California Independent System Operator Corporation

California ISO

Q2 2017 Report on Market Issues and Performance

September 25, 2017

Prepared by: Department of Market Monitoring

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Executive summary

This report covers market performance during the second quarter of 2017 (April – June). Key highlights during this quarter include the following:

- The ISO issued a Grid Stage 1 System Emergency on May 3, for the first time in nearly 10 years.
- The ISO market experienced a system-wide heat wave and very high loads, since surpassed, from June 19 to June 21.
- On June 21, system marginal prices in the day-ahead market reached record highs, since surpassed, with prices greater than $200/MWh during a five-hour period and prices over $600/MWh in one hour. On this day, prices in the market run were significantly higher than in the market power mitigation run. This has occurred on other high load days in recent months as well. DMM expects that prices should generally not be significantly higher in the final market run than in the market power mitigation run. Both DMM and the ISO will continue to investigate this issue.
- On June 14, the ISO began increasing operating reserve requirements during midday hours to account for solar generation in the system by using an existing functionality within the software that allows operators to increase the requirement by a specified percent of the load forecast. DMM recommends that the ISO continue to refine the solar adjustment to the operating reserve requirements to more granularly approximate real-time solar generation.
- The frequency of price spikes in the 15-minute and 5-minute markets increased during the quarter. This was largely the result of congestion on Path 26 as well as conditions during May 3 and June 19 to 21.
- The transition period pricing waiver expired for Puget Sound Energy and Arizona Public Service at the end of the first quarter. In the second quarter, the frequency of valid over-supply infeasibilities in Arizona Public Service decreased significantly from the previous quarter, but continued to occur regularly during about 3 percent of 15-minute and 5-minute market intervals.
- The resource adequacy availability incentive mechanism (RAAIM) became effective in April. The ISO identified a number of issues with the mechanism and is working to correct them. Some of these changes will be put in place in the fall software release and applied retroactively, and some will be released at a later date and will be applied proactively. Current settlements figures for this mechanism remain advisory, and will become financially binding after software updates.
- Analysis by DMM of same-day natural gas price volatility in Southern California during the first and second quarters of 2017 shows that there was a very limited need for the increased bidding flexibility created by raising commitment cost and default energy bid caps. Following a recommendation by DMM to address this issue, the ISO reduced the Aliso Canyon real-time gas scalars to zero beginning August 1, 2017.
- Congestion revenue rights auction revenues were $18 million less than congestion payments made to non-load-serving entities purchasing these congestion revenue rights during the quarter. This represents $0.58 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders, which is lower than $0.63 during the second quarter of 2016.

- Financial participants continued to garner the highest profits from congestion revenue rights, netting $16 million (paying 41 cents in the auction per dollar of congestion revenue rights revenue). Generators netted about $1 million (paying 50 cents per dollar of revenue), while marketers netted $0.5 million (paying 96 cents per dollar of revenue). Load-serving entities gained about $0.2 million from rights they explicitly sold in the auction in the second quarter of 2017, down from about $1 million in the same quarter of 2016.

Other key highlights are summarized here and further detail is provided below.

- Overall, average day-ahead and 15-minute market prices increased during every month of the second quarter as a result of warmer temperatures and higher loads.
- The extent to which the power balance constraint could be relaxed for over-supply conditions was reduced from 300 MW to 30 MW on April 11, 2017. Past this point, self-scheduled generation can be curtailed including self-scheduled wind and solar generation. However, during nearly all of the intervals in the second quarter when prices were negative, there were sufficient dispatchable market bids to resolve over-supply and the software did not have to relax the power balance constraint or curtail self-scheduled generation.
- Solar generation continued to increase and set a new solar peak of 9,914 MW on June 17, 2017. However, the frequency of negative prices during the second quarter decreased in the 15-minute and 5-minute markets due to the offsetting effects of higher loads due to warmer temperatures.
- In the real-time market, congestion during the quarter was higher than during any other quarter since the 15-minute market became binding in 2014. Much of the congestion in the second quarter was due to Path 26 in the north-to-south direction. This congestion increased overall San Diego Gas and Electric and Southern California Edison prices by around $0.40/MWh in the day-ahead market and $0.80/MWh in the 15-minute market.
- Bid cost recovery payments were about $28 million in the second quarter, compared to $22 million during the same quarter during 2016. Real-time bid cost recovery remained the largest category of bid cost recovery and totaled about $21 million, a significant portion from just a few specific days. Real-time bid cost recovery payments were particularly high on May 3, when the ISO declared a system emergency and many unit commitments were made in real-time.
- Net revenues for convergence bidders before accounting for bid cost recovery charges were about $4.2 million. Net revenues for virtual supply and demand fell to about $2.1 million after including about $2.1 million of virtual bidding bid cost recovery charges.
- Total payments for flexible ramping capacity in the second quarter with the flexible ramping product were about $7.5 million compared to $9.2 million in the previous quarter.
- Overall prices continued to be uniform between PacifiCorp East, NV Energy, Arizona Public Service, and the ISO during most intervals. Price separation that did occur was primarily due to flexible ramping sufficiency test failures.
- There continued to be congestion in the energy imbalance market from PacifiCorp West toward the ISO and PacifiCorp East. This caused price separation where prices in Puget Sound Energy and

PacifiCorp West were lower than those in the ISO and other energy imbalance market areas as a result of this congestion.

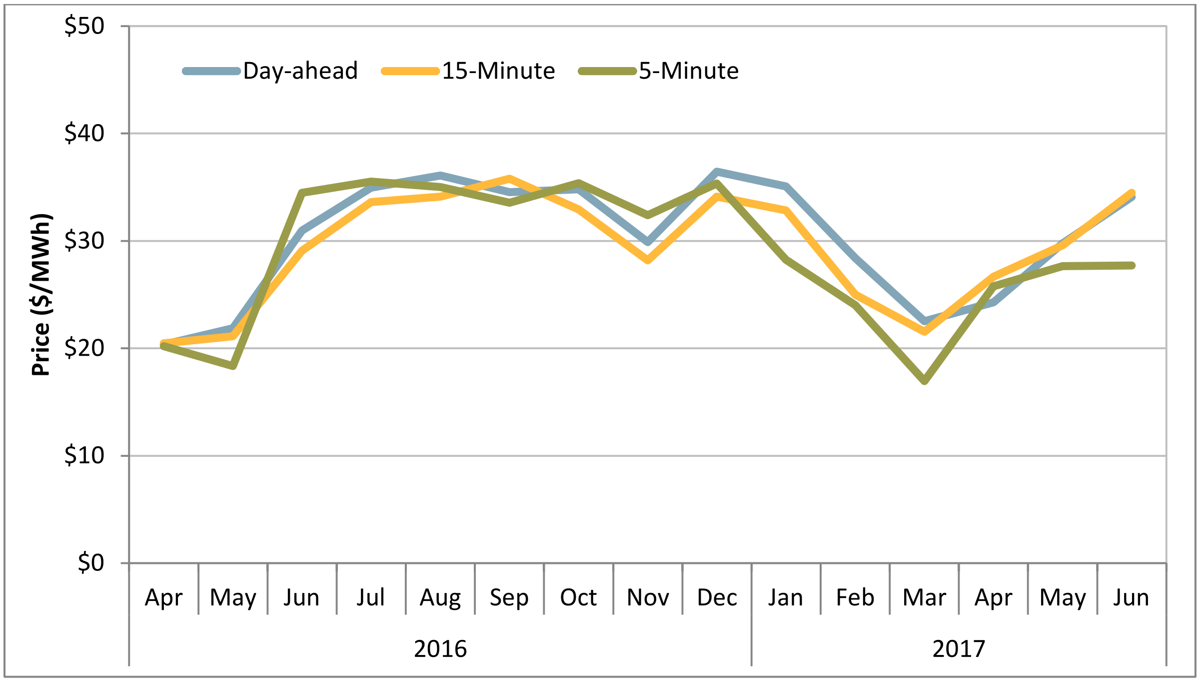
- Energy imbalance market balancing areas continued to fail the upward and downward sufficiency tests regularly during the second quarter. In particular, Puget Sound Energy failed the downward sufficiency test more frequently, during about 13 percent of hours, up from about 3 percent of hours in the previous quarter.
- The ISO and PacifiCorp West were net exporters in the energy imbalance market, while the remaining areas tended to be net importers. The volumes of transfers out of the ISO were very large, on average, during peak solar hours.
- Overall, load adjustments were typically positive in PacifiCorp East, NV Energy, Arizona Public Service and the ISO, while negative load adjustments were frequent in PacifiCorp West. Puget Sound Energy made adjustments infrequently in either direction.
- Three resources received capacity procurement mechanism payments in the second quarter. These payments totaled about $0.4 million, and the largest of these payments was made to the Otay Mesa unit, which received a 155 MW designation at $4.16/kW-month for the later part of May. This designation was made on a day when loads were higher in real-time than expectations.

Energy market performance

This section provides a more detailed summary of energy market performance in the second quarter.

Average energy prices increased during every month of the second quarter. Monthly average day-ahead energy prices increased from less than $23/MWh in March to around $34/MWh in June. This coincided with seasonally higher temperatures and associated higher loads. Prices in the 15-minute market were higher than day-ahead prices by over $2/MWh in April. In the other months, 15-minute market prices were similar to day-ahead prices on average. Prices in the 5-minute market were lower than both day-ahead and 15-minute market prices on average during the quarter. In particular, average 5-minute market prices were lower than average day-ahead and 15-minute market prices by around $2/MWh in May and over $6/MWh in June.

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



The California ISO issued a Grid Stage 1 System Emergency on May 3. For the first time in nearly 10 years, a Grid Stage 1 System Emergency was issued. During this period, operating reserves required by the Western Electricity Coordinating Council dropped below an acceptable level as a result of a combination of circumstances and compounding events leading up to the event.

The day-ahead system marginal energy price reached over $600/MWh on June 21. The ISO market experienced a system-wide heat wave and very high loads from June 19 to June 21. On June 21, the day-ahead market observed record high system marginal energy prices greater than $200/MWh during a five-hour period that peaked at just over $600/MWh when load net of wind and solar was highest. This outcome was primarily driven by tight supply conditions as a result of a number of factors in combination with high demand. On this day, prices appear to have increased following mitigation of bids in the market power mitigation run. Both DMM and the ISO will continue to investigate this issue.

Price spikes were relatively frequent in both the 15-minute and 5-minute markets. The frequency of high prices in the 15-minute market greater than $250/MWh increased significantly to over 0.5 percent of intervals during the quarter as a result of north-to-south congestion on Path 26 as well as the conditions during May 3 and June 19 to 21. In addition, the frequency of extreme 5-minute market prices larger than $750/MWh increased to 0.7 percent of intervals, the highest quarterly frequency since the third quarter of 2012.

Congestion was particularly high in the real-time market. Much of the congestion in the second quarter was due to Path 26 in the north-to-south direction which was binding because of the loss of the Midway – Whirlwind 500 kV line. Overall, day-ahead congestion increased Southern California Edison and San Diego Gas and Electric load area prices by about $0.30/MWh and $0.85/MWh, respectively, while decreasing Pacific Gas and Electric area prices by about $0.40/MWh. Similarly, in the 15-minute market, congestion increased Southern California Edison and San Diego Gas and Electric load area prices by about $1.20/MWh and $1.60/MWh, respectively, while decreasing Pacific Gas and Electric area prices by about $0.50/MWh.

Bid cost recovery payments increased. Overall bid cost recovery payments were $28 million in the quarter, higher than costs during both the prior quarter this year and the same quarter during 2016. Real-time bid cost recovery remains the largest category of bid cost recovery and totaled about $21 million in the second quarter, up from $13 million in the last quarter. Real-time bid cost recovery payments were particularly high on May 3, when the ISO declared a system emergency and many committed resources received large payments. Similar to the second quarter of 2016, bid cost recovery attributed to the day-ahead market totaled about $4 million while bid cost recovery payments for residual unit commitment totaled about $3 million.

Virtual supply revenues were negative. Convergence bidding was profitable overall during the second quarter with combined net revenues of about $2.1 million after accounting for bid cost recovery charges. However, total virtual supply accounted for around $2.4 million in net payments to the market for the quarter, before accounting for bid cost recovery charges. This was only the second quarter that virtual supply was not profitable overall since implementation of convergence bidding in February 2011.

Auction revenues from congestion revenue rights continue to fall short of payments made by ratepayers this quarter. In the second quarter of 2017, congestion revenue rights auction revenues were $18 million less than congestion payments made to non-load-serving entities purchasing these congestion revenue rights. This represents only $0.58 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders, down from $0.65, the annual average in 2016. Financial participants continued to garner the highest profits from CRRs, netting $16 million (paying 41 cents in the auction per dollar of congestion revenue rights revenue). Generators netted about $1 million (paying 50 cents per dollar of revenue), while marketers netted $0.5 million (paying 96 cents per dollar of revenue). Load-serving entities gained about $0.2 million from rights they explicitly sold in the auction in the second quarter of 2017, down from about $1 million in the same quarter of 2016.

Special issues

The ISO implemented market power mitigation enhancements in the 5-minute market on May 2, 2017. Under the new system, congestion is predicted in an advisory 5-minute interval run before the financially binding interval rather than being dependent on congestion in the 15-minute market. This change to the ISO's real-time market power mitigation procedure increased its accuracy and significantly reduced instances of underestimated congestion.

Prices increased following market power mitigation in the day-ahead market. On June 21, day-ahead prices in the day-ahead post-mitigation pricing run were substantially higher than prices in the market power mitigation run through all hours of the peak. The total bid in cost of energy in the binding pricing interval run was about $1 million higher than the as bid cost before market power mitigation. However, energy revenues were almost $25 million greater in the binding integrated forward market than in the market power mitigation run due to the magnified impact that higher prices have on the total market.

Similar discrepancies have occurred on other days in both the day-ahead and real-time markets. The ISO has offered two explanations for this phenomenon: (1) differences in commitment due to reduction in bids in the market power mitigation run and (2) differences in solution due to independence of market runs and solution error tolerance.[1] DMM's review suggests that differences in commitment due to mitigation do not appear to have caused the increase in prices on this day.

The ISO reduced the special Aliso Canyon gas price scalars to zero. The measures adopted by the ISO in response to the Aliso issue included the addition of real-time gas price scalar adjustments for the fuel component of default energy bids (25 percent) and commitment costs bids (75 percent). DMM's analysis of same day natural gas prices in Southern California since these scalars were implemented in July 2016 shows that these adders caused gas prices used to calculate bid caps to exceed prices of all but a very small portion of natural gas transactions. Based on this analysis, DMM recommended the ISO review this issue and lower the scalars. Starting on August 1, the ISO reduced the special Aliso Canyon gas price scalars being applied to commitment cost and default energy bids in the real-time market to zero. The ISO has indicated that it performed its own analysis of this issue, but has not released any more detailed information on the criteria or analysis on the decision to set the gas scalars to zero.

The resource adequacy availability incentive mechanism (RAAIM) became effective in April. The ISO identified a number of issues with the mechanism and is working to correct them. Some of these changes will be put in place in the fall software release and applied retroactively, and some will be released at a later date and will be applied proactively. Current settlements figures for this mechanism remain advisory, and will begin being financially binding after the fall software updates are made.

Key recommendations

Develop enhancement to avoid lowering system-level flexible ramping product prices and procured quantities when inappropriate. In the initial implementation of the flexible ramping product, demand curves for individual balancing areas were included in the constraint for system-level procurement. DMM believes that this implementation approach leads to system-level procurement of flexible ramping capacity, and associated flexible ramping shadow prices, that are lower than what would be consistent with the system-level flexible ramping demand curves. This aspect of the flexible ramping product was active throughout the second quarter. The ISO implemented a software change on July 13, 2017 to limit the use of demand curves from individual balancing areas to zero when sufficient transfer capability connected the area with system conditions. However, the implementation of this enhancement has resulted in market outcomes in which resources providing flexible ramping capacity received lower payments based on the balancing area specific demand curve rather than the system-level demand curve.

Further review differences between pre market power mitigation and binding pricing run results and resolve any potential software errors. As discussed in the special issues section above, prices in the day-ahead market increased substantially following mitigation on June 21, 2017. This condition has occurred on other days as well, but to a lesser degree. If it is determined that solution time and tolerance is indeed the cause of pricing discrepancies, DMM requests that the ISO evaluate revisions to solution time and tolerances in the day-ahead market given the substantial settlement impacts of this case. DMM's standalone environment is not currently capable of replicating market results consistently

[1] "MPM and IFM runs are two different market runs and they produce two completely different solutions which are independent of each other. The bid sets for IFM can be different than that of MPM run due to mitigation leading to mitigated bids. Having a different set of input bids may lead to a slightly different solutions. In the day-ahead market, another complexity is that the market is also solving a unit commitment problem, so when bids are changed in some hours it may actually lead to a different commitment profile which may result in different pricing outcome." Meeting minutes of the market update call August 3, 2017, located here: http://www.caiso.com/Documents/MeetingMinutesMarketUpdateCallAug032017.pdf

and has not been patched to June 21. If possible, DMM requests that the ISO include a replication of market results as part of the ISO's review. If it is determined that a software error resulted in erroneously high prices, DMM requests that the software error be resolved and that the ISO consider the possibility of price corrections.

Modify the process for setting operating reserve requirements to prevent over-procurement. On June 14, the ISO began increasing operating reserve requirements during midday hours to account for a quarter of solar generation in the system by using an existing functionality within the software that allows operators to increase the requirement by a specified percent of the load forecast. The application of these load-based adjustments uniformly across midday hours has often resulted in requirements that are higher than what would be expected using 25 percent of solar, particularly during peak net load hours when solar production is decreasing. DMM recommends that the solar adjustment to operating reserve requirements be adjusted to more granularly approximate real-time solar generation.

1 Market performance

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

- Overall, average day-ahead and 15-minute market prices increased during every month of the second quarter as a result of warmer temperatures and higher loads.
- The California Independent System Operator issued a Grid Stage 1 System Emergency on May 3, for the first time in nearly 10 years.
- The ISO market experienced a system-wide heat wave and very high loads from June 19 to June 21. On June 21, the day-ahead market observed record high system marginal energy prices greater than $200/MWh during a five-hour period that peaked at just over $600/MWh when load net of wind and solar was highest.
- On June 14, the ISO began increasing operating reserve requirements during midday hours to account for solar generation in the system by using an existing functionality within the software that allows operators to increase the requirement by a percent of the load forecast. Since June 14, the operating reserve requirements have been increased during midday hours by an amount adjusted from 2 to 1 to 1.5 percent of the load forecast.
- The frequency of high prices in the 15-minute market greater than $250/MWh increased significantly to over 0.5 percent of intervals during the quarter as a result of north-to-south congestion on Path 26 as well as the conditions on May 3 and June 19 to 21. In addition, the frequency of extreme 5-minute market prices larger than $750/MWh increased to 0.7 percent of intervals, the highest quarterly frequency since the third quarter of 2012.
- The extent to which the power balance constraint could be relaxed for over-supply conditions was reduced from 300 MW to 30 MW on April 11, 2017. Past this point, self-scheduled generation can be curtailed including self-scheduled wind and solar generation. However, during nearly all of the intervals in the second quarter when prices were negative, the market economically dispatched generation down and did not have to relax the power balance constraint or curtail self-scheduled generation.
- The frequency of negative prices during the second quarter decreased in the 15-minute and 5-minute markets. However, solar generation continued to increase and set a new solar peak of 9,914 MW on June 17, 2017.
- In the real-time market, congestion during the second quarter was higher than during any other quarter since the 15-minute market became binding in 2014. Much of the congestion in the second quarter was due to Path 26 in the north-to-south direction which was binding because of the loss of Midway – Whirlwind 500 kV line.
- In the day-ahead market, congestion increased Southern California Edison and San Diego Gas and Electric load area prices by about $0.30/MWh and $0.85/MWh, respectively, while decreasing Pacific Gas and Electric area prices by about $0.40/MWh. Similarly, in the 15-minute market, congestion increased Southern California Edison and San Diego Gas and Electric load area prices by about $1.20/MWh and $1.60/MWh, respectively, while decreasing Pacific Gas and Electric area prices by about $0.50/MWh.

- Bid cost recovery payments were about $28 million in the second quarter, compared to about $22 million in Q2 2016. Real-time bid cost recovery remained the largest category of bid cost recovery and totaled about $21 million, with a large portion of this occurring on a few specific days. Real-time bid cost recovery payments were particularly high on May 3, totaling $0.7 million, when the ISO declared a system emergency and many unit commitments were made in real-time.

- Convergence bidding was profitable overall during the second quarter with combined net revenues of about $2.1 million after accounting for bid cost recovery charges. However, this was just the second quarter that virtual supply was not profitable overall since its implementation in February 2011.

- During the second quarter of 2017, congestion revenue rights auction revenues were $18 million less than congestion payments made to non-load-serving entities purchasing these congestion revenue rights. This represents $0.58 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders, which is lower than $0.63 during the second quarter of 2016.

- Total payments for flexible ramping capacity in the second quarter with the flexible ramping product were about $7.5 million compared to $9.2 million in the previous quarter.

1.1 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 1.1 shows average monthly system marginal energy prices during all hours. As seen in this figure, average prices increased during the second quarter. Prices increased relative to the previous quarter due to seasonally higher temperatures and associated higher loads.

- Average day-ahead and 15-minute market prices increased during every month of the second quarter from around $22/MWh in March to over $34/MWh in June.

- In the second quarter, average 15-minute market prices tracked closely to average day-ahead prices. However, average 15-minute market prices during April were higher than day-ahead prices by over $2/MWh. In the other months during the quarter, average prices between the two markets were largely converged overall.

- Average 5-minute market prices were lower than day-ahead and 15-minute market prices on average during the quarter. In particular, average 5-minute market prices were lower than average day-ahead and 15-minute market prices by around $2/MWh in May and over $6/MWh in June.

Figure 1.1 Average monthly prices (all hours) – system marginal energy price

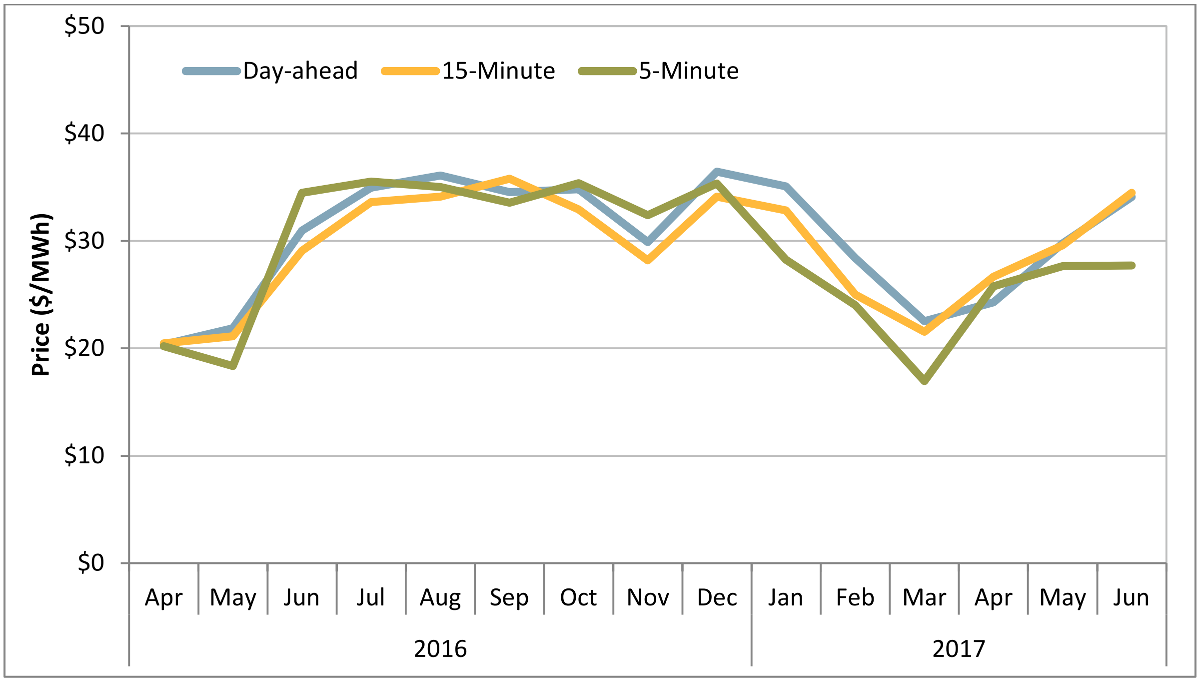


Figure 1.2 Hourly system marginal energy prices

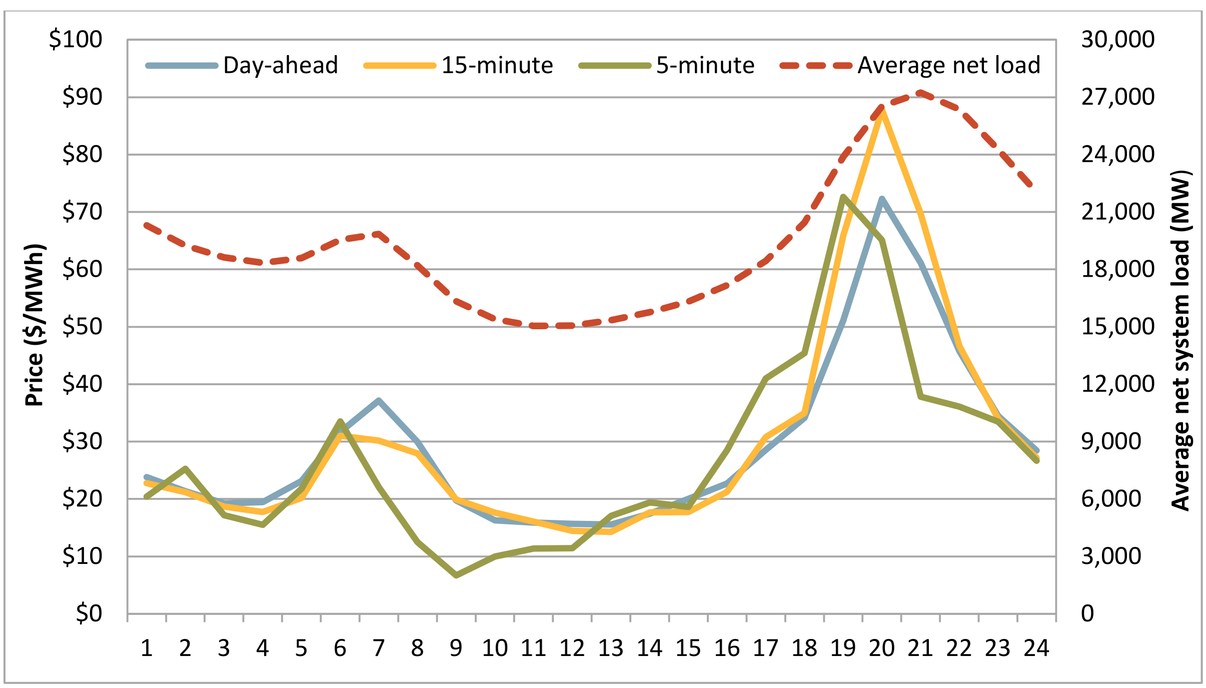


Figure 1.2 illustrates system marginal energy prices on an hourly basis in the second quarter compared to average hourly net load.[2] Prices in this figure generally follow the net load pattern; energy prices were lowest during the early morning, mid-day, and late evening hours, and were highest during the evening peak load hours. Lower prices during the middle of the day corresponded to periods when low-priced solar generation was greatest, and net demand was lowest. As additional solar is built and interconnected with the system, net loads and average system prices during the middle of the day may continue to decrease. This is a result of less expensive units setting prices during periods when net demand is lower, driven by increases in solar or other renewable generation.

Figure 1.2 also shows that average prices in the 15-minute market were as much as $15/MWh higher than average day-ahead market prices during hours ending 19 through 21. This was in part driven by conditions on several key days (May 3 and June 19 to 21) which are discussed in the following sections.

1.2 Description of May 3 events

On May 3, for the first time in nearly 10 years, the California Independent System Operator issued a Grid Stage 1 System Emergency. System emergencies can happen suddenly without notice due to a single large event or develop more gradually due to a combination of events. On May 3, a combination of circumstances and compounding events led to the notice of a Grid Stage 1 Emergency.

Earlier in the day a large resource in Southern California experienced a forced outage of over 300 MW. Although not unusual by itself, this outage set the stage for the hours leading up to the peak net load period. In this period, solar resources were ramping off faster than thermal resources could come on-line in the time period of high system demand. To meet the system demand, the ISO called upon reserves to supply energy, which in turn decreased reliability reserves below acceptable operating reserve levels required by the Western Electricity Coordinating Council (WECC) thus triggering the steps to issue the Grid Stage 1 System Emergency.

To prevent the system emergency a number of steps were taken by the ISO, not limited to, but including:

Contingency dispatch. Two contingency dispatches were issued; the second triggered reliability demand response resources.

Outages. Postponement, cancellation and early return of generation on outage was exercised.

Exceptional dispatches. Attempts were made to obtain all available resources to mitigate the conditions.

Energy imbalance market (EIM). Calls were made to energy imbalance market participants to assess availability.

Intertie availability. The ISO reached out to market participants for additional energy on the interties. Available transmission appears to have restricted some additional energy due to encumbered transmission lines.

Load conformance. Load was conformed up in both hour-ahead and the fifteen-minute markets.

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

Spin/non-spin reserve resources. The ISO called on spin and non-spin reserve resources.

Demand response. Identified potential demand response available.

Once the system emergency was declared, the ISO was able to call upon demand response from investor-owned utilities. A total of about 800 MW of demand response was available by hour ending 21 from Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E).

At 19:45, operating reserves recovered relative to the WECC requirements. At 19:56, the Stage 1 Emergency was terminated for 21:00.

1.3 Description of June 19 to 21 events

High day-ahead market prices

The ISO market experienced a system-wide heat wave and associated high loads towards the end of June with peak loads from June 19 to June 21 reaching above 42,000 MW. During the heat wave, the day-ahead market experienced record high system marginal energy prices greater than $200/MWh on Wednesday, June 21, 2017. These high prices occurred during a five-hour period and peaked around $609/MWh for hour ending 20 when load net of wind and solar was highest.

The following section looks at some of the factors, individually, leading up to the high day-ahead prices on June 21. This outcome was primarily driven by tight supply conditions during the hour in combination with high demand associated with the extreme temperatures.

Figure 1.3 shows the cumulative incremental bids from generation, imports, and virtual supply for hour ending 20 on June 21 relative to the days leading up to it.[3] On June 21, there was a downward shift in supply bids in the day-ahead market during these peak hours due to a number of factors. These factors include changes in variable energy resource forecasts, outages, imports, and virtual supply. The combination of these factors resulted in a thinner bid stack during a period with already stressed conditions due to the heat. For hour ending 20, there were around 2,500 MW fewer incremental bids from these sources at or below $100/MWh on June 21 from the previous day.

[3] Figure 1.3 and Figure 1.4 only show the incremental amounts for each bid and therefore do not account for the generation associated with the minimum operating levels of the resources. Self-scheduled generation and imports are depicted on the chart at -$190/MWh for illustrative purposes.

Figure 1.3 Comparison of incremental supply bids between June 18 and June 21, 2017 Hour 20

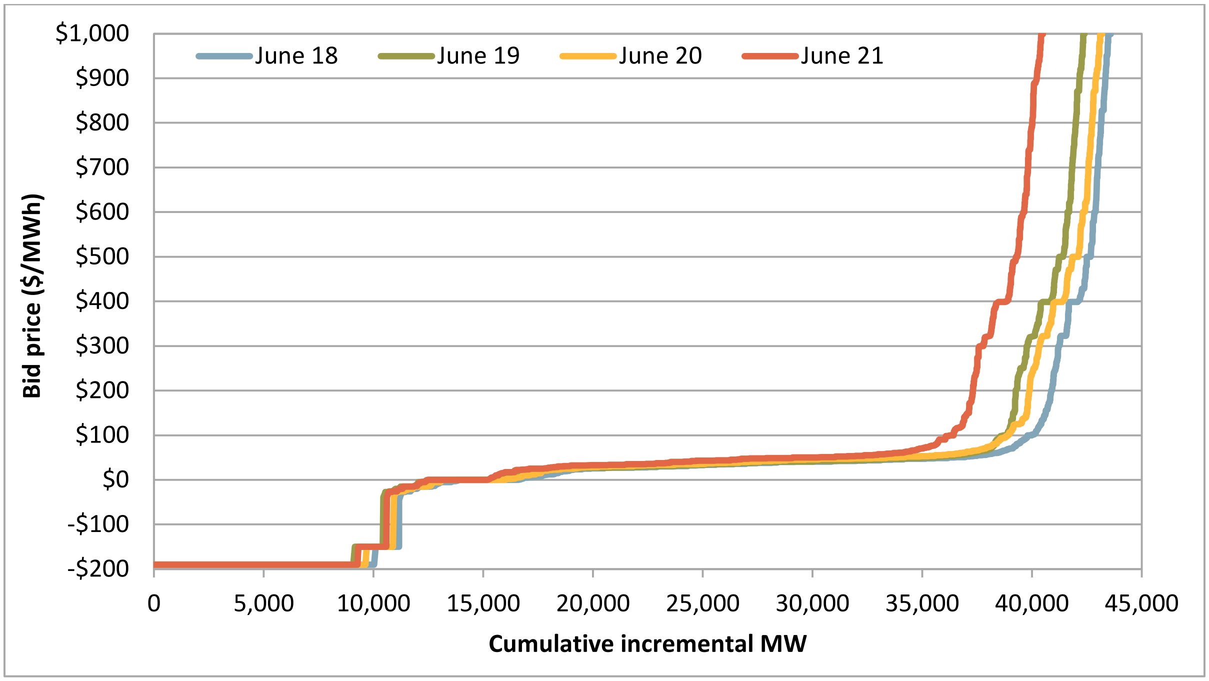


Figure 1.4 through Figure 1.6 show the cumulative incremental bids for generation, virtual supply, and imports, respectively, in the day-ahead market during hour ending 20. As shown in Figure 1.4, there was a significant downward shift in incremental bids from generation between June 20 and June 21. Between these days, generation that was bid in below $100/MWh decreased by around 800 MW. Total unavailable outage capacity further compounded the tight supply conditions that occurred on June 21, but otherwise was not significantly high nor unusual. In addition, wind forecasts were lower than the previous day and below average for the quarter.

Figure 1.5 shows the cumulative incremental bids for virtual supply in the day-ahead market. Between June 20 and June 21, there was a significant downward shift of around 1,100 MW in virtual supply bid-in at or below $100/MWh. Here, participants engaging in convergence bidding continued to move instead toward virtual demand positions in anticipation of tight supply and demand conditions as well as high prices in real-time. Further, between $100/MWh and $1,000/MWh, the supply stack in the day-ahead market is largely composed of virtual supply bids. For hour ending 20 on June 21, the high $609/MWh system marginal energy price was set by a virtual supply bid from a financial participant.

As shown in Figure 1.6, intertie imports offered in the day-ahead market during the high net load hour decreased significantly from June 18 to June 19 by around 2,100 MW and remained relatively low during the remaining days of the heat wave. In addition, price insensitive intertie exports bid into the market increased in this period. During these days, temperatures and loads across the west were extremely high which caused tight supply conditions and high prices throughout the entire region and influenced these changes in intertie activity.

Figure 1.4 Comparison of incremental generation bids between June 18 and June 21, 2017

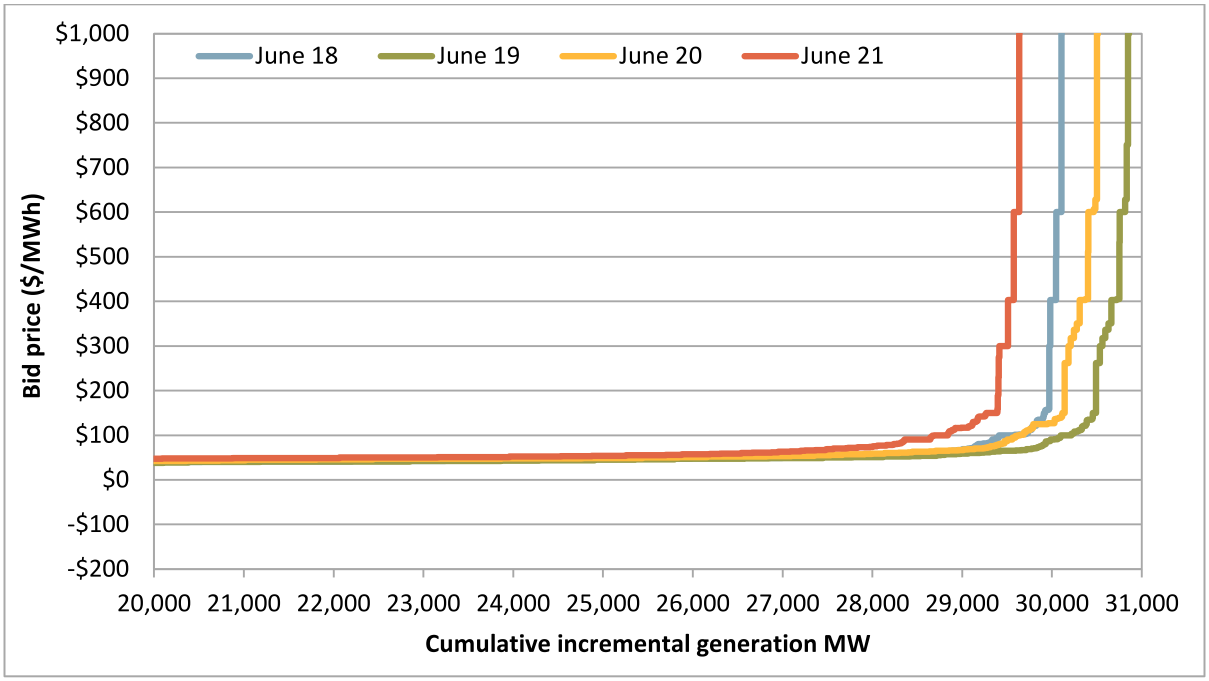


Figure 1.5 Comparison of virtual supply bids between June 18 and June 21, 2017

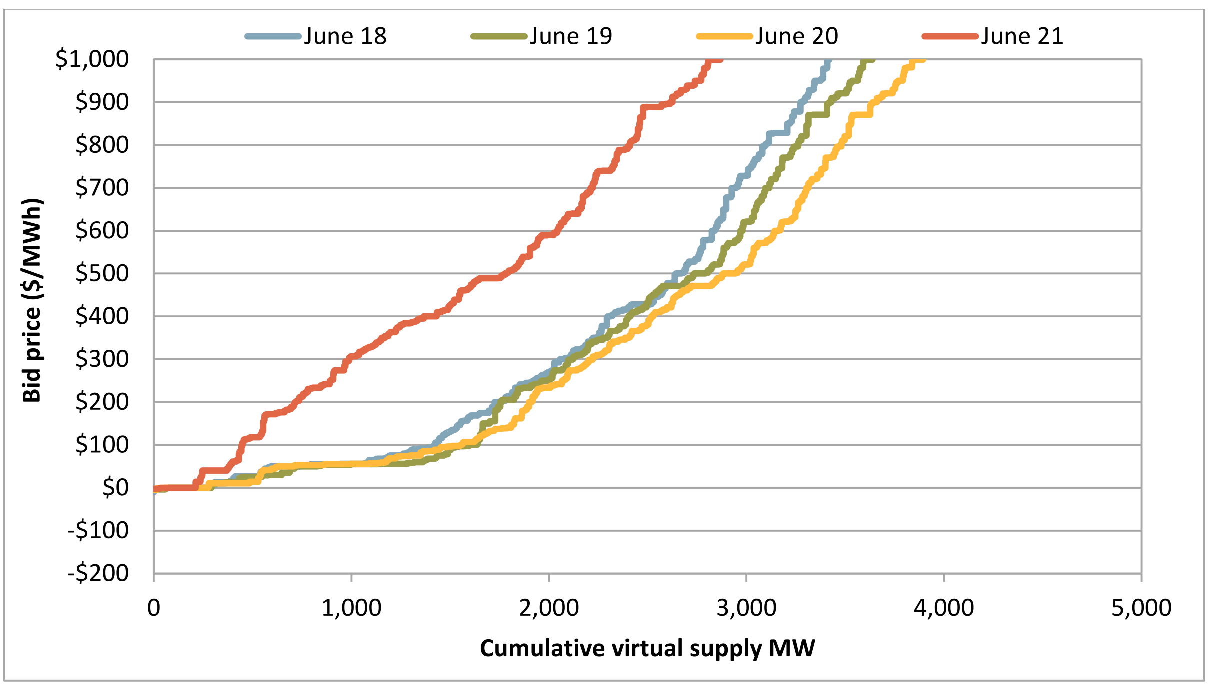
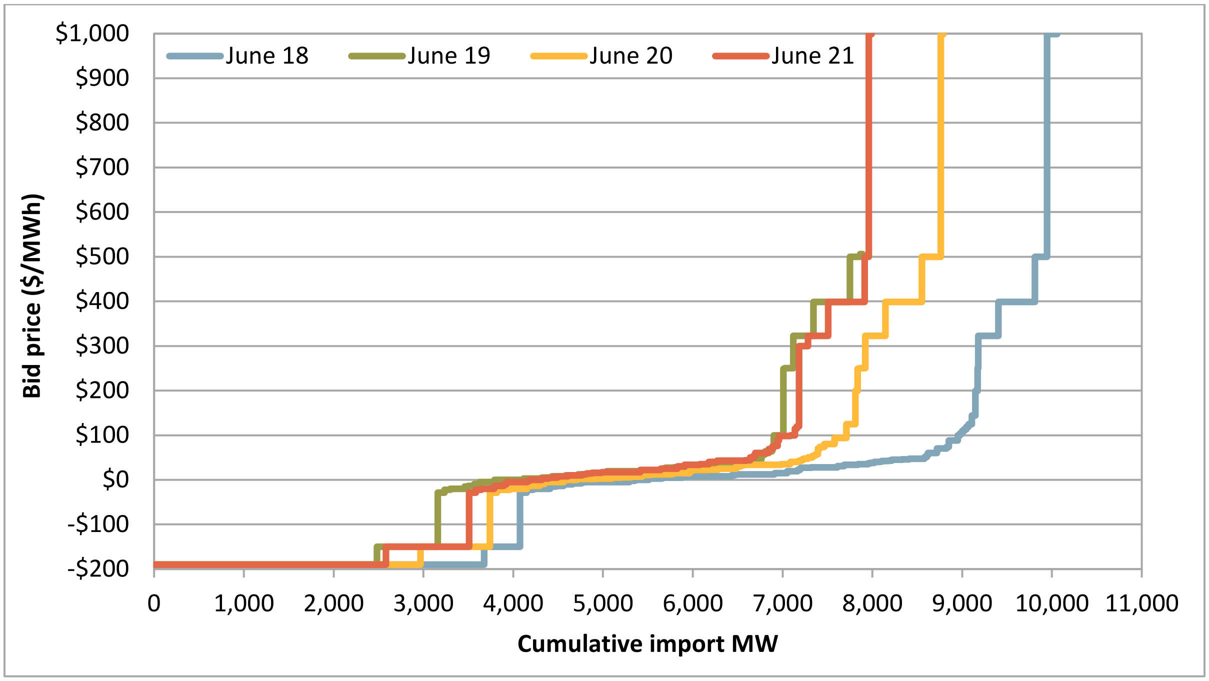


Figure 1.6 Comparison of import bids between June 18 and June 21, 2017



Operating reserve requirements and scarcity events during June

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.

In compliance with FERC Order No. 789, the ISO modified its operating reserve requirement in October 2014 to be consistent with WECC's new operating reserve standards. Since October 2014, procurement requirements in real-time for operating reserves have typically been set to the maximum of the sum of 3 percent of the load forecast and 3 percent of generation and the single most severe contingency. Day-ahead operating reserve requirements have typically been set to the maximum of (1) about 6.3 percent of the load forecast and (2) the single most severe contingency. Further, operators can increase the percent specified for the load forecast component of the calculations to exceed reliability requirements. The total operating reserve requirements are then typically split equally between spinning and non-spinning reserves.

On June 8, the North American Electric Reliability Corporation published a report that found a previously unknown reliability risk related to a frequency measurement error that can potentially cause a large loss of solar generation. Although the operating reserve requirements did not change, the ISO made an upward adjustment to the operating reserve requirements starting with trade date June 14 to account for potential loss of solar generation in the system. The ISO has indicated that the new total operating reserve requirements were set to the maximum of (1) the NERC or WECC required operating reserves and (2) up to 25 percent of total solar production.[4]

[4] *Market Notice – California ISO Temporary Increase Procurement of Operating Reserves*, July 12, 2017: http://www.caiso.com/Documents/CaliforniaISOTemporaryIncreaseProcurement-OperatingReserves.html

However, this functionality does not currently exist in the software. Instead, beginning June 14, operators have increased the percent specified for the load forecast component of the calculation during midday hours to very roughly meet the new solar criteria using the existing tools available within the software. Between June 14 and June 20, a 2 percent load forecast adder was used. Between June 21 and June 24, this was reduced to 1 percent. Since June 25, a 1.5 percent load forecast adder has been used.[5]

Figure 1.7 shows *actual* hourly average operating reserve requirements between June 14 and June 30 with the application of the load forecast adders as well as *estimated* hourly average operating reserve requirements during the same period without any adjustment to the requirement.[6] The figure also includes 25 percent of real-time solar forecasts as a point of comparison. Between June 14 and June 30, the application of these load-based adjustments has often resulted in requirements that are higher than what would be expected using 25 percent of solar, particularly during peak net load hours when solar production is decreasing. DMM recommends that the ISO modify their operating reserve requirement setting process to prevent over-procurement. Specifically, DMM recommends that adjustments to operating reserve requirements intended to reflect solar generation be more granularly based on a forecast of approximate real-time solar generation.

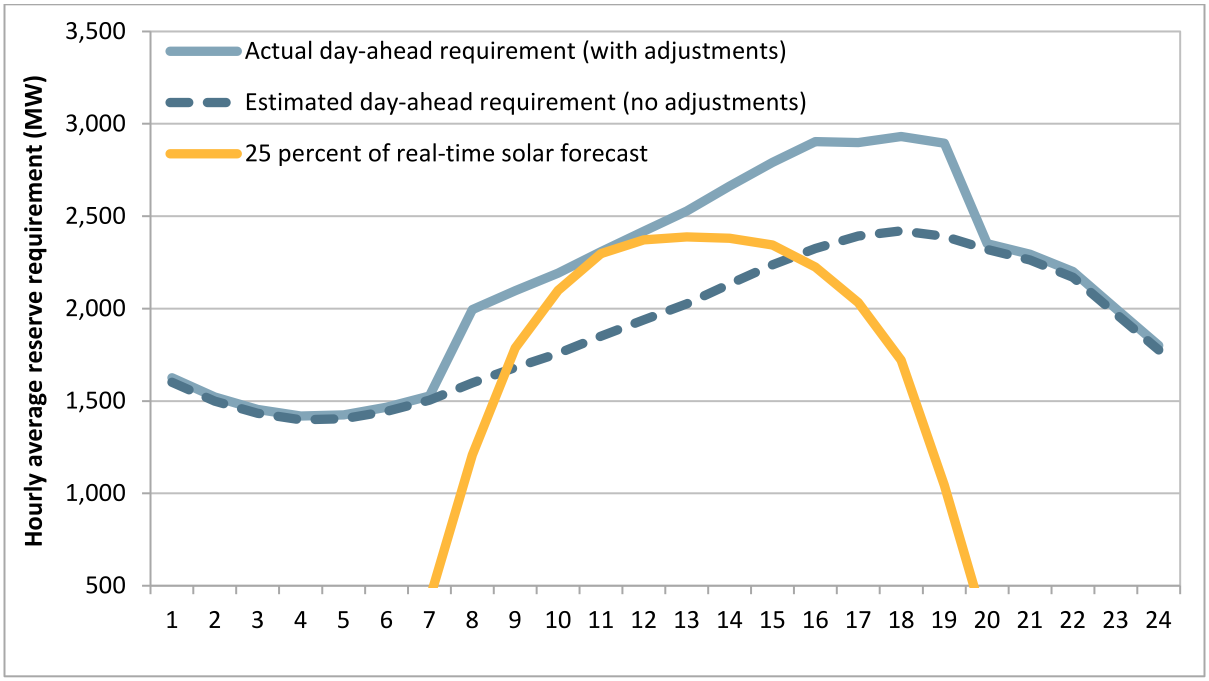
During the peak of the heat wave between June 19 and June 21, high day-ahead operating reserve requirements as a result of the adders entered into the calculation further compounded the tight supply conditions and prices in the market. In real-time, the load forecast adders were removed by operators on June 20, but otherwise had a similar impact on supply conditions on June 19 and June 21.

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. During these three days in June, 14 scarcity intervals occurred when there were shortages for procurement of non-spinning reserves in the expanded ISO region. In the same period, operators blocked a large number of ancillary service awards consisting of mostly day-ahead non-spinning awards. In real-time, the market attempted to replace this capacity by procuring an equivalent amount of mostly spinning reserves from other resources instead.

5 The load forecast adders applied to the operating reserve requirement have been applied uniformly across midday hours. Between June 14 and June 27, the adders were mostly applied between hours ending 8 and 19. Beginning on June 28, an improvement was made by instead applying the adders only between hours ending 8 and 16.

6 The load forecast adders applied in day-ahead have also been typically applied in real-time for the same hours. In Figure 1.7, corresponding values for the real-time requirement are not included, but show a similar pattern, though at slightly lower values.

Figure 1.7 Hourly average operating reserve requirements (June 14 - June 30)



Peak load and resource adequacy in June

Figure 1.8 shows daily peak loads during the second half of June. Loads from June 19 through June 21 between hours ending 16 and 20 were all above 42,000 MW with load peaking at around 44,200 MW on June 20, 2017. This peak load was about 6 percent lower than the ISO's 2017 1-in-2 year (or median) peak load forecast of 46,877 MW.[7] System resource adequacy requirements were set at about 41,100 MW for June. Procurement on the day of the peak was around 43,500 MW with around 38,700 MW (about 89 percent) available in the day-ahead market during the peak load hour.

The ISO works with the California Public Utilities Commission and other local regulatory authorities to set system level resource adequacy requirements. System resource adequacy provisions require load-serving entities to procure generation capacity to meet their forecasted peak load in each month plus a 15 percent planning reserve margin.[8] Load-serving entities meet this requirement by providing resource adequacy showings to the ISO on a year-ahead basis due in October and provide 12 month-ahead showings during the compliance year. Resource adequacy capacity must then be bid into the ISO markets through a must-offer requirement.

Figure 1.8 includes system resource adequacy requirements for June (yellow line). This value, about 41,100 MW, is substantially less than 115 percent of the ISO's 2017 1-in-2 year forecast of peak load, 53,908 MW. During the peak load period of June, the sum of monthly 1-in-2 peak load estimates for resource adequacy requirement setting provided by the California Energy Commission, 37,900 MW, was

[7] For further details, see: http://www.caiso.com/Documents/2017SummerAssessment.pdf

[8] The 115 percent requirement is designed to include the additional operating reserve needed above peak load plus an allowance for outages and other resource limitations.

less than both day-ahead forecast of load and actual load. System resource adequacy requirements are also adjusted to account for demand response. In June, these adjustments reduced requirements by over 2,000 MW. In addition, some load-serving entities have resource adequacy requirements calculated with a planning reserve margin less than 15 percent.

Around half of the capacity counted toward system resource adequacy requirements must be bid into the market for each hour of the month except when this capacity is reported to the ISO as being unavailable because of outages. This includes most gas-fired generation and imports, with a total capacity of around 21,000 MW during June. If the market participant does not submit bids, the ISO automatically creates bids for these resources.

The remaining capacity counted toward the system resource adequacy requirements does not have to offer the full resource adequacy capacity in all hours of the month. These resources are required to be available to the market consistent with their operating limitations. These include hydro, use-limited thermal, qualifying facilities, nuclear, wind, solar, demand response and other resources.[9]

The red bars in Figure 1.8 show the total amount of resource adequacy capacity used to meet resource adequacy requirements in June. Scheduling coordinators are incentivized to make resource adequacy capacity available in the market during only *availability assessment hours* through the resource adequacy availability incentive mechanism.[10] For June, these are for hours ending 14 through 18 on non-weekend days. These hours do not necessarily align with hours when loads are highest. In particular, the availability assessment hours exclude two of the highest load hours during the June heat wave with hours ending 19 and 20.

The blue bars in Figure 1.8 show the amount of resource adequacy capacity that was available in the day-ahead market through either a self-schedule or an economic bid during the peak load hour of the day. Differences between the resource adequacy capacity (red bars) and the available resource adequacy capacity in the day-ahead market (blue bars) were mostly driven by solar, wind, hydro, and nuclear resources, which have particular operating limitations.

Between June 19 and June 22, day-ahead load forecasts were significantly above real-time forecasts and actual load as shown in Figure 1.8. In particular, peak day-ahead load forecasts were between 1,000 and 3,000 MW more than actual peak load on these days. Further, both resource adequacy capacity showings and availability in the day-ahead market fell below peak day-ahead load forecasts and actual load between June 19 and June 21.

In addition, the ISO issued Flex Alerts on June 20 and June 21 as a preliminary precaution for the high loads. Flex Alerts urge consumers to voluntarily conserve electricity and are communicated through press releases, text messages, and other means.

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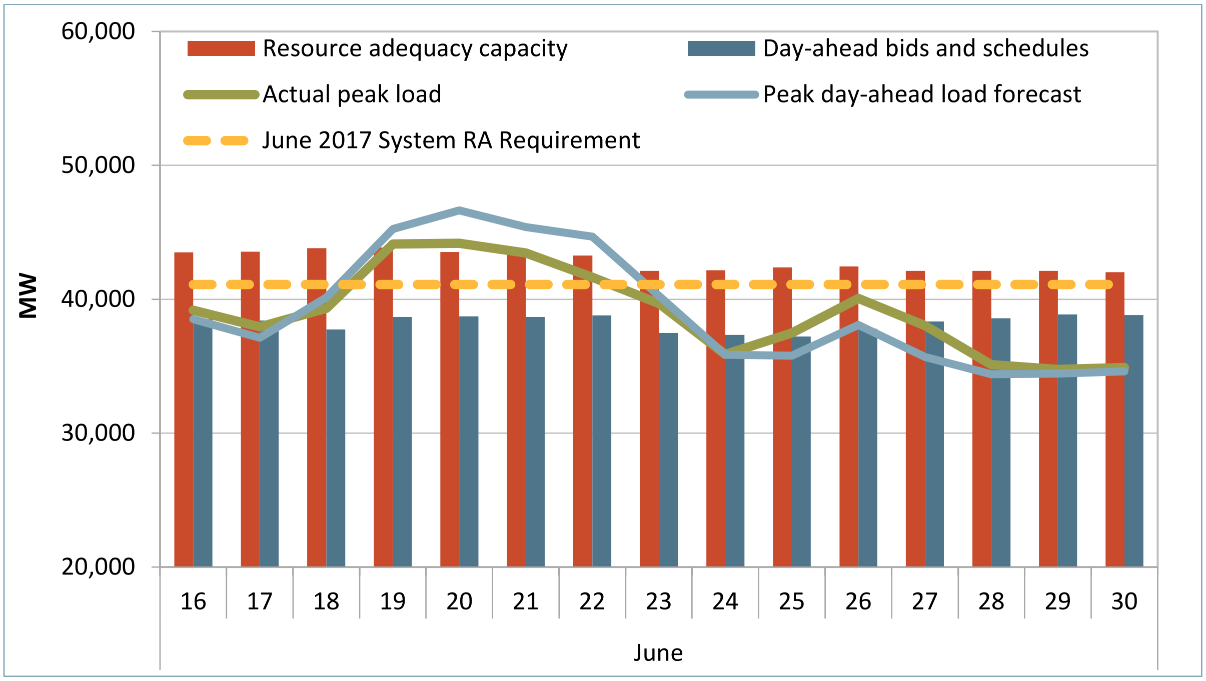
9 Use-limited thermal resources generally have environmental, regulatory or technical restrictions on the hours they can operate, such as a maximum number of operating hours or a maximum number of start-ups and shutdowns in a month or year. Market participants submit use plans to the ISO for these resources. These plans describe their restrictions and outline their planned operation.

10 See Section 4.4.1 for further discussion on the resource adequacy availability incentive mechanism.

Figure 1.8 June daily peak load, resource adequacy capacity, and planning forecast



1.4 Real-time price variability

Real-time market prices can be highly volatile with periods of extreme positive and negative prices. Even a short period of extremely high or low prices can have a significant impact on average prices. During the quarter, most of the extreme prices occurred as a result of very high or negatively priced bids clearing the market. In some instances, extremely high or low prices were the result of relaxing the power balance constraint to resolve the feasibility of the dispatch.

High prices

The frequency of high prices in the 15-minute market increased significantly during the quarter compared to both the prior quarter and the second quarter of 2016. As shown in Figure 1.9, prices above $250/MWh occurred during over 0.5 percent of 15-minute intervals in the second quarter, compared to less than 0.1 percent of intervals in the second quarter of 2016 and the first quarter of 2017. Most of these price spikes were larger than $750/MWh and occurred between hours ending 19 and 21 as a result of north-to-south congestion on Path 26 as well as the conditions on May 3 and June 19 to 21.

As shown in Figure 1.10, the frequency of price spikes in the 5-minute market greater than $250/MWh also increased from the previous quarter.

Figure 1.9 Frequency of high 15-minute prices by month

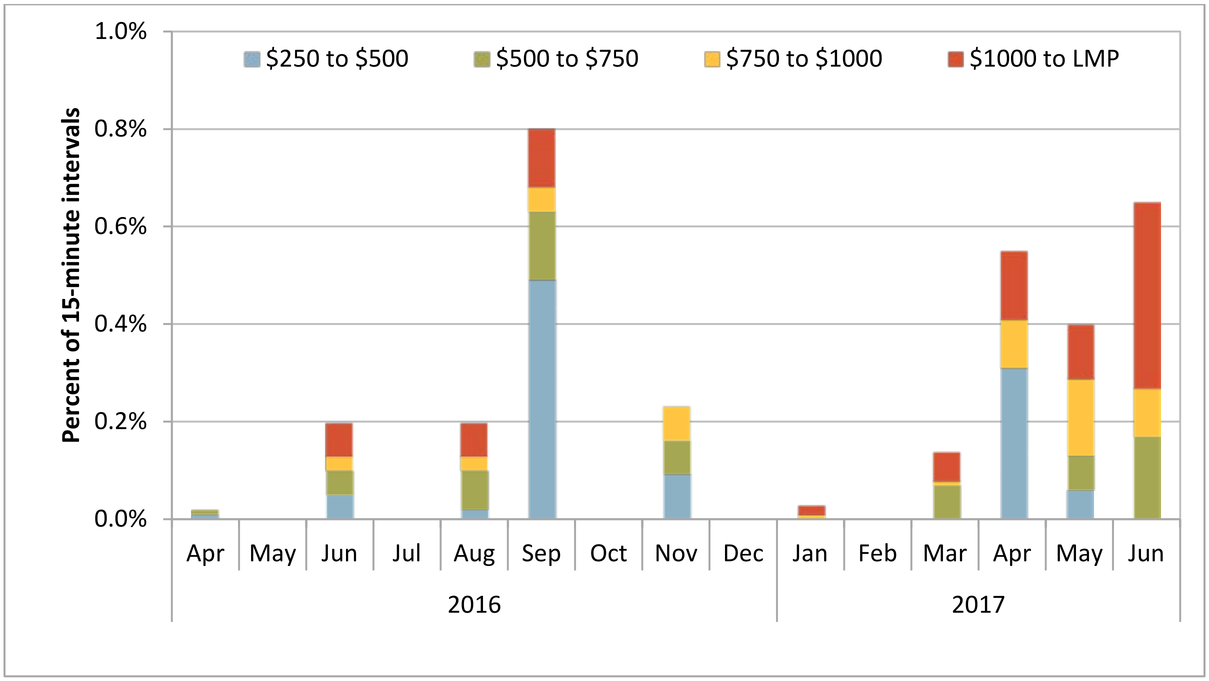
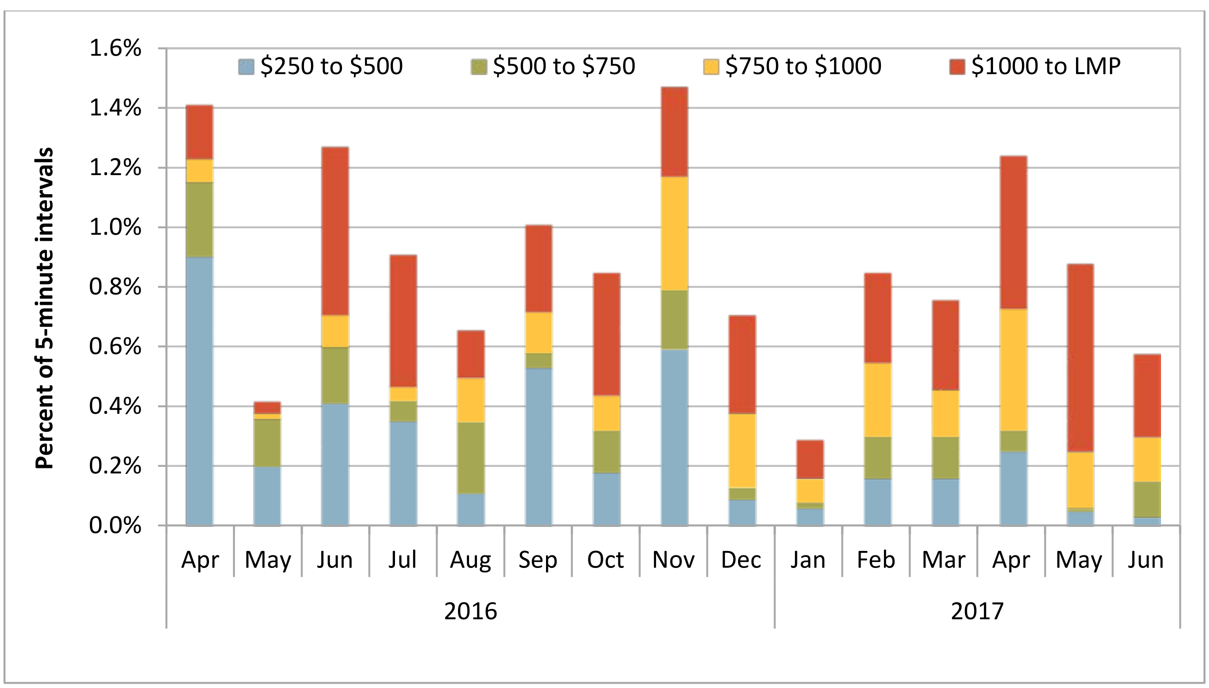


Figure 1.10 Frequency of high 5-minute prices by month



However, the frequency of more extreme 5-minute market prices larger than $750/MWh was more notable. In particular, 5-minute market prices larger than $750/MWh occurred during about 0.7 percent of intervals during the quarter. This was the highest quarterly frequency in the 5-minute market since the third quarter of 2012. These price spikes were most concentrated between hours ending 16 and 20 when supply conditions were tight while ramping to meet evening peak loads. However, it is noteworthy that during April, when loads were lowest, price spikes in the 5-minute market were actually more frequent than they were in May and June. This was mostly due to congestion on Path 26 in the north-to-south direction to account for an outage on the Midway – Whirlwind 500 kV line. This line returned to service at the end of April.

Negative prices

When a generator is dispatched down economically the market arrives at a solution by matching supply and demand. Units with negative bids can be dispatched down accordingly. During these intervals the market continues to function efficiently, and the least expensive generation serves load, while more expensive generation is dispatched down.

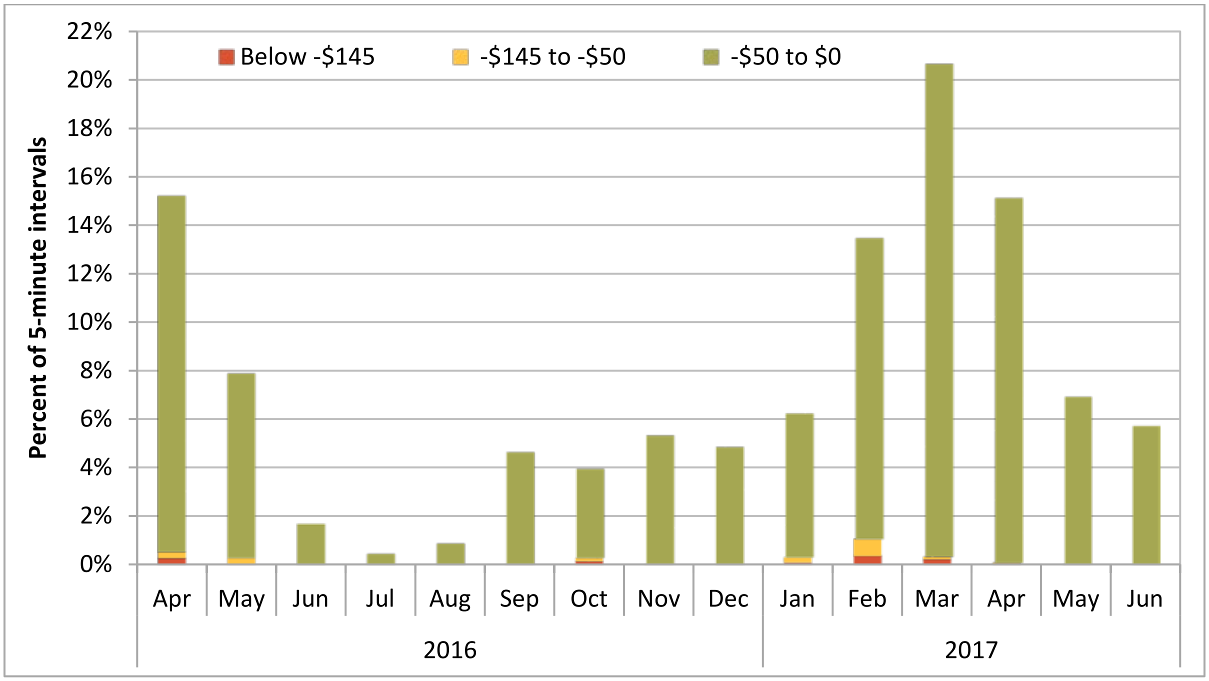
Figure 1.11 shows the frequency of negative prices in the 5-minute market by month.[11] Negative prices were most frequent in April during the quarter, at about 15 percent of intervals, when loads were lowest. Most of the negative prices in the 15-minute and 5-minute markets were between -$50/MWh and $0/MWh and were the result of economic bids from renewable generation, particularly market participating solar resources, setting market prices.

When the supply of economic bids to decrease energy are exhausted, the power balance constraint can be relaxed to reflect the role regulation plays in balancing the system. Effective April 11, 2017, the extent to which the constraint could be relaxed for over-supply conditions was reduced to 30 MW, down from 300 MW. Past this, self-scheduled generation can be curtailed including self-scheduled wind and solar generation. However, during nearly all of the intervals in the second quarter when prices were negative, the market economically dispatched generation down and did not have to relax the power balance constraint or curtail self-scheduled generation. During the second quarter, the frequency of prices near or below the -$150/MWh floor occurred during significantly less than 0.1 percent of intervals.

Negative prices during the quarter were most frequent between hours 8 and 16, when net demand was low and solar generation was greatest. During these hours negative prices occurred during over 15 percent of intervals in the 5-minute market. Solar generation set a new record at just over 9,900 MW and averaged just over 8,800 MW during midday hours, compared to about 6,800 during the second quarter of 2016.

[11] Corresponding values for the 15-minute market with Figure 1.11 show a similar pattern but lower percentages of intervals.

Figure 1.11 Frequency of negative 5-minute prices by month



1.5 Congestion

In the real-time market, congestion during the second quarter was higher than during any other quarter since the 15-minute market became binding in 2014. Much of the congestion in the second quarter was due to Path 26 in the north-to-south direction which was binding because of the loss of Midway – Whirlwind 500 kV line. In the day-ahead market, congestion increased Southern California Edison and San Diego Gas and Electric load area prices by about $0.30/MWh and $0.85/MWh, respectively, while decreasing Pacific Gas and Electric area prices by about $0.40/MWh. Similarly, in the 15-minute market, congestion increased Southern California Edison and San Diego Gas and Electric load area prices by about $1.20/MWh and $1.60/MWh, respectively, while decreasing Pacific Gas and Electric area prices by about $0.50/MWh.

1.5.1 Congestion impacts of individual constraints

Day-ahead congestion

The overall frequency of congestion continued to decline in the day-ahead market.[12] The most frequently binding constraint in the Pacific Gas and Electric area was the Round Mountain – Table Mountain 500 kV constraint which bound during a total of 2 percent of all hours. When this constraint bound, the impact increased Pacific Gas and Electric area prices by about $2/MWh and decreased Southern California Edison and San Diego Gas and Electric area prices by approximately the same

12 *Q1 2017 Report on Market Issues and Performance*, March 2017, pp. 18: http://www.caiso.com/Documents/2017FirstQuarterReport-MarketIssuesandPerformance.pdf

amount. This congestion was primarily the result of an outage on the Round Mountain – Table Mountain #2 line which returned to service late June, 2017.

In the Southern California Edison area, Path 26 (6410_CP5_NG) and Path 15 (6310_CP3_NG) constraints were the most frequently binding constraints in the north-to-south direction.[13] Congestion on Path 26 was primarily a result of an outage on Midway – Whirlwind 500 kV line which returned to service at the end of April 2017. The Path 15 nomogram was enforced to mitigate for the loss of Los Banos – Tesla 500 kV and Los Banos – Tracy 500 kV lines. Path 26 was binding in 7 percent of the intervals and increased Southern California Edison and San Diego Gas and Electric area prices by $5/MWh and decreased Pacific Gas and Electric area prices by about $7 MWh. When Path 15 bound in 5 percent of the intervals, it had a relatively smaller impact on all the load area prices.

In the San Diego Gas and Electric area, most of the congestion in the second quarter of 2017 was due to the Imperial Valley nomogram (7820_TL 230S_OVERLOAD_NG) which is modeled to mitigate for the contingency of Imperial Valley – North Gila 500 kV line. This constraint was binding during approximately 8 percent of hours, having a price impact of $4/MWh in the San Diego Gas and Electric area and no impact on the Southern California Edison area.

Table 1.1 Impact of congestion on day-ahead prices during congested hours[14]

		Frequency	Q2		
Area	Constraint	Q2	PG&E	SCE	SDG&E
PG&E	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	2.3%	$2.08	-$2.11	-$2.64
	33020_MORAGA _115_30550_MORAGA _230_XF_3 _P	0.7%	$3.82	-$3.77	-$3.77
	40687_MALIN _500_30005_ROUND MT_500_BR_1 _3	0.6%	$2.04	-$1.88	-$2.56
SCE	6410_CP5_NG	7.1%	-$6.65	$5.37	$5.08
	6310_CP3_NG	5.1%	-$0.44	$0.38	$0.34
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	0.4%	-$1.14	$1.28	
SDG&E	7820_TL 230S_OVERLOAD_NG	8.3%	-$0.28		$3.58
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	1.5%			-$6.50
	22604_OTAY _69.0_22616_OTAYLKTP_69.0_BR_1 _1	1.5%			$1.18
	7820_TL23040_IV_SPS_NG	1.3%	-$0.52		$8.24
	OMS 4602677 50002_OOS_TDM	0.8%			$3.78
	22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1	0.7%			$8.69
	22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1	0.7%			$8.76
	7820_TL 230S_TL50001OUT_NG	0.7%	-$0.48		$5.59
	22886_SUNCREST_230_92860_SUNC TP1_230_BR_1 _1	0.5%	-$1.00		$7.35
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	0.4%	-$5.12	$3.24	$8.53

15-minute market congestion

In the 15-minute market, congestion on most constraints occurred less frequently than in the day-ahead market, but often had larger effects on prices. This is typical of congestion patterns in the real-time

13 Peak RC process update – New naming convention for nomograms, Market Performance and Planning forum, slide 7: http://www.caiso.com/Documents/Agenda-Presentation-MarketPerformance-PlanningForum-Mar14_2017.pdf

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

market and is similar to patterns in recent quarters. Table 1.2 shows the frequency and magnitude of 15-minute market congestion for the quarter.

In the Pacific Gas and Electric area, similar to the day-ahead market, Round Mountain – Table Mountain 500 kV constraint bound most frequently during the second quarter at about 4 percent of intervals. When binding, it increased Pacific Gas and Electric area prices by about $9/MWh and decreased Southern California Edison and San Diego Gas and Electric area prices by $4/MWh.

In the Southern California Edison area, Path 26 (6410_CP5_NG) in the north-to-south direction bound frequently at 5 percent of intervals. When it bound, it increased Southern California Edison and San Diego Gas and Electric area prices by about $16/MWh while decreasing Pacific Gas and Electric area price by $20/MWh. It was binding because the Path 26 limit was conformed to account for an outage on the Midway – Whirlwind 500 kV line.

Similarly, in the San Diego Gas and Electric area, as mentioned earlier, the Imperial Valley constraint bound most frequently at about 1 percent of all intervals. When binding, the constraint increased San Diego Gas and Electric area prices by about $28/MWh but had significantly less effect on Pacific Gas and Electric and Southern California Edison load area prices.

As shown in Table 1.2, frequently binding constraints in the ISO such as the Path 26 and Round Mountain – Table Mountain constraints have had a significant impact on 15-minute energy imbalance market area prices. The frequency and impact of congestion in the 5-minute market is similar to that of the 15-minute market.

Table 1.2 Impact of congestion on 15-minute prices during congested intervals[15]

		Frequency	Q2							
Area	Constraint	Q2	PG&E	SCE	SDG&E	PACE	PACW	NEVP	PSEI	AZPS
PG&E	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	3.6%	$8.53	$4.32	$3.69	-$9.12	-$26.10	-$1.87	-$26.16	$2.28
	OMS_3831815_TMS_DLO	1.4%	$2.03	$1.92	$1.11	-$3.59	-$13.03		-$15.04	$0.88
	40687_MALIN _500_30005_ROUND MT_500_BR_1 _3	0.8%	$6.66	$2.63	$2.13	-$7.03	-$19.54	-$1.64	-$20.24	$1.62
	30797_LASAGUIL_230_30790_PANOCHE _230_BR_2 _1	0.3%	$9.81							
	RM_TM21_NG	0.3%	$7.05	$3.49	$2.81	-$8.47	-$22.14		-$22.19	
SCE	6410_CP5_NG	4.7%	-$20.28	$16.60	$15.77	$0.40	-$15.20	$7.51	-$14.95	$14.13
	6310_CP3_NG	1.6%	-$2.59	$2.77	$2.55	-$0.71	-$4.44	$0.87	-$4.42	$2.17
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _2	0.7%	-$22.27	$14.47	$13.85		-$17.62	$7.04	-$17.46	$12.16
SDG&E	7820_TL 230S_OVERLOAD_NG	1.3%		$1.40	$28.23	-$2.97	-$0.72	-$2.45	-$0.66	-$6.41
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	1.0%			-$11.70					-$10.02
	7820_TL 230S_TL50001OUT_NG	0.4%		$0.97	$17.34	-$2.06		-$1.70		-$4.39

1.5.2 Impact of congestion on average prices

This section provides an assessment of differences between overall average regional prices in the day-ahead and 15-minute markets caused by congestion between different areas of the ISO system. The analysis provided in the previous section focused only on hours where congestion was present. This section is based on the average congestion component as a percent of the total price during all congested and non-congested intervals. This approach shows the impact of congestion when taking into

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

account both the frequency with which congestion occurs and the magnitude of the impact.[16] The congestion price impact differs across load areas and markets.

The impact of congestion on each pricing node in the ISO system can be 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 can be done for individual nodes, as well as for groups of nodes that represent different load aggregation points or local capacity areas.

Day-ahead price impacts

Table 1.3 shows the overall impact of day-ahead congestion on average prices in each load area during the quarter by constraint.[17] The impact of congestion increased San Diego Gas and Electric and Southern California Edison area prices by about $0.85/MWh (2.8 percent) and $0.31/MWh (1.1 percent), respectively, and decreased Pacific Gas and Electric area prices by about $0.40/MWh (1.3 percent). As mentioned earlier, Path 26 (6410_CP5_NG) constraint had the highest impact, increasing San Diego Gas and Electric and Southern California Edison area prices by about $0.40/MWh and decreasing Pacific Gas and Electric area prices by about $0.50/MWh.

Table 1.3 Impact of congestion on overall day-ahead prices

	PG&E		SCE		SDG&E	
Constraint	**$/MWh**	**Percent**	**$/MWh**	**Percent**	**$/MWh**	**Percent**
6410_CP5_NG	-$0.47	-1.61%	$0.38	1.30%	$0.36	1.19%
7820_TL 230S_OVERLOAD_NG	-$0.02	-0.08%			$0.30	0.98%
30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	$0.05	0.16%	-$0.04	-0.13%	-$0.06	-0.20%
7820_TL23040_IV_SPS_NG	-$0.01	-0.02%			$0.11	0.35%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					-$0.10	-0.32%
24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.02	-0.07%	$0.01	0.05%	$0.04	0.12%
22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1					$0.06	0.21%
22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1					$0.06	0.21%
6310_CP3_NG	-$0.02	-0.08%	$0.02	0.07%	$0.02	0.06%
22886_SUNCREST_230_92860_SUNC TP1_230_BR_1 _1	-$0.01	-0.02%			$0.04	0.13%
7820_TL 230S_TL50001OUT_NG	$0.00	-0.01%			$0.04	0.13%
40687_MALIN _500_30005_ROUND MT_500_BR_1 _3	$0.01	0.05%	-$0.01	-0.04%	-$0.02	-0.05%
30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.01	0.04%	-$0.01	-0.04%	-$0.01	-0.03%
OMS 4602677 50002_OOS_TDM					$0.03	0.10%
33020_MORAGA _115_30550_MORAGA _230_XF_3 _P	$0.03	0.09%	$0.00	-0.01%	$0.00	-0.01%
22604_OTAY _69.0_22616_OTAYLKTP_69.0_BR_1 _1					$0.02	0.06%
OMS_4596757_LBN_NRAS	$0.00	0.02%	$0.00	-0.01%	$0.00	-0.01%
30435_LAKEVILE_230_30460_VACA-DIX_230_BR_1 _1	$0.01	0.04%				
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.01	-0.02%	$0.01	0.02%		
Other	$0.08	0.26%	-$0.04	-0.15%	-$0.04	-0.12%
Total	**-$0.37**	**-1.26%**	**$0.31**	**1.05%**	**$0.85**	**2.78%**

[16] This approach identifies price differences caused by congestion and does not include price differences that result from transmission losses at different locations.

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

15-minute price impacts

Table 1.4 shows the overall impact of 15-minute congestion on average prices in each load area in the quarter by constraint.[18] Congestion during the second quarter increased San Diego Gas and Electric and Southern California Edison area prices by about $1.60/MWh (5 percent) and $1.20/MWh (3.7 percent), respectively, and decreased Pacific Gas and Electric area prices by about $0.50/MWh (1.5 percent). This impact was higher than during any other quarter since the 15-minute market became binding in 2014. Similar to the day-ahead market, Path 26 constraint in the north-to-south direction had a major impact on all of the load area prices. This nomogram has been enforced to mitigate for the loss of Midway – Whirlwind 500 kV line which returned to service at the end of April 2017.

Table 1.4 Impact of congestion on overall 15-minute prices

	PG&E		SCE		SDG&E	
Constraint	**$/MWh**	**Percent**	**$/MWh**	**Percent**	**$/MWh**	**Percent**
6410_CP5_NG	-$0.95	-3.15%	$0.78	2.47%	$0.74	2.28%
30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	$0.31	1.02%	$0.16	0.50%	$0.13	0.41%
7820_TL 230S_OVERLOAD_NG			$0.02	0.05%	$0.37	1.13%
30060_MIDWAY _500_24156_VINCENT _500_BR_2 _2	-$0.15	-0.48%	$0.09	0.30%	$0.09	0.28%
6310_CP3_NG	-$0.04	-0.14%	$0.04	0.14%	$0.04	0.13%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					-$0.11	-0.35%
30630_NEWARK _230_30635_NWK DIST_230_BR_1 _1	$0.06	0.19%	-$0.03	-0.08%	-$0.03	-0.08%
40687_MALIN _500_30005_ROUND MT_500_BR_1 _3	$0.05	0.17%	$0.02	0.07%	$0.02	0.05%
92320_SYCA TP1_230_22832_SYCAMORE_230_BR_1 _1					$0.08	0.25%
7820_TL 230S_TL50001OUT_NG			$0.00	0.01%	$0.07	0.21%
30635_NWK DIST_230_30731_LS ESTRS_230_BR_1 _1	$0.06	0.21%	$0.00	-0.01%	$0.00	-0.01%
OMS_3831815_TMS_DLO	$0.03	0.09%	$0.03	0.08%	$0.02	0.05%
22886_SUNCREST_230_92860_SUNC TP1_230_BR_1 _1					$0.07	0.21%
24092_MIRALOMA_500_24093_MIRALOM _230_XF_4 _P	-$0.02	-0.05%	$0.02	0.06%	$0.02	0.07%
30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.02	0.06%	-$0.02	-0.06%	-$0.02	-0.05%
6310_CP2_NG	-$0.02	-0.06%	$0.02	0.06%	$0.02	0.05%
30440_TULUCAY _230_30460_VACA-DIX_230_BR_1 _1	$0.05	0.16%				
6410_CP1_NG	-$0.02	-0.06%	$0.01	0.04%	$0.01	0.04%
RM_TM21_NG	$0.02	0.07%	$0.01	0.03%	$0.01	0.03%
22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1					-$0.04	-0.13%
22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1					$0.04	0.11%
30797_LASAGUIL_230_30790_PANOCHE _230_BR_2 _1	$0.03	0.11%				
30435_LAKEVILE_230_30460_VACA-DIX_230_BR_1 _1	$0.03	0.10%				
37585_TRCY PMP_230_30625_TESLA D _230_BR_1 _1	$0.02	0.05%	-$0.01	-0.03%	-$0.01	-0.02%
Other	$0.05	0.17%	$0.01	0.03%	$0.12	0.38%
Total	**-$0.46**	**-1.53%**	**$1.16**	**3.67%**	**$1.63**	**5.04%**

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

Internal congestion in the energy imbalance market

Table 1.5 shows the frequency of congestion on internal constraints in the energy imbalance market since 2014. Compared to the previous quarter, internal congestion in PacifiCorp East and NV Energy declined significantly in the second quarter of 2017. In the 15-minute market, congestion dropped from 16 percent to 4 percent in the PacifiCorp East area and from 10 percent to around 2 percent in the NV Energy area. Frequency of congestion followed a similar trend in the 5-minute market. In the rest of the energy imbalance market areas, internal congestion was low, even after an increased number of constraints were enforced following FERC's November 19, 2015, Order.[19]

Persistent low congestion may be a result of the following:

- Each energy imbalance market area may be incorporating some degree of congestion management in their process when making forward unit commitments and developing base schedules.
- Bids may be structured in such a way as to limit or prevent congestion within an energy imbalance market area.
- Within the PacifiCorp areas, physical limits on local constraints, which are modeled in the full network model, may not be fully reflective of contractual limits that may be enforced through generating base schedules and the amount offered from some resources.

These reasons appear plausible because almost all of the generation within each energy imbalance market area is scheduled by a single entity.

Table 1.5 Percent of intervals with congestion on internal EIM constraints

	2014	2015				2016				2017	
	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2
15-minute market (FMM)											
PacifiCorp East	0.1%	0.2%	0.2%	0.5%	2.6%	2.2%	0.2%	1.3%	14.9%	16.1%	4.3%
PacifiCorp West	0.1%	0.0%	0.0%	0.2%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%	0.1%
NV Energy					0.0%	0.0%	0.1%	0.3%	3.2%	10.3%	1.8%
Puget Sound Energy									0.0%	0.0%	0.0%
Arizona Public Service									0.0%	0.0%	0.0%
5-minute market (RTD)											
PacifiCorp East	0.0%	0.3%	0.2%	0.4%	2.3%	2.2%	0.2%	1.3%	15.2%	17.1%	3.3%
PacifiCorp West	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.0%	0.1%
NV Energy					0.0%	0.0%	0.2%	0.3%	3.2%	11.7%	1.6%
Puget Sound Energy									0.0%	0.0%	0.0%
Arizona Public Service									0.0%	0.0%	0.0%

19 *Order on Proposed Market-Based Rate Tariff Changes*, November 19, 2015, ER15-2281-000: https://www.ferc.gov/whats-new/comm-meet/2015/111915/E-5.pdf.

1.6 Bid cost recovery

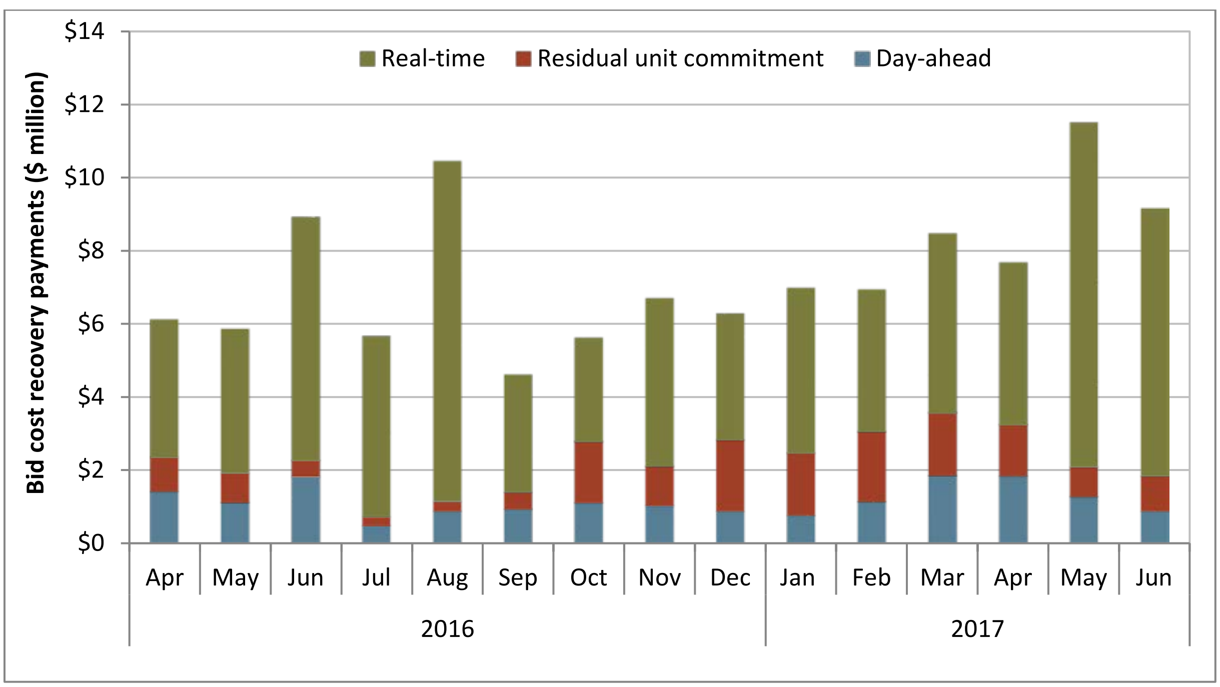
Estimated bid cost recovery payments for the second quarter totaled about $28 million, the highest total payment for a quarter since 2013. This amount was significantly larger than the total amount of bid cost recovery in the previous quarter and the second quarter of 2016, when they were about $22 million. A significant amount of the bid cost recovery payments were accrued in the real-time market on a few days during May.

Bid cost recovery attributed to the day-ahead market totaled about $4 million, or about the same as the prior quarter and the second quarter of 2016. Bid cost recovery payments for residual unit commitment during the quarter totaled about $3 million, or about the same as average payments from the prior year.

Bid cost recovery attributed to the real-time market totaled about $21 million, or about $7 million larger than payments in the first quarter of 2017 and $7 million larger than payments in the second quarter of 2016. In May, real-time payments were over $9 million with real-time payments totaling more than $1 million on May 3 and May 23. Additionally, there were several other days during the month when payments were unusually high. In recent quarters these costs have been much more uniformly spread out across all days. On May 3, the day the ISO declared a system emergency, many units committed received payments greater than $50,000.

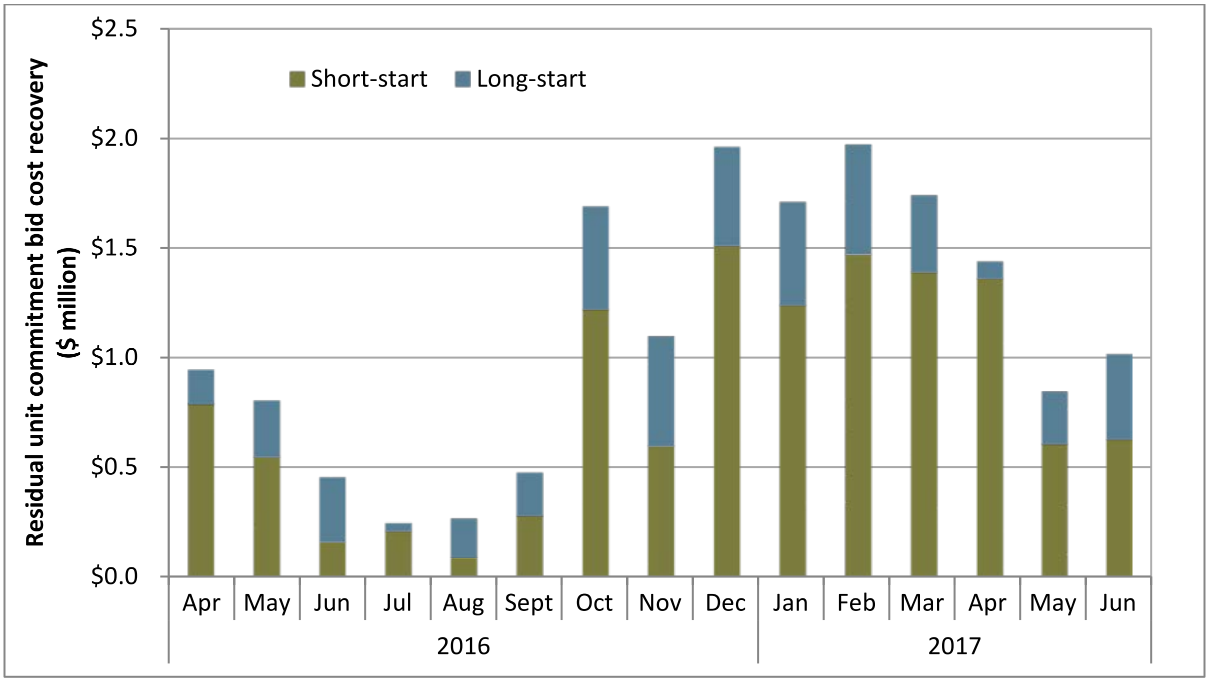
As shown in Figure 1.13, after netting against real-time revenues in the second quarter of 2017, short-start and long-start resources received about $2.6 million and $0.7 million, respectively, for residual unit commitment bid cost recovery payments, down from about a total of $5.4 million in the prior quarter.[20]

Figure 1.12 Monthly bid cost recovery payments



[20] Residual unit commitment bid cost recovery charges are calculated by netting residual unit commitment shortfalls with real-time surpluses in revenue. The same methodology is used in calculating virtual bidding bid cost recovery charges.

Figure 1.13 Residual unit commitment bid cost recovery payments by commitment type



1.7 Convergence bidding

Convergence bidding was slightly profitable overall during the second quarter. However, this was only the second quarter that virtual supply was not profitable since convergence bidding implementation in February 2011. Net revenues from the market during the quarter were about $4.2 million. Virtual demand generated net revenues of about $6.6 million, while virtual supply accounted for approximately $2.4 million in net payments to the market. Combined net revenues for virtual supply and demand fell to about $2.1 million after including about $2.1 million of virtual bidding bid cost recovery charges.

Offsetting virtual demand with supply bids at different locations is designed to profit from higher anticipated congestion between these locations in the real-time market. This type of offsetting bid represented only about 41 percent of all accepted virtual bids in the second quarter, up from 32 percent in the previous quarter.

1.7.1 Convergence bidding trends

Average hourly cleared volumes increased slightly in the second quarter to about 2,300 MW from about 2,100 MW during the previous quarter. However, average hourly virtual supply continued to decrease during the quarter to about 1,400 MW compared to around 1,500 MW in the previous quarter and 2,000 MW in the second quarter of 2016. Virtual demand averaged around 900 MW during each hour of the quarter, up from around 600 MW in the previous quarter. On average, about 37 percent of virtual supply and demand bids offered into the market cleared in the second quarter, which is up from 31 percent in the previous quarter.

Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 560 MW on average, which decreased from 850 MW of net virtual supply in the previous quarter. Virtual supply exceeded virtual demand during both peak and off-peak hours by about 610 MW and 470 MW, respectively. On average for the quarter, net cleared virtual demand exceeded net cleared virtual supply in only hour ending 21. In the remaining 23 hours, net cleared virtual supply exceeded net cleared virtual demand. The highest net cleared virtual supply hour was hour ending 13 when around 1,000 MW more virtual supply cleared than virtual demand.

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 16 of 24 hours.

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 460 MW of virtual demand offset by 460 MW of virtual supply in each hour of the quarter. These offsetting bids represented about 41 percent of all cleared virtual bids in the second quarter, up from about 32 percent in the previous quarter.

1.7.2 Convergence bidding revenues

Participants engaged in convergence bidding in the second quarter were slightly profitable overall. Net revenues for convergence bidders before accounting for bid cost recovery charges were about $4.2 million. Net revenues for virtual supply and demand fell to about $2.1 million after including about $2.1 million of virtual bidding bid cost recovery charges.

Virtual supply and demand bids are treated similarly to physical supply and demand in the day-ahead market. However, virtual bids are excluded from the day-ahead market processes for price mitigation and grid reliability (local market power mitigation and residual unit commitment). This impacts how physical supply is committed in both the integrated forward market and in the residual unit commitment process.[21] When the ISO commits units, it may pay market participants through the bid cost recovery mechanism to ensure that market participants are able to recover start-up, minimum load, transition, and energy bid costs.

Because virtual bids can influence unit commitment, they share any associated costs. Specifically, virtual bids can be charged bid cost recovery payments under two charge codes.

[21] If physically generating resources clearing in the day-ahead energy market are less than the ISO's forecasted demand, the residual unit commitment process ensures that enough additional physical capacity is available to meet the forecast demand. Convergence bidding increases unit commitment requirements to ensure sufficient generation in real time when the net position is virtual supply. The opposite is true when virtual demand exceeds virtual supply.

- Integrated forward market bid cost recovery tier 1 allocation addresses costs associated with situations when the market clears with positive net virtual demand. In this case, virtual demand leads to increased unit commitment in the day-ahead market, which may not be economic.
- Day-ahead residual unit commitment tier 1 allocation relates to situations where the day-ahead market clears with positive net virtual supply. In this case, virtual supply leads to decreased unit commitment in the day-ahead market and increased unit commitment in the residual unit commitment, which may not be economic.

Figure 1.14 shows total monthly net revenues for virtual supply (green bar), total net revenues for virtual demand (blue bar), the total amount paid for bid cost recovery charges (red bar), and the total payments for all convergence bidding inclusive of bid cost recovery charges (gold line). This chart shows that residual unit commitment costs paid for by convergence bidders increased from the previous quarter, as a result of higher overall residual unit commitment costs during the first quarter.

Before accounting for bid cost recovery charges:

- Total market revenues were positive during all three months in the quarter. Monthly net revenues during the second quarter totaled about $4.2 million, compared to about $5.7 million during the same quarter in 2016, and about $4.6 million during the previous quarter.
- Virtual supply net revenues were positive in May but were negative in April and June. In total, virtual supply accounted for around $2.4 million in net payments to the market for the quarter, before accounting for bid cost recovery charges. This was only the second quarter virtual supply was not profitable overall since convergence bidding began in 2011.
- Virtual demand net revenues were slightly negative in May but were positive in April and June. In total, virtual demand generated net revenues of about $6.6 million during the quarter.

After accounting for bid cost recovery charges:

- Convergence bidders were paid about $2.1 million after subtracting bid cost recovery charges of about $2.1 million for the quarter.[22,23] Bid cost recovery charges were about $0.7 million in April, $0.5 million in May, and $0.9 million in June.

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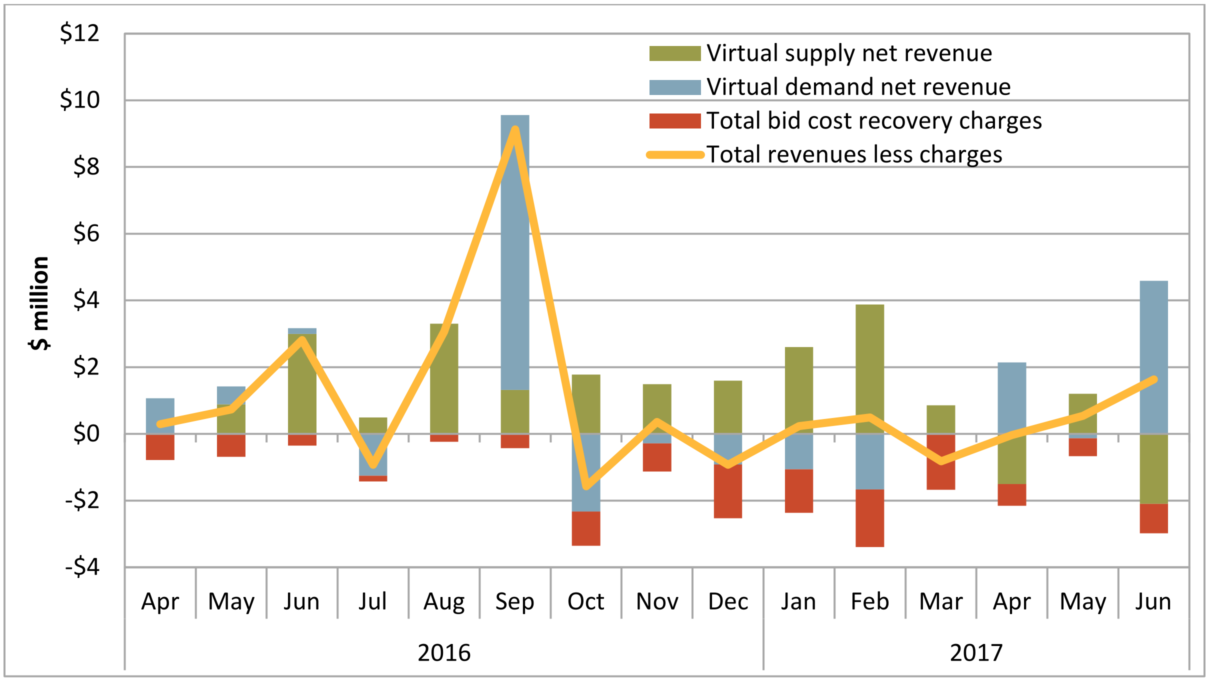
22 Further detail on bid cost recovery and convergence bidding can be found here, p.25: http://www.caiso.com/Documents/DMM_Q1_2015_Report_Final.pdf.

23 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.

Figure 1.14 Convergence bidding revenues and bid cost recovery charges



Net revenues and volumes by participant type

Table 1.6 compares the distribution of convergence bidding cleared volumes and net revenues, in millions of dollars, among different groups of convergence bidding participants in the first quarter.[24] As shown in Table 1.6, financial entities represented the largest segment of the virtual bidding market, accounting for about 55 percent of volume and about 67 percent of settlement revenue. Marketers represented about 31 percent of the trading volumes, but only 14 percent of the settlement revenue. Generation owners and load-serving entities represented a smaller segment of the virtual market in terms of volumes (about 14 percent) but a larger segment of settlement dollars (about 20 percent).

[24] 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.

Table 1.6 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	528	714	1,242	$4.09	-$0.52	$3.58
Marketer	301	405	706	$2.00	-$1.27	$0.73
Physical load	0	281	281	$0.00	-$0.58	-$0.58
Physical generation	21	12	33	$0.51	-$0.02	$0.49
Total	**850**	**1,413**	**2,263**	**$6.6**	**-$2.4**	**$4.2**

1.8 Congestion revenue rights

As discussed in DMM's 2016 annual report, since 2012 electric ratepayers – who ultimately pay for the cost of transmission managed by the ISO – received an average of about $114 million less per year in revenues from the congestion revenue rights auction compared to the congestion payments made to entities purchasing these rights.[25] During the second quarter of 2017, congestion revenue rights auction revenues were $18 million less than congestion payments made to non-load-serving entities purchasing these rights. This represents $0.58 in auction revenues paid to transmission ratepayers for every dollar paid out to auctioned rights holders, which is lower than $0.63 during the second quarter of 2016.

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.

The owners of transmission – or entities paying for the cost of building and maintaining transmission – are entitled to congestion revenues associated with transmission capacity in the day-ahead market. 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).[26] The ISO charges load-serving entities the transmission access charge in order to reimburse the entity that builds each transmission line for the costs incurred.

Load-serving entities then pass that transmission access charge through to ratepayers in their customers' electricity bills. Therefore, these ratepayers are entitled to the revenues from this transmission. When auction revenues are less than payments to other entities purchasing congestion revenue rights at auction, the difference between auction revenues and congestion payments

[25] *2016 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2017, pp. 191-204, 243-245: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.

[26] 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.

represents a loss to ratepayers. The losses therefore cause ratepayers, who ultimately pay for the transmission, to receive less than the full value of their day-ahead transmission rights.

As explained in DMM's 2016 annual report, DMM believes that the ratepayer gains or losses from the auction is the appropriate metric for assessing the congestion revenue right auction.[27]

Analysis of congestion revenue right auction returns

As described above, the performance of the congestion revenue rights auction can be assessed by comparing the auction revenues ratepayers received to the ratepayer payments to non-load-serving entities purchasing congestion revenue rights in the auction. Note that payments and charges to ratepayers are through load-serving entities. Figure 1.15 compares the following:

- auction revenues received by ratepayers from non-load-serving entities purchasing congestion revenue rights in the auction (blue bars on left axis);
- net payments from ratepayers to non-load-serving entities purchasing congestion revenue rights in the auction (green bars on left axis); and
- auction revenues received by ratepayers as a percentage of the net payments to non-load-serving entities purchasing congestion revenue rights in the auction (yellow line on right axis).

Ratepayers lost a total of $18 million during the second quarter of 2017 as payments to auctioned congestion revenue rights holders exceeded auction revenues. This was an increase from nearly $16 million ratepayers lost during the same quarter in 2016.

Auction revenues were only 58 percent of payments made to non-load-serving entities during second quarter of 2017, down from 63 percent during the second quarter of 2016.

[27] *2016 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2017, pp. 243-245: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.

Figure 1.15 Auction revenues and payments to non-load-serving entities

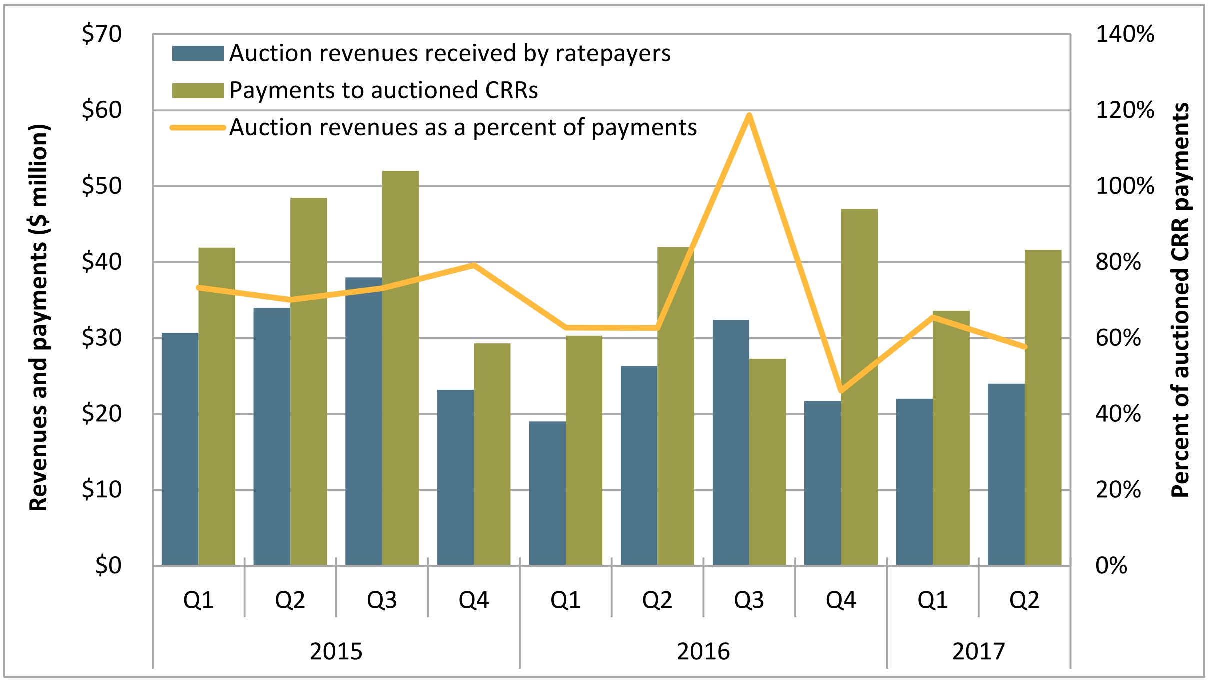


Figure 1.16 through Figure 1.19 show quarterly auction revenues paid to all entities purchasing rights in the auction compared to payments they received broken out by the following entity types:

- Financial entities participate in the ISO markets only through the convergence bidding and congestion revenue right products.
- Marketers participate in the ISO energy markets primarily through intertie transactions, rather than generators or loads internal to the ISO.
- Physical generation and load have generators and loads within the ISO footprint.

Similar to Figure 1.15, these charts show quarterly auction revenues and congestion revenue rights payments from 2015 through the second quarter of 2017. Highlights from these figures show the following for the second quarter of 2017:

- Financial entities continued to have the highest profits between the entity types, at approximately $16 million. This was an increase from $14 million in the second quarter of 2016. Marketer profits were $0.5 million, down from $2 million during the same quarter in 2016. Generator profits were $1 million, up from a loss of $0.5 million in the second quarter of 2016.
- Financial entities paid 41 cents in auction revenue per dollar received compared to 49 cents paid in 2016. Generators paid 50 cents per dollar received, down from $1.2 in 2016. Marketers paid 96 cents, up from 82 cents in 2016.
- Load-serving entities were the only auction participant type that, on net, continued to sell rights into the auction from explicit bidding. Load-serving entities gained about $0.20 million from rights they

explicitly sold in the auction in the second quarter of 2017, down from $1 million in the same quarter of 2016.

Figure 1.16 Auction revenues and payments (financial entities)

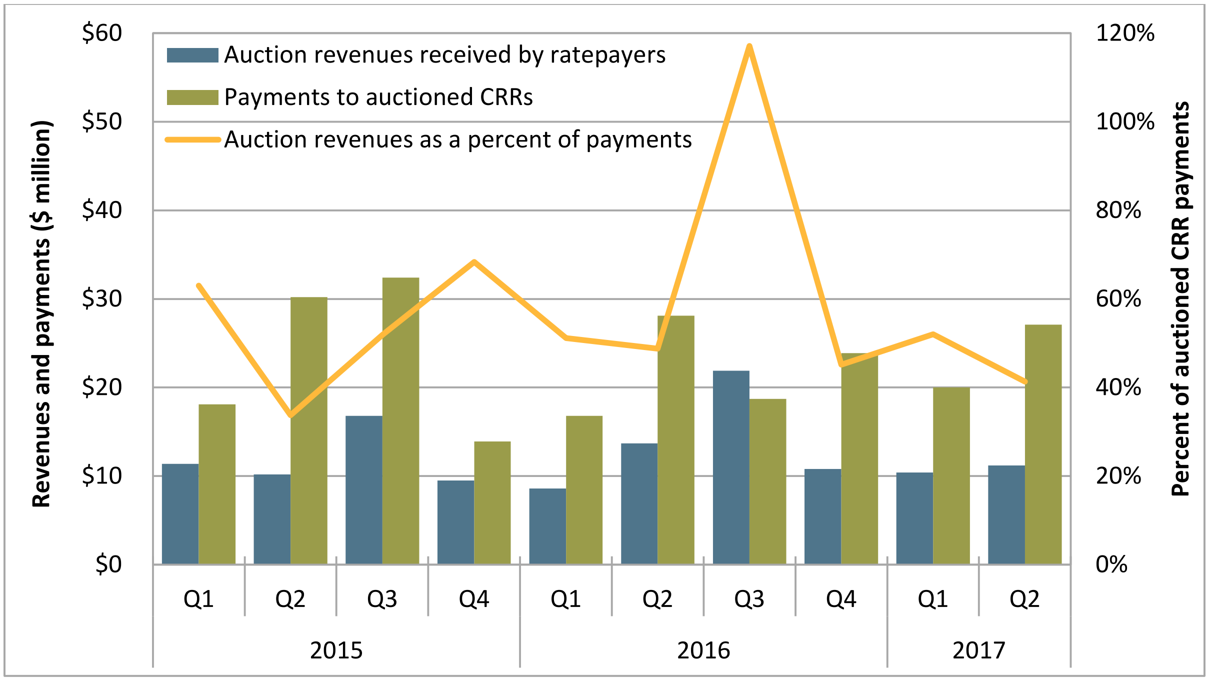


Figure 1.17 Auction revenues and payments (marketers)

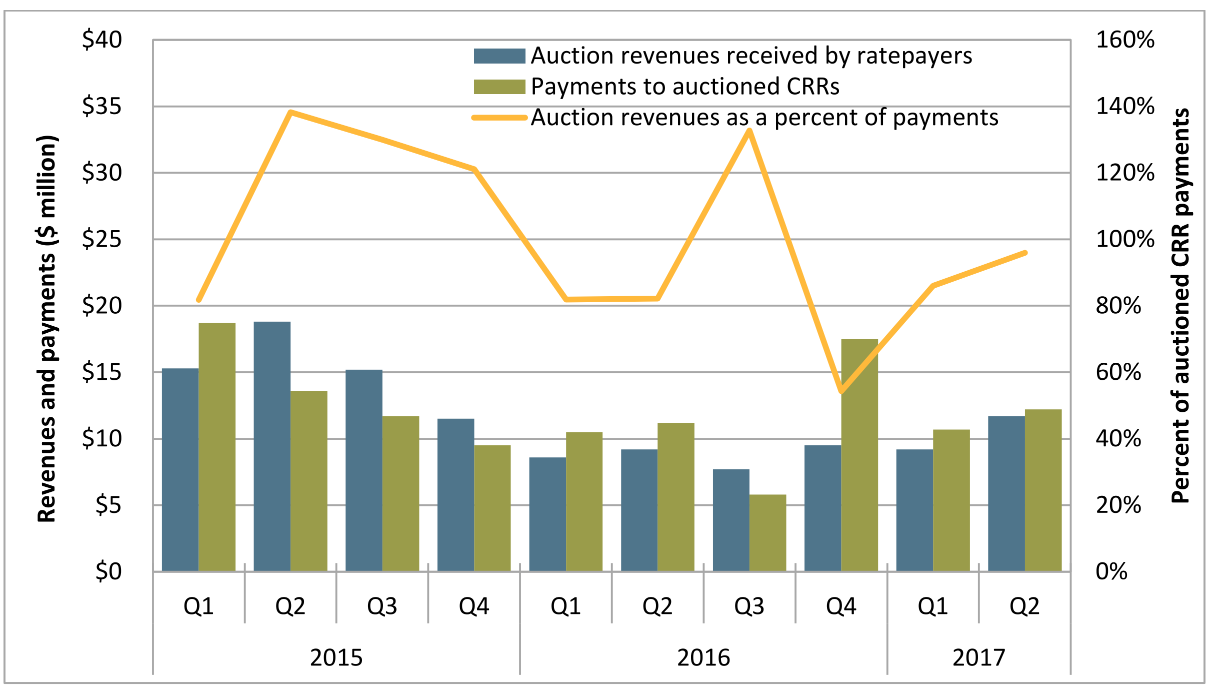


Figure 1.18 Auction revenues and payments (generators)

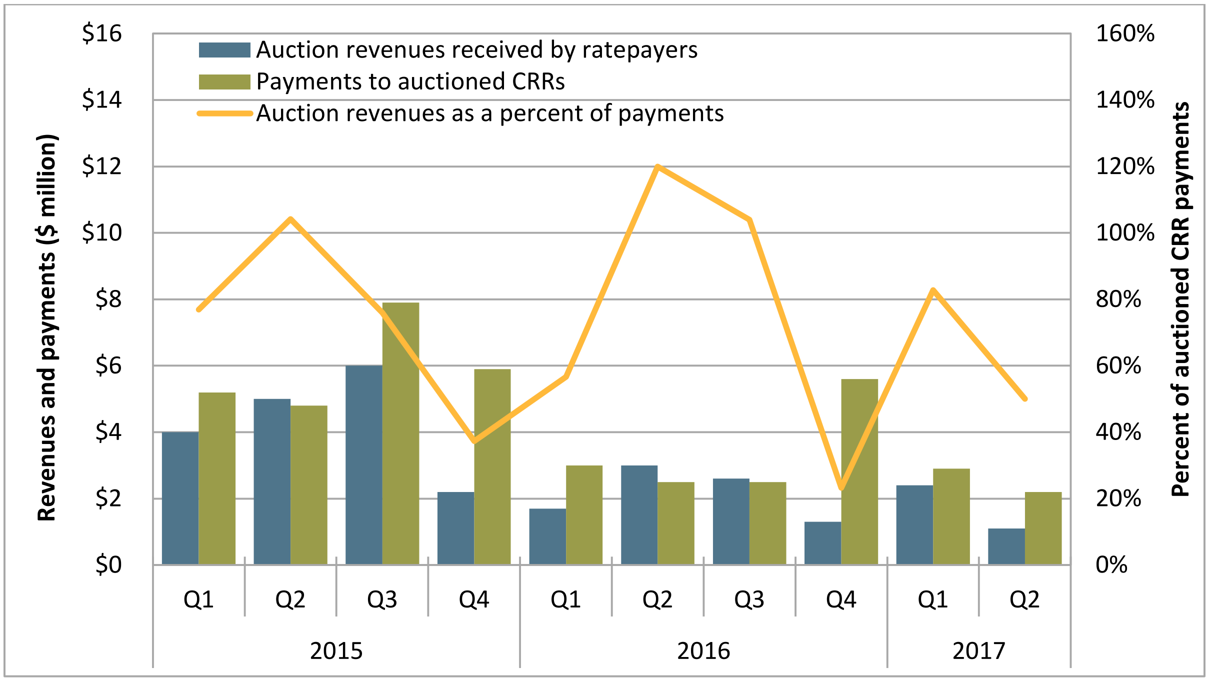
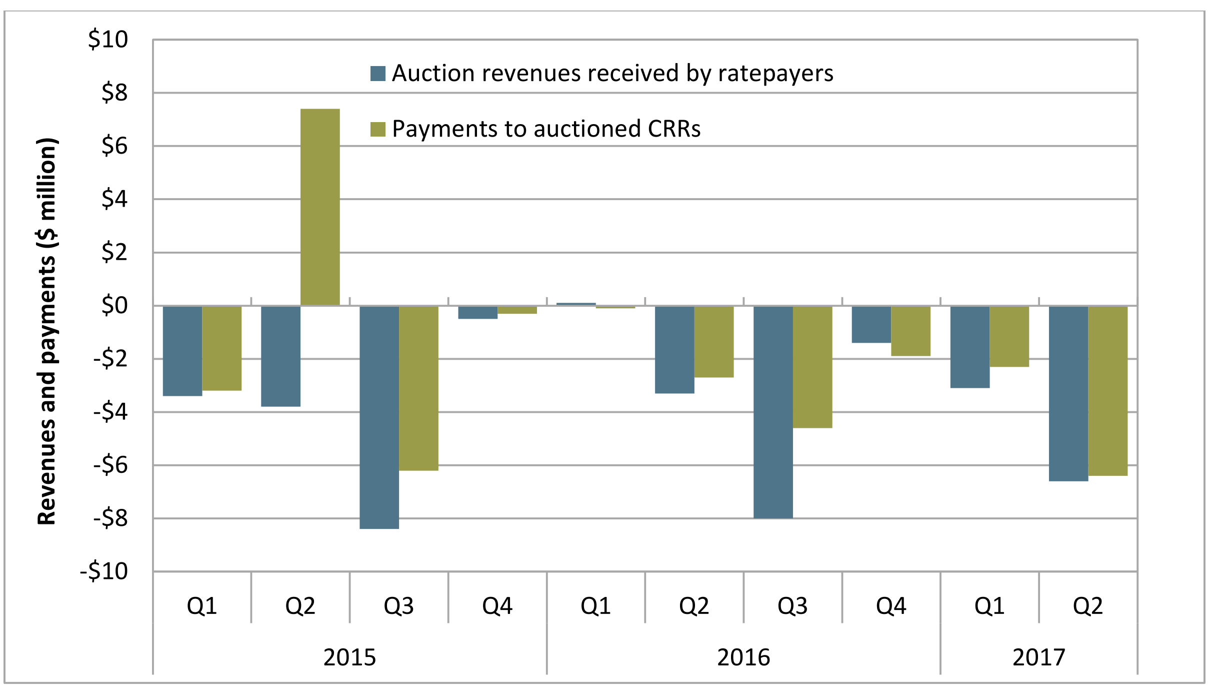


Figure 1.19 Auction revenues and payments (load-serving entities)



Potential improvements to the congestion revenue rights auction

DMM believes that the trend of revenues being transferred from electric ratepayers to other entities warrants reassessing the standard electricity market design assumption that ISOs should auction off these financial instruments on behalf of ratepayers after the congestion revenue right allocations.[28] DMM believes the current auction is unnecessary and could be eliminated. If the ISO believes it is beneficial to the market to facilitate hedging, DMM believes the current auction format should be changed to a *market* for congestion revenue rights or locational price swaps based on bids submitted by entities willing to buy or sell congestion revenue rights.

In response to DMM's recommendation at the June 2016 Board of Governors meeting, ISO management started an initiative "Congestion revenue rights auction efficiency" and adopted a two phase approach.[29] An analysis phase, in which the ISO will analyze the differences between auction prices and payouts in the congestion revenue rights market and the policy development phase, in which the ISO will consider potential policy changes. The ISO plans to begin the policy development phase once it has completed the analysis phase which is currently a work in progress.

1.9 Flexible ramping product

This section provides information about market outcomes for the flexible ramping product during the second quarter.

Background

On November 1, 2016, the ISO implemented a new market feature for procuring real-time flexible ramping capacity known as the flexible ramping product. The product replaced the previous procurement mechanism, called the flexible ramping constraint. The flexible ramping product differs from the flexible ramping constraint in several important ways.

First, while the constraint procured only upward flexible capacity in the 15-minute market, the product procures both upward and downward flexible capacity, in both the 15-minute and the 5-minute markets. As with the constraint, the 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 corresponding 5-minute market runs for the same time period. The procurement in the 5-minute market aims to ensure that enough ramping capacity is available to handle differences between consecutive 5-minute market intervals.

Second, the amount of flexible capacity that the product procures is determined from a demand curve instead of from a fixed requirement. This means that the amount of flexible capacity procured in a given market interval will depend on the willingness-to-pay for procuring flexible capacity in that interval derived from the demand curve.

[28] DMM whitepaper on *Shortcomings in the congestion revenue right auction design*, November 28, 2016: http://www.caiso.com/Documents/DMM-WhitePaper-Shortcomings-CongestionRevenueRightAuctionDesign.pdf

[29] ISO stakeholder processes – Congestion revenue rights auction efficiency: http://www.caiso.com/informed/Pages/StakeholderProcesses/CongestionRevenueRightsAuctionEfficiency.aspx

Third, the shadow prices for the flexible ramping product are used not only for compensating resources that are counted towards meeting the flexible ramping capacity demand, but also to pay or charge resources for their forecasted ramping movement.

Flexible ramping product demand curves

The ISO procures flexible ramping capacity using demand curves, such that the amount of flexible ramping capacity procured in a given interval depends on the cost of procuring flexible capacity in that interval. The demand curves, which represent the ISO's willingness-to-pay for flexible ramping capacity, reflect the expected reduction in power balance constraint relaxation costs from an increase in the amount of procured flexible ramping capacity.

The demand curves are calculated independently for each hour of the day, and differ by market (15-minute and 5-minute) and direction (upward ramping and downward ramping). Further, there are separate demand curves calculated for each energy imbalance market area, in addition to a system-level demand curve. For more information about the flexible ramping product and the calculation of the flexible ramping product demand curves, see DMM's 2016 annual report.[30]

The demand curves used in the second quarter of 2017 were similar to those used during the prior quarter. Average demand for upward ramping in the 15-minute market at the system-level was about 770 MW at $0/MWh and about 480 MW at $100/MWh. In the downward direction, average system-level demand was about 790 MW at $0/MWh and about 50 MW at $100/MWh.

Demand for flexible ramping capacity in the 5-minute market in the second quarter remained lower than demand in the 15-minute market. At the system level, average upward demand was about 160 MW at $0/MWh and about 100 MW at $100/MWh. In the downward direction, average system-level demand was about 140 MW at $0/MWh and about 20 MW at $100/MWh.

Market outcomes for flexible ramping product

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

Figure 1.20 shows the percent of intervals when the system-level flexible ramping demand curve bound, and had a positive shadow price, in the 15-minute market during the second quarter.

In the second quarter, the system-level demand curves continued to bind more frequently in the upward direction than in the downward direction. The system-level downward demand curves bound in about 7 percent of 15-minute intervals during the second quarter, compared to about 11 percent during the first quarter. As seen in Figure 1.20, the downward demand curves were mostly binding during hours with high levels of solar generation.

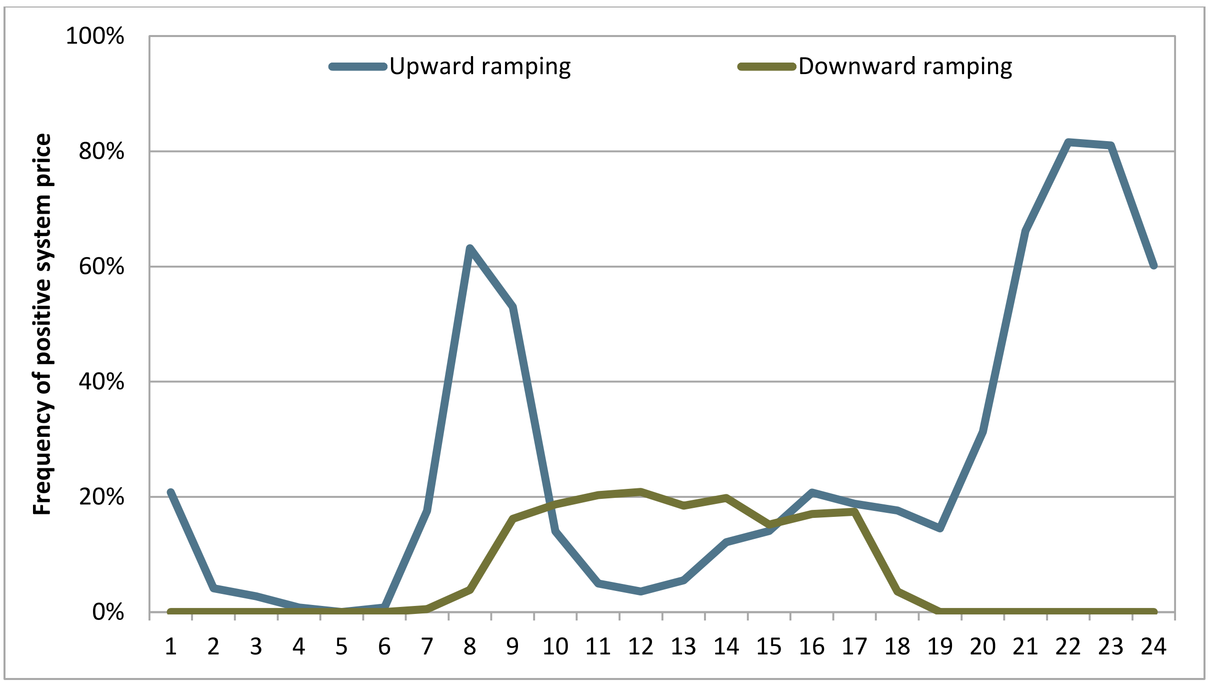
30 *2016 Annual Report on Market Issues and Performance*, Department of Market Monitoring, pp. 109-120: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.

In the upward direction, non-zero system-level flexible ramping prices were observed in the 15-minute market in about 25 percent of intervals, a decrease compared to 31 percent of intervals in the first quarter. Figure 1.20 shows that positive prices in the upward direction were most frequent in the morning and evening hours. This coincides with higher levels of demand for upward flexible ramping capacity during those hours.

The average system-level shadow price when the demand curve was binding in the 15-minute market during the second quarter was $11/MWh in the upward direction and $7/MWh in the downward direction.

In the 5-minute market, system-level flexible ramping prices were positive during less than 1 percent of intervals in both the upward and downward direction. This is because the quantity of flexible ramping capacity demanded in the 5-minute market was significantly lower than in the 15-minute market.

Figure 1.20 Hourly frequency of positive 15-minute market flexible ramping shadow price (April - June)



In addition to the system-level shadow price, an area-specific demand curve may be binding, creating an additional price for resources in that area. These demand curves continued to bind infrequently for most areas during the second quarter.

Table 1.7 shows the percent of intervals with positive flexible ramping shadow prices, and the average flexible ramping shadow price for intervals when the price was positive, for the second quarter. This is shown for both the 15-minute and 5-minute markets and for each energy imbalance market area, as well as the system-level energy imbalance market area.

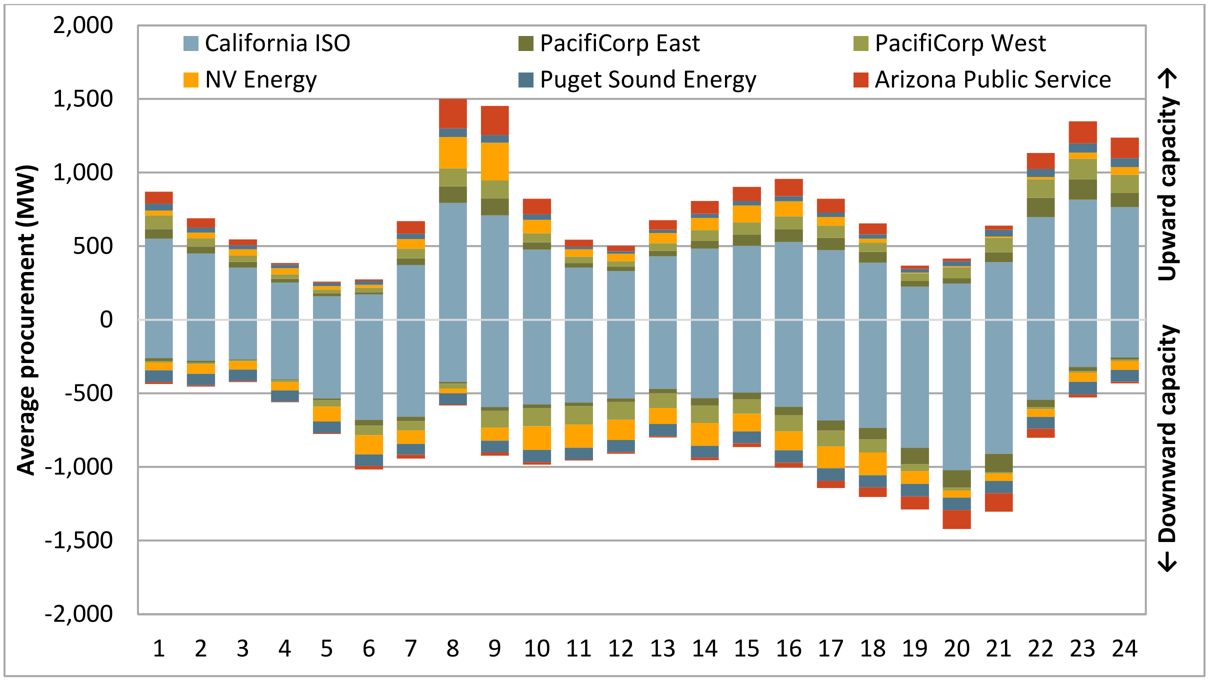
Table 1.7 Flexible ramping product shadow prices (April – June)

	Positive upward flex ramp shadow price (percent of intervals)	Average upward flex ramp shadow price ($/MWh)	Positive downward flex ramp shadow price (percent of intervals)	Average downward flex ramp shadow price ($/MWh)
PacifiCorp East				
15-minute market (FMM)	3.5%	$46	3.2%	$7
5-minute market (RTD)	0.4%	$136	0.0%	$37
PacifiCorp West				
15-minute market (FMM)	0.8%	$49	0.5%	$34
5-minute market (RTD)	0.2%	$46	0.1%	$30
NV Energy				
15-minute market (FMM)	2.9%	$116	1.2%	$35
5-minute market (RTD)	1.0%	$123	0.6%	$55
Puget Sound Energy				
15-minute market (FMM)	2.8%	$53	9.5%	$26
5-minute market (RTD)	0.6%	$158	2.6%	$78
Arizona Public Service				
15-minute market (FMM)	1.7%	$92	5.3%	$48
5-minute market (RTD)	0.6%	$174	3.4%	$63
California ISO				
15-minute market (FMM)	0.1%	$16	0.3%	$11
5-minute market (RTD)	0.0%	N/A	0.2%	$7
EIM area				
15-minute market (FMM)	25.3%	$11	7.5%	$7
5-minute market (RTD)	0.7%	$26	0.0%	$1

Figure 1.21 shows the hourly average amount of flexible ramping capacity procured in the 15-minute market during the second quarter. This capacity may have been procured to satisfy system-level demand, an area-specific demand, or both. The different colors indicate from which area the capacity was procured. The positive bars show procurement for upward flexible ramping, and the negative bars for downward flexible ramping. The hourly procurement profile is similar to the hourly profile of the system-level demand curves. This reflects that most of the flexible ramping capacity was procured to meet the system-level demand curve.

Overall, the ISO procured an hourly average of about 770 MW of upward capacity and 860 MW of downward capacity in the 15-minute market during the second quarter. Compared to the first quarter, this represents a small decrease in upward capacity and increase in downward capacity. The total hourly average quantity of flexible ramping capacity procured in the 5-minute market was about 200 MW in the upward direction and 270 MW in the downward direction.

Figure 1.21 Hourly average flexible ramping capacity procurement in 15-minute market (April – June)



Flexible ramping procurement costs

Generation capacity that satisfied the demand for flexible ramping capacity received payments based on the flexible ramping shadow price. In addition, the flexible ramping shadow price is also used to pay or charge for forecast ramping movements. This means that 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 forecasted to decrease output was charged the upward flexible ramping price and paid the downward flexible ramping price.[31]

The total net capacity payments to resources used to satisfy the demand for flexible ramping capacity typically are positive. The total net payments for forecasted movements may be either positive or negative, depending on market outcomes.

Figure 1.22 shows the total net payments to generators for flexible ramping capacity by month and balancing area.[32] For the time period before the flexible ramping product was implemented in

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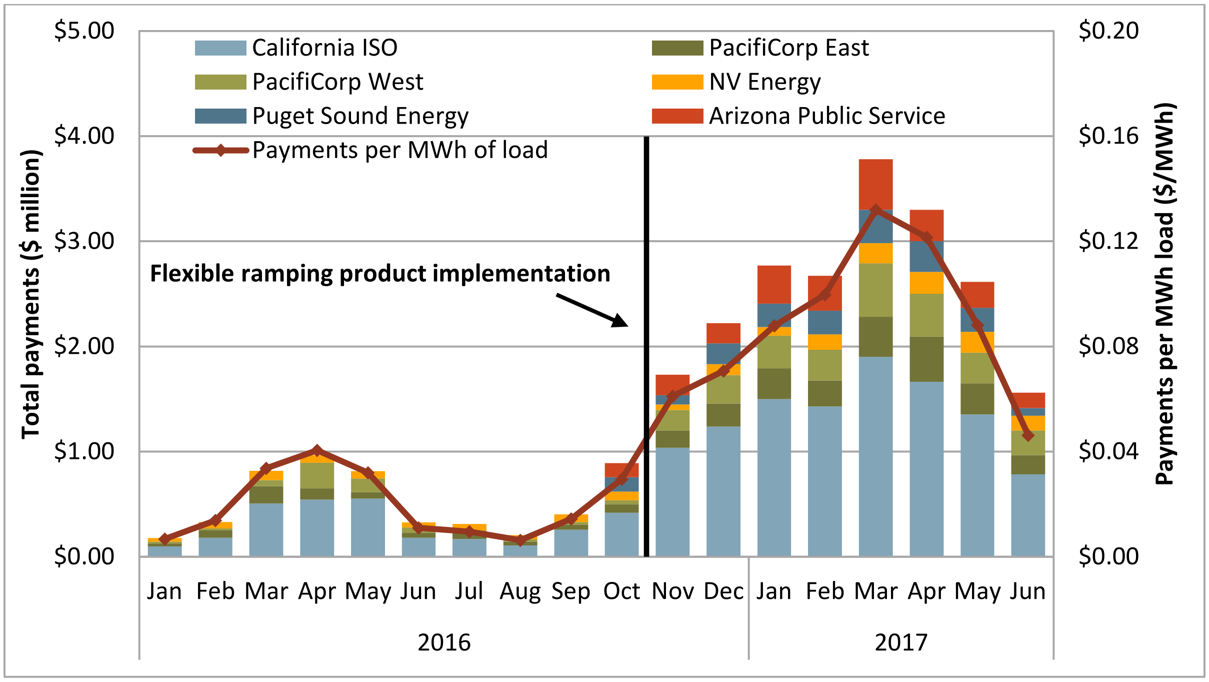
31 More information about the settlement principles can be found in the ISO's *Revised Draft Final Proposal for the Flexible Ramping Product*, December 2015: http://www.caiso.com/Documents/RevisedDraftFinalProposal-FlexibleRampingProduct-2015.pdf.

32 Secondary costs, such as costs associated with impacts of flexible ramping procurement on energy costs, bid cost recovery payments or ancillary service payments are not included in these calculations. Assessment of these costs is complex and beyond the scope of this analysis.

November 2016, Figure 1.22 shows net payments to generators from the flexible ramping constraint.[33] The values for November 2016 and onward reflect net payments to generators from the flexible ramping product. This includes the total net amount paid for upward and downward flexible ramping capacity in both the 15-minute and 5-minute markets. Payments for forecasted movements are not included.[34]

Figure 1.22 Monthly flexible ramping payments by balancing area



As shown in Figure 1.22, total payments to generators have been higher following the implementation of the flexible ramping product. Total payments for flexible ramping capacity in the second quarter were about $7.5 million, compared to $2.1 million during the same quarter of 2016, when the flexible ramping constraint was in effect. Compared to the first quarter of 2017, total payments decreased from about $9.2 million. A similar seasonal pattern can be seen for the flexible ramping constraint payments over the spring of 2016. About 51 percent of payments during the quarter were to ISO generators, which reflects the majority of flexible ramping capacity awards.

Although flexible ramping payments increased with the implementation of the flexible ramping product, payments per megawatt-hour of load remained low.[35] Average net payments per megawatt-hour of

33 Rescissions for non-performance have been excluded.

34 A prior version of this figure was shown in DMM's Q4 2016 report. The prior version included net payments for both capacity and forecasted movements. However, because of an error in the ISO's settlement calculations, the forecasted movement component of this value was inaccurate. In this version, the forecasted movement component has been excluded. The values in this section therefore differ slightly from those reported in the Q4 report.

35 Load is measured as the total load in the ISO and energy imbalance market areas.

load during the second quarter were about $0.09/MWh, a decrease from about $0.11/MWh for the first quarter.

Areas of continued review

The method used to calculate the flexible ramping demand curves represents an improvement compared to the method that was used for determining the flexible ramping constraint requirements. Nevertheless, there may be possibilities for additional enhancements after further study of the flexible ramping product. For example, it might be beneficial to base the demand curves on a larger sample of net load forecast errors.

Further, in the initial implementation of the flexible ramping product, the demand curves for individual balancing areas were included in the constraint for system-level procurement. DMM believes that this implementation approach leads to system-level procurement of flexible ramping capacity, and associated flexible ramping shadow prices, that are lower than what would be consistent with the system-level flexible ramping demand curves. This aspect of the flexible ramping product was active throughout the second quarter. However, an adjustment was made on July 13, 2017, to limit the use of demand curves from individual balancing areas to zero when sufficient transfer capability connected the area with system conditions.

This enhancement was expected to avoid lowering the system-level flexible ramping product prices and procured quantities in intervals when market conditions indicate that there is no need to procure any area-specific flexible ramping product.[36]

However, the implementation of this enhancement addressed one concern DMM had with the product, but in other instances resulted in market outcomes in which resources providing flexible ramping capacity received lower payments based on the area-specific demand curve rather than the system-level demand curve. DMM will continue to monitor the impact of this adjustment and will provide further information in a future report. DMM continues to recommend that the ISO work with DMM and stakeholders to determine an appropriate enhancement that could avoid lowering system-level flexible ramping product prices and procured quantities.

For additional information about these topics, see DMM's 2016 annual report.[37]

[36] This enhancement does not prevent lowered system-level flexible ramping product prices and procured quantities for any interval in which there is a non-zero area specific demand curve. This is not the case for a large number of intervals such that the enhancement was intended to be a significant improvement.

[37] *2016 Annual Report on Market Issues and Performance*, Department of Market Monitoring, pp. 109-120: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.

2 Energy imbalance market

This section covers the energy imbalance market performance during the second quarter. Key observations and findings include the following.

- Overall prices continued to be uniform between PacifiCorp East, NV Energy, Arizona Public Service, and the ISO during most intervals. Price separation that did occur was primarily due to flexible ramping sufficiency test failures.
- Prices in PacifiCorp West and Puget Sound Energy were often lower than the other energy imbalance market areas because of continued congestion from PacifiCorp West into the ISO and PacifiCorp East.
- The transition period pricing waiver expired for Puget Sound Energy and Arizona Public Service at the end of March 2017.
- Valid under-supply power balance constraint infeasibilities were relatively infrequent in the energy imbalance market, during less than 0.5 percent of intervals in the 15-minute and 5-minute markets in each of the balancing areas.
- The frequency of valid over-supply infeasibilities in Arizona Public Service decreased from the previous quarter, but continued to occur regularly during about 3 percent of 15-minute and 5-minute market intervals.
- The majority of power balance constraint relaxations during the quarter, across all of the energy imbalance market balancing areas, occurred during hours when the area failed the flexible ramping sufficiency test. Balancing areas continued to fail the upward and downward sufficiency tests regularly during the second quarter. In particular, Puget Sound Energy failed the downward sufficiency test more frequently during about 13 percent of hours, up from about 3 percent of hours in the previous quarter.
- The ISO and PacifiCorp West were net exporters in the energy imbalance market, while the remaining areas tended to be net importers. The volumes of transfers out of the ISO were very large, on average, during peak solar hours and they continued to export to some areas during other hours. This pattern was correlated with inexpensive renewable resources available to the ISO system.

2.1 Energy imbalance market performance

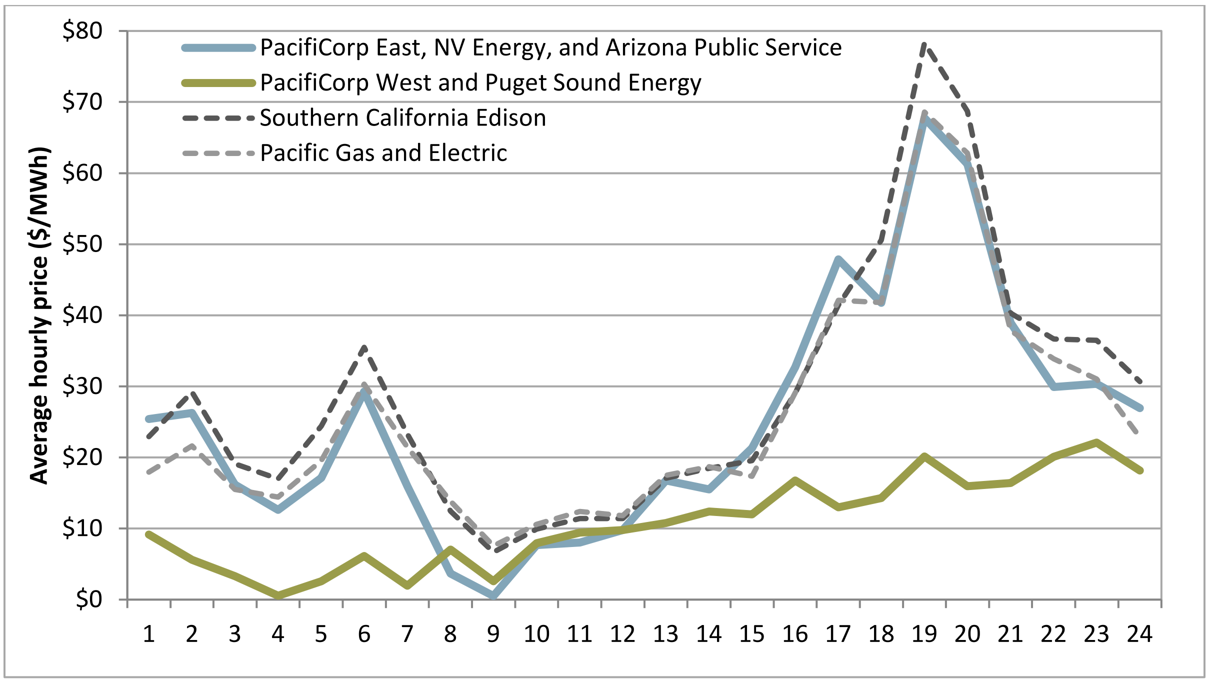
Energy imbalance market prices

Overall, prices in the energy imbalance market differed between two distinct regions. Prices in the first region – including PacifiCorp East, NV Energy and Arizona Public Service – were often similar to each other and the ISO because of large transfer capacities and little congestion. However, there was some price separation within this region. In many of these cases, one or more of these areas failed the flexible ramping sufficiency test which limited transfers and created price separation between the balancing areas. Prices in the second region – including PacifiCorp West, and Puget Sound Energy – tended to be different than those in the first and the ISO because of limited transfer capability between PacifiCorp West and PacifiCorp East and between the ISO.

Figure 2.1 shows hourly average combined 5-minute prices for PacifiCorp East, NV Energy, and Arizona Public Service as well as combined prices for PacifiCorp West and Puget Sound Energy.[38] The figures also show 5-minute market prices for Southern California Edison and Pacific Gas and Electric for comparison with the ISO. On average, hourly prices for PacifiCorp East, NV Energy, and Arizona Public Service tracked closely to system prices.

Prices in PacifiCorp West and Puget Sound Energy often formed a second pricing region. As shown in Figure 2.1, prices here were often less than prices in the ISO because of limited transmission available between PacifiCorp West and the ISO as well as between PacifiCorp West and PacifiCorp East.

Figure 2.1 Hourly 5-minute market prices (April – June)



Power balance constraint

The transition period pricing waiver expired for Puget Sound Energy and Arizona Public Service at the end of March 2017 following their initial six months of market operation.[39] Thus, prices across each

38 The individual balancing areas were grouped this way because of similar hourly pricing. Hourly 15-minute market prices show a similar pattern.

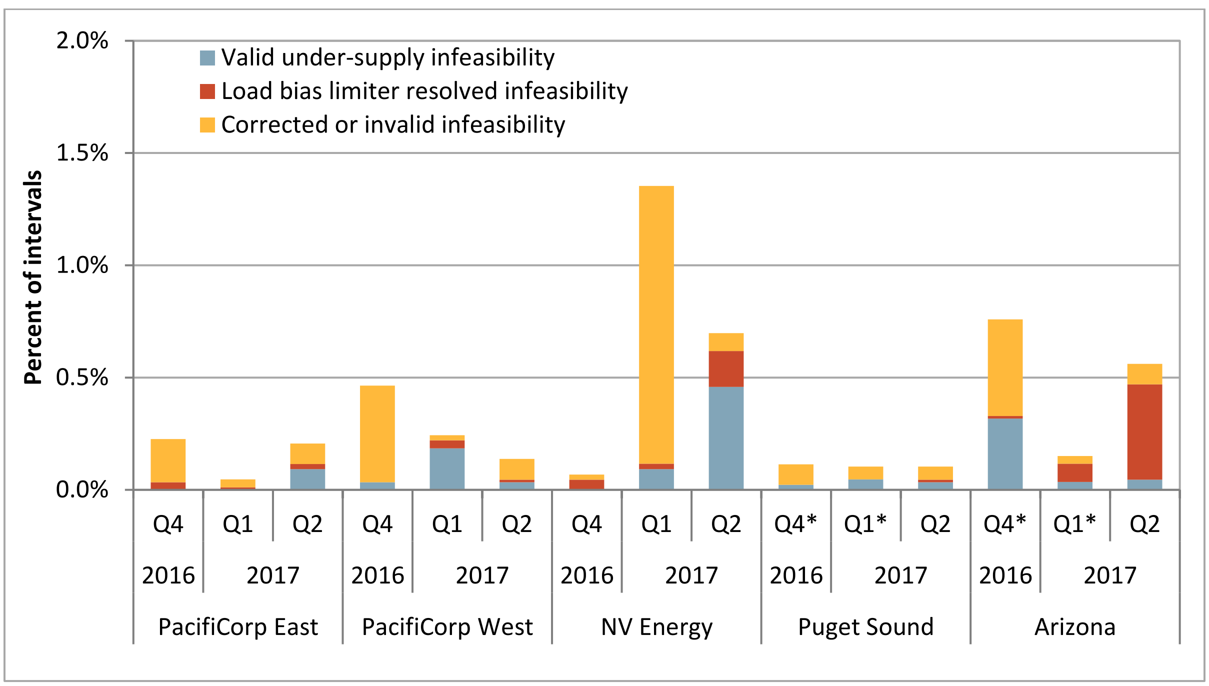
39 Transition period pricing is in effect for new energy imbalance market entities during the first six months of market participation. This mechanism sets the market price based on the last price bid into the market by a unit when the power balance constraint is relaxed.

balancing area during the quarter were susceptible to penalty parameters when the power balance constraint was relaxed. When the power balance constraint is relaxed because of insufficient upward ramping capacity (shortage or under-supply), prices could be set using the $1,000/MWh penalty price. Power balance constraint relaxation due to insufficient downward ramping capacity (surplus or over-supply) can set prices at -$155/MWh in the pricing run. When the load bias limiter is triggered, the infeasibility is resolved and prices are instead set by the last dispatched bid rather than the penalty parameters for under-supply and over-supply.[40]

Figure 2.2 shows the frequency of under-supply infeasibilities in the 5-minute market by quarter.[41] During the second quarter, valid under-supply infeasibilities were relatively infrequent, particularly in comparison to levels observed in the energy imbalance market in 2015. Valid under-supply infeasibilities occurred during less than 0.5 percent of intervals in the 15-minute market and 5-minute market in each of the energy imbalance market balancing areas.

As shown in Figure 2.3, the frequency of valid over-supply infeasibilities in Arizona Public Service decreased from the previous quarter. However, valid-over-supply infeasibilities in Arizona Public Service still occurred regularly in about 3 percent of 15-minute and 5-minute intervals. Because special transition pricing expired at the end of the first quarter, prices during the power balance constraint relaxations were often set at the -$155/MWh penalty parameter for over-supply infeasibilities.

Figure 2.2 Frequency of under-supply power balance constraint relaxation



*Area under transition period pricing for the quarter

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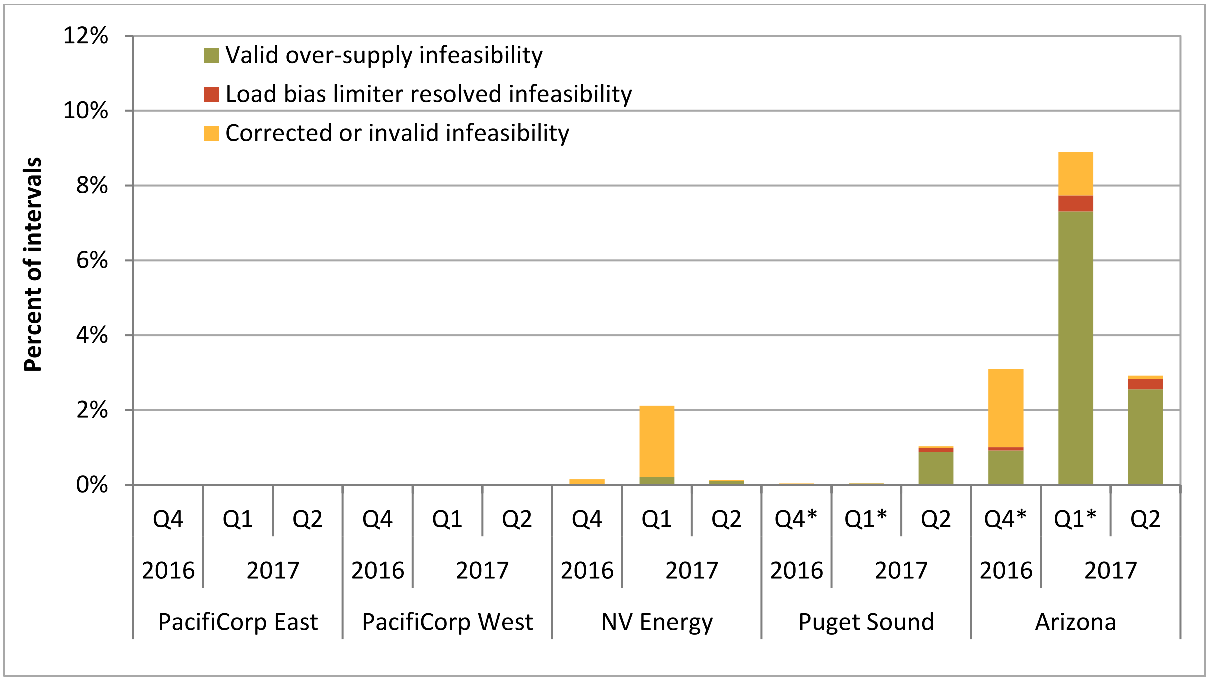
40 See section 3 for further information on load adjustments and the load bias limiter.

41 The frequency of infeasibilities in the 15-minute market showed a similar pattern to those observed in the 5-minute market.

Figure 2.3 Frequency of over-supply power balance constraint relaxation



*Area under transition period pricing for the quarter

2.2 Flexible ramping sufficiency test

The flexible ramping sufficiency test ensures that each balancing area has enough ramping resources over an hour to meet expected upward and downward ramping needs. The test is designed to ensure that each energy imbalance market area has sufficient ramping capacity to meet real-time market requirements without relying on transfers from other balancing areas. This test is performed prior to each operating hour.

When the energy imbalance market was initially implemented there was an upward ramping sufficiency test. In November 2016, the ISO implemented an additional downward ramping sufficiency test in the market with the introduction of the flexible ramping product, which replaced the flexible ramping constraint. If an area fails the upward sufficiency test, energy imbalance market imports cannot be increased.[42] Similarly, if an area fails the downward sufficiency test, exports cannot be increased. In addition to the sufficiency test, each area is also subject to a capacity test. If an area fails the capacity test, then the flexible ramping sufficiency test automatically fails as a result.[43]

When the flexible ramping sufficiency test was initially implemented requirements were determined from procurement targets for the flexible ramping constraint. The flexible ramping constraint was

42 *Business Practice Manual for the Energy Imbalance Market*, August 30, 2016, p. 45-52: https://bpmcm.caiso.com/BPM%20Document%20Library/Energy%20Imbalance%20Market/BPM_for_Energy%20Imbalance%20Market_V6_clean.docx.

43 *Business Practice Manual for the Energy Imbalance Market*, August 30, 2016, p. 45.

replaced in November, 2016 by the flexible ramping product. Unlike the flexible ramping constraint, the flexible ramping product uses a demand curve, rather than a fixed target, when procuring flexibility. When the ISO switched to the flexible ramping product, they began using the maximum requirement from the demand curve for the sufficiency test, instead of the old targets from the constraint.[44] DMM asked the ISO to reconsider how it uses the maximum point from the demand curve for the sufficiency tests, as they can change dramatically from hour to hour and they can be significantly larger than old requirements.

Limiting transfers can impact the frequency of power balance constraint relaxations and, thus, price separation across balancing areas. The majority of power balance constraint relaxations during the quarter, across all of the energy imbalance market balancing areas, occurred during hours when the area failed the flexible ramping sufficiency test. Constraining transfer capability may also impact the efficiency of the energy imbalance market by limiting transfers into and out of a balancing area that could potentially provide benefits to other balancing areas.

Figure 2.4 shows the average percent of hours in which an energy imbalance market area failed the sufficiency test in the upward direction. As shown in Figure 2.4, energy imbalance market entities failed the upward flexible ramping sufficiency test between 1 and 5 percent of hours in the quarter.

Figure 2.5 provides the same information for sufficiency tests in the downward direction. In particular, the frequency in which Puget Sound Energy failed the downward sufficiency test increased from about 3 percent of hours in the previous quarter to about 13 percent of hours in the second quarter. Alternatively, Arizona Public Service failed the downward sufficiency test less frequently, during about 6 percent of hours compared to about 26 percent of hours in the first quarter of 2017. The ISO also failed the downward sufficiency test for the first time since its implementation in November 2016, during 7 hours in April.

[44] For further detail, see DMM's presentation on January 18, 2017, to the Market Performance and Planning forum on the calculation of the flexible ramping sufficiency requirement: http://www.caiso.com/Documents/Agenda-Presentation-MarketPerformance-PlanningForum_Jan18_2017.pdf.

Figure 2.4 Frequency of upward failed sufficiency tests by month

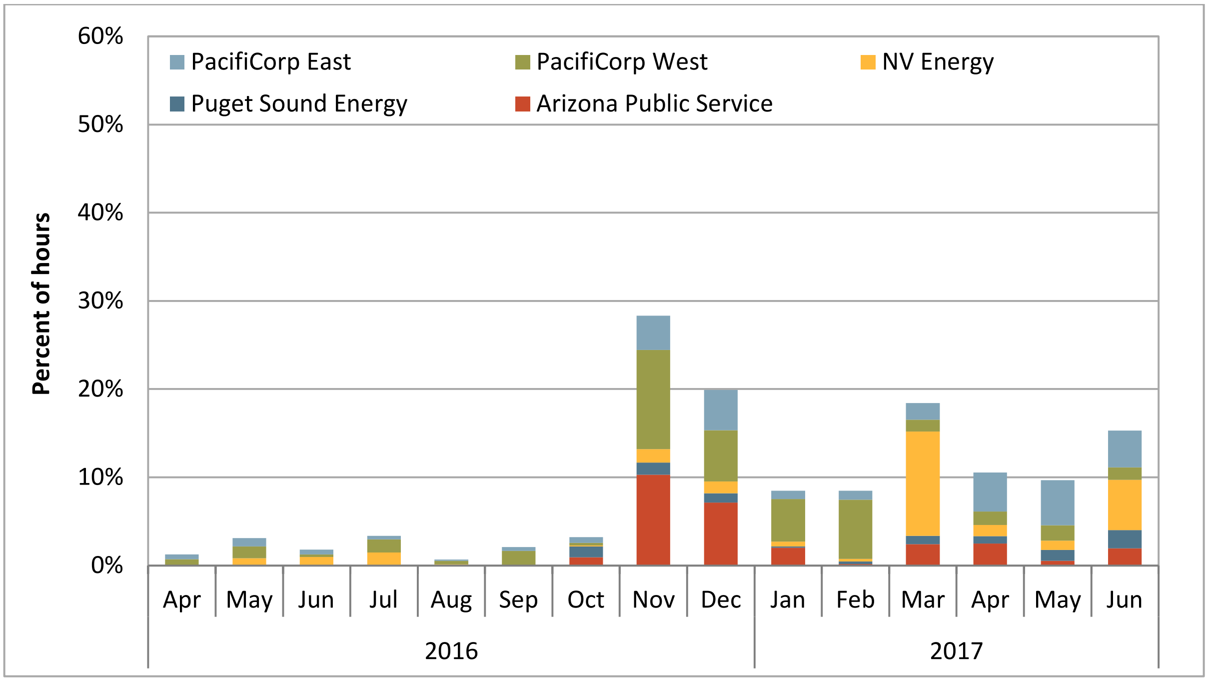
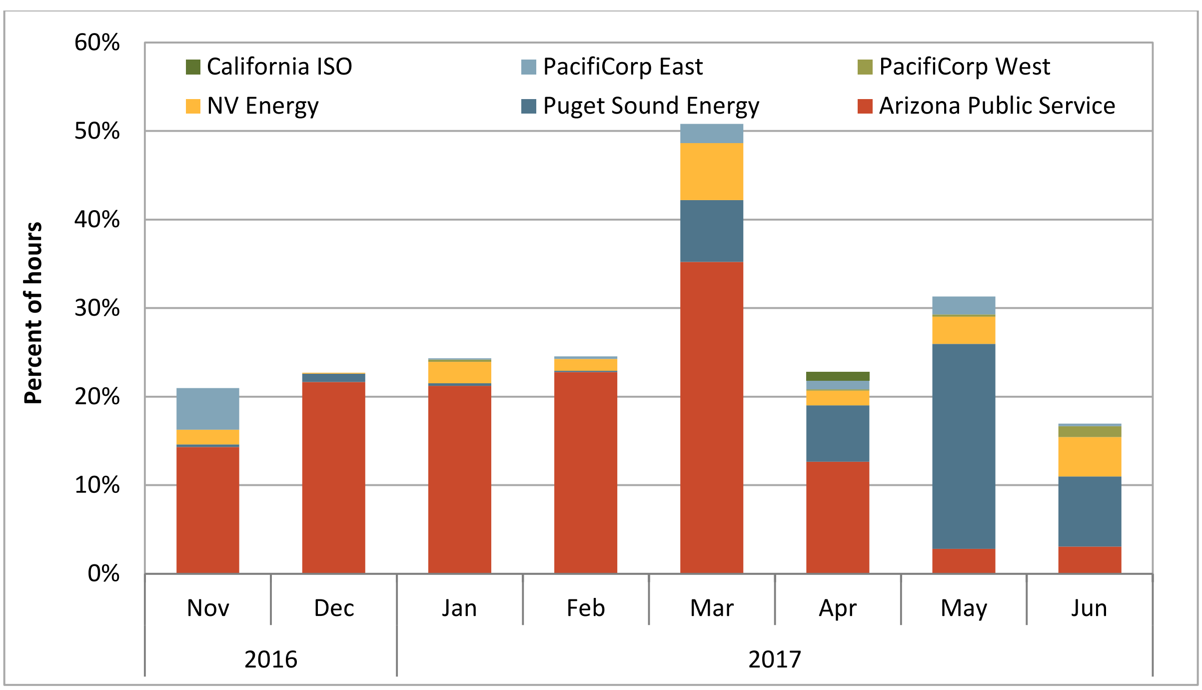


Figure 2.5 Frequency of downward failed sufficiency tests by month



2.3 Energy imbalance market transfers

The real-time market software solves a large cost minimization problem for dispatch instructions to generation considering all of the resources available to the market, including those in the energy imbalance market areas and the ISO. This software also considers a number of constraints including transmission availability between balancing areas within the energy imbalance market. Because of real-time differences in system conditions, real-time schedules for generation are frequently different than day-ahead schedules for resources in the ISO and base schedules for resources in the energy imbalance market. When aggregated, these differences can cause large changes in scheduled flows between balancing areas in the real-time market, or *energy transfers,* between areas. These transfers may represent the market software electing to use lower cost generation in one area in lieu of higher cost generation in another area, thus reducing the overall cost to meet load in the energy imbalance market. This section includes results for energy transfers between areas, which is one of the key sources of value that the energy imbalance market provides.[45]

Table 2.1 shows the percentage of intervals that each energy imbalance market area and the ISO either exported or imported energy on net and the associated average quantity in the 5-minute market. Table 2.2 shows detail about how frequently congestion occurred between any energy imbalance areas.[46] These tables show that scheduled transfers typically flowed out of the ISO and PacifiCorp West and into the remaining areas during the majority of intervals.

Table 2.1 shows that the ISO and PacifiCorp West were net exporters during the quarter, and that the ISO transferred significantly greater quantities of energy while exporting than while importing. The remaining areas tended to import energy during the quarter. Plentiful and inexpensive renewable energy was available from the ISO during the period, including significant amounts of solar and hydro generation, and these conditions combined with relatively lower loads made it economic for the ISO to export more energy.

Table 2.2 shows that congestion was infrequent between the ISO, NV Energy, PacifiCorp East, and Arizona Public Service. It also shows that there was some congestion between the combined PacifiCorp West and Puget Sound Energy areas and the ISO. These patterns caused local prices in the ISO, PacifiCorp East, NV Energy and Arizona Public Service to be set close to the system price during most intervals. This congestion tended to be in the direction of the ISO and not in the opposite direction, despite larger average exports from the ISO. This is consistent with results from prior quarters. Congestion for exports from PacifiCorp West caused 5-minute prices in PacifiCorp West and Puget Sound Energy to differ frequently from system prices and prices in the other energy imbalance market areas. When system prices were higher, constraints out of PacifiCorp West into the ISO and PacifiCorp East bound frequently and caused price separation between the PacifiCorp West and Puget Sound Energy areas and prices in the other energy imbalance market areas.

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45 In prior quarterly reports, DMM has shown real-time energy flows within the energy imbalance market. These figures show real-time energy market flows net of all base schedules.

46 This table removes all intervals when congestion could be caused by greenhouse gas compliance costs, which are usually about $5/MWh.

Table 2.1 Average net energy imbalance market transfer (April – June)

EIM participant	Net importer frequency	Net importer flows	Net exporter frequency	Net exporter flows
ISO	41%	-140	59%	480
PacifiCorp East	60%	-218	40%	69
PacifiCorp West	43%	-53	57%	68
NV Energy	58%	-152	42%	64
Puget Sound Energy	58%	-52	42%	25
Arizona Public Service	60%	-161	40%	70

Table 2.2 Congestion status and flows in EIM (April – June)[47]

	Congested toward ISO	Congested from ISO
PacifiCorp East	10%	3%
PacifiCorp West	37%	10%
NV Energy	3%	2%
Puget Sound Energy	40%	11%
Arizona Public Service	7%	2%

Different areas in the energy imbalance market exhibited different hourly transfer patterns. Generally, the ISO exported energy during most of the day with the largest quantity of exports occurring in the middle of the day, when solar generation was greatest. Energy transfers in each area were driven by the resource mix and relative prices during these times of the day.

Figure 2.6 through Figure 2.8 show details about how energy transfers moved between NV Energy, Arizona Public Service, and PacifiCorp West, respectively, and neighboring areas on an hourly basis during the quarter. Figure 2.6 shows that NV Energy typically received transfers from the ISO and sent transfers to PacifiCorp East during almost all hours. During peak solar hours these transfers tended to be larger, and during evening hours all transfers tended to be low.

Figure 2.7 shows similar information, but for Arizona Public Service rather than NV Energy. This chart shows that Arizona Public Service also received significant transfers from the ISO during peak solar hours, and that transfers were less during the other hours. During the peak solar hours, Arizona Public Service tended to export small amounts of energy to PacifiCorp East, relative to imports from the ISO. In the evening, flows tended to move from PacifiCorp East into Arizona Public Service and then out to the ISO.

47 Table 2.2 shows 5-minute market congestion between PacifiCorp West and the ISO inclusive of the transfer constraint and the constraint governing flows into the ISO on the Malin 500 kV constraint. These 5-minute constraints account for the dynamic limits imposed on transfers between the ISO and PacifiCorp West.

Figure 2.8 shows average transfers between PacifiCorp West and the neighboring areas: Puget Sound Energy, PacifiCorp East, and the ISO. This figure shows similar transfer patterns from previous quarters where transfers typically moved in from the ISO during peak solar hours and to the ISO during morning and evening hours. On average during all hours of the day, PacifiCorp West tended to export energy to Puget Sound Energy, indicating electricity typically moved in a south-to-north direction during these hours. Figure 2.8 shows that PacifiCorp West received imports from PacifiCorp East during all hours on average. This is a byproduct of the transfer limits imposed between the two areas that specify that transfers only occur in the east-to-west direction between these two areas.

Figure 2.6 Average hourly imports into NV Energy (April – June)

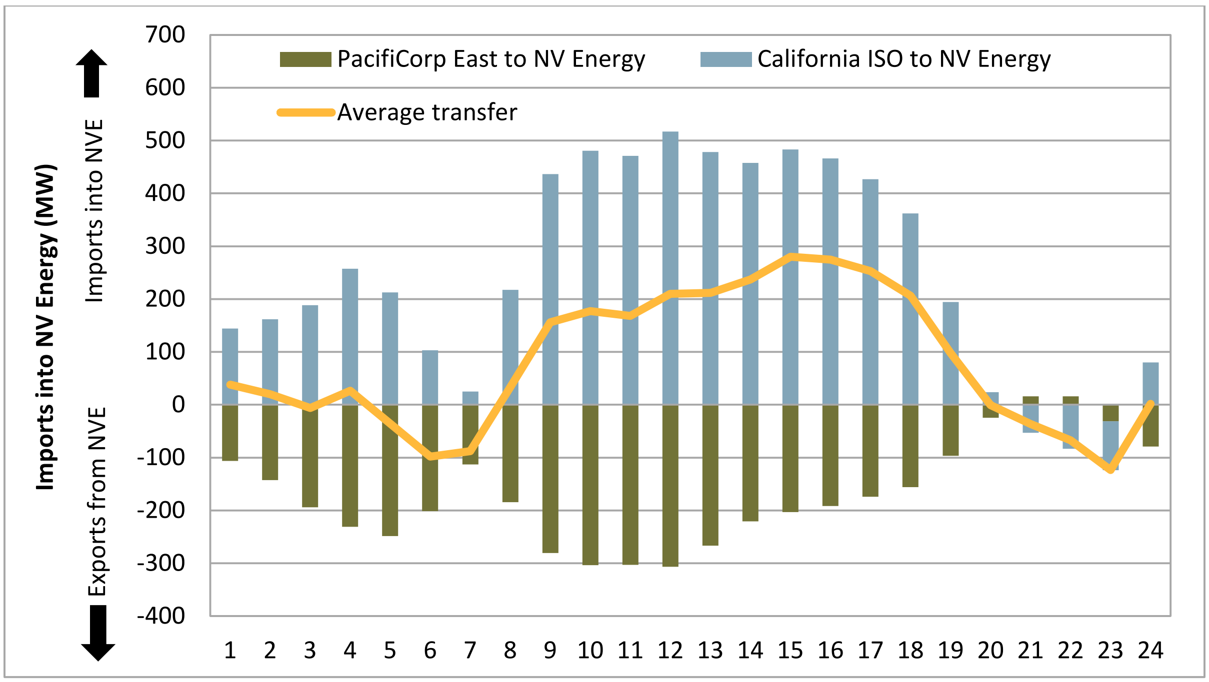


Figure 2.7 Average hourly imports into Arizona Public Service (April – June)

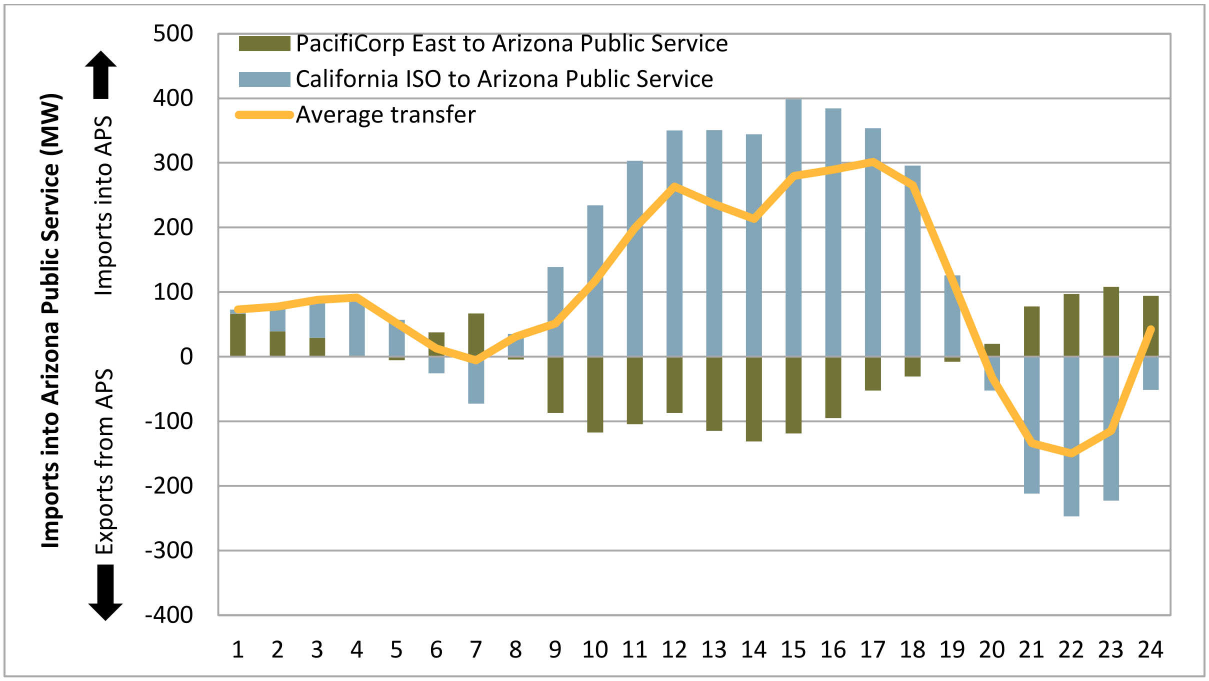
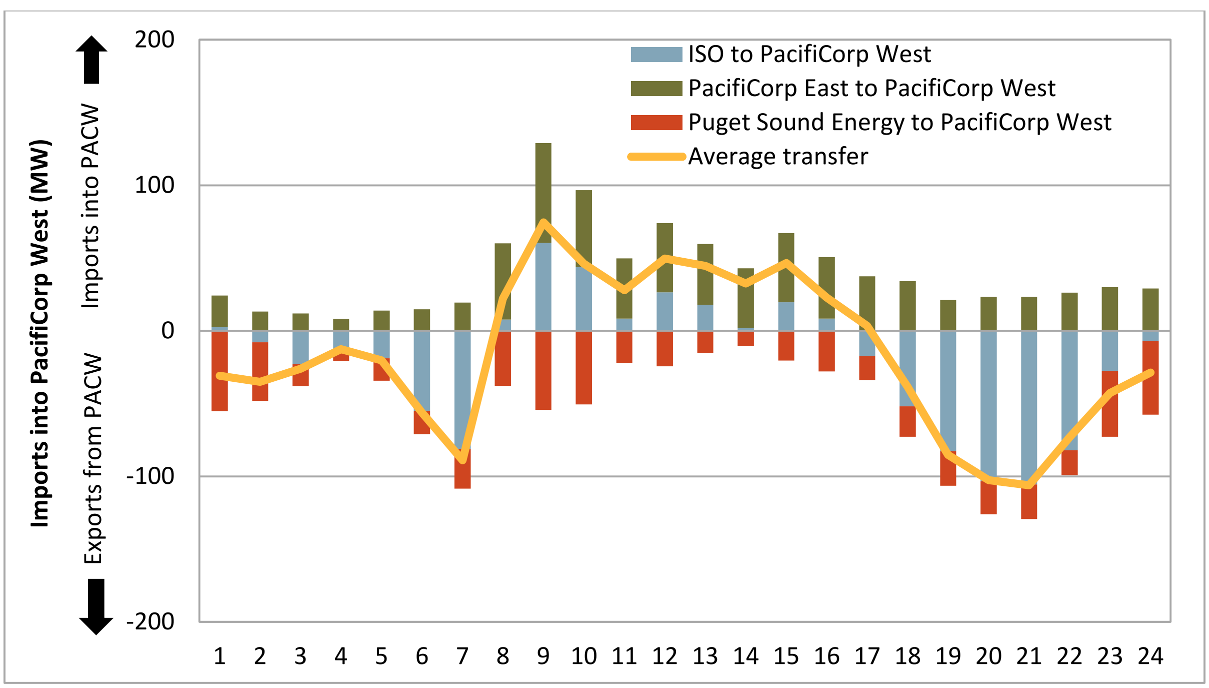


Figure 2.8 Average hourly imports into PacifiCorp West (April – June)



3 Load adjustments

This section provides a summary of load adjustments during the second quarter. Key trends include the following:

- Overall, load adjustments were typically positive in PacifiCorp East, NV Energy, Arizona Public Service and the ISO, while load adjustments were frequently negative in PacifiCorp West. Puget Sound Energy made adjustments infrequently in either direction.
- Arizona Public Service continued to adjust the load forecast significantly more frequently during the second quarter during about 81 percent of 15-minute and 5-minute intervals, compared to 40 percent of intervals in the prior quarter and 15 percent of intervals in the fourth quarter of 2016.
- The reasons selected most often for load adjustments differed significantly across the energy imbalance market areas. PacifiCorp East adjusted load primarily for generation deviation and schedule interchange variation, PacifiCorp West for generation deviation and automatic time error correction, NV Energy for reliability based control, and Arizona Public Service and Puget Sound Energy for generation deviation and load forecast deviation.[48]
- The load bias limiter had a minor impact on prices in the energy imbalance market and the ISO during the second quarter. The load bias limiter decreased average 5-minute market prices in the ISO by around $1/MWh during the quarter.
- DMM provided recommendations to the ISO for enhancements to the load bias limiter feature to limit adjustments only when a *change* in load adjustment causes a power balance constraint relaxation, rather than solely the *magnitude* of the load adjustment. The ISO posted a technical bulletin in December announcing that they intend to implement this change. Had the proposed load bias limiter been active during the quarter instead of the current load bias limiter, it would have decreased 5-minute market prices in the ISO by around $0.33/MWh, significantly less than the current load bias limiter.

Background

Operators in the ISO and energy imbalance market can manually modify load forecasts used in the market through a load adjustment. Load adjustments are also sometimes referred to as *load bias* or *load conformance*. These 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.

The ISO enhanced the real-time market software in December 2012 to limit load forecast adjustments made by operators to only the available amount of system ramp. Beyond this level of load adjustment a shortage occurs and triggers penalty pricing when the power balance constraint is relaxed, without

[48] Automatic time error correction is used to maintain interconnection frequency and to ensure that time error corrections and primary inadvertent interchange payback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection. For more information refer to WECC Reliability Standards here: http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-004-WECC-02.pdf.

achieving any increase in actual system energy. With this software enhancement, known as the *load bias limiter*, load adjustments made by operators are less likely to have extreme effects on market prices. This tool was extended to the energy imbalance market balancing areas in March 2015.

Frequency and size of load adjustments

Figure 3.1 and Figure 3.2 show the frequency of positive and negative load forecast adjustments for PacifiCorp East, PacifiCorp West, NV Energy, Puget Sound Energy, and Arizona Public Service during the previous six months for the 15-minute and 5-minute markets, respectively. The same data for the ISO is provided as a point of comparison and reference.

Table 3.1 summarizes the average frequency and size of positive and negative load forecast adjustments in the 15-minute and 5-minute markets during the second quarter. Overall, load adjustments were typically positive in PacifiCorp East, NV Energy, Arizona Public Service and the ISO, while load adjustments were frequently negative in PacifiCorp West. Puget Sound Energy adjusted the load forecast in either direction much less frequently than the other areas during the quarter. Table 3.1 also includes the average absolute positive and negative load adjustment as a percentage of area load.

PacifiCorp East operators continued to enter positive load adjustments more frequently than negative adjustments during the second quarter, during about 28 percent of 15-minute intervals and 49 percent of 5-minute intervals. During intervals with positive adjustments, the amounts averaged around 102 MW from PacifiCorp East (about 2 percent of area load) during the quarter, as shown in Table 3.1.

PacifiCorp West continued to primarily adjust loads in the downward direction in the second quarter, during about 27 percent of intervals in the 15-minute market and 40 percent of intervals in the 5-minute market. These negative adjustments averaged around -49 MW in the real-time markets.

NV Energy operators adjusted the load forecast more frequently during the second quarter in both the 15-minute and 5-minute markets. Load adjustments in the 15-minute market were primarily positive, occurring during 52 percent of intervals, compared to less than 1 percent of intervals in the negative direction. However, in the 5-minute market, negative load adjustments were entered more frequently, during 14 percent of intervals, at an average of -81 MW. Positive adjustments averaged around 106 MW in the 15-minute market and around 78 MW in the 5-minute market.

Arizona Public Service continued to adjust the load forecast significantly more frequently during the second quarter during about 81 percent of 15-minute and 5-minute intervals, compared to 40 percent of intervals in the prior quarter and 15 percent of intervals in the fourth quarter of 2016. In addition, as a percent of total area load, average load adjustments by Arizona Public Service were larger in magnitude compared to other areas, at over 4 percent of area load. The majority of these adjustments were positive and typically followed the area's load curve with more frequent and larger adjustments during the morning and evening peak load hours.

Puget Sound Energy continued to adjust the load forecast in either direction much less frequently than other areas, during about 4 percent of 15-minute intervals and 8 percent of 5-minute intervals. Because of the low frequency of load adjustments by Puget Sound Energy operators, average hourly net load adjustments were very low during the quarter.

Figure 3.1 Average frequency of positive and negative load adjustments by BAA (15-minute market)

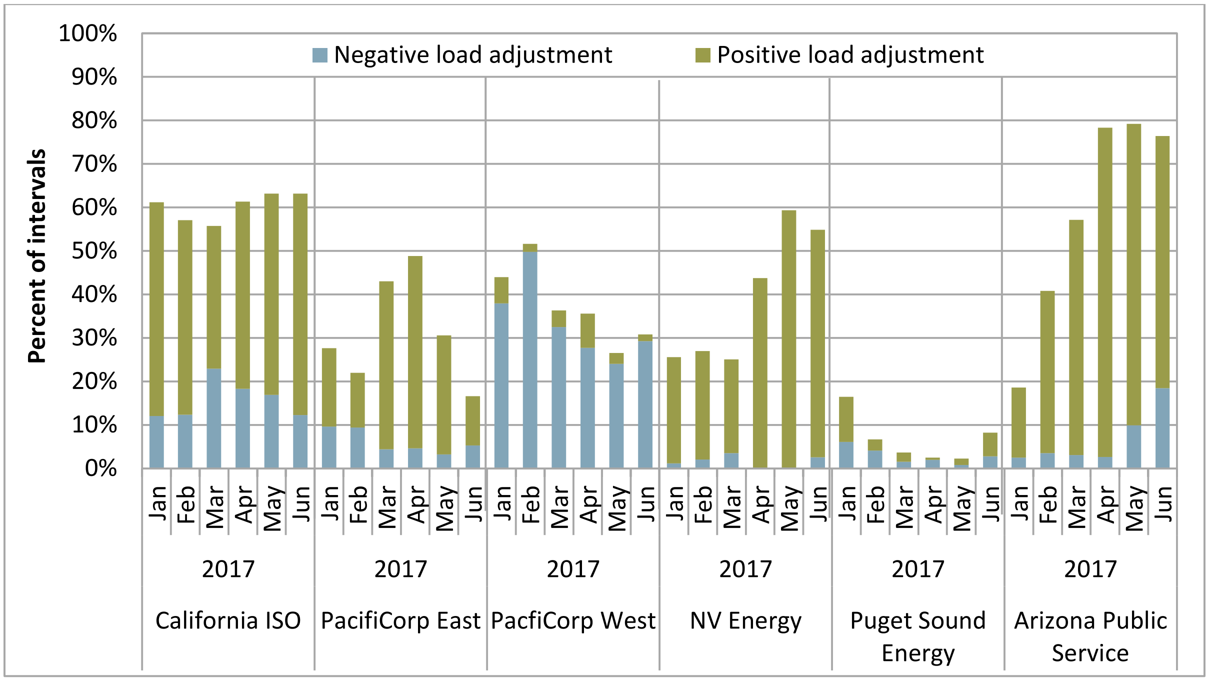


Figure 3.2 Average frequency of positive and negative load adjustments by BAA (5-minute market)

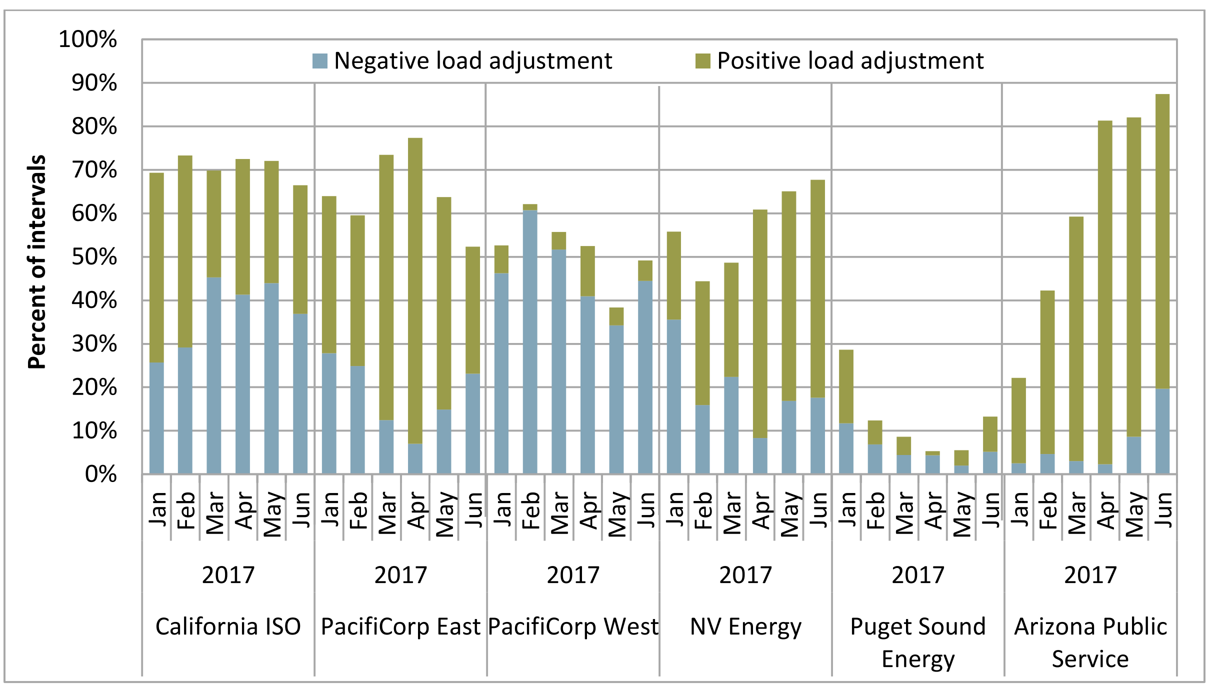


Table 3.1 Average frequency and size of load adjustments (April – June)

	Positive load adjustments			Negative load adjustments			Average hourly bias MW
	Percent of intervals	Average MW	Percent of total load	Percent of intervals	Average MW	Percent of total load	
California ISO							
15-minute market	47%	560	2.0%	16%	-360	1.6%	206
5-minute market	29%	289	1.1%	40%	-331	1.4%	-49
PacifiCorp East							
15-minute market	28%	98	2.1%	4%	-77	1.6%	24
5-minute market	49%	106	2.2%	15%	-80	1.6%	40
PacifiCorp West							
15-minute market	4%	62	2.8%	27%	-46	2.3%	-10
5-minute market	7%	62	2.8%	40%	-52	2.6%	-16
NV Energy							
15-minute market	52%	106	2.4%	1%	-258	3.8%	53
5-minute market	50%	78	1.8%	14%	-81	1.9%	28
Puget Sound Energy							
15-minute market	2%	65	2.4%	2%	-89	4.1%	0
5-minute market	4%	64	2.4%	4%	-85	3.9%	-1
Arizona Public Service							
15-minute market	68%	146	4.1%	10%	-190	5.4%	79
5-minute market	73%	146	4.1%	10%	-192	5.4%	88

Reasons for load adjustments

When the available balancing capacity mechanism was implemented the ISO developed a feature for operators to log pre-specified reasons for making load adjustments using a drop down menu. Operators in the energy imbalance market began regularly logging reasons for adjustments in the 15-minute and 5-minute markets at the beginning of April 2016. These reasons are summarized below.

Reasons for load adjustment in the ISO were classified into four groups:

- load deviation (differences between the load value in the market and actual or expected load);
- resource deviation (difference between resource dispatch operating targets and actual or expected output);
- reliability event (managing transmission exceedance or operating reserves); and
- software issue (errors in market inputs usually driven by other software).

Reasons for load adjustment in the energy imbalance market included:

- load forecast deviation (load deviation from the forecast);
- generation deviation (includes deviation in forecast for variable energy resources, generator startup or shutdown resulting in generation below its minimum operating level, and generation testing);

- reliability based control (informing the market of a need for generation increase or decrease to comply with the balancing authority area limit standard);
- automatic time error correction (informing the market of automatic generation control deviation from zero area control error due to automatic time error correction); and
- schedule interchange variation (changes in scheduled interchange within 40 minutes prior to the interval).

When operators enter a load adjustment duration and quantity, they have the option to select a reason for the load adjustment from a list of predefined reasons.[49] In addition, operators have the ability to include details about why a load adjustment was entered in a free-form text box. If operators enter a load adjustment for more than one reason, they have the ability to select only one preset reason from the list. However, additional reasons can be entered in the free-form text box. Logging additional details or reasons through the text box is optional.

During the quarter, PacifiCorp operators were more likely to include additional detail in the 5-minute market than in the 15-minute market. PacifiCorp East operators entered information in the free-form text box during about 58 percent of 5-minute intervals when load adjustments were entered, while PacifiCorp West operators entered additional information during about 49 percent of 5-minute market adjustments. PacifiCorp frequently used this feature to cite additional reasons beyond the single reason selected from the predefined list. Operators in NV Energy used the additional details text box very frequently, including additional information during around 99 percent of 15-minute and 5-minute intervals when load adjustments were entered. Puget Sound Energy used the free-form text box during about 47 percent of the time load was adjusted in the real-time market, while Arizona Public Service did not use this feature in the second quarter.

At this time, the only method for evaluating additional details about the load adjustment, including details about reliability needs and alternative options evaluated prior to entering a load adjustment, is with the free-form text box. There is no secondary drop down function for operators to track these details. DMM has not observed input in the free-form text box that addresses alternative options to load adjustments considered, and therefore cannot provide any additional information on them at this time. DMM recommends that the ISO modify its tool to allow operators to enter this information or to provide for another process to capture it.

Figure 3.3 and Figure 3.4 show the frequency of load adjustments in the energy imbalance market areas by the reason selected for the adjustment during the previous six months for the 15-minute and 5-minute markets, respectively.[50] During the second quarter, the reasons selected from energy imbalance market entities remained similar to the previous quarter.

49 In the energy imbalance market, in addition to four commonly listed reasons, four less frequently used options are: disturbance response, stranded load, stranded generation, and other event.

50 Analysis was completed for intervals when a bias was entered and a particular reason from the predefined list was specifically selected. They do not include intervals when the reason, also from the list, was indirectly logged as an additional detail in the free-form text box.

Figure 3.3 Frequency of load forecast adjustments by reason (15-minute market)

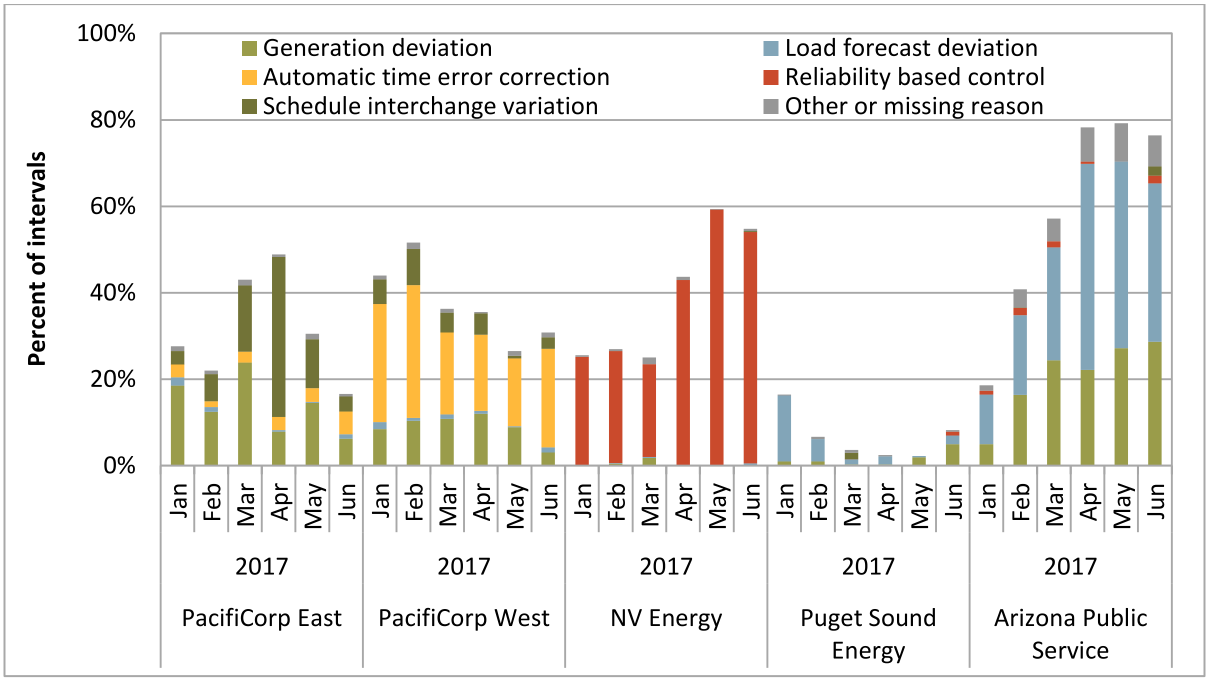
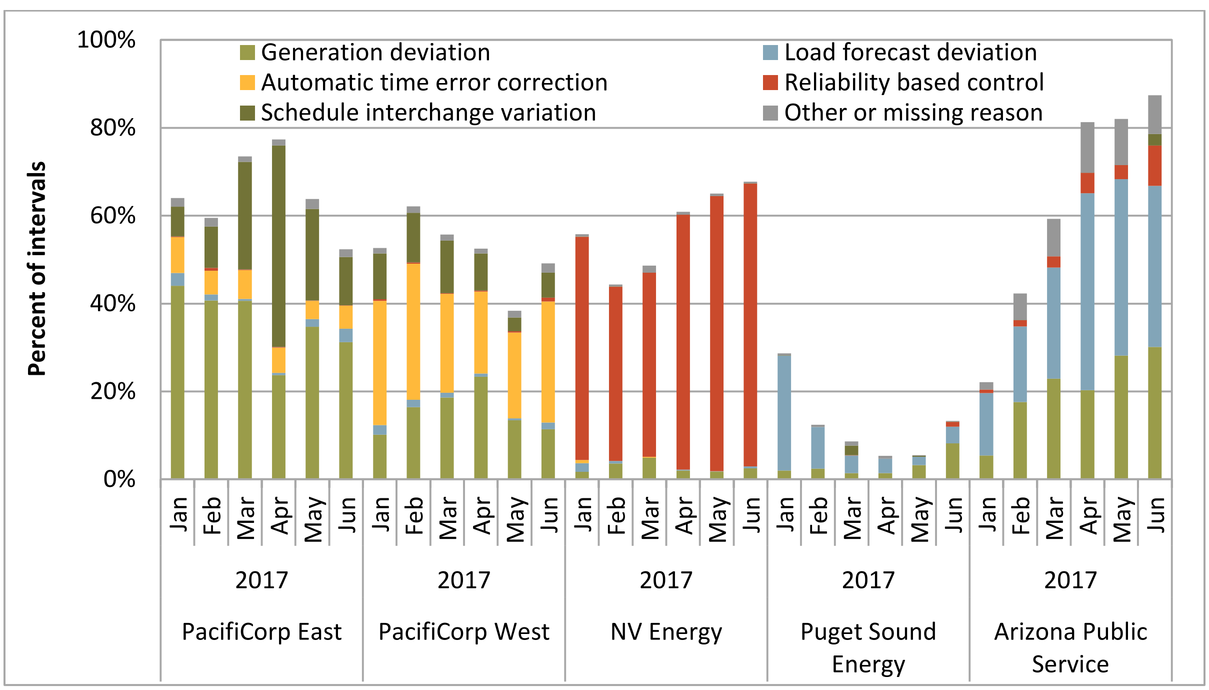


Figure 3.4 Frequency of load forecast adjustments by reason (5-minute market)



PacifiCorp East selected generation deviation during about 31 percent of 15-minute load adjustments and 58 percent of 5-minute load adjustments. These actions were often made to account for wind and solar deviation. During this quarter, PacifiCorp East operators also continued to select schedule interchange variation regularly, during about 41 percent of 15-minute and 5-minute load adjustments.

PacifiCorp West operators primarily selected automatic time error correction and generation deviation. Automatic time error correction was selected for about 61 percent of 15-minute load adjustments and 48 percent of 5-minute load adjustments to account for inadvertent energy. Generation deviation was selected in 30 percent of 15-minute load adjustments and 49 percent of 5-minute load adjustments.

In NV Energy area, operators continued to adjust load most frequently for reliability based control. Through the free-form text box, operators indicated that this option was primarily selected when the load adjustment was used to adjust generation to comply with the balancing authority area limit standards. NV Energy operators selected reliability based control in about 97 percent of intervals with load adjustments.

As mentioned earlier, Arizona Public Service adjusted the load forecast more frequently during the quarter. These adjustments were most frequently for load forecast deviation and generation deviation, in 52 percent and 32 percent of load adjustments, respectively. However, Arizona Public Service regularly did not select a reason from the predefined list during the second quarter, during almost 11 percent of 15-minute and 5-minute market load adjustments.

Impact of load adjustments on prices

The impacts that load adjustments have on prices can range widely and cannot be readily determined or estimated. When load is adjusted upwards, this tends to put upward pressure on prices in the immediate intervals by increasing the demand forecast. However, this upward adjustment may actually help to decrease prices in subsequent intervals by ramping up generation and making more supply available in subsequent periods. Likewise, downward adjustments can lower prices in immediate intervals, but may decrease supply and increase prices in subsequent intervals.

The impact of the load adjustment can be quantitatively assessed in cases when the load bias limiter is triggered.[51] The ISO implemented this feature to limit the effect of load adjustments on prices when adjustments cause power balance constraint relaxations. Prior to the pricing run, the ISO software performs a test to see if operator load adjustments contributed to the relaxation of the power balance constraint in the scheduling run. Specifically, the software compares the magnitude and direction of the power balance relaxation to the operator load adjustment for both shortage and excess events. If the load adjustment exceeds the quantity of the relaxation in the same direction, the size of the load adjustment is automatically reduced in the pricing run to prevent the shortage or excess.

When the load bias limiter is triggered it results in a market solution in the pricing run such that the price is set by the last economic unit dispatched, rather than the $1,000/MWh penalty price for under-supply power balance relaxations or the -$155/MWh penalty price for over-supply power balance relaxations. The functionality of the load bias limiter is similar to the transition period pricing feature

51 This is also sometimes referred to as the load conformance limiter or the load adjustment limiter.

that expired in Puget Sound Energy and Arizona Public Service at the end of the first quarter, as they both set price to the offer price of the last dispatched resource during power balance relaxations.[52]

Table 3.2 shows the estimated net impact of the load bias limiter on energy imbalance market prices during the second quarter. The same data for the ISO is also provided for comparison. Depending on the frequency of power balance constraint relaxations and load adjustment activity, the load bias limiter generally has a net impact that decreases average prices by mitigating potential $1,000/MWh penalty prices from under-supply infeasibilities. For all energy imbalance market areas, the overall impact of the load bias limiter was negative, decreasing average 15-minute and 5-minute prices. In particular, the load bias limiter had a larger impact on 15-minute and 5-minute market prices for Arizona Public Service and NV Energy as well as 5-minute market prices for PacifiCorp East.

In prior quarterly and annual reports, DMM recommended that the ISO consider modifying the load bias limiter to focus on instances where power balance relaxations occur as the result of a *change* in load adjustments, rather than solely the *magnitude* of the adjustment. In December 2016, the ISO released a technical bulletin announcing that they intend to implement this change. This was followed by a stakeholder call in early January to review the proposed enhancement.[53] The proposed logic focuses on the change in the load adjustment relative to changes in the size of power balance relaxations. DMM believes that this approach better isolates the cause-and-effect relationship between an excessive operator adjustment and an infeasibility. DMM provided comments in support of this proposal on May 19.[54]

Table 3.2 also includes average estimated prices during the second quarter if the proposed load bias limiter was active instead of the current load bias limiter. Overall, the proposed load bias limiter would have resulted in a smaller impact on prices during the quarter than the current load bias limiter because of fewer under-supply infeasibilities resolved. The current load bias limiter drove average 5-minute market prices in the ISO down by around $1/MWh while the proposed load bias limiter drove average 5-minute market prices down by around $0.33/MWh.[55]

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52 The transition period pricing feature is active for the first six months of market operation for new energy imbalance market entities and expired for Puget Sound Energy and Arizona Public Service at the end of March 2017.

53 The *Load Conformance Limiter Enhancement – Technical Bulletin* (December 28, 2016) can be found here: http://www.caiso.com/Documents/TechnicalBulletin_LoadConformanceLimiterEnhancement.pdf.

54 *Comments on the Load Conformance Limiter Enhancement*, Department of Market Monitoring (May 19, 2017), can be found here: http://www.caiso.com/Documents/DMMComments-LoadConformanceLimiterEnhancement.pdf.

55 The California ISO prices reflect a simple average over the three major DLAPs: PG&E, SDG&E, and SCE. The impacts of the load bias limiter did not vary much between these areas.

Table 3.2 Impact of load bias limiter on prices (April – June)

	Average price	Average estimated price without the load bias limiter	Estimated impact of current load bias limiter	Average estimated price with the proposed load bias limiter	Estimated impact of proposed load bias limiter
PacifiCorp East					
15-minute market (FMM)	$25.77	$25.95	-$0.18	$25.83	-$0.11
5-minute market (RTD)	$22.47	$24.14	-$1.67	$23.55	-$0.59
PacifiCorp West					
15-minute market (FMM)	$14.07	$14.14	-$0.07	$14.07	-$0.07
5-minute market (RTD)	$11.50	$11.63	-$0.14	$11.46	-$0.17
NV Energy					
15-minute market (FMM)	$32.50	$33.72	-$1.22	$33.54	-$0.17
5-minute market (RTD)	$29.86	$31.60	-$1.73	$31.20	-$0.39
Puget Sound Energy					
15-minute market (FMM)	$11.48	$11.50	-$0.01	$11.43	-$0.07
5-minute market (RTD)	$10.01	$10.19	-$0.18	$10.06	-$0.12
Arizona Public Service					
15-minute market (FMM)	$24.22	$27.08	-$2.86	$27.49	$0.41
5-minute market (RTD)	$23.12	$26.67	-$3.55	$26.74	$0.07
California ISO (LAP average)					
15-minute market (FMM)	$31.29	$31.59	-$0.30	$31.59	$0.00
5-minute market (RTD)	$28.25	$29.30	-$1.05	$28.96	-$0.33

4 Special issues

This section provides information about the following special issues:

- The ISO implemented enhancements to market power mitigation procedures in the 5-minute market on May 2, 2017. Under the new system, congestion is predicted in an advisory 5-minute interval run before the financially binding interval rather than being dependent on congestion in the 15-minute market. This change to the ISO's real-time market power mitigation procedure increased its accuracy and significantly reduced instances of underestimated congestion.
- On June 21, system marginal prices in the day-ahead market reached record highs, since surpassed, with prices greater than $200/MWh during a five-hour period and prices over $600/MWh in one hour. On this day, prices in the market run were significantly higher than in the market power mitigation run. This has occurred on other high load days in recent months as well. DMM expects that prices should generally not be significantly higher in the final market run than in the market power mitigation run. Both DMM and the ISO will continue to investigate this issue.
- DMM's analysis of same-day natural gas price volatility in Southern California during the first and second quarters of 2017 shows that there was a very limited need for the increased bidding flexibility created by raising the commitment cost and default energy bid caps. Following DMM's analysis and recommendations, the ISO has decided to reduce to zero the special Aliso Canyon gas price scalars which are being used in the real-time market. This change went into effect in the market starting August 1, 2017.
- The resource adequacy availability incentive mechanism (RAAIM) became effective in April. The ISO identified a number of issues with the mechanism and is working to correct them. Some of these changes will be put in place in the fall software release and applied retroactively, and some will be released at a later date and will be applied proactively. Current settlements figures for this mechanism remain advisory, and will begin being financially binding after the fall software updates are made.
- During the first two quarters of the year resource adequacy procurements and availability were highest during June. In June, about 43,300 MW of resource adequacy capacity was procured and an average of around 39,200 MW (or about 91 percent) was available in the day-ahead market.
- Three resources received capacity procurement mechanism payments in the second quarter. These payments totaled about $0.4 million, and the largest of these payments was made to the Otay Mesa unit, which received a 155 MW designation at $4.16/kW-month for the later part of May. This designation was made on a day when loads were higher in real-time than expectations.

4.1 Evaluation of real-time local market power mitigation enhancements

Starting in 2015, DMM and the ISO began designing enhancements to the real-time market power mitigation systems. Enhancements were designed for both the 15-minute and 5-minute markets. The last of these enhancements, for the 5-minute market, was implemented on May 2, 2017.

Before the 5-minute enhancements, mitigation in the 5-minute market was dependent on congestion in the 15-minute market. Under the new system, congestion is predicted in an advisory 5-minute interval run before the financially binding interval run. This system has proven much more accurate than using the results of the corresponding 15-minute interval, particularly for energy imbalance market transfer constraints.

Table 4.1 and Table 4.2 show a comparison of the accuracy before and after the recent enhancements made in the 5-minute market. For both energy imbalance market transfers and flow based constraints, the new systems represent a marked improvement. In particular, this change to the ISO's real-time market power mitigation procedure increased its accuracy and significantly reduced instances of underestimated congestion. The increased accuracy ensures the effectiveness of these automated mitigation procedures and mitigates concern that an energy imbalance market entity would have the opportunity to exercise market power through economic withholding.

Table 4.1 Comparison of 5-minute market power mitigation systems on flow based constraints

	Accurately predicted	Over predicted	Under predicted
June 2016 - May 1 2017	72%	13%	14%
May 2 - July 31 2017	84%	14%	2%

Table 4.2 Comparison of 5-minute market power mitigation systems on EIM transfer constraints

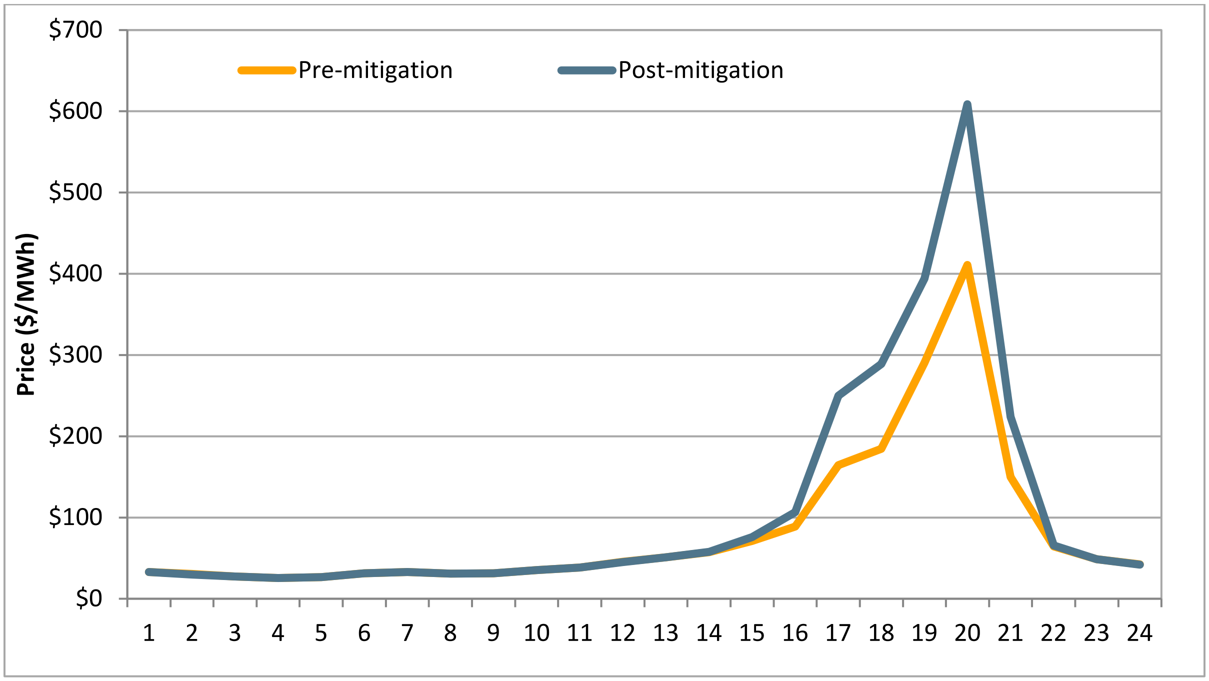
	Accurately predicted	Over predicted	Under predicted
Jun 2016-May 1 2017	29%	30%	41%
May 2 2017-July 31 2017	56%	35%	8%

4.2 Price differences following market power mitigation in the day-ahead market

In the day-ahead market, the market power mitigation run is performed immediately before the integrated forward market run and is designed to use the same initial input data, except for bids that are mitigated as a result of the market power mitigation run.

On June 21, prices in the day-ahead market post-mitigation pricing run were substantially higher than prices in the market power mitigation (MPM) run through all hours of the peak as shown in Figure 4.1. The total bid cost of energy in the binding pricing interval run was about $1 million higher than the bid cost before market power mitigation. However, energy revenues were almost $25 million greater in the binding integrated forward market run than in the market power mitigation run due to the magnified impact that higher prices have on the total market.

Figure 4.1 Comparison of day-ahead market system marginal energy prices on June 21, 2017



Similar discrepancies have occurred on other days in both the day-ahead and real-time markets. The ISO has offered two explanations for this phenomenon: (1) differences in commitment due to reduction in bids in the market power mitigation run and (2) differences in the solution due to independence of market runs and solution error tolerance.[56]

Both explanations are theoretically possible. Mitigation, when enforced, can lower energy bids or leave them unchanged, which would be expected to result in a lower energy price. However, the multi-interval optimization minimizes total bid in production costs in both the market power mitigation and binding runs. Reducing some energy bids may result in a solution with lower overall costs by committing resources with a lower commitment cost bid but higher energy bid in some hours.

In the day-ahead market on June 21, bids were mitigated in each hour between 12 and 23. The ISO's market includes local market power mitigation which can mitigate bids when market power is predicted to exist in a local area due to transmission congestion. If congestion exists post mitigation the effect of changing bids should be local within the mitigated interval.

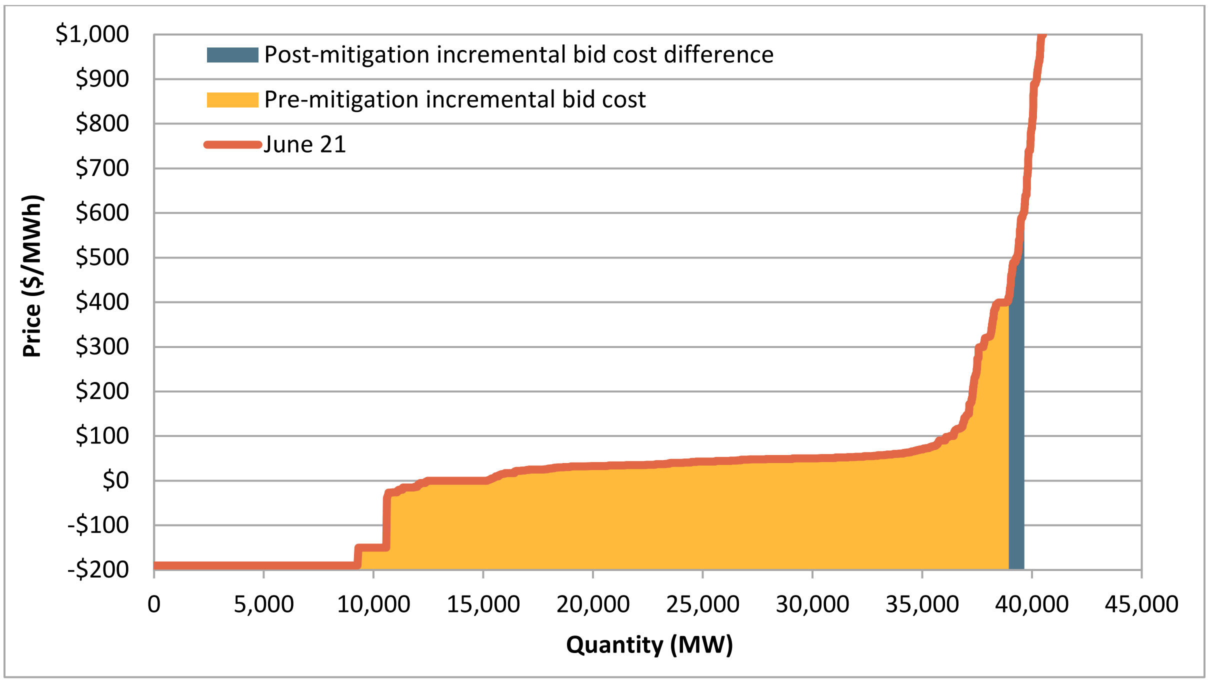
DMM's review suggests that differences in commitment due to mitigation do not appear to have caused the increase in prices on this day. Only one resource configuration with a mitigated bid was committed in the binding run but not in the mitigation run. Over all hours of June 21, the binding interval run

[56] "MPM and IFM runs are two different market runs and they produce two completely different solutions which are independent of each other. The bid sets for IFM can be different than that of MPM run due to mitigation leading to mitigated bids. Having a different set of input bids may lead to a slightly different solutions. In the day-ahead market, another complexity is that the market is also solving a unit commitment problem, so when bids are changed in some hours it may actually lead to a different commitment profile which may result in different pricing outcome." Meeting minutes of the market update call August 3, 2017, located here: http://www.caiso.com/Documents/MeetingMinutesMarketUpdateCallAug032017.pdf

included over 6 GWh of additional capacity at minimum load. Over 500 MWh of commitment occurred in each hour across the peak. A review of differences in commitment does not indicate that commitment costs were significantly lower in binding intervals. Additional committed capacity would be predicted to *decrease* rather than *increase* the total cost of dispatched energy bids.

Figure 4.2 illustrates the difference in the total incremental bid cost between the binding and market power mitigation runs on June 21 in hour ending 20. The incremental bid cost in each hour is estimated as the integral of the supply curve up to the system marginal energy cost in that hour. The difference in total incremental bid cost between the binding and mitigation run prices in this hour is represented in the chart as the blue area under the supply curve between the two prices, or over $360 thousand. The difference in total incremental bid cost summed over all hours of June 21 was almost $1 million. The difference between the total market energy cost across the day was almost $25 million.

Figure 4.2 Supply curve June 21 hour 20



The substantial increase in incremental bid cost between the runs and increase in commitment in the binding run indicates that market power mitigation is unlikely to have been the source of the increase in cost in the binding run. If mitigation itself did not cause the change in solution, the explanation must lie elsewhere.

4.3 Aliso Canyon gas-electric coordination

Following a significant natural gas leak in late 2015, the injection and withdrawal capabilities of the Aliso Canyon natural gas storage facility in Southern California were severely restricted. These restrictions impact the ability of pipeline operators to manage real-time natural gas supply and demand deviations, which in turn could have impacts on the real-time flexibility of natural gas-fired electric generators in Southern California. This primarily impacts resources operated in the Southern California Gas Company

(SoCalGas) and San Diego Gas and Electric (SDG&E) service areas, collectively referred to as the SoCalGas system.

Operational tools and corresponding mitigation measures

The ISO has developed a set of operational tools to manage potential gas system limitations that allows operators to restrict the gas burn of ISO natural gas-fired generating units. The tools, which were implemented as a set of nomogram constraints, can be used to limit either the total gas burn or deviations in gas burn compared to day-ahead schedules. These tools were available to operators beginning June 2, 2016.[57]

The ISO enforced two gas constraints (San Diego Gas and Electric system and the broader Southern California Gas Company system) on four days, from January 23-26. These constraints do not appear to have been sufficient, on their own, to limit gas burn from participating gas resources. However, based on observed system conditions, operators did not elect to enforce these constraints during the second quarter of 2017.

Additional bidding flexibility for SoCalGas resources

Starting July 6, 2016, to allow natural gas-fired generators in the SoCalGas system to reflect higher same day natural gas prices and to avoid having these resources dispatched for system needs in the event of constrained gas conditions in Southern California, the ISO adjusted the gas price indices used to calculate the commitment cost caps and default energy bids in the real-time market for natural gas-fired generators on the SoCalGas systems. A 75 percent adder was included in the fuel cost component used for calculating proxy commitment costs for resources on the SoCalGas systems in real time. The ISO also included a 25 percent adder for the fuel cost component of default energy bids in the real-time market. The 75 percent and 25 percent adders implemented by the ISO were based on analysis presented by DMM in its comments on the final Aliso Canyon gas-electric coordination proposal.[58]

DMM's analysis of same-day natural gas prices in Southern California in the second quarter of 2017 shows that these adders caused gas prices used to calculate bid caps to exceed prices of all but a very small portion of natural gas transactions. Figure 4.3 shows same-day trade prices for the SoCal Citygate during April through June 2017 compared to the next-day average price. About 20 percent of traded volume on the Intercontinental Exchange (ICE) exceeded the normal 10 percent scalar adder at the SoCal Citygate and none of the traded volume exceeded the 25 percent adder.

Figure 4.3 also shows that the majority of trades above the 10 percent level occurred on days that were the first trading day of the week, which was typically a Monday (as shown in green on the chart). Similar to the first quarter, this analysis shows that there was a very limited need for the increased bidding flexibility created by raising the commitment cost and default energy bid caps during the second quarter.

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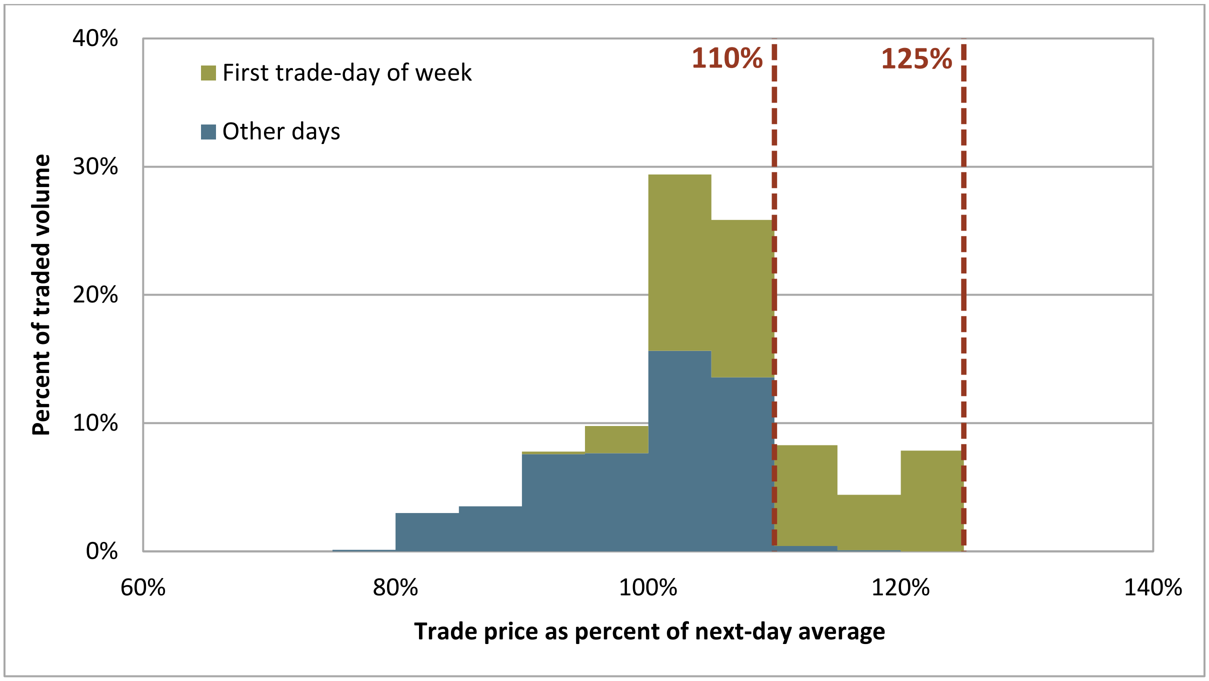
57 Refer to *Operating Procedure 4120C used during SoCalGas area limitations or outages:* http://www.caiso.com/Documents/4120C.pdf.

58 *Comments on Final Aliso Canyon Gas-Electric Coordination Proposal*, Department of Market Monitoring, May 6, 2016: http://www.caiso.com/Documents/DMMComments_AlisoCanyonGas_ElectricCoordinationRevisedDraftFinalProposal.pdf.

Following DMM's analysis and recommendations, the ISO has decided to reduce to zero the special Aliso Canyon gas price scalars which are being applied to commitment cost and default energy bids used in the real-time market.[59] This change went into effect in the market starting August 1, 2017.[60]

Following a curtailment watch issued by SoCalGas due to an unplanned pipeline outage, the ISO adjusted the scalars to 75 percent and 25 percent for commitment cost and default energy bid calculation effective August 4, 2017.[61] Effective August 8, 2017, the ISO lowered the scalars back to zero for commitment cost and default energy bid calculation based on the gas supply conditions and levels of load in the ISO system.[62]

Figure 4.3 Same-day trade prices compared to next-day index (April - June)



[59] *Comments on Aliso Canyon Gas-Electric Coordination Phase 3 Draft Final Proposal*, Department of Market Monitoring, May 6, 2016: http://www.caiso.com/Documents/DMMComments_AlisoCanyonGas_ElectricCoordinationPhase3DraftFinalProposal.pdf

[60] *Market Notice - Adjustment of Gas Price Index Scaling Factors*, July 31,2017: http://www.caiso.com/Documents/Adjustment_GasPriceIndexScalingFactors.html

[61] *Market Notice - Adjustment of Gas Price Index Scaling Factors*, August 3,2017: http://www.caiso.com/Documents/Adjustment_GasPriceIndexScalingFactors080317.html

[62] *Market Notice - Adjustment of Gas Price Index Scaling Factors*, August 7,2017: http://www.caiso.com/Documents/Adjustment-GasPriceIndexScalingFactorsEffective080817.html

More timely natural gas prices for the day-ahead market

Through its May 2016 FERC filing, the ISO also received authority to use a more timely natural gas price for calculating default energy bids and proxy commitment costs in the day-ahead market. With this modification, the ISO is basing natural gas price indices on next-day trades from the morning of the day-ahead market run instead of indices from the prior day.

Figure 4.4 and Figure 4.5 illustrate the benefit of using the updated natural gas price index in the second quarter of 2017. Figure 4.4 shows next-day trade prices reported on ICE for the SoCal Citygate during the second quarter, compared to the next-day price index previously used in the day-ahead market which was lagged by one trade day. As shown in Figure 4.4, about 3 percent of next-day trades were at a price in excess of the 10 percent adder normally included in default energy bids. None of the next-day trades were in excess of the 25 percent headroom normally included in commitment cost bid caps.

Figure 4.5 shows the same data but compares the price of each trade to a weighted average of trades reported on ICE before 8:30 am, just before the ISO runs the day-ahead market. This represents the updated method that the ISO is currently using. As shown in Figure 4.5, all trade prices are now within the 10 percent adder normally included in default energy bids.

Figure 4.4 Next-day trade prices compared to next-day index from prior day (April - June)

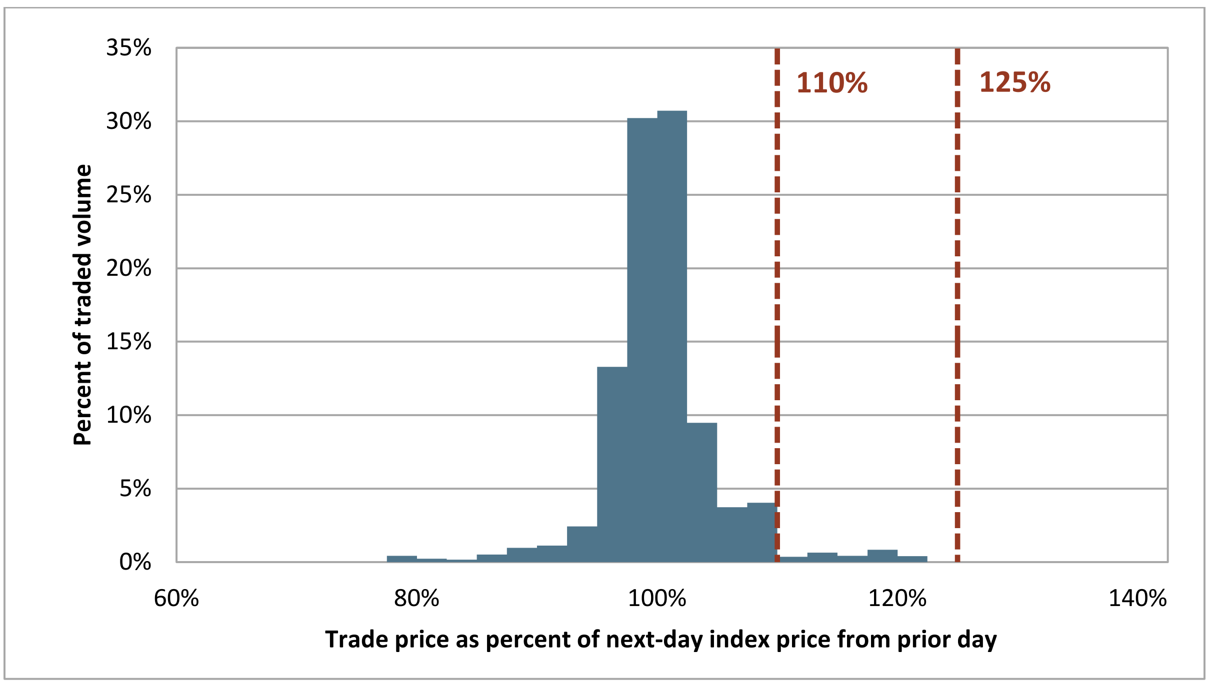
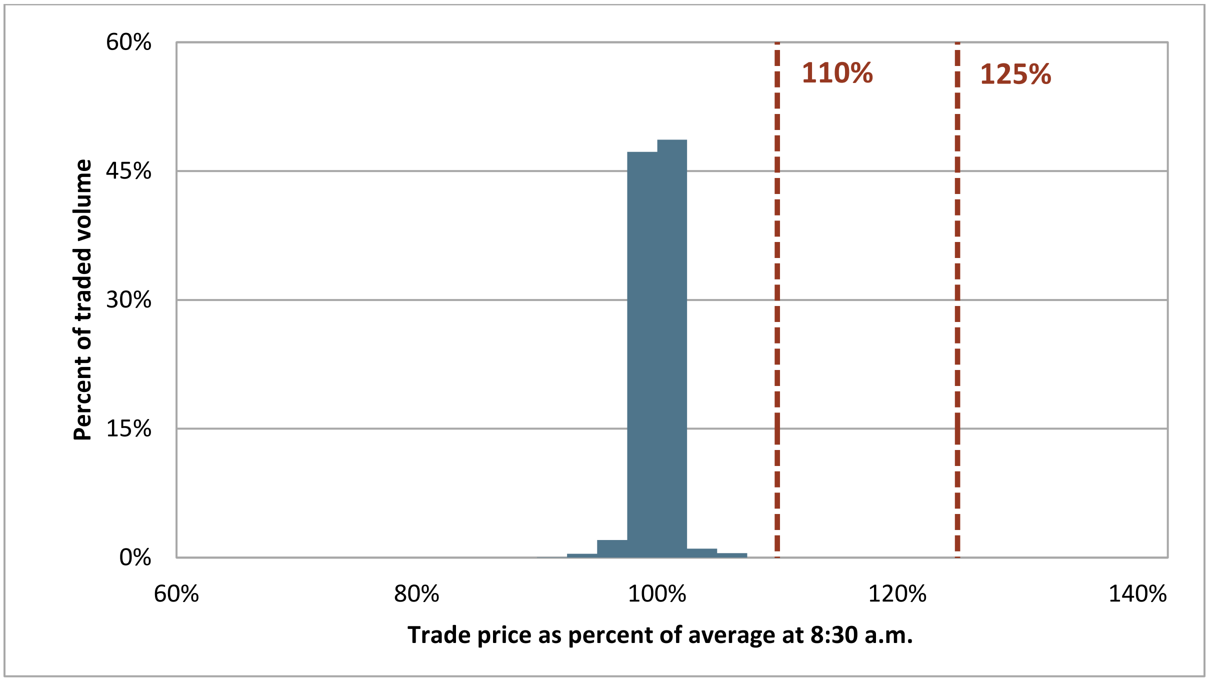


Figure 4.5 Next-day trade prices compared to updated next-day average price (April - June)



4.4 Resource adequacy

4.4.1 Resource adequacy availability incentive mechanism

The reliability services initiative is a two-phase initiative focusing on the ISO's rules and processes relating to the resource adequacy program. Issues addressed in this initiative include resource adequacy rules for replacement and substitute capacity, definitions and qualifying criteria for new technology resources, and a compliance mechanism for resource adequacy resources. The first stage of the initiative was approved by FERC in October 2015 and implementation began in 2016.

One of the biggest developments in the filing approved by FERC was the creation of the resource adequacy availability incentive mechanism (RAAIM), which is a new compliance measurement mechanism that is meant to incentivize units to provide energy bids in the day-ahead and real-time markets at or above must-offer obligations. This mechanism differs from the previous standard capacity product (SCP) mechanism in numerous ways, most notably by measuring availability by compliance with a resource's must-offer obligation instead of whether or not the resource was on outage. The basic concept of the must-offer obligation is that a resource must be available to the market, through self-scheduling or by submitting bids. This change allows for evaluation of more detailed must-offer obligation of flexible resource adequacy resources.

Although the new availability incentive mechanism was implemented on November 1, 2016, settlement results were not scheduled to be financially binding until April 2017. Advisory results were provided to scheduling coordinators for review in the interim. In the absence of financially binding resource adequacy performance penalties, resources faced no financial penalty for failure to bid into the ISO's markets in accordance with their must-offer obligation, although their tariff obligation to do so remained.

During the interval when advisory results were being published, the ISO identified a number of issues with the current implementation of the availability incentive mechanism, some of which have already been addressed, and some of which will be addressed with software updates in the fall release. The ISO will continue to produce advisory settlement totals using the current mechanism. These calculations will become financially binding, retroactively, beginning on April 1, after the software changes are implemented in November.

Further enhancements

In addition to the changes that the ISO identified above, there is an additional defect in the way that this mechanism calculates payments for resources that have awards for both flexible and system resource adequacy. The issue stems from flexible capacity and system capacity being used jointly to calculate a total capacity availability for each resource, which is then assessed availability incentive mechanism charges. Because there are more hours in a month that category 1 flexible resource adequacy is required to bid in than system capacity, and all hours are weighted the same, there can be instances where total charges for unavailable system capacity may be diluted.[63] Similarly, charges for unavailable flexible capacity may be inflated, during hours when there are no system capacity bidding requirements.

The ISO released a white paper outlining the details of this defect and the solution they wish to pursue.[64] DMM agrees that this defect should be addressed, and recommends that the ISO clearly define the mathematical calculation that will be used to assess the availability incentive mechanism payments.

The ISO plans to propose the changes outlined in the white paper on the resource adequacy availability incentive mechanism to the Board of Governors in early November 2017, and to implement changes to the mechanism in the spring of 2018. All changes implemented at that time will be effective going forward, and will not be retroactively applied to any settlements totals.

4.4.2 System resource adequacy availability

System resource adequacy capacity is especially important to meet peak loads during the summer months. Load-serving entities procure resource adequacy capacity to meet system-level requirements. Scheduling coordinators are then incentivized to make resource adequacy capacity available in the market during *availability assessment hours* through the resource adequacy availability incentive mechanism. These are hours ending 14 through 18 during April through October, and hours ending 17 through 21 during the remainder of the year.[65]

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63 Category 1 flexible resource adequacy is required to bid into the market for 17 hours during each day, and all days during the month. System capacity is only required to bid into the market during five hours of the day and between 20 and 23 (non-weekend) days during the month.

64 *Resource Adequacy Availability Incentive Mechanism Modification White Paper*, August 31, 2017. http://www.caiso.com/Documents/WhitePaper-RAAIMCalculationModifications.pdf.

65 In April, the ISO began an initiative through the business practice manual change management process to change the resource adequacy availability hours for the 2018 year, but ultimately did not. This process is documented here: https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=986.

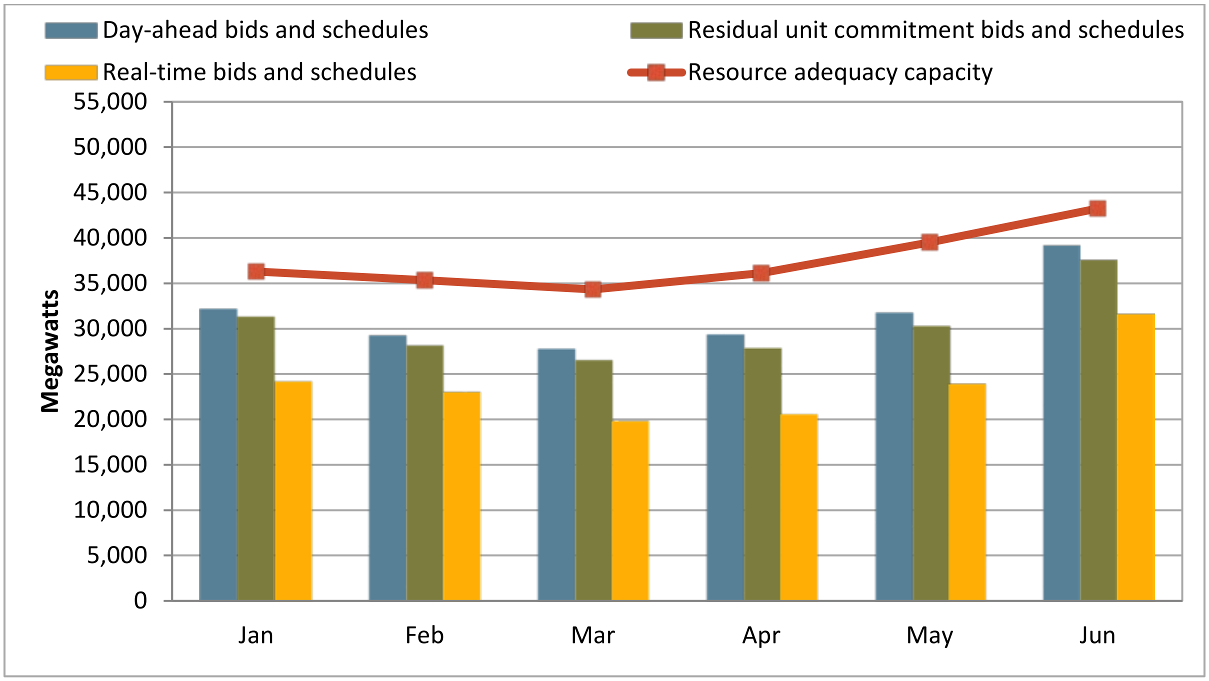
A high portion of resource adequacy capacity was available to the market throughout the first half of 2017. Figure 4.6 summarizes the average monthly amount of resource adequacy capacity available in the day-ahead, residual unit commitment and real-time markets during the availability assessment hours. The red line shows the total amount of resource adequacy capacity used to meet requirements. The bars show the amount of resource adequacy capacity that was self-scheduled or bid in the day-ahead, residual unit commitment, and real-time markets.[66]

Key findings of this analysis include the following:

- The highest percentage of resource adequacy procurements that were made available occurred during June. During this month, out of about 43,300 MW of resource adequacy capacity procured, an average of around 39,200 MW (or about 91 percent) was available in the day-ahead market. The highest amount of resource adequacy capacity procured also occurred in June, leading into the summer months when loads are typically highest.
- Solar generators in June were the fuel type that had the largest difference between procured resource adequacy capacity and the amount self-scheduled or bid during the availability assessment hours. Resource adequacy capacity availability from variable energy resources is limited by generation forecasts. In particular, the hours reflected in Figure 4.6 tend to be during times of the day when solar generation is ramping off or unavailable completely, and therefore not available in the day-ahead market.
- Almost all capacity offered in the day-ahead market during 2017 was also available in the residual unit commitment process.
- Figure 4.6 also shows that a smaller portion of resource adequacy capacity was available in the real-time market. This is primarily because many long-start gas-fired units are not available in the real-time market if they are not committed in the day-ahead energy market or residual unit commitment process.

[66] These amounts are calculated as the hourly average of total bids and schedules available to each of these markets during the resource adequacy standard capacity product *availability assessment hours* during each month. These are operating hours 14 through 18 during April through June and operating hours 17 through 21 during the remainder of the year.

Figure 4.6 Monthly resource adequacy capacity scheduled and bid into ISO markets (2017)



4.4.3 Capacity procurement mechanism

The capacity procurement mechanism within the ISO tariff provides backstop procurement authority to ensure that the ISO will have sufficient capacity available to maintain reliable grid operations. This mechanism establishes a price at which the ISO can procure backstop capacity to meet local resource adequacy capacity requirements that are not met through bilateral purchases. This backstop authority also mitigates the potential exercise of locational market power by resources needed to meet local reliability requirements.

The ISO's capacity procurement mechanism tariff authority expired in 2016 and was replaced with a new approach. FERC instructed the ISO in a 2011 order to develop enhanced backstop provisions that would do the following:

1) procure capacity at a price that accounts for market conditions that change over time;

2) provide a reasonable opportunity for suppliers to recover fixed costs; and

3) support incremental investment for existing resources to perform long-term maintenance or make improvements that are necessary to satisfy environmental requirements or address reliability needs associated with renewable resource integration.

In response, the ISO proposed replacement of the administrative rate with a competitive bid solicitation process to determine the backstop capacity procurement price for the mechanism. DMM supported the tariff revision as a means of balancing the ISO's need to procure backstop capacity for reliability and mitigate potential local market power with the broader goal of providing an incentive for capacity to be met by resource adequacy capacity procured in the bilateral market. In October 2015, FERC issued an order accepting the ISO's proposed tariff revisions amending the existing capacity procurement mechanism.[67]

The amended capacity procurement mechanism implemented on November 1 is designed to allow competition between different resources that may meet capacity needs when possible. The new program allows resources to submit bids for capacity through a competitive solicitation process. The ISO will look to those bids first, when possible, to fulfill procurement needs.

The tariff revisions include a soft offer cap initially set at $75.68/kW-year (or $6.31/kW-month) by adding a 20 percent premium to the estimated going-forward fixed costs for a mid-cost 550 MW combined cycle resource with duct firing, as estimated in a 2014 report by the California Energy Commission.[68] However, a supplier may apply to FERC to cost-justify a price higher than the soft offer cap prior to offering the resource into the competitive solicitation process or after receiving a capacity procurement mechanism designation by the ISO.

Scheduling coordinators may submit competitive solicitation process bids for three offer types: yearly, monthly and intra-monthly. In each case, the quantity offered is limited to the difference between the resource's maximum capacity and capacity already procured as either resource adequacy capacity or through the ISO's capacity procurement mechanism.

The ISO inserts bids significantly above the soft offer cap for each resource with qualified resource adequacy capacity not offered in the competitive solicitation process up to the maximum capacity of each resource as additional capacity that could be procured. If capacity in the ISO generated bid range receives a designation through the capacity procurement mechanism, the clearing price will be set at the soft offer cap. A scheduling coordinator receiving a designation for capacity with an ISO generated bid may choose to decline that designation within 24 hours of receiving notice by electronic mail.

The ISO uses the competitive solicitation process to procure backstop capacity in three distinct processes. First, if insufficient cumulative system, local, or flexible capacity is shown in annual resource adequacy plans the ISO may procure backstop capacity through an annual competitive solicitation process using annual bids. The annual process may also be used to procure backstop capacity to resolve a collective deficiency in any local area.

Second, the ISO may procure backstop capacity through a monthly competitive solicitation process in the event that insufficient cumulative capacity is shown in monthly resource adequacy plans for local, system or flexible resource adequacy. The monthly process may also be used to procure backstop capacity in the event that cumulative system capacity is insufficient due to planned outages.

Third, the intra-monthly competitive solicitation process can be triggered by exceptional dispatch or other significant events. Capacity procurement mechanism designations for risk of retirement are not included in the annual, monthly or intra-monthly competitive solicitation processes.

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[67] *Order Accepting CAISO's Proposed Capacity Procurement Mechanism Tariff Revisions* (ER15-1783), October 1, 2015: http://www.caiso.com/Documents/Oct1_2015_OrderAcceptingTariffRevisions_CapacityProcurementMechanism_ER15-1783.pdf.

[68] Rhyne, Ivin, Joel Klein. 2014*. Estimated Cost of New Renewable and Fossil Generation in California*. California Energy Commission. CEC-200-2014-003-SD.: http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SD.pdf

Capacity procurement mechanism designations issued in the second quarter of 2017 were all triggered by exceptional dispatch in the intra-monthly competitive solicitation process. The designations for the Mandalay resources were not a result of the competitive solicitation process where the scheduling coordinator submits bids.[69] Rather, the ISO generated bids for their capacity, along with other facilities, at a price above the $6.31/kW-month soft cap. Prices for accepted designations in this range were then set at the soft offer cap of $6.31/kW-month, in accordance with the process described earlier.

Several additional designations were declined by one scheduling coordinator. Scheduling coordinators receiving an exceptional dispatch for capacity that is not designated through the resource adequacy process may choose to decline a capacity procurement mechanism designation by contacting the ISO through appropriate channels within 24 hours. If the designation occurs within business hours, a scheduling coordinator may receive a courtesy notice of a designation via electronic mail. A scheduling coordinator may choose to decline a designation to avoid the associated must-offer obligation and to reduce capacity costs passed to a single transmission access charge area or to the system as a whole.

The total estimated cost of capacity procurement mechanism designations issued in the second quarter was less than $0.4 million. The total cost was charged to the system area, and there were no payments to any specific area.

Table 4.3 Capacity procurement mechanism costs

Resource	CPM desicgnation (MW)	CPM deisgnation dates	Price ($/kW-mon)	Estimated cost ($ million)	Local capacity area	Exceptional dispatch CPM trigger
OTAY MESA ENERGY CENTER	155.01	5/22-5/31	$4.16	$0.21	System	Higher loads in real-time
MANDALAY GEN STA. UNIT 1	20.01	6/18-6/30	$6.31	$0.05	System	High temperatures and loads
MANDALAY GEN STA. UNIT 2	20.01	6/18-7/17	$6.31	$0.13	System	High temperatures and loads

Additional improvements

Though DMM believes that this mechanism is a significant improvement over the previous standard capacity product, it could be further improved by incorporating a measure of performance. It is problematic to rely solely on market bids as a measure for compliance because a resource could offer into the market without necessarily having the ability to perform. The ISO, in consultation with local regulatory agencies, specifies the criteria for resource characteristics and locations that will ensure system reliability. However, if resource adequacy resources do not perform according to the characteristics the ISO assumes for the resources, the resource adequacy process may not ensure system reliability. Therefore, DMM encourages the ISO to consider performance based enhancements to this mechanism to penalize resources that cannot consistently perform at the standards the ISO assumes for the resources in the ISO's reliability studies.

DMM continues to be concerned about the mechanism's penalty price. The ISO set the penalty price for not meeting availability standards at 60 percent of the soft offer cap for the capacity procurement mechanism. As DMM has noted in past annual reports, if the cost of replacement capacity approaches the soft offer cap, it will be less costly for generating unit owners to pay the penalty rather than provide substitute capacity. This could decrease reliability and increase the probability of costly backstop

[69] At the December 7, 2016, Market Performance and Planning Forum, the ISO indicated that there were some initial implementation issues that may have affected some of the designations.

procurement. DMM recommends that the ISO monitor this issue now that the new incentive mechanism is implemented.