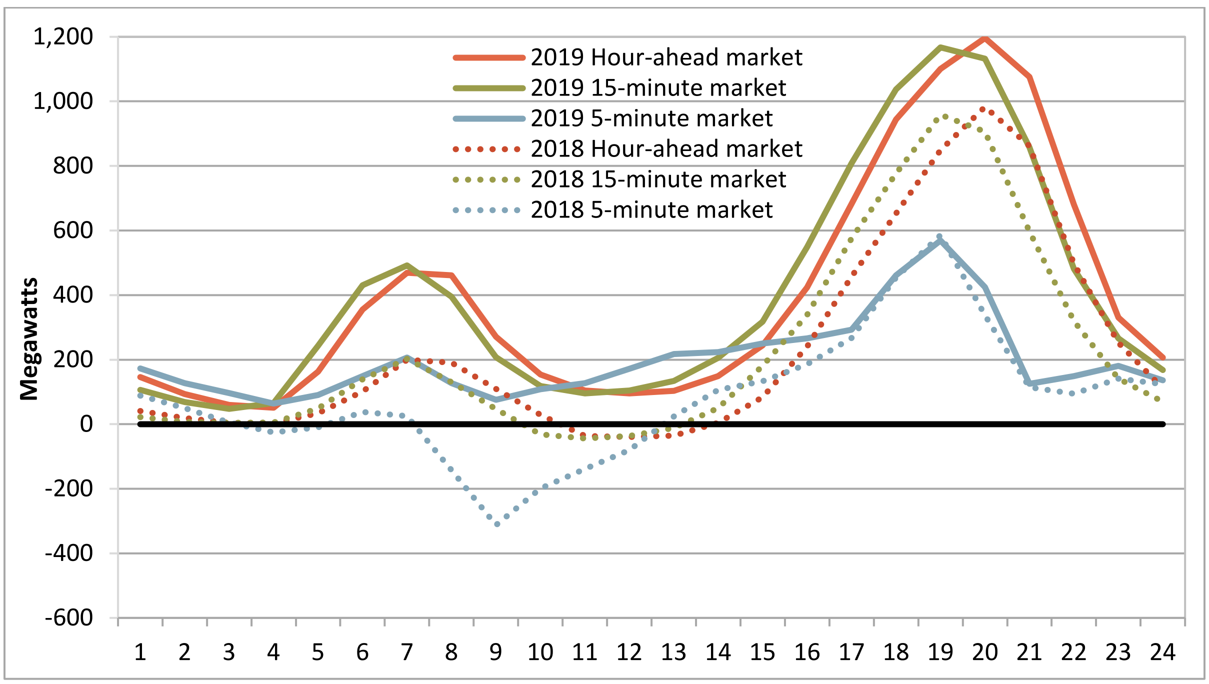
22 Additional detail can be found in Section 9, Market Adjustments, in the *2016 Annual Report on Market Issues and Performance*, which is available on the ISO website at: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf

day and remained positive when comparing the third quarter of 2019 with the same period in 2018. Figure 1.34 shows the average hourly load adjustment profile for the hour-ahead, 15-minute and 5-minute markets for the third quarter in 2019 and 2018.

Load adjustments in the hour-ahead and 15-minute markets are very similar to each other throughout the day. However, like the previous year and quarters, the 2019 5-minute market adjustments differ dramatically from other markets for nearly all hours of the day. Unlike the same quarter in 2018 where the daily average hourly adjustment was about only 75 MW in the positive direction, the average hourly adjustment for the third quarter of 2019 was about 200 MW in the positive direction with no negative conformance on average in any hour of the day. In the hour-ahead and 15-minute markets the lowest adjustment period was in the early morning/late evening and mid-day hours.

The shape of the adjustments for the 5-minute market was similar to the other markets with the exception of the mid-day period where adjustments just exceed 200 MW, while the hour-ahead and 15-minute market adjustments were about 120 MW. However, this changed sharply surrounding the morning and evening ramp periods, when the average hourly adjustment was nearly 1,200 MW in hour-ending 19 for the hour-ahead and 15-minute markets whereas the load adjustment in the 5-minute market was closer to 590 MW. Adjustments are often associated with over/under-forecasted load, changes in expected renewable generation, and morning or evening net load ramp periods.

Figure 1.34 Average hourly load adjustment (Q3 2018 – Q3 2019)



1.15 Local market power mitigation

Rates of mitigation decreased relative to the third quarter of 2018, due in part to a reduction in the frequency of congestion. Incremental energy subject to mitigation have increased relative to prior years due, in part, to the increase in concentration of generation in the portfolios of net sellers and load in the portfolios of net buyers.

Background

The ISO's automated local market power mitigation (LMPM) procedures were enhanced in numerous ways since 2012 to more accurately identify and mitigate resources with the ability to exercise local market power in the day-ahead and real-time markets. The ISO is currently working on more enhancements to real-time market power mitigation processes for implementation in November 2019. As part of this policy, the ISO is proposing several measures including prevention of flow reversal by eliminating balance of hour mitigation, and providing an option for EIM areas to limit exports when mitigation is triggered due to import congestion.[23] On September 30, 2019, FERC rejected a proposal to limit net exports by an EIM balancing authority area.[24] Subsequently, the ISO filed on October 30, 2019, a request for rehearing at FERC regarding the net export limit proposal. [25]

The impact on market prices of bids that were mitigated can only be assessed precisely by re-running the market software without bid mitigation. However, DMM does not have the ability to re-run the day-ahead and real-time market software to perform such analysis. Instead, DMM has developed a variety of metrics to estimate the frequency with which mitigation is triggered and the effect of this mitigation on each unit's energy bids and dispatch levels. These metrics identify bids lowered from mitigation each hour and estimate the additional energy dispatched from these price changes.[26]

The following sections provide analysis on the frequency and impact of bid mitigation in day-ahead and real-time markets, for the ISO's balancing authority area.

Frequency and impact of automated bid mitigation

Rates of mitigation decreased relative to the third quarter of 2018, due to a reduction in the frequency of congestion. As shown in Figure 1.35, in the day-ahead market, about 733 MW was subject to mitigation but their corresponding bids were not lowered compared to 1,072 MW in the same quarter of 2018. About 310 MW of incremental energy had bids lowered due to mitigation compared to 495 MW in 2018. As a result, there was on average about 40 MW increase in dispatch, compared to 74 MW in 2018.

Figure 1.36 shows the same metrics but for the ISO's 15-minute and 5-minute markets. As shown in the figure, the average incremental energy that is subject to mitigation and either had bids lowered or not due to mitigation in the ISO is consistently higher in the 5-minute than in the 15-minute market. In the 15-minute market, about 450 MW of incremental energy was subject to mitigation in the third quarter of 2019. Of this energy, 362 MW did not have their bids lowered compared to 88 MW which had their

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23 Draft final proposal, *Local market power mitigation enhancements*, January 31, 2019: http://www.caiso.com/Documents/DraftFinalProposal-LocalMarketPowerMitigationEnhancements-UpdatedJan31_2019.pdf

24 FERC order on LMPM enhancements tariff revisions, September 30, 2019: http://www.caiso.com/Documents/Sep30-2019-Order-TariffRevisions-Accepting-Part-Rejecting-Part-LMPME-ER19-2347.pdf

25 ISO's request for rehearing and alternative motion for clarification, October 30, 2019: http://www.caiso.com/Documents/Oct302019_RequestforRehearingorClarification-LocalMarketPowerMitigationER19-2347.pdf

26 The methodology has been updated to show incremental energy instead of units that have been subject to automated bid mitigation. This metric also captures carry over mitigation (balance of hour mitigation) in 15-minute and 5-minute markets by comparing the market participant submitted bid at the top of each hour (in the 15-minute market) to the bid used in each interval of 15-minute and 5-minute market runs.

bid lowered due to mitigation. Similarly, in the 5-minute market, about 573 MW had their bids unchanged due to mitigation compared to 183 MW which had their bid lowered. In the third quarter of 2019, potential increase in 15-minute and 5-minute schedules from bid mitigation was down by almost 50 percent when compared to the third quarter of 2018.

Figure 1.35 Average incremental energy mitigated in day-ahead market

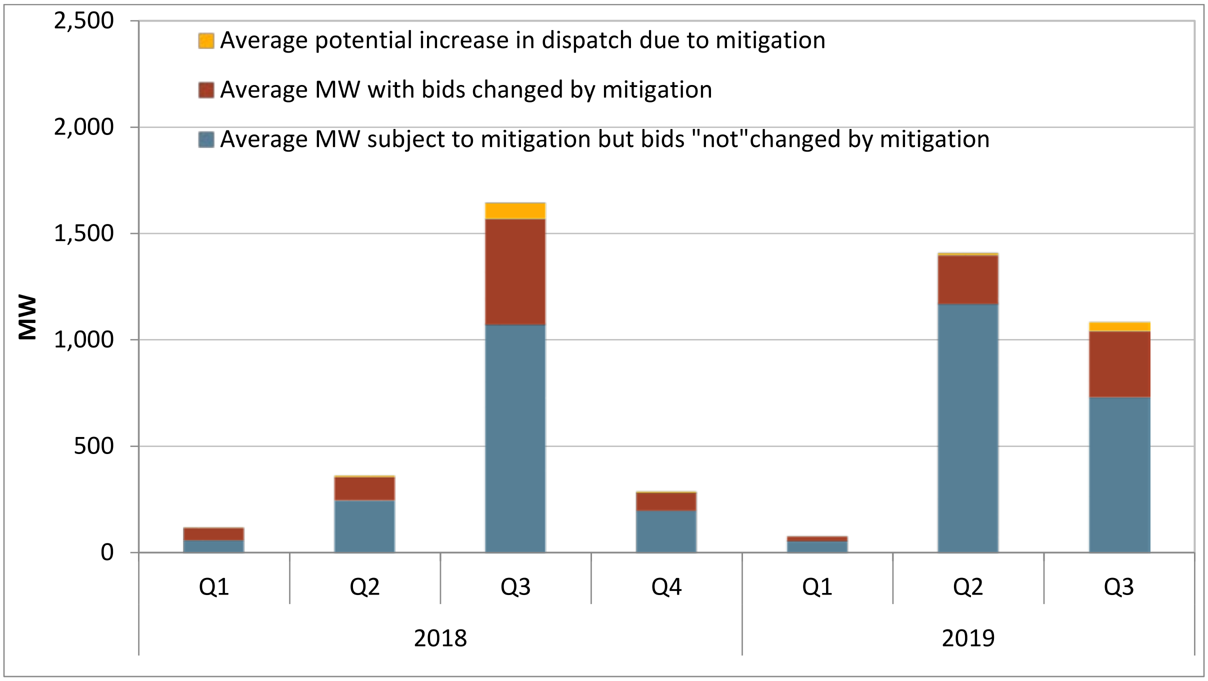
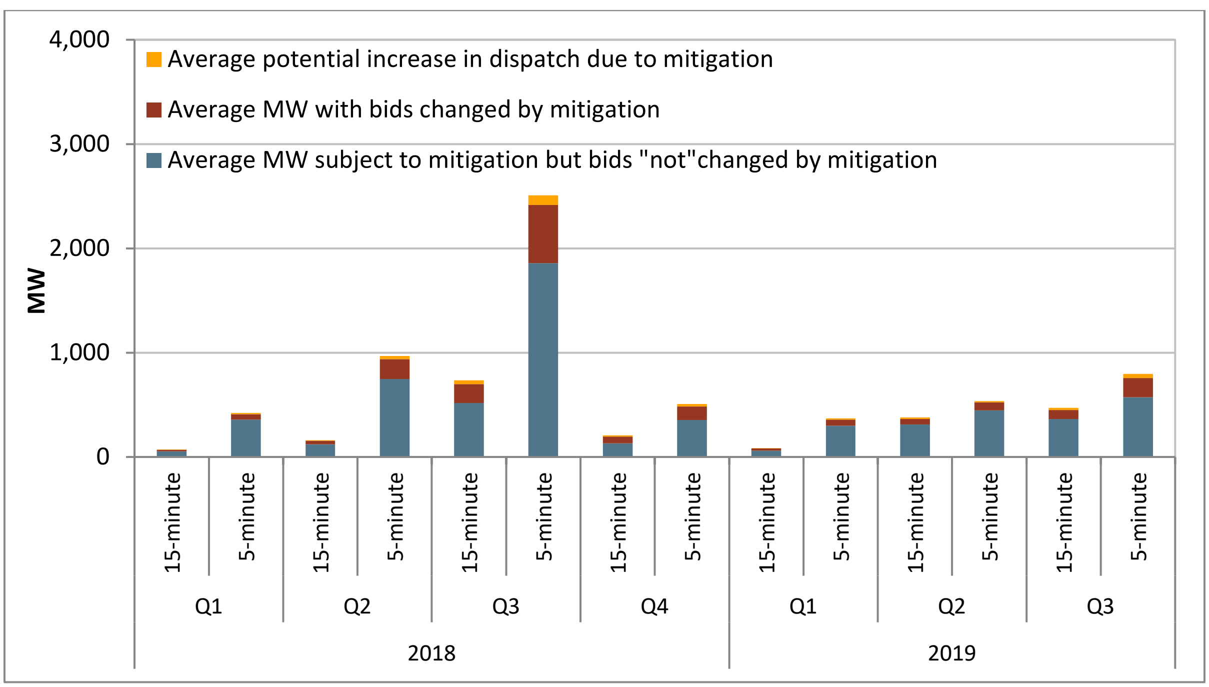


Figure 1.36 Average incremental energy mitigated in real-time market (ISO)



1.16 Congestion revenue rights

Background

Congestion revenue rights are paid (or charged), for each megawatt held, the difference between the hourly day-ahead congestion prices at the sink and source node defining the right. These rights can have monthly or seasonal (quarterly) terms, and can include on-peak or off-peak hourly prices. Congestion revenue rights are allocated to entities serving load. Congestion revenue rights can also be procured in monthly and seasonal auctions.

In the ISO, most transmission is paid for by ratepayers of the state's investor-owned utilities, and other load-serving entities through the transmission access charge (TAC).[27] The ISO charges utility distribution companies the transmission access charge to reimburse the entity that builds each transmission line for the costs incurred. As the owners of transmission or the entities paying for the cost of building and maintaining transmission, the ratepayers of utility distribution companies should collect the congestion revenues associated with transmission capacity in the day-ahead market.

When auction revenues are less than payments to other entities purchasing congestion revenue rights at auction, the difference between auction revenues and congestion payments represents a loss to ratepayers. The losses cause ratepayers, who ultimately pay for the transmission, to receive less than the full value of their day-ahead transmission rights.

In the ten years since the start of the congestion revenue rights auction, revenues from rights sold have consistently been well below the congestion revenues paid to entities purchasing these rights. Through 2018, transmission ratepayers have lost about $860 million in congestion revenues paid in excess of revenues received from the auction. This represents about 50 cents in auction revenues for every dollar paid to congestion revenue rights holders. Most of these profits are received by financial entities that do not sell power or serve load in the ISO.[28]

Congestion revenue rights auction modifications

In 2016, DMM recommended the ISO modify or eliminate the congestion revenue rights auction to reduce the losses to transmission ratepayers from congestion revenue rights sold in the auction. In 2018, the ISO proposed several changes to the congestion revenue rights auction design to reduce the systematic losses from congestion revenue rights sold in the auction.

- **Track 1A.** The first major change significantly reduces the number and pairs of nodes at which congestion revenue rights are purchased in the auction.[29] This change was designed to limit rights

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27 Some ISO transmission is built or owned by other entities such as merchant transmission operators. The revenues from transmission not owned or paid for by load-serving entities gets paid directly to the owners through transmission ownership rights or existing transmission contracts. The analysis in this section is not applicable to this transmission. Instead, this analysis focuses on transmission that is owned or paid for by load-serving entities only.

28 A more detailed discussion of congestion revenue rights is provided in DMM's *2018 Annual Report on Market Issues and Performance* (pp.197-205). http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

29 See *FERC Order on Tariff Amendment - Congestion Revenue Rights Auction Efficiency Track 1A,* April 11, 2018*:* http://www.caiso.com/Documents/Apr11_2018_TariffAmendment-CRRAuctionEfficiencyTrack1A_ER18-1344.pdf

sold in the auction to pairs of nodes at which physical generation and load is located, which in some cases may be purchased as hedge for actual sales and trading of energy.

- **Track 1B.** The second major change limits the net payments to congestion revenue right holders if payments to congestion revenue rights exceeds associated congestion charges collected in the day-ahead market on a targeted constraint-by-constraint basis.[30]

These tariff changes were implemented by the ISO beginning with the annual and monthly auctions for 2019.

Congestion revenue right auction returns

Auctioned congestion revenue rights profitability or ratepayer losses are payments received by buyers of auctioned rights less the auction price and estimated offsets charged to auctioned congestion revenue rights. Based on this framework, ratepayers lost about $4.1 million during the third quarter of 2019 as payments to auctioned congestion revenue rights holders exceeded auction revenues. This compares to average losses of $15 million in the third quarter of the prior three years. As shown in Figure 1.37, auction revenues were 79 percent of payments made to non-load-serving entities during the third quarter of 2019, up from 43 percent during the same quarter in 2018.

Financial entities (which do not schedule or trade physical power or serve load) continued to have the highest profits among the entity types, at approximately $4.4 million. This was a decrease from $27.4 million profits during the third quarter of 2018. Energy marketers profited about $2.2 million, down from more than $6 million profit during the same quarter in 2018. Generators' lost about $2.3 million compared to $8 million in profits in the third quarter of 2018.

The reduction in third quarter losses from the congestion revenue rights in the auction is due to a combination of at least three factors:

- Changes 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).[31]
- Changes in the settlement of congestion revenue rights implemented in 2019 (Track 1B).
- A significant drop in the impact and direction of congestion on day-ahead prices compared to Q3 in prior years.

The impact of Track 1A changes which limits the types of congestion revenue rights sold in the auction cannot be directly quantified. However, based on current settlement records, DMM estimates that changes in the settlement of congestion revenue rights made under Track 1B reduced losses to transmission ratepayers from sales of congestion revenue rights by about $5.7 million. A more detailed description of these Track 1B changes and the impact of these changes is provided in a later section of this report.

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30 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

31 An explanation of these changes is available in DMM's *2018 Annual Report on Market Issues and Performance*, Section 8.4, available here: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

The impact of the drop in congestion and change in congestion patterns in 2019 on transmission ratepayer losses from congestion revenue rights in the third quarter cannot be directly quantified. However, as shown by Figure 1.23 and Figure 1.24, there was a very significant drop in the impact and direction of congestion on day-ahead prices compared to the same quarter in 2018.[32]

Prior to offset adjustments related to Track 1B of about $5.7 million, payments to auctioned rights holders totaled $25.1 million in the third quarter of 2019. This is about 45 percent lower than the average of $46 million in the third quarter of each of the prior four years (2015-2018).

[32] See Figure 1.23 and Figure 1.24 on page 30 of this report.

Figure 1.37 Auction revenues and payments to non-load-serving entities

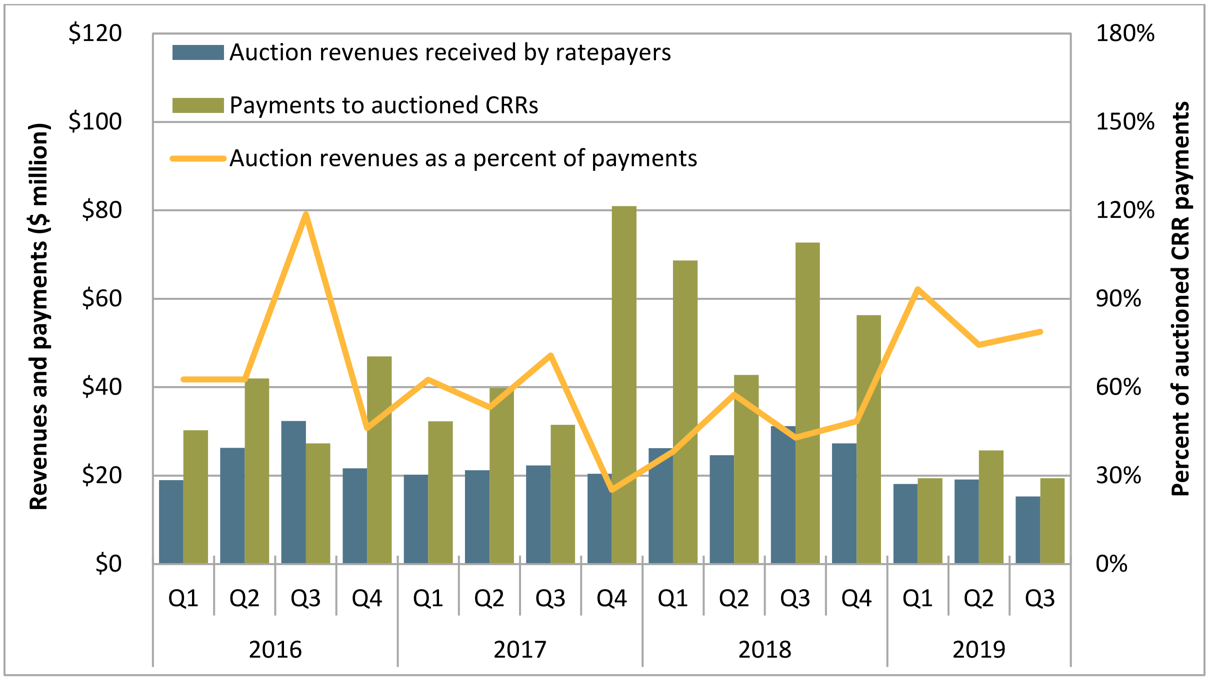
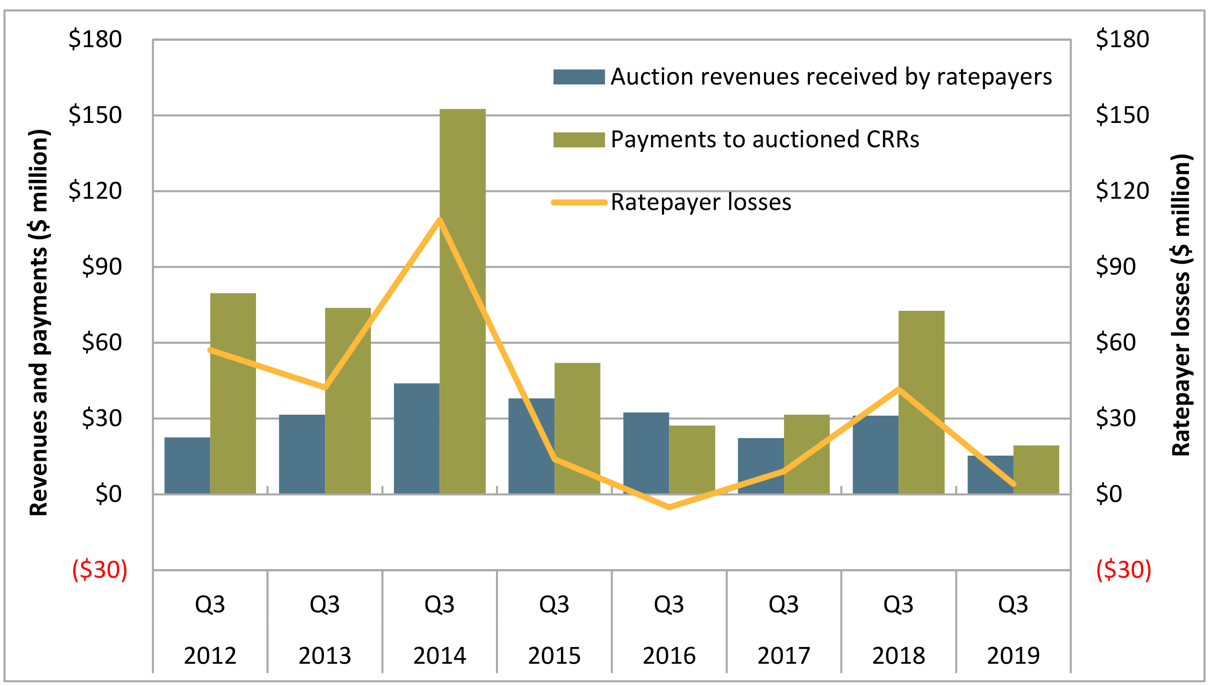


Figure 1.38 Q3 auction revenues and payments to non-load-serving entities (2012-2019)



Impact of Track 1B changes

Beginning on January 1,2019, changes made under the ISO's Track 1B filing state congestion revenue rights are paid only up to the amount of congestion rent actually collected on the constraints underlying the congestion revenue right source and sink marginal congestion components (MCC). The total congestion revenue rights payments, netted by scheduling coordinator from each constraint, are calculated over the month. The total congestion rent is calculated by constraint, and compared to the total congestion revenue rights payments across all scheduling coordinators from the constraint. If the congestion revenue rights payments are greater than the congestion rent collected for a constraint, the difference is charged to scheduling coordinators with net positive flows on the constraint as an offset.

Based on current settlement records, DMM estimates that the changes made under Track 1B reduced losses to transmission ratepayers from sales of congestion revenue rights by about $5.7 million.

2 Energy imbalance market

This section covers the Western EIM performance during the third quarter. Key observations and findings include:

- During peak system load hours, prices in the Northwest region, which includes PacifiCorp West, Puget Sound Energy, Portland General Electric, and Powerex, were regularly lower than prices in the ISO and other balancing areas due to limited transfer capability out of this region.
- Sufficiency test failures and subsequent under-supply power balance constraint relaxations are often not resolved by the enhanced load conformance limiter. As a result, these intervals are priced at the penalty parameter of $1,000/MWh. The high frequency of these intervals explains high average real-time prices for NV Energy.
- The enhancement for the load conformance limiter significantly reduced the frequency in which the conformance limiter triggered for under-supply conditions for Arizona Public Service and Nevada Energy. Instead, prices for these areas were often set at the $1,000/MWh penalty parameter in these instances.
- Export transmission capacity from Powerex and Portland General Electric to the ISO was often limited in both the 15-minute and 5-minute markets. Export limits from Powerex to the ISO were set to zero during 100 percent of 15-minute and 5-minute intervals and 93 percent of 5-minute market intervals. Similarly, export limits from Portland General Electric to the ISO were set to zero during 80 percent of 15-minute intervals and 92 percent of 5-minute intervals.
- The Western EIM's greenhouse gas prices increased as the deemed delivered resources shifted from lower to higher greenhouse gas emissions. In November 2018, the ISO implemented a revised EIM greenhouse gas bid design which limited greenhouse gas bid capacity to the differences between base schedule and available capacity, the weighted average greenhouse gas cost increased as the deemed delivered resources shifted from hydroelectric to natural gas.
- About 25 percent of capacity subject to mitigation had bids lowered in the 15-minute and 5-minute market. Because of bid mitigation, the potential average increase in both 15-minute and 5-minute dispatch is about 23 MW and 27 MW, respectively.

2.1 Western EIM performance

Western EIM prices

Figure 2.1 and Figure 2.2 show real-time prices for the Western EIM between April 3 and June 30, 2019. Several balancing areas are grouped together because of similar average hourly pricing. The figures also show prices at the Pacific Gas and Electric default load aggregation point as a point of comparison.

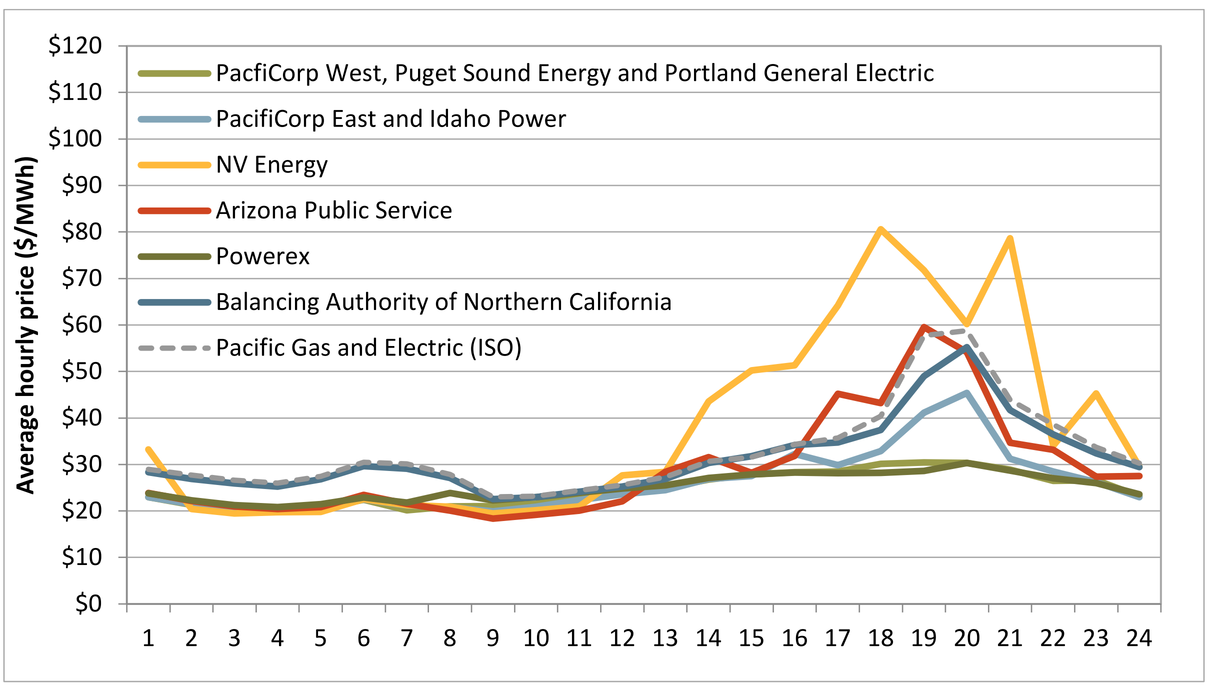
The Balancing Authority of Northern California (BANC) joined the Western EIM on April 3, 2019. Prices in the BANC tracked very closely to prices in the ISO because of significant transfer capability and little congestion between the areas. Prices in the Arizona Public Service area also tracked closely to prices in the ISO due to low congestion and a significant drop in flexible ramping sufficiency test failures from the second quarter to the third quarter in 2019.

During peak system load hours, prices in the Northwest region, which include PacifiCorp West, Puget Sound Energy, Portland General Electric, and Powerex, were regularly lower than those in the ISO and other balancing areas because of limited transfer capability out of this region. Additionally, prices in the Powerex area were often different from prices in ISO and the other Northwest areas because of very limited transfer capability into or out of the area during the third quarter.

Prices in PacifiCorp East and Idaho Power were often similar to each other and lower than prices in the ISO. As shown in Figure 2.1 and Figure 2.2, price separation between these areas and the ISO was most pronounced during peak load hours when transfers from PacifiCorp East and Idaho Power into the ISO hit export limits.

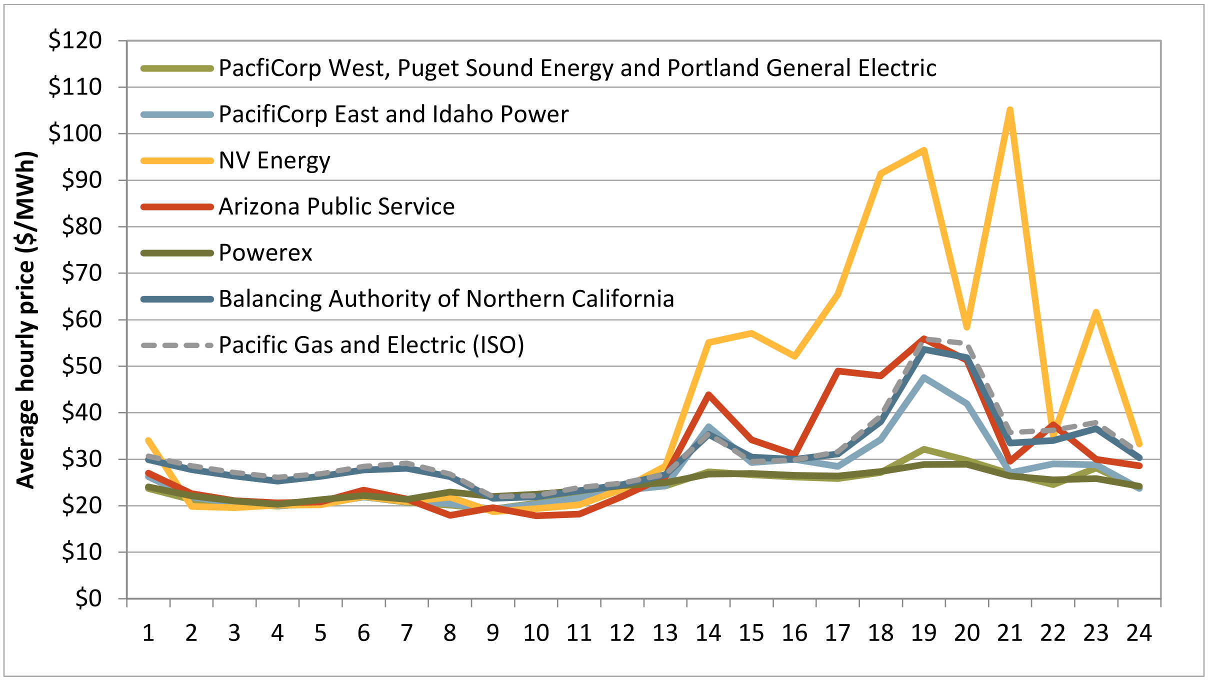
Average real-time prices for NV Energy were significantly higher than prices in the ISO between hours ending 14 and 21. This was mostly due to a number of flexible ramping sufficiency test failures and subsequent under-supply power balance constraint relaxations. The majority of these infeasibilities were not resolved by the enhanced load conformance limiter and were therefore priced at the penalty parameter of $1,000/MWh.[33]

Figure 2.1 Hourly 15-minute market prices (July – September)



[33] See Section 2.4 for further details on the load conformance limiter enhancement and its impact.

Figure 2.2 Hourly 5-minute market prices (July – September)



Western EIM wholesale energy cost

In the Western EIM, total estimated wholesale cost to serve load, excluding the ISO, was about $11.2 million or $0.16/MWh in the third quarter of 2019, which is a decrease from about $25 million or $0.36/MWh in the same quarter of 2018.

As shown in Figure 2.3 and Table 2.1, real-time energy costs contributed the largest portion of the costs, while imbalance offset costs typically reduced costs overall. Real-time energy costs and imbalance offset costs per megawatt-hour of total load decreased by about 46 percent and 28 percent, respectively, from the same quarter in 2018, while other costs remained about the same. In the EIM, offset costs paid to non-California balancing areas include payments to offset greenhouse gas cap-and-trade obligations incurred due to market dispatch.

Figure 2.3 Total EIM quarterly wholesale costs per MWh of load

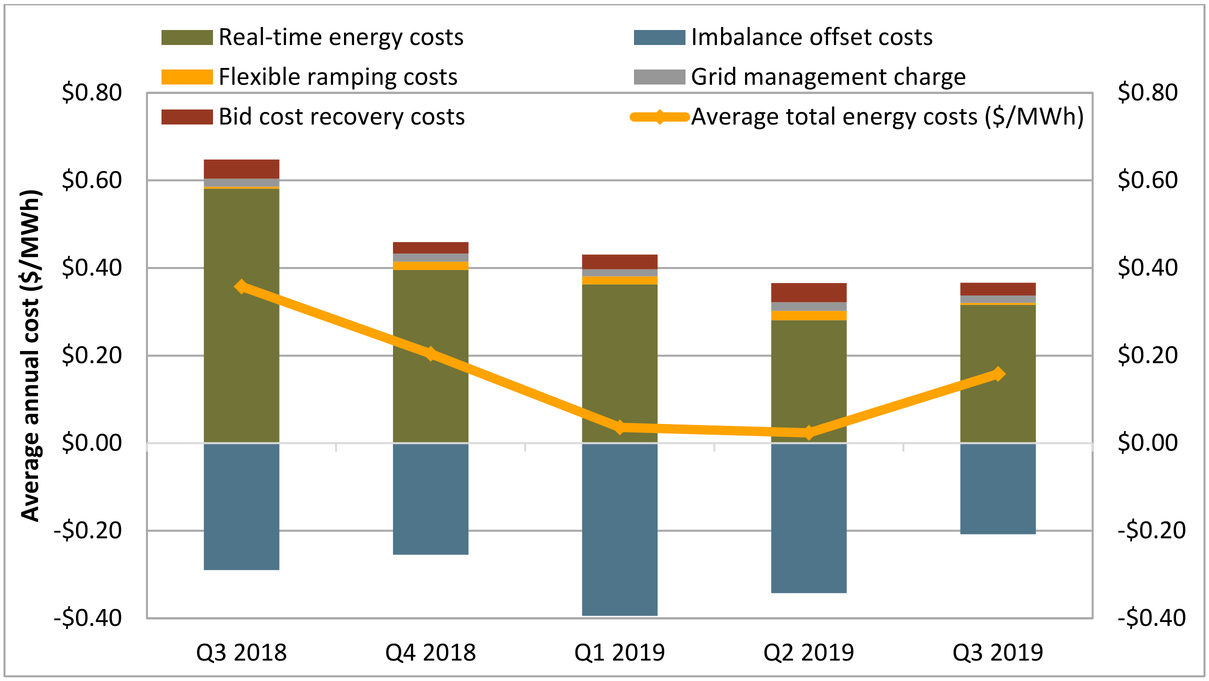


Table 2.1 Estimated average EIM wholesale energy costs per MWh

	Q3 2018	Q4 2018	Q1 2019	Q2 2019	Q3 2019	Change Q3 2018-Q3 2019
Real-time energy costs	$ 0.58	$ 0.40	$ 0.36	$ 0.28	$ 0.32	$ (0.27)
Imbalance offset costs	$ (0.29)	$ (0.25)	$ (0.39)	$ (0.34)	$ (0.21)	$ 0.08
Flexible ramping costs	$ 0.00	$ 0.02	$ 0.02	$ 0.02	$ 0.00	$ (0.00)
Grid management charge	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ (0.00)
Bid cost recovery costs	$ 0.04	$ 0.03	$ 0.03	$ 0.04	$ 0.03	$ (0.01)
Average total energy costs ($/MWh)	**$ 0.36**	**$ 0.20**	**$ 0.04**	**$ 0.02**	**$ 0.16**	**$ (0.20)**

2.2 Flexible ramping sufficiency test

The flexible ramping sufficiency test is performed every hour and ensures each balancing area has enough ramping resources to meet expected upward and downward ramping needs in the real-time market without relying on transfers from other balancing areas.

If an area fails the upward sufficiency test, EIM transfers into that area cannot be increased.[34] Similarly, if an area fails the downward sufficiency test, transfers out of that area cannot be increased. An area will also fail the flexible ramping sufficiency test when the capacity test fails for the specific direction. The capacity test ensures that there are sufficient incremental or decremental economic energy bids above or below the base schedules to meet the demand forecast.[35]

The flexible ramping sufficiency test requires balancing areas to show sufficient ramping capability from the start of the hour to each of the four 15-minute intervals within the hour. Previously, a failure of any of these four 15-minute interval sub-tests would result in a failure of the sufficiency test and limit transfers for the entire hour. The ISO implemented an enhancement on May 6, 2019, which evaluates sufficiency test results and potentially limits transfers on a 15-minute interval basis rather than for the entire hour. This decreased the frequency in which EIM areas failed the upward or downward sufficiency test.

Figure 2.4 and Figure 2.5 show the percent of *intervals* in which an EIM area failed the sufficiency test in the upward or downward direction.[36] Since May 6, the figures reflect that the flexible ramping sufficiency test evaluates sufficient ramping capability in 15-minute increments rather than hourly increments. In particular, NV Energy failed the upward sufficiency test during 8.5 percent of intervals during August, and around 3 percent of intervals in July and September. The ISO failed the upward sufficiency test during six intervals in early September.

Failures of the sufficiency test are important because these outcomes limit transfer capability. Constraining transfer capability may affect the efficiency of the EIM by limiting transfers into and out of a balancing area that could potentially provide benefits to other balancing areas. Reduced transfer capability also affects the ability for an area to balance load, as there is less availability to import from or export to neighboring areas. This can result in local prices being set at power balance constraint penalty parameters.

34 If an area fails the upward sufficiency test, net EIM imports (negative) cannot exceed the lower of either the base transfer or optimal transfer from the last 15-minute interval. Similarly, if an area fails the downward sufficiency test, net EIM exports are capped at the higher of either the base transfer or optimal transfer from the last 15-minute interval.

35 *Business Practice Manual for the Energy Imbalance Market*, February 28, 2019, p. 50.

36 Intervals in which an energy imbalance market entity is entirely disconnected from the market (market interruption) are removed.

Figure 2.4 Frequency of upward failed sufficiency tests by month

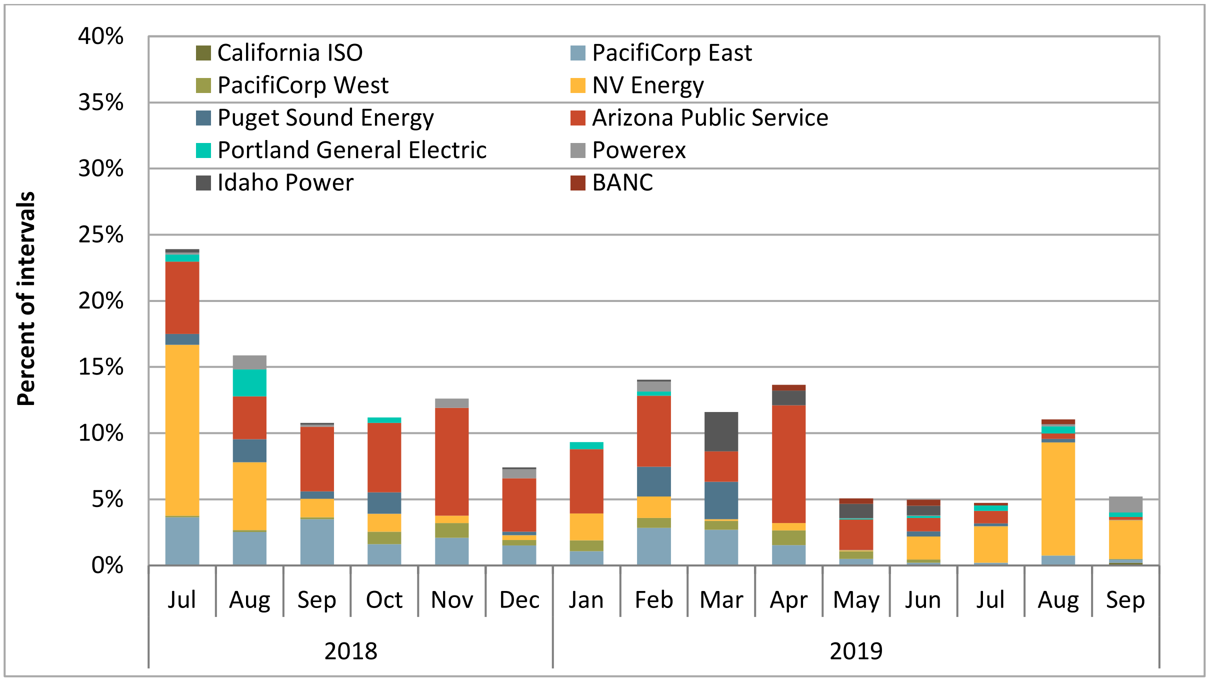
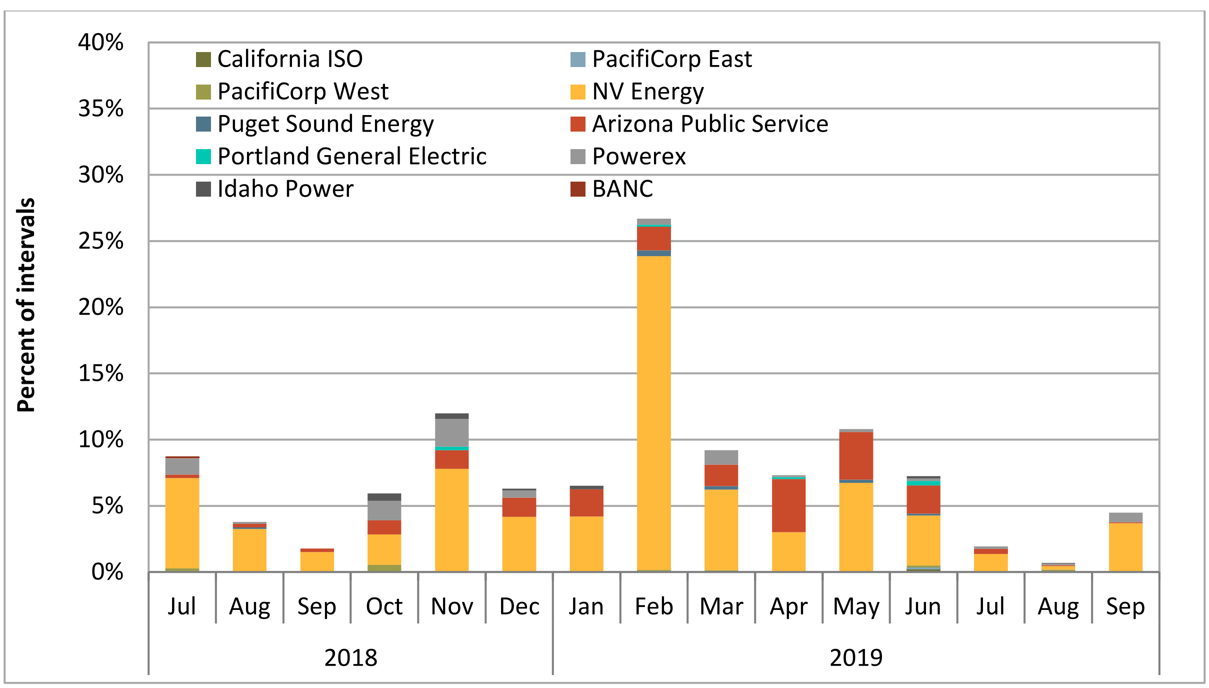


Figure 2.5 Frequency of downward failed sufficiency tests by month

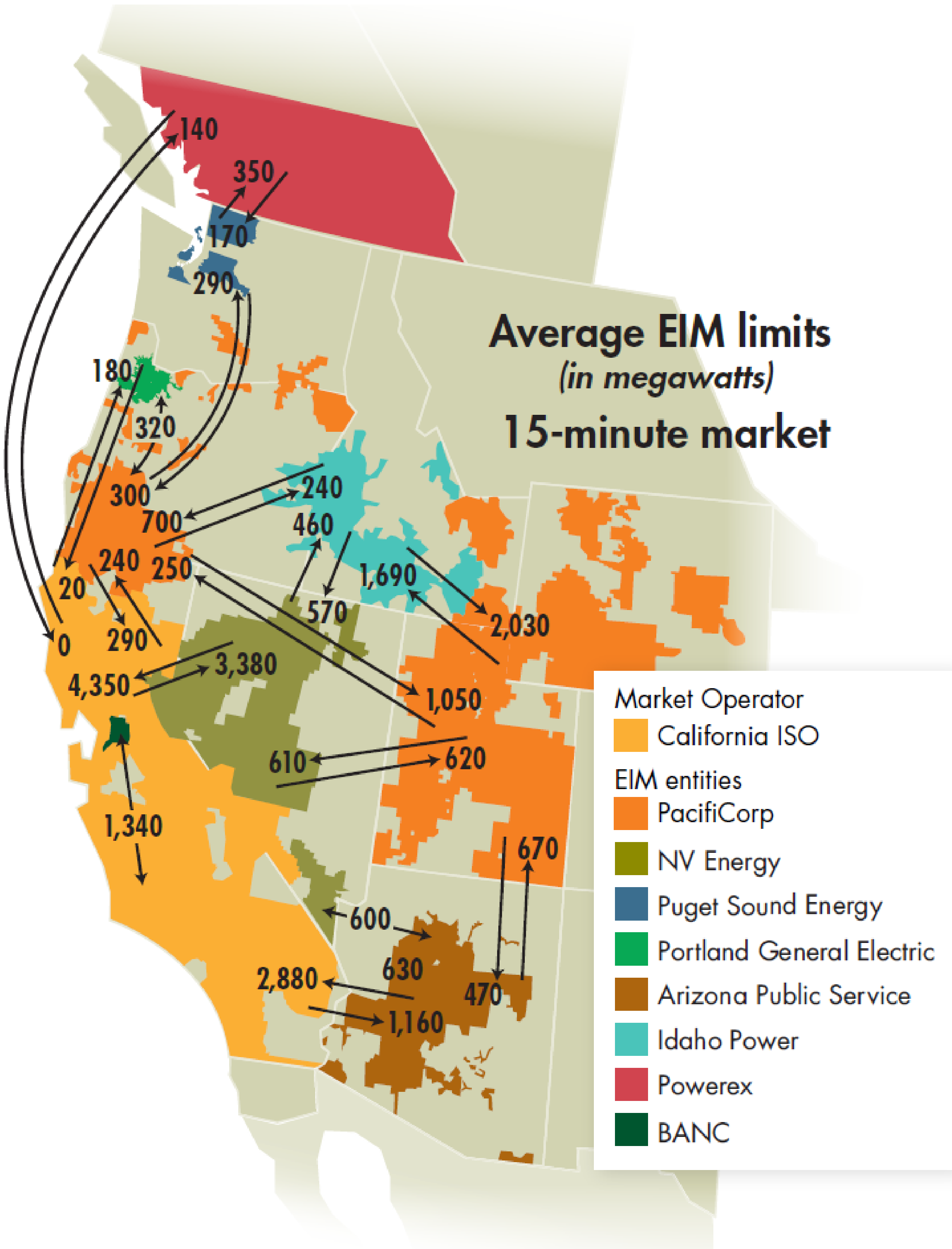


2.3 Western EIM transfers

Western EIM transfer limits

One of the key benefits of the EIM is the ability to transfer energy between areas in the 15-minute and 5-minute markets. Figure 2.6 shows average 15-minute market limits between each of the EIM areas during the third quarter. The map shows that there was significant transfer capability between the ISO, NV Energy, Arizona Public Service, and the BANC. Transfer capability between these areas, PacifiCorp East and Idaho Power was lower but still significant. These limits allowed energy to flow between these areas with relatively little congestion. Transfer capability was more limited between the ISO and the Northwest areas which include PacifiCorp West, Puget Sound Energy, Portland General Electric and Powerex. In particular, export limits from Powerex toward the ISO were limited to zero MW in all intervals in both the 15-minute and 5-minute markets. Similarly, export limits from Portland General Electric toward the ISO were set to zero during 80 percent of 15-minute intervals and 92 percent of 5-minute intervals during the third quarter.

Figure 2.6 Average 15-minute market energy imbalance market limits (July 1 – September 30)



Hourly energy imbalance market transfers

As highlighted in this section, transfers in the EIM are marked by distinct daily and seasonable patterns, which reflect differences in regional supply conditions and transfer limitations.

Figure 2.7 compares average hourly imports (negative values) and exports (positive values) between the ISO and other EIM areas during the last five quarters in the 15-minute market.[37] The bars show the average hourly transfers with the connecting areas. The gray line shows the average hourly net transfer.

In the third quarter of 2019, average exports during the middle of the day from the ISO were lower when compared to the previous quarter, but much higher compared to the third quarter of the previous year. In particular, exports from the ISO to areas in the Northwest increased significantly from the previous year. In addition, midday exports from the ISO to the BANC increased from 60 MW in the second quarter to almost 150 MW during the third quarter.

Figure 2.7 California ISO - average hourly 15-minute market transfer

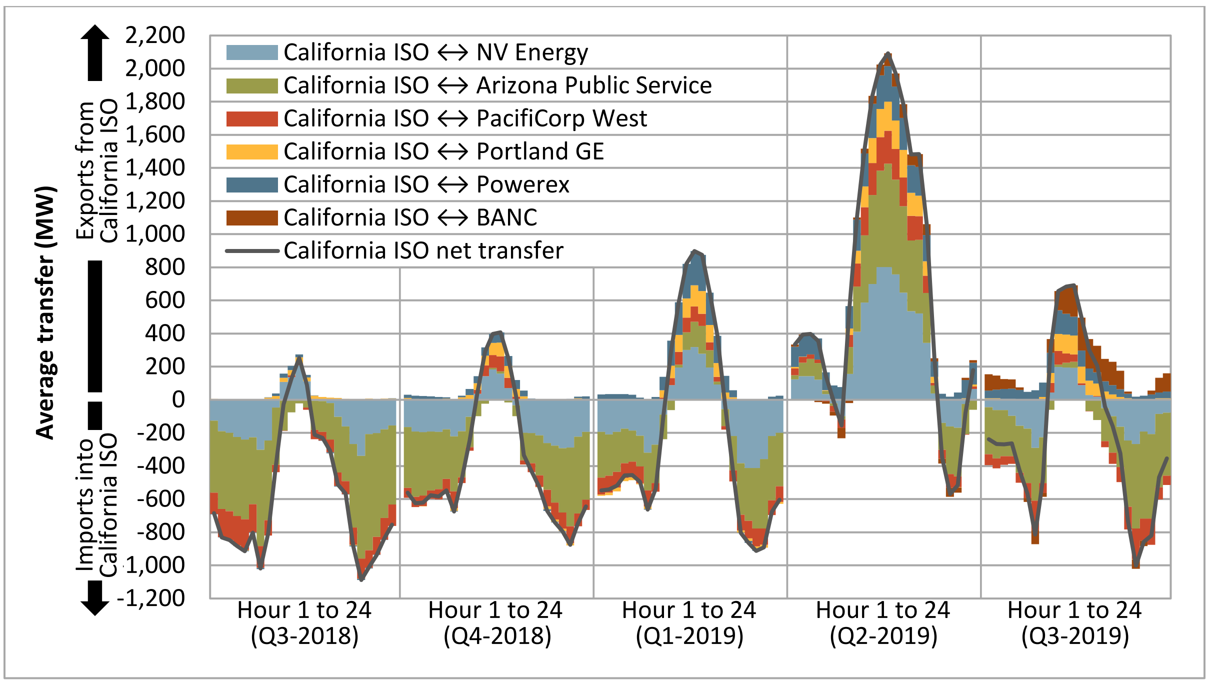


Figure 2.8 through Figure 2.12 show the same information on imports and exports for NV Energy, Arizona Public Service, Idaho Power, PacifiCorp West, and Powerex in the 15-minute market.[38] The amounts included in these figures are net of all base schedules and therefore reflect dynamic market flows between EIM entities.[39]

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[37] Average transfers for the second quarter of 2019 include April 3 to June 30 only, and therefore reflect transfers after the Balancing Authority of Northern California joined the energy imbalance market.

[38] Figures showing transfer information from the perspective of PacifiCorp East, Puget Sound Energy, and BANC are not explicitly included, but are represented in Figure 2.7 through Figure 2.12.

[39] Base schedules on EIM transfer system resources are fixed bilateral transactions between EIM entities.

As shown in Figure 2.7, a large portion of the ISO's transfer capability in the EIM is with NV Energy and Arizona Public Service. Per Figure 2.8 and Figure 2.9, NV Energy and Arizona Public Service were generally net exporters during most hours.

Figure 2.10 shows the hourly 15-minute market transfer pattern between Idaho Power and neighboring areas, net of all base schedules. Idaho Power has transfer capacity between PacifiCorp West, PacifiCorp East, and NV Energy. On average, Idaho Power base scheduled around 540 MW in imports from PacifiCorp East and 310 MW in exports to PacifiCorp West. As shown in Figure 2.10, dynamic transfers were much lower during the quarter.

Figure 2.8 NV Energy – average hourly 15-minute market transfer

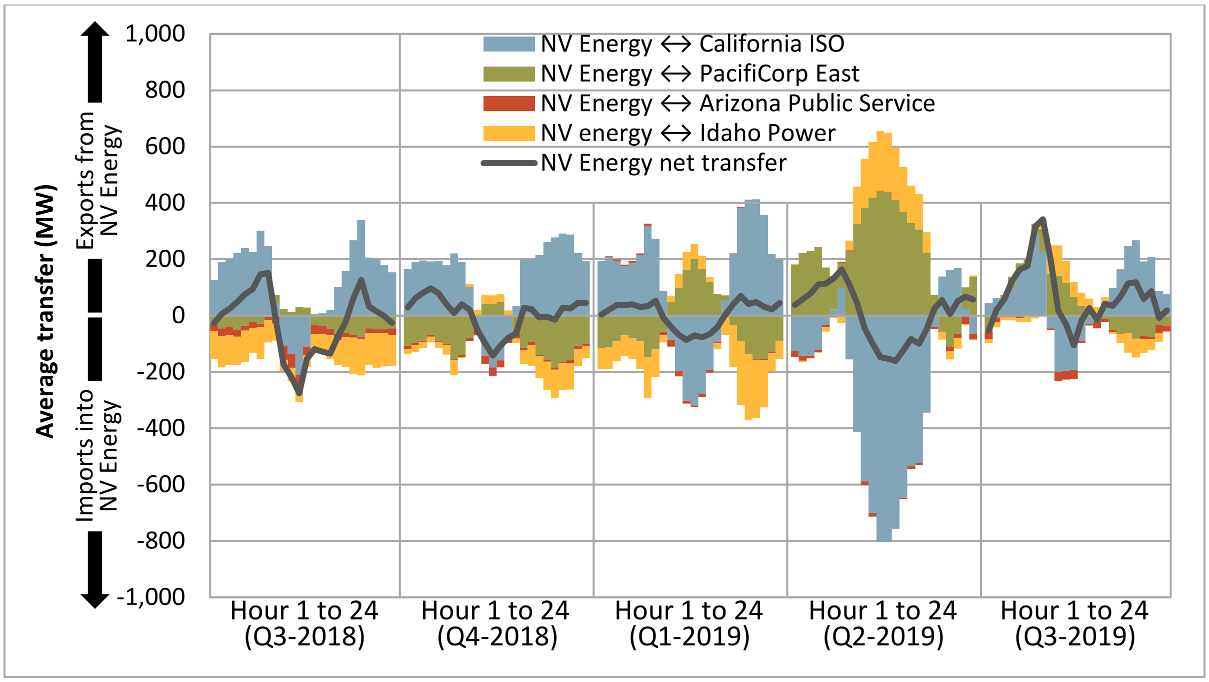


Figure 2.9 Arizona Public Service – average hourly 15-minute market transfer

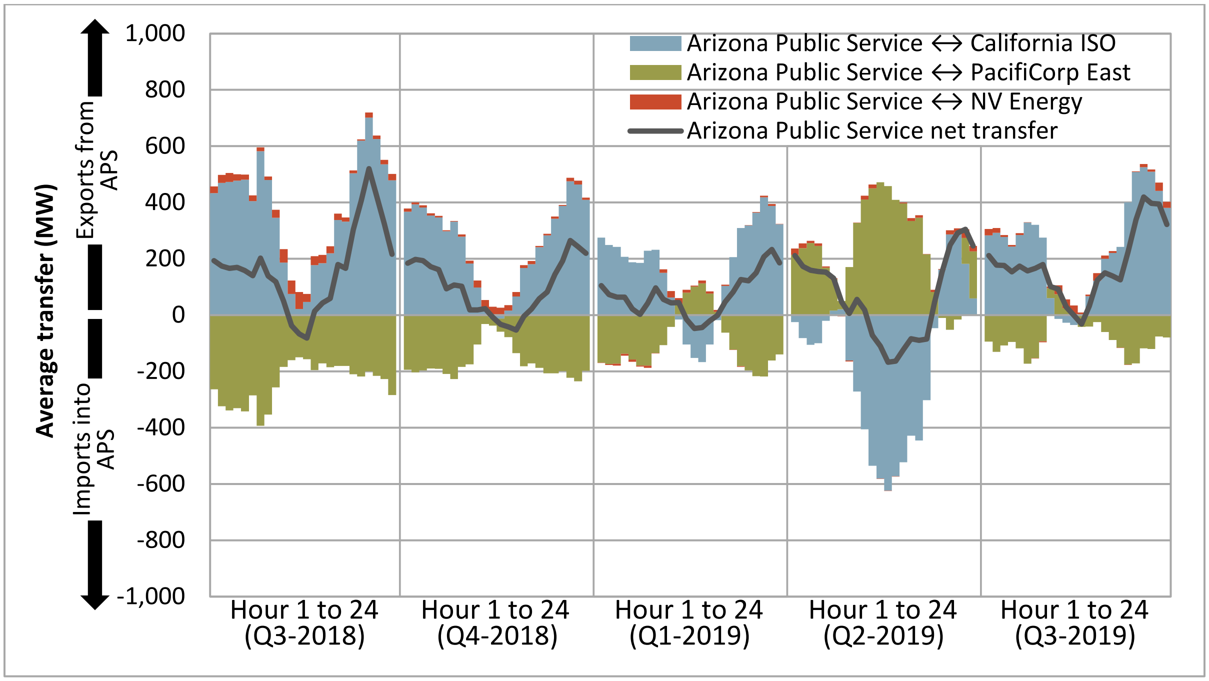


Figure 2.10 Idaho Power – average hourly 15-minute market transfer

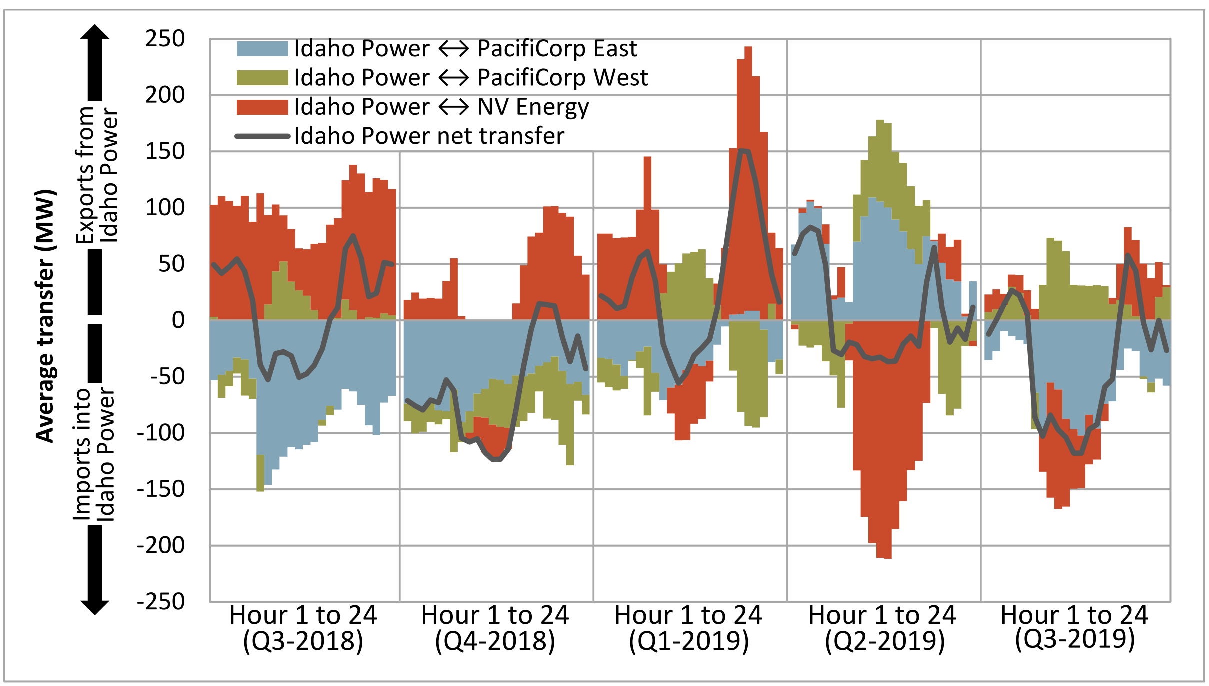


Figure 2.11 shows the hourly 15-minute market transfer pattern between PacifiCorp West and neighboring areas during the last five quarters. PacifiCorp West has transfer capacity between the ISO, PacifiCorp East, Puget Sound Energy, Portland General Electric, and Idaho Power. Similar to previous quarters, most of the transfers with Idaho Power and PacifiCorp East were base scheduled in the market, so therefore fixed. PacifiCorp West base scheduled roughly 1,050 MW in exports to PacifiCorp East on average during the third quarter. However, net of all base schedules, PacifiCorp West imported around 80 MW on average from PacifiCorp East.

Figure 2.12 shows average hourly 15-minute market imports and exports into and out of Powerex. During the third quarter of 2019, export transmission capacity from Powerex toward the ISO was limited to zero MW in all intervals in both the 15-minute and 5-minute markets.

Similarly, Figure 2.13 shows average hourly transfers into and out of the Portland General Electric area. Export limits from Portland General Electric toward the ISO were set to zero during 80 percent of 15-minute intervals and 92 percent of 5-minute intervals during the third quarter. Alternatively, average *import* limits into the Portland General Electric area from the ISO were around 180 MW in the 15-minute market.

Figure 2.11 PacifiCorp West – average hourly 15-minute market transfer

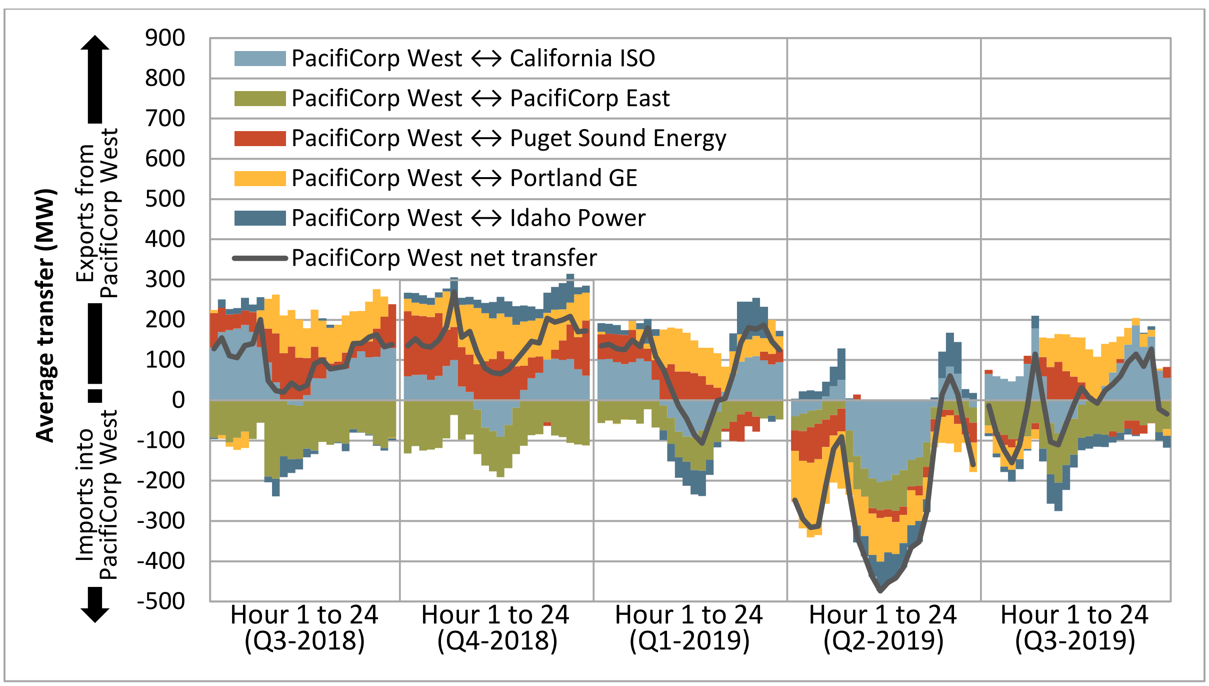


Figure 2.12 Powerex – average hourly 15-minute market transfer

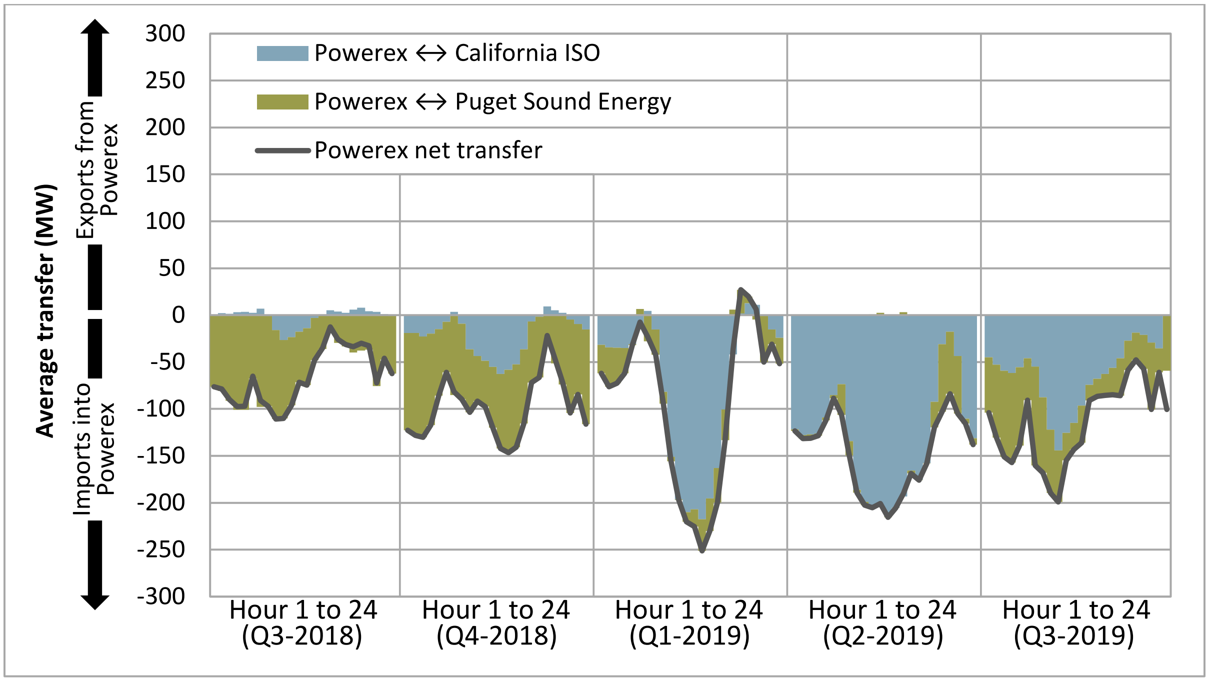
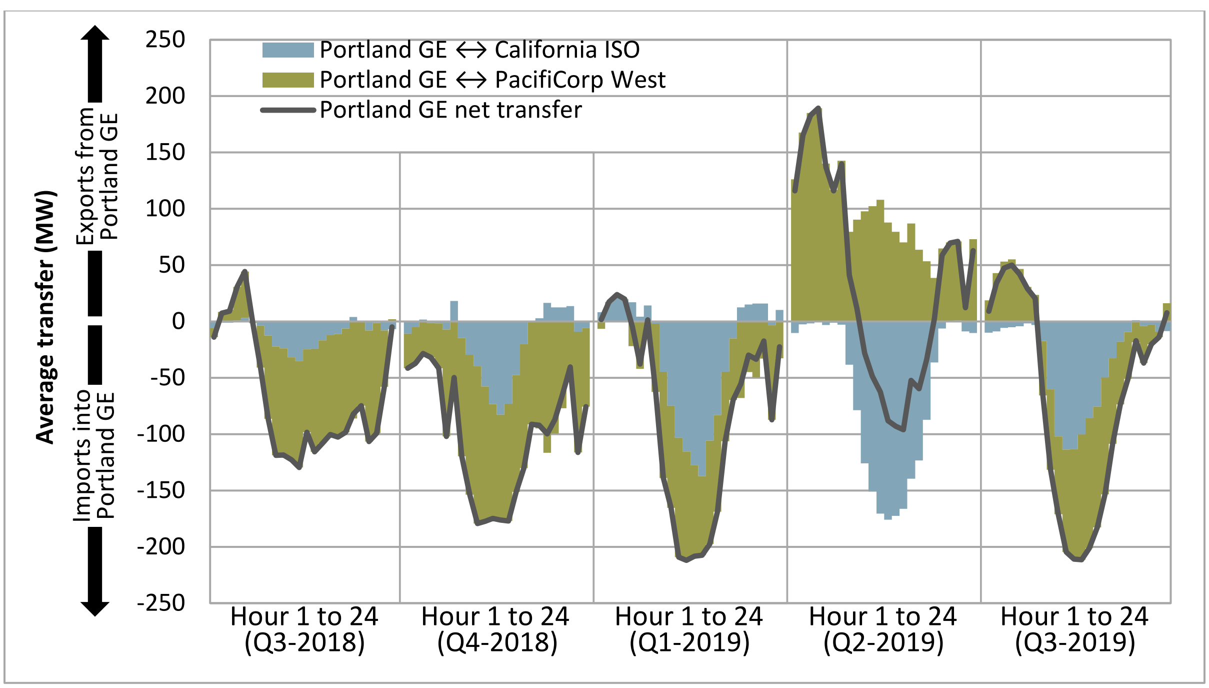


Figure 2.13 Portland General Electric – average hourly 15-minute market transfer



Inter-balancing area congestion

Congestion between an EIM area and the ISO causes price separation.

Table 2.2 shows the percent of 15-minute and 5-minute market intervals when there was congestion on the transfer constraints into or out of an EIM area, relative to prevailing system prices in the ISO.[40]

During intervals when there is net import congestion into an EIM area, the ISO market software triggers local market power mitigation in that area.[41] Table 2.2 includes the frequency in which transfer limits bound from the ISO into the other balancing areas. For example, the highest frequency of such congestion was from the ISO into the Powerex area, during 18 percent of 15-minute market intervals and 23 percent of 5-minute market intervals during the third quarter.

Table 2.2 Frequency of congestion in the energy imbalance market (July – September)

	15-minute market		5-minute market	
	Congested toward ISO	Congested from ISO	Congested toward ISO	Congested from ISO
BANC	0%	0%	0%	0%
Arizona Public Service	0%	0%	0%	0%
PacifiCorp East	1%	1%	0%	1%
Idaho Power	0%	1%	0%	1%
NV Energy	2%	4%	1%	3%
PacifiCorp West	12%	2%	9%	2%
Portland General Electric	15%	5%	12%	2%
Puget Sound Energy	13%	5%	11%	5%
Powerex	13%	18%	13%	23%

As shown in the table, the highest frequency of congestion in the EIM continued to be from the Northwest areas in the direction toward the ISO. Congestion in the 15-minute market in the direction toward the ISO occurred during roughly 13 percent of intervals from PacifiCorp West, Portland General Electric, Puget Sound Energy and Powerex.

Table 2.2 also shows that congestion in either direction between the BANC, NV Energy, Arizona Public Service, PacifiCorp East, Idaho Power, or the ISO area was infrequent during the third quarter. Congestion that did occur between these areas was often the result of a failed upward or downward sufficiency test, which limited transfer capability.

40 Greenhouse gas prices can contribute to lower energy imbalance market prices relative to those inside the ISO. The current methodology uses prevailing greenhouse gas prices in each interval to account for and omit price separation that is the result of greenhouse gas prices only. Intervals in which an energy imbalance market entity is entirely disconnected from the market (market interruption) are removed.

41 Structural market power may exist if the demand for imbalance energy within a balancing area exceeds the transfer capacity into that balancing area from the ISO or other competitive markets.

2.4 Load adjustments in the EIM

Frequency and size of load adjustments

Table 2.3 summarizes the average frequency and size of positive and negative load adjustments entered by operators in the EIM for the 15-minute and 5-minute markets during the third quarter.[42] The same data for the ISO is provided as a point of reference. In particular, Arizona Public Service entered positive load adjustments in around 69 percent of 15-minute and 5-minute intervals, at an average of around 100 MW. Nearly all EIM entities had a greater frequency of 5-minute market load adjustments than 15-minute market load adjustments during the third quarter.

[42] Load adjustments are sometimes referred to as *load bias* or *load conformance*. The ISO uses the term *imbalance conformance* to describe this process.

Table 2.3 Average frequency and size of load adjustments (July – September)

	Positive load adjustments			Negative load adjustments			Average hourly adjustment MW
	Percent of intervals	Average MW	Percent of total load	Percent of intervals	Average MW	Percent of total load	
California ISO							
15-minute market	59%	668	2.2%	0.1%	-269	1.0%	396
5-minute market	65%	337	1.1%	11%	-194	0.7%	200
PacifiCorp East							
15-minute market	0.01%	100	1.4%	0.7%	-94	1.5%	-1
5-minute market	17%	80	1.3%	25%	-75	1.3%	-5
PacifiCorp West							
15-minute market	0%	N/A	N/A	0.4%	-140	6.4%	-1
5-minute market	3%	46	2.1%	12%	-48	2.1%	-4
NV Energy							
15-minute market	3%	88	1.3%	0.01%	-50	0.7%	2
5-minute market	13%	77	1.2%	3%	-72	1.5%	8
Puget Sound Energy							
15-minute market	0.4%	26	0.9%	4%	-45	1.9%	-2
5-minute market	1%	37	1.4%	43%	-38	1.6%	-16
Arizona Public Service							
15-minute market	69%	99	2.1%	19%	-53	1.4%	59
5-minute market	69%	100	2.1%	19%	-53	1.4%	59
Portland General Electric							
15-minute market	0.1%	47	1.4%	0.02%	-50	2.7%	0
5-minute market	24%	25	1.1%	0.4%	-74	3.6%	6
Idaho Power							
15-minute market	0%	N/A	N/A	0%	N/A	N/A	0
5-minute market	9%	49	1.8%	3%	-52	2.4%	3
BANC							
15-minute market	0.4%	37	1.6%	0.4%	-85	6.9%	0
5-minute market	2.9%	29	1.6%	1.0%	-67	5.0%	0

Load conformance limiter enhancement

The load conformance limiter works the same way in the EIM as it does in the ISO. It reduces the impact of an excessive load adjustment on market prices when it is considered to have caused a power balance constraint relaxation. Previously, if the operator load adjustment exceeded the size of a power balance constraint and in the same direction, the size of the adjustment was automatically reduced and the price was set by the last economic signal rather than the penalty parameter for the relaxation, for instance the $1,000/MWh price for a shortage. However, there have been instances in which the application of this logic did not appear to reflect actual conditions such as periods when a persistent load conformance across multiple intervals would resolve smaller infeasibilities that did not appear to be caused by the level of load adjustment.

The ISO implemented an enhancement to the load conformance limiter, effective February 27, 2019. With the enhancement, the load conformance limiter triggers by a measure based on the change in load adjustment from one interval to the next, rather than the total level of load adjustment. DMM's monitoring and review of real-time market performance suggests that the enhanced logic for the load conformance limiter is likely to better capture the cause-and-effect relationship between an excessive operator adjustment and an infeasibility. Previous analysis by DMM showed that this change is expected to significantly reduce the frequency in which the limiter triggers.[43]

Figure 2.14 shows the frequency of infeasibilities in the 5-minute market during the third quarter in which the current (enhanced) conformance limiter triggered and/or the previous limiter would have triggered.[44] The green bars represent intervals when the current limiter did not trigger, but would have under the previous approach. For intervals with ramping shortages in this category, the current approach increases prices relative to the previous method since prices would have been set by an economic bid under the previous approach, but were instead set by the $1,000/MWh penalty parameter. The red bars represent intervals when the current limiter triggered, but would not have under the previous approach. These intervals were infrequent during the quarter.

Under current market conditions, the enhancement to the conformance limiter is not expected to have a significant impact on average prices in the ISO. This is because in most intervals when the limiter triggers in the ISO, the highest priced bids dispatched are often at or near the $1,000/MWh bid cap such that the resulting price is often very similar with or without the limiter.

However, the changes to the conformance limiter can have a significant impact on prices for some of the EIM areas. As shown in Figure 2.14, the enhancement significantly reduced the frequency in which the conformance limiter triggered for under-supply conditions for NV Energy during the third quarter. Instead, prices for the NV Energy area were often set at the $1,000/MWh penalty parameter in these instances.

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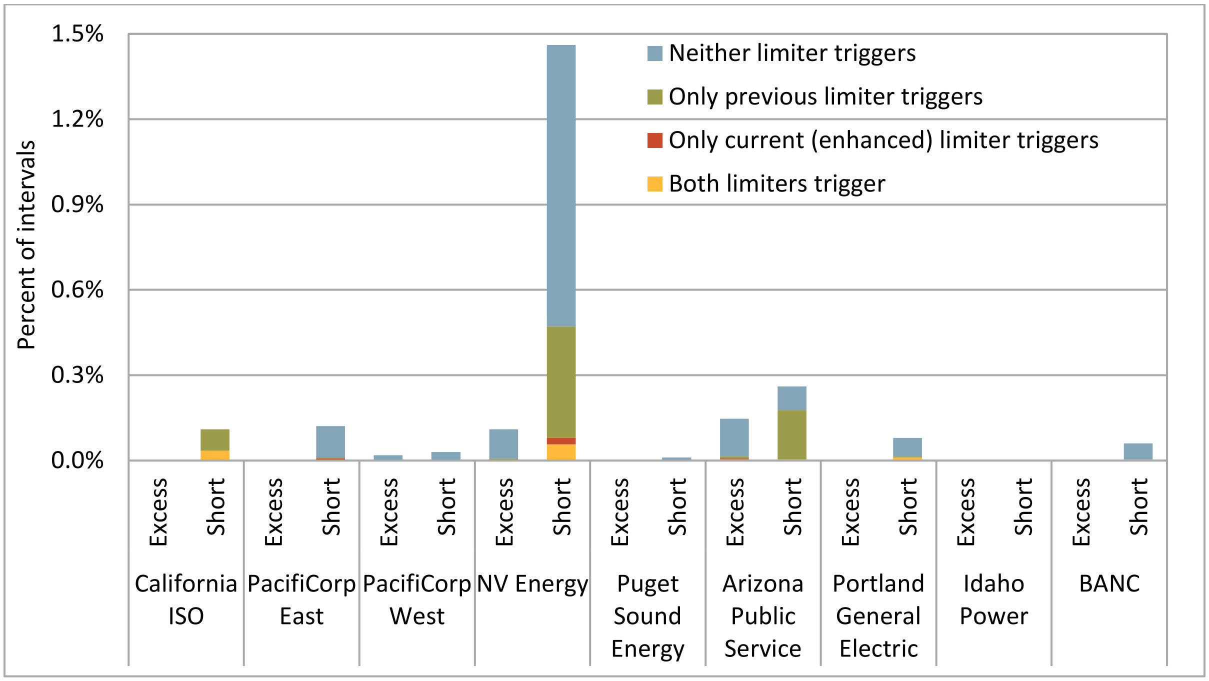
43 *EIM power balance constraint relaxation and imbalance conformance limiter*, Department of Market Monitoring, January 18, 2019. http://www.caiso.com/Documents/EIMpowerbalanceconstraintrelaxationandimbalanceconformancelimiter.pdf

44 In the figure, intervals when the power balance constraint needed to be relaxed due to excess supply are labeled *Excess*. Intervals when the power balance constraint needed to be relaxed due to a shortage of upward ramping capability are labeled *Short*.

Figure 2.14 Frequency of load conformance limiter in the 5-minute market (July – September)



2.5 Greenhouse gas in the EIM

Under the current design, all energy transferred into the ISO to serve ISO load through an EIM transfer is subject to California's cap-and-trade regulation.[45] A participating resource submits a separate bid representing the cost of compliance for its energy attributed to the participating resource as serving the ISO load. The EIM optimization minimizes costs of serving load in both the ISO and EIM taking into account greenhouse gas compliance cost for all energy deemed delivered to California. The EIM greenhouse gas price in each 15-minute or 5-minute interval is set at the greenhouse gas bid of the marginal megawatt attributed as serving the ISO load. This information serves as the basis for greenhouse gas compliance obligations under California's cap-and-trade program.

This greenhouse gas revenue is returned to participating resource scheduling coordinators with energy that is deemed delivered as compensation for compliance obligations. The revenue is equal to the cleared 15-minute market quantity priced at the 15-minute price plus the incremental greenhouse gas dispatch in the 5-minute market valued at the 5-minute market price. Incremental dispatch in the 5-minute market may be either positive or negative.

As of November 2018, the ISO implemented a new policy to address the concerns that the market design was not capturing the full greenhouse gas effect of EIM imports into California to serve the ISO load for compliance with California's cap-and-trade regulation.[46] The amount of capacity that can be

[45] Further information on energy imbalance market entity obligations under the California Air Resources Board cap-and-trade regulation is available in a posted FAQ on ARB's website here: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/eim-faqs.pdf.

[46] Further information on the energy imbalance market greenhouse gas enhancements proposal can be found here: http://www.caiso.com/Documents/ThirdRevisedDraftFinalProposal-EnergyImbalanceMarketGreenhouseGasEnhancements.pdf

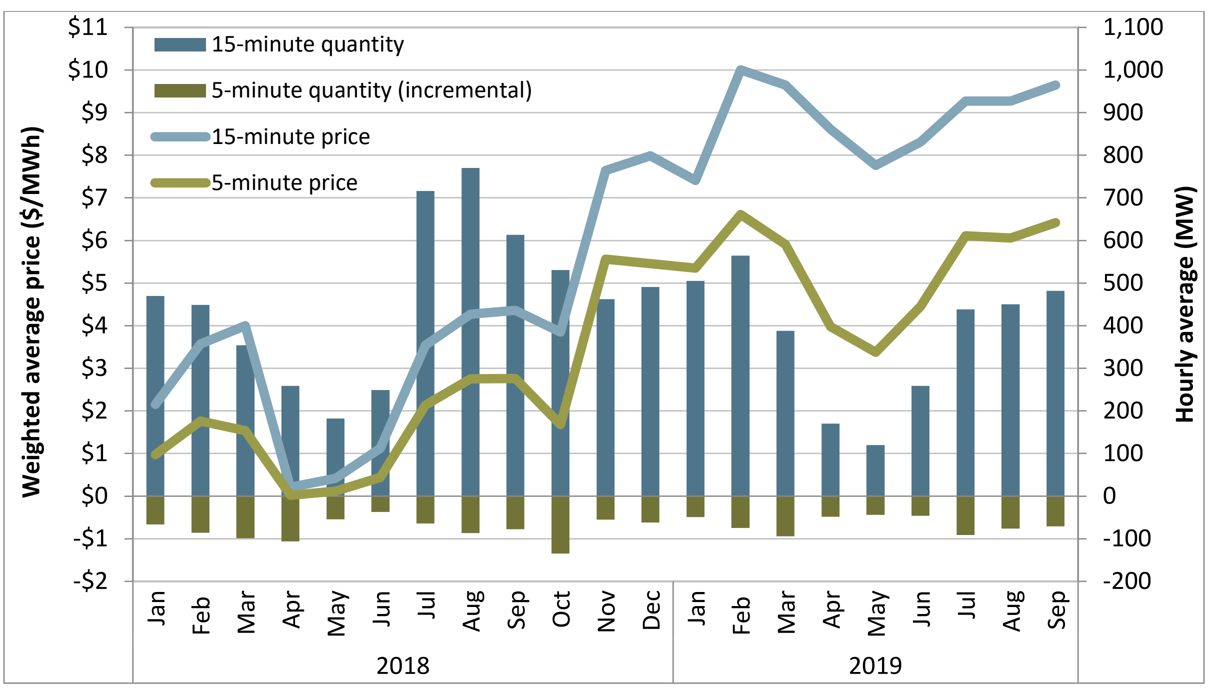
deemed delivered to California will now be limited to the upper economic bid limit of a resource minus the resource's base schedule. Since the policy change in November, there have been notable changes in the greenhouse gas price in the EIM discussed below.

Greenhouse gas prices

Figure 2.15 shows monthly average cleared EIM greenhouse gas prices and hourly average quantities for transfers serving the ISO load settled in the EIM in the third quarter of 2019. Weighted average prices are calculated using 15-minute deemed delivered megawatts as weights in the 15-minute market and the absolute value of incremental 5-minute greenhouse gas dispatch in the 5-minute market. Hourly average 15-minute and 5-minute deemed delivered quantities are represented by the blue and green bars in the chart, respectively.

Weighted 15-minute greenhouse gas prices averaged around $9/MWh for each month of the third quarter while 5-minute prices averaged about $6/MWh. Prior to the policy change in November 2018, monthly greenhouse gas prices from January to October averaged around $2.75/MWh in the 15-minute market and $1.40/MWh in the 5-minute market. The increase in greenhouse gas prices relative to last year was likely the result of the policy change, which limits the EIM capacity that can be deemed delivered to California and results in higher emitting resources setting the price. Another potential contribution to the increase in the EIM greenhouse gas price compared to 2018 is a notable increase in the market clearing price of the California Air Resources Board quarterly auction for emission allowances.

Figure 2.15 Energy imbalance market greenhouse gas price and cleared quantity

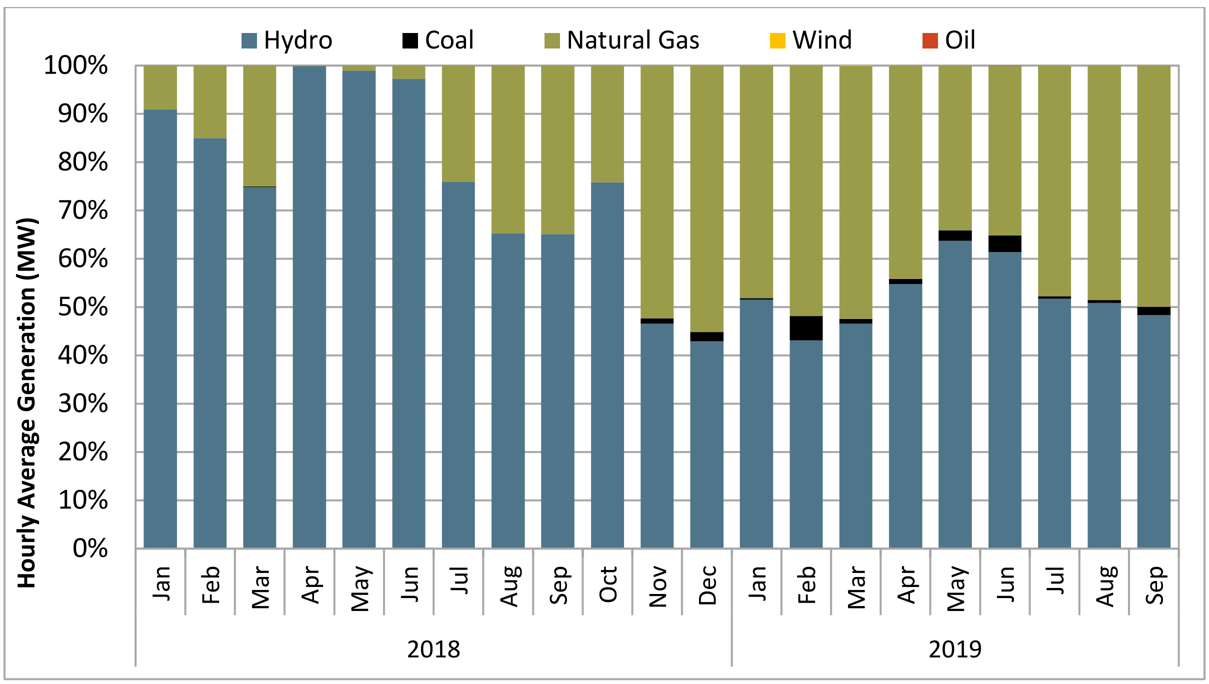


DMM estimates the total profit accruing for greenhouse gas bids attributed to EIM participating resources serving the ISO load by subtracting estimated compliance costs from greenhouse gas revenue calculated in each interval. This value totaled around $5.1 million in the third quarter, compared to roughly $3.6 million in the third quarter of the previous year.

Energy delivered to California by fuel type

Figure 2.16 shows the hourly average energy deemed delivered to California by fuel type and by month. About 49 percent of EIM greenhouse gas compliance obligations were awarded to gas resources, an increase from 31 percent in the third quarter of the previous year. Hydroelectric resources accounted for about 50 percent of total energy delivered to California which decreased from around 69 percent in the same quarter of 2018. Additionally, energy originating from coal resources has increased since the policy change, but only accounted for about 1 percent of energy delivered in the third quarter, a slight decrease compared to the first two quarters of 2019.

Figure 2.16 Hourly average EIM greenhouse gas generation by fuel type



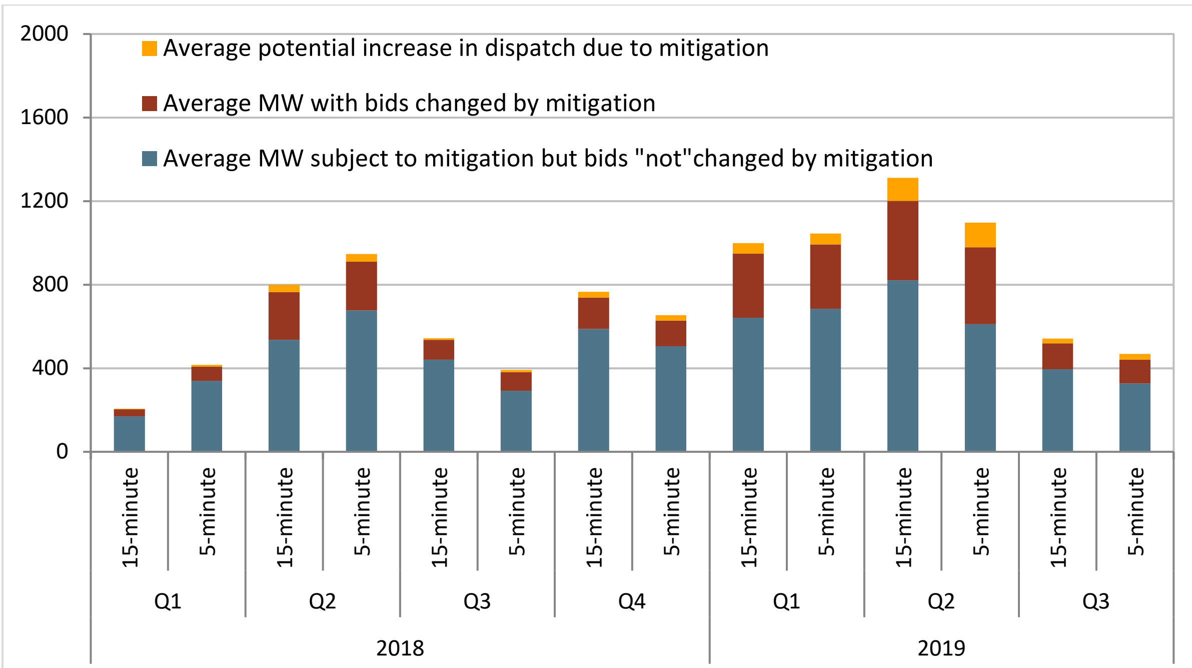
2.6 Mitigation in the EIM

Figure 2.17 highlights the frequency and volume of 15-minute and 5-minute market mitigation in all the balancing authority areas in the EIM:

- As shown in the figure, average incremental energy subject to mitigation in the EIM in the third quarter of 2019 in the 15-minute and 5-minute market, is similar when compared to the same quarter in 2018.

- Of the megawatts that were subject to mitigation, about 25 percent had their bids lowered due to 15-minute and 5-minute market mitigation in the third quarter of 2019. This is slightly higher from the same quarter in 2018.
- Because of bid mitigation, the potential average increase in both 15-minute and 5-minute dispatch is about 23 MW and 27 MW, respectively.

Figure 2.17 Average incremental energy mitigated in real-time market (EIM)



3 Special issues

This section provides information about the following special issues.

Flexible ramping product

- Flexible ramping prices were frequently zero in both the 15-minute and 5-minute markets in both the upward and downward directions. In these intervals, flexible ramping capacity was readily available relative to the need for it so that no cost is associated with the level of procurement.
- Total uncertainty payments to generators for providing flexible ramping capacity during the third quarter were around $0.6 million, compared to around $2.1 million in the previous quarter.
- In the 12 months, 44 percent of payments for flexible ramping capacity have been to resources internal to the ISO while 43 percent of payments for flexible ramping capacity have been to areas in the Northwest region that includes PacifiCorp West, Puget Sound Energy, Portland General Electric, and Powerex. Fifty-three percent of payments have been to hydroelectric generators, 32 percent to gas resources while around 6 percent have been to each of coal and proxy demand response units.
- A recent ISO report highlighted several issues with current flexible ramping product design and implementation including procurement of flexible ramping capacity from resources that are not able to meet system uncertainty either because of resource characteristics or congestion. This can reduce the effectiveness of the flexible ramping product to manage net load volatility and prevent power balance violations.
- Uncertainty over load and the future availability of resources to meet that load contributes to operators needing to enter systematic and large imbalance conformance adjustments, as described in Section 1.14 of this report. The ISO could reduce the need for manual load adjustments and more efficiently integrate distributed and variable energy resources by designing a real-time flexible ramping product that could procure and price the appropriate amount of ramping capability to account for uncertainty over longer time horizons than the current design considers.

Batteries

- Though non-generator resource energy bids appeared to be more economic in the second and third quarters of 2019 than in prior quarters, there has not been a significant increase in energy schedules compared to regulation capacity schedules in 2019.

Demand response resource adequacy

- Analysis of 2019 market data suggests that the aggregate demand response capacity that proxy demand response (PDR) resources have shown on resource adequacy supply plans exceeds both bids in the day-ahead market in some hours and appears to exceed the total capability of this resource fleet. This means that the resource adequacy capacity bid into the ISO was frequently in excess of the actual load reduction capability from these resources.

Exceptional dispatch

- Total energy resulting from all types of exceptional dispatch accounted for almost 1 percent of system load, comparable to the same quarter in 2018.
- In the third quarter, out-of-sequence energy costs were $8.1 million, while commitment costs for exceptional dispatch paid through bid cost recovery were $9.3 million.
- In the third quarter, mitigation of exceptional dispatches should reduce total exceptional dispatch costs by about $15.4 million. Almost all of this reduction was due to mitigation of exceptional dispatches to ramp units up to a minimum dispatchable level. The ISO's settlement system did not apply mitigation to exceptional dispatches prior to mid-2019, so the ISO will apply mitigation retroactively through settlement corrections.
- Many exceptional dispatches were issued to commit and ramp up slower ramping gas units during the evening ramping hours in the third quarter. Most of these exceptional dispatches were issued to slow ramping gas generating resources located in the Los Angeles basin. These exceptional dispatches were issued to increase the amount of ramping capacity available to meet the evening net load ramp and to respond to other uncertainties in real-time, the same issues that the flexible ramping product is designed to address.
- Exceptional dispatches to RA Max are not subject to energy bid mitigation, and are paid the higher of the unit's energy bid or the market price. The total unmitigated RA Max exceptional dispatch energy costs were around $5.2 million, about $3.3 million above market prices in the third quarter.
- DMM is recommending that RA Max exceptional dispatch energy should be subject to mitigation as there is a strong potential for suppliers to exercise market power and raise bids substantially over marginal cost.

System market power

- In 2019, the residual supply index with the three largest suppliers removed (RSI_3) was less than one during 95 hours, and the index was less than one during 33 hours with the two largest suppliers removed (RSI_2). There have been no hours so far in 2019 with the index less than one and the largest single supplier removed. A reduction in potentially non-competitive hours in 2019, relative to the previous two years, is the result of factors supporting competitive conditions including lower loads and high rates of low cost renewable production.
- For the first three quarters of 2019, the average price-cost markup was about $0.73 or about 2 percent. This slight positive markup indicates that prices have been very competitive, overall, for the year.
- In the last few years, market power has had a very limited effect on system market prices even during hours when the ISO system was structurally uncompetitive. However, DMM has expressed concern that market conditions may evolve in a way that will increase the potential for system-level market power.
- DMM supports the ISO's proposal to continue with an initiative to design system market power mitigation and looks forward to working with the ISO throughout that process.

- DMM continues to recommend several other market design changes that may help mitigate system market power beyond the bid mitigation options being examined as part of this initiative. These include consideration of options that would increase the supply and availability of energy from resource adequacy imports beyond the day-ahead market into real-time. DMM also continues to recommend that the ISO's plan for implementing FERC Order No. 831 include provisions to (1) ensure that import bids over $1,000/MWh are subject to ex ante cost justification and (2) avoid setting penalty prices at $2,000/MWh except when needed to implement the provisions of the order.

3.1 Flexible ramping product

The flexible ramping product is designed to enhance reliability and market performance by procuring flexible ramping capacity in the real-time market to help manage volatility and uncertainty of real-time imbalance demand. The amount of flexible capacity the product procures is derived from a demand curve which reflects a calculation of the optimal willingness-to-pay for that flexible capacity. The demand curves allow the market optimization to consider the trade-off between the cost of procuring additional flexible ramping capacity and the expected reduction in power balance violation costs.

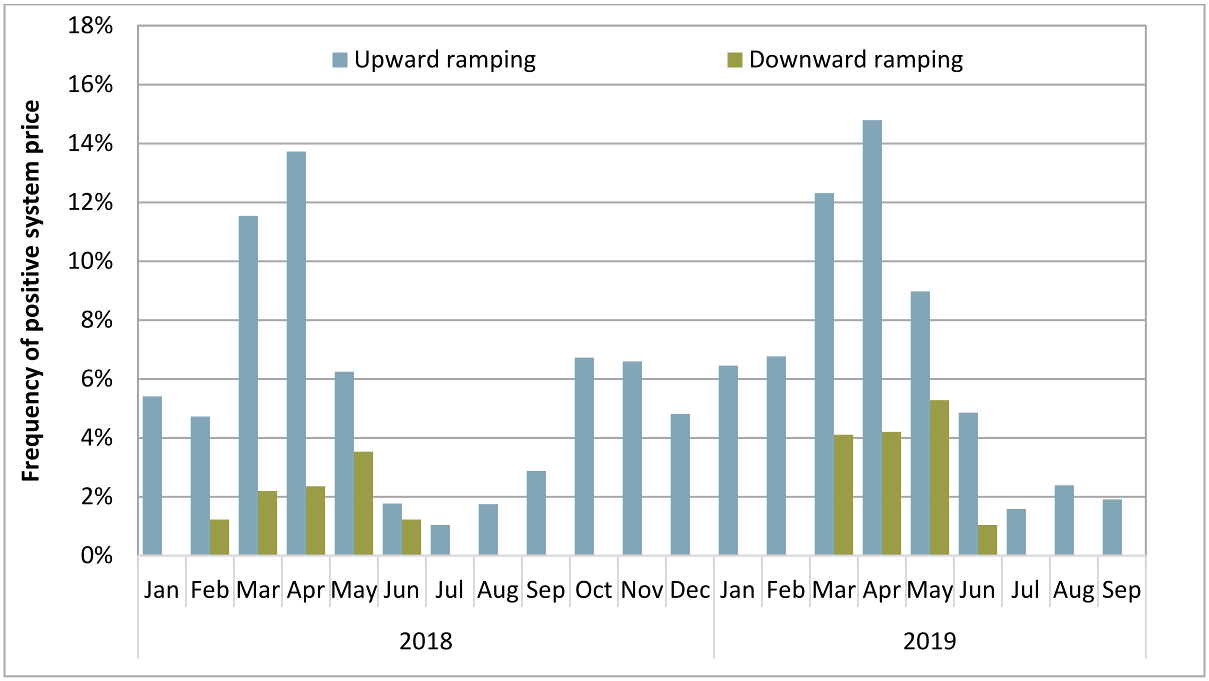
The flexible ramping product procures both upward and downward flexible capacity, in both the 15-minute and 5-minute markets. Procurement in the 15-minute market is intended to ensure that enough ramping capacity is available to meet the needs of both the upcoming 15-minute market run and the three 5-minute market runs within that 15-minute interval. Procurement in the 5-minute market is aimed at ensuring that enough ramping capacity is available to manage differences between consecutive 5-minute market intervals.

3.1.1 Market outcomes for the flexible ramping product

This section describes the amount of flexible ramping capacity that was procured in the third quarter, and corresponding flexible ramping shadow prices. The flexible ramping product procurement and shadow prices are determined from demand curves. When the shadow price is $0/MWh, the maximum value of capacity on the demand curve is procured. This reflects that flexible ramping capacity was readily available relative to the need for it, such that there is no cost associated with the level of procurement.

Figure 3.1 shows the percent of intervals that the system-level flexible ramping demand curve bound and had a positive shadow price in the 15-minute market. In the third quarter, there was a decreased frequency in nonzero shadow prices. The 15-minute market system-level demand curves bound in around 2 percent of intervals in the upward direction and never in the downward direction during the quarter. In the 5-minute market, the system-level demand curves bound in less than 0.3 percent of intervals.

Figure 3.1 Monthly frequency of positive 15-minute market flexible ramping shadow price



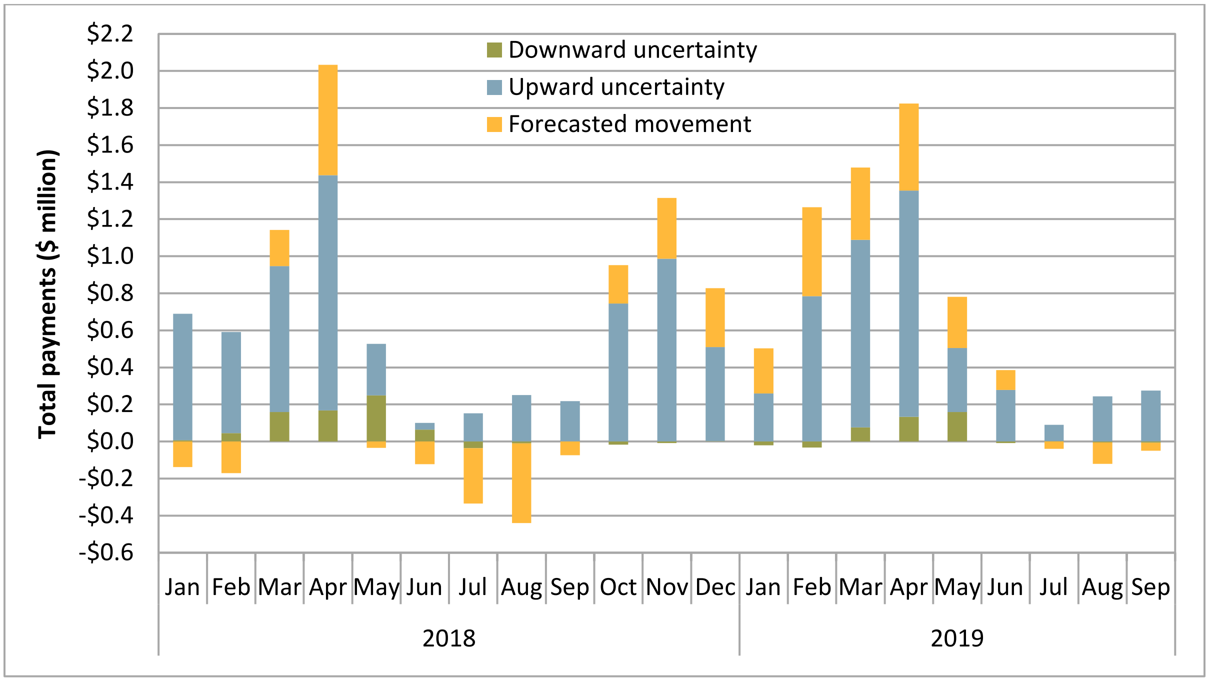
3.1.2 Flexible ramping product costs

Flexible ramping capacity that satisfy the demand for upward and downward uncertainty receive payments based on the combined system and area-specific flexible ramping shadow price. In addition, the combined flexible ramping shadow price is used to pay or charge for forecasted ramping movements. This means a generator that was given an advisory dispatch by the market to increase output was paid the upward flexible ramping price and charged the downward flexible ramping price. Similarly, a generator that was forecast to decrease output was charged the upward flexible ramping price and paid the downward flexible ramping price.[47]

The following section looks at flexible ramping product payments from three different perspectives: (1) by payment type, (2) by area, and (3) by fuel type. Figure 3.2 shows the total monthly net payments to resources from the flexible ramping product, including both payments for flexible ramping capacity to meet upward and downward uncertainty as well as payments for forecasted movements. As shown in the figure, payments for all types were down from the previous quarter, consistent with a lower frequency of nonzero prices for flexible ramping capacity. Total uncertainty payments to generators in the ISO and the EIM for providing flexible ramping capacity during the third quarter were around $0.6 million, compared to around $2.1 million in the previous quarter.

47 More information about the settlement principles can be found in the ISO's *Revised Draft Final Proposal for the Flexible Ramping Product*, December 2015: http://www.caiso.com/Documents/RevisedDraftFinalProposal-FlexibleRampingProduct-2015.pdf.

Figure 3.2 Monthly flexible ramping product payments by type



The following two figures do not include payments for forecasted movements and therefore only reflect payments to generators for upward and downward ramping capacity to meet uncertainty needs Figure 3.3 shows these payments by area, arranged generally by geographic location. Payments for this capacity may have been procured to satisfy system-level demand, area-specific demand, or both. In the last year, 44 percent of payments for flexible ramping capacity have been to resources internal to the ISO while 43 percent of payments for flexible ramping capacity have been to areas in the Northwest region that includes PacifiCorp West, Puget Sound Energy, Portland General Electric, and Powerex. In both cases, the large majority of payments have been for system uncertainty needs rather than area-specific uncertainty needs.

Figure 3.3 Monthly flexible ramping product uncertainty payments by area

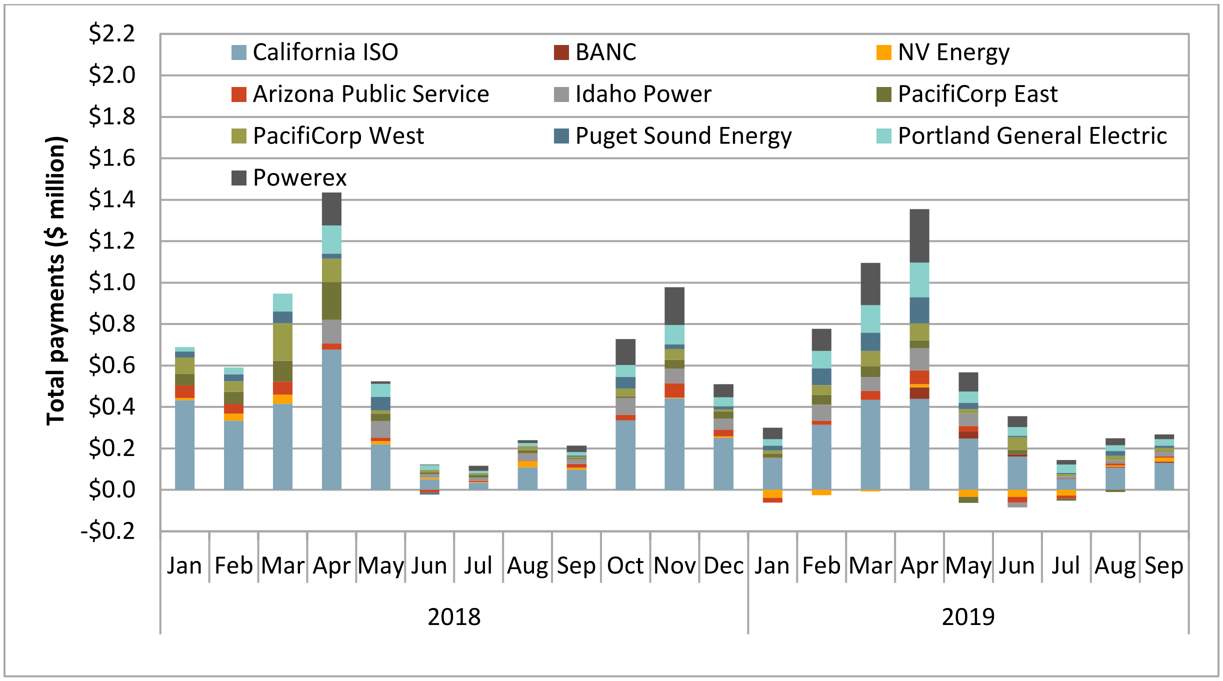


Figure 3.4 Monthly flexible ramping product uncertainty payments by fuel type

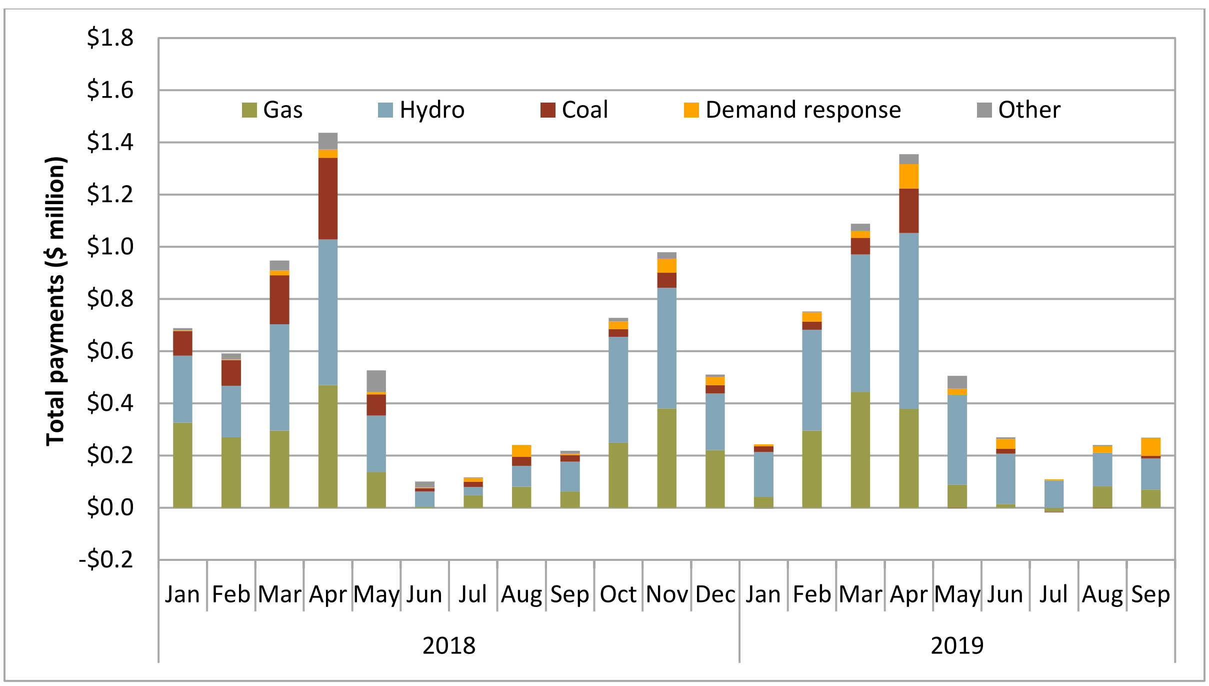


Figure 3.4 shows the same information by fuel type. In the last year (October 2018 through September 2019), around 53 percent of flexible capacity payments for upward and downward uncertainty have

been to hydroelectric generators. Similarly, 32 percent of payments have been to gas resources while around 6 percent of payments have been to each of coal and proxy demand response units. Procuring ramping capacity from proxy demand response units presents an issue because of the ability of these resources to respond to isolated 5-minute dispatches. This item and other flexible ramping product issues are discussed in the following section.

3.1.3 Flexible ramping product issues

The ISO published a report in September 2019 that included a discussion of several issues with the flexible ramping product.[48] Further, the ISO initiated a stakeholder process to review refinements to the flexible ramping product and address these inefficiencies.[49] Some of the items addressed in these reports are discussed in the section below.

The flexible ramping product was designed to ensure a margin of sufficient ramping capacity beyond the forecasted ramping needs to protect against uncertainty that can arise from load or renewable generation. The upward and downward demand curves are based on a distribution of net load errors in a 95 percent confidence interval.[50] Therefore, when the full amount of the upward and downward uncertainty requirements are procured in flexible ramping capacity for a given interval, the majority of potential net loads in the advisory interval are expected to become feasible based on the historical data.

However, procurement of flexible ramping capacity from resources that are not able to meet system uncertainty — either because of resource characteristics or congestion — can reduce the effectiveness of the flexible ramping product to manage net load volatility and prevent power balance violations.

Procurement from proxy demand response resources

The ISO's September report highlighted the issue of procuring flexible ramping capacity from proxy demand response units. In particular, the market may frequently procure flexible capacity from demand response units, since there is typically no opportunity cost of providing such capacity in lieu of energy as these units generally bid at or near the price cap of $1,000/MWh. However, these units are not able to respond to isolated 5-minute dispatches and therefore can contribute to lower deliverability of flexible ramping capacity and suppress the true opportunity cost of providing such capacity instead of energy.

One of the key objectives of the flexible ramping product is to address the challenges of maintaining power balance in real-time between supply and demand. The flexible ramping product allows the market to account and procure for uncertainty surrounding a forecasted value that could otherwise result in an infeasibility.

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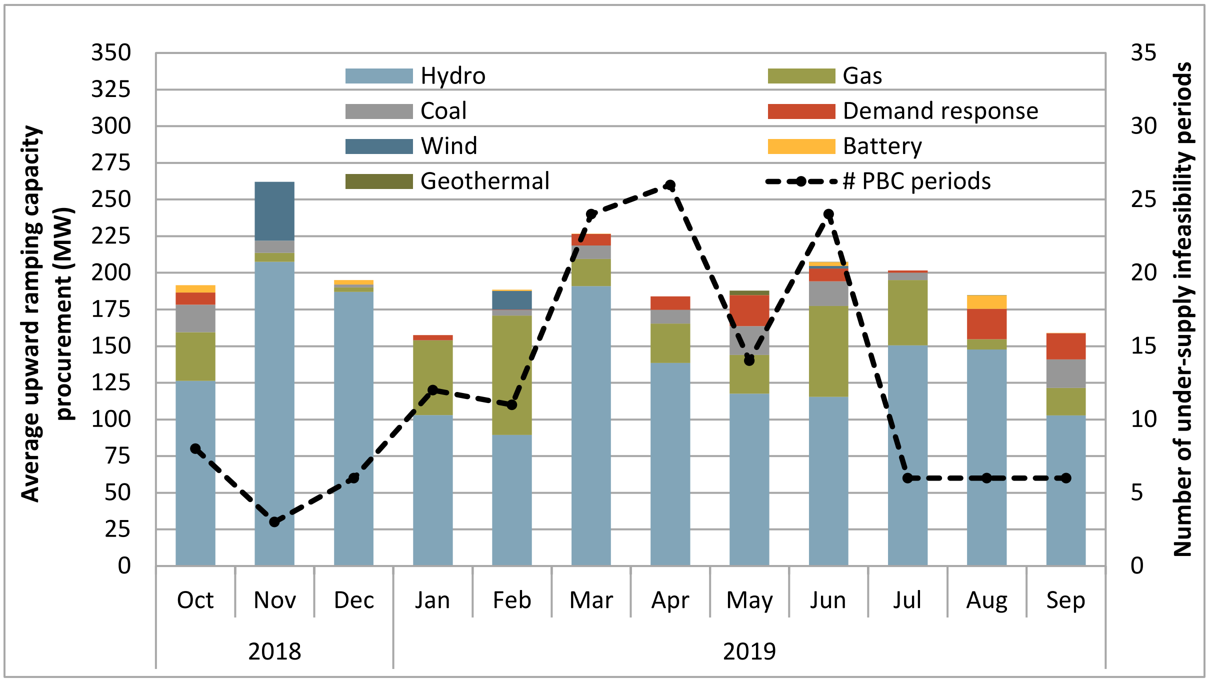
48 *CAISO Energy Markets Price Performance Report*, California ISO, September 23, 2019: http://www.caiso.com/Documents/FinalReport-PricePerformanceAnalysis.pdf

49 *Flexible Ramping Product Refinements Issue Paper and Straw Proposal*, California ISO, November 14, 2019: http://www.caiso.com/Documents/IssuePaper-StrawProposal-FlexibleRampingProductRefinements.pdf

50 Weekday distributions use data for the same hour from the last 40 weekdays. For weekends, the last 20 weekend days are used instead.

Figure 3.5 shows the average upward ramping capacity procured in the 5-minute market by fuel type in the interval prior to any under-supply infeasibility (or period of consecutive infeasibilities).[51] The dotted line shows the underlying number of under-supply infeasibility periods in each month. The bars shows the average procurement of upward ramping capacity by fuel type in the interval prior to these periods. During May, August and September, upward flexible ramping capacity awards to demand response resources made up 11 percent of procurement in the intervals prior to infeasibility periods.

Figure 3.5 Average 5-minute market upward ramping capacity procurement prior to under-supply infeasibility periods - by fuel type



Stranded flexible ramping capacity

The system-level demand curve for the entire CAISO and EIM footprint is always enforced in the market. However, the uncertainty requirement for the individual areas is reduced in every interval by balancing area transfer capability.[52] Therefore, when the uncertainty requirement for all of the individual areas is zero, then only the system-level uncertainty requirement is active. Due to the potential for system-level flexible ramping capacity procurement external to one area to be stranded behind EIM transfer constraints, the ISO implemented an enhancement in the spring of 2018 to cap procurement in each area by the sum of the area-specific uncertainty requirement and net export capability (for upward

51 For under-supply infeasibility periods lasting longer in duration than one 5-minute interval, only procurement in the interval prior to these periods are summarized in Figure 3.5 and Figure 3.7.

52 In each interval, the upward uncertainty requirement is reduced by net import capability while the downward uncertainty requirement is reduced by net export capability. If the balancing authority area fails the flexible ramping sufficiency test in the corresponding direction, the uncertainty requirement will not include this reduction.

direction).[53] Upward ramping capacity in excess of the area-specific uncertainty requirement is capped by net export capability.

However, even with the enhancement, there is still the potential for stranded flexible ramping capacity, particular in the Northwest region that includes PacifiCorp West, Puget Sound Energy, Portland General Electric, and Powerex. For instance, in cases when supply conditions are tight in the ISO and surrounding system but export capability out of the Northwest region is zero, these areas may still have export capability to each other within the Northwest region. As a result, the export capability cap on upward flexible ramping capacity will often do little to prevent procurement that is stranded in this region. Further, when supply conditions are tight, it can often be economic to procure more flexible ramping capacity from the Northwest region than from the ISO and surrounding system as the opportunity cost of providing that ramping capacity in lieu of energy is lower in the Northwest.

Figure 3.6 illustrates an example of this interaction from an actual interval in the 15-minute market. In the figure, the arrows show net export capability out of each area, and the red arrows further indicate zero net export capability. In this particular interval, there was 822 MW of upward ramping capacity awarded to resources in the Northwest region (or 69 percent of the system requirement), but 0 MW of actual export capability to the surrounding system through any of Idaho Power, PacifiCorp East, or the ISO. Here, export capability to each other within the Northwest region allowed for higher system-level procurement than was actually accessible for the ISO and surrounding system.

Similar to Figure 3.5, Figure 3.7 shows the average upward ramping capacity procured in the 5-minute market by area in the interval prior to any under-supply infeasibility (or period of consecutive infeasibilities). During the last year, flexible ramping capacity awards to resources in the Northwest region made up 59 percent of procurement in the intervals prior to under-supply infeasibility periods.

The ISO launched a stakeholder initiative designed to address stranding and other flexible ramping product concerns.[54] DMM supports the ISO's initiative to design locational procurement for both day-ahead and real-time flexible ramping products. Locational procurement that accounts for transmission constraints would result in more deliverable reserves. This could significantly increase the efficiency of the ISO's market awards and dispatches. It could also help to resolve the very low prices for flexible reserves from undeliverable reserves being counted towards meeting a reliability need that they cannot actually help to meet.

53 Net export capability is the sum of export energy imbalance market transfer limits in excess of the net energy imbalance market transfer. Downward ramping capacity is instead capped by the sum of the area-specific uncertainty requirement and net *import* capability.

54 For more information on this process see: http://www.caiso.com/StakeholderProcesses/Flexible-ramping-product-refinements

Figure 3.6 Example – Stranded upward ramping capacity in the Northwest

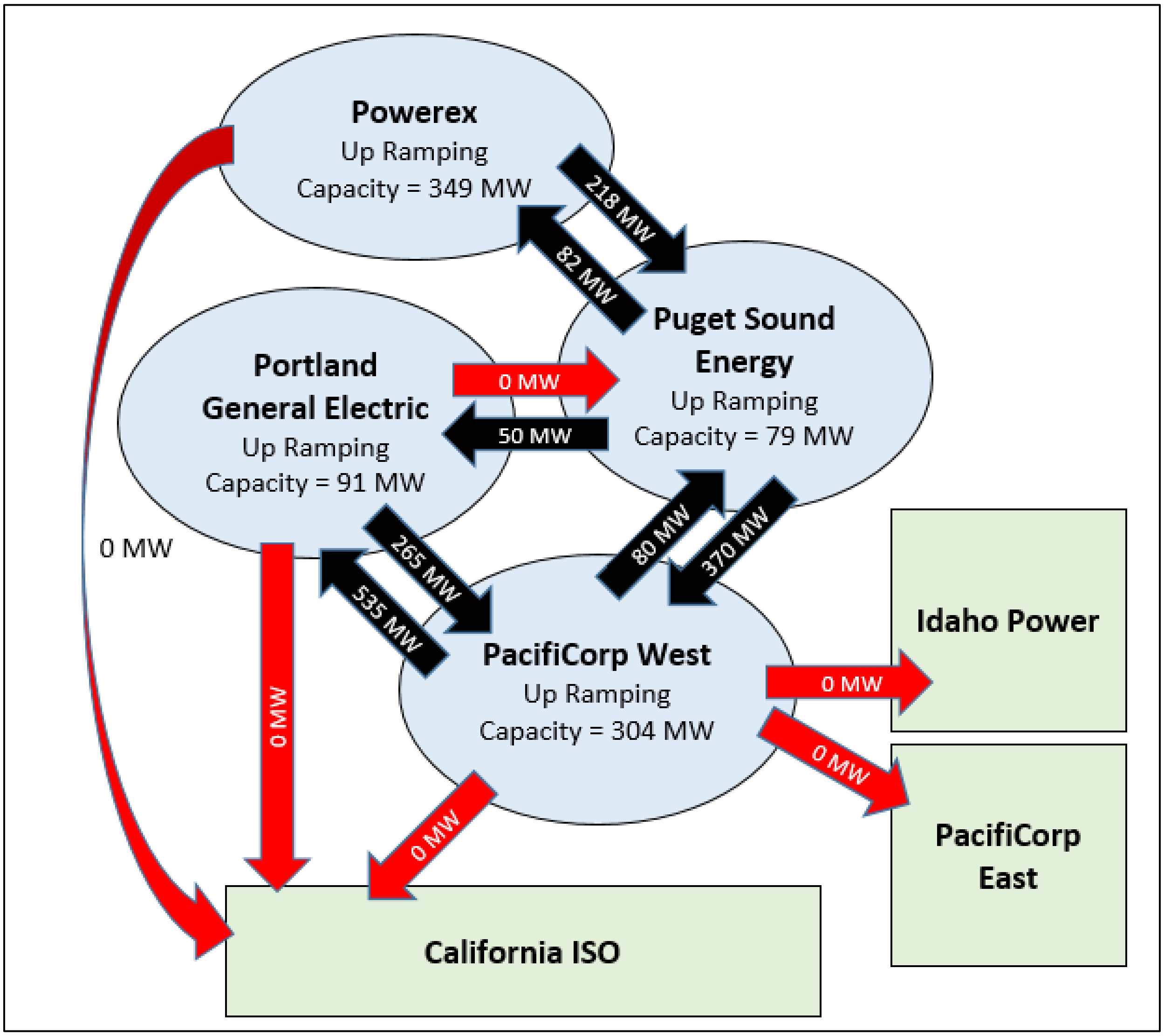
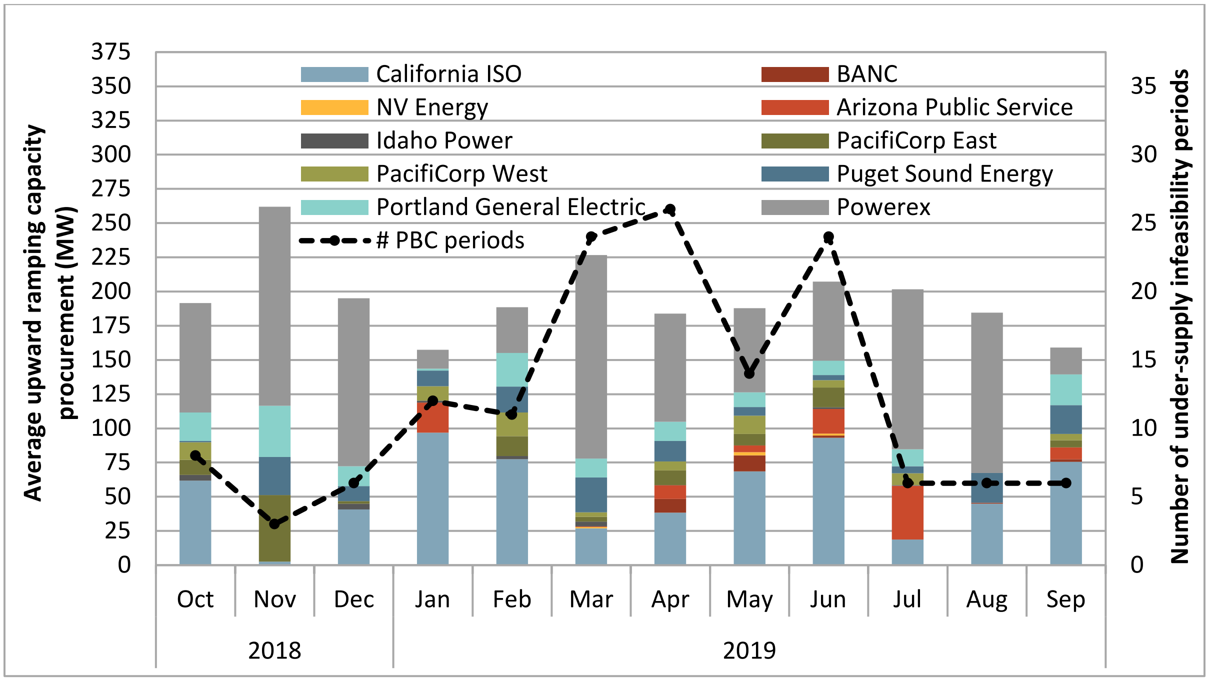


Figure 3.7 Average 5-minute market upward ramping capacity procurement prior to under-supply infeasibility periods - by area



Uncertainty over longer time horizon

The current flexible ramping product design procures and prices ramping capability in the 15-minute market to account for uncertainty between the 15-minute and 5-minute markets. In the 5-minute market, the market software then procures and prices the appropriate amount of ramping capability to account for the uncertainty in only 5-minute net load forecasts. As the ISO incorporates growing quantities of distributed and variable energy resources, there will be increasingly greater uncertainty in the net load forecasts for intervals 30, 60, or 120 minutes out from a given real-time market run.

Grid operators face significant uncertainty over load and the future availability of resources to meet that load. As highlighted in this report, the ISO operators regularly take significant out-of-market actions to address the net load uncertainty over a longer multi-hour time horizon (e.g., 2 or 3 hours). These actions include routine upward biasing of the hour-ahead and 15-minute load forecast, and exceptional dispatches to commit and begin to ramp up additional gas-fired units in advance of the evening ramping hours. Thus, rather than rely on the flexible ramping product, operators take significant manual actions to address ramping needs and net load uncertainty. This uncertainty contributes to operators needing to enter systematic and large imbalance conformance adjustments, as described in Section 1.14 of this report. The ISO could reduce the need for manual load adjustments and more efficiently integrate distributed and variable energy resources by designing a real-time flexible ramping product that could procure and price the appropriate amount of ramping capability to account for uncertainty over longer time horizons than the current design considers.

The ISO launched a new initiative to address the deliverability of the real-time flexible ramping product and proposed adding a new day-ahead market imbalance reserve product to address net load uncertainty. However, the ISO has indicated that it does not intend to extend the flexible ramping product uncertainty horizon beyond five minutes to address uncertainty in what the actual net load will be further out in time from the current interval.

DMM continues to recommend that the ISO work on designing an extension of the uncertainty horizon of the real-time flexible ramping product in the real-time market.[55] DMM recognizes that this enhancement could be a complicated and time-consuming endeavor. However, DMM believes it is prudent to start work on this enhancement prior to implementation of a new day-ahead market imbalance reserve product. Without the enhancement, the real-time market software may not commit or position resources to be able to provide the flexibility purchased as imbalance reserves in the extended day-ahead market. [56]

3.2 Batteries

The number of batteries participating in the ISO markets has increased over the past four years. Battery resources can currently participate in the ISO markets through the non-generator resource (NGR) model or as demand response resources. The majority of batteries participating in the ISO markets are located in locally constrained areas.

Figure 3.8 shows average hourly schedules in the third quarter of 2019 of battery resources participating under the NGR model. Similar to 2018, batteries primarily received awards for ancillary services, including regulation up, regulation down, and spin reserves.[57] When providing energy, schedules are highest during the morning and evening ramping hours, particularly during hour ending 20.

55 *DMM Comments on Day-Ahead Market Enhancements June 20, 2018 Technical Workshop*, July 24, 2019, p. 1: http://www.caiso.com/InitiativeDocuments/DMMComments-Day-AheadMarketEnhancementsWorkshop-June20-2019.pdf.

DMM Comments on Day-Ahead Market Enhancements August 13, 2019 Working Group, September 6, 2019, pp. 1-3: http://www.caiso.com/InitiativeDocuments/DMMCommentsDay-AheadMarketEnhancements-Aug13-Aug19Meetings.pdf

56 *DMM Comments on Issue Paper on Extending the Day-Ahead Market to EIM Entities, November 26*, 2019: http://www.caiso.com/InitiativeDocuments/DMMComments-ExtendedDay-AheadMarket-IssuePaper.pdf

57 In 2019, one resource registered as an NGR changed its participation model to the regulation-only Regulation Energy Management (REM) option. NGR-REM resources do not provide energy or spin reserves. For more information on NGR-REM, see http://www.caiso.com/Documents/NGR-REMOverview.pdf.

Figure 3.8 Average hourly battery schedules (2019 Q3)

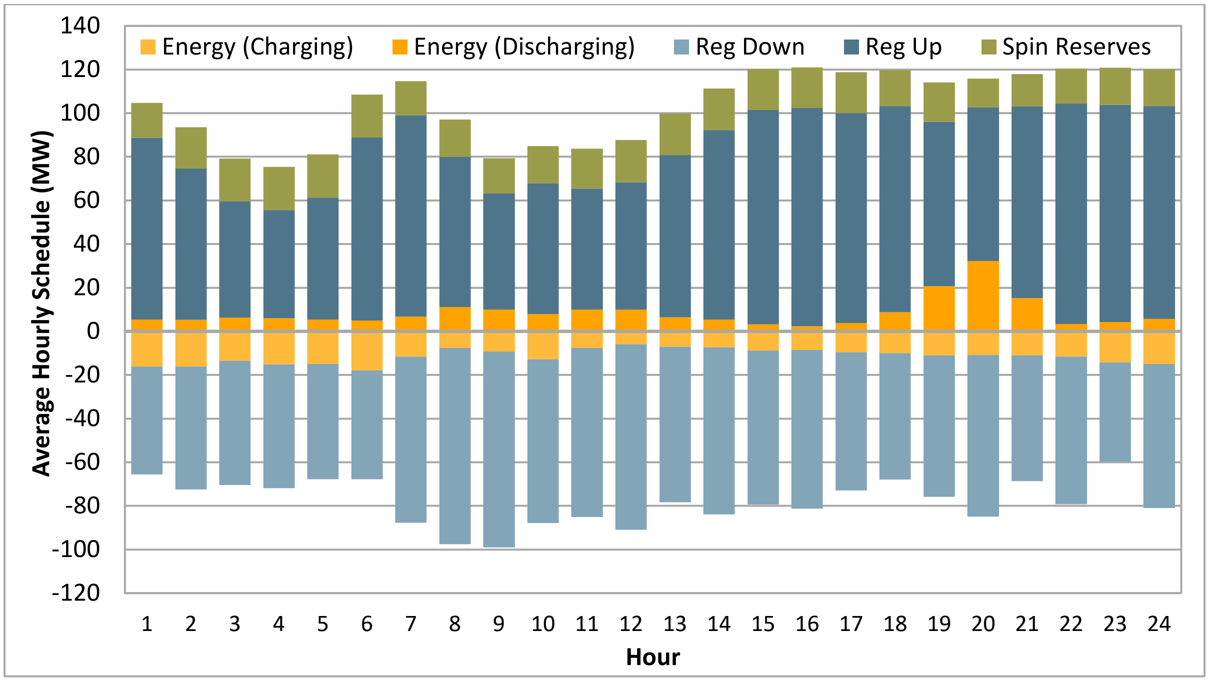
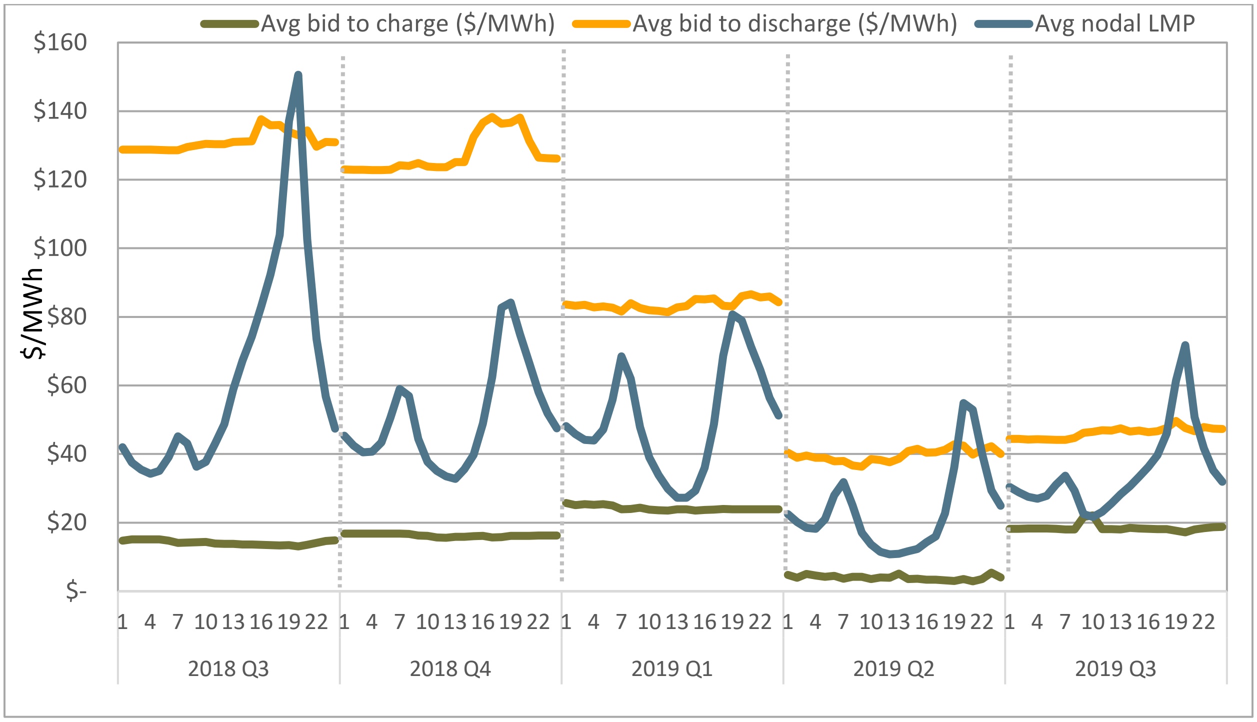


Figure 3.9 shows the average day-ahead energy bids of non-generator resources by quarter since the third quarter of 2018 compared to average nodal prices. Under the NGR model, resources submit a single energy bid curve which reflects both willingness to charge and discharge. Compared to the third quarter of 2018, average discharge bid prices decreased while average charge bids increased, implying the average price spread between willingness to charge and discharge decreased in 2019.

As shown in Figure 3.9, discharge bids were generally economic in hours 19-21 in the second and third quarters of 2019. However, average charge bids continued to trend below corresponding nodal prices. Energy schedules on non-generator resources appear to be more limited by the economics of resources' charge bids, particularly in real-time where the market may not be able to look out far enough to capture potential energy arbitrage opportunities between the lowest and highest net load hours.

Figure 3.9 Average hourly battery bids and nodal prices (2018 Q3-2019 Q3)



Though non-generator resource energy bids appeared to be more economic in the second and third quarters of 2019 than in prior quarters, non-generator resource schedule compositions have remained consistent compared to 2018, as shown in Figure 3.8. In particular, there has not been a significant increase in energy schedules compared to regulation capacity schedules in 2019.

While energy bids have appeared more economic in recent quarters, non-generator resources remain effective for meeting both regulation capacity and mileage requirements. These resources have very fast ramp rates which allows them to provide more mileage per megawatt of regulation capacity. Non-generator resources also bid relatively low prices to provide both regulation capacity and mileage. Thus, non-generator resources can contribute towards meeting both regulation and mileage requirements at relatively low cost compared to other resource types. Additionally, real-time ancillary service schedules shown in Figure 3.8 generally reflect day-ahead ancillary service awards, which are considered binding commitments in real-time.

3.3 Demand response resource adequacy

Demand response resources shown on monthly resource adequacy supply plans are subject to must-offer obligations into the day-ahead and real-time markets, and face potential Resource Adequacy Availability Incentive Mechanism (RAAIM) charges if must-offer obligations are not met. Demand response capacity represents customer load that can be counted on to curtail when called upon by the ISO. Analysis of 2019 market data suggests that the aggregate demand response capacity that proxy demand response (PDR) resources have shown on resource adequacy supply plans exceeds both bids in the day-ahead market in some hours and appears to exceed the total capability of this resource fleet.

Bid capacity compared to metered demand

Figure 3.10 shows average bids in day-ahead and real-time markets across Availability Assessment Hours for proxy demand response (PDR) resources shown on monthly resource adequacy supply plans. Bids (blue and green bars) are compared to meter data submitted to the ISO (red line) and associated resource adequacy values (gray line). Figure 3.9 shows that PDR resources shown on resource adequacy supply plans often submit bids in excess of actual load observed in corresponding intervals.

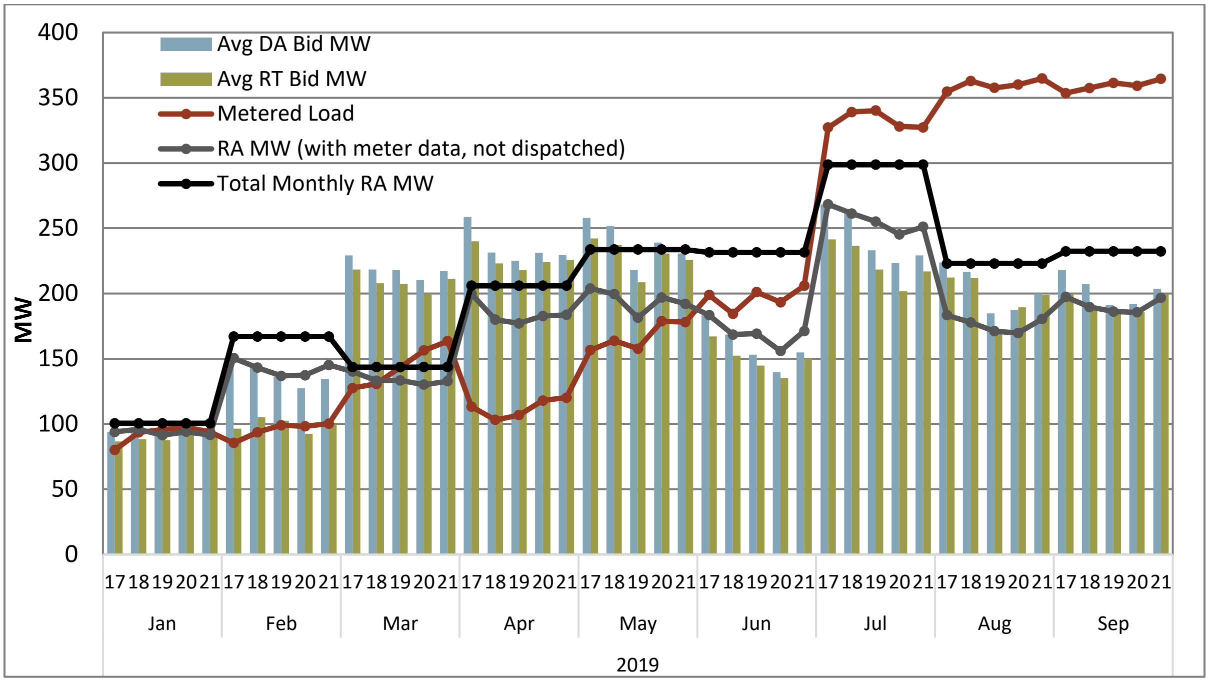
Figure 3.10 shows aggregate bid and meter data of the PDR fleet shown on resource adequacy supply plans, excluding hours where meter data was not submitted for a resource, and hours where a resource was dispatched in the 5-minute market. Hours where meter data was not submitted for a resource are excluded because scheduling coordinators are only required to submit meter data for resources over certain timeframes based on demand response events.[58] Hours where a resource received a 5-minute market dispatch are excluded because demand response resources are expected to reduce load according to real-time dispatch instructions. Meter data in event intervals would reflect load reductions in response to an event and are therefore excluded from this analysis.

Figure 3.10 shows that in Availability Assessment Hours in the first half of 2019, the PDR resource adequacy fleet often bid capacity far in excess of actual metered load. This means that PDR resource adequacy capacity bid into the ISO was frequently in excess of the actual load reduction capability from these resources.

The gray line shows the average resource adequacy value of PDR resources for which meter data exists and the resource was not dispatched in the hour. The black line shows the total monthly resource adequacy value of all PDR resources shown on supply plans. Comparing bids to associated resource adequacy values (gray line) shows that the PDR resource adequacy fleet generally bids up to resource adequacy values, largely avoiding RAAIM penalties. However, actual load was often insufficient to support load reduction up to resource adequacy values and capacity bid into the market in the beginning of the year. Starting in June 2019, metered load began to trend above average bid and resource adequacy values.

[58] For detailed requirements governing the submission of meter data to the ISO for demand response resources, see CAISO BPM for Metering, Section 12.1.

Figure 3.10 Average bids and metered load of PDR resources on RA supply plans



3.4 Exceptional dispatch

Exceptional dispatches are unit commitments or energy dispatches issued by operators when they determine that market optimization results may not sufficiently address a particular reliability issue or constraint. This type of dispatch is sometimes referred to as an out-of-market dispatch. While exceptional dispatches are necessary for reliability, they may create uplift costs not fully recovered through market prices, affect market prices, and create opportunities for the exercise of market power by suppliers.

Exceptional dispatches can be grouped into three distinct categories:

- **Unit commitment** — Exceptional dispatches can be used to instruct a generating unit to start up or continue operating at minimum operating levels. Exceptional dispatches can also be used to commit a multi-stage generating resource to a particular configuration. Almost all of these unit commitments are made after the day-ahead market to resolve reliability issues not met by unit commitments resulting from the day-ahead market model optimization.

- **In-sequence real-time energy** — Exceptional dispatches are also issued in the real-time market to ensure that a unit generates above its minimum operating level. This report refers to energy that would likely have cleared the market without an exceptional dispatch (i.e., that has an energy bid price below the market clearing price) as in-sequence real-time energy.

- **Out-of-sequence real-time energy** — Exceptional dispatches may also result in out-of-sequence real-time energy. This occurs when exceptional dispatch energy has an energy bid priced above the market clearing price. In cases when the bid price of a unit being exceptionally dispatched is subject to the local market power mitigation provisions in the ISO tariff, this energy is considered out-of-sequence if the unit's default energy bid used in mitigation is above the market clearing price.

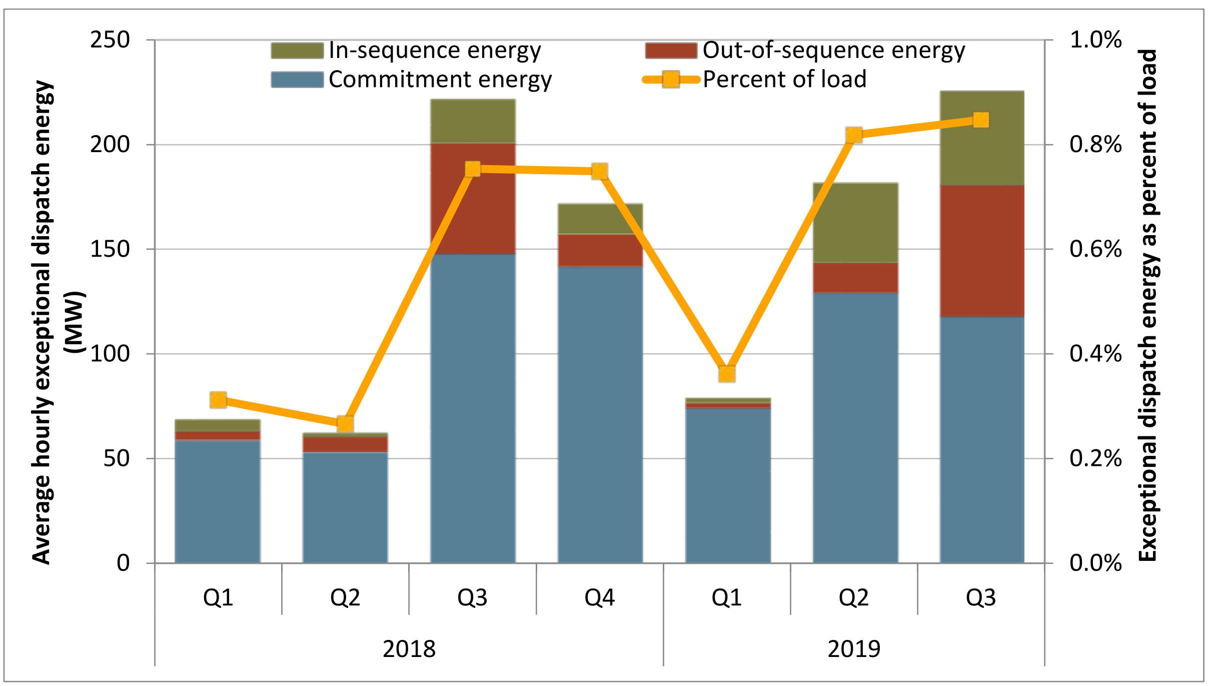
In the third quarter, a significant amount of exceptional dispatches were issued to commit and ramp up slower ramping gas units during the evening ramping hours. Most of these exceptional dispatches were issued to slow ramping gas generating resources located in the Los Angeles basin. These exceptional dispatches were issued to increase the amount of ramping capacity available to meet the evening net load ramp and to respond to other uncertainties in real-time. Thus, many of these exceptional dispatches are used to address the same issues that the flexible ramping product is designed to address.

Energy from exceptional dispatch

Energy from exceptional dispatch accounted for almost 1 percent of total load in the ISO balancing area. Total energy from exceptional dispatches, including minimum load energy from unit commitments, averaged 225 MWh in the third quarter of 2019 which is about the same amount when compared to the third quarter in 2018.

As shown in Figure 3.11,[59] exceptional dispatches for unit commitments accounted for about 52 percent of all exceptional dispatch energy in this quarter. About 28 percent of energy from exceptional dispatches was from out-of-sequence energy, and the remaining 20 percent was from in-sequence energy.

Figure 3.11 Average hourly energy from exceptional dispatch

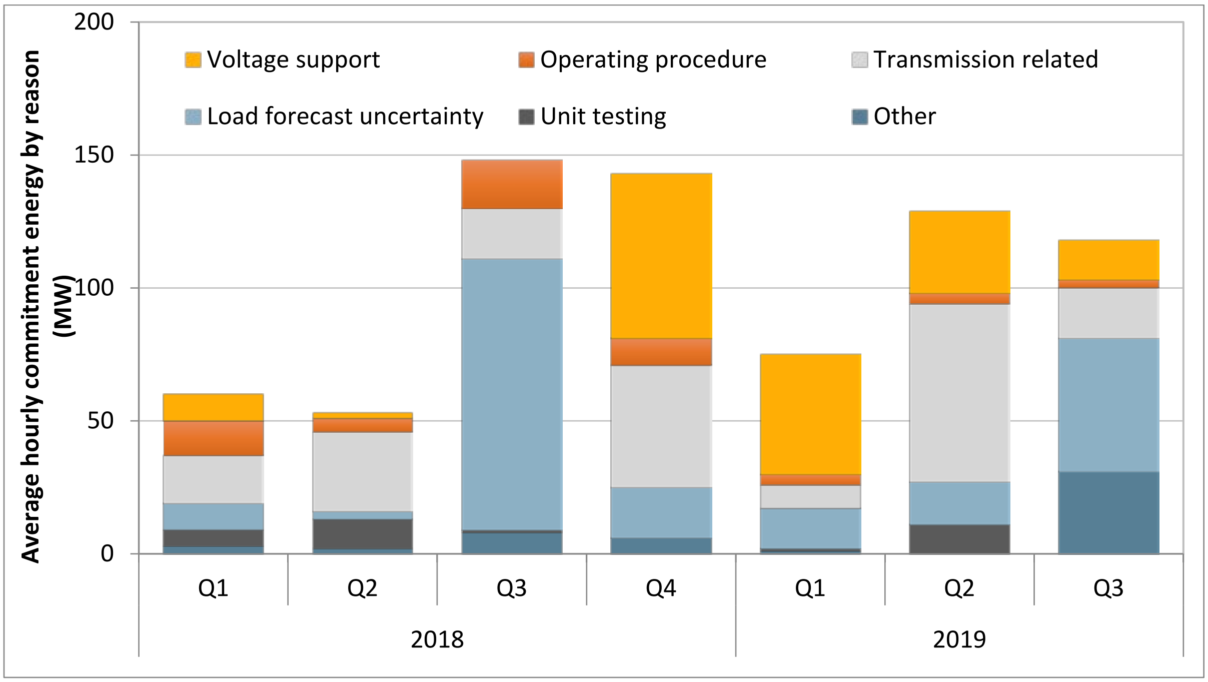


59 All exceptional dispatch data are estimates derived from Market Quality System (MQS) data, market prices, dispatch data, bid submissions, and default energy bid data. DMM's methodology for calculating exceptional dispatch energy and costs has been revised and refined since previous reports. Exceptional dispatch data reflected in this report may differ from previous annual and quarterly reports as a result of these enhancements.

Exceptional dispatches for unit commitment

Minimum load energy from exceptional dispatch unit commitments in the third quarter decreased on average by 20 percent relative to the third quarter of the prior year. Declined levels of exceptional dispatch unit commitment were offset by an increase in exceptional dispatch energy above minimum load. The majority of exceptional dispatch unit commitments were issued for load forecast uncertainty or to bridge day-ahead schedules that would have been infeasible due to time-horizon limitations in the market software.

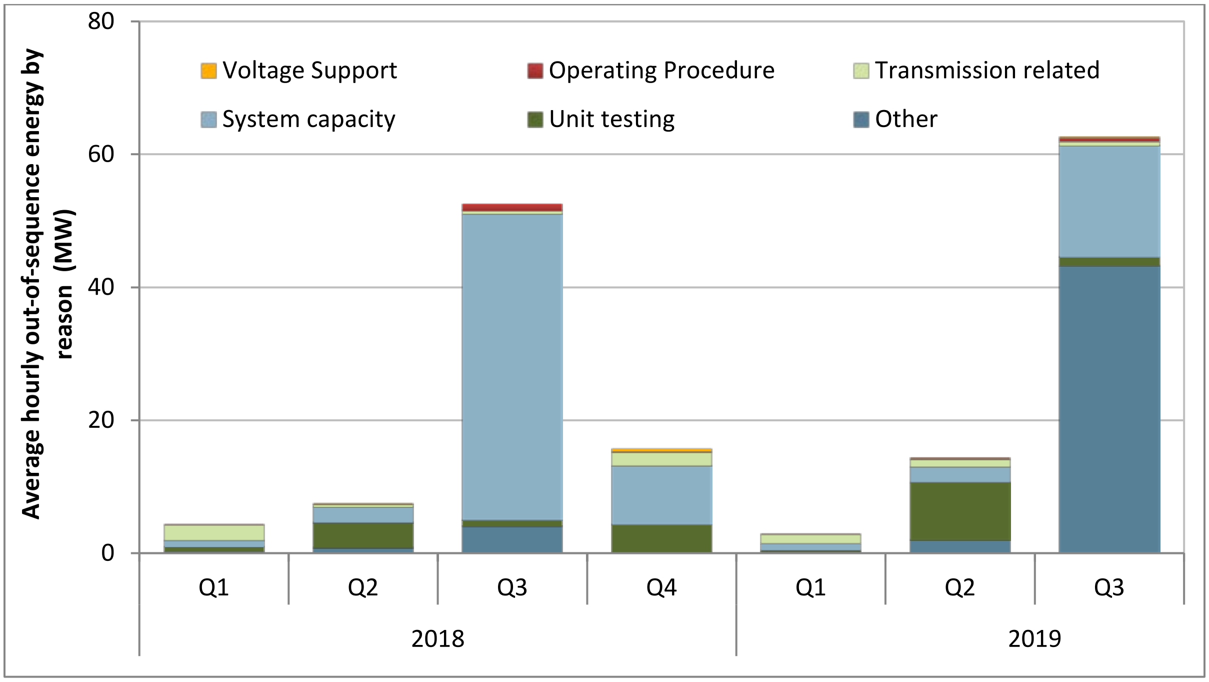
Figure 3.12 Average minimum load energy from exceptional dispatch unit commitments



Exceptional dispatches for energy

Energy from real-time exceptional dispatches to ramp units above minimum load or their regular market dispatch increased by about 50 percent relative to the same quarter in 2018. As previously illustrated in Figure 3.11, about 58 percent of this exceptional dispatch energy was out-of-sequence, meaning the bid price (or default energy bid if mitigated, or if the resource did not submit a bid) was greater than the locational market clearing price. Figure 3.13 shows the change in out-of-sequence exceptional dispatch energy by quarter for 2018 and 2019. Most of the out-of-sequence energy in the third quarter was exceptionally dispatched for software limitations, shown as “Other” reason in Figure 3.13.

Figure 3.13 Out-of-sequence exceptional dispatch energy by reason



Exceptional dispatch costs

Exceptional dispatches can create two types of additional costs not recovered through the market clearing price of energy.

- Units committed through exceptional dispatch that do not recover their start-up and minimum load bid costs through market sales can receive bid cost recovery for these costs.
- Units exceptionally dispatched for real-time energy out-of-sequence may be eligible to receive an additional payment to cover the difference in their market bid price and their locational marginal energy price.

Figure 3.14 shows the estimated costs for unit commitment and additional energy resulting from exceptional dispatches in excess of the market price for this energy. In the third quarter, out-of-sequence energy costs were $8.1 million, while commitment costs for exceptional dispatch paid through bid cost recovery were $9.3 million.

Some exceptional dispatches for energy above minimum are subject to bid mitigation. These include exceptional dispatches (1) for unit testing, (2) to ramp a unit up to its minimum dispatchable level (or DPmin), and (3) to mitigate congestion on a specific constraint that is logged by system operators and is found to be structurally uncompetitive. Otherwise, exceptional dispatches for energy above minimum load are paid the higher of the resource's bid price or the market price. As shown in Figure 3.15, the average volume of exceptional dispatches for out-of-sequence energy subject to mitigation increased compared to the previous third quarter.

In the third quarter, mitigation of exceptional dispatches should reduce total exceptional dispatch costs by about $15.4 million. Almost all of the reduction in costs was due to mitigation of exceptional dispatches to ramp units up to a minimum dispatchable level. The ISO's settlement system did not apply mitigation to exceptional dispatches prior to mid-2019, so the ISO will apply mitigation retroactively through settlement corrections. Exceptional dispatch costs in Figure 3.14 are based on DMM's estimate of cost after these settlement corrections.

Figure 3.14 Excess exceptional dispatch cost by type

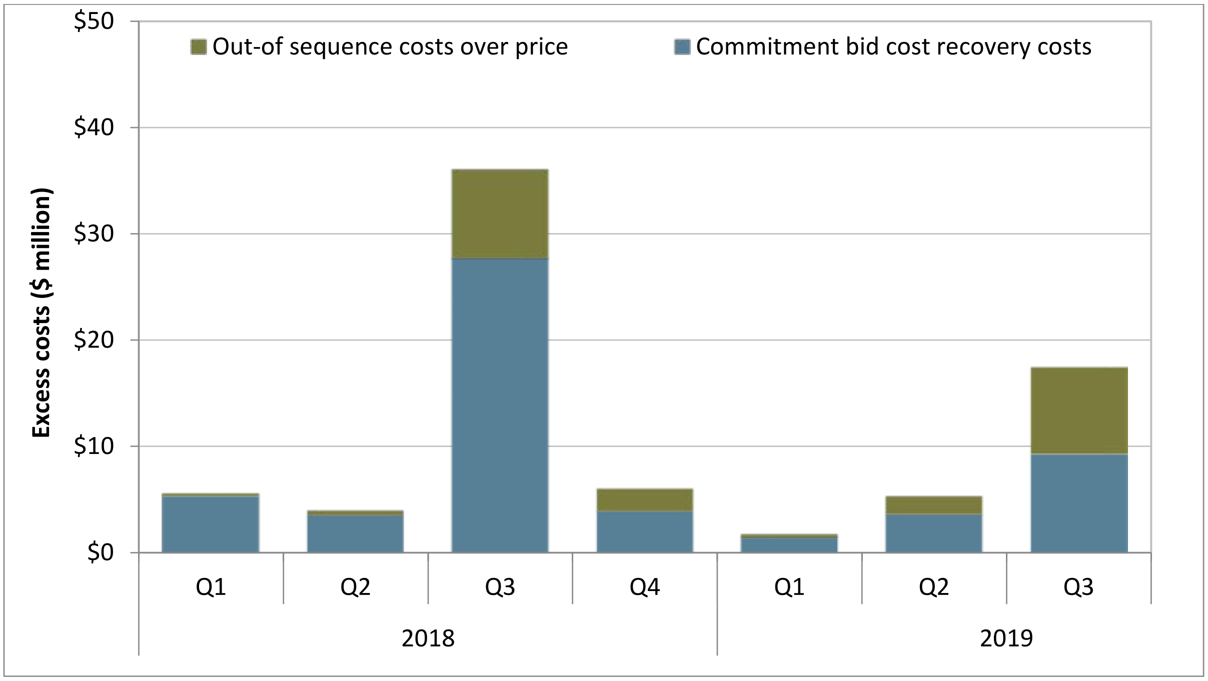
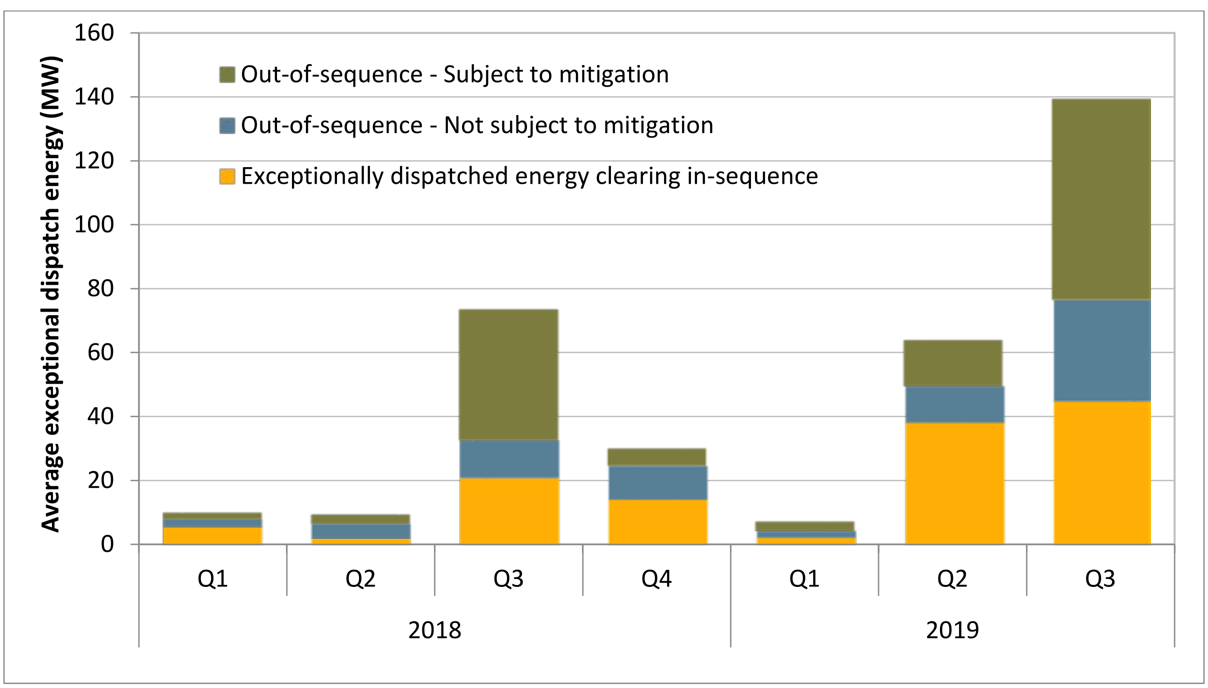


Figure 3.15 Exceptional dispatches subject to mitigation



Exceptional dispatches for ramping energy

In the third quarter, many exceptional dispatches were issued to commit and start slower ramping gas units during the evening ramping hours. Most of these exceptional dispatches are issued to slow ramping gas generating resources located in the Los Angeles basin. These exceptional dispatches are issued to increase the amount of ramping capacity available to meet the evening net load ramp and to respond to other uncertainties in real-time.

Figure 3.16 shows the average volume of energy from exceptional dispatches to gas-fired resources by hour in the third quarter. As shown in Figure 3.16:

- The average amount of minimum load energy from gas units committed via exceptional ranged from 100 MW during off-peak hours up to almost 200 MW in the peak ramping hours (blue bars).

- During the evening ramping hours, the ISO often starts some slower ramping gas units to their minimum dispatchable levels or dispatchable PMin. Energy from these exceptional dispatches averaged about 120 MW over the peak load hours of 17-22 (orange bars).

- Beginning in the third quarter of 2019, the ISO started to exceptionally dispatch some units to the maximum of their resource adequacy contracts, which is typically at or near the unit’s maximum capacity. These exceptional dispatches are referred to as RA Max exceptional dispatches by the ISO operators. Energy from these exceptional dispatches averaged about 70 MW over the peak load hours of 17-22 (red bars).

- In the third quarter, energy from other exceptional dispatches averaged about 40 MW during off-peak hours and about 90 MW in the peak ramping hours (yellow bars).

Total energy from exceptional dispatches averaged nearly 100 MW during off-peak hours and about 450 MW in the peak ramping hours. However, the amount of exceptional dispatched energy from gas units is much higher on days with higher peak loads. As shown in Figure 3.17, on days with peak loads over 37,000 MW, total energy from exceptional dispatches often ranged from over 600 MW to almost 1,000 MW on some days.

RA Max exceptional dispatches

As noted above, in the third quarter of 2019 the ISO started to issue RA Max exceptional dispatches to manually dispatch units to the maximum of their resource adequacy contracts. These RA Max exceptional dispatches totaled around 38,000 MWh in the third quarter, or about 16 percent of all energy above minimum load exceptionally dispatched. As shown in Figure 3.17, most of these exceptional dispatches were issued on days with peak loads over 37,000 MW. About 98 percent of these exceptional dispatches were issued to units controlled by a single supplier.

Exceptional dispatches to RA Max are not subject to energy bid mitigation, and are paid the higher of the unit's energy bid or the market price.[60] The total unmitigated RA Max exceptional dispatch energy costs were around $5.2 million, about $3.3 million above market prices in the third quarter. The average unmitigated price paid for these exceptional dispatches was about $150/MWh, compared to an average price of about $55/MWh. If these exceptional dispatches were subject to bid mitigation, the average price paid for this energy would have been about $70/MWh.

DMM is recommending that RA Max exceptional dispatch energy should be subject to mitigation as there is a strong potential for suppliers to exercise market power and raise bids substantially over marginal cost.

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60 More information on exceptional dispatch mitigation can be found in Section 39.10 of ISO's tariff: http://www.caiso.com/Documents/Section39-MarketPowerMitigationProcedures-asof-Sep28-2019.pdf

Figure 3.16 Average hourly exceptional dispatch energy by type (July – September)

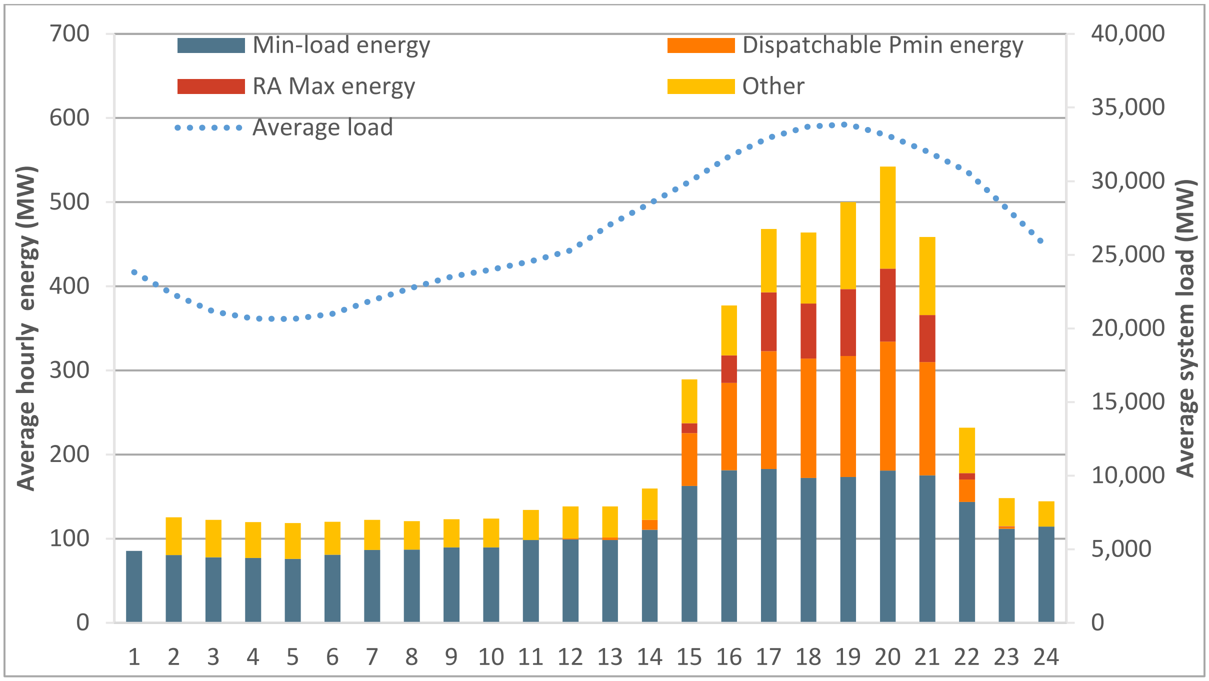
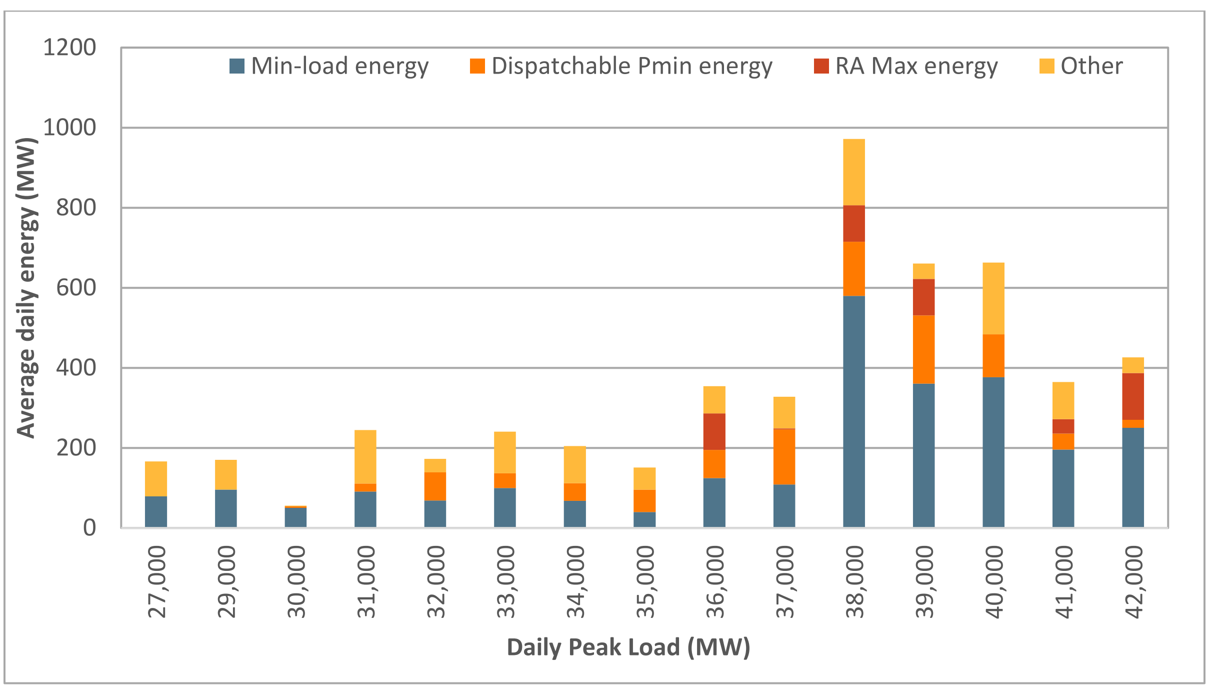


Figure 3.17 Average exceptional dispatch energy by peak load amount (July-September, hours ending 17-21)



3.4.1 Manual dispatch on the interties

Exceptional dispatches on the interties are referred to by the ISO operators as manual dispatches. In previous annual reports, DMM cautions that when the ISO procures imports out-of-market at prices higher than the 15-minute price paid for other imports, this could encourage economic and physical withholding of available imports.[61]

In 2019, the frequency and volume of manual dispatches for imports on the interties has been low. In the third quarter, the total volume of manual dispatches increased slightly from the previous quarter to about 7,600 MWh. Almost 60 percent of these were export dispatches for emergency assistance to another balancing authority occurring primarily during the evening ramp hours.

3.5 System market power

This section assesses the competitiveness of the ISO's 2019 energy markets in four parts: a case study of a single day in the third quarter, structural measures of market competitiveness, day-ahead market software simulation, and DMM recommendations.

3.5.1 September 25, 2019: A case study

DMM issued a report containing information on the competitiveness of the ISO's day-ahead market on September 25, 2019.[62] The report was in response to market participant requests for the ISO to provide more transparency on the competitiveness of day-ahead market outcomes on relatively high priced days. Key findings from this report were:

- Prices in the ISO's day-ahead market on September 25 equated to implied heat rates ranging from 25.35 to 28.86 MMBtu/MWh for the PG&E and SCE areas during hours ending 19 and 20.
- Prices in the ISO's day-ahead market on this day were substantially above both 15-minute and bilateral prices.
- On this date, bid-in load increased relative to two days prior, while overall supply offered decreased, particularly from wind resources and virtual supply bids.
- Structural measures of market power indicate that the market was uncompetitive during hours 19 and 20 on September 25.
- A significant portion of supply from gas-fired resources offered by net sellers was bid at prices significantly above cost-based default energy bids used when local market power mitigation is triggered. Most supply from gas resource offered by load-serving entities was offered at prices at or below default energy bids.

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61 *2017 Annual Report on Market Issues and Performance*, pp.206-207: http://www.caiso.com/Documents/2017AnnualReportonMarketIssuesandPerformance.pdf

62 Report on day-ahead market competitiveness: For September 25, 2019. http://www.caiso.com/Documents/Reportonday-aheadmarketcompetitivenessforSeptember252019-Oct302019.pdf

- About 5,000 MW of offered gas capacity did not clear the market. Much of this capacity, including the minimum generation level, was shown as resource adequacy and some was offered at costs below system marginal energy cost.
- The average price-cost markup was 4.4 percent on this date, calculated across all hours in all DLAPs.

3.5.2 Structural measures of competitiveness

Market structure refers to the ownership of available supply in the market. The structural competitiveness of electric markets is often assessed using two related quantitative measures: the pivotal supplier test and the residual supply index. Both of these measures assess the sufficiency of supply available to meet demand after removing the capacity owned or controlled by one or more entities.

- **Pivotal supplier test**. If supply is insufficient to meet demand with the supply of any individual supplier removed, then this supplier is pivotal. This is referred to as a single pivotal supplier test. The two-pivotal supplier test is performed by removing supply owned or controlled by the two largest suppliers. For the three-pivotal test, supply of the three largest suppliers is removed.
- **Residual supply index**. The residual supply index is the ratio of supply from non-pivotal suppliers to demand. A residual supply index less than 1.0 indicates an uncompetitive level of supply.

In the electric industry, measures based on two or three suppliers in combination are often used because of the potential for oligopolistic bidding behavior. The potential for such behavior is high in the electric industry because the demand for electricity is highly inelastic, and competition from new sources of supply is limited by long lead times and regulatory barriers to siting of new generation.

In this report, when the residual supply index is calculated by excluding the largest supplier, we refer to this measure as RSI_1. With the two or three largest suppliers excluded, we refer to these results as RSI_2 and RSI_3, respectively.

The residual supply index values reflect load conditions, generation availability, and resource ownership or control. Some generating units have tolling contracts, which transfer the control from unit owners to load-serving entities. These tolling contracts improve overall structural competitiveness in the period.

The values presented below include several changes in how supply and demand may be measured when calculating the RSI which DMM believes may represent refinements in the methodology used by DMM in prior annual reports. These include:

- Use of day-ahead *input bids* for physical generating resources (adjusted for outages and de-rates) instead of post-processed bids used in the final market software optimization (or output bids);
- Accounting for losses (typically increasing demand by 2 to 3 percent);
- Including self-scheduled exports as demand (combined with the day-ahead load forecast plus upward ancillary service requirements and transmission losses);
- Including ancillary services bids in excess of energy bids to account for this additional supply available to meet ancillary service requirements in the day-ahead market;
- Exclusion of CPUC jurisdictional investor-owned utilities as potentially pivotal suppliers;

- Accounting for the maximum availability of non-pivotal imports offered relative to import transmission constraint limits. The end of this section provides additional details on this; and
- As in prior DMM analyses, virtual bids are excluded.

Figure 3.18 shows the quarterly number of hours with a residual supply index less than one since 2016, based on the assumptions listed above. During the first three quarters of 2019, DMM has observed fewer hours with an RSI less than one relative to the previous two years. For year-to-date 2019, the residual supply index with the three largest suppliers removed (RSI_3) was less than one during 95 hours, and the index was less than one during 33 hours with the two largest suppliers removed (RSI_2). There have been no hours so far in 2019 with the index less than one and the largest single supplier removed. A reduction in potentially non-competitive hours in 2019 relative to the previous two year is the result of factors supporting competitive conditions including lower loads and high rates of low cost renewable production.

Figure 3.19 shows the lowest 250 RSI_1 values for each year. For comparability, the fourth quarter was removed for all years. The hourly RSI_1 value reached just above 1.00 at its lowest between January and September 2019, compared to around 0.89 in each of 2017 and 2018, and 0.96 in 2016.

Figure 3.18 Hours with residual supply index less than one

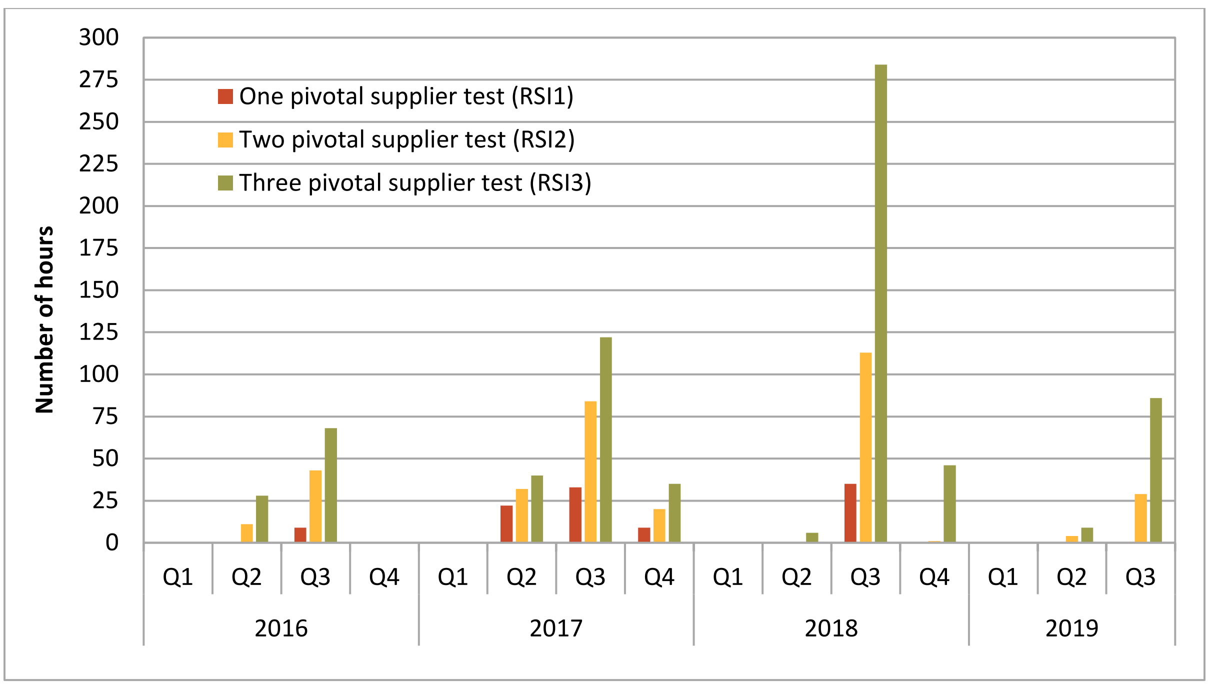
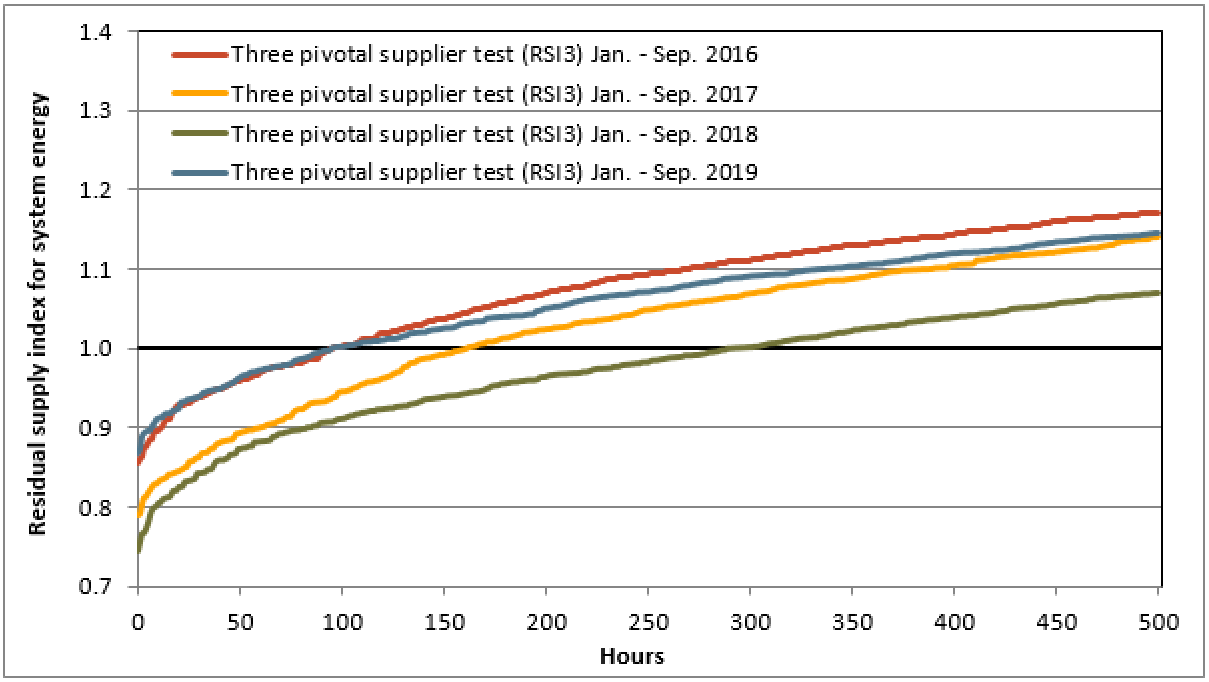


Figure 3.19 Residual supply index with largest supplier excluded (RSI_1) – lowest 250 hours (January to September)

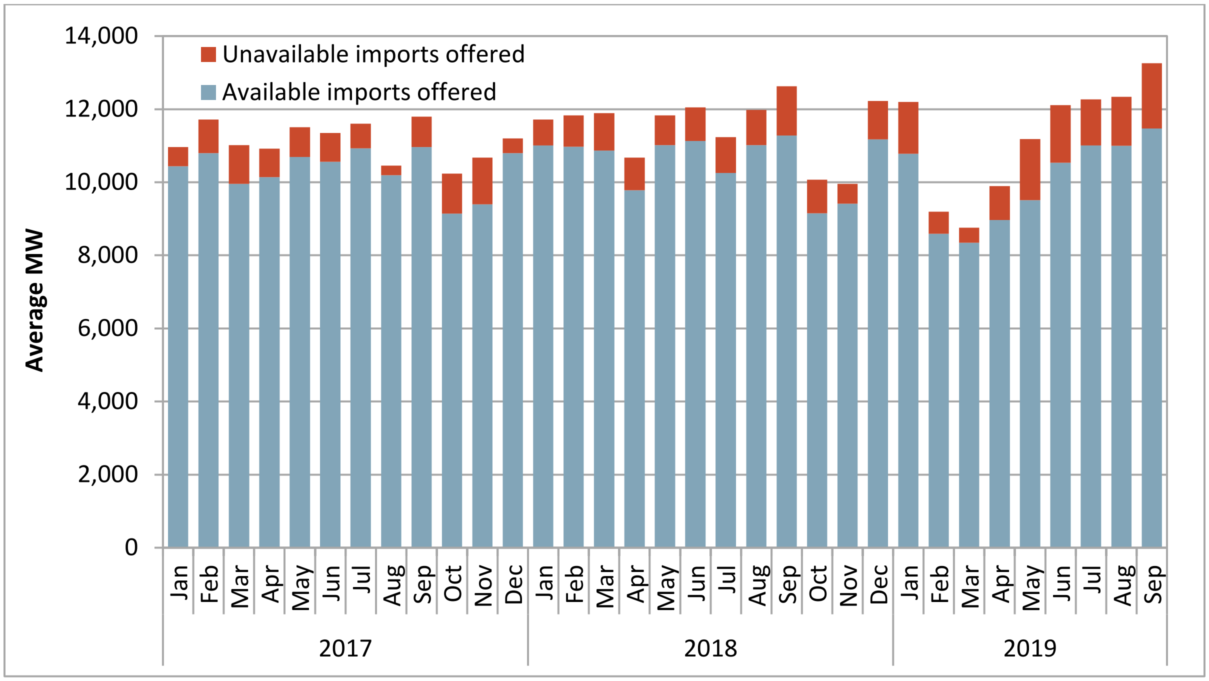


In June 2019, DMM presented residual supply index results showing 272 hours during 2018 with a residual supply index less than one with the three largest suppliers removed.[63] The only change since that analysis is a refinement to account for the maximum availability of non-pivotal imports offered relative to import transmission constraint limits. To illustrate this distinction, Figure 3.20 shows the average hourly MW of all imports offered in the day-ahead market, and the maximum proportion that is feasible relative to the applicable intertie scheduling limits.[64] After accounting for this factor, DMM calculated 336 hours during 2018 with a residual supply index less than one.

63 DMM presentation on *Analysis on System Market Power,* June 7, 2019: http://www.caiso.com/Documents/Presentation-AnalysisOfSystemLevelMarketPowerDMM-June7_2019.pdf

64 The highest amounts of imports offered is derived using only self-scheduled exports as counter-flow and maximizing imports relative to corresponding intertie constraint or scheduling limits.

Figure 3.20 Day-ahead market imports offered and transmission availability



3.5.3 Day-ahead market software simulation

To assess the competitiveness of the ISO energy markets, DMM compares actual market prices to competitive benchmark prices we estimate would result under highly competitive conditions. DMM estimates competitive baseline prices by re-simulating the market after replacing the market bids of all gas-fired units with the lower of their submitted bids or their default energy bids (DEB). This methodology assumes competitive bidding of price-setting resources, and is calculated using DMM's version of the actual market software.[65]

As shown in Figure 3.21, hourly prices in the day-ahead market were very similar to or slightly above the estimated competitive baseline prices on average. DMM calculates the day-ahead price-cost markup by comparing the competitive benchmark to the base case load-weighted average price for all energy transactions in the day-ahead market.

Each market simulation is preceded by a base case rerun with all of the same inputs as the original market run before completing the benchmark simulation, to screen for accuracy. For 2019, the base

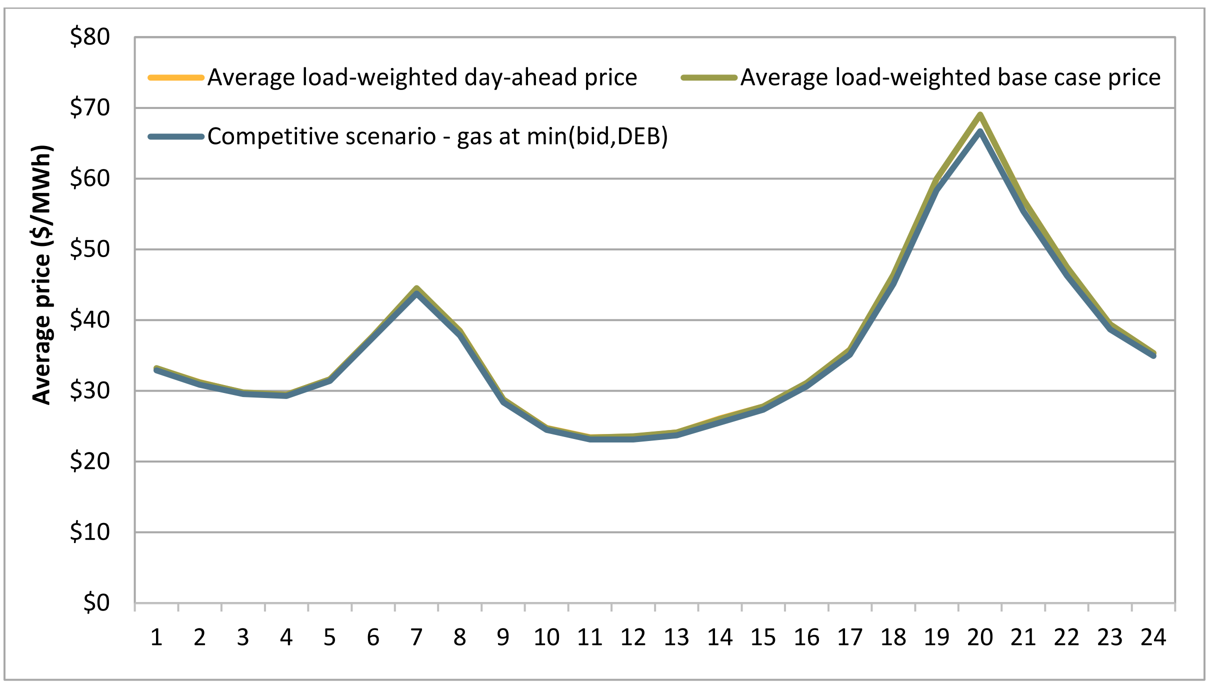
[65] In previous years, the competitive baseline was a scenario where bids for gas-fired generation were set to their default energy bids, convergence bids were removed, and system demand was set to actual system load. This tended to overestimate the competitive baseline price, because a significant amount of gas-fired supply is bid at prices lower than their default energy bids (which include a 10 percent adder), and actual system load tended to be greater than day-ahead bid-in load.

case reruns have replicated original prices with a greater frequency than recent years, allowing a higher percentage of days to be included in this analysis.[66]

As shown in Figure 3.22, for the first three quarters of 2019, the average price-cost markup was about $0.73 or about 2 percent. This slight positive markup indicates that prices have been very competitive, overall, for the year.[67]

DMM notes that the price-cost metric may be a conservative measure of system market power. The only change in market inputs made in the competitive scenario is that energy bids of gas-fired resources are capped by each resource's default energy bid -- which includes a 10 percent adder above estimated marginal costs. All other bids are assumed to be competitive, including those of non-resource specific imports. Also, this analysis does not change commitment cost bids for non-gas or gas-fired resources which are capped at 125 percent of each resource's estimated start-up and minimum load costs. DMM is working to develop the capability to assess the potential impact of these market bids on overall system prices using the ISO's day-ahead market software.

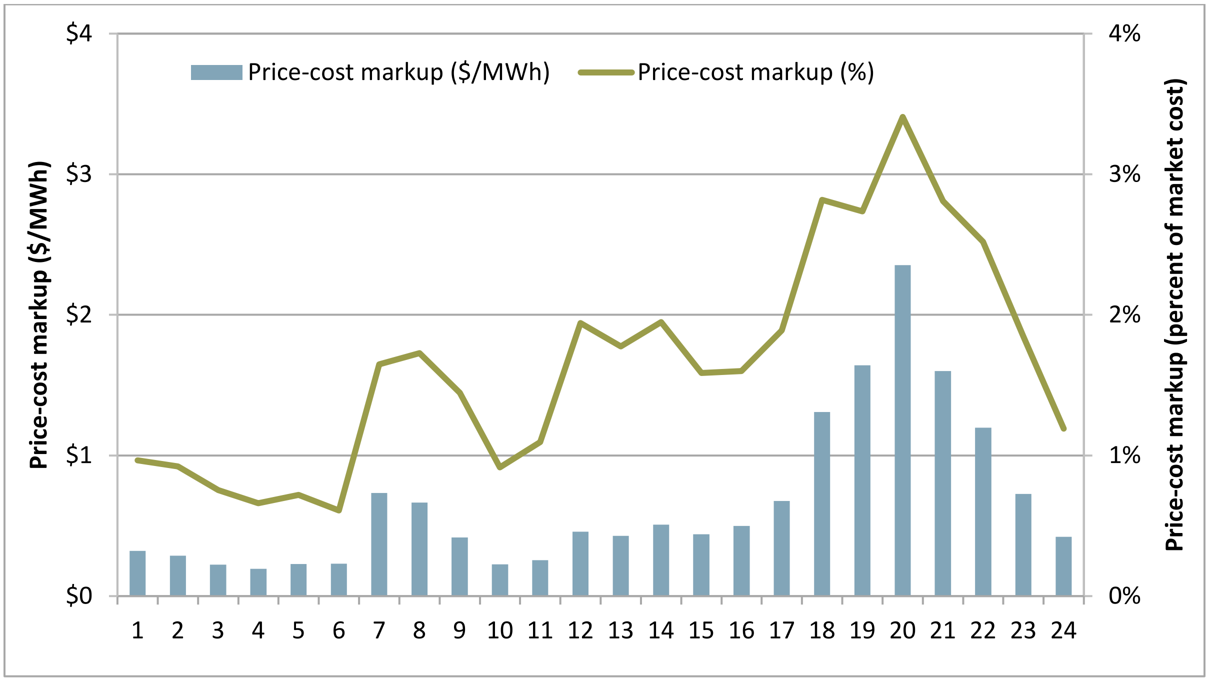
Figure 3.21 Comparison of competitive baseline with hourly day-ahead prices (Jan-Sep)



66 In 2017 and 2018, DMM was unable to include multiple days in the analysis because of issues replicating original prices in the base case rerun. For 2019, the ISO was able to resolve these issues such that a greater percentage of dates was able to be included.

67 DMM calculates the price-cost markup index as the percentage difference between base case market prices and prices resulting under this competitive baseline scenario. For example, if base case prices averaged $55/MWh and the competitive baseline price was $50/MWh, this would represent a price-cost markup of 10 percent.

Figure 3.22 Hourly price-cost markup (Jan-Sep)



3.5.4 DMM recommendations

Analysis by DMM indicates that in the last few years system market power has had a limited effect on market prices even during the limited number of hours when the ISO system was structurally uncompetitive. In 2019, market prices have continued to be relatively low and stable due to a combination of favorable market and system conditions. However, DMM continues to be concerned that market conditions in the coming years may change in ways that will exacerbate the potential for system-level market power.

Potential for increased system market power

In the last few years, market power has had a very limited effect on system market prices even during hours when the ISO system was structurally uncompetitive based on the three pivotal supplier test used in the ISO's local market power mitigation procedures. However, DMM has expressed concern that market conditions may evolve in a way that will increase the potential for system-level market power. Changes and trends that may increase the potential for system market power in the coming years include:

- Retirement and mothballing of gas capacity.
- Increasing portion of resource adequacy requirements being met by solar and wind resources, which often provide significantly less energy during the evening ramping hours than the resource adequacy rating of these resources.
- Fewer energy tolling contracts between gas units within the ISO and load-serving entities without an incentive to exercise market power.

- Increasing portion of resource adequacy requirements met by imports not backed by energy contracts or physical resources, which can avoid being called upon by simply bidding at high prices in the day-ahead market.
- Tightening regional supply conditions.

The ISO's comments in the CPUC's Integrated Resource Planning Proceeding indicate that ISO planners also have significant concerns about many of these same issues, and that the supply/demand balance in the CAISO system may tighten to the point where system reliability is in jeopardy as soon as summer 2021.

The ISO's comments in the CPUC proceedings emphasize the threat to reliability posed by these trends. However, as illustrated in DMM's comments submitted in the ISO's system market power initiative, for each hour tight supply/demand conditions may pose a threat to reliability due to a shortage of supply, there are many more hours in which tight supply/demand conditions create the potential for market power when there is no actual shortage of supply to meet demand. This suggests that there is the potential for reliability issues and market power within the next few years.

The ISO is proposing to start a market design initiative on system level market power mitigation which would begin with development of system market power provisions in the real-time market. A second phase would consider extension of the mitigation mechanism to other areas of the Western EIM and to the day-ahead market. DMM supports the ISO's proposal to continue with an initiative to design system market power mitigation and looks forward to working with the ISO throughout that process. The approach outlined by the ISO will be an incremental improvement that would help to mitigate potentially uncompetitive system conditions.

DMM recommends several other market design changes that may help mitigate system market power beyond the bid mitigation options being examined as part of the ISO's system market power initiative.

Given the increasing role that resource adequacy imports may play in ISO system reliability and market competitiveness, DMM recommends consideration of options that would increase the supply and availability of energy from resource adequacy imports beyond the day-ahead market into real-time. Options might include mechanisms to increase the amount of resource adequacy imports clearing the day-ahead market in tight supply conditions or high load uncertainty.

Such options likely involve a combination of resource adequacy rules for imports established by the CPUC as well as CAISO market rules. In the ISO's Resource Adequacy Enhancements Revised Straw Proposal, the ISO is proposing to require specification of the Source BA for all RA imports. However, the ISO is no longer considering extension of the resource adequacy must-offer requirement beyond the day-ahead market.

DMM also recommends that under the ISO's plan for implementing FERC Order No. 831, the ISO should (1) ensure that import bids over $1,000/MWh are subject to ex ante cost justification and (2) avoid setting penalty prices at $2,000/MWh except when needed to implement the provisions of the order. These market design features have important implications in terms of mitigating potential system market power. The ISO has committed to consider these potential design rules in a future stakeholder initiative, but has submitted a compliance filing on FERC Order No. 831 that does not include these elements.[68]

[68] *Motion to Intervene and Comments of the Department of Market Monitoring*, Docket No. ER19-2757-000, September 26, 2019. http://www.caiso.com/Documents/MotiontoInterveneandCommentsoftheDepartmentofMarketMonitoringonOrder831Compliance-ER19-2757-Sept262019.pdf