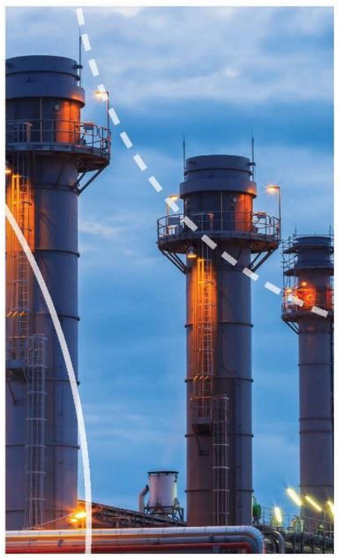
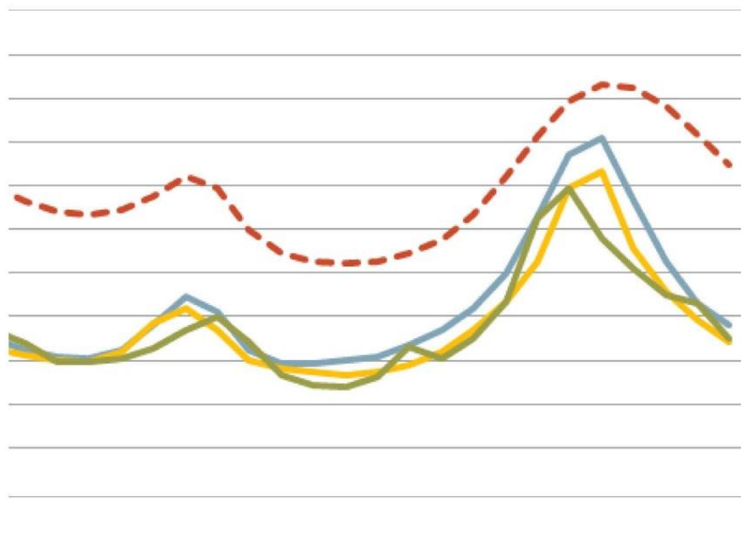
2018

ANNUAL REPORT ON MARKET ISSUES & PERFORMANCE

California ISO

ACKNOWLEDGEMENT

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Executive summary

This report presents the annual report on market issues and performance by the Department of Market Monitoring (DMM). The report finds that the ISO and energy imbalance markets continued to perform efficiently and competitively overall in 2018. Other key highlights include the following:

- The total estimated wholesale cost of serving load in 2018 was about $10.8 billion or about $50/MWh. This represents a 24 percent increase that was driven primarily by a 25 percent increase in natural gas prices. After adjusting for higher natural gas costs and changes in greenhouse gas prices, wholesale electric costs increased by about 4 percent.

- System loads were moderate and significantly lower than in 2017. Summer loads peaked at 46,427 MW, close to the 1-in-2 year load forecast and 7 percent lower than in 2017. System energy totaled 223,705 GWh or 2 percent lower than 2017 and the lowest annual system energy in five years.

- Day-ahead prices were often driven by gas prices in the next-day gas market for SoCal Citygate, where gas prices increased significantly in 2018. The very high prices at SoCal Citygate were driven by supply limitations and the potential for high noncompliance charges associated with operational flow orders (OFOs).

- The ISO's energy markets were generally competitive in 2018. However, analysis indicates that prices were significantly in excess of competitive levels in some hours when net load that must be met by gas-fired units is highest.

- Day-ahead prices reached historic highs on a few days, driven largely by spikes in the price of natural gas at SoCal Citygate. Prices in the day-ahead market were consistently higher than real-time prices in most hours, particularly the third and fourth quarters when day-ahead prices were highest.

- Lower prices in the real-time market were driven in part by additional supply from renewables and other balancing areas available in real time. Real-time prices were also lower in many hours due to manual adjustments made to the hour-ahead load forecast and additional energy from out-of-market unit commitments and energy dispatches issued after the day-ahead market.

- The frequency of negative system marginal prices in the day-ahead market dropped from 110 hours in 2017 to 80 hours in 2018.

- Expansion of the western energy imbalance market (EIM) helped improve the overall structure and performance of the real-time market in the ISO and other participating balancing areas. In April 2018, two new market participants, Powerex and Idaho Power, joined the energy imbalance market.

- The frequency and impact of automated local market power bid mitigation provisions increased notably in 2018 but remained relatively low overall. Most of the increase in mitigation in EIM was due to an increase in the number of balancing areas participating in 2018 compared to 2017.

- Payouts to congestion revenue rights (CRRs) sold in the ISO's auction exceeded auction revenues by over $131 million in 2018. These losses are borne by transmission ratepayers who pay for the full cost of the transmission system through the transmission access charge (TAC). These losses now total over $866 million since the start of the congestion revenue rights auction in 2009.

Several other factors contributed to increased wholesale energy costs in 2018:

- Ancillary service costs increased to $189 million, up from $158 million in 2017 and $116 million in 2016. The increase in operating reserve costs was primarily driven by tight supply conditions and high energy prices during the summer.
- Bid cost recovery payments in the ISO increased to the highest value since 2011, totaling $153 million, or about 1.4 percent of total energy costs. These costs had been decreasing since 2013 until 2017. High gas prices in the SoCalGas service area were a key driver of higher bid cost recovery payments. Payments for gas units committed to operate by grid operators through exceptional dispatches were also a key driver, increasing from $16.6 million in 2017 to $40.6 million in 2018.
- Total energy from all types of exceptional dispatches by grid operators increased in 2018 but continued to account for a relatively low portion of total system load (.07 percent).
- Total above-market costs due to exceptional dispatch increased over 150 percent to about $52 million. Over $40 million of these payments were for units committed to operate via exceptional dispatch. Bid mitigation which was applied to some exceptional dispatches for energy avoided about $18 million in additional out-of-market costs in 2018.
- Total real-time imbalance offset costs increased by 56 percent to $128 million. Much of this increase appears to have been caused by persistent and significant reductions in constraint limits made by grid operators in the 15-minute market relative to higher limits used in the day-ahead market.
- Locational price differences due to congestion increased in 2018, particularly on constraints associated with major transmission limits separating northern and southern California (Path 26) in the third quarter. For the year, congestion increased day-ahead prices in SCE by $1.87/MWh and in SDG&E by about $4.19/MWh, and decreased prices in the PG&E area by $2.73/MWh.

This report also highlights key aspects of market performance and issues relating to longer-term resource investment, planning and market design.

- Gas capacity retiring from the market was largely replaced with renewable resources. The ISO anticipates a continued increase in renewable generation in the coming years to meet state goals.
- The number of batteries participating in ISO markets has increased over the past four years with total installed capacity reaching about 136 MW by the end of 2018. Most battery capacity participating in ISO markets is located in locally constrained areas.
- Costs for capacity procured under the ISO's two backstop capacity procurement mechanisms (reliability must-run contracts and the capacity procurement mechanism) increased from $24 to $156 million or from $0.10/MWh to $0.73/MWh of system load.
- The market for capacity needed to meet local resource adequacy requirements continues to be structurally uncompetitive in almost all local areas.
- For more than a decade, California has relied on long-term procurement planning and resource adequacy requirements placed on load-serving entities by the CPUC to ensure that sufficient capacity is available to meet system and local reliability requirements. However, a number of structural changes, such as the increase in load served by community choice aggregators (CCAs), are driving the need for significant changes in this resource adequacy framework.

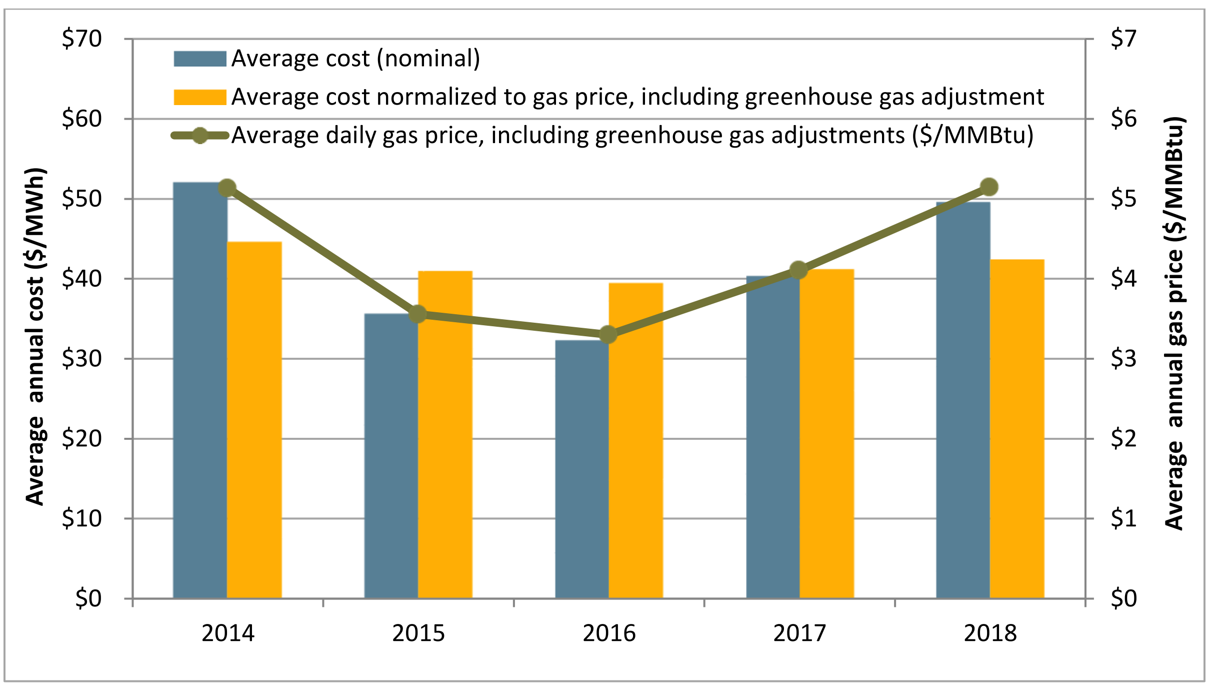
Total wholesale market costs

The total estimated wholesale cost of serving load in 2018 was about $10.8 billion or about $50/MWh. This represents an increase of about 24 percent from wholesale costs of about $40/MWh in 2017. The increase in electricity prices was driven mainly by an increase in spot market natural gas prices of about 25 percent.[1] After normalizing for natural gas prices and greenhouse gas compliance costs, DMM estimates that total wholesale energy costs increased by about 4 percent.[2]

A variety of factors contributed to the increase in total wholesale costs. As highlighted elsewhere in this report, conditions that contributed to higher prices include the following:

- Increased prices for natural gas, especially in Southern California;
- Higher uplift payments, such as bid cost recovery and energy offset costs;
- Additional costs for capacity procured under reliability must-run contracts and the capacity procurement mechanism; and
- Increased costs due to congestion.

Figure E.1 Total annual wholesale costs per MWh of load (2014-2018)



[1] For the wholesale energy cost calculation, an average of annual gas prices was used from the SoCal Citygate and PG&E Citygate hubs.

[2] Greenhouse gas compliance costs are calculated by multiplying a load-weighted annual average greenhouse gas allowance price by an emission factor that is a measure of the greenhouse gas content of natural gas. Derivation of the emission factor used here, 0.531148, is discussed in further detail in Section 1.2.4. Gas prices are normalized to 2010 prices.

Figure E.1 shows total estimated wholesale costs per megawatt-hour of system load from 2014 to 2018. Wholesale costs are provided in nominal terms (blue bar), and after being normalized for changes in natural gas prices and greenhouse gas compliance costs (gold bar). The green line represents the annual average daily natural gas price including greenhouse gas compliance and is included to illustrate the correlation between natural gas prices and the total wholesale cost estimate.

Energy market prices

Day-ahead and real-time market prices increased in 2018. This was attributed primarily to an increase in natural gas prices and tight system conditions, especially in the third and fourth quarters of the year. Figure E.2 and Figure E.3 highlight the following:

- Average energy market prices were relatively high during the second half of 2018, primarily because of increased gas prices.
- Prices in the day-ahead were higher than 15-minute real-time prices, on average, in all hours and in all quarters of the year, particularly the third and fourth when day-ahead prices were highest.
- Hourly prices in the day-ahead and real-time markets followed the shape of the net load curve, which subtracts wind and solar from load.

Figure E.2 Comparison of quarterly prices – system energy (all hours)

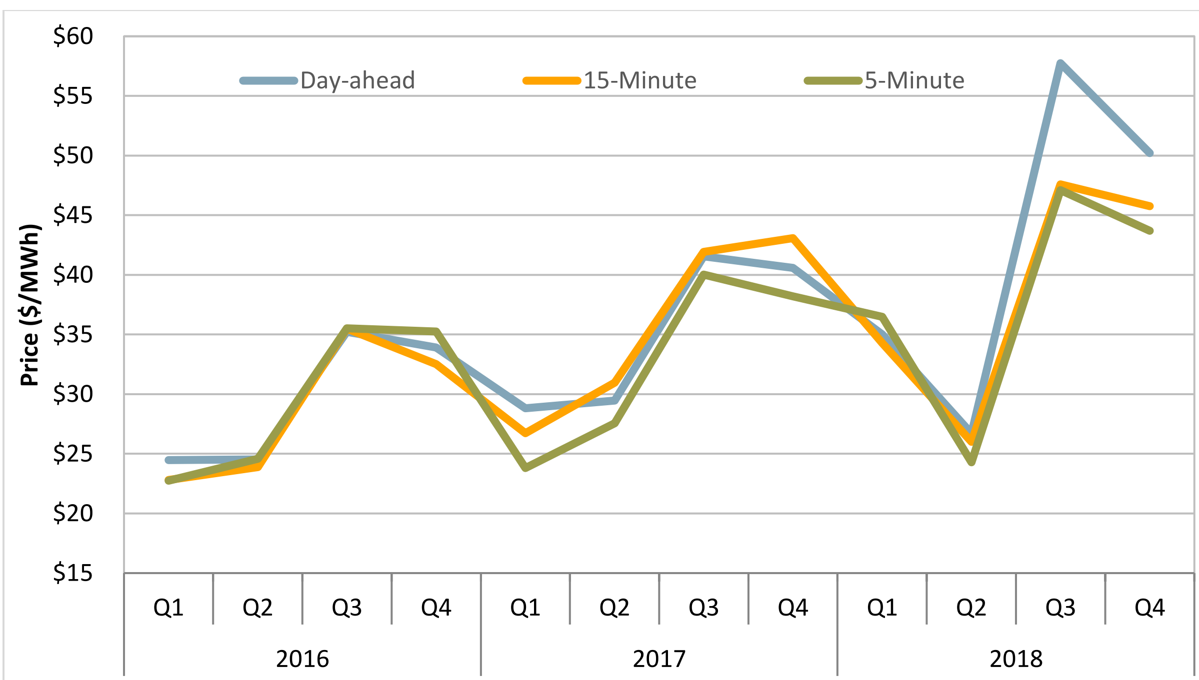
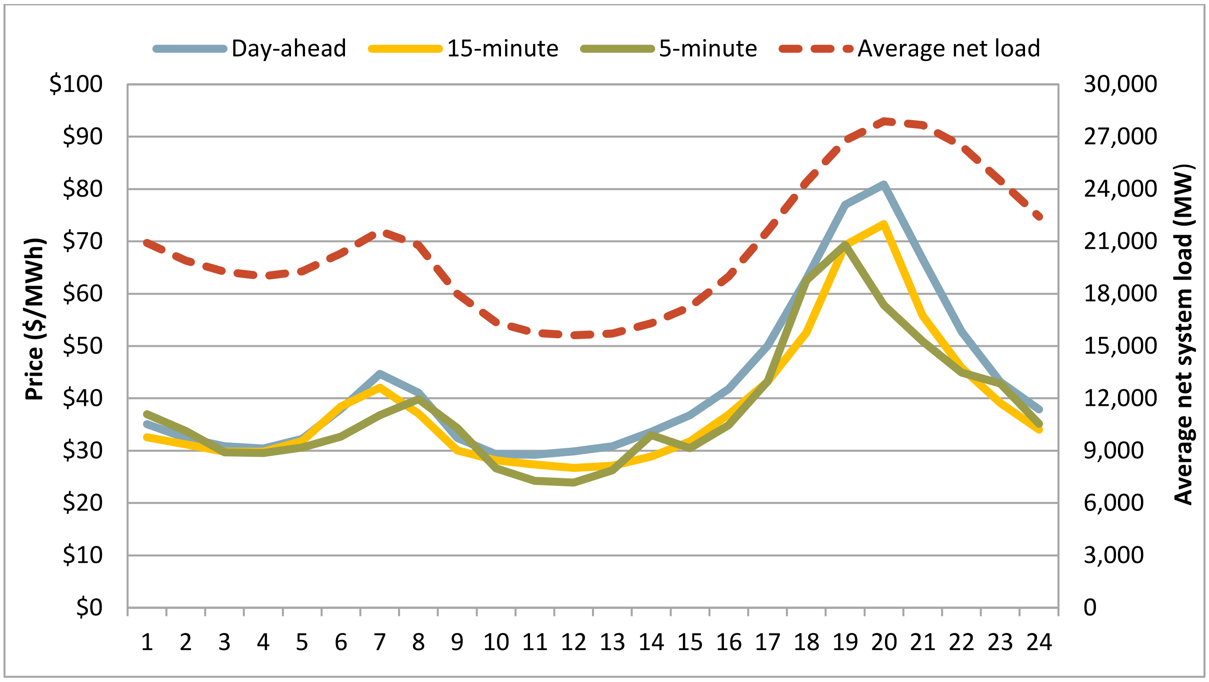


Figure E.3 Hourly system energy prices (2018)



Market competitiveness

Prices in the ISO's energy markets were generally competitive in 2018. However, analysis indicates that prices were significantly in excess of competitive levels in some hours when net load that must be met by gas-fired units is highest.

The competitiveness of overall market performance can be assessed based on the *price-cost markup*, which represents a comparison of actual market prices to an estimate of prices that would result in a highly competitive market in which all suppliers bid at or near their marginal costs. In some years, DMM has estimated the price-cost markup for the day-ahead market by rerunning a version of the market software after replacing the market bids of all gas-fired units with default energy bids (DEBs) used in local market power mitigation. As in prior years, the negative markup calculated is within the range that can be caused by the 10 percent headroom above marginal cost included in the default energy bids.

Due to limitations of this metric, this report assesses the competitiveness of prices in the day-ahead market using two other additional methodologies. The first method estimates the price-cost markup by recalculating prices based on the intersection of hourly day-ahead supply and demand curves constructed from market bids and cost-based bids for each unit. The average competitive scenario price is slightly less than the estimated base case price in most hours, but is roughly $2/MWh to $3/MWh lower during the hours when net loads are highest.

The second method assesses the competitiveness of prices based on the difference between the system marginal energy cost and the cost of the highest cost gas fired resource dispatched in the day-ahead market. By this measure, hours with price-cost markups over $25/MWh dropped from 161 in 2017 to 49 in 2017. This decrease may be due, in part, to the increased gas costs and lower peak and net loads that occurred in 2018 compared to 2017.

Ancillary services

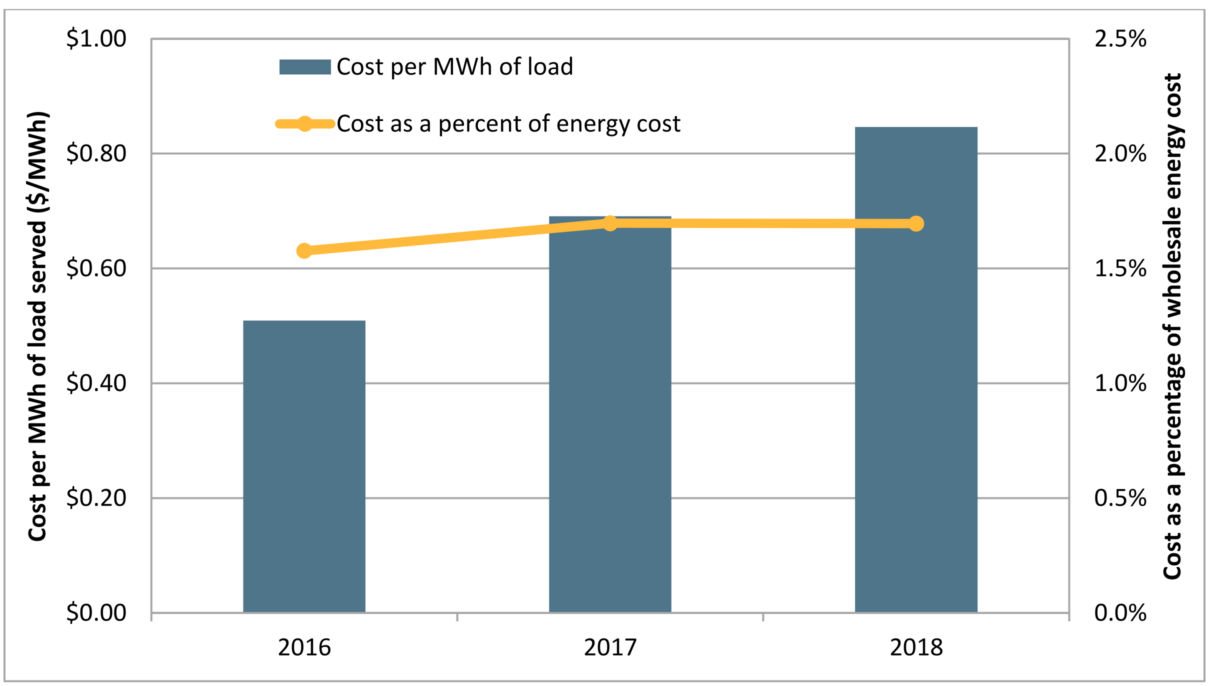
Ancillary service costs increased to $189 million, up from $158 million in 2017 and $116 million in 2016. The increase in operating reserve costs was primarily driven by tight supply conditions and high energy prices during the summer.

On January 1, 2018, operating reserve requirements increased with the implementation of the revised NERC reliability standard (BAL-002-2). Under the revised standard, the ISO considers the sudden loss of scheduling on the Pacific DC Intertie as one possible single largest contingency. The impact on operating reserve requirements was largest in morning and evening hours in the first and second quarter, but did not have a significant impact on total ancillary service payments.

Average day-ahead requirements for regulation down increased by about 14 percent from 2017. Requirements for regulation down were typically highest in the morning and evening hours when solar is ramping on and off.

As shown in Figure E.4, ancillary service costs increased to $0.85/MWh of load served in 2018 from $0.69/MWh in 2017. The $0.85/MWh cost was the highest yearly value since 2011. Ancillary service costs were around 1.7 percent of total wholesale energy costs in 2018, similar to the previous year, but an increase from 1.6 percent in 2016.

Figure E.4 Ancillary service cost as a percentage of wholesale energy cost



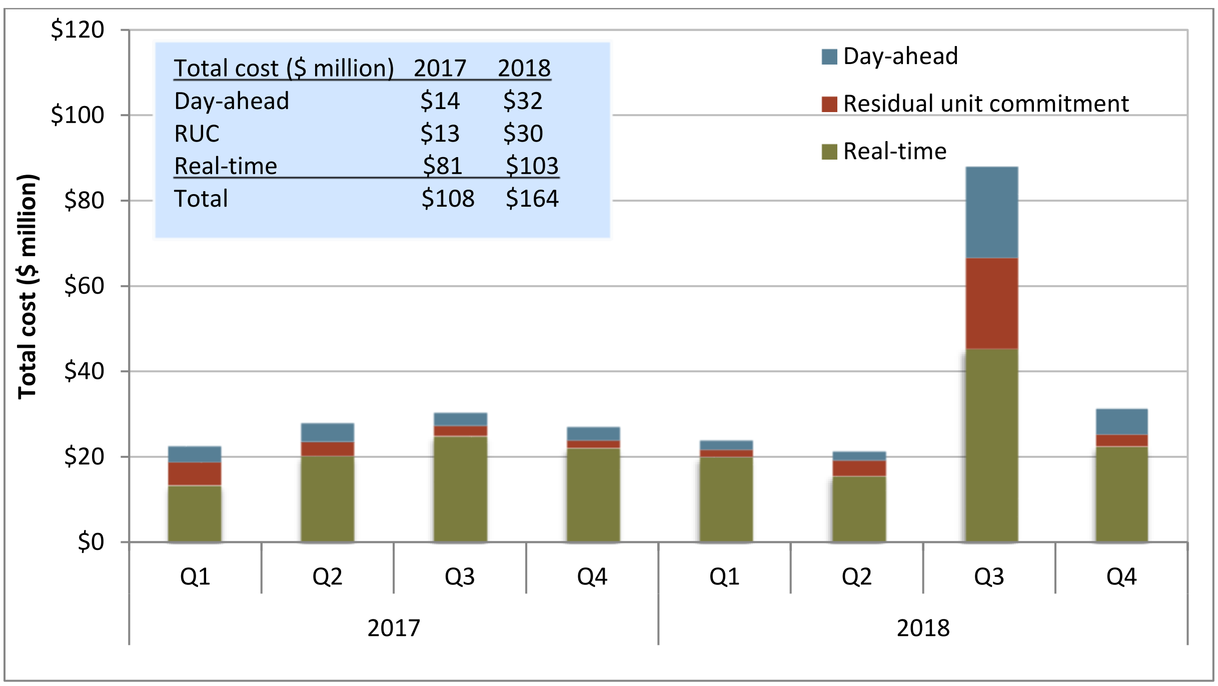
Bid cost recovery payments

Generating units are eligible to receive bid cost recovery payments if total market revenues earned over the course of a day do not cover the sum of all the unit's accepted bids. Excessively high bid cost recovery payments can indicate inefficient unit commitment or dispatch.

Figure E.5 provides a summary of total estimated bid cost recovery payments in 2018. Estimated bid cost recovery payments for units in the ISO and energy imbalance market totaled around $153 million and $12 million, respectively. This represents the highest level of bid cost recovery payments since 2011, and a significant increase from 2017, when bid cost recovery totaled $108 million. Bid cost recovery payments represent about 1.4 percent of total ISO wholesale energy costs.

Real-time bid cost recovery payments were $103 million in 2018, which was a significant increase from about $81 million in 2017. About $33 million of the $45 million third quarter real-time payments were awarded to gas resources in the SoCalGas service area. Payments for real-time bid cost recovery for units in the energy imbalance market were included in this figure and totaled about $12 million in 2018 similar to the amount in 2017.

Figure E.5 Bid cost recovery payments



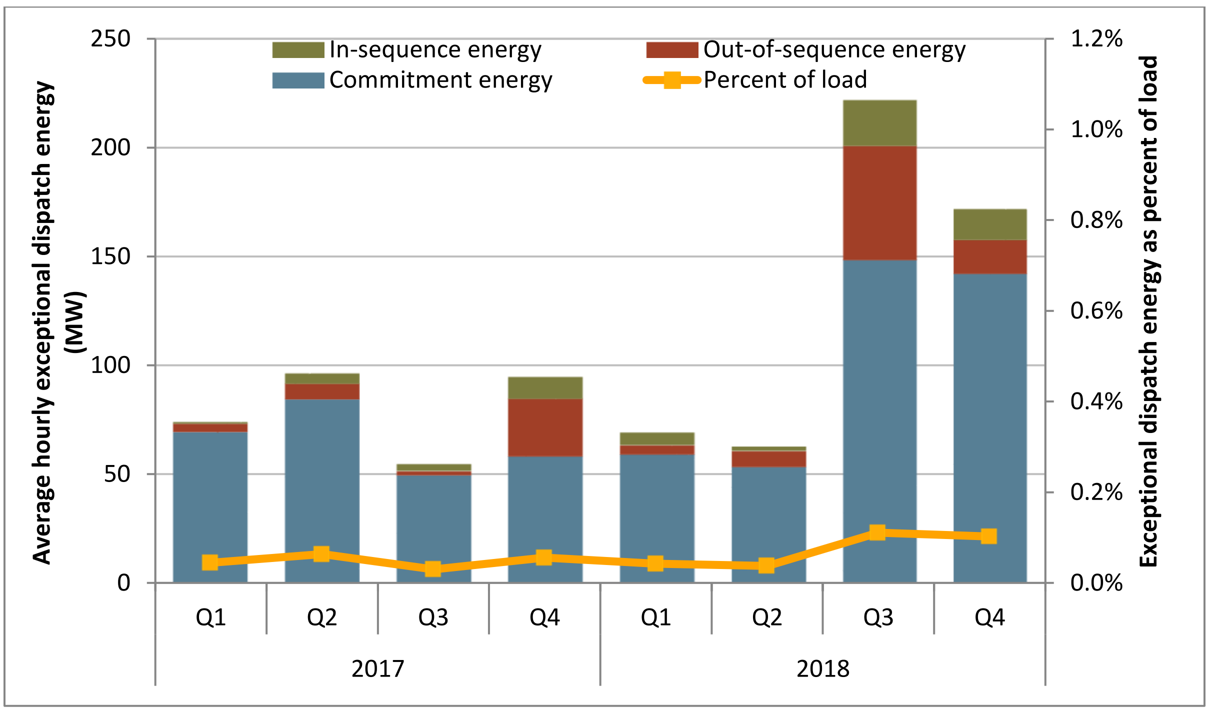
Exceptional dispatches

Exceptional dispatches are instructions issued by grid operators when the automated market optimization is not able to address particular reliability requirements or constraints. These dispatches are sometimes referred to as *manual* or *out-of-market* dispatches. Over the past several years, the ISO has made an effort to reduce exceptional dispatches by refining operational procedures and incorporating additional constraints into the market model that reflect reliability requirements.

Total energy from exceptional dispatches continued to account for a relatively low portion of total system load, but above-market costs from exceptional dispatches increased significantly.

- Total energy from all exceptional dispatches increased in 2018, growing to 0.07 percent of system load from 0.05 percent in 2017 and 0.03 percent in 2016.
- Total above-market costs due to exceptional dispatch increased more than 150 percent to $51.9 million from $20.6 million in 2017 and $10.7 million in 2016. Commitment costs for exceptional dispatch paid through bid cost recovery accounted for almost 80 percent of above-market costs, increasing from $16.6 million to $40.6 million.
- Above-market costs for out-of-sequence energy dispatched via exceptional dispatches increased from $4.0 million to $11.2 million.[3] Bid mitigation applied to some exceptional dispatches for energy avoided about $18 million in additional out-of-market energy payments in 2018 compared to $33,000 in 2017.

Figure E.6 Average hourly energy from exceptional dispatches



Manual out-of-market dispatches on the interties increased significantly in 2017. DMM's 2017 annual report cautioned that procurement of imports out-of-market at prices higher than the 15-minute price paid for other imports can encourage economic and physical withholding of available imports.

[3] The out-of-sequence costs are estimated by multiplying the out-of-sequence energy by the bid price (or the default energy bid if the exceptional dispatch was mitigated or the resource had not submitted a bid) minus the locational price for each relevant bid segment. Commitment costs are estimated from the real-time bid cost recovery associated with exceptional dispatch unit commitments.

In 2018, the ISO implemented improved procedures, training and logging practices which appear to have been effective at ensuring proper settlement and allowing better tracking and monitoring of manual dispatches of imports. In 2018, out-of-market dispatches decreased significantly, accounting for less than 5,500 MWh.

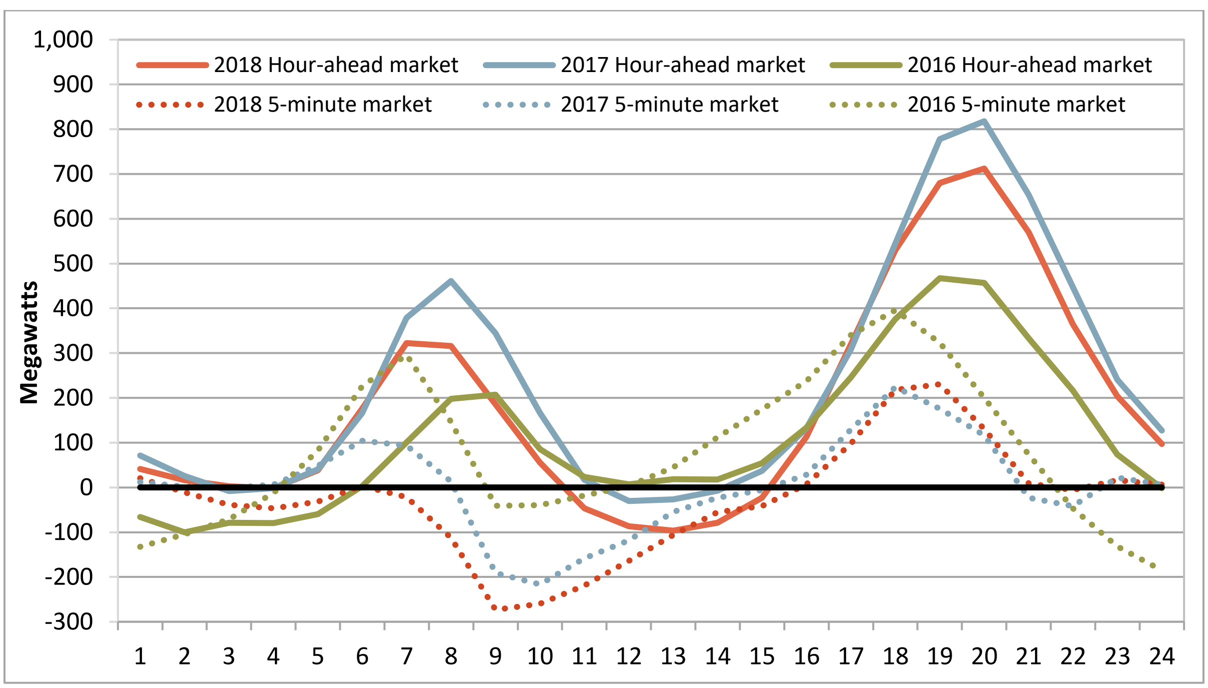
Load forecast adjustments

ISO grid operators can manually modify load forecasts used in the real-time market through a load adjustment. Load adjustments are also referred to as *load bias* or *load conformance*. Load forecast adjustments can be used to account for potential modeling inconsistencies and inaccuracies.

In the ISO, load adjustments are also routinely used in the hour-ahead and 15-minute scheduling processes in a manner which helps to increase the supply of ramping capacity within the ISO during morning and evening hours when net loads increase sharply. Increasing the hour-ahead and 15-minute forecast can increase ramping capacity within the ISO by increasing hourly imports and committing additional units within the ISO.

As shown in Figure E.7, load forecast adjustments in the hour-ahead and 15-minute scheduling processes routinely mirror the pattern of net loads over the course of the day, averaging 400 MW to 800 MW during the morning and evening ramping hours. During these hours, imports made in the hour-ahead process often increase significantly, which allows additional generation within the ISO to be available for dispatch in the 15-minute and 5-minute markets. These adjustments decreased slightly compared to 2017, but remain high and have increased dramatically since 2016.

Figure E.7 Average hourly load adjustment (2016 - 2018)



Flexible ramping product

The flexible ramping product is designed to enhance reliability and market performance by procuring flexible ramping capacity in the real-time market to help manage variability and uncertainty of real-time imbalance demand. Flexible ramping product procurement and prices are determined through demand curves calculated from historical net load forecast errors, or the *uncertainty* surrounding ramping needs.

Total net payments for flexible ramping capacity decreased significantly in 2018 to about $7 million, compared to almost $25 million during the previous year. The frequency of zero price intervals increased from 78 to 94 percent in the upward direction and from 95 to over 99 percent in the downward direction. Power balance constraint relaxations in the 15-minute and 5-minute markets were infrequent during 2018 relative to 2017.

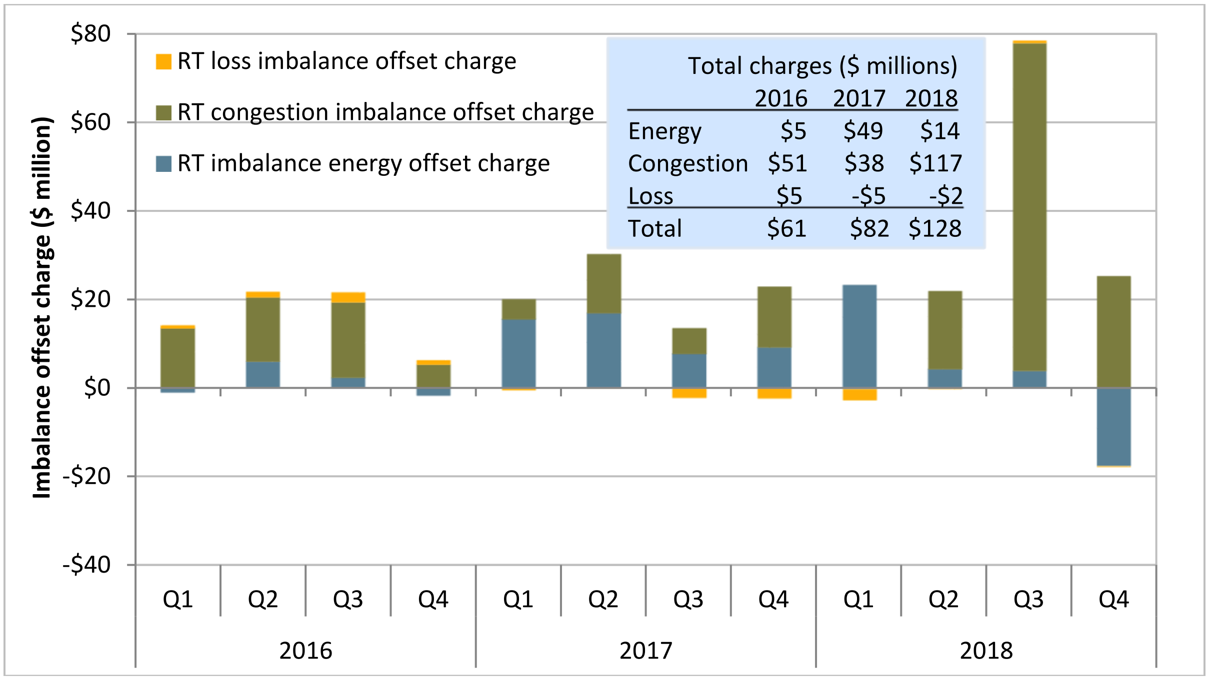
Real-time imbalance offset costs

The real-time imbalance offset charge is the difference between the total money paid by the ISO and the total money collected by the ISO for energy settled at real-time prices. The charge is allocated as an uplift to load-serving entities and exporters based on measured system demand.

The real-time imbalance offset charge consists of three components. Any revenue imbalance from the energy component of real-time energy settlement prices is collected through the *real-time imbalance energy offset charge*. Any revenue imbalance from the congestion component of real-time energy settlement prices is recovered through the *real-time congestion imbalance offset charge*. Since October 2014, any revenue imbalance from the loss component of real-time energy settlement prices is collected through the *real-time loss imbalance offset charge*.

Total real-time imbalance offset costs increased by about 56 percent to $128 million compared to $82 million in 2017. Much of this increase is attributable to a $79 million increase in real-time congestion imbalance offset costs which appears to have been caused by persistent and significant reductions in constraint limits relative to limits used in the day-ahead market made by grid operators in the 15-minute market.

Figure E.8 Real-time imbalance offset costs



Congestion

Locational price differences due to congestion in both the day-ahead and 15-minute markets increased in 2018, particularly on constraints associated with major transmission limits separating Northern and Southern California (Path 26) in the third quarter. Key congestion trends during the year include the following:

- For the year, congestion increased day-ahead prices in the SCE area by $1.87/MWh and in the SDG&E area by about $4.19/MWh. Congestion decreased day-ahead prices in the PG&E area by $2.73/MWh in the day-ahead market.
- In the 15-minute market, patterns of congestion were similar to the day-ahead market. The primary constraints impacting price separation were the constraints associated with Path 26, the Serrano 500/230 kV transformer, and the Round Mountain-Table Mountain nomogram. These constraints increased prices in Southern California and in EIM areas with significant transmission capacity into Southern California, and decreased prices elsewhere.
- In the fourth quarter, significant congestion on the Tracy-Los Banos outage nomogram increased prices in Northern California and EIM areas north of the constraint and decreased prices south of the constraint. Over the course of the fourth quarter, this south-to-north congestion offset much of the impact of continued congestion on Path 26 and other constraints, so that the overall net average impact of congestion on prices was relatively low for the fourth quarter.

- The frequency and impact of congestion in the day-ahead market on most major interties was lower in 2018 compared to 2017. This was primarily driven by lower congestion on interties connecting the ISO to the Pacific Northwest (Malin and NOB).

Congestion revenue rights

This report includes an analysis of the performance of the congestion revenue rights auction from the perspective of the ratepayers of load-serving entities. Key findings from this analysis include the following:

- As shown in Figure E.9Figure E, congestion revenue rights not allocated to load-serving entities that are sold in the auction consistently generate significantly less revenue than is paid to the entities purchasing these rights in the auction.
- From 2009 through 2018, ratepayers received about 50 percent of the value of their congestion revenue rights that the ISO auctioned. This represents a shortfall of about $131 million in 2018 and more than an $866 million shortfall since 2009.
- Entities purchasing congestion revenue rights are primarily financial entities that do not purchase these rights as a hedge for any physical load or generation.

In 2018, FERC approved a set of changes to the congestion revenue rights auction process which will reduce the number and pairs of nodes at which congestion revenue rights can be purchased in the auction (Track 1A).[4] FERC also approved a second set of changes which would reduce the net payment to a congestion revenue right holder if payments to congestion revenue rights exceed associated congestion charges collected in the day-ahead market on a targeted constraint-by-constraint basis (Track 1B).[5]

DMM supports the various measures implemented by the ISO starting in the 2019 congestion revenue rights auction as incremental improvements that are likely to help partially address the very large losses being imposed on transmission ratepayers from the auction. DMM continues to recommend that the ISO begin to develop an approach based on a voluntary market for financial contracts that is cleared with bids from willing buyers and sellers – rather than being funded by congestion revenues that are otherwise refunded to transmission ratepayers.

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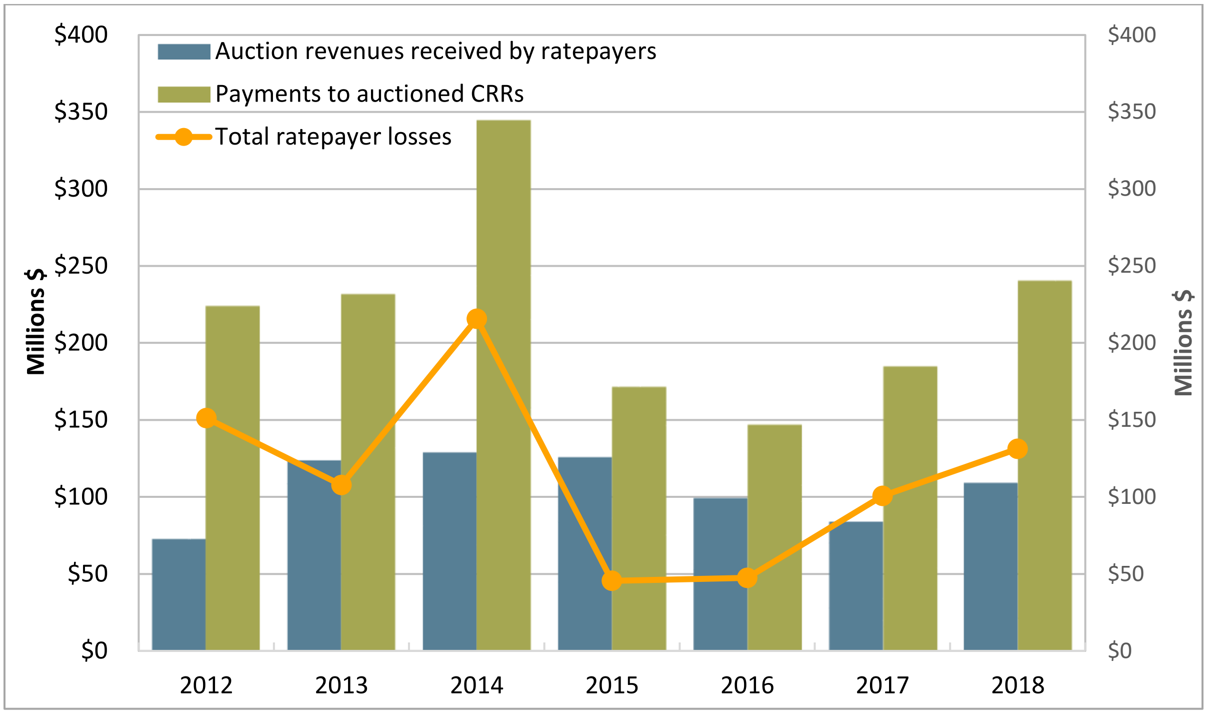
4 *Tariff Amendment to Increase Efficiency of Congestion Revenue Rights Auctions*, California Independent System Operator Corporation, ER18- 1344, April 11, 2018. http://www.caiso.com/Documents/Apr11_2018_TariffAmendment-CRRAuctionEfficiencyTrack1A_ER18-1344.pdf

5 *Tariff Amendment to Increase Efficiency of Congestion Revenue Rights Auctions*, California Independent System Operator Corporation, ER18- 2034, July 17, 2018. http://www.caiso.com/Documents/Jul17_2018_TariffAmendment-CRRAuctionEfficiencyTrack1B_ER18-2034.pdf

Figure E.9 Ratepayer auction revenues compared with congestion payments for auctioned CRRs



Local market power mitigation

The ISO's day-ahead and real-time markets incorporate a transmission competitiveness evaluation and mitigation mechanism to address local market power. The frequency and impact of automated bid mitigation increased significantly in 2018 compared to 2017 in the ISO's day-ahead and real-time markets, as well as in the EIM.

In the day-ahead market, the number of resources that had bids changed by mitigation remained low at an average of about 3 units per hour, up from 1.4 resources per hour in 2017. Day-ahead dispatch instructions from bid mitigation increased by about 22 MW per hour in 2018, compared to 7 MW per hour in 2017. This potential increase in dispatch due to mitigation is concentrated mostly during peak hours.

In the 15-minute market, the number of units with bids lowered by mitigation also remained low, averaging 1.6 resources per hour in the ISO and 1.4 units per hour in the EIM. In the 5-minute market, the number of units with bids lowered by mitigation each hour averaged 3.6 units in the ISO and 1.2 resources in the EIM. In the 15-minute market, bid mitigation lead to an increase in energy from the mitigated unit of about 15 MW per hour in 2018, compared to 6 MW per hour in 2017. Similarly, 5-minute dispatch instructions in EIM areas increased by 40 MW in 2018 compared to 16 MW in 2017.

Most of the increase in mitigation within the ISO was due to an increase in the concentration of supply that could relieve congested constraints controlled by the three largest suppliers. This caused congested constraints to be structurally uncompetitive a higher portion of the time. Most of the increase in mitigation in the EIM was due to an increase in the number of participating balancing areas and resources in 2018 compared to 2017.

The market for capacity needed to meet local resource adequacy requirements continues to be structurally uncompetitive in almost all local areas. Analysis in this report shows that one pivotal supplier controls a significant portion of capacity needed to meet local requirements in the San Diego/Imperial Valley, LA Basin, Stockton, Sierra, and the North Coast/North Bay areas.

Resource adequacy

California's wholesale market relies heavily on a long-term procurement planning process and resource adequacy program adopted by the California Public Utilities Commission (CPUC) to provide sufficient capacity to ensure reliability. The resource adequacy program includes ISO tariff requirements that work in conjunction with regulatory requirements and processes adopted by the CPUC and other local regulatory authorities. Analysis in this report shows that:

- During peak load hours of the year, system resource adequacy requirements were sufficient to meet peak day-ahead load forecasts and actual peak loads for all days in 2018. In July, these requirements were sufficient to cover the instantaneous peak load (46,427 MW), even though the requirements were substantially less than the 115 percent of the ISO's 2018 1-in-2 year forecast of peak load (53,619 MW).

- During the top 210 load hours of the year, 96 percent of system resource adequacy capacity was available after outages. About 93 percent of this capacity was bid or self-scheduled in the day-ahead market (90 percent of total system resource adequacy). About 99 percent of this capacity was available after outages in the real-time market (89 percent of total), and 91 percent of this capacity was bid or self-scheduled in the real-time (81 percent of total).

- Most system resource adequacy capacity was procured by investor-owned utilities (IOU). Investor-owned utilities accounted for about 71 percent of procurement, community choice aggregators (CCA) procured 11 percent, municipal entities contributed 9 percent, and direct access (DA) providers accounted for 7 percent. The remaining 2 percent was substitute capacity for resources on outage.

- The total amount of local resource adequacy capacity available to bid into the day-ahead and real-time markets exceeded the total local capacity requirement; some individual areas did not meet the requirement, relying on resources from within the greater transmission access charge area.

This year was the third year that flexible resource adequacy requirements and procurement were in place. These requirements are set based on projections of the maximum three-hour net load ramp during each month. Analysis of these requirements in this report highlight the following:

- Flexible resource adequacy requirements fell short of the maximum three-hour net load ramp in six months in 2018. Due to varying must-offer hours for different flexible capacity the *effective* resource adequacy requirement fell short of the actual net load ramp in eight months.

- Despite requirements, load-serving entities collectively procured more flexible capacity than required. This procurement exceeded the actual maximum three-hour net load ramp in all months except for February and March. Procurement consisted mostly of gas-fired generation that qualified as Category 1 (base flexibility) capacity.

In 2018, two forms of backstop capacity procurement were utilized:

- The capacity procurement mechanism (CPM) was used throughout the year to dispatch non-resource adequacy capacity for conditions requiring exceptional dispatch. The ISO also issued significant event designations in September and October 2018 in response to a higher, alternative load forecast presented by the California Energy Commission.[6] The total estimated cost of these intra-monthly designations was about $21.9 million in 2018 up from $7 million in 2017 and $4.3 million in 2016.

- There were also three year-ahead capacity procurement mechanism designations in 2018 to resolve individual resource adequacy plan and collective local resource adequacy deficiencies. These were the first year-ahead designations made since the mechanism was implemented in 2016. The total estimated cost of these designations was about $78 million.

- During 2017, capacity designated as being subject to reliability must-run (RMR) contracts beginning in 2018 increased sharply. Three newer, efficient gas units representing almost 700 MW were designated by the ISO for reliability must-run service beginning in 2018.

- About 600 MW of the 700 MW of gas-fired generation designated by the ISO as being needed under reliability must-run contracts during 2018 was not re-designated for service in 2019. The need to designate these resources was eliminated by transmission upgrades completed in December 2018 and January 2019. Total reliability must-run costs for 2018 were about $63 million.

The procurement of a significant amount of newer and more efficient units under reliability must-run contracts in 2017 highlighted gaps in the state's resource adequacy process, as well as problems with the ISO's capacity procurement and reliability must-run backstop procurement mechanisms. The CPUC and the ISO continue to work to refine and enhance the resource adequacy framework through ongoing stakeholder initiatives and proceedings.

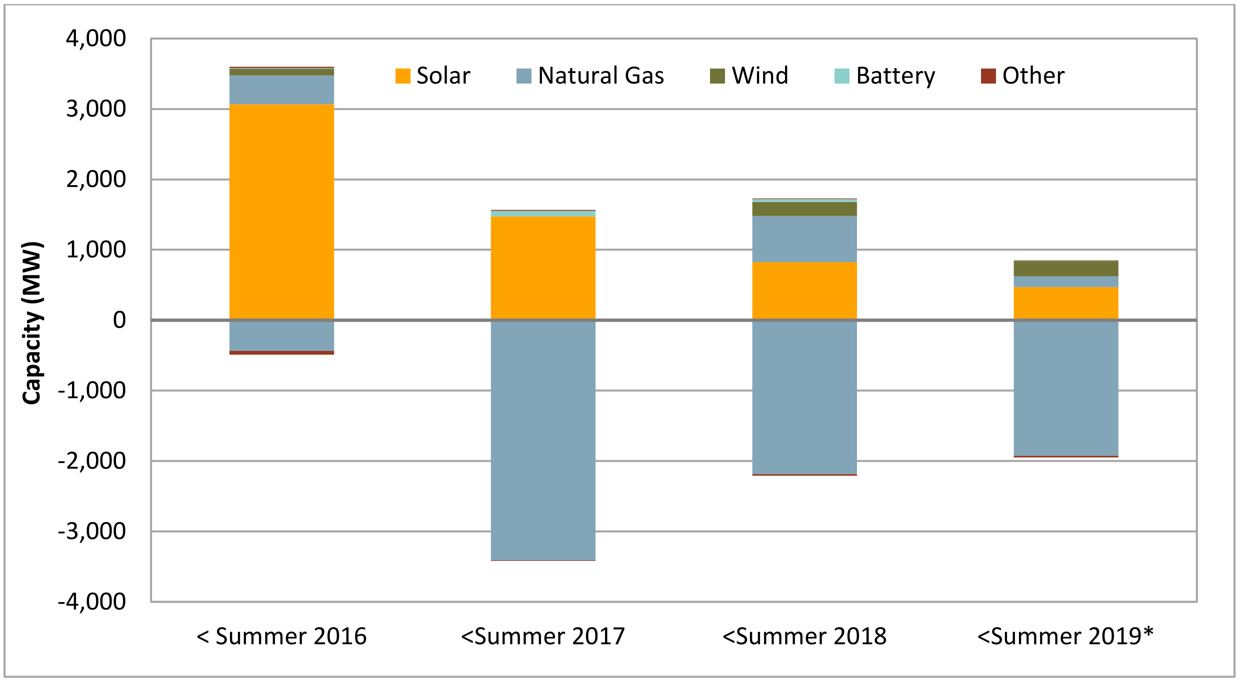
Capacity additions and withdrawals

California currently relies on long-term procurement planning and resource adequacy requirements placed on load-serving entities by the CPUC to ensure that sufficient capacity is available to meet system and local reliability requirements. Trends in the amount of generation capacity being added and retired each year provide an indication of the effectiveness of the California market and regulatory structure in incenting new generation investment.

Figure E.10 summarizes the trends in capacity additions and retirements from June of 2015 through the end of 2018. From June 2015 to June 2018 (first three bars in the chart), roughly 6,000 MW of generation withdrew from market participation. The majority of this retired capacity was from natural gas resources in local capacity areas. Over the same time period, over 1,000 MW of gas, over 5,300 MW of solar, about 300 MW of wind and 130 MW of battery capacity was added or returned to the market. Since June of 2018, an additional 2,000 MW of gas has withdrawn and an additional 470 MW of solar, 220 MW of wind and 150 MW of gas generation has been added or returned as of May 2019.

6 *Intent to designate CPM capacity pursuant to CPM significant event*, California ISO, August 2, 2018. http://www.caiso.com/Documents/Presentation-CapacityProcurementMechanismSignificantEvent.pdf

Figure E.10 Generation additions and retirements (June 2015- June 2019*)



The ISO anticipates a continued increase in renewable generation in the coming years to meet the state's goal to have 50 percent renewable generation by 2025 and 60 percent by 2030. Going forward, significant reductions in total gas-fired capacity may continue beyond 2018 because of the state's restrictions on once-through cooling technology as well as other retirement risks. The ISO has emphasized the need to maintain adequate flexibility from both conventional and renewable generation resources to maintain reliability as more renewable resources come on-line.

Under the ISO market design, fixed costs for existing and new units critical for meeting reliability needs can be recovered through a combination of long-term bilateral contracts and spot market revenues. Each year DMM analyzes the extent to which revenues from the spot markets would contribute to the annualized fixed cost of typical new gas-fired generating resources. This market metric is tracked by all ISOs and the Federal Energy Regulatory Commission.

DMM estimates net revenues for new gas-fired generating resources using market prices for gas and electricity. Although estimated revenues for combined cycle units in 2017 and 2018 were higher than 2016, estimates in all three years fell substantially below estimates of the annualized fixed costs for these technologies, as did estimates for combustion turbines in all three years.

DMM's analysis tests net revenues using multiple scenarios which provide a range of potential results. For a new combined cycle unit, DMM estimates net operating revenues earned from the energy markets in 2018 ranged from $33/kW-yr to $47/kW-yr. This compares to potential annualized fixed costs of approximately $166/kW-year. For a new combustion turbine unit, our estimates ranged from $19/kW-yr to $28/kW-yr compared to potential annualized fixed costs of about $177/kW-yr.

As shown in the figures below, the 2018 net revenue estimates were also less than the ISO's capacity procurement mechanism soft offer cap price ($75.68/kW-yr) for both a hypothetical combined cycle unit and combustion turbine in either the NP15 or the SP15 region.

Figure E.11 Estimated net revenue of hypothetical combined cycle unit

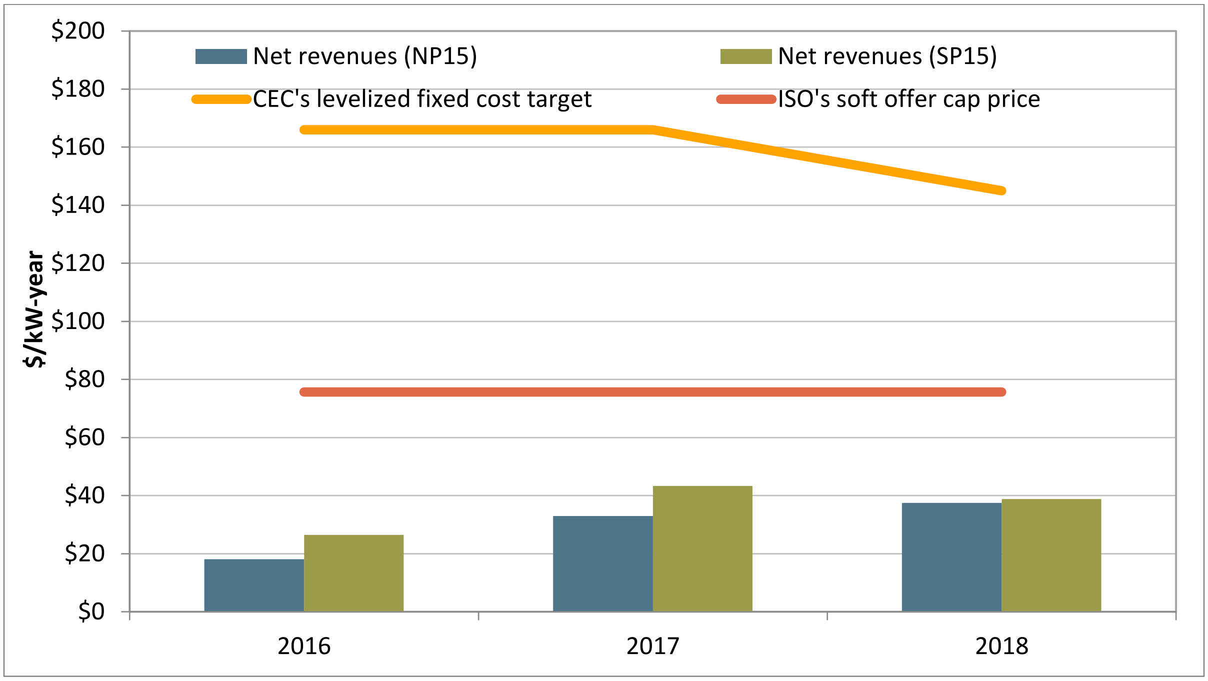
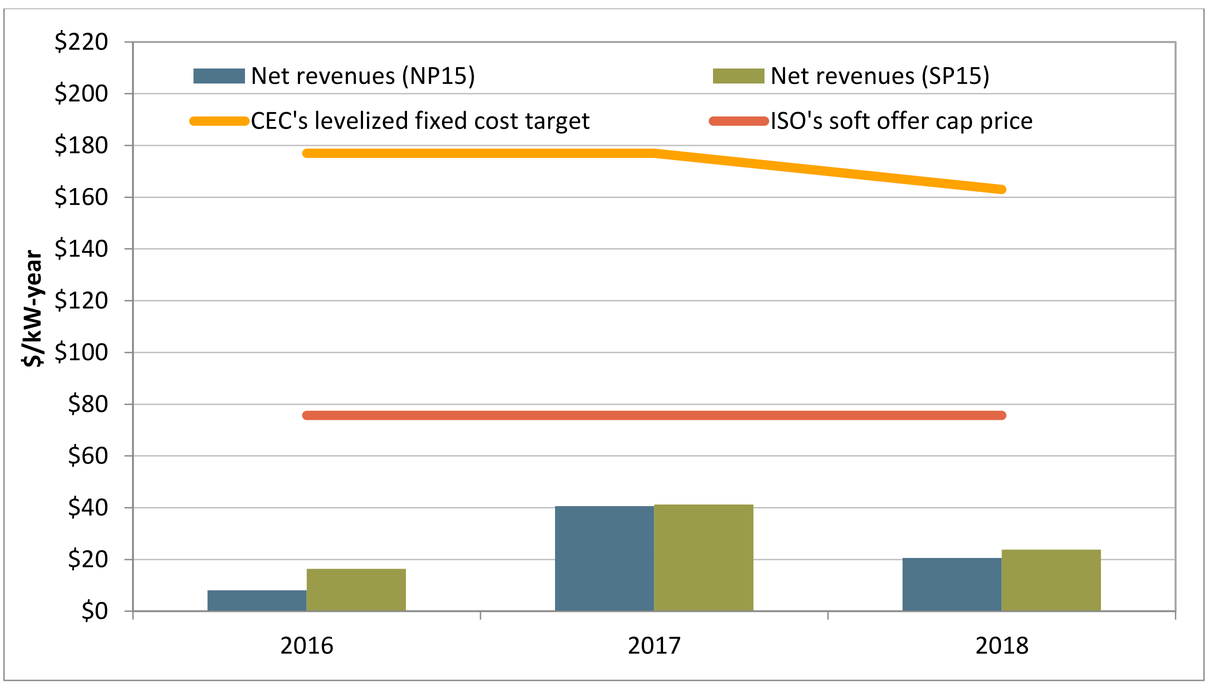


Figure E.12 Estimated net revenues of hypothetical combustion turbine



Recommendations

As the ISO's independent market monitor, one of DMM's key duties is to provide recommendations on current market issues and new market design initiatives to the ISO, the ISO Governing Board, FERC staff, the California Public Utilities Commission, market participants, and other interested entities.[7] DMM provides written comments and recommendations in the ISO's stakeholder process and in quarterly, annual and other special reports.[8] DMM's current recommendations on key market design initiatives are summarized below and in Chapter 11.

Bid caps used in mitigation

Bid caps for start-up and minimum load commitment costs currently include a 25 percent *headroom scalar* above estimated costs. Default energy bids (DEBs) used when energy price mitigation is triggered include a 10 percent headroom scalar that is applied above marginal costs. The commitment costs and default energy bid enhancements (CCDEBE) proposal approved by the ISO Board in 2018 includes numerous provisions that will allow commitment cost and energy bid caps used in market power mitigation to be substantially higher in some cases.

Under the CCDEBE proposal, the ISO would allow participants to request increases in cost-based bid caps if they believe their actual gas costs exceed the 25 percent and 10 percent headroom already included in commitment cost and default energy bid caps. Under the ISO's final 2018 proposal, requests for bid cap increases would be automatically approved for use in the market if the requests were within about 10 percent of the current caps.[9]

DMM opposed this aspect of the ISO's 2018 proposal since under this approach bid caps for gas-fired units in the real-time market would continue to be based primarily on gas prices from the next-day market plus a static level of additional headroom. During most days, this additional headroom proposed by the ISO would not be justified by actual same-day gas market prices. But on the limited number of days which same-day gas prices rise significantly, the additional headroom would be too low.[10]

DMM has continued to recommend a more dynamic approach for adjusting bid caps used in real-time market power mitigation based on same-day gas market trade data available at the start of each operating day. In early 2019, the ISO modified the CCDEBE proposal so that the reasonableness thresholds used to screen requests for bid cap increases will be based on same-day gas market trade prices. The revised proposal also allows EIM participants, which do not procure gas in liquid trading points, to request customized bid cap increases based on other supporting documentation.

7 Tariff Appendix P, ISO Department of Market Monitoring, Section 5.1. http://www.caiso.com/Documents/AppendixP_CAISODepartmentOfMarketMonitoring_asof_Apr1_2017.pdf

8 See Market Monitoring Reports and Presentations at: http://www.caiso.com/market/Pages/MarketMonitoring/MarketMonitoringReportsPresentations/Default.aspx#CommentsRegulatory

9 On the first gas trade day of each week (usually Monday), the threshold used to automatically screen requested bid cap increases would be set at 25 percent.

10 Memo to ISO Board of Governors, Eric Hildebrandt, March 14, 2018. *pp. 5-6.* *http://www.caiso.com/Documents/Decision_CCDEBEProposal-Department_MarketMonitoringMemo-Mar2018.pdf*

DMM supports the more dynamic approach for determining reasonableness thresholds being proposed by the ISO in 2019. This approach will ensure greater market efficiency, reliability and more accurate mitigation than the static approach approved by the ISO Board in 2018.

Dynamic mitigation of commitment costs

Under the final commitment costs and default energy bid enhancements proposal approved by the ISO Board in 2018, start-up and minimum load bids would be mitigated using a dynamic structural test of potential market power based on system and market conditions during that time interval (e.g., hour or 15-minute interval). Unless the supply of capacity needed to meet a constraint is deemed uncompetitive, then resources would be subject to significantly higher commitment cost bid caps.

DMM supports development of a more dynamic approach to mitigation of commitment costs as a way of allowing more bidding flexibility. While the ISO's final CCDEBE proposal includes the basic framework for dynamic mitigation of commitment costs, DMM believes the final proposal approved by the Board in 2018 still has several significant gaps, implementation uncertainties and risks. Thus, DMM recommends that commitment cost bid caps be raised on a more gradual basis only after the effectiveness of dynamic mitigation is confirmed based on actual operational experience.

In 2019, the ISO announced that its proposal for dynamic mitigation of commitment costs will be delayed until at least 2020.

Opportunity cost adders for start-up and minimum load bids

In 2019, the ISO is implementing the option for resources to include *opportunity cost adders* in commitment cost bid caps to reflect the potential opportunity costs associated with any limits on start-up or run hours of individual resources. The ISO's final design for this new feature includes a provision that would allow opportunity costs to be calculated based on start-up or run hour limits included in qualifying commercial contracts (rather than representing actual physical or environmental limits).

DMM does not support basing opportunity cost adders on contractual use limitations since it is inefficient and inequitable to treat contractual limitations as actual physical or environmental limitations when calculating bids caps used in the market optimization.[11] To the extent these contractual limitations may reflect actual physical or environmental limits, it is more efficient and appropriate to incorporate any actual physical or environmental limits directly into unit operating constraints or opportunity cost bid adders.

Some contract limitations may be designed to limit maintenance costs associated with starting up and running a unit. The ISO market is explicitly designed so that any incremental maintenance costs associated with starting up and operating a unit can be incorporated directly in commitment cost bids through major maintenance adders (MMAs). These adders represent the most efficient and appropriate way to incorporate any incremental maintenance costs associated with starting up and operating resources into unit commitments.

The ISO tariff filing approved by FERC will allow contractual limitations to qualify a resource for the opportunity cost adder for three years after the proposed revisions go into effect. The ISO has indicated it will review this issue and may extend this exemption beyond the initial three year period. However,

[11] See *Motion to intervene and protest of the Department of Market Monitoring*, ER18-1169. April 13, 2018. http://www.caiso.com/Documents/Apr13_2018_DMMIntervention_Protest-CCEPhase3TariffAmendment_ER18-1169.pdf

DMM recommends that the ISO provide participants with a clear indication that the initial three year extension will not be further extended.

Gas usage nomograms

In 2016, the ISO was granted temporary authority from FERC to help address the limited operability of the Aliso Canyon gas storage facility by enforcing a maximum gas constraint (or nomogram) for groups of units in the SoCalGas system. In 2018, DMM supported the ISO's request for extension of this temporary authority through 2019.

However, market performance during the limited times the ISO has utilized maximum gas constraints shows that this measure can increase market costs significantly and may not provide the intended reliability benefits. Therefore, DMM continues to recommend that if the ISO continues to use this feature, the ISO should refine how it utilizes the constraint and improve how gas usage constraint limits are set and adjusted in the market software for different hours of the day.

Specifically, while gas usage constraints are modeled as hourly and 15-minute constraints in the ISO's day-ahead and real-time markets, these gas constraints are actually applicable only over a much longer daily or multi-hour period. However, the ISO does not adjust these constraints in the day-ahead or real-time market based on gas usage in prior hours. When the gas constraints bind during the peak ramping hours, there appears to be surplus gas from hours prior in the day when gas usage is well below the constraint set by the ISO. This causes the constraint to unnecessarily restrict use of gas units during the evening hours when the need for upward ramping capacity is highest.[12]

Resource adequacy imports

Imports used to meet resource adequacy requirements are not required to originate from specific generating units or to be backed by specific portfolios of generating resources. These imports can be bid at any price up to the $1,000/MWh bid cap and do not have any further obligation if not scheduled in the day-ahead market or residual unit commitment process. DMM has expressed concern in prior annual reports that under current rules and implementation processes imports have very limited availability or value during critical system and market conditions.

As part of the ISO's resource adequacy enhancements initiative, the ISO is assessing the requirements and rules for the resources or supply behind imports that are used to meet resource adequacy requirements.[13] As part of this initiative, DMM recommends that the ISO and stakeholders come to an explicit policy decision on whether or not resource adequacy capacity must be backed by specific generation resources and how any such requirements should be enforced in practice.

System market power

In 2018, DMM recommended that the ISO begin to consider various actions that might be taken to reduce the likelihood of conditions in which system market power may exist and to mitigate the impacts

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12 A specific examples of this occurring in 2018 are provided in *Comments of the Department of Market Monitoring*, ER18-2520. October 19, 2018. http://www.caiso.com/Documents/CommentsoftheDepartmentofMarketMonitoirng-Aliso4-Oct192018.pdf

13 *Resource adequacy enhancements straw proposal—part 1*, CAISO, December 20, 2018, p. 8: http://www.caiso.com/Documents/StrawProposalPart1-ResourceAdequacyEnhancements.pdf

of system market power on market costs and reliability. DMM recognizes that this recommendation involves major market design and policy issues, including the possible development of new market design options to mitigate potential system market power.

Because of the potential severity of the impact of market power, DMM has made this recommendation at this time so that the ISO, stakeholders and regulatory entities can give thorough consideration to this issue and potential options to address it.[14] In 2018, the ISO initiated a process to analyze the structural competitiveness of the ISO system, and, depending on results of this analysis, consider options for mitigating system market power.[15]

One of DMM's specific recommendations for helping to protect against system market power is to make a filing at FERC so that when the ISO implements FERC Order 831, imports in excess of the current $1,000/MWh bid cap would be subject to *ex ante* cost verification in order to set market clearing prices. Without such a filing by the ISO, imports up to $2,000/MWh would not be subject to cost verification and could set market clearing prices under Order 831.

Reliability must-run units

All ISOs have backstop procurement authority, such as the reliability must-run (RMR) provisions in the ISO's tariff, to ensure sufficient capacity is available to maintain system reliability. Backstop procurement serves two functions: ensuring reliability and mitigating the market power of units needed for reliability.

In November 2017, DMM and numerous other entities filed protests at FERC on the grounds that provisions of RMR Condition 2 contracts are "economically inefficient, distort overall market prices, undermine the CAISO's automated market power mitigation procedures, and are unjust and unreasonable for consumers."[16] DMM recommended that the following two basic flaws in the contract and tariff provisions for reliability must-run units under Condition 2 be addressed on an expedited basis.

- Remove the prohibition on RMR capacity under Condition 2 being offered in the ISO's energy market except when needed for local area reliability; and
- Require RMR resources to be subject to a must-offer requirement with cost-based bids.

The ISO initiated a stakeholder process in 2018 to consider changes to the reliability must-run and capacity procurement mechanism provisions of the ISO tariff.[17] In March 2019, the ISO Board approved tariff modifications that address these two key recommendations. The ISO's March 2019 proposal also

14 Under recently established ISO policies, all recommendations by DMM must be formally submitted in writing to the ISO in order to be considered.

15 Stakeholder process information is available here: http://www.caiso.com/informed/Pages/StakeholderProcesses/SystemMarketPower.aspx

16 *Motion to Intervene and Protest of the Department of Market Monitoring*, ER18-240-000, November 22, 2017. http://www.caiso.com/Documents/Nov22_2017_DMMMotion_Intervene_Protest-MetcalfEnergyCenterRMRAgreement_ER18-240.pdf

17 *Review of Reliability Must Run and Capacity Procurement Mechanism, Issue Paper and Straw Proposal for* Phase *1 Items*, California ISO, January 23, 2018. http://www.caiso.com/Documents/IssuePaperandStrawProposal-ReviewReliabilityMustRunandCapacityProcurementMechanism.pdf

indicates that the ISO will seek to limit reliability must-run contracts only to units that would retire or mothball if they did not receive a contract.

DMM supports the changes approved by the Board in March 2019. However, DMM believes that the ISO's proposal does not address some other key concerns with the current capacity procurement and reliability must-run mechanisms that are needed as part of a comprehensive reform.[18] DMM supports a more comprehensive effort to reform the ISO's backstop capacity procurement authority which accounts for the fact that resources procured under these mechanisms typically have local market power.

Capacity procurement mechanism

As noted above, the ISO initiated a stakeholder process in 2018 to consider changes to the reliability must-run and capacity procurement mechanism provisions of the ISO tariff.[19] DMM believes that the ISO's proposal does not address some other key concerns with the ISO's current backstop procurement mechanisms that are needed as part of a comprehensive reform.

In 2019, the ISO has committed to continue to consider changes to the $76/kW-year soft cap used in the capacity procurement mechanism provisions. DMM believes the scope of the 2019 initiative should be expanded to encompass a wider range of issues and changes, which include the following.

Need for 20 percent adder above going forward fixed costs

The current $76/kW-year soft cap for the capacity procurement mechanism is designed to reflect a reference unit's annual going forward fixed costs (GFFC) *plus* 20 percent.[20] The ISO's 2019 proposal would also allow units to submit a cost-based filing at FERC for payments in excess of this soft cap based on the specific unit's actual GFFC *plus* 20 percent. Units designated under the capacity procurement mechanism would also retain all net market revenues earned from bilateral or ISO market sales.

As explained in prior comments, DMM does not believe that an adder less than 20 percent is inconsistent with prior FERC orders and guidance, as the ISO contends. DMM has been recommending that instead of assigning an arbitrary percentage adder to GFFC (e.g., 20 percent), the ISO could allow suppliers seeking compensation above the soft offer cap to explicitly file for actual costs associated with long term maintenance or environmental upgrades. This would eliminate any need to set the market-wide soft offer cap above the annual going forward fixed costs of a typical unit.

Test competitiveness of capacity procurement mechanism designations

If the capacity procurement mechanism process were competitive, suppliers would be expected to submit bids reflecting their GFFC net of projected market revenues, plus a reasonable profit. DMM and

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18 Memorandum to ISO Board of Governors, Re: DMM Comments - Decision on reliability must-run and capacity procurement mechanism enhancements proposal, Eric Hildebrandt, March 20, 2019. http://www.caiso.com/Documents/Decision-ReliabilityMust-Run-CapacityProcurementMechanismEnhancementsProposal-DMMComments-Mar2019.pdf

19 *Review of Reliability Must Run and Capacity Procurement Mechanism, Issue Paper and Straw Proposal for* Phase *1 Items*, California ISO, January 23, 2018. http://www.caiso.com/Documents/IssuePaperandStrawProposal-ReviewReliabilityMustRunandCapacityProcurementMechanism.pdf

20 The soft offer cap is based on the going forward fixed costs of a merchant-constructed mid-cost 550 MW combined cycle with duct firing as determined in the California Energy Commission's 2015 Cost of Generation report: https://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SF.pdf

some stakeholders have raised concerns that capacity procurement mechanism solicitations, particularly annual solicitations, are not competitive.

A lack of competition – coupled with a soft offer cap that is too high for annual capacity procurement mechanism solicitations – raises concern that the soft offer cap for annual solicitations is not an effective form of market power mitigation. Thus, as part of the ISO's review of the soft offer cap for annual solicitations, DMM encourages the ISO to consider options for applying a market power test to offers and then linking limits on compensation to the competitiveness of the solicitations.

Merge CPM and RMR into a single backstop procurement mechanism

Capacity procurement mechanism designations will continue to be voluntary and can be declined by suppliers with market power that prefer reliability must-run compensation. DMM shares concerns raised by other stakeholders that under the current and proposed framework, newer pivotal resources with undepreciated capital costs would have an incentive to self-select reliability must-run compensation while older pivotal resources would prefer to self-select capacity procurement mechanism compensation. It is not clear what efficiencies this self-selection provides.

In the ISO's future discussions of the backstop procurement framework, the ISO should consider consolidating these two mechanisms, or, at the very least, aligning the compensation and adding supplemental rules to prevent self-selection between designations based on maximization of compensation.

Resource adequacy program

California has now maintained adequate supply capacity reserves under the state's resource adequacy program and bilateral long-term procurement process for more than a decade. However, a number of structural changes are creating the need for significant changes in this resource adequacy framework, as summarized in a recent report by the California Public Utilities Commission.[21]

The CPUC has identified a number of options for addressing these issues and is currently working with the ISO and stakeholders on moving forward with policy decisions. These options include (1) a multi-year framework for local resource adequacy, and (2) establishing a *central buyer* to procure capacity needed for various reliability requirements on behalf of load-serving entities.

DMM supports these options. Some key details of the central buyer framework could significantly impact the overall efficiency of resource procurement and subsequent participation in the ISO markets. Important details include whether the central buyer will perform full or residual resource adequacy procurement, and how the central buyer may procure energy dispatch rights. Due to the importance of these details, DMM supports the CPUC decision to delay implementing a central procurement structure in order to allow more time this year for stakeholder discussion of these important issues.

Flexible ramping product enhancements

The flexible ramping product is designed to procure additional ramping capacity to address uncertainty in imbalance demand through the market software. DMM supports the ISO's efforts in the ongoing day-ahead market enhancements initiative to design a product that procures flexible ramping capability in

[21] *Current Trends in California's Resource Adequacy Program*, Energy Division Working Draft Staff Proposal, California Public Utilities Commission, February 16, 2018. http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457193

the day-ahead market. DMM also recommends that the ISO seek to enhance the current flexible ramping capacity market design to address two key issues.

Locational procurement

The ISO has demonstrated that the current real-time flexible ramping product may not be deliverable because of transmission constraints.[22] DMM recommends that the ISO work on designing locational procurement accounts for transmission constraints for both day-ahead and real-time flexible ramping products.

Real-time product for uncertainty over longer time horizons

The current flexible ramping product is designed to address uncertainty between the 15- and 5-minute markets. In real time, grid operators face significant uncertainty about loads and resources over a longer timeframe (e.g., 30, 60, and 120 minutes from the current market interval). By designing a flexible ramping product that could account for uncertainty over longer time horizons, the ISO may be able to reduce the need for manual load adjustments and more efficiently integrate distributed and variable energy resources.

Battery resource cost modeling and bid mitigation

Currently, the amount of battery resources operating in the ISO is very limited, with installed capacity reaching about 130 MW in 2018. The ISO currently does not mitigate the energy bids of battery resources. However, many battery resources are located in transmission constrained areas that are frequently downstream of congested non-competitive constraints.

Therefore, it is very likely that these resources will need to be subject to energy bid mitigation within the next few years. DMM is recommending that the ISO and stakeholders begin to develop default energy bids for batteries as part of the ISO's ongoing energy storage and distributed energy resources (ESDER 4) initiative.

Through engagement with stakeholders in the ESDER stakeholder processes, DMM also understands that ISO's current structures for modeling battery resources may not accurately reflect the ways in which operating a battery accelerates the need for the battery owner to incur significant, lumpy maintenance costs such as augmenting battery cells. Managing potential maintenance costs through contractual limitations or negotiated warranties could result in inefficient utilization of battery resources in wholesale electricity markets.

Therefore, DMM is recommending that the ISO, local regulatory authorities, and the battery community work together as part of the ESDER 4 initiative to identify and model how some kinds of battery usage, such as deep charging or discharging, accelerate the need to incur significant maintenance costs. This will allow the ISO optimization to accurately consider these lumpy costs when determining efficient dispatch. Accurately modeling the actual causes of these costs will also allow market participants to efficiently limit the kinds of battery operations that cause significant maintenance costs and to recover these costs through their market revenues.

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22 *Discussion on flexible ramping product*, California ISO, September 8, 2017 pg. 16-17: http://www.caiso.com/Documents/Discussion_FlexibleRampingProduct.pdf

Organization of report

The remainder of this report is organized as follows:

- **Loads and resources.** Chapter 1 summarizes load and supply conditions impacting market performance. This chapter includes an updated analysis of net operating revenues earned by hypothetical new gas-fired generation from the ISO markets.
- **Overall market performance.** Chapter 2 summarizes overall market performance.
- **Real-time market performance.** Chapter 3 provides an analysis of real-time market performance and prices including the energy imbalance market. This chapter also includes a discussion of the real-time market impacts of the Aliso Canyon natural gas storage facility limitations.
- **Energy imbalance market.** Chapter 4 highlights the growth and performance of the energy imbalance market.
- **Convergence bidding.** Chapter 5 analyzes the convergence bidding feature and its effects on the market.
- **Ancillary services.** Chapter 6 reviews performance of the ancillary service markets.
- **Market competitiveness and mitigation.** Chapter 7 assesses the competitiveness of the energy market, along with impact and effectiveness of market power and exceptional dispatch mitigation provisions.
- **Congestion.** Chapter 8 reviews congestion and the market for congestion revenue rights.
- **Market adjustments.** Chapter 9 reviews the various types of market adjustments made by the ISO to the inputs and results of standard market models and processes.
- **Resource adequacy.** Chapter 10 assesses the short-term performance of California's system and flexible resource adequacy programs.
- **Recommendations.** Chapter 11 highlights DMM recommendations on current market issues and new market design initiatives on an ongoing basis.

1 Load and resources

This chapter reviews key aspects of demand and supply conditions that affected overall market prices and performance. In 2018, wholesale electricity prices were driven by a 25 percent increase in gas prices, combined with moderate load, an increase in supply from new solar generation and a decrease in hydroelectric generation. More specific trends highlighted in this chapter include the following:

- The average price of natural gas in the daily spot markets in California increased by about 25 percent from 2017, with particularly high prices at SoCal Citygate. This was the main driver in the 24 percent increase in the annual wholesale energy cost per megawatt-hour of load served in 2018.
- Summer loads peaked at 46,427 MW, close to the 1-in-2 year load forecast, and 7 percent lower than peak load in 2017. Total load was higher in July and August of 2018 compared to 2017, though otherwise lower for every other month of 2018 compared to 2017.
- Annual system energy totaled 223,705 GWh, roughly 2 percent lower than 2017. The drop in total annual load in 2018 continued a trend of decreasing loads since 2011.
- Hydroelectric generation decreased in 2018 to around 10 percent of supply, compared to 15 percent in 2017 and 11 percent in 2016.
- Imports from the Southwest increased by about 9 percent and imports from the Northwest decreased by about 9 percent. In total, net imports were similar in volume to 2017.
- Non-hydro renewable generation accounted for about 26 percent of total supply in 2018, an increase from 24 percent in 2017.[23] Solar generation increased by about 9 percent and accounted for around 12 percent of total supply. The increase was primarily driven by the addition of new solar generation capacity.
- Gas capacity retiring or otherwise withdrawing from the market was replaced, in part, with solar and other renewable resources. The number of batteries participating in ISO markets has increased over the past four years. The majority of batteries participating in ISO markets are located in locally constrained areas.
- While the total amount of registered capacity and energy bids from demand response increased significantly between 2017 and 2018, the additional proxy demand response capacity was primarily offered into the day-ahead market at bid prices over $750/MWh and into the real-time market near the $1,000/MWh bid cap.
- The estimated net operating revenues for typical new gas-fired generation in 2018 were substantially below the annualized fixed cost of new generation. This analysis does not include revenues earned from resource adequacy contracts or other bilateral contracts. These findings highlight the critical importance of long-term contracting as the primary means for investment in any new generation or retrofit of existing generation needed under the ISO's current market design.

23 In this analysis, non-hydro renewables include tie generators but do not include other imports or behind the meter generation such as rooftop solar. Thus, this analysis may differ from other reports of total renewable generation.

1.1 Load conditions

1.1.1 System loads

The instantaneous peak load and total annual energy within the ISO decreased in 2018. Table 1.1 summarizes annual system peak loads and energy use over the last five years.

Table 1.1 Annual system load in the ISO: 2014 to 2018

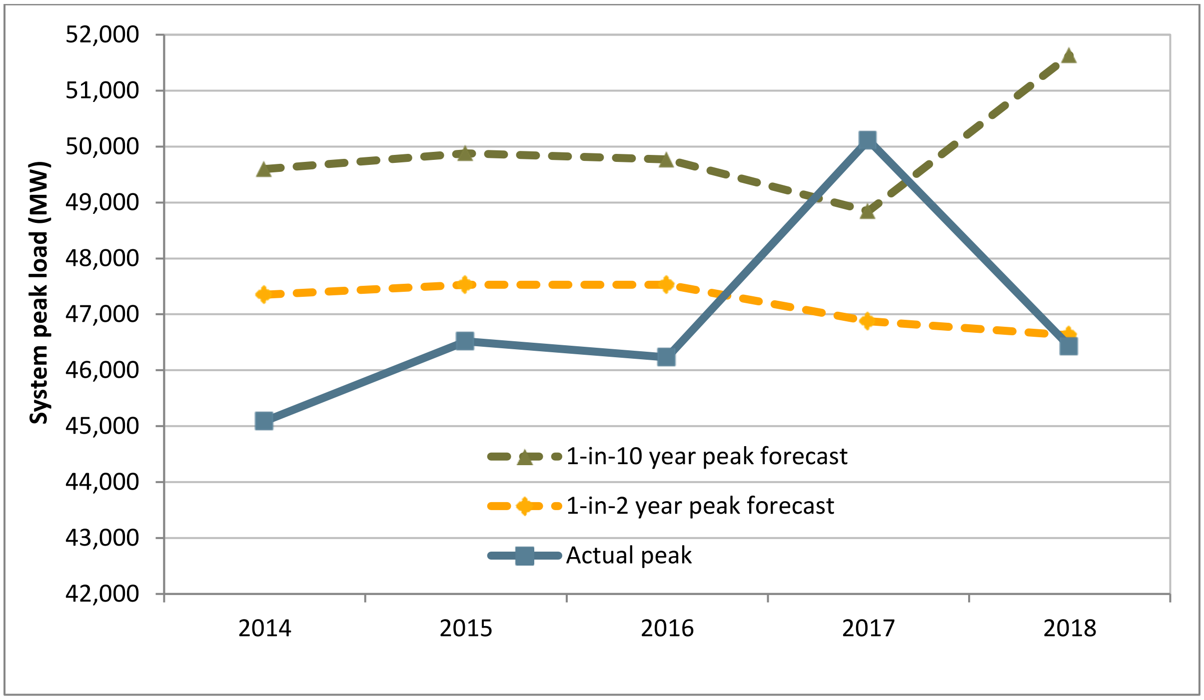
Year	Annual total energy (GWh)	Average load (MW)	% change	Annual peak load (MW)	% change
2014	231,610	26,440	-0.1%	45,090	0.0%
2015	231,495	26,426	0.0%	46,519	3.2%
2016	228,794	26,047	-1.4%	46,232	-0.6%
2017	228,191	26,049	0.0%	50,116	8.4%
2018	223,705	25,537	-2.0%	46,427	-7.4%

The drop in total annual load in 2018 continued a trend of decreasing loads since 2011. Annual system energy totaled 223,705 GWh, the lowest load in the last 5 years. Total load was higher in July and August of 2018 compared to 2017, but was lower for every other month of 2018 compared to 2017.

Summer loads peaked at 46,427 MW on July 25 at 15:58 pm, which was similar to peak loads during recent years with the exception of 2017. System demand during the single highest load hour often varies substantially year-to-year. The potential for heat-related peak loads creates a continued threat to operational reliability and drives many of the ISO's reliability planning requirements.

The peak load in 2018 was very similar to the ISO's 1-in-2 year load forecast (46,625 MW) and about 10 percent lower than the 1-in-10 year forecast (51,632 MW) as shown in Figure 1.1. The ISO works with the California Public Utilities Commission and other local regulatory authorities to set system level resource adequacy requirements. These requirements are based on the *1-in-2 year* (or median year) forecast of peak demand. Resource adequacy requirements for local areas are based on the *1-in-10 year* (or 90th percentile year) peak forecast for each area.

Figure 1.1 Actual load compared to planning forecasts



1.1.2 Local transmission constrained areas

The ISO has defined ten local capacity areas for use in establishing local reliability requirements for the state's resource adequacy program. Local capacity areas are by definition transmission constrained, and are therefore an important point of focus for reliability reasons as well as for the potential for market power. Chapter 7 of this report assesses the structural competitiveness of the market for capacity in local areas, along with the frequency and impact of local energy market power mitigation procedures. This section provides a high level perspective of supply and demand conditions in each local area.

Table 1.2 presents forecasted peak load, current dependable generation, and capacity requirements for these local capacity areas. Figure 1.2 shows the location of each local capacity area and the proportion of each area's load relative to the total peak load defined for all local areas.[24] The local capacity requirement is defined as the resource capacity needed to reliably serve load within a local capacity area. Dependable generation is the net qualifying capacity of available resources within the locally constrained area.

Local capacity requirements increased to a total of 25,207 MW for 2018 compared to 24,594 in 2017. However, dependable generation in each area decreased. This was largely due to recent gas generation retirements, described in greater detail in Section 1.2. Table 1.2 also shows the proportion of dependable generation capacity required to meet local reliability requirements established in the state resource adequacy program. In most areas, a high proportion of the available capacity is needed to

[24] Note that the total local area peak load figure, as well as proportion of each local capacity area's load of the total, is illustrative. Each local area's load will peak at a different time from one another and from the system-coincident peak load.

meet peak reliability planning requirements.[25] One or two entities own the bulk of generation in each of these areas. As a result, the potential for locational market power in these load pockets is significant.

Of the local capacity areas, the Los Angeles Basin and the Greater Bay Area have the highest local capacity requirements, in part due to high peak load based on 1-in-10 year forecasts. In these areas, the forecasted peak load projections decreased compared to 2017 by about 400 and 200 MW, respectively. In the Greater Bay Area, the amount of dependable generation decreased by about 2,700 MW compared to 2017. As a result, the requirement for the Greater Bay Area as a percent of generation increased from 57 percent in 2017 to 73 percent in 2018, indicating a greater reliance on fewer resources to meet local reliability needs.

Table 1.2 Load and supply within local capacity areas in 2018[26]

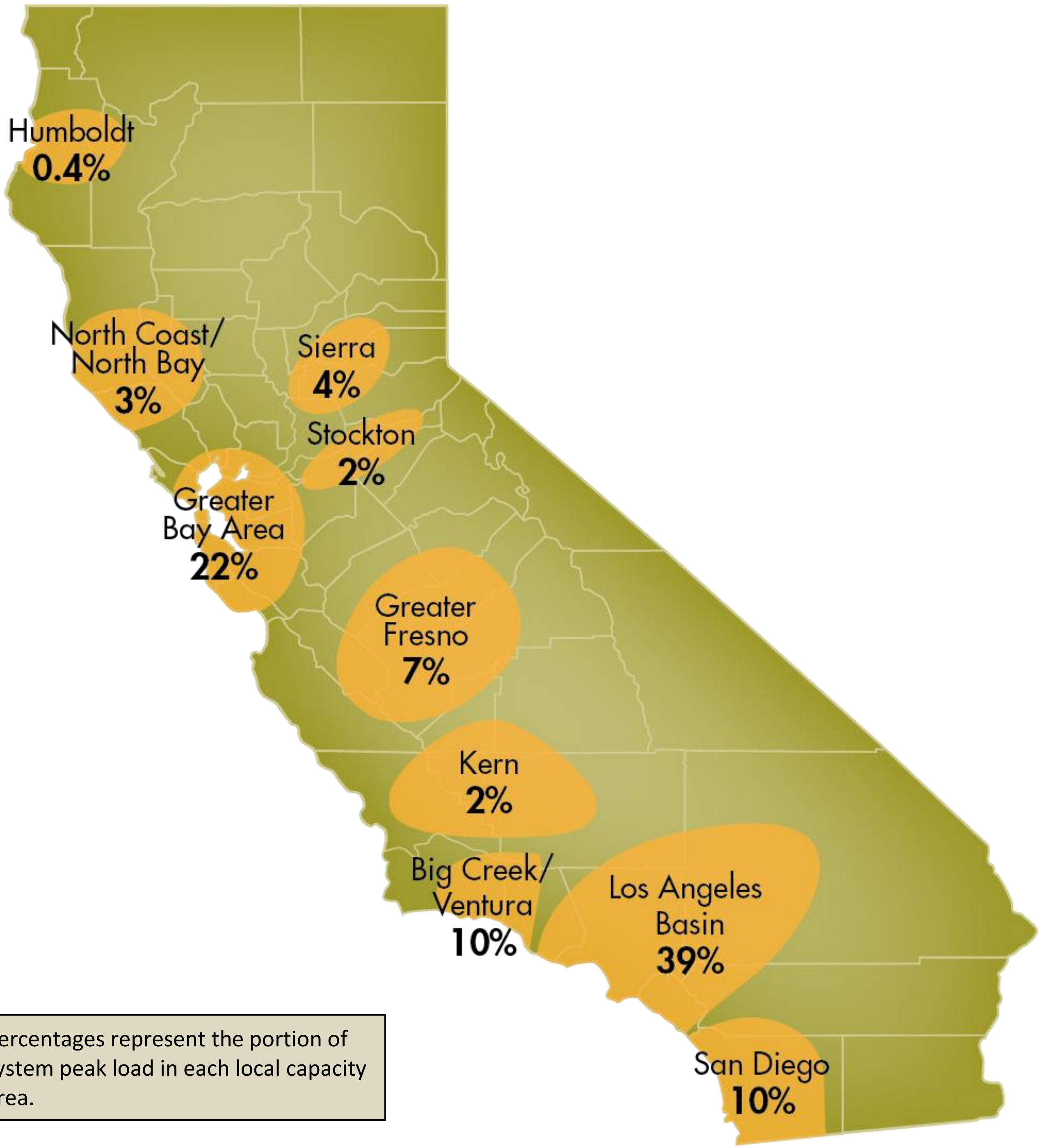
Local Capacity Area	LAP	Peak Load (1-in-10 year) MW	%	Dependable Generation (MW)	Local Capacity Requirement (MW)	Requirement as Percent of Generation
Greater Bay Area	PG&E	10,247	22%	7,103	5,160	73%
Greater Fresno	PG&E	3,290	7%	3,579	2,081	58%
Sierra	PG&E	1,818	4%	2,125	2,113	99%*
North Coast/North Bay	PG&E	1,333	3%	869	634	73%
Stockton	PG&E	1,169	2%	605	719	119%*
Kern	PG&E	867	2%	566	453	80%
Humboldt	PG&E	187	0.4%	210	169	80%
LA Basin	SCE	18,466	39%	10,735	7,525	70%
Big Creek/Ventura	SCE	4,802	10%	5,657	2,321	41%
San Diego	SDG&E	4,924	10%	4,915	4,032	82%
Total		**47,103**		**36,364**	**25,207**	

* Resource deficient LCA (or with sub-area that is deficient) – deficiency included in LCR. Resource deficient area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.

25 California's once-through cooling (OTC) regulations affect a significant proportion of capacity needed to meet requirements in four areas: Greater Bay Area, Los Angeles Basin, Big Creek/Ventura and San Diego.

26 Obtained from the *2018 Local Capacity Technical Analysis*, May 1, 2017, p. 23, table 6: http://www.caiso.com/Documents/Final2018LocalCapacityTechnicalReport.pdf.

Figure 1.2 Local capacity areas



Percentages represent the portion of system peak load in each local capacity area.

1.2 Supply conditions

1.2.1 Generation mix

Natural gas, non-hydro renewables, and net imports were the largest sources of energy in the ISO's energy mix in 2018, comprising about 30, 26, and 22 percent of total system energy, respectively.[27] The share of energy from natural gas generators increased by about 2 percent compared to 2017. The share of hydroelectric generation of total generation decreased by about 7 percent in 2018 relative to the high levels observed in 2017. The share of non-hydro renewable generation increased about 3 percent, driven by new solar generation capacity. Solar generation increased to about 12 percent of total generation, up from about 11 percent in 2017.

Monthly generation by fuel type

Figure 1.3 provides a profile of average hourly generation by month and fuel type. Figure 1.4 illustrates the same data on a percentage basis. These figures show the following:

- Natural gas, non-hydro renewables, and net imports were the largest sources of generation in 2018, with 30, 26, and 22 percent respectively. Compared to 2017, the share of energy from natural gas increased around 2 percent, renewables increased 3 percent, and net imports were unchanged.
- Hydroelectric generation decreased to 10 percent of supply, compared to 15 percent in 2017.
- Non-hydro renewable generation accounted for about 26 percent of total supply, an increase from about 24 percent in 2017, driven primarily by growth in generation from solar resources.[28]
- Nuclear generation provided 10 percent of supply, roughly the same as its contribution in 2017.

[27] Including all tie generation in net imports (as was done in 2016 and years prior), these percentages were 30, 24, and 28 percent respectively.

[28] In this analysis, non-hydro renewables do not include imports or behind the meter generation such as rooftop solar, but do include tie generation. Thus, this analysis may differ from other reports of total renewable generation.

Figure 1.3 Average hourly generation by month and fuel type in 2018

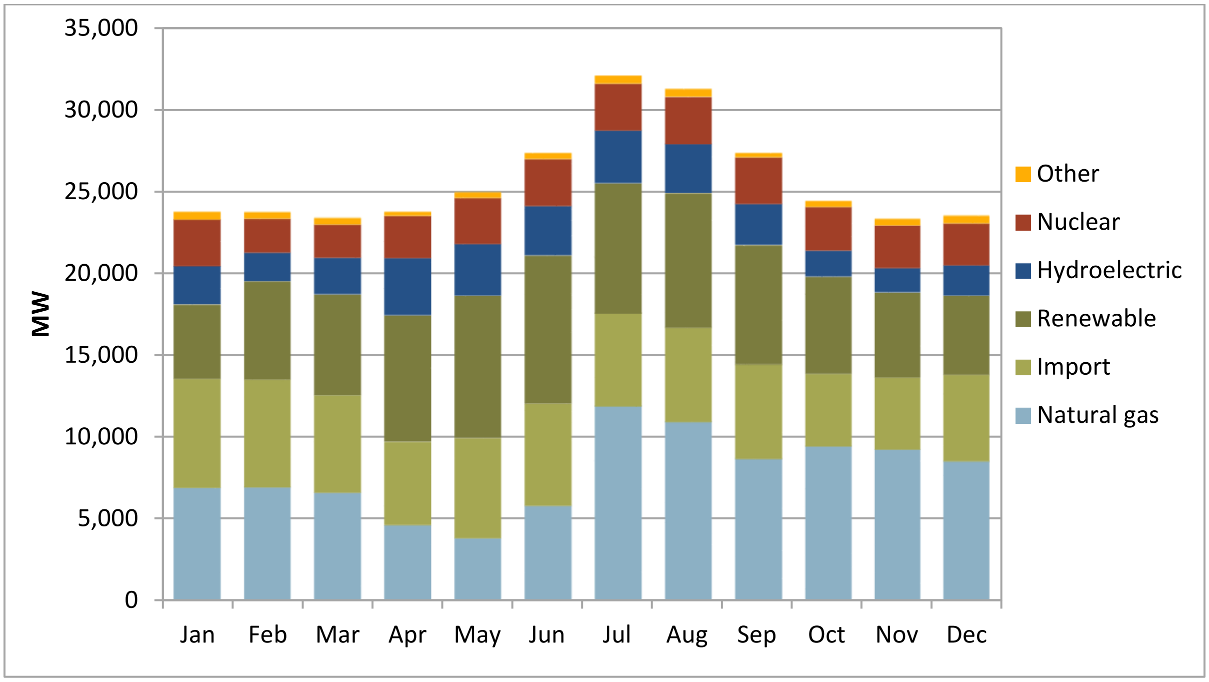
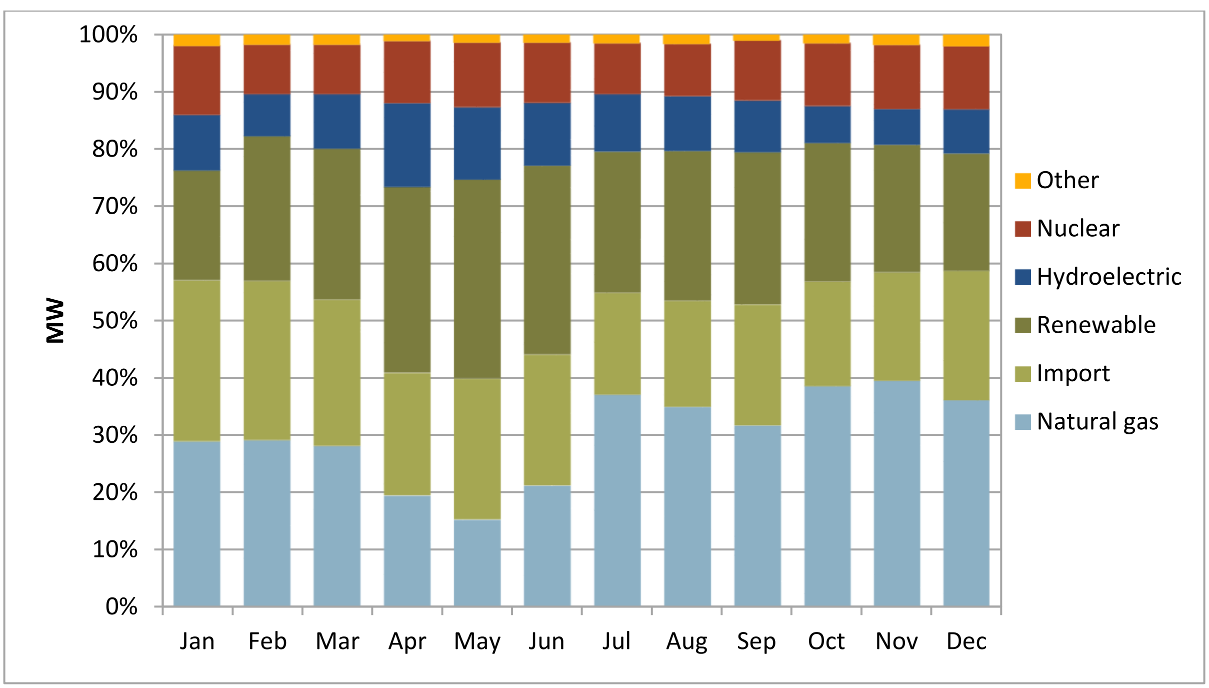


Figure 1.4 Average hourly generation by month and fuel type in 2018 (percentage)



Renewable generation

As noted above, about 26 percent of ISO load was met by non-hydro renewable and about 10 percent from hydroelectric generation. Figure 1.5 provides a detailed breakdown of non-hydro renewable generation including imports which are specifically identified as wind and solar resources.[29] As shown in Figure 1.5:

- In 2015, solar power became the largest source of renewable energy within the ISO. In 2018, overall output from solar generation increased by about 9 percent compared to 2017 and accounted for around 12 percent of total supply. The increase was primarily driven by the addition of new solar resources.
- Generation from wind resources increased by about 19 percent and contributed about 7 percent of total system energy.
- The overall output from geothermal generation decreased about 2 percent compared to 2017, and provided about 4 percent of system energy.
- Biogas, biomass, and waste generation accounted for about 2 percent of system energy, slightly increasing compared to 2017.

Figure 1.6 compares average monthly generation from hydro, wind and solar resources. With decreased precipitation, the amount of energy produced by hydroelectric was lower than solar generation, but was still greater than wind generation for most months of 2018.

In 2018, average hourly solar generation peaked at 10,760 MW on June 29 hour ending 13. Generation from wind resources peaked in May, while generation from hydro resources peaked in April. Non-hydro renewable generation made up the greatest portion of system generation during May, when it accounted for nearly 35 percent of total generation.

[29] In addition to values reported here, renewable and hydro resource generators provide energy through imports and behind the meter generation. These values are excluded due to lack of input data.

Figure 1.5 Total renewable generation by type (2015-2018)

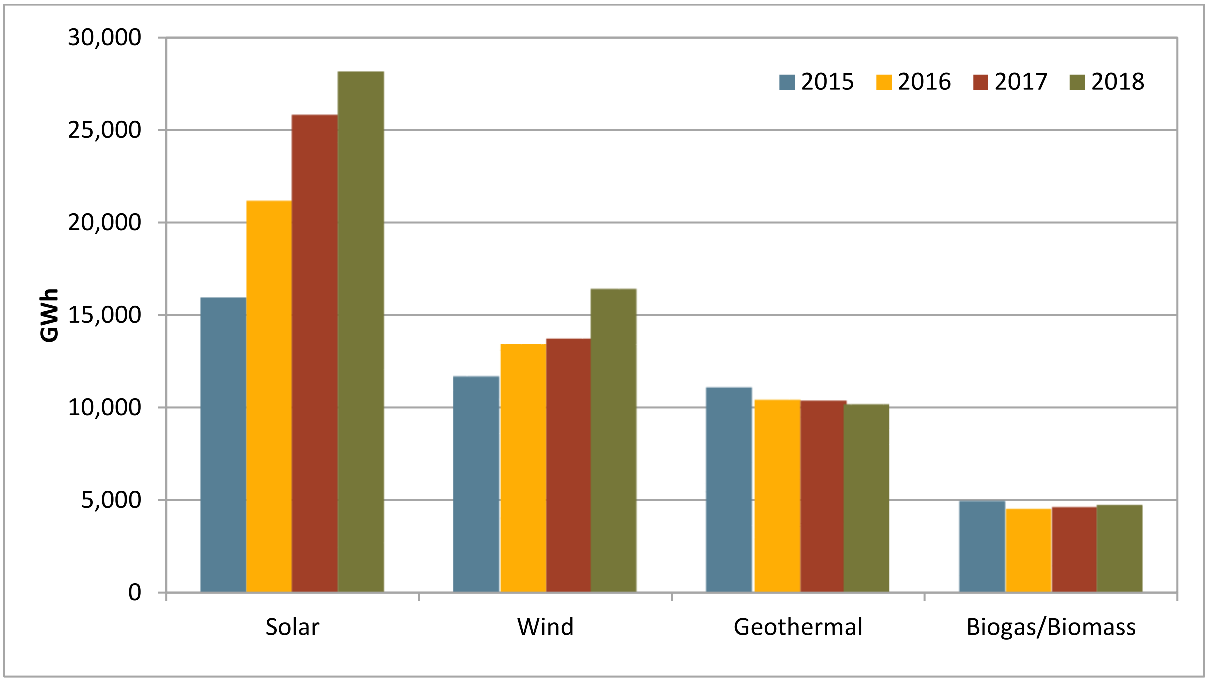
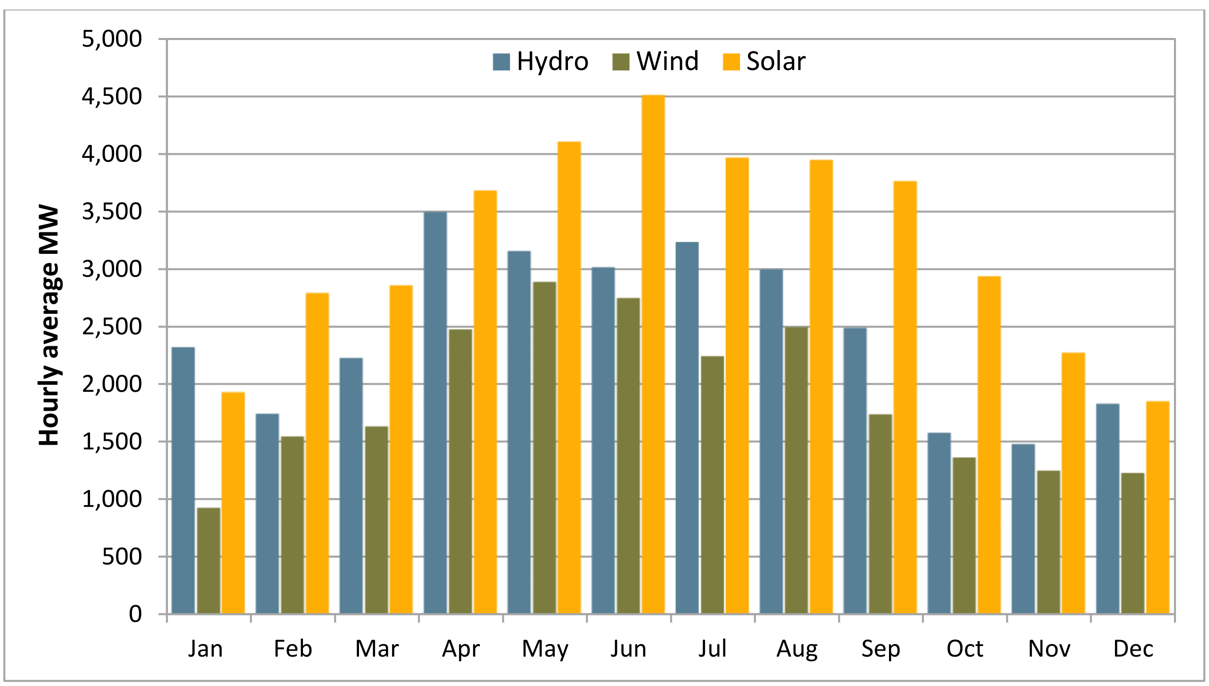


Figure 1.6 Monthly comparison of hydro, wind and solar generation (2018)



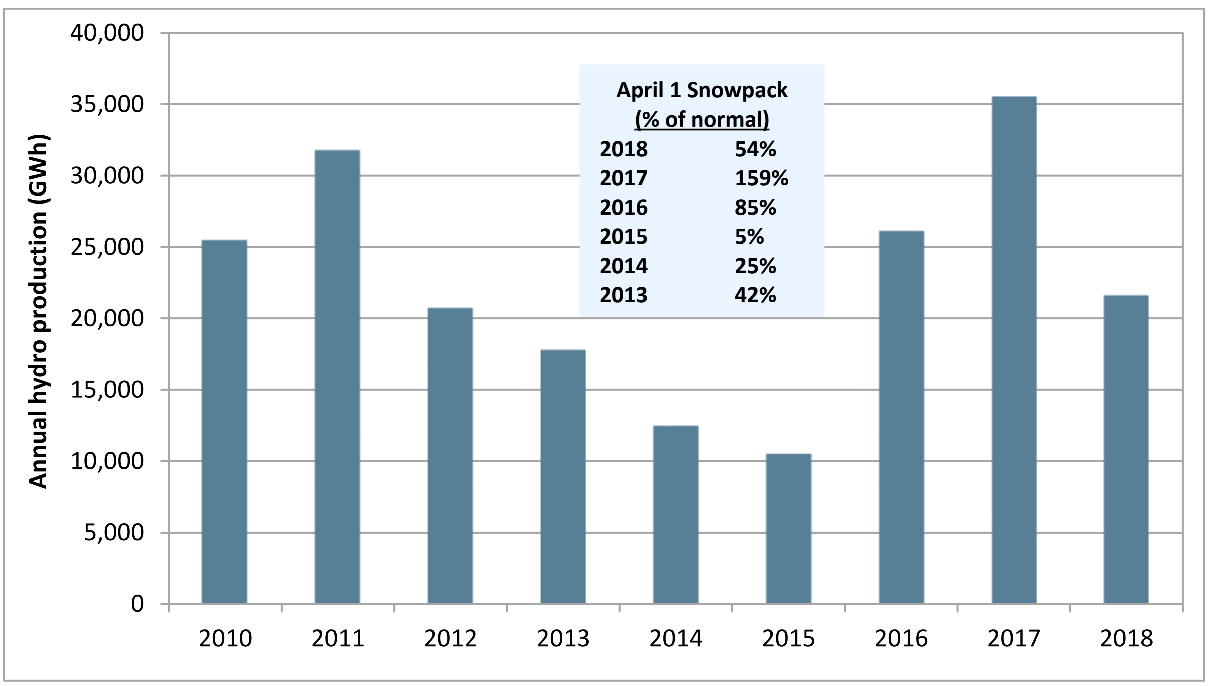
Hydroelectric supplies

Year-to-year variation in hydroelectric power supply in California can have a significant impact on prices and the performance of the wholesale energy market. More supply of run-of-river hydroelectric power generally reduces the need for baseload generation and imports. Hydro conditions also impact the amount of hydroelectric power and ancillary services available during peak hours from units with reservoir storage. In 2018, almost all hydroelectric resources in the ISO were owned by load-serving entities that were net buyers of electricity.

Total hydroelectric production in 2018 decreased 39 percent from the prior year.[30] Statewide snowpack, as measured on April 1, 2018, was 54 percent of the long-term average – lower than the last two years.[31]

Figure 1.8 compares monthly hydroelectric output from resources within the ISO system for each month during the last three years. As in previous years, hydro generation in 2018 followed a seasonal pattern, with the highest generation in the late spring and early summer months. Generation in 2018 was lower than generation from the previous two years during every month except January. Monthly generation in 2018 was about 40 percent lower, on average, than in 2017.

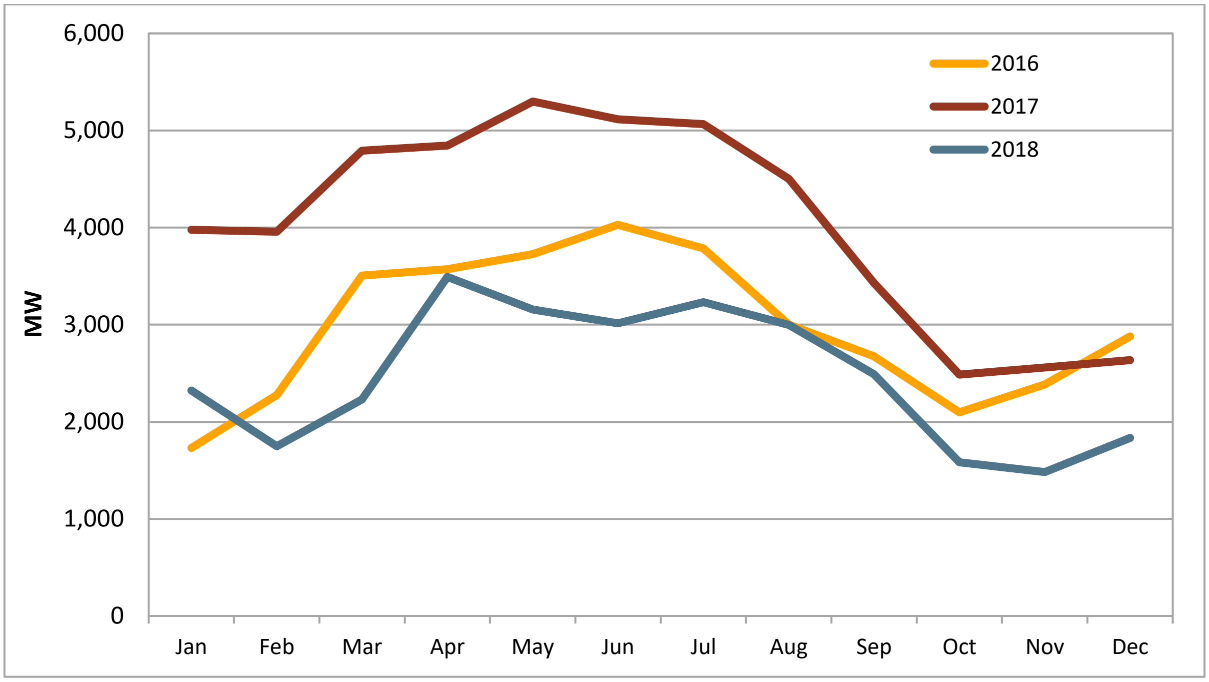
Figure 1.7 Annual hydroelectric production (2010-2018)



30 Starting in 2016, annual hydroelectric production includes all tie generators. Due to data limitations in years prior to 2015, historical values do not include all tie generators. Due to this change, hydroelectric production in 2016 increased by about 10 percent compared to the value previously reported.

31 For snowpack information, please see: California Cooperative Snow Surveys' Snow Water Equivalents (inches), California Department of Water Resources: https://cdec.water.ca.gov/cgi-progs/products/April_1_SWC.pdf.

Figure 1.8 Average hourly hydroelectric production by month (2016-2018)



Batteries

The number of batteries participating in ISO markets has increased over the past four years. Battery resources can currently participate in ISO markets through the non-generator resource (NGR) model or as demand response resources. The majority of batteries participating in ISO markets are located in locally constrained areas. DMM has made recommendations in Chapter 11 related to increasing volume, modeling and potential need for mitigation of bids of batteries.

Figure 1.9 shows the total capacity of batteries participating as non-generator resources represented both in terms of maximum output (MW) and maximum continuous energy (MWh). Since 2015, the total capacity of batteries has increased each year, and totaled about 136 MW by the end of 2018.

Figure 1.9 Battery capacity (2015-2018)

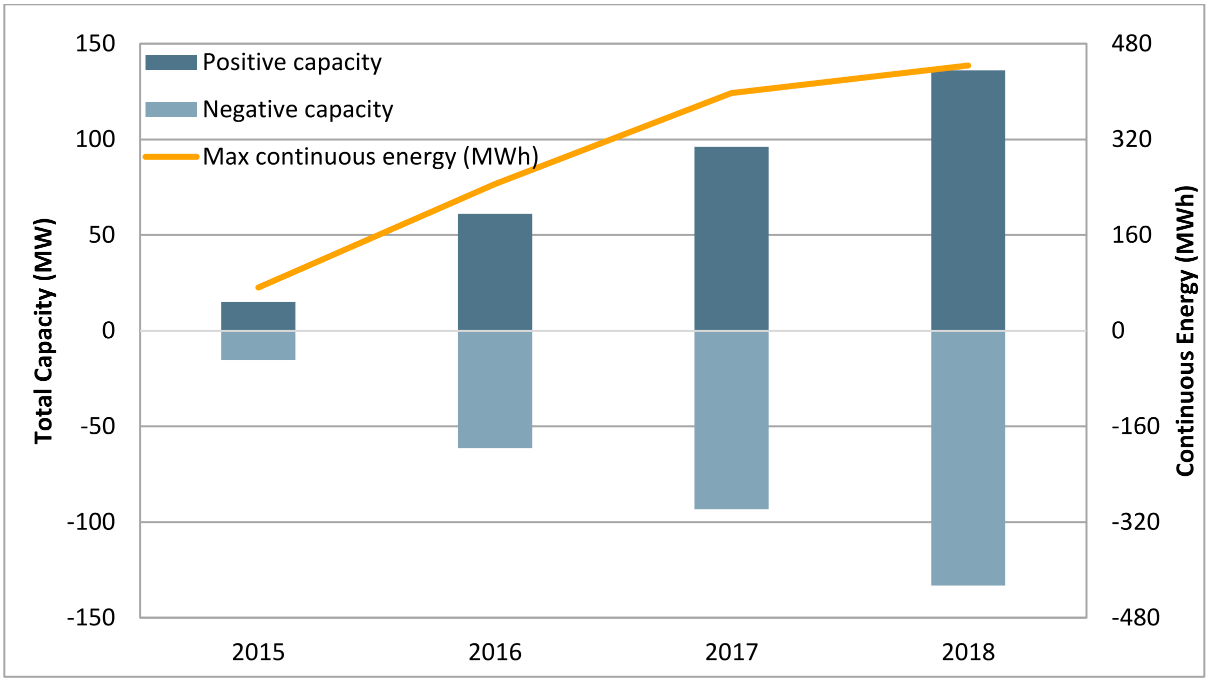


Figure 1.10 shows total capacity and duration for front-of-the-meter market participating battery resources. The duration of each battery is rounded to the nearest integer. Although duration ranges from one to seven hours, the greatest number of resources participating have a duration of four hours.

Figure 1.11 shows average hourly schedules in 2018. Batteries primarily received awards for ancillary services, including regulation up, regulation down, and spin reserves. When providing energy, schedules are highest during the morning and evening ramping hours. Batteries often recharged overnight and during mid-day hours when renewable energy production was highest.

Figure 1.10 Total battery capacity and duration (2018)

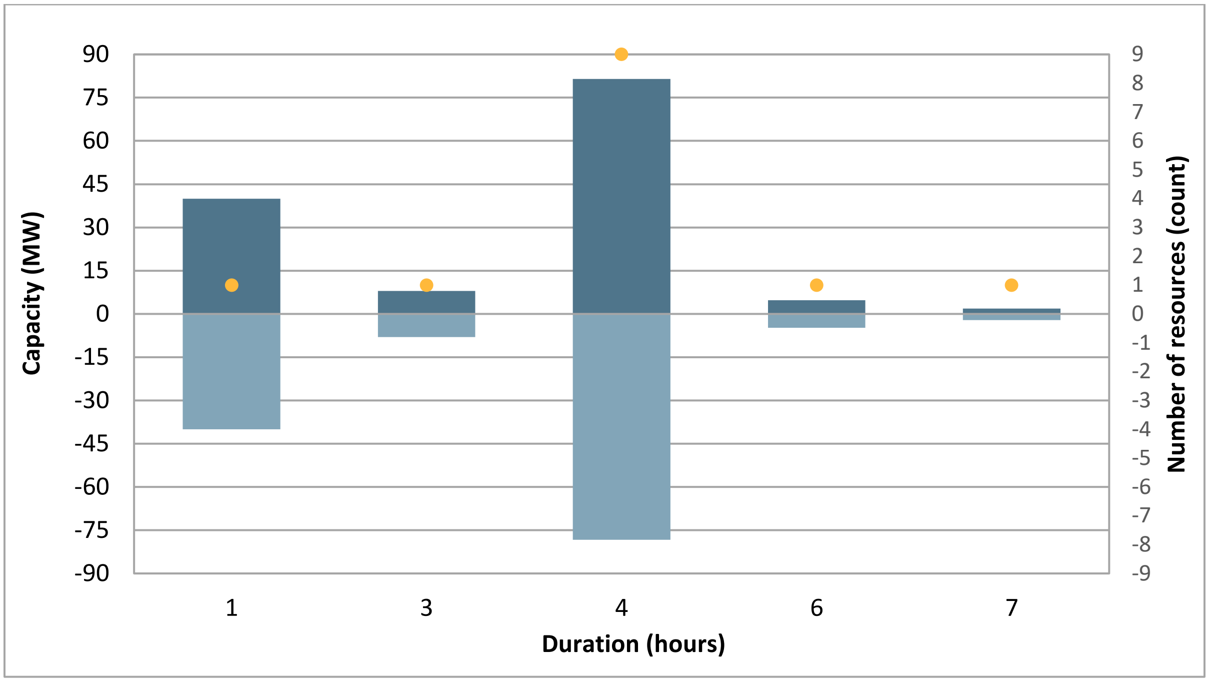
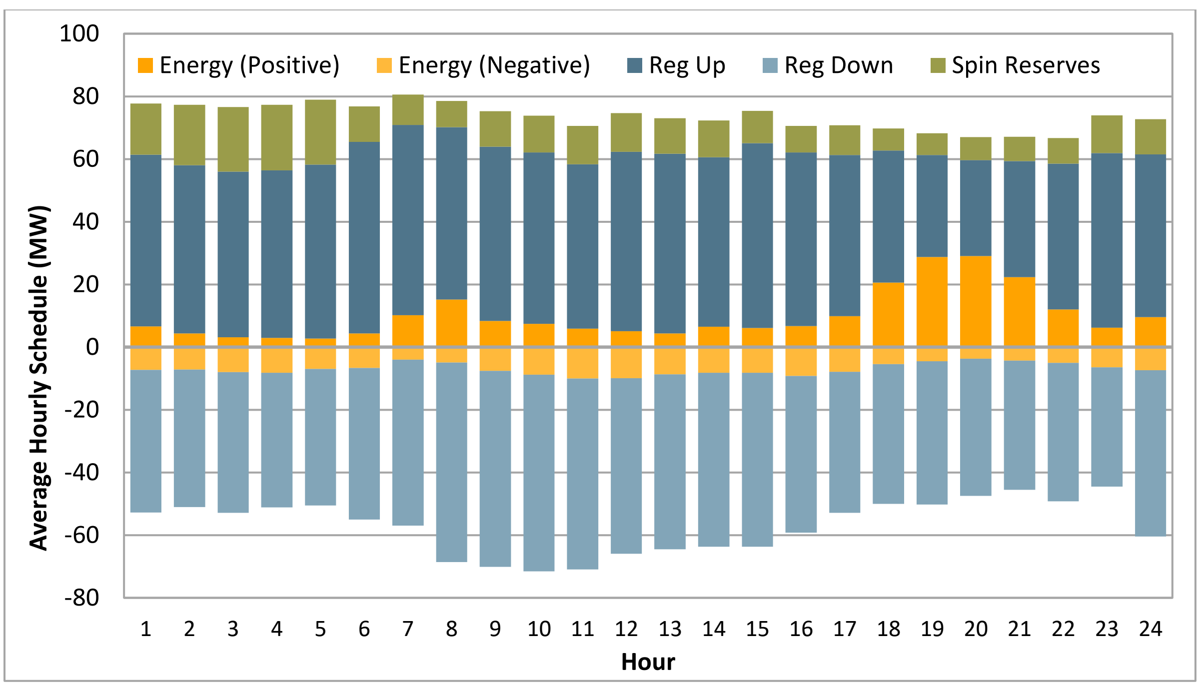


Figure 1.11 Average hourly battery schedules (2018)



Net imports

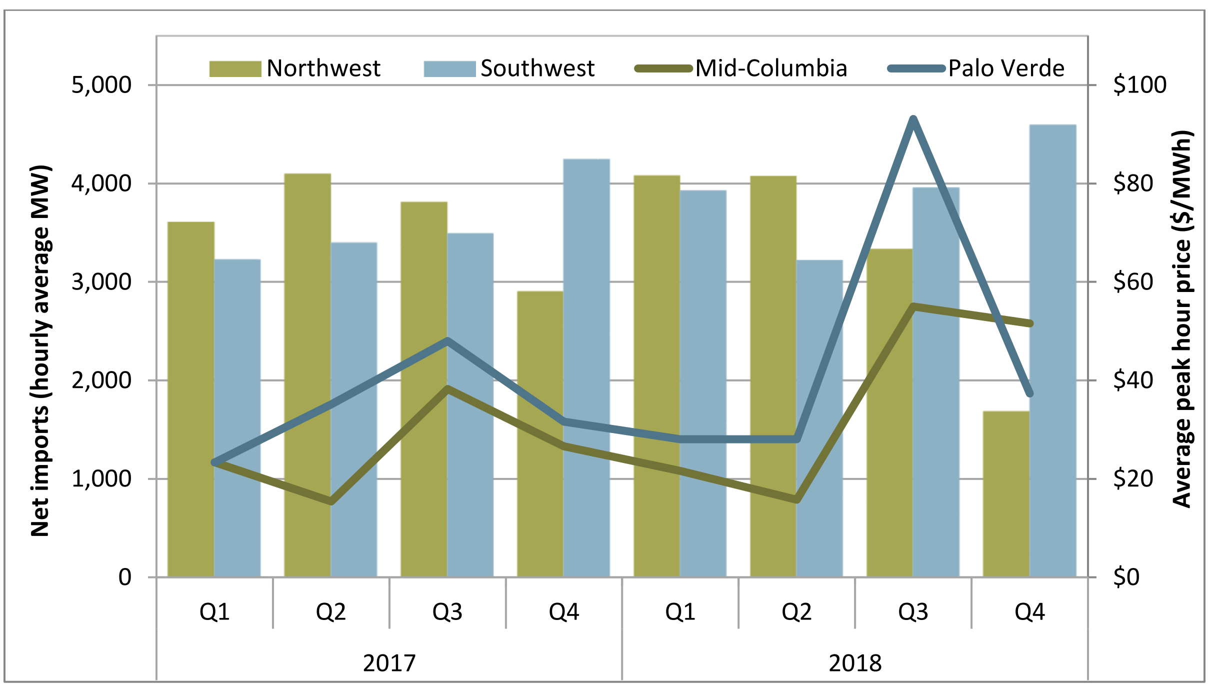
Total generation from net imports in 2018 was similar to 2017.[32] Net imports from sources in the Northwest decreased by around 9 percent while net imports from the Southwest increased by about 9 percent. Figure 1.12 compares net imports by region for each quarter during 2017 and 2018. Net imports from the Southwest were higher than the previous year in all but the second quarter, while net imports from the Northwest were higher during the first quarter, but lower in the third and fourth quarters.

Figure 1.12 also shows the quarterly average bilateral prices at Mid-Columbia (Mid-C) and Palo Verde. During the first three quarters of 2018, Palo Verde prices exceeded prices at Mid-C. In the first two quarters, net imports in the Northwest exceeded those in the Southwest.

In the third quarter of 2018, Palo Verde prices were significantly higher than Mid-Columbia prices; however, net imports from the Southwest were greater than the Northwest. This reflects higher gas prices in the south and constraints that limit transmission of generation from the Northwest to the southern parts of California and the Southwest.

In the fourth quarter, Mid-C prices increased relative to Palo Verde and net imports from the Northwest were at their lowest point. High Mid-C prices in the end of 2018 were driven by a natural gas pipeline outage in the Northwest in October.

Figure 1.12 Net imports and average day-ahead price difference (peak hours, 2017-2018)



[32] Net imports are equal to scheduled imports minus scheduled exports in any period. These net imports exclude any transfers associated with the energy imbalance market.

Demand response

Demand response continues to play a role in meeting California's capacity planning requirements for peak summer demand. Demand response is a resource that allows consumers to adjust electricity use in response to forecast or actual market conditions, including high prices and reliability signals.

Demand response programs are operated by load-serving entities throughout the state as well as third party providers. All demand response capacity shown on monthly resource adequacy supply plans was scheduled by third-party (non-load-serving entity) demand response providers (DRPs), whose participation in the ISO market has increased significantly since June 2016. Utility-operated demand response programs not shown on monthly resource adequacy supply plans may also be credited toward load-serving entity resource adequacy requirements under CPUC provisions.

Historically, many demand response programs were dispatched and administered by utilities, rather than by the ISO. However, beginning in 2015, utility and third-party demand response programs have been offered directly into the ISO markets. The increase in ISO-participating demand response and third-party ownership can be attributed in part to the CPUC's Demand Response Auction Mechanism (DRAM) pilots, which sought to integrate demand response into the resource adequacy framework and allow for direct participation of demand response in the ISO market. Utilities have also continued to integrate their demand response programs into the wholesale market. Pumping load not associated with utility programs also provides a significant amount of demand response directly to the ISO.[33]

Proxy demand response (PDR) resources can be bid economically in the day-ahead and real-time markets as supply. Reliability demand response resources (RDRR) can also participate economically in the day-ahead market. In the real-time market, uncommitted reliability demand response resource capacity must be offered as energy for reliability-only purposes at 95 to 100 percent of the bid cap. When an emergency condition is declared, reliability demand response resources are made available in the bid stack at prices between $950/MWh to $1,000/MWh.

In addition to these demand response programs, the ISO issues Flex Alerts when system conditions are expected to be particularly stressed. Flex Alerts urge consumers to voluntarily reduce demand and are communicated through press releases, text messages and other means. During 2018, the ISO declared Flex Alerts on July 24 and July 25 in response to reliability concerns related to high temperatures, reduced imports, tight natural gas supply in Southern California, and high wildfire risk.[34]

Figure 1.13 shows the total demand response capacity (proxy demand response and reliability demand response resources) from 2016 to 2018 that was reflected on monthly load-serving entity resource adequacy supply plans (does not include utility-operated demand response counted toward resource adequacy requirements under CPUC provisions). Between 2016 and 2018, demand response capacity shown on monthly supply plans increased significantly, particularly in summer months. This capacity has solely been scheduled by third-party providers.

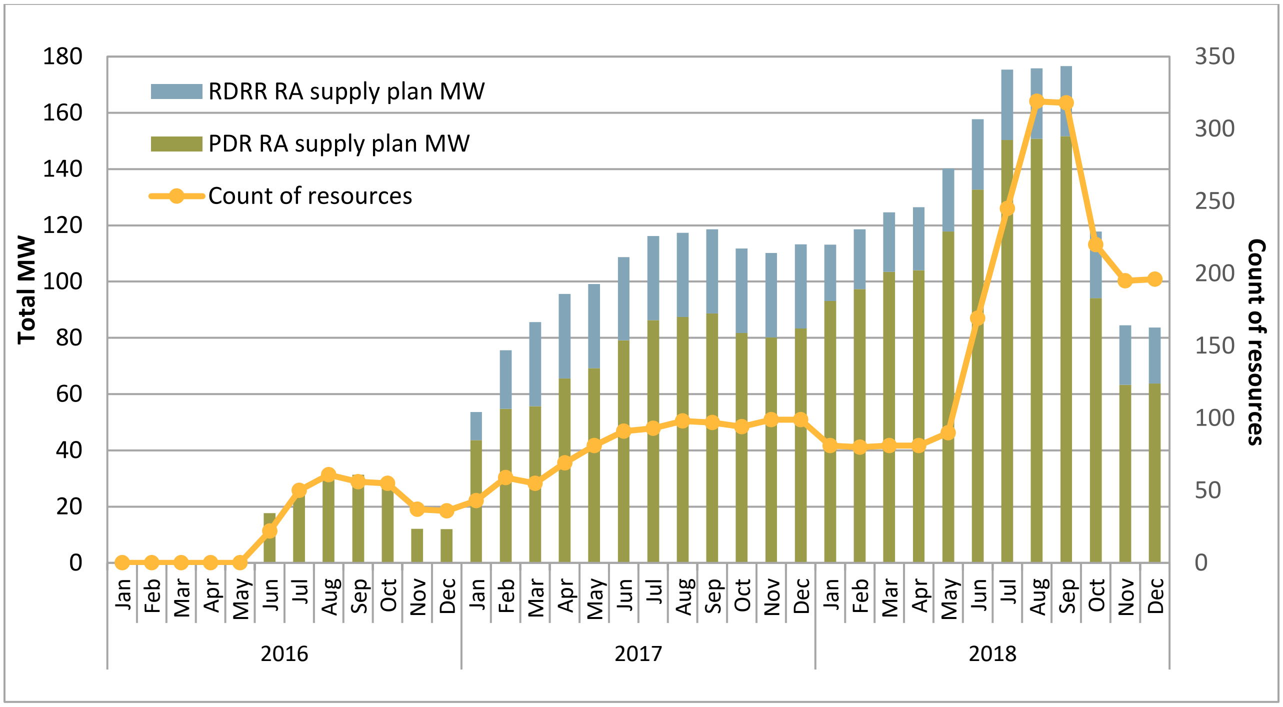
The number of individual resources comprising this capacity also increased in 2018. The resource to capacity ratio indicates that demand response shown on monthly resource adequacy supply plans generally provided under 1 MW of resource adequacy capacity per resource ID. However, these

[33] The ISO does not release information on the amount of participating loads since virtually all this capacity is operated by one market participant – the California Department of Water Resources.

[34] See: http://www.caiso.com/Documents/FlexAlertIssuedforTuesday-Wednesday_July24-25.html#search=flex%20alert%20-%20a%20call%20for%20energy%202018

resources' registered maximum capacity averaged about two times the corresponding resource adequacy capacity.

Figure 1.13 Demand response capacity reflected on monthly LSE RA supply plans



In addition to the increase in demand response reflected on monthly resource adequacy supply plans, registered proxy demand response and reliability demand response resource capacity increased overall in the ISO market in 2018 as well as the number of demand response providers, particularly third-party providers. Between 2017 and 2018, total registered proxy demand response capacity (Pmax MW) increased from about 270 MW to about 700 MW. About 140 MW of this increase was associated with resources shown on load-serving entity resource adequacy supply plans. Between 2017 and 2018, total registered reliability demand response resource capacity increased from about 1,000 MW to about 1,700 MW. The vast majority of this capacity is not reflected on resource adequacy supply plans. There were 11 active demand response providers in 2018.

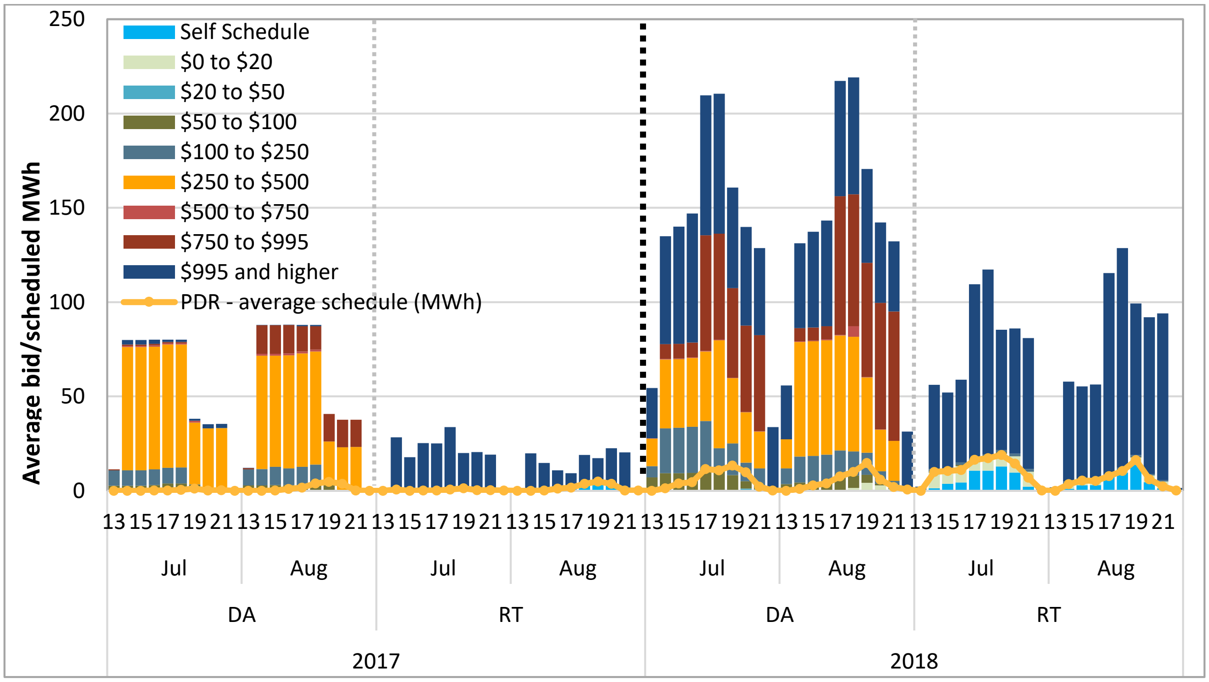
While the total amount of registered capacity and energy bids from demand response increased significantly between 2017 and 2018, the additional proxy demand response capacity was primarily offered into the day-ahead market at bid prices over $750/MWh and into the real-time market near the $1,000/MWh bid cap. The incremental bid capacity in 2018 was from both supply plan and non-supply plan resources. The majority of demand response capacity remained concentrated at the top of the resource supply stack and was infrequently dispatched in the day-ahead and real-time markets.

Figure 1.14 shows the total average volume of bid energy by price range from all proxy demand response resources and average energy schedules in the day-ahead and real-time market in July/August of 2017 and 2018, in hours where demand response is most frequently bid and dispatched (HE 14 to 21).[35] Beginning in June 2016 and continuing through 2018, there was a significant increase in the

[35] Hours ending 13 and 22 are also shown to capture the change in bid and scheduled capacity outside of the HE 14-21 window.

volume of proxy demand response capacity bid in the day-ahead and real-time markets. Proxy demand response dispatched in the day-ahead and real-time markets also increased in 2018, particularly in July and August on days with high day-ahead forecasts and peak system loads.

Figure 1.14 Proxy demand response bid prices and average schedules July and August (HE 13-22)

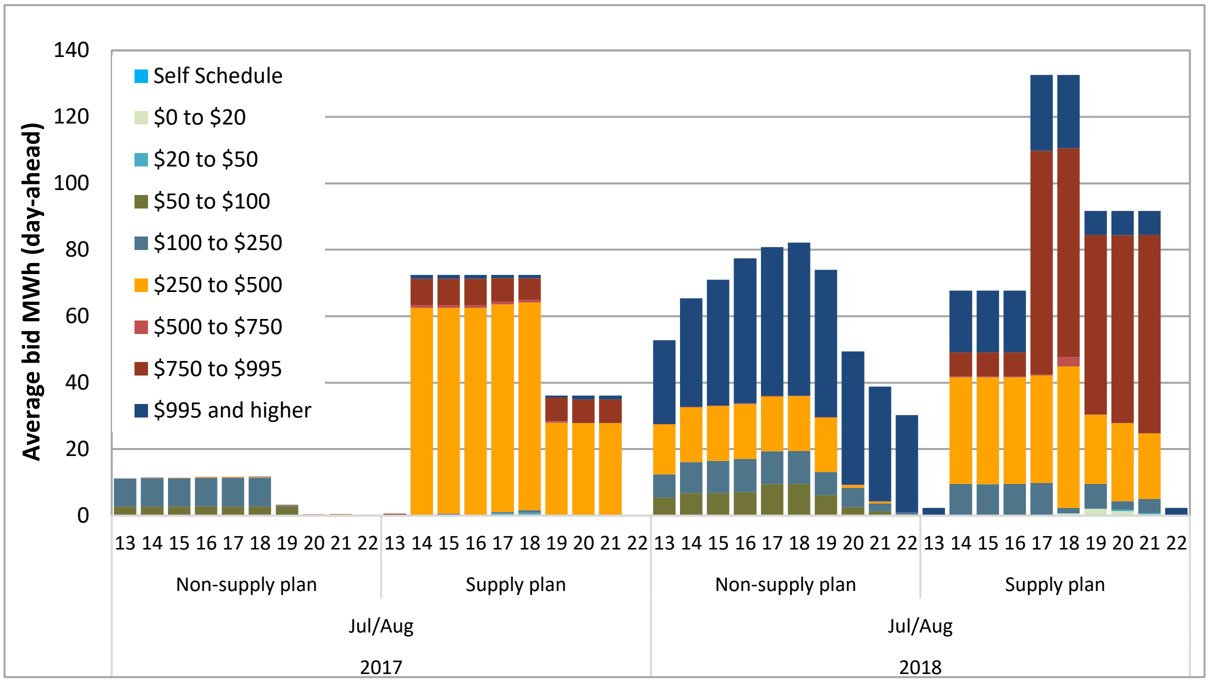


Reliability demand response resources were also scheduled more frequently in both the day-ahead and real-time markets in 2018 versus 2017, particularly in July and August in hours ending 19 and 20. In 2018 in the day-ahead market, the average schedule in hours 19 and 20 of July and August was about 28 MWh compared to 8 MWh in 2017.

In July and August of 2018, resources reflected on load-serving entity resource adequacy supply plans (supply plan resources) offered a greater volume of proxy demand response capacity to the ISO than resources not reflected on supply plans (non-supply plan resources) on average, particularly between hours 17-21 in day-ahead and real-time.

Figure 1.15 shows the change in average bid proxy demand response capacity in the day-ahead market between July/August of 2017 and 2018, separating supply plan and non-supply plan resources. Non-supply plan resource availability tended to be shaped and concentrated around hours 14-20 while supply plan resource availability more closely aligned with applicable years' availability assessment hours (AAH). Additionally, while comparable levels of non-supply plan capacity were bid more economically than supply plan capacity in 2018, the majority of all proxy demand response supply is bid in at prices greater than $250/MWh.

Figure 1.15 Supply plan and non-supply plan day-ahead PDR bid prices July and August



Dispatch and performance of demand response

In 2016 and 2017 reports, DMM noted that proxy demand response resources can be required to bid into the real-time market by the residual unit commitment process and be dispatched for incremental energy on a 5-minute basis, even though these resources may not have the capability to respond to isolated 5-minute dispatches. When resources are dispatched in the 5-minute market that cannot respond to such dispatches, it can result in market inefficiency. This occurs when these units set or contribute to system marginal prices.

In situations where the power balance constraint was relaxed in 2018, these resources frequently had the highest priced bids dispatched, and thus set system prices when the load bias limiter was triggered. While proxy demand response resources were dispatched in these circumstances, the underlying demand response programs were often not able to respond to single isolated 5-minute dispatches.

In September 2018, the ISO Board approved the energy storage and distributed energy resources phase 3 (ESDER 3) policy which will allow scheduling coordinators to use less flexible (15-minute and hourly block) bid options.[36] These bid options could help resources that cannot respond to 5-minute dispatches reduce exposure to infeasible dispatches by allowing resources to be scheduled in the hour-ahead or 15-minute market scheduling processes, and locking schedules in corresponding 5-minute market intervals.

[36] *Energy Storage and Distributed Energy Resources Phase 3 Draft Final Proposal*, California ISO, July 11, 2018: http://www.caiso.com/Documents/RevisedDraftFinalProposal-EnergyStorage-DistributedEnergyResourcesPhase3.pdf

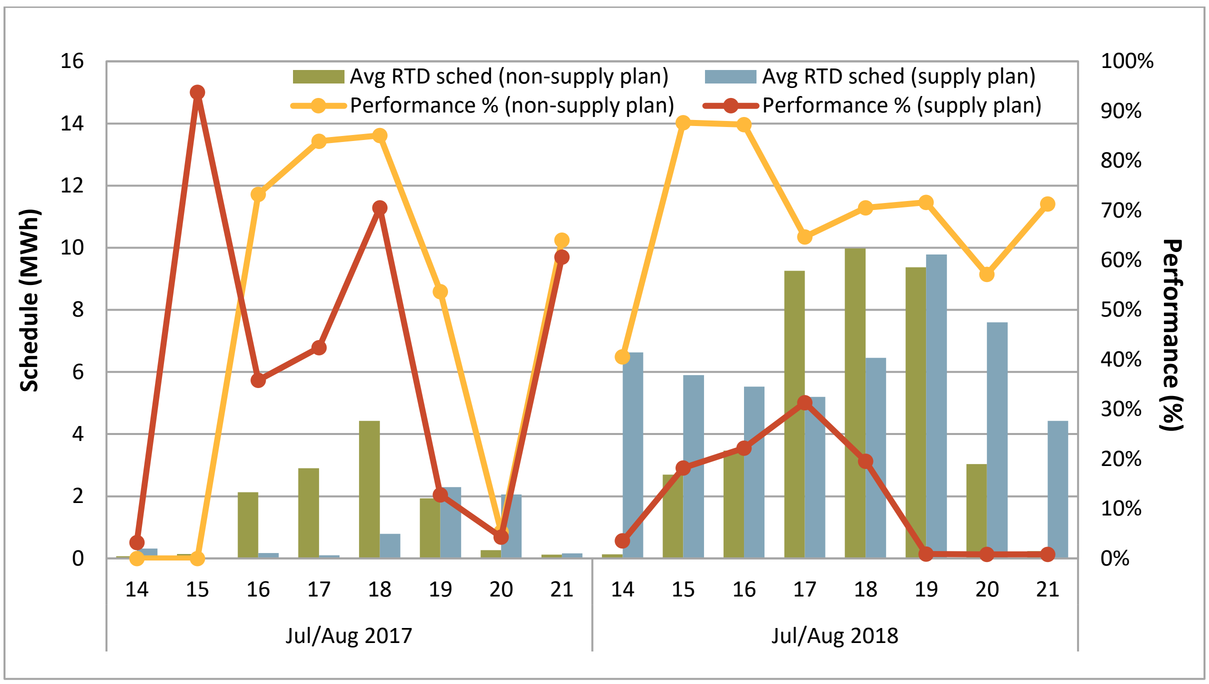
The ISO is also considering additional enhancements to improve the efficiency of demand response scheduling in its ESDER 4 stakeholder process.[37]

While the inability to respond to isolated 5-minute dispatches could contribute to non-performance, an overall assessment of proxy demand response performance indicates that performance could also be related to time of day and thus resources' underlying load profiles.

Figure 1.16 below shows average hourly 5-minute market dispatch of supply plan and non-supply plan proxy demand response resources in July and August of 2017 and 2018, compared to performance in hours ending 14 to 21.[38] Proxy demand response dispatches increased in 2018 for supply plan and non-supply plan resources, while average performance improved for non-supply plan resources.

In 2017 and 2018, proxy demand response was dispatched most frequently between hours ending 17 to 20, while performance was generally higher in earlier hour windows. This trend persisted for both supply plan and non-supply plan resources. Non-supply plan resources performed comparably better than supply plan resources in this timeframe. Note that while performance rates in hours 15 and 21 of 2017 appear high, average dispatched megawatt-hours are very small.

Figure 1.16 Proxy demand response schedules and performance July and August



37 ESDER 4 stakeholder page: http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_DistributedEnergyResources.aspx

38 Performance rate is bound between 0 and 100 percent. For example, if a resource curtailed more load relative to its baseline than its dispatch instruction, performance would be capped at 100 percent. If a resource's load exceeded its load baseline, its performance would be 0 percent.

1.2.2 Generation outages

This section provides a summary of generation outages in 2018. Overall, the total amount of generation outages, and their seasonal variation over the year, was similar to prior years.

Under the ISO's current outage management system, known as WebOMS, all outages are categorized as either planned or forced. An outage is considered to be planned if a participant submitted it more than 7 days prior to the beginning of the outage.

WebOMS has a menu of subcategories indicating the reason for the outage. Examples of such categories are: plant maintenance, plant trouble, ambient due to temperature, ambient not due to temperature, unit testing, environmental restrictions, transmission induced, transitional limitations and unit cycling.

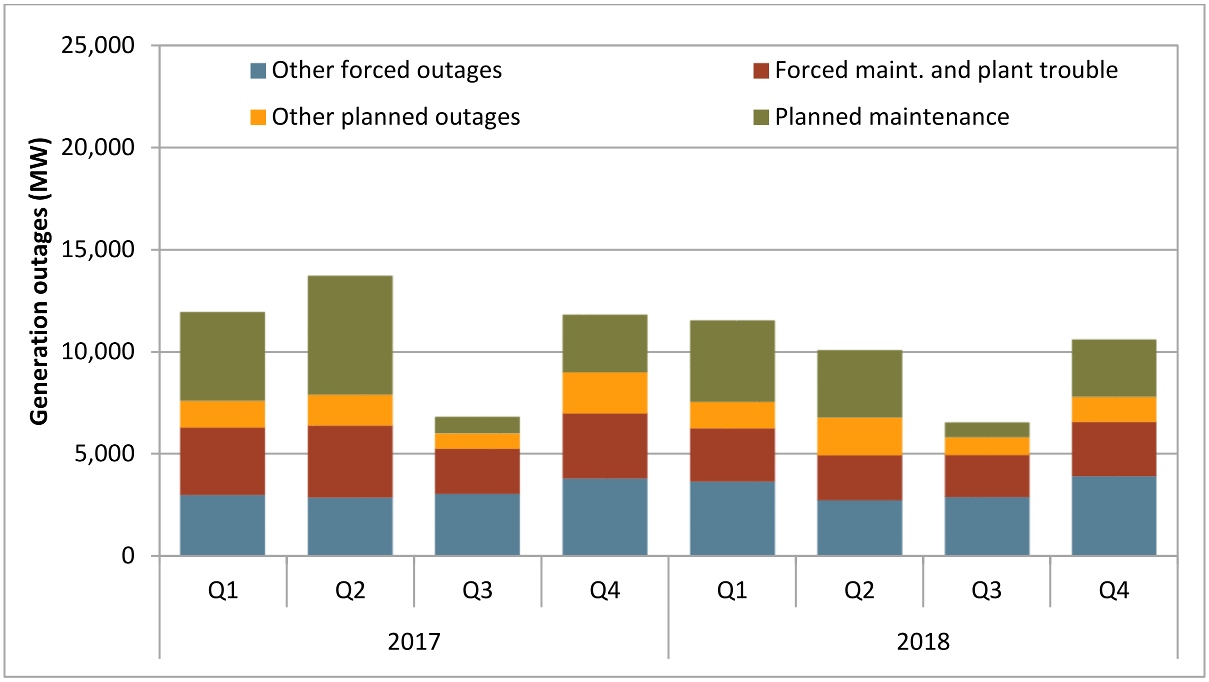
Figure 1.17 shows the quarterly averages of maximum daily outages broken out by type during peak hours. Overall, generation outages follow a seasonal pattern with the majority taking place in the non-summer months. This pattern is primarily driven by planned outages for maintenance, as maintenance is performed outside the higher summer load period.

At an aggregated level, the average total amount of generation outages in the ISO was slightly lower in 2018 at about 10,000 MW versus 2017 at 11,000 MW.[39] Outages for planned maintenance averaged about 2,700 MW during peak hours in 2018, and ranged from about 700 MW in the third quarter to about 4,000 MW in the first quarter. Combined, all other types of planned outages averaged about 1,300 MW in 2018. Some common types of outages in this category were ambient outages (both due to temperature and not due to temperature) and transmission outages.

Forced outages for either plant maintenance or plant trouble totaled about 2,400 MW in 2018. All other types of forced outages totaled about 3,300 MW for 2018. This included ambient due to temperature, ambient not due to temperature, environmental restrictions, unit testing and outages for transition limitations. There was less seasonal variation for forced outages compared to planned outages.

[39] This average is calculated as the average of the daily maximum level of outages, excluding off-peak hours. Values reported here only reflect generators in the ISO balancing area and do not include outages from the energy imbalance market.

Figure 1.17 Average of maximum daily generation outages by type – peak hours



1.2.3 Natural gas prices

Electricity prices in western states typically follow natural gas price trends because natural gas units are often the marginal source of generation in the ISO and other regional markets. The average price of natural gas in the daily spot markets increased significantly in 2018 from 2017 levels, especially at SoCal Citygate hub in California. At SoCal Citygate hub, the average price increase was about 43 percent in 2018 compared to that of 2017. The increase in natural gas prices was one of the main drivers causing the annual wholesale energy cost to increase relative to 2017.

Figure 1.18 shows monthly average natural gas prices at key delivery points in Northern California (PG&E Citygate) and in Southern California (SoCal Citygate) as well as for the Henry Hub trading point. Henry Hub acts as a point of reference for the national market for natural gas.

As shown in Figure 1.18, the prices at SoCal Citygate were extremely high on some days in July and August of 2018. This was primarily due to a combination of factors, including unplanned pipeline maintenance, restricted storage activity at Aliso Canyon and anticipation of potential low operational flow order (OFO) non-compliance penalty charges as well as increased natural gas demand amid high temperatures. Prices remained high in the fourth quarter of 2018 due to ongoing pipeline outages and low OFO penalties.

SoCal Citygate prices often impact overall system electricity prices for several reasons. First, there are large numbers of natural gas resources in the south. In addition, there is often greater congestion in the south that creates load pockets.

The October 9, 2018, pipeline explosion near Prince George, British Columbia, restricted Canadian imports into the U.S. This raised supply concerns in the Pacific Northwest and caused price spikes at the

Sumas gas hub and Mid-Columbia power hub. PG&E Citygate prices were affected by the supply restrictions in the Northwest and the Camp fire in the fourth quarter of 2018.

Figure 1.18 Monthly average natural gas prices (2014-2018)

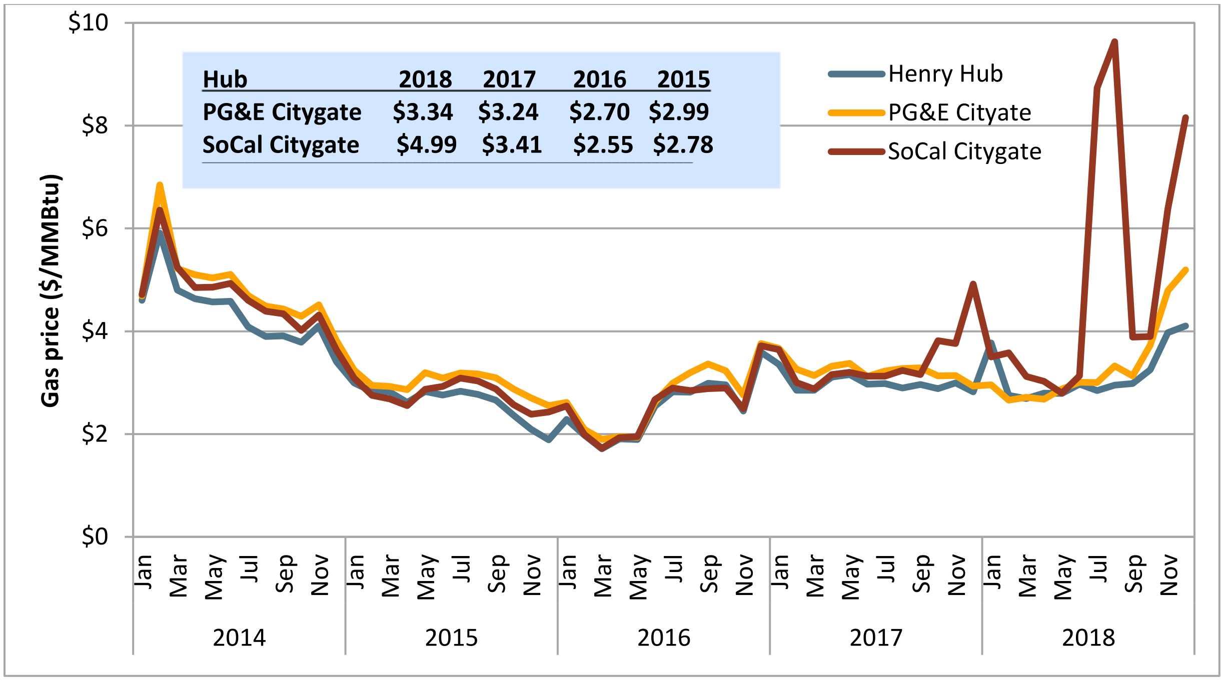


Figure 1.19 Yearly average natural gas prices compared to the Henry Hub

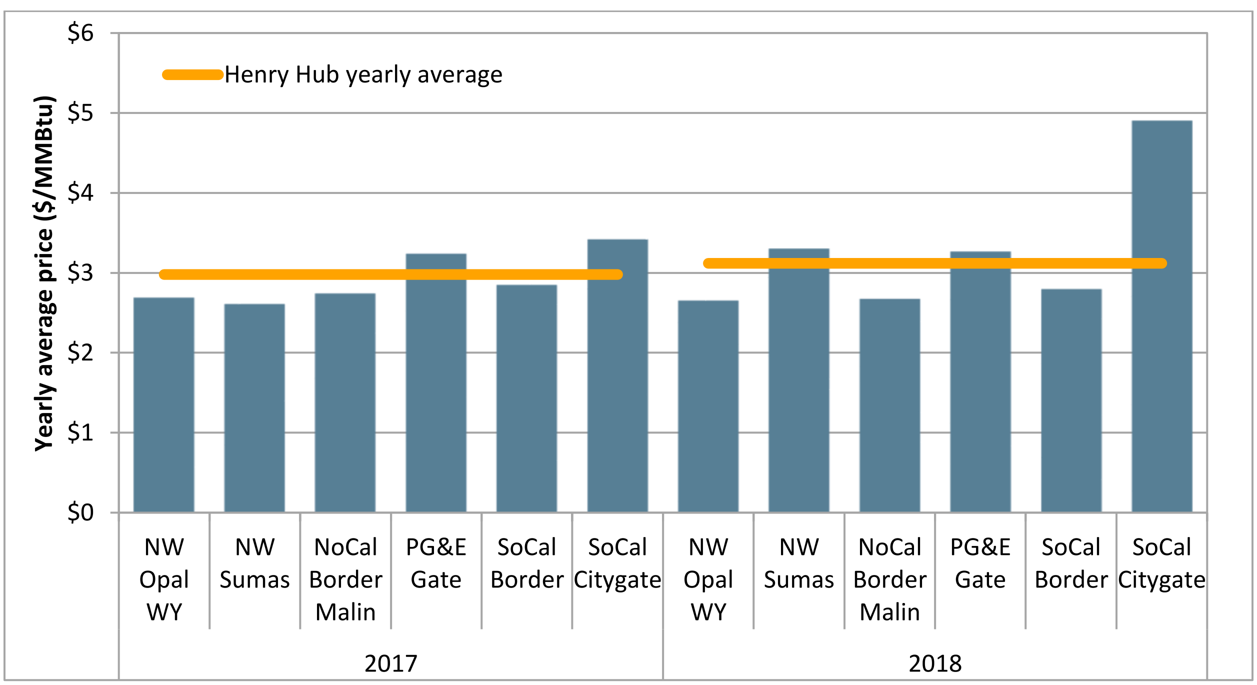


Figure 1.19 compares the yearly average natural gas prices at six major western trading points to the Henry Hub reference average for 2018 and 2017. The yearly average prices in 2018 remained at or below the Henry Hub reference price at all but SoCal Citygate trading point. On average, the yearly price at SoCal Citygate exceeded the Henry Hub average by 57 percent.

As mentioned earlier, the pipeline explosion near British Columbia has placed an upward pressure on gas prices at Sumas hub during the fourth quarter of 2018. On one day, Sumas traded at an all-time high of $100/MMBtu. Compared to 2017, there was a 27 percent price increase at the Sumas hub.

Impact of operational flow orders on Southern California gas prices

Operational flow orders (OFOs) and emergency flow orders (EFOs) are gas system balancing tools. They give gas shippers economic incentive to ensure their scheduled deliveries match demand within a prescribed tolerance. SoCalGas issues operational flow orders when the system forecast of gas supply is not in balance with the system forecast of demand, after considering storage withdrawal or injection capacity allocated to the balancing function. The operational flow order structure has five stages, plus a final emergency flow order stage. Noncompliance charges start at $25/dth for Stage 4 and Stage 5 orders.

In August 2018, Southern California Edison and Southern California Generation Coalition submitted a joint petition to the CPUC to lower the noncompliance charges associated with Stage 4 and Stage 5 orders.[40] DMM filed a response to this joint motion at the CPUC with supporting analysis on the impact of the relatively high level of potential noncompliance under Stage 4 and Stage 5 orders on gas and electricity prices and costs.[41] In January 2019, SoCalGas issued comments on the CEC/CPUC joint workshop on Southern California Natural Gas Prices held on January 11, 2019. These comments included clarifying explanations on the cause of recent reliability and gas price volatility challenges, SoCalGas's proposed solutions to these challenges and additional information on pipeline capacity reductions and outages.

Figure 1.20 shows the difference between next-day gas prices at SoCal Citygate versus SoCal Border (shown by the yellow line) along with potential noncompliance charges on days when low operational flow orders were declared (shown as blue dots) for different time periods. As shown in Figure 1.20, the $25/dth noncompliance charge triggered during a Stage 4 or Stage 5 low OFO has been reflected in next-day gas price spikes in the SoCalGas system.

[40] Joint Motion Of Southern California Edison Company (U 338-E) And Southern California Generation Coalition For Expedited Relief, August 10, 2018: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M221/K852/221852215.PDF

[41] DMM response to joint petition for modification of low OFO stage 4 and stage 5 noncompliance charges, September 4, 2018: http://www.caiso.com/Documents/ResponsetoJointPetitionforModificationofDMMofCAISO-Sept42018.pdf

Figure 1.20 Impact of potential low OFO noncompliance charges on next-day SoCal Citygate prices

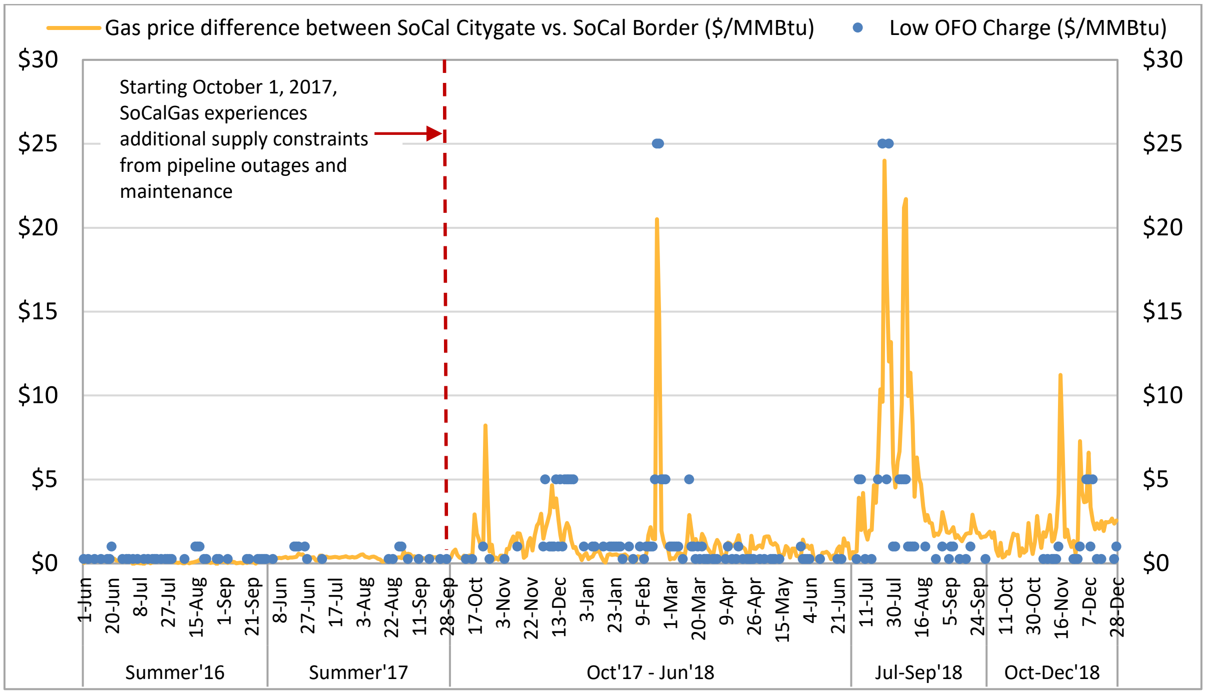


Figure 1.20 illustrates how next-day market gas prices at SoCal Citygate tend to increase following days when operational flow orders were declared. The magnitude of these gas price increases correlates with the level of potential noncompliance charges associated with the order. High gas prices often persist for a significant period after operational flow orders are declared. As shown in Figure 1.20, the magnitude and persistence of high gas prices, triggered by the high $25/dth noncompliance charges under Stage 4 orders, have become particularly significant during the months of February, July, August and December 2018.

Table 1.3 shows a statistical summary of the difference between next-day gas prices at SoCal Citygate and SoCal Border for the various periods of time included in Figure 1.20. As shown in Table 1.3:

- During summer 2016 limitations on the Aliso Canyon gas storage facility were first in effect. In this period, average next-day prices at SoCal Citygate were only $0.10/MMBtu (4 percent) higher than prices at SoCal Border.
- During summer 2017, this price difference increased to $0.36/MMBtu (13 percent).
- In October 2017, additional limitations on the SoCalGas system began due to pipeline outages and maintenance. From October 2017 to June 2018, this price difference further increased to $1.21/MMBtu (45 percent).
- During the third quarter of 2018, average next-day prices at SoCal Citygate were $4.85/MMBtu higher than prices at SoCal Border (168 percent).
- During the fourth quarter of 2018, average next-day prices at SoCal Citygate were $2.20/MMBtu higher than prices at SoCal Border (55 percent).

Table 1.3 Difference in next-day gas prices at SoCal Citygate vs SoCal Border

Time period	*Difference between gas price at SoCal Citygate versus SoCal Border ($/MMBtu)*		
	Min/Max	Average	Percent
Summer '16 (June - Sept)	-$0.05 - $0.29	$0.10	4%
Summer '17 (June - Sept)	$0.09 - $0.73	$0.36	13%
Oct 2017 - June 2018	$0.05 - $20.50	$1.21	45%
July - September 2018	$0.65 - $24.00	$4.85	168%
Oct - December 2018	$0.35 - $11.24	$2.20	55%

1.2.4 California's greenhouse gas allowance market

This section provides background on California's greenhouse gas allowance market under the state's cap-and-trade program, which was applied to the wholesale electric market in 2013. A more detailed description of the cap-and-trade program and its impact on wholesale electric prices in 2013 was provided in DMM's prior annual reports.[42] Greenhouse gas compliance costs are included in the calculation of cost-based bids used in commitment cost bid caps and local market power mitigation of energy.

In addition, all energy imbalance market transfers serving ISO load are attributed to energy imbalance market participating resources to facilitate compliance with California's cap-and-trade program and mandatory reporting regulations. Resource specific compliance obligations are determined by the ISO's optimization based on energy bids and greenhouse gas bid adders and are reported to participating resource scheduling coordinators for compliance. Further detail on greenhouse gas compliance in the energy imbalance market is provided in Section 4.7 of this report.

Greenhouse gas allowance prices

When calculating various cost-based bids used in the ISO market software, the ISO uses a calculated greenhouse gas allowance index price as a daily measure for greenhouse gas allowance costs. The index price is calculated as the average of two market based indices.[43] Daily values of the ISO greenhouse gas allowance index are plotted in Figure 1.21.

42 *2015 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2016, pp. 45-48: http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf.

43 The indices are ICE and ARGUS Air Daily. As the ISO noted in a market notice issued on May 8, 2013, the ICE index is a settlement price but the ARGUS price was updated from a settlement price to a volume-weighted price in mid-April of 2013. For more information, see the ISO notice: http://www.caiso.com/Documents/GreenhouseGasAllowancePriceSourcesRevisedMay8_2013.htm.

Figure 1.21 ISO's greenhouse gas allowance price index

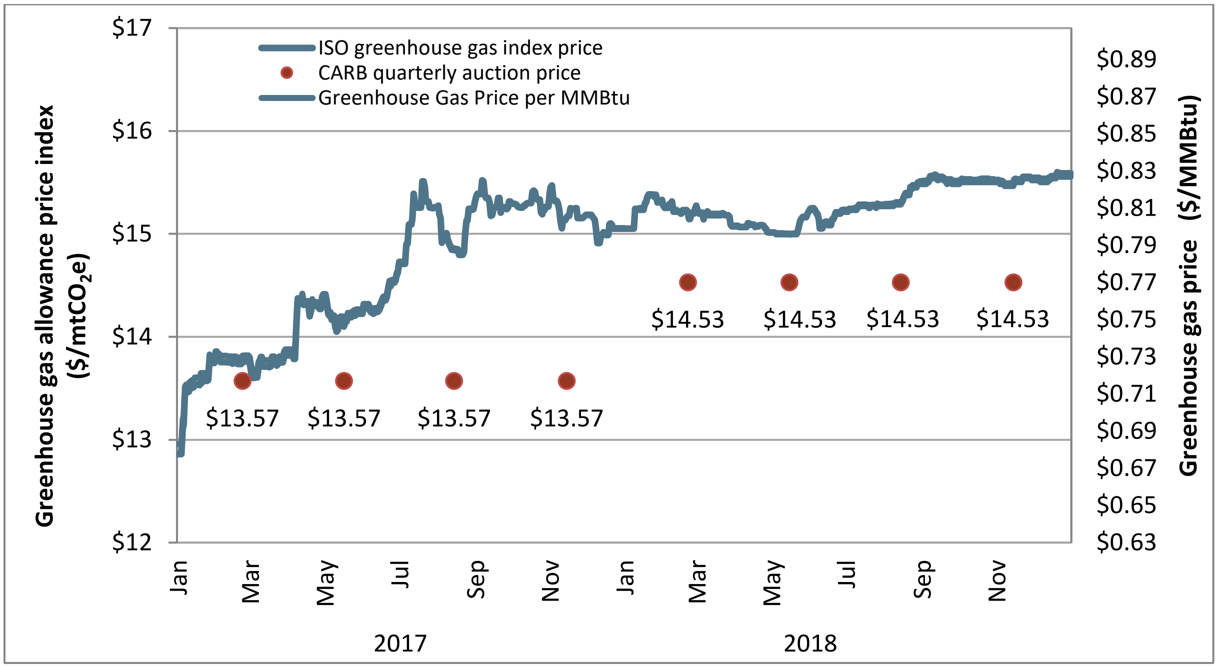


Figure 1.21 also shows market clearing prices in the California Air Resources Board's quarterly auctions of emission allowances that can be used for the 2017 or 2018 compliance years. The values displayed on the right axis convert the greenhouse gas allowance price into an incremental gas price adder, dollars per MMBtu, by multiplying the greenhouse gas allowance price by an emissions factor that is a measure of the greenhouse gas content of natural gas.[44] Thus, the blue line can be read from both the left and right hand axes.

As shown in Figure 1.21, the average cost of greenhouse gas allowances in bilateral markets increased from a load-weighted average of \$14.57/mtCO_2e in 2017 to \$15.31/mtCO_2e in 2018. In 2018, each of the California Air Resources Board's quarterly allowance auctions sold a fraction of allowances offered and thus cleared at the annual auction reserve price of \$14.53/mtCO_2e.

The greenhouse gas compliance cost expressed in dollars per MMBtu in 2018 ranged from about \$0.90/MMBtu to \$0.83/MMBtu. This represents about one sixth to one quarter of the average cost of gas during this period.

[44] The emissions factor, 0. 0.05416 mtCO_2e/MMBtu, is the sum of the product of the global warming potential and emission factor for CO_2, CH_4 and N_2O for natural gas. Values are reported in tables A-1, C-1 and C-2 of *Title 40 – Protection of Environment, Chapter 1 – Environmental Protection Agency, Subchapter C – Air Programs (Continued), Part 98-Mandatory Greenhouse Gas Reporting*, available here: http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl. (Updated 2019)

Impact of greenhouse gas program

A detailed analysis of the impact of the state's cap-and-trade program on wholesale electric prices in 2013 was provided in DMM's 2013 annual report.[45] The $15.31/mtCO_2e average in 2018 would represent an additional cost of about $6.60/MWh for a relatively efficient gas unit.[46] The average price in 2017, $14.57/mtCO_2e, would represent an additional cost of about $6.20/MWh for the same relatively efficient gas resource.

1.2.5 Capacity additions and withdrawals

California currently relies on long-term procurement planning and resource adequacy requirements placed on load-serving entities to ensure that sufficient capacity is available to meet reliability planning requirements on a system-wide basis and within local areas. Trends in the amount of generation capacity being added and retired in the ISO system each year provide important insight into the effectiveness of the California market and regulatory structure in new generation development.

The section highlights trends in generation capacity and the number of generators participating in the ISO system each year. As shown in Figure 1.22, roughly 6,000 MW of generation withdrew from market participation from June 2015 to June 2018. The majority of the retired capacity was from natural gas resources.[47] Over the entire 2015 to 2018 period, roughly 4,000 MW of gas-fired capacity withdrew in accordance with once-through cooling provisions.

Over the 2015 to June 2018 time period, over 1,000 MW of gas capacity, over 5,300 MW of solar, about 300 MW of wind and 130 MW of battery capacity was added or returned to the market. An additional 470 MW of solar, 220 MW of wind and 150 MW of gas generation was added or returned following June of 2018.[48]

Values reported here differ from those reported in prior reports due to several revisions in data source and analysis. First, the figures have been updated to evaluate changes to the *market*, rather than the decommissioning or interconnection of a unit. A generation retirement represents a resource that was once participating in ISO markets, and no longer participates.

In addition to decommissioned units, "retirements" may include resources that withdraw for a short period of time before returning (also known as mothballing), resources that withdraw to upgrade the unit and then repower, and resources whose contracts have expired with the ISO regardless of the units' capability to provide power. A generation addition is reported whenever a market participant enters the market, which includes resources that re-enter after a period of mothballing.[49] Graphs reflect nameplate

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45 *2013 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2014, pp. 123-136: http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf.

46 DMM calculates this cost by multiplying the average index price by the heat rate of a relatively efficient gas unit (8,000 Btu/kWh) and an emissions factor for natural gas: 0.0531148 mtCO_2e/MMBtu derived in footnote 44.

47 Please note this is not an indication of the number of resources that have retired. Gas generators are often large and have high levels of max output. There are a number of resources of other fuel types that have also recently withdrawn from the market, but their max output values are significantly smaller.

48 Resource additions transition into the market often with phases of testing, so the exact date of market entry reported can vary.

49 These figures do not account for generation outages, despite being similar in nature.

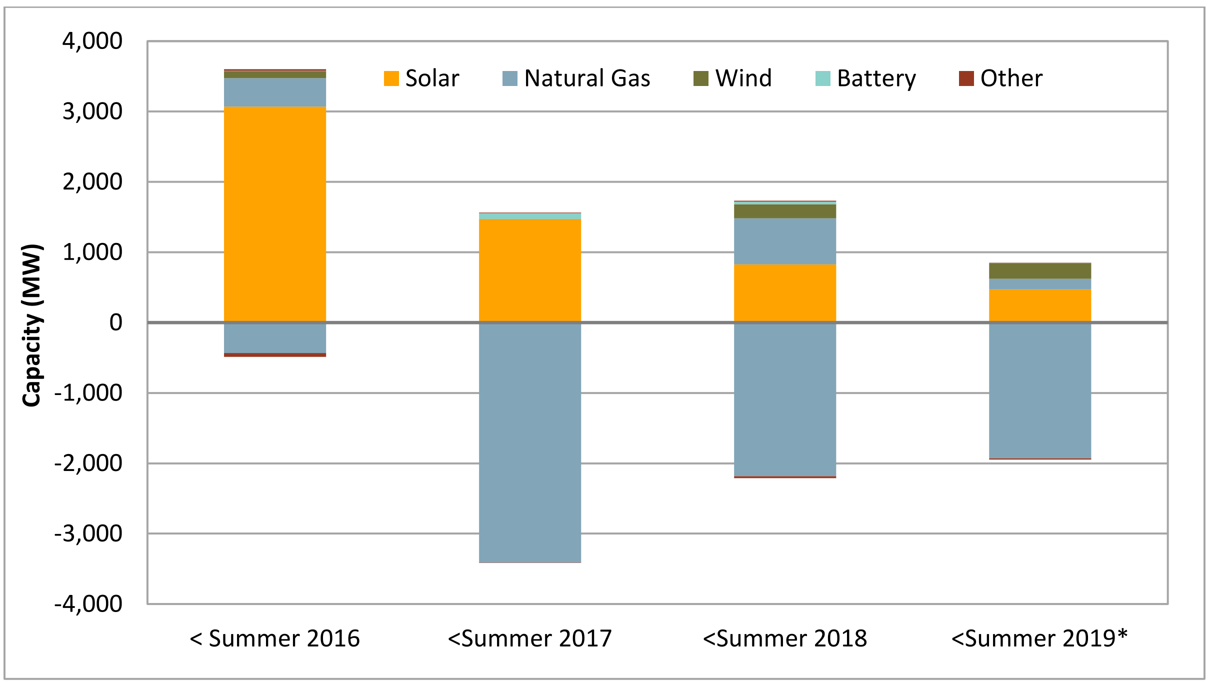
capacity, rather than net qualifying capacity, and changes between June of one year to the next to reflect changes to peak summer capacity.[50]

Of the nearly 3,500 MW of generation that withdrew from market participation, roughly 270 MW of withdrawn capacity is from resources that have since returned to the market and are currently fully participating. The time period that each of these resources was absent from the market varies significantly, ranging from less than one year to indefinitely.

Withdrawals from market participation have largely come from the state's three largest local areas: the Bay Area, LA Basin, and San Diego – Imperial Valley. Over the past few years, the greatest capacity of retirement has occurred in the Bay Area (about 2,700 MW). About 1,600 MW of generation withdrew in the LA Basin area, and about 1,300 MW in the San Diego – Imperial Valley area. About 1,700 MW came from resources designated for the ISO system.

As shown in Figure 1.22, retiring gas capacity has been replaced with solar and other renewable capacity. The net change in capacity shown in the chart is a reduction of about 320 MW. Because resources can and do change registered capacity while participating in the market, a resource joining the market in one year and choosing to withdraw in another may not net to zero.

Figure 1.22 Capacity additions and withdrawals (June 2015 – 2018*)[51]

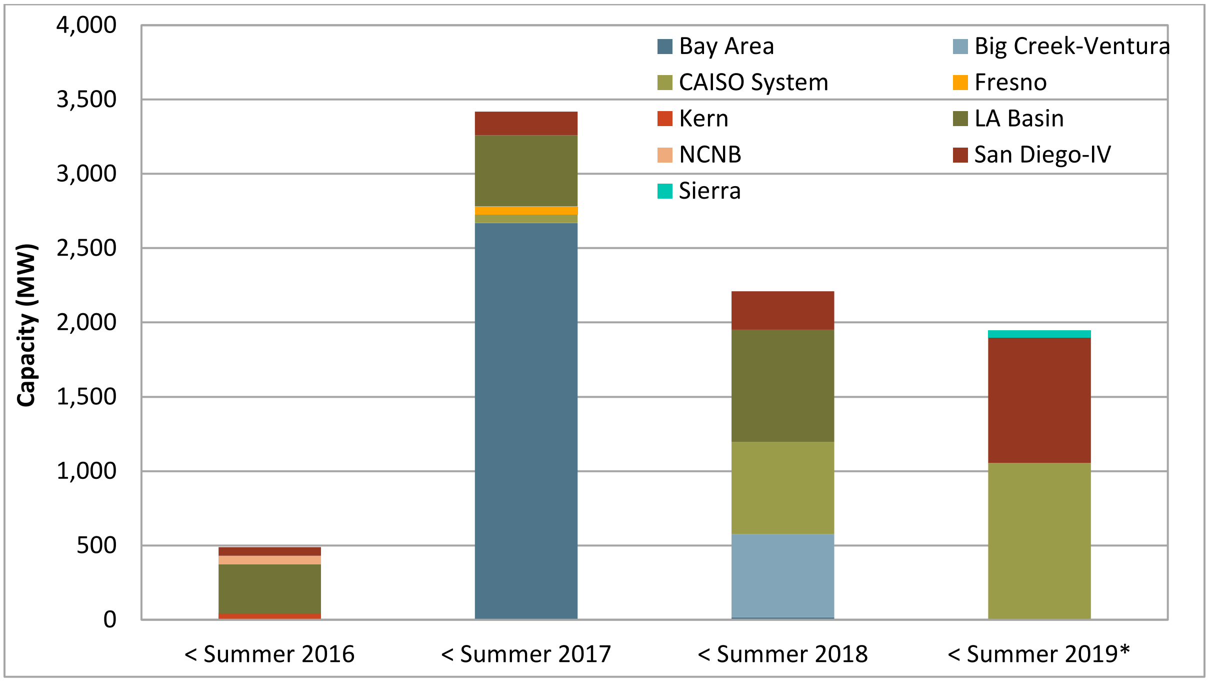


*Preliminary estimate of anticipated capacity additions and withdrawals as of December 31, 2018.

50 A resource's start, withdraw, or return date can vary by source due to different milestones associated with generation interconnection procedures. The figures below represent a rough estimate of the timeline when resources were added, withdrawn, or returned to the market and may differ from other reports.

51 Please note that this is not a complete picture of capacity changes and resource availability in the ISO system. Other capacity changes that are not included in this metric include 1) generation outages, 2) increases and decreases to capacity without changes in participation status, 3) changes associated with qualifying facilities, demand response, tie-generators, or any other non-typical participating generator type.

Figure 1.23 Withdrawals from market participation by local area



*Preliminary estimate of anticipated additions and withdrawals as of December 31, 2018.

1.3 Net market revenues of new gas-fired generation

Every wholesale electric market must have an adequate market and regulatory framework for facilitating investment in needed levels of new capacity. In California, the CPUC's long-term procurement process and resource adequacy program are currently the primary mechanisms to ensure investment in new capacity when and where it is needed. Given this regulatory framework, annual fixed costs for existing and new units critical for meeting reliability needs should be recoverable through a combination of long-term bilateral contracts and spot market revenues.

Each year, DMM examines the extent to which revenues from the spot markets contribute to the annualized fixed cost of typical new gas-fired generating resources. This represents an important market metric tracked by all ISOs.

In 2016, DMM revised the methodology used to perform this analysis to more accurately model total production costs and energy market revenues using a SAS/OR optimization tool.[52] Incremental energy

[52] Net revenues due to ancillary services and flexible ramping capacity have not been modeled in the optimization model. For a combined cycle unit in the ISO, average net revenues for regulation and spinning reserves were approximately $0.8/kW-yr and payments for flexible ramping capacity were around $0.03/kW-yr. Similarly, for a combustion turbine unit in the ISO, average net revenues for non-spinning reserve were $4/kW-yr while average flexible ramping payments were $0.1/kW-yr. Therefore, ancillary service and flexible ramping revenues would have had a very small impact on the overall net revenues for both combined cycle and combustion turbine units.

costs are calculated using default energy bids.[53] Commitment costs are calculated using the proxy start-up and minimum load cost methodology.[54]

For a combined cycle unit, our analysis estimated energy market revenues based on day-ahead and 5-minute real-time market prices. For a combustion turbine unit, our analysis estimated energy market revenues on a generator's commitment and dispatch in the 15-minute real-time market. Our analysis evaluated hypothetical combined cycle and combustion turbine units against both NP15 and SP15 prices, independently.

In 2017, the optimization horizon was changed from daily to annual. The objective of the optimization problem was revised to maximize annual net revenues subject to resource operational constraints listed in Table 1.4 for a combined cycle unit and Table 1.6 for a combustion turbine unit.

The analysis in this section shows that net revenues for the same combined cycle unit in the ISO may have ranged between $33/kW-yr and $47/kW-yr given day-ahead and real-time market conditions that existed in the ISO in 2018. This analysis shows that net revenues for a similar combustion turbine in the ISO may have ranged between $19/kW-yr and $28/kW-yr for real-time market conditions that existed in the ISO in 2018.

In 2019, the California Energy Commission (CEC) estimated that the annualized fixed costs for a hypothetical combined cycle unit was about $145/kW-year, down from $166/kW-year as reported in their 2015 report. For a hypothetical combustion turbine unit, the annualized fixed costs were down to $163/kW-year from $177/kW-year.[55] As shown in this analysis, net revenues earned through the ISO's energy market are significantly lower than the CEC's estimate of fixed costs for both types of units. This underscores the need for new resources necessary for reliability to recover additional costs from long-term bilateral contracts.

Hypothetical combined cycle unit

Table 1.4 shows the key assumptions used in this analysis for a typical new combined cycle unit. Included in this table are the technical parameters for two configurations of a hypothetical new combined cycle unit that were used in the optimization model. Also included in the table is the breakdown of financial parameters that contribute to the CEC's estimate of annualized fixed costs for a new combined cycle unit.

53 Default energy bids are calculated using the variable cost option as described in the Market Instruments Business Practice Manual version 43, pp. 203 – 207: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments.

54 Start-up and minimum load costs are calculated using the proxy cost option as described in the Market Instruments Business Practice Manual version 43, pp. 234 – 239: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments. The energy price index used in the proxy start-up costs is calculated using the retail rate option, Market Instruments Business Practice Manual version 43, pp. 281 – 282: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments.

55 Annual fixed costs are derived from California Energy Commission's *Estimated Cost of New Renewable and Fossil Generation in California* report which is published once every couple years. The annual fixed costs in this report are the average between IOU, POU and Merchant fixed costs reported in the May 2019 final staff report, Appendix D: https://www.energy.ca.gov/2019publications/CEC-200-2019-005/CEC-200-2019-005.pdf

Table 1.4 Assumptions for typical new combined cycle unit[56]

Technical Parameters	**Configuration 1**	**Configuration 2**
Maximum capacity	350 MW	500 MW
Minimum operating level	150 MW	351 MW
Heat rates (Btu/kWh)		
Maximum capacity	7,500 Btu/kWh	7,100 Btu/kWh
Minimum operating level	7,700 Btu/kWh	7,300 Btu/kWh
Variable O&M costs	$2.40/MWh	$2.40/MWh
GHG emission rate	0.053165 $mtCO_2e$/MMBtu	0.053165 $mtCO_2e$/MMBtu
Start-up gas consumption	1,400 MMBtu	1,400 MMBtu
Start-up time	35 minutes	35 minutes
Start-up auxillary energy	2 MWh	1 MWh
Start-up major maintenance cost adder	$200	$200
Minimum load major maintenance cost adder	$300	$400
Minimum up time	60 minutes	60 minutes
Minimum down time	60 minutes	60 minutes
Ramp rate	13 MW/minute	13 MW/minute
Financial Parameters		
Financing costs		$79 /kW-yr
Insurance		$6 /kW-yr
Ad Valorem		$8 /kW-yr
Fixed annual O&M		$43 /kW-yr
Taxes		$9 /kW-yr
Total Fixed Cost Revenue Requirement		**$145 /kW-yr**

The hypothetical combined cycle unit was modeled as a multi-stage generating resource. A constraint was enforced in the optimization model to ensure that only one configuration could be committed, which is optimized based on the most profitable configuration during each hour of the optimization horizon.

Table 1.5 shows the optimization model results using the parameters specified in Table 1.4. Results were calculated using three different price scenarios for a unit located in Northern California (NP15) or Southern California (SP15), separately. These scenarios show how different assumptions would change 2018 net revenues.

56 Some technical parameters, such as maximum capacity, minimum operating level and heat rates, and all the financial parameters for a typical unit in this table, were derived directly from the data presented in the March 2015 *Estimated Cost of New Renewable and Fossil Generation in California,* CEC Final Staff Report: http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SF.pdf. The cost of actual new generators varies significantly due to factors such as ownership, location and environmental constraints. More detailed information can be found in the CEC report.

The remaining technical characteristics such as variable O&M, start-up parameters, minimum load parameters and ramp rate are assumed based on the technology type (GE F-class turbines) and resource operational characteristics of a typical combined cycle unit within the ISO.

Maximum number of start-up and run-hours constraint has been relaxed in the annual optimization problem.

DMM's 2019 annual report will use the updated technical parameters from the 2019 CEC report.

Table 1.5 Financial analysis of new combined cycle unit (2018)[57]

Zone	Scenario	Capacity factor	Total energy revenues ($/kW-yr)	Operating costs ($/kW-yr)	Net revenue ($/kW-yr)
NP15	Day-ahead prices and default energy bids	21%	$123.25	$89.85	$33.40
	Day-ahead prices and default energy bids without adder	23%	$133.51	$97.78	$35.73
	Day-ahead commitment with dispatch to day-ahead and 5-minute prices using default energy bids	28%	$161.70	$118.40	$43.30
SP15	Day-ahead prices and default energy bids	22%	$139.22	$105.73	$33.49
	Day-ahead prices and default energy bids without adder	24%	$147.94	$111.71	$36.23
	Day-ahead commitment with dispatch to day-ahead and 5-minute prices using default energy bids	27%	$174.14	$127.32	$46.82

The first scenario evaluated the combined cycle unit commitment and dispatch to day-ahead prices using the default energy bids. In 2018, for a unit located in NP15 with the above assumptions, net revenues were $33/kW-yr with a 21 percent capacity factor.[58] Using the same assumptions for a hypothetical unit located in SP15, net revenues were $33/kW-yr with a 22 percent capacity factor.

The next scenario optimized the units' commitment and dispatch instructions with day-ahead prices using default energy bids without the 10 percent adder. The adder was removed because we understand that, in practice, many resources do not include the full adder as part of their regular bidding approach. This reflects the fact that the default energy bid with the 10 percent adder may overstate the true marginal cost of a resource.[59] With the assumptions in place for 2018, net revenues for a hypothetical unit in the NP15 area were $36/kW-yr with a 23 percent capacity factor. In the SP15 area, net revenues were $36/kW-yr with a 24 percent capacity factor.

The third scenario used day-ahead prices and default energy bids (with the 10 percent scalar adder) to commit and start the combined cycle resource, but the dispatch in this scenario was also based on the higher of the day-ahead and 5-minute real-time prices rather than only day-ahead prices. Using this scenario for 2018, net revenues for the hypothetical unit located in the NP15 area were about $43/kW-yr with a 28 percent capacity factor. In the SP15 area, net revenues were about $47/kW-yr with a 27 percent capacity factor.

Figure 1.24 shows how net revenue results from the optimization model compare to the CEC's estimated annualized fixed cost of a hypothetical combined cycle unit as well as the ISO's soft offer cap

57 2016 and 2017 results can be found in previous DMM annual market issues and performance reports: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf http://www.caiso.com/Documents/2017AnnualReportonMarketIssuesandPerformance.pdf

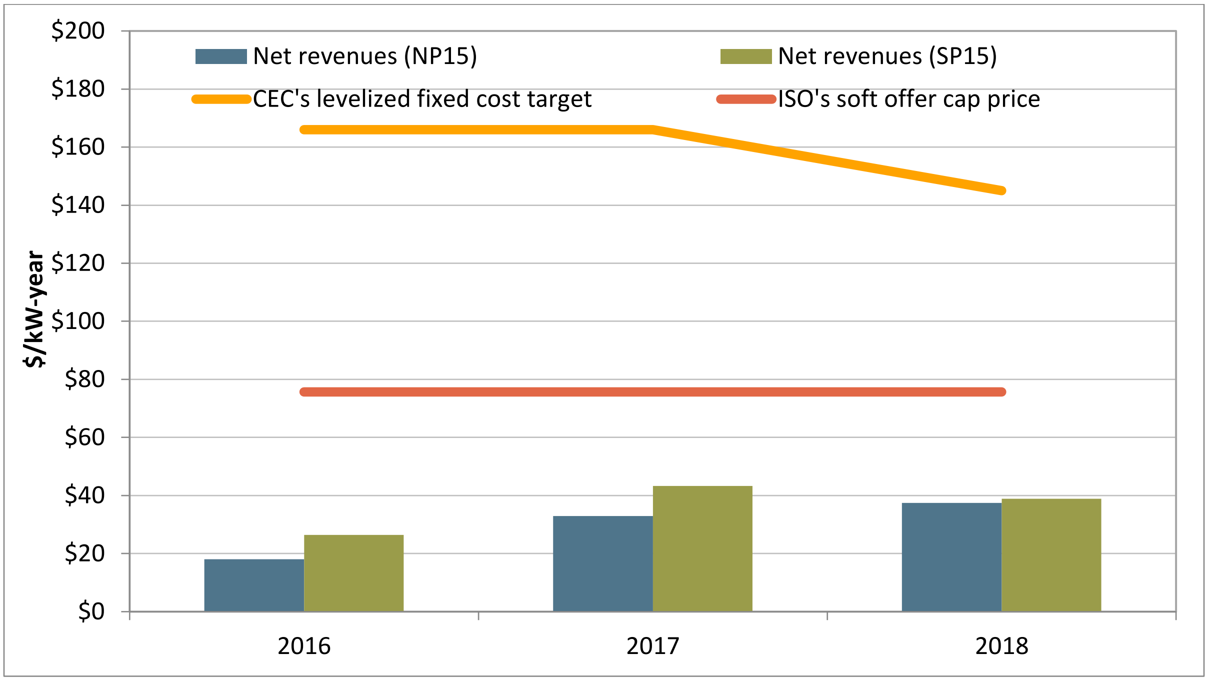
58 The capacity factor was derived using the following equation:

Net generation (MWh) / (facility generation capacity (MW) * hours/year).

59 See Chapter 7 for further discussion on price-cost markup and default energy bids.

price for the capacity procurement mechanism ($75.68/kW-yr).[60] Net revenues from the optimization model are shown for the NP15 (blue bar) and SP15 (green bar) regions over the past three years.

Figure 1.24 Estimated net revenue of hypothetical combined cycle unit



As shown in Figure 1.24, net revenues in 2017 increased significantly from 2016 levels in both NP15 and SP15 areas. This is because of historically high day-ahead prices on some days during 2017 which led to increased energy market revenues with only a slight increase in operating costs of the hypothetical combined cycle unit. Net revenues in NP15 increased again in 2018, but not by nearly as much as in 2017. Net revenues in SP15 decreased from 2017 to 2018. Operating costs in SP15 only slightly increased between 2017 and 2018 with an average increase of $8/kW-yr among the three scenarios; however, revenues increased even less with an average increase of $4/kW-yr.

Figure 1.24 shows that the 2018 net revenue estimates for a hypothetical combined cycle unit in both the NP15 and SP15 regions fall substantially below the annualized fixed cost estimate from the CEC for a hypothetical new combined cycle unit. The figure also shows that in 2018, the average net energy market revenues were about $38/kW-yr less than the ISO's soft offer cap price ($75.68/kW-yr) for the capacity procurement mechanism.

In reality, the net revenues of a combined cycle resource can be sensitive to the unit's realized capacity factor. We compared the hypothetical combined cycle capacity factors from Table 1.5 with existing combined cycle resources in NP15 and SP15 as a benchmark. In the NP15 area, actual capacity factors in 2018 ranged between 10 and 85 percent. In the SP15 area, actual capacity factors ranged between 5

60 More information on the capacity procurement mechanism can be found in section 43A of ISO's tariff: http://www.caiso.com/Documents/Section43A_CapacityProcurementMechanism_asof_Mar16_2018.pdf

and 60 percent. Our estimates ranged from 21 to 28 percent and were relatively low compared to actual results.

These differences in hypothetical capacity factors compared to existing resource capacity factors stem from several factors. First, the model optimally shuts the unit down if it's not economic during any hour. We noted that the hypothetical dispatch would frequently cycle resources during the midday hours when solar generation was highest and prices were lowest. This can differ from actual unit performance as many units have a limited number of starts per day.[61] Additionally, software limitations make shutdown instructions less frequent for these resources during the middle of the day because of the limited dispatch horizon used.[62] This can result in a resource staying on in the midday hours even when it is uneconomic to do so. This in turn might lead to out-of-market uplift payments. Some combined cycle units may also operate at minimum load during off-peak hours instead of completely shutting down because participants may be concerned about wear and tear on units and increased maintenance costs from frequent shutting down and starting up.[63]

61 DMM has observed many resources with contract limitations that limit the number of starts to one per day even though there may be no technical or environmental reason for limiting the number of starts per day to this level.

62 The real-time market only sees a couple hours ahead of the current dispatch interval. This can be an issue for resources that have to honor minimum downtime constraints. DMM has observed cases where resources could turn off and honor their minimum downtime if they received the signal to shut down early enough. However, the market does not always look out far enough to give enough time for a resource to shut down and honor its minimum downtime. Our optimization model does not have this limitation.

63 While we have observed this in practice, we note that major maintenance adders exist to cover the costs of start-up and run hour major maintenance. Not all participants have availed themselves of these adders.

Hypothetical combustion turbine unit

Table 1.6 shows the key assumptions used in this analysis for a typical new combustion turbine unit. Also included in the table is the breakdown of financial parameters that contribute to the CEC's estimated annualized fixed costs for a hypothetical combined cycle unit.

Table 1.6 Assumptions for typical new combustion turbine[64]

Technical Parameters	
Maximum capacity	100 MW
Minimum operating level	40 MW
Heat rates (Btu/kWh)	
Maximum capacity	9300 Btu/kWh
Minimum operating level	9700 Btu/kWh
Variable O&M costs	$4.80 /MWh
GHG emission rate	0.053165 $mtCO_2e$/MMBtu
Start-up gas consumption	50 MMBtu
Start-up time	5 minutes
Start-up auxillary energy	1.5 MWh
Start-up major maintenance cost adder	$400
Minimum load major maintenance cost adder	$115
Minimum up time	60 minutes
Minimum down time	60 minutes
Ramp rate	50 MW/minute
Financial Parameters	
Financing costs	$101 /kW-yr
Insurance	$8 /kW-yr
Ad Valorem	$10 /kW-yr
Fixed annual O&M	$34/kW-yr
Taxes	$10 /kW-yr
Total Fixed Cost Revenue Requirement	**$163 /kW-yr**

Table 1.7 shows the optimization model results using the parameters specified in Table 1.6. Results were calculated using three different price scenarios for a unit located in Northern California (NP15) or Southern California (SP15), separately. These scenarios show how different assumptions would change net revenues.

[64] See Footnote 56 for information about technical and financial parameters. The remaining technical characteristics such as variable O&M, start-up parameters, minimum load parameters and ramp rate are assumed based on the technology type (GE LM6000 turbines) and resource operational characteristics of a typical peaking unit within the ISO.

DMM's 2019 annual report will use the updated technical parameters from the 2019 CEC report.

Table 1.7 Financial analysis of new combustion turbine (2018)[65]

Zone	Scenario	Capacity factor	Real-time energy revenues ($/kW-yr)	Operating costs ($/kW-yr)	Net revenue ($/kW-yr)
NP15	15-minute prices and default energy bids	3.3%	$37.48	$18.55	$18.94
	15-minute prices and default energy bids without adder	4.3%	$43.50	$23.46	$20.04
	15-minute commitment with dispatch to 15-minute and 5-minute prices using default energy bids	5.7%	$53.60	$30.85	$22.75
SP15	15-minute prices and default energy bids	3.8%	$46.04	$25.14	$20.90
	15-minute prices and default energy bids without adder	4.8%	$52.72	$30.36	$22.36
	15-minute commitment with dispatch to 15-minute and 5-minute prices using default energy bids	6.6%	$68.60	$40.54	$28.06

In the first scenario, we simulated commitment and dispatch instructions the combustion turbine would receive given 15-minute prices, using default energy bids as costs. In this scenario, for a hypothetical unit located in the NP15 area and using 2018 prices, net revenues were approximately $19/kW-yr with a 3 percent capacity factor. Similarly, in the SP15 area, net revenues were approximately $21/kW-yr with a 4 percent capacity factor.

The second scenario assumes that 15-minute prices are used for commitment and dispatch instructions, but does not factor the 10 percent scalar into the default energy bids as a measure of incremental energy costs.[66] Using this scenario, the hypothetical unit in NP15 earned 2018 net revenues that were approximately $20/kW-yr with a 4 percent capacity factor. The hypothetical unit in SP15 earned net revenues of about $22/kW-yr with a 5 percent capacity factor.

The third scenario includes all of the unit assumptions made in the first scenario, but also includes 5-minute prices for calculating unit revenues in addition to 15-minute prices. Specifically, this methodology commits the resource based on 15-minute market prices and then re-optimizes the dispatch based on 15-minute and 5-minute market prices. As in the first scenario, default energy bids were used for incremental energy costs. Simulating this scenario in the NP15 area, net revenues were about $23/kW-yr with a 6 percent capacity factor. In the SP15 area, net revenues were about $28/kW-yr with a 7 percent capacity factor.

Figure 1.25 shows how net revenue results from the optimization model compare to the CEC's estimated annualized fixed cost of a hypothetical combustion turbine unit as well as the ISO's soft offer cap price for the capacity procurement mechanism ($75.68/kW-yr).[67] Net revenues from the

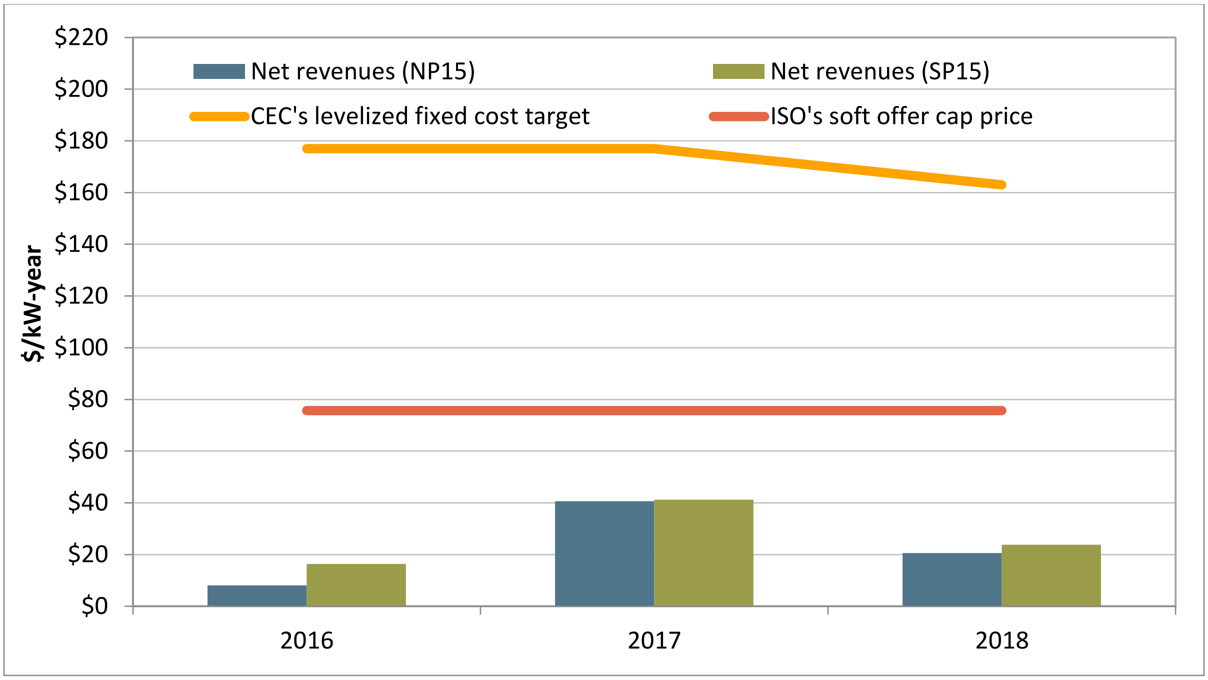
65 2016 and 2017 results can be found in previous DMM annual market issues and performance reports: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf http://www.caiso.com/Documents/2017AnnualReportonMarketIssuesandPerformance.pdf

66 As noted above, we frequently find resources that bid in excluding the full 10 percent adder in their incremental energy bids.

67 More information on the capacity procurement mechanism can be found in section 43A of ISO's tariff: http://www.caiso.com/Documents/Section43A_CapacityProcurementMechanism_asof_Mar16_2018.pdf

optimization model are shown for the NP15 (blue bar) and SP15 (green bar) regions over the past three years.

Figure 1.25 Estimated net revenues of new combustion turbine



As shown in Figure 1.25, net revenues for a hypothetical combustion turbine rose significantly in 2017 when compared to 2016. This is because of significantly high real-time prices in both NP15 and SP15 areas. Net revenues then decreased in 2018, but remained higher than 2016 levels. Both regions experienced a drop in operating costs with an average decrease of about $14/kW-yr between 2017 and 2018; however, real-time energy revenues dropped even more with an average decrease of $33/kW-yr. 2018 net revenues for a new combustion turbine were also significantly lower than net revenues for a combined cycle unit. This is mainly due to the consistent difference in day-ahead market prices that the combined cycle unit was exposed to and real-time market prices that the combustion turbine was exposed to.

Figure 1.25 shows that the 2018 net revenue estimates for a hypothetical combustion turbine unit in both the NP15 and the SP15 region fall substantially below the annualized fixed cost estimate from the CEC for a hypothetical new combustion turbine unit. The figure also shows that in 2018, the average net energy market revenues were about $54/kW-yr less than the ISO's soft offer cap price ($75.68/kW-yr) for the capacity procurement mechanism.

In practice, the net revenues of a combustion turbine resource can be sensitive to the unit's realized capacity factor. Therefore, DMM compared the capacity factors for the hypothetical combustion turbine from Table 1.6 with existing combustion turbines in NP15 and SP15 as a benchmark. In the NP15 area, actual capacity factors in 2018 ranged between 2 and 8 percent. In the SP15 area, actual capacity factors ranged between 0.5 and 10 percent. DMM's estimates ranged from 3 to 7 percent and were relatively close to these actual capacity factors.

2 Overview of market performance

The ISO markets continued to perform efficiently and competitively overall in 2018.

- Total wholesale electric costs increased by about 24 percent, driven primarily by a 25 percent increase in natural gas prices compared to 2017. After controlling for the higher natural gas costs and changes in greenhouse gas prices, wholesale electric costs increased by about 4 percent from 2017.
- Energy market prices were generally competitive, with prices usually reflecting resources' marginal costs. However, analysis also indicates that day-ahead market prices may have been significantly in excess of competitive levels in some summer hours when net demand that needs to be met by gas-fired capacity is highest.
- Day-ahead prices reached historic highs on a few days, driven largely by spikes in the price of natural gas at SoCal Citygate. Prices in the day-ahead market were consistently higher than real-time prices in most hours, particularly the third and fourth quarters when day-ahead prices were highest.
- Lower prices in the real-time market were driven in part by additional supply from renewables and other balancing areas available in real time. Real-time prices were also lower in many hours due to manual adjustments made to the hour-ahead load forecast and additional energy from out-of-market commitments and dispatches issued after the day-ahead market.[68]

Several other factors contributed to the increase in wholesale energy costs in 2018.

- Bid cost recovery payments in the ISO increased to the highest value since 2011, totaling $153 million, or about 1.4 percent of total energy costs. Total bid cost recovery payments in the ISO were $108 million in 2017 and $76 million in 2016. High gas prices in the SoCalGas service area were a key driver of higher bid cost recovery payments. Bid cost recovery payments for resources committed to operate through exceptional dispatches also increased from $16.6 million in 2017 to $40.6 million in 2018.
- Costs for capacity procured under reliability must-run contracts and the capacity procurement mechanism increased from $24 to $156 million or from $0.10/MWh to $0.73/MWh of system load. About $78 million of these costs were paid to four resources that were procured on an annual basis under the capacity procurement mechanism at prices close to or at the $76/kW-year soft offer cap.[69]
- Total real-time imbalance offset costs increased by about 56 percent to $128 million compared to $82 million in 2017. Much of this increase is attributable to a $79 million increase in real-time congestion imbalance offset costs which appears to have been caused by persistent and significant reductions in constraint limits made by grid operators in the 15-minute market relative to limits used in the day-ahead market.

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68 The ISO is investigating factors contributing to a day-ahead price premium in an on-going stakeholder process. The ISO's initial findings are available here: http://www.caiso.com/Documents/WhitePaper-PricePerformanceAnalysis-Apr3-2019.pdf

69 Additional discussion of these costs is available in this report in Sections 10.5 and 10.6.

2.1 Total wholesale market costs

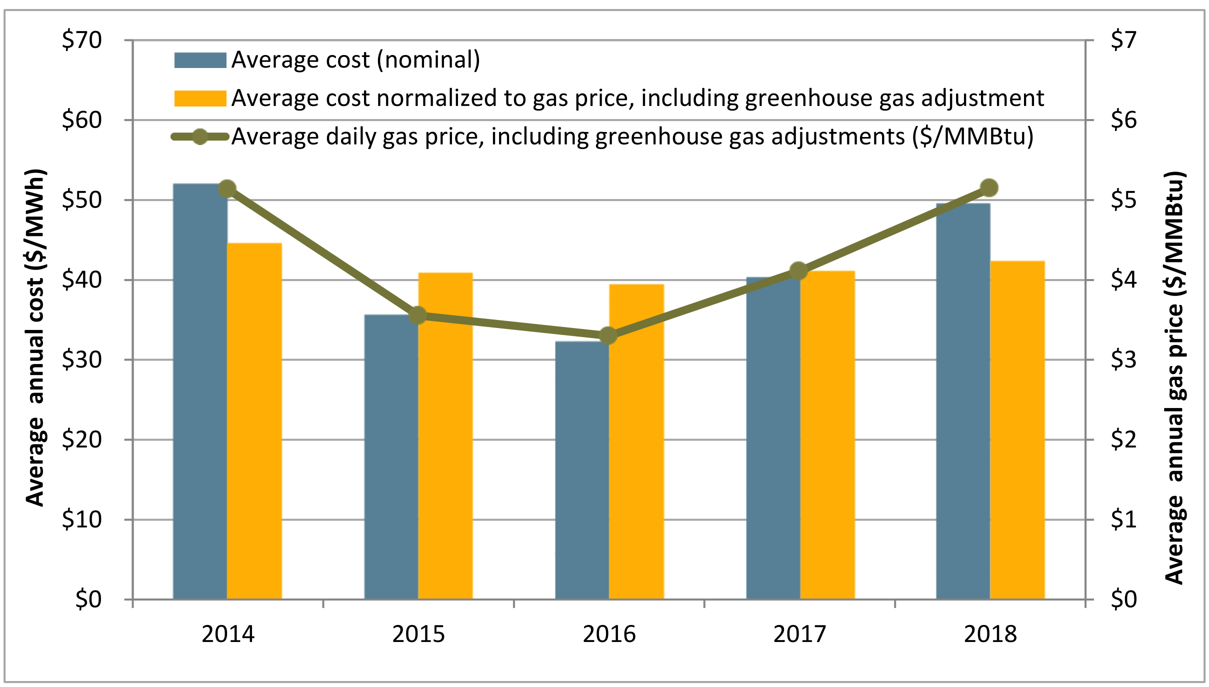
The total estimated wholesale cost of serving load in 2018 was about $10.8 billion or about $50/MWh. This represents an increase of about 24 percent from wholesale costs of about $40/MWh in 2017. The increase in electricity prices was driven mainly by an increase in spot market natural gas prices of about 25 percent.[70] After normalizing for natural gas prices and greenhouse gas compliance costs, DMM estimates that total wholesale energy costs increased by about 4 percent, a slight increase from 2017 but comparable to 2014 when average gas prices were similar.

A variety of factors contributed to the increase in total wholesale costs. As highlighted elsewhere in this report, conditions that contributed to higher prices include the following:

- Increased prices for natural gas, especially in Southern California;
- Higher uplift payments, such as bid cost recovery and energy offset costs;
- Additional costs for capacity procured under reliability must-run contracts and the capacity procurement mechanism; and
- Increased costs from congestion.

Figure 2.1 shows total estimated wholesale costs per megawatt-hour of system load from 2014 to 2018. Wholesale costs are provided in nominal terms (blue bar), and normalized for changes in natural gas prices and greenhouse gas compliance costs (gold bar). The greenhouse gas compliance cost is included to account for the estimated cost of compliance with California's greenhouse gas cap-and-trade program. The green line represents the annual average daily natural gas price including greenhouse gas compliance.

Figure 2.1 Total annual wholesale costs per MWh of load (2014-2018)



[70] For the wholesale energy cost calculation, an average of annual gas prices was used from the SoCal Citygate and PG&E Citygate hubs.

Table 2.1 provides annual summaries of nominal total wholesale costs by category from 2014 through 2018. In previous reports, costs incurred from the energy imbalance market were included in this table. These costs are now reported separately in Chapter 4. The total wholesale energy cost also includes costs associated with ancillary services, convergence bidding, residual unit commitment, bid cost recovery, reliability must-run contracts, the capacity procurement mechanism, the flexible ramping constraint and product, and grid management charges.[71]

As seen in Table 2.1, the 24 percent increase in total cost in 2018 was primarily due to increases in day-ahead energy costs, which changed by about $9/MWh, or roughly 23 percent from 2017. The remaining components of the wholesale energy cost, which represent a relatively small but growing portion of total cost, include bid cost recovery costs, which increased 65 percent, and reliability costs, which increased from $0.10/MWh to $0.73/MWh.

Table 2.1 Estimated average wholesale energy costs per MWh (2014-2018)

	2014	2015	2016	2017	2018	Change '17-'18
Day-ahead energy costs	$ 49.53	$ 34.23	$ 30.49	$ 37.40	$ 46.06	$ 8.65
Real-time energy costs (incl. flex ramp)	$ 1.19	$ 0.18	$ 0.54	$ 0.90	$ 0.76	$ (0.14)
Grid management charge	$ 0.42	$ 0.42	$ 0.42	$ 0.43	$ 0.43	$ 0.01
Bid cost recovery costs	$ 0.40	$ 0.38	$ 0.30	$ 0.42	$ 0.69	$ 0.27
Reliability costs (RMR and CPM)	$ 0.14	$ 0.12	$ 0.11	$ 0.10	$ 0.73	$ 0.63
Average total energy costs	**$ 51.68**	**$ 35.33**	**$ 31.86**	**$ 39.25**	**$ 48.67**	**$ 9.42**
Reserve costs (AS and RUC)	$ 0.30	$ 0.27	$ 0.53	$ 0.71	$ 0.87	$ 0.16
Average total costs of energy and reserve	**$ 51.98**	**$ 35.60**	**$ 32.39**	**$ 39.96**	**$ 49.54**	**$ 9.58**

2.2 Impact of gas prices on ISO system energy prices

The average price of natural gas in the daily spot markets increased significantly in 2018, especially at SoCal Citygate hub in California. As discussed in Chapter 1, the very high prices for gas at the SoCal Citygate delivery point in the next-day gas market appear to have been driven by anticipation of the potential for declaration of operational flow orders and high potential noncompliance charges associated with such orders (see Section 1.2.3).

Figure 2.2 shows the very close correlation between average daily electricity prices for the ISO system with gas costs based on prices in the next-day gas market. Gas costs in Figure 2.2 are based on next-day prices at SoCal Citygate and PG&E Citygate, plus the costs of greenhouse gas emissions credits and

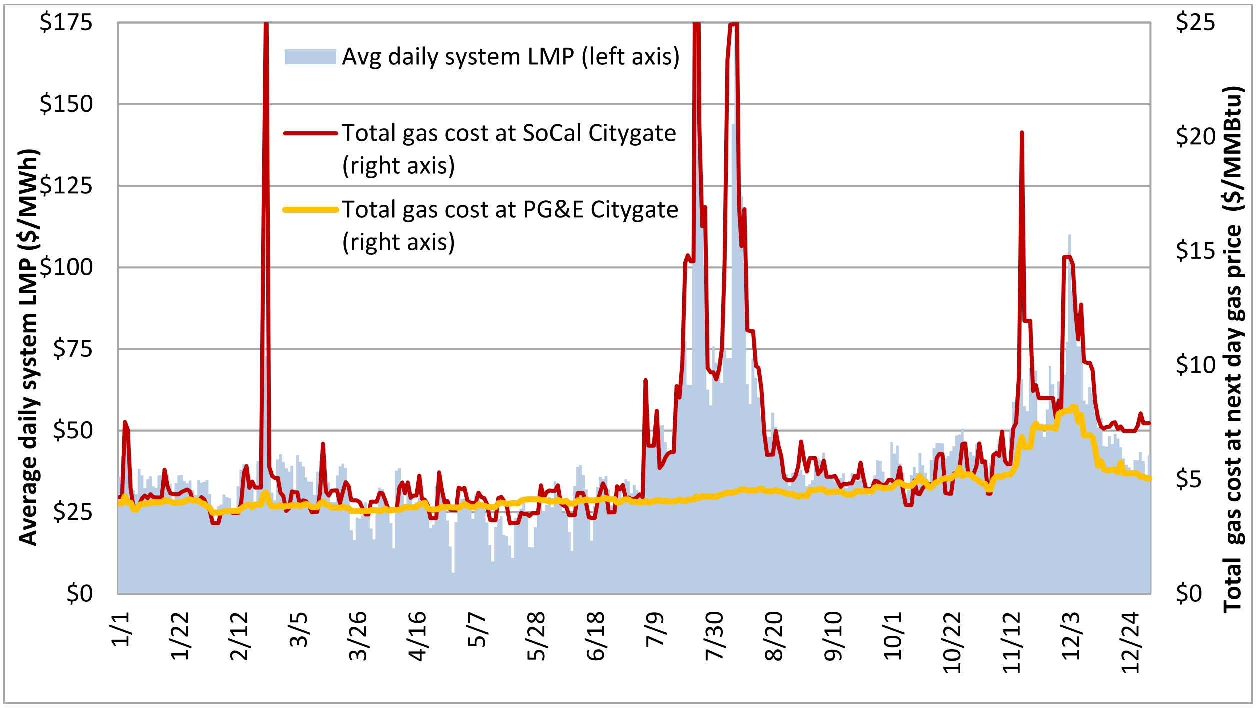
[71] A description of the basic methodology used to calculate the wholesale costs is provided in Appendix A of DMM's *2009 Annual Report on Market Issues and Performance*, April 2010, http://www.caiso.com/2777/27778a322d0f0.pdf. This methodology was modified to include costs associated with the flexible ramping constraint and then the flexible ramping product when introduced in November of 2016. Flexible ramping costs are added to the real-time energy costs. This calculation was also updated to reflect the substantial market changes implemented on May 1, 2014. Following this period, both 15-minute and 5-minute real-time prices are used to calculate real-time energy costs. Prior year reported values have been adjusted to account for an inconsistency in treatment of convergence bids and load aggregation by market, resulting in slightly lower costs per megawatt-hour than previously reported. These changes were made to conform this calculation to settlement values.

additional gas transport costs. The left and right axis in Figure 2.2 are scaled (using a 7 to 1 ratio) so that the electricity prices shown on the left axis correspond to the marginal fuel cost of a gas unit with a heat rate of 7,000 Btu/kWh given the gas cost on right axis.

As shown in Figure 2.2, the average daily price in the ISO's day-ahead market for the entire ISO system was generally driven by gas prices in the next-day gas market for gas at SoCal Citygate. This reflects the fact that system marginal energy prices in the ISO tended to be set by resources in the southern portion of the system even when gas prices in the SoCalGas system were significantly higher than gas prices for the PG&E area.

In addition, Figure 2.2 shows that during most periods average daily prices in the ISO's day-ahead market were generally consistent with the marginal cost of an efficient gas-fired resource (e.g., 7,000 Btu/kWh) located in the SoCalGas area. Additional analysis of the relationship between gas and electric prices is provided in the following section.

Figure 2.2 Average daily prices for electricity and natural gas (2018)



2.3 Market heat rates

Market heat rates are calculated by dividing the price of power by the price of natural gas for a specific term and location. In a highly competitive market with prices being set by the marginal operating costs of gas units, this provides an indication of the average efficiency of marginal units setting market prices. In practice, however, gas-fired units are no longer the marginal resources during many hours in the ISO due to the increased amounts of renewable generation.

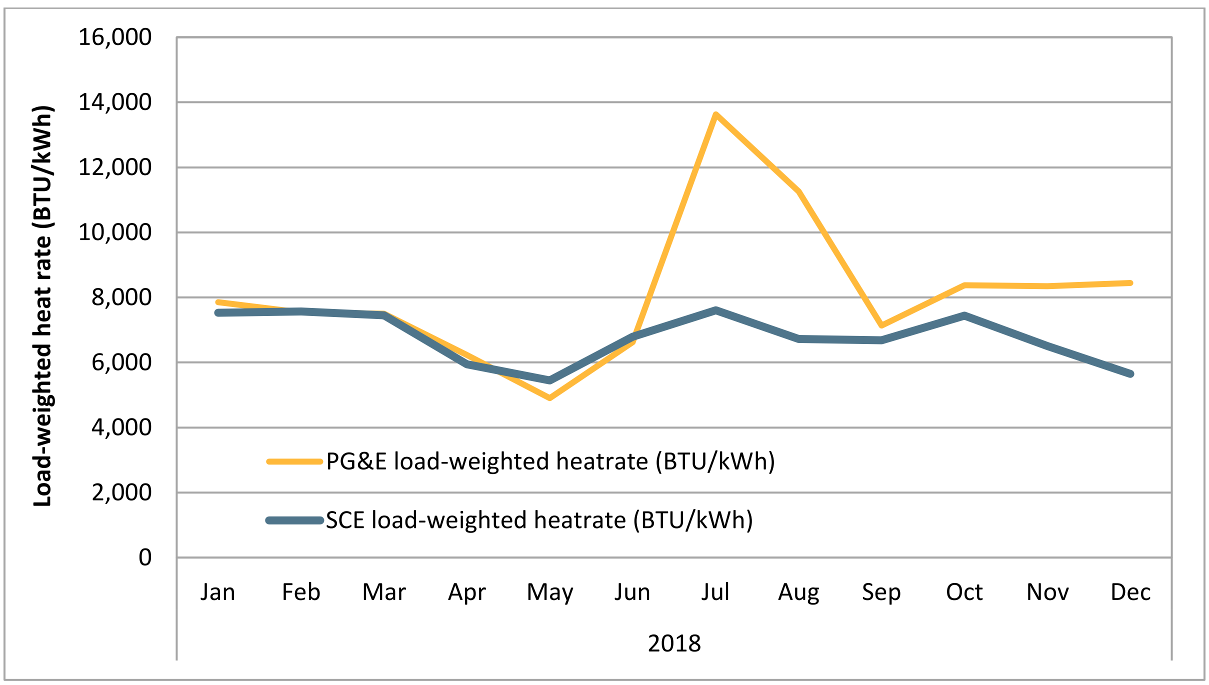
In this report, DMM calculated the market heat rate for the southern and northern parts of the ISO system using total gas costs based on next-day prices at the SoCal Citygate and PG&E Citygate, plus the costs of greenhouse gas emissions credits and additional gas transport costs. These additional components add about $1/MMBtu to the cost of natural gas for gas units in California.[72]

Figure 2.3 shows average market heat rates for the SCE and PG&E areas for each month in 2018 using this approach. The average market heat rate for SCE area (based on gas prices at SoCal Citygate) ranged between about 6,000 to 8,000 Btu/kWh each month, and averaged about 6,800 Btu/kWh over the course of the year.

As shown in Figure 2.3, the average market heat rate for PG&E area (based on gas prices at PG&E Citygate) is much higher in the summer months, reflecting the fact that prices in the PG&E area were often set by higher cost gas-fired units in the SCE area in these months. The average market heat rate in the PG&E area was about 8,300 Btu/kWh over the course of the year.

These results provide an indication that ISO system prices were generally competitive in 2018. However, other analysis indicates that in some hours day-ahead market prices may have been significantly in excess of competitive levels. Additional discussion of the competitiveness of market prices is provided in the following section and Chapter 7 of this report.

Figure 2.3 Average monthly market heat rate for PG&E and SCE areas (2018)



72 In addition, the analysis accounts of non-fuel components of a unit's marginal costs by subtracting $2.80/MWh from the market price of electricity, which is variable O&M cost for combined cycle units included in default energy bids used in bid mitigation.

2.4 Energy market prices

This section reviews energy market prices in the ISO balancing area by focusing on price trends and comparison of prices in the day-ahead and real-time market. Key points highlighted in this section include the following:

- Average energy market prices were relatively high during the second half of 2018, primarily due to high load conditions and increased gas prices.
- Prices in the day-ahead market were higher than prices in both the 15-minute and 5-minute markets on average in each quarter during the year.
- Average hourly prices generally moved in tandem with the average net load. Average hourly prices in the 15-minute market were lower than the day-ahead prices for all hours except hour ending 6. 5-minute market prices were lower than day-ahead prices for all hours except hours ending 1, 2 and 9.

Figure 2.4 shows load-weighted average energy prices across the three largest load aggregation points in the ISO (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric) during all hours. Overall, price convergence between the day-ahead and real-time markets decreased from the previous year while price convergence between the 15-minute and 5-minute markets increased. Other key trends include the following:

- Energy market prices were particularly high during the third and fourth quarters of 2018. Higher prices in the second half of the year resulted from increased gas prices and decreased output from hydroelectric resources, combined with periods of system-wide heat waves and associated high loads.
- Average prices in the 15-minute market in the third and fourth quarters of 2018 were significantly lower than average prices in the day-ahead market by about $7/MWh. This difference was only about $0.50/MWh in first two quarters.
- Average prices in the 5-minute market were lower than average day-ahead and 15-minute market prices during all quarters except the first quarter. The average difference between 5-minute market prices and 15-minute market prices during the year was about $0.50/MWh.
- Similar to the previous year, negative average energy prices were relatively frequent in the day-ahead market. Prices fell below zero in nearly 80 hours in 2018, a decrease from about 110 hours in 2017. Negative prices in the day-ahead market occurred during midday hours in the first two quarters when solar generation was on-line.
- Day-ahead prices reached historic highs yet again in 2018. On July 24, average energy prices in the day-ahead market were greater than $600/MWh during a four-hour period with prices peaking at nearly $1,000/MWh.

Figure 2.5 illustrates hourly load-weighted average energy prices in the ISO in the day-ahead and real-time markets and average hourly net load.[73] Average hourly prices in this figure follow the net load pattern as energy prices were lowest during the early morning, midday, and late evening hours, and

73 Net load is calculated as actual load less generation produced by wind and solar directly connected to the ISO grid.

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 generation is installed and interconnected with the system, net loads and average system prices during the middle of the day are likely to continue decreasing. This is a result of less expensive units setting prices during periods where net demand is lower, driven by more solar and other renewable generation.

Figure 2.4 Average quarterly prices (all hours) – load-weighted average energy prices

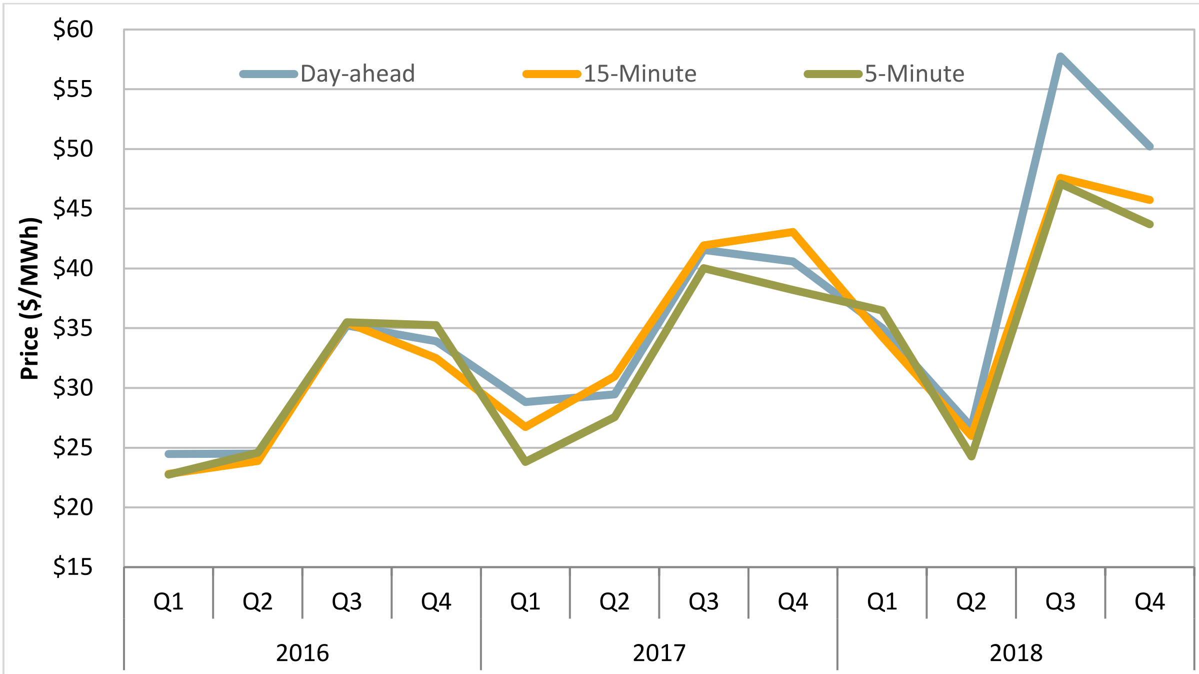
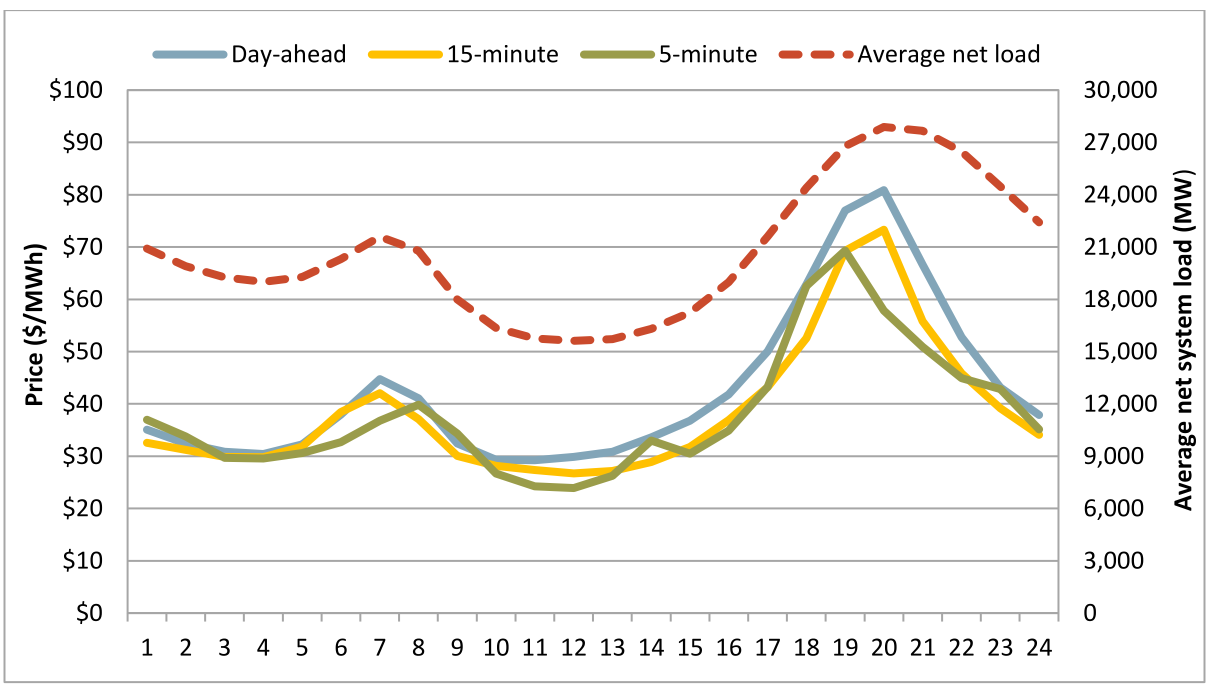


Figure 2.5 Hourly load-weighted average energy prices (2018)

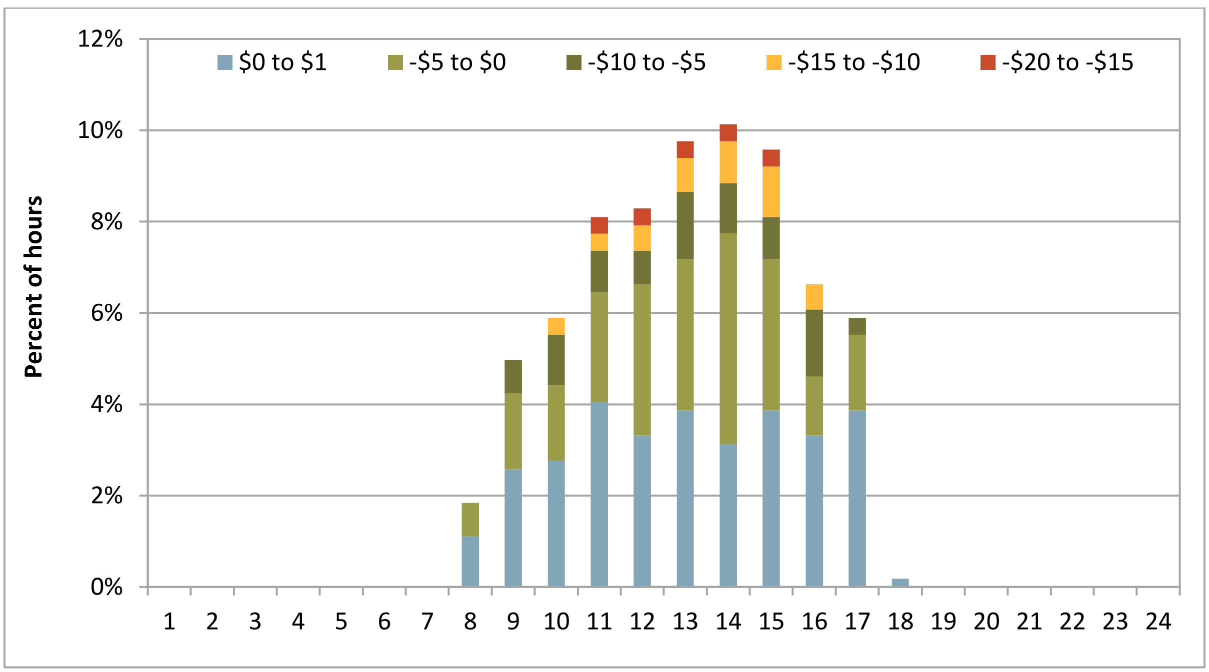


Negative day-ahead market prices

Negative prices were relatively frequent in the day-ahead market in the first two quarters of 2018. There were 76 hours when day-ahead prices were negative, nearly 2 percent of all hours in the first six months of 2018. Although a slight decrease in comparison to 2017, day-ahead market system marginal energy prices have been negative during only three hours since 2013 excluding the last two years. More frequent negative prices in the day-ahead market were the result of additional installed renewable capacity and additional generation from hydro resources.

Figure 2.6 shows the frequency of negative prices near or below $0/MWh in the day-ahead market by hour during the first six months of 2018. Negative prices in the day-ahead market occurred during midday hours beginning in late February through mid-June, when solar generation was greatest and loads were seasonally mild. During the first six months, day-ahead prices were negative during around 5 percent of hours between hours 11 through 15. Negative prices occurred more frequently on weekends when loads were lower.

Figure 2.6 Hourly frequency of day-ahead prices near or below $0/MWh (January – June)



High load and price days during the summer

The ISO market experienced system-wide heat waves and associated high loads beginning in July and continuing into the end of August. Similar to last year, the day-ahead market experienced record high system marginal energy prices during these periods. In addition to high volumes of day-ahead prices greater than $200/MWh, there were three days when day-ahead prices reached over $600/MWh for several intervals in duration. In particular, on June 24, prices in the day-ahead market reached an all-time high at around $980/MWh during hour ending 20.

High price days in the day-ahead market during the summer can largely be explained by tight supply conditions with very high demand and limited natural gas availability. High prices in the day-ahead market were most common during periods when net load was very high, typically between hours ending

18 through 21. In addition, intertie activity was impacted by extremely high temperatures and loads across the west. On days when prices reached above $600/MWh, there were fewer imports offered and cleared in the day-ahead market than in previous days.

Comparison to bilateral prices

High prices in California, relative to bilateral prices at trading hubs elsewhere in the west, reflect both the greenhouse gas compliance cost associated with delivering energy into the state and the cost of congestion associated with limited transfer capacity with other balancing authority areas. Figure 2.7 shows monthly average day-ahead prices in the ISO compared to monthly average peak energy prices traded at the Palo Verde and Mid-Columbia hubs published by the Intercontinental Exchange.[74]

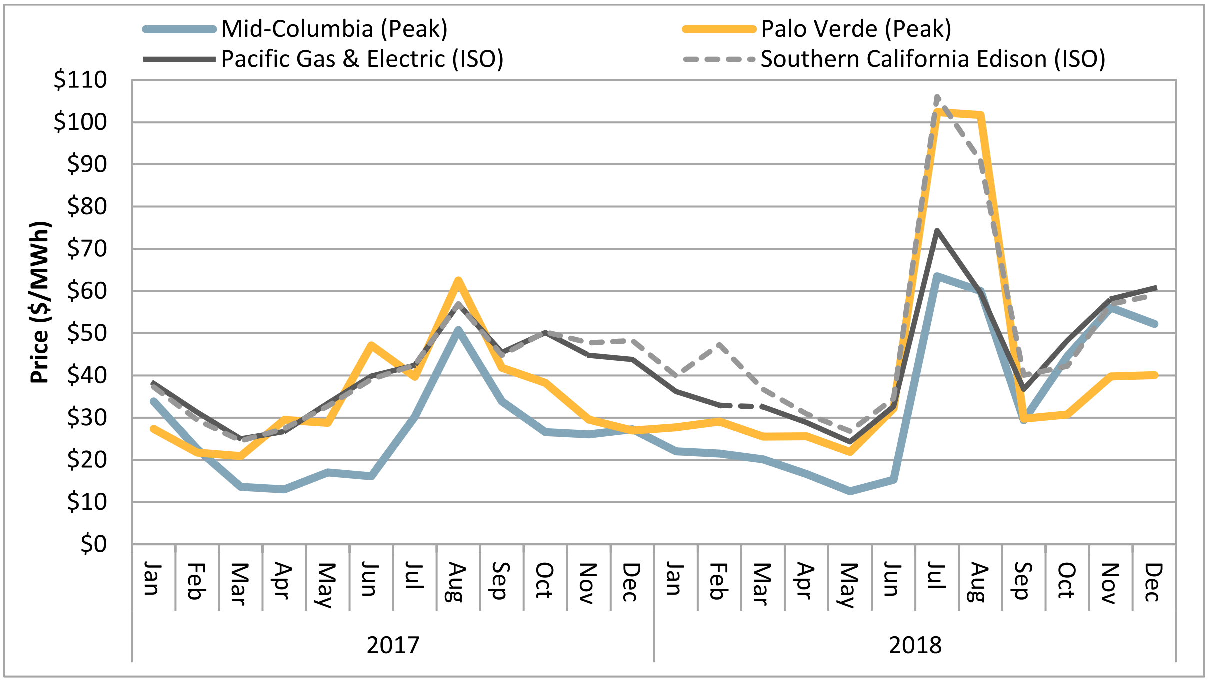
Prices in the ISO are represented in Figure 2.7 by prices at the Southern California Edison and Pacific Gas and Electric load aggregation points. Prices at Mid-Columbia and Palo Verde were lower than prices in the PG&E area during about 88 percent and 77 percent of days, respectively. Prices at Mid-Columbia and Palo Verde were lower than prices in the SCE area during about 88 percent and 87 percent of days, respectively.

Day-ahead prices in the ISO were also compared to hourly energy prices traded at Mid-Columbia and Palo Verde hubs published by Powerdex. Prices in the PG&E area across all hours in 2018 were greater on average than prices in Mid-Columbia and Palo Verde by $11/MWh and $7/MWh, respectively. Prices in SCE area compared across all hours in 2018 were greater on average than prices in Mid-Columbia and Palo Verde by $16/MWh and $11/MWh, respectively.

Relatively higher prices in California reflect both the greenhouse gas compliance cost associated with delivering energy into the state and the cost of congestion associated with limited transfer capacity with other balancing authority areas. Natural gas prices and availability in the ISO and other locations also play a large role in energy price differences across the west. There were several days during the summer when the ISO experienced record high day-ahead prices that were significantly higher than hourly prices at the Mid-Columbia and Palo Verde hubs. For example, on July 24 during hours ending 19 through 21 average prices in both the PG&E and SCE areas reached over $800/MWh compared to Mid-Columbia and Palo Verde prices at less than $200/MWh during the intervals.

[74] Day-ahead prices from the ISO include only the peak hours for comparison to peak bilateral prices from the Intercontinental Exchange (ICE).

Figure 2.7 Monthly average day-ahead and bilateral market prices



2.5 Residual unit commitment

Total residual unit commitment volume increased in 2018, compared to 2017. ISO operators are also able to increase the amount of residual unit commitment requirements for reliability purposes. These operator adjustments increased significantly in 2018 compared to 2017, with adjustments starting to occur frequently from June 2018.[75]

The purpose of the residual unit commitment market is to ensure that there is sufficient capacity on-line or reserved to meet actual load in real time. The residual unit commitment market is run directly after the day-ahead market and procures sufficient capacity to bridge the gap between the amount of physical supply cleared in the day-ahead market and the day-ahead forecast load. Capacity procured through residual unit commitment must be bid into the real-time market.

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

[75] See Section 9.4 for further discussion on operator adjustments in the residual unit commitment process.

Figure 2.8 Residual unit commitment costs and volume

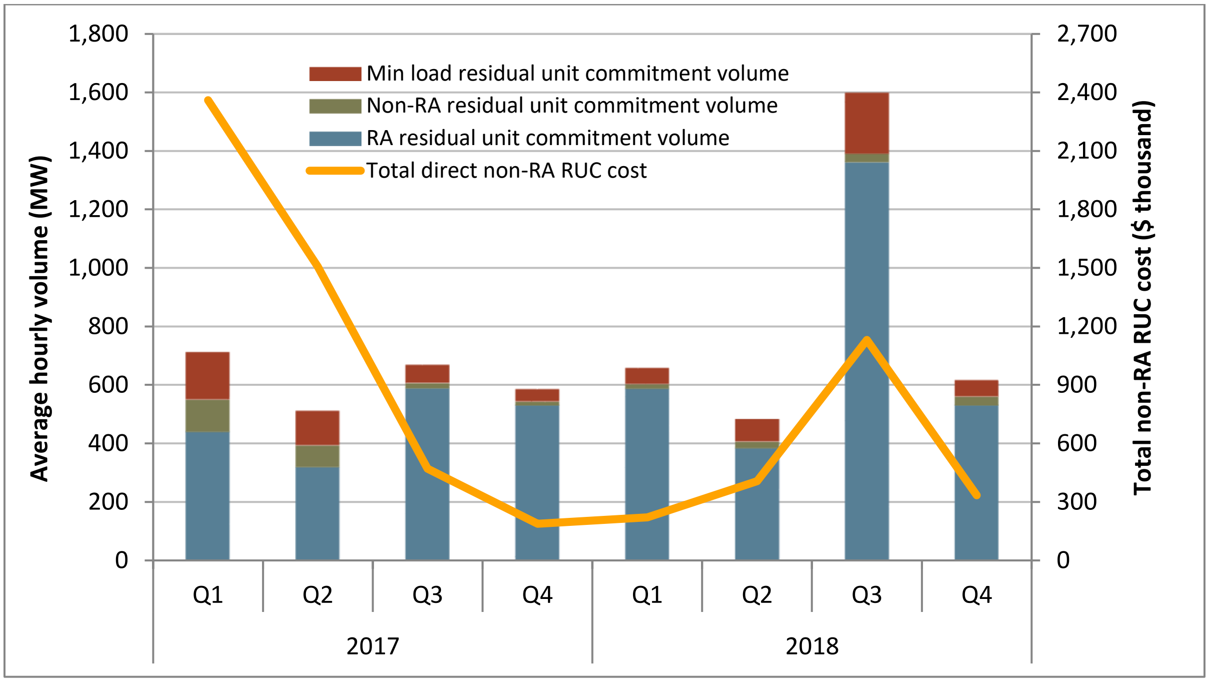


Figure 2.8 shows quarterly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. Total residual unit commitment procurement increased to 839 MW per hour in 2018 from an average of 620 MW in 2017. Specifically, the figure shows increased residual unit commitment volumes and costs due to high residual unit commitment requirements in the third quarter of 2018. Total residual unit commitment procurement increased to about 1,600 MW per hour in the third quarter of 2018 from an average of 670 MW in the same quarter of 2017.

The primary reason for the increase in residual unit commitment volumes in 2018 can be attributed to the relatively high operator adjustments and an increase in amounts of cleared net virtual supply in the third quarter of 2018. When the market clears with net virtual supply, residual unit commitment capacity is needed to replace net virtual supply with physical supply.

While residual unit commitment capacity must be bid into the real-time market, only a fraction of this capacity is committed to be on-line by the residual unit commitment process.[76] Most of the capacity procured in the residual unit commitment process is from units which are already scheduled to be on-line through the day-ahead market or from short-start units that do not need to be started up unless they are actually needed in real time.

The total average hourly volume of residual unit commitment capacity was at or above 500 MW in each quarter of 2018 and the capacity committed to operate at minimum load averaged 99 MW each hour. This was an increase of about 2 percent from the capacity that was procured and committed to operate at minimum load in 2017. Third quarter of 2018 was an exception when the capacity committed to

[76] Only the small portion of minimum load capacity from *long-start units*, units with start-up times greater than or equal to five hours, is committed to be on-line in real-time by the residual unit commitment process.

operate at minimum load averaged about 207 MW each hour compared to 63 MW in the third quarter of 2017. In 2018, about 19 percent of this capacity was from long-start units compared to 9 percent in 2017.[77]

Most of the capacity procured in the residual unit commitment market does not incur any direct costs from residual unit capacity payments because only non-resource adequacy units committed in the residual unit commitment receive capacity payments.[78] As shown by the small green segment of each bar in Figure 2.8, the non-resource adequacy residual unit commitment averaged about 25 MW per hour in 2018, down from about 54 MW procured in 2017. The total direct cost of non-resource adequacy residual unit commitment, represented by the gold line in Figure 2.8, decreased to about $2 million in 2018, down from a direct cost of about $4.5 million in 2017.

2.6 Bid cost recovery payments

Estimated bid cost recovery payments for units in the ISO and energy imbalance market totaled around $153 million and $12 million, respectively. The total represents the highest ever bid cost recovery payments since 2011. Bid cost recovery payments increased significantly in 2018 compared to 2017, when bid cost recovery totaled $108 million.[79] The ISO's portion of these payments represent about 1.4 percent of total ISO wholesale energy costs.

Generating units in both the ISO and the energy imbalance market are eligible to receive bid cost recovery payments if total market revenues earned over the course of a day do not cover the sum of all the unit's accepted bids. This calculation includes bids for start-up, minimum load, ancillary services, residual unit commitment availability, day-ahead energy, and real-time energy. Excessively high bid cost recovery payments can indicate inefficient unit commitment or dispatch.

77 Long-start commitments are resources that require 300 or more minutes to start up. These resources receive binding commitment instructions from the residual unit commitment process. Short-start units receive an advisory commitment instruction in the residual unit commitment process, but the actual unit commitment decision for these units occurs in real-time.

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

79 All values reported in this section refer to DMM estimates for bid cost recovery totals.

Figure 2.9 Bid cost recovery payments

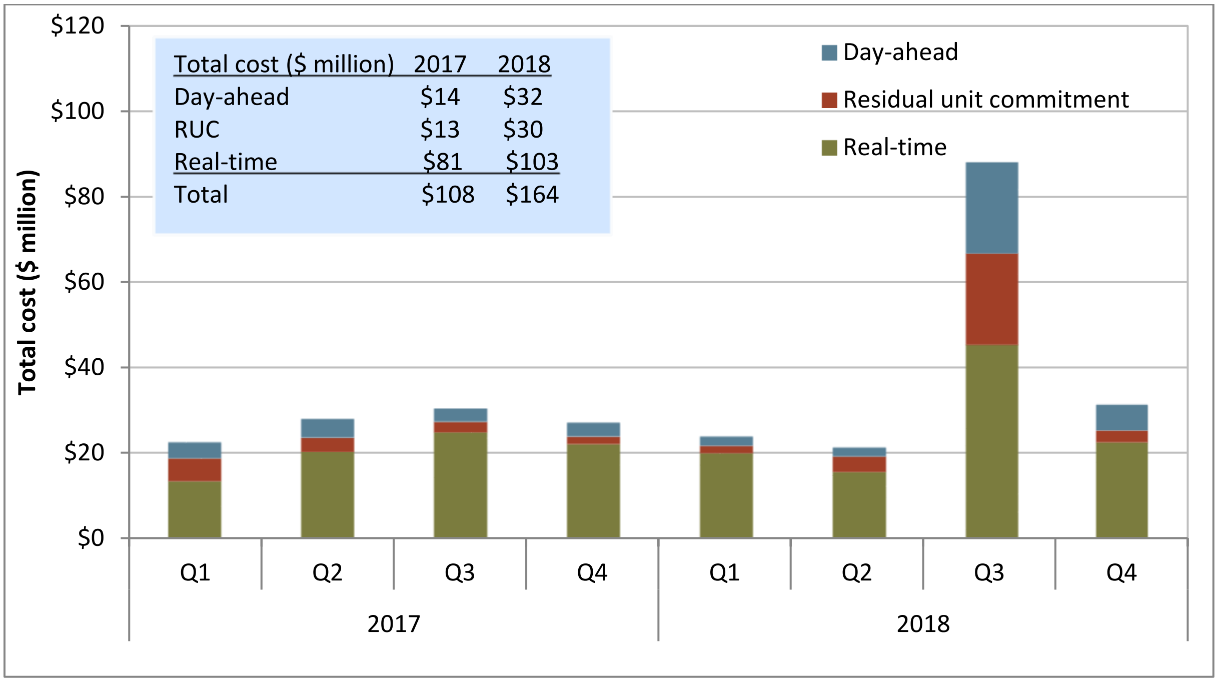


Figure 2.9 provides a summary of total estimated bid cost recovery payments in 2018 and 2017 by quarter and market. The significant increase in total bid cost recovery payments in 2018 from 2017 resulted largely from more than doubling of day-ahead and residual unit commitment bid cost recovery payments and a $22 million increase in real-time market payments during the same period.

Day-ahead bid cost recovery payments totaled $32 million in 2018, a significant increase from $14 million in 2017. Bid cost recovery associated with minimum on-line constraints accounted for about $4 million, a small portion of overall bid cost recovery payments in 2018, similar to the payments in 2017.[80]

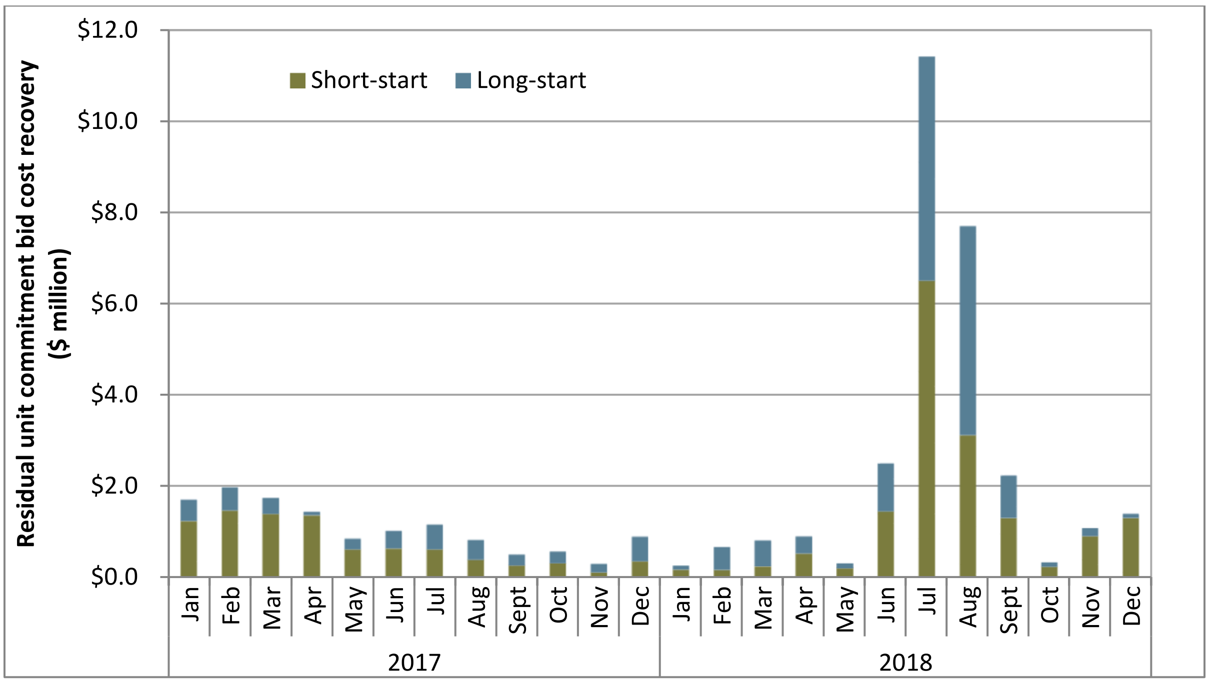
Real-time bid cost recovery payments were $103 million in 2018, which was a significant increase from about $81 million in 2017. About $45 million of these payments are from third quarter of 2018. Of the $45 million, about $33 million were awarded to gas resources in the SoCalGas service area. More than $25 million of the real-time bid cost recovery payments were awarded to gas resources bidding their start-up and minimum load costs at the 125 percent proxy cost cap. Payments for real-time bid cost recovery for units in the energy imbalance market were included in this figure and totaled about $12 million in 2018, similar to the amount in 2017.

Bid cost recovery payments for units committed through the residual unit commitment process totaled about $30 million in 2018. This is about 18 percent of total bid cost recovery payments, up from about $13 million in 2017. Units committed by the residual unit commitment can be either long- or short-start units. As shown in Figure 2.10, short-start units accounted for about $16 million in bid cost recovery payments, while long-start unit commitment accounted for $14 million. These totals represent all bid

[80] Minimum on-line constraints are used to meet special reliability issues that require having units on-line to meet voltage requirements and for contingencies. These constraints are based on existing operating procedures that require a minimum quantity of on-line capacity from a specific group of resources in a defined area. These constraints ensure that the system has enough longer-start capacity on-line to meet locational voltage requirements and respond to contingencies that cannot be directly modeled in the market.

cost recovery payments to units committed in the residual unit commitment process and are calculated by netting residual unit commitment shortfalls with real-time surpluses in revenue. Out of the $30 million, $21 million of these payments were accrued in the third quarter alone. The significant increase in residual unit commitment bid cost recovery payments in the quarter can be attributed to high volumes of net virtual supply combined with periods of high loads in July and August along with operator adjustments causing the residual unit commitment process to procure more capacity.

Figure 2.10 Residual unit commitment bid cost recovery payments by commitment type



Bid cost recovery payments for units committed through exceptional dispatches also played an important role in real-time bid cost recovery payments. DMM estimates these payments for resources committed to operate through exceptional dispatches totaled about $40.6 million in 2018, compared to $16.6 million in payments in 2017. In the third quarter alone, the payments exceeded $24 million. Exceptional dispatches are tools that real-time operators can use to help ensure reliability across the system.[81] The majority of these exceptional dispatches were due to load forecast uncertainty in July and August. Although the exceptional dispatch volume in the fourth quarter continued to remain high, bid cost recovery payments to units committed in the real-time market for exceptional dispatches totaled only about $3.6 million.

DMM estimates that activation of gas price scalars associated with Aliso gas-electric coordination resulted in over $8.5 million in excess uplift payments to resources using the scalar since 2016. These excess payments were estimated by calculating a counterfactual of resulting bid cost recovery payments if the resources using the scalars only bid up to their proxy cost cap calculated without any scalars.[82]

[81] Additional details regarding exceptional dispatches are covered in Section 9.1 of this report.

[82] Additional details on Aliso gas-electric coordination provided in Section 3.4 of this report.

2.7 Real-time imbalance offset costs

Total real-time imbalance offset costs increased by about 56 percent in 2018 to $128 million from $82 million in 2017. Much of this increase is attributable to a $79 million increase in real-time congestion imbalance offset costs. Real-time imbalance energy offset costs fell in 2018 and real-time loss imbalance costs stayed relatively low.

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

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

Real-time imbalance energy offset charges fell from $49 million in 2017 to $14 million in 2018. A $23 million real-time energy offset cost in the first quarter was offset by low and negative charges in the remaining quarters of 2018. The ISO enforced total gas burn constraints associated with Aliso Canyon gas-electric coordination, in both the day-ahead and real-time markets in the first quarter. These constraints were binding in the real-time market during numerous intervals in peak hours on February 20 to 23. These gas constraints may have contributed to higher real-time imbalance energy offset costs, which totaled about $19 million during this four day period in February.

Real-time congestion imbalance offset charges increased from $38 million in 2017 to $117 million in 2018. In 2018, persistent and significant constraint limit reductions in the 15-minute market across most of the binding 15-minute market hours for binding constraints appears to have caused the majority of the real-time congestion imbalance charges.[83]

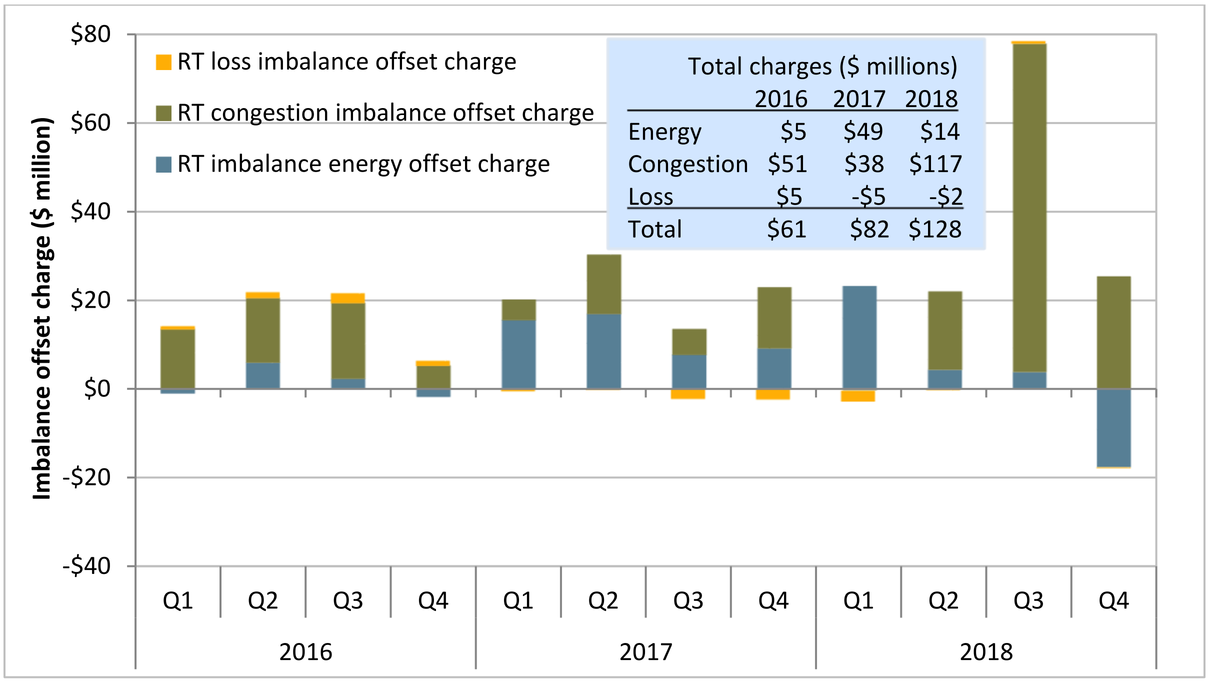
Overall real-time congestion imbalance is the sum of specific constraint congestion imbalances. When a change to a real-time energy schedule reduces flows on a constraint, that schedule is paid the real-time constraint congestion price for making space available on the constraint. Generally, if the constraint is still binding with a non-zero price, another schedule has increased flows on the constraint. The schedule that increased flows would then pay the ISO enough to cover the ISO's payments to the schedule that reduced flows—and the ISO congestion accounts would remain balanced. However, there are several reasons the congestion payments will not balance.[84] One reason is that the real-time constraint limits are lower than the day-ahead market limits. With a lower limit, schedules may be forced to reduce flows

83 A more detailed constraint specific offset estimate is available in DMM's recent quarterly reports, *Q3 2018 Report on Market Issues and Performance,* November 1, 2018, and *Q4 2018 Report on Market Issues and Performance,* February 13, 2019, both available here: http://www.caiso.com/market/Pages/MarketMonitoring/AnnualQuarterlyReports/Default.aspx

84 One is that flows increase causing a constraint to bind generating additional congestion rent. Others include when some flow changes are settled and others are not.

over the still binding constraint without a corresponding flow increase. The ISO will pay the flow reduction but cannot balance this payment with collections from a flow increase. To maintain revenue balance, the ISO charges an uplift to measured demand to offset the imbalance.[85]

Figure 2.11 Real-time imbalance offset costs



85 For a more detailed explanation see the DMM paper *Real-Time Revenue Imbalance in CAISO Markets,* April 24, 2013: http://www.caiso.com/Documents/DiscussionPaper-Real-timeRevenueImbalance_CaliforniaISO_Markets.pdf

3 Real-time market volatility and flexibility

Real-time prices in the ISO and energy imbalance market can experience periods of market volatility. This volatility is often driven by brief periods when the market software has exhausted upward and downward flexibility, requiring relaxation of the system power balance constraint. As more variable renewable generation is integrated into the ISO system to meet state renewable generation goals, the importance of real-time resource flexibility increases, for all resource types.

This chapter provides key trends relating to the performance of the real-time markets including price volatility and resource flexibility. Highlights in this chapter include the following:

- High prices in both the 15-minute and 5-minute markets were as frequent as the previous year. Extreme price spikes greater than $750/MWh in the real-time markets were concentrated during the evening ramping period between hours ending 18 and 20.
- Negative prices occurred significantly less frequently in the 15-minute and 5-minute markets compared to the previous year.
- Total net payments for flexible ramping capacity decreased significantly in 2018 to about $7 million, compared to almost $25 million during the previous year, as the frequency of zero price intervals increased from 78 to 94 percent in the upward direction and from 95 to over 99 percent in the downward direction. Of note, power balance constraint relaxations in the 15-minute and 5-minute markets were infrequent during 2018 relative to 2017.
- In 2018, the gas price scalars were active from January 1 – 31 and February 20 – March 7. On November 26, 2018, FERC rejected ISO's proposal to extend the use of gas price scalars. DMM estimates that total excess bid cost recovery payments as a result of these scalars was over $8 million since their activation in 2016.
- Enforcement of gas burn nomograms in peak hours in the real-time market from February 20 to 23 was concurrent with very high levels of real-time energy offset, totaling about $19 million and accounting for most of the $21 million total offset cost for the first quarter.
- Participants submitted economic bids, rather than self-schedules, for about one third of generation resources into the ISO real-time market in 2018.[86] Imports represent the largest share of self-scheduled generation, at 39 percent, followed by nuclear and solar generation.

3.1 Real-time price variability

Prices in the 15-minute and 5-minute markets were slightly less volatile in 2018 than in 2017. Negative prices occurred less frequently in the ISO area, while high prices in the real-time markets occurred with about the same frequency as in 2017.

[86] This analysis focuses on the real-time energy bids that market participants submit to the ISO balancing area, and does not include bids in the energy imbalance market.

High prices in the ISO area

During 2018, most high prices occurred as a result of high bids in the market and heavy congestion within the ISO, compounded with a decrease in generation from hydroelectric resources. Real-time market price spikes continued to occur most frequently during the third quarter when there was high demand associated with system-wide heat waves, high natural gas prices, and congestion between ISO load areas. Most high real-time prices also continued to occur in the morning and evening ramping hours.

Figure 3.1 shows the frequency of prices above $250/MWh at load aggregation points (LAPs) with the ISO in the 15-minute market in 2017 and 2018. The overall frequency of 15-minute prices above $250/MWh was about the same as 2017, or about 0.5 percent of intervals. A greater portion of 15-minute price spikes in 2018 were less than $500/MWh.

The frequency of prices greater than $750/MWh was down slightly in 2018 to less than 1 percent of intervals. The frequency of more extreme 15-minute market prices larger than $750/MWh decreased slightly to around 0.2 percent of intervals from about 0.3 percent of intervals in 2017. A greater portion of price spikes in 2018 were less than $500/MWh. The frequency of high prices in the 15-minute market was highest in the third quarter, particularly in the month of August when prices above $250/MWh occurred in over 2 percent of intervals.

Figure 3.2 shows the frequency of prices above $250/MWh in the 5-minute market. The frequency of 5-minute prices greater than $750/MWh was similar to the prior year, or about 0.9 percent of intervals. High price spikes in the 5-minute market are often associated with congestion. In other instances, extreme price spikes were the result of power balance constraint infeasibilities resolved at a penalty price or set by an extremely high bid when resolved by the load bias limiter.

High prices in the 15-minute market were most common between hours ending 18 and 20 during periods when net load was very high. In the 5-minute market, high prices occurred less predictably with the majority occurring in the morning ramp period between hours 8 and 10. However, price spikes in the 5-minute market were also common during the middle of the day due to variability of generation from renewable energy resources and then again in the evening ramping periods.

When there is no congestion between balancing areas, prices in the energy imbalance market tend to reflect overall system conditions. As the market optimization dispatches higher cost generation to meet system needs or relaxes the system power balance constraint because of insufficient upward ramping capacity, prices in the energy imbalance market can be set by a high system price if transfer limits do not bind.

Figure 3.1 Frequency of positive 15-minute price spikes (ISO LAP areas)

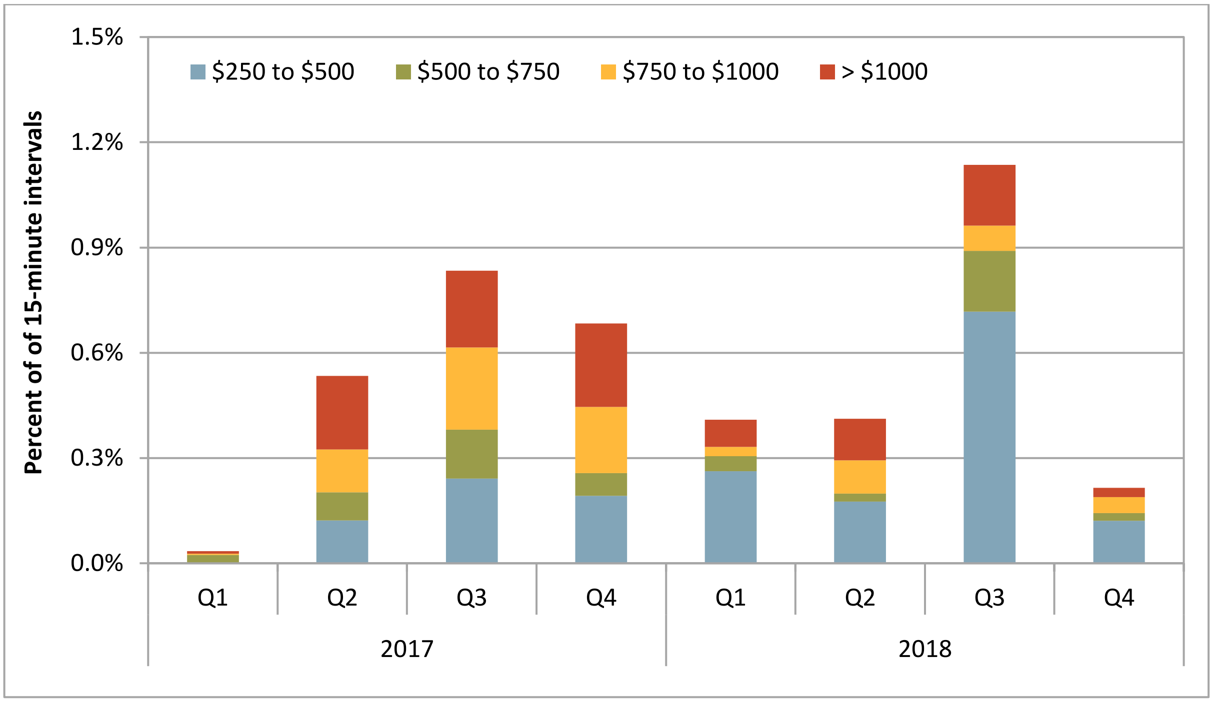
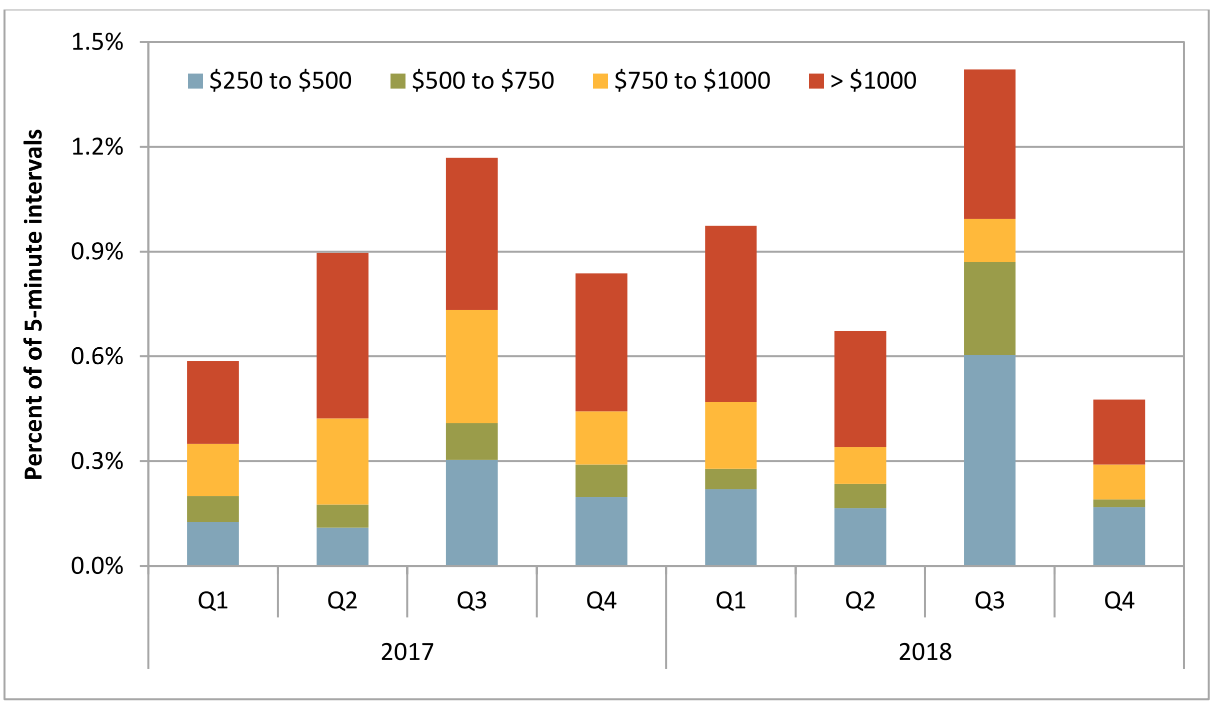


Figure 3.2 Frequency of positive 5-minute price spikes (ISO LAP areas)



Negative prices in the ISO area

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 3.3 and Figure 3.4 show the frequency of negative prices in the 15-minute and 5-minute markets by quarter. Negative prices occurred much less frequently in both the 15-minute and 5-minute markets during 2018 compared to the previous year, with almost all negative prices falling between negative $50/MWh and $0/MWh.

The lower frequency of negative prices this year is likely a result of decreased hydroelectric generation. Negative prices during 2018 were most frequent in the midday hours when renewable generation is highest with many renewable resources (primarily participating solar resources) bidding negative. Most negative prices occurred between February and June when hydroelectric generation was greatest.

When the supply of economic bids to decrease energy is exhausted, the power balance constraint can be relaxed up to the regulation requirement to reflect the role regulation plays in balancing the system. Beginning 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. Beyond this threshold, self-scheduled generation can be curtailed including self-scheduled wind and solar generation. However, during nearly all of the intervals in 2018 when prices were negative, there was sufficient generation with bids that could be dispatched down so that the market software did not have to relax the power balance constraint or curtail self-scheduled generation.

During 2018, the frequency of prices near or below the -$150/MWh floor remained infrequent, occurring in around 0.1 percent of intervals, similar to the previous year. This result reflects the bidding flexibility of renewable resources and increased transfer capability in the real-time market from the energy imbalance market.[87]

Figure 3.5 shows the annual frequency of negative prices in the 5-minute market since 2014.[88] The overall frequency of negative prices has been increasing every year since 2013 until this current year. The decline of negative prices in 2018 reflects decreased generation from hydroelectric resources relative to prior years.

Figure 3.6 shows the hourly frequency of negative 5-minute prices in the last three years. The figure illustrates that the majority of negative prices during 2018 generally occurred during midday hours when solar generation was highest and net demand was low. This has been a trend since 2015, although in 2018 the frequency of negative prices during the midday hours was significantly lower than in previous years.

87 See Section 3.5 for further discussion on renewable bidding flexibility.

88 The bid floor was lowered to a hard bid floor of -$150/MWh from a soft bid floor of -$30/MWh in May 2014.

Figure 3.3 Frequency of negative 15-minute prices (ISO LAP areas)

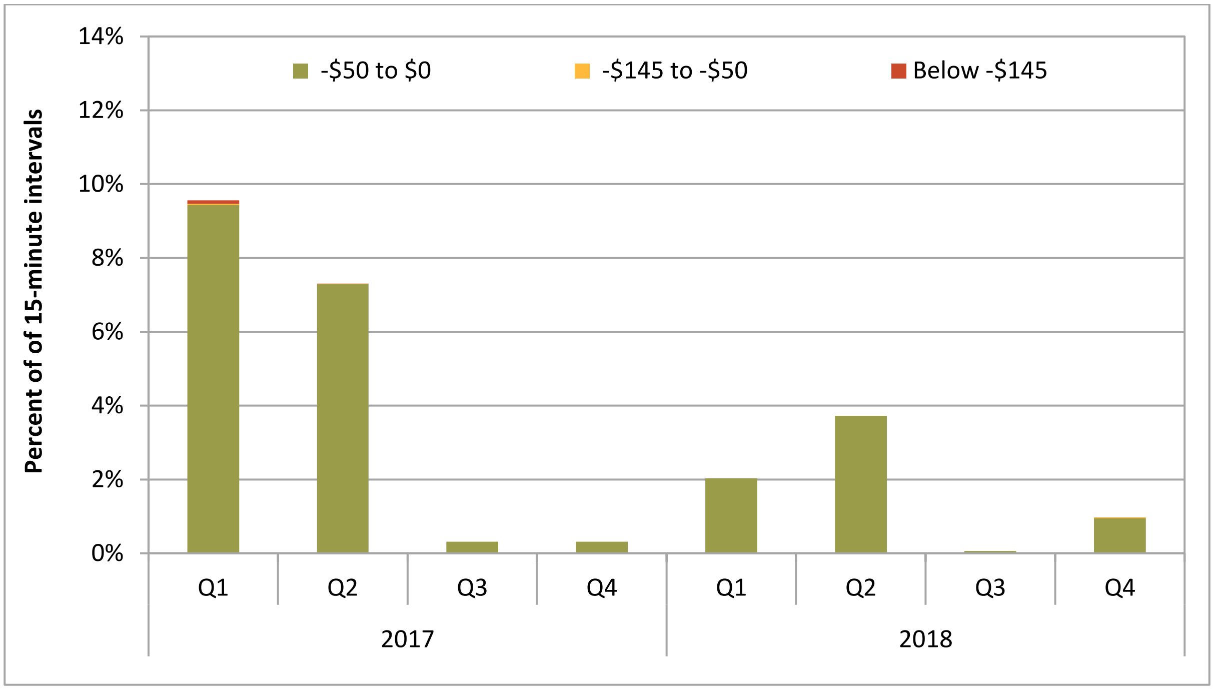


Figure 3.4 Frequency of negative 5-minute prices (ISO LAP areas)

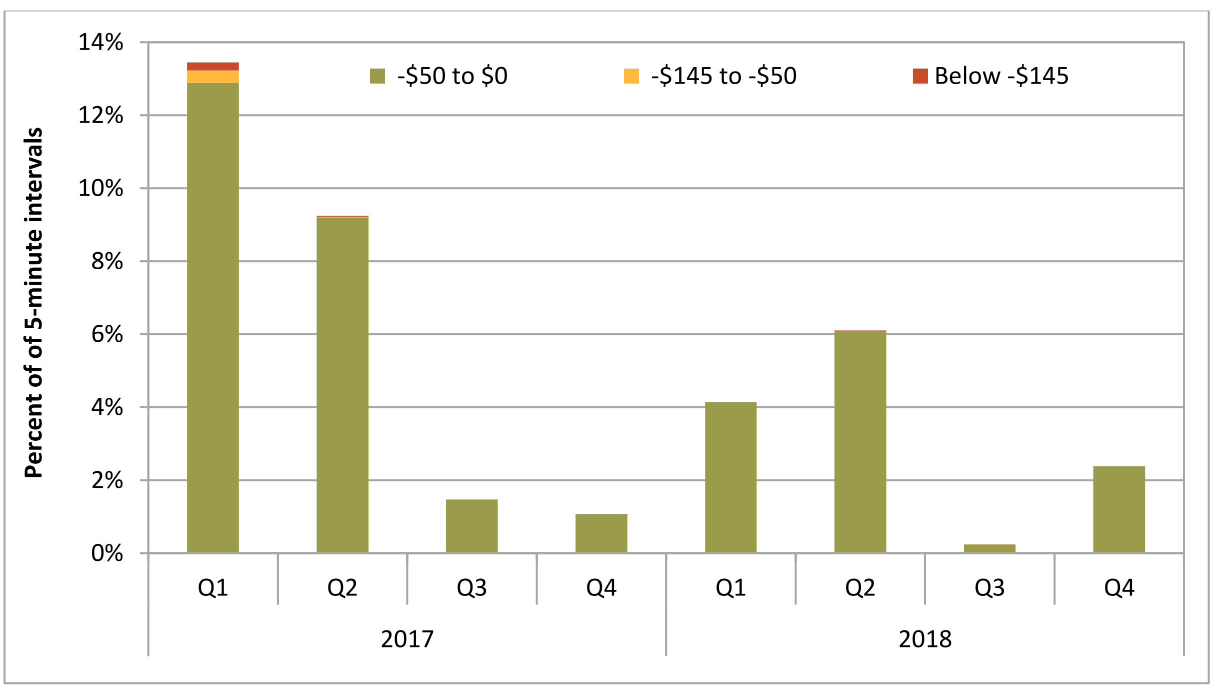


Figure 3.5 Frequency of negative 5-minute prices (ISO LAP areas)

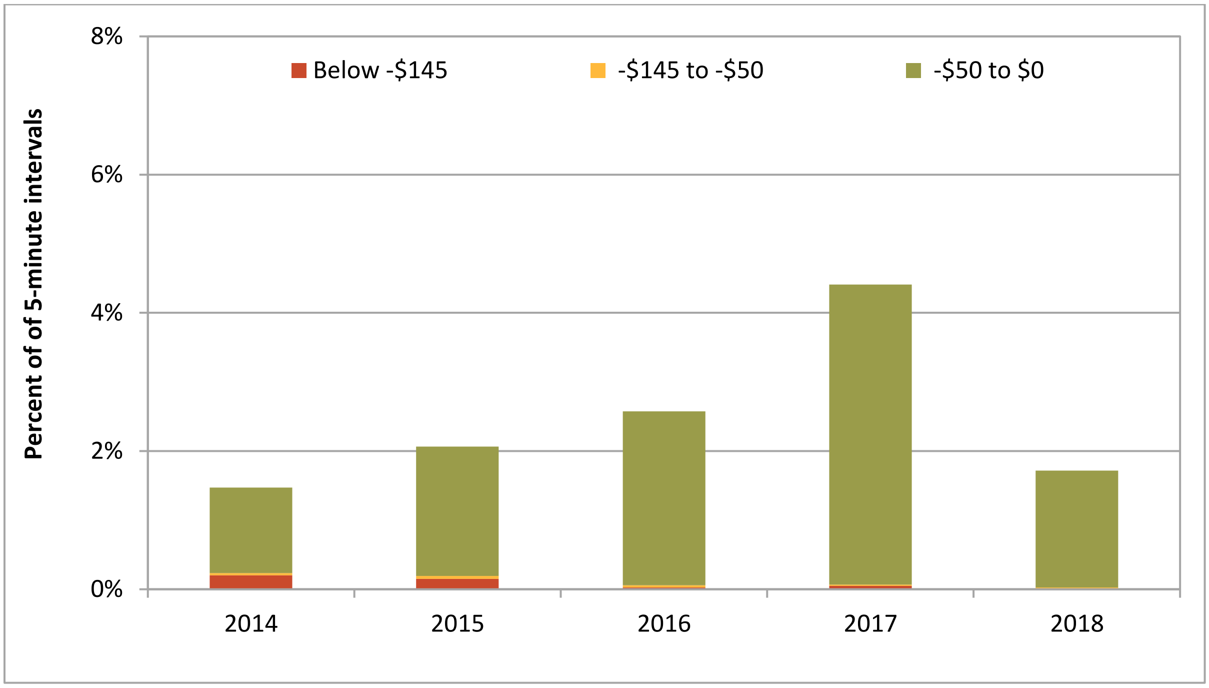
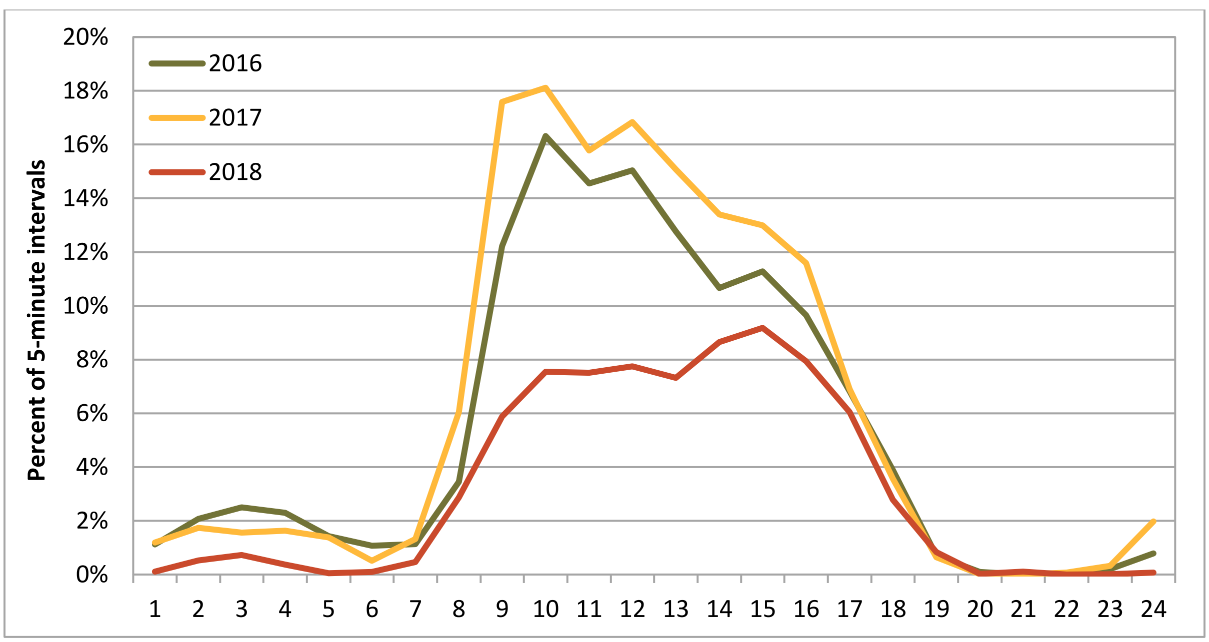


Figure 3.6 Hourly frequency of negative 5-minute prices by year (ISO LAP areas)



3.2 Power balance constraint

The ISO and energy imbalance market areas can run out of ramping capability in either the upward or downward direction to solve the real-time market solution. This condition is known as a power balance constraint relaxation.[89] When this occurs, prices can be set at the $1,000/MWh penalty parameter while relaxing the constraint for shortages (under-supply infeasibility), or the -$155/MWh penalty parameter while relaxing the constraint for excess energy (over-supply infeasibility).

If the operator load adjustment exceeds the size of the power balance constraint relaxation and in the same direction, the size of the load adjustment is automatically reduced and the price is set by the last dispatched economic bid rather than the penalty parameter for the relaxation.

In prior quarterly and annual reports, DMM has 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. As of late February 2019, the ISO has implemented these changes to the load bias limiter.[90]

System power balance constraint relaxations

The frequency of system power balance constraint violations decreased in 2018 compared to the previous year. As in 2017, prices were set by the load bias limiter during most of these intervals. However, during many of the under-supply infeasibilities when the load bias limiter triggered, accessible economic bids near the bid cap of $1,000/MWh were cleared resulting in prices that were near the penalty parameter.

Figure 3.7 and Figure 3.8 show the quarterly frequency of under-supply infeasibilities in the 15-minute market and 5-minute market, respectively. Before accounting for the load bias limiter, under-supply infeasibilities in the 15-minute market decreased slightly to around 0.1 percent of intervals from around 0.2 percent of intervals in the previous year. In the 5-minute market, under-supply infeasibilities occurred during 0.3 percent of intervals in 2018, a decrease from 0.5 percent of intervals in 2017.

The majority of under-supply infeasibilities continued to be resolved by the load bias limiter as in the previous year. Valid under-supply infeasibilities when the load bias limiter was not triggered occurred very infrequently during 2018 – during less than 0.1 percent of 5-minute and 15-minute intervals.

Excluding intervals that were corrected due to an underlying issue, the load bias limiter resolved around 71 percent of the undersupply infeasibilities in 2018. This percentage decreased from the previous year where the load bias limiter resolved around 90 percent of undersupply infeasibilities.

However, when the load bias limiter was triggered in 2018, the resulting price from the highest bid dispatched was often near the penalty parameter. When the load bias limiter resolved under-supply infeasibilities during 2018, system prices were greater than $900/MWh during about 96 percent of these

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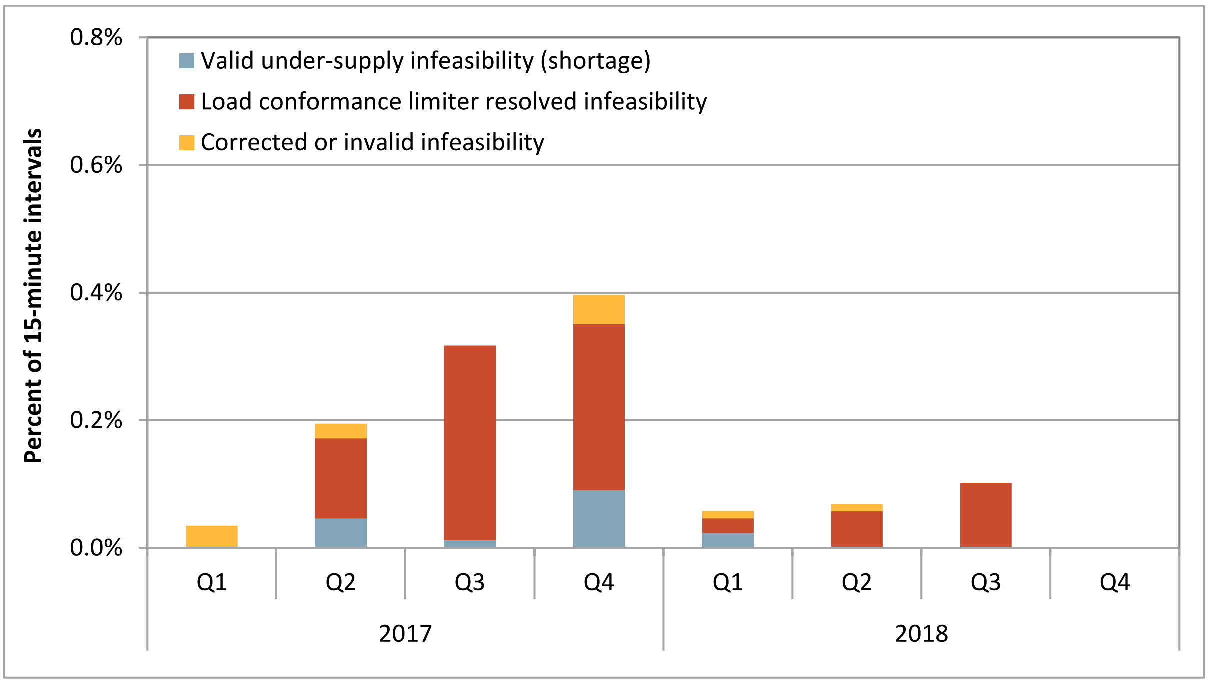
89 A more detailed description of the power balance constraint and load bias limiter was provided in DMM's *2016 Annual Report on Market Issues and Performance,* pp.101-103: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.

90 The *Revised Draft Final Proposal on the Load Conformance Limiter Enhancement* (March 14, 2018) can be found here: http://www.caiso.com/Documents/RevisedDraftFinalProposal-ImbalanceConformanceEnhancements.pdf.

intervals. This outcome has often been related to economic bids by proxy demand response resources near the bid cap of $1,000/MWh.

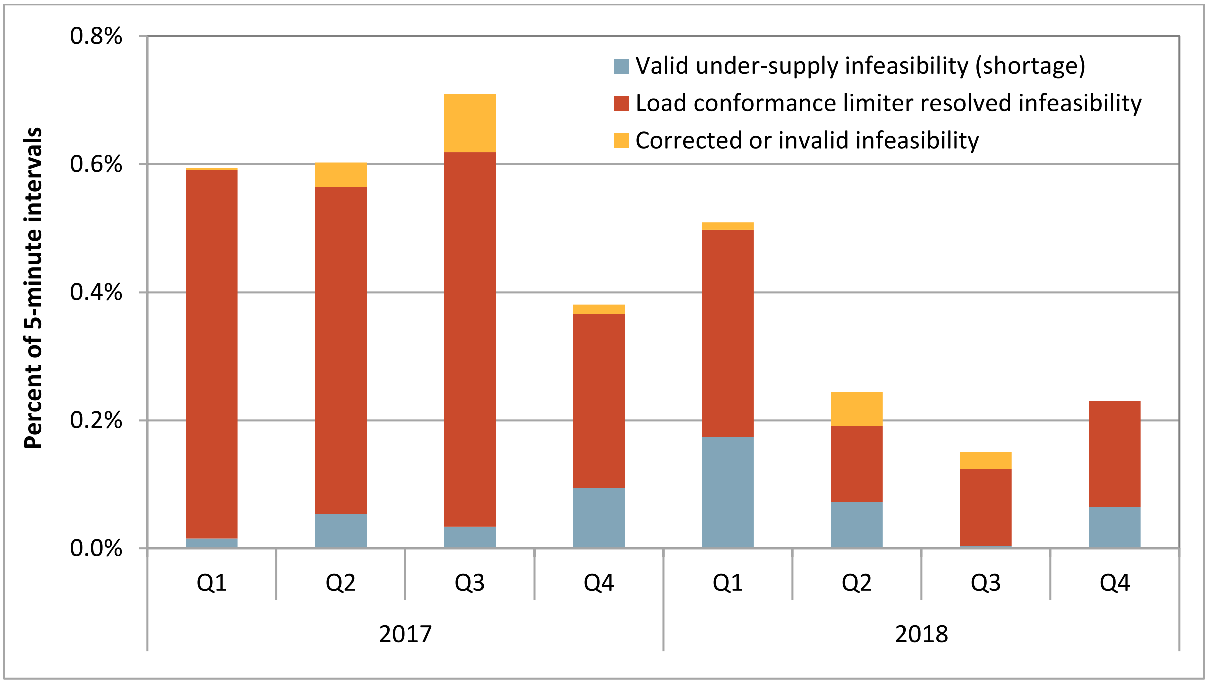
Relaxations because of insufficient downward supply in the 5-minute market occurred significantly less frequently than the previous year.[91] After accounting for corrections due to an underlying software issue, there were only 6 valid oversupply infeasibilities in the 5-minute market occurring all on the same day on April 3rd during hour ending 21. Bidding flexibility from renewable resources and increased transfer capability from the energy imbalance market continued to contribute to reduced oversupply conditions.

Figure 3.7 Frequency of under-supply power balance constraint infeasibilities (15-minute market)



91 The power balance constraint was not relaxed due to insufficient downward capability in the 15-minute market in the ISO system during 2018

Figure 3.8 Frequency of under-supply power balance constraint infeasibilities (5-minute market)



As in prior years, most of the upward ramping shortages were very short in duration. Similar to 2017, about 82 percent of upward ramping capacity shortages in the 5-minute market during 2018 persisted for one to three 5-minute intervals (or 5 to 15 minutes). Over-supply infeasibilities were much less frequent overall than last year with only one over-supply infeasibility in total which persisted for six 5-minute intervals (or 30 minutes). In the 15-minute market, about 91 percent of under-supply infeasibilities persisted for one to three 15-minute intervals (or 15 to 45 minutes).

3.3 Flexible ramping product

Background

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

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

Uncertainty calculation implementation issues

Flexible ramping product procurement and prices are determined through demand curves, expected to be calculated from historical net load forecast errors, or the *uncertainty* surrounding ramping needs. In February 2018, DMM identified specific errors in flexible ramping product implementation related to the calculation of uncertainty.[92] These errors systematically biased flexible ramping capacity procurement and prices in the direction opposite of the net load ramp (down when net load is ramping up and vice versa).

These errors impacted flexible ramping procurement, prices and payments. The direction and magnitude of the impact varies from hour to hour. However, DMM's analysis indicates this error resulted in under-procurement of upward flexible ramping capacity during key net load ramping intervals.

In February 2018, the ISO corrected the net load error distributions so that uncertainty was based on an advisory and binding net load in the same time-interval. These distributions were used in the market to calculate the uncertainty requirements and demand curves beginning February 22, 2018.

Figure 3.9 and Figure 3.10 show the difference between the hourly system-level uncertainty requirements on February 20, 2018 (pre-fix) and February 22, 2018 (post-fix) for the 15-minute and 5-minute markets, respectively. The upward uncertainty requirements were equal to the upper lines while the downward uncertainty requirements were equal to the lower lines. The uncertainty requirements used in the market are capped at zero megawatts at one end and at the uncertainty thresholds at the other.[93] Since the implementation of the new distributions, upward and downward uncertainty requirements have been non-zero during all hours.

[92] For more detailed information on the individual implementation issues and the impact of these errors, see DMM's special report: *Flexible Ramping Product Uncertainty Calculation and Implementation Issues,* April 18, 2018: http://www.caiso.com/Documents/FlexibleRampingProductUncertaintyCalculationImplementationIssues.pdf.

[93] Uncertainty requirements are capped by uncertainty thresholds, designed to prevent extreme outlier or erroneous net load errors from impacting the uncertainty requirement and associated market outcomes.

Figure 3.9 15-minute market system-level uncertainty requirements (February 20 versus February 22, 2018)

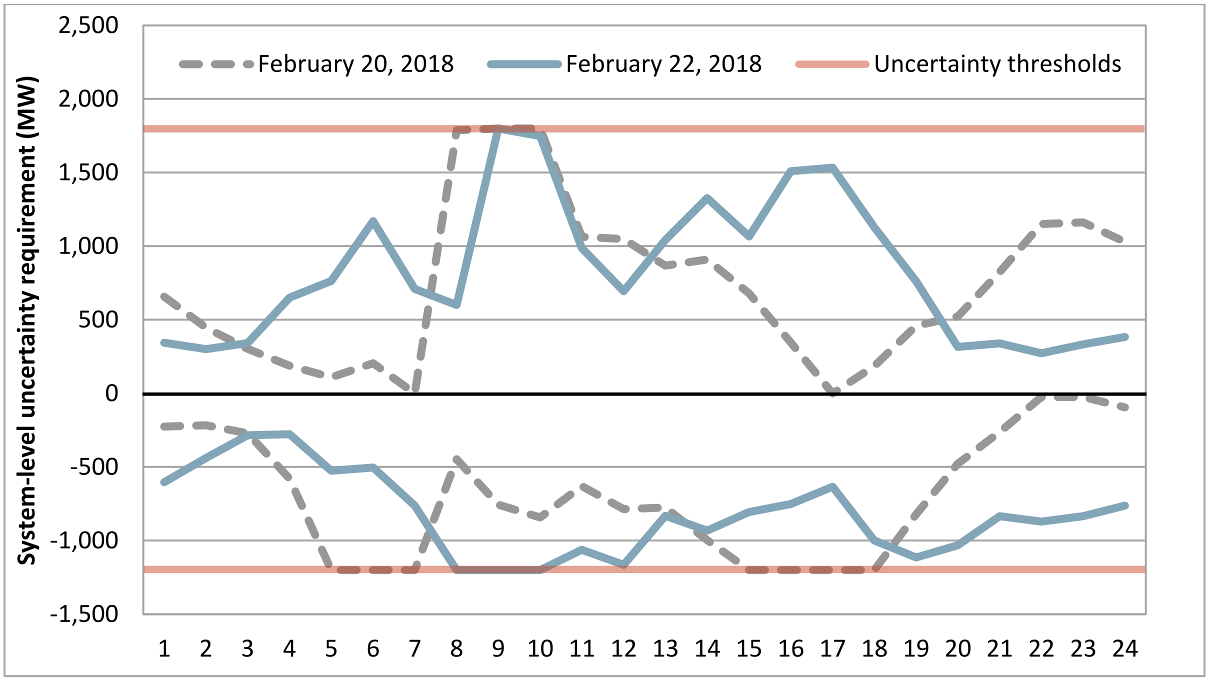
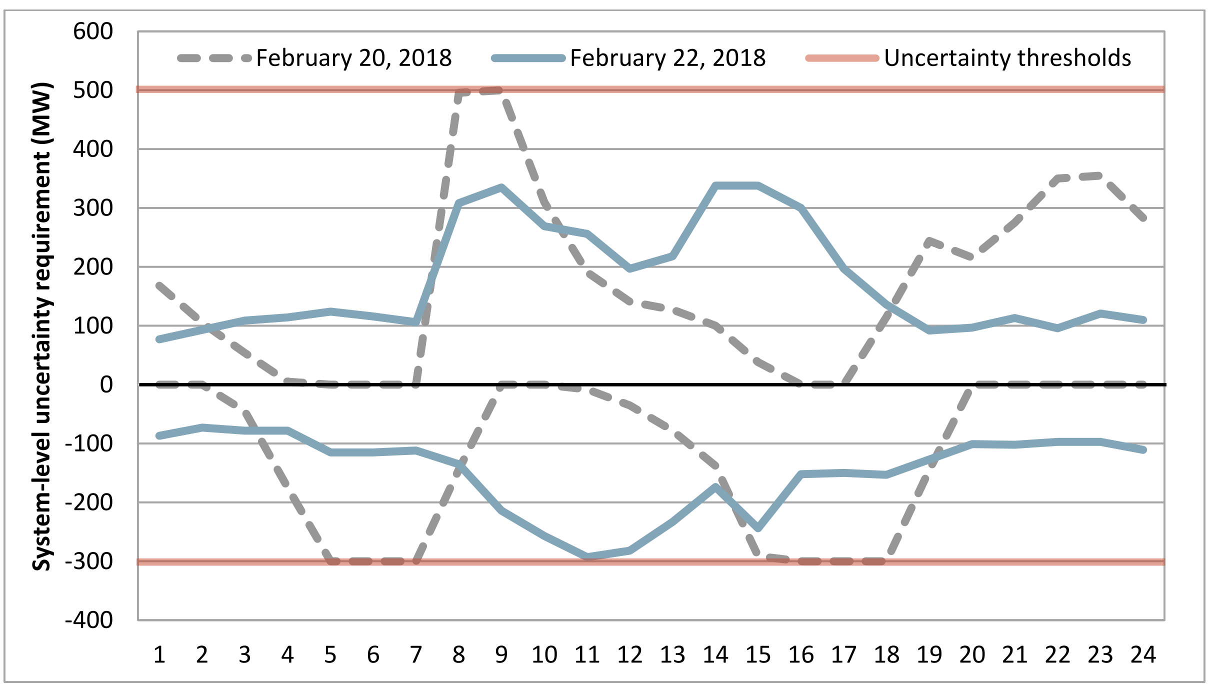


Figure 3.10 5-minute market system-level uncertainty requirements (February 20 versus February 22, 2018)

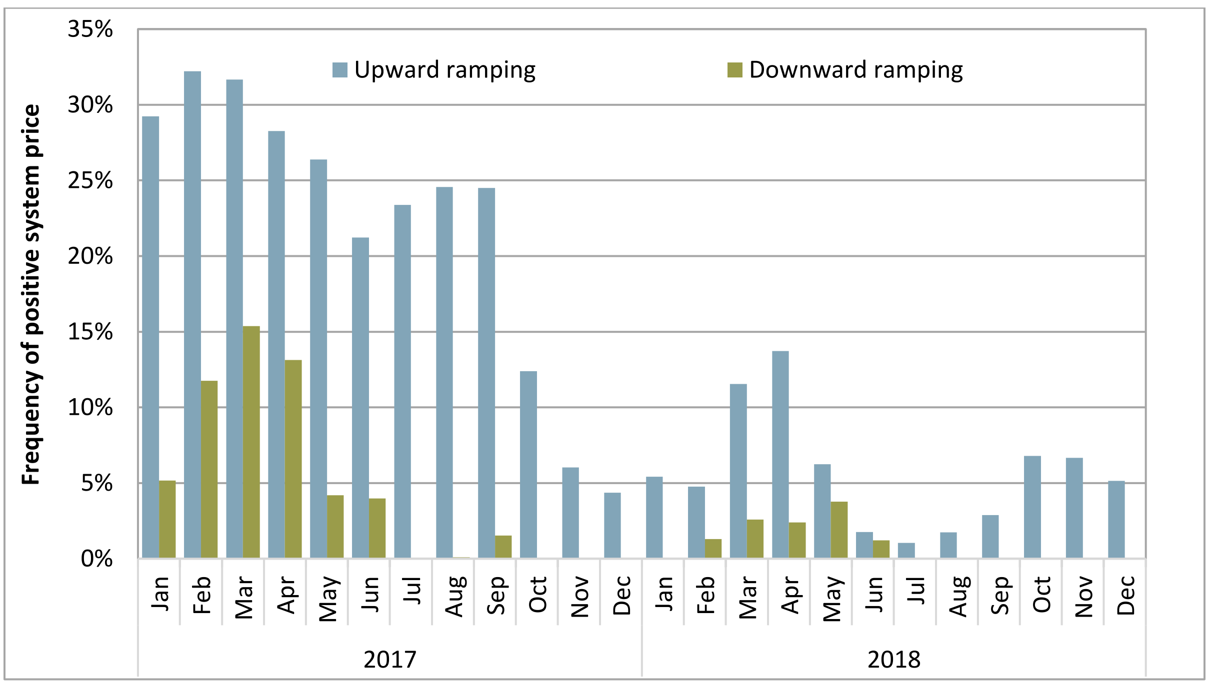


Flexible ramping product prices

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

Figure 3.11 shows the percent of intervals that the system-level flexible ramping demand curve bound and had a positive shadow price in the 15-minute market. During 2018, there was a significant decrease overall in the frequency of binding system-level shadow prices in both directions. The 15-minute market system-level demand curves bound in around 6 percent of intervals in the upward direction and in less than 1 percent of intervals in the downward direction during the year. In comparison, they bound during 2017 in around 22 percent and 5 percent of intervals, for the upward and downward directions respectively.

Figure 3.11 Monthly frequency of positive 15-minute market flexible ramping shadow price



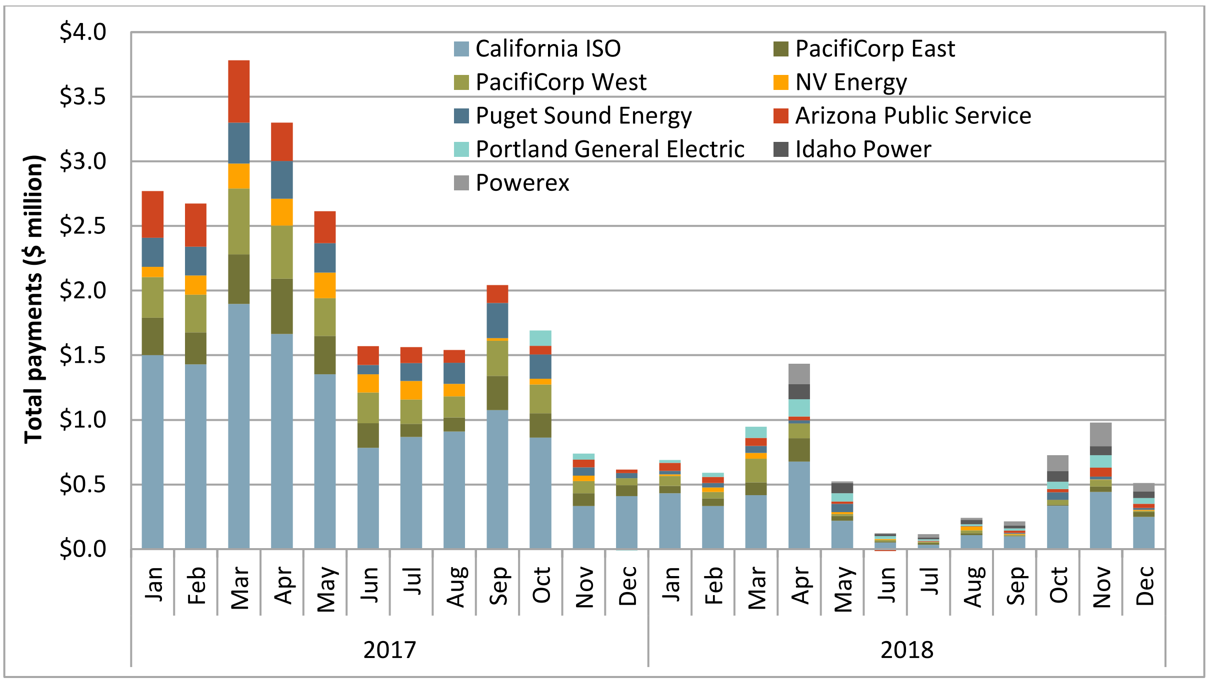
Flexible ramping procurement costs

Generation capacity that satisfied the demand for flexible ramping capacity received payments based on the combined system and area-specific flexible ramping shadow price. In addition, the combined flexible ramping shadow price was also used to pay or charge for forecasted 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 forecast to decrease output was charged the upward flexible ramping price and paid the downward flexible ramping price.[94]

Figure 3.12 shows the total net payments to generators for flexible ramping capacity from the flexible ramping product by month and balancing area.[95] 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 forecast movements are not included.

Total net payments to generators in the ISO and energy imbalance market areas for providing flexible ramping capacity decreased significantly in 2018 to about $7 million, compared to almost $25 million during the previous year. This was in part driven by the lower frequency of non-zero system flexible ramping shadow prices. Of note, power balance constraint relaxations in the 15-minute and 5-minute markets were infrequent during 2018 relative to 2017.

Figure 3.12 Monthly flexible ramping payments by balancing area



94 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.

95 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.

3.4 Aliso Canyon gas issues

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 impacted the ability of pipeline operators to manage real-time natural gas supply and demand deviations, which in turn could have had impacts on the real-time flexibility of natural gas-fired electric generators in Southern California. This primarily impacted 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.

In response to the gas supply restrictions stemming from the Aliso Canyon natural gas leak, the ISO received temporary authority to implement numerous measures to improve gas-electric coordination and the ISO's ability to maintain reliability while limiting gas usage by generators in the SoCalGas system. The following sections discuss DMM's review and recommendations on two of these key measures.

Gas usage nomogram constraints

One of the tools the ISO has developed to manage potential gas-system limitations are constraints (or nomograms) that allow operators to restrict the gas burn of groups of natural gas-fired generating units. These gas usage nomograms 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.[96]

While DMM has supported temporary extension of the ISO's ability to enforce a maximum gas constraint for groups of units in the SoCalGas system, DMM continues to recommend that the ISO improve how gas usage constraint limits are set and adjusted in real-time.[97] DMM has also expressed concern about the potential impacts of the gas usage constraints on real-time energy offset costs.

In 2018, the ISO enforced these constraints in both day-ahead and real-time markets in selected sub-regions of SoCalGas service area. In the day-ahead market, these nomograms were enforced on all the days from February 21 through March 5 except February 23. In the real-time market, they were enforced during some hours from February 20 through March 5 except February 24 – 25.

Enforcement of gas burn nomograms in peak hours in the real-time market from February 20 to 23 coincided with very high levels of real-time energy offset, totaling about $19 million and accounting for most of the $21 million total offset cost for the first quarter of 2018. Real-time gas constraints were not enforced or not binding in most intervals when enforced on other days. Energy offset costs are allocated as an uplift to measured demand (i.e., physical load plus exports).

If additional offset costs are caused by real-time gas burn constraint enforcement, DMM recommends that the additional cost and allocation of that cost be considered before placing real-time gas burn constraints in the market. In addition, use of the gas constraints may have contributed to the market

96 Refer to *Operating Procedure 4120C SoCalGas Service Area Limitations or Outages:* http://www.caiso.com/Documents/4120C.pdf.

97 FERC filing - Comments on Aliso Canyon Gas-Electric Coordination Phase 4 (ER18-2520), Department of Market Monitoring, October 19,2018: http://www.caiso.com/Documents/CommentsoftheDepartmentofMarketMonitoirng-Aliso4-Oct192018.pdf

impact of transmission constraints including congestion on the Serrano 500/230 kV constraint, binding for much of the first quarter.[98] In addition, DMM's review of the ISO's limited experience with maximum gas usage constraints suggests that additional refinement is needed of the software and operational processes through which the constraints are implemented.

For example, while gas usage constraints are modeled as 15-minute constraints in the ISO's real-time market, these gas constraints are actually applicable only over a much longer multi-hour time period spanning all or part of each operating day. Although operators are able to adjust constraints in real time in response to changing conditions, the ISO does not adjust these constraints in real time based on actual gas usage in prior hours. Therefore, when these gas constraints bind in the ISO's real-time market during the peak ramping hours, there appears to be surplus gas from hours prior in the day when actual usage was well below the constraint as modeled by the ISO. This represents a significant design flaw that remains in the gas nomograms. Thus, DMM continues to recommend that the ISO improve how gas usage constraint limits are set and adjusted in real-time based on actual gas usage in prior hours.[99]

Gas price scalars

Another measure that the ISO implemented in 2016 to help mitigate potential gas-system limitations in the SoCalGas system was temporary authority to increase the gas prices used to calculate commitment cost and energy bid caps for the real-time market using *gas price scalars*. The price scalars were intended to allow natural gas generators in the SoCalGas system to reflect higher same-day gas prices as well as to change the merit order of commitment cost bids so that the ISO market dispatches these resources only for local reliability needs and not for system needs.

The gas price scalars were first activated on July 6, 2016, and included a 75 percent adder (or 175 percent scalar) on the fuel cost component used for calculating proxy commitment costs, and a 25 percent adder (or 125 percent scalar) on the fuel cost component of default energy bids in the real-time market.[100] In 2017 and 2018, analysis by DMM indicated that the gas price scalars were a crude tool to reflect the volatility in same-day gas prices and to manage potential reliability issues associated with gas limitations in the real-time market.

In 2018, these scalars were active on two occasions (January 1 – 31 and February 20 – March 7).[101] DMM's analysis indicates that gas price scalars continued to be an ineffective mechanism for managing gas limitations in the real-time market when activated in 2018.[102] DMM estimates that the total amount

98 The ISO presented results showing a large increase in day-ahead congestion rent on both February 21 and 22, to a sum of over $25 million. Typical day-ahead rents during this period were less than $3 million per day. Market Performance and Planning Forum presentation, April 19 2018, slide 35: http://www.caiso.com/Documents/Agenda-PresentationMarketPerformance-PlanningForum-Apr192018.pdf

99 See example and discussion in Comments of the Department of Market Monitoring of the California Independent System Operator, ER17-2568, October 26, 2017, pp 14-17: http://www.caiso.com/Documents/Oct26_2017_DMMCommentsAlisoCanyonElectric-GasCoordinationPhase3_ER17-2568.pdf

100 These gas price adders are in addition to the 10 percent adder that is included in cost-based default energy bids, and the 25 percent adder that is included in the calculation for commitment cost caps.

101 Since 2016, Aliso gas price scalars were active on 5 occasions: July 6, 2016 – July 31, 2017, August 4 – 8, 2017, October 23 – 25, 2017, December 7 – January 31, 2018, and February 20 – March 7, 2018.

102 Effectiveness of Aliso gas price scalars, *Q1 2018 market issues and performance report*, pp 53 – 56: http://www.caiso.com/Documents/2018FirstQuarterReportonMarketIssuesandPerformance.pdf

of excess bid cost recovery payments as a result of these scalars has exceeded $8 million since their activation in 2016.

On September 28, 2018, the ISO filed tariff amendments to extend Aliso Canyon provisions for the third time until December 31, 2019.[103] DMM filed comments opposing the further extension of applying a gas price scalar to increase the gas price used in calculating caps for commitment costs and default energy bids used in the real-time market for resources in the SoCalGas area.[104] On November 26, 2018, FERC ruled on the ISO's filing, accepting the ISO's proposal to temporarily extend six of its Aliso Canyon-related tariff provisions but rejected the ISO's proposal to temporarily extend the tariff revisions regarding gas price scalars.[105]

Updating natural gas prices in the real-time market

DMM continues to recommend that the ISO develop the ability to adjust gas prices used in the real-time market based on observed prices on the Intercontinental Exchange (ICE) the morning of each operating day. This approach would closely align the gas price used in the ISO's real-time market with the actual costs for gas purchased in the same-day gas market.[106]

Figure 3.13 shows same-day trade prices reported on ICE for SoCal Citygate during 2018 compared to the next-day average price. About 16 percent of traded volume at SoCal Citygate exceeded the normal 10 percent adder and 19 percent of the traded volume exceeded the 25 percent adder.

Figure 3.13 further shows that a significant portion of same-day traded volume that was more than 10 percent higher than the next-day average occurred on the first trade day of the week. These trades are represented by the green bars. Same-day trades for the first trade day of the week (which is typically a Monday, unless the Monday is a holiday) are more likely to exceed the next-day average because, in the next-day market, the first day of the week is traded as a package together with the weekend. The next-day prices for these weekend packages are typically somewhat lower than for weekdays.

Figure 3.14 compares the price of each same-day trade at SoCal Citygate to an updated volume-weighted average price of same-day trades reported on ICE before 8:30 am. This reflects gas prices that would be used for the real-time market under DMM's s recommendation.

As shown in Figure 3.14, if the real-time gas prices were updated using an updated same-day price during 2018, then about 97 percent of the same-day trades at SoCal Citygate would have been at or below the 10 percent adder included in default energy bids used in mitigation. Just under 3 percent of the volume traded in the same-day gas market would have exceeded the 10 percent adder, but still would have been less than the 25 percent adder included in commitment cost caps. A very insignificant

[103] Tariff Amendment - Aliso Canyon Gas-Electric Coordination Phase 4 (ER18-2520), September 28, 2018: http://www.caiso.com/Documents/Sep28-2018-TariffAmendment-AlisoCanyonGas-ElectricCoordination-Phase4-ER18-2520.pdf

[104] FERC filing - Comments on Aliso Canyon Gas-Electric Coordination Phase 4 (ER18-2520), Department of Market Monitoring, October 19,2018: http://www.caiso.com/Documents/CommentsoftheDepartmentofMarketMonitoirng-Aliso4-Oct192018.pdf

[105] FERC Order on Tariff Revisions - Aliso Canyon Gas-Electric Coordination Phase 4 (ER18-2520), November 26, 2018: http://www.caiso.com/Documents/Nov26-2018-Order-TariffRevisions-AlisoCanyonGas-ElectricCoordinationPhase4-ER18-2520.pdf

[106] *Decision on Commitment costs and default energy bids enhancements proposal,* Department of Market Monitoring board memo, March 2018: http://www.caiso.com/Documents/Decision_CCDEBEProposal-Department_MarketMonitoringMemo-Mar2018.pdf

amount of the same-day traded volume would have exceeded the 25 percent adder included in commitment cost caps.

Figure 3.13 Same-day trade prices compared to next-day index (January – December)

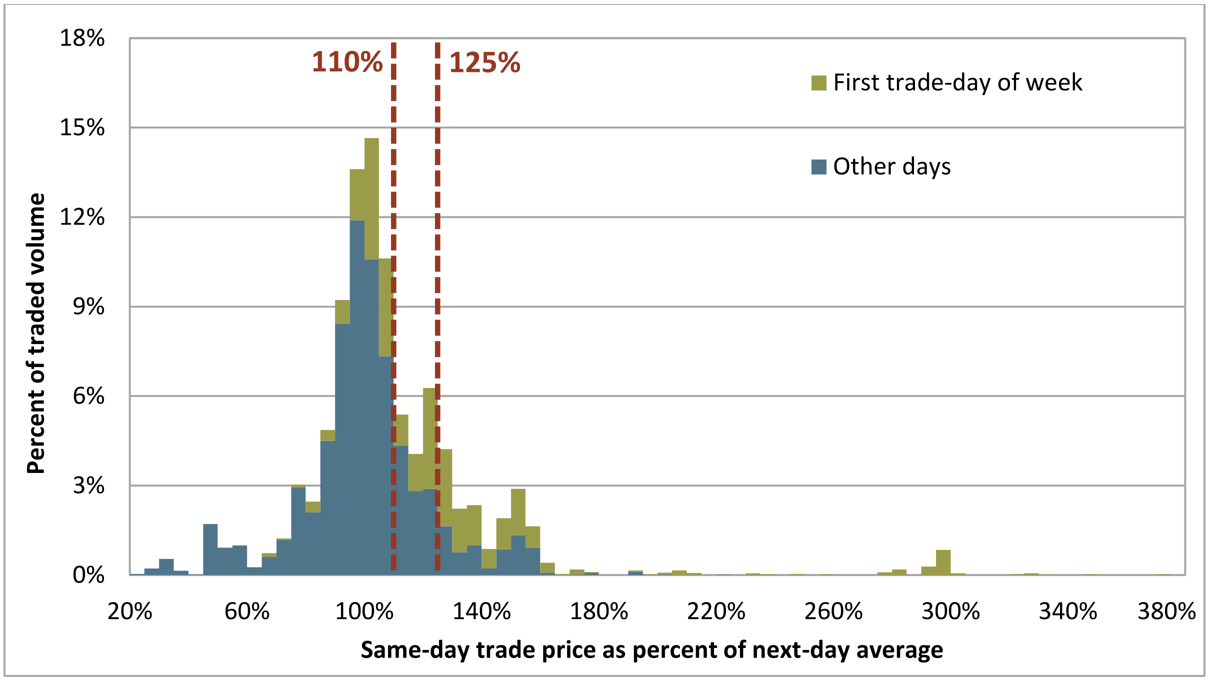
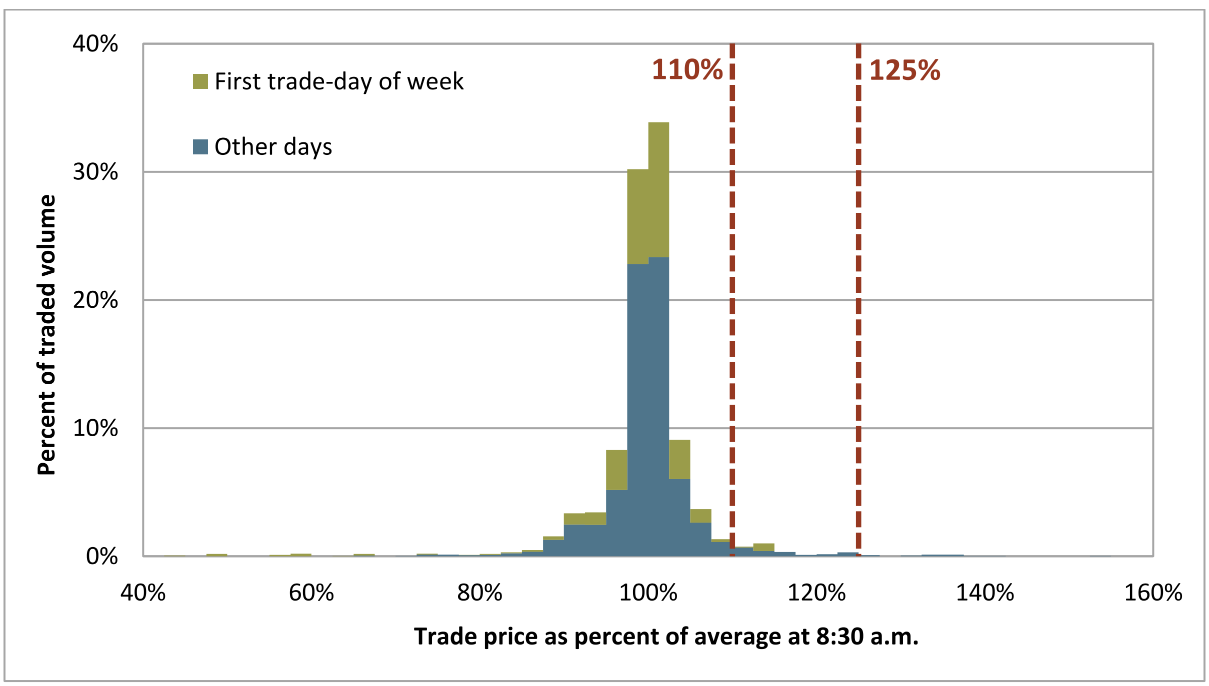


Figure 3.14 Same-day prices as a percent of updated same-day averages (January – December)



The ISO did not include DMM's recommendation to update gas prices used in calculating bid caps for the real-time market in the commitment cost and default energy bid enhancement (CCDEBE) proposal that was approved by the ISO Board in May 2018. However, in 2019 the ISO subsequently included provisions to update bid caps using same-day gas prices as part of the local market power mitigation enhancements initiative. Under this revised proposal*, reasonableness thresholds* used to automatically approve generators' requests to increase bid caps will be updated if the same-day gas price for a fuel region exceeds 10 percent of the next-day index for the same gas flow day.[107]

3.5 Bidding flexibility in real time

As more renewable generation is added to meet California state goals, economic bids provide flexibility that helps the market resolve surplus supply conditions without resorting to curtailment of self-schedules by the market software. Having sufficient economic bids can reduce the likelihood of prices set by penalty parameters, or manual intervention by operators to address over-generation conditions. This section highlights the availability of economic bids, as opposed to self-schedules, in the real-time market.

Figure 3.15 Average hourly self-scheduled generation compared to load (2018)

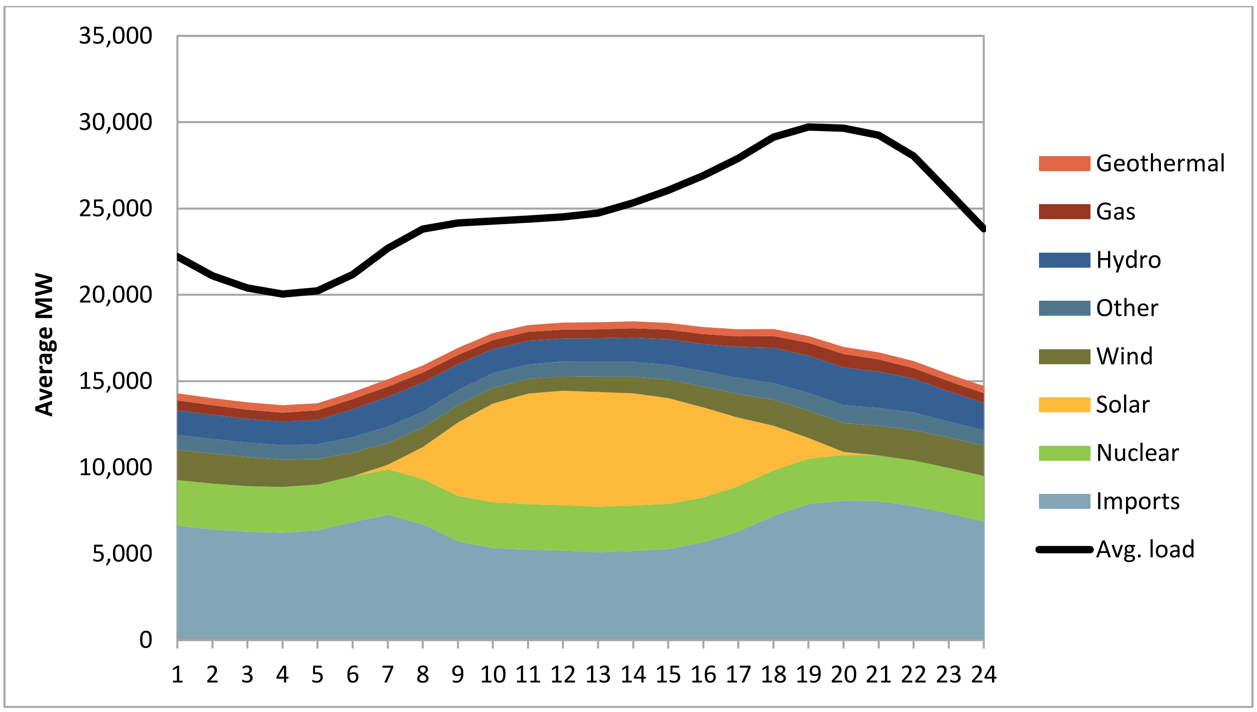


Figure 3.15 compares the average hourly ISO load curve to the average quantity of self-scheduled generation by type. As shown in this figure, self-scheduled generation averaged about 16,400 MW in 2018, a slight decrease from 2017, which equates to about 66 percent of load. As shown in Figure 3.15, imports continue to represent the largest share (39 percent) of self-scheduled generation in the real-

[107] *Draft final proposal, Local Market Power Mitigation Enhancements,* February 1, 2019: http://www.caiso.com/Documents/DraftFinalProposal-LocalMarketPowerMitigationEnhancements-UpdatedJan31_2019.pdf

time market. Most real-time self-scheduled imports come from schedules carried over from the day-ahead market.

In 2018, nuclear and solar generation were the second and third largest sources of self-scheduled generation, accounting for an average of 16 and 15 percent, respectively. Averaged over hours ending 10 through 17, solar generation represented about 32 percent of self-scheduled generation in the real-time market. Hydroelectric generation accounted for an average of about 10 percent of self-schedules, a decrease from last year of about 17 percent. Natural gas and geothermal generation only accounted for about 4 and 2 percent of real-time self-schedules, respectively.

Economic bids in the real-time markets can have either positive or negative offer prices. When negative bids clear the market, these prices signal oversupply conditions and the ISO makes payments to generators to decrease output. Almost all negative bids were submitted by renewable resources including solar, wind, and geothermal in 2018, a trend similar to the last two previous years.[108]

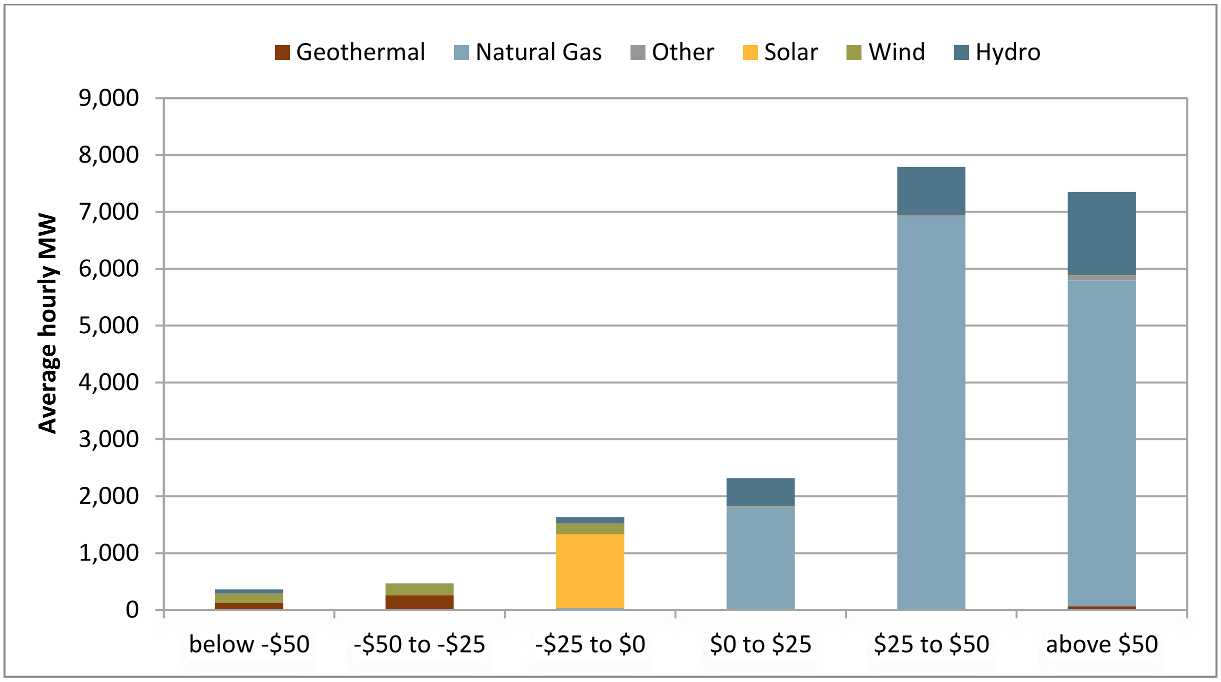
Figure 3.16 shows the range of bids submitted to the 15-minute market by resource type in 2018.[109] Nearly 100 percent of natural gas-fired generation bid in between $0/MWh and $50/MWh, which is consistent with prevailing natural gas and greenhouse gas prices, resource heat rates, and emissions factors. About 94 percent of bids for hydroelectric generation were between $0/MWh and $50/MWh during most hours.[110] Geothermal, solar, and wind generation, on the other hand, primarily bid less than $0/MWh, 84 percent, 100 percent and 99 percent respectively.

[108] These resources receive tax incentives and renewable energy credits that may be foregone when output is curtailed. Thus these credits and tax incentives can create negative marginal costs for renewable resources.

[109] This figure only reflects the incremental amounts for each bid and therefore does not account for the generation associated with the minimum operating levels of resources. Prior year results were based on the 5-minute market and only contained incremental bids for the active configuration thus reducing the total incremental economic bid range.

[110] Hydro resources may have variable bids because of prevailing conditions at specific facilities, such as spring run-off when bids are low or negative and summer months when water is scarce and bids can tend to be higher to conserve water.

Figure 3.16 15-minute market economic bids by bid range and resource type (2018)



Almost all negative bids submitted were for renewable resources. These bids were generally between -$50/MWh and -$10/MWh, which corresponds to the range of tax credits that these resources receive for each megawatt-hour of output. When output from these resources is decreased due to real-time market dispatch, these tax credits represent the opportunity cost of lost production. The highest frequency of negative prices occurred in the first and second quarters in both real-time markets with a dramatic drop in the third and fourth quarters. This seasonal pattern is a result of higher loads absorbing low-cost renewable generation during the summer months.

When the amount of supply on-line exceeds demand, the market dispatches generation down. Generally, generators are dispatched down in merit order from highest bid to lowest. As with typical incremental dispatch, the last unit dispatched sets the system price and dispatch instructions are subject to constraints including transmission, ramping, and minimum generation. During some intervals, wind and solar resources, which generally have very low or negative bids, are dispatched down.

The condition in which these resources are dispatched down is referred to as *oversupply*. If the supply of bids to decrease energy is completely exhausted in the real-time market, the software relaxes the power balance constraint for excess energy up to a point. Past this point, self-scheduled generation can be curtailed including self-scheduled wind and solar generation.

Renewable output can be reduced by economically dispatching renewable generation down or by curtailing self-scheduled renewable generation. Figure 3.17 shows the total quantity of wind and solar in the ISO that was dispatched down economically (green bars) as well as curtailment of self-scheduled wind and solar generation (red bars). The figure also includes the total reduction of wind and solar as a percent of total 5-minute market wind and solar forecasts (yellow line on right axis).

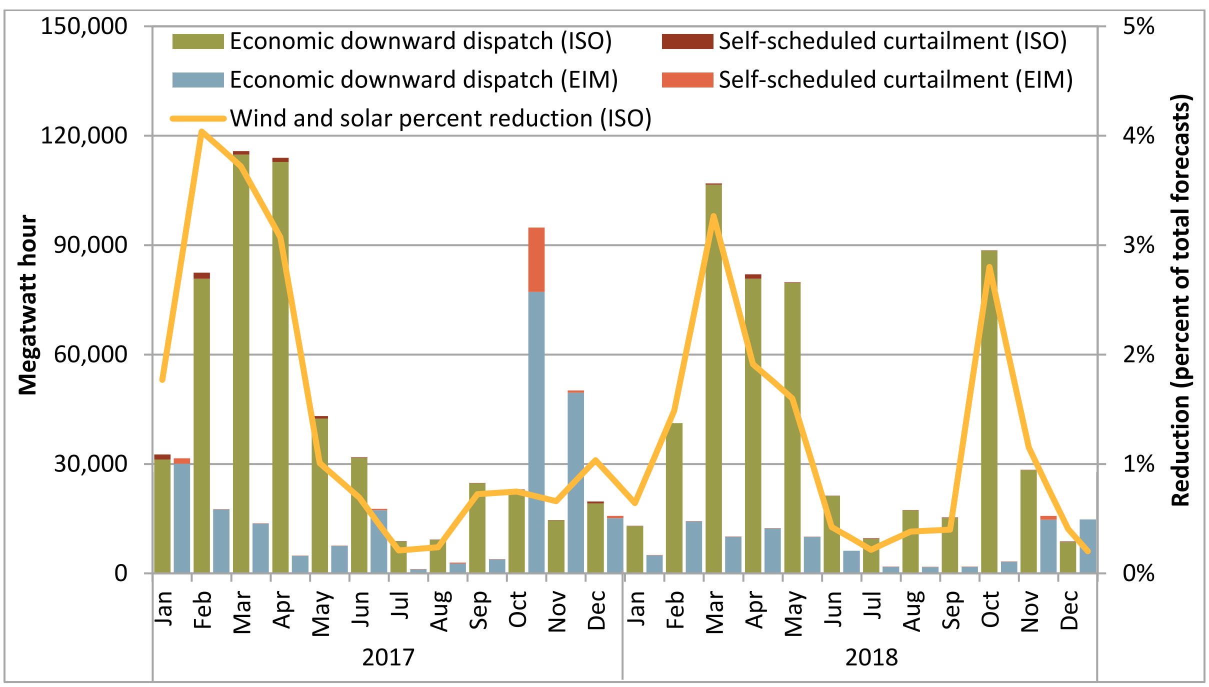
Figure 3.17 shows that nearly all of the reduction in wind and solar output during 2018 was the result of economic downward dispatches rather than self-scheduled curtailments. The majority of renewable generation in the ISO dispatched down were solar resources, rather than wind resources, primarily because market participants bid more economic downward capacity for these resources. The total quantity of wind and solar generation dispatched down in the ISO remained about the same compared to 2017.

In 2018, economic downward dispatch was lower in the spring, though higher in the month of October, compared to the previous year. The relatively high level of economic downward dispatch in October was likely related to congestion on a particular constraint that isolated generation from the rest of the ISO system. The total reduction as a percent of total forecasts decreased slightly from 1.34 percent in 2017 to 1.19 percent in 2018.

Figure 3.17 also shows the amount of economic downward dispatch to energy imbalance market wind and solar resources. Compared to 2017, the quantity of downward dispatches for wind and solar resources in the energy imbalance market decreased significantly compared to the previous year.

The frequency of prices near or below the -$150/MWh floor continued to occur infrequently at about 0.1 percent of 5-minute intervals. This indicates a low frequency of intervals when the supply of bids to decrease energy were exhausted leading to potential self-scheduled generation curtailment.

Figure 3.17 Reduction of wind and solar generation by month



When the market dispatches a wind or solar resource below its forecasted value, scheduling coordinators receive a downward dispatch instruction indicating a need to adjust the resource's output. Figure 3.18 and Figure 3.19 show monthly solar and wind compliance with economic downward dispatch instructions during 2018.[111] The blue bars represent the quantity of renewable generation that

[111] This analysis includes variable energy resources in the ISO balancing area only.

complied with economic downward dispatch. The green bars represent the quantity that did not comply with these dispatch instructions. The gold line represents the rate of compliance.

For solar resources, the quantity and performance of complied economic downward dispatch increased in 2018 compared to the previous year. Solar resource performance was roughly 89 percent compliant, compared to 82 percent compliant in 2017. Performance dipped slightly in July and December, when the quantity of downward dispatch instruction was lower.

Wind performance improved significantly compared to the previous year, complying with roughly 78 percent of megawatt hours of downward dispatch instructions, compared to roughly 45 percent complied during 2017. Under ISO market rules, all market participants and resources are expected to follow ISO dispatch instructions.

Figure 3.18 Compliance with ISO dispatch instructions – solar generation

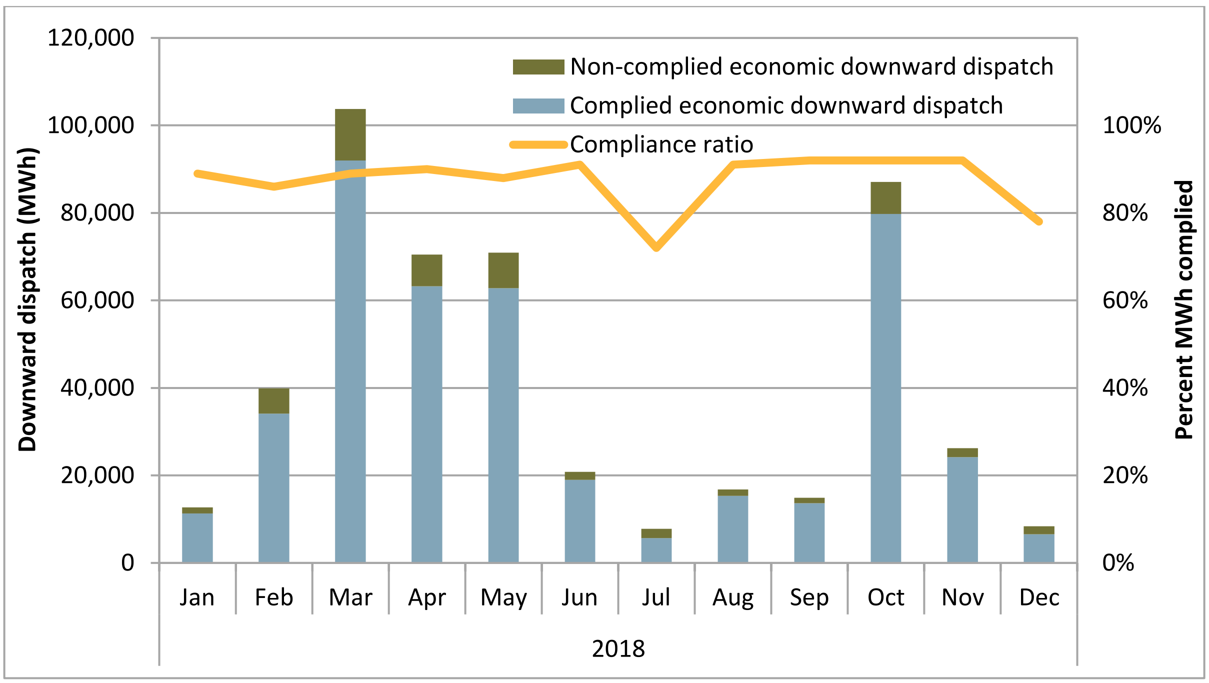
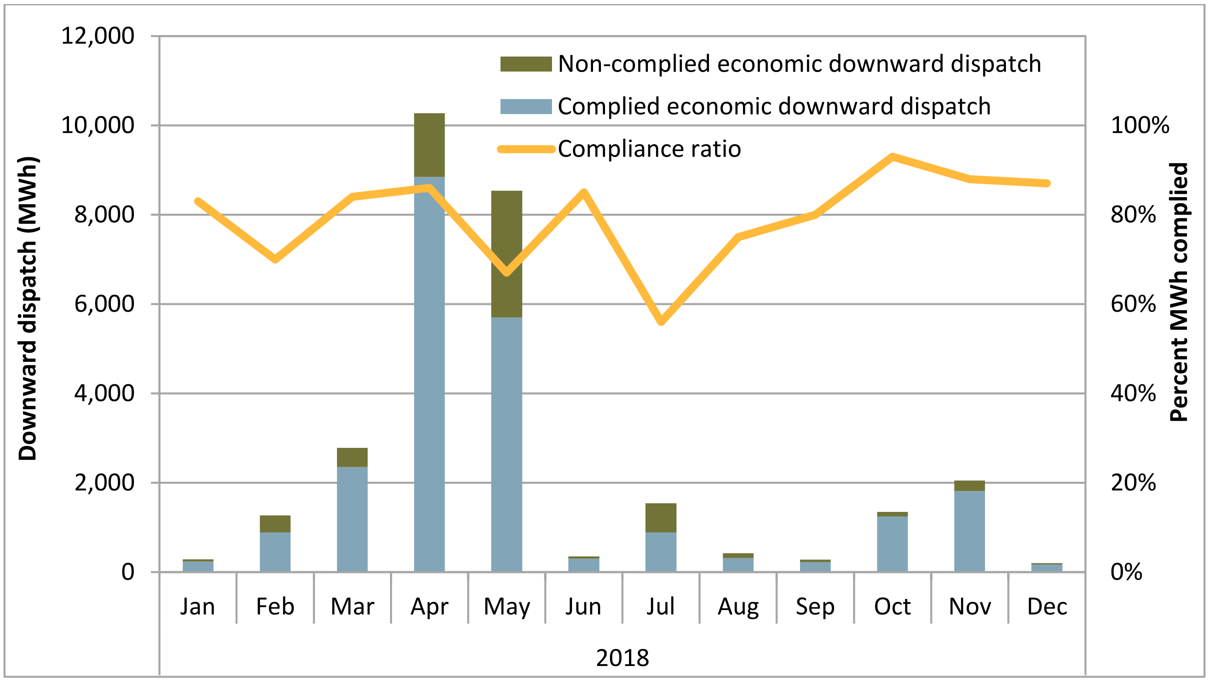


Figure 3.19 Compliance with ISO dispatch instructions – wind generation



4 Energy imbalance market

The energy imbalance market allows balancing authority areas outside of the ISO balancing area to participate in the ISO real-time market. This chapter provides a summary of energy imbalance market performance during 2018. Key elements highlighted in this chapter include the following:

- The energy imbalance market continued to perform well and grow by addition of new participants in 2018. The growth of the energy imbalance market since 2015 and increase in available transmission has increased the economic transfers between balancing areas. Prices and transfers of energy in the energy imbalance market are now marked by distinct daily and seasonable patterns which reflect differences in regional supply conditions and transfer limitations.
- Average prices tend to be somewhat lower in the energy imbalance market balancing areas compared to the ISO. These price differences are driven by a combination of transmission transfer limitations and greenhouse gas emissions costs in California. Prices also reflect a distinct geographic pattern, with higher average prices in the southern areas and lower prices in the northern areas.
- During periods of relatively low net loads and high solar production, the ISO tends to transfer energy out to other balancing areas in the energy imbalance market. During the morning and evening ramping hours, the ISO tends to transfer energy in from other balancing areas. By allowing the ISO to transfer energy out during periods of relatively low net loads and high solar production, the energy imbalance market has also helped to reduce the need to curtail solar production in some intervals.
- Similarly, prices and transfers between other areas in the energy imbalance market reflect how the market allows entities in the other areas to "buy low and sell high" during different hours and seasons based on supply conditions in each area relative to the rest of the market.
- Idaho Power entered the energy imbalance market in April 2018. This added significant transfer capability linking together different EIM balancing areas in the Northwest, which includes PacifiCorp West, PacifiCorp East, Puget Sound Energy, and Portland General Electric. This new transmission combined with new direct transfer capability from PacifiCorp West to PacifiCorp East allows transfers of power between the ISO and other balancing areas in the energy imbalance market in both a clockwise and counterclockwise direction.
- Powerex also became a participant in the energy imbalance market in April 2018. This added additional transfer capability from the Northwest region to the ISO. However, prices in Powerex are still often lower than prices in the ISO and the other balancing areas because of limited transmission from Powerex to the ISO.
- Bid cost recovery payments in the energy imbalance market totaled only about $12 million. The cost of these payments is allocated back to the energy imbalance market balancing area in which the units receiving these payments is located.
- In November, the ISO implemented a revised energy imbalance market greenhouse gas bid design, addressing concerns that the previous design did not capture the full impact of energy imbalance market imports into California on global greenhouse gas emissions for compliance with California's cap-and-trade regulation. Following implementation of these changes, which limited greenhouse

gas bid capacity to the differences between base schedule and energy dispatch, the weighted average greenhouse gas cost increased as the deemed delivered resources shifted from lower to higher greenhouse gas emissions.

4.1 Background

The energy imbalance market allows balancing authority areas outside of the ISO balancing area to voluntarily take part in the ISO real-time market. The energy imbalance market was designed to provide benefits from increased regional integration by enhancing the efficiency of dispatch instructions, reduced renewable curtailment and reduced total requirements for flexible reserves. The energy imbalance market became financially binding with PacifiCorp becoming the first participant on November 1, 2014.

The ISO's 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 can allow the energy imbalance market to increase market efficiency in two ways. First, the market software can re-optimize dispatches and manage congestion within each energy imbalance market area. Second, the market software can allow economic transfers in real-time from lower cost balancing areas to higher cost balancing areas participating in the market.

These changes in scheduled flows between balancing areas in the real-time market are referred to as *energy transfers* between energy imbalance market balancing areas. The ability to transfer energy between balancing areas in real time also helps to reduce the degree to which low cost renewables or hydro energy may need to be curtailed in one balancing area during times of excess generation.

In 2015, with just PacifiCorp in the energy imbalance market, there was little transfer capability between the two areas and the ISO. This limited the benefits of this market. However, when NV Energy was integrated into the market in December 2015, this added a significant amount of transfer capability with the ISO and PacifiCorp East. As a result, energy transferred in the real-time markets increased between the ISO and the energy imbalance market areas.

Puget Sound Energy and Arizona Public Service joined the energy imbalance market in October 2016, further increasing the total amount of transfer capability available between different balancing areas. In October 2017, Portland General Electric joined the energy imbalance market, with additional transfer capability in the Northwest. In April 2018, two new market participants, Powerex and Idaho Power, joined the energy imbalance market.

As highlighted in this chapter, the growth of the energy imbalance market since 2015 and increase in available transmission has increased the economic transfers between balancing areas. Prices and transfers in the energy imbalance market are now marked by distinct daily and seasonable patterns which reflect differences in regional supply conditions and transfer limitations.

4.2 Energy imbalance market total wholesale market costs

The total estimated wholesale cost of serving load in the energy imbalance market in 2018 was about $66 million or $0.29/MWh. This calculation includes the cost of services provided through the EIM to load in participating balancing authority areas on a per megawatt-hour of total load basis.[112] Additional

[112] Further detail on the calculation is available in Section 2.1

balancing areas are added to the calculation as they enter the market, so wholesale market costs are not directly comparable between years.

Figure 4.1 shows total estimated wholesale costs per megawatt-hour of EIM load from 2016 to 2018. Costs are provided in nominal terms, stacked by cost category. The real-time energy costs contribute the largest portion of the costs, while imbalance offset costs typically reduce costs overall.

Figure 4.1 Total EIM annual wholesale costs per MWh of load (2016-2018)

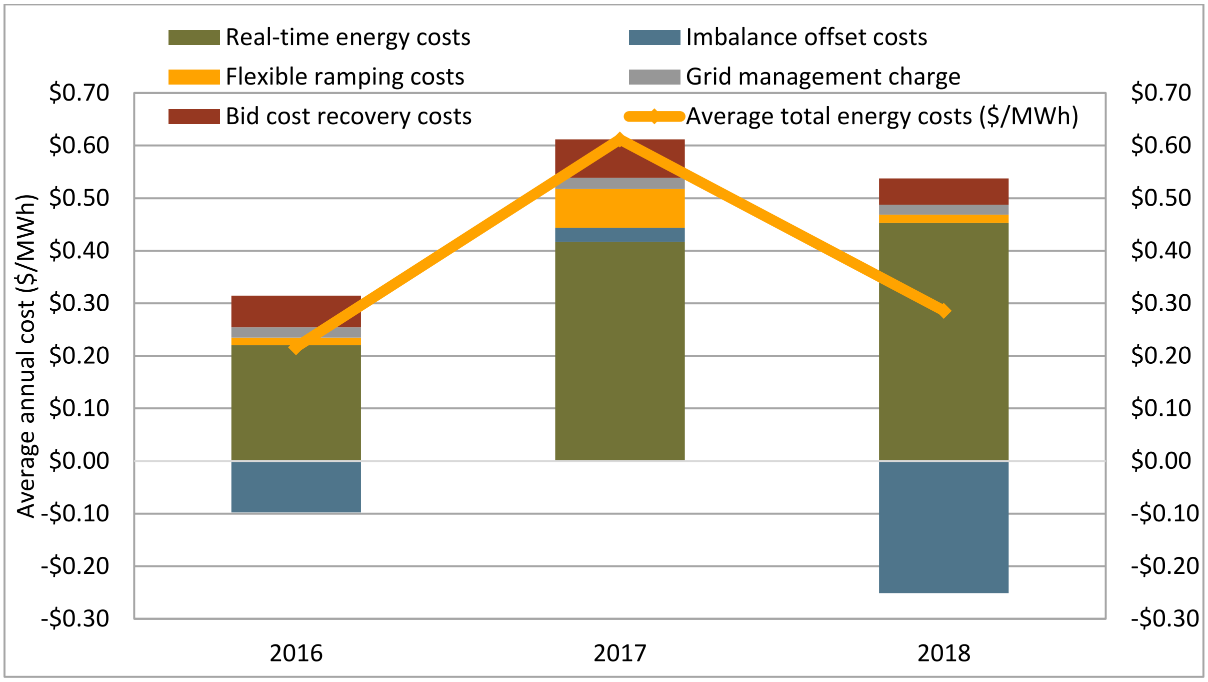


Table 4.1 provides annual summaries of the nominal total wholesale costs by category from 2016 through 2018. These costs include costs associated with real-time energy, imbalance offset, flexible ramping, bid cost recovery, and grid management. As shown in Table 4.1, each year the cost breakdown per megawatt-hour changes based on when new entities join the market; the megawatt volumes and cost components change accordingly.

Table 4.1 Estimated average EIM wholesale energy costs per MWh (2016-2018)

	2016	2017	2018	Change '17-'8
Real-time energy costs	$ 0.22	$ 0.42	$ 0.45	$ 0.04
Imbalance offset costs	$ (0.10)	$ 0.03	$ (0.25)	$ (0.28)
Flexible ramping costs	$ 0.01	$ 0.07	$ 0.02	$ (0.06)
Grid management charge	$ 0.02	$ 0.02	$ 0.02	$ (0.00)
Bid cost recovery costs	$ 0.06	$ 0.07	$ 0.05	$ (0.02)
Average total energy costs ($/MWh)	**$ 0.22**	**$ 0.61**	**$ 0.29**	**$ (0.33)**

4.3 Energy imbalance market prices

Figure 4.2 through Figure 4.5 show average hourly real-time prices for the energy imbalance market balancing areas during 2018. In these figures several balancing areas are grouped together because of similar average hourly pricing. Figure 4.2 and Figure 4.3 show hourly averages between January 1 and April 4 while Figure 4.4 and Figure 4.5 show hourly averages between April 4 and December 31 to distinguish when Powerex and Idaho Power entered the energy imbalance market. The figures also show prices for the southernmost area in the ISO (Southern California Edison) and the northernmost area (Pacific Gas and Electric) for comparison with energy imbalance market areas.

As shown in the figures below, average hourly prices tend to be somewhat lower in the energy imbalance market balancing areas compared to areas in the ISO. These price differences are driven by a combination of transmission transfer limitations and greenhouse gas emissions costs in California.[113] Prices also reflect a distinct geographic pattern, with higher average prices in the southern areas and lower prices in the northern areas.

Average prices for NV Energy and Arizona Public Service were often similar to each other and track closely with prices for the southern portion of the ISO (e.g., Southern California Edison) because of large transfer capacities and little congestion between these three balancing areas. Prices for the Southern California Edison area are somewhat higher than for NV Energy and Arizona Public Service primarily due to the impact of greenhouse gas emissions costs in California.

Prices for PacifiCorp East and Idaho Power tracked closely with ISO system prices during most hours except hours 19 through 22 when prices were significantly lower. This price separation was primarily due to several days with high system prices when energy imbalance market transfers out of PacifiCorp East and Idaho Power reached their upper scheduling limits – driving down prices in these areas compared to the ISO. In other hours one or more of these areas failed the sufficiency test which limited transfers and created price separation between the balancing areas.

Prices in the energy imbalance area in the Northwest (PacifiCorp East, Puget Sound Energy, Portland General Electric and Powerex) tend to be lower than prices in the ISO and other balancing areas because of limited transmission from this region to the ISO and the rest of the energy imbalance market area.

[113] See Section 4.7 for further information on greenhouse gas in the energy imbalance market.

Figure 4.2 Hourly 15-minute market prices (January 1 – April 4, 2018)

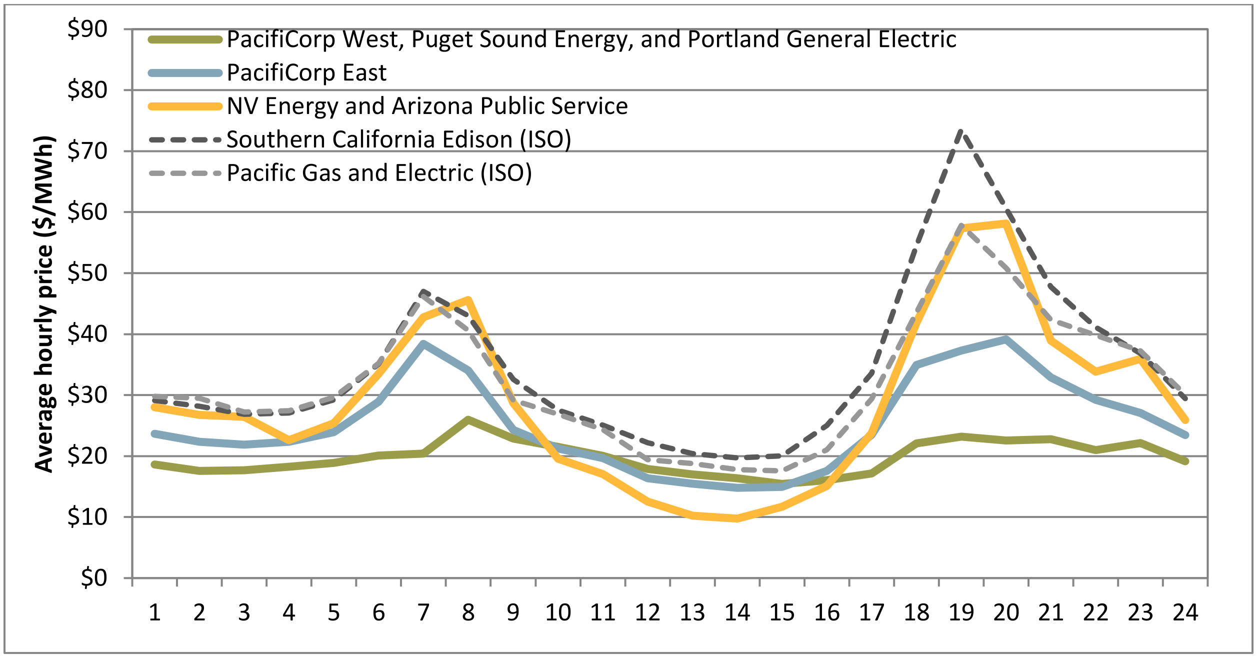


Figure 4.3 Hourly 5-minute market prices (January 1 – April 4, 2018)

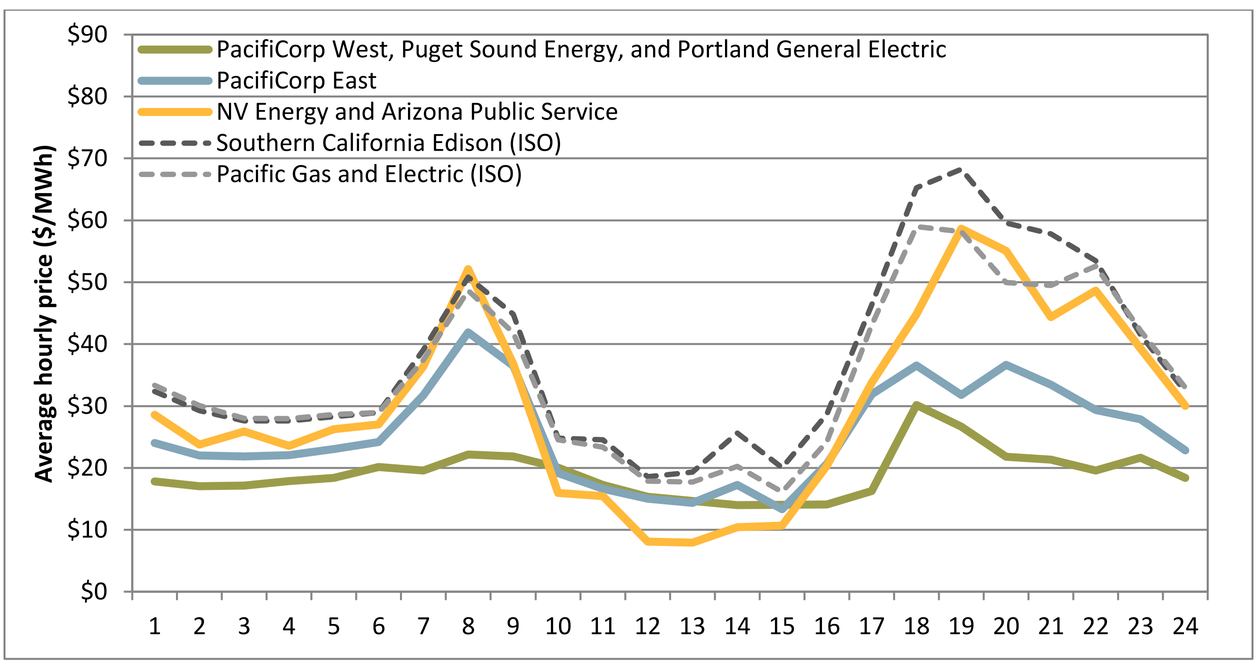


Figure 4.4 Hourly 15-minute market prices (April 4-December 31, 2018)

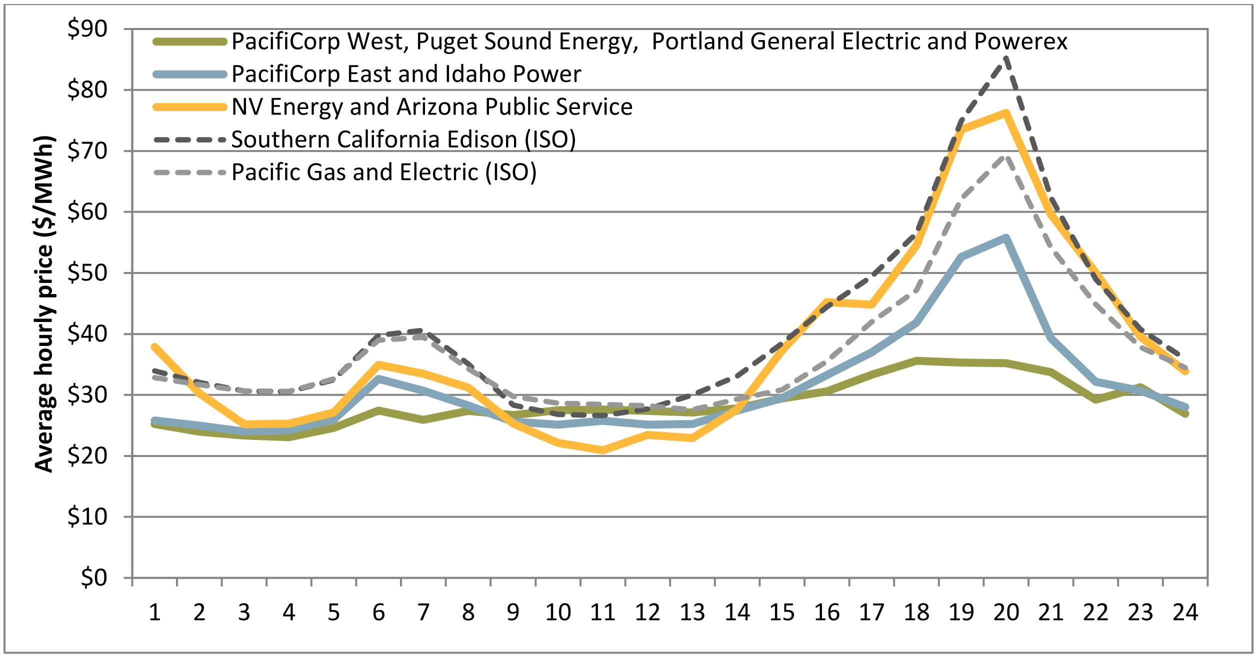
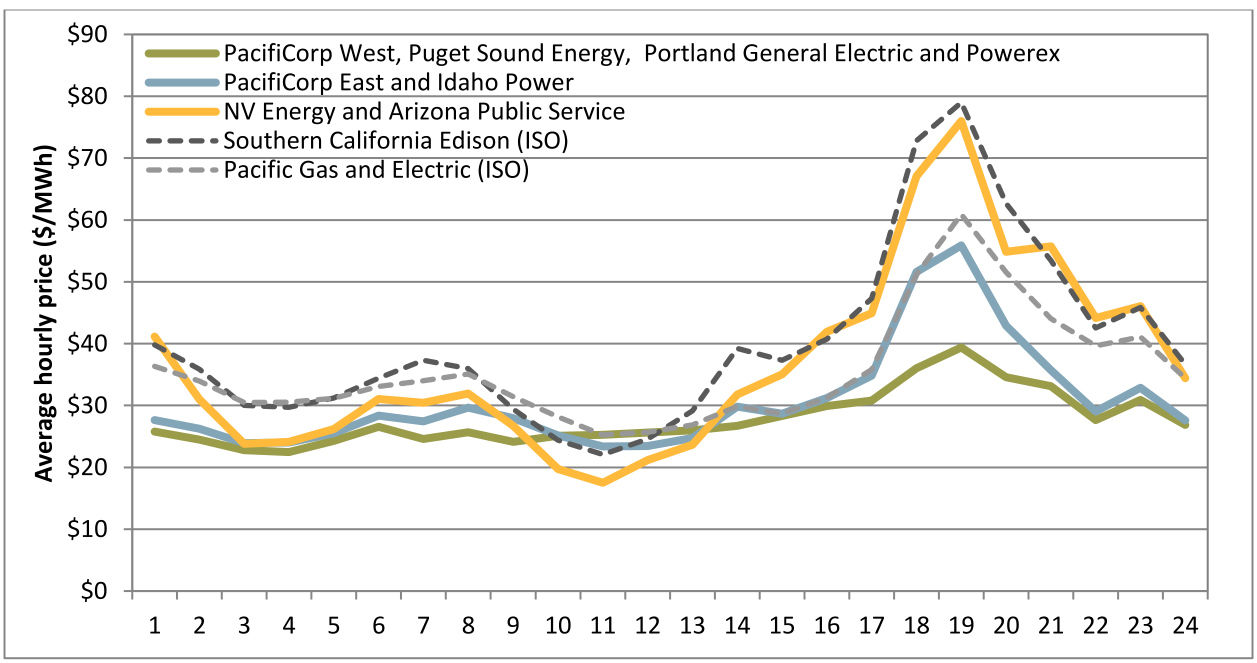


Figure 4.5 Hourly 5-minute market prices (April 4-December 31, 2018)



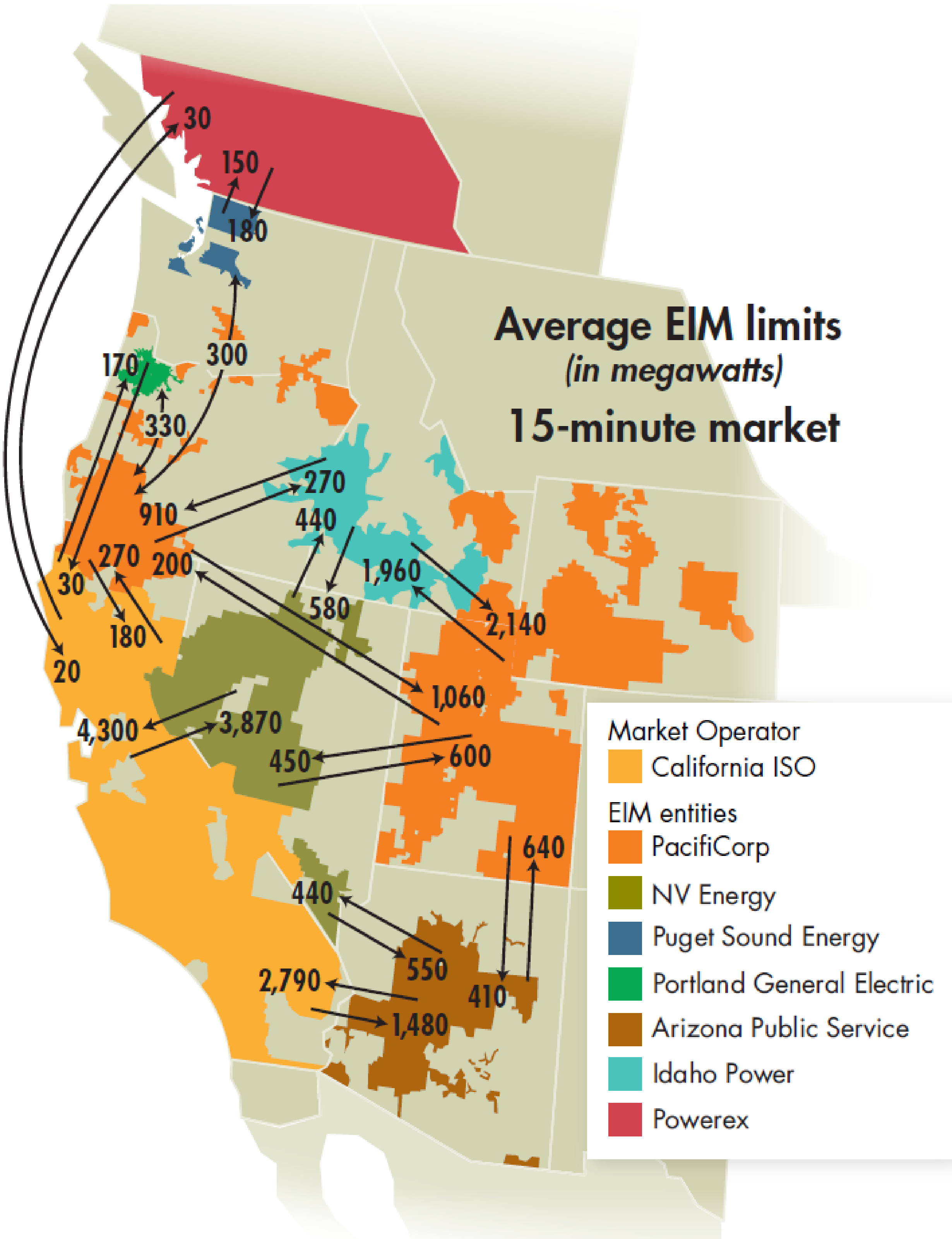
4.4 Energy imbalance market transfers

Energy imbalance market transfer limits

Figure 4.6 shows average 15-minute market limits between each of the energy imbalance market areas in 2018 after the addition of Idaho Power and Powerex (April 4 to December 31, 2018). The map shows that there was significant transfer capability between the ISO, NV Energy and Arizona Public Service. Transfer capability between these areas, PacifiCorp East and Idaho Power was also relatively large. The availability of this transmission capacity allowed energy to flow between these areas with relatively little congestion.

Transfer capability was more limited between the ISO and Northwest areas which includes PacifiCorp West, Puget Sound Energy, Portland General Electric and Powerex. This resulted in more transmission congestion between these areas and the ISO. The 15-minute market transfer limits from each of Portland General Electric and Powerex toward the ISO was particularly limited, averaging less than 30 MW in 2018.

Figure 4.6 Average 15-minute market energy imbalance market limits (April 4 – June 30, 2018)

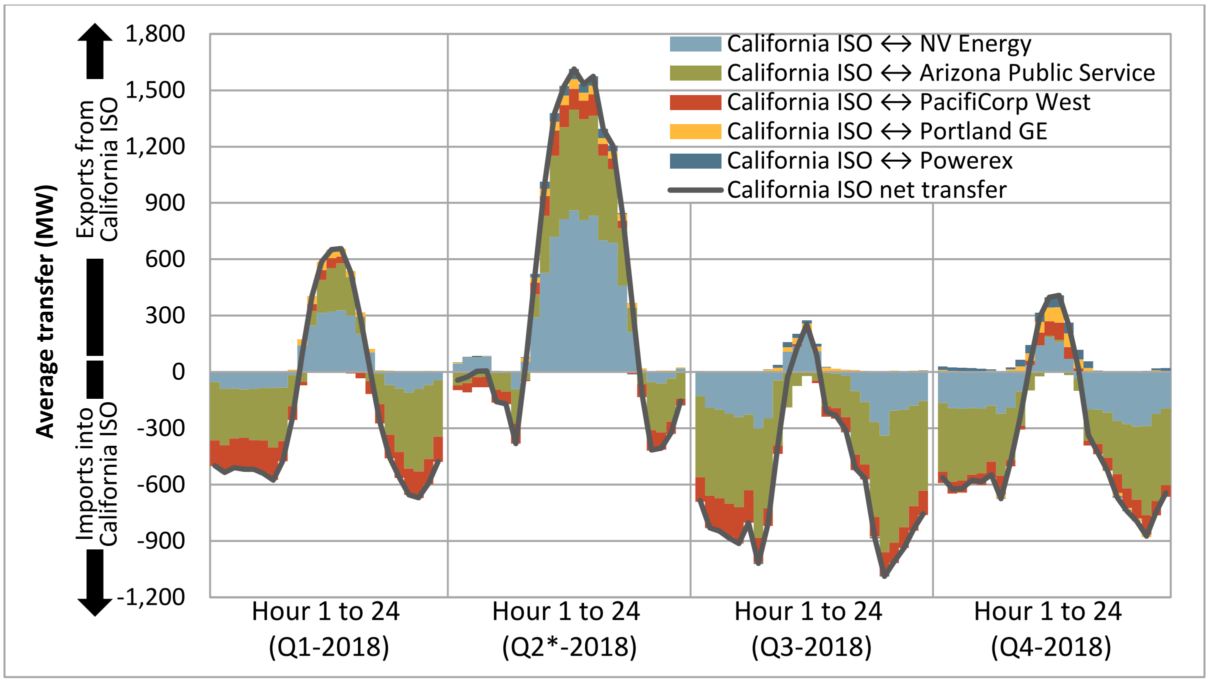


Hourly energy imbalance market transfers

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

Figure 4.7 shows average hourly imports (negative values) and exports (positive values) between the ISO and other energy imbalance market areas during each quarter in the 15-minute market. The bars show the average hourly transfers with the connecting areas. The gray line shows the average hourly net transfer. Similar to the previous year, net exports were highest during the second quarter, particularly during midday hours as a result of high solar and mild load conditions. During the third and fourth quarters, the pattern shifted significantly with the ISO importing during most hours.

Figure 4.7 California ISO - average hourly 15-minute market transfer



*April 4 to June 30, 2018

Figure 4.8 through Figure 4.12 show the same information on imports and exports for NV Energy, Arizona Public Service, Idaho Power, PacifiCorp West, and Powerex in the 15-minute market.[114] The amounts included in these figures are net of all base schedules and therefore reflect dynamic market flows between EIM entities.[115]

As shown in Figure 4.7, a large portion of the ISO's transfer capability in the energy imbalance market is with NV Energy and Arizona Public Service. Per Figure 4.8 and Figure 4.9, NV Energy and Arizona Public Service were generally net importers during periods when ISO load net of solar generation was lowest

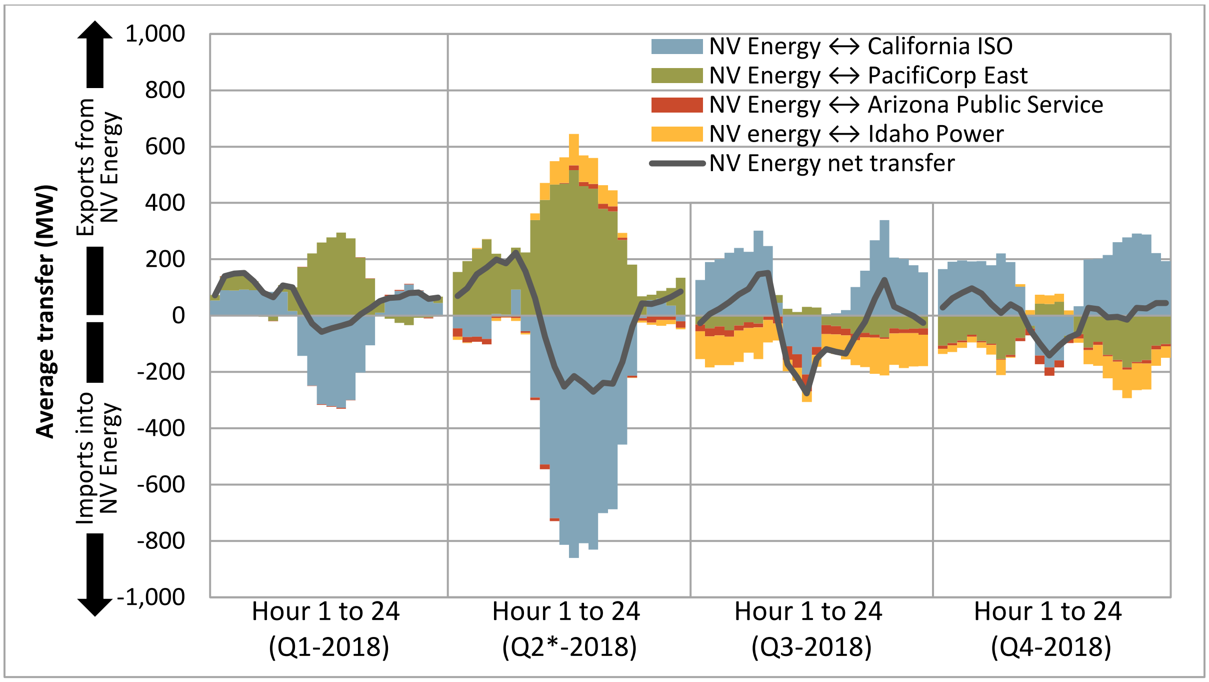
[114] Figures showing transfer information from the perspective of PacifiCorp East, Puget Sound Energy and Portland General Electric are not explicitly included, but are represented in Figure 4.6 through Figure 4.10.

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

and net exporters during other periods. During the third and fourth quarters, Arizona Public service imported from PacifiCorp East and exported to the ISO during almost all hours on average.

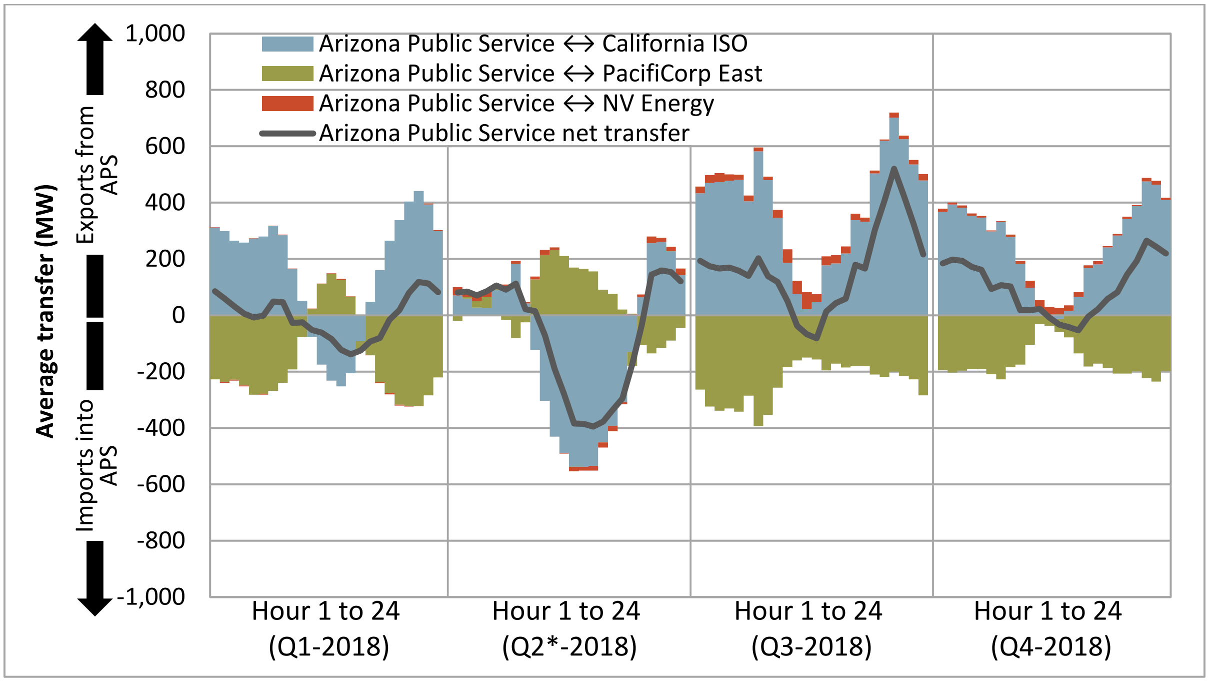
Figure 4.10 shows the hourly 15-minute market transfer pattern between Idaho Power and neighboring areas, net of all base schedules. Idaho Power has transfer capacity between PacifiCorp West, PacifiCorp East, and NV Energy. On average since joining the energy imbalance market, Idaho Power base scheduled roughly 1,100 MW in imports from PacifiCorp East and 700 MW in exports to PacifiCorp West. However, as shown in Figure 4.10, dynamic transfers were significantly lower in all hours during the year.

Figure 4.8 NV Energy – average hourly 15-minute market transfer



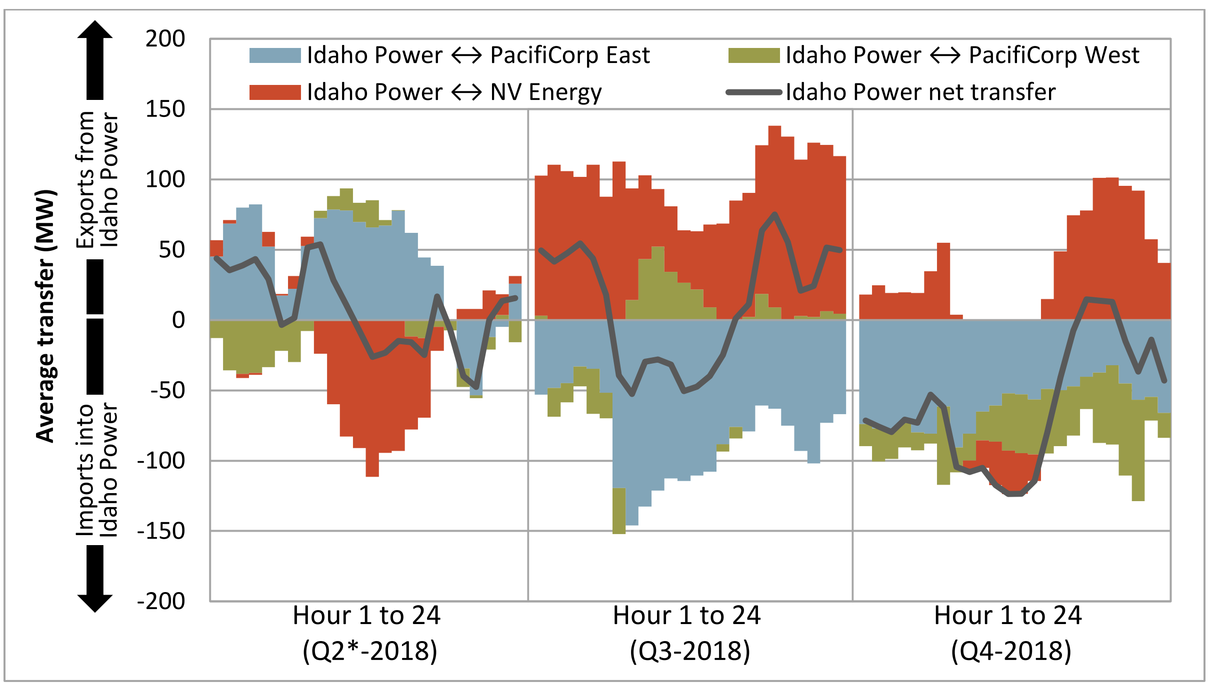
*April 4 to June 30, 2018

Figure 4.9 Arizona Public Service – average hourly 15-minute market transfer



*April 4 to June 30, 2018

Figure 4.10 Idaho Power – average hourly 15-minute market transfer



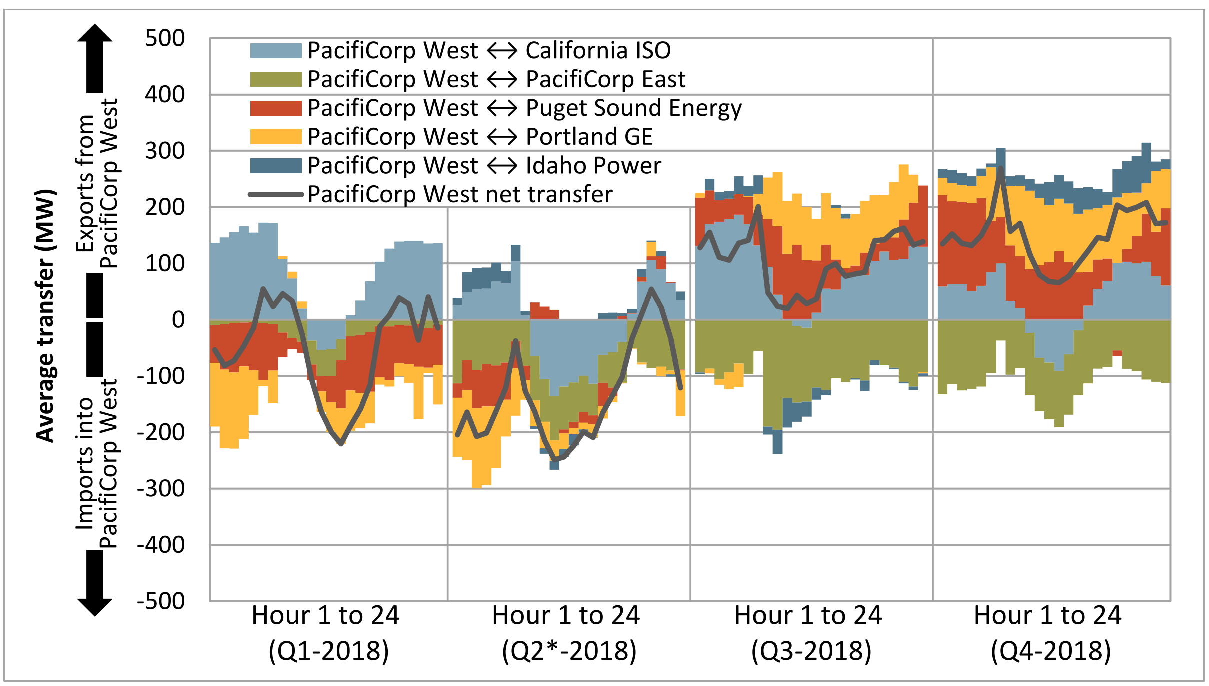
*April 4 to June 30, 2018

Figure 4.11 shows the hourly 15-minute market transfer pattern between PacifiCorp West and neighboring areas during the year. PacifiCorp West has transfer capacity between the ISO, PacifiCorp East, Puget Sound Energy, Portland General Electric, and Idaho Power. Since the second quarter, most of the transfers with Idaho Power and PacifiCorp East were base scheduled in the market, so therefore fixed. PacifiCorp West base scheduled almost 1,100 MW in exports to PacifiCorp East on average during this period. However, net of all base schedules, PacifiCorp West imported around 100 MW on average from PacifiCorp East.

Figure 4.12 shows average hourly 15-minute market imports and exports into and out of Powerex during 2018. Since joining the energy imbalance market, import and export transmission capacity from Powerex to the ISO were limited to 34 MW or less during the majority of 15-minute intervals. However, transfer limits between Powerex and the ISO were much higher in both import and export directions in the 5-minute market. Between April 4 and the end of the year, Powerex import and export transfer limits with the ISO averaged about 100 MW higher in the 5-minute market than in the 15-minute market.

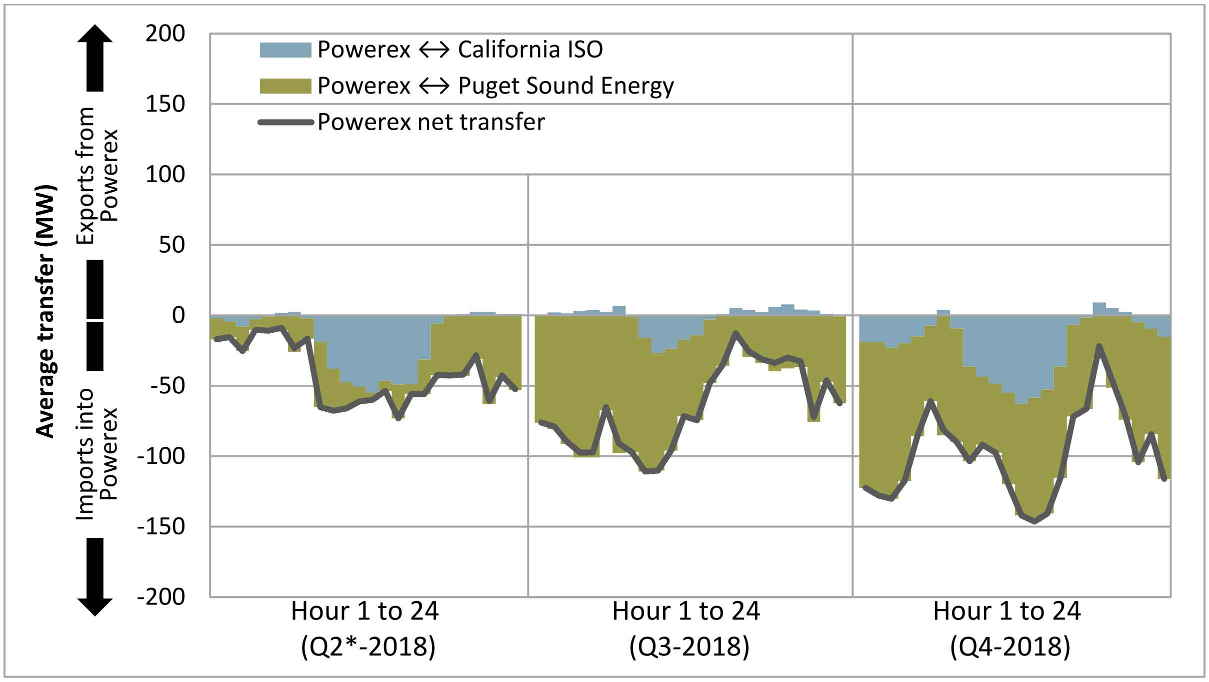
Similarly, export transmission capacity from Portland General Electric to the ISO during 2018 was limited to zero MW during around 79 percent of 15-minute market intervals and 86 percent of 5-minute market intervals during 2018. Export transfer limits from Portland General Electric to PacifiCorp West were much more substantial, averaging around 330 MW during the year.

Figure 4.11 PacifiCorp West – average hourly 15-minute market transfer



*April 4 to June 30, 2018

Figure 4.12 Powerex – average hourly 15-minute market transfer



*April 4 to June 30, 2018

Inter-balancing area congestion

Congestion between an energy imbalance market area and the ISO causes price separation.

Table 4.2 shows the percent of 15-minute and 5-minute market intervals when there was congestion on the transfer constraints into or out of an energy imbalance market area, relative to prevailing system prices in the ISO.[116]

During intervals when there is net import congestion into an energy imbalance market area, the ISO market software triggers local market power mitigation in that area.[117] Table 4.2 includes the frequency in which transfer limits bound from the ISO into the other balancing areas. For example, the highest frequency of such congestion was from the ISO into the Powerex area, during 30 percent of 15-minute market intervals since Powerex joined the Energy Imbalance Market in April 2018.

116 Greenhouse gas prices can contribute to lower energy imbalance market prices relative to those inside the ISO. The current methodology uses prevailing greenhouse gas prices in each interval to account for and omit price separation that is the result of greenhouse gas prices only.

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

Table 4.2 Frequency of congestion in the energy imbalance markets (2018)

	15-minute market		5-minute market	
	Congested toward ISO	Congested from ISO	Congested toward ISO	Congested from ISO
NV Energy	3%	3%	3%	2%
Arizona Public Service	3%	3%	2%	3%
PacifiCorp East	10%	2%	8%	3%
Idaho Power*	6%	5%	3%	6%
PacifiCorp West	39%	3%	31%	6%
Portland General Electric	39%	4%	32%	7%
Puget Sound Energy	39%	7%	32%	9%
Powerex*	31%	30%	16%	24%

*April 4 to December 31, 2018 only

As shown in the table, the highest frequency of congestion in the energy imbalance market continued to be from the Northwest areas in the direction toward the ISO. Congestion in the 15-minute market in the direction toward the ISO occurred during 31 percent of intervals from Powerex and 39 percent of intervals from PacifiCorp West, Portland General Electric and Puget Sound Energy. This led to lower prices in 2018 in these areas relative to the rest of the energy imbalance market and the ISO.

However, the Northwest region was less frequently congested in comparison to the previous year when congestion toward the ISO from these areas occurred in around 50 percent of intervals. The difference was mostly due to added west-to-east transfer capability in the second quarter both with the joining of Idaho Power as well as the addition of new direct transfer capability from PacifiCorp West to PacifiCorp East. Previously, transfer capability between PacifiCorp West (and Northwest areas) and PacifiCorp East (and the rest of the system) was only one-directional, from East to West.

Table 4.2 also shows that congestion in either direction between NV Energy, Arizona Public Service, or the ISO area was infrequent during the year. Congestion that did occur between these areas was often the result of a failed upward or downward sufficiency test, which limited transfer capability. In comparison, the frequency of congestion to and from the PacifiCorp East and Idaho Power areas was slightly higher, particularly in the direction towards the ISO, but remained relatively low overall. This congestion primarily occurred when less expensive generation in these areas was constrained going into NV Energy and Arizona Public Service.

4.5 Flexible ramping sufficiency test

The flexible ramping sufficiency tests 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, including the ISO 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.

If an area fails the upward sufficiency test, energy imbalance market transfers into that area cannot be increased.[118] Similarly, if an area fails the downward sufficiency test, transfers out of that area cannot be increased.

An area will also fail the flexible ramping sufficiency test for any hour when the capacity test fails for the specific direction. The capacity test is a test designed to ensure that there is sufficient incremental or decremental economic energy bids above or below the base schedules to meet the demand forecast.[119] Overall, energy imbalance market areas failed the capacity test infrequently during 2018 with the exception of NV Energy which failed the upward capacity test during 0.6 percent of hours, or around 15 percent of upward sufficiency test failures.

Figure 4.13 shows the quarterly frequency in which an energy imbalance market area failed the sufficiency test in the upward direction. Most notably, NV Energy and Arizona Public Service each failed the sufficiency test in the upward during almost 4 percent of hours in 2018. Idaho Power also failed the upward sufficiency test frequently in the first few months after joining the energy imbalance market in April, but otherwise failed the test infrequently during the remaining months of the year.

Figure 4.14 provides the same information on failed sufficiency tests for the downward direction. Most notably, Arizona Public Service failed the downward sufficiency test significantly less frequently during 2018, during less than 2 percent of hours. In comparison, Arizona Public Service failed this test during over 26 percent of hours in the first quarter of 2017. Also, NV Energy failed the downward sufficiency test more frequently in 2018, during around 5 percent of hours, compared to 3 percent of hours from the previous year.

The flexible ramping sufficiency test is also applicable to the California ISO area. During 2018, the ISO did not fail any upward or downward flexible ramping sufficiency test.

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

The ISO implemented multiple enhancements to the flexible ramping sufficiency test during 2019. First, a tolerance threshold was implemented effective February 15, 2019 that allows an energy imbalance market entity to pass the test if the insufficiency is less than either of 1 MW or 1 percent of the requirement.[120] A second enhancement, expected in early May 2019, will evaluate sufficiency test results and limit transfers on a 15-minute interval basis rather than for the entire hour.

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

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

120 Market Notice - EIM Resource Sufficiency Enhancements 1% Threshold Implementation, February 8, 2019: http://www.caiso.com/Documents/EIMResourceSufficiencyEnhancements-1-ThresholdImplementation-021519-Active-MAPStage.html

Figure 4.13 Frequency of upward failed sufficiency tests by quarter

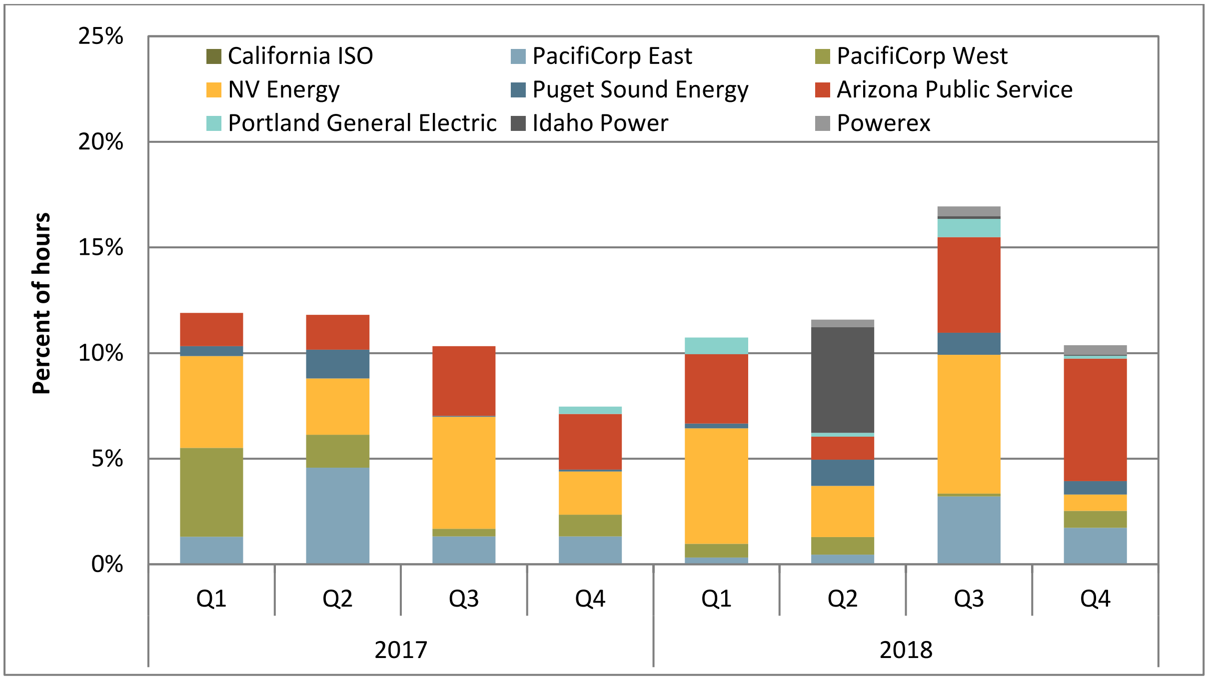
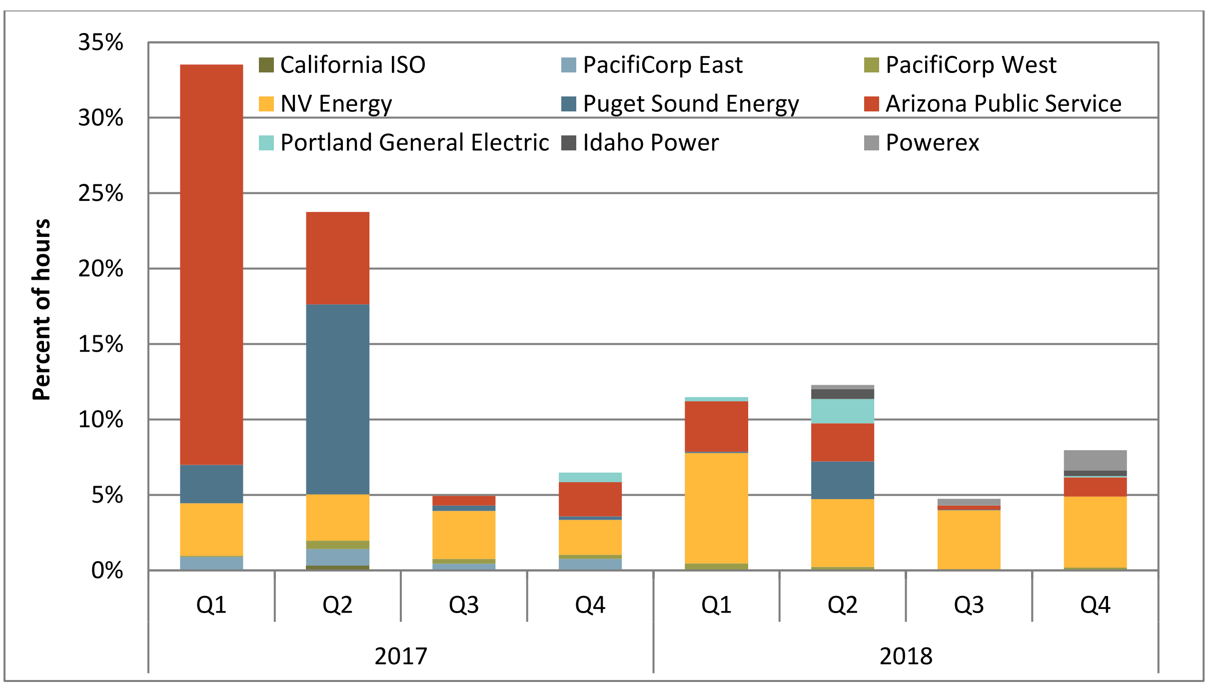


Figure 4.14 Frequency of downward failed sufficiency tests by quarter



4.6 Energy imbalance market power balance constraint relaxations

Energy imbalance market power balance constraints have several unique features. First, because the energy imbalance market does not include ancillary services and therefore excludes co-optimization of regulation, the power balance is not relaxed up to the seasonal regulation requirement. Second, the penalty parameter for shortages in the scheduling run is set at $1,450/MWh rather than $1,100/MWh. Third, during the first six months after joining the energy imbalance market, prices in new balancing areas are not set by the price cap or floor when the power balance constraint is relaxed. Instead, prices are set by the last dispatched economic bid. This is known as *transition period pricing*, or *price discovery*.[121]

Prices in different energy imbalance market areas are often driven by the frequency with which the power balance constraint is relaxed. When the power balance constraint is relaxed for undersupply conditions in an energy imbalance market area, prices are set using the $1,000/MWh penalty price for this constraint in the pricing run of the market model if transition period prices were not in place. When transition period pricing is active and the power balance constraint is relaxed, market prices are based on the last price bid into the market by a unit.[122] Transition period pricing for Powerex and Idaho Power expired on October 4 following the end of their six-month transition period.

The load bias limiter was implemented in the energy imbalance market in March 2015, and works the same way as the load bias limiter in the ISO.[123] The load bias limiter creates a feasible market solution by reducing the change in magnitude of load adjustment if the change in load adjustment exceeds the size of the power balance relaxation. This market solution is then created in a similar manner to transition period pricing in that the price is set by the last economic bid instead of the penalty price. The load bias limiter feature is more important during periods when transition period pricing is not in effect for an area.

As noted previously, the ISO is implementing changes to 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. This change went in to effect as of late February 2019.

Figure 4.15 and Figure 4.16 show the frequency of power balance constraint relaxations in the 5-minute market by quarter for undersupply (shortage) and oversupply (excess) conditions.[124] The red bars in these figures show infeasibilities that were resolved by the load bias limiter (or would have been without transition period pricing), and the yellow bars show the infeasibilities that required a price

121 For further detail on transition period pricing, see Section 11.1.8 in the Energy Imbalance Market Business Practice Manual, https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Energy Imbalance Market.

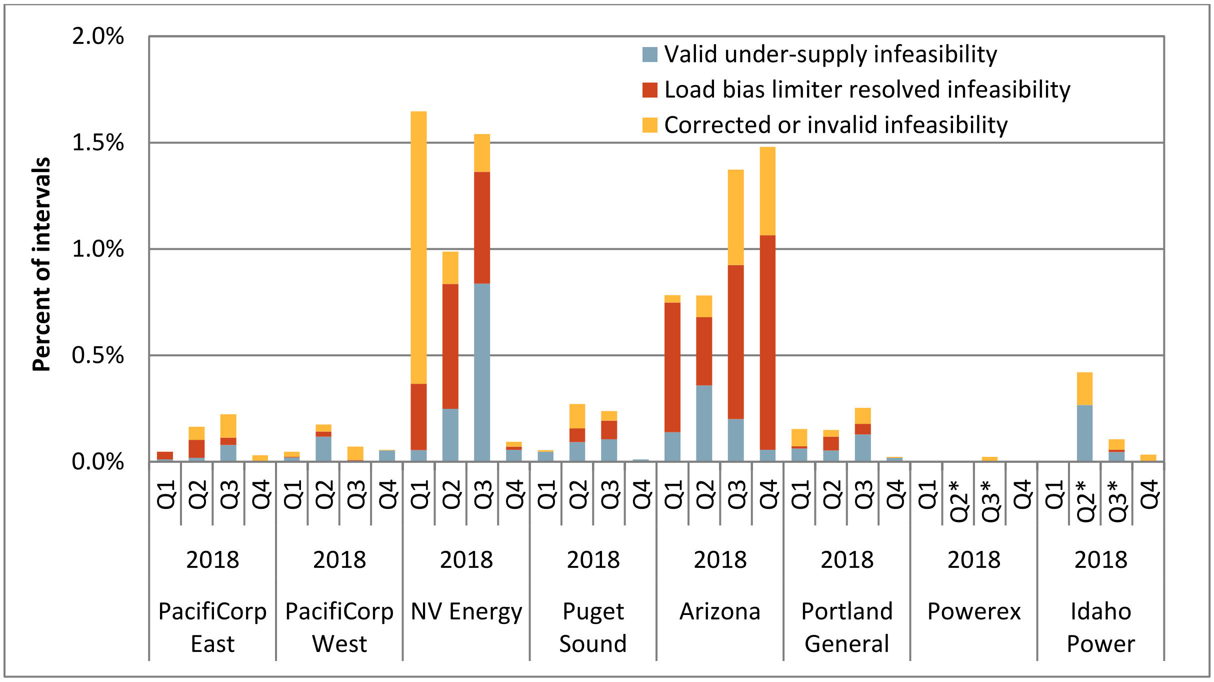
122 When transition period pricing triggers, any shadow price associated with the flexible ramping product is set to $0/MWh to allow the market software to use the last economic bid.

123 For further detail on the load bias limiter (conformance limiter), see Attachment M.2 in the Market Operations Business Practice Manual, https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market Operations.

124 The frequency of power balance constraint relaxations in the 15-minute market had similar patterns to those observed in the 5-minute market.

correction, would have triggered price correction if transition period pricing was not active, or were otherwise invalid.[125]

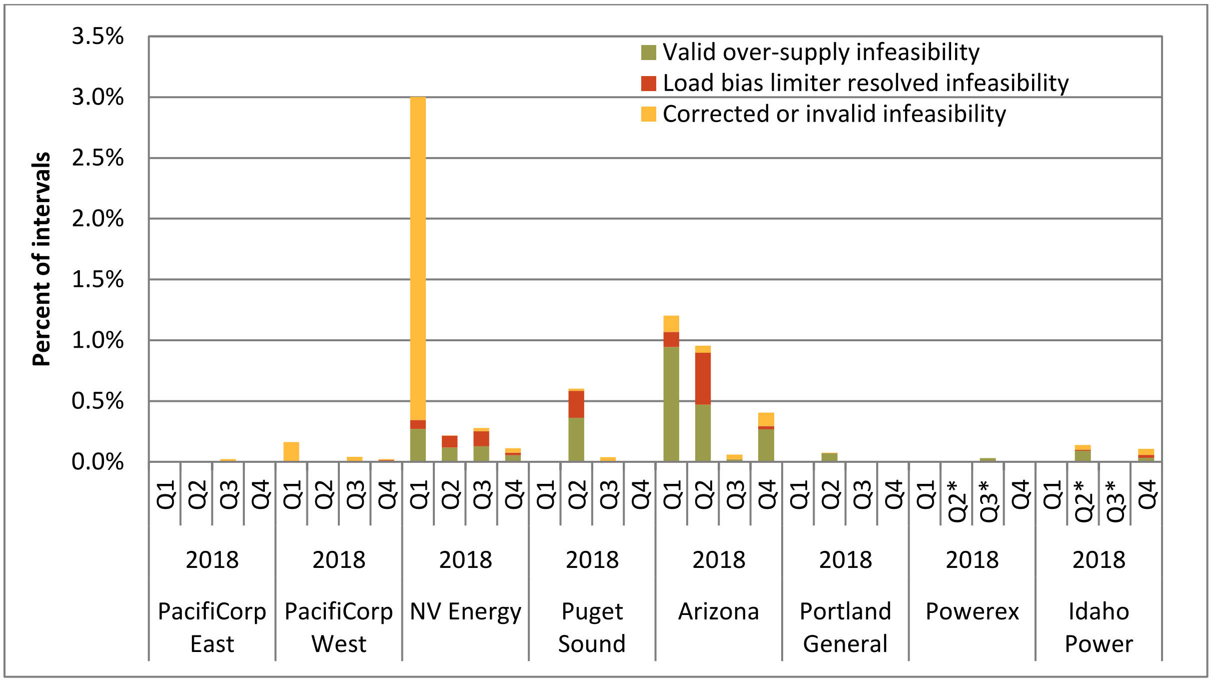
Figure 4.15 Frequency of power balance constraint undersupply (5-minute market)



*Area under transition period pricing for most of the quarter

[125] Section 35 of the ISO tariff provides the ISO authority to correct prices if it detects an invalid market solution or issue due to a data input failure, occurrence of hardware or software failure, or a result that is inconsistent with the ISO tariff. During erroneous intervals, the ISO determined that prices resulting under transitional pricing were equivalent to prices that would result from price correction, so no further price adjustment was appropriate. http://www.caiso.com/Documents/Section35_MarketValidationAndPriceCorrection_May1_2014.pdf.

Figure 4.16 Frequency of power balance constraint oversupply (5-minute market)



*Area under transition period pricing for most of the quarter

4.7 Greenhouse gas in the energy imbalance market

Background

Under the current energy imbalance market design, all energy transferred into the ISO to serve ISO load through an energy imbalance market transfer is subject to California's cap-and-trade regulation.[126] Under the energy imbalance market design, a participating resource submits a separate bid representing the cost of compliance for its energy attributed to the participating resource as serving ISO load. These bids are included in the optimization for energy imbalance market resource dispatch. Resource specific market results determined within the energy imbalance market optimization are reported to participating resource scheduling coordinators. This information serves as the basis for greenhouse gas compliance obligations under California's cap-and-trade program.

The energy imbalance market optimization minimizes costs of serving load in both the ISO and energy imbalance market taking into account greenhouse gas compliance cost for all energy deemed delivered to California. The energy imbalance market greenhouse gas price in each 15-minute or 5-minute interval is set at the greenhouse gas bid of the marginal megawatt attributed as serving ISO load. The greenhouse gas price determined within the optimization is included in the price difference between

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

serving the ISO and energy imbalance market load, which can contribute to lower energy imbalance market prices relative to those inside the ISO by at least the greenhouse gas price during any interval.[127]

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

Scheduling coordinators can guarantee that greenhouse gas compliance costs are covered by bidding in marginal compliance costs for greenhouse gas. The settlement price is set by the highest cleared greenhouse gas bid for the interval and will equal or exceed all cleared bids. The greenhouse gas price may thus be set above the greenhouse gas bid of a marginal resource, which provides energy imbalance market participating resources with low emissions an incentive to export energy to the ISO.

As of November 2018, the ISO implemented a new policy change to address the concerns that the market design was not capturing the full greenhouse gas effect of energy imbalance market imports into California to serve ISO load for compliance with California's cap-and-trade regulation. The California Air Resources Board and other stakeholders raised concern that the market optimization's least cost dispatch was structured such that the decrease in emissions within California was being offset by an increase in emissions outside of California. This would have resulted from instances where low-emitting resources were scheduled as imports in to California due to the lower cost of compliance with the ARB's cap-and-trade regulations. In such cases, higher-emitting resources would be dispatched to make up the difference in demand in the energy imbalance areas, an outcome the ISO has defined as "secondary dispatch".

To address the concern over "secondary dispatch", the ISO has implemented changes that restrict capacity that can be deemed delivered to California from energy imbalance areas. The amount of capacity that can be deemed delivered to California will now be limited to the upper economic bid limit of a resource minus the resource's base schedule. Since the policy change in November, both the resource mix of deliveries in to California and the energy imbalance entities providing imports in to California have been impacted, as discussed below.

Greenhouse gas prices

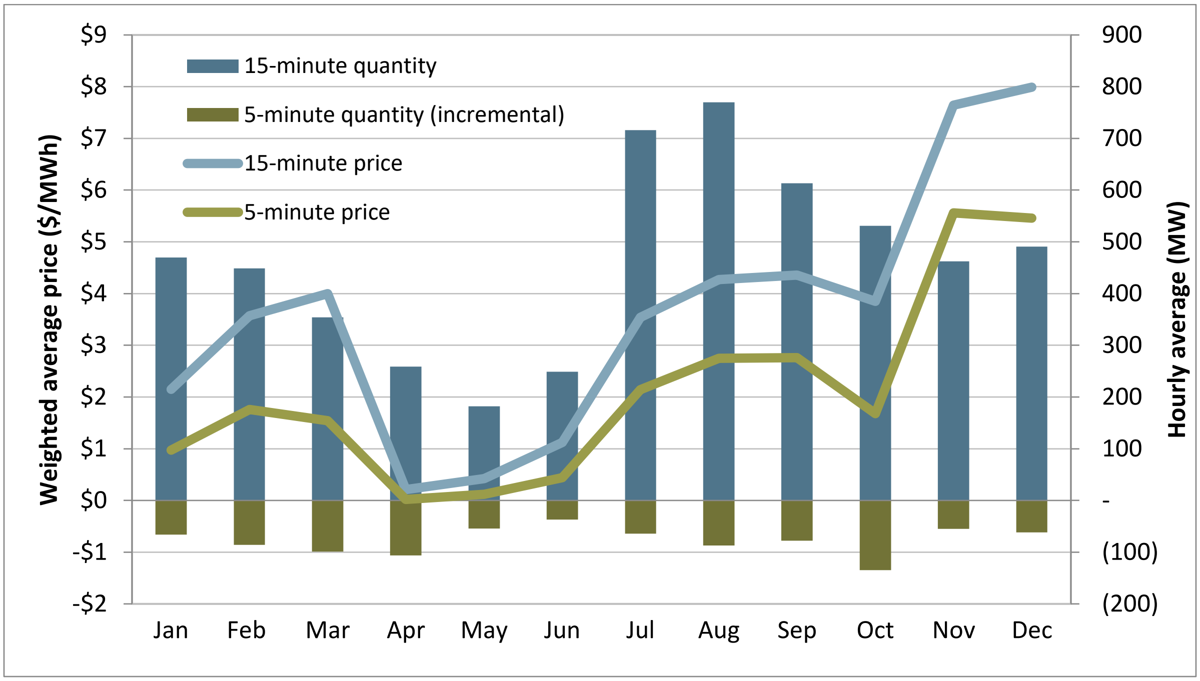
Figure 4.17 shows monthly average cleared energy imbalance market greenhouse gas prices and hourly average quantities for transfers serving ISO load settled in the energy imbalance market in 2018. Weighted average prices are calculated using 15-minute deemed delivered megawatts as weights in the 15-minute market and the absolute value of incremental 5-minute greenhouse gas dispatch in the 5-minute market. Hourly average 15-minute and 5-minute deemed delivered quantities are represented by the blue and green bars in the chart, respectively.

Weighted average greenhouse gas prices in the 5-minute market were lower than 15-minute prices for each month of the year, averaging about $1.49/MWh less. Weighted 15-minute prices averaged around $3.60/MWh for each month of the year while 5-minute prices averaged around $2.10/MWh. Price differences may occur if high emitting resources are procured in the 15-minute market and

[127] Further detail on the determination of deemed delivered greenhouse gas megawatts within the energy imbalance market optimization is available in Section 11.3.3, Locational Marginal Prices, of the Energy Imbalance Market Business Practice Manual located here: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Energy%20Imbalance%20Market.

subsequently decrementally dispatched in the 5-minute market. In the 15-minute market, a gas resource with positive greenhouse gas costs may be the marginal resource, but if emitting resources are decremented in the 5-minute market, the next marginal resource may be a hydro or solar resource that will set greenhouse gas prices at zero.

Figure 4.17 Energy imbalance market greenhouse gas price and cleared quantity



Both 15-minute and 5-minute price levels are at or below estimated greenhouse gas compliance costs for an efficient gas resource. Greenhouse gas prices increase with the percentage of gas resources attributed as serving ISO load through the energy imbalance market. This result is consistent with greenhouse gas bidding requirements adopted under phase 1 of the energy imbalance market year 1 enhancements which required greenhouse gas bids to be cost based.[128]

DMM estimates the total profit accruing for greenhouse gas bids attributed to energy imbalance market participating resources serving ISO load by subtracting estimated compliance costs from greenhouse gas revenue calculated in each interval. This value totaled over $10 million in 2018, compared to roughly $6 million in 2017. This increase in profits is likely due to a greater portion of energy transfers scheduled into the ISO from non-emitting resources in 2018 as shown below in Figure 4.18.

[128] FERC's acceptance of tariff revisions required for the energy imbalance market are available here: http://www.caiso.com/Documents/Jun19_2014_OrderConditionallyAcceptingEIMTariffRevisions_ER14-1386.pdf. These required "CAISO to make a compliance filing within one year after the date on which the energy imbalance market commences operation, with a proposal to implement the flag mechanism. Additionally, as the flag mechanism will obviate the need to use the GHG bid adder to signify that an energy imbalance market participating resource does not wish to be dispatched into California, such compliance filing should include revisions implementing a cost-based GHG bidder concurrent with implementation of the flag mechanism. A flag and cost-based GHG bid adder would support further expansion of the EIM." Paragraph 240.

Energy transfers to California by fuel type and balancing area

Figure 4.18 shows the hourly average energy deemed delivered to California by fuel type and balancing area. In 2018, about 72 percent of energy imbalance market greenhouse gas compliance obligations were assigned to hydro resources, compared to almost 65 percent in the previous year. The increase in hydroelectric resources used to serve ISO load likely resulted from increased hydroelectric capacity with Powerex and Idaho Power joining the energy imbalance market in April.

The portion of energy deemed delivered to California from natural gas resources was roughly 27 percent, down from around 35 percent in 2017. Delivery from non-gas and non-hydro resources accounted for less than 0.03 percent for the year. Notably, this includes a small amount of energy from coal resources in the fourth quarter which haven't been deemed delivered to California since 2016. This was most likely related to the policy change.

Figure 4.19 shows the percentage of total energy delivered to California by EIM area. In the first three months of 2018, nearly all of the energy deemed delivered to California was from Portland General Electric, Puget Sound Energy, and PacifiCorp West. After Idaho Power joined in April 2018, roughly 38 percent of total energy on average came from the area for the rest of the year. After the policy change was implemented in November, a few noticeable changes in greenhouse gas procurement occurred. First, both Arizona Public Service and NV Energy accounted for on average around 7 percent and 6 percent, respectively, compared to a minimal amount in prior months. Compared to the month of October, the percentage of greenhouse gas procured from PacifiCorp East and West increased while the percentage from Portland General Electric, Puget Sound Energy, and Idaho Power decreased.

Figure 4.18 Hourly average EIM greenhouse gas megawatts by fuel type

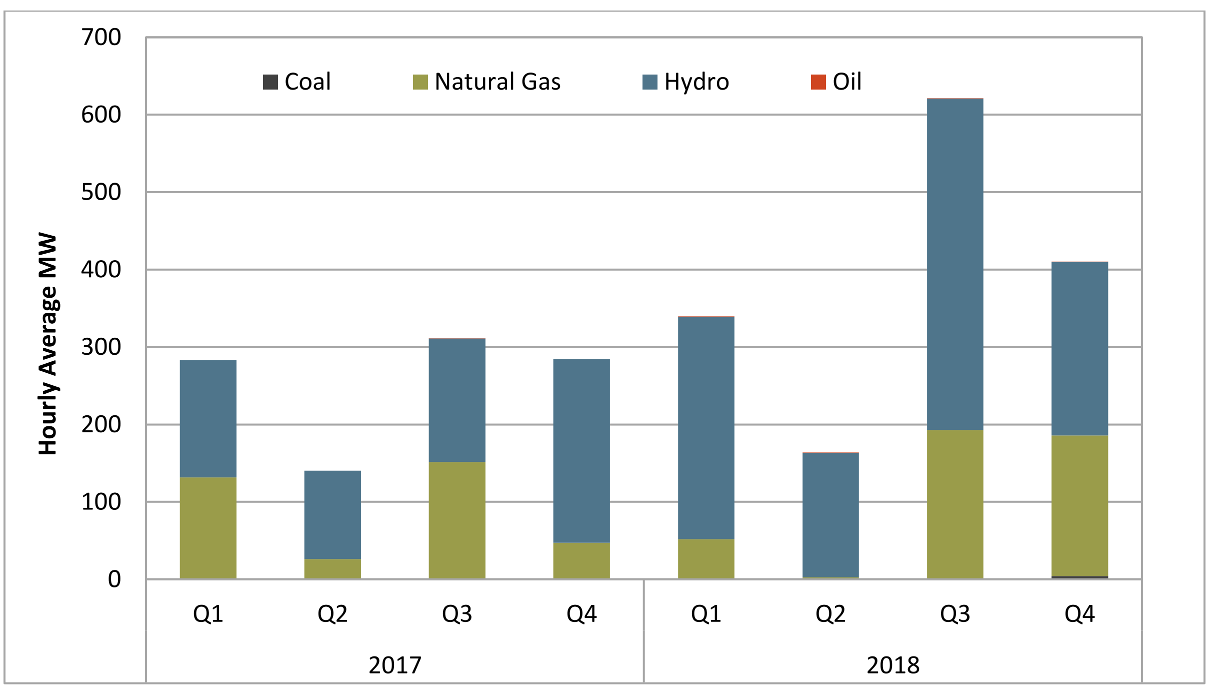
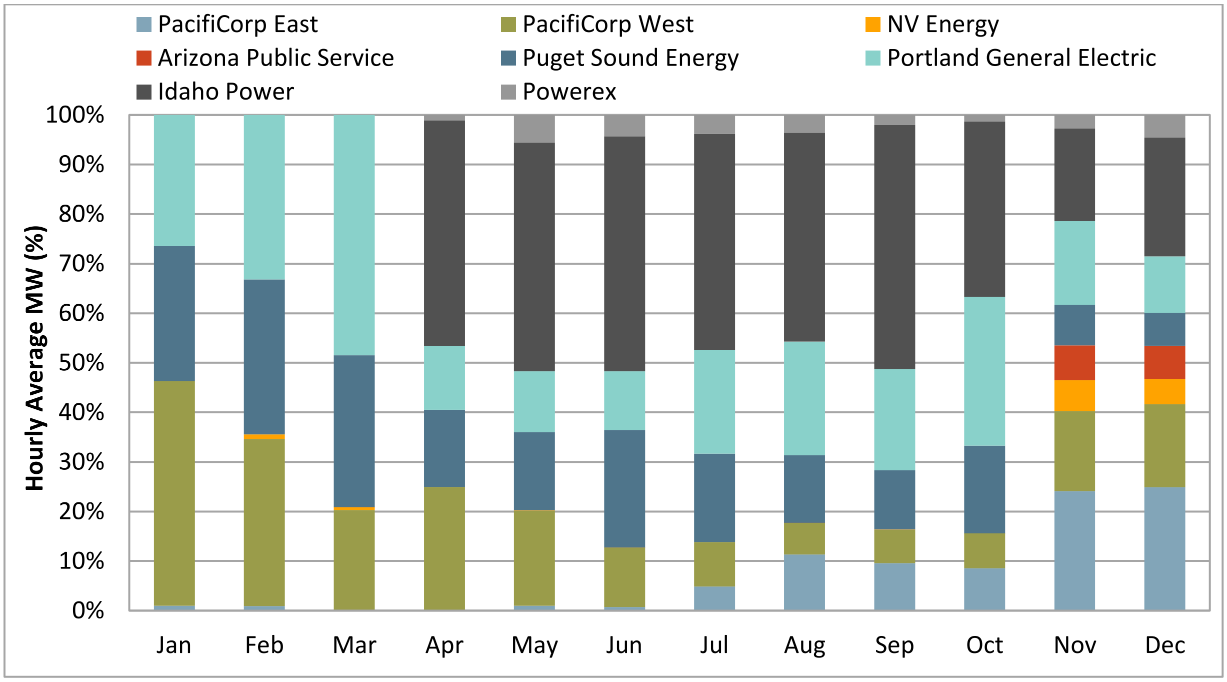


Figure 4.19 Percentage of greenhouse gas megawatts by area (2018)



4.8 Available balancing capacity

The ISO implemented the available balancing capacity (ABC) mechanism in the energy imbalance market in late March 2016. This enhancement allows for market recognition and accounting of capacity that entities in the energy imbalance market areas have available for reliable system operations, but is not bid into the market. Available balancing capacity is identified as upward capacity (to increase generation) or downward capacity (to decrease generation) by each energy imbalance market entity in their hourly resource plans. The available balancing capacity mechanism enables the ISO system software to deploy such capacity through the energy imbalance market, and prevents market infeasibilities that may arise without the availability of this capacity.[129]

Table 4.3 summarizes the quarterly frequency of upward and downward available balancing capacity offered and scheduled in each energy imbalance market area.[130] During 2018, NV Energy, Puget Sound Energy and Powerex offered upward and downward balancing capacity during almost all hours. Table 4.3 also shows the average magnitude of the available balancing capacity when offered in their hourly resource plan. In particular, Powerex on average offered roughly 1,100 MW and 700 MW of upward and downward available balancing capacity, respectively, in each hour since joining the energy imbalance market in April 2018. NV Energy offered around 80 MW on average of upward and downward available

[129] See December 17, 2015, *Order Accepting Compliance Filing – Available Balancing Capacity* (ER15-861-006): http://www.caiso.com/Documents/Dec17_2015_OrderAcceptingComplianceFiling_AvailableBalancingCapacity_ER15-861-006.pdf.

[130] The ISO has identified instances when a resource is required to cross the operational range where available balancing capacity is defined, therefore "scheduling" it in the real-time market without scarcity conditions. Therefore, dispatched available balancing capacity without scarcity pricing in the scheduling run are omitted from this table.

balancing capacity in each hour during 2018. Puget Sound Energy offered around 40 MW on average of upward and downward available balancing capacity during hours when the area offered such capacity (around 90 percent of hours).

Upward available balancing capacity offered by Arizona Public Service increased significantly during the year, to around 20 percent of hours in the second half of the year compared to less than 2 percent of hours in the first half. PacifiCorp East offered downward available balancing capacity significantly less frequently during 2018 from the previous year, during around 12 percent of hours compared to around 38 percent of hours in 2017.

PacifiCorp West and Idaho Power offered available balancing capacity in either direction infrequently, during less than 3 percent of hours for each direction during 2018. Portland General Electric did not offer upward or downward available balancing capacity for any hour during the year.

Overall, available balancing capacity was dispatched for scarcity conditions infrequently during 2018. However, upward and downward available balancing capacity offered by NV Energy was dispatched most frequently during the year compared to other balancing areas due to a relatively high frequency of infeasibilities and offered available balancing capacity.

Table 4.3 Frequency of available balancing capacity offered and scheduled (2018)

	Offered		Scheduled	
	Percent of hours	Average MW	Percent of intervals (15-minute market)	Percent of intervals (5-minute market)
Upward ABC				
NV Energy	100%	84	1.6%	1.8%
Powerex*	100%	1,135	0.1%	0.0%
Puget Sound Energy	90%	35	0.1%	0.2%
PacifiCorp East	11%	110	0.0%	0.0%
Arizona Public Service	11%	94	0.1%	0.1%
PacifiCorp West	3%	76	0.0%	0.0%
Idaho Power*	1%	78	0.0%	0.0%
Portland General Electric	0%	N/A	0.0%	0.0%
Downward ABC				
NV Energy	100%	-83	0.6%	0.8%
Powerex*	100%	-705	0.1%	0.0%
Puget Sound Energy	91%	-40	0.0%	0.1%
PacifiCorp East	12%	-73	0.0%	0.0%
Arizona Public Service	6%	-57	0.0%	0.0%
PacifiCorp West	1%	-54	0.0%	0.0%
Idaho Power*	3%	-124	0.0%	0.0%
Portland General Electric	0%	N/A	0.0%	0.0%

*April 4 to December 31, 2018 only

5 Convergence bidding

Virtual bidding is a part of the Federal Energy Regulatory Commission's standard market design and has been part of the ISO's market since February 2011. Virtual bidding allows participants to profit from any difference between day-ahead and real-time prices. Findings from this chapter include the following:

- Net revenues paid to convergence bidders totaled around $40 million, a significant increase from about $12 million in 2017, after accounting for about $16 million in bid cost recovery charges allocated to virtual bids.
- Net revenues before accounting for uplift costs charged to virtual bidders were around $56 million—the highest amount since 2012. This increase may reflect convergence bidding entities adjusting for sustained day-ahead prices greater than real-time prices over the year when virtual supply bids are profitable.
- Virtual supply exceeded virtual demand by an average of about 680 MW per hour, compared to 640 MW in 2017. The percent of cleared virtual supply and demand was around 34 percent, about the same as in 2017.
- Physical generators and load-serving entities received slightly over 2 percent of net virtual bidding revenues. Most profits from virtual bidding continue to be received by financial entities, who received 75 percent of net revenues, and marketers, who received 22 percent of net revenues.

Background

Virtual bidding is a part of the Federal Energy Regulatory Commission's standard market design and is in place at all other ISOs with day-ahead energy markets. In the California ISO markets, virtual bidding is formally referred to as *convergence bidding*. The ISO implemented convergence bidding in February 2011.

Convergence bidding allows participants to place purely financial bids for supply or demand in the day-ahead energy market. These virtual supply and demand bids are treated similarly to physical supply and demand in the day-ahead market. However, all virtual bids clearing the day-ahead market are removed from the real-time markets, which are dispatched based only on physical supply and demand. Virtual bids accepted in the day-ahead market are liquidated financially in the real-time market as follows:

- Participants with virtual demand bids accepted in the day-ahead market pay the day-ahead price for this virtual demand. These virtual demand bids are then liquidated in the 15-minute real-time market and participants are paid the real-time price.
- Participants with accepted virtual supply bids are paid the day-ahead price for this virtual supply. These virtual supply bids are then liquidated in the 15-minute real-time market and participants are charged the real-time price.

Virtual bidding allows participants to profit from any difference between day-ahead and real-time prices. In theory, as participants take advantage of opportunities to profit through convergence bids, this activity should tend to converge prices in markets, as illustrated by the following:

- If prices in the real-time market tend to be higher than day-ahead market prices, convergence bidders will seek to arbitrage this price difference by placing virtual demand bids. Virtual demand will raise load in the day-ahead market and thereby increase prices. This increase in load and prices could also lead to the commitment of additional physical generating units in the day-ahead market, which in turn could tend to reduce average real-time prices. In this scenario, virtual demand could help improve price convergence by increasing day-ahead prices and reducing real-time prices.

- If real-time market prices tend to be lower than day-ahead market prices, convergence bidders will seek to profit by placing virtual supply bids. Virtual supply will tend to lower day-ahead prices by increasing supply in the day-ahead market. This increase in virtual supply and decrease in day-ahead prices could also reduce the amount of physical supply committed and scheduled in the day-ahead market.[131] This would tend to increase average real-time prices. In this scenario, virtual supply could help improve price convergence by reducing day-ahead prices and increasing real-time prices.

Convergence bidding also provides a mechanism for participants to hedge or speculate against price differences in the two following circumstances:

- Price differences between the day-ahead and real-time markets; and

- Congestion at different locations.

However, the degree to which convergence bidding has actually increased market efficiency by improving unit commitment and dispatches has not been assessed. In some cases, virtual bidding may be profitable for some market participants without increasing market efficiency significantly or may even decrease market efficiency.[132]

Virtual bids at internal ISO locations accepted in the day-ahead market are settled against prices in the 15-minute market. Prior to implementation of the 15-minute market in May 2014, these bids were settled against 5-minute market prices. All results reported in this chapter reflect the prevailing settlement rules at the time the market ran.

Virtual bidding on interties was temporarily suspended in November 2011 due to issues with settlement of these bids that tended to lead to high revenue imbalance costs and reduced the potential benefits of virtual bids at nodes within the ISO system.[133] In late September 2015, FERC issued an order requiring the ISO to remove tariff provisions that provided for reinstatement of convergence bids at interties.[134]

131 This will not create a reliability issue as the residual unit commitment process occurs after the integrated forward market run. The residual unit commitment process removes convergence bids and re-solves the market using the ISO forecasted load. If additional units are needed, the residual unit commitment process will commit more resources.

132 A report reviewing the effectiveness of virtual bidding indicates that under certain conditions, virtual bidding may be parasitic to the market rather than adding value and improving efficiency. The report focused on issues that had been identified and noted in the California ISO markets. For more information see:

Parsons, John E., Cathleen Colbert, Jeremy Larrieu, Taylor Martin and Erin Mastrangelo. 2015. *Financial Arbitrage and Efficient Dispatch in Wholesale Electricity Markets*. MIT Center for Energy and Environmental Policy Research, Working Paper, February.

Retrieved from http://www.mit.edu/~jparsons/publications/20150300_Financial_Arbitrage_and_Efficient_Dispatch.pdf.

133 As described in DMM's 2011 annual report, this problem was created by the fact that virtual bids at interties were settled on hour-ahead prices, while virtual bids at internal locations were settled at 5-minute prices. For further detail see the *2011 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2012, pp. 77-79: http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.

134 For further details see: http://www.ferc.gov/CalendarFiles/20150925164451-ER15-1451-000.pdf.

5.1 Convergence bidding trends

Convergence bidding volumes increased steadily over the year with net cleared volumes of virtual supply outweighing virtual demand for all quarters in 2018. This continues a trend of cleared virtual supply outweighing cleared virtual demand for all quarters since 2014. Figure 5.1 shows the quantities of both virtual supply and demand offered and cleared in the market. Figure 5.2 shows the average net cleared virtual positions for each operating hour.

Key convergence bidding trends include the following:

- On average, 38 percent of virtual supply and demand bids offered into the market cleared in 2018, compared to 35 percent in 2017.
- The average hourly cleared volume of virtual supply exceeded virtual demand for all quarters by about 680 MW per hour, an increase from about 640 MW per hour in 2017.
- Average hourly cleared virtual supply was about 1,790 MW in 2018, compared to about 1,400 MW in 2017. This increase was mainly driven by an increase in cleared virtual supply by both financial participants and marketers by 370 MW and 160 MW, respectively. Average hourly cleared virtual demand increased to 1,100 MW in 2018 from about 770 MW in 2017. This was largely the result of increased bidding activity by financial participants and marketers.

Figure 5.1 Quarterly average virtual bids offered and cleared

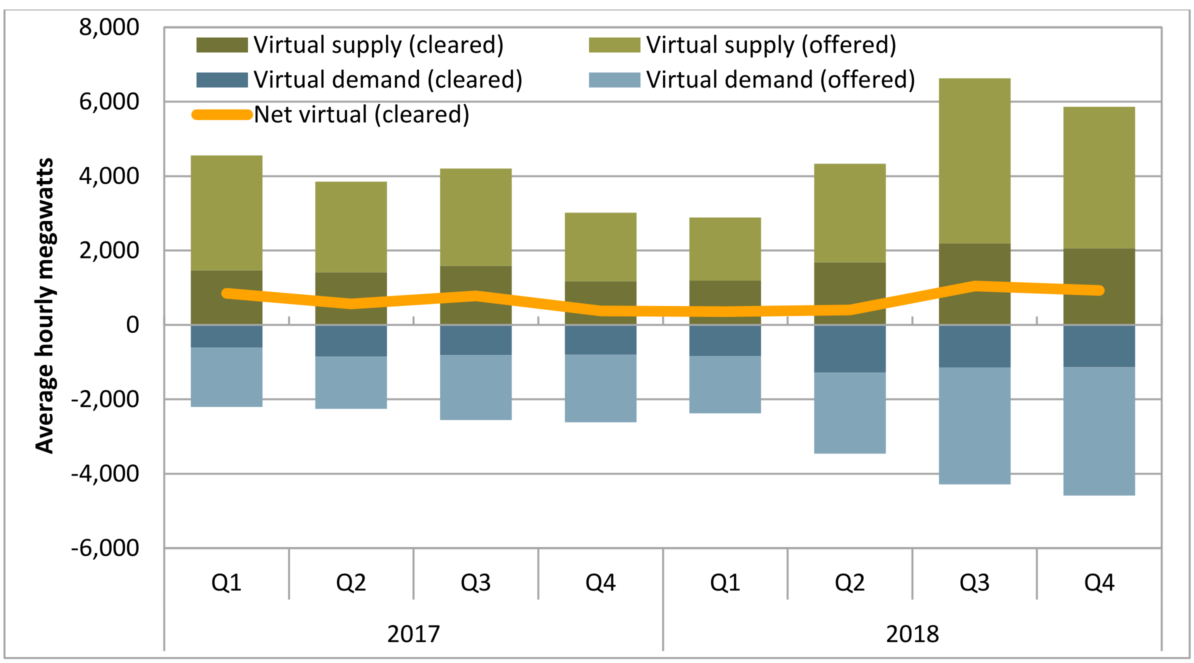
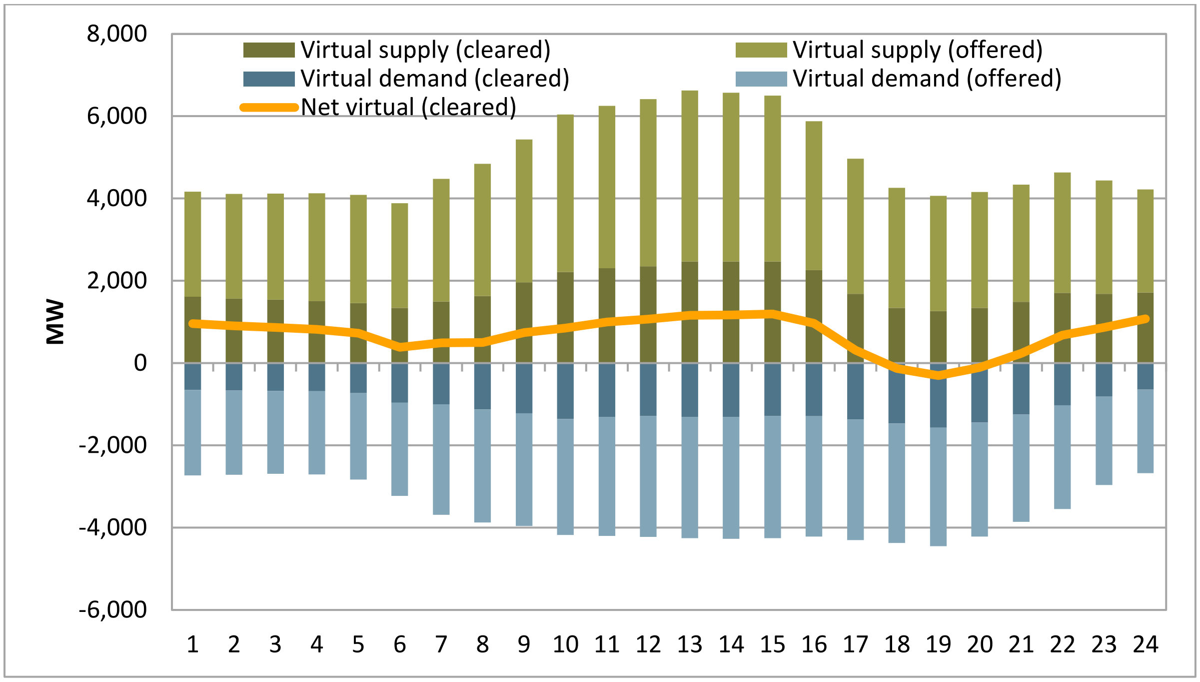


Figure 5.2 Average net cleared virtual bids in 2018



- Net virtual supply was most prevalent during the last two quarters of the year when virtual supply exceeded virtual demand by around 980 MW per hour on average, a decrease from about 580 MW for the same period in 2017.
- About 75 percent of cleared virtual positions in 2018 were held by financial participants, an increase from 67 percent in 2017. Financial participants bid more virtual supply than demand in 2018, which contributed to the increase in net virtual supply.
- Net virtual supply was lowest during evening peak hours. During evening peak hours (hours 17 through 21) average hourly cleared bidding volumes were equal between supply and demand. Virtual supply was negative on average during hours ending 18, 19, and 20. For all other hours, virtual supply outweighed virtual demand.
- Virtual demand is generally more attractive to bidders during the evening peak hours (hours 17 through 21) when there are tighter supply conditions and often higher real-time prices relative to day-ahead prices. However, day-ahead prices were higher on average during all evening peak hours in 2018 making virtual demand during these hours less profitable than prior years.

Offsetting virtual supply and demand bids

Market participants can also hedge congestion costs or seek to profit from differences in congestion between different locations within the ISO system by placing equal quantities of 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. However, the combination of these offsetting bids can be profitable if there are differences in congestion in the day-ahead and real-time markets between these two locations.

Offsetting virtual positions accounted for an average of about 730 MW of virtual demand offset by 730 MW of virtual supply during each hour in 2018, a substantial increase from about 400 MW in 2017. The share of these offsetting bids totaled to about 51 percent of all cleared virtual bids in 2018 up from about 38 percent in 2017. Offsetting bids made up 41 percent of cleared virtual supply and 66 percent of cleared virtual demand during 2018.

The increase in offsetting virtual positions halted a trend of decreasing offsetting bids since 2013. Virtual bidding to hedge or profit from congestion was used to a greater extent than in prior years, likely due to the opportunity to take advantage of relatively higher levels of congestion.

Consistency of price differences and volumes

Convergence bidding is designed to help make day-ahead and real-time prices more consistent. Virtual bids are profitable when the net market virtual position is directionally consistent with the price difference between the two markets. Net convergence bidding volumes were generally less consistent with price differences between the day-ahead and real-time markets on average during 2018 compared to previous years. Particularly, the inconsistency can be seen with high volumes of virtual demand bids during a year where virtual demand was unprofitable on average in each quarter.

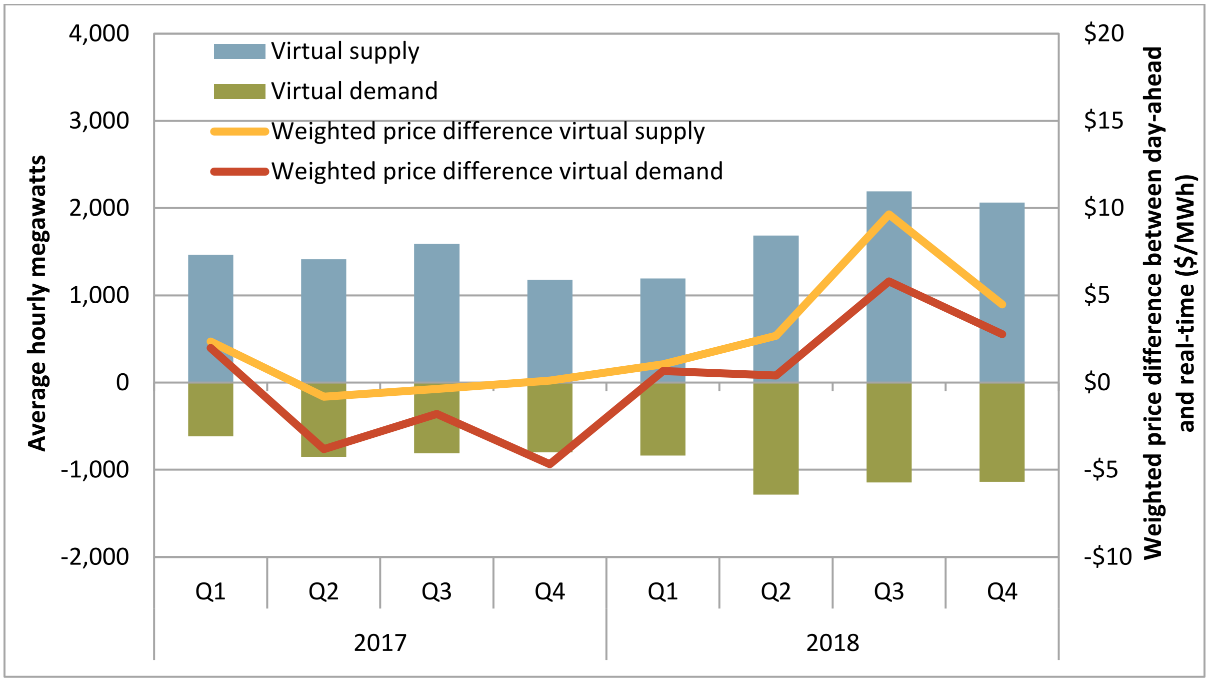
Figure 5.3 compares cleared convergence bidding volumes with the volume-weighted average price differences at which these virtual bids were settled. The difference between day-ahead and real-time prices shown in this figure represents the average price difference weighted by the amount of virtual bids cleared at different locations.

Periods when the red line is negative indicate that the weighted average price charged for virtual demand in the day-ahead market was lower than the weighted average real-time price paid for this virtual demand and, thus, was a profitable period. In 2018, virtual demand positions were not profitable in any quarter during the year.

As noted earlier, a large portion of the virtual supply clearing the market was paired with demand bids at different locations by the same market participant. Such offsetting virtual supply and demand bids are likely used as a way of hedging or speculating from congestion within the ISO. 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 due to congestion. This might help explain the surge of virtual demand bids during ostensibly unprofitable periods which could be earning revenue by speculating on congestion.

Quarters where the yellow line is positive indicate a higher weighted average price paid for virtual supply in the day-ahead market than the weighted average real-time price charged when this virtual supply was liquidated in the real-time market. Unlike virtual demand, virtual supply was consistently profitable in all quarters during 2018. As shown in Figure 5.3, virtual supply bid volumes were highly consistent with weighted price differences throughout the year.

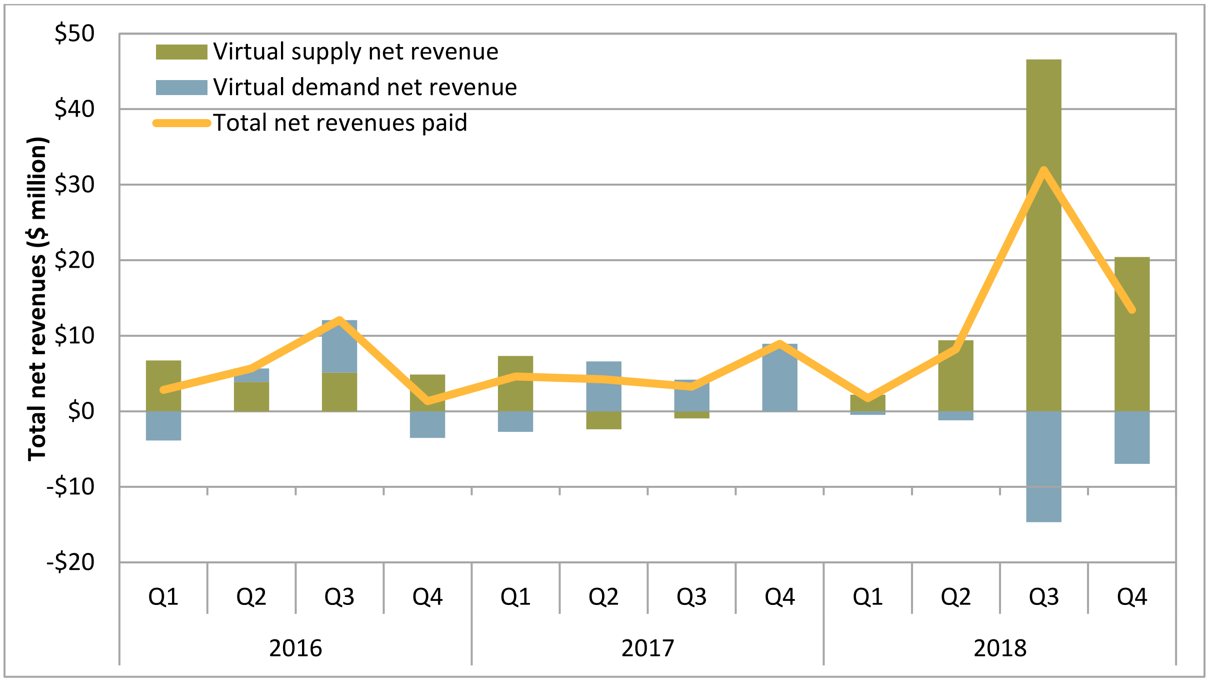
Figure 5.3 Convergence bidding volumes and weighted price differences



5.2 Convergence bidding payments

Net revenues paid to convergence bidders (prior to any allocation of bid cost recovery payments) totaled about $56 million in 2018, an increase of about $35 million from 2017 or about 60 percent. All net revenues were from virtual supply bids in 2018, a change from the previous year where the majority of net revenues were from virtual demand. This was largely due to sustained higher average prices in the day-ahead market than in the real-time market throughout the year allowing virtual supply bids to be profitable. Figure 5.4 shows total quarterly net revenues paid for accepted virtual supply and demand bids.

Figure 5.4 Total quarterly net revenues from convergence bidding



As shown in Figure 5.4:

- All total net revenues paid ($56 million) were from cleared virtual supply. Net revenues from virtual supply equaled around $80 million and cleared virtual demand accounted for about $24 million in net losses.
- Virtual supply positions were profitable in all quarters during 2018. This trend was primarily driven by sustained average day-ahead market prices greater than real-time market prices in all quarters during the year. Particularly, virtual supply net revenues were greatest in the third quarter at nearly $47 million when system marginal day-ahead prices reached record highs on several days related to a system-wide heat wave and associated high loads.
- Virtual demand positions were not profitable in any quarter during 2018. Virtual demand net losses totaled around $24 million for the year. This again is the result of the year-long trend of negative average price differences between the day-ahead and real-time markets when virtual demand is not profitable.
- Total net revenues for virtual bidders peaked in the third quarter at almost $47 million, more than double net revenues from any other quarter during 2018. Total net revenues were lowest in the first quarter at around $2 million.

Net revenues and volumes by participant type

All of the total revenues for virtual bids were derived from virtual supply in 2018. This is an increase from 2017 when about 80 percent of total revenues were from virtual demand. Additionally, the hourly average volume of virtual demand and virtual supply clearing the markets increased from 2017 by 330 megawatts and 375 megawatts, respectively.

Most convergence bidding activity is typically conducted by entities engaging in purely financial trading that do not serve load or transact physical supply. These entities accounted for about $42 million, or about 75 percent, of the total convergence bidding revenues in 2018. This was an increase from 2017 where financial entities accounted for $14 million, or 67 percent of total convergence bidding revenues. Marketers, the second largest trading entity in terms of revenue and trading, also received increased revenue from convergence bidding to $12.5 million in 2018 compared to almost $6 million in 2017.

Table 5.1 compares the distribution of convergence bidding volumes and revenues among different groups of convergence bidding participants. The trading volumes show cleared virtual positions along with the corresponding revenues in millions of dollars.

Table 5.1 Convergence bidding volumes and revenues by participant type (2018)

Trading entities	Average hourly megawatts			Revenues\Losses ($ million)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	697	1,122	1,819	-$13.7	$55.8	$42.1
Marketer	397	573	970	-$9.9	$22.3	$12.5
Physical generation	0	90	90	$0.0	$1.5	$1.5
Physical load	8	2	10	-$0.4	$0.0	-$0.4
Total	**1,102**	**1,787**	**2,889**	**-$24.0**	**$79.6**	**$55.7**

DMM categorizes participants who own no physical energy and participate in only the convergence bidding and congestion revenue rights markets as financial entities. Physical generation and load are categories of participants that primarily participate in the ISO 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 markets.

As shown in Table 5.1, financial participants represent the largest segment of the virtual market, accounting for about 63 percent of cleared volume and about 75 percent of revenue. Marketers represent about 34 and 22 percent of volume and revenue, respectively. Marketers increased their net revenues from convergence bidding although their share of total revenues decreased by about 5 percent. Generation owners and load-serving entities account for the smallest share of both total revenues and volume at 2 and 3.5 percent, respectively.

Table 5.1 shows that all participant types held significantly more virtual supply than virtual demand, similar to the prior year. In fact, cleared virtual supply bids have outweighed virtual demand bids in average hourly megawatts since 2013 highlighting a long-term trend since the introduction of convergence bidding in to the ISO market in 2011.

5.3 Bid cost recovery charges to virtual bids

As previously noted, 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.[135] 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 costs, minimum load costs, transition costs, and incremental energy bid costs.[136]

Because virtual bids can influence unit commitment, they share in the associated costs. Specifically, virtual bids can be charged for bid cost recovery payments under two charge codes.[137]

- Integrated forward market bid cost recovery tier 1 allocation addresses costs associated with situations when the market clears with positive net virtual demand.[138] 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.[139] 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.

The day-ahead residual unit commitment tier 1 allocation charge associated with virtual supply increased from the previous year. In particular, the third quarter accounted for the highest increase in bid cost recovery charges resulting from higher residual unit commitment costs which were just under $12 million accounting for about 75 percent of the total residual unit commitment costs for the year.

Nonetheless, the third quarter was also the most profitable quarter for convergence bidders despite facing the highest residual unit commitment costs for the year. In total, about 7 percent of bid cost recovery charges during 2018 were attributed to the day-ahead residual unit commitment tier 1 allocation charge, a decrease from about 9 percent in the prior year.

Figure 5.5 shows estimated total convergence bidding revenues, total revenues less bid cost recovery charges, and costs associated with the two charge codes. The total convergence bidding bid cost recovery costs for the year were about $16 million, an increase from around $9 million in 2017. As noted earlier, the total 2018 estimated net revenue for convergence bidding was around $56 million. Adjusting

135 If physical generation resources clearing 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 forecasted 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.

136 Generating units, pumped-storage units, or resource-specific system resources are eligible to receive bid cost recovery payments.

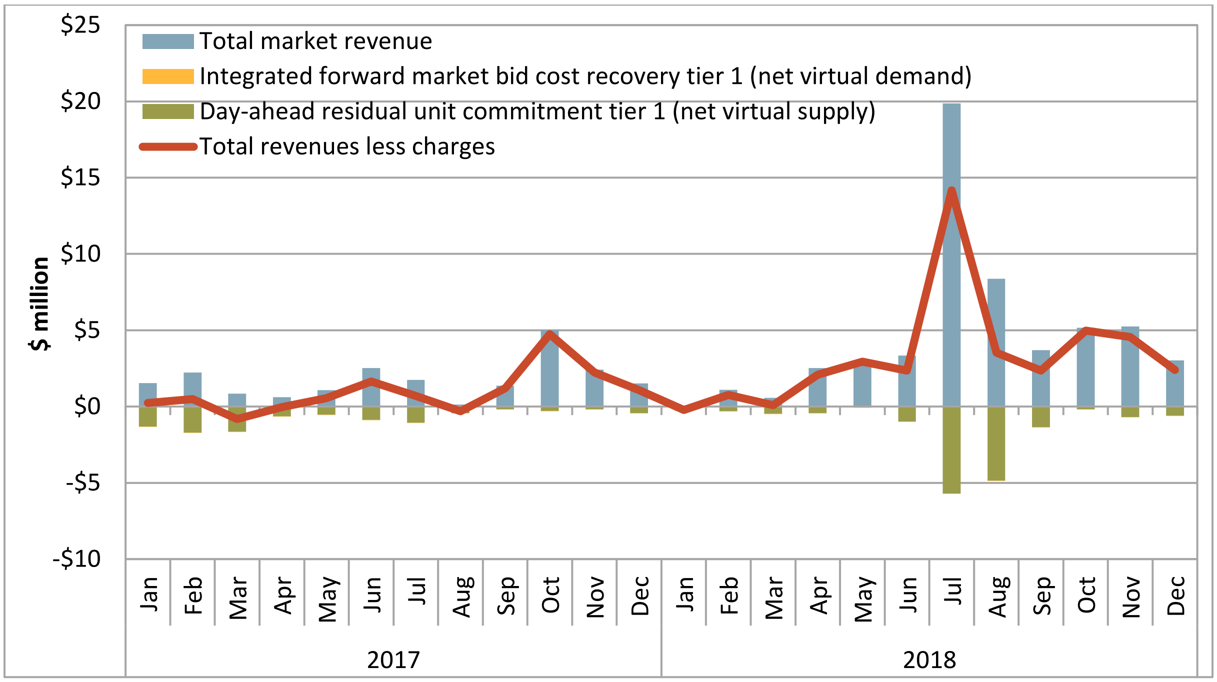
137 Both charge codes are calculated by hour and charged on a daily basis.

138 For further detail, see Business Practice Manual configuration guides for charge code (CC) 6636, IFM Bid Cost Recovery Tier1 Allocation_5.1a: http://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing.

139 For further detail, see Business Practice Manual configuration guides for charge code (CC) 6806, Day Ahead Residual Unit Commitment (RUC) Tier 1 Allocation_5.5: http://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing.

this total by the bid cost recovery costs allocated to virtual bids results in total convergence bidding revenue of about $40 million.

Figure 5.5 Convergence bidding revenues and costs associated with bid cost recovery tier 1 and RUC tier 1



6 Ancillary services

This chapter provides a summary of the ancillary service market in 2018. Key trends highlighted in this chapter include the following:

- Ancillary service costs increased to $189 million, up from $158 million in 2017 and $116 million in 2016. The increase in operating reserve costs was primarily driven by tight supply conditions and high energy prices during the summer.
- On January 1, 2018, operating reserve requirements increased with the implementation of the revised NERC reliability standard (BAL-002-2). Under the revised standard, the ISO considers the sudden loss of scheduling on the Pacific DC Intertie as one possible single largest contingency. The impact on operating reserve requirements was largest in morning and evening hours in the first and second quarter, but did not have a significant impact on total ancillary service payments.
- Average day-ahead requirements for regulation down increased by about 14 percent from 2017. Requirements for regulation down were typically highest in the morning and evening hours when solar is ramping on and off.
- There were over 180 intervals in the 15-minute market with scarcity operating reserves, with most occurring between March and August. In comparison, there were 54 scarcity instances during 2017 and 26 instances in all of 2016.

The ISO's ancillary service market design includes co-optimizing energy and ancillary service bids provided by each resource. With co-optimization, units are able to bid all of their capacity into the energy and ancillary service markets without risking the loss of revenue in one market when their capacity is sold in the other. Co-optimization allows the market software to determine the most efficient use of each unit's capacity for energy and ancillary services. A detailed description of the ancillary service market design is provided in DMM's 2010 annual report.[140]

6.1 Ancillary service costs

Costs for ancillary services totaled about $189 million in 2018, an increase from about $158 million in 2017 and about $116 million in 2016.

Figure 6.1 shows ancillary service costs both as a percentage of wholesale energy costs and per megawatt-hour of load from 2016 through 2018. Ancillary service costs increased to $0.85/MWh of load served in 2018 from $0.69/MWh in 2017. The $0.85/MWh cost was the highest yearly value since 2011. However, ancillary service costs as a percent of total wholesale energy costs were around 1.7 percent in 2018, similar to the previous year.

Figure 6.2 shows the total cost of procuring ancillary service products by quarter and the total ancillary service cost for each megawatt-hour of load served. With the exception of the third quarter, total costs during the year were similar to 2017 despite higher operating reserve requirements and more scarcities.

[140] *2010 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2011, pp. 139-142: http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf.

High ancillary service costs during the third quarter were typically between hours ending 18 and 21 on the highest load days during the summer when day-ahead market energy prices were similarly high.

Figure 6.1 Ancillary service cost as a percentage of wholesale energy costs (2015-2018)

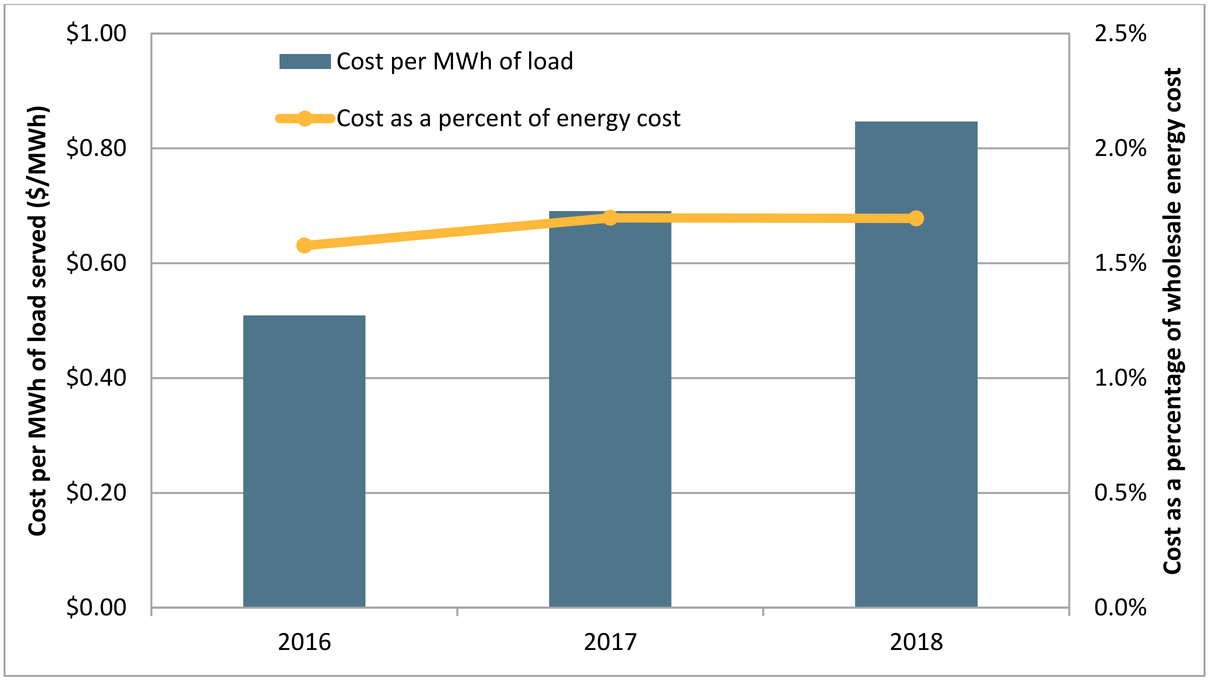
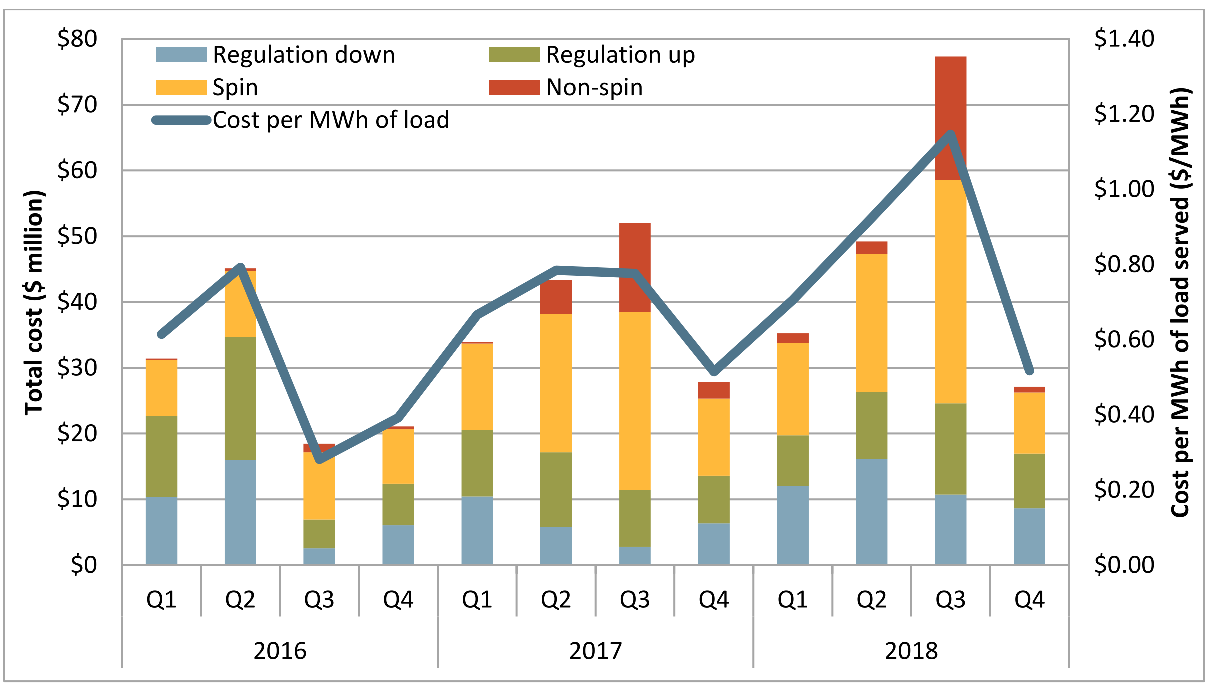


Figure 6.2 Total ancillary service cost by quarter and type



6.2 Ancillary service requirements and procurement

The ISO procures four ancillary services in the day-ahead and real-time markets: regulation up, regulation down, spinning reserves, and non-spinning reserves.[141] Ancillary service procurement requirements are set for each ancillary service to meet or exceed Western Electricity Coordinating Council's minimum operating reliability criteria and North American Electric Reliability Corporation's control performance standards. The ISO attempts to procure all ancillary services in the day-ahead market to the extent possible.

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

In the past, only four of these regions were typically utilized: expanded system (or expanded ISO), internal system, expanded South of Path 26, and internal South of Path 26. Since December 14, 2017, operators began setting expanded and internal North of Path 26 region minimum requirements to match the expanded and internal South of Path 26 region requirements. The new requirements were initially entered as a result of outages but have been maintained to facilitate the distribution of ancillary service procurement across the ISO.

Operating reserve requirements

Operating reserve requirements in the day-ahead market are typically set by the maximum of three factors: (1) 6.3 percent of the load forecast, (2) the most severe single contingency and (3) 15 percent of forecasted solar production.[142] Operating reserve requirements in real-time are calculated similarly except using 3 percent of the load forecast and 3 percent of generation instead of 6.3 percent of the load forecast. The total operating reserve requirements are then typically split equally between spinning and non-spinning reserves.

The Federal Energy Regulatory Commission approved a set of newly defined requirements in BAL-002-2, effective January 1, 2018, that required the ISO to reevaluate the most severe single contingency.[143] Both poles of the Pacific DC Intertie were agreed upon as a credible multiple contingency that qualifies as a single event for the purpose of the most severe single contingency. Beginning January 1, 2018,

141 In addition, in June 2013 the ISO added a performance payment referred to as mileage to the regulation up and down markets, in addition to the existing capacity payment system.

142 On June 8, 2017, 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. Only solar forecasts from resources that have the potential for the inverter issue are considered.

143 Further information on BAL-002-2 and operating reserve requirement changes implemented by the ISO is available here: http://www.caiso.com/Documents/Presentation-BAL-002-2DisturbanceControlStandard-kContingencyReserveforRecoveryfromaBalancingContingencyEvent.pdf or in the NERC BAL-002-2 reliability standard here: http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-2.pdf.

operating reserve requirements account for the contingency of the loss of projected schedules on the Pacific DC Intertie sinking in the ISO balancing area. This can include a higher volume than the share that sinks directly in the ISO and resulted in an increase to the operating reserve requirements overall.

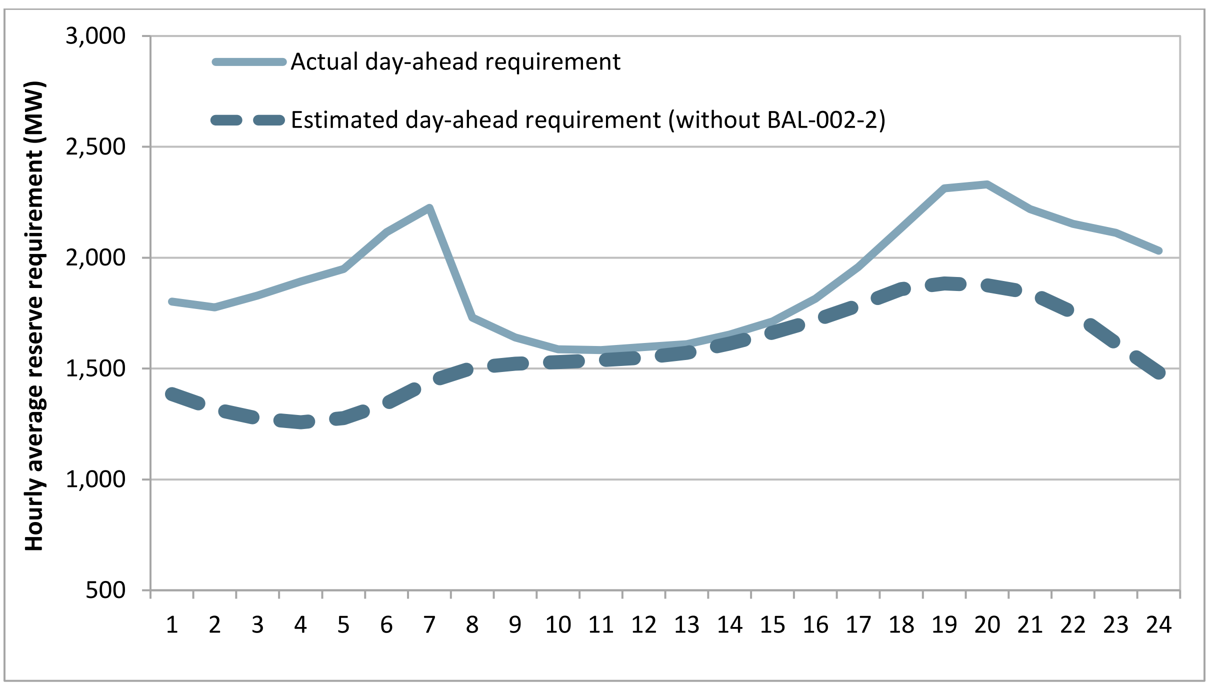
Figure 6.3 shows actual average operating reserve requirements during the year as well as estimated average operating reserve requirements had the changes associated with BAL-002-2 not been implemented.[144] Actual day-ahead operating reserve requirements were higher than estimated requirements without the change during morning hours ending 1 through 7 and evening hours ending 19 through 24, on average.

This difference was largely driven by increases in the first and second quarter when actual requirements were 900 MW greater on average during these hours.

During the third quarter when loads were higher, the impact of the new definition on operating reserve requirements was largely limited to morning hours. During the fourth quarter, Pacific DC Intertie schedules infrequently set the operating reserve requirements as the most severe single contingency.

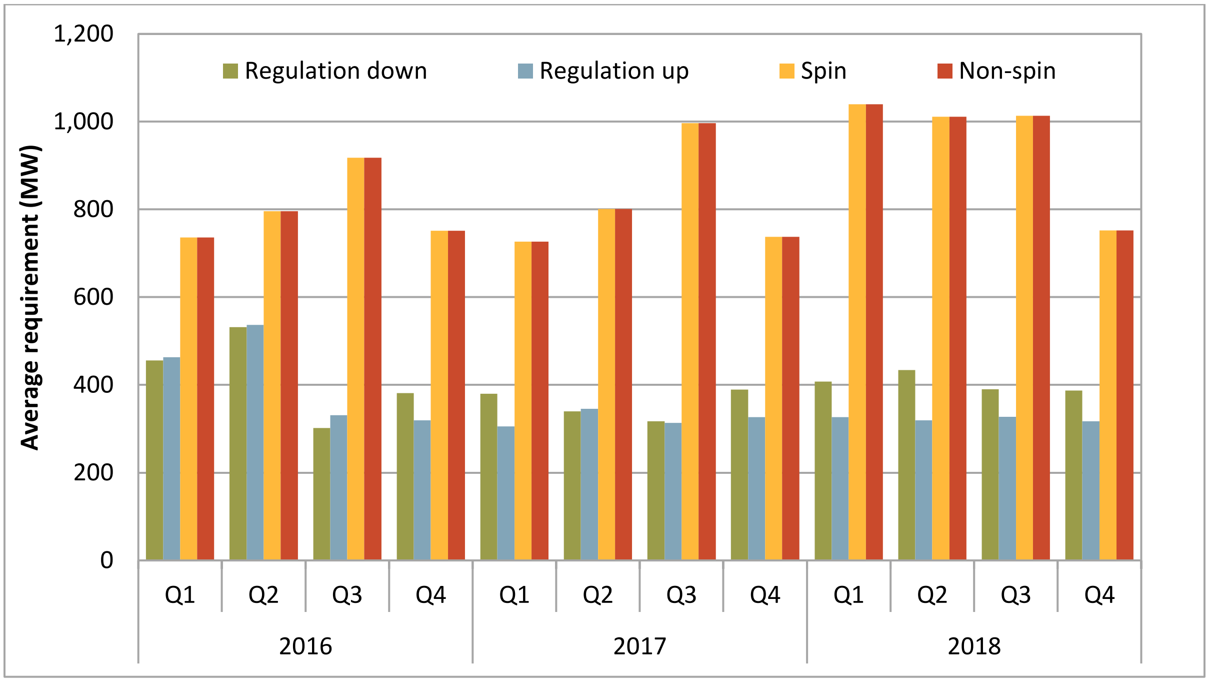
Figure 6.4 includes quarterly average day-ahead operating reserve requirements since 2016. During 2018, combined requirements for spinning and non-spinning operating reserves averaged around 1,900 MW, compared to around 1,600 MW in each of 2017 and 2016. The increases in operating reserve requirements associated with the BAL-002-2 reliability standard were mostly during off-peak periods in the first and second quarter when prices were lower which lessened the impact on overall costs.

Figure 6.3 Hourly average operating reserve requirements (2018)



[144] Corresponding values for the real-time requirement are not included, but show a similar pattern.

Figure 6.4 Quarterly average ancillary service requirements



Regulation requirements

Since October 2016, the ISO calculates regulation requirements based on observed regulation needs during the same time period in the prior year. Requirements are calculated for each hour of the day, and the values are updated regularly. Furthermore, the ISO can adjust requirements manually for periods when conditions indicate higher net load variability.

Figure 6.4 also shows average regulation requirements by quarter. During 2018, day-ahead requirements averaged around 400 MW for regulation down and 320 MW for regulation up. Compared to 2017, this represents an increase of about 14 percent for regulation down and almost no change for regulation up. In the real-time market, average requirements were very similar to requirements in the day-ahead market during 2018.

During 2018, regulation requirements were typically set at increments of 50 MW between 300 MW and 650 MW. Figure 6.5 summarizes the average hourly profile of the day-ahead regulation requirements in this period. Regulation up requirements were highest during afternoon hours. Requirements for regulation down were typically highest in morning hours when solar is ramping on and evening hours when solar is ramping off. Requirements for regulation down were typically higher than requirements for regulation up.

Figure 6.5 Hourly average day-ahead regulation requirements (2018)

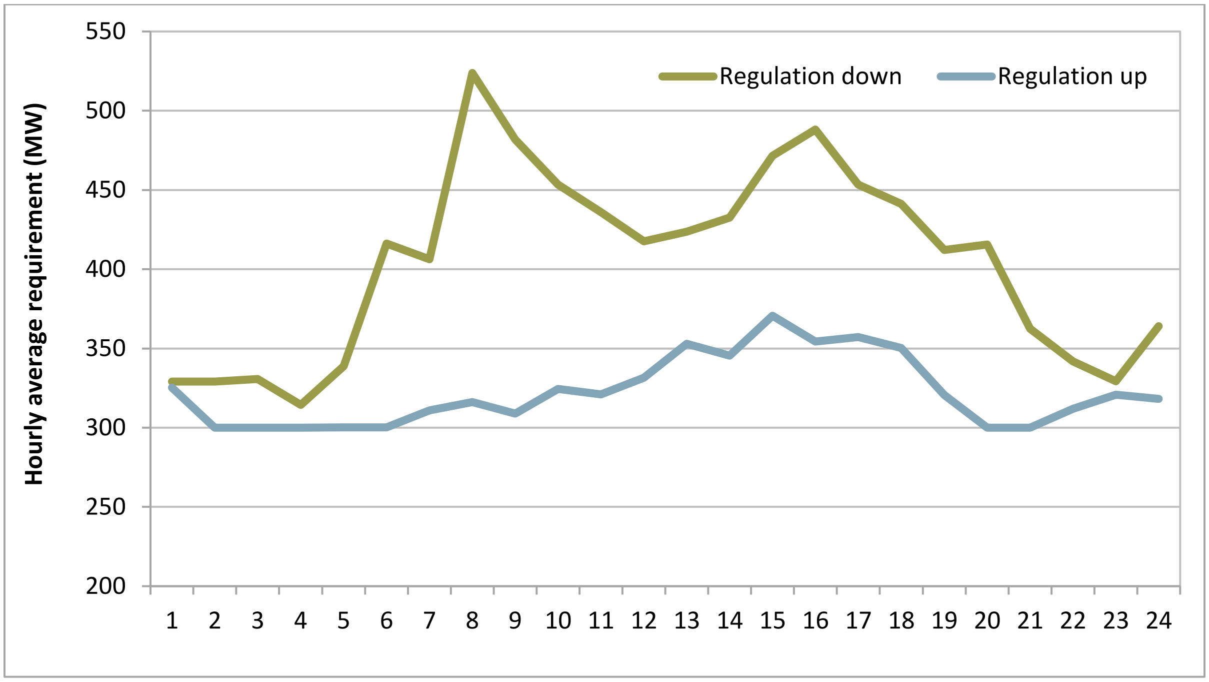
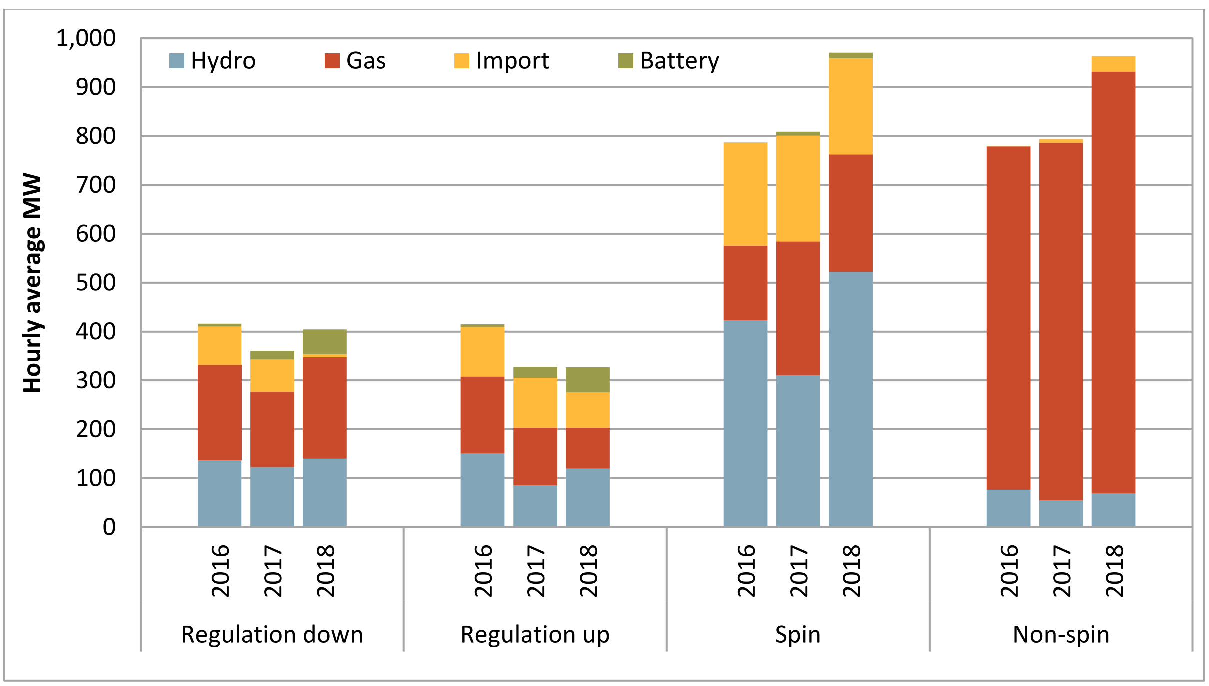


Figure 6.6 Procurement by internal resources and imports



Ancillary service procurement by fuel

Figure 6.6 shows the portion of ancillary services procured by fuel type from 2016 through 2018. Ancillary service requirements are met by both internal resources and imports. Ancillary service imports are indirectly limited by minimum requirements set for procurement of ancillary services from within the ISO system. In addition, ancillary services that bid across interties have to compete for transmission capacity with energy. Most ancillary service requirements continue to be met by ISO resources, partly because scheduling coordinators awarded ancillary services are charged applicable intertie congestion rates.

Total procurement of regulation in 2018 increased slightly compared to 2017. Total procurement of spinning and non-spinning reserves increased significantly from the previous year because of increased operating reserve requirements associated with BAL-002-2. The composition of ancillary service resources is characterized as follows:

- Compared to 2017, hydroelectric resources in 2018 provided a larger proportion of ancillary services overall although there were worse hydroelectric generation conditions. This reflects a shift towards providing ancillary services in lieu of hydroelectric production. Average hourly procurement of ancillary services from hydroelectric resources increased in 2018 to 850 MW. This is a 48 percent increase from around 574 MW in 2017.
- Average hourly procurement of ancillary service imports decreased from around 390 MW in the previous year to around 307 MW. In particular, imports only provided 2 percent of regulation down capacity, compared to about 18 percent in the previous year.
- Gas-fired resources provided 1,396 MW on average in 2018, up 9 percent from 1,276 MW in 2017. These resources provided the vast majority of non-spinning reserves, as in previous years.
- Average hourly provision of ancillary services from limited energy storage resources which includes batteries and other limited devices increased significantly during 2018, but remained low overall. Average hourly procurement from these resources for ancillary services increased from around 48 MW in 2017 to 113 MW in 2018, or about 4 percent of ancillary service procurement.

6.3 Ancillary service pricing

Resources providing ancillary services receive a capacity payment at market clearing prices in both the day-ahead and real-time markets. Capacity payments in the real-time market are only for incremental capacity above the day-ahead award. Figure 6.7 and Figure 6.8 show the weighted average market clearing prices for each ancillary service product by quarter in the day-ahead and real-time markets during 2017 and 2018.

As seen in Figure 6.7, weighted average day-ahead prices for regulation increased from 2017 to 2018. The increase was largest for regulation down, primarily because of slightly higher requirements and tight supply conditions in the third quarter. Weighted average day-ahead prices for spin and non-spin operating reserves also reached their highest levels in the third quarter, at around \$15/MWh and \$8/MWh, respectively. Overall, day-ahead prices for operating reserves decreased slightly relative to the previous year.

Figure 6.7 Day-ahead ancillary service market clearing prices

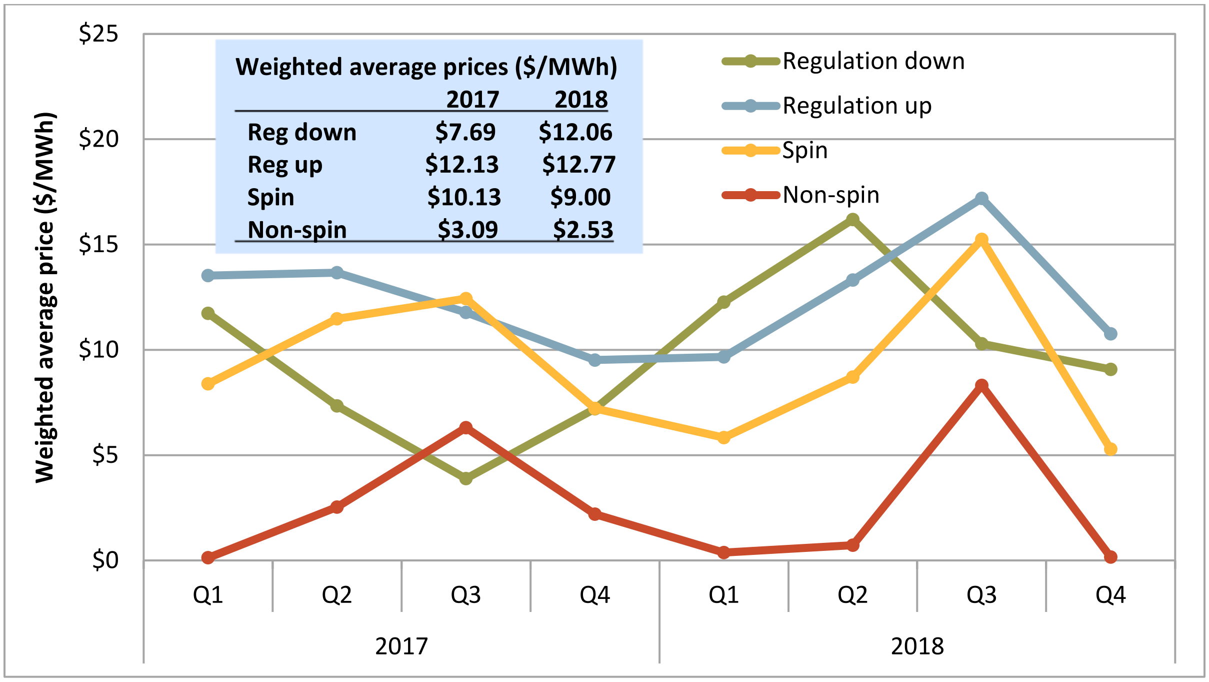
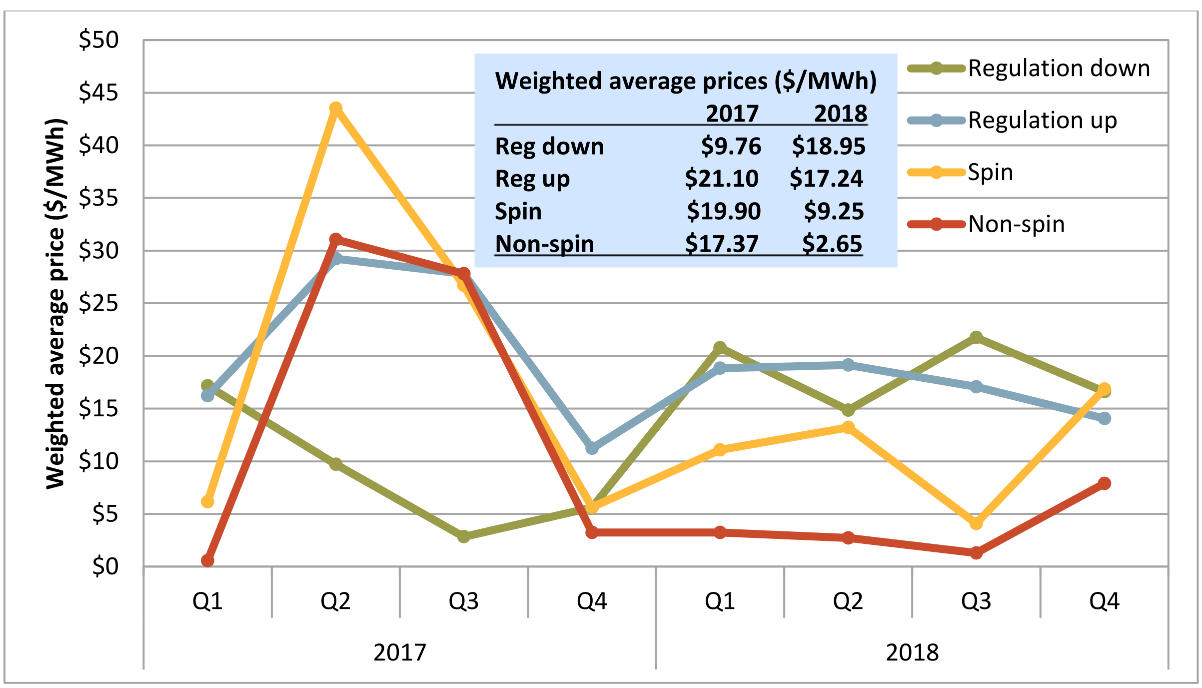


Figure 6.8 Real-time ancillary service market clearing prices



The weighted average market clearing prices for mileage up and mileage down remained low throughout 2018 in both the day-ahead and real-time markets. The day-ahead weighted average price for mileage up and mileage down was about the same from the previous year at about $0.02 per unit in 2018. In the real-time market, weighted average mileage prices were similar. One reason for the low average prices of mileage is that the least-cost regulation resources often supplied sufficient mileage to meet requirements, resulting in frequent non-binding mileage requirements and $0/MWh market clearing prices.

6.4 Ancillary service scarcity

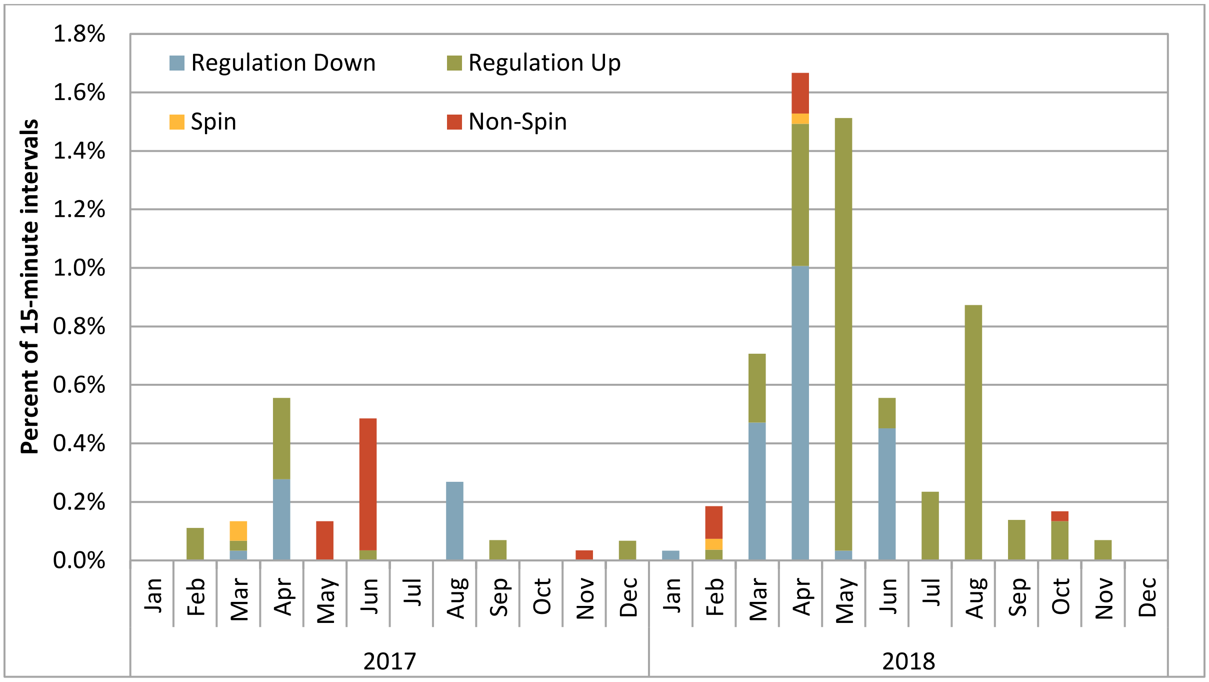
Ancillary service scarcity pricing occurs when there is insufficient supply to meet reserve requirements. Under the ancillary service scarcity price mechanism, implemented in December 2010, the ISO pays a pre-determined scarcity price for ancillary services procured during scarcity events. The scarcity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

Figure 6.9 shows the monthly frequency of ancillary service scarcities in the 15-minute market by type. Similar to the previous year, there were no day-ahead market ancillary service scarcities during 2018. However, there were over 180 valid scarcity intervals in the 15-minute market with most occurring between March and August. In comparison, there were 54 instances during 2017 and 26 instances in all of 2016. During 2018, 62 percent of the scarcity intervals were for regulation up while 33 percent were for regulation down. By region, around 61 percent of scarcity events occurred in the expanded South of Path 26 region, 24 percent in the recently enforced North of Path 26 region, and 14 percent in the expanded system region.

The increase in scarcity events in real-time from the previous year is associated with a combination of two factors: (1) modifications to the ancillary service requirements and (2) observed changes of available capacity between the day-ahead and 15-minute markets. Higher operating reserve requirements and the enforcement of a North of Path 26 sub-regional requirement in 2018 increased demand for regionally limited supply to meet ancillary service requirements. The majority of scarcity events were triggered by decreases in available ancillary services in real-time from schedules in the day-ahead market.

In particular, ancillary services scheduled in the day-ahead market can be capped in real-time at telemetry limits submitted by the plant, which can be as little as a fraction of a megawatt less than the day-ahead schedule. That shortfall must then be replaced by other units to meet ancillary service requirements in the real-time market. However, it can often be economic to relax the requirement in this scenario at the scarcity price in lieu of committing a unit or moving a unit to a higher bid segment. This is because the majority of ancillary services are settled at the day-ahead market price with only incremental real-time awards settled at the 15-minute market price. For this reason, 74 percent of the scarcities in 2018 were for less than 5 MW.

Figure 6.9 Frequency of ancillary service scarcities (15-minute market)



6.5 Ancillary service compliance testing

Resources may be subject to two types of testing: performance audits and compliance tests. A performance audit occurs when a resource is flagged for failing to meet dispatch during a contingency run. The compliance test is an unannounced test when a resource is called upon to produce energy at a time when it is scheduled to hold reserves. Failing either of these tests results in a warning notice, after which the resource will be subject to a second test. Failing the second test results in disqualification of the resource for the particular ancillary service and rescission of payments that were made to the resource as payment for ancillary services provided. The ISO can initiate a compliance test without the resource first experiencing a contingency related performance audit.[145]

During 2018, the ISO performed a total of 145 performance audits and unannounced compliance tests for resources with spinning or non-spinning reserves. Resources failed around 19 percent of these tests. Two failures occurred during a period when a warning notice for the resource was in effect, resulting in disqualification of these units for the concerned ancillary service.

Effective January 1, 2019, the ISO adopted a new policy for regulation testing and recertification.[146] Resources that fall below a performance threshold will receive a warning notice in the first month of the following quarter followed by a performance evaluation in the next two months. Resources that fail to meet the performance evaluation threshold will be decertified from providing the ancillary service.

[145] For more information about the ISO's ancillary service testing procedures, see Operating Procedure 5370: http://www.caiso.com/Documents/5370.pdf.

[146] For more information on the changes to regulation testing and recertification, see: https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=1095&IsDlg=0.

7 Market competitiveness and mitigation

This chapter assesses the competitiveness of the ISO's energy markets, local capacity areas, and the impact and effectiveness of various market power mitigation provisions. Key findings include the following:

- Overall prices in the ISO energy markets in 2018 were competitive, averaging close to what DMM estimates would result under highly efficient and competitive conditions, with most supply being offered at or near marginal operating cost.
- The day-ahead energy market, which accounts for most of the total wholesale market, remained competitive during most hours in 2018. However, analysis also indicates that prices may have been significantly in excess of competitive levels in some peak summer hours.
- The ISO has initiated a stakeholder process to assess the structural competitiveness of the ISO's energy market and potentially develop system market power mitigation measures.[147]
- The market for capacity needed to meet local resource adequacy requirements continues to be structurally uncompetitive in almost all local areas.
- The dynamic path assessment used to trigger local market power mitigation accurately identified non-competitive constraints in the day-ahead and real-time markets in 2018. This automated test is incorporated in the market software to determine the structural competitiveness of transmission constraints based on actual system and market conditions in each interval.
- Most resources subject to mitigation submitted competitive offer prices, so that a very low portion of bids were lowered as a result of the bid mitigation process. The number of units in the day-ahead market that had bids changed by mitigation remained low at an average of about 3 units per hour.
- The number of units with bids lowered by mitigation in the 15-minute market also remained low, averaging 1.6 per hour in the ISO and 1.4 per hour in the EIM. In the 5-minute market, the number of units with bids lowered by mitigation averaged 3.6 per hour in the ISO and 1.2 units in the EIM.
- In the day-ahead and real-time markets, the frequency and impact of automated bid mitigation increased significantly in 2018 compared to 2017 in both the ISO and EIM. However, the overall impact of this mitigation remained low.
- The above-market costs associated with exceptional dispatches increased in 2018, totaling about $52 million compared to $20.6 million in 2017 and $10.7 million in 2016. The majority of this cost was associated with exceptional dispatch commitments to run at minimum operating level, rather than for exceptional dispatches for additional energy above minimum levels.
- Local market power mitigation of exceptional dispatches for energy played a significant role in limiting above-market costs in 2018, reducing above-market costs by about $18 million in 2018 compared to $33,000 in 2017.

[147] Stakeholder process information is available here: http://www.caiso.com/informed/Pages/StakeholderProcesses/SystemMarketPower.aspx

7.1 Day-ahead energy market

DMM's 2017 annual report provided analysis showing that while the day-ahead market was competitive during most hours, the day-ahead market was showing some signs of becoming less competitive in a growing number of hours.[148] DMM recommended that the ISO begin to consider various actions that might be taken to reduce the likelihood of conditions in which system market power may exist and to mitigate the impacts of system market power on market costs and reliability.[149]

In 2018, the ISO initiated a process to analyze the structural competitiveness of the ISO system and then potentially consider options for mitigating system market power.[150] As the initial step in this process, the ISO has provided hourly residual supply indices for the day-ahead energy market in 2018.[151] DMM will continue to participate in this process and work with the ISO towards measuring structural competitiveness of the ISO system.

7.2 Competitiveness of bids for gas-fired units

One indicator of market competitiveness is the degree to which suppliers offer supply into the market at prices close to marginal cost. ISO markets classify each supplier as either a net seller or a net buyer, based on purchases and sales over an extended period. Net buyers are not considered potentially pivotal in ISO markets as these suppliers are assumed to have no incentive to offer capacity into the market above marginal cost.

Figure 7.1 compares input energy bids to reference marginal costs (default energy bids) for gas generation held by net buyers. The blue line shows supply energy bids for these resources in the day-ahead market for hour-ending 20 on July 24 of 2018.[152] During this hour, day-ahead system marginal energy prices reached a record high at almost $980/MWh. The supply curve shown in green shows the marginal cost reference constructed from the default energy bids associated with each bid segment. For all but a 1,000 MW segment at the peak of the curve, supply from net buyers is offered into the market at or below default energy bid reference levels.

Figure 7.2 provides the same comparison for gas capacity held by net sellers in this hour. For net sellers, input bids are at or below default energy bids for the first approximately 6,000 MW segment of the curve, but exceed reference levels for the remaining 4,000 MW of supply. This difference in bidding behavior, which has been observed in other hours, is consistent with non-competitive conduct in the presence of market power.

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[148] *2017 Annual Report*, p. 153.

[149] *2017 Annual Report*, p. 251.

[150] Stakeholder process information is available here: http://www.caiso.com/informed/Pages/StakeholderProcesses/SystemMarketPower.aspx

[151] Wang, Jiankang and Guillermo Bautista Aldereté, System Market Power discussion, Market Surveillance Committee April 5, 2019. http://www.caiso.com/Documents/SystemMarketPower-Presentation-Apr5_2019.pdf#search=system%20market%20power

[152] Supply curves depicted in Figure 7.1 and Figure 7.2 show the incremental amount for each bid segment and therefore do not account for the generation associated with the minimum operating levels of the resources. Self-scheduled generation is depicted on the charts at -$190/MWh for illustrative purposes.

Figure 7.1 Net buyers supply input bid and reference, July 24, 2018 hour 20

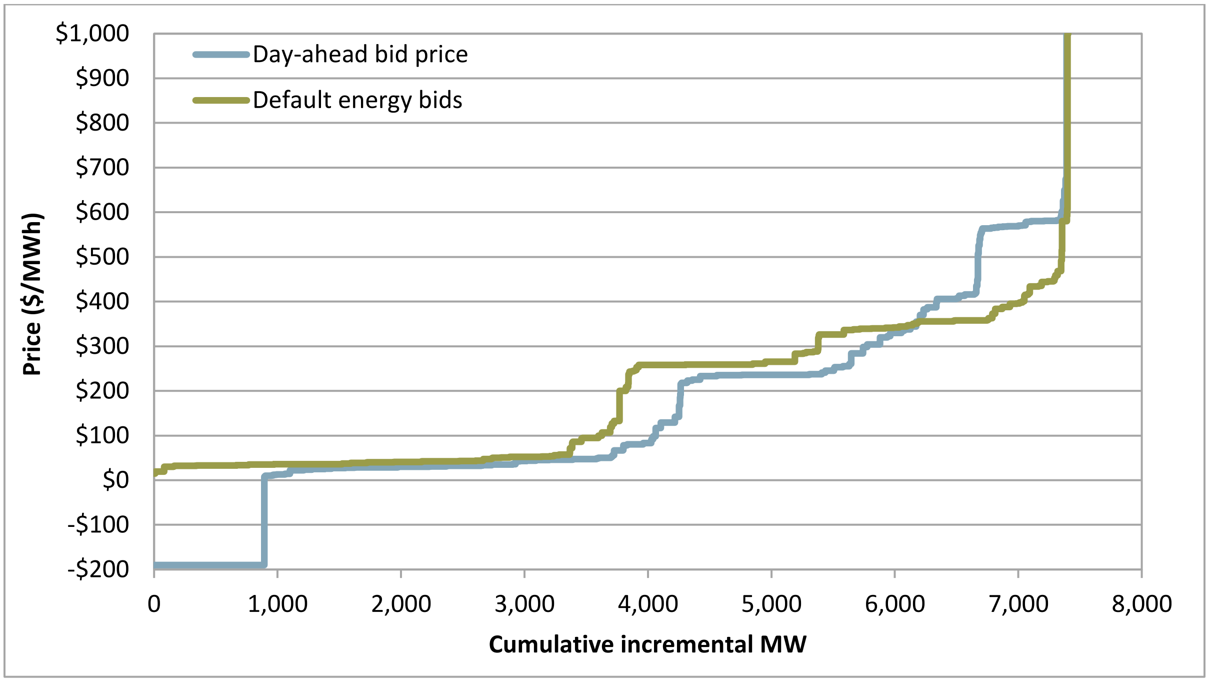
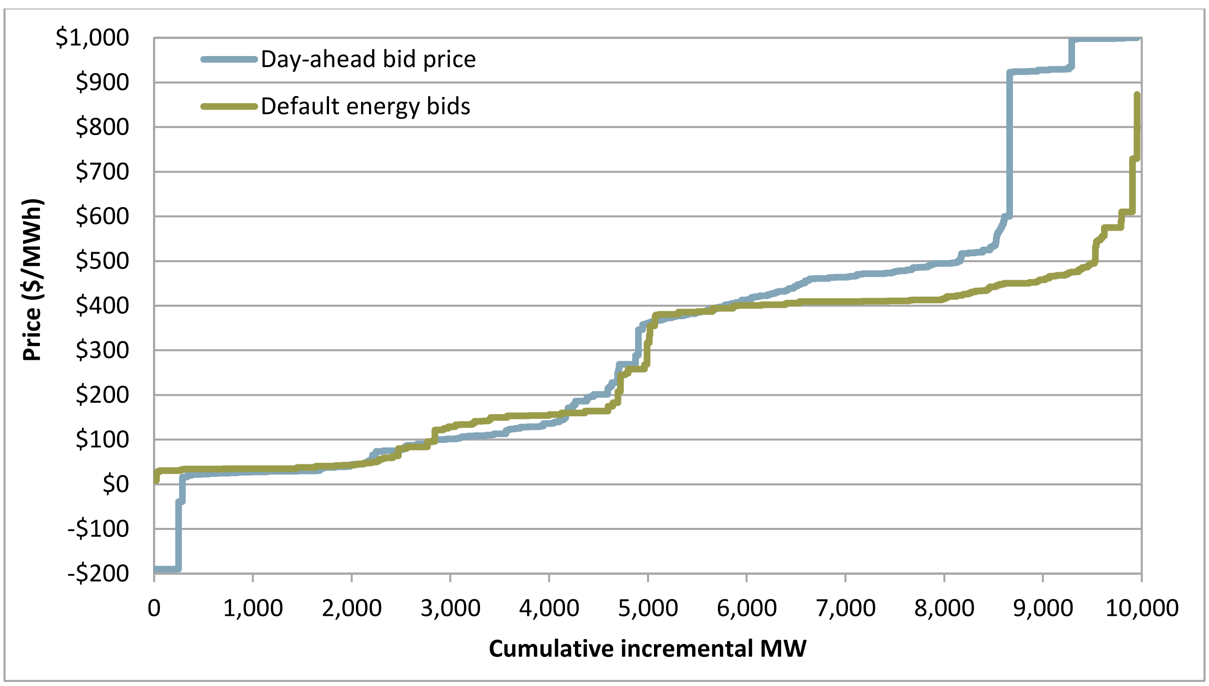


Figure 7.2 Net sellers supply input bid and reference, July 24, 2018 hour 20



7.3 Competitiveness of day-ahead market prices

The competitiveness of overall market performance can be assessed based on the *price-cost markup*, which represents a comparison of actual market prices to an estimate of prices that would result in a highly competitive market in which all suppliers bid at or near their marginal costs.[153] DMM refers to this counterfactual competitive scenario as the *competitive baseline price*. DMM calculates this competitive baseline price by recalculating day-ahead market prices after replacing the market bids of all gas-fired units with bids designed to represent each unit's actual marginal costs. The price-cost markup is a measure of the degree to which market prices exceed this competitive baseline price (in $/MWh or as a percentage of the market price).[154]

In some years, DMM has estimated the price-cost markup for the day-ahead market by rerunning a version of the market software after replacing the market bids of all gas-fired units with default energy bids (DEBs) used in local market power mitigation. However, because a significant amount of gas-fired supply is bid at prices lower than the unit's default energy bid (which includes a 10 percent adder), using default energy bids tends to overestimate the competitive baseline price. In addition, analysis using this software could not be completed for a significant number of days in 2017 and 2018.[155] Limited analysis performed using this day-ahead market software for days in 2017 and 2018 is provided in Section 7.3.3.

This report also assesses the competitiveness of prices in the day-ahead market using two other methodologies. The first method estimates the price-cost markup by recalculating prices based on the intersection of hourly day-ahead supply and demand curves constructed from market bids and cost-based bids for each unit. The second method assesses the competitiveness of prices based on the difference between the system marginal energy cost and the cost of the highest cost gas-fired resource dispatched in the day-ahead market. As discussed below, both of these analyses indicate that prices have been generally competitive, but have been significantly in excess of competitive levels in some hours.

7.3.1 Price-cost markup

For this report, DMM estimated the price-cost markup by recalculating day-ahead prices based on the intersection of hourly day-ahead supply and demand curves constructed from market bids and cost-based bids for each unit. With this approach, day-ahead market prices are first recalculated from actual market bids. This is referred to as the *base case*. A *competitive baseline price* is then calculated after replacing the market bids of selected resources with an estimate of each unit's marginal cost.

[153] *2017 Annual Report on Market Issues and Performance*, Department of Market Monitoring, June 2018, pp. 70.

[154] DMM calculates the price-cost markup index as the percentage difference between load-weighted average day-ahead market base case prices and prices resulting under the competitive baseline scenario. For example, if base case market prices averaged $55/MWh during a month and the competitive baseline price was $50/MWh, this would represent a price-cost markup of 10 percent.

[155] For many days, results for the base case (prior to replacing market bids with default energy bids) are not consistent with actual market prices. In other cases, a model solution cannot be completed. In addition, results that can be obtained tend to exclude days with higher day-ahead prices.

Supply curves for each hour include self-scheduled energy, energy offers from committed resources, and the minimum operating level for those committed units.[156] Demand curves include transmission losses and all self-scheduled and economically bid demand including exports, virtual demand and pumped load.

Supply curves used in the competitive scenario are created by replacing the market bids of some resources with an estimate of each unit's marginal cost.[157] These cost-based bid segments are calculated from the minimum of (1) the energy bid for that hour and (2) the default energy bid. Using the lower of these two bid prices reflects that the default energy bid includes a 10 percent adder and a significant amount of capacity is therefore offered at prices just below the unit's default energy bid.

This simplified approach does not directly account for transmission and other constraints that are included in the ISO's day-ahead market software. The base scenario price and competitive scenario cost are not intended to perfectly replicate the market. The price-cost markup calculated for each hour is solely a function of high priced energy offers from gas units moving to lower points in the supply stack and shifting the intersection of the supply and demand curves.

In this analysis, the set of resources with bids changed in the competitive scenario is limited to gas resources that were actually committed in the day-ahead market. This approach does not account for potential economic withholding by units that were not committed in the day-ahead market due to bids in excess of costs. As a result, this approach is likely to underestimate the price-cost markup.

Figure 7.3 summarizes results of this analysis in terms of average load-weighted annual prices in 2018 for each operating hour of the day. The green line shows the average day-ahead system marginal energy price; the blue line shows the average base case price calculated using this simplified approach with actual bids; and the dotted red line shows the average competitive baseline price calculated with cost-based bids for gas fired units.

As shown in Figure 7.3, the base case price is below average day-ahead prices in all hours. This is likely due to additional constraints included in the ISO's day-ahead market software that are not captured in the simplified base case. However, the price-cost markup in each hour is based on the difference between the base case price and the competitive scenario price. This approach controls for modeling differences that can cause the base case price to be lower than actual day-ahead prices.

As shown in Figure 7.3, the average competitive scenario price is slightly less than the estimated base case price in most hours, but is roughly $2/MWh to $3/MWh lower during the hours when net loads are highest. In 2018, this analysis indicates a load weighted average price-cost markup of about $0.76/MWh or just under 2 percent of the average day-ahead energy price.

The price-cost markup measured with this approach increased in these hours between 2017 and 2018. Figure 7.4 shows average markups by hour for both 2017 and 2018. In both years, markups are greatest

[156] Supply curves also include offers from virtual supply and any other resource type without commitment costs. In addition, the capacity between configurations of multi-stage generation resources, committed or uncommitted in the market, is included if the resource itself is committed. Energy offers that were economic but did not clear the optimization (for instance due to an ancillary service award, use limitation, or commitment status) are assumed to be unavailable to provide energy and are not included as available supply.

[157] The competitive scenario replaces bids for a limited set of resources: gas-fired resources committed in the day-ahead market. This set includes uncommitted configurations of committed multi-stage generators.

in the peak hours of the day (hours ending 18 through 21). However, since prices were significantly lower in 2017, the price-cost markup in 2017 was about $0.54/MWh compared to $0.76/MWh in 2018.

Figure 7.5 shows a duration curve of the price-cost markup calculated with this approach during the hours with the highest markup in 2017 and 2018. As shown in the figure, the number of hours with markup greater than $20/MWh increased from 5 to 19 between 2017 and 2018. When comparing results between these two years, it should be noted that loads were significantly lower in 2018. As noted in Chapter 1, peak load in 2018 (46,427 MW) was slightly lower than the ISO's 1-in-2 year load forecast, while peak load in 2017 (50,116 MW) exceeded the ISO's 1-in-10 year load forecast.

Figure 7.3 Load-weighted average system marginal price, base case price, and competitive scenario price (2018)

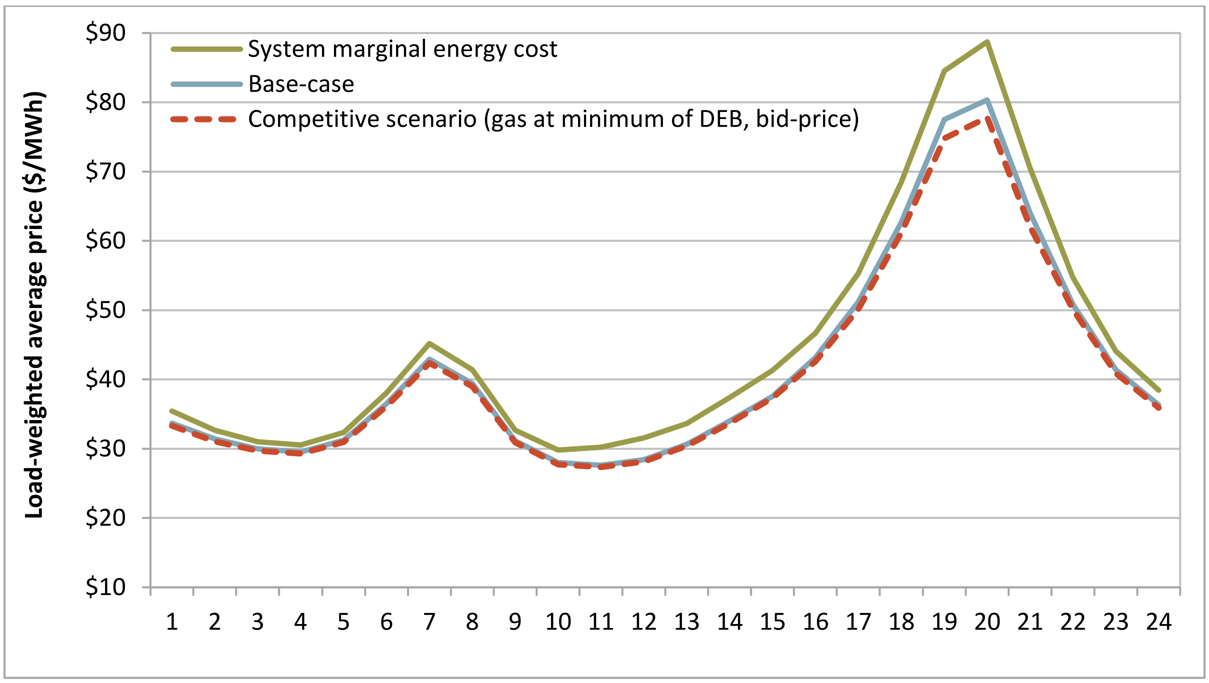


Figure 7.4 Load-weighted average hourly price-cost markup (2017-2018)

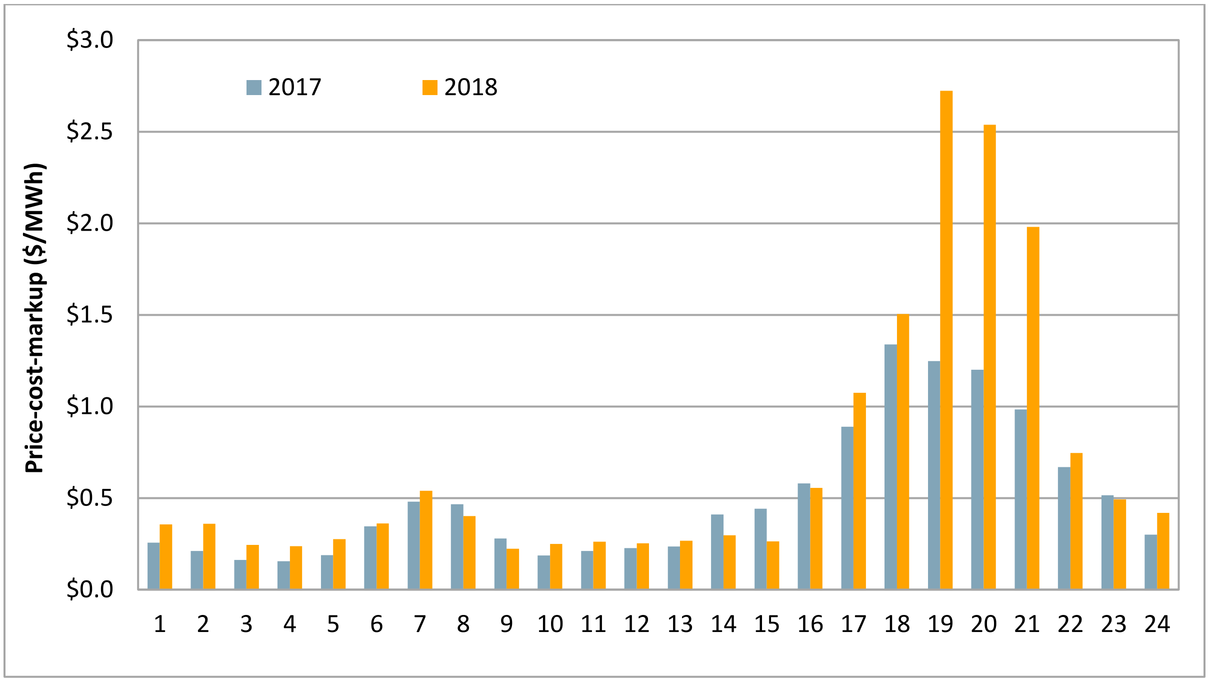
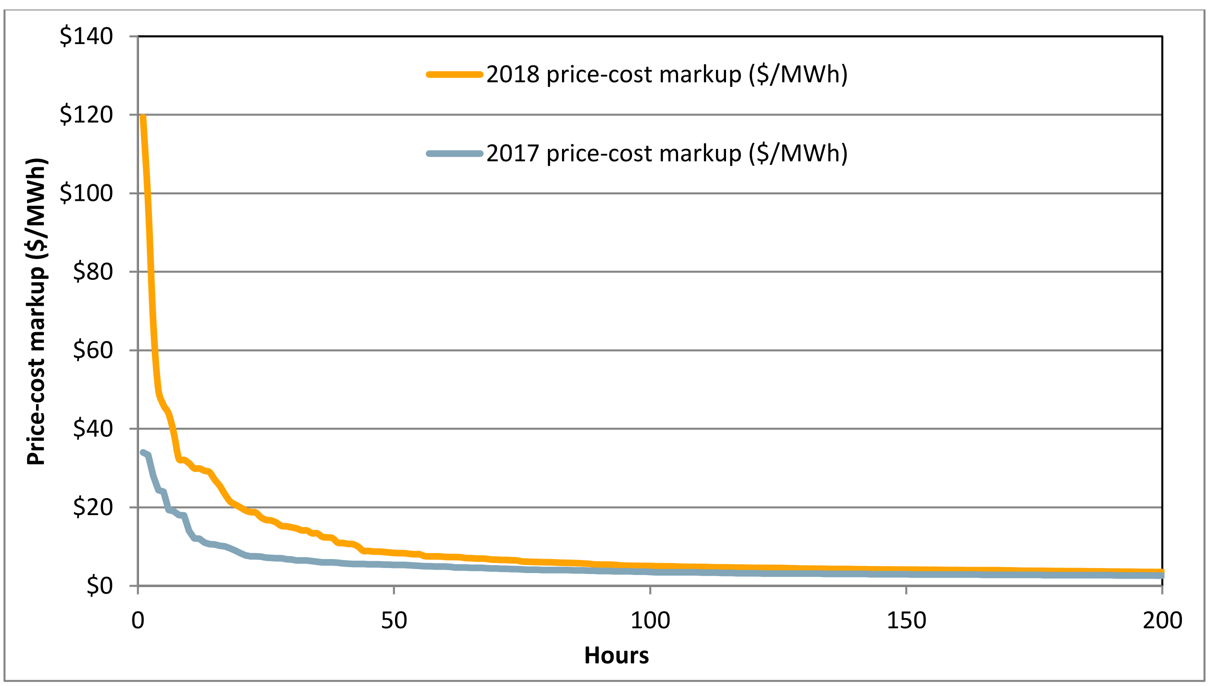


Figure 7.5 Duration curve of highest hourly price-cost markups



7.3.2 Highest cost of gas units dispatched

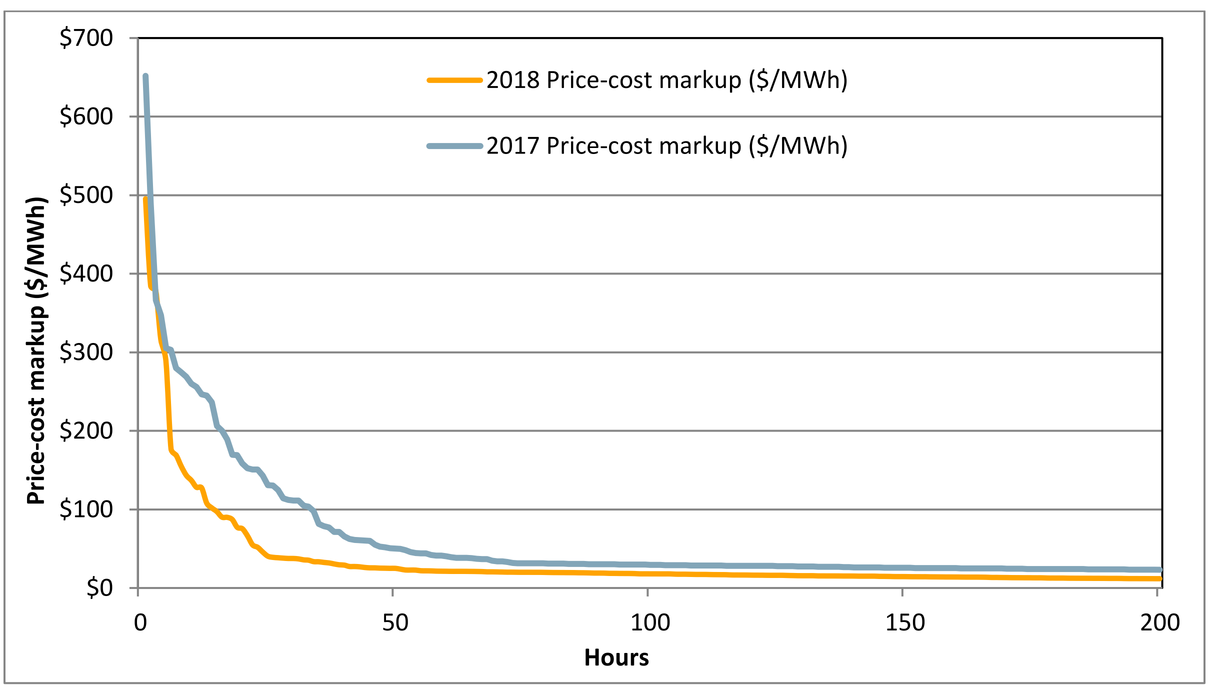
Another approach for assessing the competitiveness of day-ahead prices in specific hours is to compare the system marginal energy cost to the bid cost of the gas unit with the highest marginal cost that was dispatched by the day-ahead software. As in the price-cost markup analysis, each unit's marginal cost is based on the minimum of (1) each gas resource's final energy bid for that hour and (2) the unit's default energy bid.

The approach does not account for *economic withholding,* or bidding some lower cost supply at relatively high prices so that higher cost units must be dispatched and market prices are higher. The approach also does not account for the fact that some higher cost units may be dispatched by the day-ahead software due to unit constraints, congestion or other constraints, rather than to meet system wide energy demand. This analysis ignores non-gas-fired capacity with bid cost greater than the highest marginal cost dispatched gas resource.

Figure 7.6 shows a duration curve of this measure during high priced hours in 2017 and 2018. The price-cost markup shown in Figure 7.6 is the amount ($/MWh) by which the system price exceeded their bid costs. Most of the hours with the highest price-cost markup in the day-ahead market are during the evening ramping hours (hours ending 18 to 21) when net demand that needs to be met by gas-fired capacity is highest.

As shown in Figure 7.6, by this measure, the hours with high price-cost markups in the day-ahead market dropped in 2018 compared to 2017. This decrease may be due, in part, to the increased gas costs and lower peak and net loads that occurred in 2018 compared to 2017.

Figure 7.6 Price-cost markup based on gas-fired units dispatched (2017-2018)



7.3.3 Day-ahead market software simulation

In some years, DMM has estimated the price-cost markup for the day-ahead market by rerunning a version of the market software after replacing the market bids of all gas-fired units with default energy bids used in local market power mitigation. However, because a significant amount of gas-fired supply is bid at prices lower than the unit's default energy bid (which includes a 10 percent adder), using default energy bids tends to overestimate the competitive baseline price. In addition, analysis using this software could not be completed for a significant number of days in 2017 and 2018.[158] Results for days that could be successfully analyzed with this method tend to exclude some higher-priced summer days, when DMM's review indicates that prices may have been significantly in excess of competitive levels in some hours.

Figure 7.7 compares the competitive benchmark prices to load-weighted prices in the day-ahead market. DMM could not perform this analysis for the early part of 2017 with the software provided by the ISO due to problems with the automated inputs for the competitive scenario.[159] The chart below presents current results for June 2017 through December 2018.

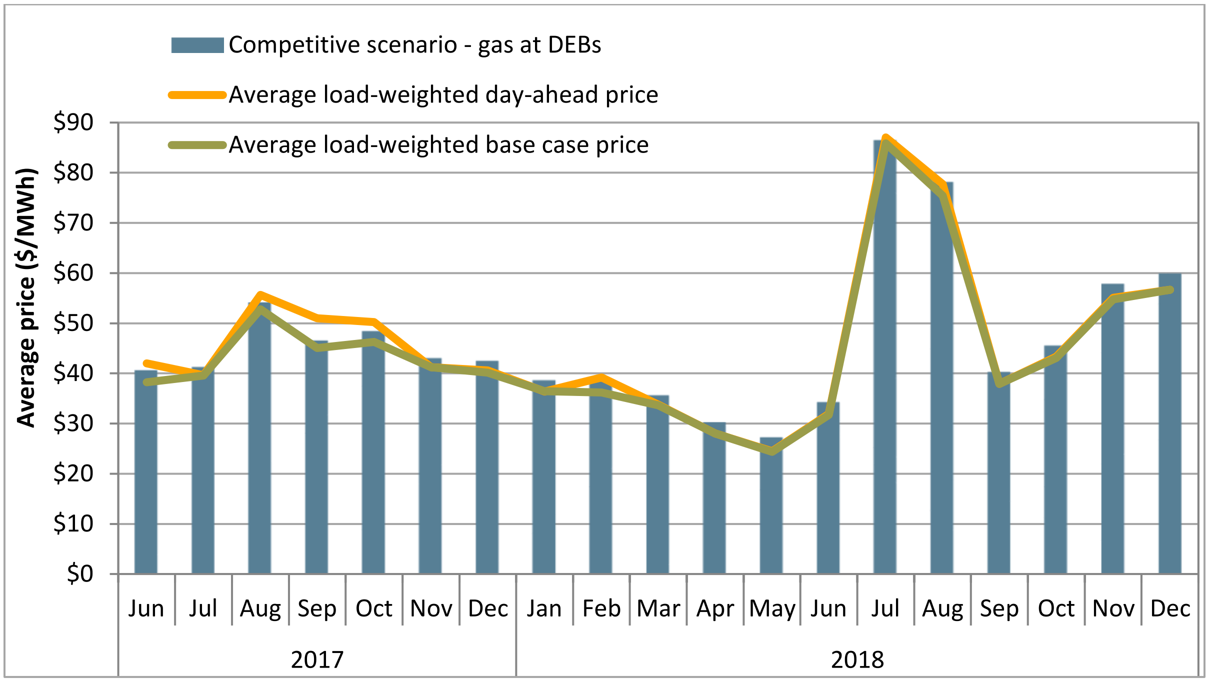
As shown in Figure 7.7, prices in the day-ahead market were similar to or slightly below the competitive benchmark on an average basis in all available months. DMM calculates the day-ahead price-cost markup by comparing the competitive benchmark to the base case load-weighted average price for all energy transactions in the day-ahead market.

Of cases passing DMM's screens for accuracy of the market reruns, the price-cost markup in 2018 was -$2.49/MWh or about -5 percent. This -5 percent markup is within the range that can be caused by the 10 percent headroom above marginal cost which is included in the default energy bids used in the market re-run to determine the competitive baseline.

[158] For 16 days in 2018 and 4 in 2017, results for the base case (prior to replacing market bids with default energy bids) are not consistent with actual market prices. Six of the missing dates were in July, a particularly high cost month.

[159] Beginning in late 2014, a new version of the competitive scenario was provided to DMM by the market software vendor as a standalone component in the market software. Two errors in the competitive scenario definition built into this software biased the results to such a degree that they were not reliable as a basis for assessing competitiveness. These errors have been resolved.

Figure 7.7 Comparison of competitive baseline price with day-ahead prices



Additional analysis of energy market prices relative to gas prices in the ISO also suggests that average daily prices in 2018 closely tracked the marginal costs of a relatively efficient gas-fired unit. While these results provide further indication that ISO system prices were generally competitive in 2018, DMM's review indicates that prices may have been significantly in excess of competitive levels in some peak summer hours.

7.4 Capacity in local reliability areas

The ISO has defined 10 local capacity areas for which local reliability requirements are established under the state's resource adequacy program. In most of these areas, a high portion of the available capacity is needed to meet peak reliability planning requirements. One or two entities own most of the generation needed to meet local capacity requirements in each of these areas.

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

- **Pivotal supplier test.** If supply is insufficient to meet demand with the supply of any individual supplier removed, then this supplier is pivotal. This is referred to as a single pivotal supplier test. The two-pivotal supplier test is performed by removing supply owned or controlled by the two largest suppliers. For the three-pivotal test, supply of the three largest suppliers is removed.

- **Residual supply index.** The residual supply index is the ratio of supply from non-pivotal suppliers to demand.[160] A residual supply index less than 1.0 indicates an uncompetitive level of supply.

In the electric industry, measures based on two or three suppliers in combination are often used because of the potential for oligopolistic bidding behavior. In this report, when the residual supply index is calculated by excluding the largest supplier, we refer to this measure as RSI_1. With the two or three largest suppliers excluded, we refer to these results as RSI_2 and RSI_3, respectively.[161]

Table 7.1 provides a summary of the residual supply index for major local capacity areas in which the total local resource adequacy requirement exceeds capacity held by net buyers. These areas have a net non-load-serving entity capacity requirement. The demand in this analysis represents the local capacity requirements set by the ISO. Load-serving entities meet these requirements through a combination of self-owned generation and capacity procured though bilateral contracts. For this analysis, we assume that all capacity scheduled by load-serving entities will be used to meet these requirements, with any remainder procured from non-load-serving entities that own generation in the local area.

Table 7.1 shows that the total amount of supply owned by non-load-serving entities meets or exceeds the additional capacity needed by load-serving entities to meet these requirements in all local capacity areas with a net non-load-serving entity local capacity requirement except Stockton. However, in some areas, at least one supplier is individually pivotal for meeting the remainder of the capacity requirement. In other words, some portion of these suppliers' capacity is needed to meet local requirements.

Key finding of this analysis include the following:

- The North Coast/North Bay, Sierra, Stockton, LA Basin, and San Diego/Imperial Valley local areas are not structurally competitive because there is at least one supplier that is pivotal and controls a significant portion of capacity needed to meet local requirements.

- The Greater Bay local area is not structurally competitive under a two pivotal supplier test. In 2017, the Greater Bay local area was not structurally competitive under a single pivotal supplier test.

- In 2017, LA Basin did not have a net non-load-serving entity capacity requirement, since the amount of capacity owned or under a tolling contract by load-serving entities exceeded the area requirements. In 2018, there is one single non-load-serving entity supplier that is pivotal. This reflects a change in the contractual control of a significant portion of supply in the area in 2018.

- All other local areas that were not structurally competitive in 2018 were not structurally competitive in 2017.

In addition to the capacity requirements for each local area used in this analysis, additional reliability requirements exist for numerous sub-areas within each local capacity area. Some of these require that capacity be procured from specific individual generating plants. Others involve complex combinations of units that have different levels of effectiveness at meeting the reliability requirements.

These sub-area requirements are not formally included in local capacity requirements incorporated in the state's resource adequacy program. However, these additional sub-area requirements represent

[160] For instance, assume demand equals 100 MW and the total available supply equals 120 MW. If one supplier owns 30 MW of this supply, the residual supply index equals 0.90, or (120 – 30)/100.

[161] A detailed description of the residual supply index was provided in Appendix A of DMM's 2009 annual report.

additional sources of local market power. If a unit needed for a sub-area requirement is not procured in the resource adequacy program, the ISO may need to procure capacity from the unit using the backstop procurement authority under the capacity procurement mechanism of the ISO tariff.[162]

Table 7.1 Residual supply index for major local capacity areas based on net qualifying capacity

Local capacity area	Net non-LSE capacity requirement (MW)	Total non-LSE capacity (MW)	Total residual supply ratio	RSI_1	RSI_2	RSI_3	Number of individually pivotal suppliers
PG&E TAC area							
Greater Bay	1,867	3,648	1.95	1.16	0.53	0.22	0
North Coast/North Bay	503	709	1.41	0.02	0.00	0.00	1
Sierra	281	336	1.19	0.37	0.03	0.02	2
Stockton	115	31	0.27	0.10	0.01	0.00	All*
SCE TAC area							
LA Basin	2,923	4,951	1.69	0.39	0.27	0.18	1
San Diego/Imperial Valley	1,388	1,918	1.38	0.76	0.34	0.10	2

*Available capacity is insufficient to meet the LCA requirement; All supply is needed to contribute toward the LCA requirement

In the day-ahead and real-time energy markets, the potential for local market power is mitigated through bid mitigation procedures. These procedures require that each congested transmission constraint be designated as either competitive or non-competitive. This designation is based on established procedures for applying a pivotal supplier test in assessing the competitiveness of constraints. Section 7.5 examines the actual structural competitiveness of transmission constraints when congestion occurred in the day-ahead and real-time markets.

7.5 Competitiveness of transmission constraints and accuracy of congestion predictions

Local market power is created by insufficient or concentrated control of supply within a local area. In addition to load and generation, the availability of transmission to make additional supply available to meet load in the local area plays an important role in determining where local market power exists.

The ISO local market power mitigation provisions require that each transmission constraint be designated as either *competitive* or *non-competitive* prior to the binding market run using the *dynamic competitive path assessment*, or DCPA. This assessment uses results of a pre-market mitigation run that clears supply and demand with un-mitigated bids. If any internal transmission constraints are binding in the pre-market run they are assessed for competitiveness of supply of counter-flow.

Competitiveness of each constraint is measured using a residual supply index based on supply and demand of counter-flow from internal resources for each binding constraint. If there is sufficient supply of counter-flow for the binding constraint after removing the three largest net suppliers, then the residual supply index is greater than or equal to one, and the constraint is deemed competitive. Otherwise, it is deemed non-competitive. A non-competitive constraint is considered indicative of local

[162] For further information on the capacity procurement mechanism, see Section 10.5.

market power and resources that can supply counter-flow to a non-competitive constraint may subsequently be subject to bid mitigation.

7.5.1 Accuracy of transmission congestion assessment in ISO

Evaluating the performance of the current mitigation procedures involves examining both the accuracy with which the mitigation run predicts congestion that also occurs during the same interval in the market run as well as the portion of constraints congested in the mitigation or market run which are non-competitive. The framework DMM uses to quantify overall accuracy of mitigation procedures is shown in Table 7.2.

All constraint-intervals defined by the *consistent* group in Table 7.3 were congested in both the mitigation run and the market run. When congestion is *resolved in market run* this means that congestion occurs in the mitigation run but is resolved in the market run. In these cases, the congestion may have been resolved due to mitigation. In the real-time market, it is also possible that congestion was resolved because of different inputs in the market run. Otherwise, it is possible that mitigation did not play a role in resolving congestion.

Mitigation is only applied when the congested constraint is deemed non-competitive. As described later in this section, the frequency of such mitigation has been extremely low in both the day-ahead and real-time markets under the current mitigation procedures.

When congestion is *under-identified*, or is not predicted in the mitigation run but then occurs in the market run, mitigation is not applied even if the congested constraint would have been deemed non-competitive. This is referred to as *under-mitigation*. Because the dynamic competitive path assessment procedure does not evaluate uncongested constraints, we do not know exactly how many under-identified constraints would have been deemed competitive or non-competitive. However, as discussed in the following sections, other analysis by DMM indicates that constraints on which congestion occurs are competitive a high portion of the time.

Table 7.2 Framework for analysis of overall accuracy of transmission competitiveness

Congestion prediction (mitigation run vs. market run)	Competitive status	
	Competitive	Non-competitive
Consistent (congested in both runs)	No mitigation	Mitigation applied, congestion present in market run
Resolved in Market Run (congestion present in mitigation run, but resolved in market run)	No mitigation	Mitigation applied, congestion resolved in market run
Under-identified (not congested in mitigation run, congested in market run)	No mitigation	Mitigation not applied, needed in market run

The following analysis is performed at the constraint-interval level. Each time a constraint is congested for a given interval it is counted as one constraint-interval. A total of 100 constraint-intervals, then, could include 100 constraints each congested for 1 interval, or 1 constraint congested for 100 intervals, or 50 constraints each congested for 2 intervals. For day-ahead results, we refer to the constraint-intervals as constraint-hours, as the intervals in the day-ahead market each represent one hour.

Day-ahead market

In the day-ahead market, the mitigation run is performed immediately before the actual market run and uses the same initial input data – except for bids that are mitigated as a result of the market power mitigation run. DMM has found that the congestion predicted in the day-ahead mitigation run is highly consistent with actual congestion that occurs in the subsequent day-ahead market.

The first panel of Table 7.3 shows that 89 percent of congested constraint-hours were consistent in the mitigation and market runs in 2018, which is equal to results for 2017. Congestion was present in the mitigation run but resolved in the market run during 5 percent of constraint-hours, and under-identified during 7 percent of constraint-hours.

If the proportion of competitive to non-competitive constraint-hours was the same for under-identified as for constraints with predicted congestion, then about 1.2 percent of congested constraint-hours may represent missed mitigation in 2018. This is approximately equal to the 1.3 percent share of congested constraint intervals with potential missed mitigation in the previous year.

Table 7.3 Consistency of congestion and competitiveness in local market power mitigation

Market	Congestion prediction	Competitive # constraint intervals	Competitive %	Non-competitive # constraint intervals	Non-competitive %	Total # constraint intervals	Total %
DA	Consistent	23,695	73%	4,998	15%	28,693	89%
	Resolved in Market Run	1,049	3%	536	2%	1,585	5%
	Under-identified	---	---	---	---	2,107	7%
	Total					**32,385**	**100%**
15-minute	Consistent	45,421	76%	8,966	15%	54,387	90%
	Resolved in Market Run	3,021	5%	847	1%	3,868	6%
	Under-identified	---	---	---	---	1,856	3%
	Total					**60,111**	**100%**
5-minute	Consistent	104,493	60%	36,944	21%	141,437	81%
	Resolved in Market Run	23,690	14%	5,876	3%	29,566	17%
	Under-identified	---	---	---	---	3,811	2%
	Total					**174,814**	**100%**

Congestion prediction:
Consistent = Congestion in mitigation and market runs.
Resolved in Market Run = Congestion in mitigation run, congestion resolved in market run.
Under-identified = No congestion in mitigation run, but congestion in market.

Real-time market

No changes were made to the mitigation procedures in the ISO's real-time markets in 2018, and the results were also largely the same as in 2017.

Results in the second panel of Table 7.3 show the accuracy of the 15-minute dynamic competitive path assessment process in predicting congestion in the binding run of the 15-minute market. The assessment run predicted congestion consistently with the binding 15-minute market run during about 90 percent of constraint-intervals, compared to 92 percent in 2017.

Under-identified congestion was the same in 2018 as in 2017, at 3 percent of congested constraint-intervals. Congestion that was resolved in the market run increased from 5 percent in 2017 to 6 percent of congested constraint-intervals in 2018.

About 81 percent of constraint-intervals congested in the assessment run were competitive. If the same ratio of competitive to non-competitive intervals held for the under-identified constraint-intervals, it would suggest that under-mitigation occurred in about one half of 1 percent of the total number of congested constraint-intervals in 2018, which is down from 1 percent in 2017.

Results for the 5-minute market were largely similar in 2018 to 2017. In this case the comparison is to the second half of 2017 when the newer protocol was in place. The third panel in Table 7.3 shows that under predicted constraint-intervals were about 2 percent of the total in the 5-minute market for 2018, identical to the second part of 2017 when the current system was in place. Constraints that were congested in the mitigation run but resolved in the market run made a larger part of the whole in 2018, up to 17 percent from 15 percent in 2017.

7.5.2 Accuracy of transmission congestion assessment for EIM transfer limits

Transfer constraints between balancing areas in the energy imbalance market work differently than flow-based constraints. However, the same logic can be applied to measuring the accuracy of congestion predictions made by local market power mitigation systems. One important difference is that there is no need to include measures of competitiveness in these assessments, since there is a single pivotal suppler in each current balancing area in the energy imbalance market. Results of this analysis for transfer constraints are shown in Table 7.4.

Table 7.4 Accuracy of congestion prediction on EIM transfer constraints

Market	Region	Consistent	Resolved in Market Run	Under identified
FMM	PACE	91%	6%	3%
	PACW	91%	5%	3%
	PGE	92%	5%	3%
	BCHA	91%	6%	3%
	PSEI	90%	6%	4%
	IPCO	91%	6%	2%
	NEVP	93%	4%	2%
	AZPS	92%	5%	3%
RTD	PACE	76%	19%	6%
	PACW	72%	20%	8%
	PGE	73%	19%	7%
	BCHA	68%	27%	5%
	PSEI	67%	25%	8%
	IPCO	76%	18%	6%
	NEVP	78%	18%	5%
	AZPS	73%	22%	5%

In the 15-minute market, congestion on transfer constraints was accurately predicted in around 91 percent of congested constraint-intervals. As shown in Table 7.4, congestion on transfer constraints for each energy imbalance market area was predicted with about the same degree of accuracy, with 90 percent to 93 percent of congested constraint-intervals being congested in both runs. Overall, in all areas, 4 percent or fewer congested constraint-intervals were under-predicted, meaning that possible instances of unmitigated market power were very rare.

In the 5-minute market, the accuracy of predicting congestion on transfer constraints improved substantially from 2017, as shown in the bottom of Table 7.4. In 2018, under prediction of congestion ranged from only 5 to 8 percent of congested constraint-intervals for different transfer constraints.

7.6 Local market power mitigation

This section provides an assessment of the frequency and impact of the automated local market power mitigation procedures described earlier. The section also provides a summary of the volume and impact of non-automated mitigation procedures that are applied for exceptional dispatches, or additional dispatches issued by grid operators to meet reliability requirement issues not met by results of the market software.

7.6.1 Frequency and impact of automated bid mitigation

In the day-ahead and real-time market, in both the ISO and energy imbalance markets, the frequency and impact of automated bid mitigation increased significantly in 2018 compared to 2017.

Background

The ISO's automated local market power mitigation (LMPM) procedures have been enhanced in numerous ways since 2012 to more accurately identify and mitigate resources with the ability to exercise local market power in the day-ahead and real-time markets. The ISO is currently working on further enhancements to real-time market mitigation processes to be implemented in fall 2019. As part of this policy, the ISO is proposing several measures including prevention of flow reversal by eliminating balance of hour mitigation and providing an option for energy imbalance market areas to limit exports when mitigation is triggered due to import congestion.[163]

The impact on market prices of bids that were actually mitigated can only be assessed precisely by re-running the market software without bid mitigation. However, DMM does not have the ability to re-run the day-ahead and real-time market software to perform such analysis. Instead, DMM has developed a variety of metrics to estimate the frequency with which mitigation was triggered and the effect of this

[163] Draft final proposal, Local market power mitigation enhancements 2018, Feb 1, 2019: http://www.caiso.com/Documents/DraftFinalProposal-LocalMarketPowerMitigationEnhancements-UpdatedJan31_2019.pdf

mitigation on each unit's energy bids and dispatch levels. These metrics identify bids lowered from mitigation each hour and also estimate the additional energy dispatched from these price changes.[164]

The following sections provide analysis on the frequency and impact of bid mitigation in day-ahead and real-time markets, for both the ISO and energy imbalance markets.

Day-ahead market

Both the frequency of mitigation (as shown in Figure 7.8) and the average estimated change in schedules (as shown in Figure 7.9) increased in the day-ahead market in 2018 compared to 2017, with the highest increase in the third quarter of 2018.

- An average of 30 units in each hour were subject to day-ahead mitigation in 2018, an increase from 19 units in 2017.
- An average of 3 units had day-ahead bids changed in 2018, an increase from 1.4 units in 2017.
- Day-ahead dispatch instructions from bid mitigation increased by about 22 MW per hour in 2018, compared to 7 MW per hour in 2017. This potential increase in dispatch due to mitigation is concentrated mostly during peak hours in 2018, similar to 2017.

[164] More information on these metrics is in Section A.4 of Appendix A of DMM's *2009 Annual Report on Market Issues and Performance*, April 2010:
http://www.caiso.com/Documents/2009AnnualReportonMarketIssuesandPerformance.pdf
For 2018, the methodology has been updated to capture carry over mitigation (balance of hour mitigation) in 15-minute and 5-minute markets. This is done by comparing the market participant submitted bid at the top of each hour (in the 15-minute market) to the bid used in each interval of 15-minute and 5-minute market runs. 2017 numbers have been recalculated using this updated methodology to be directly comparable to 2018.

Figure 7.8 Average number of units mitigated in day-ahead market

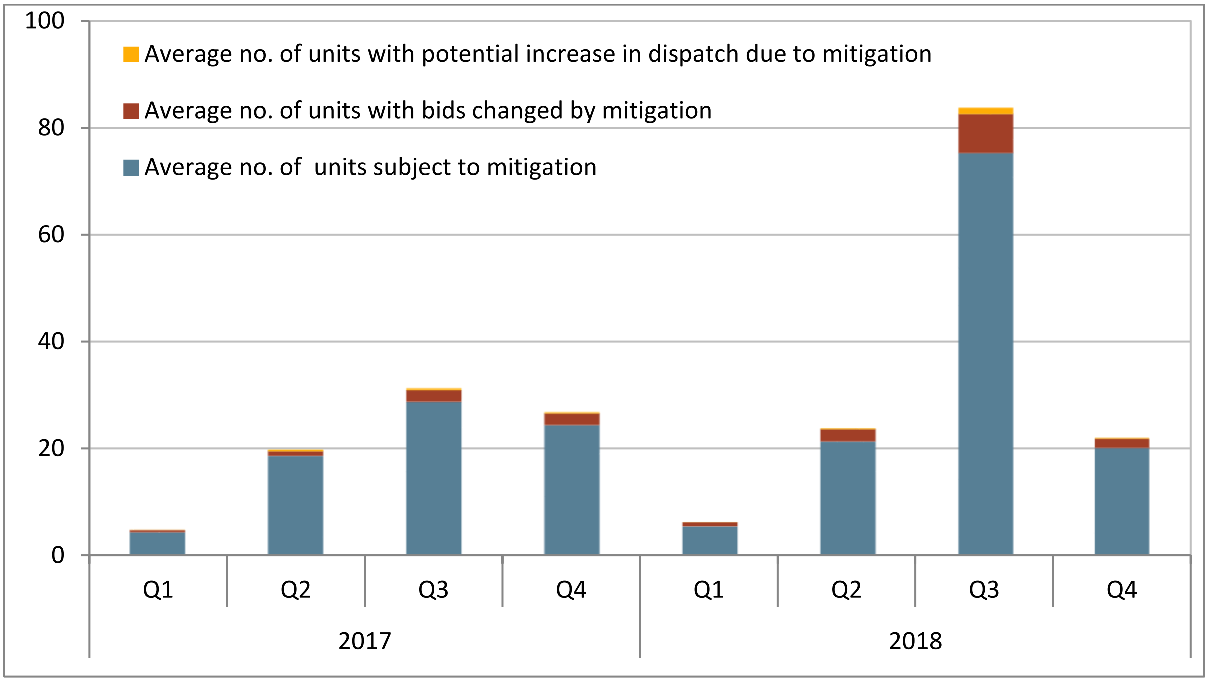
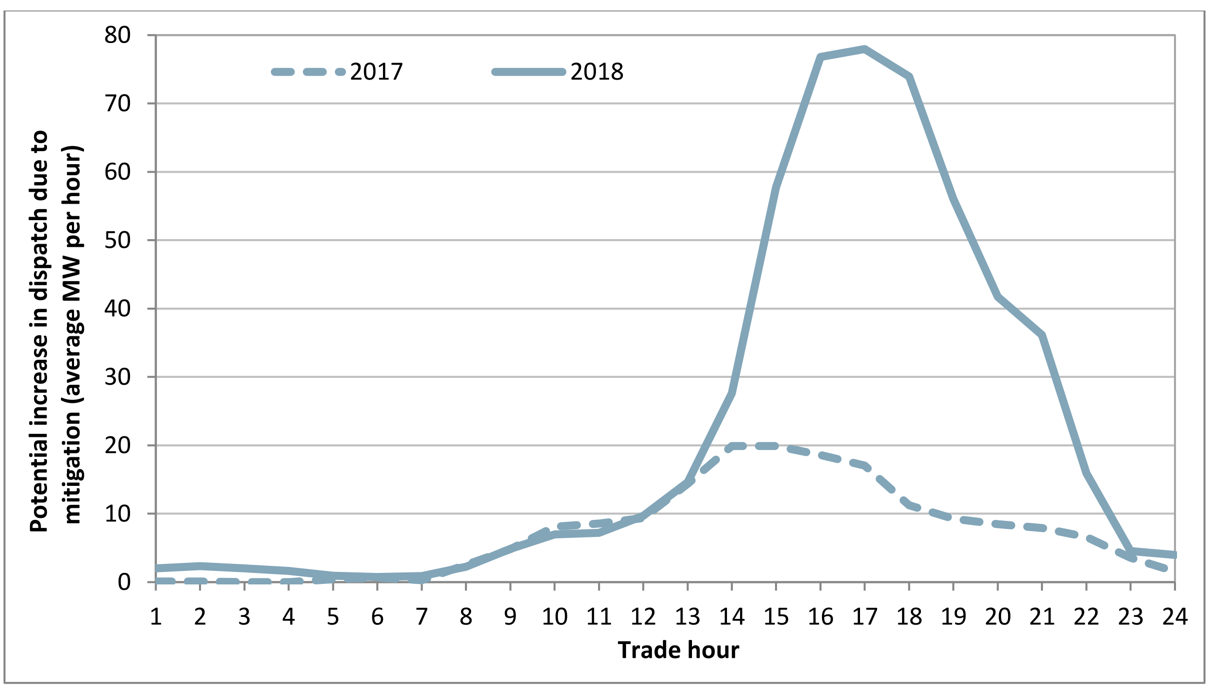


Figure 7.9 Potential increase in day-ahead dispatch due to mitigation (hourly averages)

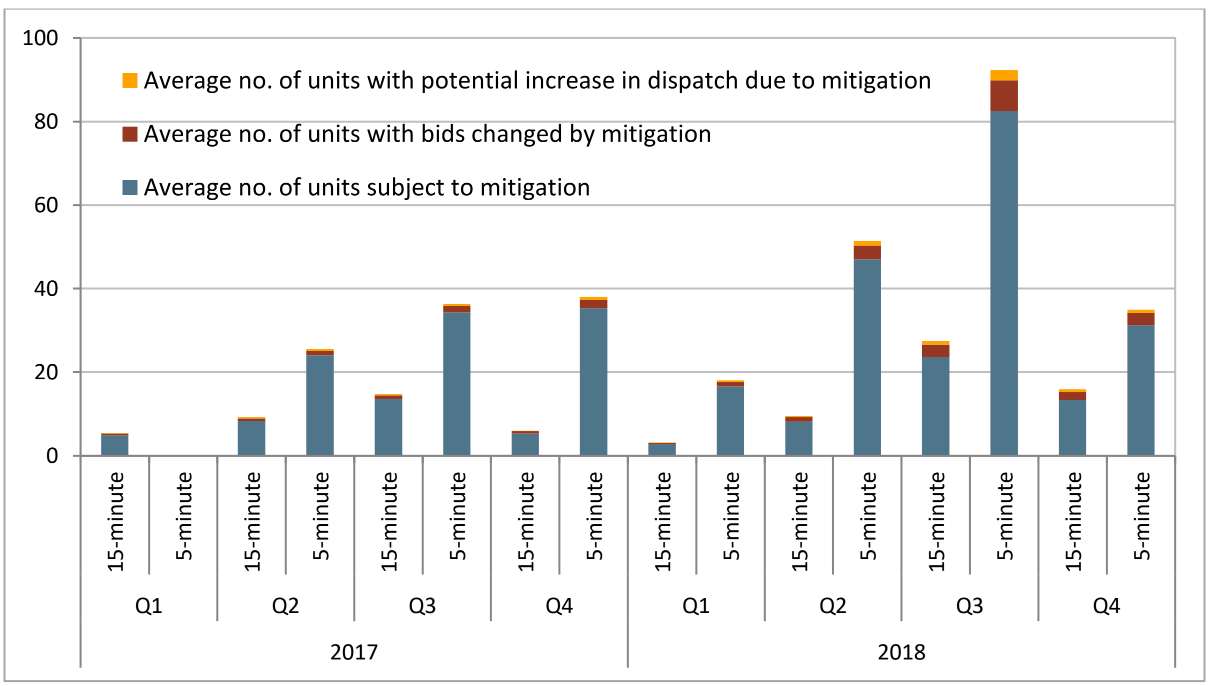


Real-time market

Figure 7.10 and Figure 7.11 highlight the frequency and volume of 15-minute and 5-minute market mitigation in the ISO.

- As shown in these figures, the average number of units subject to mitigation in the ISO is consistently higher in the 5-minute than in the 15-minute market. An average 12 units in each hour were subject to 15-minute market mitigation in 2018, compared to 8 in 2017. In the 5-minute market, an average of 44 units were subject to mitigation compared to 31 units in 2017.[165]
- Of the units subject to mitigation in 2017 and 2018, a relatively small percentage of unit bids were lowered and as a result dispatched at a higher output in both the 15-minute and 5-minute markets. The average number of ISO unit bids lowered by mitigation increased to 12 from 8 in the 15-minute market and to 3.6 from 1.6 in the 5-minute market in 2017 post 5-minute market mitigation.
- 15-minute schedules from bid mitigation increased by about 15 MW per hour in 2018, compared to 6 MW per hour in 2017. Similarly, 5-minute dispatch instructions increased by 40 MW per hour in 2018 compared to 16 MW per hour in 2017.

Figure 7.10 Average number of units mitigated in 15-minute and 5-minute market (ISO)



[165] Mitigation in the 5-minute market was implemented in May 2017.

Figure 7.11 Potential increase in 15-minute and 5-minute dispatch due to mitigation (ISO)

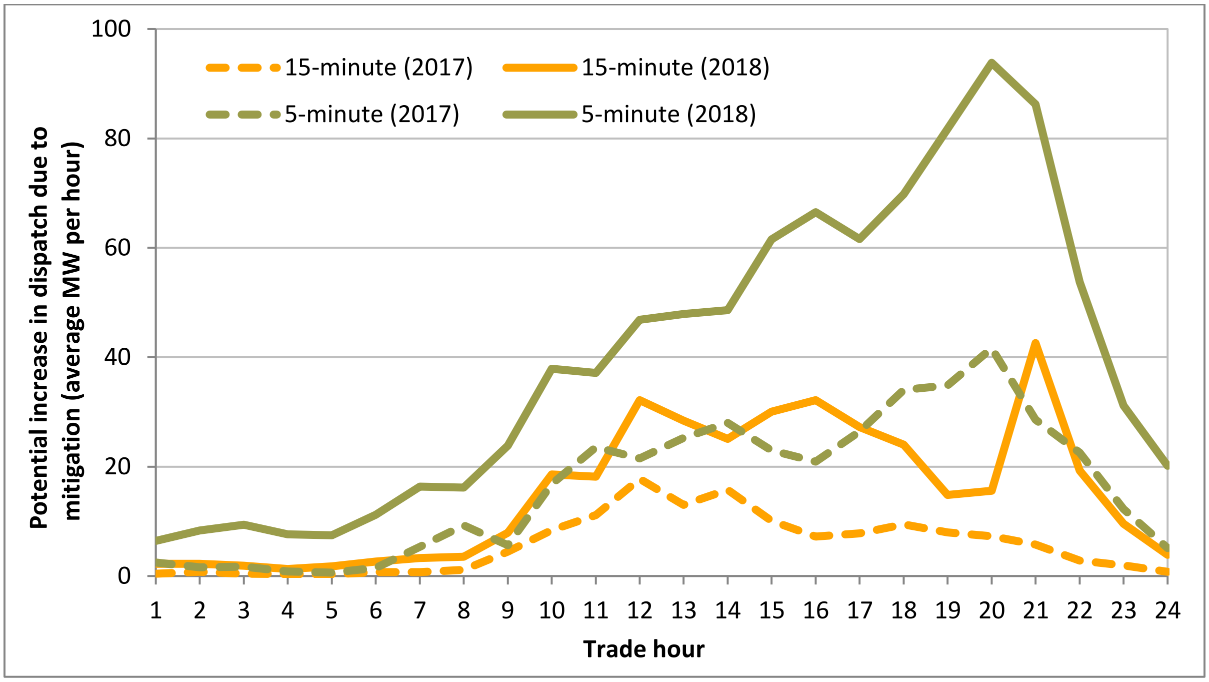


Figure 7.12 and Figure 7.13 highlight the frequency and volume of 15-minute and 5-minute market mitigation in all the balancing authority areas in the energy imbalance market:

- As shown in Figure 7.12, the number of units subject to mitigation in the energy imbalance market increased significantly in 2018 in both 15-minute and 5-minute markets.
- Of the units that were subject to mitigation, about 34 percent of the units had their bids lowered due to 15-minute and 5-minute market mitigation in 2018. This is considerably higher than the percentage of the ISO units with bids lowered due to mitigation, and a significant increase from 2017.
- As shown in Figure 7.13, as a result of increased bid mitigation in 2018, the potential increase in both 15-minute and 5-minute dispatch also increased significantly in the energy imbalance market areas.

Figure 7.12 Average number of units mitigated in 15-minute and 5-minute market (EIM)

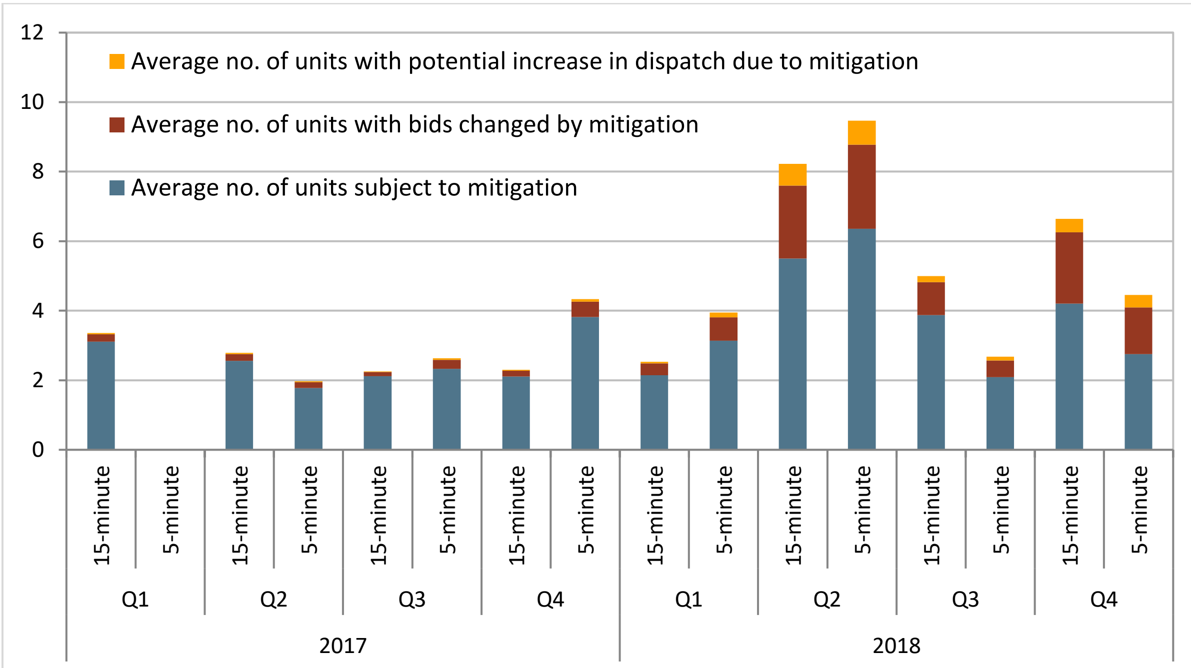
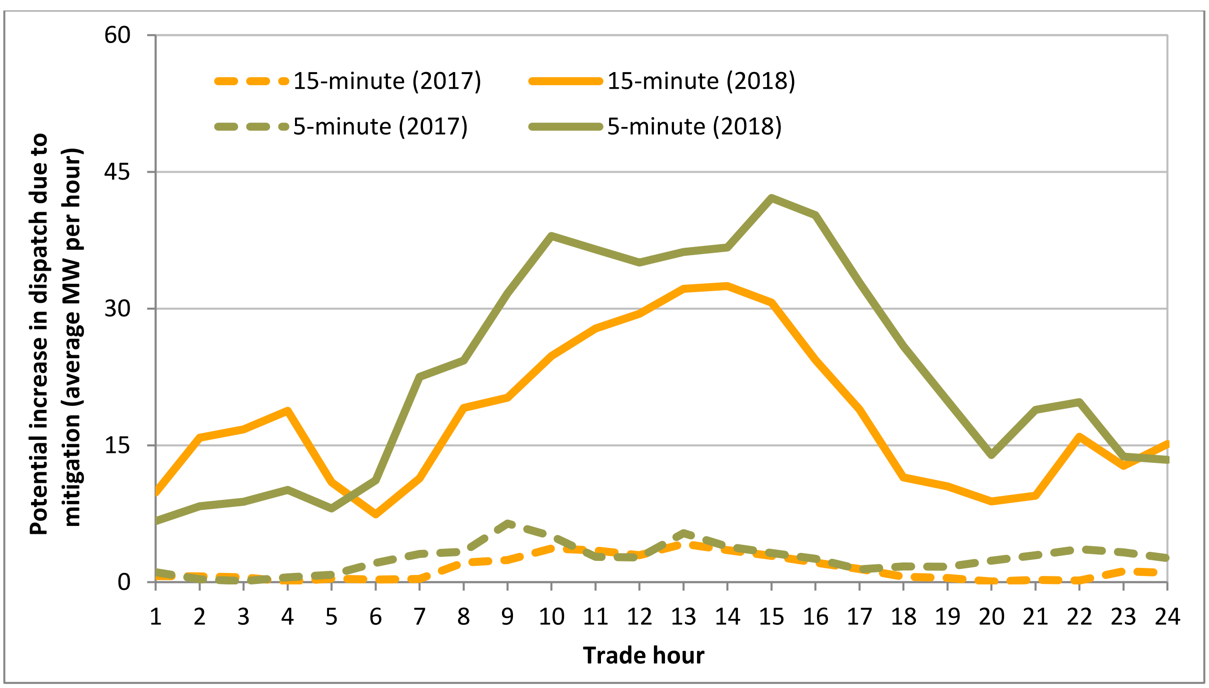


Figure 7.13 Potential increase in 15-minute and 5-minute dispatch due to mitigation (EIM)



7.6.2 Mitigation of exceptional dispatches

Overview

Exceptional dispatches are instructions issued by grid operators when the automated market optimization is not able to address a particular reliability requirement or constraint.[166] Total energy from exceptional dispatches increased in 2018. The above-market costs associated with these exceptional dispatches increased as well, totaling $51.9 million in 2018 compared to $20.6 million in 2017. A majority of this cost was associated with exceptional dispatch commitments to minimum load rather than out-of-market costs for exceptional dispatch incremental energy.

Commitment cost bids for units that are committed via exceptional dispatch are not subject to any additional mitigation beyond the commitment cost bid caps, which include 25 percent headroom above estimated start-up and minimum load costs. Exceptional dispatches for energy above minimum load are subject to mitigation if a grid operator indicates the dispatch is made for any of the following reasons:

- Address reliability requirements related to non-competitive transmission constraints;
- Ramp resources with ancillary services awards or residual unit commitment capacity to a dispatch level that ensures their availability in real time;
- Ramp resources to their minimum dispatch level in real time, allowing the resource to be more quickly ramped up if needed to manage congestion or meet another reliability requirement; or
- Address unit-specific environmental constraints not incorporated into the model or the ISO's market software that affect the dispatch of units in the Sacramento Delta, commonly known as *Delta Dispatch*.

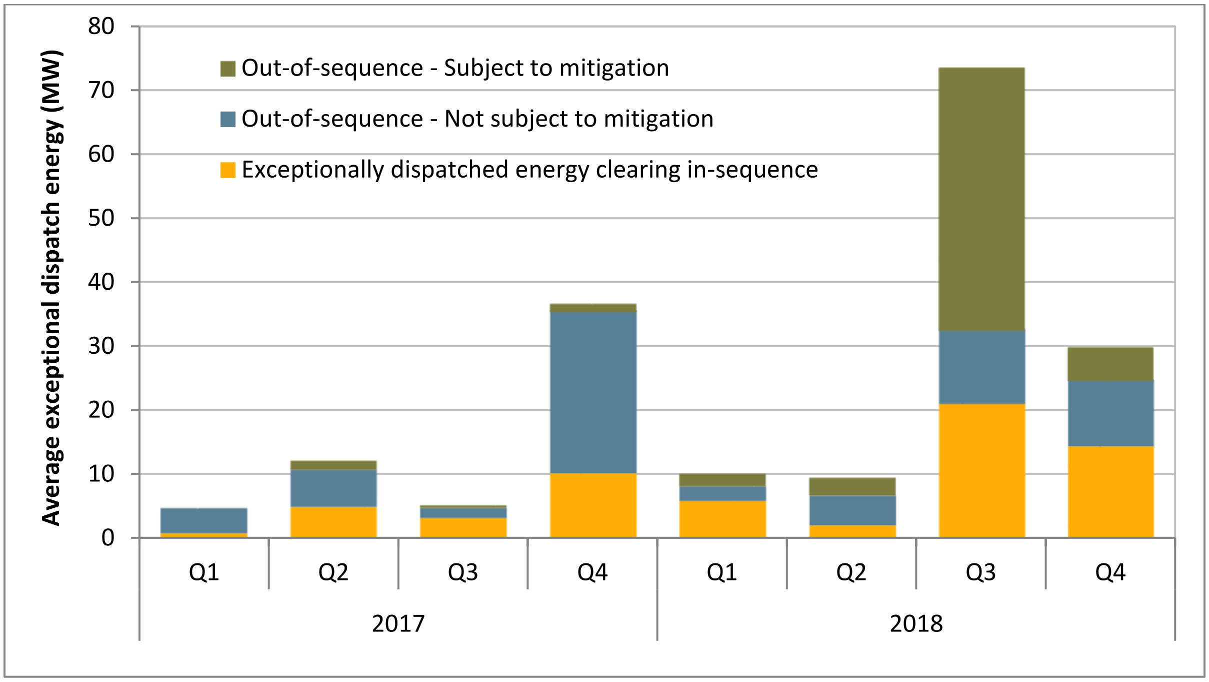
In 2018, local market power mitigation played a substantial role in limiting above-market costs for exceptional dispatches for energy, reducing these costs by $17.9 million.

Volume and percent of exceptional dispatches subject to mitigation

As shown in Figure 7.14, the overall volume of exceptional dispatch energy above minimum load rose in 2018 when compared to 2017. Out-of-sequence exceptional dispatch energy rose sharply overall. Out-of-sequence energy is energy with bid prices above the market clearing price. Out-of-sequence exceptional dispatches not subject to mitigation declined by 20 percent in 2018 compared to 2017. However, out-of-sequence exceptional dispatches subject to mitigation were 14 times higher in 2018 than in 2017. This sharp rise largely came from exceptional dispatches in the third quarter.

[166] A more detailed discussion of exceptional dispatches is provided in Section 9.1.

Figure 7.14 Exceptional dispatches subject to bid mitigation



Impact of exceptional dispatch energy mitigation

Out-of-sequence costs for exceptional dispatch energy are out-of-market costs paid for exceptional dispatch energy with bids that exceed the market clearing price. In cases when the bid price of a unit being exceptionally dispatched is subject to local market power mitigation provisions of the ISO tariff, this energy is considered out-of-sequence if the unit's default energy bid used in mitigation is above the market clearing price.

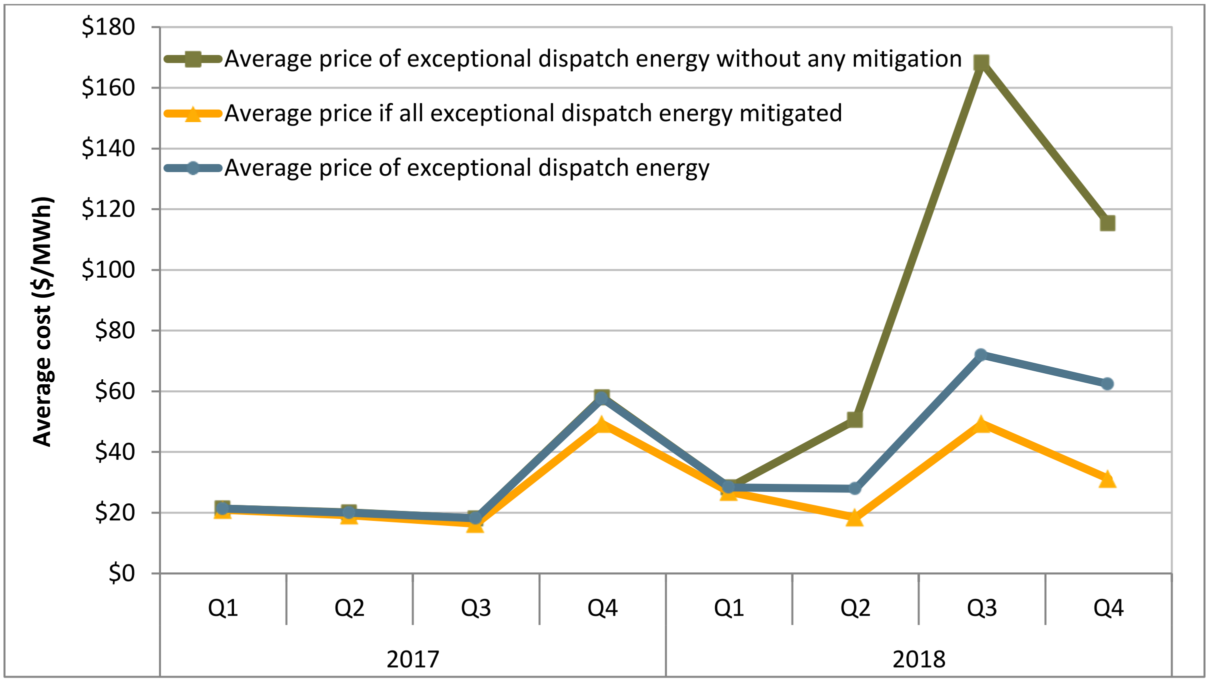
Using the value of out-of-sequence costs with the corresponding megawatt quantities of out-of-sequence exceptional dispatch energy, one can calculate the average price of out-of-sequence exceptional dispatch energy. This price is the amount per megawatt-hour by which out-of-sequence exceptional dispatch energy exceeds the locational marginal price.

Figure 7.15 shows the difference in the average price for out-of-sequence exceptional dispatch energy under three scenarios. The distance between the green and blue lines in Figure 7.15 illustrates the impacts of exceptional dispatch mitigation. The distance between these lines is the difference between the settled average price of out-of-sequence exceptional dispatch energy (blue line) and the average price of out-of-sequence exceptional dispatch energy in the absence of mitigation (green line). Greater distance between these two lines implies a larger overall impact of mitigation. As Figure 7.15 shows, this impact was low in 2017 and much higher in 2018.

The yellow line in Figure 7.15 shows the average price of out-of-sequence exceptional dispatch energy if all exceptional dispatch energy had been subject to mitigation. A greater distance between the green line and the yellow line is indicative of lower quantities of exceptional dispatch energy subject to mitigation. The distance between these lines was largest in the third quarter of 2018, and was much greater than in the third quarter of 2017.

The average price of out-of-sequence exceptional dispatch energy increased in 2018 to $47/MWh from $29/MWh in 2017. This increase is due in large part to a year-over-year increase in the third and fourth quarters. In 2018, the third quarter average price for exceptional dispatch energy was $71/MWh and the fourth quarter average price was $62/MWh. The exceptional dispatches driving these values were largely due to load forecast uncertainty.

Figure 7.15 Average prices for out-of-sequence exceptional dispatch energy



7.7 Start-up and minimum load bids

This section provides analysis on the amount of day-ahead and real-time capacity under proxy cost option for commitment cost bids. Beginning the third quarter of 2018, gas resources bidding their minimum load costs at the proxy cost cap has significantly increased. As mentioned in Section 2.6, more than $25 million of the real-time bid cost recovery payments was awarded to gas resources bidding their start-up and minimum load costs at the 125 percent proxy cost cap.

Background

Additional start-up and minimum load bidding flexibility was implemented at the end of 2014. Depending on the limitations of a resource, owners could choose from two options for their start-up and minimum load bid costs: proxy costs (variable cost) and registered costs (fixed cost). The proxy cost bid cap was increased from 100 percent to 125 percent and remained available to all resources.[167] The ISO modified this option to capture the fluctuations of daily fuel prices for natural gas-fired resources and

[167] For more information, see the following FERC order accepting the tariff revisions: https://www.caiso.com/Documents/Dec302014_OrderAcceptingCommitmentCostEnhancementsTariffRevision_ER15-15-001.pdf.

combined it with the flexibility to bid above 100 percent of proxy costs to incorporate additional costs that may not be captured under the proxy cost option.

The ISO retained the registered cost option, but restricted it to use-limited resources. Participants with resources on the registered cost option continued to have the ability to bid up to 150 percent of the cap.[168] However, the registered costs continued to remain fixed for a period of 30 days.[169] The ISO implemented these changes partly in response to the high and volatile natural gas prices on certain days in December 2013 and February 2014.

Under the commitment costs enhancement phase 3 (CCE3) initiative, the ISO is implementing opportunity cost adders to proxy start-up and proxy minimum load costs for use-limited resources which have limitations on numbers of starts, run hours and energy output.[170] This initiative will phase out the registered cost option and will limit the use of that option to resources which do not have sufficient data to calculate an opportunity cost adder.

Day-ahead capacity under the proxy cost option

Figure 7.16 and Figure 7.17 highlight how proxy costs were bid into the day-ahead market in 2018 compared to 2017.[171] As shown in Figure 7.16, in the day-ahead market about 37 percent of capacity submitted start-up bids at or below the proxy cost compared to 57 percent in 2017. About 33 percent of the capacity submitted start-up bids at the proxy cost cap in 2018 compared to 20 percent in 2017.

As shown in Figure 7.17 about 50 percent of minimum load capacity was bid at or below the proxy cost in the day-ahead market during 2018 compared to about 60 percent in 2017. About 30 percent of the capacity associated with minimum load bids was at or near the cap in 2018 up from 20 percent in 2017.

[168] Registered cost bids were at 150 percent of projected costs as calculated under the proxy cost option beginning in November 2013, whereas registered costs were capped at 200 percent before. One of the reasons for providing this bid-based registered cost option was to provide an alternative for generation unit owners who believed they had significant non-fuel start-up or minimum load costs not covered under the proxy cost option. See the following filing: http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/CommitmentCostsRefinement2012.aspx.

[169] Updated use-limited resource definition, CAISO tariff, pp 10-11: http://www.caiso.com/Documents/Section30-Bid-Self-ScheduleSubmission-CAISOMarkets-asof_Apr1-2019.pdf

[170] Commitment costs enhancements stakeholder process: http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostEnhancements.aspx

[171] For start-up capacity, resource Pmin (ONLY startable configurations Pmin for multi-stage generating units) is used to calculate total start-up capacity. For minimum load capacity, Pmin of resources (or configurations) is used to calculate total minimum load capacity.

Figure 7.16 Day-ahead gas-fired capacity under the proxy cost option for start-up cost bids

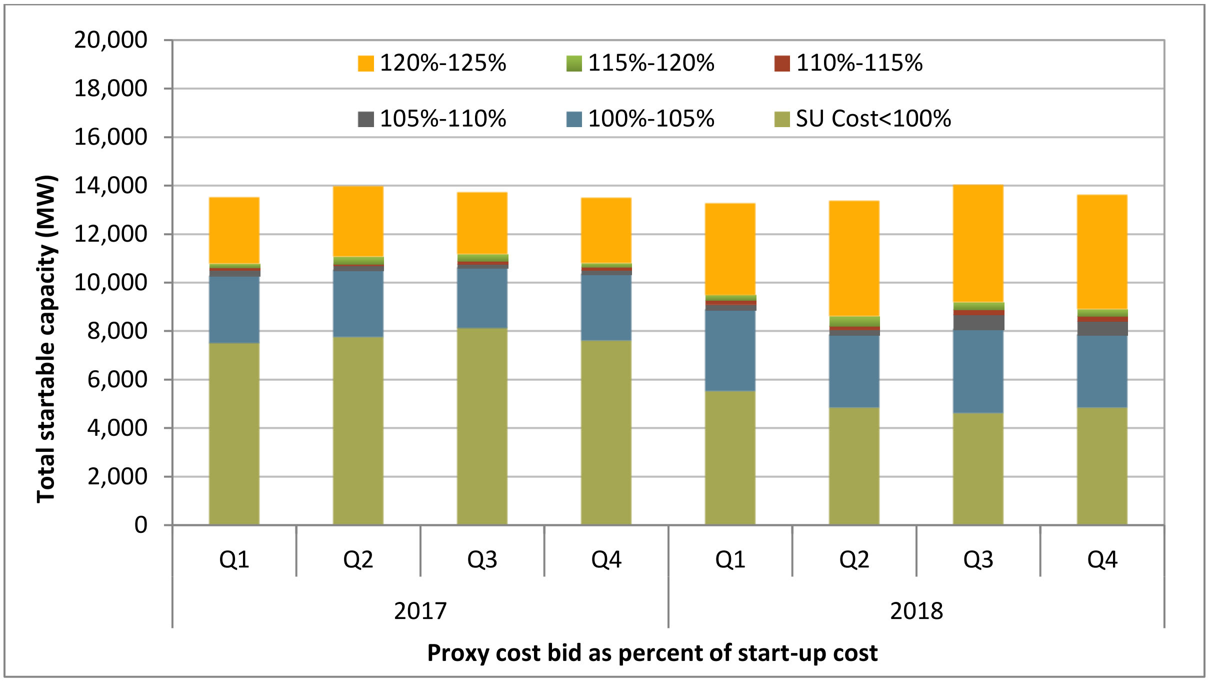
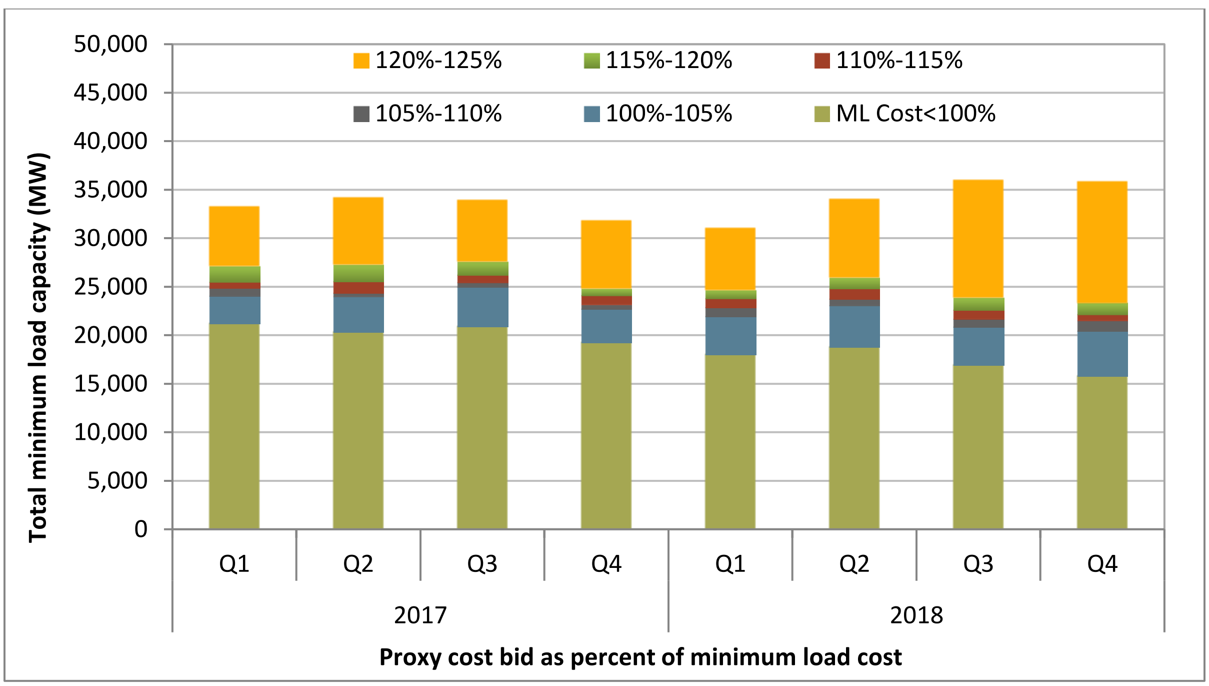


Figure 7.17 Day-ahead gas-fired capacity under the proxy cost option for minimum load cost bids



Real-time capacity under the proxy cost option

Figure 7.18 and Figure 7.19 summarize commitment cost bids for gas-fired capacity in the real-time market under the proxy cost option for start-up and minimum load bids, respectively. In 2018, real-time start-up and minimum load bids at or near the 125 percent cap doubled compared to 2017. About 34 percent of capacity submitted start-up bids at or near the cap in 2018 compared to 18 percent in 2017. Similarly, about 27 percent of real-time minimum load capacity bids were at or near the cap in 2018 compared to 13 percent in 2017. As previously noted, over $25 million of the real-time bid cost recovery payments was awarded to gas resources bidding their start-up and minimum load costs at the 125 percent proxy cost cap.

Figure 7.18 Real-time gas-fired capacity under the proxy cost option for start-up cost bids

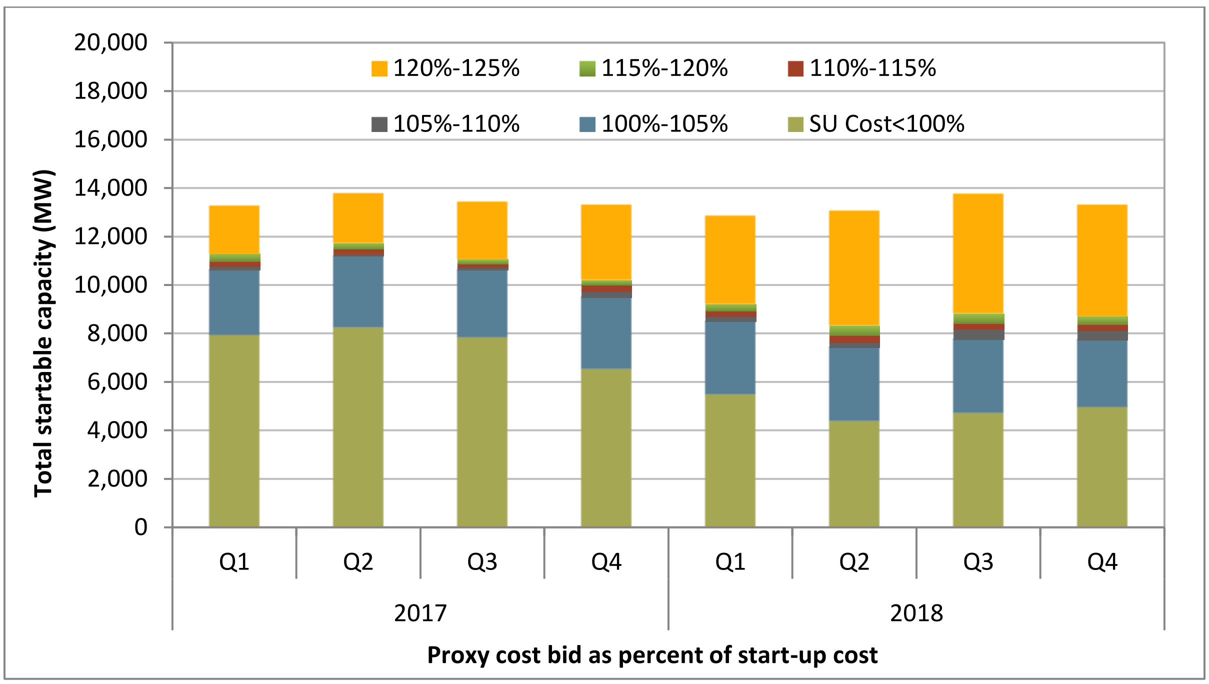
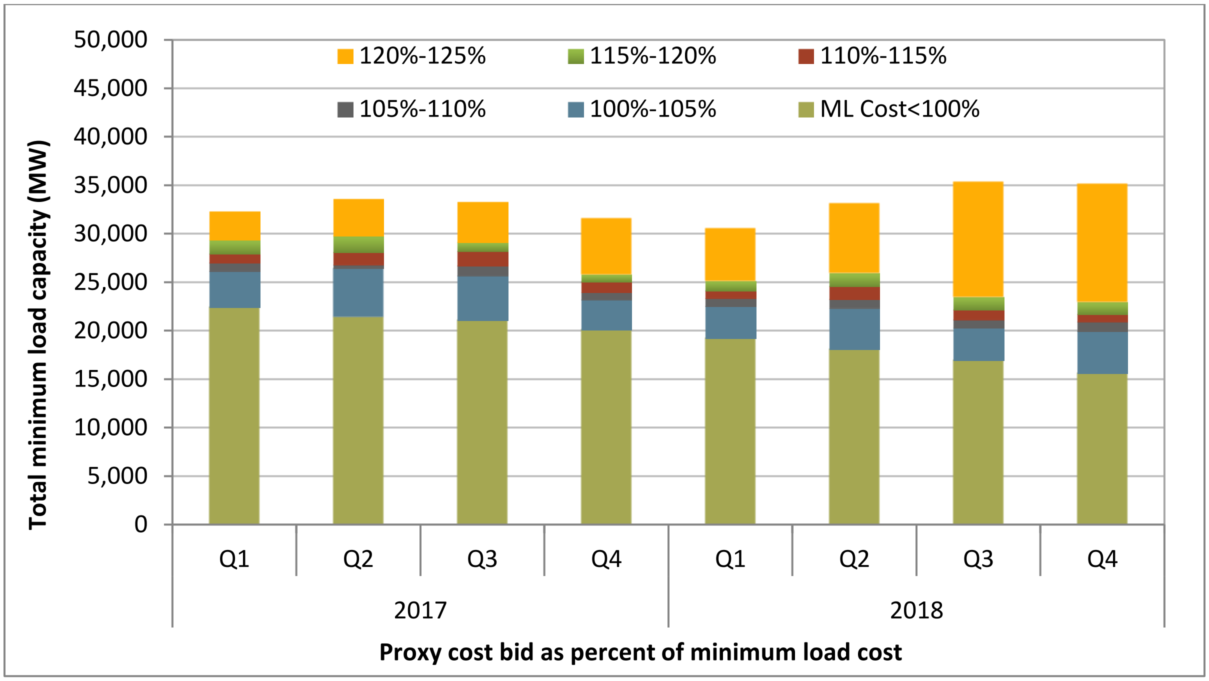


Figure 7.19 Real-time gas-fired capacity under the proxy cost option for minimum load cost bids



8 Congestion

This chapter provides a review of congestion and the congestion revenue rights auction in 2018. The findings from this chapter include the following:

- In the day-ahead market, locational price differences due to congestion increased in 2018, particularly in the third quarter. This increase was primarily due to congestion on constraints associated with Path 26.
- In the 15-minute market, patterns of congestion were similar to the day-ahead market. The primary constraints impacting price separation were the constraints associated with Path 26, the Serrano 500/230 kV transformer, and the Round Mountain-Table Mountain nomogram. These constraints increased prices in Southern California and in energy imbalance market areas with significant transmission capacity into Southern California, and decreased prices elsewhere.
- In the fourth quarter, significant congestion on the Tracy-Los Banos outage nomogram increased prices in Northern California and in energy imbalance market areas north of the constraint and decreased prices south of the constraint. Over the course of the fourth quarter, this south-to-north congestion offset much of the impact of congestion in the opposite direction in terms of average prices, so that the overall net impact of congestion on prices was relatively low for the fourth quarter.
- The frequency and impact of congestion in the day-ahead market on most major interties was lower in 2018 compared to 2017. This was primarily driven by lower congestion on interties connecting the ISO to the Pacific Northwest.

This chapter includes an analysis of the performance of the congestion revenue rights auction from the perspective of the ratepayers of load-serving entities. Key findings of this analysis include the following:

- Congestion revenue rights not allocated to load-serving entities that were sold in the auction consistently generate significantly less revenue than is paid to the entities purchasing these rights at auction. From 2012 through 2018, ratepayers received about 48 percent of the value of their congestion revenue rights that the ISO auctioned. This represents a shortfall of about $131 million in 2018 and more than an $860 million shortfall since 2009.
- In 2018, FERC approved a set of changes to the congestion revenue rights auction process which will reduce the number and pairs of nodes at which congestion revenue rights can be purchased in the auction (Track 1A). FERC also approved a second set of changes which would reduce the net payment to a congestion revenue right holder if payments to congestion revenue rights exceed associated congestion charges collected in the day-ahead market on a targeted constraint-by-constraint basis (Track 1B).
- Both of these sets of changes have been implemented for the 2019 auction. DMM supported both initiatives as incremental improvements that should help reduce the losses incurred by transmission rate payers due to the ISO’s auction of congestion revenue rights.

8.1 Background

Locational marginal pricing enables the ISO to efficiently manage congestion and provide price signals to market participants to self-manage congestion. Over the longer term, nodal prices are intended to provide more efficient signals that encourage development of new supply and demand-side resources within more constrained areas. Nodal pricing also helps identify transmission upgrades that would be most cost-effective for reducing congestion.

Congestion in a nodal energy market occurs when the market model estimates flows on the transmission network have reached or exceeded the limit of a transmission constraint. As congestion appears on the network, locational marginal prices at each node reflect marginal congestion costs or benefits from supply or demand at that particular location. Within areas where flows are constrained by limited transmission, higher cost generation is dispatched to meet demand. Outside of these transmission constrained areas, demand is met by lower cost generation. This results in higher prices within congested regions and lower prices in unconstrained regions.

When a constraint binds the market software produces a shadow price on that constraint. This generally represents the cost savings that would occur if that constraint had one additional megawatt of transmission capacity available in the congested direction. This shadow price is not directly charged to participants; it only indicates a decremental cost on the objective function of the market software for the limited transmission on the binding constraint.

There are three major types of transmission constraints that are enforced in the market model and may impact prices when they bind:

- Flowgates represent a single transmission line or path with a single maximum limit.
- Branch groups represent multiple transmission lines with a limit on the total combined flow on these lines.
- Nomograms are more complex constraints that represent interdependencies and interactions between multiple transmission system limitations that must be met simultaneously.

The impact of congestion from any constraint on each pricing node in the ISO can be calculated as the product of the shadow price for the constraint and the shift factor of the constraint for that node. This calculation can be done for individual nodes, as well as groups of nodes that represent different load aggregation points or local capacity areas.[172]

The overall impact to average regional prices shows the impact of congestion accounting for both the frequency and magnitude of impact. These values are calculated by taking the average congestion component as a percent of the total price during all congested and non-congested intervals.[173]

Congestion on interties between the ISO and other balancing areas impacts the price of imports and affects payments for congestion revenue rights. However, intertie congestion has generally had a minimal impact on prices for load and generation within the ISO system. This is because when

[172] Appendix A of DMM's 2009 annual report provides a detailed description of this calculation for both load aggregation points and prices within local capacity areas.

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

congestion limits additional imports on one or more interties, there is usually additional supply available from other interties or from within the ISO at a relatively small increase in price.

8.2 Congestion on interties

The frequency and financial impact of congestion on most interties connecting the ISO with other balancing authority areas decreased in 2018 compared to 2017, particularly for interties connecting the ISO to the Pacific Northwest.

Table 8.1 provides a detailed summary of congestion frequency on interties with average and total congestion charges in the day-ahead market. The congestion price reported in Table 8.1 is the megawatt weighted average shadow price for the binding intertie constraint. For a supplier or load-serving entity trying to import power over a congested intertie, assuming a radial line, the congestion price represents the difference between the higher price of the import on the ISO side of the intertie and the lower price outside of the ISO. This congestion charge also represents the amount paid to owners of congestion revenue rights that are sourced outside of the ISO at points corresponding to these interties.

Figure 8.1 compares the percentage of hours that major interties were congested in the day-ahead market during the last three years. Figure 8.2 provides a graphical comparison of total congestion charges on major interties in each of the last three years.

The table and figures highlight the following:

- Overall congestion on interties totaled about $108 million, compared with $114 million in 2017 and $92 million in 2016. The decrease from 2017 was largely driven by decreased congestion on the two major interties linking the ISO with the Pacific Northwest: the Nevada/Oregon Border (NOB) and MALIN 500 (PACI/Malin 500).[174]
- Total congestion on the Nevada/Oregon Border and MALIN 500 decreased to about $80 million from about $100 million in 2017. This was likely driven by decreased hydroelectric generation in the Northwest imported into the ISO from the Northwest and Northern California in 2018.
- Congestion increased significantly on Palo Verde, which is the largest intertie linking the ISO with the Southwest. Congestion on Palo Verde increased to $22 million from about $8 million in 2017. This was largely due to transmission outages in Southern California in December.

[174] The California ISO Technical Bulletin '*Pricing Logic for Scheduling Point – Tie Combination*,' revised on February 24, 2016, describes that MALIN 500 kV intertie scheduling limit replaced the Pacific A/C Intertie constraint with the implementation of the full network model on October 15, 2014: http://www.caiso.com/Documents/RevisedTechnicalBulletin_PricingLogicforSchedulingPoint-TieCombination.pdf

Table 8.1 Summary of import congestion (2016-2018)

Import region	Intertie	Frequency of import congestion			Average congestion charge ($/MW)			Import congestion charges (thousands)		
		2016	2017	2018	2016	2017	2018	2016	2017	2018
Northwest	PACI/Malin 500	32%	28%	19%	$7.4	$12.2	$10.7	$51,139	$60,716	$43,435
	NOB	27%	26%	22%	$6.7	$11.6	$12.2	$24,346	$40,503	$36,799
	Tracy 500		0%			$19.8			$125	
	COTPISO	6%	2%	2%	$12.7	$25.8	$33.9	$158	$117	$137
	Cascade	2%	1%		$19.5	$21.4	$8.0	$244	$67	$15
	Summit		0%			$9.4			$8	
Southwest	Palo Verde	5%	2%	6%	$19.5	$22.3	$13.8	$12,942	$8,234	$21,802
	IPP Utah	13%	18%	17%	$3.6	$7.9	$7.6	$803	$2,362	$2,139
	IPP DC Adelanto		3%	1%		$9.2	$11.2		$950	$590
	Mead	1%	0%		$12.2	$21.5	$5.4	$1,023	$808	$241
	Market Place Adelanto		0.2%	0.1%		$16.0	$22.5		$139	$59
	West Wing Mead	3%		1%	$34.4		$14.0	$865		$157
	CFE_ITC	0%			$138		$645.8	$56		$1,844
	Sylmar AC	0.2%			$4.8	$0.2	$0.2	$70		$0
	El Dorado									
	Other							$92	$308	$1,417
Total								***$91,939***	***$114,336***	***$108,637***

Figure 8.1 Percent of hours with congestion on major interties (2016-2018)

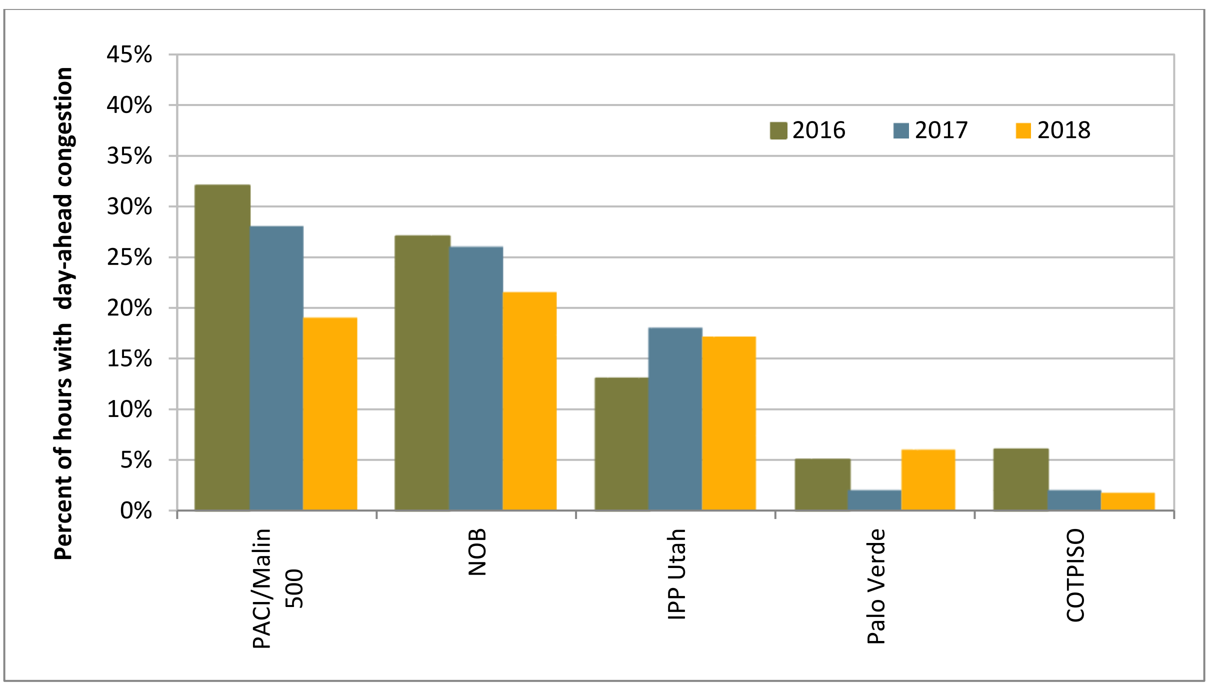
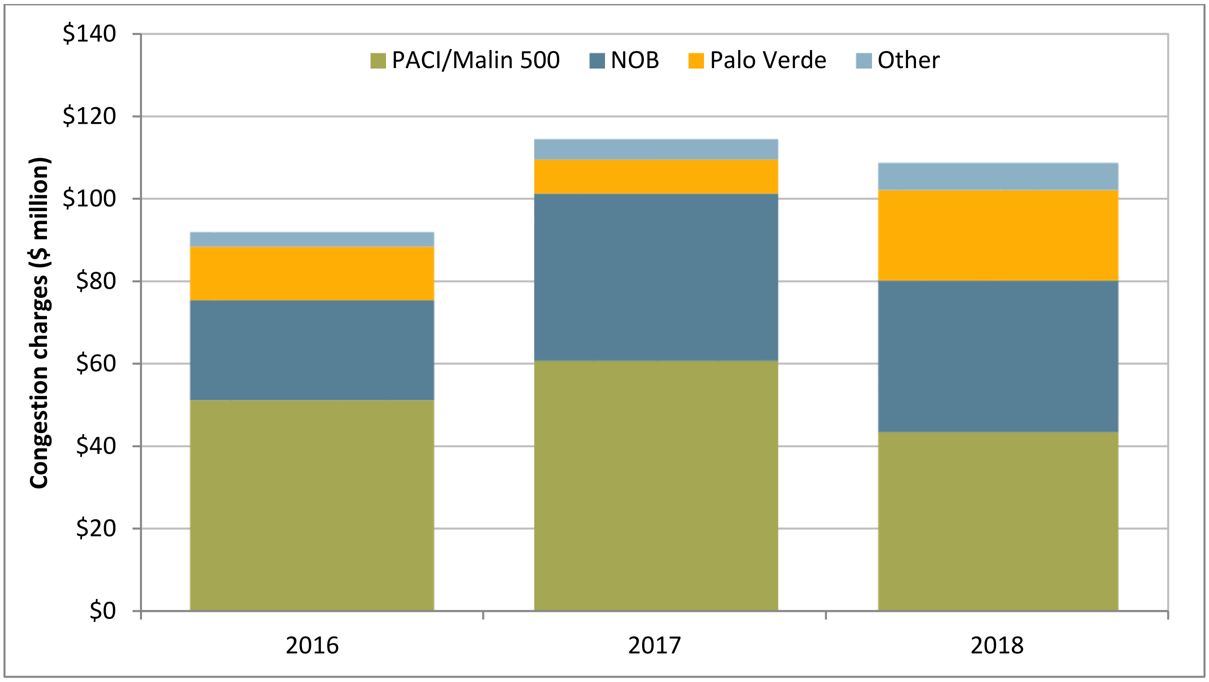


Figure 8.2 Import congestion charges on major interties (2016-2018)



8.3 Congestion impacts on locational prices

This section provides an assessment of the frequency and impact of congestion on locational price differences in the day-ahead and 15-minute markets. The section assesses the impact of congestion to the major load serving areas in the ISO (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric), as well as prices for each balancing area in the energy imbalance market.

Congestion on constraints within Southern California generally increases prices within the SCE and SDG&E areas, but decreases prices in the PG&E area. Similarly, congestion within Northern California increases prices in the PG&E area, and decreases prices in Southern California.

Highlights of congestion in 2018 include the following:

- In the day-ahead market, locational price separation due to congestion was greater than 2017, particularly in the third quarter. This was primarily a result of congestion on the constraints associated with Path 26. In the third quarter, these constraints bound in the north-to-south direction due to high gas prices in the south and outages on the lines that comprise Path 26.
- In the 15-minute market, patterns of congestion followed a similar pattern to the day-ahead market. The primary constraints impacting price separation were the constraints associated with Path 26, the Serrano 500/230 kV transformer, and the Round Mountain-Table Mountain nomogram. These constraints increased prices in Southern California and in EIM areas with significant transmission capacity into Southern California, and decreased prices throughout the rest of the west.
- In the fourth quarter, significant congestion on the Tracy-Los Banos outage nomogram increased prices in Northern California and EIM areas north of the constraint and decreased prices south of

the constraint. Over the course of the quarter, this south-to-north congestion offset much of the impact of congestion in the opposite direction in terms of average prices, so that the overall net impact of congestion on prices was relatively low for the fourth quarter.

8.3.1 Day-ahead congestion

In the day-ahead market, congestion frequency is typically higher than in the 15-minute market, but impacts on price differences between load areas tend to be lower. The congestion patterns over 2018 reflect this overall trend. Figure 8.3 shows price separation resulting from congestion by quarter for the current and previous year. Figure 8.4 shows the frequency of congestion.

The overall impact of day-ahead congestion on price separation increased in 2018 relative to 2017. In both years, congestion increased average prices in the SDG&E and SCE areas and decreased average prices in the PG&E area. The following summary values can be seen in Table 8.2:

- For SDG&E, congestion increased average prices above the system average by about $4.19/MWh or about 9 percent, compared to about $0.90/MWh or roughly 2.5 percent in 2017.
- For SCE, congestion drove prices up by about $1.87/MWh or 4.2 percent, compared to $0.42/MWh or about 1 percent in 2017.
- For PG&E, congestion reduced prices below the system average by about $2.73/MWh or 7 percent, compared to a decrease of $0.60/MWh or 2 percent in 2017.
- Within each quarter of 2018, the greatest net price separation occurred in the third quarter. However, in SDG&E, the percent of price impact compared to the locational marginal price (LMP) for each area remained roughly the same in the first three quarters. This occurred because prices in the third quarter were much higher than in the first and second quarters.

The frequency with which congestion impacts prices at aggregated load areas provides additional insight into trends in congestion. There was a notable increase in frequency of congestion in PG&E and SCE starting in the fourth quarter of 2017 which continued through the fourth quarter of 2018. The frequency of congestion impacting prices peaked for PG&E and SDG&E in the third quarter of 2018, and for SCE in the first quarter of 2018. Congestion in the third quarter was mostly a result of the constraints associated with Path 26 binding. Congestion in the first quarter was primarily due to congestion associated with the Serrano 500/230 kV transformer.

Measuring the net impact of congestion on price separation reduces the full impact of constraints that offset each other within a given time period. For example, the total impact of congestion in the fourth quarter of 2018 was low, though there was a relatively high frequency of congestion. In this period, some congestion increased prices in the south and decreased prices in the north, while at other times congestion decreased prices in the south and increased prices in the north. By contrast, in the third quarter of 2018, almost all of the congestion occurred in the north-to-south direction, increasing prices in the south and decreasing prices in the north.

Information regarding the impact of congestion from individual constraints appears below, with additional detail on the cause of congestion for constraints with the largest impact on prices.

Figure 8.3 Overall impact of congestion on price separation in the day-ahead market

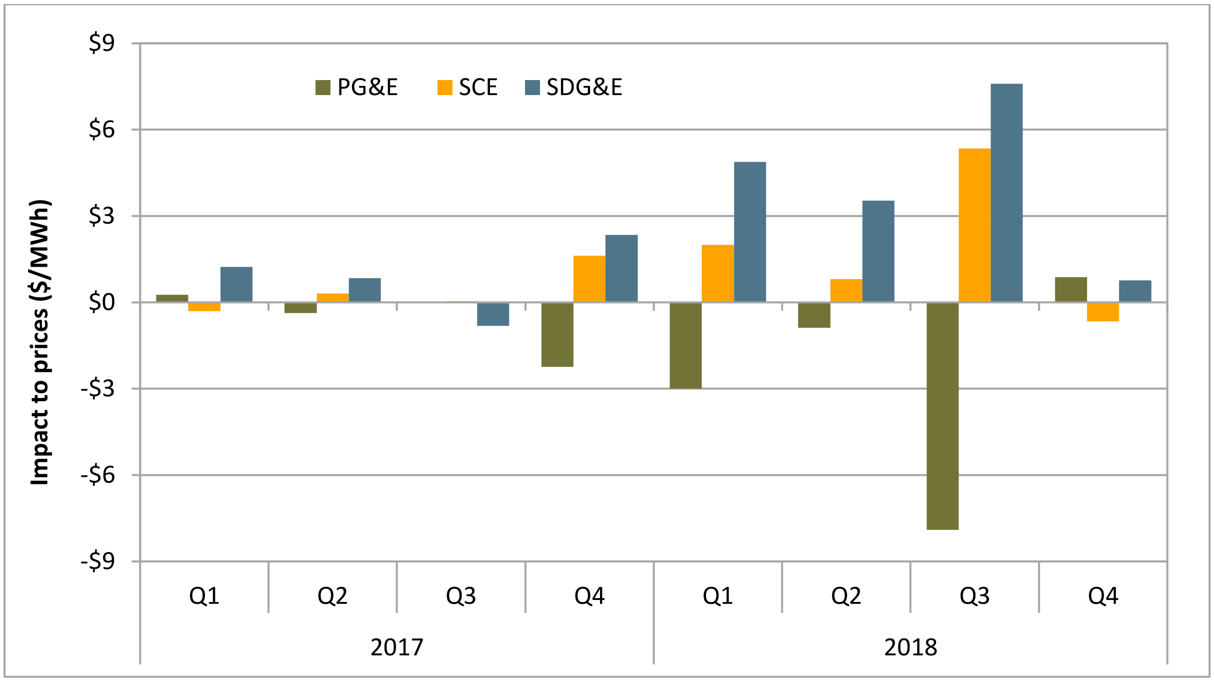


Figure 8.4 Percent of hours with congestion impacting prices by load area

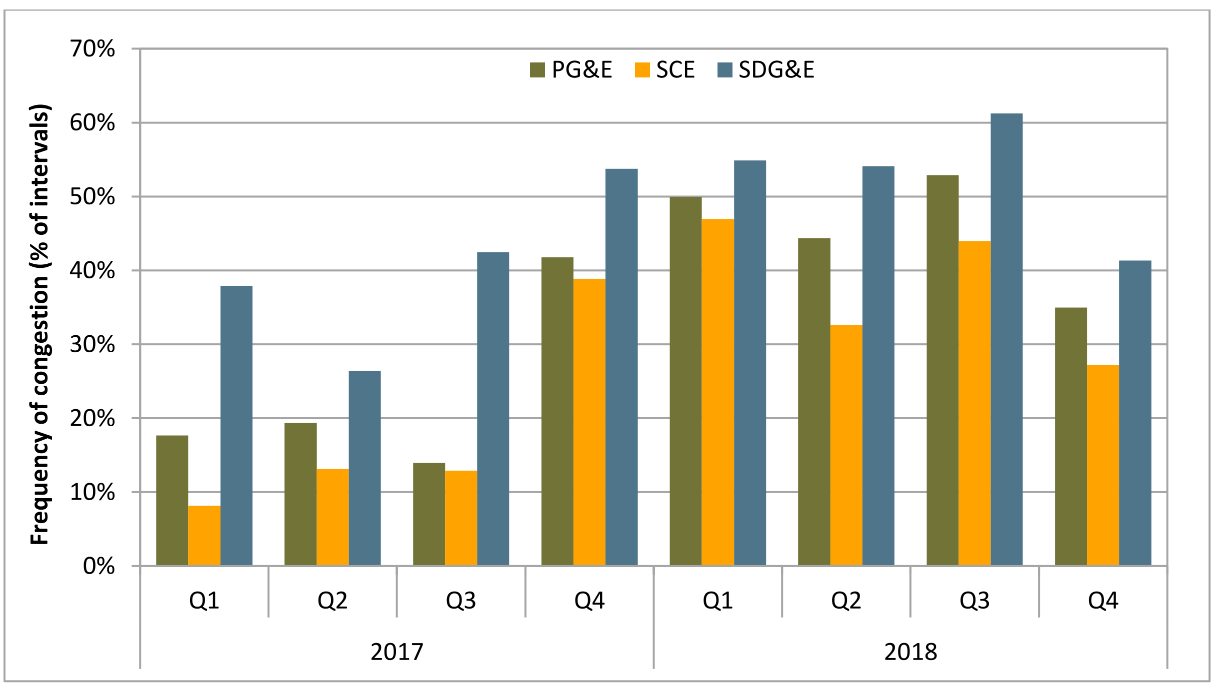


Table 8.2 shows the overall impact of congestion from different constraints on average prices in each load aggregation area in 2018. The table also shows the frequency with which the constraint was binding in each quarter.[175] The constraints that had the greatest impact on price separation throughout the year were the Serrano 500 kV/230 kV transformer, a group of constraints associated with Path 26, and the Imperial Valley nomogram.

Serrano 500/230 kV transformer

Congestion on the Serrano 500/230 kV transformer (24138_SERRANO _500_24137_SERRANO _230_XF_1 _P) significantly impacted price separation, primarily in the first quarter. On average for the year, this constraint increased SDG&E and SCE prices by $1.10/MWh and $0.47/MWh, respectively, and decreased prices in PG&E by $0.72/MWh. In the first quarter, the constraint was binding in more than 40 percent of hours. In the second quarter, it bound in roughly 3 percent of hours. This congestion was caused by a planned outage on a portion of the Serrano transformer bank, which started at the end of October 2017 and ended in April 2018.

Path 26

The transmission path called Path 26 is composed of three high voltage lines: the Midway-Vincent #1 500 kV line, Midway-Vincent #2 500 kV line, and the Midway-Whirlwind 500 kV line. This group of lines is a major point of connection between northern and southern parts of California. There are a number of constraints used to manage flows over these lines to protect for contingencies. In 2018, three constraints associated with this path bound frequently and caused price separation within the ISO system: 30060_MIDWAY _500_24156_VINCENT _500_BR_1 _1, 6410_CP5_NG, and 6410_CP1_NG. These three constraints increased prices in SDG&E and SCE by $1.14/MWh and $1.18/MWh, respectively, and decreased prices in PG&E by $1.77/MWh. In the third quarter, congestion related to Path 26 contributed to roughly 85 percent of the price difference in PG&E and SCE, and roughly 55 percent of the price difference in SDG&E.

Congestion across Path 26 was driven primarily by high north-to-south flows resulting from regional differences in natural gas prices, which were substantially higher in the south through the peak periods of the year. Additionally, there were a number of days with planned and forced outages of the Midway-Whirlwind 500 kV line and of equipment at the Midway and Vincent substations.

Imperial Valley nomogram

The Imperial Valley nomogram (7820_TL 230S_OVERLOAD_NG) bound frequently in every quarter of 2018. When binding, the impact of this constraint on price separation was much lower than the constraints discussed above, though the frequency of congestion led to a notable impact for the entire year. The constraint primarily impacted the SDG&E area, increasing prices by $0.62/MWh or 1.32 percent compared to the system energy price for the year. The nomogram is enforced to mitigate for the loss of the Imperial Valley-North Gila 500 kV line. There were no significant outages directly impacting this constraint in 2018, though it is frequently used to manage flows in the San Diego area.

[175] To see the breakdown of each individual constraint's impact on prices during the respective quarter, please see DMM's quarterly reports. A comprehensive set of DMM's quarterly reports is located at http://www.caiso.com/market/Pages/MarketMonitoring/AnnualQuarterlyReports/Default.aspx

Tracy-Los Banos outage nomogram

Located in the PG&E area, the Tracy-Los Banos nomogram (OMS_6451207_TRACY-LOSBANOS) had a significant impact on prices in the fourth quarter. It is one of few constraints that lowered prices in SCE and SDG&E and increased prices in PG&E. As mentioned above, the net impact of congestion in the fourth quarter is low relative to other quarters. This is a result of the offsetting effect of congestion due to this outage. For the year, congestion associated with this constraint increased PG&E prices about $0.16/MWh and decreased SCE and SDG&E prices by about $0.11/MWh. This nomogram was enforced to manage flows during a planned outage of both the Tracy-Los Banos 500 kV line and Tesla-Tracy 500 kV line that lasted the month of October.

Table 8.2 Impact of constraint congestion on overall day-ahead prices during all hours

Constraint Location	Constraint	Frequency				PG&E		SCE		SDG&E	
		Q1	Q2	Q3	Q4	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
PG&E	OMS_6451207_TRACY-LOSBANOS				10.5%	$0.16	0.41%	-$0.12	-0.27%	-$0.11	-0.23%
	RM_TM12_NG		7.2%	2.4%		$0.03	0.07%	-$0.01	-0.01%	-$0.04	-0.08%
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	1.4%				$0.02	0.06%	-$0.02	-0.04%	-$0.02	-0.04%
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _1		2.8%		0.8%	$0.02	0.04%	-$0.01	-0.03%	-$0.01	-0.03%
	6310_MWN_NRAS				1.1%	$0.02	0.04%	-$0.01	-0.03%	-$0.01	-0.02%
	30055_GATES1 _500_30900_GATES _230_XF_11_S	1.2%	2.2%	2.3%	0.0%	$0.01	0.03%	-$0.01	-0.03%	-$0.01	-0.02%
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	0.1%	0.6%		1.0%	$0.01	0.03%	-$0.01	-0.02%	-$0.01	-0.02%
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2			0.2%	1.1%	$0.01	0.03%	-$0.01	-0.02%	-$0.01	-0.02%
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1		0.0%	0.6%	1.0%	$0.01	0.03%	-$0.01	-0.02%	-$0.01	-0.01%
	30885_MUSTANGS_230_30900_GATES _230_BR_2 _1				3.9%	$0.01	0.03%	-$0.01	-0.02%	-$0.01	-0.01%
	30879_HENTAP1 _230_30885_MUSTANGS_230_BR_1 _1				5.7%	$0.01	0.02%	-$0.01	-0.01%	-$0.01	-0.01%
	30915_MORROBAY_230_30916_SOLARSS _230_BR_1 _1			1.4%	1.4%	$0.01	0.02%	$0.00	-0.01%	$0.00	0.00%
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3				0.4%	-$0.01	-0.01%	$0.00	0.01%	$0.00	0.01%
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _1	0.1%		15.0%		-$0.94	-2.37%	$0.60	1.35%	$0.56	1.20%
SCE	6410_CP5_NG		2.3%	11.0%		-$0.54	-1.37%	$0.41	0.94%	$0.39	0.83%
	6410_CP1_NG		0.1%	4.7%		-$0.29	-0.73%	$0.17	0.40%	$0.18	0.39%
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1		9.4%	9.0%	1.4%	-$0.13	-0.33%	$0.14	0.31%	$0.05	0.10%
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	0.2%	2.1%	8.8%	0.1%	-$0.06	-0.16%	$0.07	0.15%	$0.02	0.05%
	24036_EAGLROCK_230_24059_GOULD _230_BR_1 _1	4.3%	15.6%	2.8%	0.3%	-$0.08	-0.20%	$0.06	0.14%	$0.00	0.01%
	24092_MIRALOMA_500_24093_MIRALOM _230_XF_4 _P		2.8%	2.4%		-$0.09	-0.22%	$0.06	0.14%	$0.06	0.13%
	24092_MIRALOMA_500_24093_MIRALOM _230_XF_1 _P			1.1%		-$0.04	-0.10%	$0.02	0.06%	$0.03	0.05%
	24029_DELAMO _230_24021_CENTER S_230_BR_1 _1	2.8%				-$0.02	-0.06%	$0.02	0.05%	$0.01	0.02%
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	7.0%	3.5%	4.8%	10.6%	-$0.01	-0.02%	$0.01	0.02%	$0.02	0.05%
	24021_CENTER S_230_24091_MESA CAL_230_BR_1 _1	2.0%				-$0.01	-0.03%	$0.01	0.02%	$0.01	0.02%
	24025_CHINO _230_24093_MIRALOM _230_BR_3 _1		0.9%		0.4%	-$0.01	-0.03%	$0.01	0.01%	$0.03	0.07%
	24091_MESA CAL_230_24126_RIOHONDO_230_BR_1 _1		1.0%		0.3%	-$0.01	-0.02%	$0.01	0.02%	$0.01	0.01%
	25001_GOODRICH_230_24076_LAGUBELL_230_BR_1 _1	0.7%	2.7%	0.7%		-$0.01	-0.02%	$0.00	0.01%	$0.01	0.01%
	24114_PARDEE _230_24147_SYLMAR S_230_BR_2 _1	1.0%	0.8%		1.8%	$0.00	0.00%	$0.00	0.00%	-$0.02	-0.04%
	7750_D-ECASCO_OOS_CP6_NG	0.1%	0.6%		16.2%	$0.02	0.06%	-$0.02	-0.04%	-$0.01	-0.02%
	6410_CP10_NG	1.3%		0.1%		$0.03	0.07%	-$0.02	-0.05%	-$0.02	-0.04%
SDG&E	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	40.7%	2.9%			-$0.72	-1.82%	$0.47	1.08%	$1.10	2.33%
	7820_TL 230S_OVERLOAD_NG	9.1%	17.7%	12.0%	11.6%	-$0.06	-0.14%	$0.00	0.00%	$0.62	1.32%
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	22.3%	22.5%	13.0%	1.7%	$0.00	0.00%	$0.00	0.00%	$0.36	0.77%
	7820_TL23040_IV_SPS_NG	0.7%	4.3%	14.4%	1.8%	-$0.02	-0.06%	$0.00	0.00%	$0.29	0.61%
	MIGUEL_BKs_MXFLW_NG	0.6%	0.6%	0.6%	2.4%	-$0.01	-0.02%	$0.00	0.00%	$0.15	0.32%
	22500_MISSION _138_22496_MISSION _69.0_XF_1			0.6%		$0.00	0.00%	$0.00	0.00%	$0.11	0.23%
	22820_SWEETWTR_69.0_22476_MIGUELTP_69.0_BR_1 _1	0.3%	2.2%	0.1%		$0.00	0.00%	$0.00	0.00%	$0.04	0.08%
	OMS 5717006_50001_OOS_NG		1.5%			$0.00	-0.01%	$0.00	0.00%	$0.04	0.08%
	OMS 5649479 50002_OOS_TDM		2.7%			$0.00	0.00%	$0.00	0.00%	$0.04	0.07%
	OMS 4646120 ELD_MKP_SCIT_NG	2.8%				-$0.03	-0.08%	$0.02	0.05%	$0.03	0.06%
	OMS 6369451_50001_OOS_NG			0.5%		$0.00	-0.01%	$0.00	0.00%	$0.03	0.05%
	22476_MIGUELTP_69.0_22456_MIGUEL _69.0_BR_1 _1	0.3%				$0.00	0.00%	$0.00	0.00%	$0.02	0.05%
	22824_SWTWTRTP_69.0_22820_SWEETWTR_69.0_BR_1 _1	2.2%	0.7%	0.1%		$0.00	0.00%	$0.00	0.00%	$0.02	0.05%
	22597_OLDTWNTP_230_22504_MISSION _230_BR_1 _1		0.7%	0.1%		$0.00	0.00%	$0.00	0.00%	$0.02	0.05%
	OMS 5730606 TL50003_NG		0.9%			$0.00	-0.01%	$0.00	0.00%	$0.02	0.04%
	22500_MISSION _138_22120_CARLTNHS_138_BR_1 _1	1.8%	0.1%			$0.00	0.00%	$0.00	0.00%	$0.02	0.04%
	OMS 6355729 TL50003_NG				0.5%	$0.00	0.00%	$0.00	0.00%	$0.02	0.04%
	OMS 6355712 TL50003_NG				0.5%	$0.00	0.00%	$0.00	0.00%	$0.02	0.03%
	OMS 6355725 TL50003_NG				0.4%	$0.00	0.00%	$0.00	0.00%	$0.02	0.03%
	OMS6286861 TL50005_NG			0.4%		$0.00	0.00%	$0.00	0.00%	$0.01	0.03%
	22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1	0.4%		1.4%		$0.00	0.00%	$0.00	0.00%	$0.01	0.03%
	IID-SCE_BG	0.8%		0.1%	3.1%	$0.00	0.00%	$0.00	0.00%	-$0.09	-0.19%
Other	Other					$0.00	-0.01%	$0.04	0.09%	$0.21	0.44%
Total	**Total**					**-$2.73**	**-6.92%**	**$1.87**	**4.26%**	**$4.19**	**8.90%**

8.3.2 Real-time congestion

Congestion in the 15-minute real-time market typically occurs less frequently overall, but has a larger impact on locational price differences. Congestion patterns over 2018 reflect this overall trend.[176]

Figure 8.5 shows price separation resulting from congestion between ISO area and energy imbalance market area prices by quarter. Figure 8.6 shows the frequency of intervals with congestion impacting prices by more than $0.05/MWh by area and quarter. For energy imbalance market areas, reported impact and frequency of congestion include congestion due to transfer constraints in addition to flow-based constraints.

Over the entire year, congestion resulted in a net increase to prices south of Path 26 (SCE and SDG&E) and areas with high transfer capacity south of Path 26 (NV Energy and APS), and resulted in a net decrease to prices in the rest of the ISO system. The greatest net increase to prices occurred in SDG&E, while the greatest net decrease occurred in the balancing areas in the Pacific Northwest. This is primarily a result of limited transmission capacity between the congested local areas and the rest of the system.

On a quarterly basis, net price separation due to congestion was greatest in the third quarter. For some areas prices in the third quarter were much higher so the impact of congestion as a percent of prices was not as pronounced. As a percent of area prices, separation due to congestion across the west in the third quarter was similar to the second quarter. In the fourth quarter, there was significant offsetting congestion primarily resulting from the Tracy-Los Banos outage nomogram, leading to a small net impact in price separation relative to other quarters.

The frequency with which congestion impacts prices at aggregated load areas provides additional insight into trends in congestion that are not apparent in the net impact. The greatest frequency of congestion occurred in the third quarter, followed by the first quarter. In the fourth quarter, there was significant congestion that occurred in both the positive and negative direction. Figure 8.6 provides insight that the frequency of congestion in the fourth quarter was similar to that of the second quarter.

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

[176] Historically, we have provided 5-minute market congestion in addition to 15-minute and day-ahead market congestion. Given that most of the imbalance in real time occurs in the 15-minute market we are only reporting on this congestion at this time. In 2018, overall frequency of congestion is similar between the 15-minute and 5-minute markets; however, the price impact was higher in the 5-minute market compared to the 15-minute market.

Figure 8.5 Overall impact of congestion on price separation in the 15-minute market

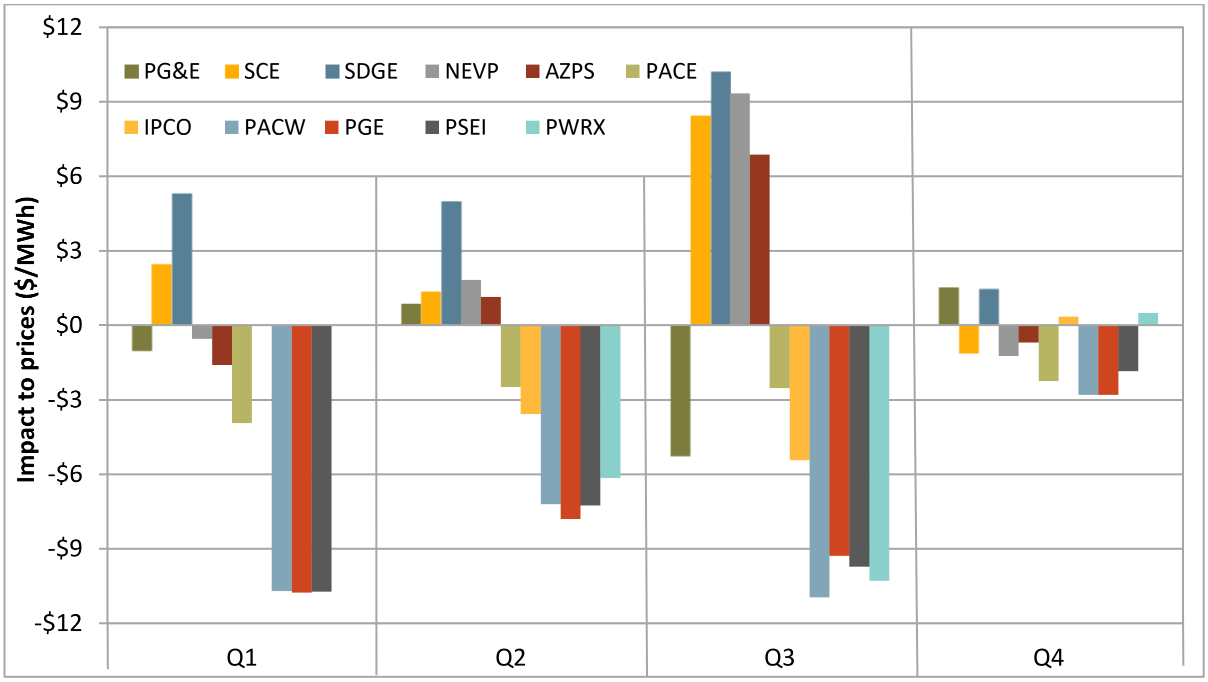


Figure 8.6 Percent of intervals with congestion impacting prices (>$0.05/MWh)

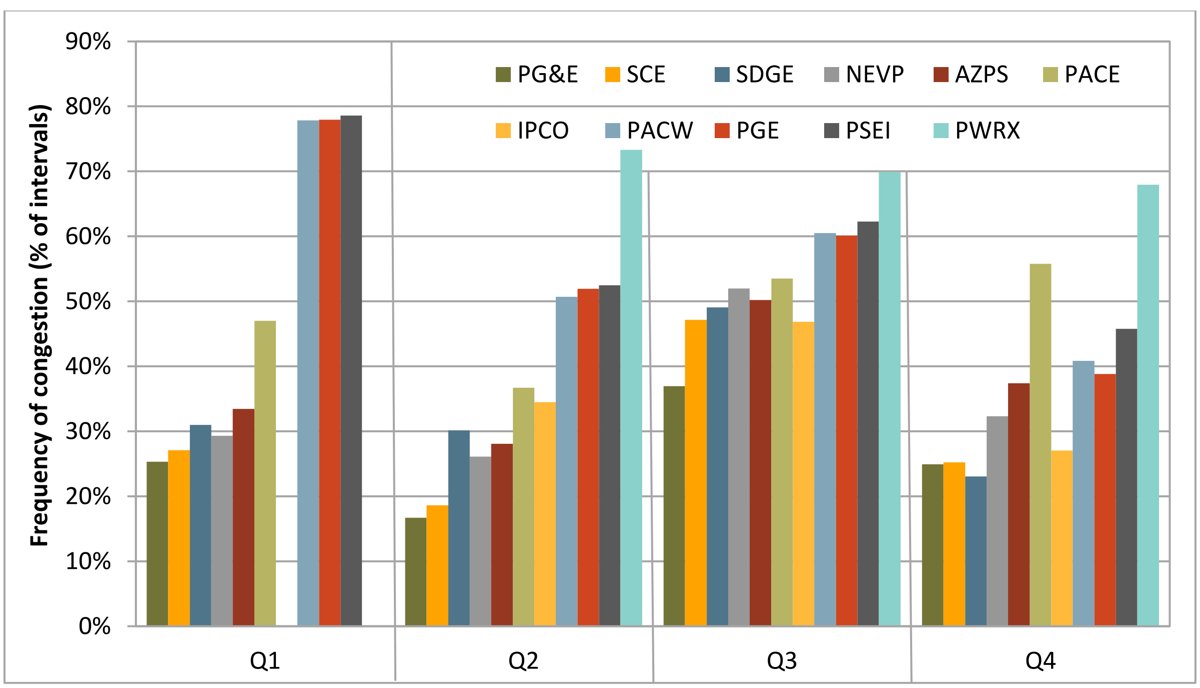


Table 8.3 shows the overall impact of 15-minute congestion on average prices in each load area in 2018. The color scales in the table below apply only to the individual constraints. The category labeled "other" includes the impact of energy imbalance market transfer constraints, which have the greatest impact on

price separation for EIM areas. These transfer constraints are discussed in greater depth in Chapter 4. This section will focus on the individual flow-based constraints.

The constraints that had the greatest impact on price separation in the 15-minute market were the constraints associated with Path 26, the Serrano 500/230 kV transformer, the Round Mountain-Table Mountain nomogram, and the nomogram used to manage the Tracy-Los Banos outages.

Path 26

As mentioned in the discussion of day-ahead congestion, the transmission path called Path 26 is composed of three high voltage lines: the Midway-Vincent #1 500 kV line, Midway-Vincent #2 500 kV line, and the Midway-Whirlwind 500 kV line. Congestion on this path is also indicative of separation between northern and southern parts of California and balancing areas across the west due to constrained transmission capacity into areas north and south of the path.

In 2018, a number of constraints that are used to manage flows over these lines bound frequently and caused price separation across the west: in particular 30060_MIDWAY _500_24156_VINCENT _500_BR_1 _1, 6410_CP5_NG, and 6410_CP1_NG. For the year, these three constraints increased prices in each area south of the path (in SCE, SDG&E, NEVP, and AZPS) by about $1/MWh, and decreased prices in each area north of the path (in PG&E, PACW, PGE, PSEI, and PWRX) by about $1/MWh.

Serrano transformer 500/230 kV

Similar to the day-ahead market, congestion on the Serrano 500/230 kV transformer (24138_SERRANO _500_24137_SERRANO _230_XF_1 _P) significantly impacted price separation in the first quarter, binding in roughly 13 percent of intervals. This constraint increased SCE and SDG&E prices and decreased prices for all other areas. Because it bound primarily in the first quarter, the constraint had little impact on Powerex and Idaho Power prices for the year. This congestion was caused by a planned outage on a portion of the Serrano transformer bank, which started at the end of October 2017 and ended in April 2018.

Round Mountain-Table Mountain nomogram

The Round Mountain-Table Mountain nomogram (RM_TM12_NG) impacted price separation in the west across all quarters, though had the greatest net impact in the first and second quarters. The Round Mountain-Table Mountain 500 kV line is located in Northern California. As a result, it increased prices in California and the EIM areas that have significant transmission capacity with California south of the constraint, and decreased prices throughout the rest of the west. The nomogram is enforced to protect for the loss of either Round Mountain-Table Mountain 500 kV #1 or Table Mountain 500 kV #2.

Tracy-Los Banos outage nomogram

Located in the PG&E area, the Tracy-Los Banos and Tesla-Tracy outages (OMS_6451207_TRACY-LOSBANOS) had a significant impact on nearly all load areas. In 2018, this was one of a few constraints that had the impact of decreasing prices in the south and increasing prices in the north, as can be seen by the shift in colors below. As mentioned above, the net impact of congestion in the fourth quarter is low relative to other quarters. This result is largely driven by congestion due to this outage. On average, it increased prices to each area north of the constraint by about $0.23/MWh and decreased prices to each area south of the constraint by about $0.24/MWh. Congestion from this nomogram occurred due to a planned outage of both the Tracy-Los Banos 500 kV line and Tesla-Tracy 500 kV line that lasted the month of October.

Table 8.3 Impact of constraint congestion on overall 15-minute prices during all hours

Constraint Location	Constraint	PGAE	SCE	SDGE	NEVP	AZPS	PACE	IPCO	PACW	PGE	PSEI	PWRX
NEVP	GON-IPP 230	$0.00	$0.00	$0.00	$0.02	$0.00	-$0.05	-$0.03	$0.00	$0.00	$0.00	$0.00
	RBS-HA_525KV	$0.00	$0.01	$0.01	$0.00	$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
PACE	WYOMING_EXPORT	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.14	$0.00	$0.00	$0.00	$0.00	$0.00
PG&E	RM_TM12_NG	$0.36	$0.20	$0.17	$0.04	$0.13	-$0.21	-$0.52	-$0.54	-$0.54	-$0.53	-$0.69
	30055_GATES1 _500_30900_GATES _230_XF_11_S	$0.17	$0.01	$0.00	-$0.03	-$0.02	-$0.03	-$0.15	-$0.16	-$0.16	-$0.16	-$0.20
	OMS_6451207_TRACY-LOSBANOS	$0.16	-$0.29	-$0.28	-$0.16	-$0.25	-$0.01	$0.14	$0.25	$0.25	$0.25	$0.32
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.03	-$0.04	-$0.04	-$0.02	-$0.03	$0.00	$0.00	$0.03	$0.03	$0.03	$0.00
	RM_TM21_NG	$0.02	$0.01	$0.01	$0.00	$0.01	-$0.01	-$0.02	-$0.03	-$0.03	-$0.03	-$0.03
	37585_TRCY PMP_230_30625_TESLA D _230_BR_1 _1	$0.02	-$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _1	$0.02	-$0.03	-$0.03	-$0.02	-$0.02	$0.00	$0.01	$0.02	$0.02	$0.02	$0.03
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	$0.01	-$0.02	-$0.02	-$0.01	-$0.02	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01
	40687_MALIN _500_30005_ROUND MT_500_BR_1 _3	$0.01	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	30523_CC SUB _230_30525_C.COSTA _230_BR_1 _1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.02	-$0.02	-$0.02	-$0.02
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.12	$0.11	$0.10	$0.06	$0.09	$0.00	-$0.07	-$0.09	-$0.09	-$0.08	-$0.11
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _1	-$0.75	$0.67	$0.64	$0.38	$0.57	$0.00	-$0.43	-$0.55	-$0.55	-$0.53	-$0.70
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.01	$0.39	$0.26	-$0.19	-$0.19	-$0.15	-$0.09	-$0.03	-$0.03	-$0.04	-$0.03
	6410_CP5_NG	-$0.36	$0.35	$0.33	$0.20	$0.30	$0.01	-$0.18	-$0.26	-$0.26	-$0.25	-$0.33
	6510_CP1_NG	-$0.10	$0.28	$0.30	-$0.10	-$0.10	-$0.10	-$0.13	-$0.10	-$0.10	-$0.10	-$0.13
	6410_CP1_NG	-$0.21	$0.19	$0.19	$0.11	$0.17	$0.00	-$0.12	-$0.16	-$0.16	-$0.15	-$0.20
	24021_CENTER S_230_24091_MESA CAL_230_BR_1 _1	-$0.10	$0.14	$0.18	-$0.01	$0.00	-$0.05	$0.00	-$0.08	-$0.08	-$0.08	$0.00
	24092_MIRALOMA_500_24093_MIRALOM _230_XF_4 _P	-$0.05	$0.10	$0.09	-$0.04	$0.01	-$0.03	-$0.06	-$0.05	-$0.05	-$0.05	-$0.06
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.01	$0.06	$0.05	-$0.03	-$0.03	-$0.03	-$0.01	-$0.02	-$0.02	-$0.02	-$0.01
	24029_DELAMO _230_24021_CENTER S_230_BR_1 _1	-$0.03	$0.05	$0.03	-$0.02	$0.00	-$0.02	$0.00	-$0.03	-$0.03	-$0.03	$0.00
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.03	$0.04	$0.04	-$0.11	-$0.10	-$0.06	-$0.04	$0.00	$0.00	$0.00	$0.00
	6410_CP6_NG	-$0.03	$0.04	$0.03	$0.02	$0.03	$0.00	-$0.02	-$0.02	-$0.02	-$0.02	-$0.03
	24156_VINCENT _500_24155_VINCENT _230_XF_3	-$0.02	$0.02	$0.01	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.02
	OP-6610_ELD-LUGO	$0.01	$0.01	$0.01	-$0.03	-$0.03	-$0.02	-$0.01	$0.00	$0.00	$0.00	$0.00
	OMS 6414477_OP-6610	$0.01	$0.01	$0.00	-$0.02	-$0.02	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00
	6410_CP10_NG	$0.02	-$0.02	-$0.02	-$0.01	-$0.02	$0.00	$0.00	$0.02	$0.02	$0.02	$0.00
	7750_D-ECASCO_OOS_CP6_NG	$0.06	-$0.04	$0.00	-$0.02	-$0.17	-$0.04	$0.00	$0.01	$0.01	$0.01	$0.01
	24092_MIRALOMA_500_24093_MIRALOM _230_XF_1 _P	-$0.01	$0.01	$0.01	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
SDG&E	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	-$0.22	$0.37	$0.84	-$0.24	-$0.18	-$0.22	-$0.01	-$0.22	-$0.22	-$0.22	-$0.01
	MIGUEL_BKs_MXFLW_NG	$0.00	$0.00	$0.54	-$0.05	-$0.19	-$0.06	$0.00	$0.00	$0.00	$0.00	$0.00
	7820_TL 230S_OVERLOAD_NG	$0.00	$0.03	$0.47	-$0.04	-$0.11	-$0.04	-$0.03	$0.00	$0.00	$0.00	$0.00
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	$0.00	$0.00	$0.27	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	7820_TL23040_IV_SPS_NG	$0.00	$0.00	$0.18	-$0.01	-$0.03	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 5820664 MG_BK80_NG	$0.00	$0.00	$0.16	-$0.01	-$0.05	-$0.02	$0.00	$0.00	$0.00	$0.00	$0.00
	22886_SUNCREST_230_92860_SUNC TP1_230_BR_1 _1	$0.00	$0.00	$0.15	-$0.02	-$0.05	-$0.02	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 4646120 ELD_MKP_SCIT_NG	-$0.02	$0.08	$0.09	-$0.02	-$0.11	-$0.05	$0.00	-$0.03	-$0.03	-$0.03	$0.00
	OMS 5092302 MG_BK81_NG	$0.00	$0.00	$0.07	-$0.01	-$0.02	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 5730606 TL50003_NG	$0.00	$0.00	$0.07	-$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	$0.00	$0.00	$0.07	$0.00	-$0.02	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00
	22831_SYCAMORE_138_22832_SYCAMORE_230_XF_1	$0.00	$0.00	$0.05	$0.00	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 5717006_50001_OOS_NG	$0.00	$0.00	$0.05	$0.00	-$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 6355729 TL50003_NG	$0.00	$0.00	$0.05	$0.00	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	22886_SUNCREST_230_22885_SUNCREST_500_XF_1 _P	$0.00	$0.00	$0.05	-$0.01	-$0.02	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00
	Other	$0.13	$0.06	$0.30	$2.78	$2.01	-$1.36	-$0.64	-$5.81	-$5.56	-$5.31	-$2.57
	Total	**-$0.99**	**$2.78**	**$5.49**	**$2.37**	**$1.45**	**-$2.80**	**-$2.47**	**-$7.90**	**-$7.64**	**-$7.37**	**-$4.81**

8.4 Congestion revenue rights

Congestion revenue rights that are not allocated to load-serving entities which are sold in the auction consistently generate significantly less revenue than is paid to the entities purchasing these rights at auction. If these congestion revenue rights were not sold in the auction, all of these congestion revenues would be allocated back to load-serving entities based on their share of total load. From 2012 through 2018, ratepayers received about 48 percent of the value of their congestion revenue rights that the ISO auctioned. This represents a shortfall of about $131 million in 2018 and more than a $860 million shortfall since 2009.

Section 8.4.1 provides an overview of allocated and auctioned congestion revenue rights holdings. Section 8.4.2 provides more details on the performance of the congestion revenue rights auction.

8.4.1 Allocated and auctioned congestion revenue rights

Background

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

Congestion revenue rights are either allocated or auctioned to market participants. Participants serving load are allocated rights monthly, annually (with seasonal terms), or for 10 years (for the same seasonal term each year). All participants can procure congestion revenue rights in the auctions. Annual auctions are held prior to the year in which the rights will settle. Rights sold in the annual auctions have seasonal terms. Monthly auctions are held the month prior to the settlement month. Rights sold in the monthly auction have monthly terms.[177]

Ratepayers own the day-ahead transmission rights not held by merchant transmission or long-term rights holders. In this report rights owned by ratepayers are referred to as non-merchant day-ahead transmission rights.

Allocated congestion revenue rights are a means of distributing the revenue from the sale of these non-merchant day-ahead rights, also known as congestion rent, to entities serving load to then be passed to ratepayers. Any revenues remaining after the distribution to allocated congestion revenue rights are allocated based on load share, or are used to pay congestion revenue rights procured at auction.

In exchange for backing the auctioned rights, ratepayers receive the net auction revenue which is allocated by load share. If there is insufficient transmission sales revenue to pay all the congestion revenue rights, a condition known as revenue inadequacy, ratepayers are charged based on load share to cover the difference.

Congestion revenue right holdings

Interpreting congestion revenue right megawatt holding changes can be difficult as it is not clear what the megawatt volume represents. Consider a participant holding 10 megawatts from node A to node B,

177 A more detailed explanation of the congestion revenue right processes is provided in the ISO's *2015 Annual CRR Market Results Report*. See: http://www.caiso.com/Documents/2015AnnualCRRMarketResultsReport.pdf.

and 10 megawatts from node B to node A. The participant's net holding of transmission rights is zero megawatts but the total megawatts of congestion revenue rights held is 20 megawatts. Total congestion revenue right megawatts does not give a complete view of the transmission rights held.

One alternative is measuring the implied value of transmission rights held by congestion revenue rights. Congestion revenue rights are allocated and auctioned across different time frames. A valuation of the rights held can be computed using the seasonal auction, monthly auction, or day-ahead transmission prices.

Figure 8.7 shows the percentage congestion revenue right megawatts held by allocated, seasonally auctioned, and monthly auctioned rights. Figure 8.8 shows the percentage of rights held when valued at the monthly auction prices. Both figures include all peak and off-peak rights. In 2018, allocated congestion revenue rights made up less than a third of total megawatts, but were worth more than two thirds of the implied value of rights at monthly auction prices, a continued trend since 2013.

Figure 8.9 shows payments to congestion revenue rights with auction prices at or below $0/MWh.[178] Figure 8.10 shows payments to rights with auction prices greater than $0/MWh, which indicate positions in the prevailing flow of congestion, typically from a generation area to a load area. Both figures include peak and off-peak rights. The majority of payments were to rights with positive auction prices which were in the prevailing flow of congestion.

Although there continued to be a significant number of megawatts held priced at $0/MWh, net payments to these rights were insignificant when compared to total payments to auctioned rights in 2018.[179] Net payments to zero priced rights totaled $2 million in 2018, up from $0.10 million in 2017. Total payments to auctioned rights were about $216 million in 2018 and $175 million in 2017. Congestion revenue rights priced below zero dollars but greater than negative 25 cents were paid $14 million in 2018 and $7 million and $2 million in 2017 and 2016, respectively.

[178] This includes congestion revenue right positions that are counter to the prevailing flow of generation and are known as counter-flow positions. For example, a counter-flow congestion revenue right may go from a load area to a generation area. These positions are paid to take the congestion revenue right in the auction and then make payments based on day-ahead congestion. This grouping also includes positions that have a $0/MWh price in the auction and cannot be classified as counter-flow or prevailing flow because it is possible that they may be prevailing flow or counter-flow in the day-ahead market, which differs from the results in the auction.

[179] In 2013 and 2014 the total amount of rights held priced at $0/MWh increased sharply. See Section 7.4 of the *2014 Annual Report on Market Issues and Performance*, Department of Market Monitoring: http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf.

Figure 8.7 Percent of congestion revenue right megawatts held by procurement type

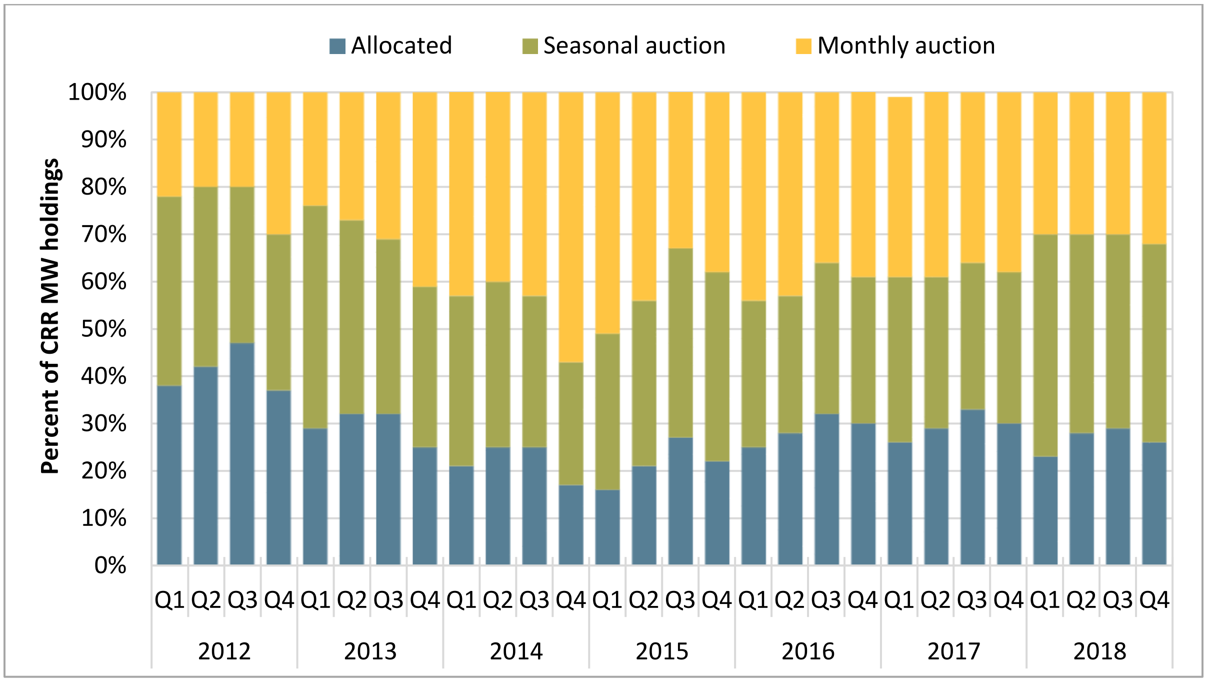


Figure 8.8 Percent of congestion revenue right monthly auction value by procurement type

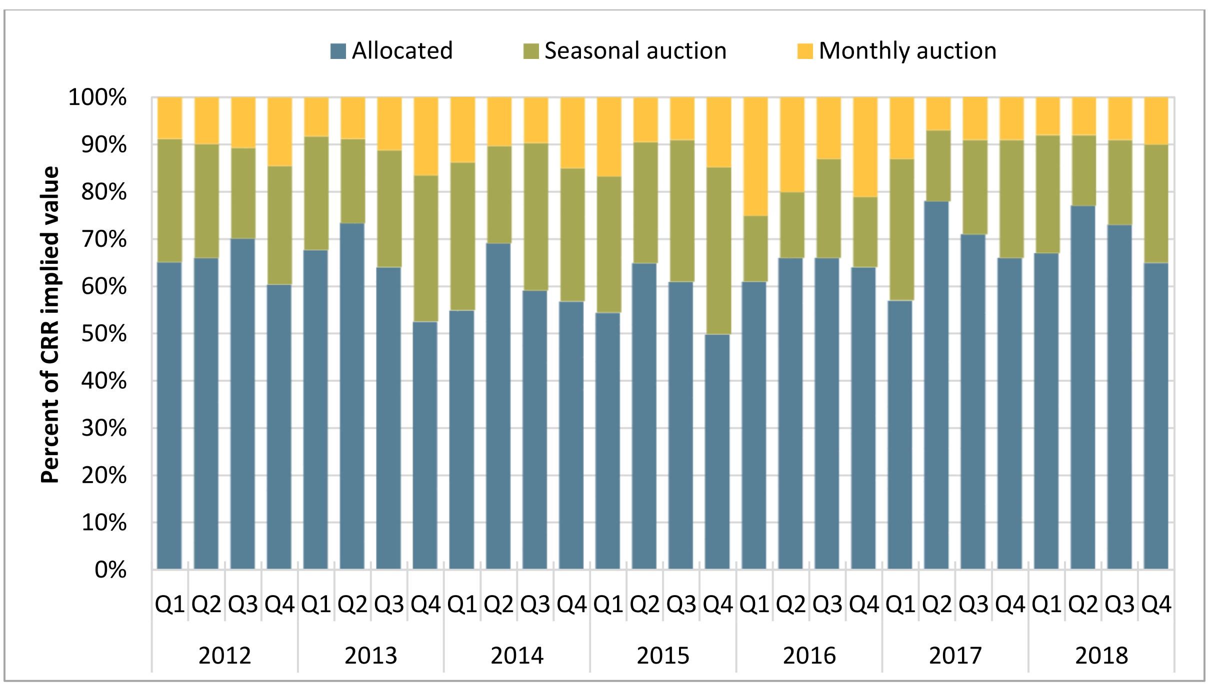


Figure 8.9 Payments to non-positively priced auctioned congestion revenue rights

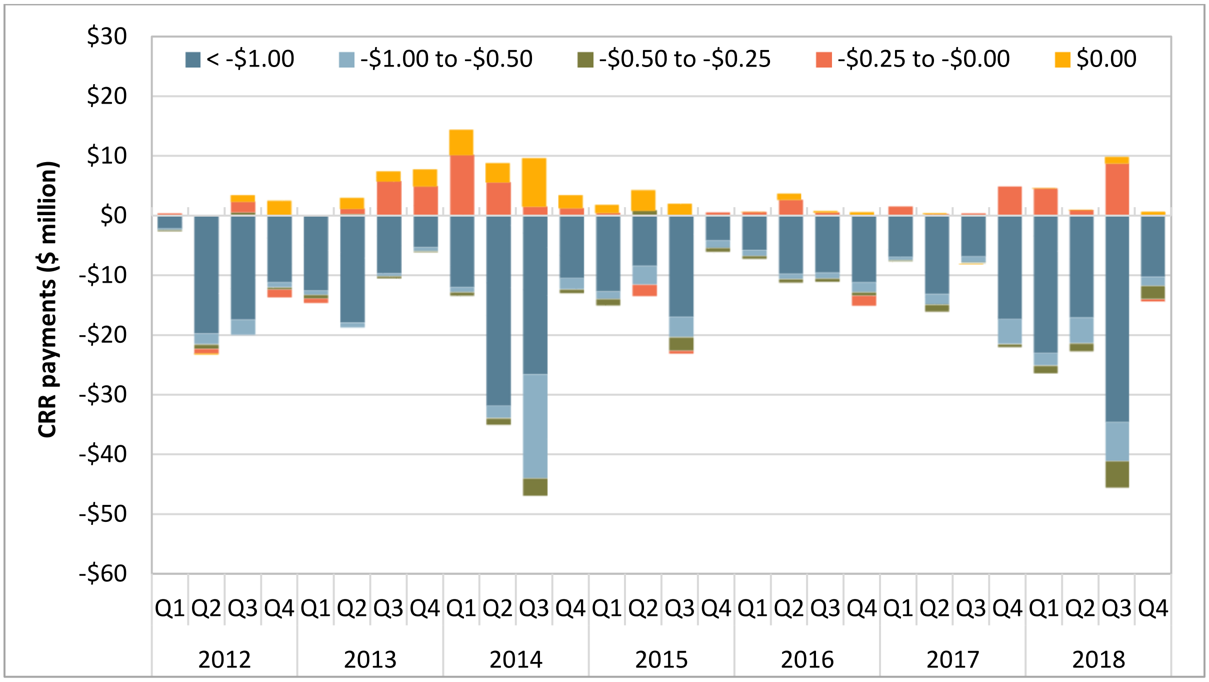
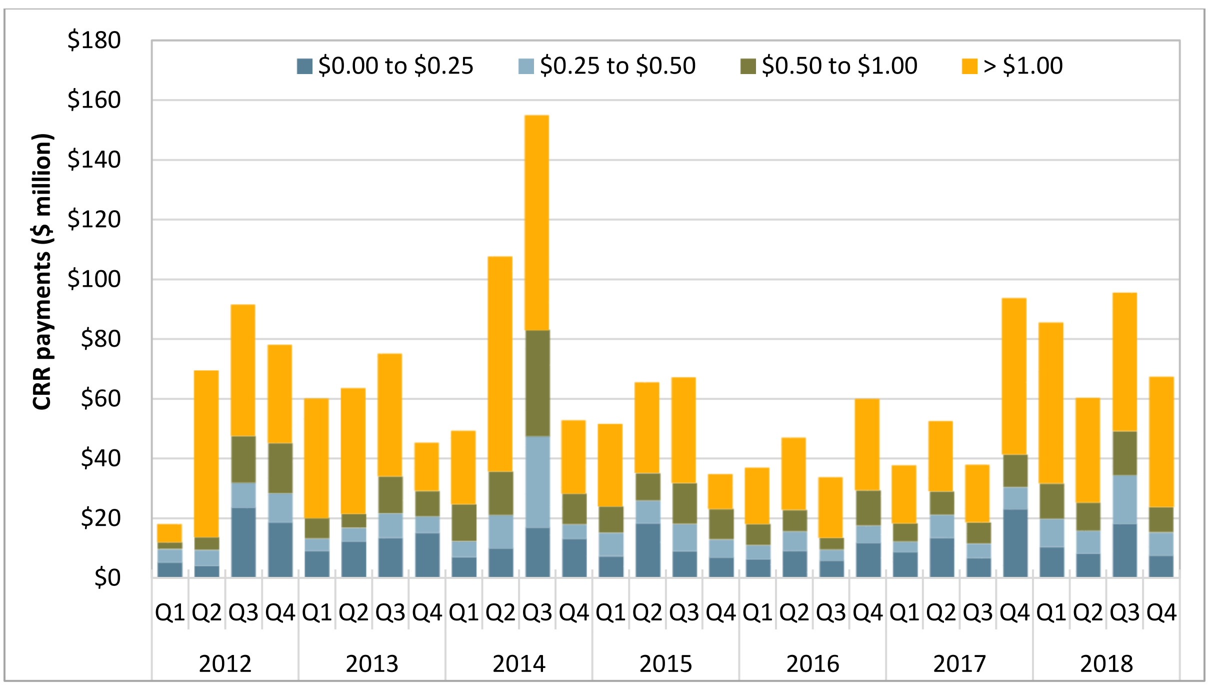


Figure 8.10 Payments to positively priced auctioned congestion revenue rights



8.4.2 Congestion revenue right auction returns

The ISO tracks and reports on congestion revenue right revenue inadequacy as a primary metric to evaluate how well the congestion revenue right market is functioning. This section presents an alternative metric that DMM believes is more appropriate for assessing the congestion revenue right market.[180] This metric compares the auction revenues that ratepayers receive for rights sold in the ISO's auction to the payments made to these auctioned rights at day-ahead market prices.

Results presented in this report show that auction revenues received by ratepayers have persistently been far below day-ahead market congestion revenues that ratepayers would have received if the ISO had not auctioned any congestion revenue rights.[181] This discrepancy 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.[182,183]

DMM believes the current auction is unnecessary and could be eliminated.[184] 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.

Background

When a transmission constraint is binding in the day-ahead market, this creates congestion revenue. This is because load that is within the congested area of a constraint is charged a higher price than the price paid to generation on the uncongested side of the constraint. When congestion occurs, each megawatt of the constraint's transmission capacity produces market revenue equal to the constraint's day-ahead market congestion price (or shadow price). For instance, when a 1,000 MW constraint is binding at a $10/MWh congestion price, this generates $10,000 in congestion revenues.

The owners of transmission – or entities paying for the cost of building and maintaining transmission – are entitled to the 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).[185] The ISO charges load-serving

180 The ISO reports on a similar metric in its market performance metric catalogue in its congestion revenue right section: http://www.caiso.com/market/Pages/ReportsBulletins/Default.aspx.

181 For further information, see DMM's whitepaper: *Shortcomings in the Congestion Revenue Right Auction Design*, November 28, 2016*:* http://www.caiso.com/Documents/DMM-WhitePaper-Shortcomings-CongestionRevenueRightAuctionDesign.pdf.

182 It is a convenient analogy to describe the auction as selling excess transmission rights. However, an alternative analogy is that the auction makes ratepayers the counterparty to financial cash settled forward contracts. The difference between the auction revenues and payments to the rights are the gains or losses to ratepayers on these forward contracts.

183 DMM whitepaper *"Problems in the performance and design of the congestion revenue rights auction",* November 27, 2017: http://www.caiso.com/Documents/DMMWhitePaper-Problems_Performance_Design_CongestionRevenueRightAuction-Nov27_2017.pdf

184 DMM whitepaper on Market alternatives to the congestion revenue rights auction, November 27, 2017: http://www.caiso.com/Documents/DMMWhitePaper-Market_Alternatives_CongestionRevenueRightsAuction-Nov27_2017.pdf

185 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.

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.

These ratepayers currently receive the day-ahead market revenues from a large part of their transmission directly through the congestion revenue right allocation process. This process allocates a portion of congestion rights to load-serving entities which pay the transmission access charge based on these entities' historical load. These entities receive the day-ahead market congestion revenues associated with these congestion revenue rights. These entities then pass on these congestion revenues — along with transmission access charges — to their ratepayers.

The analysis in this section does not apply to this portion of ratepayers' transmission. Instead, this analysis only includes the portion of transmission that is paid for by ratepayers, but is not directly allocated to their load-serving entities. Therefore, the congestion revenues from this transmission are not given directly to ratepayers through this congestion revenue right allocation process.

Not all transmission is allocated through the congestion revenue right allocation process. Ratepayers are still entitled to the day-ahead market congestion revenues generated by the transmission capacity that is not allocated to ratepayers through the congestion revenue right allocation process. However, a current principle incorporated in standard electricity market design is that day-ahead market congestion revenues from this additional transmission capacity is not provided directly to ratepayers. Instead, the ISO auctions off congestion revenue rights, which are intended to represent the rights to the day-ahead market congestion revenues of this excess transmission capacity.

For each megawatt of ratepayer transmission capacity auctioned off by the ISO, ratepayers are effectively giving up their right to the day-ahead market congestion revenue for that capacity. In exchange for the right to this congestion revenue, ratepayers receive the auction revenues generated from auctioning off this excess capacity. Ratepayers directly receive the day-ahead market congestion revenues for any of the excess transmission that is available in the day-ahead market that was not auctioned off through the congestion revenue right balancing account.

As long as the auction revenue that ratepayers receive for a megawatt auctioned off is greater than or equal to the day-ahead market congestion payments made for that megawatt, ratepayers benefit from having the ISO auction off that megawatt. However, if the auction revenue from that megawatt is expected to be less than the day-ahead market congestion revenue of that megawatt, then ratepayers should not want the ISO to auction off this extra transmission.

Ratepayers would be better off directly receiving revenues from this transmission when congestion occurs in the day-ahead market, rather than receiving a lower price through the congestion revenue right auction process. For this reason, DMM believes it is appropriate to assess the performance of the congestion revenue right auction from the perspective of ratepayers by comparing the auction revenues that ratepayers receive for rights sold in the ISO's auction to the day-ahead market congestion revenues that ratepayers would have received if these congestion revenue rights were not sold in the auction.[186]

Congestion revenue rights auction modifications

In March 2018, the Board of Governors approved policy changes that will reduce the number and pairs of nodes at which congestion revenue rights can be purchased in the auction (Track 1A). The changes also require transmission owners to submit planned outages prior to the annual allocation and auction processes. These tariff changes were approved by FERC on June 29, 2018.

A second set of changes (Track 1B) was approved by the Board of Governors in June 2018.[187] This proposal would reduce the net payment to a congestion revenue right holder if payments to congestion revenue rights exceed associated congestion charges collected in the day-ahead market on a targeted constraint-by-constraint basis. On November 9, 2018, FERC accepted the ISO's proposal to fund congestion revenue right payments using only the day-ahead market congestion revenue and revenue from counterflow rights.[188]

Both of these sets of changes have been implemented for the 2019 auction. DMM supported both initiatives as incremental improvements that should help reduce the losses incurred by transmission ratepayers due to the ISO's auction of congestion revenue rights. However, DMM believes the current auction is unnecessary and could be eliminated.[189] If the ISO and stakeholders believe it is beneficial to facilitate hedging by selling through additional congestion revenue rights after the allocation of rights to load-serving entities, 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.[190]

[186] For example, consider a case where there is expected to be 1,000 MW of transmission capacity available in the day-ahead market which has not already been allocated to load-serving entities through the congestion revenue right allocation process. If the ISO auctions off the rights to the day-ahead market congestion revenues for 50 percent of this 1,000 MW capacity, ratepayers receive the auction revenues for this 500 MW of capacity. Ratepayers also receive day-ahead congestion revenues from the other 500 MW of capacity that was not auctioned off through the congestion revenue right balancing account. From the perspective of ratepayers, it is appropriate to compare the auction revenues received for 500 MW of congestion revenue rights sold in the ISO's auction to the day-ahead market congestion revenues that ratepayers would have received for the 500 MW of transmission if these rights were not sold in the auction.

[187] DMM presentation on *Potential Market Alternatives to the CRR Auction*, April 10, 2018: http://www.caiso.com/Documents/Presentation-RogerAvalosDMM-Apr102018.pdf

[188] *FERC Order on Tariff Amendment - Congestion Revenue Rights Auction Efficiency Track 1B,* September 20, 2018*:*
https://www.ferc.gov/CalendarFiles/20180920172657-ER18-2034-000.pdf?csrt=1015546819097727752

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

[189] DMM whitepaper on Market alternatives to the congestion revenue rights auction, November 27, 2017: http://www.caiso.com/Documents/DMMWhitePaper-Market_Alternatives_CongestionRevenueRightsAuction-Nov27_2017.pdf

[190] *DMM comments on congestion revenue rights auction efficiency track 1 B*, June 21, 2018: http://www.caiso.com/Documents/DecisiononCongestionRevenueRightsAuctionEfficiencyTrack1BProposal-DMMComments-Jun2018.pdf

Revenue inadequacy

This section explains why the revenue inadequacy commonly reported is not an accurate or appropriate measure of how well the congestion revenue right market is functioning from the perspective of ratepayers. To illustrate this, consider the following example:

- There is 100 MW of transmission, which is paid for by ratepayers of a load-serving entity through the transmission access charge.
- The load-serving entity is allocated 75 MW of this transmission in the allocation process. These congestion revenue rights exactly match the transmission needed to meet the load-serving entity's actual load.
- The remaining 25 MW is sold to a financial entity in the auction for a price of $5/MWh, resulting in a $125 credit in the balancing account.
- The day-ahead transmission price is $10/MWh.
- The load-serving entity's ratepayers pay $750 into the balancing account as part of the day-ahead congestion charges to meet their load and receive $750 from the balancing account for their 75 MW of congestion revenue rights.
- Other entities utilizing the remaining 25 MW of transmission in the day-ahead market pay $250 into the balancing account.
- The financial entity receives $250 from the balancing account for their 25 MW of congestion revenue rights.

In this example, the balancing account has a net balance of $0 without auction revenues, and a +$125 balance with auction revenues. However, the $125 in the balancing account that is paid to the load-serving entity represents only 50 percent of the $250 value of the 25 MW of transmission paid for by ratepayers that is sold in the congestion revenue rights auction. The remaining $125 of this value is paid to the financial entity purchasing these 25 MW of congestion revenue rights.

As illustrated by this example, revenue inadequacy represents only a portion of the overall performance of the congestion revenue rights auction from the perspective of ratepayers. A positive congestion revenue right account balance with auction revenues does not reflect the actual market value of additional congestion revenue rights sold in the auction. More information on revenue inadequacy can be found in DMM's 2016 annual report.[191]

Although there was net revenue inadequacy (without auction revenues) in 2018, the third quarter of 2018 was revenue "adequate" by about $53.4 million, meaning net day-ahead congestion rents collected by the ISO exceeded the congestion revenue right payments to the holders of the rights. Table 8.4 shows the top 10 constraints that contributed to the revenue surplus. Most of these constraints were also causing high real-time congestion imbalance offset charges as well.[192]

Even though the third quarter of 2018 was revenue adequate, the ratepayer losses were about $42 million. Hence, the performance of the congestion revenue rights auction from the perspective of

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

[192] Refer to Section 2.7 for more information on real-time imbalance offset charges.

ratepayers should instead be assessed by directly comparing the revenues from auctioning off additional transmission rights to the payments made to these rights at day-ahead prices. DMM believes that the ratepayer gains or losses from the auction is the appropriate metric for assessing the congestion revenue right auction.

Table 8.4 Top 10 constraints contributing to congestion revenue right surplus (Q3 2018)

Constraint	Net day-ahead congestion rents ($ million)	CRR entitlements ($ million)	Estimated CRR surpluses ($ million)
30060_MIDWAY_500_24156_VINCENT_500_BR_1_1	$83.5	$46.9	$36.6
6410_CP1_NG	$22.7	$12.3	$10.4
6410_CP5_NG	$28.0	$24.6	$3.3
24016_BARRE_230_24154_VILLAPK_230_BR_1_1	$15.5	$13.3	$2.2
24092_MIRALOMA_500_24093_MIRALOM_230_XF_4_P	$11.4	$9.4	$2.0
CFE_ITC	$1.8	$0.0	$1.9
NOB_ITC	$16.1	$14.4	$1.8
24092_MIRALOMA_500_24093_MIRALOM_230_XF_1_P	$9.6	$7.8	$1.7
24016_BARRE_230_25201_LEWIS_230_BR_1_1	$15.5	$13.8	$1.7
NdGrp:24036_EAGLROCK_230_B2	$2.6	$1.8	$0.8

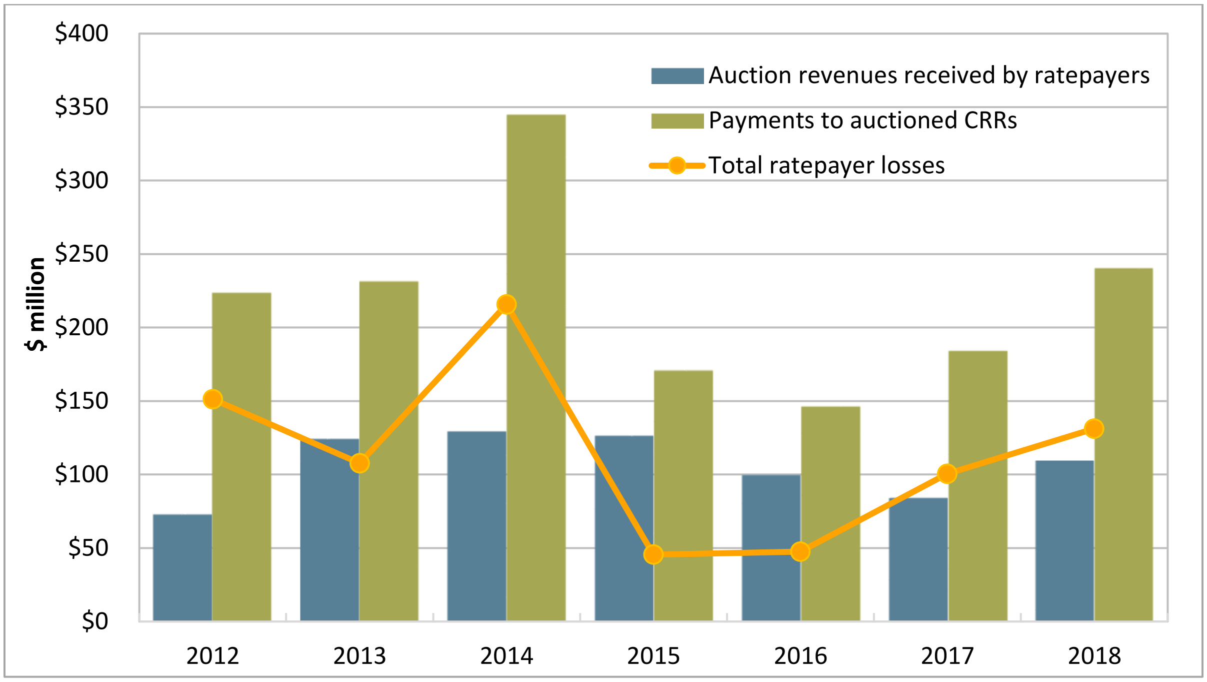
Analysis of congestion revenue right auction returns

As described above, the performance of the congestion revenue rights auction from the perspective of ratepayers can be assessed by comparing the auction revenues received for auctioning transmission rights to the day-ahead congestion payments to these rights. Figure 8.11 compares the following for each of the last seven years:

- Auction revenues received by ratepayers from congestion revenue rights sold in auction (blue bars on left axis).[193]
- Net payments made to the non-load-serving entities purchasing congestion revenue rights in auction (green bars on left axis).
- Auction revenues received by ratepayers as a percentage of the net payments made to the entities purchasing congestion revenue rights in auction (yellow line on right axis)

[193] The auction revenues received by ratepayers are the auction revenues from congestion revenue rights paying into the auction less the revenues paid to "counter-flow" rights. Similarly day-ahead payments made by ratepayers are net of payments by "counter-flow" rights.

Figure 8.11 Ratepayer auction revenues compared with congestion payments for auctioned CRRs



Between 2012 and 2018, ratepayers received, on average, about $114 million less per year from auction revenues than entities purchasing these rights in the auction received from day-ahead congestion revenues. Over this seven year period, ratepayers received an average of only about 48 cents in auction revenues for every dollar paid to congestion revenue rights holders, summing to a total shortfall of $800 million, including $131 million in 2018.

This analysis illustrates that auction revenues ratepayers received were consistently below the day-ahead market congestion revenues that ratepayers would have received if these congestion revenue rights were not auctioned off. These findings are not unique to the California ISO market design. DMM believes these results warrant reassessing the standard electricity market design assumption that ISOs should auction off transmission capacity that remains in excess of the capacity allocated to load-serving entities. Instead, it would be much more beneficial to allow ratepayers to collect these congestion revenues directly.

Figure 8.12 through Figure 8.15 compare the auction revenues received by ratepayers with ratepayer payments to auctioned congestion revenue rights by market participant type.[194] The difference between auction revenues and the payments to congestion revenue rights are the profits for the entities holding the auctioned rights. These profits are losses to ratepayers.

[194] DMM has defined financial entities as participants who own no physical energy and participate in only the convergence bidding and congestion revenue rights markets. Physical generation and load are represented by participants that primarily participate in the ISO 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 markets. Balancing authority areas are participants that are balancing authority areas outside the ISO. With the exception of financial entities, the classification of the other groups is based on the primary function but could include instances where a particular entity performs a different function. For example, a generating entity that has load-serving obligations may be classified as a generator and not a load-serving entity.

- Financial entities continued to have the highest net revenue among auctioned rights holders in 2018 at $91 million, up from $76 million in 2017.
- Marketers received net revenues of $24 million from auctioned rights in 2018, an increase from $16 million in 2017.
- Physical generation entities received $17 million in net revenue from auctioned rights in 2018, up from nearly $9 million in 2017. Physical generators continued to receive the lowest overall payments from auctioned congestion revenue rights, among non-load-serving entities.
- Load-serving entities received negative $9 million in net revenue from auction rights in 2018, down from about negative $2 million in 2017. Auction revenues received by load-serving entities were less than their auctioned congestion revenue rights day-ahead payments in 2018. Because the auction revenues and congestion revenue right payments are made simultaneously to and from load-serving entities as a group, they are not the direct effect on ratepayers.

One of the benefits of auctioning congestion revenue rights is to allow day-ahead market participants to hedge congestion costs. However, in 2018, physical generators as a group accounted for a relatively small portion of congestion revenue rights held. As a group, generators received the lowest overall payments from congestion revenue rights, even after including allocated rights. Generators received congestion revenue rights payments, for both auctioned and allocated congestion revenue rights, of $76 million, while incurring day-ahead congestion costs of $107 million. Except for balancing authority areas,[195] the other categories of entities had congestion revenue right payments in excess of their day-ahead congestion costs.

The losses to ratepayers from the congestion revenue rights auction could in theory be avoided if load-serving entities purchased the congestion revenue rights at the auction from themselves. However, there are significant technical and regulatory hurdles making it difficult for load-serving entities to purchase these rights. Moreover, DMM does not believe it is appropriate to design an auction so that load-serving entities would have to purchase rights in order to avoid obligations to pay other congestion revenue rights holders.

DMM believes it would be more appropriate to design the auction so that load-serving entities will only enter obligations to pay other participants if they are actively willing to enter these obligations at the prices offered by the other participants. With this approach, any entity placing a value on purchasing a hedge against congestion costs could seek to purchase it directly from the load-serving, financial, or other entities.

[195] Balancing authority areas held only allocated rights and did not participate in the auctions. Because balancing authority areas did not participate in the auction they do not affect the auction performance metric.

Figure 8.12 Auction revenues and payments (financial entities)

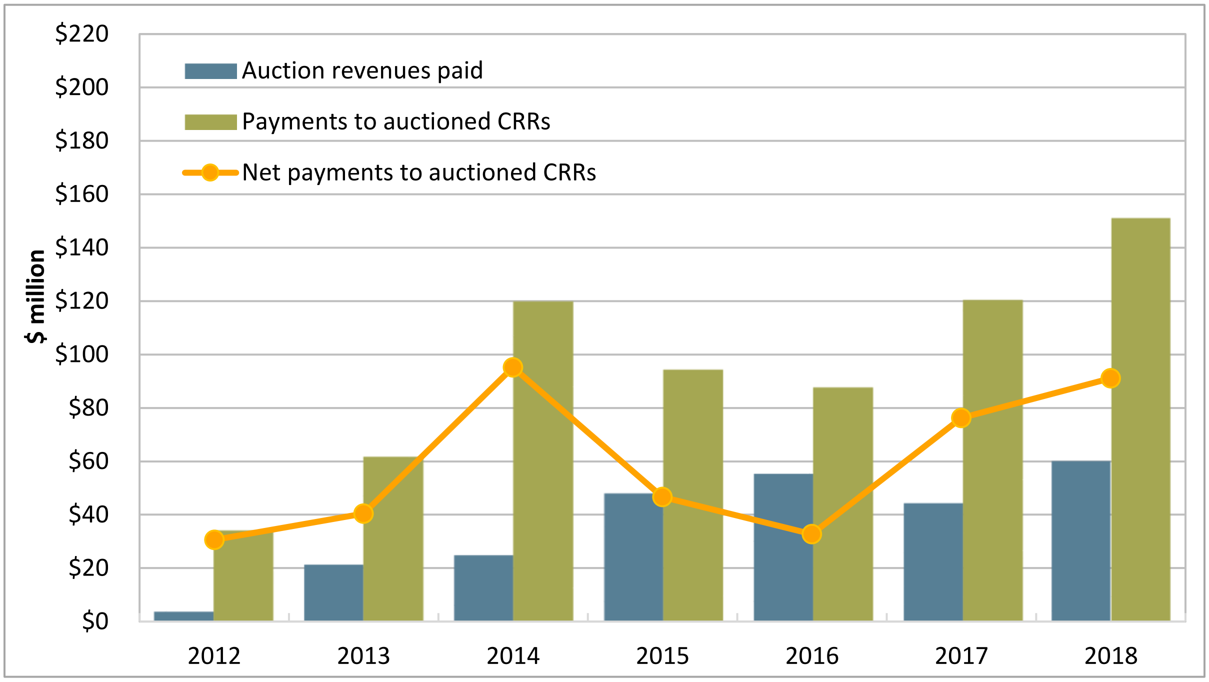


Figure 8.13 Auction revenues and payments (marketers)

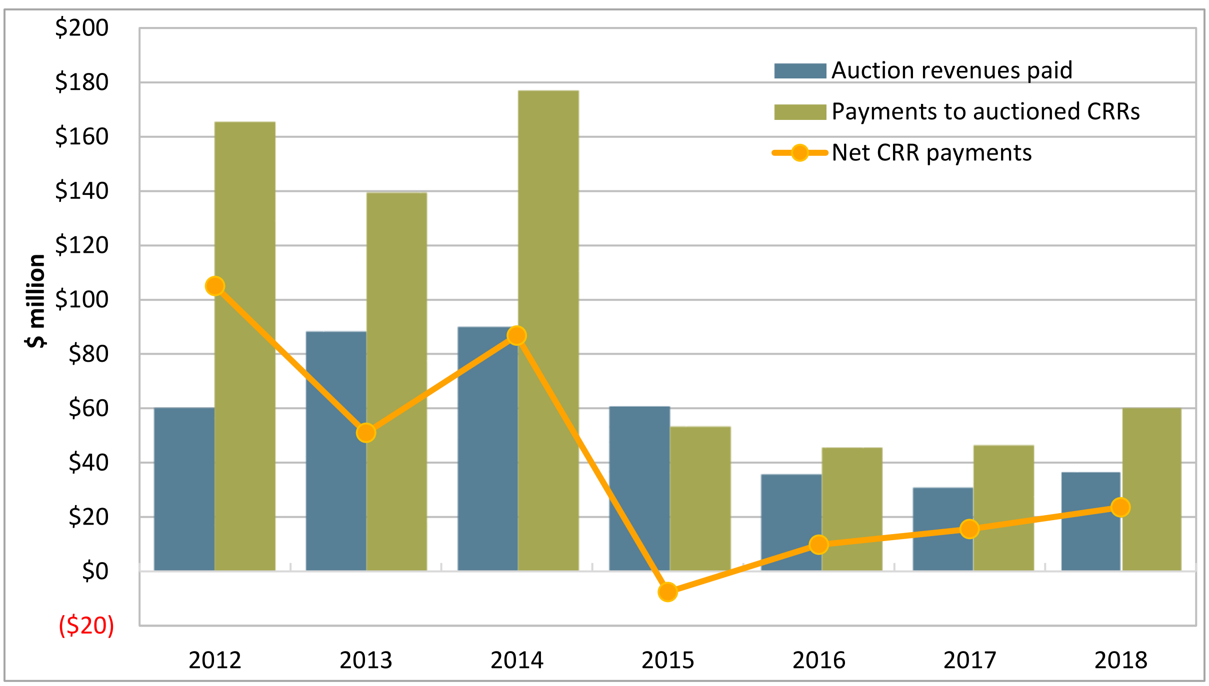


Figure 8.14 Auction revenues and payments (generators)

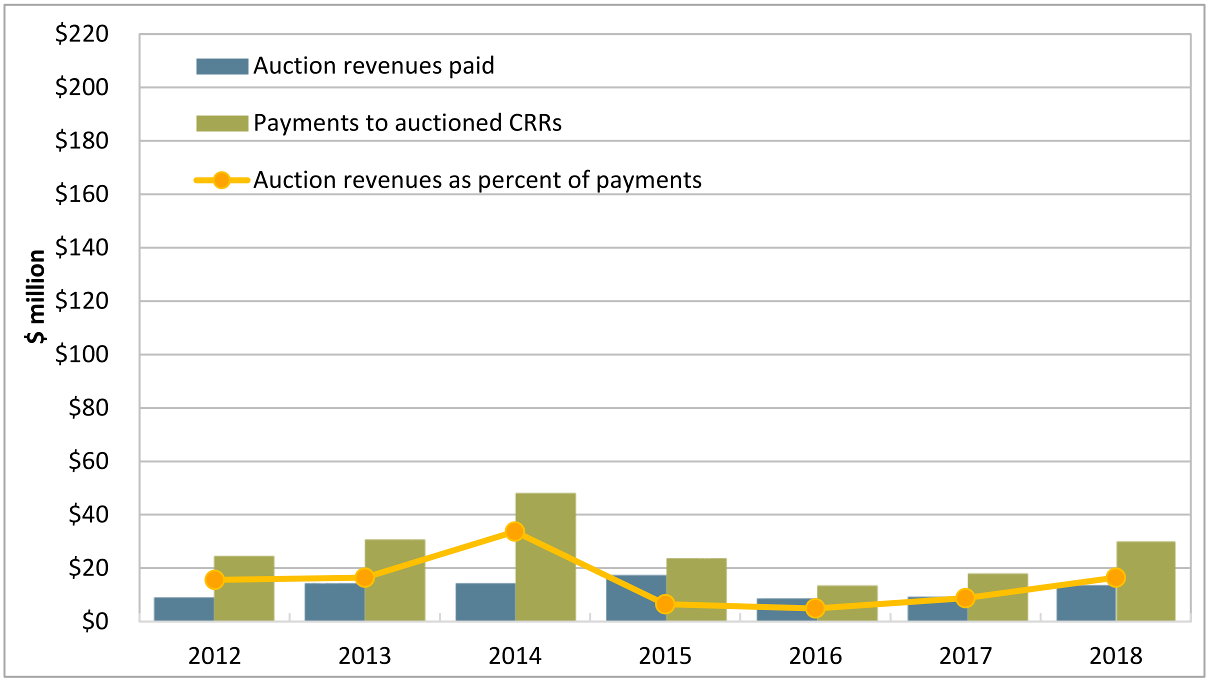
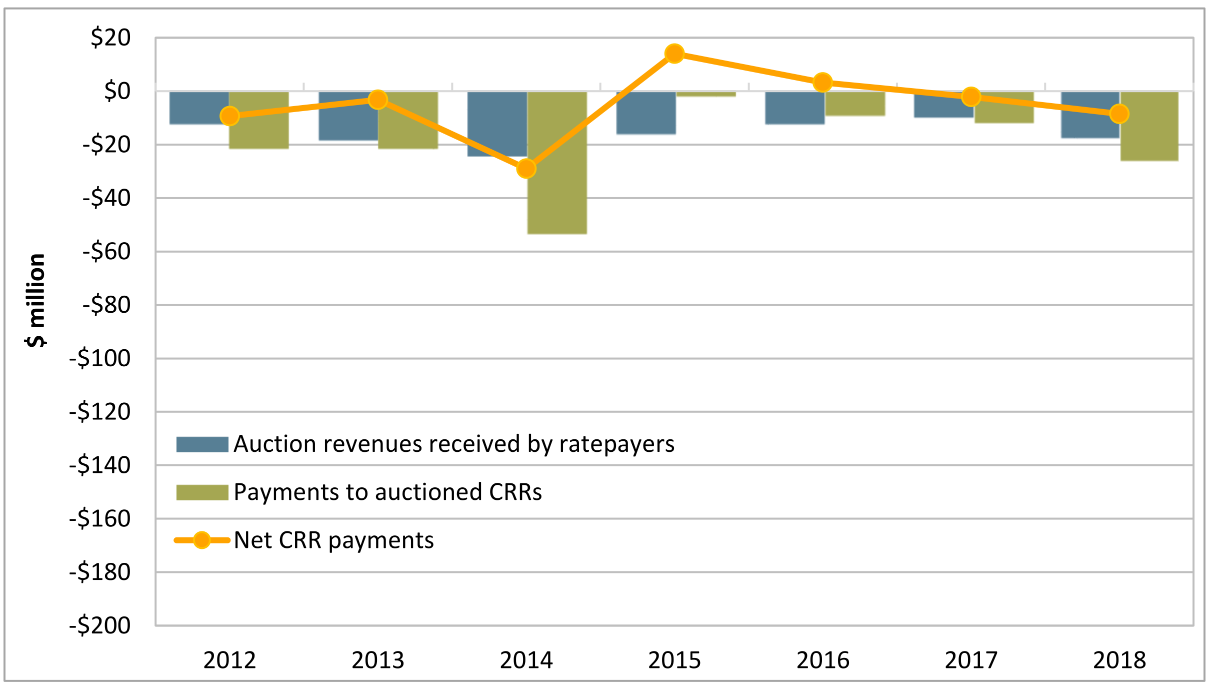


Figure 8.15 Auction revenues and payments (load-serving entities)



9 Market adjustments

Given the complexity of market models and systems, all ISOs make some adjustments to the inputs and outputs of their standard market models and processes. Market model inputs – such as transmission limits – may sometimes be modified to account for potential differences between modeled power flows and actual real-time power flows. Load forecasts may be adjusted to account for potential differences in modeled versus actual demand and supply conditions, including uninstructed deviations by generation resources.

This chapter reviews the frequency of and reasons for a variety of key market adjustments, including exceptional dispatches, adjustments to modeled loads and residual unit commitment requirements, and blocked dispatch instructions and pricing runs in the real-time market. Over the last few years, the ISO has placed a priority on reducing various market adjustments and continues to work toward reducing market adjustments going forward. Findings from this chapter include the following:

- Total energy resulting from all types of exceptional dispatch grew in 2018, but continued to account for a relatively low portion of total system load (0.07 percent). Total above-market costs due to exceptional dispatch increased from $20.6 million in 2017 to $51.9 million in 2018.
- Exceptional dispatches to commit units to operate at minimum load were particularly high in the third quarter. Hourly minimum load energy from these commitments averaged almost 150 MW and total costs were almost $29 million. These commitments were largely due to load forecast uncertainty.
- Load forecast adjustments in the ISO's hour-ahead and 15-minute markets decreased slightly compared to 2017, but remain high and have increased dramatically since 2016. As in 2017, the 5-minute market load forecast adjustment decreased relative to the same time periods in 2016.
- ISO operator adjustments to residual unit commitment requirements increased to an average of 335 MW per hour in 2018 compared to about 39 MW in 2017. In the third quarter, the average adjustment was about 985 MW per hour. In 2018, these manual adjustments were primarily attributed to load forecast uncertainty, fire danger and renewable variability concerns.
- The overall number of blocked instructions for internal ISO units increased from a daily average of 15 to 18 in 2018. Blocked shut-down instructions continued to be the most common reason for blocked instructions at about 72 percent in 2018, an increase from nearly 60 percent the previous year.

9.1 Exceptional dispatch

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

Exceptional dispatches can be grouped into three distinct categories:

- **Unit commitment** — Exceptional dispatches can be used to instruct a generating unit to start up or continue operating at minimum operating levels. Exceptional dispatches can also be used to commit a multi-stage generating resource to a particular configuration. Almost all of these unit commitments are made after the day-ahead market to resolve reliability issues not met by unit commitments resulting from the day-ahead market model optimization.
- **In-sequence real-time energy** — Exceptional dispatches are also issued in the real-time market to ensure that a unit generates above its minimum operating level. This report refers to energy that would likely have cleared the market without an exceptional dispatch (i.e., that has an energy bid price below the market clearing price) as *in-sequence* real-time energy.
- **Out-of-sequence real-time energy** — Exceptional dispatches may also result in *out-of-sequence* real-time energy. This occurs when exceptional dispatch energy has an energy bid priced above the market clearing price. In cases when the bid price of a unit being exceptionally dispatched is subject to the local market power mitigation provisions in the ISO tariff, this energy is considered out-of-sequence if the unit's default energy bid used in mitigation is above the market clearing price.

Summary of exceptional dispatch

Energy from exceptional dispatch continued to account for a relatively low portion of total system loads. Total energy from exceptional dispatches, including minimum load energy from unit commitments, averaged 0.07 percent of system loads in 2018, compared to 0.05 percent in 2017.

Total energy resulting from all types of exceptional dispatch increased by approximately 64 percent in 2018 from 2017, as shown in Figure 9.1.[196] Minimum load energy from units committed via exceptional dispatch accounted for about 77 percent of all exceptional dispatch energy in 2018. About 15 percent of energy from exceptional dispatches was from out-of-sequence energy (to operate above minimum load), and the remaining 8 percent was from in-sequence energy.

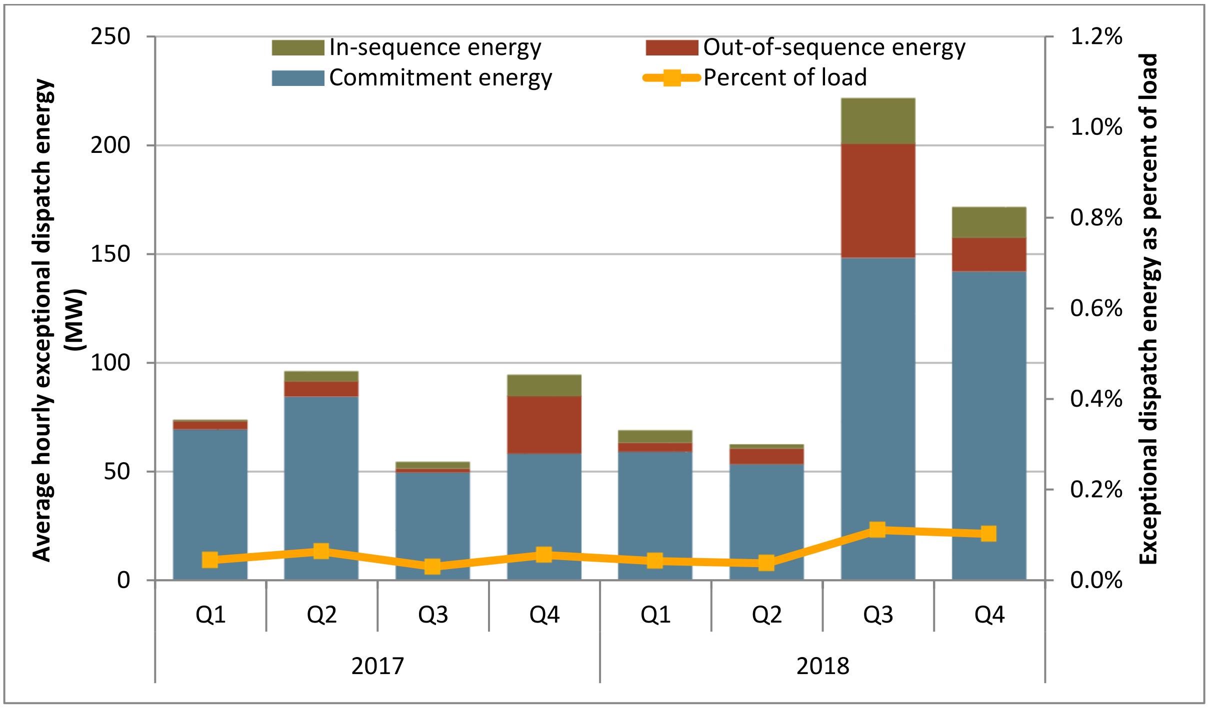
The growth in total energy from exceptional dispatches in 2018 was driven by increases in the third and fourth quarters. In those quarters exceptional dispatches for minimum load were particularly high. These exceptional dispatches were largely due to load forecast uncertainty in the third quarter and voltage support in the fourth quarter.

Although exceptional dispatches are not priced and paid based on market clearing energy prices, they can affect the market clearing price for energy. Energy resulting from exceptional dispatch effectively reduces the remaining load to be met by other supply. This can reduce market prices relative to a case where no exceptional dispatch was made. However, most exceptional dispatches appear to be made to resolve specific constraints that would make energy from these exceptional dispatches ineligible to set the market price for energy if these constraints were incorporated in the market model.

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

For instance, as discussed later in this section, the bulk of energy from exceptional dispatches is minimum load energy from unit commitments. Energy from this type of exceptional dispatch would not be eligible to set market prices even if incorporated in the market model. In addition, because exceptional dispatches occur after the day-ahead market, energy from these exceptional dispatches primarily affects the real-time market. If energy needed to meet these constraints was included in the day-ahead market, prices in the day-ahead market could be lower.

Figure 9.1 Average hourly energy from exceptional dispatch



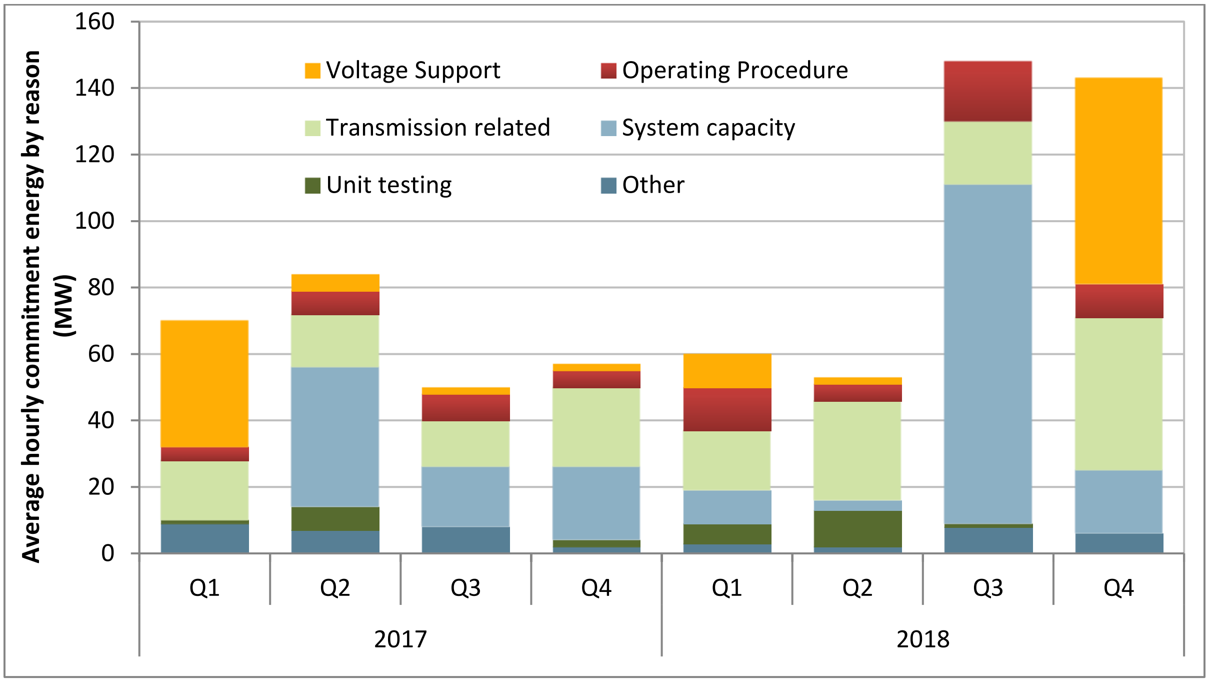
Exceptional dispatches for unit commitment

ISO operators sometimes find instances where the day-ahead market process did not commit sufficient capacity to meet certain reliability requirements not directly incorporated in the day-ahead market model. In some cases, a scheduling coordinator may request to operate a resource out-of-market for purposes of unit testing. In these instances, the ISO may commit additional capacity by issuing an exceptional dispatch for resources to come on-line and operate at minimum load. Multi-stage generating units may be committed to operate at the minimum output of a specific multi-stage generator configuration, e.g., one by one or duct firing.

Minimum load energy from exceptional dispatch unit commitments increased by 55 percent in 2018 compared to 2017, with most occurring in the third and fourth quarters of 2018. Elevated levels of exceptional dispatch unit commitment in the third quarter of 2017 were driven by an increase in system capacity exceptional dispatches. The fourth quarter increases were driven by transmission related and voltage support exceptional dispatches.

The most frequent reason given for system capacity exceptional dispatches was load forecasting uncertainty. When ISO operators believe the load forecast is too low, exceptional dispatches may be issued for load forecast uncertainty. This is the primary reason for exceptional dispatches reported in the category of system capacity.

Figure 9.2 Average minimum load energy from exceptional dispatch unit commitments



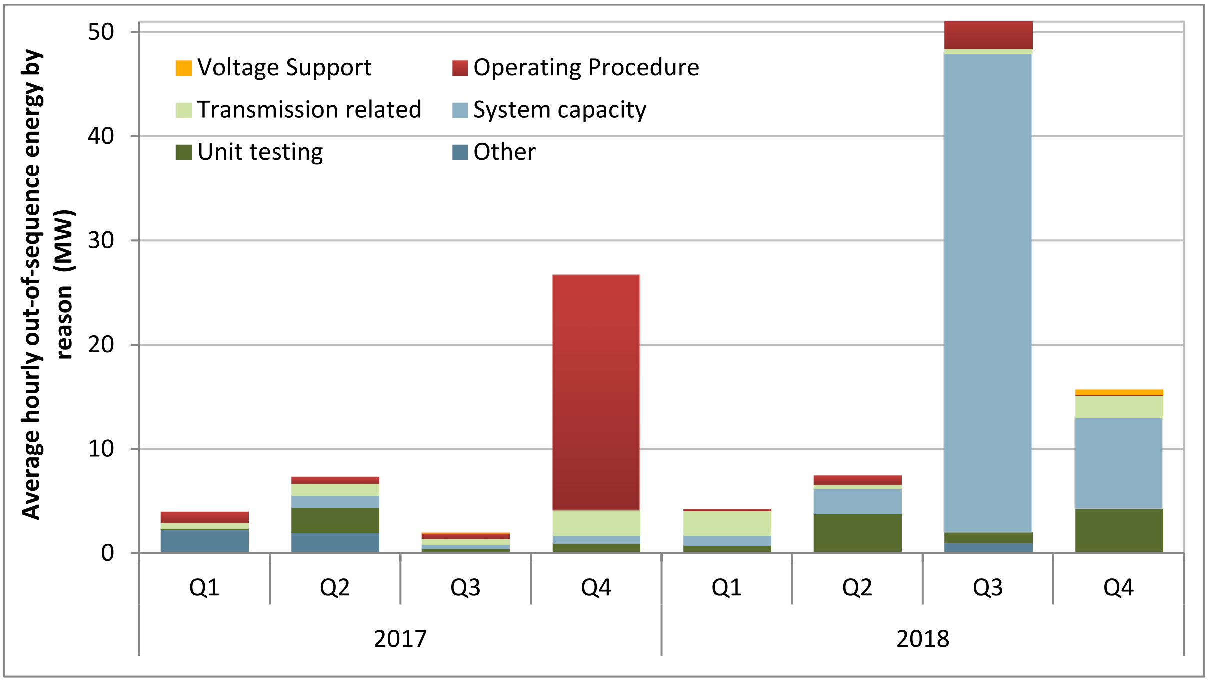
Exceptional dispatches for energy

Energy from real-time exceptional dispatches to ramp units above minimum load or to ensure they do not operate below their regular market dispatch increased by 109 percent in 2018. As illustrated in Figure 9.1, much of this exceptional dispatch energy (about 65 percent) was out-of-sequence, meaning the bid price was greater than the locational market clearing price.[197] While the overall level of exceptional dispatch energy increased in 2018, the portion of exceptional dispatch for out-of-sequence energy was comparable to previous years.

Figure 9.3 shows the change in out-of-sequence exceptional dispatch energy by quarter for 2017 and 2018. Out-of-sequence exceptional dispatch energy was much higher in the third quarter of 2018 compared to the same quarter in 2017. This increase was largely due to an increase in exceptional dispatches issued for system capacity. The two primary reasons for those system capacity exceptional dispatches were to address load forecast uncertainty and planned transmission outages.

[197197] The unit's bid price can equal the resource's default energy bid if subject to energy bid mitigation or if the resource did not submit a bid.

Figure 9.3 Out-of-sequence exceptional dispatch energy by reason



Exceptional dispatch costs

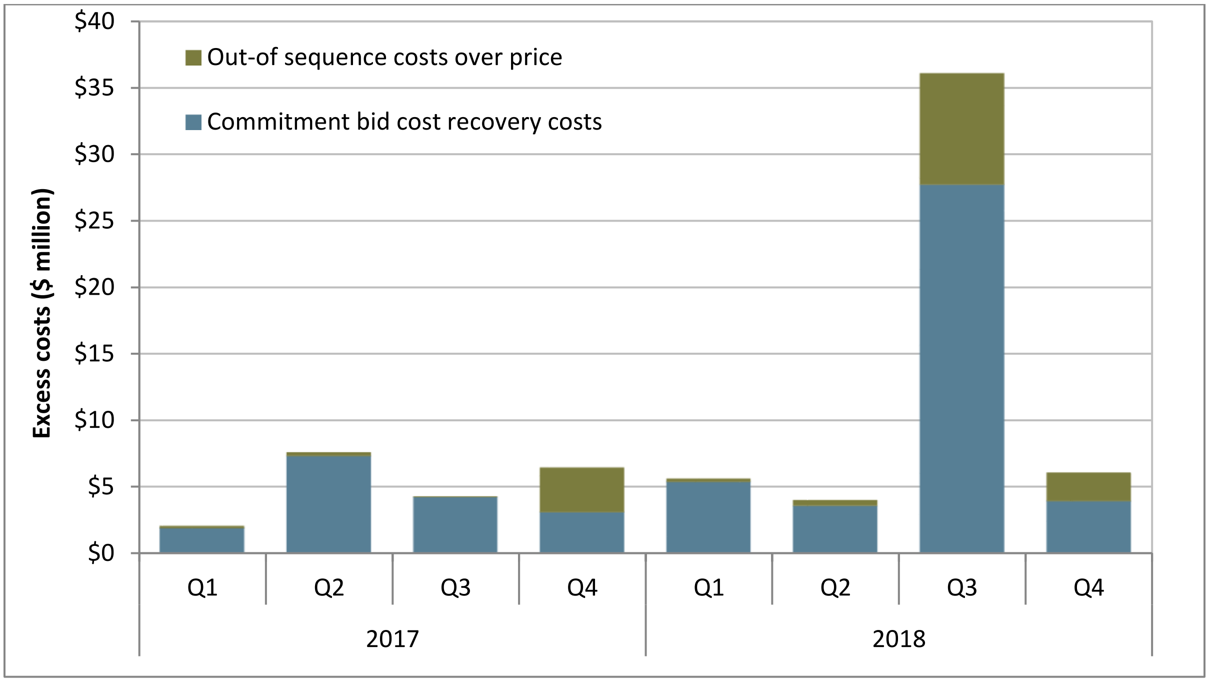
Exceptional dispatches can create two types of additional costs not recovered through the market clearing price of energy.

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

Figure 9.4 shows the estimated costs for unit commitment and additional energy resulting from exceptional dispatches in excess of the market clearing price for this energy. Commitment costs for exceptional dispatch paid through bid cost recovery increased from $16.6 million to $40.6 million, while out-of-sequence energy costs increased from $4.0 million to $11.2 million.[198] Total above-market costs increased 150 percent to $51.9 million in 2018 from $20.6 million in 2017.

[198] The out-of-sequence costs are estimated by multiplying the out-of-sequence energy by the bid price (or the default energy bid if the exceptional dispatch was mitigated or the resource had not submitted a bid) minus the locational price for each relevant bid segment. Commitment costs are estimated from the real-time bid cost recovery associated with exceptional dispatch unit commitments.

Figure 9.4 Excess exceptional dispatch cost by type



9.2 Manual dispatches

Manual dispatch on the interties

Exceptional dispatches on the interties are referred to by the ISO operators as *manual dispatches*. In 2017, imports procured through manual dispatches increased significantly. DMM's 2017 annual report cautioned when the ISO procures imports out-of-market at prices higher than the 15-minute price paid for other imports, this can encourage economic and physical withholding of available imports.[199] DMM also recommended that the ISO improve its logging of manual dispatches to ensure proper settlement and allow tracking and monitoring.

In 2018, the ISO implemented improved procedures, training and logging which appear to have been effective at ensuring proper settlement and allowing better tracking and monitoring of manual dispatches of imports.

Compared to 2017, out-of-market dispatches in 2018 have decreased significantly. There were nearly 60 instances of manual dispatches on the ties in 2018 accounting for less than 5,500 MWh. Over half of these were export dispatches for emergency assistance to another balancing authority. No non-emergency assistance manual dispatches occurred in the first quarter of the year. Non-emergency manual dispatch intervals occurred on only seven separate days in 2018, April 10, June 11, August 9, August 12, October 1, October 11 and October 16.

[199] *2017 Annual Report on Market Issues and Performance*, pp.206-207: http://www.caiso.com/Documents/2017AnnualReportonMarketIssuesandPerformance.pdf

Energy imbalance market

Energy imbalance market areas sometimes need to dispatch resources out-of-market for reliability, to manage transmission constraints or for other reasons. These out-of-market dispatches are referred to as *manual dispatches*. In the energy imbalance market, manual dispatches are similar to exceptional dispatches in the ISO. Manual dispatches within the energy imbalance market are not issued by the ISO and can only be issued by an energy imbalance market entity for their respective balancing authority area. Manual dispatches may be issued for both participating and non-participating resources.

Like exceptional dispatches in the ISO system, manual dispatches in the energy imbalance market do not set prices, and the reasons for these manual dispatches are similar to those given for ISO exceptional dispatches. However, manual dispatches in the energy imbalance market are not settled in the same manner as exceptional dispatches within the ISO. Energy from these manual dispatches is settled on the market clearing price, similar to uninstructed energy. This eliminates the possibility of exercising market power by either setting prices or by being paid “as-bid” at above-market prices.

Figure 9.5 through Figure 9.10 summarize monthly manual dispatch activity of participating and non-participating resources across the energy imbalance market areas. The volume of manual dispatches in the energy imbalance market areas has tended to peak in the first few months that new market participants were active in the market (such as in Idaho Power in 2018).

However, manual dispatches in the Arizona Public Service area also remained relatively high in 2018. In September, Portland General Electric experienced a period of high decremental manual dispatches on participating resources. This was related to software limitations associated with a multi-stage generator which were resolved.

Figure 9.5 EIM manual dispatches – PacifiCorp areas

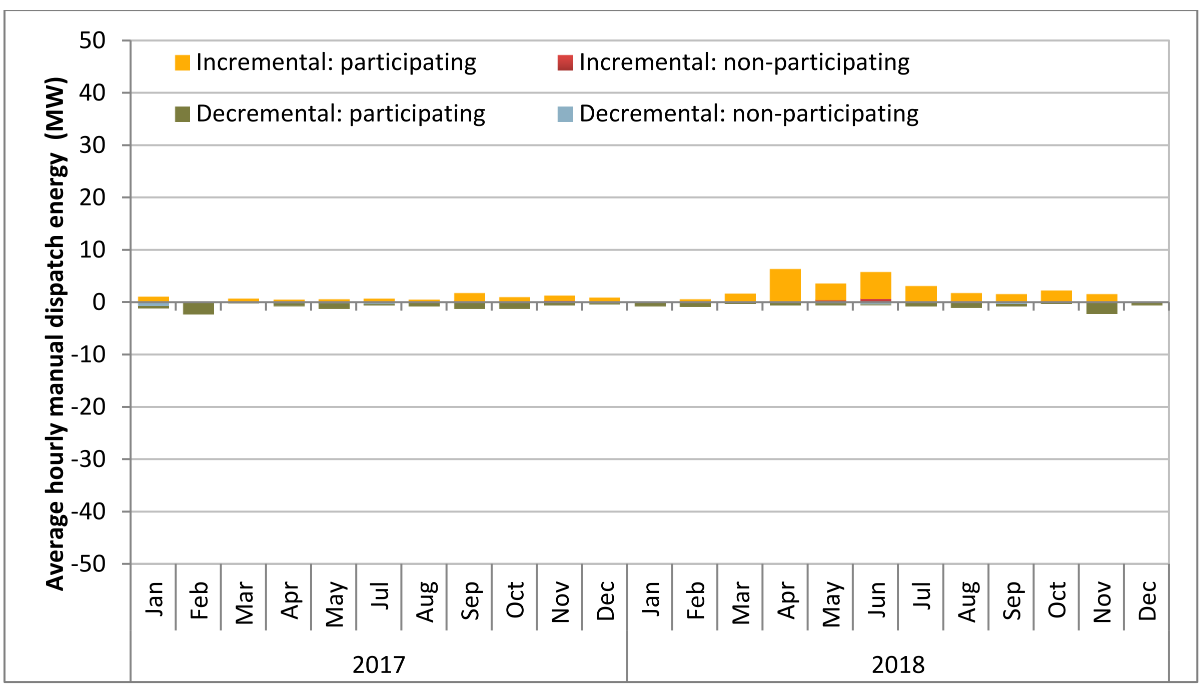


Figure 9.6 EIM manual dispatches – NV Energy area

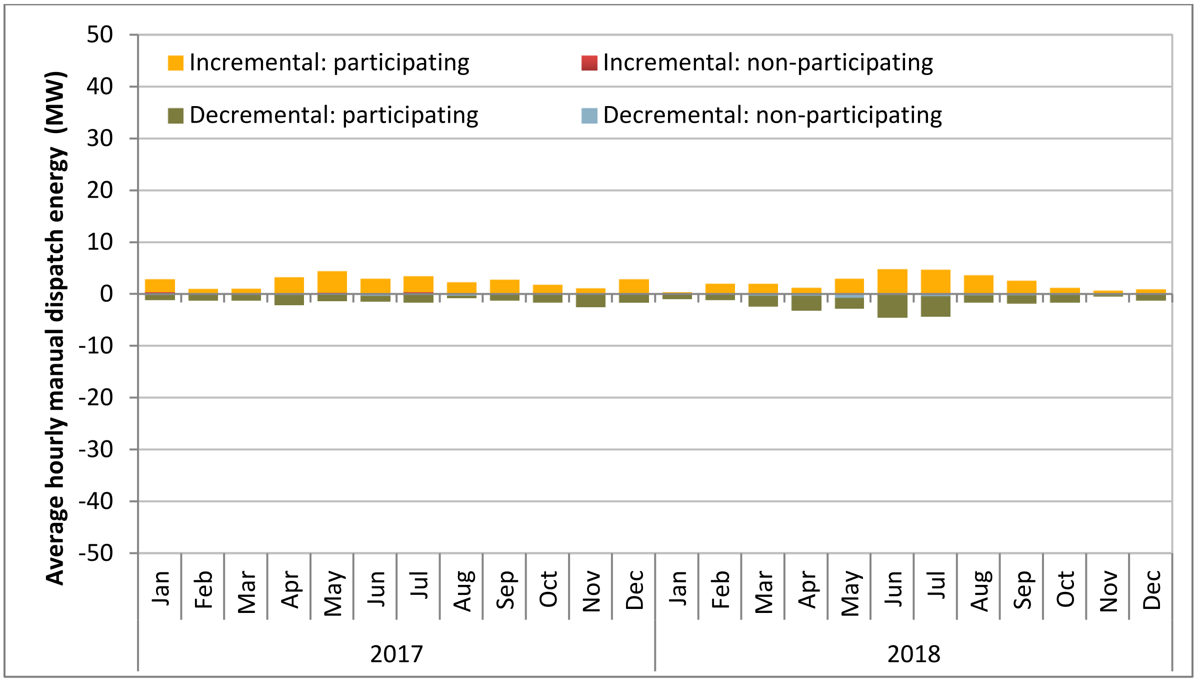


Figure 9.7 EIM manual dispatches – Arizona Public Service area

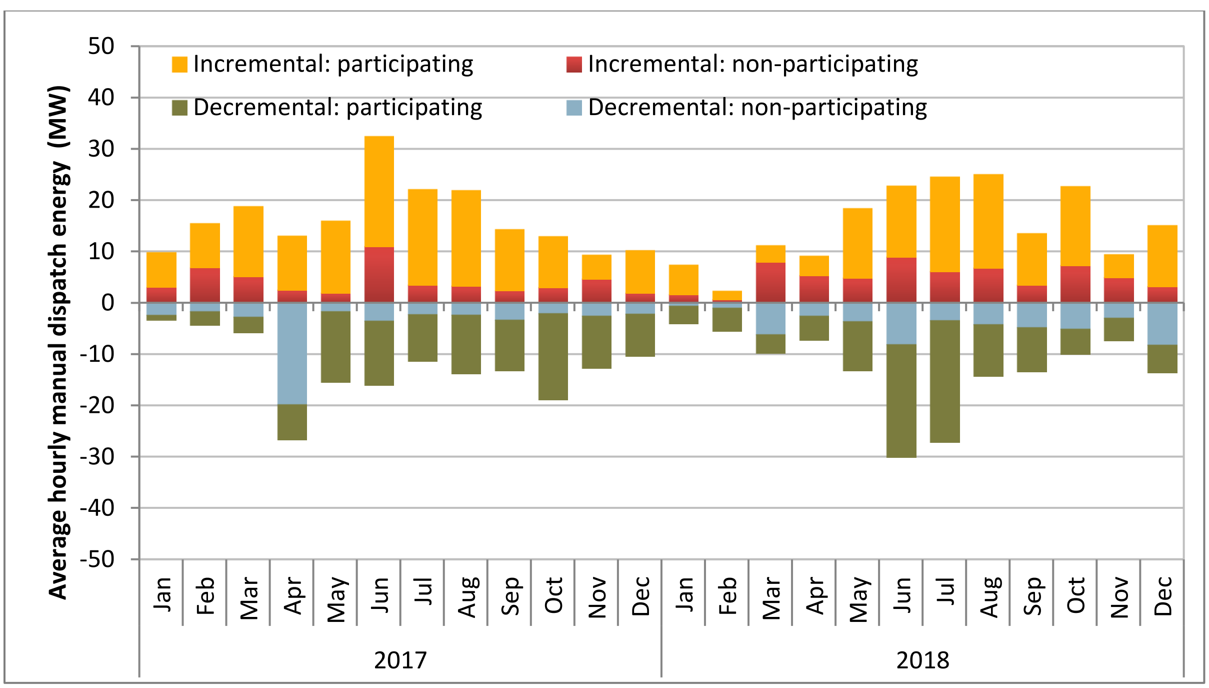


Figure 9.8 EIM manual dispatches – Puget Sound Energy area

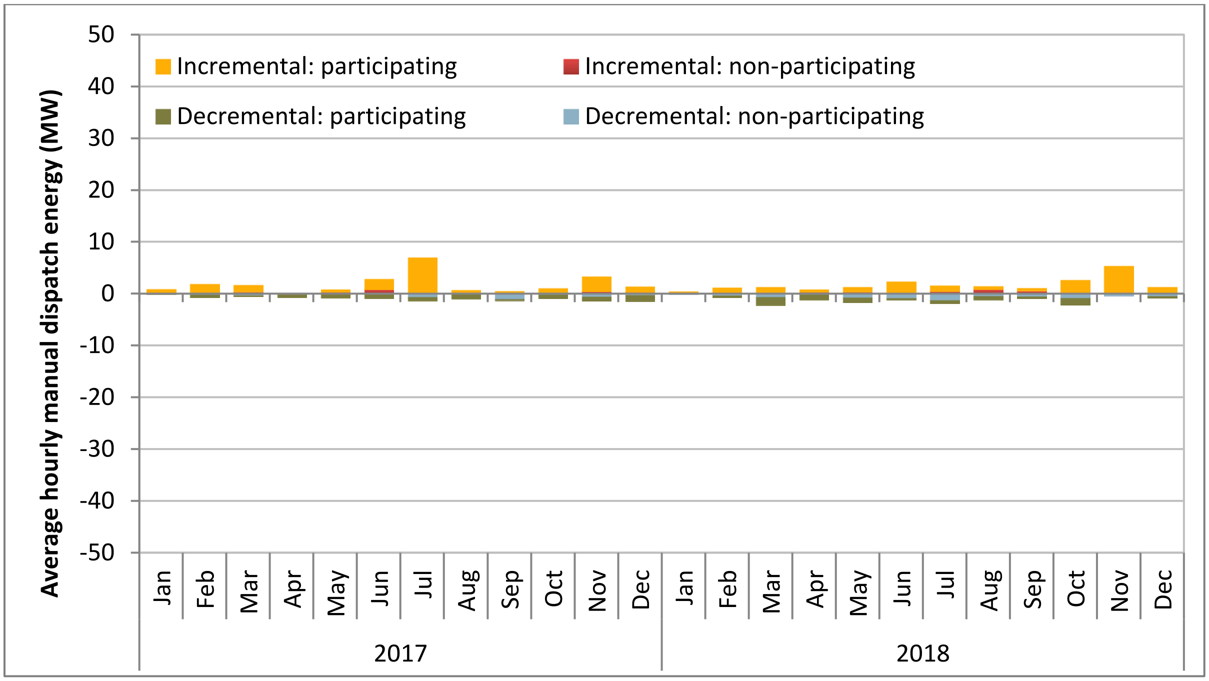


Figure 9.9 EIM manual dispatches – Portland General Electric area

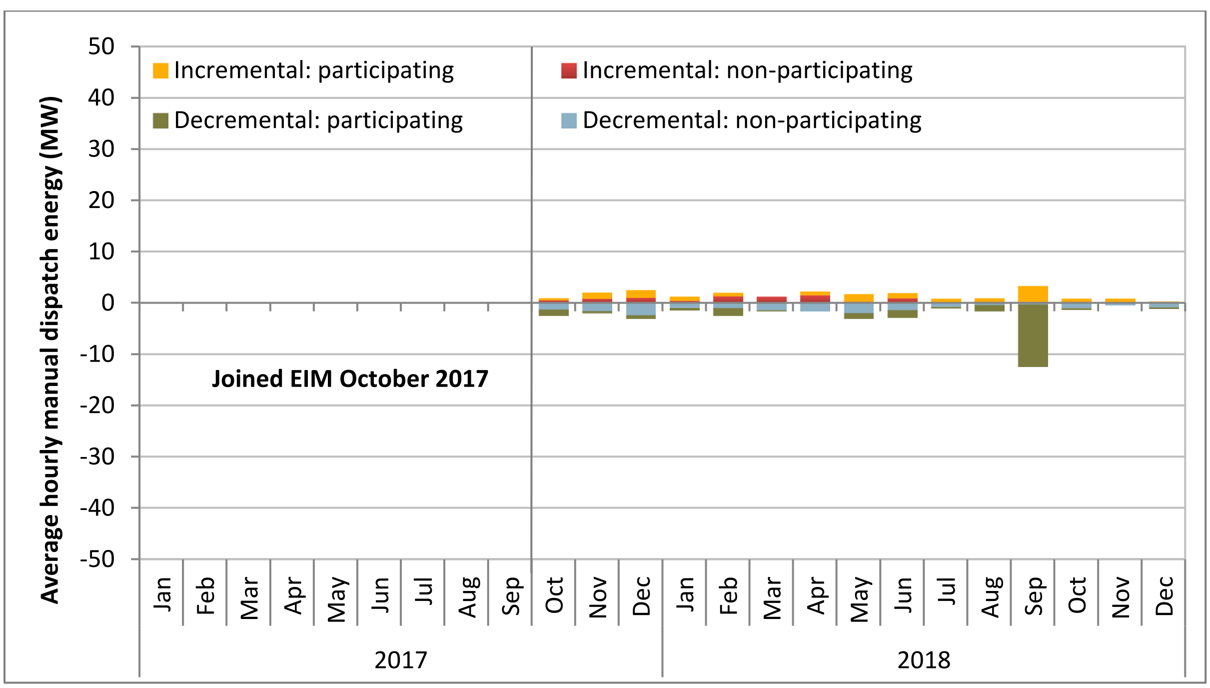
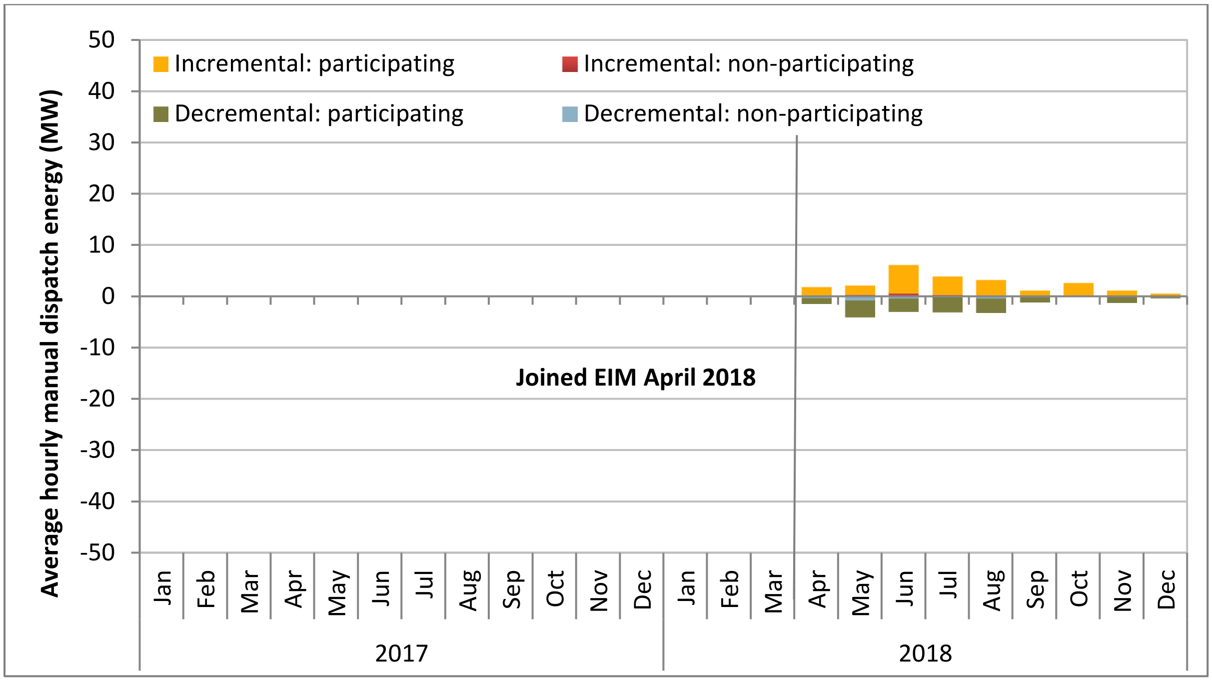


Figure 9.10 EIM manual dispatches – Idaho Power



9.3 Load adjustments

Load forecast adjustments

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*. Recently, the ISO has begun using the term *imbalance conformance* to describe these adjustments. Load forecast adjustments are used to account for potential modeling inconsistencies and inaccuracies.

In the ISO, load adjustments are also routinely used in the hour-ahead and 15-minute scheduling processes in a manner which helps to increase the supply of ramping capacity within the ISO during morning and evening hours when net loads increase sharply. Increasing the hour-ahead and 15-minute forecast can increase ramping capacity within the ISO by increasing hourly imports and committing additional units within the ISO.

Real-time market load adjustments by the ISO

Figure 9.11 shows the average hourly load adjustment profile for the hour-ahead and 5-minute markets for 2016 to 2018.[200] As in prior years, the general shape and direction of load adjustments were similar for hour-ahead and 15-minute adjustments, but the average level of adjustments has grown nearly two fold relative to 2016.

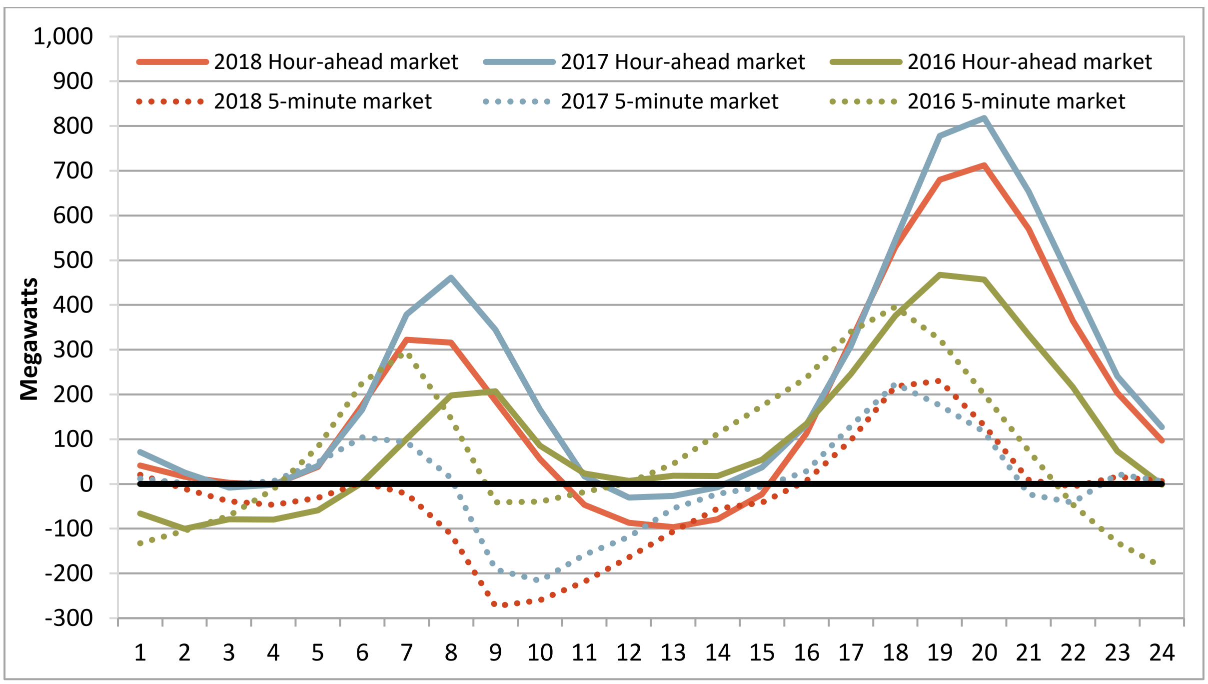
[200] Load adjustments in the hour-ahead and 15-minute markets are very similar to each other throughout the day. The 15-minute market data has been removed from the figure for clarity.

As shown in Figure 9.11 average load forecast adjustments in the ISO's hour-ahead and 15-minute scheduling processes mirror the pattern of net loads over the course of the day, averaging +400 MW to +800 MW during the morning and evening ramping hours.

The load adjustments in the hour-ahead market continue to differ from 5-minute market adjustments in nearly all hours of the day in 2018. The largest positive deviations between the 5-minute and other markets were observed in hours ending 19 to 21, when the hour-ahead adjustments exceeded the 5-minute adjustments by around 450 MW, 580 MW and 560 MW, respectively.

The average hour-ahead adjustment also exceeded the 5-minute market adjustment in the morning ramp hours ending 7 to 9 by 340 MW to 460 MW. In this period the 5-minute load adjustments were negative. Both positive and negative adjustments are often associated with over-forecasted load, changes in expected renewable generation as well as morning or evening net load ramp.

Figure 9.11 Average hourly load adjustment (2016 - 2018)



One of the key reasons for the pattern of real-time market load adjustments that has developed over the last few years cited by grid operators is to increase the hourly import bids which are accepted by the market software during the morning and evening ramping hours. By increasing imports in these hours, the supply of remaining generation within the ISO that can be ramped up or down in the 15-minute and 5-minute market remains higher.

Similarly, since unit commitments and transitions for resources within the ISO are made in the 15-minute market, maintaining a relatively high positive load bias in the 15-minute market can help make additional generation available within the ISO during the morning and evening ramping hours. However, in the 5-minute market, positive load adjustments are less effective or not needed to ensure that ramping needs are met during these hours.

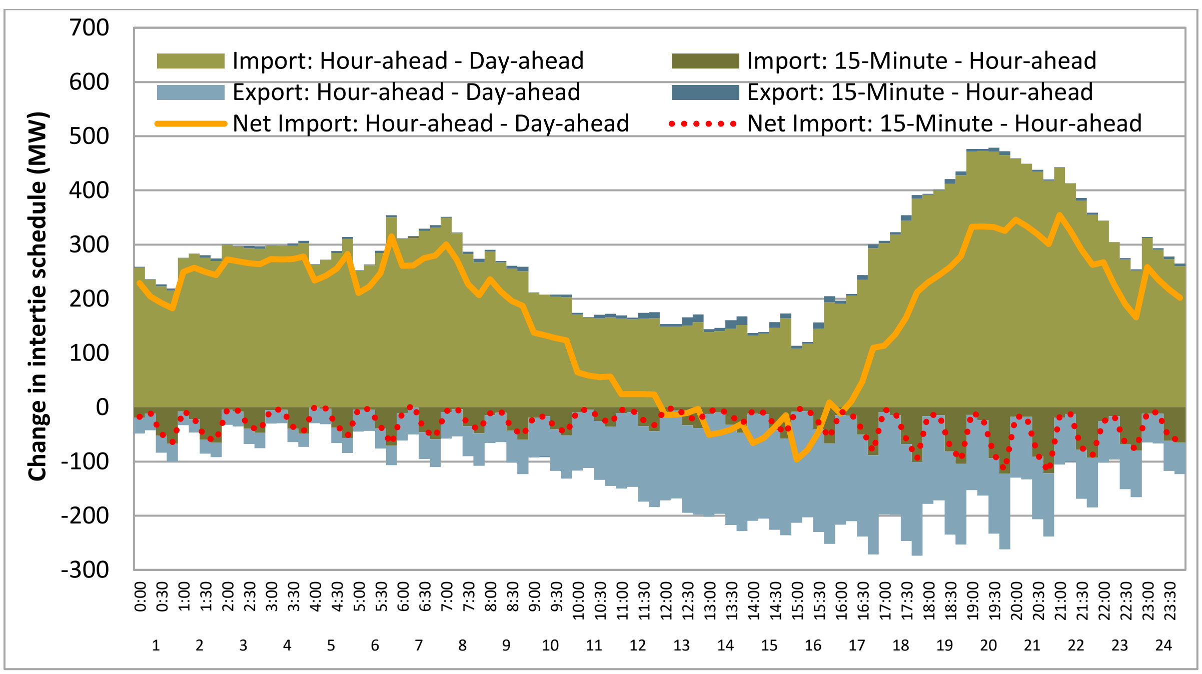
The impact of the hour-ahead load bias on real-time imports is reflected in Figure 9.12, which shows the incremental change in gross and net imports in the real-time market. The light green area in Figure 9.12 shows the average incremental increase in imports between the day-ahead and hour-ahead markets. The light blue area shows the incremental change in exports between the day-ahead and hour-ahead markets where an increased export is displayed as a negative value.

The yellow line in Figure 9.12 shows the change in net interchange, summing the effects of increased imports and increased exports. The red dotted line represents the change in net interchange between the 15-minute and hour-ahead markets and is the sum of incremental decreases in imports (dark green) and exports (dark blue). These are lower values relative to the changes observed between the day-ahead and the hour-ahead.

As shown in Figure 9.12, most incremental commitment of imports occurs in the hour-ahead market. On average, over 300 MW of net interchange was committed in 2018, a decrease from an average of 500 MW during these hours in 2017. As in 2017, the highest average net interchange, almost 500 MW, occurred during the peak net load hour of the day, hour ending 20.

In 2018, there was also a noticeable increase in both imports and exports between the hour-ahead and day-ahead markets during mid-day solar peak periods, compared to 2017. Net imports fell between the day-ahead and hour-ahead markets in these hours, as occurred in 2017 during these hours. This appears associated with low day-ahead market clearing prices below bids with energy re-bid in the hour-ahead market at the price-taker energy bid floor for supply self-schedules.

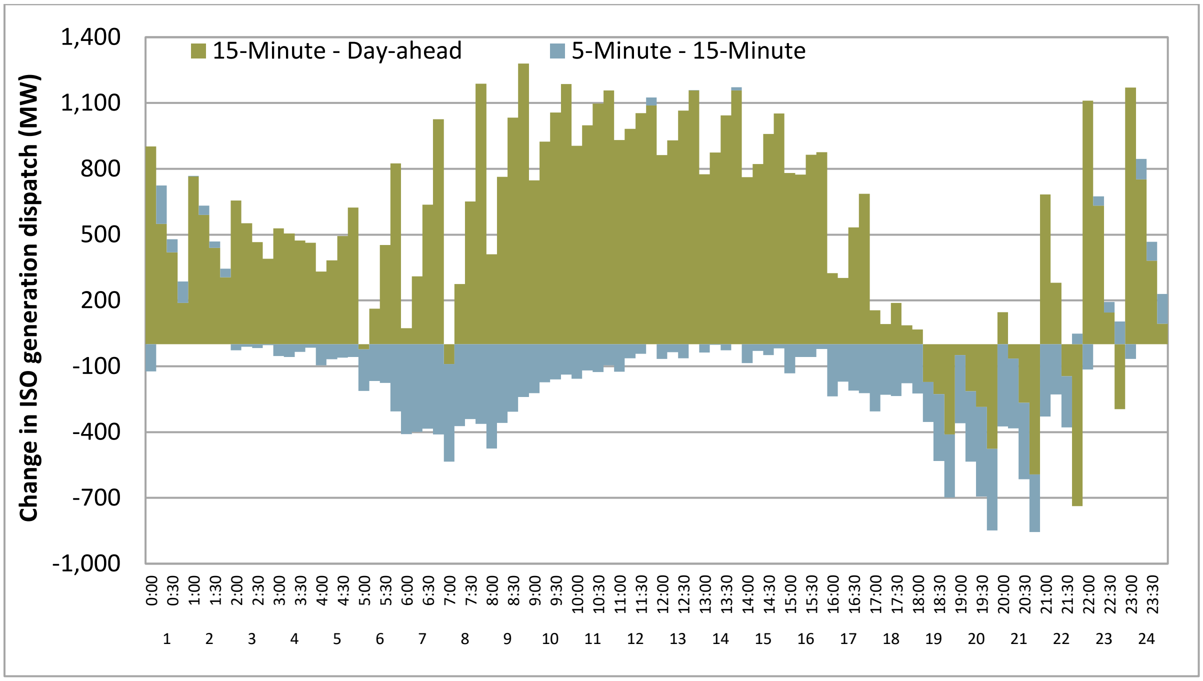
Figure 9.12 Net interchange dispatch volume



Meanwhile, incremental dispatch of internal generation between the day-ahead and 15-minute real-time markets tended to decrease during the morning and evening ramping hours in 2018. Figure 9.13 shows the average incremental change for internal generators between the day-ahead and the 15-

minute market (green bars) and between the 15-minute market and the 5-minute market (blue bars). This decrease in generation within the ISO tends to offset the increases in energy imports in the hour-ahead market as shown in Figure 9.12.

Figure 9.13 Imbalance generation dispatch volume



The ISO also adjusts loads in the 15-minute and 5-minute real-time markets to account for potential modeling inconsistencies. Some of these inconsistencies are due to changing system and market conditions, such as changes in load and supply, between the executions of different real-time markets.[201] Operators have listed multiple reasons for use of load adjustments including managing load and generation deviations, automatic time error correction, scheduled interchange variation, reliability events, and software issues.

Load adjustments in the energy imbalance market

Energy imbalance market operators can also make load adjustments in their respective balancing areas. Figure 9.14 and Figure 9.15 show the frequency of positive and negative load forecast adjustments for the ISO and different energy imbalance market areas during 2018 for the 15-minute and 5-minute markets, respectively.

For much of 2018, positive load adjustments in the 15-minute market were most frequent in Arizona Public Service, PacifiCorp East and NV Energy areas. Negative load adjustments in the Puget Sound Energy and Idaho Power areas were most frequent in the first quarters of 2018.

[201] See 153 FERC ¶ 61,305, order on compliance filing, issued December 17, 2015: http://www.caiso.com/Documents/Dec17_2015_OrderAcceptingComplianceFiling_AvailableBalancingCapacity_ER15-861-006.pdf.

In general, load adjustments in the 5-minute market were more frequent than load adjustments in the 15-minute market for all balancing areas and quarters during the year. This trend was particularly notable in the ISO, NV Energy, Puget Sound Energy, Arizona Public Service, and the PacifiCorp areas.

Figure 9.14 Average frequency of positive and negative load adjustments (15-minute market)

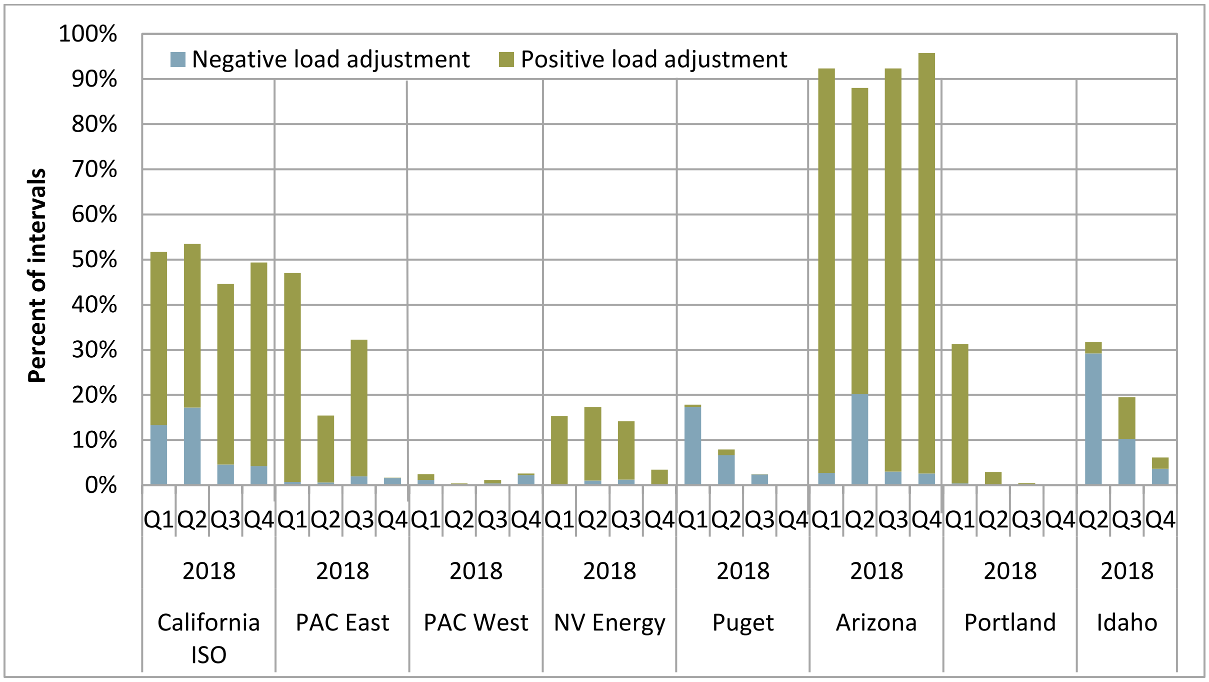
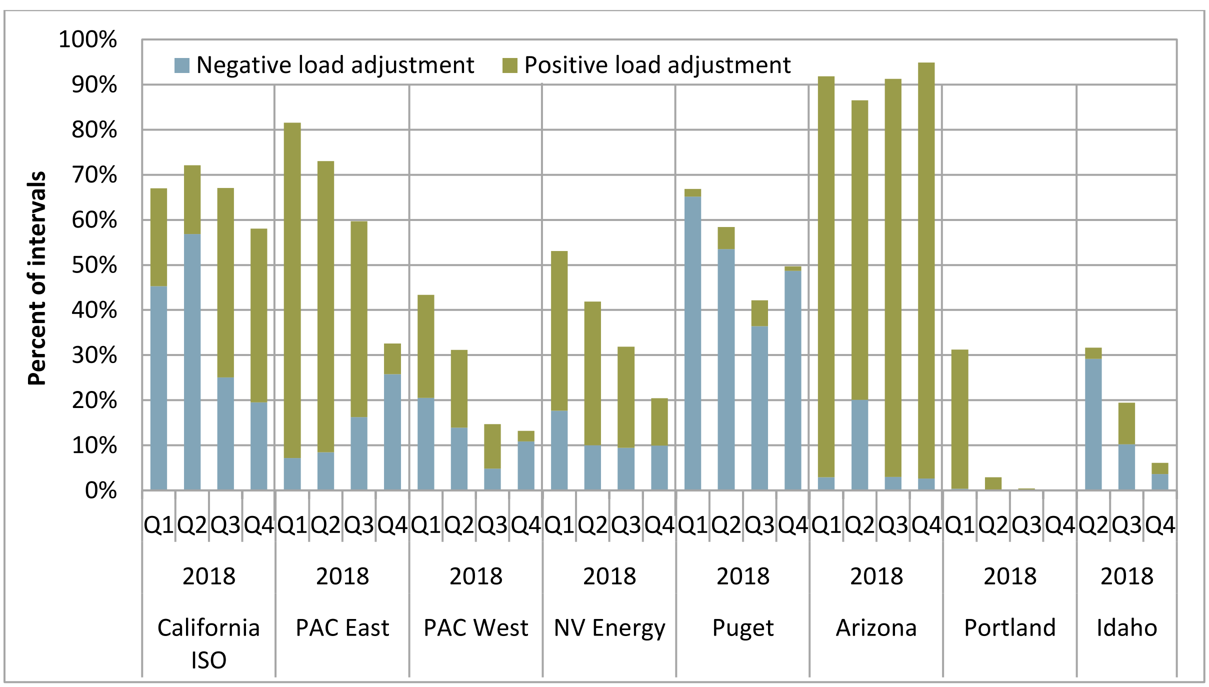


Figure 9.15 Average frequency of positive and negative load adjustments (5-minute market)



9.4 Residual unit commitment adjustments

As noted in Section 2.5, the purpose of the residual unit commitment market is to ensure that there is sufficient capacity on-line or reserved to meet actual load in real time. The residual unit commitment market is run immediately after the day-ahead market and procures capacity to bridge the gap between the amount of load cleared in the day-ahead market and the day-ahead forecast load.

The quantity of residual unit commitment procured is determined by several components which are automatically calculated, as well as any manual adjustment that ISO operators make to increase residual unit commitment requirements for reliability purposes. These operator adjustments to residual unit commitment requirements have increased significantly starting in June 2018.

Figure 9.16 shows the average hourly determinants of capacity requirements used in residual unit commitment process by quarter in 2017 and 2018.

The blue bars in Figure 9.16 show the portion of the residual unit commitment requirement that is calculated based on the difference in cleared supply (both physical and virtual) in the day-ahead market compared to the ISO's day-ahead load forecast.[202] On average, this difference contributed to decreasing residual unit commitment requirements in 2018 similar to 2017. This reflects the fact that cleared supply in the day-ahead market has tended to exceed the day-ahead forecast.

The residual unit commitment also includes an automatic adjustment to account for differences between the day-ahead schedules of variable energy resources and the forecast output of these renewable resources. This intermittent resource adjustment reduces residual unit commitment procurement targets by the estimated under-scheduling of renewable resources in the day-ahead market. This automated adjustment is represented by the yellow bar in Figure 9.16.

The residual unit commitment process also includes an automated adjustment to account for the need to replace net virtual supply clearing in the day-ahead market, which can offset physical supply in the day-ahead market. This automated adjustment is shown in the green bars in Figure 9.16. The average increase in residual unit commitment requirements due to net virtual supply rose slightly in 2018, particularly in the third and fourth quarters.

Finally, ISO operators can also make manual adjustments to increase the amount of residual unit commitment requirements. These manual adjustments are shown in the red bar in Figure 9.16. Operators increased the residual unit commitment load forecast by an average of 335 MW per hour in 2018 compared to about 39 MW in 2017. In 2018, these manual adjustments were primarily attributed to load forecast uncertainty, fire danger and renewable variability concerns. These operator adjustments were frequent from June through September. In the third quarter, the average adjustment was about 985 MW per hour.

Figure 9.17 shows these same four determinants of the residual unit commitment requirements for 2018 for each operating hour of the day. As shown by the red bars in Figure 9.17, manual adjustments by grid operators tended to be greatest between the peak load hours ending 9 through 22. During most days of the third quarter operators increased the residual unit commitment requirement by about 2,000 MW from hours ending 10 through 22 and by about 1,000 MW for hours ending 9 and 23.

[202] Because of the loss of source data, DMM estimated the values reported in the blue bar by subtracting price sensitive load including losses from the sum of forecast load, day-ahead exports and pumped storage load.

While ISO operator adjustments were low in the off-peak hours, net virtual supply was a major driver of residual unit commitment procurement in these periods. On average, day-ahead cleared capacity was greater than day-ahead load forecast during mid-day peak hours in 2018. Intermittent resource adjustments were greatest in hours ending 9 to 18.

Figure 9.16 Determinants of residual unit commitment procurement

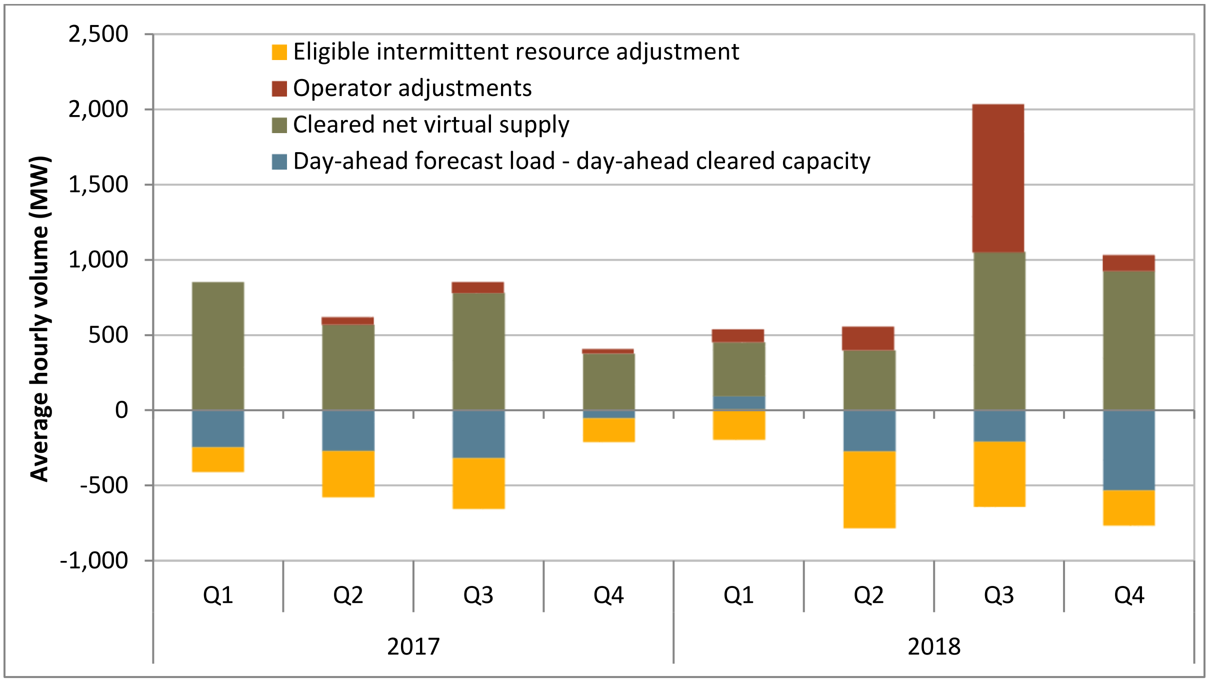
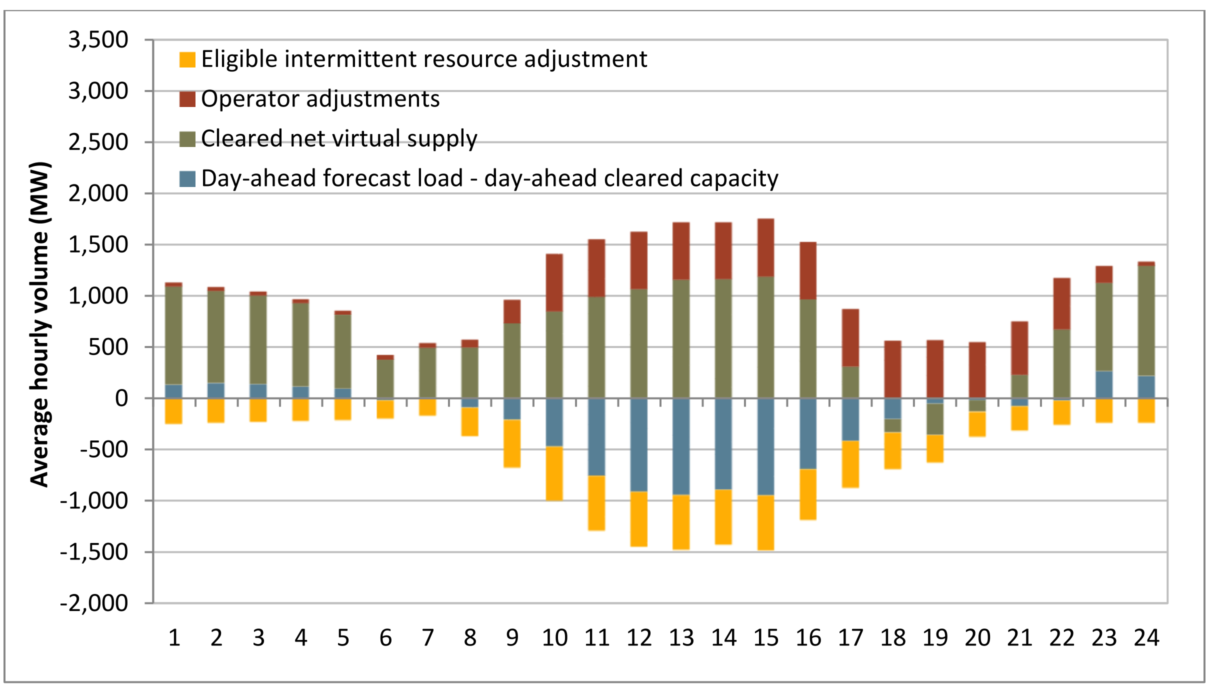


Figure 9.17 Average hourly determinants of residual unit commitment procurement (2018)



9.5 Blocked instructions

The ISO's real-time market functions use a series of processes in real time including the 15-minute and 5-minute markets. During each of these processes, the market model occasionally issues commitment or dispatch instructions that are inconsistent with actual system or market conditions. In such cases, operators may cancel or *block* commitment or dispatch instructions generated by the market software.[203] This can occur for a variety of reasons, including the following:

- **Data inaccuracies.** Results of the market model may be inconsistent with actual system or market conditions as a result of a data systems problem. For example, the ISO takes telemetry data and feeds the telemetry into the real-time system. If the telemetry is incorrect, the market model may try to commit or de-commit units based on the bad telemetry data. Operators may act accordingly to stop the instruction from being incorrectly sent to market participants.

- **Software limitations of unit operating characteristics.** Software limitations can also cause inappropriate commitment or dispatch decisions. For example, some unit operating characteristics of certain units are also not completely incorporated in the real-time market models. For instance, the ISO software has problems with dispatching pumped storage units as the model does not reflect all of its operational characteristics.

- **Information systems and processes.** In some cases, problems occur in the complex combination of information systems and processes needed to operate the real-time market on a timely and accurate basis. In such cases, operators may need to block commitment or dispatch instructions generated by the real-time market model.

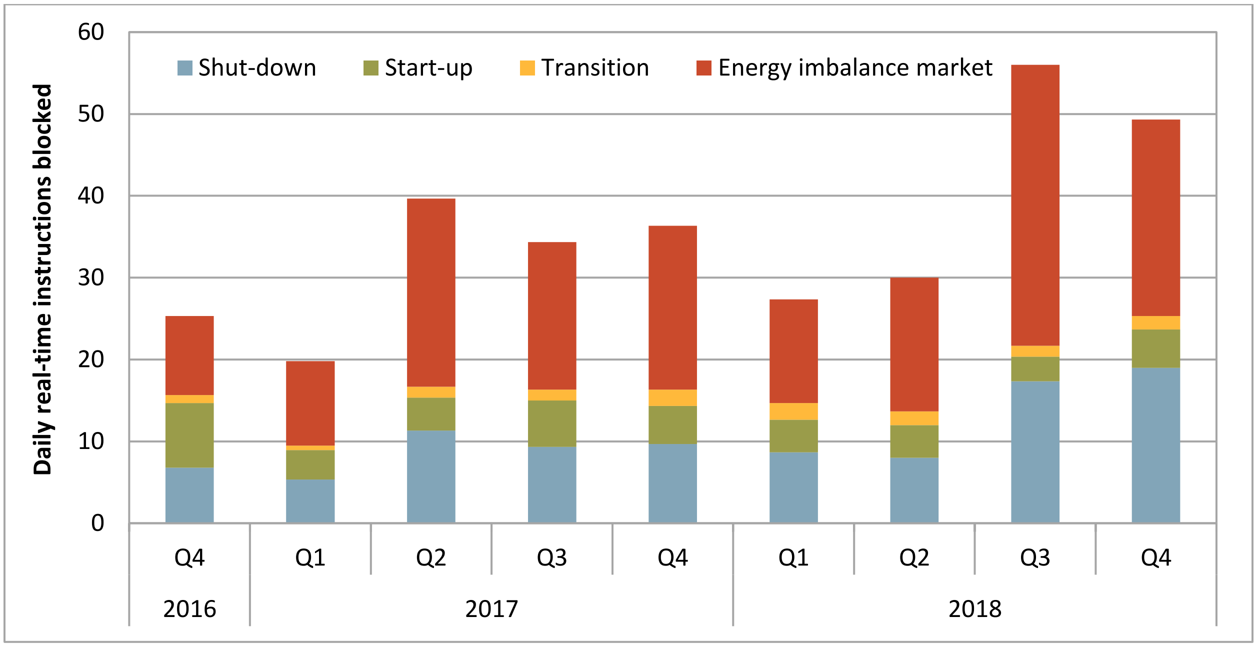
Figure 9.18 shows the frequency of blocked real-time commitment start-up, shut-down, and multi-stage generator transition instructions. The overall number of blocked instructions for internal ISO units increased during 2018 from the previous year. Blocked shut-down instructions continued to be the most common reason for blocked instructions at about 72 percent in 2018, an increase from nearly 60 percent the previous year.

Blocked start-up instructions accounted for about 20 percent of blocked instructions within the ISO in 2018, a decrease from nearly 30 percent in 2017. Blocked transition instructions to multi-stage generating units also decreased to about 8 percent from 11 percent in 2017. Some reasons for blocked instructions in the ISO include multi-stage generating unit transition issues, a limited number of start-ups for peaking units, and inconsistent instructions for pumping and generation for some units.

Figure 9.18 also includes blocked commitment instructions from energy imbalance market operators (red bars). During 2018, many of these actions were to block start-up and/or transition instructions between unit configurations. In some cases this was to prevent a drop in reserves as a result of transitioning to a resource with a slower ramp rate. Although a market solution was implemented in 2017 to better manage reserves during unit transitions, the number of blocked dispatches for the energy imbalance market remains high due to a single energy imbalance area's selection of this tool to limit transitions of a multi-stage generating resource.

[203] The ISO reports on blocked instructions in its monthly performance metric catalog. Blocked instruction information can be found in the later sections of the monthly performance metric catalog report: https://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=AF1E04BD-C7CE-4DCB-90D2-F2ED2EE8F6E9.

Figure 9.18 Frequency of blocked real-time commitment instructions



9.6 Blocked dispatches

Grid operators review dispatches issued in the real-time market before these dispatch and price signals are sent to the market. If the ISO operators determine that the 5-minute dispatch results are inappropriate, they are able to block the entire real-time dispatch instructions and prices from reaching the market.

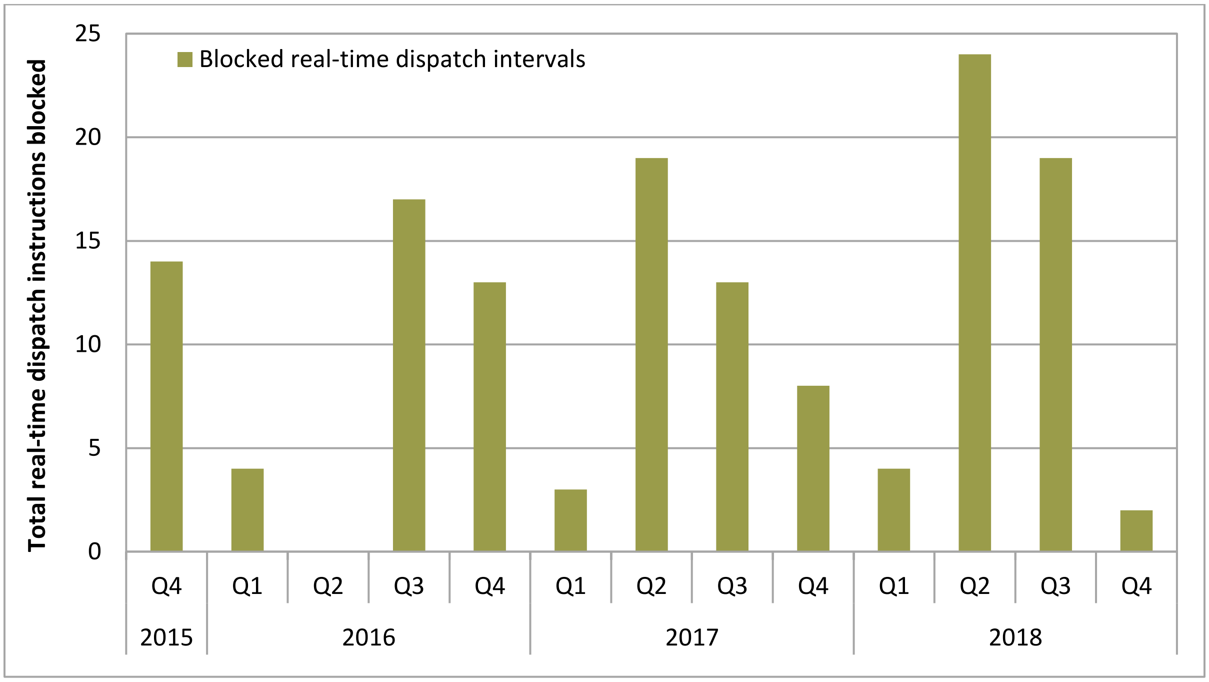
The ISO began blocking dispatches in 2011 as both market participants and ISO staff were concerned that inappropriate price signals were being sent to the market even when they were known to be problematic. These inappropriate dispatches would often have caused participants to exacerbate issues with system conditions that were not modeled. Frequently, many of the blocked intervals eliminated the need for a subsequent price correction.

Operators can choose to block the entire market result to stop dispatches and prices resulting from a variety of factors including incorrect telemetry, intertie scheduling information or load forecasting data. Furthermore, the market software is also capable of automatically blocking a solution when market results exceed threshold values.[204]

Figure 9.19 shows the frequency that operators blocked price results in the real-time dispatch from the fourth quarter 2015 through 2018. The total number of blocked intervals in 2018 increased about 14 percent from 2017. Similar to 2017 the majority of blocked dispatches in 2018 occurred in the second and third quarters, with the highest months between April and August. Although there was a year-over-year increase, the frequency of blocked dispatches in 2018 was significantly lower than during 2011 and 2012 due to improvements in market software functionality.

[204] For example, if the load were to drop by 50 percent in one interval, the software can automatically block results.

Figure 9.19 Frequency of blocked real-time dispatch intervals



10 Resource adequacy

The purpose of the resource adequacy (RA) program is to ensure the ISO system has enough resources to operate the grid safely and reliably in real time and to provide incentives for the siting and construction of new resources to operate the grid reliably in the future. Key findings in this chapter include:

- System resource adequacy requirements were sufficient to meet peak day-ahead load forecasts and actual peak loads for all days in 2018. Peak system loads were observed on July 25, while resource adequacy requirements were highest in August. Peak day-ahead load forecasts and actual peak loads approached, but did not surpass, system resource adequacy requirements of almost 50,000 MW on July 23, July 24, and July 25. Additionally, forecasted and actual peak loads in July and August were substantially lower than 115 percent of the ISO's 2018 1-in-2 year forecast of peak load (53,619 MW).
- Most system resource adequacy capacity was procured by investor-owned utilities (IOU). Investor-owned utilities accounted for about 71 percent of procurement, community choice aggregators (CCA) procured 11 percent, municipal entities contributed 9 percent, and direct access (DA) providers accounted for 7 percent.
- During the top 210 load hours of the year, 96 percent of system resource adequacy capacity was available after outages; 93 percent of this capacity was bid or self-scheduled in the day-ahead market (90 percent of total system resource adequacy); 99 percent of this capacity was available after outages in the real-time market (89 percent of total); and 91 percent of this capacity was bid or self-scheduled in the real-time (81 percent of total).
- Energy bid prices for some resource adequacy imports were relatively high compared to other resource adequacy resources. Energy bid prices for resource adequacy imports averaged above $175/MWh for the entire year. Since a significant portion of these imports do not clear the day-ahead market, only about 82 percent were bid or self-scheduled into the real-time market during peak hours.
- Overall, total local resource adequacy capacity exceeded requirements in local capacity areas. Even after adjusting for outages, total available capacity exceeded local requirements in the day-ahead and real-time markets by 113 percent and 103 percent, respectively.
- Procurement in some local capacity areas was significantly lower than the local requirement. Total resource adequacy capacity was below the local requirement in the PG&E transmission access charge area in Sierra, Stockton, and Humboldt. This deficit was offset by capacity procurement that surpassed local requirements in the Greater Bay Area, Greater Fresno, North Coast/North Bay, and Kern.
- Year-ahead total flexible resource adequacy procurement by load-serving entities exceeded requirements. Total flexible resource adequacy procurement exceeded the total requirement in all months of the year in 2018. However, forward requirements fell short of the maximum three-hour net load ramp in four months in 2018.

- Intra-monthly capacity procurement mechanism (CPM) designations cost about $22 million in 2018. Intra-monthly designations were triggered by exceptional dispatches and a significant event to address potential contingency events, potential thermal overloads, and an alternate load forecast.
- Year-ahead capacity procurement mechanism designations in 2018 cost about $78 million. In December 2017, the ISO issued annual designations to address collective local resource adequacy deficiencies for 2018 in the South Bay-Moss Landing sub-area of the Bay Area local capacity area and the San Diego-Imperial Valley local capacity area.

10.1 Background

The purpose of the resource adequacy program is to ensure the ISO system has enough resources to operate the grid safely and reliably in real time and to provide incentives for the siting and construction of new resources to operate the grid reliably in the future. In order to achieve this, the California Public Utilities Commission establishes yearly obligations for all load-serving entities within their jurisdiction to procure enough resources to ensure capacity is available to the ISO when and where needed to operate the power system. Similarly, non-CPUC jurisdictional load-serving entities must procure enough capacity to satisfy the requirements of their local regulatory authority (LRA).

The bilateral transactions between load-serving entities and electricity suppliers that result from these requirements are meant to provide sufficient revenue to compensate the fixed costs of existing generators and the financing needed for new generator construction. The resource adequacy program includes ISO tariff requirements that work in conjunction with regulatory requirements and processes adopted by the CPUC and other local regulatory authorities.

The resource adequacy program includes obligation requirements for three types of capacity:

1. System resource capacity needed to ensure reliability during system-level peak demand;
2. Local resource capacity needed to ensure reliability in specific areas with limited import capability; and
3. Flexible resource capacity needed to ensure reliability during ramping periods.

Load-serving entities are required to make filings to demonstrate that they have procured enough capacity to fulfill their obligations for all three types of resource adequacy. Once established in an entity's supply plan, capacity must be made available to the ISO according to rules that depend on requirement type and resource type. This chapter reviews and analyzes the rules, requirements, and availability of resources for each category of resource adequacy.

10.2 System resource adequacy

Analysis in this section focuses on the availability of system resource adequacy resources throughout the year as well as a special focus on peak loads during the summer months where loads are the highest and energy supply is the tightest in California.

System resource adequacy requirements are set based on system-level peak demand. While system capacity is important to meet peak loads during the summer months, it is also important that sufficient capacity be made available to the market throughout the year. For example, significant amounts of generation can be out for maintenance during the non-summer months. This can make the remaining available resources offering resource adequacy capacity instrumental in meeting even moderate loads during non-summer months.

Regulatory requirements

The ISO works with the CPUC and other local regulatory authorities to set system-level requirements. These requirements are specific to individual load-serving entities based on their forecasted peak load in each month (based on a 1-in-2 year peak forecast) plus a planning reserve margin, which is typically 15 percent of peak load.[205] Load-serving entities then procure capacity to meet these requirements and demonstrate this procurement through the filing of annual and monthly supply plans to the ISO.

For annual showings, CPUC-jurisdictional load-serving entities are required to demonstrate they have procured 90 percent of their system resource adequacy obligations for the five summer months in the coming compliance year. For monthly showings, CPUC-jurisdictional entities must demonstrate they have procured 100 percent of their monthly system obligation. Annual supply plans are submitted to the ISO by the last business day of October prior to the coming compliance year. Monthly supply plans are submitted to the ISO at least 45 days prior to the compliance month.

Bidding and scheduling obligations

Scheduling coordinators representing procured resource adequacy capacity must make the capacity listed in a load-serving entity's monthly supply plan available to the ISO markets through economic bids or self-schedules as follows:

- **Day-ahead energy and ancillary services market** – All available resource adequacy capacity must be either self-scheduled or bid into the day-ahead energy market. Resources certified for ancillary services must offer this capacity in the ancillary services market.
- **Residual unit commitment process** – Market participants are also required to submit bids priced at $0/MW into the residual unit commitment process for all resource adequacy capacity.
- **Real-time market** – All resource adequacy resources committed in the day-ahead market or residual unit commitment process must also be made available and offered into the real-time markets. Short-start units providing resource adequacy capacity must also be offered in the real-time energy and ancillary services markets even when they are not committed in the day-ahead market or residual unit commitment process.[206] Long-start units and imports providing resource adequacy capacity that are not scheduled in the day-ahead market or residual unit commitment process are not required to bid into the real-time markets.

Resource adequacy capacity from system resources that were not scheduled in the day-ahead market (other than short-start units) are not required to be offered in the real-time markets. In 2018, almost half of the capacity procured for resource adequacy requirements was from resources that must bid into the market for each hour of the month, except when reported to the ISO as unavailable due to outages.

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[205] The planning reserve margin is designed to include additional operating reserve needed above peak load as well as an allowance for outages and other resource limitations. The requirement is then adjusted for several factors including a credit for demand response programs.

[206] This must-offer obligation is explicitly designated to medium-start units in the Tariff as of April 1, 2019.

This includes most gas-fired and other generators. If the market participant does not submit bids, the ISO automatically creates bids for these resources.

The remaining 2018 resource adequacy capacity counted toward system requirements does not have to offer their 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 availability-limited resources.

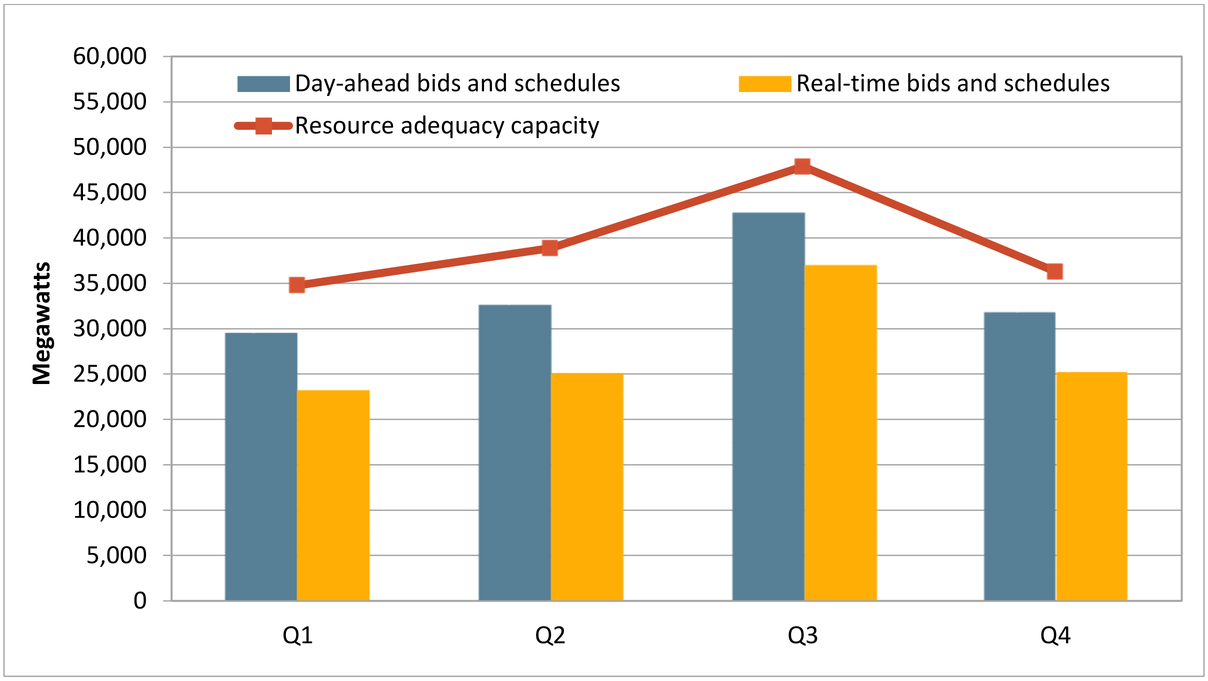
Availability

The ISO uses the resource adequacy availability incentive mechanism (RAAIM) to incentivize the availability of resources providing system, local, and flexible resource adequacy capacity during the availability assessment hours each month. This mechanism gives scheduling coordinators the incentive to make resource adequacy capacity available in the market during the availability assessment hours by charging a penalty to resources that are not made available at least 94.5 percent of the time and paying resources that are available at least 98.5 percent of the time during those hours. In 2018, the availability assessment hours were hours ending 17 through 21 of non-holiday weekdays.

Figure 10.1 captures resource adequacy availability at a quarterly level by showing average capacity procurement and market bidding and scheduling activity during the availability assessment hours. The red line shows the average quarterly capacity procured to meet system-level requirements. The bars summarize the average amount of available capacity bid in or scheduled in the day-ahead and real-time markets during the availability assessment hours.[207]

[207] Real-time bid in or scheduled resource adequacy capacity in the figure does not include capacity from long-start units and imports that were not scheduled in the day-ahead market or residual commitment process. Uncommitted resource adequacy capacity from long-start units and imports does not have a real-time must-offer obligation in the real-time market. This figure does not account for resource adequacy capacity that may not be available in real-time due to ramping limitations.

Figure 10.1 Quarterly resource adequacy capacity scheduled and bid into ISO markets (2018)



Key findings of this analysis include:

- ***On average, bids and schedules were lower than total capacity in each quarter***. Less than 90 percent resource adequacy capacity on average was available in the day-ahead market during availability assessment hours on a quarterly basis.
- ***The percentage of capacity available during availability assessment hours was highest in the third quarter***. During these months, an average of about 43,000 MW out of about 48,000 MW of procured resource adequacy capacity (or 89 percent) was available in the day-ahead market. Availability was similar for the remaining quarters at about 86 percent of resource adequacy capacity available in the day-ahead market.
- ***A smaller proportion of capacity was available in the real-time market compared to the day-ahead market for each quarter of 2018.*** This is primarily because many long-start gas-fired units and import capacity are not available in the real-time market if these resources are not committed in the day-ahead energy market or residual unit commitment process.

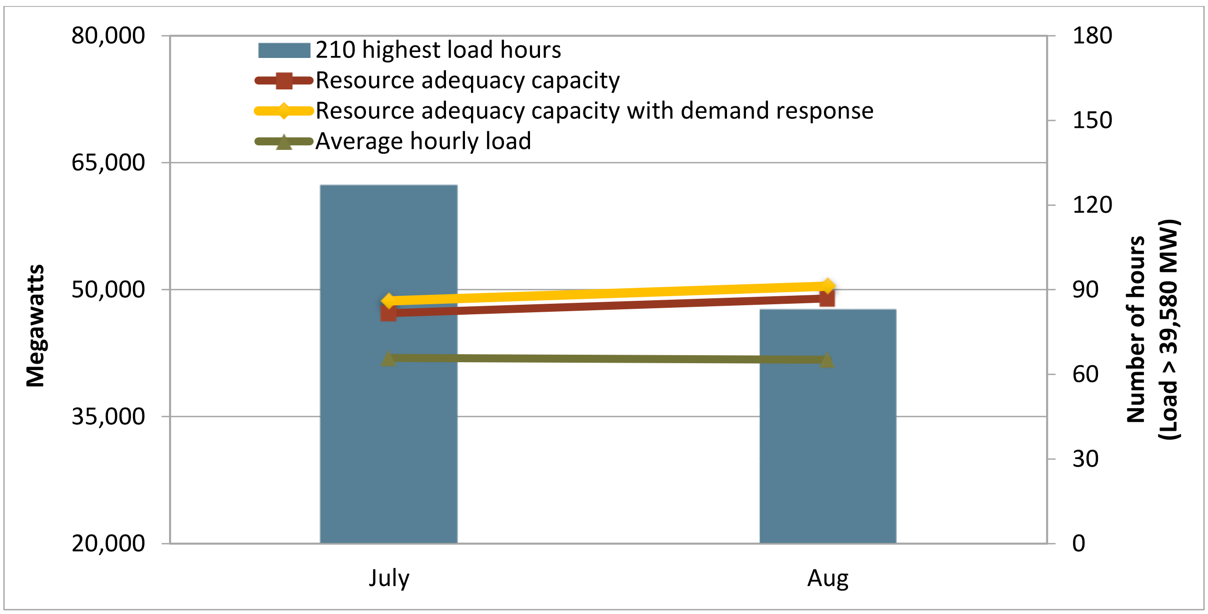
Availability during summer peak hours

California's resource adequacy program recognizes that a portion of the state's generation is only available during limited hours. To accommodate this, load-serving entities are allowed to meet a portion of their resource adequacy requirements with availability-limited generation. This element of the program reflects assumptions that generation will generally be available and used during hours when peak loads are highest.

The CPUC's resource adequacy program is designed to ensure that the highest peak loads are met by requiring that all resource adequacy capacity be available at least 210 hours over the summer months.[208] The rules do not specify that these hours must include the hours when load is highest or system conditions are most critical because participants do not have perfect foresight for when these will actually occur. However, the program assumes these use-limited resources are managed so that they are available during the peak load hours.

Figure 10.2 provides an overview of resource adequacy capacity during the 210 highest load hours in 2018. The red and green lines compare average resource adequacy capacity and load, respectively, during these hours. The yellow line adjusts the resource adequacy capacity so that it includes utility-operated demand response capacity credited against requirements under CPUC provisions. In addition, the blue bars show the number of hours in each month that belong to the highest 210 hours of load during the year.

Figure 10.2 Average hourly resource adequacy capacity and load (210 highest load hours)



Key findings of this analysis include:

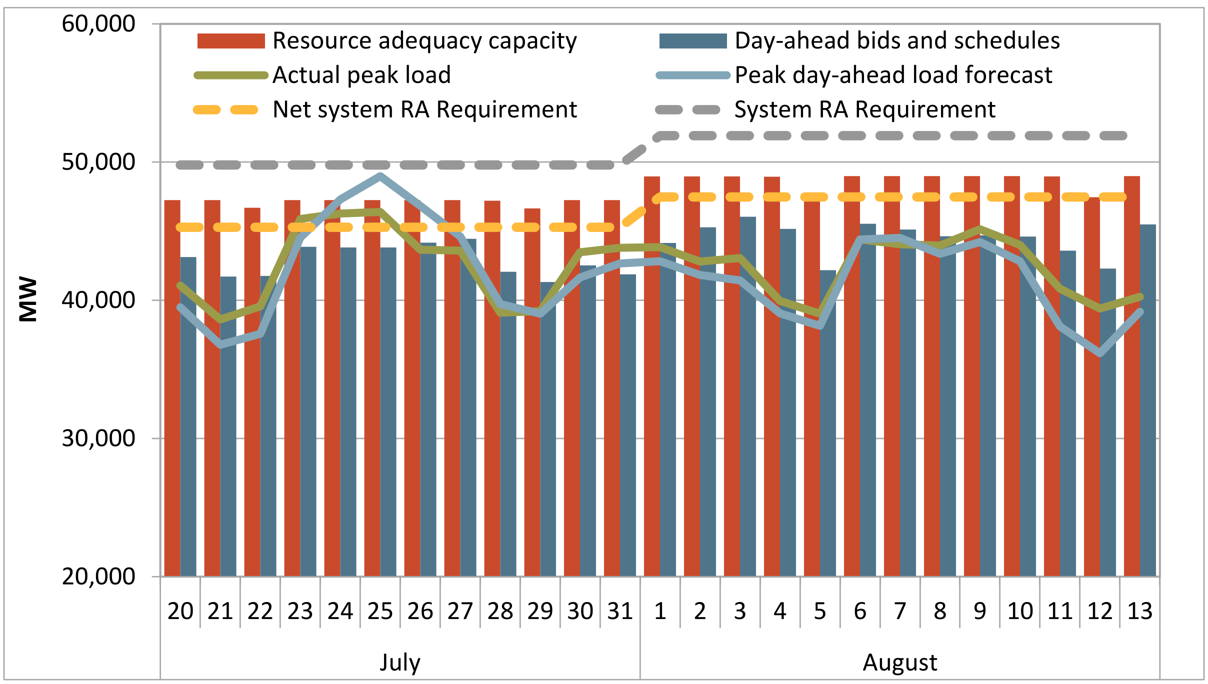
- ***Average resource adequacy capacity exceeded average load during the 210 highest load hours in 2018***. Average hourly load was around 42,000 MW for these hours, while average resource adequacy capacity was around 48,000 MW.

[208] 210 hours is derived from the CPUC's maximum cumulative capacity (MCC) bucket construct. Under this construct, all resources counted toward resource adequacy requirements (except for demand response) must be available for at least 210 hours across summer months. While analysis in this section is based on the top 210 highest load hours regardless of month, the MCC bucket construct specifies minimum required availability in each month, May through September.

- ***During 2018, the 210 highest load hours had loads greater than 39,580 MW.*** These hours were typically concentrated in high temperature days during July and August.

Figure 10.3 relates system resource adequacy requirements, capacity, and day-ahead market bidding and schedules to actual and forecasted daily peak loads in July and August of 2018. The dashed lines show the monthly system resource adequacy requirement (grey) and the net system requirement (gold). The net system requirement reflects actual resource adequacy procurement obligations after load-serving entities receive credits for utility-operated demand response, cost allocation mechanism, and reliability must-run resources. The bars show procured resource adequacy capacity (red) and day-ahead bids and schedules of these resources (blue). Finally, the solid lines show the day-ahead peak load forecast (blue) and the actual daily peak load (green) that the system experienced.

Figure 10.3 Daily peak load, resource adequacy capacity, and planning forecast



Key findings of this analysis include:

- ***System resource adequacy requirements, which include demand response, cost allocation mechanism, and reliability must-run capacity, were sufficient to meet peak day-ahead load forecasts and actual peak loads for all days in 2018.*** Peak day-ahead load forecasts and actual peak loads approached, but did not surpass, system resource adequacy requirements of almost 50,000 MW on July 23, July 24, and July 25. Additionally, forecasted and actual peak loads in July and August were substantially lower than 115 percent of the ISO's 2018 1-in-2 year forecast of peak load (53,619 MW).

- ***Resource adequacy showings exceeded net system resource adequacy requirements.*** When peak day-ahead load forecasts and actual peak loads approached system requirements on July 23, July 24, and July 25, resource adequacy procurement (red bars) surpassed the net system requirements (gold line), which does not include demand response, cost allocation mechanism, and reliability must-run capacity.

- ***Availability was relatively high during days in July with highest peak load***. Resource adequacy procurement was just above 47,000 MW, with nearly 44,000 MW (93 percent) available in the day-ahead market during the peak load hours on all three days.
- ***Day-ahead bids and schedules were lower than resource adequacy capacity during all days.*** Lower available resource adequacy capacity in the day-ahead market was mostly driven by solar, wind, and hydro resources which have limited availability. Peak load hours in this timeframe were concentrated in hours ending 18 and 19.

Load-serving entities can contract with multiple types of resources to fulfill their resource adequacy obligations. Table 10.1 provides insight into what types of resources were procured for system capacity, what their bidding obligations are, and what their availability was on average during the 210 highest load hours in 2018. Separate sub-totals are provided for resources that the ISO creates bids for if market participants do not submit a bid or self-schedule (must-offer), and resources the ISO does not create bids for (other).

Table 10.1 Average system resource adequacy capacity and availability by fuel type (210 highest load hours)

Resource type	Total resource adequacy capacity (MW)	Day-ahead market				Real-time market			
		Adjusted for outages		Bids and self-schedules		Adjusted for outages/availability		Bids and self-schedules	
		MW	% of total RA Cap.	MW	% of adjusted RA Cap	MW	% of total RA Cap.	MW	% of adjusted RA Cap
Must-Offer:									
Gas-fired generators	20,818	19,785	95%	19,785	100%	17,268	83%	16,835	97%
Other generators	1,672	1,543	92%	1,543	100%	1,543	92%	1,480	96%
Subtotal	**22,490**	**21,328**	**95%**	**21,328**	**100%**	**18,811**	**84%**	**18,315**	**97%**
Other:									
Imports	3,904	3,895	100%	3,732	96%	3,328	85%	2,725	82%
Use-limited gas units	5,043	4,900	97%	4,769	97%	4,799	95%	4,553	95%
Hydro generators	6,149	5,684	92%	5,242	92%	5,684	92%	5,249	92%
Nuclear generators	2,894	2,878	99%	2,875	100%	2,878	99%	2,814	98%
Solar generators	3,973	3,953	100%	2,611	66%	3,923	99%	2,738	70%
Wind generators	1,569	1,564	100%	1,008	64%	1,564	100%	1,158	74%
Qualifying facilities	1,403	1,375	98%	1,152	84%	1,292	92%	1,106	86%
Other non-dispatchable	494	487	99%	304	62%	465	94%	392	84%
Subtotal	**25,429**	**24,736**	**97%**	**21,693**	**88%**	**23,933**	**94%**	**20,735**	**87%**
Total	**47,919**	**46,064**	**96%**	**43,021**	**93%**	**42,744**	**89%**	**39,050**	**91%**

Key findings of this analysis include:

- ***Most resource adequacy capacity is procured from non-use-limited gas-fired generators***. Gas-fired resources supplied almost 21,000 MW of resource adequacy capacity during the 210 highest load hours of 2018. Hydro generators accounted for the second highest amount of capacity at 6,100 MW.

- ***Most of the capacity that must bid during all hours continued to be from gas-fired resources***. Less than half of system resource adequacy capacity (22,490 MW) must be bid into the market for each hour of the month.[209] Gas-fired generation made up about 21,000 MW (43 percent) of total resource adequacy capacity. Other generators accounted for 3 percent.

- ***Hydro generators made up the largest portion of resource adequacy capacity not required to bid in during all hours***. Hydro resources contributed about 6,100 MW of total capacity (13 percent), use-limited gas resources contributed 11 percent, imports contributed 8 percent, solar resources contributed 8 percent, nuclear resources contributed 6 percent, wind resources contributed 3 percent, qualifying facility resources contributed 3 percent, and other non-dispatchable resources (e.g., demand response) contributed 1 percent of system capacity.[210]

- ***Capacity available after reported outages and derates continued to be significant***. Average resource adequacy capacity was around 47,900 MW during the 210 highest load hours in 2018, about the same amount as 2017. After adjusting for outages and derates, the remaining capacity available in the day-ahead market was about 96 percent of the overall resource adequacy capacity, which was unchanged from 2017.

- ***Day-ahead market availability was high for all resource types***. About 95 percent of must-offer and 97 percent of non must-offer resources were available in the day-ahead market. Must-offer resources bid in about 100 percent of day-ahead availability. Non must-offer resources bid in about 88 percent of the day-ahead availability. These are typically variable and non-dispatchable energy resources. Additionally, some of the 210 highest load hours occurred in evening hours when solar resources and other non must-offer resources have limited availability.

- ***Most capacity was available in the real-time market, after accounting for outages and derates***. The last four columns of Table 10.1 compare the total resource adequacy capacity potentially available in the real-time market timeframe with the actual amount of capacity scheduled or bid in the real-time market. The capacity available in the real-time market timeframe is calculated as the resource adequacy capacity from resources with a day-ahead or residual unit commitment schedule plus the resource adequacy capacity from uncommitted short-start units. This capacity has been adjusted for outages and derates. About 91 percent of the resource adequacy capacity that was potentially available to the real-time market was scheduled or bid in the real-time market.

- ***Most use-limited gas capacity was bid into the day-ahead market***. Around 5,000 MW of use-limited gas resources were used to meet resource adequacy requirements. About 97 percent of this

209 When scheduling coordinators did not submit bids for these resources, they were automatically generated by the ISO. Generation was excluded from bidding requirement when an outage was reported to the ISO.

210 Beginning in January 2012, the ISO began to automatically create energy bids for unit-specific imports during all hours of the month and for non-unit-specific imports during availability assessment hours in the day-ahead market when market participants failed to submit bids for this capacity and did not declare the capacity unavailable. If imports were not committed in the day-ahead market, the importer was not required to submit bids for this capacity in the real-time market.

capacity was bid in the day-ahead market during the highest 210 load hours. In real time, about 4,600 MW of 4,800 MW (95 percent) of net available capacity was scheduled or bid in the real-time market.

Table 10.2 shows the availability of resources in ISO markets aggregated by the types of load-serving entity that they contracted with. In this analysis, supply plans were used to proportionally assign resource bid availability to load-serving entities based on corresponding contracted capacity.[211] Bid availability is aggregated by load type, depending on whether the entity is a community choice aggregator (CCA), direct access (DA) service, investor-owned utility (IOU), or a municipal/government (Muni) entity. Substituted capacity represents resources that substituted for a resource that went on outage, but were not originally on a load-serving entity's supply plan.

Table 10.2 Average system resource adequacy capacity and availability by load type (210 highest load hours)

Load Type	Total resource adequacy capacity	Day-ahead				Real-time			
		Adjusted for outages		Bids and self-schedules		Adjusted for outages/availability		Bids and self-schedules	
		MW	% of total RA Cap.	MW	% of adjusted RA Cap.	MW	% of total RA Cap.	MW	% of adjusted RA Cap.
CCA	5,224	5,135	98%	4,670	91%	4,914	94%	4,516	92%
DA	3,509	3,435	98%	3,227	94%	3,071	88%	2,682	87%
IOU	34,100	32,576	96%	30,833	95%	30,005	88%	27,575	92%
Muni	4,209	4,042	96%	3,414	84%	3,942	94%	3,482	88%
Substituted capacity	878	878	100%	877	100%	813	93%	796	98%
Total	**47,919**	**46,065**	**96%**	**43,021**	**93%**	**42,744**	**89%**	**39,050**	**91%**

Key findings of this analysis include:

- ***Most system capacity was procured by investor-owned utilities.*** Investor-owned utilities accounted for about 34,000 MW (or 71 percent) of system resource adequacy procurement, community choice aggregators contributed 11 percent, municipal utilities contributed 9 percent, and direct access services contributed 7 percent.
- ***Day-ahead availability was high for all load types***. About 98 percent of resource adequacy capacity was available from resources that contracted with community choice aggregators and direct access services and 96 percent was available from investor-owned and municipal utilities.
- ***CCAs, DAs, and municipal utilities contracted with a higher percentage of resources without all hour must-offer obligations than IOUs***. Community choice aggregators, direct access services, and municipal utilities procured most of their resource adequacy capacity (65 percent, 64 percent, and 73 percent, respectively) from resources that do not have a must-offer obligation in all hours compared to investor-owned utilities who procured 43 percent of their capacity from such

211 Since a single resource can contract with multiple load-serving entities, bidding behavior for individual resources was distributed proportionately among entities according to their contracted share of a resource's capacity. For example, if Generator A has 100 MW of resource adequacy capacity in total and contracted 60 MW of capacity to LSE 1 and 40 MW to LSE 2, then 60 percent of Generator A's bids in the markets are assigned to LSE 1 and 40 percent to LSE 2. Load-serving entity assigned bids are then aggregated up to the type of load the entity serves.

resources. For community choice aggregators, lower day-ahead bid participation came from solar, wind, qualifying facilities, and other non-dispatchable resources. Direct access services and municipal utilities also saw relatively low day-ahead and real-time market participation from imports which accounted for 16 percent and 22 percent of their overall resource adequacy capacity procurement, respectively.

- ***Most capacity was available in the real-time market for each load type***. Real-time resource adequacy capacity availability ranged from 88 percent to 94 percent for each load type. Availability of resources contracted with direct access services and investor-owned utilities were slightly lower than for community choice aggregators and municipal utilities after accounting for outages and derates. Both direct access and investor-owned utility resources experienced slightly lower availability from must-offer gas-fired generators, and direct access services experienced low availability from import resources.
- ***Substitute capacity had high rates of availability and market participation.*** About 880 MW (or 2 percent) of resource adequacy capacity came from substituted capacity.

Resource adequacy imports

Load-serving entities are allowed to use imports to meet system resource adequacy requirements, but import availability may be limited compared to must-offer resources in the ISO markets. Resource adequacy imports are only required to be bid into the day-ahead market. Imports can be bid at any price as they are not subject to market power mitigation and do not have any further bid obligation if not scheduled in the day-ahead energy or residual unit commitment process.

DMM has expressed concern that these rules could allow a significant portion of resource adequacy requirements to be met by imports that may have limited availability and value during critical system and market conditions. For example, imports could be routinely bid significantly above projected prices in the day-ahead market to ensure they do not clear and would then have no further obligation to be available in the real-time market. Analysis of resource adequacy resources shows that during peak hours of 2018, the availability of imports in the real-time market is relatively low and that energy bid prices for imports are relatively high compared to other resources.

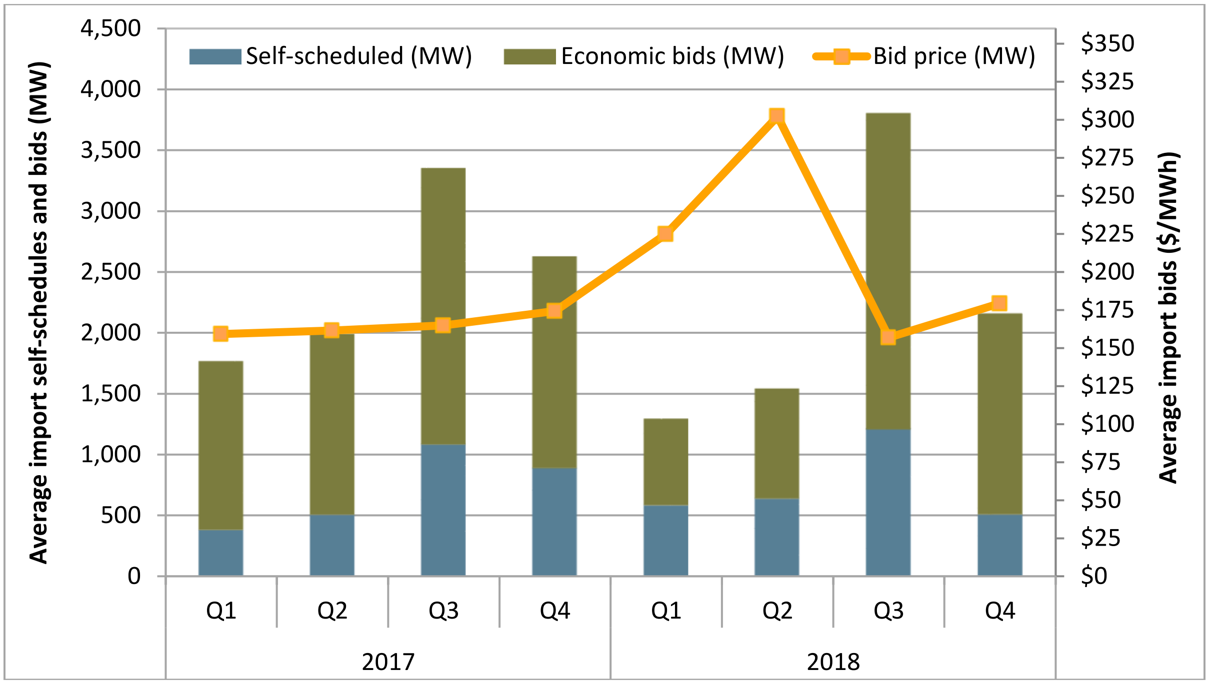
Table 10.1 shows that load-serving entities used about 3,900 MW of imports (or about 8 percent of total resource adequacy capacity) to meet system requirements during the top 210 load hours of 2018. These resources had a high participation rate in the day-ahead market with about 96 percent of available capacity submitting bids and self-schedules. In the real-time market, however, imports had the lowest participation rate of these resources with only 82 percent of capacity available through bids or self-schedules.

In addition, energy bid prices for many resource adequacy imports were relatively high in 2018. Figure 10.4 summarizes the bid prices and volume of self-scheduled and economic bids for import resources in the day-ahead market during peak hours for each quarter of each year.[212] The blue and green bars (plotted against the left axis) show the average amounts of resource adequacy import capacity that market participants either self-scheduled (blue bar) or economically bid (green bar) in the day-ahead

[212] Peak hours are defined as Monday through Saturday, excluding North American Electric Reliability Council holidays, from hour-ending 7 to hour-ending 22.

market. The gold line (plotted against the right axis) shows the weighted average energy bid prices for import resources for which market participants submitted economic bids to the day-ahead market.

Figure 10.4 Resource adequacy import self-schedules and bids (peak hours)



Key findings of this analysis include:

- ***Overall volume of resource adequacy import bids in 2018 was similar to peak hour bids in 2017***. Quarterly averages for import bids and self-schedules ranged from about 1,800 MW to 3,300 MW in 2017 to 1,300 MW to 3,800 MW in 2018.
- ***Weighted average prices for energy bids from resource adequacy imports rose significantly in the first half of 2018***. Energy bid prices averaged above $175/MWh for the entire year.
- ***There were more economic bids for imports than self-schedules in every quarter***. Self-scheduled resource adequacy imports accounted for about 33 percent of total bids from these resources in the day-ahead market compared to 29 percent in 2017.

10.3 Local resource adequacy

Analysis in this section focuses on the market availability of resource adequacy resources in local capacity areas during summer month peak load hours where loads are the highest and energy supply is the tightest in California. The goal of local resource adequacy requirements is to ensure reliability in specific transmission constrained load pockets. As part of local requirements, load-serving entities are required to procure resource adequacy generation capacity within certain local capacity areas that have limited import capability and may be at risk of having insufficient transmission to serve load due to outages or congestion.

Requirements

Local resource adequacy requirements are determined from the local capacity technical study that is performed by the ISO on an annual basis. This study identifies the minimum amount of megawatts that must be available within local capacity areas for reliability using a 1-in-10 weather year and N-1-1 contingencies. The ISO allocates local capacity area obligations to scheduling coordinators for non-CPUC jurisdictional load-serving entities based on each entity's proportionate share of transmission access charge (TAC) area load during the coincident forecasted peak for the resource adequacy compliance year as determined by the California Energy Commission. For CPUC-jurisdictional load-serving entities, the CPUC must first adopt the results of the ISO's technical study; the CPUC allocates the adopted local requirements to each load-serving entity in each transmission access charge area using the ratio of load-serving entities' peak load to total peak load in each TAC area in August of the compliance year, as indicated in each entity's peak load forecast. An entity can meet its megawatt responsibility for each area that they serve load by procuring capacity in any local capacity area in that area.

For annual showings, CPUC-jurisdictional load-serving entities are required to demonstrate they have procured 100 percent of their local resource adequacy requirements for each month of the compliance year. Annual supply plans are submitted to the ISO by the last business day of October prior to the compliance year. Load-serving entities must also demonstrate they have met their revised local obligation on a monthly basis from May through December due to load migration.

Bidding and scheduling obligations

Scheduling coordinators representing procured resource adequacy capacity that satisfies local requirements must make the capacity listed in a load-serving entity's monthly supply plan available to the day-ahead, ancillary services, residual unit commitment, and real-time markets through economic bids or self-schedules consistent with the obligations for resources providing system resource adequacy.

Availability during summer peak hours

Table 10.3 shows an analysis similar to the availability analysis for system resource adequacy. This table compares the local area capacity requirements established by the CPUC to the amount of capacity that was procured (adjusted for availability) and actually bid into both the day-ahead and real-time markets during the highest 210 load hours in 2018.[213]

[213] Local capacity area resource adequacy requirements obtained from the *2019 Local Capacity Technical Analysis*, April 23, 2018, pg. 23, Table 6: http://www.caiso.com/Documents/Draft2019LocalCapacityTechnicalReport.pdf.

Table 10.3 Average local resource adequacy capacity and availability (210 highest load hours)

Local capacity area	TAC area	Total resource adequacy capacity	Local requirement	Day-ahead				Real-time			
				Adjusted for outages		Bids and self-schedules		Adjusted for outages/availability		Bids and self-schedules	
				MW	% of local RA Req.	MW	% of total RA Net Adj	MW	% of local RA Req.	MW	% of total RA Net Adj
Greater Bay Area	PG&E	6,109	5,160	5,855	113%	5,693	97%	5,800	112%	5,582	96%
Greater Fresno	PG&E	3,073	2,081	2,966	143%	2,844	96%	2,916	140%	2,764	95%
Sierra	PG&E	1,968	2,113	1,686	80%	1,536	91%	1,619	77%	1,433	89%
North Coast/North Bay	PG&E	816	634	772	122%	671	87%	772	122%	752	97%
Stockton	PG&E	627	719	598	83%	539	90%	598	83%	580	97%
Kern	PG&E	470	453	448	99%	403	90%	448	99%	327	73%
Humboldt	PG&E	72	169	65	38%	52	80%	65	38%	45	69%
LA Basin	SCE	8,645	7,525	8,288	110%	8,013	97%	6,961	93%	6,562	94%
Big Creek/Ventura	SCE	4,141	2,321	3,808	164%	3,657	96%	3,035	131%	2,885	95%
San Diego	SDG&E	4,058	4,032	3,938	98%	3,671	93%	3,663	91%	3,388	92%
Total		**29,979**	**25,207**	**28,424**	**113%**	**27,079**	**95%**	**25,877**	**103%**	**24,318**	**94%**

Key findings of this analysis include:

- ***Overall, total resource adequacy capacity exceeded requirements in local capacity areas***. Load-serving entities procured about 30,000 MW of capacity in local areas in 2018, compared to about 25,000 MW of required capacity. Even after controlling for outages, the overall available capacity exceeded local requirements in the day-ahead (113 percent of requirements) and real-time (103 percent of requirements) markets.
- ***Procurement in some local capacity areas was significantly lower than the local requirement***. Total resource adequacy capacity was below the local requirement in the PG&E TAC area in Sierra, Stockton, and Humboldt. This deficit was offset by capacity procurement that surpassed local requirements in the Greater Bay Area, Greater Fresno, North Coast/North Bay, and Kern.[214]
- ***Significant amounts of energy, beyond requirements, were bid into several local capacity areas in the day-ahead market***. Capacity in the Greater Bay Area, Greater Fresno, North Coast/North Bay, LA Basin, and Big Creek/Ventura bid in between 106 percent and 137 percent of the local area requirement. This offset lower participation rates from capacity in Sierra, Stockton, Kern, Humboldt, and San Diego. Overall, about 107 percent of local capacity area requirements were bid into the day-ahead market.
- ***Bidding behavior of available capacity was consistent in the day-ahead and real-time markets***. About 95 percent of available capacity (107 percent of local capacity area requirements) bid into the day-ahead market, while 94 percent of available capacity (96 percent of local area requirements) bid into the real-time market.

[214] According to the local resource adequacy reallocation process adopted in the CPUC's Decision (D.) 10-12-038, incremental local resource adequacy requirements may be aggregated by transmission access charge area.

In instances where available resource adequacy capacity does not meet the needs of a local area, the ISO has the ability to designate additional capacity through the capacity procurement mechanism. Capacity procurement mechanism designations in 2018 are described in depth in Section 10.5.

Table 10.4 shows the availability of local resource adequacy resources in the ISO markets aggregated by transmission access charge area and types of loads that they contracted with. Supply plans were used to proportionally assign resource bid availability to load-serving entities based on corresponding contracted capacity. Bid availability was then aggregated by load type, depending on whether the entity is a community choice aggregator, direct access service, investor-owned utility, or a municipal/government entity. Substituted capacity represents bids from resources that substituted for a resource that went on outage, but were not originally on a load-serving entity's supply plan.

Table 10.4 Average local resource adequacy capacity and availability by TAC area load type (210 highest load hours)

Area	Load Type	Total resource adequacy capacity	Day-ahead				Real-time			
			Adjusted for outages		Bids and self-schedules		Adjusted for outages/availability		Bids and self-schedules	
			MW	% of total RA Cap.	MW	% of adjusted RA Cap	MW	% of total RA Cap.	MW	% of adjusted RA Cap
PG&E	CCA	2,137	2,088	98%	1,897	91%	2,024	95%	1,913	95%
	DA	830	793	95%	768	97%	781	94%	731	94%
	IOU	8,626	8,037	93%	7,770	97%	7,954	92%	7,476	94%
	Muni	1,030	961	93%	791	82%	948	92%	860	91%
	Substituted Capacity	512	512	100%	512	100%	512	100%	501	98%
	Subtotal	**13,136**	**12,390**	**94%**	**11,737**	**95%**	**12,219**	**93%**	**11,482**	**94%**
SCE	CCA	254	248	97%	197	80%	204	80%	178	87%
	DA	761	742	97%	704	95%	704	93%	648	92%
	IOU	10,642	10,017	94%	9,878	99%	8,018	75%	7,707	96%
	Muni	1,098	1,060	97%	861	81%	1,039	95%	885	85%
	Substituted Capacity	30	30	100%	29	99%	30	100%	28	95%
	Subtotal	**12,786**	**12,096**	**95%**	**11,670**	**96%**	**9,995**	**78%**	**9,447**	**95%**
SDG&E	CCA	59	58	99%	58	100%	26	44%	24	90%
	DA	610	600	98%	600	100%	478	78%	465	97%
	IOU	3,059	2,951	96%	2,683	91%	2,894	95%	2,639	91%
	Muni	-	-	-	-	-	-	-	-	-
	Substituted Capacity	330	330	100%	330	100%	265	80%	261	99%
	Subtotal	**4,058**	**3,938**	**97%**	**3,671**	**93%**	**3,663**	**90%**	**3,388**	**92%**
	Total	**29,981**	**28,424**	**95%**	**27,078**	**95%**	**25,877**	**86%**	**24,317**	**94%**

Key findings of this analysis include:

- ***Most local resource adequacy capacity was procured by investor-owned utilities***. Investor-owned utilities accounted for about 22,000 MW (or about 75 percent) of local resource adequacy procurement, community choice aggregators contributed 8 percent, direct access services contributed 7 percent, and municipal utilities contributed 7 percent.
- ***Most local resource adequacy capacity procurement by community choice aggregators occurred in the PG&E TAC area***. Community choice aggregators procured about 16 percent of total resource adequacy capacity in the PG&E area, mostly in the Greater Bay Area, Greater Fresno, and Sierra local

capacity areas. These resources had high availability rates in the day-ahead and real-time markets except in the North Coast/North Bay and Humboldt local capacity areas where less than 65 percent of capacity was bid into the day-ahead market.

- ***Day-ahead availability was high for all load types in each TAC area***. Availability in the day-ahead market ranged from 93 percent to 99 percent of total resource adequacy capacity for each area and load type.
- ***Most resource adequacy capacity was available in the real-time market for all load types in each TAC area.*** About 86 percent of the total local resource adequacy capacity was available to the real-time market. Resources in the SCE TAC area had the lowest availability in the real-time market out of the three TAC areas with 78 percent availability. This was mainly due to outages of resources that contracted with the investor-owned utilities and community choice aggregators.

10.4 Flexible resource adequacy

The purpose of flexible resource adequacy capacity is to ensure the system has enough flexible resources available to meet forecasted net load ramps, plus contingency reserves. With increased reliance on renewable generation, the need for flexible capacity has also increased to manage changes in net load. This ramping capability is generally needed in the downward direction in the morning when solar generation ramps up and replaces gas generation. In the evening, upward ramping capability is needed as solar generation rapidly decreases while system loads are increasing. The greatest need for three-hour ramping capability occurs during evening hours.

To address flexibility needs for changing system conditions, the CPUC and the ISO developed flexible resource adequacy requirements. The flexible resource adequacy framework was approved by FERC in 2014 and became effective in January 2015, and now serves as an additional tool to help maintain grid reliability.[215]

Requirements

Flexible capacity needs are determined from the flexible capacity needs assessment study that is performed by the ISO on an annual basis. This study identifies the minimum amount of flexible capacity that must be available to the ISO to address ramping needs for the upcoming year. The ISO uses the results to allocate shares of the system flexible capacity need to each local regulatory authority that has load-serving entities responsible for load in the ISO balancing authority area.

The flexible resource adequacy framework is specifically designed to provide capacity with the attributes required to manage the grid during extended periods of ramping needs. Under this framework, the monthly flexible requirement is set at the forecast maximum contiguous three-hour net load ramp plus a capacity factor.[216,217] Because the grid commonly faces two pronounced upward net load ramps per

[215] For more information, see the following FERC order: http://www.caiso.com/Documents/Oct16_2014_OrderConditionallyAcceptingTariffRevisions-FRAC-MOO_ER14-2574.pdf.

[216] The capacity factor is the greater of the loss of the most severe single contingency or 3.5 percent of expected peak load for the month.

[217] Net load is defined as total load less wind and solar production.

day, flexible resource adequacy categories were designed to address both the maximum primary and secondary net load ramp.[218]

For annual showings, load-serving entities are required to demonstrate they have procured 90 percent of their flexible resource adequacy requirements for each month of the coming compliance year. Annual supply plans are submitted to the ISO by the last business day of October prior to the coming compliance year. For the monthly showings, load-serving entities must demonstrate they have procured 100 percent of their flexible resource adequacy obligation.

Bidding and scheduling obligations

All resources providing flexible capacity are required to submit economic energy and ancillary service bids in both the day-ahead and real-time markets and to participate in the residual unit commitment process. However, the must-offer obligations for these resources differ by category. A brief description of each category, its purpose, requirements, and must-offer obligations is presented below.

- **Category 1 (base flexibility):** Category 1 resources must have the ability to address both the primary and secondary net load ramps each day. These resources must submit economic bids for 17 hours a day and be available 7 days a week. The Category 1 requirement is designed to cover 100 percent of the secondary net load ramp and a portion of the primary net load ramp. The requirement is therefore based on the forecasted maximum three-hour secondary ramp. There is no limit to the amount of resources that meet the Category 1 criteria that can be used to meet the total system flexible capacity requirement.
- **Category 2 (peak flexibility):** Category 2 resources must be able to address the primary net load ramp each day. These resources must submit economic bids for 5 hours a day (which vary seasonally) and be available 7 days a week. The Category 2 operational need is based on the difference between the forecasted maximum three-hour secondary net load ramp (the Category 1 requirement) and 95 percent of the forecasted maximum three-hour net load ramp. The calculated Category 2 operational need serves as the *maximum* amount of flexible capacity in this category that can be used to meet the total system flexible capacity requirement.
- **Category 3 (super-peak flexibility):** Category 3 resources must be able to address the primary net load ramp. These resources must submit economic bids for 5 hours (which vary seasonally) on non-holiday weekdays. The Category 3 operational need is set at 5 percent of the forecasted three-hour net load ramp. The calculated Category 3 operational need serves as the *maximum* amount of flexible capacity in this category that can be used to meet the total system flexible capacity requirement.

Requirements compared to actual maximum net load ramps

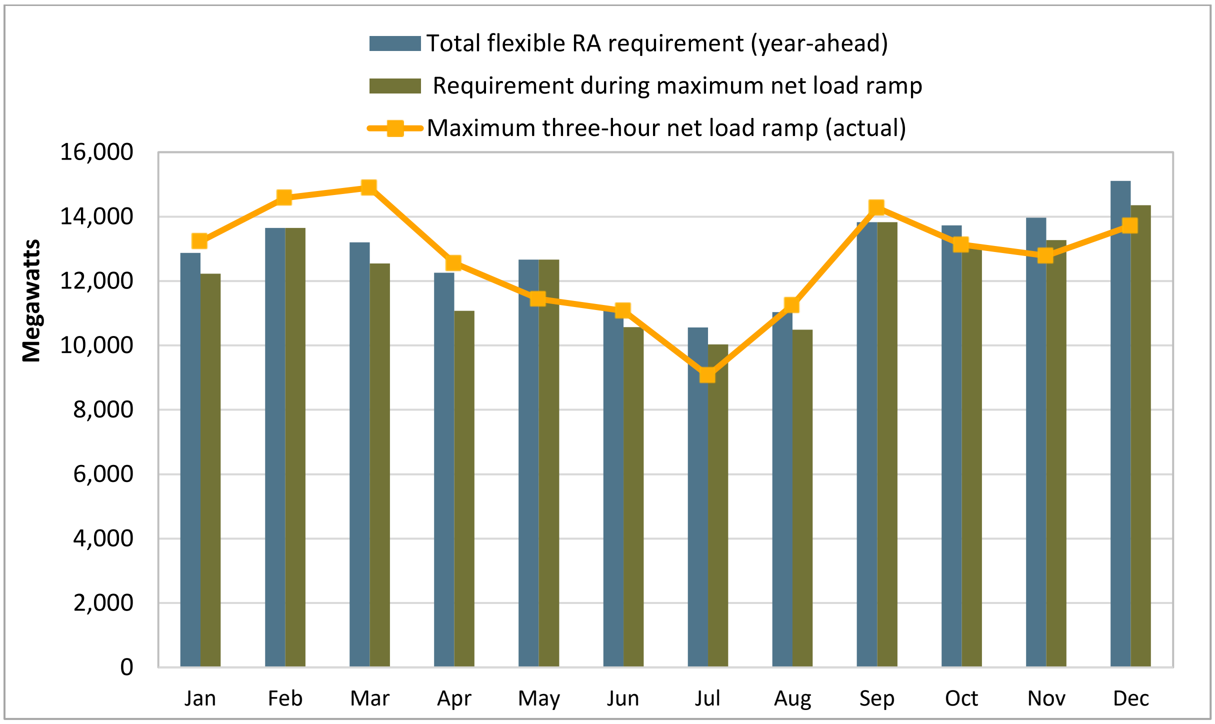
Figure 10.5 investigates how well flexible resource adequacy requirements addressed system load ramping needs in 2018 by comparing the requirements and the actual maximum three-hour net load

[218] The ISO system typically experiences two extended periods of net load ramps, one in the morning and one in the evening. The magnitude and timing of these ramps change throughout the year. The larger of the two three-hour net load ramps (the primary ramp) generally occurs in the evening for non-summer months and in the morning during the summer. The must-offer obligation hours vary seasonally based on this pattern for Category 2 and 3 flexible resource adequacy.

ramp on a monthly basis.[219] In this figure the blue bars represent total three-hour requirements for the month and the gold line represents the maximum three-hour net load ramp. The green bars in the figure represent the requirement *during* the period of the maximum three-hour net load ramp.

Because each category of flexible resource capacity has different must-offer hours, the requirement will effectively differ from day-to-day and hour-to-hour.[220] Figure 10.5 was therefore calculated by first identifying the day and hours the maximum net load ramp occurred, then averaging the flexible capacity requirements for the categories with must-offer obligations during those hours.

Figure 10.5 Flexible resource adequacy requirements during the actual maximum net load ramp



Key findings of this analysis include:

- ***Year-ahead flexible resource adequacy requirements were insufficient to meet the actual maximum three-hour net load ramp for six months in 2018.*** This is shown where the blue bars are lower than the gold line. The maximum three-hour net load ramp in January, February, March, April, August, and September were all greater than the year-ahead requirements set in those months.
- ***Actual flexible resource adequacy requirements set at the time of the peak ramp were insufficient to meet actual maximum three-hour net load ramps for most months***. This is shown when the green bars are lower than the gold line. The maximum three-hour net load ramps in January, February, March, April, June, August, September, and October were all greater than the actual requirements set at the time of the peak ramp set in those months.

[219] Our estimates of the net load ramp may vary slightly from the ISO's calculations because we used 5-minute interval data and the ISO uses one-minute interval data.

[220] For example, because Category 3 resources do not have must-offer obligations on weekends and holidays, the effective requirement during the net load ramps on those days will be less than the total flexible requirement set for the month.

The effectiveness of flexible resource adequacy requirements and must-offer rules in addressing supply during maximum load ramps is very dependent on the ability to predict the size of the maximum net load ramp as well as the time of day the ramp occurs. This analysis suggests that the 2018 requirements and must-offer hours were insufficient in reflecting actual ramping needs.

Table 10.5 provides another comparison of actual net load ramping times to flexible resource adequacy capacity requirements and must-offer hours. The average requirement during the maximum net load ramp is calculated by summing Category 1, 2, and 3 requirements for each of the three hours in the max net load ramp (as applicable) and finding the average.

Table 10.5 Maximum three-hour net load ramp and flexible resource adequacy requirements

Month	Maximum 3-hour net load ramp (MW)	Total flexible RA requirement (MW)	Average requirement during maximum net load ramp (MW)	Date of maximum net load ramp	Ramp start time	Average requirement met ramp? (Y/N)	Why average requirement during max net load ramp was less than the maximum 3-hour net load ramp
Jan	13,230	12,869	12,224	1/28/2018	14:50	N	Total flexible RA requirement less than max ramp; Max ramp occurred on Sunday
Feb	14,578	13,643	13,643	2/23/2018	15:25	N	Total flexible RA requirement less than max ramp
Mar	14,895	13,203	12,543	3/4/2018	15:30	N	Total flexible RA requirement less than max ramp; Max ramp occurred on Sunday
Apr	12,554	12,257	11,071	4/22/2018	16:10	N	Total flexible RA requirement less than max ramp; Max ramp occurred on Sunday; Category 2 requirement ended at 19:00
May	11,438	12,666	12,666	5/15/2018	16:25	Y	
Jun	11,069	11,130	10,571	6/17/2018	16:35	N	Max ramp occurred on Sunday
Jul	9,064	10,561	10,034	7/4/2018	16:25	Y	
Aug	11,251	11,036	10,484	8/26/2018	15:50	N	Max ramp occurred on Sunday
Sep	14,274	13,829	13,829	9/15/2018	15:30	N	Max ramp occurred on Saturday
Oct	13,129	13,732	13,044	10/14/2018	15:35	N	Max ramp occurred on Sunday
Nov	12,785	13,968	13,271	11/11/2018	14:25	Y	
Dec	13,720	15,108	14,353	12/2/2018	14:20	Y	

Key results of this analysis include:

- ***The average requirement during the maximum net load ramp was insufficient to meet the actual maximum three-hour net load ramps in most months***. This occurred during the maximum three-hour net load ramps of January, February, March, April, June, August, September, and October.
- ***For most of the months with insufficient average requirements, the maximum net load ramps occurred at least partially outside of Category 2 and Category 3 must-offer hours***. The maximum net load occurred on either Saturday or Sunday when Category 3 resources do not have must-offer obligations in January, March, April, June, August, September, and October. In addition, the maximum three-hour net load ramp in April occurred from 16:10-19:10 and Category 2 must-offer obligations ended at 19:00 during that month in 2018.

Procurement

Table 10.6 shows what types of resources provided flexible resource adequacy and details the average monthly flexible capacity procurement in 2018 by fuel type. The flexible resource adequacy categories and must-offer rules were designed to be technology neutral allowing for a variety of resources to provide flexibility to the ISO to meet ramping needs. While the CPUC and ISO created counting criteria for a variety of resource types, almost all flexible ramping procurement continued to be composed of natural gas-fired generation in 2018.

Table 10.6 Average monthly flexible resource adequacy procurement by resource type

Resource type	Category 1		Category 2		Category 3	
	Average MW	Total %	Average MW	Total %	Average MW	Total %
Gas-fired generators	10,148	76%	88	13%	2	7%
Use-limited gas units	1,957	15%	597	86%	5	15%
Hydro generators	874	7%	5	1%	0	0%
Geothermal	250	1.9%	0	-	0	-
Energy Storage	38	0.3%	2	0.3%	24	77.1%
Total	13,267	**100%**	692	**100%**	31	**100%**

Key findings of this analysis include:

- ***Most flexible resource adequacy capacity was procured from non-use-limited gas-fired generators***. About 10,000 MW (or 73 percent) of total flexible capacity. This is a slight increase from 2017 when gas-fired generators accounted for about 71 percent of total flexible capacity. Almost all (99 percent) of the capacity supplied by gas-fired generators served as Category 1 resources in 2018.
- ***Use-limited gas units made up the second largest volume of flexible resource adequacy capacity***. These generators made up about 15 percent of Category 1 capacity and 18 percent of overall flexible capacity.
- ***Hydroelectric generators made up the third largest volume of Category 1 flexible resource adequacy capacity***. Hydro generators accounted for about 7 percent of Category 1 capacity, down from about 9 percent in 2017.
- ***Load-serving entities procured significantly less than the maximum allowed amount of Category 3 flexible capacity in 2018***. Load-serving entities procured a monthly average of 31 MW of Category 3 capacity. This is significantly less than the maximum amount that they are allowed to procure, or 5 percent of the total flexible requirement each month.
- ***Energy storage comprised a significant proportion of Category 3 flexible resource adequacy capacity***. Energy storage resources accounted for a small amount of total flexible capacity, but they made up about 77 percent of Category 3 capacity which is a significant increase from 18 percent in 2017. This can be attributed to both an increase in energy storage Category 3 capacity from 15 MW in 2017 to 24 MW in 2018 as well as a large drop in use-limited gas Category 3 capacity from 61 MW in 2017 to 5 MW in 2018.

Table 10.7 shows what types of load-serving entities procure different categories of flexible resource adequacy and details the average monthly flexible capacity procurement in 2018 by load type. Supply plans were used to proportionally assign resource bidding behavior to load-serving entities based on corresponding contracted capacity. Bid availability was then aggregated by load type, depending on whether the entity is a community choice aggregator, direct access service, investor-owned utility, or a municipal/government entity.

Table 10.7 Average monthly flexible resource adequacy procurement by resource type and load type

Load Type	Category 1		Category 2		Category 3	
	Average MW	Total %	Average MW	Total %	Average MW	Total %
CCA	1,398	11%	0	0%	0	0%
DA	1,053	8%	16	2%	4	13%
IOU	10,358	78%	585	85%	20	65%
Muni	458	3%	91	13%	7	23%
Total	**13,267**	**100%**	**692**	**100%**	**31**	**100%**

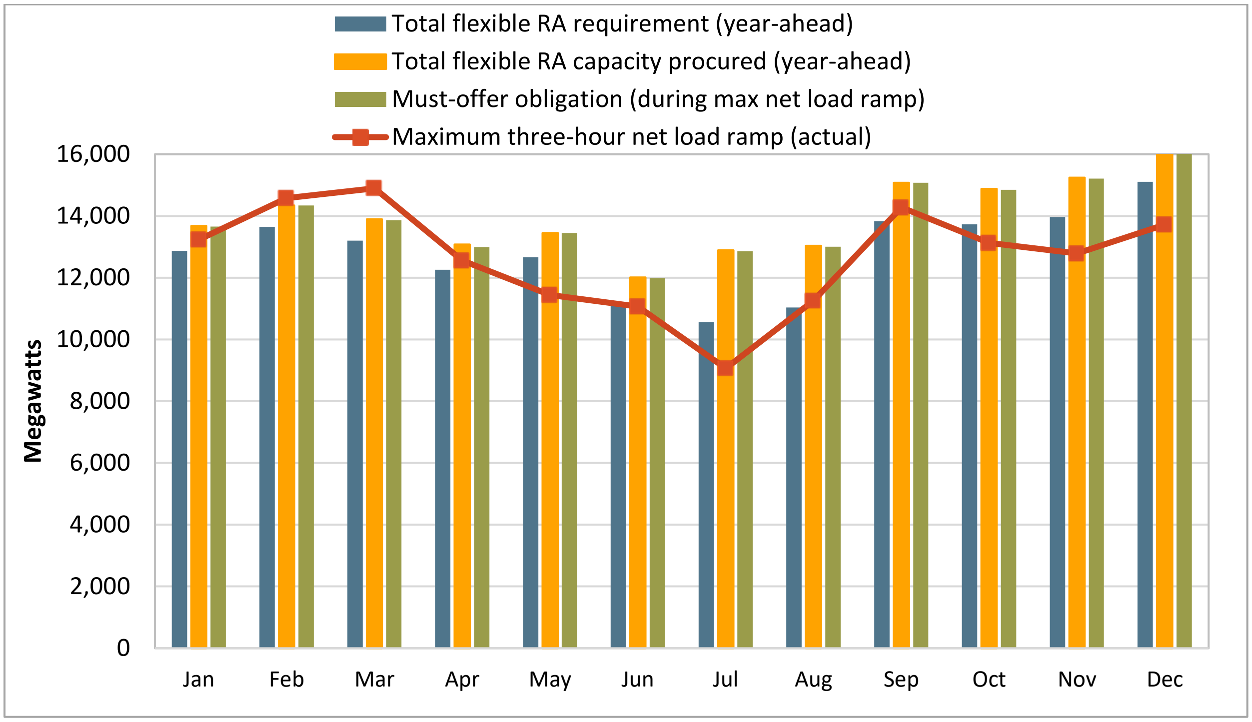
Key findings of this analysis include:

- ***Investor-owned utilities procured the highest proportion of each flexible resource adequacy category***. Investor-owned utilities procured 78 percent of total flexible capacity, community choice aggregators procured 10 percent, direct access services procured 8 percent, and municipals procured 4 percent. Investor-owned utilities procured at least 65 percent of the capacity of each category.
- ***Most load types procured resources for each flexible resource adequacy category***. Investor-owned utilities, direct access services, and municipals procured Category 1, 2, and 3 flexible resource adequacy resources. Community choice aggregators did not procure any Category 2 or Category 3 capacity.
- ***Municipal utilities procured the second highest proportion of Category 2 and Category 3 flexible capacity***. Municipals procured most of their flexible capacity from Category 1 resources, but their highest procurement proportion was for Category 2 (13 percent) and Category 3 (23 percent) resources.

Due in part to greater amounts of Category 1 capacity, total flexible resource adequacy procurement exceeded requirements for all months in 2018. Figure 10.6 builds upon the information presented in Figure 10.5, adding information about the total monthly flexible capacity that was procured by load-serving entities to be compared to requirements, maximum net load ramps, and must-offer obligations. Figure 10.6 shows total monthly flexible requirements and procured capacity, which are determined a year-ahead. It also shows the total capacity that should be offered during the actual maximum three-hour net load ramp.[221] Must-offer obligations differ from the total flexible capacity procured because the actual net load ramps can occur outside of Category 2 and 3 must-offer hours.

[221] The must-offer obligation estimate used in this chart is calculated including long-start and extra-long-start resources regardless of whether or not they were committed in the necessary time frame to actually have an obligation in real time.

Figure 10.6 Flexible resource adequacy procurement during the maximum net load ramp



Key findings of this analysis include:

- ***Year-ahead total flexible resource adequacy procurement exceeded total requirements***. Total flexible resource adequacy procurement (gold bars) exceeded the total requirement (blue bars) in all months of the year.
- ***The must-offer obligation for procured resources during the maximum three-hour net load ramp is lower than total procurement in most months***. Must-offer obligations during maximum net load ramps (green bars) is close to but lower than total procurement (gold bars) in all months except February when it was more than 200 MW less. This suggests that some of the capacity that was procured year-ahead was not obligated to offer during the actual maximum net load ramp hours.
- ***The must-offer obligation for procured capacity was sufficient to meet the maximum net load ramp for most months***. The must-offer obligation during actual maximum net load ramp (green bars) exceeded the actual three-hour net load ramp (red line) for all months except for February and March in 2018.

Availability

Table 10.8 presents an assessment of the availability of flexible resource adequacy capacity in both the day-ahead and real-time markets. For purposes of this analysis, average capacity represents the must-offer obligation of flexible capacity. Availability is measured by assessing economic bids and outages in the day-ahead and real-time markets. For the resources where minimum output qualified as flexible capacity, the minimum output was only assessed as available if no part of the resource was self-scheduled.

Extra-long-start resources are required to participate in the extra-long-start commitment process and economically bid into the day-ahead and real-time markets when committed by this process. For purposes of this analysis, extra-long-start resources were assessed as available in the day-ahead market to the extent that the resource did not have outages limiting its ability to provide its full obligation. Long-start and extra-long-start resources were only assessed in the real-time market analysis if they received schedules in the day-ahead market or the residual unit commitment process. Day-ahead energy schedules are excluded from real-time economic bidding requirements in this analysis, as in the resource adequacy availability incentive mechanism (RAAIM) calculation.

This is a high level assessment of the availability of flexible resource adequacy capacity to the day-ahead and real-time markets in 2018. This analysis is not intended to replicate how availability is measured under the incentive mechanism, which was implemented by the ISO in November 2016.[222] The incentive penalties became financially binding on April 1, 2017.

Table 10.8 Average flexible resource adequacy capacity and availability

Month	Average DA flexible capacity (MW)	Average DA Availability		Average RT flexible capacity (MW)	Average RT Availability	
		MW	% of Capacity		MW	% of Capacity
January	13,147	11,763	89%	9,116	8,430	92%
February	13,913	12,272	88%	10,544	8,901	84%
March	13,306	11,050	83%	9,415	8,112	86%
April	12,644	10,117	80%	9,310	7,882	85%
May	13,049	11,327	87%	9,213	8,281	90%
June	11,444	10,559	92%	7,539	6,763	90%
July	12,304	11,285	92%	8,432	6,839	81%
August	12,527	11,163	89%	7,661	6,428	84%
September	14,705	13,366	91%	8,714	7,535	86%
October	14,136	12,561	89%	10,504	9,442	90%
November	14,846	13,044	88%	10,508	9,279	88%
December	16,009	14,497	91%	11,156	10,039	90%
Total	**13,503**	**11,917**	**88%**	**9,343**	**8,161**	**87%**

Key findings of this analysis include:

- ***Flexible resource adequacy resources had fairly high levels of availability in both the day-ahead and real-time markets in 2018***. Average availability in the day-ahead market was 88 percent and ranged from 80 percent to 92 percent. This is similar to 2017 when average availability in the day-

[222] The RAAIM calculation allows exemptions that are not included in DMM's calculations in Table 10.8. Specifically, the RAAIM calculation exempts resources with Pmax less than 1 MW, non-resource specific imports, some load following meter sub system resources, qualifying facility resources, participating pumping load, reliability must-run resources, use-limited resources approaching or exceeding a registered use limitation and flexible resources that are shown in combination with another resource. In addition, the RAAIM adjusts the obligation of a variable energy resource based on the resource forecast and the portion of effective flexible capacity shown on a monthly flexible resource adequacy showing.

ahead market was about 87 percent with a range from 79 percent to 94 percent. Average availability in the real-time market was 87 percent and ranged from 81 percent to 92 percent. This is an improvement compared to 2017 when average real-time availability was 83 percent and ranged from 79 percent to 88 percent.

- ***The real-time average must-offer obligation is much lower than the day-ahead obligation***. Flexible capacity was almost 14,000 MW in the day-ahead market and only about 9,000 MW in the real-time market on average. This reflects several factors. First, resources may receive ancillary service awards in the day-ahead market covering all or part of their resource adequacy obligation. Second, long-start and extra-long-start resources do not have an obligation in the real-time market if they are not committed in the day-ahead market, residual unit commitment process, or the extra-long-start commitment process. In addition, day-ahead energy awards are excluded from the real-time availability requirement for the incentive mechanism calculation.

Table 10.9 is based on the same data summarized in Table 10.8, but aggregates average flexible resource adequacy availability by the type of load that the resources contracted with. Supply plans were used to proportionally assign resource bidding behavior to load-serving entities based on their corresponding contracted flexible capacity. Bid availability was then aggregated by load type, depending on whether the entity is a community choice aggregator, direct access service, investor-owned utility, or a municipal/government entity.

Table 10.9 Average flexible resource adequacy capacity and availability by load type

Load Type	Average DA flexible capacity (MW)	Average DA Availability		Average RT flexible capacity (MW)	Average RT Availability	
		MW	% of Capacity		MW	% of Capacity
CCA	1,398	1,128	81%	1,100	992	90%
DA	1,069	932	87%	849	780	92%
IOU	10,534	9,409	89%	6,943	5,979	86%
Muni	501	447	89%	451	411	91%
Total	**13,503**	**11,917**	**88%**	**9,343**	**8,161**	**87%**

Key findings from this analysis include:

- ***Flexible resource adequacy resources had similar availability in the day-ahead and real-time markets across load types***. Resources that contracted with investor-owned utilities and municipals had 89 percent availability in the day-ahead market, direct access services had 87 percent availability, and community choice aggregators had the lowest availability at 81 percent. In the real-time market, resources that contracted with direct access services were available 92 percent of the time, municipals had 91 percent availability, community choice aggregators had 90 percent, and investor-owned utilities had 86 percent.

- ***The real-time average must-offer obligation as a proportion of day-ahead obligation was lowest for investor-owned utility flexible resources***. Real-time flexible resource adequacy capacity was about 66 percent of the day-ahead capacity for investor-owned utility resources on average. Real-time flexible capacity was about 79 percent of day-ahead capacity for community choice aggregators and direct access services and 90 percent for municipal utilities.

10.5 Capacity procurement mechanism

Background

The capacity procurement mechanism (CPM) provides backstop procurement authority to ensure that the ISO will have sufficient capacity available to maintain reliable grid operations. This mechanism facilitates pay-as-bid competitive solicitations for backstop capacity and also establishes a price cap at which the ISO can procure backstop capacity to meet resource adequacy requirements that are not met through resource adequacy showings by load-serving entities. This backstop authority should also mitigate the potential exercise of locational market power by resources needed to meet local reliability requirements.

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. Bids may range up to a soft offer cap set at $6.31/kW-month ($75.68/kW-year).

The ISO inserts bids 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, its clearing price is set at the soft offer cap. Resources can also file at FERC for costs that exceed 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 a year-ahead competitive solicitation process using annual bids. The year-ahead 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 of insufficient cumulative capacity in monthly 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.

Annual designations

There were three annual capacity procurement designations in 2018. These were the first annual designations made since the implementation of the current framework in 2016. Table 10.10 shows which resources were designated, megawatts procured, price, estimated cost of the procurement, local area that had insufficient capacity, and the event that triggered the designation and annual costs.

Table 10.10 Annual capacity procurement mechanism costs

Resource	Designated MW	Price ($/kW-mon)	Estimated cost ($ million)	Local capacity area	CPM designation trigger
MOSSLD_2_PSP1	20	$6.31	$1.5	PG&E	Material sub-area deficiency
MOSSLD_2_PSP1	490	$6.19	$36.9	PG&E	Material sub-area deficiency
ENCINA_7_EA4	272	$6.31	$19.7	SDG&E	Material sub-area deficiency
ENCINA_7_EA5	273	$6.31	$19.8	SDG&E	Material sub-area deficiency
Total	1,055		$78.0		

Key findings of this analysis include:

- ***Annual capacity procurement mechanism designations were issued in 2018 to address local resource adequacy deficiencies***. In December 2017, the ISO issued year-ahead designations to address local resource adequacy deficiencies for 2018 in the South Bay-Moss Landing sub-area of the Bay Area local capacity area and the San Diego-Imperial Valley local capacity area. The ISO conducted a local capacity technical study and found there were both individual resource adequacy plan and collective deficiencies in these local capacity areas.[223]
- ***About 1,000 MW of capacity was procured using the annual designations in 2018 at prices at or near the soft offer cap***. The price for 490 MW of the Moss Landing resource was $6.19/kW-month, while the price of 20 MW from the same resource was $6.31/kW-month, i.e., the soft offer cap. The price of the capacity for each Encina unit was the soft offer cap price of $6.31/kW-month. The total estimated cost for annual capacity procurement was about $78 million in 2018.[224]

Intra-monthly and monthly designations

Table 10.11 shows the intra-monthly capacity procurement mechanism designations that occurred in 2018. The table shows which resources were designated, amount of megawatts procured, the date range of the designation, the price, estimated cost of the procurement, the area that had insufficient capacity, and the event that triggered the designation.There were no monthly capacity procurement mechanism designations made in 2018, and there have not been any since the program was implemented in 2016.

[223] In the case of the Encina units, CPM designations were driven by a few specific events. First, the State Water Resources Control board extended Encina Power Station's once-through cooling compliance date. In addition, construction of the Carlsbad Energy Center experienced delays, and a prior CPUC ruling (D.12-04-046) precluded SDG&E from procuring capacity from Encina. These circumstances led the ISO to issue annual CPM designations to the Encina units until the Carlsbad Energy Center could be completed in December 2018 and shown as resource adequacy.

[224] This estimate takes into account forced outages of the Encina units that happened during December 2018.

Table 10.11 Intra-monthly capacity procurement mechanism costs

Resource	Designated MW	CPM Start Date	CPM End Date	CPM Type	Price ($/kW-mon)	Estimated cost ($ mil)	Estimated cost 2018 ($ mil)	Local capacity area	CPM designation trigger
MNDALY_7_UNIT 3	130	12/5/17	2/2/18	ED	$6.31	$1.64	$0.90	SCE	Potential contingency event
MNDALY_7_UNIT 1	215	12/5/17	2/2/18	ED	$6.31	$2.71	$1.49	SCE	Potential contingency event
MNDALY_7_UNIT 2	215	12/5/17	2/2/18	ED	$6.31	$2.71	$1.49	SCE	Potential contingency event
ENCINA_7_EA3	20	5/9/18	7/8/18	ED	$6.31	$0.26	$0.26	SDG&E	Potential thermal overload
BIGCRK_2_EXESWD	64	9/1/18	9/30/18	SIGEVT	$5.07	$0.32	$0.32	SYS	Alternate load forecast
BLACK_7_UNIT 2	84	9/1/18	9/8/18	SIGEVT	$5.50	$0.12	$0.12	SYS	Alternate load forecast
BLACK_7_UNIT 2	84	9/10/18	9/15/18	SIGEVT	$5.50	$0.09	$0.09	SYS	Alternate load forecast
BLACK_7_UNIT 2	84	9/17/18	9/30/18	SIGEVT	$5.50	$0.22	$0.22	SYS	Alternate load forecast
COLEMN_2_UNIT	2	9/1/18	9/30/18	SIGEVT	$5.50	$0.01	$0.01	SYS	Alternate load forecast
ELKHIL_2_PL1X3	12	9/1/18	9/30/18	SIGEVT	$3.25	$0.04	$0.04	SYS	Alternate load forecast
ETIWND_6_GRPLND	46	9/1/18	9/30/18	SIGEVT	$5.07	$0.23	$0.23	SYS	Alternate load forecast
HYTTHM_2_UNITS	60	9/1/18	9/30/18	SIGEVT	$2.00	$0.12	$0.12	SYS	Alternate load forecast
MOSSLD_2_PSP2	29	9/1/18	9/30/18	SIGEVT	$4.25	$0.12	$0.12	SYS	Alternate load forecast
PIT1_7_UNIT 2	8	9/1/18	9/30/18	SIGEVT	$5.50	$0.04	$0.04	SYS	Alternate load forecast
PIT5_7_PL3X4	28	9/1/18	9/30/18	SIGEVT	$5.50	$0.15	$0.15	SYS	Alternate load forecast
PIT6_7_UNIT 1	39	9/1/18	9/8/18	SIGEVT	$5.50	$0.06	$0.06	SYS	Alternate load forecast
PIT6_7_UNIT 1	5	9/9/18	9/9/18	SIGEVT	$5.50	$0.00	$0.00	SYS	Alternate load forecast
PIT6_7_UNIT 1	39	9/10/18	9/22/18	SIGEVT	$5.50	$0.09	$0.09	SYS	Alternate load forecast
PIT6_7_UNIT 1	5	9/23/18	9/23/18	SIGEVT	$5.50	$0.00	$0.00	SYS	Alternate load forecast
PIT6_7_UNIT 1	39	9/24/18	9/30/18	SIGEVT	$5.50	$0.05	$0.05	SYS	Alternate load forecast
PWRX_MALIN500_I_F_ CPM01	210	9/1/18	9/30/18	SIGEVT	$5.00	$1.05	$1.05	SYS	Alternate load forecast
SYCAMR_2_UNIT 1	10	9/1/18	9/30/18	SIGEVT	$5.07	$0.05	$0.05	SYS	Alternate load forecast
SYCAMR_2_UNIT 2	11	9/1/18	9/30/18	SIGEVT	$5.07	$0.06	$0.06	SYS	Alternate load forecast
SYCAMR_2_UNIT 3	10	9/1/18	9/30/18	SIGEVT	$5.07	$0.05	$0.05	SYS	Alternate load forecast
SYCAMR_2_UNIT 4	11	9/1/18	9/30/18	SIGEVT	$5.07	$0.06	$0.06	SYS	Alternate load forecast
HUMBPP_6_UNITS	26	9/10/18	11/8/18	ED	$6.31	$0.32	$0.32	PG&E	Potential thermal overload
ARBWD_6_QF	2	10/1/18	10/30/18	SIGEVT	$3.79	$0.01	$0.01	SYS	Alternate load forecast
BASICE_2_UNITS	89	10/1/18	10/30/18	SIGEVT	$3.79	$0.34	$0.34	SYS	Alternate load forecast
BLACK_7_UNIT 2	2	10/1/18	10/30/18	SIGEVT	$5.50	$0.01	$0.01	SYS	Alternate load forecast
BRODIE_2_WIND	9	10/1/18	10/30/18	SIGEVT	$3.79	$0.03	$0.03	SYS	Alternate load forecast
CARBOU_7_PL4X5	69	10/1/18	10/30/18	SIGEVT	$3.79	$0.26	$0.26	SYS	Alternate load forecast
CARBOU_7_UNIT 1	5	10/1/18	10/30/18	SIGEVT	$3.79	$0.02	$0.02	SYS	Alternate load forecast
CHEVCD_6_UNIT	1	10/1/18	10/30/18	SIGEVT	$3.79	$0.00	$0.00	SYS	Alternate load forecast
CHEVCY_1_UNIT	5	10/1/18	10/30/18	SIGEVT	$3.79	$0.02	$0.02	SYS	Alternate load forecast
COLEMN_2_UNIT	2	10/1/18	10/30/18	SIGEVT	$5.50	$0.01	$0.01	SYS	Alternate load forecast
CONTRL_1_CASAD1	3	10/1/18	10/30/18	SIGEVT	$3.79	$0.01	$0.01	SYS	Alternate load forecast
CONTRL_1_CASAD3	5	10/1/18	10/30/18	SIGEVT	$3.79	$0.02	$0.02	SYS	Alternate load forecast
DIABLO_7_UNIT 1	471	10/1/18	10/30/18	SIGEVT	$3.79	$1.78	$1.78	SYS	Alternate load forecast
DIABLO_7_UNIT 2	977	10/1/18	10/30/18	SIGEVT	$3.79	$3.70	$3.70	SYS	Alternate load forecast
DSABLA_7_UNIT	2	10/1/18	10/30/18	SIGEVT	$3.79	$0.01	$0.01	SYS	Alternate load forecast
ELECTR_7_PL1X3	36	10/1/18	10/30/18	SIGEVT	$3.79	$0.14	$0.14	SYS	Alternate load forecast
ENCINA_7_EA2	104	10/1/18	10/30/18	SIGEVT	$3.47	$0.36	$0.36	SYS	Alternate load forecast
ENCINA_7_EA3	110	10/1/18	10/30/18	SIGEVT	$2.98	$0.33	$0.33	SYS	Alternate load forecast
ENCINA_7_EA4	28	10/1/18	10/30/18	SIGEVT	$3.96	$0.11	$0.11	SYS	Alternate load forecast
ENCINA_7_EA5	57	10/1/18	10/30/18	SIGEVT	$3.96	$0.23	$0.23	SYS	Alternate load forecast
ENCINA_7_GT1	15	10/1/18	10/30/18	SIGEVT	$3.96	$0.06	$0.06	SYS	Alternate load forecast
ETIWND_6_GRPLND	46	10/1/18	10/30/18	SIGEVT	$5.07	$0.23	$0.23	SYS	Alternate load forecast
FELLOW_7_QFUNTS	1	10/1/18	10/30/18	SIGEVT	$3.79	$0.01	$0.01	SYS	Alternate load forecast

FLOWD2_2_FPLWND	2	10/1/18	10/30/18	SIGEVT	$3.79	$0.01	$0.01	SYS	Alternate load forecast
HATCR2_7_UNIT	2	10/1/18	10/30/18	SIGEVT	$3.79	$0.01	$0.01	SYS	Alternate load forecast
HATRDG_2_WIND	9	10/1/18	10/30/18	SIGEVT	$3.79	$0.03	$0.03	SYS	Alternate load forecast
JAWBNE_2_NSRWND	14	10/1/18	10/30/18	SIGEVT	$3.79	$0.05	$0.05	SYS	Alternate load forecast
MNDALY_6_MCGRTH	47	10/1/18	10/30/18	SIGEVT	$3.39	$0.16	$0.16	SYS	Alternate load forecast
MOSSLD_2_PSP2	29	10/1/18	10/30/18	SIGEVT	$4.25	$0.12	$0.12	SYS	Alternate load forecast
MOSSLD_2_PSP2	7	10/1/18	10/30/18	SIGEVT	$6.00	$0.04	$0.04	SYS	Alternate load forecast
PEABDY_2_LNDFL1	5	10/1/18	10/30/18	SIGEVT	$3.79	$0.02	$0.02	SYS	Alternate load forecast
PIT1_7_UNIT 1	7	10/1/18	10/30/18	SIGEVT	$3.79	$0.02	$0.02	SYS	Alternate load forecast
PIT1_7_UNIT 2	8	10/1/18	10/30/18	SIGEVT	$5.50	$0.04	$0.04	SYS	Alternate load forecast
PIT4_7_PL1X2	25	10/1/18	10/30/18	SIGEVT	$3.79	$0.09	$0.09	SYS	Alternate load forecast
PIT5_7_PL3X4	28	10/1/18	10/30/18	SIGEVT	$5.50	$0.15	$0.15	SYS	Alternate load forecast
PIT6_7_UNIT 1	39	10/1/18	10/30/18	SIGEVT	$5.50	$0.21	$0.21	SYS	Alternate load forecast
PIT6_7_UNIT 2	37	10/1/18	10/30/18	SIGEVT	$3.79	$0.14	$0.14	SYS	Alternate load forecast
PIT7_7_UNIT 1	51	10/1/18	10/30/18	SIGEVT	$3.79	$0.19	$0.19	SYS	Alternate load forecast
PIT7_7_UNIT 2	51	10/1/18	10/30/18	SIGEVT	$3.79	$0.19	$0.19	SYS	Alternate load forecast
PWRX_MALIN500_I_F_ CPM01	500	10/1/18	10/30/18	SIGEVT	$5.00	$2.50	$2.50	SYS	Alternate load forecast
RTREE_2_WIND2	2	10/1/18	10/30/18	SIGEVT	$3.79	$0.01	$0.01	SYS	Alternate load forecast
SALTSP_7_UNITS	6	10/1/18	10/30/18	SIGEVT	$3.79	$0.02	$0.02	SYS	Alternate load forecast
SISQUC_1_SMARIA	1	10/1/18	10/30/18	SIGEVT	$3.79	$0.00	$0.00	SYS	Alternate load forecast
SOUTH_2_UNIT	2	10/1/18	10/30/18	SIGEVT	$3.79	$0.01	$0.01	SYS	Alternate load forecast
SPBURN_2_UNIT 1	5	10/1/18	10/30/18	SIGEVT	$3.79	$0.02	$0.02	SYS	Alternate load forecast
SPIAND_1_ANDSN2	4	10/1/18	10/30/18	SIGEVT	$3.79	$0.02	$0.02	SYS	Alternate load forecast
SPQUIN_6_SRPCQU	5	10/1/18	10/30/18	SIGEVT	$3.79	$0.02	$0.02	SYS	Alternate load forecast
SUNSHN_2_LNDFL	6	10/1/18	10/30/18	SIGEVT	$3.79	$0.02	$0.02	SYS	Alternate load forecast
TIGRCK_7_UNITS	3	10/1/18	10/30/18	SIGEVT	$3.79	$0.01	$0.01	SYS	Alternate load forecast
TXMCKT_6_UNIT	1	10/1/18	10/30/18	SIGEVT	$3.79	$0.00	$0.00	SYS	Alternate load forecast
UNCHEM_1_UNIT	2	10/1/18	10/30/18	SIGEVT	$4.00	$0.01	$0.01	SYS	Alternate load forecast
VOLTA_2_UNIT 1	2	10/1/18	10/30/18	SIGEVT	$3.79	$0.01	$0.01	SYS	Alternate load forecast
WESTPT_2_UNIT	8	10/1/18	10/30/18	SIGEVT	$3.79	$0.03	$0.03	SYS	Alternate load forecast
BLACK_7_UNIT 2	2	10/31/18	10/31/18	SIGEVT	$5.50	$0.00	$0.00	SYS	Alternate load forecast
BLACK_7_UNIT 2	84	11/1/18	11/29/18	SIGEVT	$5.50	$0.45	$0.45	SYS	Alternate load forecast
COLEMN_2_UNIT	2	10/31/18	11/29/18	SIGEVT	$5.50	$0.01	$0.01	SYS	Alternate load forecast
ETIWND_6_GRPLND	46	10/31/18	11/29/18	SIGEVT	$5.07	$0.23	$0.23	SYS	Alternate load forecast
MOSSLD_2_PSP2	29	10/31/18	11/29/18	SIGEVT	$4.25	$0.12	$0.12	SYS	Alternate load forecast
PIT1_7_UNIT 2	8	10/31/18	11/29/18	SIGEVT	$5.50	$0.04	$0.04	SYS	Alternate load forecast
PIT5_7_PL3X4	28	10/31/18	11/29/18	SIGEVT	$5.50	$0.15	$0.15	SYS	Alternate load forecast
PIT6_7_UNIT 1	39	10/31/18	11/29/18	SIGEVT	$5.50	$0.21	$0.21	SYS	Alternate load forecast
PWRX_MALIN500_I_F_ CPM01	210	10/31/18	11/29/18	SIGEVT	$5.00	$1.05	$1.05	SYS	Alternate load forecast
HUMBPP_1_UNITS3	16	11/12/18	1/10/19	ED	$6.31	$0.20	$0.17	PG&E	Potential thermal overload
HUMBPP_6_UNITS	12	11/14/18	1/12/19	ED	$6.31	$0.16	$0.13	PG&E	Potential thermal overload
STANIS_7_UNIT 1	5	11/28/18	1/26/19	ED	$6.31	$0.07	$0.04	PG&E	Potential thermal overload
Total	4,694					$25.16	$21.89		

Key findings of this analysis include:

- ***About 4,700 MW of capacity was procured with an estimated cost of about $22 million in 2018.*** Intra-monthly designations were triggered by exceptional dispatches and a significant event to address potential contingency events, potential thermal overloads, and an alternate load forecast.

- ***Most designations in 2018 were due to a significant event triggered by an alternate load forecast***. About 4,000 MW (costing $17 million) of backstop capacity was procured for system reliability needs. The designations were made initially for the month of September with extensions and increased procurement through October and November. The event was issued in light of an alternate load forecast presented by California Energy Commission staff which projected higher peak loads than the load forecast used to set resource adequacy requirements. The significant event designations were calculated as the difference between the requirements of the alternate load forecast (including the planning reserve margin) and the quantity of resource adequacy capacity shown for the months of September, October, and November.
- ***About 190 MW of capacity was procured in the SCE area to address a potential multiple contingency event***. The ISO issued the capacity procurement mechanism designation to manage transmission conditions and load serving capability due to the Thomas fire. This procurement cost about $7 million overall with about $4 million of the total costs occurring in 2018.
- ***About 80 MW of capacity was procured to address potential thermal overloads in 2018***. 20 MW (costing $0.26 million) of this capacity was procured in the SDG&E TAC area while the remaining 60 MW (costing $0.65 million in 2018) was procured in the PG&E area.
- ***Several intra-monthly designations were declined***. Scheduling coordinators who receive an exceptional dispatch for capacity not designated through the resource adequacy process may choose to decline the designation by contacting the ISO through appropriate channels within 24 hours of the designation. A scheduling coordinator may choose to decline a designation to avoid the associated must-offer obligation, which could reduce capacity costs passed to a single transmission access charge area or to the system as a whole.

10.6 Reliability must-run contracts

From 1998 through 2007, reliability must-run contracting played a significant role in the ISO, ensuring the reliable operation of the grid. In 2007, the CPUC's resource adequacy program became effective and provided a cost-effective alternative to reliability must-run contracting by the ISO. In late 2017, however, capacity designated as being subject to reliability must-run contracts during 2018 increased sharply.

In 2017, three new efficient gas units that represent almost 700 MW were designated by the ISO to provide reliability must-run service beginning in 2018.[225]

In 2018, about 600 MW of the 700 MW of gas-fired generation designated by the ISO to provide reliability must-run service during 2018 was not re-designated for reliability must-run service in 2019. The need to designate the Metcalf Energy Center as a reliability must-run unit was eliminated by transmission upgrades completed in December 2018 and January 2019, with Metcalf Energy Center returning as a resource adequacy unit in 2019. Moreover, in 2018 the ISO designated one unit at the Ormond Beach Generating Station and Ellwood Energy Support Facility as reliability must-run units (aggregating 800 MW) extending the life of the units to the retirement dates originally considered in

[225] These included 593 MW of capacity from the combined cycle Metcalf Energy Center, and 94 MW of peaking capacity owned by Calpine.

system planning. These units were later picked up in the resource adequacy program, obviating the need for reliability must-run contracts.

In 2018, the ISO also initiated a stakeholder process aimed at reforming the current reliability must-run policy. DMM has provided several recommendations to improve the ISO's reliability must-run policy and ensure it functions well in conjunction with the CPUC's resource adequacy program (see Chapter 11). The new tariff provisions resulting from the stakeholder process were filed on April 22, 2019.

11 Recommendations

As the ISO's independent market monitor, one of DMM's key duties is to provide recommendations on current market issues and new market design initiatives to the ISO, the ISO Governing Board, FERC staff, the California Public Utilities Commission, market participants, and other interested entities.[226]

DMM participates in the ISO's stakeholder process and provides recommendations in written comments submitted in this process. DMM also provides written recommendations in quarterly, annual and other special reports, which are also posted on the ISO's website.[227] This chapter summarizes DMM's current recommendations on key market design initiatives and issues.

11.1 Bid caps used in mitigation

Bid caps for start-up and minimum load commitment costs currently include a 25 percent *headroom scalar* above estimated costs. Default energy bids (DEBs) used when energy price mitigation is triggered include a 10 percent headroom scalar that is applied above marginal costs. In early 2018, the ISO completed proposed changes in the bid caps used in mitigation under the commitment cost and default energy bid enhancements (CCDEBE) proposal. The CCDEBE proposal includes numerous provisions that will allow higher bid caps for gas-fired units used in mitigation of start-up, minimum load and energy bids.

Under the CCDEBE proposal, bid caps for gas-fired units in both the day-ahead and real-time market will continue to be based on gas prices in the next-day market that occurs the day prior to each operating day. However, the ISO would allow participants to request increases in cost-based bid caps if they believe their actual gas costs exceed the 25 percent and 10 percent headroom already included in commitment cost and energy bid caps, respectively.

The ISO will screen participants' requests for higher bids caps prior to real-time market operation based on *reasonableness thresholds*. Requests to increase bids used in mitigation up to these reasonableness thresholds will be automatically approved and used in the market to determine prices and dispatches. Requests to increase bids used in mitigation in excess of the reasonableness thresholds will be capped at the threshold and used in the market to determine prices and dispatches. Requests for increases above the thresholds will be subject to *ex post* cost justification and payment if verified.

Under the ISO's final 2018 CCDEBE proposal, reasonableness thresholds would be set at a level that reflects a gas price that is 10 percent higher than the next-day gas price index. The ISO refers to this increase in the gas price used in calculating the reasonableness threshold as a *fuel volatility scalar*. On Mondays (or the first trade day after a holiday) the ISO would set this fuel volatility scalar to 25 percent. This proposal was approved by the Board in March 2018.

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[226] Tariff Appendix P, ISO Department of Market Monitoring, Section 5.1. http://www.caiso.com/Documents/AppendixP_CAISODepartmentOfMarketMonitoring_asof_Apr1_2017.pdf

[227] See Market Monitoring Reports and Presentations at: http://www.caiso.com/market/Pages/MarketMonitoring/MarketMonitoringReportsPresentations/Default.aspx#CommentsRegulatory

DMM opposed the ISO's final 2018 CCDEBE proposal for a number of reasons, as summarized in DMM's stakeholder comments and memo to the ISO Board on this initiative.[228] One of these reasons was that bid caps for gas-fired units in the real-time market would continue to be based on gas prices in the next-day gas market and that the gas volatility scalars used to set reasonableness thresholds would be statically set at 25 percent on Monday and 10 percent other days.

Analysis of gas prices by DMM shows that during almost all days the additional 10 to 25 percent headroom provided through the new gas volatility scalar would not be justified by actual same-day gas market prices. Meanwhile, on the very few days each year that same-day gas prices rise above the 10 to 25 percent headroom already incorporated in bid caps, the additional 10 to 25 percent headroom allowed by the static 10 percent and 25 percent gas volatility scalars proposed by the ISO would usually be below levels that may be justified based on actual same-day gas market prices.[229]

DMM has continued to recommend a more dynamic approach for adjusting reasonableness thresholds based on same-day gas market trade data available at the start of each operating day. DMM has also provided analysis showing that when the price of gas in the same-day market increases significantly relative to the next-day gas index used by the ISO, the same-day market at major gas trading hubs is sufficiently liquid and provides a very accurate basis for adjusting the reasonableness thresholds.[230]

The ISO has not yet filed the CCDEBE proposal at FERC and has delayed implementation of the proposal until at least fall 2019. In early 2019, the ISO modified the proposal to include a provision that will allow the ISO to update the reasonableness thresholds used to set real-time market bid caps using same-day gas market trade prices. Under the modified proposal, the fuel volatility scalar used to determine reasonableness thresholds will be set to 10 percent and can be updated if same-day gas market prices rise more 10 percent above the next-day gas index used to set caps.[231] The revised proposal also allows EIM participants which do not procure gas in liquid trading points to request customized bid cap increases based on other supporting documentation.

The more dynamic approach for determining reasonableness thresholds recommended by DMM that is being proposed by the ISO in 2019 will ensure greater market efficiency, reliability and more accurate mitigation than the very static approach approved by the ISO Board in 2018.

11.2 Dynamic mitigation of commitment costs

Start-up and minimum load bids for gas-fired units are currently capped at 125 percent of estimated costs. Commitment costs include fuel and variable O&M costs, as well as major maintenance adders

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[228] *Department of Market Monitoring Comments on CCDEBE Proposal,* Memo to ISO Board of Governors, Eric Hildebrandt, March 14, 2018. http://www.caiso.com/Documents/Decision_CCDEBEProposal-Department_MarketMonitoringMemo-Mar2018.pdf

Comments on Revised Draft Final Proposal for Commitment Cost and Default Energy Bid Enhancements, Department of Market Monitoring, February 28, 2018. http://www.caiso.com/Documents/DMMComments-CommitmentCostsandDefaultEnergyBidEnhancementsRevisedDraftFinalProposal.pdf

[229] Memo to ISO Board of Governors, Eric Hildebrandt, March 14, 2018. *pp. 5-6. http://www.caiso.com/Documents/Decision_CCDEBEProposal-Department_MarketMonitoringMemo-Mar2018.pdf*

[230] Memo to ISO Board of Governors, Eric Hildebrandt, March 14, 2018. Attachment A, pp.10-14.

[231] *Local Market Power Mitigation Enhancements Draft Final Proposal*, California ISO, January 31, 2019, pp. 43-46. http://www.caiso.com/Documents/DraftFinalProposal-LocalMarketPowerMitigationEnhancements-UpdatedJan31_2019.pdf

which reflect longer term variable maintenance costs that are incurred once a gas unit reaches a certain number of starts and/or run hours.[232]

Under the final CCDEBE proposal approved by the ISO Board in 2018, commitment costs would be mitigated using a dynamic structural test of potential market power based on system and market conditions during that time interval (e.g., hour or 15-minute interval). Under the proposal, a 3-pivotal supplier test will be used to assess if the supply of capacity needed to meet a constraint is uncompetitive.

Under this proposal, if supply for a capacity constraint is structurally uncompetitive, then commitment cost bids would be capped at current levels (i.e., 125 percent of estimated costs plus the additional headroom provided by the new fuel volatility scalar). Otherwise, start-up and minimum load bids will be subject to a higher cap of about 187 percent of estimated costs.[233] After 18 months, the cap for resources not deemed to have potential market power will be increased to at least 330 percent of costs, and the caps for resources deemed to have potential market power will be lowered to 110 percent of costs.

In 2019, the ISO announced that its proposal for dynamic mitigation of commitment costs will be delayed until at least 2020. DMM supports development of a more dynamic approach to mitigation of commitment costs as a way of allowing more bidding flexibility. While the ISO's final CCDEBE proposal includes the basic framework for dynamic mitigation of commitment costs, DMM believes the final proposal still has several significant gaps, implementation uncertainties and risks.

- **Economic withholding**. Under the revised final proposal, units that are not committed will often not be subject to mitigation of commitment costs – even if the resource owner has been determined to have structural market power. This means that dynamic mitigation will fail to mitigate economic withholding (e.g., bidding lower cost units at a higher price, so that a higher cost unit must be dispatched).

- **Manual dispatches and intervention by grid operators**. The ISO proposal fails to ensure mitigation for exceptional dispatches or any commitments (or blocking of de-commitments) that occur as a result of various forms of manual intervention in the market dispatch by grid operators. DMM's experience indicates that in many or most cases when operators cause units to be committed or transitioned, operators have very little choice between different resources to meet reliability or market needs. If such alternatives exist, operators have limited ability to identify and choose the lowest cost option.

- **Inter-temporal constraints and gaming.** The ISO's proposal does not ensure mitigation will be triggered when units are committed or prevented from getting de-committed due to inter-temporal modeling and resource constraints. A specific example of this gap is provided in DMM's comments on the ISO's final proposal.[234]

[232] In 2019, the ISO also plans to implement the option for including *opportunity cost adders* which reflect marginal opportunity costs per start or run hour for units with regulatory limits on start-up or run hours.

[233] Memo to ISO Board of Governors, Eric Hildebrandt, March 14, 2018. Attachment A, pp. 2-3.

[234] *Comments on Revised Draft Final Proposal for Commitment Cost and Default Energy Bid Enhancements,* pp. 18-19.

DMM also notes that relatively complicated software changes, such as the ISO's dynamic mitigation proposal, are subject to significant implementation errors and unexpected performance issues.[235] The complexity of dynamic mitigation of commitment costs warrants a more cautious approach to raising the commitment cost bid caps. Thus, DMM also recommends that commitment cost bid caps be raised on a more gradual basis only after the effectiveness of dynamic mitigation is confirmed based on actual operational experience.

11.3 Opportunity cost adders for start-up and minimum load bids

In early 2016 the ISO gained Board approval of several changes to the way that commitment costs for natural gas units are calculated as part of its commitment cost enhancements phase 3 (CCE3) initiative.[236] The CCE3 proposal includes the option to include opportunity cost adders in commitment cost bid caps for use-limited resources to reflect the potential opportunity costs associated with any limits on start-up or run hours of individual resources.

The ISO's final CCE3 proposal included a provision that would allow opportunity costs to be calculated based on start-up or run hour limits included in commercial contracts (rather than representing actual physical or environmental limits). The proposal will allow contractual limitations to qualify a resource for the opportunity cost adder for three years after the proposed revisions go into effect (which has now been delayed to at least 2019). The ISO has indicated it will review this issue and may extend this exemption beyond the initial three year period.

The proposed exemption for contractual use limitations reverses what the ISO itself describes as "its longstanding position that economic limitations such as those originating from contracts, such as power purchase or tolling agreements, are not acceptable limitations for establishing an opportunity cost adder under the resources bid cap."[237] To the extent these contractual limitations may reflect actual physical or environmental limits, it is more efficient and appropriate to incorporate any actual physical or environmental limits directly into unit operating constraints or opportunity cost bid adders.

Some contract limitations may be designed to limit maintenance costs associated with starting up and running a unit. The ISO market is explicitly designed so that any incremental maintenance costs associated with starting up and operating a unit can be incorporated directly in commitment cost bids through major maintenance adders (MMAs). These adders represent the only efficient and appropriate way to incorporate any incremental maintenance costs associated with starting up and operating resources into unit commitments.

DMM supports developing an approach for incorporating any opportunity costs associated with environmental or physical limits on start-ups or run hours into commitment cost bids. However, DMM does not support the exemption for contractual use limitation on the grounds that it is inefficient and

[235] Recent examples of such errors and unintended performance issues in the real-time market include (1) the flexible ramping product implemented in 2016, (2) the new dynamic energy bid mitigation implemented in 2016 and 2017, and (3) the Aliso Canyon gas constraint implemented in 2016 and 2017.

[236] *Commitment Cost Enhancements Phase 3 Draft Final Proposal*, February 17, 2016: http://www.caiso.com/Documents/DraftFinalProposal-CommitmentCostEnhancementsPhase3.pdf.

[237] *Commitment Cost Enhancements Phase 3 Revised Straw Proposal*, November 3, 2015, p. 8, http://www.caiso.com/Documents/RevisedStrawProposal-CommitmentCostEnhancementPhase3. pdf

inequitable to treat contractual limitations as actual physical or environmental limitations when calculating bids caps used in the market optimization.[238]

In 2018, the ISO filed a tariff amendment to implement opportunity cost bid adders. The ISO's proposal for opportunity cost adders was approved by FERC in June 2018. However, as noted by the Commission:

> .. we find that CAISO's proposed limited three-year exemption period for contractual limitations strikes a reasonable balance between requiring load-serving entities to renegotiate their contracts immediately and allowing contractual limitations to qualify for the entire life of the contracts. *Although CAISO commits to evaluate potential market and reliability impacts if the provisions were to be extended, we view three years as an adequate length of time for the load-serving entities to renegotiate their contracts*. [emphasis added] [239]

The ISO has not firmly committed to a clear end date for this initial three year period allowing opportunity cost adders for contractual limitations. The opinion of the Market Surveillance Committee (MSC), comments by the CPUC, and some other stakeholders, suggest that this exemption should be extended beyond three years to the life of these contracts. DMM therefore recommends that the ISO provide participants with a clear indication that the initial three year extension will not be further extended.

11.4 Gas usage nomograms

In 2016, the ISO gained temporary authority from FERC to help address the limited operability of the Aliso Canyon gas storage facility by enforcing a maximum gas constraint (or nomogram) for groups of units in the SoCalGas system. In 2018, DMM supported the ISO's request for extension of this temporary authority through 2019.

However, market performance during the limited times the ISO has utilized maximum gas constraints shows that this measure can increase market costs significantly and should be more effectively designed and implemented in order to help ensure reliability. DMM continues to recommend that the ISO refine how it utilizes the maximum gas constraint and improve how gas usage constraint limits are set and adjusted in real-time.

For example, while gas usage constraints are modeled as 15-minute constraints in the ISO's real-time market, these gas constraints are actually applicable only over a much longer daily multi-hour time period. Although operators are able to adjust constraints in real-time in response to changing conditions, the ISO does not appear to adjust these constraints in real time based on actual gas usage in prior hours. Therefore, when the gas constraints bind in the day-ahead or real-time market during the peak ramping hours, there appears to be surplus gas from hours prior in the day when actual usage was well below the constraint as modeled by the ISO.

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[238] See *Motion to intervene and protest of the Department of Market Monitoring*, ER18-1169. April 13, 2018. http://www.caiso.com/Documents/Apr13_2018_DMMIntervention_Protest-CCEPhase3TariffAmendment_ER18-1169.pdf

[239] *Order Accepting in Part, Subject to Condition, and Rejecting in Part, Proposed Tariff Revisions*, ER18-1169, June 21, 2018. http://www.caiso.com/Documents/Jun21_2018_OrderAccepting_Part_Subject_Condition_Rejecting_PartTariffAmendment-CCEPhase3_ER18-1169.pdf

DMM has provided empirical examples of when this issue has occurred in the day-ahead and real-time markets in comments filed at FERC on the ISO's requests to extend its authority to use the gas nomograms.[240] This represents a significant flaw that remains in the gas nomograms. Thus, DMM continues to recommend that the ISO improve how gas usage constraint limits are set and adjusted in real-time based on actual gas usage in prior hours.

In November 2018, FERC issued an order extending the ISO's temporary authority to apply gas usage constraints to help manage gas limitations in the SoCalGas system. FERC's order indicated that:

> While we find that there is merit to DMM's suggestion that the maximum gas burn constraint could be improved through additional refinement in how it is set and managed, such a proposal is not before us …. However, we encourage CAISO to work towards additional refinement of the software and operational process through which the maximum gas burn constraint is implemented.[241]

Since the ISO's authority to implement gas usage constraints was extended in November 2018, the ISO has only utilized these gas constraints during 16 days in the winters of 2018 and 2019. Based on this most recent experience, DMM continues to recommend that the ISO refine how it utilizes the maximum gas constraint and improve how gas usage constraint limits are set and adjusted in real-time.

11.5 Congestion revenue rights

Since the start of the ISO's congestion revenue rights (CRR) auction in 2009, payouts to non-load-serving entities purchasing congestion revenue rights have exceeded the auction revenues by over $866 million. These losses are borne by transmission ratepayers since these congestion revenue rights would otherwise be credited back to transmission ratepayers. Most of this $866 million has gone to purely financial entities. These losses have not declined over time, and actually increased to about $100 million in 2017 and $131 million in 2018.

In 2018, FERC approved a set of changes to the congestion revenue rights auction process which will reduce the number and pairs of nodes at which congestion revenue rights can be purchased in the auction (Track 1A).[242] FERC also approved a second set of changes which would reduce the net payment to a congestion revenue right holder if payments to congestion revenue rights exceed associated congestion charges collected in the day-ahead market on a targeted constraint-by-constraint basis (Track 1B).[243]

[240] See example in *Comments of the Department of Market Monitoring for the California Independent System Operator*, ER18-2520, October 19, 2018, pp.24-25. . http://www.caiso.com/Documents/CommentsoftheDepartmentofMarketMonitoirng-Aliso4-Oct192018.pdf

Also see example in *Comments of the Department of Market Monitoring of the California Independent System Operator*, ER17-2568, October 26, 2017, pp 15-17. http://www.caiso.com/Documents/Oct26_2017_DMMComments-AlisoCanyonElectric-GasCoordinationPhase3_ER17-2568.pdf

[241] *Order on Tariff Revisions*, ER18-2520-00, November 26, 2018, ¶ 52 page 20. http://www.caiso.com/Documents/Nov26-2018-Order-TariffRevisions-AlisoCanyonGas-ElectricCoordinationPhase4-ER18-2520.pdf

[242] *Tariff Amendment to Increase Efficiency of Congestion Revenue Rights Auctions*, California Independent System Operator Corporation, ER18- 1344, April 11, 2018. http://www.caiso.com/Documents/Apr11_2018_TariffAmendment-CRRAuctionEfficiencyTrack1A_ER18-1344.pdf

[243] *Tariff Amendment to Increase Efficiency of Congestion Revenue Rights Auctions*, California Independent System Operator Corporation, ER18- 2034, July 17, 2018. http://www.caiso.com/Documents/Jul17_2018_TariffAmendment-CRRAuctionEfficiencyTrack1B_ER18-2034.pdf

DMM supports the various measures implemented by the ISO starting in the 2019 congestion revenue rights auction as incremental improvements that are likely to help partially address the very large losses being imposed on transmission ratepayers from the auction. However, if the ISO believes it is beneficial to facilitate financial hedging of transmission costs in the ISO markets, DMM continues to recommend that the ISO begin to develop an approach based on a voluntary market for financial contracts that is cleared with bids from willing buyers and sellers – rather than being funded by congestion revenues that are otherwise refunded to transmission ratepayers.

11.6 System market power

In 2018, DMM recommended that the ISO begin to consider various actions that might be taken to reduce the likelihood of conditions in which system market power may exist and to mitigate the impacts of system market power on market costs and reliability. DMM recognizes that this recommendation involves major market design and policy issues, including the possible development of new market design options to mitigate potential system market power. DMM also recognizes that the competitiveness of the ISO's markets is heavily affected by the procurement decisions of the state's load-serving entities and policies of their local regulatory authorities.

Because of the potential severity of the impact of market power, DMM has made this recommendation at this time so that the ISO, stakeholders and regulatory entities can give thorough consideration to this issue and potential options to address it. DMM has provided some initial suggestions for actions for reducing and mitigating the potential for system market power that might be considered. These include the following:

- Begin consideration of options for system market power mitigation.
- Set local and system resource adequacy requirements sufficiently high to ensure both reliability and reduced likelihood of non-competitive market outcomes.
- Reexamine resource adequacy provisions relating to imports, which are only required to be bid into the day-ahead market (at any price) and do not have any further obligation if not scheduled in the day-ahead energy or residual unit commitment process.
- Eliminate or reduce exemptions to must-offer obligations for resources procured to satisfy resource adequacy requirements or through ISO backstop capacity procurement (RMR and CPM).
- Strengthen the penalties and the enforcement of the penalties for must-offer obligations.
- Carefully track and seek to limit out-of-market purchases of imports at above-market prices, which can encourage economic and physical withholding of available imports.
- Closely monitor for potential errors or software issues affecting market power mitigation.

In 2018, the ISO initiated a process to analyze the structural competitiveness of the ISO system, and, depending on results of this analysis, consider options for mitigating system market power.[244]

[244] Stakeholder process information is available here: http://www.caiso.com/informed/Pages/StakeholderProcesses/SystemMarketPower.aspx

11.7 Reliability must-run units

Mandatory backstop procurement serves two functions: ensuring reliability and mitigating the market power of units needed for reliability. The ISO must be able to procure and compensate capacity needed to ensure local and system reliability. However, since owners of capacity needed to ensure reliability have market power, such compensation must be subject to mitigation to ensure just and reasonable rates.

Resources designated as reliability must-run units by the ISO have the option of selecting Condition 2 of the ISO's *pro forma* reliability must-run contract. Under Condition 2, units receive fixed payments that cover all going forward costs of service plus recovery of full fixed (sunk) costs plus a 12 percent return on equity. The contract refers to that as a unit's *annual fixed revenue requirement* (AFRR).

When dispatched to operate by the ISO, units under Condition 2 are reimbursed for operating costs, with any net market revenues being used to offset the AFRR payments to the unit. However, the current Condition 2 contract severely restricts when units can be dispatched to operate — even when it would be economic do so. This creates market inefficiency and is inequitable for ratepayers who pay the AFRR payments of the unit.

In November 2017, DMM and numerous other entities filed protests at FERC on the grounds that provisions of reliability must-run Condition 2 contracts are "economically inefficient, distort overall market prices, undermine the CAISO's automated market power mitigation procedures, and are unjust and unreasonable for consumers."[245] DMM recommended that the following two basic flaws in the contract and tariff provisions for reliability must-run units under Condition 2 be addressed on an expedited basis.

- Remove the prohibition on reliability must-run capacity under Condition 2 being offered in the ISO's energy market except when needed for local area reliability; and
- Require reliability must-run resources to be subject to a must-offer requirement with cost-based bids.

The ISO initiated a stakeholder process in 2018 to consider changes to the reliability must-run and capacity procurement mechanism provisions of the ISO tariff.[246] In March 2019, the ISO Board approved tariff modifications that address these two key recommendations. With these changes, Condition 2 units will be required to be offered in the ISO markets at cost-based bids, and net revenues earned will be credited back to transmission owners who pay the fixed costs of Condition 2 units.[247]

The ISO's March 2019 proposal also indicates that the ISO will seek to limit reliability must-run contracts only to units that would retire or mothball if they did not receive a contract. To help ensure this, the ISO

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[245] *Motion to Intervene and Protest of the Department of Market Monitoring*, ER18-240-000, November 22, 2017. http://www.caiso.com/Documents/Nov22_2017_DMMMotion_Intervene_Protest-MetcalfEnergyCenterRMRAgreement_ER18-240.pdf

[246] *Review of Reliability Must Run and Capacity Procurement Mechanism, Issue Paper and Straw Proposal for* Phase *1 Items*, California ISO, January 23, 2018. http://www.caiso.com/Documents/IssuePaperandStrawProposal-ReviewReliabilityMustRunandCapacityProcurementMechanism.pdf

[247] Memorandum to ISO Board of Governors, Re: Decision on reliability must-run and capacity procurement mechanism enhancements proposal, Keith Casey, March 20, 2019. http://www.caiso.com/Documents/Decision-ReliabilityMust-Run-CapacityProcurementMechanismEnhancementsProposal-Memo-Mar2019.pdf

will require the owner of any resource that wants to be considered for a reliability must-run designation to submit a formal affidavit stating that the unit is retiring or mothballing because it is uneconomic for the resource to remain in operation or if the resource is retiring for other reasons (such as loss of license).[248]

DMM supports the changes approved by the Board in March 2019. However, DMM believes that the ISO's proposal does not address some other key concerns with the current reliability must-run and capacity procurement mechanisms that are needed as part of a comprehensive backstop procurement reform.[249] More generally, DMM supports a more comprehensive effort to replace or combine the ISO's reliability must-run provisions with the capacity procurement mechanism in the ISO tariff as part of more comprehensive changes to the ISO's backstop capacity procurement authority (see Section 11.9).

11.8 Capacity procurement mechanism

As noted in the previous section, the ISO initiated a stakeholder process in 2018 to consider changes to the reliability must-run and capacity procurement mechanism provisions of the ISO tariff.[250] This initiative resulted in numerous changes that were approved by the ISO Board in March 2019. However, DMM believes that the ISO's proposal does not address some other key concerns with the ISO's current backstop procurement mechanisms that are needed as part of a comprehensive reform.

In 2019, the ISO has committed to continue to consider changes in the $76/kW-year soft cap used under the capacity procurement mechanism provisions. DMM believes the scope of the 2019 initiative should be expanded to encompass a wider range of issues and changes, as described below.

20 percent adder above going forward fixed costs

The current $76/kW-year soft cap for the capacity procurement mechanism is designed to reflect a typical unit's annual going forward fixed costs (GFFC) *plus* 20 percent. The ISO's 2019 proposal would allow units to submit cost-based filing at FERC for payments in excess of this soft cap based on the specific unit's actual GFFC *plus* 20 percent. Capacity procurement mechanism units also retain all net market revenues earned from bilateral or ISO market sales.

The ISO contends that the 20 percent adder is required by prior FERC direction and is necessary to ensure recovery of additional fixed costs. Specifically, the ISO cites a FERC order which rejected the ISO's 2010 soft offer cap proposal ($55/kW-year, based on a reference unit's GFFC plus a 10 percent adder). However, DMM has noted that this FERC order simply indicated that the ISO's filing had *not demonstrated* or *explained* how the proposed methodology would provide sufficient revenues for several specific types of costs or scenarios not directly addressed in the ISO's proposal. As FERC explained:

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248 Ibid, p. 4-5.

249 Memorandum to ISO Board of Governors, Re: DMM Comments - Decision on reliability must-run and capacity procurement mechanism enhancements proposal, Eric Hildebrandt, March 20, 2019. http://www.caiso.com/Documents/Decision-ReliabilityMust-Run-CapacityProcurementMechanismEnhancementsProposal-DMMComments-Mar2019.pdf

250 *Review of Reliability Must Run and Capacity Procurement Mechanism, Issue Paper and Straw Proposal for Phase 1 Items*, California ISO, January 23, 2018. http://www.caiso.com/Documents/IssuePaperandStrawProposal-ReviewReliabilityMustRunandCapacityProcurementMechanism.pdf

> …we find that CAISO has failed to demonstrate that the proposed long-term, fixed price CPM, which is based on a resource's going-forward costs plus a 10 percent adder, is just and reasonable compensation for the capacity procured to maintain reliable operations, and find that it may be unjust and unreasonable …..[251]
>
> CAISO, in this filing, has not explained how the use of going-forward costs for CPM compensation will provide incentives or revenue sufficiency for resources to perform long-term maintenance or make improvements that may be necessary to satisfy new environmental requirements or address reliability needs associated with renewable resource integration …[252]

Based on this order, DMM does not believe that an adder less than 20 percent is inconsistent with prior FERC orders and guidance. The ISO has not yet sought to analyze or demonstrate in any FERC filing that a lower 10 percent adder plus net market revenues received by capacity procurement mechanism units would be sufficient to contribute to the type of additional fixed costs or plant upgrades cited by FERC – i.e., long-term maintenance or improvements to satisfy new environmental requirements.

DMM has been recommending that instead of assigning an arbitrary percentage adder to GFFC (e.g., 20 percent), the ISO could allow suppliers seeking compensation above the soft offer cap to explicitly file for actual costs associated with long term maintenance or environmental upgrades. DMM believes such additional fixed costs are in practice a form of going forward costs and could be included in a supplier's resource-specific cost filing. This eliminates the need to set the market-wide soft offer cap above the annual going forward costs of a typical unit.

Testing competitiveness of CPM designations

If the capacity procurement mechanism process was competitive, suppliers would be expected to submit bids reflecting their GFFC *net* of projected market revenues, plus a reasonable profit. Instead, the ISO's primary proposal would allow suppliers to recover full GFFC *plus* 20 percent and also retain net market revenues. This may represent excessive compensation for units with locational market power.

Stakeholders have raised concerns that capacity procurement mechanism solicitations, particularly annual solicitations, are not competitive.[253] These concerns are based in part on the fact that prices for most selections made by the ISO have cleared at or close to the soft offer cap.[254] DMM's own review indicates that recent monthly solicitations in fall 2018 were not structurally competitive.

A lack of competition – coupled with a soft offer cap that is too high for annual solicitations – raises concern that the soft offer cap is not an effective form of market power mitigation. Thus, as part of the ISO's review of the soft offer cap for annual solicitations, DMM encourages the ISO to consider options for applying a market power test to capacity procurement mechanism offers, and link limits on compensation to the competitiveness of the solicitations.

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[251] *Order on tariff revisions,* 134 FERC ¶ 61,211, Docket No. ER11-2256, March 11, 2011, p. 19: https://www.ferc.gov/whats-new/comm-meet/2011/031711/E-12.pdf

[252] Id., p. 20

[253] Comments on RMR and CPM Enhancements Revised Straw Proposal, SCE, October 23, 2018, p.2: http://www.caiso.com/Documents/SCEComments-ReliabilityMust-RunandCapacityProcurementMechanismEnhancements-RevisedStrawProposal.pdf

[254] *December 22, 2017 Year Ahead Local CPM Designation Report*

Merging CPM and RMR into a single backstop procurement mechanism

DMM has noted that the ISO's first option for procuring additional capacity needed to meet reliability requirements – the capacity procurement mechanism – is voluntary and can be declined by suppliers with local market power. This could undermine the capacity procurement mechanism if suppliers view reliability must-run compensation to be more favorable than capacity procurement mechanism compensation. DMM shares concerns raised by other stakeholders that under the current and proposed framework, newer pivotal resources with undepreciated capital costs would have an incentive to self-select reliability must-run compensation while older pivotal resources would prefer to self-select capacity procurement mechanism compensation. It is not clear what efficiencies this self-selection provides.

A compensation structure based on going forward fixed costs plus a reasonable net profit would provide fair compensation to resources contracted for backstop capacity. If a unit needed for reliability would truly retire or mothball if not contracted by the ISO, then compensating the unit based on its GFFC plus any additional net profit would be more profitable for the unit than if it was actually retired or mothballed. GFFC-based compensation also avoids market distortions that may incent resources to seek a backstop capacity contract rather than participating in the resource adequacy process.

Paying cost-of-service, defined as a resource's annual fixed revenue requirement (AFRR), compensates resources with market power for sunk costs and can therefore send inefficient investment signals for longer term substitutes. Specifically, paying a required resource AFRR can create the incentive to build new supply or transmission capacity whose annualized costs would be greater than the existing resource's GFFC but less than the existing resource's AFRR. Investing in the new capacity would be inefficient relative to only incurring the GFFC of the existing resource. DMM provided an example of how providing compensation based on AFRR would encourage uneconomic and inefficient investments in alternatives using approximate values for AFRR and GFFC for the Metcalf Energy Center, which received a reliability must-run designation for 2018.[255]

In the ISO's future discussions of the backstop procurement framework, the ISO should consider consolidating capacity procurement mechanism and reliability must-run provisions or, at the very least, aligning compensation and adding supplemental rules to prevent self-selection between designations based on maximization of compensation.

11.9 Resource adequacy

California has maintained adequate supply capacity reserves under the state's resource adequacy program and bilateral long-term procurement process for more than a decade. However, a number of structural changes are creating the need for significant changes in this resource adequacy framework. As summarized in a 2018 report by the CPUC, these changes include the following:[256]

[255] *Motion to Intervene and Protest of the Department of Market Monitoring of the California Independent System Operator*, ER-641-000, February 2, 2018, pp. 10-11. http://www.caiso.com/Documents/Feb2_2018_DMMIntervention_Protest-RORCPM_ER18-641.pdf

[256] *Current Trends in California's Resource Adequacy Program*, Energy Division Working Draft Staff Proposal, California Public Utilities Commission, February 16, 2018. http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457193

- Reliance on a growing amount of capacity from intermittent renewable resources, which has limited availability of capacity during many hours and increases the need for overall system flexibility during most hours.
- The need to repower or retire gas-fired power plants that rely on once-through cooling (OTC) technology, and an increasing number of resources that approach their design life in the coming years.
- The rapid expansion of community choice aggregators (CCAs), which appears to be reducing long-term contracting and complicates the process for procurement of capacity needed to meet local resource adequacy requirements by load-serving entities.

The CPUC identified a number of options for addressing these issues and is currently working with the ISO and stakeholders on moving forward with policy decisions. DMM supports these efforts and views the options being considered by the CPUC as potentially effective steps in addressing the current gaps and problems with the state's resource adequacy framework. The following sections provide recommendations regarding some key elements of the overall framework.

Multi-year central buyer local resource adequacy framework

DMM supports the CPUC decision to adopt a multi-year framework for local resource adequacy for the upcoming 2020 compliance year. As parties have explained in the CPUC resource adequacy proceeding, requiring load-serving entities, or a *central buyer*, to procure capacity several years in advance should provide contracted resources with greater financial stability while providing non-contracted resources better information for making retirement decisions. Moreover, this would give the CPUC, ISO, load-serving entities, and central buyers several years notice when the capacity needed to meet a reliability requirement has not been procured. This advance notice would allow these entities more time to consider developing new transmission or generation options to mitigate the need to rely on existing non-contracted resources.[257]

DMM also supports the CPUC decision to develop a central buyer framework for local resource adequacy. As described above, the electric power sector in California is undergoing significant and rapid structural changes, which will result in a larger number of smaller load-serving entities that face regulatory requirements to procure increasing quantities of intermittent renewable resource capacity. These changes increase the likelihood that in the coming years these decentralized load-serving entities will be unable to procure the flexible resources necessary to meet local reliability requirements. As a result, DMM believes the implementation of some type of central buyer framework will be essential for efficiently procuring local resources.

Some key details of the central buyer framework could significantly impact the overall efficiency of resource procurement and subsequent participation in the ISO markets. Important details include whether the central buyer will perform full or residual resource adequacy procurement, and how the central buyer may procure energy dispatch rights. Due to the importance of these details, DMM supports the CPUC decision to delay implementing a central procurement structure in order to allow more time for stakeholder discussion of these important issues.

[257] *Decision refining the resource adequacy program,* California Public Utilities Commission, Agenda ID #17045 (Rev. 1) in Rulemaking 17-09-020, February 21, 2019 Item #32, p. 20.

Resource adequacy imports

As part of the ISO's resource adequacy enhancements initiative, the ISO is assessing the requirements and rules for the resources or supply behind imports that are used to meet resource adequacy requirements.[258] The resource adequacy framework is intended to ensure that sufficient capacity exists and has been contracted for load-serving entities to meet load. However, rules for resource adequacy imports could allow a significant portion of resource adequacy requirements to be met by imports that may have limited availability and value during critical system and market conditions.

Imports used to meet resource adequacy requirements are not required to originate from specific generating units or to be backed by specific portfolios of generating resources. These imports can be bid at any price up to the $1,000/MWh bid cap and do not have any further bid obligation if not scheduled in the day-ahead market or residual unit commitment process.

DMM recommends that the ISO continue to facilitate public stakeholder discussion of this issue and come to an explicit policy decision on whether or not resource adequacy capacity must be backed by specific generation resources and how any such requirements should be enforced in practice. Ambiguous rules may allow some importers or load-serving entities to meet resource adequacy requirements with imports that have very limited availability and value during critical system and market conditions. Ambiguous rules could also increase capacity costs for load-serving entities that feel their imports must be backed by a specific resource dedicated to serving California load.

If the ISO decides that system resource adequacy capacity showings do not need to be backed by specific generation resources dedicated to serving California load, there is likely to be increased focus on how ISO and other WECC balancing authority areas maintain WECC-wide resource adequacy during critical system and market conditions. DMM believes that over time broader coordination with WECC balancing authority areas would result in more reliable and efficient outcomes than ambiguous import resource adequacy rules which create the potential for double counting resource capacity across areas.

11.10 Flexible ramping product enhancements

The flexible ramping product is designed to procure additional ramping capacity to address uncertainty in imbalance demand through the market software. This product has the potential to help increase reliability and efficiency, while reducing the need for manual load adjustments by grid operators. However, DMM has viewed the initial design approved by the Board in February 2016 as just the starting point for the more comprehensive set of flexible ramping market products that will be needed to facilitate the integration of distributed and variable energy resources into the western grid.

DMM supports the ISO's efforts in the ongoing day-ahead market enhancements initiative to design a product that procures flexible ramping capability in the day-ahead market. Even before the initial implementation of the flexible ramping product, DMM has recommended that the ISO start another

[258] *Resource adequacy enhancements straw proposal—part 1*, CAISO, December 20, 2018, p. 8: http://www.caiso.com/Documents/StrawProposalPart1-ResourceAdequacyEnhancements.pdf

stakeholder initiative to work on other important enhancements to the product's basic design.[259] DMM continues to recommend these enhancements described in more detail below.

Locational procurement

The ISO has demonstrated that the current real-time flexible ramping product may not be deliverable because of transmission constraints.[260] In the day-ahead market enhancements initiative, the ISO has considered attempting to address the deliverability of flexible reserves.

DMM recommends that the ISO work on designing locational procurement for both day-ahead and real-time flexible ramping products. Locational procurement that accounts for transmission constraints would result in deliverable reserves. This could significantly increase the efficiency of the ISO's market awards and dispatches. It could also help to resolve the very low prices for flexible reserves that result from undeliverable reserves being counted towards meeting a reliability need that they cannot actually help to meet.

Real-time product for uncertainty over longer time horizons

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

Grid operators face significant uncertainty over load and the future availability of resources to meet that load. This uncertainty contributes substantially to operators needing to systematically enter the large imbalance conformance adjustments described in Section 9.3 of this report. The ISO could reduce the need for manual load adjustments and more efficiently integrate distributed and variable energy resources by designing a real-time flexible ramping product that could procure and price the appropriate amount of ramping capability to account for uncertainty over longer time horizons than the current product design considers.

Incorporate uncertainty from dispatchable resources into demand curve and cost allocation

The flexible ramping product demand curve assigns the value of flexible reserves based on uncertainty in load and non-dispatchable resource forecasts. However, the possibility that internal dispatchable resources will not follow dispatch or start-up instructions, or that intertie resources will not deliver their awards, also creates uncertainty that operators must account for through manual commitments or other dispatches that create flexibility. Therefore, DMM continues to recommend that the ISO attempt to incorporate this uncertainty into its flexible ramping product demand curves and to allocate costs to the dispatchable resource deviations that cause increases in demand.

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[259] *2017 Stakeholder Initiatives Catalog*, Discretionary Initiative 11.6 Flexible Ramping Product Enhancements requested by the Department of Market Monitoring, September 15, 2016, p. 22: http://www.caiso.com/Documents/Draft_2017StakeholderInitiativesCatalog.pdf

[260] *Discussion on flexible ramping product*, California ISO, September 8, 2017 pg. 16-17: http://www.caiso.com/Documents/Discussion_FlexibleRampingProduct.pdf

11.11 Battery resource cost modeling and bid mitigation

As part of its ongoing energy storage and distributed energy resources (ESDER 4) initiative, the ISO is considering whether to design and implement default energy bids for use in mitigation of battery resources. Some stakeholders have questioned the urgency of addressing this issue at this time and suggested that the ISO should delay designing battery default energy bids until there is more evidence of battery resources exercising market power. DMM strongly supports the ISO's effort to develop default energy bids for batteries as part of the current ESDER 4 initiative.

Currently, the amount of battery resources operating in the ISO is very limited, with installed capacity reaching about 150 MW in 2018. DMM has not yet observed bidding of battery resources in a way that would warrant immediate implementation of energy bid mitigation for batteries. However, DMM's analysis indicates that many of these resources are located in areas that are frequently downstream of congested non-competitive constraints. Therefore, it is very likely that these resources will need to be subject to energy bid mitigation within the next few years, regardless of whether or not stakeholders prioritize designing default energy bids at this time.

Designing default energy bids that accurately reflect the marginal or opportunity cost of batteries during periods of incremental energy production or withdrawal could be complex. DMM recommends that the ISO and battery storage community work together to define these costs now. Working on this design now will reduce the risk of implementing hastily and potentially poorly designed default energy bids when it becomes urgent to address market power that could be exercised by battery resources. This effort should also include potential improvements to the energy storage resource (NGR) model to consider how some battery usage patterns may cause significant maintenance costs that cannot be accurately modeled as a cost of incremental energy production or withdrawal.

Through engagement with stakeholders in the ESDER stakeholder processes, DMM understands that the ISO's current structures for modeling battery resources may not accurately reflect the ways in which operating a battery accelerates the need for the battery owner to incur significant, lumpy maintenance costs such as augmenting battery cells. For example, the depth of a battery's charge or discharge may significantly impact how often a battery resource requires cell augmentation.

Stakeholders have explained that battery owners may agree to less expensive tolling contracts with developers if the contract or negotiated warranty includes provisions that limit how the battery can operate in ISO's markets. However, managing potential maintenance costs through contractual limitations or negotiated warranties could result in inefficient utilization of battery resources in wholesale electricity markets. Furthermore, when the ISO begins mitigating battery resource energy bids, market participants may not be able to control whether ISO dispatches of battery resources are consistent with contractual arrangements with third parties.

The ISO currently does not mitigate the energy bids of battery resources. As a result, market participants can rely on energy bids to operate the resource in ways that minimize the wear and tear on the battery and avoid violating contractual limitations. When the ISO begins to mitigate energy bids of batteries, the cost-based default energy bids will sometimes be used in place of the scheduling coordinator submitted energy bids. Therefore, market participants will no longer be able to rely solely on their submitted energy bids to control battery operation.

The cost-based default energy bids for batteries which may be used when mitigation is triggered should only include incremental energy costs associated with incremental energy production or withdrawal. Inflating default energy bids with costs caused by other operational characteristics such as depth of charge would result in inefficient dispatch. The ISO also recently reaffirmed that "CAISO maintains its longstanding position that economic limitations such as those originating from contracts, such as power purchase or tolling agreements, are not acceptable limitations for establishing an opportunity cost".[261] The ISO should clarify at this time that market participants will not be able to use contractual limitations to justify increasing the opportunity costs in a battery's default energy bids.

Moreover, the ISO does not permit market participants to constrain resource parameters below the resource's actual physical operating characteristics in order to manage contractual limitations or to limit costs, such as major maintenance costs.[262] Artificially constraining resource parameters could lead to inefficient market outcomes if a battery resource dispatch that may be part of a least cost market solution does not occur because the resource is constrained by a physical-type parameter set below the battery's actual physical characteristics.

Therefore, DMM continues to recommend that the ISO and the battery community work closely together as part of the ESDER 4 initiative to identify and model how some kinds of battery usage, such as deep charging or discharging, accelerate the need to incur significant maintenance costs. This will allow the ISO optimization to accurately consider these lumpy costs when determining the efficient dispatch. Accurately modeling the actual causes of these costs will also allow market participants to efficiently limit the kinds of battery operations that cause significant maintenance costs and allow resources to recover these costs through market revenues.

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261 *Filing to Implement Commitment Cost Enhancements Phase 3 Initiative, Request for Timely Commission Order, and Request for Waiver of Notice Requirement*, March 23, 2018, p. 24-25: http://www.caiso.com/Documents/Mar23_2018_TariffAmendment-CommitmentCostEnhancementsPhase3_ER18-1169.pdf.

262 *California ISO Market Notice: Outage Reporting for Energy Storage Resources with Physical Limitations*, May 11, 2017: http://www.caiso.com/Documents/OutageReporting-EnergyStorageResources-PhysicalLimitations.html.