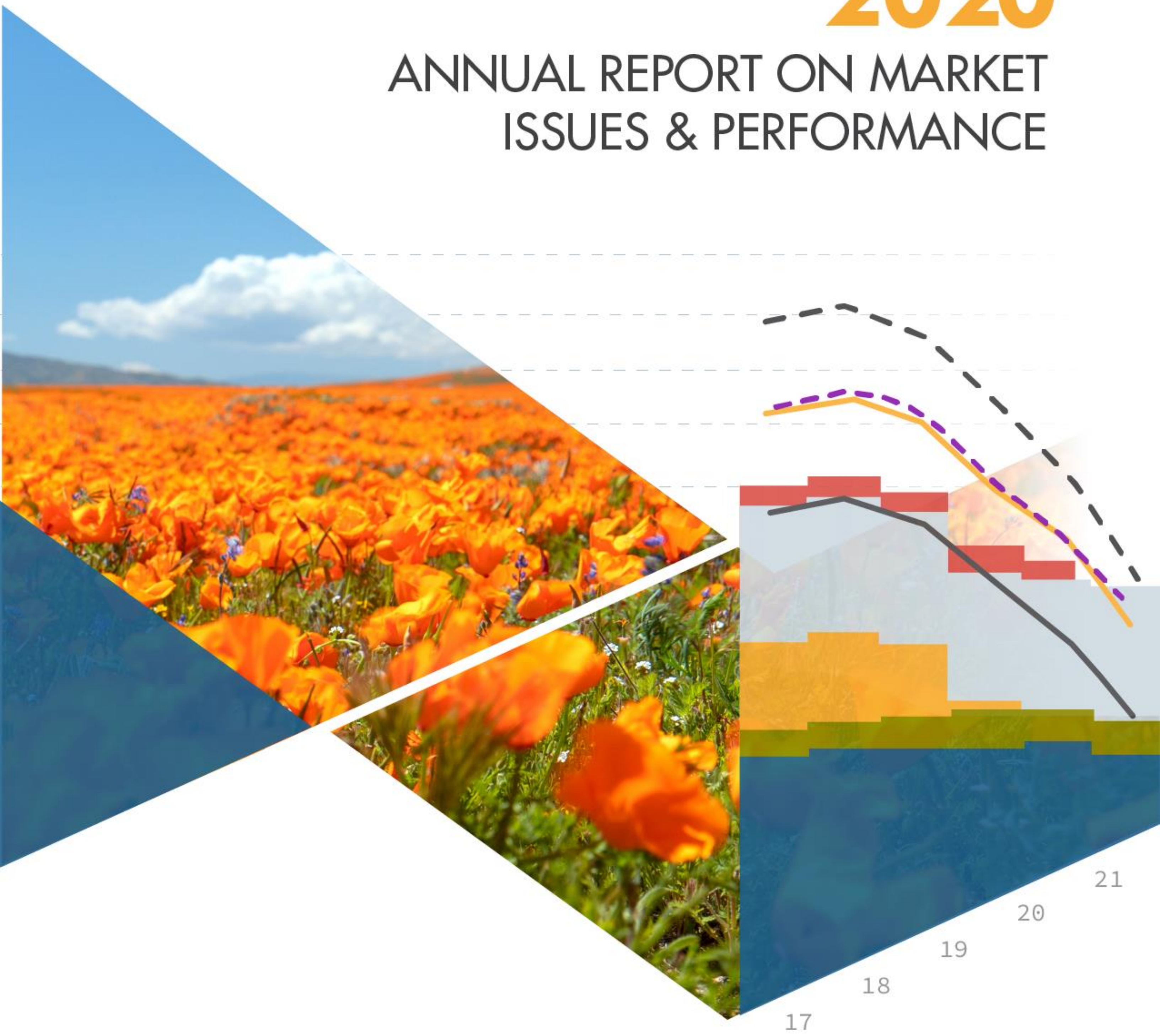
2020

ANNUAL REPORT ON MARKET ISSUES & PERFORMANCE



California ISO

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Executive summary

This annual report provides analysis and recommendations by the Department of Market Monitoring (DMM) on market issues and performance of California's wholesale energy markets and the Western Energy Imbalance Market (EIM). The report finds that the ISO and energy imbalance markets continued to perform efficiently and competitively in 2020. Other key highlights include the following:

- **The total estimated wholesale cost of serving California ISO load in 2020 rose by 3 percent, despite substantially lower natural gas prices.** Total wholesale costs for the ISO footprint were about $8.9 billion or about $42/MWh. After adjusting for lower natural gas costs and changes in greenhouse gas prices, wholesale electric costs per megawatt-hours increased by about 19 percent.
- **The increase in prices was driven by a combination of factors**, including lower hydroelectric output, higher prices during peak evening ramping periods, and very high prices during the third quarter, related in part to warm temperatures increasing peak demand in the ISO and in the West.
- **On August 14 and 15, CAISO grid operators called upon load serving entities to curtail load** for several hours for the first time since 2001. From mid-August to September 7, 2020, regional high temperatures led to a high demand across the entire western region. This load curtailment event and the combination of factors that contributed to it are covered in more detail in a separate standalone report.[1] Following the load curtailment event in August, the ISO revised the market algorithm to give the residual unit commitment process the ability to curtail exports.
- **The ISO's energy markets were competitive in 2020**. The combination of low gas prices with the growth in low marginal cost generation supported competitive market outcomes. Overall, wholesale energy prices were about equal to competitive baseline prices DMM estimates would result under competitive conditions, even during the August heatwave.
- **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 2020, two new market participants (Seattle City Light and the Salt River Project) joined the energy imbalance market.
- **ISO load continued to decrease in 2020**, on average, due in part to increases in behind-the-meter solar generation, continued initiatives to improve energy efficiency, and the public health order that directed Californians to stay at home in response to COVID-19. This effect was offset during peak hours, however, when higher than average temperatures caused large increases in demand. Summer load in the ISO system peaked at 47,121 MW, exceeding peaks in 2018 and 2019, and was about 3 percent higher than the ISO's 1-in-2 year load forecast.

[1] An in-depth analysis and report of these factors may be found in the Department of Market Monitoring's *Report on Market Conditions, Issues and Performance – August and September 2020*. http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

Several other factors contributed to increased wholesale energy costs in 2020:

- **Locational price differences due to congestion increased** in 2020, particularly on constraints associated with major transmission line limits separating northern and southern California. In the real-time markets, EIM transfer constraint congestion had a far greater impact on prices than internal constraint congestion in all areas outside of the ISO.

- **Ancillary service costs increased** to $199 million from $148 million in 2019 and $177 million in 2018. Increased costs were driven by higher regulation and operating reserve requirements and increased prices in the third and fourth quarters.

- **Total real-time imbalance offset costs increased to $177 million from $105 million in 2019.** About $64 million of these costs were energy offset costs and $117 million were congestion offset costs. As in 2018, congestion offset costs were caused largely by significant reductions in constraint limits made by grid operators in the 15-minute market relative to higher limits in the day-ahead.

- **Bid cost recovery payments in the ISO increased slightly to $126 million, remaining high by longer term historical standards.** These uplift payments were about 1.4 percent of total energy costs, compared to $123 million in 2019 and $150 million in 2018. This represents the second highest level since 2011. Uplift payments for units in the energy imbalance market totaled about $9 million in 2020, about $1 million lower than in 2019.

- **Payouts to congestion revenue rights sold in the ISO's auction exceeded auction revenues by over $70 million in 2020**. About $36 million of the $70 million in ratepayer losses was from small load serving entities selling allocated rights at a loss in the third quarter. These losses are borne by transmission ratepayers who pay for the full cost of the transmission system through the transmission access charge (TAC). Losses from congestion revenue rights sold in the auction totaled about $100 million in 2017, $131 million in 2018, and fell to $22 million in 2019.

- **Net profits paid to convergence bidders increased to $45 million**. Virtual demand bids were profitable in the third quarter and virtual supply bids were profitable in hours with day-ahead prices higher than real-time prices.

- **Total above-market costs due to exceptional dispatches issued by ISO grid operators decreased** to about $16 million from $26 million in 2019. About $7 million of these payments were for units committed via exceptional dispatch. Bid mitigation, which was applied to some exceptional dispatches for energy, avoided about $5.5 million in additional out-of-market costs in 2020.

- **Manual adjustments to ISO system loads remained high at about 1,000 MW in peak net load ramp hours** in the hour-ahead and 15-minute markets, continuing a dramatic increase over 2018 and 2017, which were both substantially above previous years. High hour-ahead load adjustments tend to increase imports in the ISO's hour-ahead market. ISO operator adjustments added over 600 MW per hour to residual unit commitment requirements, on average, in peak net load hours.

- **The day-ahead energy market,** which accounts for most of the total wholesale market**, was structurally uncompetitive in more hours than any of the last 5 years, but remained competitive during most hours in 2020**. Low hydroelectric availability and extreme summer loads in 2020 contributed to an increase in potentially non-competitive hours relative to previous years. Despite this, prices were consistent with competitive baseline levels.

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.
- About 350 MW of battery storage capacity was added to the ISO system and began participating in the ISO market in 2020. In total, about 490 MW of battery capacity participated in the ISO market in 2020. Most battery capacity participating in ISO markets is located in locally constrained areas.
- The market for capacity needed to meet local resource adequacy requirements continues to be structurally uncompetitive in most 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 increased reliance on energy-limited resources and the increase in load served by community choice aggregators (CCAs) are driving the need for significant changes in this resource adequacy framework.

Load curtailment event

Regional high temperatures led to a high demand heat wave across the entire western region in mid-August and again over Labor Day weekend in 2020. On August 14 and 15, CAISO grid operators called upon load serving entities to curtail load due to system-wide conditions for the first time since 2001. In the following days and weeks, loads remained high but were well below forecasted levels, due largely to voluntary conservation efforts. Prices in the CAISO, the Western Energy Imbalance Market, and bilateral markets reached record levels on August 17-19, but no further load curtailments occurred.

There was no single cause of the rotating outages. Instead, a combination of factors led to the extraordinary market events of this period, including resource adequacy and forward planning processes that allowed load serving entities to procure less generation than was required to serve load during an atypically high, widespread, and extended heat wave. Conditions were exacerbated by ISO market practices that allowed exports to increase demand to a level not supported by physical generation. Further discussion of these factors are available in a special report published by DMM as well as a preliminary and final root cause analysis issued by the ISO, CPUC, and CEC.[2]

DMM agrees with many of the key recommendations related to resource adequacy in the CAISO/CPUC/CEC reports and supports the coordinated efforts by the CAISO, CPUC, and stakeholders to

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[2] DMM report: *Report on Market Conditions, Issues and Performance – August and September 2020*, November 24, 2020. http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

Preliminary root cause analysis: *Preliminary Root Cause Analysis: Mid-August 2020 Heat Storm*, October 6, 2020, prepared by the California Independent System Operator, California Public Utilities Commission and California Energy Commission. http://www.caiso.com/Documents/Preliminary-Root-Cause-Analysis-Rotating-Outages-August-2020.pdf. Preliminary CAISO/CPUC/CEC report

Final root cause analysis: *Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave*, January 13, 2020, prepared by the California Independent System Operator, California Public Utilities Commission and California Energy Commission. http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf make the various planning, market design, and operational enhancements identified in these reports. The most significant and actionable of these recommendations involve California's resource adequacy program. To limit the potential for similar resource shortages in future years, a high priority should be placed on the following two recommendations:

- **Increase resource adequacy requirements to more accurately reflect increasing risk of extreme weather events** (e.g., beyond the 1-in-2 year load forecast and 15 percent planning reserve margin currently used to set system resource adequacy targets).
- **Continue to work with stakeholders to clarify and revise the resource adequacy capacity counting rules,** especially as they apply to hydro resources, demand response resources, renewable resources, imports, and other use limited resources. Counting rules should specifically take into account the availability of different resource types during the net load peak.

In addition, DMM provided the following recommendation regarding the issue of exports:

- **Further changes and clarifications in the rules and processes for limiting or curtailing exports should be discussed and pursued by the CAISO in conjunction with other balancing areas.** The ISO partially addressed this through interim changes to export and wheeling rules implemented as part of the Market Enhancements for Summer 2021 Reliability Initiative. More comprehensive, longer term changes are being considered as part of another ISO initiative, the External Load Forward Scheduling Rights Process Initiative, launched in July 2021.

DMM also provides the following recommendation regarding demand response:

- **Take steps to ensure a higher portion of demand response used to meet resource adequacy requirements is available during critical net load hours**. These steps include eliminating the 15 percent adder currently applied to demand response resources used to meet resource adequacy requirements, and establishing a significant financial incentive for all resource adequacy capacity to be available and perform in the real time market. The CPUC is taking steps to address this issue, as noted in Chapter 10 of this report.

Total wholesale market costs

The total estimated wholesale cost of serving load in 2020 was about $8.9 billion, or about $42/MWh. This represents an increase of about 3 percent from wholesale costs of about $41/MWh in 2019. Costs increased despite a substantial decrease in spot market natural gas prices.[3] After normalizing for changes in natural gas prices and greenhouse gas compliance costs, DMM estimates that total wholesale energy costs increased by about 19 percent.[4]

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:

- Relatively high prices during the third quarter, related in part to warm temperatures increasing peak demand in the ISO and in the West which include the August heat wave;
- Increased prices during peak evening ramping periods; and
- Decreased production from hydroelectric resources.

Figure E.1 Total annual wholesale costs per MWh of load (2016-2020)

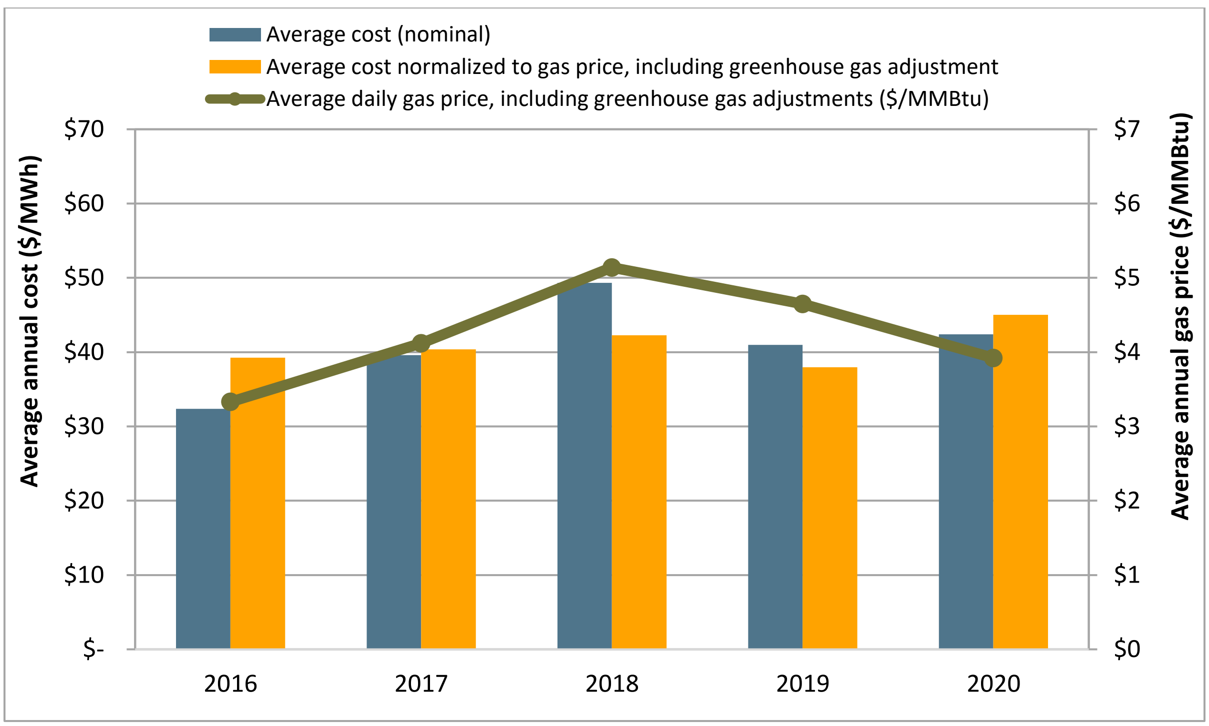


Figure E.1 shows total estimated wholesale costs per megawatt-hour of system load from 2016 to 2020. Wholesale costs are provided in nominal terms (blue bar), and after being normalized for changes in natural gas prices and greenhouse gas compliance costs (gold bar). The green line represents the annual 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.

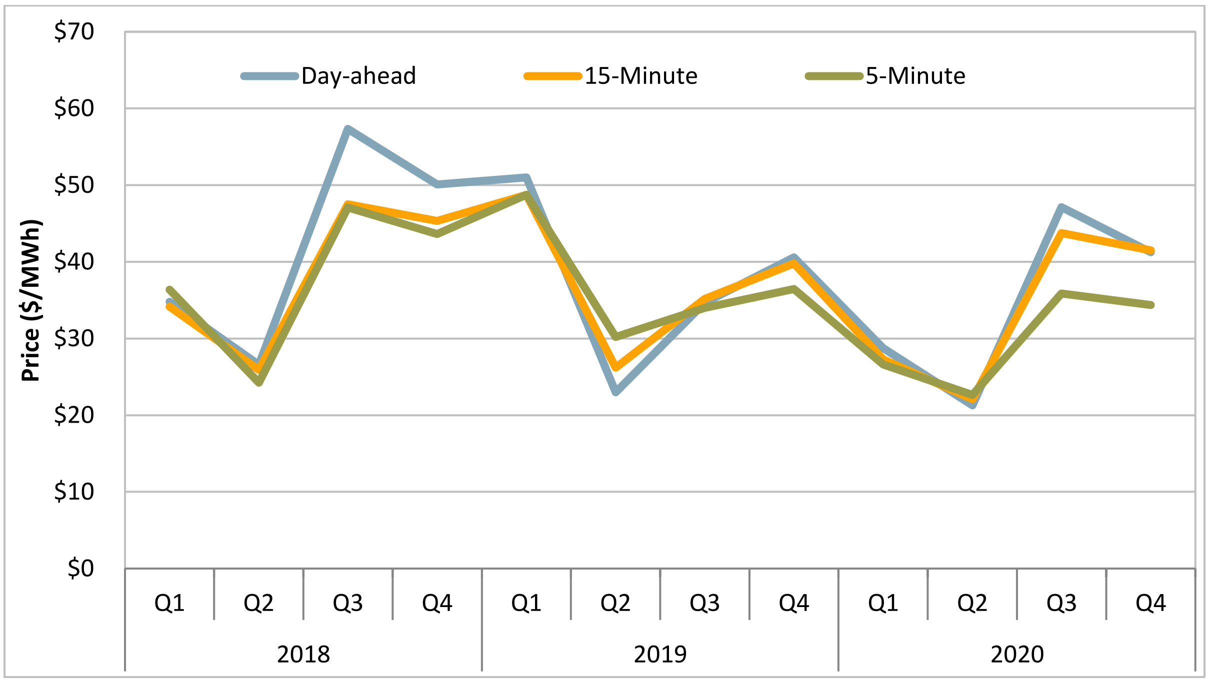
Energy market prices

ISO day-ahead and real-time market prices decreased in 2020, driven primarily by a decrease in natural gas prices, lower load, and moderate system conditions in most hours.

Figure E.2 and Figure E.3 highlight the following:

- ISO prices in the day-ahead were slightly higher than 15-minute real-time prices, but significantly higher than 5-minute prices. Day-ahead energy prices averaged about $35/MWh, 15-minute prices were about $34/MWh, and 5-minute prices were about $30/MWh.
- 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.

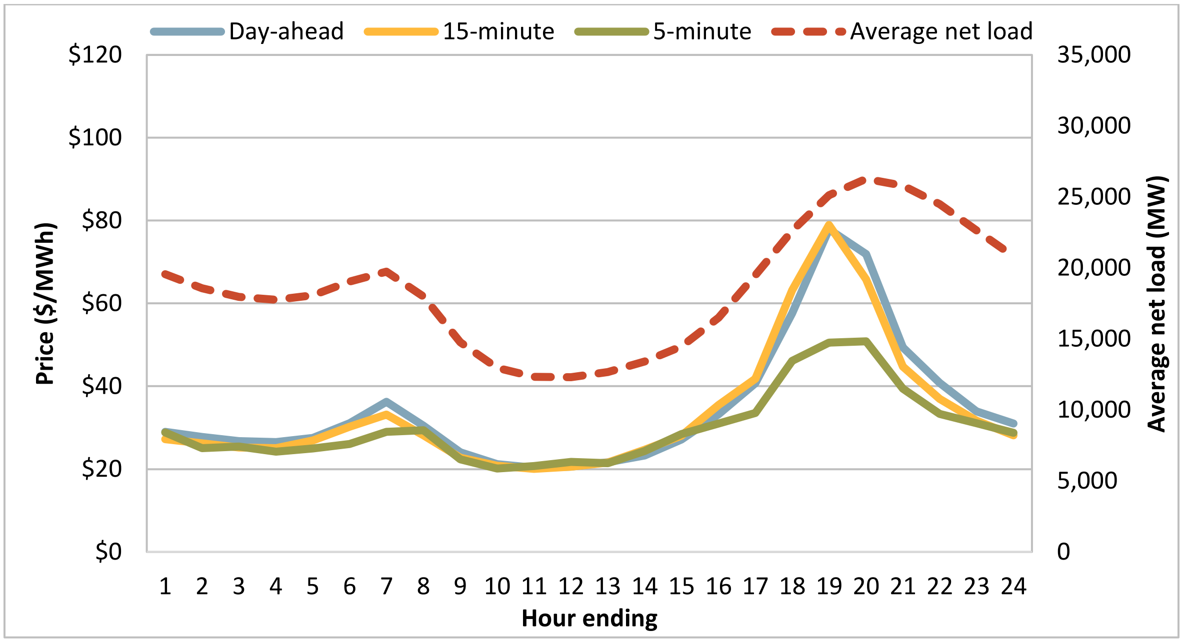
Figure E.2 Comparison of quarterly prices – load-weighted average energy prices



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

4 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 1.2.8. Gas prices are normalized to 2010 prices.

Figure E.3 Hourly system energy prices (2020)



Market competitiveness

Prices in the ISO's energy markets were competitive in 2020. The combination of low gas prices with the growth in low marginal cost generation supported a competitive outcome. Overall, wholesale energy prices were about equal to competitive baseline prices DMM estimates would result under perfectly competitive conditions.

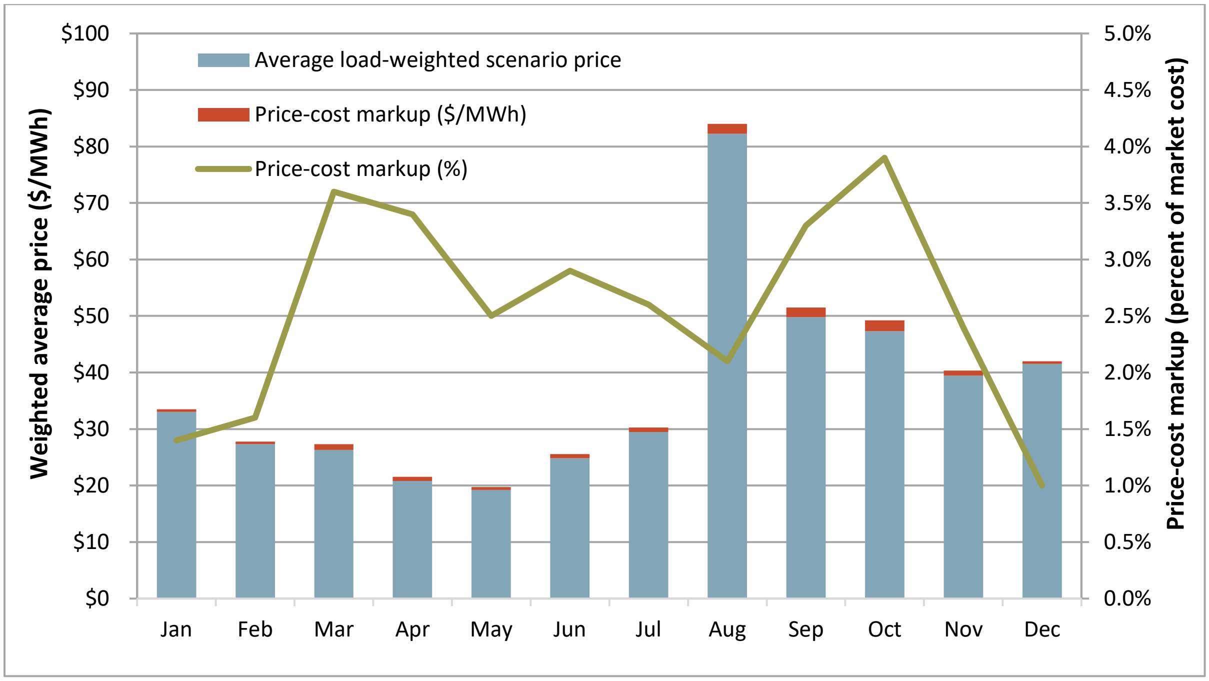
The competitiveness of overall market prices can be assessed based on the *price-cost markup*, which represents a comparison of actual market prices to an estimate of prices that would result in a highly competitive market in which all suppliers bid at or near their marginal costs. DMM estimates competitive baseline prices by re-simulating the market after replacing the market bids of all imports with the lower of their bid and a generous default energy bid (DEB) and replacing the energy and commitment cost bids of gas-fired units with the lower of their submitted bids or their DEB or estimated commitment cost. This methodology assumes competitive bidding of price-setting resources, and is calculated using DMM's version of the actual market software.[5]

DMM estimates an average price-cost markup of $1/MWh or about 2.5 percent, as shown in **Error! Reference source not found.**. This slight positive markup indicates that prices have been very competitive, overall, for the year.[6]

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

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

Figure E.4 Day-ahead market price-cost markup - default energy, commitment cost, and import bids scenario (2020)[7]



Ancillary services

Ancillary service costs increased to $0.95/MWh from $0.69/MWh in 2019, and from 1.68 to 2.23 as a percent of total wholesale energy cost, as shown in Figure E.5. Total ancillary service costs increased to $199 million, up from $148 million in 2019, and $177 million in 2018. Increased costs were driven primarily by higher requirements and higher prices in the third and fourth quarter.

Regulation and operating reserve requirements increased. Regulation down requirements increased 22 percent to 520 MW and regulation up requirements increased 12 percent to 390 MW, relative to 2019. Average combined requirements for spinning and non-spinning operating reserves also increased by 12 percent from the previous year to about 1,800 MW.

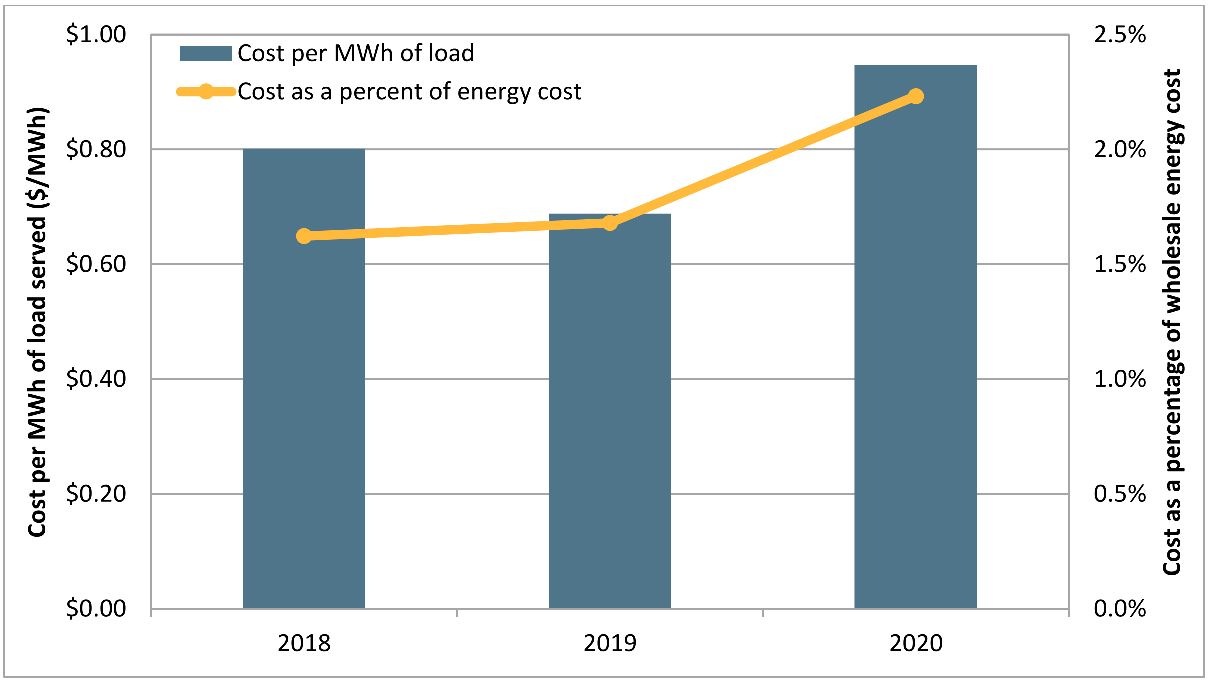
The frequency of ancillary service scarcity intervals decreased, remaining low. There were 129 intervals in the 15-minute market with ancillary service scarcity, compared to almost 200 scarcity instances in the previous year. The number of regulation scarcities decreased substantially. However, the number of non-spin scarcities increased from 2019 to 2020, particularly in August and September when the ISO faced very tight conditions.

7 This figure shows the results for a scenario where bids for gas-fired units were set to the minimum of their submitted bid or default energy bid, bids for gas-fired resources commitment costs were set to the minimum of their bid or 110 percent of proxy price, and import bids were set to the minimum of their bid or an estimated hydro default energy bid. In previous years, the competitive baseline was a scenario where bids for gas-fired generation were set to their default energy bids, convergence bids were removed, and system demand was set to actual system load. This tended to overestimate the competitive baseline price, because a significant amount of gas-fired supply is bid at prices lower than their default energy bids (which include a 10 percent adder), and the actual system load measure used was often greater than day-ahead cleared load.

Thirty percent of resources failed ancillary service performance audits and unannounced compliance tests for spinning and non-spinning reserves in 2020, compared to 20 percent the previous year. The ISO adopted a new monthly process for performance audits of regulation, starting in February 2020, with a failure rate of about 5%. Only one resource was disqualified for successive failures.

Provision of ancillary services from limited energy storage resources continued to increase. Limited energy storage resources include batteries and other limited devices. Average hourly procurement from these resources for regulation increased from around 166 MW in 2019 to 191 MW in 2020, or around 21 percent of regulation requirements.

Figure E.5 Ancillary service cost as a percentage of wholesale energy cost



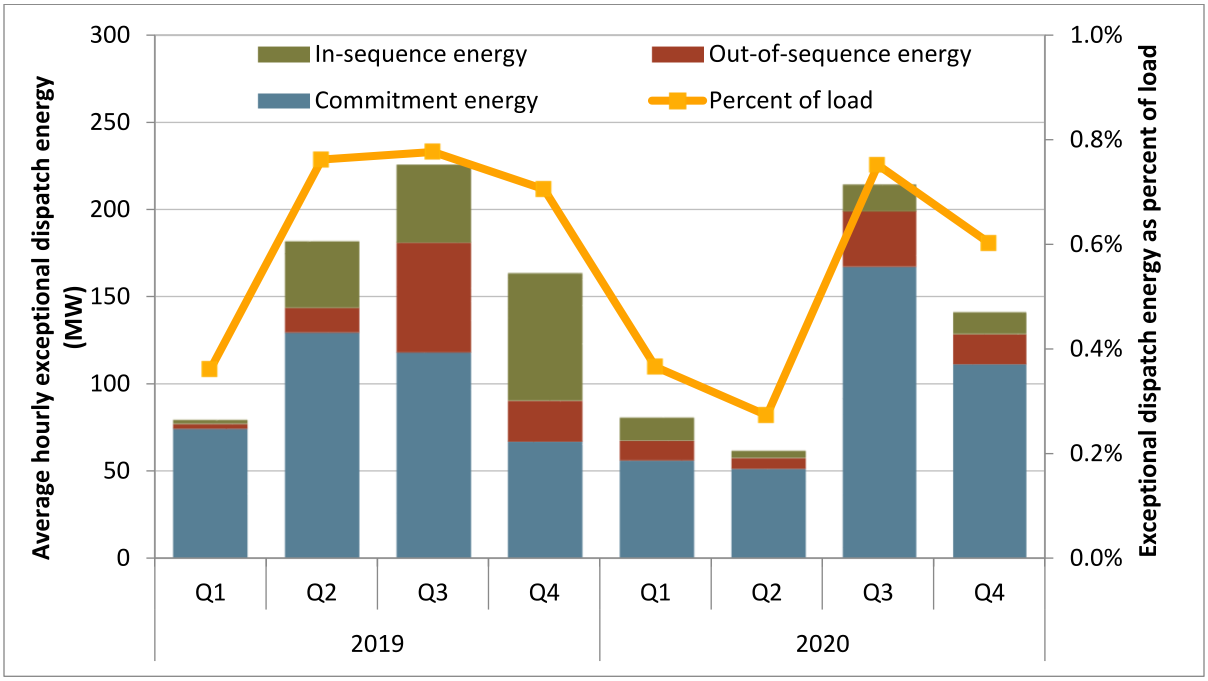
Exceptional dispatches

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 resulting from all types of exceptional dispatch decreased in 2020 and continued to account for a relatively low portion of total system load, as shown in Figure E.6. The decrease in total energy from exceptional dispatches in 2020 was driven by less exceptional dispatch energy above minimum load, while minimum load energy from exceptional dispatch unit commitments largely stayed the same.

- Total above-market costs due to exceptional dispatch decreased to about $15.8 million in 2020 from $26.4 million in 2019. Although exceptional dispatches to commit units to operate at minimum load stayed about the same, the cost of this category fell from $15 million in 2019 to $6.9 million in 2020.

Figure E.6 Average hourly energy from exceptional dispatches



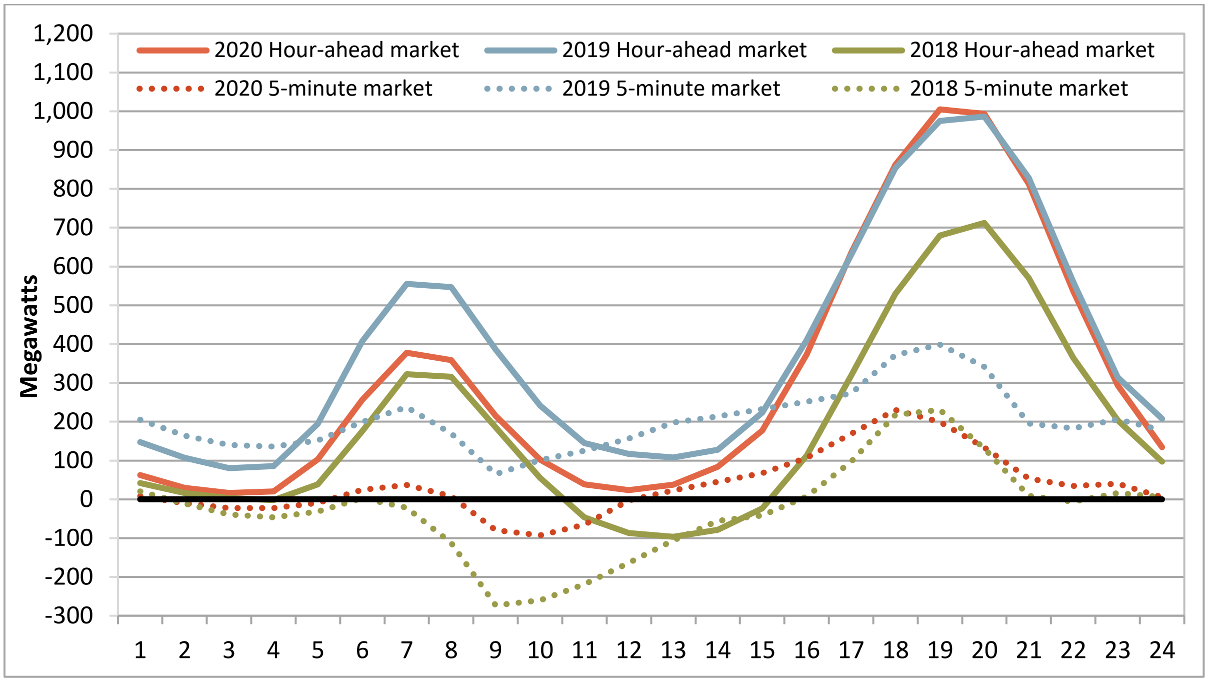
Load forecast adjustments

Operators in the ISO and energy imbalance market can manually modify load forecasts used in the market through load adjustments, sometimes referred to as load bias or load conformance. The ISO has begun using the term imbalance conformance to describe these adjustments which are used to account for potential modeling inconsistencies and inaccuracies.

In the ISO, load adjustments are routinely used in the hour-ahead and 15-minute scheduling processes 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 routinely mirror the pattern of net loads over the course of the day, averaging 350 MW to about 1,000 MW during the morning and evening ramping hours respectively. Fifteen-minute market adjustments are very similar to hour-ahead and are not included in the figure. 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.

Figure E.7 Average hourly load adjustment (2018 - 2020)



Residual unit commitment process

During the period between mid-August to September 7, 2020, when regional high temperatures led to high demand across the entire western region, the ISO made two specific changes outlined below which impacted the residual unit commitment process, allowing that process to better align physical supply with demand.

- On August 16, the ISO announced the suspension of virtual bidding effective in the day-ahead market for operating day August 18, in part to prevent virtual supply bids from allowing additional exports to be scheduled in the day-ahead market which would ultimately need to be met by physical supply from within the ISO system.[8] The ISO reinstated virtual bidding in the day-ahead market for August 22.[9] By this time, system and market conditions had changed so that virtual bidding was again viewed as providing market benefits without presenting a risk to the system.

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8 Market Notice: *California ISO Suspends Convergence Bidding due to Current System Conditions,* August 16, 2020: http://www.caiso.com/Documents/CaliforniaISOSuspendsConvergenceBiddingCurrentSystemConditions.html

9 Market Notice: *California ISO Reinstates Convergence Bidding for 8/22/20 due to Updated System Conditions*, August 20, 2020: http://www.caiso.com/Documents/CaliforniaISOReinstatesConvergenceBiddingfor82220DuetoUpdatedSystemConditions.html

- Effective September 5, the ISO implemented several software modifications in the residual unit commitment process designed to reduce exports which could not be supported by available physical supply in the ISO system.[10]

The September 5 change revised the market algorithm to give the residual unit commitment process the ability to curtail exports. With this change, the residual unit commitment process is able to curtail certain exports before relaxing the power balance constraint. These reduced exports no longer receive a real-time scheduling priority that exceeds real-time ISO load and can choose to re-bid in real-time or resubmit as self-schedules in real-time.[11]

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 in 2020 were $177 million, about a 68 percent increase from $105 million in 2019, as shown in Figure E.8. Congestion offset costs were $117 million of the total $177 million real-time imbalance offset costs in 2020. As in 2019, much of the congestion offset charges appear to have been caused by differences in the network model used in the day-ahead and real-time markets. Many of these differences are caused by significant reductions in constraint limits by grid operators in the 15-minute market relative to limits used in the day-ahead market.

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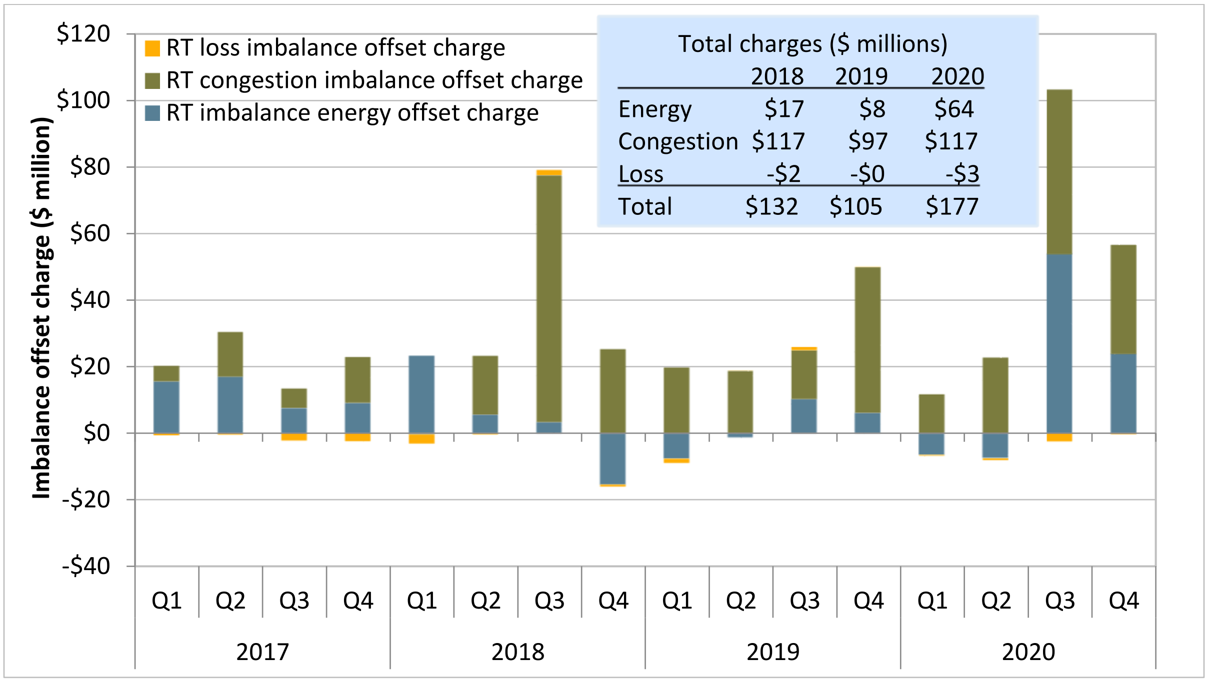
10 PRR 1282 Market Operations BPM, Emergency PRR, Scheduling of export resources in real time market, September 4, 2020: https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=1282&IsDlg=0

11 The ISO provided details and examples of this change in the Market Performance and Planning Forum meeting on September 9, 2020: http://www.caiso.com/Documents/Presentation-MarketPerformance-PlanningForum-Sep9-2020.pdf#search=market%20performance%20and%20planning%20forum

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 2020, particularly on constraints associated with major transmission line limits separating Northern and Southern California as well as those connecting the ISO and the Pacific Northwest. Key congestion trends during the year include the following:

- For the year, congestion increased day-ahead prices in the Southern California Edison and San Diego Gas and Electric areas by about $0.94/MWh and $1.66/MWh, respectively. Congestion decreased day-ahead prices in the Pacific Gas and Electric area by $1.46/MWh.
- In the real-time market, EIM transfer constraint congestion had a far greater impact than internal constraint congestion in many EIM areas, decreasing prices in the Pacific Northwest and increasing prices in the Southwest.
- Within the ISO, patterns of real-time congestion followed a similar pattern to the day-ahead market. The constraints that had the greatest impact on making prices higher in the south and lower in the north parts of the ISO system were the Midway-Vincent #2 500 kV line, the Malin-Round Mountain 500 kV line, and the constraints associated with the Round Mountain-Table Mountain nomogram.
- The frequency and impact of congestion in the day-ahead market on most major interties was higher in 2020 compared to both 2019 and 2018. This was primarily driven by increased congestion on interties connecting the ISO to the Pacific Northwest (Malin and NOB).

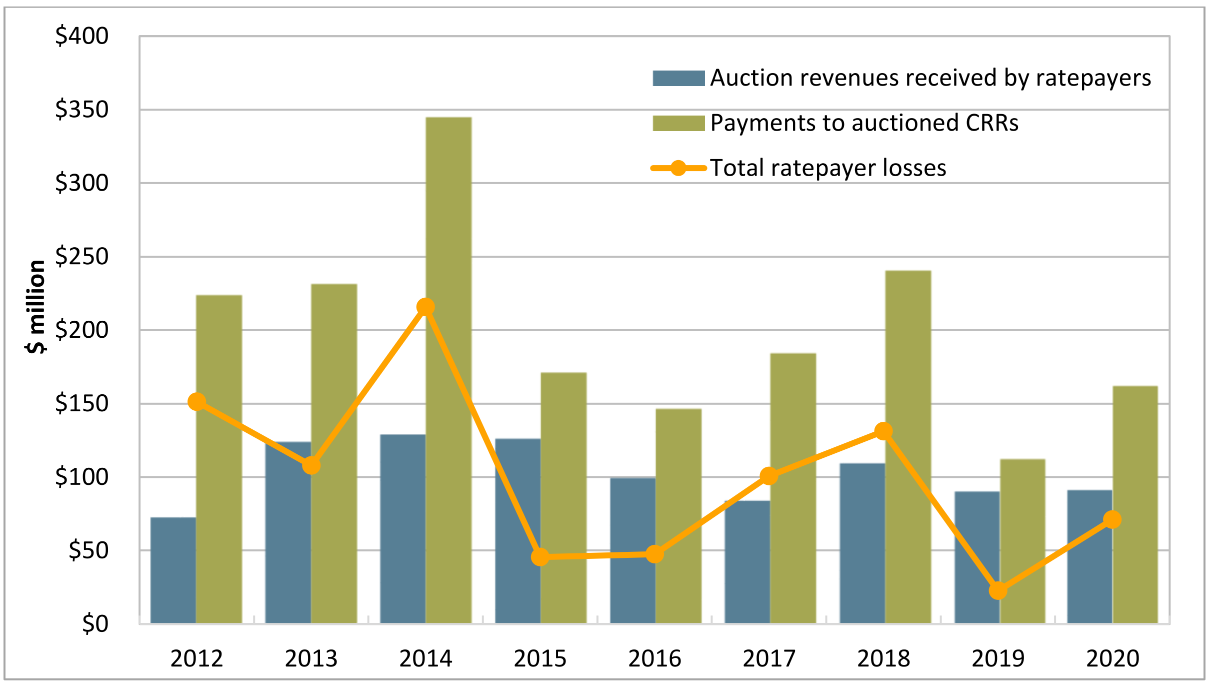
Congestion revenue rights

As shown in Figure E.9, in 2020 ratepayer losses from the auctions totaled over $70 million. About $36 million of the $70 million in ratepayer losses was from small load serving entities selling allocated rights at a loss in the third quarter. Historically, trades of allocated rights by load serving entities have resulted in relatively low losses or gains.

Transmission ratepayers received about 56 cents in auction revenue per dollar paid out to these rights purchased in the auction in 2020. Track 1B revenue deficiency offsets reduced payments to auctioned CRRs by about $47 million. Losses from auctioned congestion revenue rights totaled about 14 percent of total day-ahead congestion rent in 2020, compared to about 6 percent in 2019 and 21 percent in 2018.

DMM believes the current auction is unnecessary and could be eliminated.[12,13] If the ISO believes it is beneficial to the market to facilitate hedging, DMM believes the current auction format could 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.

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



12 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

13 DMM whitepaper: *Market alternatives to the congestion revenue rights auction*, November 27, 2017: http://www.caiso.com/Documents/DMMWhitePaper-Market_Alternatives_CongestionRevenueRightsAuction-Nov27_2017.pdf

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.

When the resource adequacy program began in 2006, coincidentally the year the ISO served all-time peak load (50,270 MW), requirements were typically met by traditional investor-owned utilities holding merchant gas-fired generation under long-term tolling contracts or bidding-in utility owned generation.[14] These investor-owned utilities bid this capacity into the market at cost, under least-cost bidding requirements set by the CPUC.

Over the last five years, California's load has shifted from investor-owned utilities to community choice aggregators (CCAs). The percent of load served by CCAs grew from 2 percent in 2015 to 30 percent in 2021. Load served by investor-owned utilities fell from 89 to 61 percent over the same time.[15] This shift, together with uncertainty about future load migration, reduced demand for long-term tolling contracts. Resource adequacy requirements are now more typically met by short-term resource adequacy only contracts.

For over 15 years, long-term procurement has contributed to ISO market competitiveness. Despite the lack of any bid mitigation for system market power, the ISO's energy markets have been highly competitive at a system level since the early 2000s due to a high level of forward bilateral energy contracting by the ISO's load serving entities, relatively high supply margins, and access to imports from other balancing areas. The long-term procurement framework and resource adequacy requirements, developed by the CPUC and other local regulatory authorities, have played a key role in making the ISO's energy market competitive at a system level.

Analysis in this report shows that:

- **Most system resource adequacy capacity was procured by investor-owned utilities**. Investor-owned utilities accounted for about 66 percent of procurement, community choice aggregators procured 19 percent, municipal entities contributed 8 percent, and direct access providers accounted for 7 percent.
- **Over half of resource adequacy capacity was classified as use-limited** and thus exempt from ISO bid insertion in all hours.
- **On high load days, resource adequacy resources bid in sufficient capacity to meet average hourly load**. During the evening load ramp, however, changes in bids from RAAIM exempt solar causes increased reliance on RAAIM exempt gas, demand response, and imports to meet system needs.

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14 *Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations. (Decision 21-07-014),* R.19-11-009, CPUC, July 16, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M393/K334/393334426.PDF , p.5-6.

15 Ibid. p6.

- **In the real-time market, less than 90 percent of system resource adequacy capacity was bid or self-scheduled during high load hours**. During the top 210 load hours of the year, 95 percent of system resource adequacy capacity was available in the day-ahead market after outages, 90 percent was offered in the day-ahead market, 94 percent was available after outages in the real-time market, and 88 percent was offered in the real-time market. Resource adequacy availability during the load curtailment event was similar in the 6 to 7 p.m. hour but lower in the 7 to 8 p.m. hour.[16]
- **Overall, total local resource adequacy capacity exceeded requirements in local capacity areas**. Significant amounts of energy, beyond requirements, were available in the day-ahead market for several local capacity areas, but procurement in other local capacity areas was significantly lower than the local area requirements.

Capacity additions and withdrawals

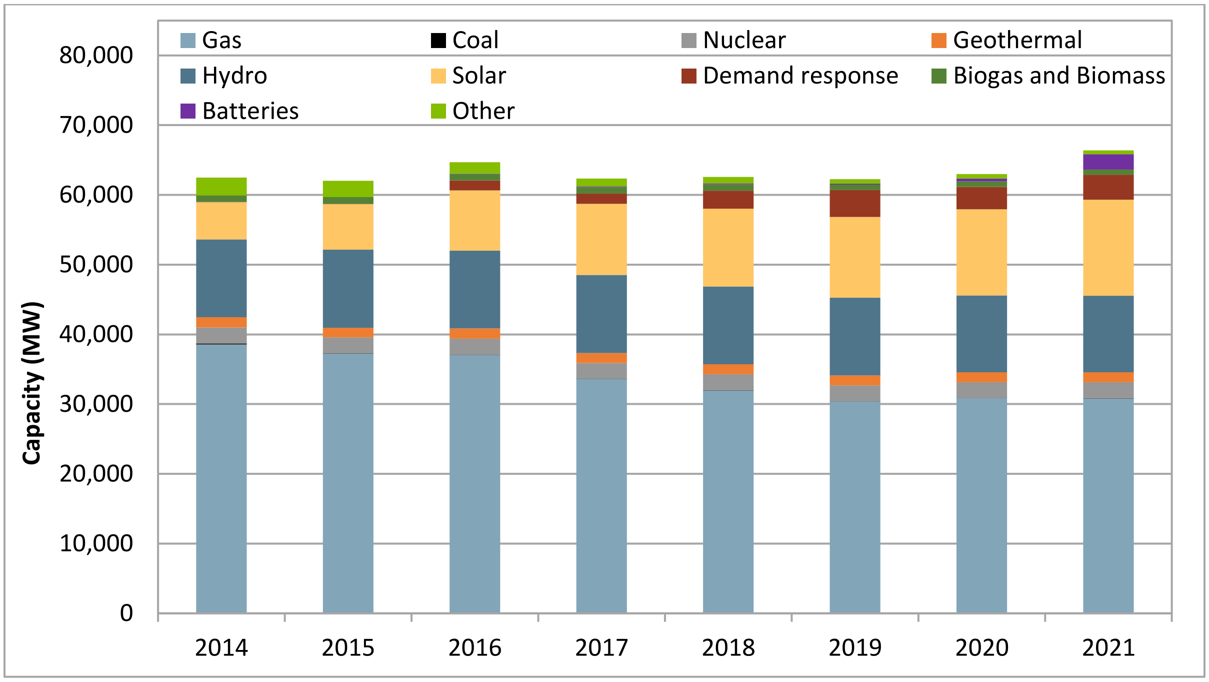
California currently relies on long-term procurement planning and resource adequacy requirements placed on load serving entities by the CPUC to ensure that sufficient capacity is available to meet system and local reliability requirements. CPUC policies also have a major impact on the type of different generating resources retained and added to the ISO system.

Figure E.10 summarizes the trends in available nameplate capacity from June of 2014 through 2021. During this time gas capacity internal to the ISO fell from about 38 GW to 31 GW. This capacity was replaced by solar, which grew from about 5.3 GW to 13.8 GW; by wind, which grew from 5.3 GW to 5.9 GW; by demand response which grew from 0 GW to 3.6 GW; and by batteries which grew from 0 GW to 2.2 GW. Most of the retired natural gas capacity was located in local capacity areas. While solar, wind, and demand response nameplate capacity additions have exceeded reductions in gas capacity, variable energy and demand response resources generally have limited energy and availability compared to gas capacity.[17]

16 An in-depth analysis and report of these factors may be found in the Department of Market Monitoring's *Report on Market Conditions, Issues and Performance – August and September 2020*. http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

17 In contrast to gas and nuclear capacity the resource adequacy contributions, or qualifying capacity (QC), of wind and solar resources in the ISO is discounted compared to nameplate capacity to reflect that these resource types have limited availability across peak net load hours. Additionally, compared to nuclear and most gas resources demand response resources generally are limited to operating only a subset of hours each month.

Figure E.10 Total ISO participating capacity by fuel type and year (as of June 1)



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 2021, if conditions allow, 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 spot market revenues and bilateral contracts, both multi-year and short-term. 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. In 2020, estimated net revenues for both combined cycles and combustion turbines in southern California exceeded estimated going-forward fixed costs. Estimated net revenues for new gas resources in northern California rose, but fell below estimated going-forward fixed costs, and substantially below annualized fixed costs. These findings highlight the critical importance of capacity payments including resource adequacy contracts and other bilateral contracts, and the 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.

DMM's analysis tests net revenues using multiple scenarios which provide a range of potential results. For a new combined cycle unit, DMM estimates that net operating revenues earned from the energy markets in 2020 ranged from \$23/kW-yr to \$48/kW-yr. This compares to estimated going-forward fixed costs ranging from \$26/kW-yr to \$35/kW-yr and potential annualized fixed costs of approximately \$116/kW-year. Net revenues summed with a generous capacity payment (\$76/kW-yr, the ISO's backstop capacity soft offer cap) are well in excess of going-forward fixed costs in all years but fall short of annualized fixed costs in every year, with the exception of SP15 in 2020 and 2017.

For a new combustion turbine unit, our estimates ranged from $27/kW-yr to $43/kW-yr compared to going-forward fixed costs of $27/kW-yr to $28/kW-yr and potential annualized fixed costs of about $142/kW-yr.

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

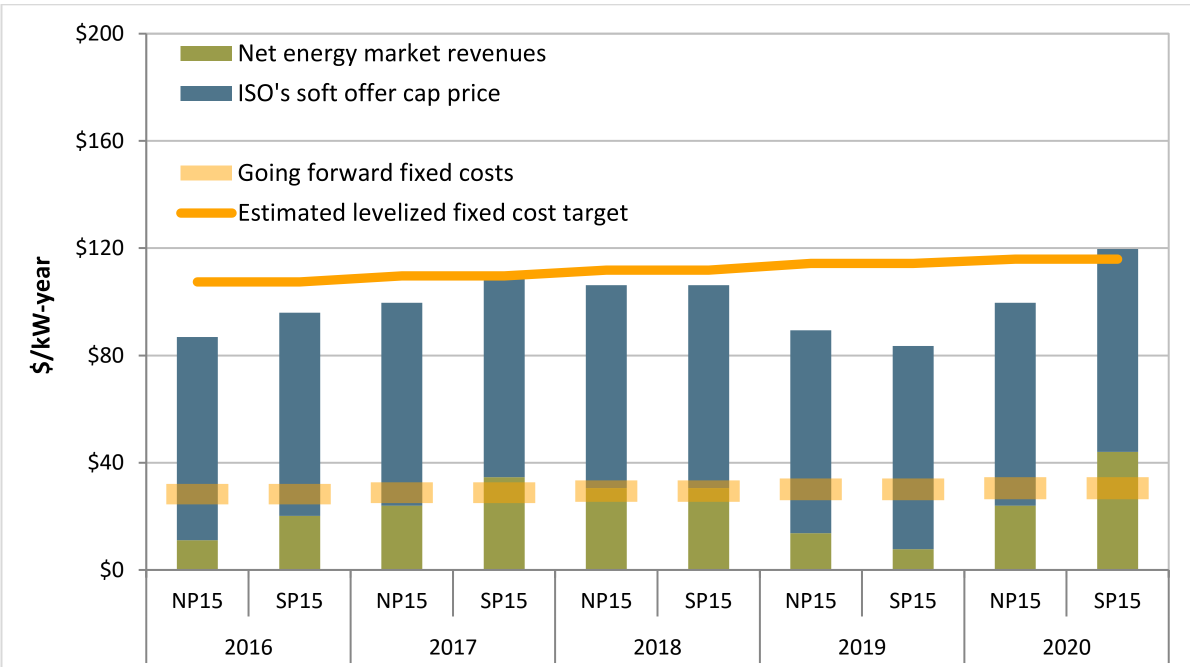
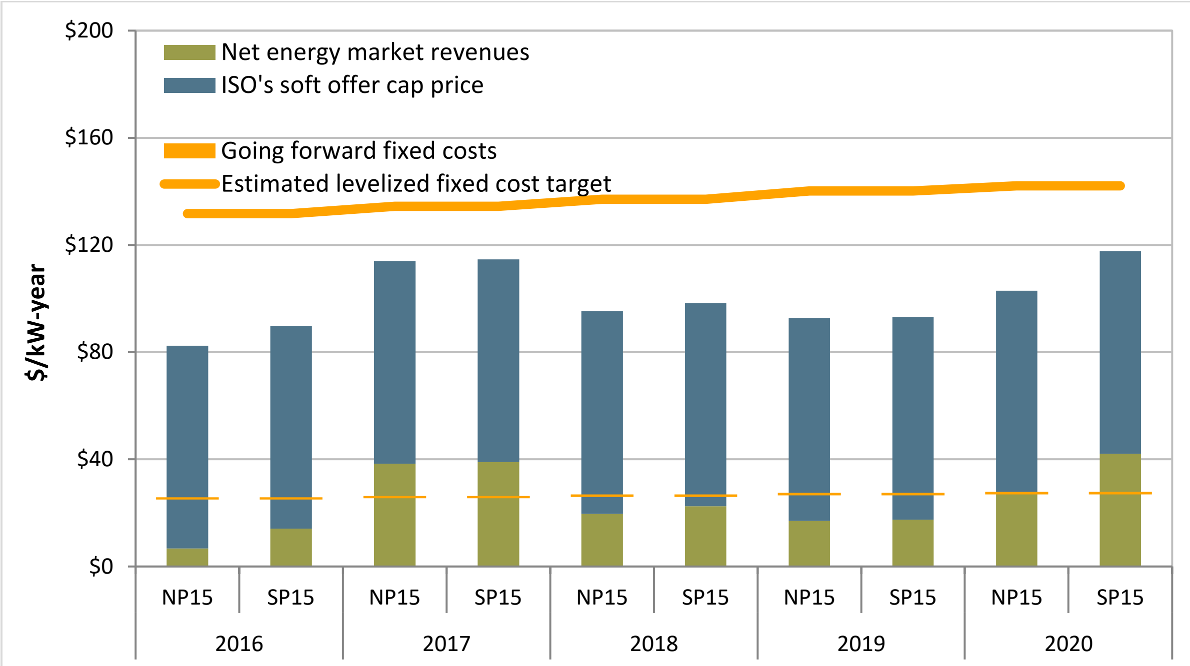


Figure E.12 Estimated net revenues of hypothetical combustion turbine



For 2020, this analysis has been expanded to include net market revenues for a new battery energy storage system. As shown in Table E.1, results from the analysis show that net market revenues for a battery unit participating in both energy and regulation markets significantly exceeded net market revenues for gas-fired resources. In addition, net revenues are higher in southern local capacity areas than northern areas.

Table E.1 New battery energy storage net market revenues by LCA (2020)

Local capacity area	TAC area	Net market revenues ($/kW-yr)	
		Scenario 1	Scenario 2
		Energy arbitrage only	Energy and Regulation
Greater Bay Area	PG&E	$10.98	$102.41
North Coast & North Bay (NCNB)	PG&E	$16.58	$110.56
Greater Fresno	PG&E	$20.65	$118.86
Sierra	PG&E	$18.41	$108.38
Stockton	PG&E	$11.35	$103.79
Kern	PG&E	$12.59	$111.41
LA Basin	SCE	$27.52	$135.26
Big Creek/Ventura	SCE	$23.28	$132.08
San Diego/Imperial Valley	SDG&E	$24.93	$134.99
CAISO System		$16.20	$119.37

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, the CPUC, market participants, and other interested entities.[18] DMM provides written comments and recommendations in the ISO's stakeholder process in quarterly, annual, and other special reports.[19] DMM's current recommendations on key market design initiatives are summarized below and in Chapter 10.

Resource adequacy

California has relied upon the state's long-term bilateral procurement process and resource adequacy program to maintain adequate system capacity and help mitigate market power for over 16 years. However, numerous regulatory and structural market changes have occurred in recent years which create the need for significant changes in the state's resource adequacy framework.

The CPUC is currently working with the ISO and stakeholders on moving forward with more detailed market design options and decisions. These include:

- Developing resource adequacy requirements that consider both energy and capacity needs across all hours of the day, including the peak net load hours.
- Developing resource adequacy requirements and resource capacity ratings that ensure sufficient flexible capacity needed to integrate a high level of renewable resource capacity.
- Adopting a multi-year framework for local resource adequacy requirements and procurement by load serving entities.
- Developing a central buyer framework for meeting any local resource adequacy requirements not met by resource adequacy capacity procured by CPUC-jurisdictional load serving entities.

DMM supports these efforts and views the options being considered by the CPUC as potentially effective steps in addressing the current gaps in the state's resource adequacy framework. In addition:

- **Performance incentives.** The ISO's current resource adequacy availability incentive mechanism (RAAIM) is based solely on resource availability (as measured by bids submitted to the market) during a large number of hours, rather than on actual performance during the most important hours. Potential penalties under this mechanism are very limited compared to resource adequacy capacity payments in recent years. DMM recommends that the ISO and local regulatory authorities consider developing strong financial incentives tied to resource performance that could better ensure that resource adequacy capacity is available and performs on critical operating days.
- **Resource adequacy imports.** DMM recommended that the ISO and local regulatory authorities adopt a source-specific framework for resource adequacy imports with a real-time must-offer requirement, which ensures that import energy cannot be recalled to other balancing areas,

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

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

particularly when other balancing areas also face supply shortages. This recommendation is described in more detail below.

Resource adequacy imports

DMM has a longstanding concern that existing ISO 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.[20] DMM recommended that the ISO address this issue by requiring that resource adequacy imports be backed by specific resources to avoid double counting of capacity across the west, and that the ISO establish a must-offer requirement for these imports in the real-time market.

The CPUC sought to address concerns about the reliability of resource adequacy imports through rules applicable to CPUC jurisdictional entities using imports to meet resource adequacy requirements. In 2020, the CPUC issued a decision specifying that non-resource specific import resource adequacy resources must be self-scheduled or bid into ISO markets at or below $0/MWh during peak net load hours of 4 to 9 pm.[21] DMM supported the CPUC's approach as an interim measure to better ensure delivery of import resource adequacy in peak net load hours while the CPUC and stakeholders considered alternative solutions that would allow resource adequacy imports to participate more flexibly in the market.[22]

The ISO is currently considering further changes to import resource adequacy rules including a real-time must-offer obligation for resource adequacy imports, and requirements that resource adequacy imports be associated with a specific source and delivered on firm transmission to the ISO border.

DMM supports development of a source-specific framework for resource adequacy imports with a real-time must-offer requirement, which ensures that import energy cannot be recalled to other balancing areas, particularly when other balancing areas also face supply shortages.

DMM also suggested that resource adequacy imports could be subject to lower bidding limits when potential system market power exists. Unlike other imports, resource adequacy imports receive capacity payments and can be subject to must-offer obligations.

Demand response

In August and September 2020, the ISO relied on demand response to curtail load more frequently and at much higher levels than in nearly two decades. Demand response resources were used to meet about 4 percent of total system resource adequacy capacity requirements in August and September 2020.

However, about one-third of that demand response resource adequacy capacity was not available for dispatch during the hours when load was curtailed during August. In addition, the actual aggregate load

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[20] Under ISO rules, resource adequacy imports only need to submit bids into the day-ahead market (up to the $1,000/MWh bid cap), and have no further obligation to be offered in the real-time market if these bids are not accepted in the day-ahead market. If accepted in the day-ahead market, these imports do not face any significant financial penalty if they are not delivered in real-time.

[21] *Decision Adopting Resource Adequacy Import Requirements (D.20-06-028)*, CPUC, June 25, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K516/342516267.PDF

[22] *Comments on Proposed Decision Clarifying Resource Adequacy Import Rules*, R.17-09-020, September 26, 2019. http://www.caiso.com/Documents/CommentsofDepartmentofMarketMonitoringonProposedDecisionClarifyingRAImportRules-R17-09-020-Sept262019.pdf

reduction of these resources was significantly lower than the amount of this capacity that was dispatched. Based on these outcomes, DMM recommended that the ISO and CPUC take steps to ensure that a higher portion of demand response capacity used to meet resource adequacy requirements be available for dispatch in the ISO markets and respond when dispatched.

Current CPUC rules apply a 15 percent adder to demand response capacity which contributes to reducing resource adequacy procurement requirements. DMM recommended that the CPUC consider removing the 15 percent adder that is applied to demand response capacity as this adder appears to overstate underlying demand response programs' actual contribution to resource adequacy requirements. The CPUC will reduce this adder to 9 percent for 2022 and will consider further reductions or the elimination of this adder beyond 2022. [23]

DMM also recommended the ISO and local regulatory authorities consider developing stronger resource adequacy mechanisms tied to resource performance which could better ensure that resource adequacy capacity is available and is incentivized to perform on critical operating days. This recommendation includes stronger performance incentives for demand response resources. DMM outlined additional detailed recommendations related to demand response in its 2021 report on demand response resource issues and performance. These included adopting a process to manually dispatch proxy demand response resources counted for resource adequacy and removing the exemption for long-start proxy demand response resources to be available in the residual unit commitment process.[24]

Energy storage resources

Beginning in 2019, DMM provided analysis and expressed concern about the cumulative impacts of various energy-limited or availability-limited resources, including batteries, which are being relied upon to meet an increasing portion of resource adequacy requirements.[25] DMM noted that the costs and actual operation of these types of energy and availability limited resources in ISO markets, to meet both peak demand and energy needs, will be important to consider in procurement directives by the CPUC and other local regulatory entities, particularly if these resources will comprise an increasing share of the resource adequacy fleet going forward.

DMM recommended potential changes to CPUC and ISO rules that could help mitigate availability concerns related to battery resources. These recommendations include developing default energy bids and subjecting battery resources participating under the ISO's non-generator resource (NGR) model to local market power mitigation.[26] In 2020, the ISO finalized a proposal for developing default energy bids for energy storage resources which is expected to be implemented in fall 2021. DMM supported the

[23] *Decision adopting Local Capacity Obligations for 2022 – 2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program (D.21-06-029)*, CPUC, June 24, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.PDF

[24] Report on *demand response issues and performance*, Department of Market Monitoring, February 25, 2021: http://www.caiso.com/Documents/ReportonDemandResponseIssuesandPerformance-Feb252021.pdf

[25] *Reply Comments of the Department of Market Monitoring*, 16-02-007, August 12, 2019: http://www.caiso.com/Documents/CPUC-DMMReplyCommentsonRulingInitiatingProcurementTrackandSeekingCommentonPotentialReliabilityIssues-Aug122019.pdf

[26] *2018 Annual Report on Market Issues and Performance*, p. 24: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

ISO's proposal, but also recommended that the ISO consider further refinements to default energy bid calculations which could better capture the variability of resource costs across a day.

DMM also observed that exceptional dispatch (ED) instructions sent to battery resources have sometimes resulted in inefficient outcomes on days where system conditions have been very tight. DMM recommends that the ISO consider enhancing processes for issuing exceptional dispatches to battery resources by issuing these dispatches as state of charge values instead of megawatt values.

Flexible ramping product enhancements

The flexible ramping product is designed to procure additional ramping capacity to address uncertainty in imbalance demand through the real-time market software. Although the ISO has implemented numerous improvements to this product since its introduction in 2016, ISO operators continue to rely primarily on significant manual interventions to ensure sufficient ramping capacity is available during the peak ramping hours. These manual interventions include significant upward biasing of the load forecast used in the residual unit commitment and hour-ahead scheduling processes as well as manual commitments and upward dispatches of gas-fired generating units. These manual interventions have remained high, or even increased, since introduction of the flexible ramping product.

In 2021, the ISO completed the design of locational procurement of flexible ramping capacity to decrease the likelihood that the product is not deliverable (or *stranded*) because of transmission constraints. An interim solution, implemented in November of 2020, enforces minimum procurement constraints by area for the 15-minute flexible ramping product in some intervals. DMM recommends that locational procurement be implemented in both the 5- and 15-minute markets.

DMM continues to recommend that the ISO begin to develop an approach for extending the time horizon of the flexible ramping product to account for uncertainty over longer time horizons. The current flexible ramping product is designed to address uncertainty between the 15-minute 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). Extending the time horizon of the flexible ramping product should significantly reduce the need for manual load adjustments and out-of-market dispatches of gas resources.

Day-ahead market enhancements

In 2018, the ISO initiated a process to develop a proposal for day-ahead market enhancements. The ISO released an initial straw proposal in February 2020.[27] A key element of the ISO's initial straw proposal is the introduction of a day-ahead imbalance reserve product that is intended to ensure sufficient ramping capacity is available in the real-time market. DMM supports development of a day-ahead imbalance reserve product. The new reserve product will increase day-ahead market costs through the direct payments for this new product as well as through increases to day-ahead market energy prices resulting from procurement of this product.

[27] *Day-Ahead Market Enhancements Straw Proposal*, February 3, 2020, http://www.caiso.com/InitiativeDocuments/StrawProposal-Day-AheadMarketEnhancements.pdf

However, if the ISO does not extend the uncertainty horizon of the real-time flexible ramping product, DMM is concerned that the imbalance reserves that are procured in the day-ahead market will provide limited benefit in terms of increased ramping capacity in real-time or reduced real-time market costs. Thus, DMM continues to recommend that the ISO take steps to extend the time horizon of the real-time flexible ramping product to enable the market software to commit and position resources to address uncertainty in net load forecasts further out in the future.

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. In 2020, the ISO completed development of potential system market power mitigation measures for the real-time market only. The proposed measures would be triggered when the ISO, or the ISO with a larger sub-area of the western interconnection, may be import constrained.[28,29] In early 2021, the ISO decided to defer further work on developing a final proposal that could be approved and implemented before summer of 2021.

DMM supports the ISO's efforts to design and implement system market power mitigation and is generally supportive of the proposal being developed. Despite some limitations of the ISO's current proposal, DMM believes that the proposal may mitigate real-time market power in some situations. Mitigation of market power in the real-time market may also help mitigate market power in the day-ahead market to some degree. DMM supports the ISO's continued development of system-level market power mitigation measures for the day-ahead and real-time markets in the second phase of the initiative.

The ISO is scheduled to resume consideration of its system market power mitigation proposal in late 2021, as part of an initiative that will include consideration of changes to the ISO's scarcity pricing provisions. DMM cautioned that if scarcity pricing provisions are not well designed and do not accurately account for all available capacity, such provisions could encourage withholding of supply in order to trigger scarcity pricing.

DMM also suggested that resource adequacy imports could be subject to lower bidding limits when potential system market power exists. Unlike other imports, resource adequacy imports receive capacity payments and can be subject to must-offer obligations. DMM also recommended that the ISO consider options for increasing the supply and availability of energy from resource adequacy imports beyond the day-ahead market into real-time.

28 *System Market Power Mitigation Straw Proposal*, California ISO, December 11, 2019: http://www.caiso.com/InitiativeDocuments/StrawProposal-SystemMarketPowerMitigation.pdf

29 *System Market Power Mitigation Revised Straw Proposal*, California ISO, April 7, 2020: http://www.caiso.com/InitiativeDocuments/RevisedStrawProposal-SystemMarketPowerMitigation.pdf

Congestion revenue rights

Congestion revenue rights sold in the auction consistently collect much less in total auction revenues than the total payments that are made to entities purchasing these revenue rights. 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 2009 through 2018, transmission ratepayers received about 48 percent of the value of their congestion revenue rights sold at auction, with a total shortfall of more than $860 million. Most of these losses have resulted from profits received by purely financial entities which purchase congestion revenue rights but do not schedule power or load in the ISO.

In response to these systematic losses from congestion revenue right auction sales, the ISO instituted significant changes to the congestion revenue right auction starting in the 2019 settlement year. While changes implemented by the ISO reduced losses from the congestion revenue rights auction, losses to ratepayers from the auction were still significant. In 2019, losses from auctioned congestion revenue rights totaled about $22 million. In 2020, transmission ratepayer losses from congestion revenue right auctions totaled over $70 million.

DMM believes that under current rules it remains likely that the congestion revenue rights auction will continue to result in significant losses to transmission ratepayers. DMM continues to recommend that the ISO take steps to discontinue auctioning congestion revenue rights and instead reallocate all congestion revenues back to ratepayers who pay for the cost of the transmission system through the transmission access charge. If the ISO believes it is highly beneficial for the ISO to actively facilitate hedging of congestion costs by suppliers, DMM recommends that the ISO replace the auction with a market for financial hedges based on clearing of bids from willing buyers and sellers.

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.
- **Energy imbalance market.** Chapter 3 highlights the growth and performance of the energy imbalance market.
- **Convergence bidding.** Chapter 4 analyzes the convergence bidding feature and its effects on the market.
- **Ancillary services.** Chapter 5 reviews performance of the ancillary service markets.
- **Market competitiveness and mitigation.** Chapter 6 assesses the competitiveness of the energy market, along with impact and effectiveness of market power and exceptional dispatch mitigation provisions.
- **Congestion.** Chapter 7 reviews congestion and the market for congestion revenue rights.
- **Market adjustments.** Chapter 8 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 9 assesses the short-term performance of California's system and flexible resource adequacy programs.
- **Recommendations.** Chapter 10 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 2020, wholesale electricity prices were higher despite a decrease in gas prices, lower load and an increase in supply from both hydroelectric and new solar generation.

More specific trends highlighted in this chapter include the following:

- **ISO load continued to decrease in 2020**, on average, due in part to increases in behind-the-meter solar generation, continued initiatives to improve energy efficiency, and the public health order that directed Californians to stay at home in response to COVID-19. This effect was offset during peak hours, however, when higher than average temperatures caused peak demand to significantly exceed the 1-in-2 load forecast for a number of days.
- **Peak load exceeded peaks in 2018 and 2019,** and was about 3 percent higher than the ISO's 1-in-2 year load forecast and about 3 percent lower than the 1-in-10 year forecast.
- **The average price of natural gas in the California spot market decreased by about 30 percent at SoCal Citygate and by 15 percent at PG&E Citygate**. Lower gas prices reflect the return to service of gas pipeline capacity, revised Aliso Canyon storage protocols, and lower gas penalty prices.
- **Hydroelectric generation decreased to 8 percent of supply in 2020,** a 36 percent decrease compared to the average of about 13 percent over the previous four years.
- **Net imports accounted for 21 percent of generation, increasing from about 19 percent** in 2019, as the source of imports shifted from the Southwest to the Northwest.
- **Non-hydro renewable generation accounted for about 28 percent of total supply in 2020**, up from 27 percent in 2019.[30] Solar generation increased by about 7 percent and accounted for around 14 percent of total supply. The increase was primarily driven by the addition of new solar generation capacity.
- **Over 4,000 MW of gas capacity was scheduled to retire before the summer of 2021,** but instead remains operational. The ISO took steps to prevent these retirements to keep necessary capacity online to maintain reliability during the summer peak.
- **Demand response resource capacity that was registered and bid into the market decreased** between 2019 and 2020, but the percentage of supply plan demand response with long-start operating characteristics more than doubled from 2019. Long-start demand response capacity is not available to the ISO in the residual unit commitment process or in real-time unless committed in the day-ahead market.
- **Capacity from battery storage resources grew dramatically between summer of 2019 and 2020 and again before the summer of 2021** and continued to be dispatched primarily for ancillary services rather than energy.

[30] 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.

- **The estimated net operating revenues for typical new gas-fired generation in 2020 fell below DMM's estimate of the going-forward fixed costs** of gas capacity and remained substantially below the annualized fixed cost of new generation in northern areas. In southern areas, estimated net revenues exceeded going-forward fixed costs. For combined cycles in southern areas, the sum of net market revenues with additional capacity payment at the soft-offer cap exceeded annualized fixed cost of new generation.

- **The estimated net operating revenues for a typical new fast-ramping lithium-ion battery energy storage system** exceeded that of gas-fired generation in 2020, once ancillary service payments were included, averaging about $109/kW-yr in northern local capacity areas compared to $134/kW-yr in southern areas.

1.1 Load conditions

1.1.1 System loads

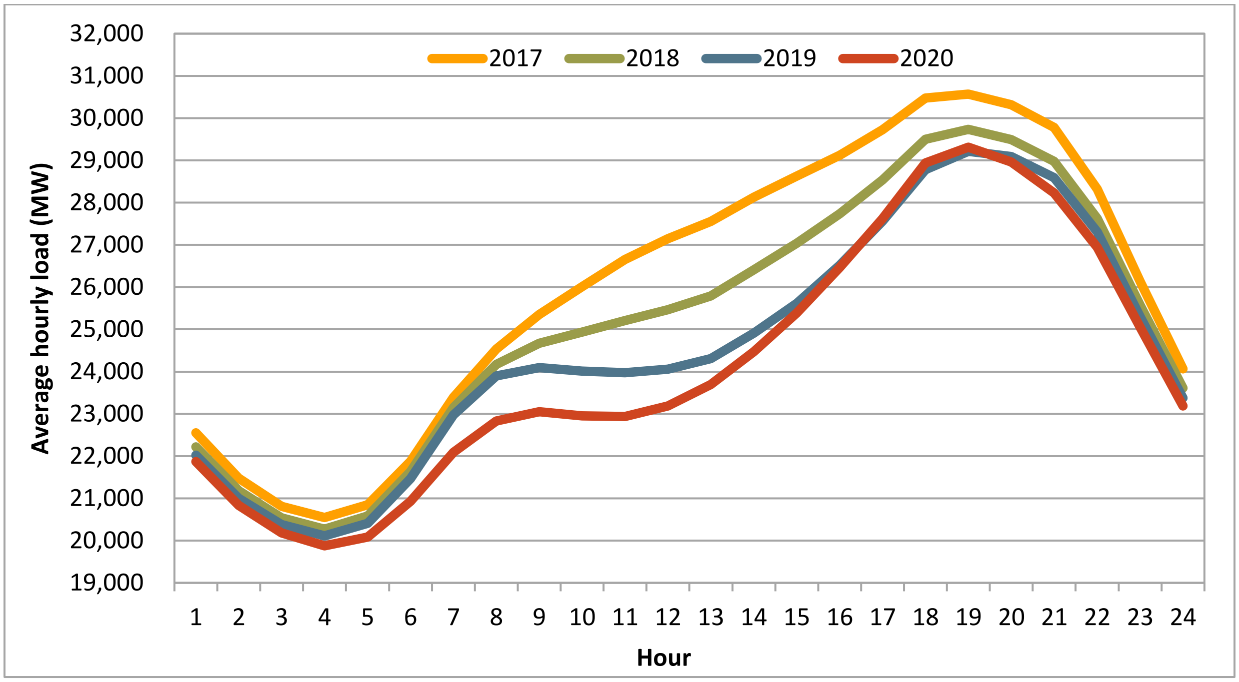
ISO load measured in total energy and average load decreased in 2020, but the instantaneous peak increased over previous years. Table 1.1 summarizes annual system peak loads and energy use over the last four years. The drop in total annual load in 2020 continued a trend of decreasing loads since 2011. In 2020, annual system load totaled 211,919 GWh, and averaged about 24,130 MW on an hourly basis. This was about a 1.7 percent decrease from 2019 and a 7.2 percent decrease from 2017. The increase in the annual instantaneous peak load in 2020 was a reversal from previous years. In 2020, the instantaneous peak load reached 47,121 MW. This was about a 6.4 percent increase from 2019 and a 1.5 percent increase since 2018.

Table 1.1 Annual system load in the ISO: 2017 to 2020

Year	Annual total energy (GWh)	Average load (MW)	% change	Annual peak load (MW)	% change
2017	227,749	26,002	0.0%	50,116	8.4%
2018	220,458	25,169	-3.2%	46,427	-7.4%
2019	214,955	24,541	-2.5%	44,301	-4.6%
2020	211,919	24,128	-1.7%	47,121	6.4%

Figure 1.1 shows average hourly loads by year. This figure shows how the overall load shape has changed since 2017. Lower loads are due, in part, to increases in behind-the-meter solar generation, continued initiatives to improve energy efficiency, as well as variation in statewide temperatures. The divergence in load across years through the middle of the day, when solar production is high, shows the effect of increased behind-the-meter solar generation on load in California. Additionally, the shift in commercial and industrial load to residential load that resulted from the COVID-19 stay-at-home orders resulted in lower morning peak loads in 2020.

Figure 1.1 Average hourly load (2017-2020)



Seasonal load trends

Figure 1.2 shows the average hourly load by quarter as observed in 2020 and the prior three years. Figure 1.3 shows the average hourly load by month for these same years to show more detail. These figures work to paint a clearer picture of the trends and fluctuations of load over the years.

Average load was lower in the first three quarters of 2020 compared to the previous three years. Average load in the fourth quarter of 2020 was higher than the same quarter in 2019 and is largely attributed to a warmer than usual October. Load trends are influenced by a number of factors, but tend to follow statewide temperatures on average.[31] This trend was broken in 2020, however, when the COVID-19 related stay-at-home orders resulted in lower loads even when statewide quarterly temperatures were at or higher than those experienced over the past few years.

31 For statewide temperature data, please see: Climate at a Glance: Statewide Mapping, National Oceanic and Atmospheric Administration (NOAA): https://www.ncdc.noaa.gov/cag/.

Figure 1.2 Average hourly load by quarter (2017-2020)

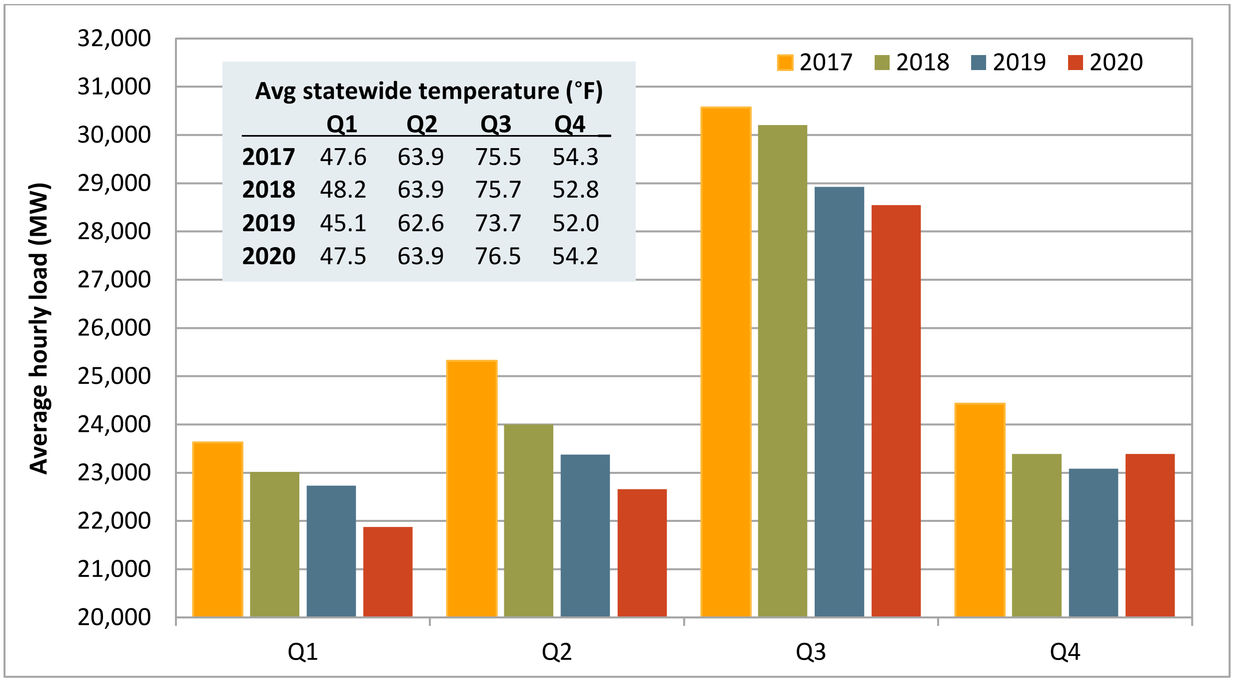
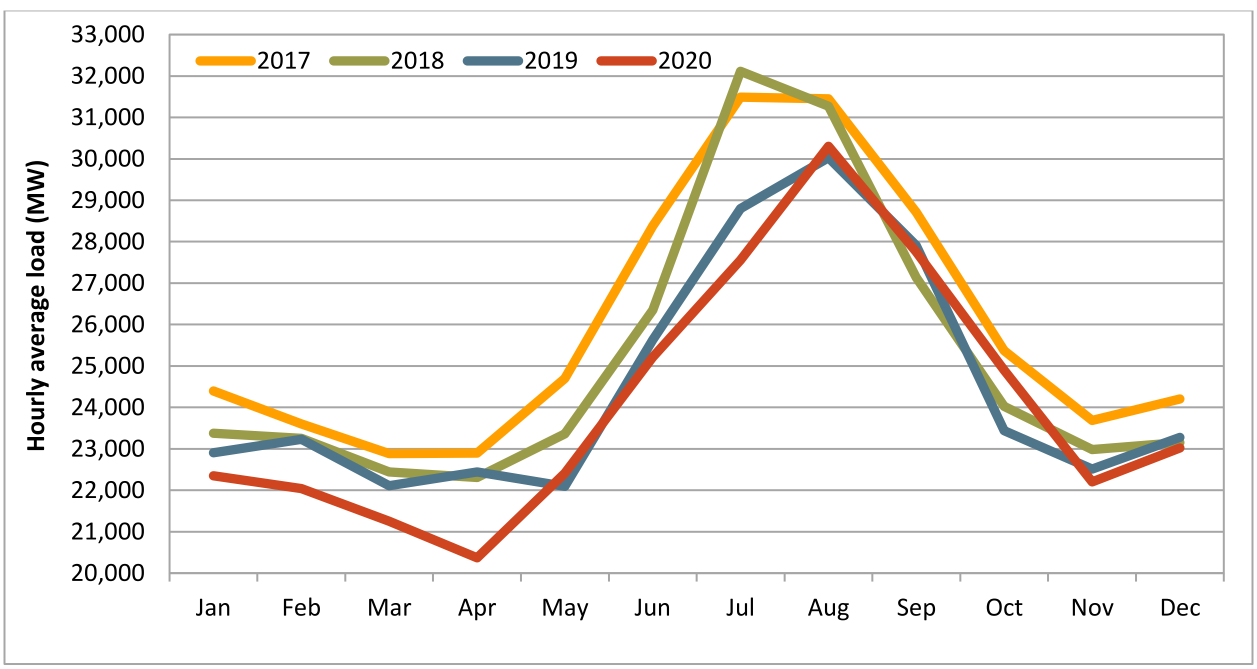


Figure 1.3 Average hourly load by month (2017-2020)

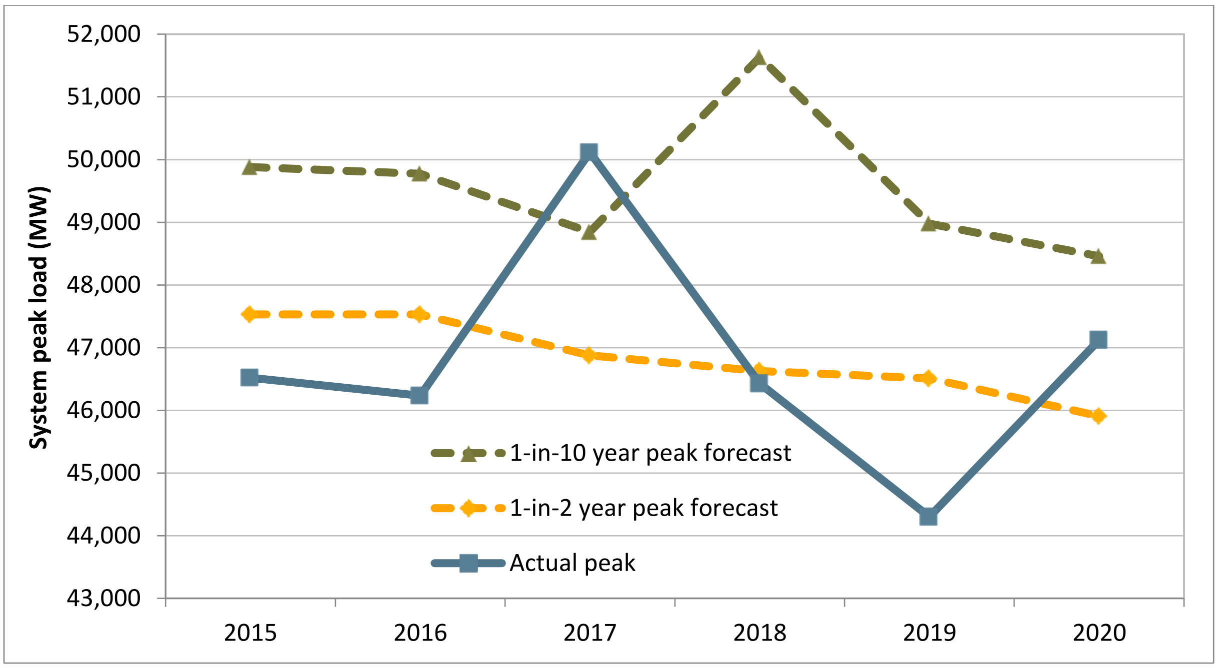


Peak load

Summer loads peaked at 47,121 MW on August 18, the highest peak experienced since 2017. System demand during the single highest load hour often varies substantially year-to-year based on the weather conditions that drive each year's peak load. The potential for extreme 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 2020 was about 3 percent higher than the ISO's 1-in-2 year load forecast (45,907 MW) and about 3 percent lower than the 1-in-10 year forecast (48,457 MW) as shown in Figure 1.4. 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 1.4 Actual load compared to planning forecasts



Summer heat wave event

The ISO experienced stressed system conditions from mid-August to September 7, 2020. During this period, regional high temperatures led to a high demand heat wave across the entire western region. On August 14 and 15, the ISO grid operators called upon load serving entities to curtail load due to system-wide conditions for the first time since 2001. In the following days and weeks, the ISO loads remained high but were well below forecasted levels, due largely to voluntary conservation efforts. For more information about the system conditions and performance of the ISO's day-ahead and real-time markets during this period, please refer to DMM's *Report on system and market conditions, issues, and performance: August and September 2020.*[32]

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 6 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 1.5 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.[33] 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 decreased to a total of 23,643 MW for 2020 compared to 25,244 in 2019. Dependable generation also decreased overall in these areas. This was largely due to recent gas generation retirements, described in greater detail in Section 1.2.9. 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 meet peak reliability planning requirements.[34] 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.

[32] DMM (2020). *Report on system and market conditions, issues, and performance: August and September 2020*. Available at: http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf.

[33] 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.

[34] 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.

Table 1.2 Load and supply within local capacity areas in 2020[35]

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	10,488	22%	7,067	4,550	64%
Greater Fresno	PG&E	3,278	7%	3,158	1,694	54%*
Sierra	PG&E	1,862	4%	2,160	1,764	82%*
North Coast/North Bay	PG&E	1,492	3%	833	742	89%
Stockton	PG&E	1,275	3%	653	629	96%*
Kern	PG&E	1,169	2%	465	465	100%*
Humboldt	PG&E	153	0.3%	197	130	66%
LA Basin	SCE	19,261	40%	10,439	7,364	71%
Big Creek/Ventura	SCE	4,956	10%	5,050	2,410	48%
San Diego	SDG&E	4,613	10%	4,334	3,895	90%
Total		**48,547**		**34,356**	**23,643**	

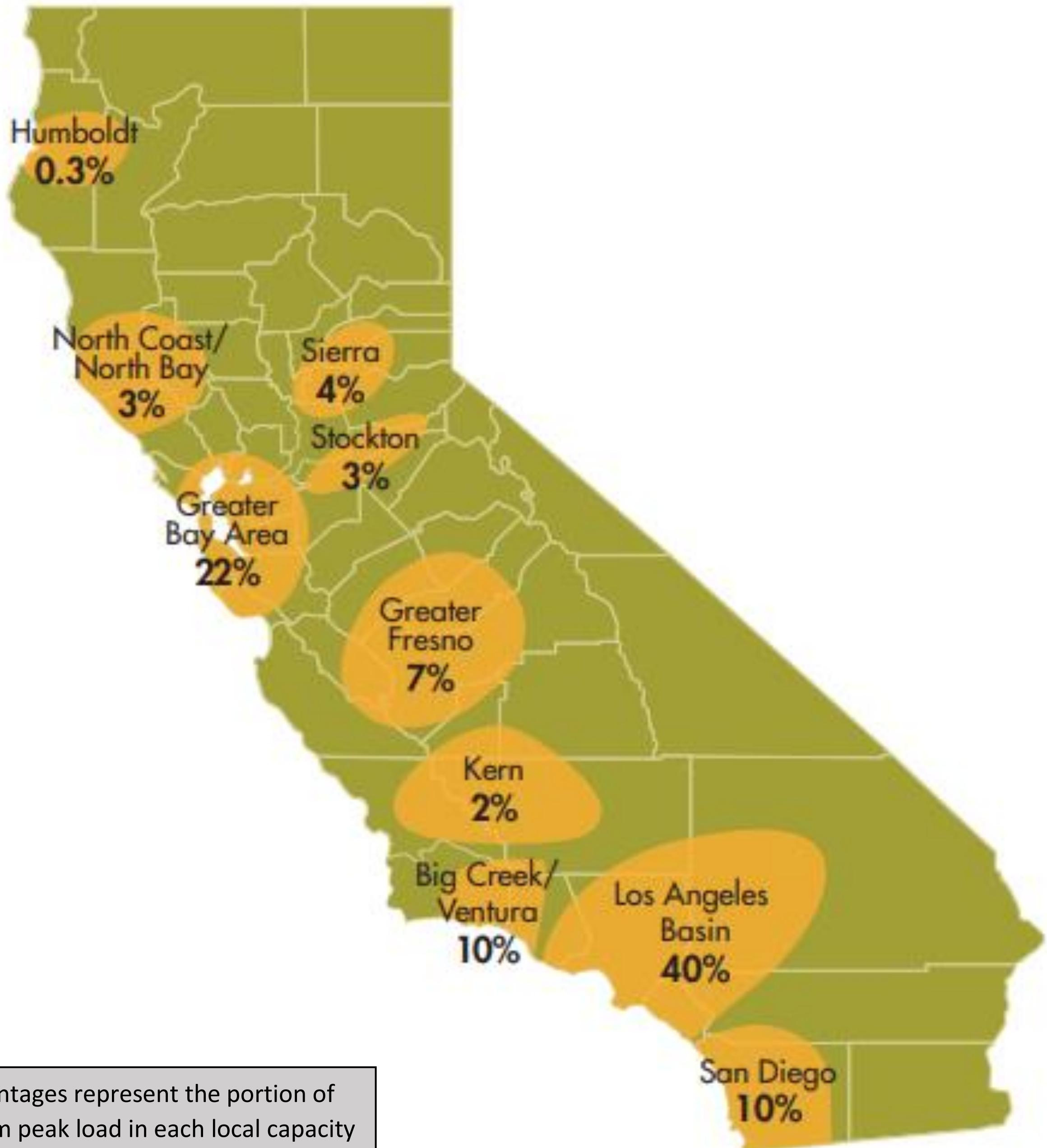
* Resource deficient LCA (or with sub-area that is deficient) – deficiency included in LCR. Resource deficient area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.

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. Between 2019 and 2020, the Greater Bay Area experienced an increase in peak load projection (258 MW) and dependable generation (13 MW). This resulted in a slight increase of the capacity requirement as a percentage of generation from 63 percent in 2019 to 64 percent in 2020.

Conversely, the LA Basin local capacity area experienced a decrease in peak load projection (5 MW) and an increase in dependable generation (213 MW) over this period. This resulted in a decrease of the capacity requirement as a percentage of generation from 79 percent in 2019 to 71 percent in 2020.

35 Obtained from the *2020 Local Capacity Technical Analysis*, May 1, 2019, p. 24, Table 3.1-1: http://www.caiso.com/Documents/Final2020LocalCapacityTechnicalReport.pdf

Figure 1.5 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 2020, together comprising over 80 percent of total system energy. The share of energy from natural gas generators increased by about 3 percent compared to 2019. The share of hydroelectric generation of total generation decreased by about 6 percent in 2020 relative to the levels observed in 2019, driven primarily by a below average snowpack level. The share of non-hydro renewable generation increased 1 percent. Solar generation increased to about 14 percent of total generation, up from about 13 percent in 2019.

Monthly generation by fuel type

Figure 1.6 provides a profile of average hourly generation by month and fuel type. Figure 1.7 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 2020, representing 32, 28, and 21 percent of total generation, respectively.[36] Compared to 2019, the share of energy from renewables increased about 1 percent, natural gas increased around 3 percent, and net imports increased about 2 percent.[37]
- Hydroelectric generation decreased to 8 percent of supply, a 43 percent decline from 2019.
- Natural gas generation accounted for about 32 percent of total supply, an increase from about 30 percent in 2019, driven primarily by reduced hydroelectric generation.
- Nuclear generation provided 10 percent of supply, roughly the same as its contribution in 2019.

[36] Including all tie generation in net imports (as was done in 2016 and years prior), these percentages were 29, 25, and 25 percent, respectively.

[37] 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 1.6 Average hourly generation by month and fuel type in 2020

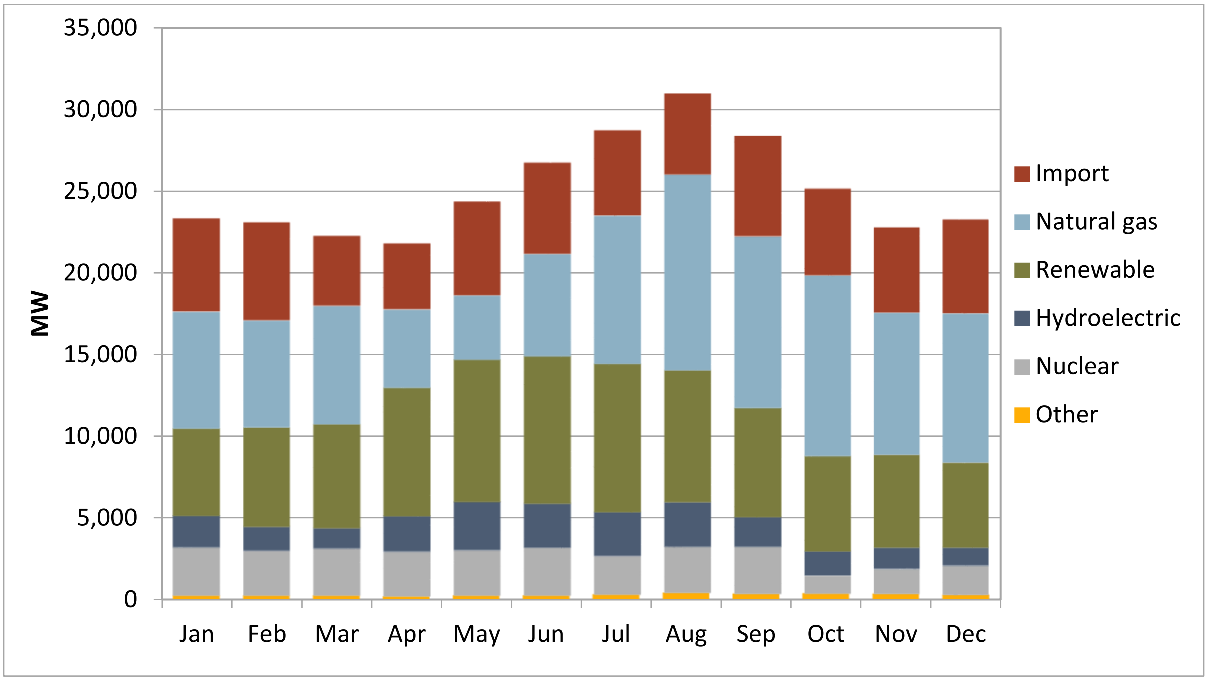
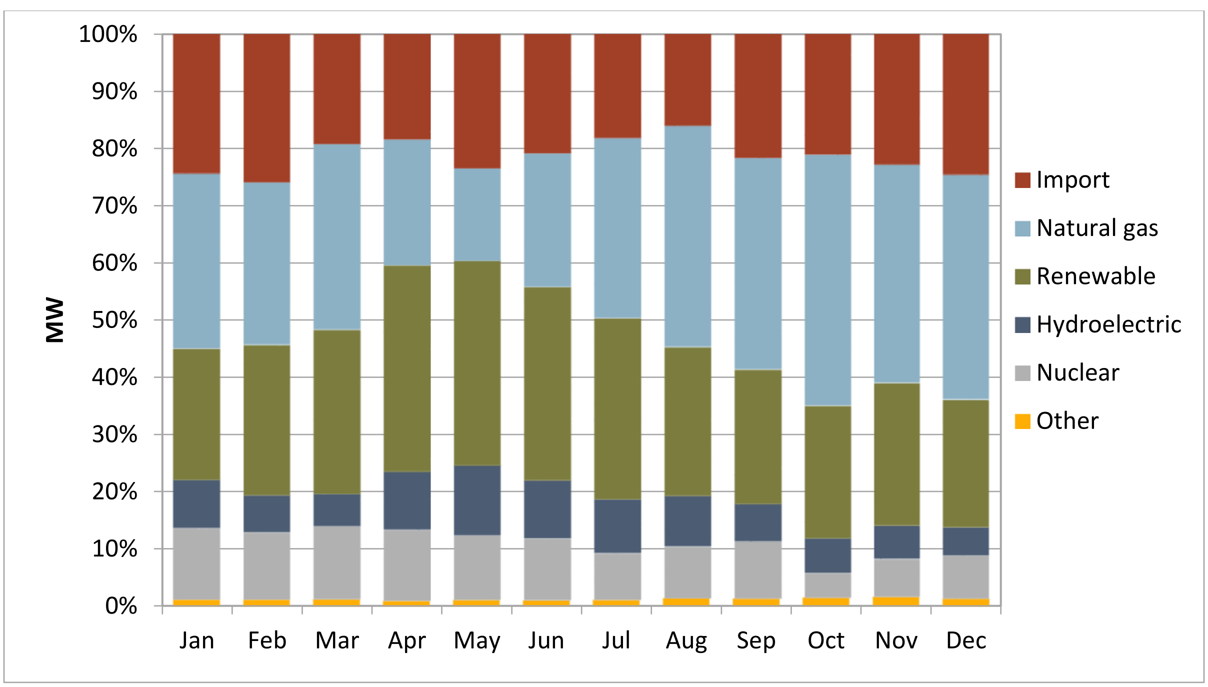


Figure 1.7 Average hourly generation by month and fuel type in 2020 (percentage)



Generation by fuel type

Figure 1.8 shows average hourly generation for the year by fuel type. During the first and second quarters in hours ending 18 through 21, as solar ramped down, the resources being used to meet the evening peak included natural gas, imports, and hydro. In the third quarter, higher loads and lower wind and hydroelectric generation resulted in significantly more production from natural gas relative to the prior quarter, particularly in the evening hours. During the fourth quarter, lower loads coincided with lower solar, hydroelectric, and nuclear generation, which resulted in significantly more production from natural gas relative to other resource types compared to the third quarter.

Overall for 2020, hour ending 19 averaged the highest amount of generation at about 29,900 MW, while hour ending 4 averaged the lowest at about 20,350 MW. Generation from nuclear, bio-based resources, and geothermal resources comprised about 3,900 MW of inflexible base generation on average. Generation from "other" resources, including coal, battery storage, demand response, and additional technologies, was a small share of generation, averaging about 290 MW.

Figure 1.8 Average hourly generation by fuel type (2020)

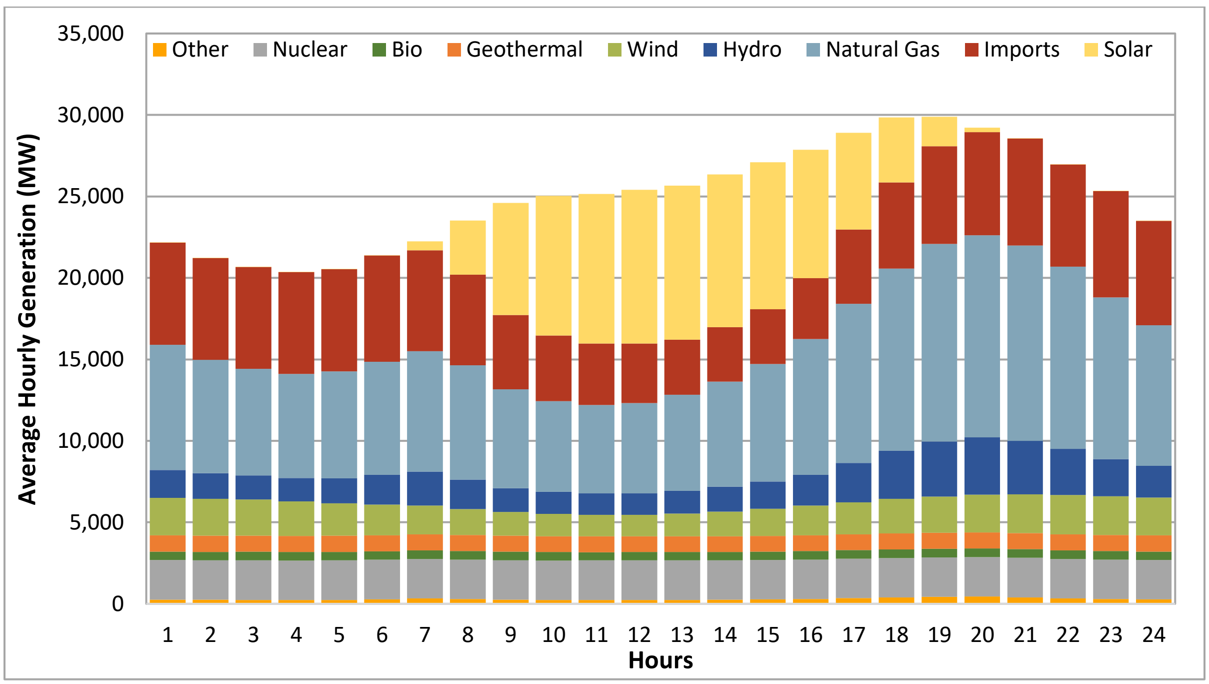
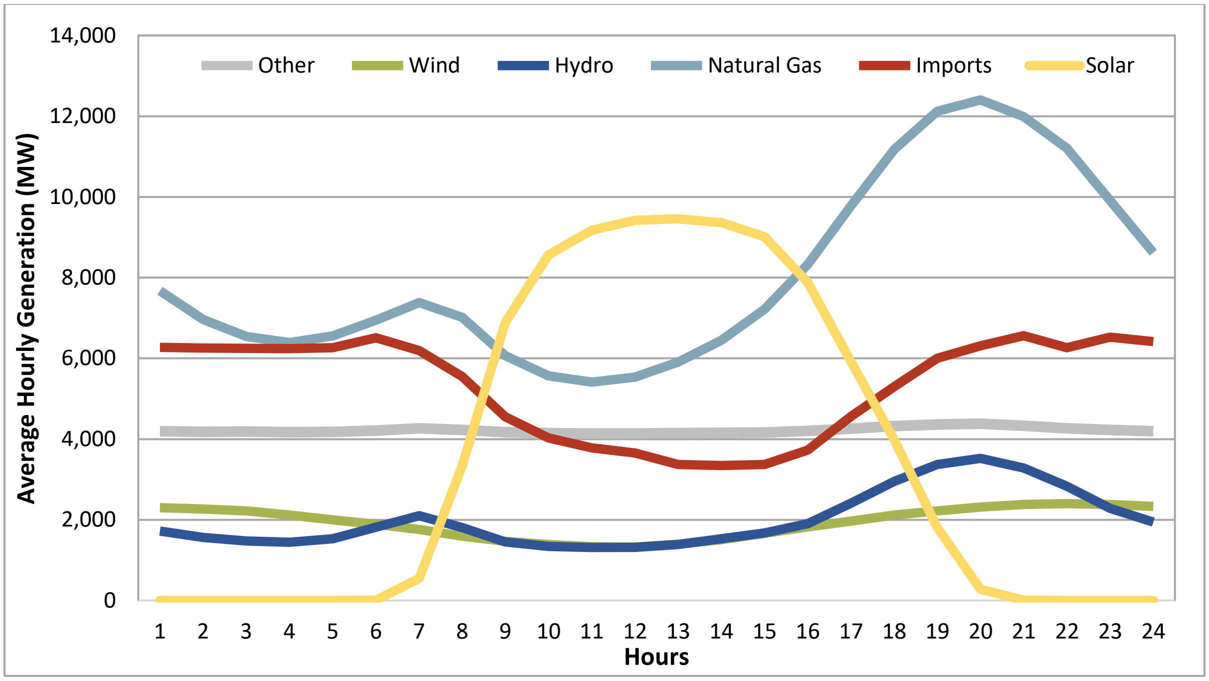


Figure 1.9 shows hourly variation of generation by fuel group, primarily driven by hourly variation of solar production. Throughout the year, natural gas varied most over the day and produced significantly more than other resource types during the peak net load hours. Net imports and hydroelectric generation also varied significantly over the day, ramping up for the morning and evening net load peaks, and backing down when solar was producing.

During the year, imports consistently had higher levels of production than hydroelectric resources throughout the day. Wind generation typically complements solar production by generating more in the early morning and late evening, and less in the middle of the day, a trend that is observable in the annual average. There was little variability from resources in the “other” category on an hourly basis.[38]

Figure 1.9 Hourly variation in generation by fuel type (2020)



1.2.2 Renewable generation

As noted above, about 28 percent of ISO load was met by non-hydro renewable and about 8 percent from hydroelectric generation. This section provides additional detail about trends in renewable generation, factors influencing renewable resource availability, and the impact of renewable generation on prices.

Figure 1.10 provides a detailed breakdown of non-hydro renewable generation including imports which are specifically identified as wind and solar resources.[39] As shown in Figure 1.10:

- In 2015, solar power became the largest source of renewable energy within the ISO. In 2020, overall output from solar generation increased by about 7 percent compared to 2019 and accounted for around 14 percent of total supply. The increase was primarily driven by the addition of new solar resources. The rate of increase in generation from solar has continued to be slow over recent years.
- Generation from wind resources increased by about 2 percent and contributed about 8 percent of total system energy.

[38] In this figure, the “other” category contains nuclear, geothermal, bio-based resources, coal, battery storage, demand response, and additional resources of unique technologies.

[39] 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.

- The overall output from geothermal generation remained unchanged compared to 2019, and continued to provide about 4 percent of system energy.
- Biogas, biomass, and waste generation decreased about 4 percent. Together they accounted for about 2 percent of system energy, similar to that of 2019.

Figure 1.10 Total renewable generation by type (2017-2020)

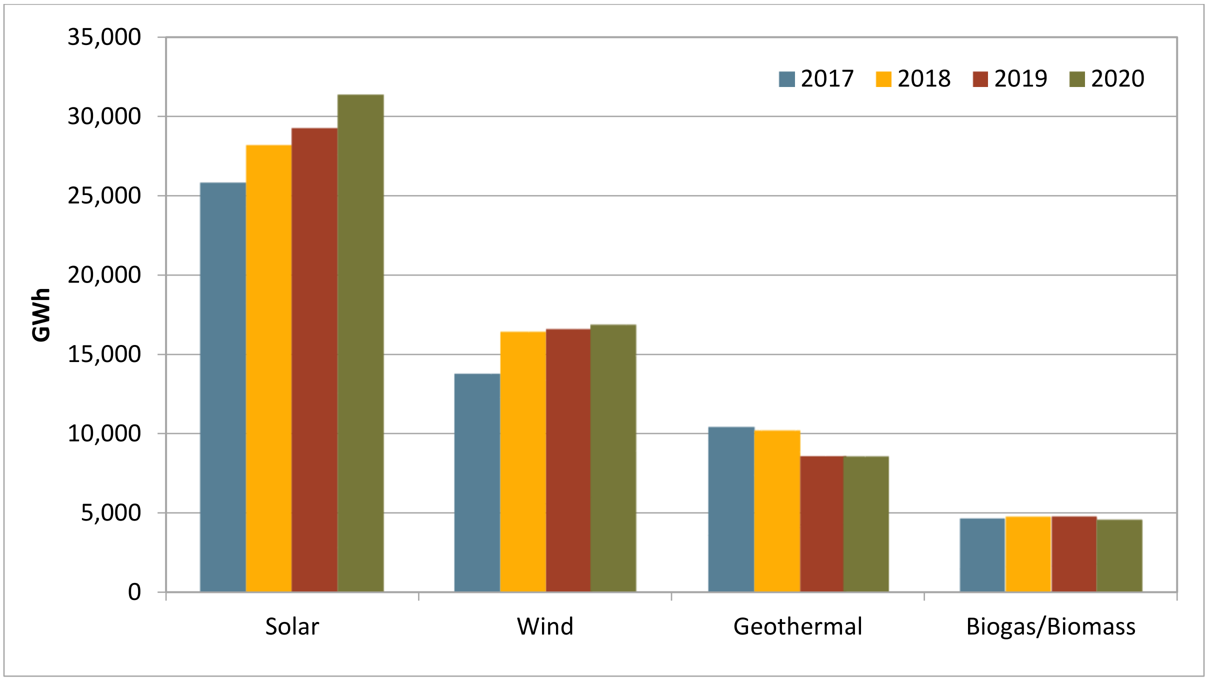
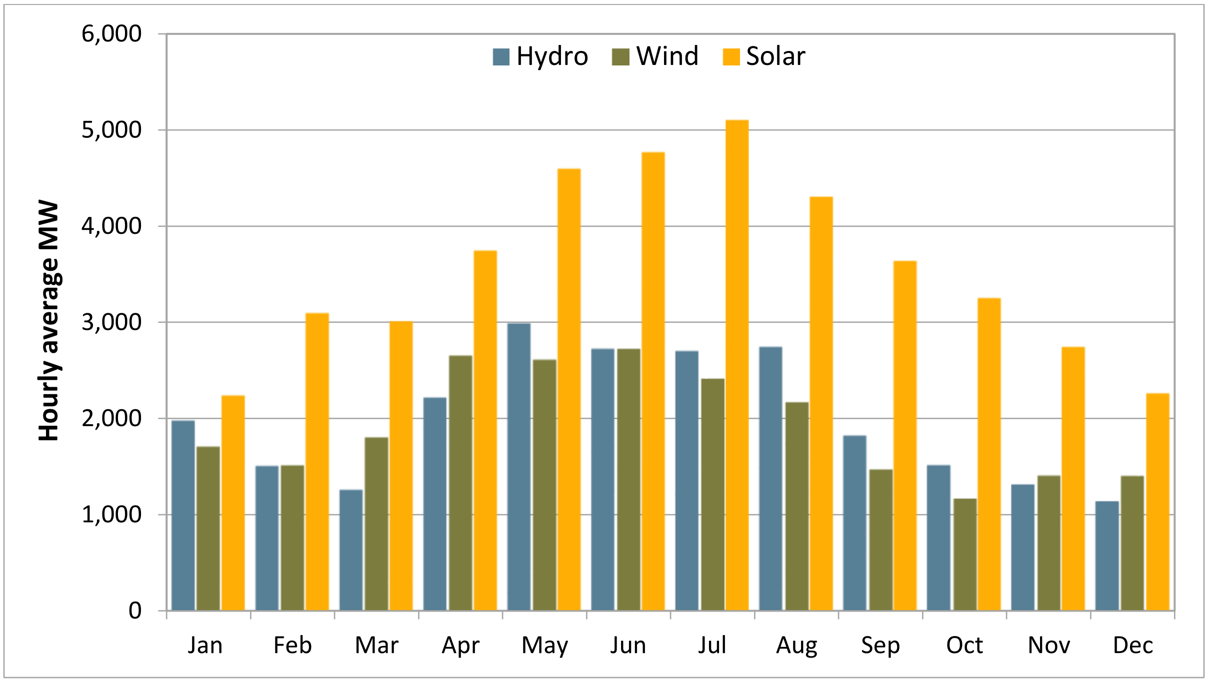


Figure 1.11 compares average monthly generation from hydro, wind, and solar resources. With dramatically decreased snowpack, the amount of energy produced by hydroelectric was closer to that of wind generation for most months of 2020.

In 2020, average hourly solar generation peaked at 11,672 MW on June 29 during hour ending 13. Generation from hydroelectric and wind resources peaked in May and June, respectively. Non-hydro renewable generation made up the greatest portion of system generation during April, when it accounted for 36 percent of total generation.

Figure 1.11 Monthly comparison of hydro, wind and solar generation (2020)



Downward dispatch and curtailment of variable energy resources

When the amount of supply on-line exceeds demand, the real-time 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 economically.

If the supply of bids to decrease energy is completely exhausted in the real-time market, the software may curtail self-scheduled generation including self-scheduled wind and solar generation.

Figure 1.12 shows the curtailment of wind and solar resources by month in the ISO. Curtailments fall into six categories:

- **Economic downward dispatch**, in which an economically bid resource is dispatched down and the market price falls within one dollar of a resource bid, below a resource bid, or the resource's upper limit is binding;[40]
- **Exceptional economic downward dispatch**, in which a resource receives an exceptional dispatch or out of market instruction to decrease dispatch;
- **Other economic downward dispatch**, in which the market price is greater than one dollar above a resource bid and that resource is dispatched down;

[40] A resource's upper limit is determined by a variety of factors and can vary throughout the day.

- **Self-schedule curtailment**, in which a price-taking self-scheduled resource receives an instruction to reduce output while the market price is below a resource bid or the resource's upper limit is binding;
- **Exceptional self-schedule curtailment**, in which a self-scheduled resource receives an exceptional dispatch or out of market instruction to reduce output; and
- **Other self-schedule curtailment**, in which a self-scheduled resource receives an instruction to reduce output and the market price is above the bid floor.

The majority of the reduction in wind and solar output during the year was a result of economic downward dispatch, rather than self-schedule curtailment. Most renewable generation dispatched down in the ISO were solar resources, rather than wind, because solar resources typically bid more economic downward capacity than wind resources.

In the ISO, total curtailment was 54 percent higher in 2020 compared to 2019. Economic downward dispatch accounted for about 1,582,000 MWh (93 percent) of curtailment during the year, compared to about 982,000 MWh during the previous year. Self-scheduled curtailment accounted for about 65,000 MWh (4 percent) of total curtailment, down from about 76,000 MWh in 2019. Over the year, exceptional dispatch curtailments of both self-scheduled and economic bid resources was about 32,000 MWh (2 percent). The roughly 18,000 MWh (1 percent) of remaining curtailment came from "other" economic and self-scheduled curtailment.

Figure 1.13 shows downward dispatch of non-ISO wind and solar resources. Curtailments fall into four categories: economic downward dispatch, other economic downward dispatch, self-schedule curtailment, and other self-schedule curtailment, each defined above. In the energy imbalance market, total curtailment of wind and solar resources was 95 percent higher this year compared to last. Economic downward dispatch in the EIM during 2020 accounted for roughly 134,000 MWh (95 percent) of total curtailment, a large increase from the 63,000 MWh during 2019. Much of this was due to the high frequency of congestion on the Wyoming Export constraint, which led to one resource being heavily curtailed.[41] Self-scheduled curtailment was roughly 5,500 MWh (4 percent), while "other" economic and self-scheduled curtailment was about 1,700 MWh (1 percent) of total curtailment over the course of the year.

[41] The Wyoming_Export constraint was congested during 29.6 percent of intervals during the year. The overall effects of transfer congestion are discussed in detail in Section 7.1.3.

Figure 1.12 Reduction of wind and solar generation by month (ISO)

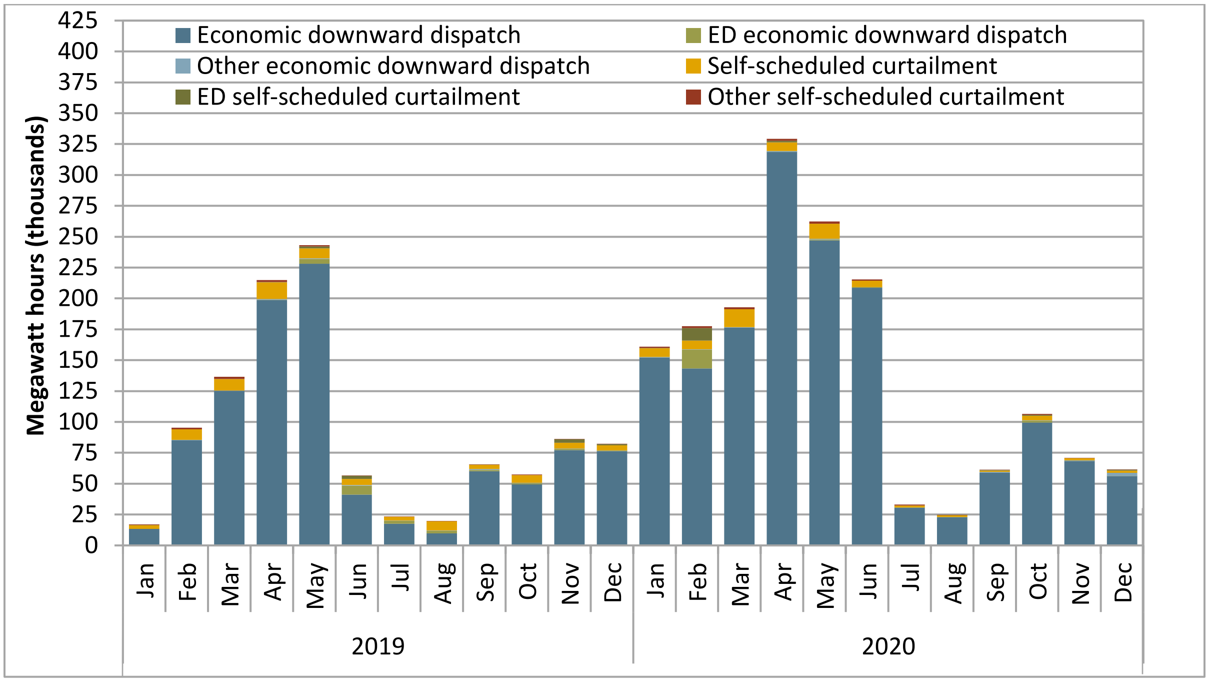
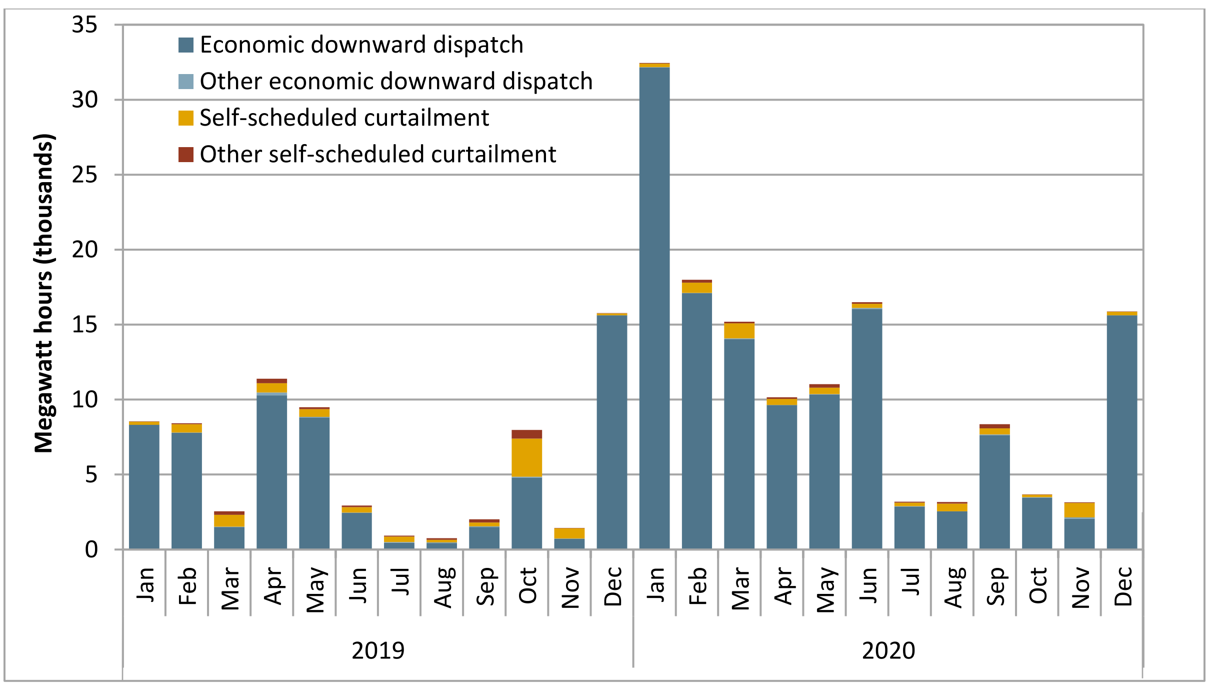


Figure 1.13 Reduction of wind and solar generation by month (EIM)

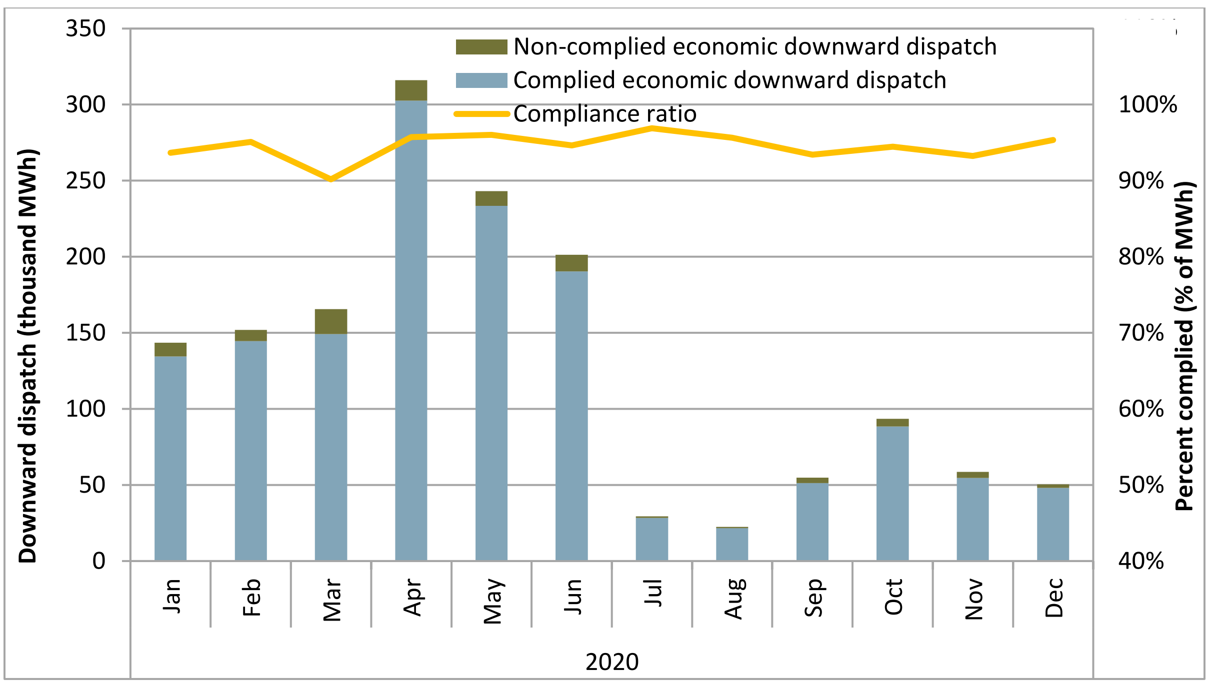


When the market dispatches a wind or solar resource below its forecasted value, scheduling coordinators receive a downward dispatch instruction indicating the need to adjust the resource's output. Figure 1.14 and Figure 1.15 show monthly solar and wind compliance with economic downward dispatch instructions during the year.[42] The blue bars represent the quantity of renewable generation that complied with economic downward dispatch, while the green bars represent the quantity that did not comply. The gold line represents the monthly rate of compliance.

For solar resources, the quantity and performance of complied economic downward dispatch increased over the year compared to the previous year. Solar resources were about 95 percent compliant, compared to 91 percent compliant last year.

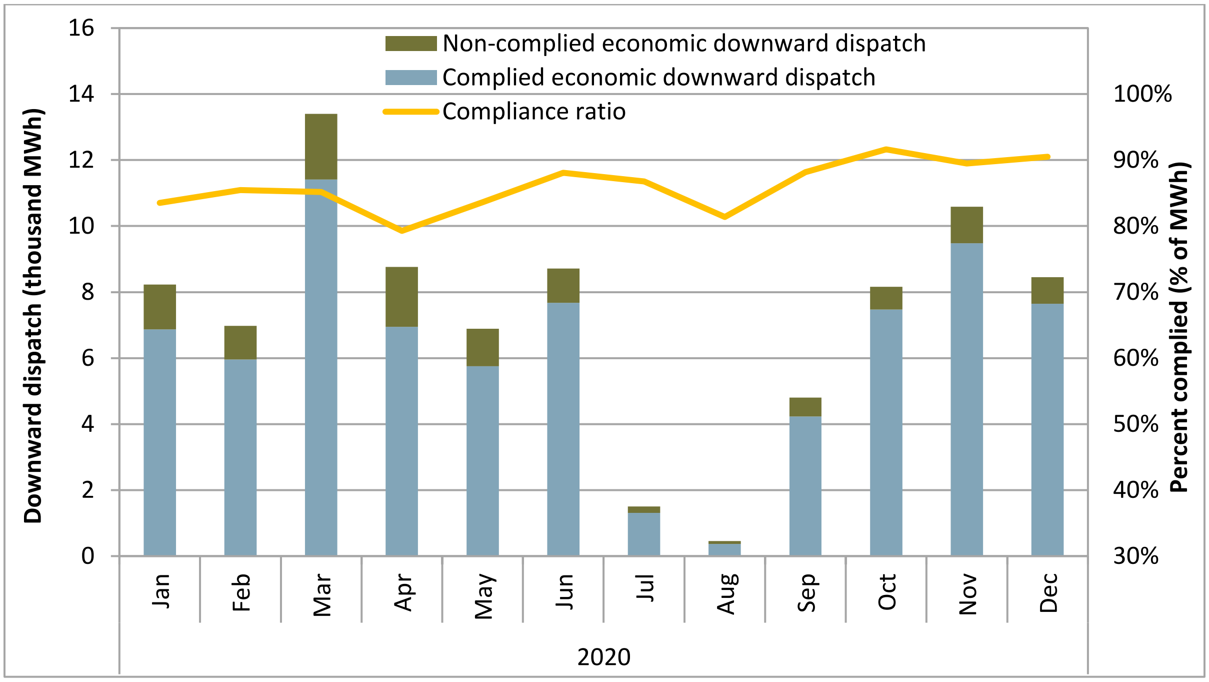
Wind performance improved in 2020 compared to the previous year. Wind resources complied with 86 percent of downward dispatch instructions, compared to 81 percent complied last year. Under ISO market rules, all market participants and resources are expected to follow ISO dispatch instructions.

Figure 1.14 Compliance with ISO dispatch instructions – solar generation



42 This analysis includes variable energy resources in the ISO balancing area only.

Figure 1.15 Compliance with ISO dispatch instructions – wind generation



Hydroelectric supplies

Total hydroelectric production in 2020 decreased 43 percent from the prior year.[43] Statewide snowpack, as measured on April 1, 2019, was 50 percent of the long-term average.[44]

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. 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 2020, almost all hydroelectric resources in the ISO were owned by CPUC jurisdictional investor-owned utilities.

Figure 1.17 compares monthly hydroelectric output from resources within the ISO system for each month during the last four years. As in previous years, hydro generation in 2020 followed a seasonal pattern, with the highest generation in the late spring and early summer months. Generation for the year was lower than all three prior years, but was marginally higher in January than January 2019. On average, monthly generation in 2020 was about 43 percent lower than in 2019, and 19 percent lower than 2018.

43 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.

44 For snowpack information, please see: California Cooperative Snow Surveys' Snow Course Measurements, California Department of Water Resources: https://cdec.water.ca.gov/cgi-progs/prevsnow/COURSES

Figure 1.16 Annual hydroelectric production (2010-2020)

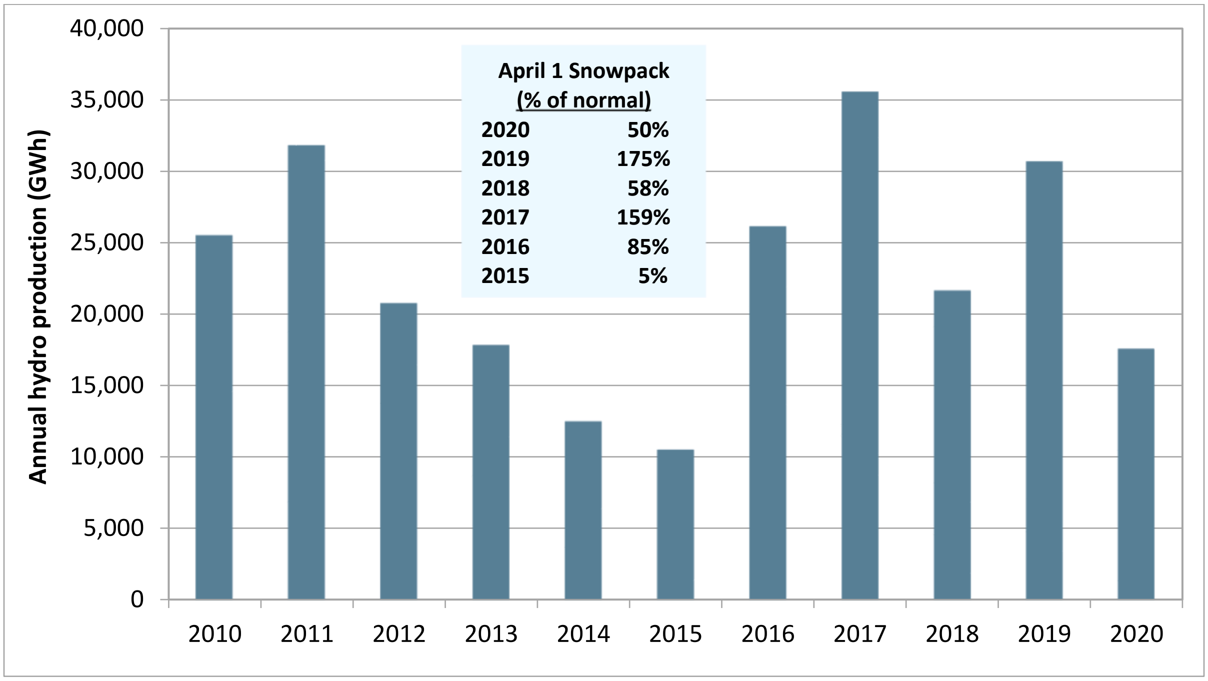
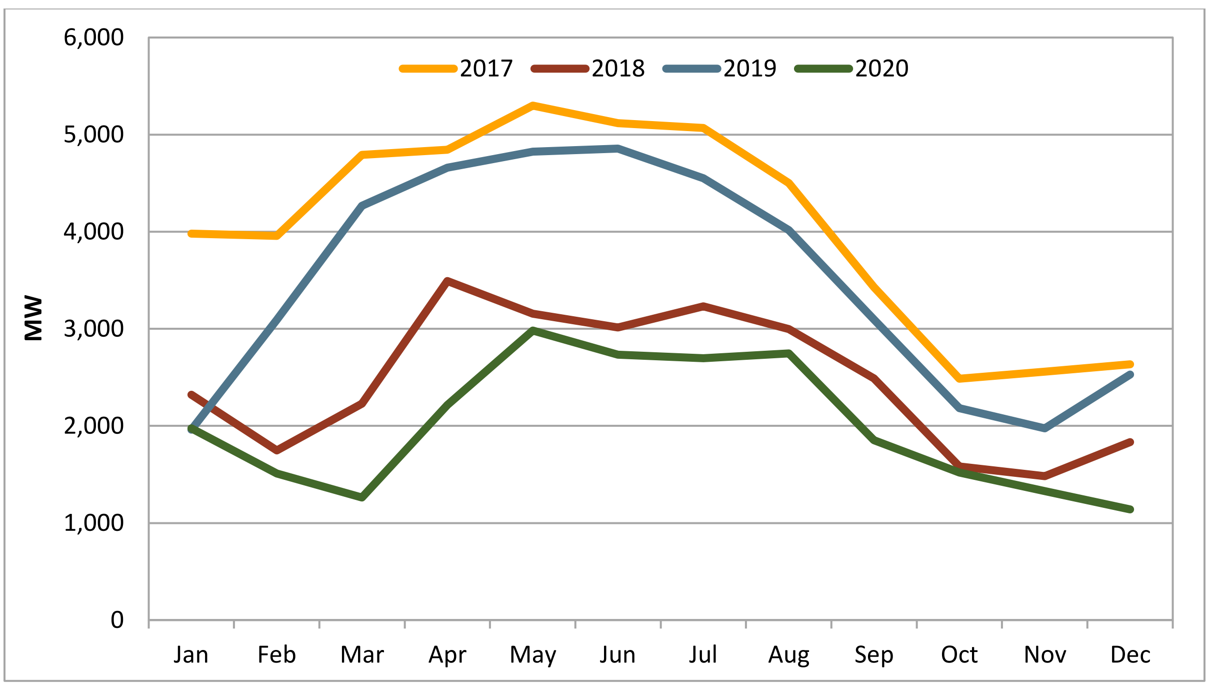


Figure 1.17 Average hourly hydroelectric production by month (2017-2020)



1.2.3 Net imports

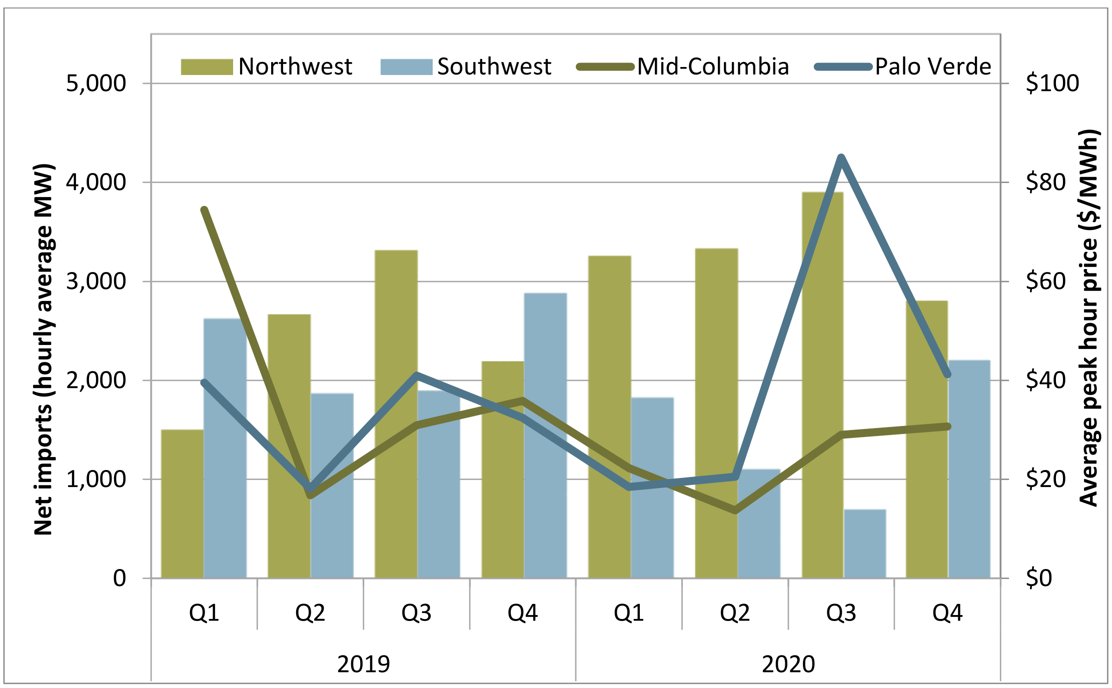
Peak hours and average prices

Total generation from net imports in 2020 was similar to 2019, but shifted from Southwest to Northwest.[45] As shown in Figure 1.18, net imports from sources in the Northwest increased by 37 percent, while net imports from the Southwest decreased by about 37 percent.

Figure 1.18[46] also shows the quarterly average bilateral prices at Mid-Columbia (Mid-C) and Palo Verde. In the third quarter of 2020, prices at Palo Verde were substantially higher than Mid-Columbia, clearing above the $1,000 WECC soft-offer cap during the regional heat wave in August.[47] Bilateral prices in other quarters of the year were similar.

Net imports from the Northwest increased in all quarters over the previous year, while net imports from the Southwest were lower in all quarters. In the first three quarters net imports from the Southwest decreased each quarter while those from the Northwest gradually increased; in the last quarter the opposite occurred.

Figure 1.18 Net imports and average day-ahead price difference (peak hours, 2019-2020)



[45] 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.

[46] Effective 2019 this figure removes pseudo tie generators and incorporates the same peak hours for the bilateral prices as for net imports. This is a change from the prior year and results in a decrease in net import megawatts from both the Northwest and Southwest; representation of bilateral prices were not impacted by the change.

[47] Further coverage of bilateral prices relative to prices within the ISO is available in Section 2.3.1 of this report.

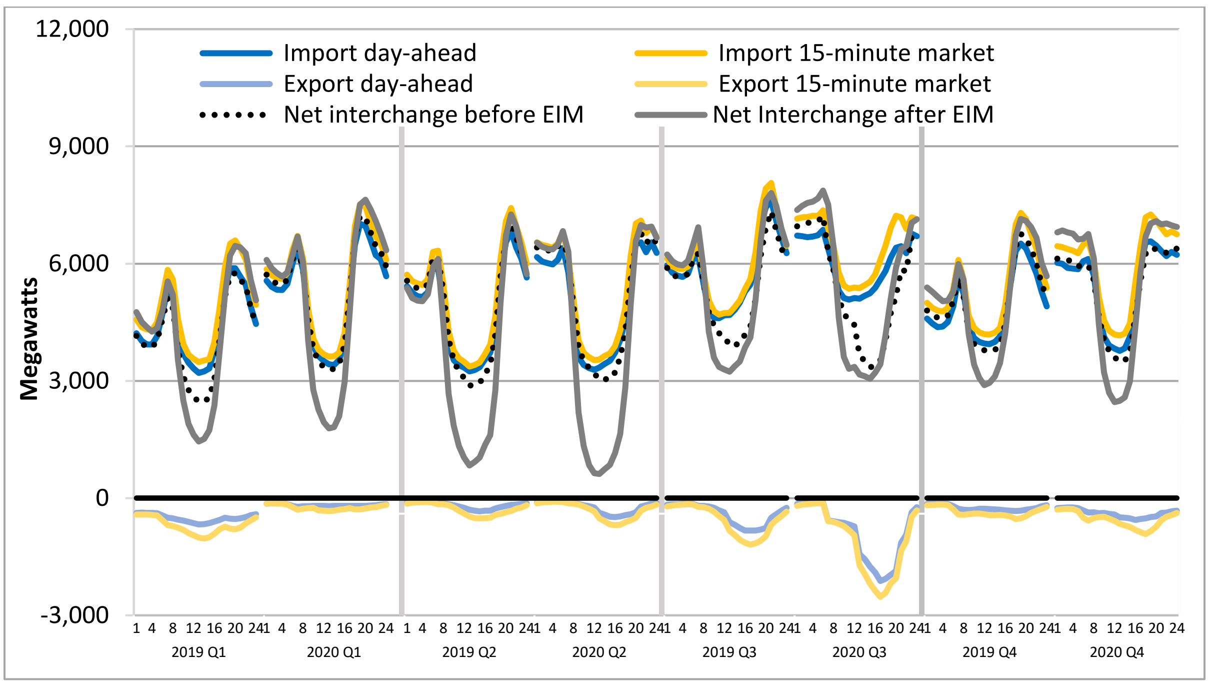
Net interchange – ISO imports and exports with EIM transfers

The energy imbalance market provides additional interchange between the ISO and other balancing authority areas, both in the import and export directions. The net quantity of imports to and exports from the ISO as well as EIM transfers is the ISO system net interchange.

As shown in Figure 1.19 average hourly cleared imports (shown in dark blue and dark yellow) peaked at a similar hour, volume, and quarter as in 2019. However, a change from the prior year can be seen in the higher volumes just before the morning and after the evening peak periods. This change in shape may be attributed to drought conditions[48] in 2020 as imports substituted for hydroelectric production.

Exports (shown as negative numbers below the horizontal axis in pale blue and yellow), were the highest in the third quarter, peaking at about 2,500 MW in hour ending 17. The average net interchange, excluding EIM transfers (shown in dashes), is based on meter data and averaged by hour and quarter. The solid grey line adds incremental EIM interchange; the lowest point occurred in the second quarter in hour ending 13 with a low point of about 620 MW.

Figure 1.19 Average hourly net interchange by quarter



1.2.4 Energy storage and distributed energy resources

Batteries

The amount of battery storage capacity participating in ISO markets increased significantly in 2020. Battery resources currently participate in ISO markets through the non-generator resource (NGR) model

48 U.S. Drought Monitor Conditions for California: https://www.drought.gov/states/california

or as demand response resources. The majority of batteries participating in ISO markets are located in locally constrained areas.

Figure 1.20 shows the total capacity of standalone battery storage participating as non-generator resources represented both in terms of maximum output (megawatt) and maximum duration (megawatt-hour). Since 2015, total battery capacity participating in the ISO market has increased significantly and totaled about 488 MW of discharge capacity by the end of 2020.[49] The increase in battery capacity in 2020 is primarily associated with two large energy storage projects that began participating in the ISO market in the second half of 2020. The amount of standalone and hybrid storage capacity participating in the ISO market is expected to increase even further in 2021, where storage discharge capacity is expected to reach up to 2,000 megawatts.

In 2020, 149 megawatts of standalone storage was shown as resource adequacy capacity in September, compared to 92 megawatts in September 2019.

Figure 1.20 Battery capacity (2015-2020)

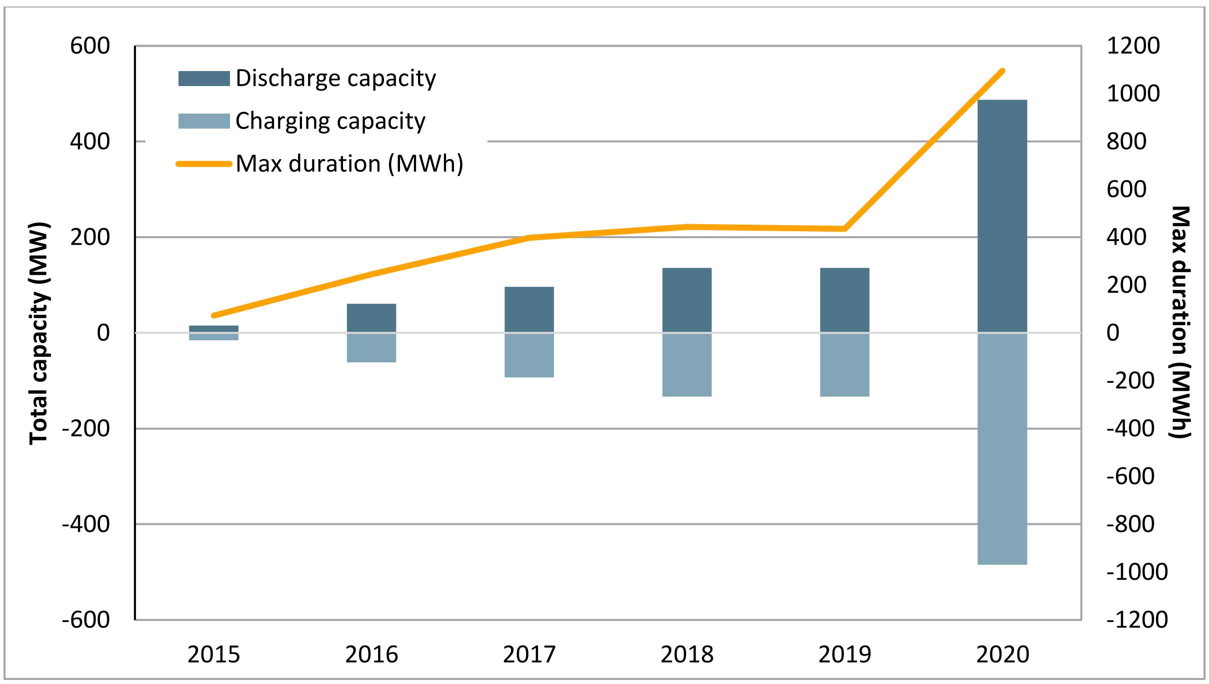


Figure 1.21 shows average hourly real-time (15-minute market) schedules of standalone battery resources in 2020. On average, batteries continued to primarily provide ancillary services, including regulation up, regulation down, and spin reserves. Batteries also began to provide more flexible ramp up in 2020 than in prior years. When providing energy, schedules remain highest during the morning and evening ramping hours. Batteries are often recharged overnight and during mid-day hours when renewable energy production is highest. While the battery fleet provided primarily regulation capacity

49 As of the end of 2020, there was about 1,300 MW of standalone storage capacity registered with the ISO. However, only a subset of this registered capacity was actively participating in the ISO market in 2020.

on average throughout the year, batteries were scheduled to provide energy more frequently in real-time on high load days in August and September compared to the rest of the year.[50]

Battery resources remain effective for meeting both regulation capacity and mileage requirements. Generally, batteries have very fast ramp rates which allows them to provide a significant amount of mileage per megawatt of regulation capacity. Batteries have also bid relatively low prices to provide both regulation capacity and mileage. Thus, battery resources can contribute towards meeting both regulation and mileage requirements at relatively low cost compared to other resource types. Additionally, real-time ancillary service schedules shown in Figure 1.21 generally reflect day-ahead ancillary service awards, which are considered binding commitments in real-time.

Figure 1.21 Average hourly battery schedules (2020)

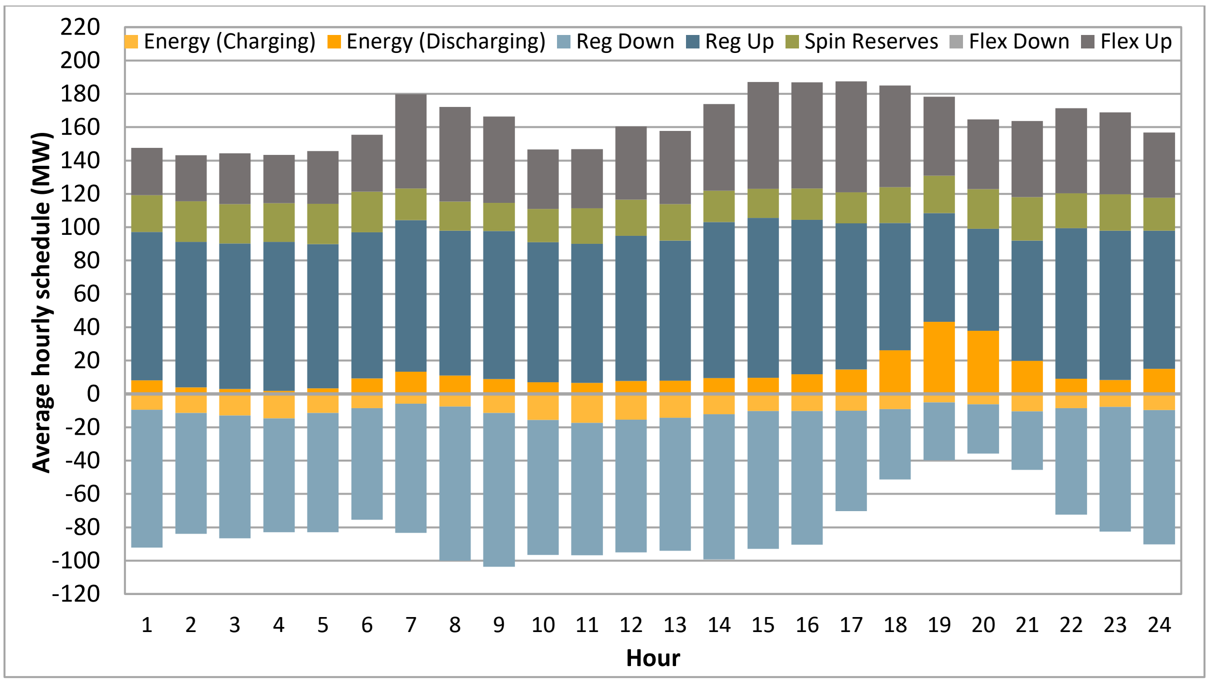


Figure 1.22 shows the average day-ahead energy bids of battery non-generator resources compared to average nodal prices by quarter.[51] Under the non-generator resource model, batteries submit a single energy bid curve which reflects both willingness to charge and discharge. Compared to 2019, average discharge bid prices generally increased while average charge bids decreased, implying the average price spread between willingness to charge and discharge increased in 2020. The increase in average discharge bid prices in the third quarter of 2020 was primarily associated with new resources that entered the market in the second half of 2020.

50 *Department of Market Monitoring, Q3 Report on Market Issues and Performance*, December 10, 2019, pp. 126-127: http://www.caiso.com/Documents/2019ThirdQuarterReportonMarketIssuesandPerformance.pdf

51 Both bids and nodal prices are weighted average values, weighted by the bid quantity at each price and location.

As shown in Figure 1.22, discharge bids were generally economic between hours ending 18 and 21 in the second quarter and third quarter of 2020. However, average charge bids continued to trend below corresponding nodal prices.

Figure 1.22 Average day-ahead battery bids and nodal prices (Q3 2019 – 2020)

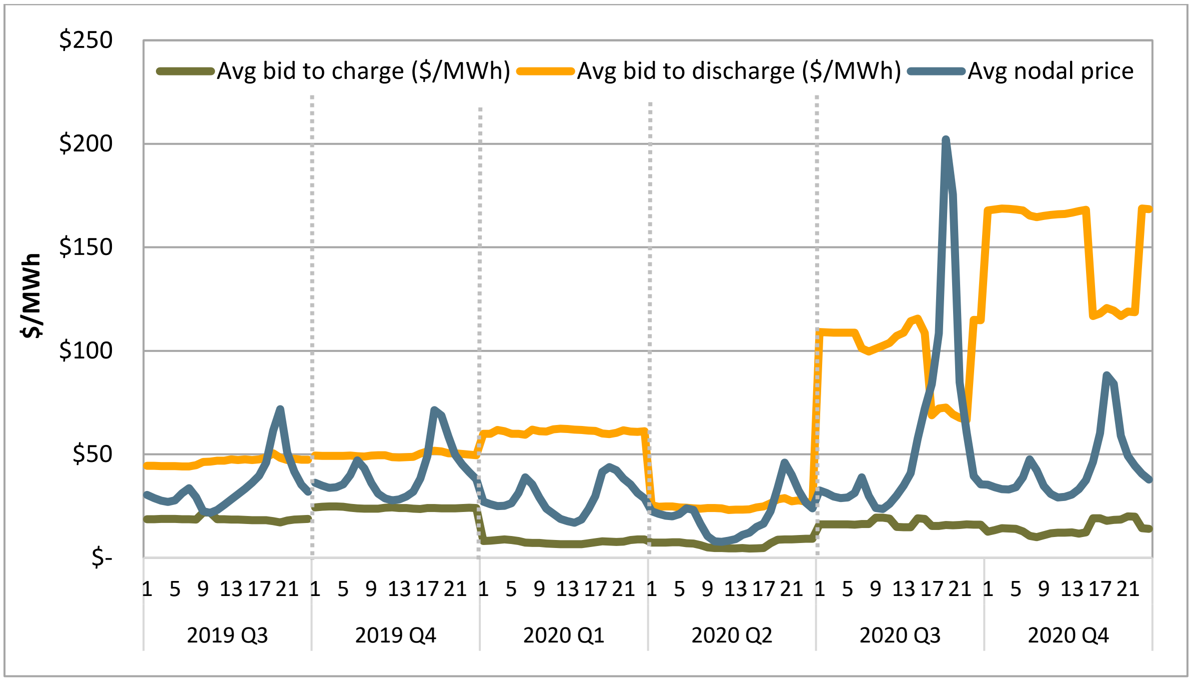


Figure 1.23 Average real-time battery bids and nodal prices (Q3 2019 – 2020)

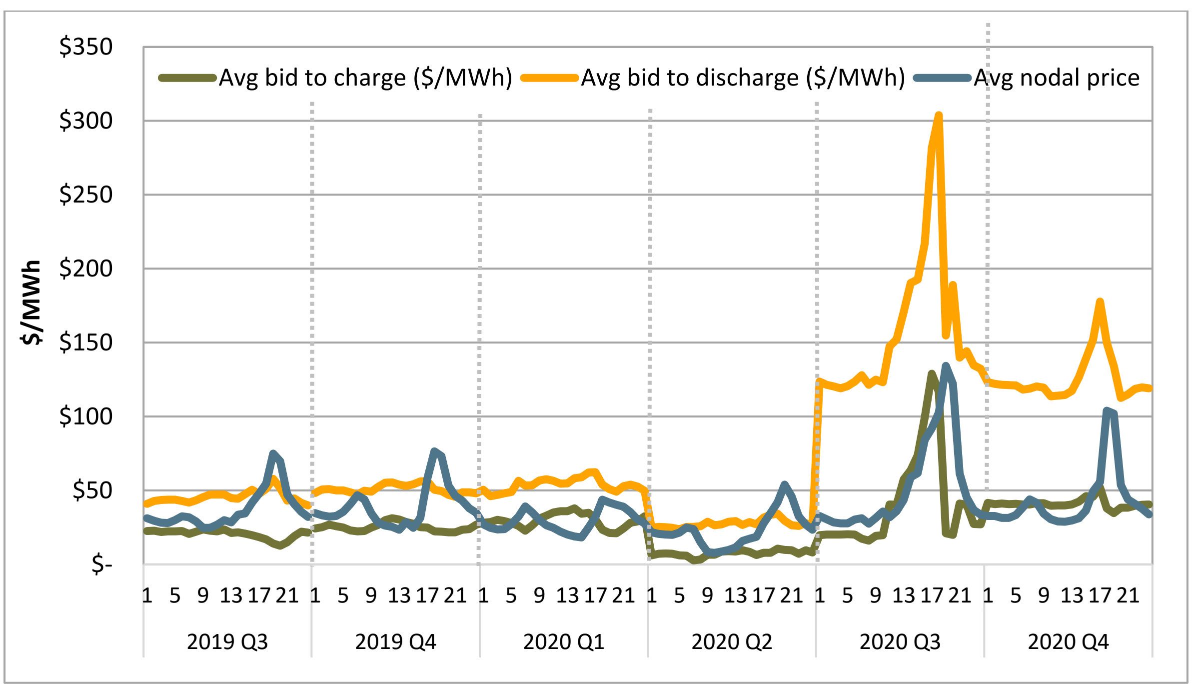


Figure 1.23 shows average real-time bids of battery resources for the portion of resources' dispatch range that is available to the real-time market (i.e., operating range that is not covered by real-time self-schedules or day-ahead ancillary service awards held in real-time). In the second half of 2020, battery resource bids were changed significantly more in real-time than in previous quarters. Real-time bids appear to reflect a higher willingness to charge (and less willingness to discharge) in hours leading up to net load peak hours (6:00 pm to 8:00 pm).

Demand response

Demand response programs are operated by load serving entities as well as third-party providers. Currently, demand response resources shown on monthly resource adequacy supply plans are scheduled by third-party (non-load serving entity) demand response providers. Utility-operated demand response programs are not shown on monthly resource adequacy supply plans and are instead credited against (used to reduce) load serving entity resource adequacy obligations under local regulatory authority provisions.

Proxy demand response (PDR) resources are 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, any incremental reliability demand response capacity must be between 95 to 100 percent of the energy bid cap, and can only be called on when a system warning is issued.

In addition to these demand response participating models, 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. In 2020, the ISO declared Flex Alerts on several days in August, September, and October in response to reliability concerns related to high temperatures and high system demand in California.[52]

Figure 1.24 shows the total demand response resource adequacy capacity (proxy demand response and reliability demand response resources) shown on monthly supply plans in 2019 and 2020. This capacity is scheduled by third-party providers. Third-party demand response participating in the ISO market has increased significantly since 2016, but declined slightly in 2020 compared to 2019. Third-party demand response capacity dropped between January and May 2020 because contracts from the CPUC's demand response auction mechanism (DRAM) did not become active until summer of 2020, as reforms were made to the program in the beginning of 2020.

Several demand response resources shown on resource adequacy supply plans continued to be sized less than 1 megawatt in 2020, which exempts these resources from the ISO's resource adequacy availability incentive mechanism (RAAIM). In summer months, about 47 percent of demand response resources shown on resource adequacy supply plans were sized less than 1 megawatt. Additionally, about 70 percent of this capacity qualified as long-start in summer 2020 compared to about 38 percent in 2019. Long-start proxy demand response resources have no obligation to offer into the residual unit commitment process or real-time market if not economically committed in the day-ahead market.

52 Flex Alerts were issued on August 14, August 16-19, September 5-6, October 1, and October 15.

Figure 1.24 Third-party demand response shown on monthly resource adequacy supply plans

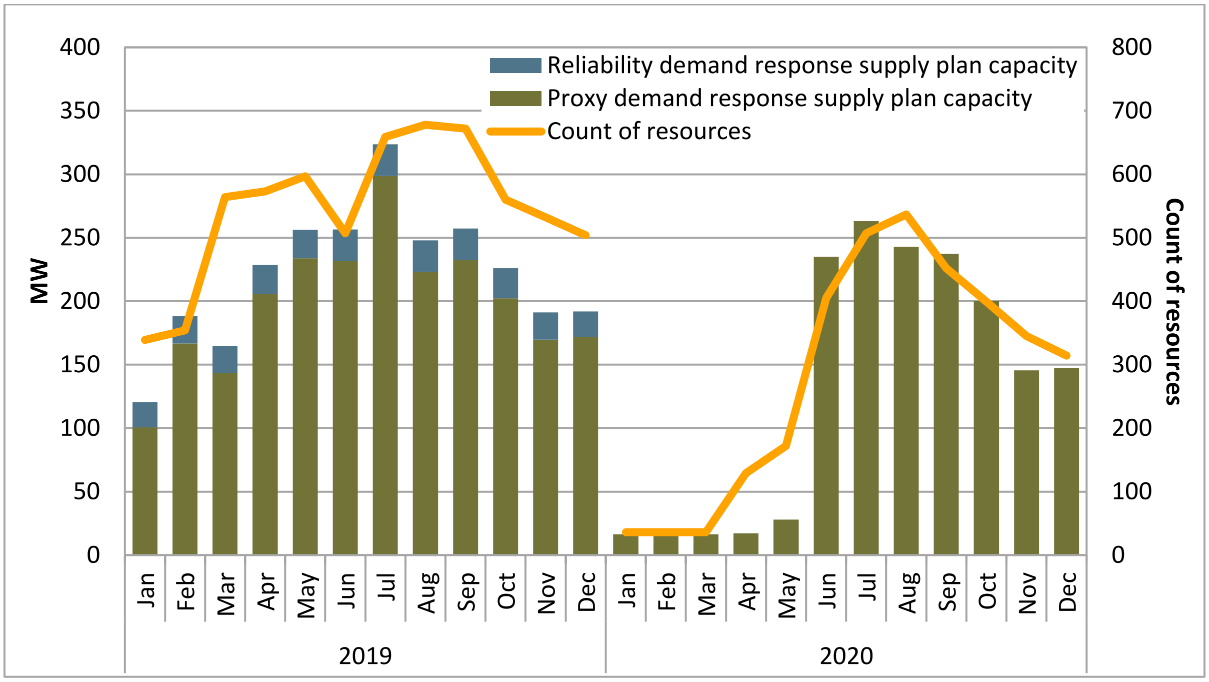


Figure 1.25 CPUC-jurisdictional utility demand response resource adequacy credits

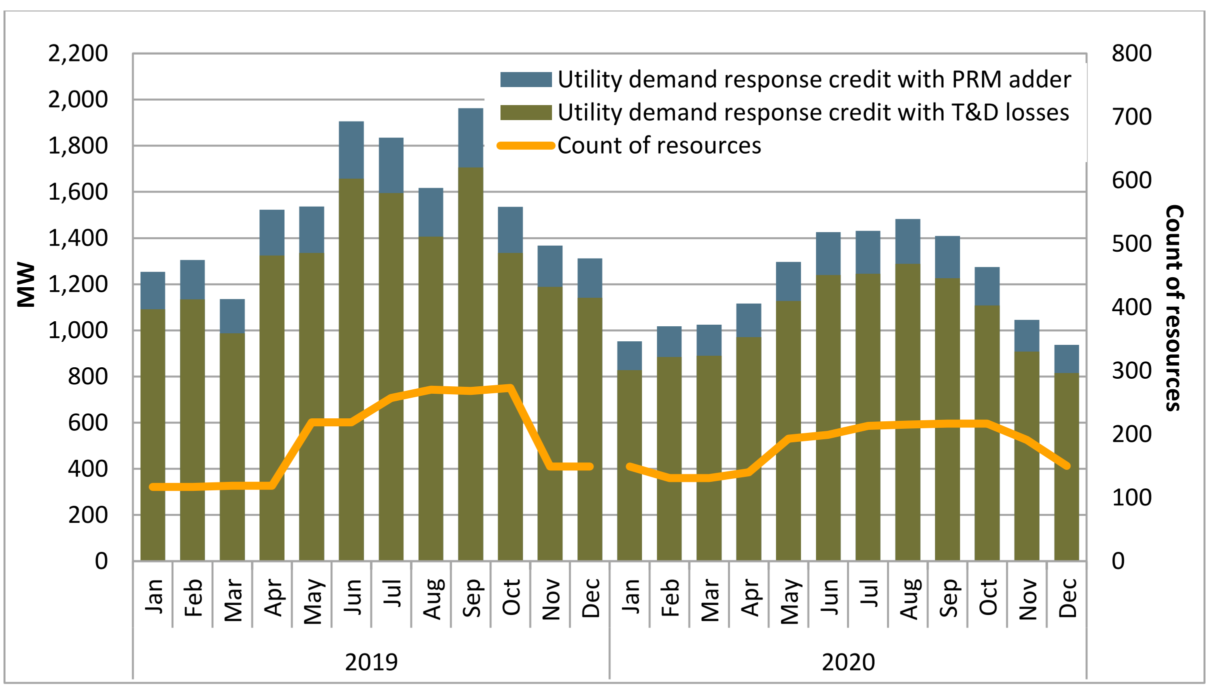
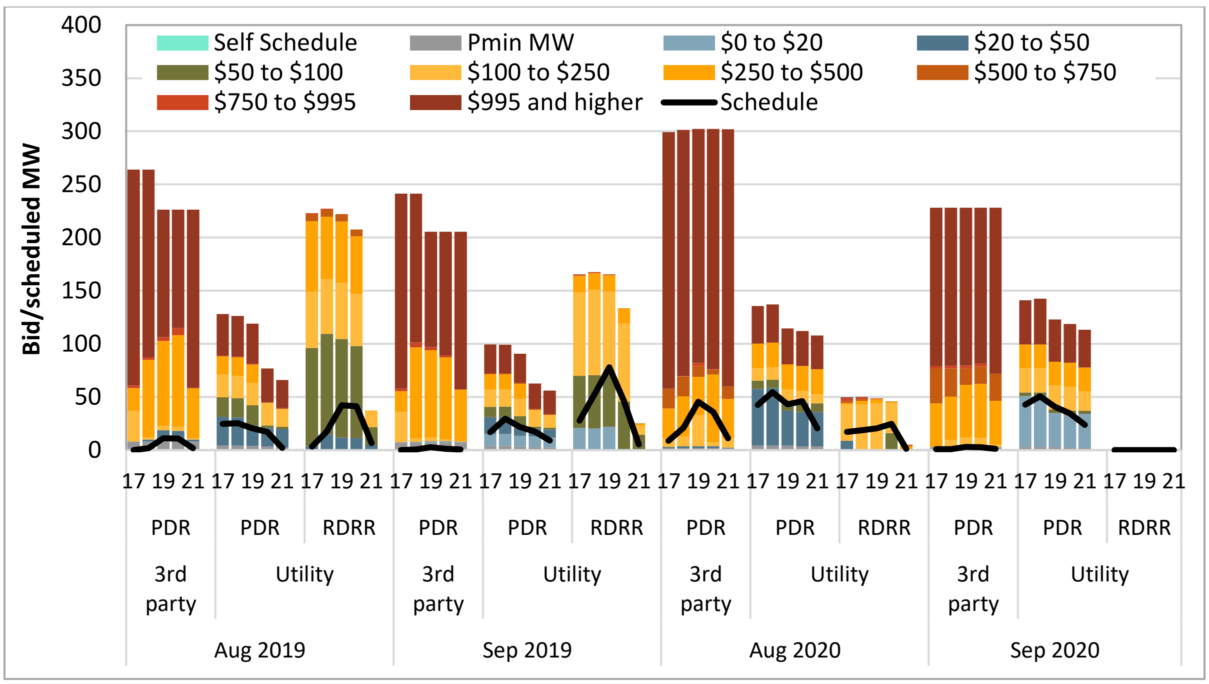


Figure 1.25 shows the total demand response resource adequacy capacity (proxy demand response and reliability demand response resources) associated with CPUC-jurisdictional utility demand response programs. Utility demand response capacity is credited against load serving entity resource adequacy

obligations, which reduces the amount of resource adequacy capacity load serving entities are required to procure. Utility demand response capacity is grossed up for avoided transmission and distribution line losses. A 15 percent planning reserve margin adder is also applied to CPUC-jurisdictional utility demand response capacity, which further reduces load serving entities' resource adequacy obligations. Utility demand response capacity is not shown on resource adequacy supply plans and therefore is not subject to the ISO's must-offer obligations or resource adequacy availability incentive mechanism.

Figure 1.26 shows the day-ahead bids and schedules of utility and third-party demand response resource adequacy resources in August and September of 2019 and 2020 (not capped at individual resources' resource adequacy values). Figure 1.26 reflects bids in the ISO's availability assessment hours (between 4:00 to 9:00 pm on non-holiday weekdays). Utility demand response bids tend to be shaped and taper off across peak net load hours, while third-party resource bids are less shaped and are concentrated in availability assessment hours.

Figure 1.26 Demand response resource adequacy day-ahead bids August and September



Over half of third-party demand response capacity continued to be offered in the day-ahead market at prices at or near the $1,000/MWh bid cap. Additionally, as discussed in more detail in DMM's report on demand response issues and performance, some proxy demand response resources also submit high commitment costs (start-up and minimum load costs) which resulted in some demand response capacity being uneconomic to commit in the day-ahead market even on high load days in August and September.[53]

53 *Demand Response Issues and Performance*, February 25, 2021, pp. 12-14: http://www.caiso.com/Documents/ReportonDemandResponseIssuesandPerformance-Feb252021.pdf

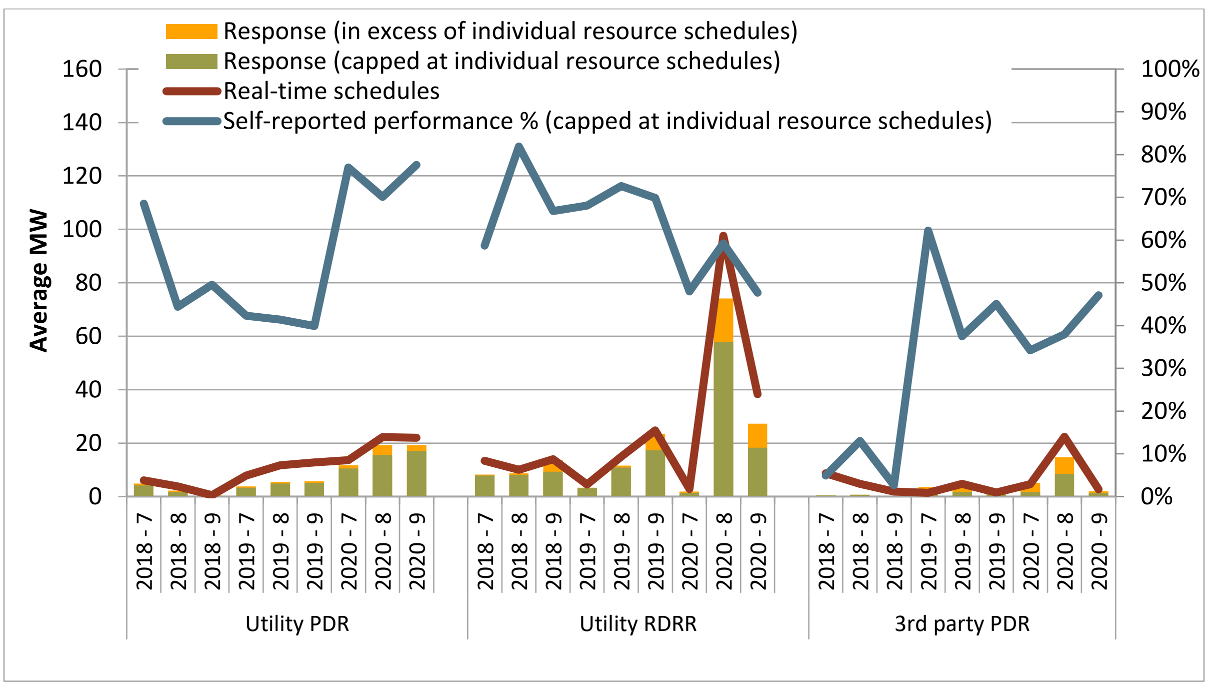
Dispatch and performance of demand response

The ISO relied on demand response resources, including reliability demand response, during high load days in August and September 2020. Proxy demand response resources were economically scheduled by the ISO, and the ISO issued manual dispatches to reliability demand response resources on several days in August and September. However, outside of these heatwave periods, demand response resource adequacy resources were rarely scheduled in the ISO markets.

DMM reported on demand response performance during the August and September heatwaves in its report on demand response issues and performance.[54] While the reported response for several demand response resources fell below expected load curtailment, DMM acknowledges that baseline methodologies based on historic load observations and baseline adjustments (which the majority of demand response resources are registered under) did not appear to fully capture load levels on high load days. Thus, DMM acknowledges that reported performance values during the heatwave periods may have been suppressed due to caps on baseline adjustments.

Figure 1.27 below shows the expected load curtailment (schedule) of demand response resource adequacy resources compared to reported performance in July to September of 2018 to 2020 in peak net load hours (4:00 to 9:00 pm). Real-time schedules are not capped at resource adequacy values.[55]

Figure 1.27 Demand response resource adequacy performance July to September (4:00 - 9:00 pm)



54 *Ibid.* pp. 17-24.

55 Of note, 2019 third-party demand response average performance decreased compared to July/August performance reported in DMM's *2019 Annual Report on Market Issues and Performance* (pp. 55-56). This change is due to some scheduling coordinators submitting updated performance data which was picked up in settlement recalculations issued 9 months (T+9M) after relevant 2019 market dates.

1.2.5 Generation outages

This section provides a summary of generation outages in 2020. Overall, the total amount of generation outages was higher than previous years. The seasonal variation over the year was similar to the typical trend of prior years. During the peak net load hours of 2020, an average of 1.6 percent of the total resource adequacy (RA) gas capacity was unavailable due to temperature.

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.

These categories are separated into four main groups:

- **Planned maintenance**, which includes plant maintenance that has been submitted more than 7 days prior;
- **Other planned outages**, which includes other types of de-rates that have been submitted more than 7 days prior;
- **Forced maintenance and plant trouble**, which includes plant maintenance or trouble that has been submitted less than 7 days prior; and
- **Other forced outages**, which includes other types of de-rates that have been submitted less than 7 days prior.

Figure 1.28 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, as maintenance is performed outside the higher summer load period.

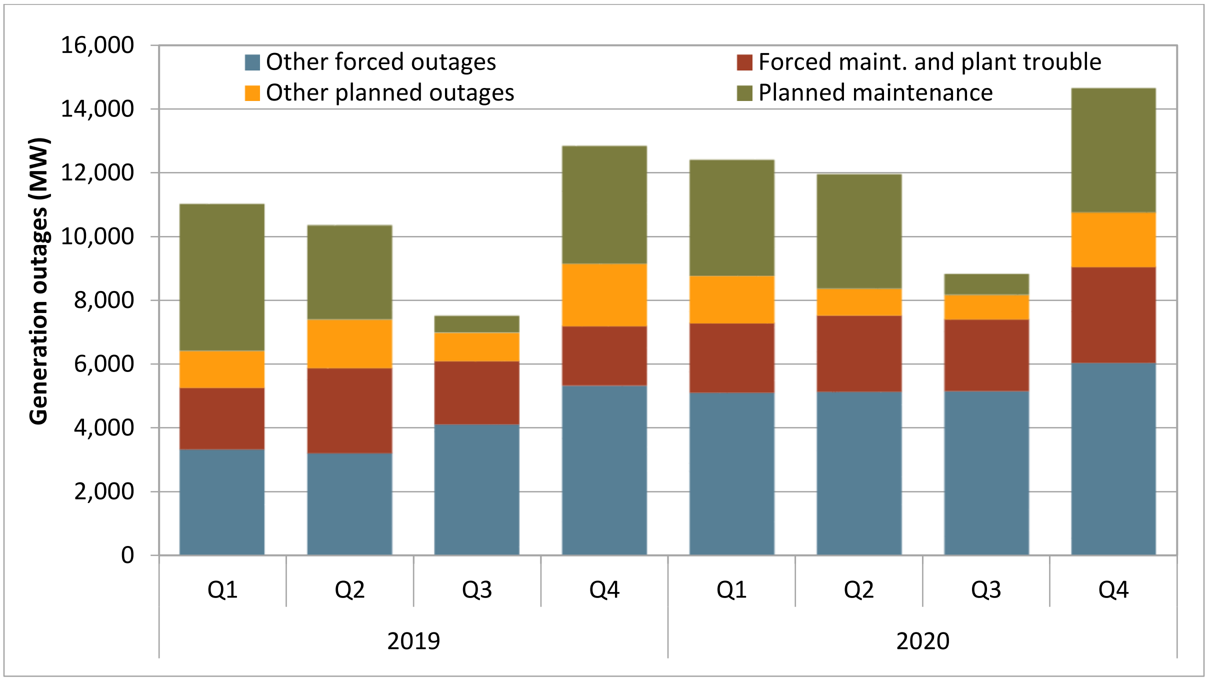
Overall for 2020, the average total amount of generation outages in the ISO was about 12,000 MW, up from 10,400 MW in 2019.[56] Outages for planned maintenance averaged about 2,900 MW during peak hours in 2020, and ranged from about 700 MW in the third quarter to about 3,900 MW in the fourth quarter. Combined, all other types of planned outages averaged about 1,200 MW in 2020. Some common types of outages in this category were ambient de-rates (both due to temperature and not due to temperature) and transmission outages.

Forced outages for either plant maintenance or trouble totaled about 2,500 MW, while all other types of forced outages totaled about 5,300 MW for the year. Included in the other category of forced outages are ambient due to temperature, ambient not due to temperature, environmental restrictions, unit testing, and outages for transition limitations. The steady increase in forced outages from 2019 through

[56] 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. In the third quarter of 2020, revisions and enhancements were made to this analysis which updated some of the results. Therefore historic values were retroactively updated to reflect the revisions. Detailed revised historical charts can be found in Section 1.1.5 of the Department of Market Monitoring's 2020 third quarter report: http://www.caiso.com/market/Pages/MarketMonitoring/AnnualQuarterlyReports/Default.aspx

2020 may be due in part to the ISO keeping older units online to maintain adequate capacity for system reliability. As with prior years, there was less seasonal variation for forced outages compared to planned outages.

Figure 1.28 Average of maximum daily generation outages by type – peak hours

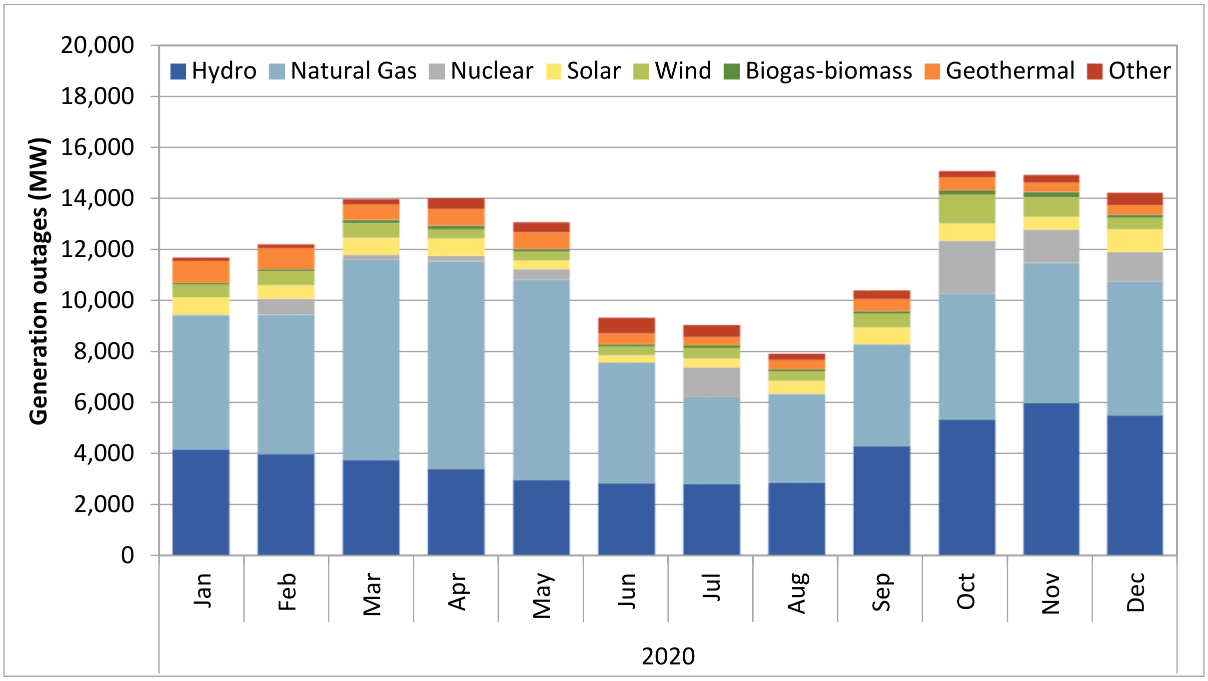


Generation outages by fuel type

Natural gas and hydroelectric generation averaged 5,487 MW and 3,982 MW on outage during 2020. Together, these two fuel types accounted for 78 percent of the generation on outage for the year.

Figure 1.29 shows the monthly average generation on outage by fuel type during peak hours. The overall increase in generation outages in the fourth quarter was primarily due to an increase in nuclear generation outages. October experienced the highest monthly average generation on outage at 15,048 MW in total, 14 percent of which was from nuclear generation outages.

Figure 1.29 Monthly average of maximum daily generation outages by fuel type – peak hours



Gas generation outages and ambient de-rates

Ambient de-rates due to temperature account for 19 percent of total resource adequacy and non-resource adequacy gas capacity on outage between hours ending 17 and 21. On average for the year, 1.6 percent of total resource adequacy gas capacity was de-rated due to temperature during these hours.[57]

Figure 1.30 shows the hourly average gas generation on outage by type during peak net load hours. On average for 2020, 4,825 MW of resource adequacy and non-resource adequacy gas generation was de-rated or on outage, 940 MW of which can be attributed to ambient de-rates due to temperature during these hours.

Figure 1.31 shows the monthly average of daily maximum gas generation outages during peak hours in 2019 and 2020. The overall trend in 2020 is similar to that of 2019, with the exception of November. During this month, gas generation on outage did not spike like it had in prior years, but rather continued to gradually increase and then plateau in December.[58]

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57 Over the past few years, hours ending 17 through 21, often referred to as peak net load hours, have grown to become the most critical hours in terms of system reliability. During these hours, solar generation ramps down rapidly while demand remains high, leading gas generation to make up the difference.

58 For a historical version of Figure 1.31 going back to 2016, see Section 1.1.5 of the Department of Market Monitoring's 2020 third quarter report: http://www.caiso.com/market/Pages/MarketMonitoring/AnnualQuarterlyReports/Default.aspx

Figure 1.30 Hourly average gas generation outages – peak net load hours

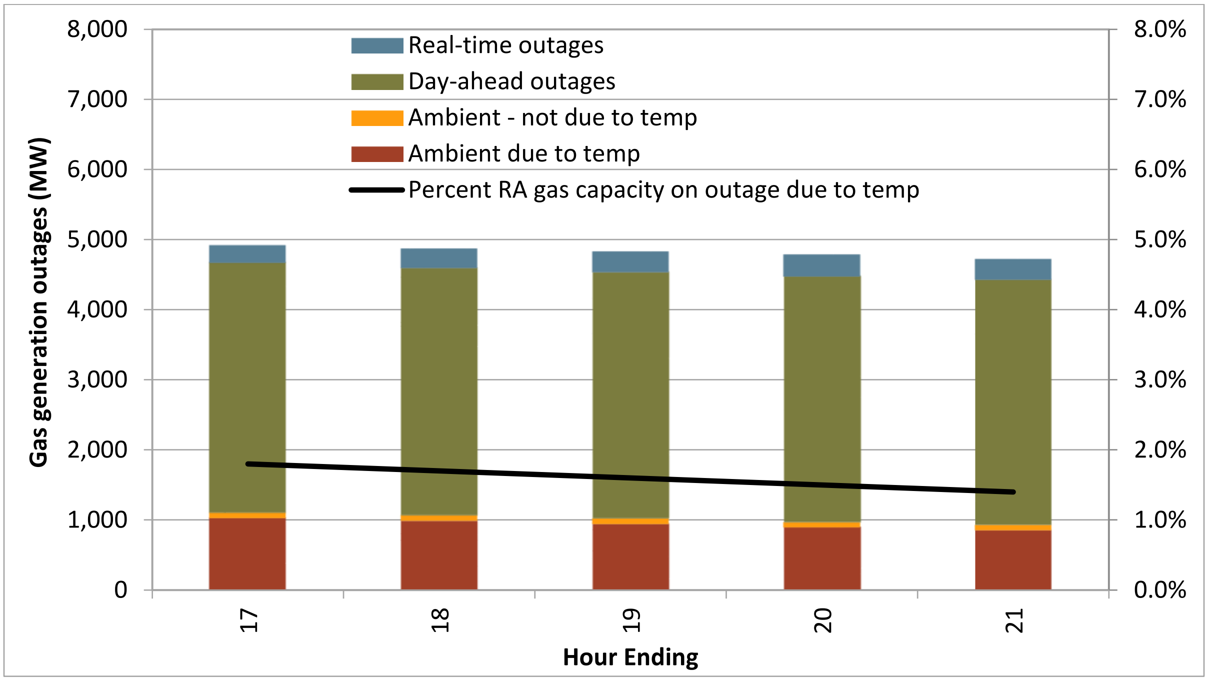
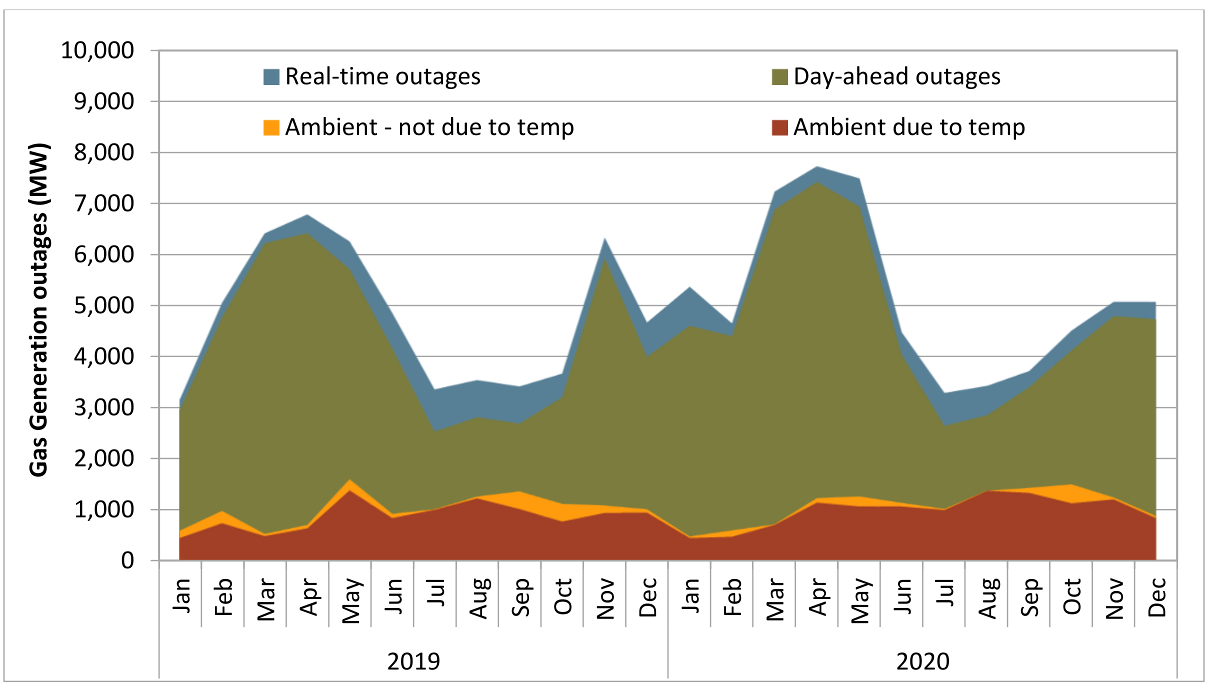


Figure 1.31 Monthly average gas generation outages and ambient de-rates (2019-2020)



1.2.6 Natural gas prices

Electricity prices in western states typically follow natural gas price trends. This is because natural gas units are often the marginal source of generation in the ISO and other regional markets. Across key delivery points in the west, the average price of natural gas in the daily spot markets averaged less than $3/MMBtu in 2020. Due to high temperatures and gas demand on some days in August and September, the increase in natural gas prices contributed to higher system marginal energy prices across the ISO footprint on those days.

Figure 1.32 shows monthly average natural gas prices at PG&E Citygate, SoCal Citygate, Northwest Sumas, and El Paso Permian, as well as for the Henry Hub trading point which acts as a point of reference for the national market for natural gas.

SoCal Citygate prices often impact overall system prices. First, there are large numbers of natural gas resources in the south. Second, these resources can set system prices in the absence of congestion. As shown in Figure 1.32, the prices at SoCal Citygate spiked in August and averaged $2.95/MMBtu for 2020. During the days of high gas demand in August, prices at SoCal Citygate reached a high of about $13/MMBtu.

The Aliso Canyon protocol remained in effect in 2020 making the facility available for withdrawals for Stage 2 or above low operational flow orders (OFO). It is put in place to help mitigate gas price spikes and maintain system reliability.[59] SoCalGas withdrew gas from the Aliso Canyon storage facility from August 13-20. No low OFOs were declared during this period. In 2020, SoCalGas withdrew gas from the Aliso Storage facility on 57 gas days.

Consistent with the California Public Utilities Commission's ruling on April 29, 2019, SoCalGas Company made changes to its OFO stages and associated non-compliance penalty structure.[60] For the summer period, June 1 through September 30, SoCalGas temporarily reduced the number of non-compliance stages from 8 to 5. The non-compliance charge was reduced from $25/Dth and capped at $5/Dth for Stage 4 and Stage 5 flow orders. For the winter period, October 1 through May 31, SoCalGas expanded the number of non-compliance stages from 5 to 8. The non-compliance charge for Stage 3 flow orders follows a tiered structure ranging from $5/Dth to $20/Dth and for Stage 4 and Stage 5 was set at $25/Dth.

In 2020, SoCalGas declared 53 low OFOs, primarily stage 1 or 2. This is in comparison to 104 low OFOs in 2019, which included a high number of stage 3 or 4 orders. The revisions from the CPUC's ruling are set to expire in October 2021. DMM submitted comments to a new CPUC ruling to revise the existing penalty structure.[61]

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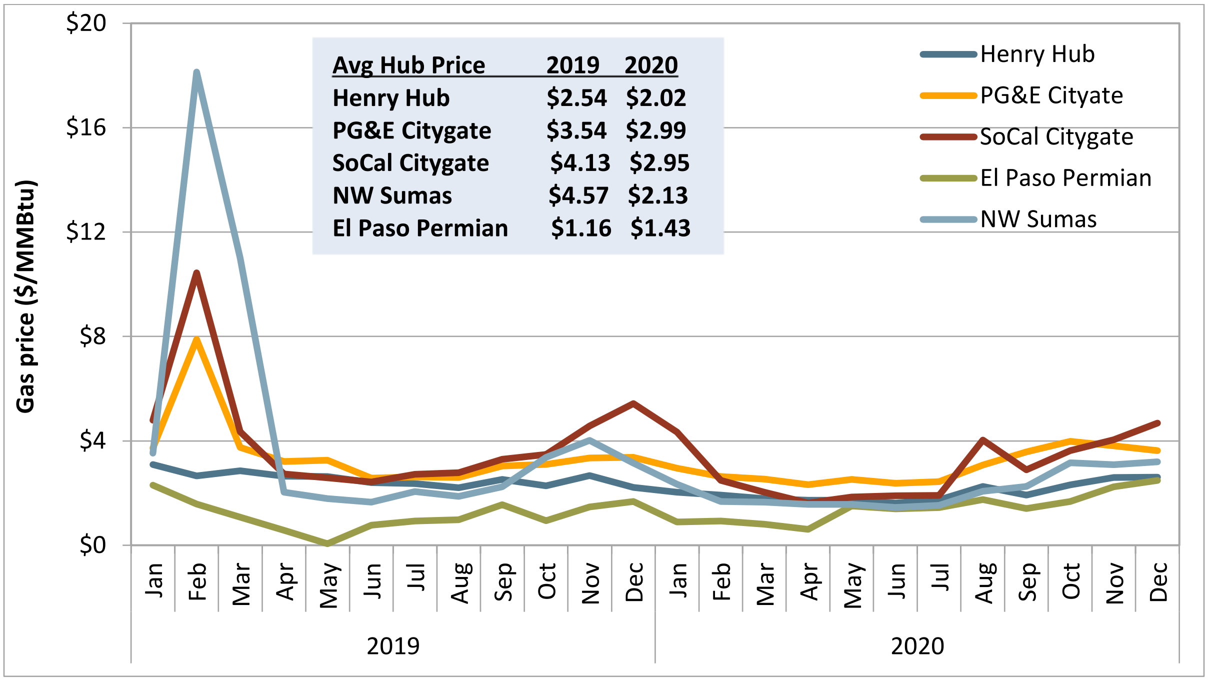
59 Aliso Canyon Withdrawal Protocol, July 23, 2019: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/UpdatedWithdrawalProtocol_2019-07-23%20-%20v2.pdf

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

61 DMM Response to Judge's Ruling Seeking Comments - Safe and Reliable Gas Systems - R20-01-007, Aug 14, 2020: http://www.caiso.com/Documents/CPUC-ResponsetoJudgesRulingSeekingComments-SafeandReliableGasSystems-R20-01-007-Aug142020.pdf

Permian prices continued to be low and sometimes negative during April 2020. This is because of reduced takeaway capacity resulting from pipeline maintenance. For the rest of the second quarter, there was lower production in the Permian basin and higher demand from warm temperatures in the Southwest. Prices fell again in September 2020 because El Paso Pipeline Company declared a force majeure on one of its pipelines thereby limiting takeaway capacity from the supply basin.

Figure 1.32 Monthly average natural gas prices (2019-2020)



Avg Hub Price	2019	2020
Henry Hub	$2.54	$2.02
PG&E Citygate	$3.54	$2.99
SoCal Citygate	$4.13	$2.95
NW Sumas	$4.57	$2.13
El Paso Permian	$1.16	$1.43

Figure 1.33 Yearly average natural gas prices compared to the Henry Hub

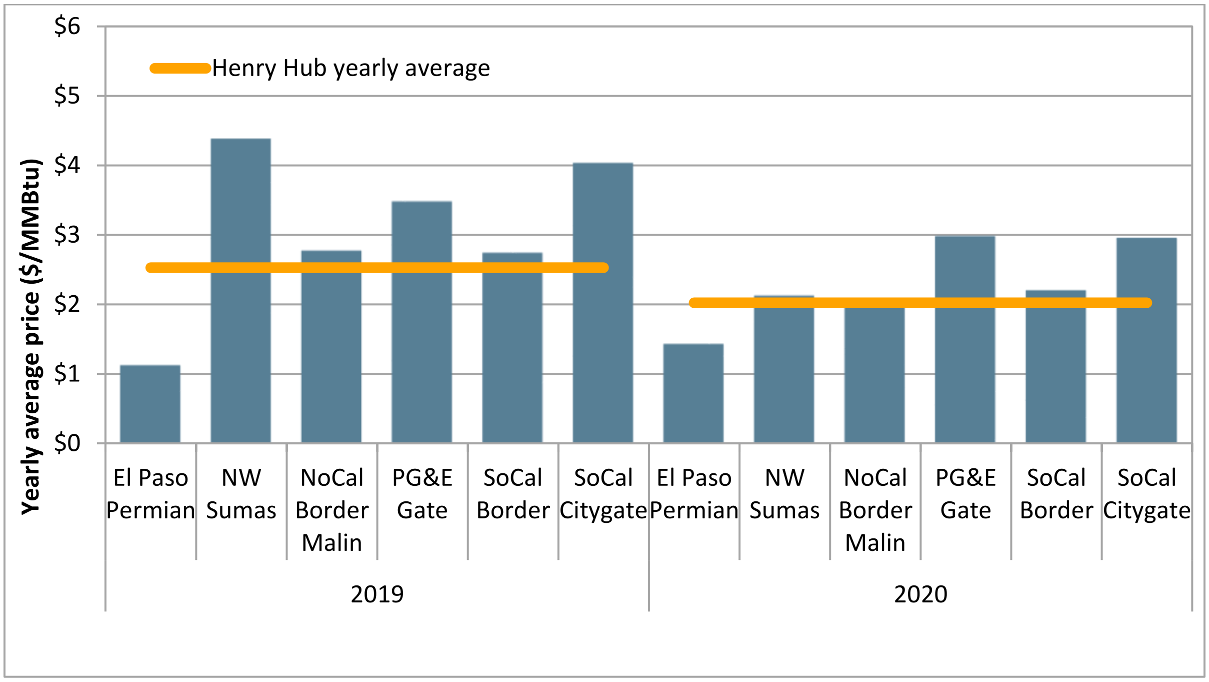


Figure 1.33 compares the yearly average natural gas prices at six major western trading points to the Henry Hub reference average for 2019 and 2020. The yearly average prices in 2020 exceeded the Henry Hub reference price at all but El Paso Permian trading point. On average, the yearly price at SoCal Citygate exceeded the Henry Hub average by 46 percent. Similarly, PG&E Citygate and Northwest Sumas exceeded Henry Hub average by 47 percent and 5 percent, respectively. The average Permian price was 71 percent of the Henry Hub average.

1.2.7 Aliso Canyon gas-electric coordination

Background

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.

On February 9, 2017, the CPUC opened a proceeding to determine the feasibility of minimizing or eliminating the use of SoCalGas Company's Aliso Canyon storage facility while still maintaining energy and electric reliability for the Los Angeles region.[62]

62 Order Instituting Investigation; I.17-02-002, Aliso Canyon minimizing or eliminating proceeding, Feb 9, 2017: https://www.cpuc.ca.gov/AlisoOII/

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. Beginning in 2020, FERC granted ISO permanent authority to extend the use of gas burn constraints and updated gas prices in the day-ahead market. The following section discusses DMM's review and recommendations on one of these key measures.

Gas usage nomogram constraints

One of the tools the ISO has developed to manage potential gas system limitations is a set of constraints (or nomograms) that allow operators to restrict, through the market dispatches, 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.[63]

In 2020, the ISO enforced maximum gas burn constraints in both day-ahead and real-time markets. These constraints were enforced in selected sub-regions of the SoCalGas service area during six periods: April 7-11, May 11-15, May 29-June 12, July 3, July 17-20, and September 14 through October 24.

In April, the gas burn constraint was enforced to facilitate pipeline maintenance work in the SDG&E area. In the day-ahead market, this constraint was binding in about 36 percent of hours during which it was enforced. In the real-time market, the constraint was binding in about 21 percent and 13 percent of 15-minute and 5-minute intervals, respectively.

In May and June, the gas burn constraint was enforced to facilitate pipeline maintenance work in the southern system of the SoCalGas area. In the day-ahead market, this constraint was binding in about 9 percent of hours when enforced. In the real-time market, this constraint was binding in 10 percent of the 15-minute intervals and 6.5 percent of the 5-minute intervals when enforced.

In July and September, the gas burn constraint was enforced again to facilitate pipeline maintenance work in the southern system of the SoCalGas area. During the July period, this constraint was binding in about 9 percent, 2 percent, and 0.2 percent of day-ahead, 15-minute, and 5-minute intervals, respectively.

During the September and October period, this constraint was binding in about 25 percent of hours when enforced in the day-ahead market. In the real-time market, this constraint was binding in 14 percent of the 15-minute intervals and 11 percent of the 5-minute intervals when enforced.

On October 31, 2019, the ISO filed tariff amendments to extend Aliso Canyon provisions permanently.[64] One of these measures gives ISO the authority to enforce gas burn constraints (or nomograms) in the ISO market. These constraints limit the gas usage through market dispatches from groups of power plants in the SoCalGas system. In its filing, the ISO proposed refining the shaping of the maximum gas burn limit using net load rather than gross load.

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

64 Tariff Amendment: *Aliso Canyon Gas-Electric Coordination Phase 5* (ER20-273), October 31, 2019: http://www.caiso.com/Documents/Oct312019-TariffAmendment-SoCalMaxGasConstraint-AlisoCanyon_ER20-273.pdf

DMM recommended further refinement of the gas burn constraint to avoid artificially constraining gas usage during peak net load hours. DMM also expressed concern about the potential impacts of the gas burn constraints on real-time energy offset costs.[65] Beginning in 2020, FERC approved these tariff amendments and directed the ISO to file annual informational filings relating to the performance of the enforced nomograms.[66,67]

Effective May 20, 2021, the ISO implemented DMM's recommendations on better shaping the maximum gas burn constraint limit using the net load approach and also based on estimated gas burn from the two-day-ahead runs of the market software that the ISO performs.[68,69] In addition, DMM continues to recommend that the ISO improve how gas burn constraint limits are set and adjusted in real-time based on actual gas usage in prior hours. DMM understands that currently this process is manual and cumbersome for the operators to use in real-time and hence the operators opt for out-of-market actions such as exceptional dispatches.

Figure 1.34 shows the nomogram limits being adjusted in real-time in response to changing system conditions on October 4, 2020. DMM believes that incorporating maximum gas constraints into the market software can in theory be more effective and efficient at managing gas limitations than the use of manual dispatches made by system operators. The ISO is still working on automating the process of including the maximum gas burn constraint as part of the local market power mitigation (LMPM) process to automatically designate a constraint as competitive or not.[70]

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65 DMM recommendation on gas usage nomograms, *2018 Annual Report on Market Issues and Performance*, pp 261-262, May 2019: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

66 FERC Order accepting Aliso Canyon Gas-Electric Coordination Phase 5 tariff revisions (ER20-273), December 30, 2019: http://www.caiso.com/Documents/Dec30-2019-OrderAcceptingTariffRevisions-AlisoCanyonGasElectricCoordination-MaximimGasConstraint-ER20-273.pdf

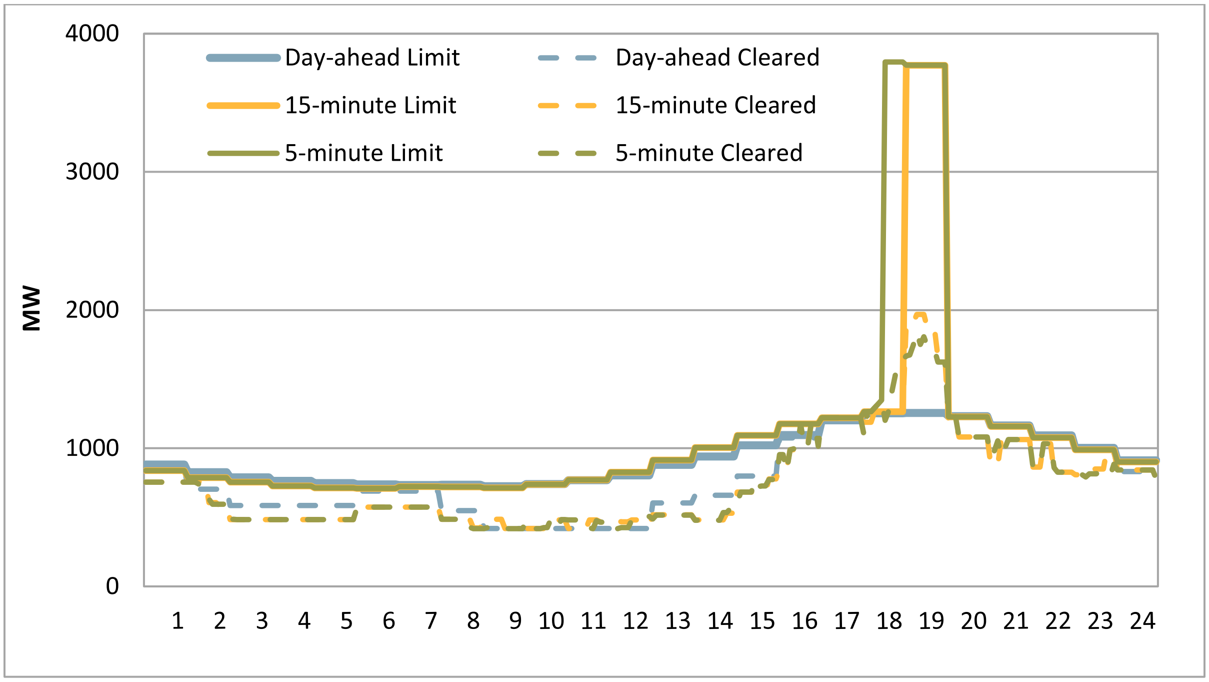
67 ISO's Annual Report on use of the Maximum Gas Burn Constraint – Aliso Canyon (ER20-273), Jun 30, 2020: http://www.caiso.com/Documents/Jun30-2020-AnnualReport-Use-MaximumGasBurnConstraint-AlisoCanyon-ER20-273.pdf

68 FERC filing - DMM Comments on Aliso Canyon Gas-Electric Coordination Phase 5 (ER20-273), November 21,2019: http://www.caiso.com/Documents/MotiontoInterveneandCommentsoftheDepartmentofMarketMonitoring-Aliso5-ER20-273-000-Nov212019.pdf

69 PRR 1262 Aliso Canyon gas-electric coordination Phase 5: https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=1262&IsDlg=0

70 Business requirements specifications for Aliso Canyon Phase 5 functionality: http://www.caiso.com/Documents/BusinessRequirementsSpecification-AlisoCanyonPhase5.pdf

Figure 1.34 Aliso gas nomogram binding status in day-ahead and real-time market (Oct 4, 2020)



1.2.8 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.[71] 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, greenhouse gas compliance costs are attributed to resources who participate in the energy imbalance market and serve ISO load. This facilitates 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 3.4 of this report.

[71] *2015 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2016, pp. 45-48: http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf

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.[72] Daily values of the ISO greenhouse gas allowance index are plotted in Figure 1.35.

Figure 1.35 ISO's greenhouse gas allowance price index

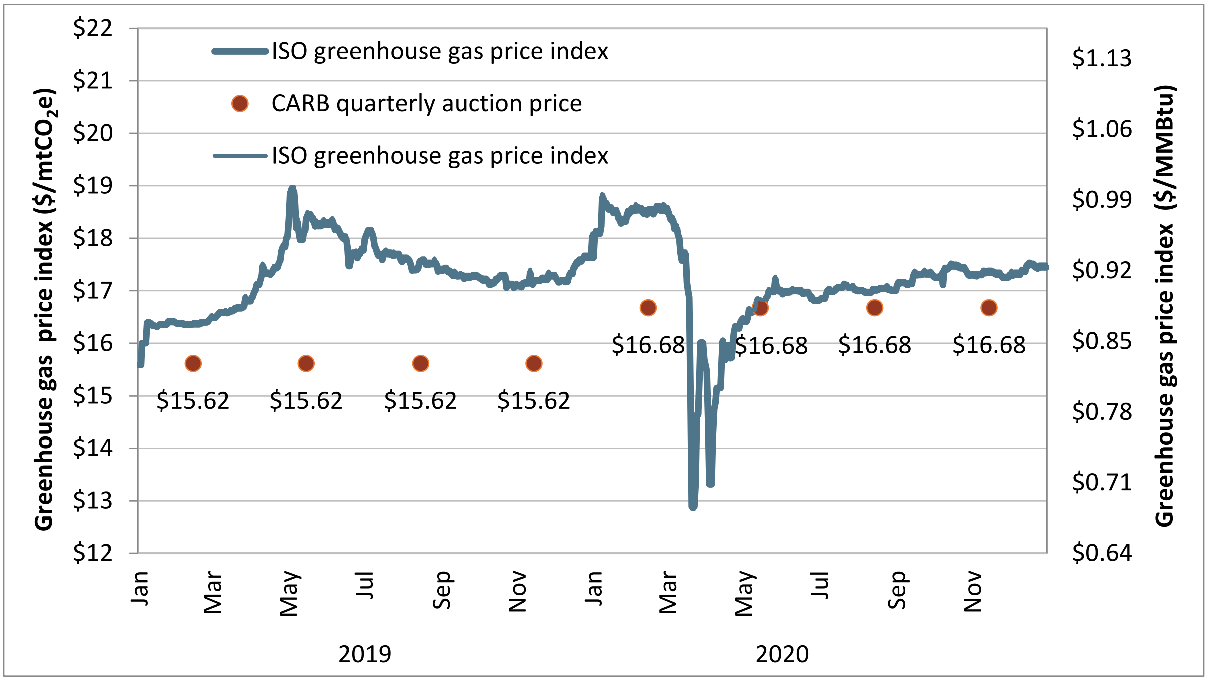


Figure 1.35 also shows market clearing prices in the California Air Resources Board's quarterly auctions of emission allowances that can be used for the 2019 or 2020 compliance years. The values displayed on the right axis convert the greenhouse gas allowance price into an incremental gas price adder, 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.[73] Thus, the blue line can be read from both the left and right hand axes.

As shown in Figure 1.35, the average cost of greenhouse gas allowances in bilateral markets decreased slightly from a load-weighted average of \$17.28/mtCO_2e in 2019 to \$17.16/mtCO_2e in 2020. In 2020

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72 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

73 The emissions factor, 0.0531148 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

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 \$16.68/mtCO_2e.

The greenhouse gas compliance cost expressed in dollars per MMBtu in 2020 ranged from about \$1.00/MMBtu to \$0.68/MMBtu. This represents about one third of the average cost of gas during this period.

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.[74] The \$17.16/mtCO_2e average in 2020 would represent an additional cost of about \$7.29/MWh for a relatively efficient gas unit.[75] The average price in 2019, \$17.28/mtCO_2e, would represent an additional cost of about \$7.34/MWh for the same relatively efficient gas resource.

1.2.9 Capacity changes

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 each year provide important insight into the effectiveness of the market and California's regulatory structure in incenting new generation development.

In late 2019, the ISO identified several upcoming challenges to meeting summer evening peak load including capacity shortfall in 2020 and 2021.[76] In response, the ISO outlined several recommendations including increasing resource adequacy contracting, securing available import capacity, extending the once-through cooling compliance date, and procuring resources that are available during net peak hours. The two primary trends in capacity changes following the discussions of potential shortfalls have been delayed retirement of natural gas facilities and an increase in battery capacity.[77]

Values reported here may differ from those reported elsewhere. First, these figures evaluate changes to the market, rather than exclusively the decommissioning or new interconnection of a unit. A generation withdrawal represents a resource that was once participating in ISO markets and no longer participates. In addition to decommissioned units, withdrawals may include resources that exit the market 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.

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74 *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.

75 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 73.

76 Board of Governors Meeting, Briefing on Grid Operational Outlook: https://www.caiso.com/Documents/Briefing-Post-2020-GridOperationalOutlook-Presentation-Sep2019.pdf

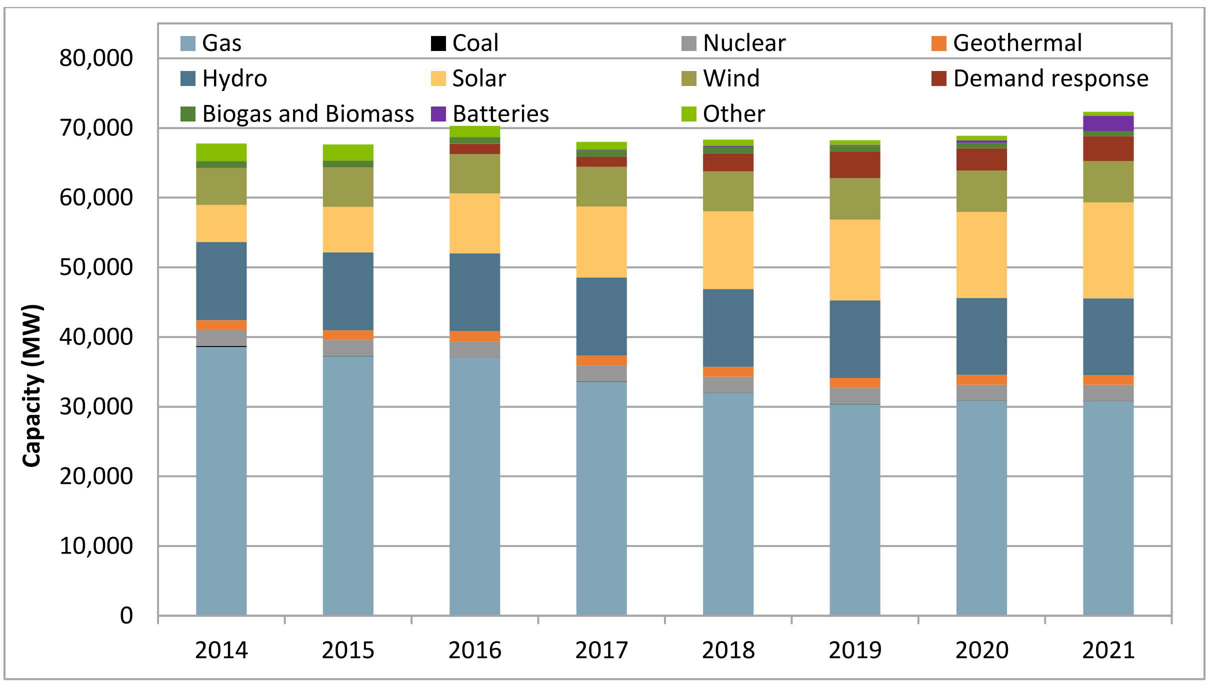
77 There has been a significant increase in the number of storage resources requesting interconnection to the ISO market. Board of Governors Meeting: Briefing on Renewables and Energy Storage in Generation and Interconnections Queue: http://www.caiso.com/Documents/Briefing-Renewables-Generator-Interconnection-Queue-Presentation-July-2021.pdf

Graphs reflect nameplate capacity and changes between June of one year to the next to reflect changes to peak summer capacity.[78]

Total ISO registered and participating capacity

Figure 1.36 summarizes the trends in available nameplate capacity from June 2014 through June 2021.[79] Since 2014 there has been a decrease in gas capacity, falling from 38.5 GW in June 2014 to 30.8 GW in June 2021. This capacity was replaced by solar, which grew from 5.3 GW to 13.8 GW; by wind which grew from 5.3 GW to 5.9 GW; and by demand response which grew from 0 GW to 3.6 GW. While solar, wind, and demand response nameplate capacity have exceeded reductions in gas capacity, variable energy and demand response resources generally have limited energy and availability compared to gas capacity.[80] Batteries, which can be more flexible than the three resource types previously mentioned, are currently the fastest growing resource type, growing from 300 MW in June 2020 to 2,186 MW as of June 2021.

Figure 1.36 Total ISO participating capacity by fuel type and year (as of June 1)



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78 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.

79 Data for 2021 includes all available capacity as of June 1, 2021.

80 In contrast to gas and nuclear capacity resource adequacy contributions, qualifying capacity (QC) of wind and solar resources in the ISO is discounted compared to nameplate capacity to reflect that these resources have limited availability across peak net load hours. Additionally, compared to nuclear and most gas resources, demand response resources are generally limited to operating only a subset of hours.

Withdrawal and retirement of ISO participating capacity

Figure 1.37 and Figure 1.38 summarize the trends in withdrawal and retirement of capacity from June of 2016 through 2021. Since June of 2016, roughly 9.4 GW of capacity withdrew from market participation, 97 percent of which was gas-fired capacity. This reduction is in large part due to the State Water Resource Control Board's regulations to phase out once-through cooling (OTC) technology at coastal power plants that utilize marine water for cooling. About 60 percent of natural gas capacity that withdrew from the market since June 2016 were OTC units.

In Figure 1.37, the striped segment represents capacity that was set to retire before the summer of 2021 but instead remained operational. The ISO took steps to prevent these retirements to keep necessary capacity online to maintain reliability during the summer peak. This included a request to extend the water board's once-through cooling regulation compliance dates for gas-fired generating units as well as the use of reliability must-run (RMR) contracts.[81] The water board approved and extended the closure date for four gas-fired generating facilities, totaling about 3.8 GW of capacity, from the end of 2020 to 2023.[82] In addition, the ISO rejected retirement requests from two gas plants, Midway Sunset Cogeneration and Kingsbury Cogeneration, and instead approved reliability must-run contracts for the two plants, totaling 282 MW. These two contracts are the first ones based on meeting system-wide reliability deficiencies, as opposed to local reliability deficiencies, since the tariff filing in late 2019.[83]

81 CAISO comments to CPUC: https://www.caiso.com/Documents/Jul22-2019-Comments-PotentialReliabilityIssues-R16-02-007.pdf

82 State Water Resources Control Board Resolution No. 2020-0029: https://www.waterboards.ca.gov/board_decisions/adopted_orders/resolutions/2020/rs2020_0029_stffrpt_amend.pdf

83 FERC Docket No. ER10-1641-001: https://www.ferc.gov/sites/default/files/CalendarFiles/20190927191222-ER19-1641-001.pdf

Figure 1.37 Withdrawals from ISO market participation by fuel type[84]

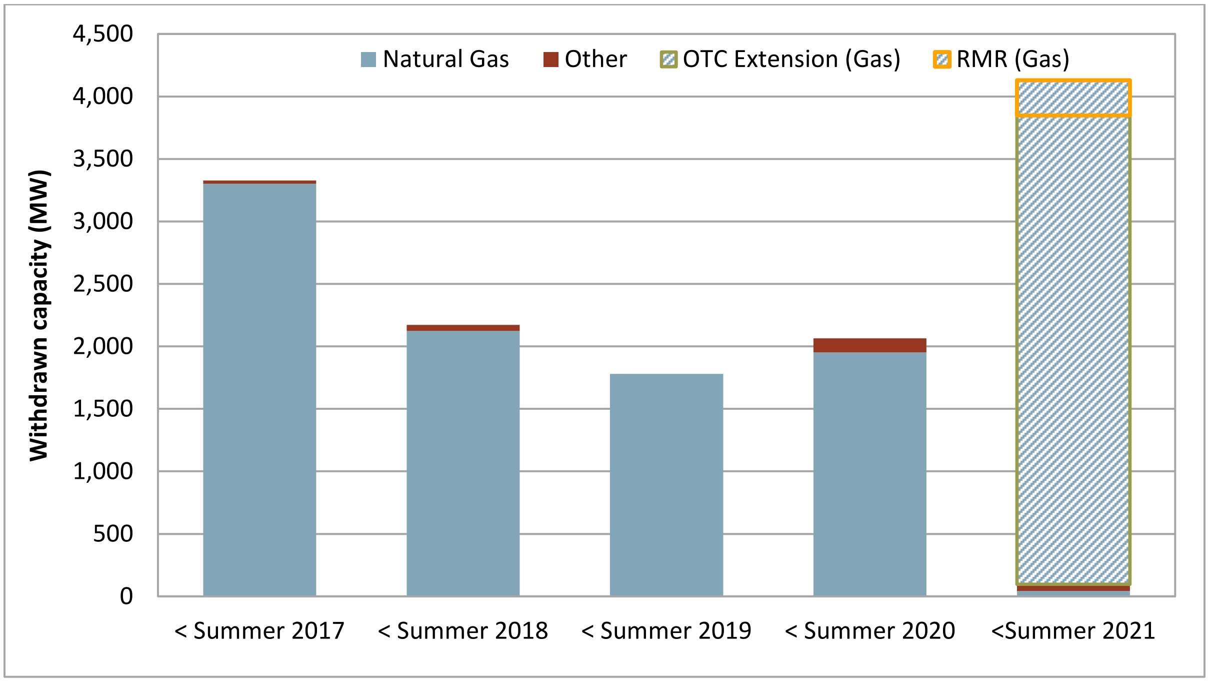
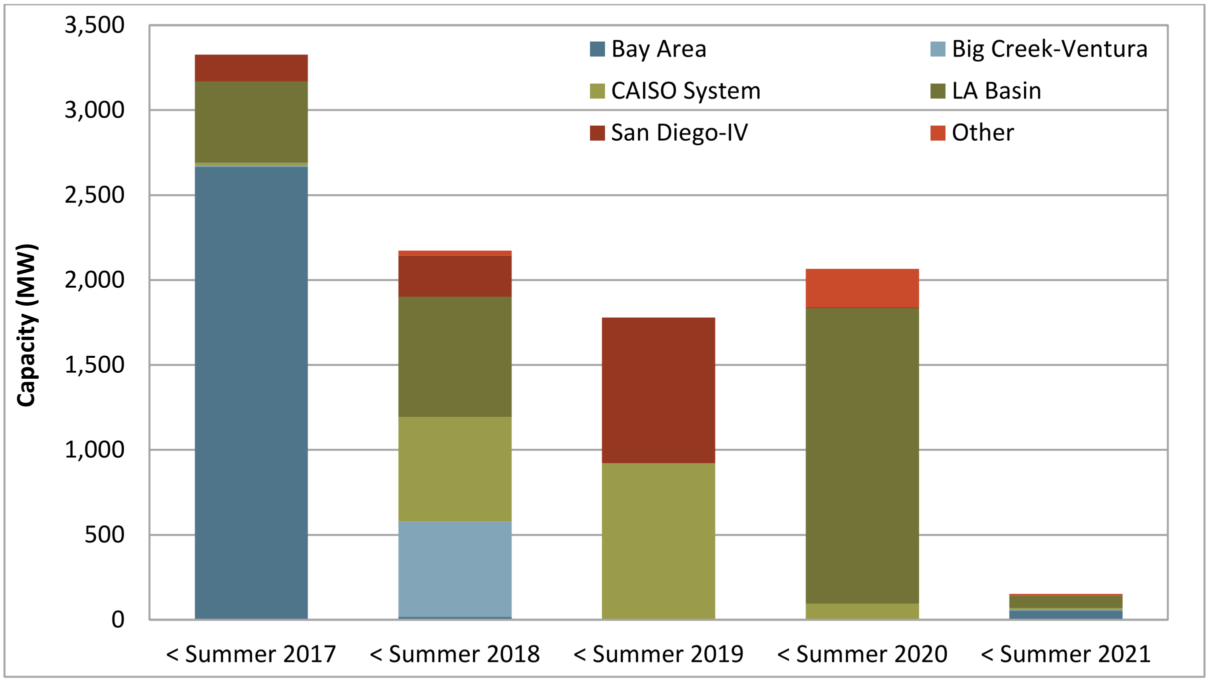


Figure 1.38 shows withdrawals by local area. The chart shows that withdrawals from ISO market participation have largely come from the state's four largest local areas: the Bay Area, LA Basin, San Diego-Imperial Valley, and Big Creek-Ventura. With the extension of the once-through cooling regulations and the two reliability must-run contracts, there is a substantial decrease in natural gas withdrawals. Without the OTC extension, gas withdrawals would have been 2,250 MW in the LA Basin and 1,500 MW in Big Creek-Ventura. This past year, only 152 MW of capacity withdrew from the market, primarily in the LA Basin (73 MW) and the Bay Area (55 MW).

[84] Please note that this is not a complete picture of capacity changes and resource availability in the ISO system. Other changes in available capacity 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 1.38 Withdrawals from ISO market participation by local area



Additions to participating capacity

Figure 1.39 shows additions to ISO market participation. A generation addition is reported whenever a market participant enters the market, which includes resources that re-enter after a period of mothballing.[85] During June 2016 to June 2021, 8,900 MW of solar, 2,500 MW of gas capacity, 1,500 MW of wind, and 2,100 MW of battery capacity was added or returned to the market.[86] The majority of the increase in battery capacity happened in the last year, with over 75 percent (1.7 GW) of this added capacity coming into the market since June 2020. This increase in batteries led to discussions on how to ensure sufficient storage capacity at the peak net load hours, including possible implementation of a minimum state of charge requirement under tight conditions.[87]

Other additions between June 2020 and June 2021 include 12.5 MW of hydro, 3.15 MW of biomass, and 10.5 MW of geothermal. In March 2021, the ISO suggested the CPUC should initiate procurement for at least 10,000 MW of incremental effective capacity by 2026. In particular, the ISO stresses this capacity should be effective after sunset when solar generation has decreased but consumer demand is still high. This push for more flexible capacity has increased the desire to include storage and geothermal resources.[88] Additionally, there are discussions taking place at the CPUC and the ISO to consider steps to

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

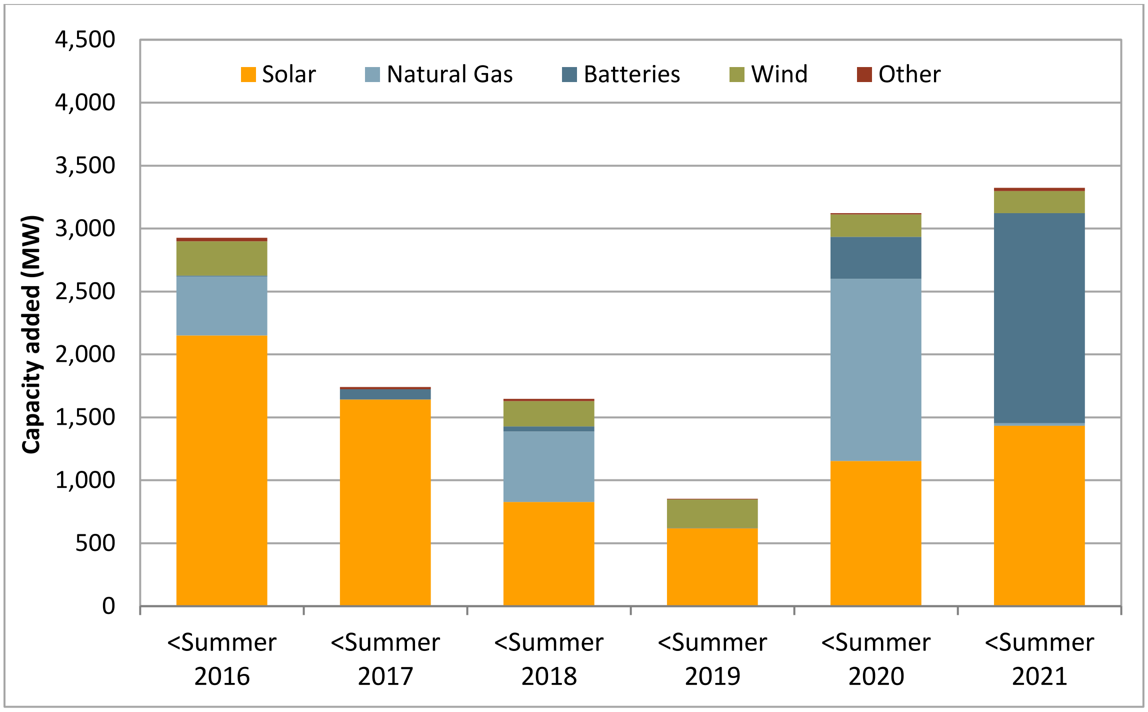
86 Resource additions transition into the market often with phases of testing, so the exact date of market entry reported can vary.

87 *Resource Adequacy Enhancements Final Proposal – Phase 1*, February 17, 2021: http://www.caiso.com/InitiativeDocuments/ResourceAdequacyEnhancements-Phase1FinalProposal.pdf

88 CAISO comments to CPUC: https://www.caiso.com/Documents/Jul22-2019-Comments-PotentialReliabilityIssues-R16-02-007.pdf

increase the supply of demand response resources. Additional information on these resources is discussed in Section 1.2.4.

Figure 1.39 Additions to ISO market participation by fuel type[89]



1.3 Net market revenues of new generation

Overview

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 other energy market revenues.

Each year, DMM examines the extent to which revenues from the ISO's day-ahead and real-time markets contribute to the annualized fixed cost of typical new gas-fired generating resources. This represents a market metric tracked by FERC and all other ISOs. For 2020, this analysis has been expanded to include net market revenues for a new battery energy storage system (BESS). Results from the analysis show that net market revenues for a battery unit participating in both energy and regulation

[89] Please note that this is not a complete picture of capacity changes and resource availability in the ISO system. Other changes in available capacity 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.

markets is significantly higher than just participating in energy price arbitrage. In addition, net revenues are higher in southern local capacity areas than northern areas under these scenarios.

For new gas-fired units, net revenues earned through the ISO's energy market continued to be lower than DMM's estimate of levelized fixed costs. For 2020, DMM estimates that net energy market revenues for a typical gas combined cycle unit ranged from $23 to $48/kW-yr compared to total annualized fixed costs of about $116/kW-yr. For a typical combustion turbine unit, DMM estimates net energy market revenues of about $27 to $43/kW-yr compared to total annualized fixed costs of about $142/kW-yr.

However, the estimated net energy market revenues of gas units in 2020 were, on average, higher than DMM's estimate of the annual going-forward fixed costs of gas generation. DMM estimates that the annual going-forward fixed costs of a typical combined cycle unit are about $26 to $35/kW-yr, compared to net energy market revenues of $23 to $48/kW-yr. In 2019, DMM estimated net energy market revenues for combined cycle units of about $8 to $14/kW-yr, which was significantly lower than estimated annual going-forward fixed costs. For a typical combustion turbine unit, DMM estimates net energy market revenues of about $27 to $43/kW-yr in 2020 compared to estimated annualized going-forward fixed costs of about $27 to $28/kW-yr.

These results continue to underscore the need for any new gas resources needed for local or system reliability to recover additional costs from long-term bilateral contracts. In addition, results indicate that at 2020 price levels, the net energy market revenues for many or most gas units would cover their annual going-forward fixed costs.

Existing gas units that cannot recover their going-forward fixed costs from their energy market revenues would be expected to mothball or retire if they did not receive additional revenues from a resource adequacy contract, the ISO's capacity procurement mechanism, or a reliability must-run contract. The ISO's soft cap for the capacity procurement mechanism is currently set at $76/kW-yr, which DMM estimates is more than twice the annual going-forward fixed costs of gas units. Under the capacity procurement mechanism, units also retain all net market revenues from market operations.

Methodology

In 2016, DMM revised the methodology used to perform this analysis for new gas units to more accurately model total production costs and energy market revenues using a SAS/OR optimization tool.[90] Incremental energy costs are calculated using default energy bids used in local market power

[90] Net revenues due to ancillary services and flexible ramping capacity are not modeled in the optimization model. For a combined cycle unit in the ISO, 2020 total average annual net revenues for regulation (up & down), and spinning reserves were approximately $1.38/kW-yr and payments for flexible ramping capacity were around $0.08/kW-yr. Similarly, for a combustion turbine unit in the ISO, 2020 total average net revenues for spin and non-spinning reserve were $5.7/kW-yr while average flexible ramping payments were $0.18/kW-yr. Therefore, ancillary service and flexible ramping revenues would have had a small impact on the overall net revenues for both combined cycle and combustion turbine units.

mitigation.[91] Commitment costs are calculated using the ISO's proxy start-up and minimum load cost methodology.[92]

For a combined cycle unit, energy market revenues are estimated based on day-ahead and 5-minute real-time market prices. For a combustion turbine unit, estimated energy market revenues are based on a generator's commitment and dispatch in the 15-minute real-time market and any incremental dispatch using the 5-minute prices. The analysis includes estimated net revenues for hypothetical combined cycle and combustion turbine units based on NP15 and SP15 prices, independently.

In 2017, the optimization horizon for these new gas units was changed from daily to annual. The objective of the optimization problem was revised to maximize annual net revenues subject to resource operational constraints. The characteristics and constraints for a combined cycle unit and combustion turbine unit are listed in Table 1.3 and Table 1.5, respectively.

In 2019, DMM updated several resource characteristic assumptions and financial parameters for gas units and re-ran analysis for prior years. The most significant change made was to revise estimates of the fixed annual going-forward costs of gas units. DMM continued to use estimates from a report by the California Energy Commission (CEC) for most components of a unit's going-forward fixed costs (insurance and *ad valorum*).[93] However, instead of fixed annual O&M costs from the CEC report, DMM now uses estimates derived from DMM's review of California-specific and nationwide sources.[94] DMM's analysis indicates that the annual fixed O&M from the CEC report, which is used by the ISO to set the capacity procurement mechanism soft offer cap, significantly overstates the actual fixed annual O&M costs of combined cycle gas units. In this report, DMM estimates that annual going-forward fixed costs

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91 Default energy bids are calculated using the variable cost option as described in the Market Instruments Business Practice Manual Appendix F, https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments

92 Start-up and minimum load costs are calculated using the proxy cost option as described in the Market Instruments Business Practice Manual, Appendix G.2. The energy price index used in the proxy start-up costs is calculated using the retail rate option, Market Instruments Business Practice Manual, Appendix M.2, https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments

93 The annual fixed costs used by DMM represent the average between IOU, POU, and Merchant fixed costs reported by the CEC. See *Estimated Cost of New Renewable and Fossil Generation in California,* California Energy Commission, May 2019. Appendix D: https://www.energy.ca.gov/2019publications/CEC-200-2019-005/CEC-200-2019-005.pdf

94 DMM Comments on CPM Tariff Filing ER20-1075 - Apr 3, 2020: http://www.caiso.com/Documents/AnswerandMotionforLeavetoAnswer-DMMCommentsonCPMTariffFilingER20-1075-Apr32020.pdf

Metcalf RMR Agreement Filing, ER18-240, Schedule F, Article II Part B, pp 140-142, November 2, 2017: https://elibrary.ferc.gov/IDMWS/common/OpenNat.asp?fileID=14741407

Gilroy RMR Agreement Filing, ER18-230, Schedule F, Article II Part B, pp 140-147, November 2, 2017: https://elibrary.ferc.gov/IDMWS/common/OpenNat.asp?fileID=14739579

S&P Global Average. (2019). Data downloaded from S&P Global's online screener tool. S&P Global Market Intelligence (subscription required): https://platform.mi.spglobal.com range from $26 to $35/kW-yr for a typical combined cycle resource and $27 to $28/kW-yr for a typical combustion turbine.[95]

In 2020, potential revenue streams for a battery energy storage system are evaluated under two scenarios using a profit maximization optimization model. The first scenario considers energy price arbitrage in the day-ahead market across 350 pricing nodes, independently. Energy arbitrage refers to purchasing (charging) energy when electricity prices are low, and selling (discharging) energy when electricity prices are high. The second scenario calculates revenues by co-optimizing energy and ancillary services (AS) products (regulation up and down) in the day-ahead market across the same 350 pricing nodes, independently. Both of these scenarios use one years' worth of pricing data across those nodes with a 24 hour optimization horizon window. The mathematical model also considers end of day state of charge as an initial condition for next day's optimization. Battery resource characteristics and constraints used in the model are listed in Table 1.7.

Battery charging and discharging costs in the model scenarios are calculated using default energy bids proposed in the Energy Storage and Distributed Energy Resources (ESDER) 4 initiative.[96] Market revenues in the first scenario (energy price arbitrage) are calculated using day-ahead market prices. In the second scenario (energy and ancillary service co-optimization), regulation up and down ancillary services marginal prices (ASMPs) are also used in addition to day-ahead market nodal prices to calculate market revenues. Section 1.3.3 provides detailed description and results for the two scenarios.

1.3.1 Hypothetical combined cycle unit

Table 1.3 shows the key assumptions used in this analysis for a typical new combined cycle unit. This includes the technical parameters for two configurations of a hypothetical new combined cycle unit that were used in the optimization model. The table also provides a breakdown of financial parameters that contribute to the estimate of total annualized fixed costs for a new 2x1 combined cycle unit.

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

Table 1.4 shows the optimization model results using the parameters specified in Table 1.3. 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 for 2020.

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95 The upper end of DMM's estimate of going-forward fixed costs for each technology type is based on the average of reported annual fixed O&M ($19.8/kW for CC and $8.7/kW for CT) for all gas-fired units in California listed in S&P Global data (which includes 71 combined cycle units and 160 combustion turbines). The lower end of DMM's estimate of going-forward fixed costs is based on the average reported annual fixed O&M ($11.7/kW for CC and $7.8/kW for CT) values for a subset of all units in California which are most similar to the size of the hypothetical units used in this analysis. This subset includes 20 combined cycle units and 60 combustion turbines in California listed in the S&P Global data.

96 ESDER 4 business requirements specifications, Appendix B day-ahead market storage default energy bid calculation examples, pp 44: http://www.caiso.com/Documents/BusinessRequirementsSpecification-EnergyStorageandDistributedEnergyResourcesPhase4.pdf

The first scenario in Table 1.4 modeled unit commitment and dispatch based on day-ahead energy prices and the unit's default energy bids. In 2020, for a unit located in NP15 with the above assumptions, net revenues were $22.60/kW-yr with a 9 percent capacity factor.[97] Using the same assumptions for a hypothetical unit located in SP15, net revenues were $41.30/kW-yr with a 10 percent capacity factor.

The second scenario in Table 1.4 optimized the unit's commitment and dispatch instructions with day-ahead market prices combined with default energy bids excluding the 10 percent adder which is included under the tariff. The 10 percent adder was removed in this scenario because the default energy bid with the 10 percent adder may overstate the true marginal cost of some resources.[98] Many resources do not include the full adder as part of their typical energy bid. Under this scenario, net revenues in 2020 for a hypothetical unit in the NP15 area were $24.30/kW-yr with an 11 percent capacity factor. In the SP15 area, net annual revenues were $43/kW-yr with a 13 percent capacity factor.

The third scenario in Table 1.4 is based on the same assumptions as the first scenario to commit and start the combined cycle resource, but bases the dispatch of energy above minimum operating level on the higher of the day-ahead and 5-minute real-time prices (rather than day-ahead prices alone). This reflects how after the day-ahead market, gas units can rebid and get re-dispatched in the real-time market. Under this scenario, net revenues for a hypothetical unit located in the NP15 area were $25/kW-yr with a 12 percent capacity factor. In the SP15 area, net annual revenues were $47.60/kW-yr with a 14 percent capacity factor.

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[97] The capacity factor was derived using the following equation:
Net generation (MWh) / (facility generation capacity (MW) * hours/year).

[98] See Section 2.2 for further discussion on price-cost markup.

Table 1.3 Assumptions for typical new 2x1 combined cycle unit[99]

Technical Parameters	Configuration 1	Configuration 2
Maximum capacity	360 MW	720 MW
Minimum operating level	150 MW	361 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	$2.40/MWh
GHG emission rate	0.053165 mtCO$_2$e/MMBtu	0.053165 mtCO$_2$e/MMBtu
Start-up gas consumption	1,400 MMBtu	2,800 MMBtu
Start-up time	35 minutes	50 minutes
Start-up auxillary energy	5 MWh	5 MWh
Start-up major maintenance cost adder (2020)	$5,950	$11,900
Minimum load major maintenance cost adder (2020)	$298	$596
Minimum up time	60 minutes	60 minutes
Minimum down time	60 minutes	60 minutes
Ramp rate	40 MW/minute	40 MW/minute
Financial Parameters (2019)		
Financing costs		$80 /kW-yr
Insurance		$6 /kW-yr
Ad Valorem		$8 /kW-yr
Fixed annual O&M		$11.8 /kW-yr
Taxes		$9 /kW-yr
Total Fixed Cost Revenue Requirement		**$116/kW-yr**

99 Start-up and minimum load major maintenance adders are derived based on Siemens SGT6-5000F5 gas turbine technology and costs reported in a NYISO study and adjusted each year for inflation: https://www.nyiso.com/documents/20142/1391705/Analysis Group NYISO DCR Final Report - 9 13 2016 - Clean.pdf/55a04f80-0a62-9006-78a0-9fdaa282cfc2
The cost of actual new generators varies significantly due to factors such as ownership, location, and environmental constraints.
The remaining technical characteristics were assumed based on the manufacturer spec sheet and resource operational characteristics of a typical combined cycle unit within the ISO.
https://assets.new.siemens.com/siemens/assets/api/uuid:d91426bf-3555-4677-9ad9-db9d2de0cb28/version:1572432184/sgt6-5000f-pac-highres.pdf

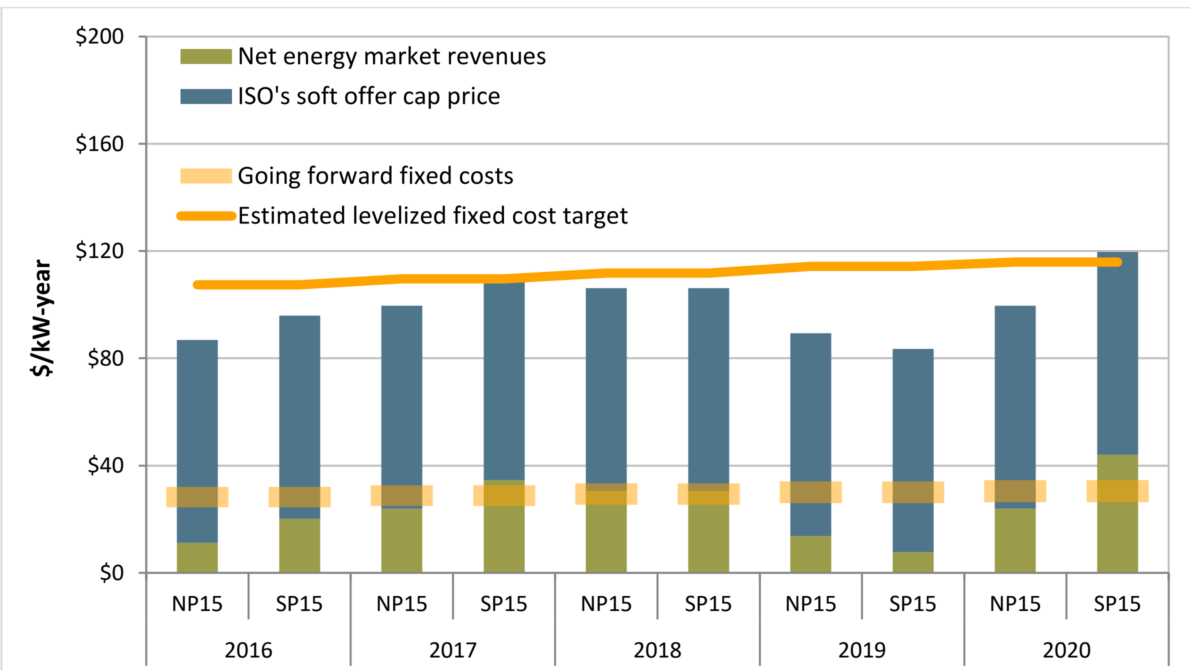
Maximum number of start-up and run-hours constraint has been relaxed in the annual optimization problem.

Table 1.4 Financial analysis of new combined cycle unit (2020)

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	9%	$61.12	$38.47	$22.65
	Day-ahead prices and default energy bids without adder	11%	$69.56	$45.28	$24.28
	Day-ahead commitment with dispatch to day-ahead and 5-minute prices using default energy bids	12%	$75.30	$50.32	$24.97
SP15	Day-ahead prices and default energy bids	10%	$82.83	$41.56	$41.28
	Day-ahead prices and default energy bids without adder	13%	$93.09	$50.05	$43.04
	Day-ahead commitment with dispatch to day-ahead and 5-minute prices using default energy bids	14%	$102.62	$55.01	$47.61

Figure 1.40 shows how net revenue results from the optimization model compare to the estimated annual fixed costs of a hypothetical combined cycle unit over the last five years. The green bars in this chart show the average net revenue estimates over all the scenarios listed in Table 1.4. The blue bars in the chart show the potential capacity payment a unit would receive based on the ISO's soft offer cap price for the capacity procurement mechanism ($75.68/kW-yr).

Figure 1.40 Estimated net revenue of hypothetical combined cycle unit



As shown in Figure 1.40, net revenues in 2020 were close to 2017-18 levels in both NP15 and SP15 areas. This is because of relatively low gas prices and very high day-ahead prices, which persisted on some days in the third and fourth quarters of 2020. This in turn led to increased unit commitment, low operating costs, and hence decreased net energy market revenues.

Figure 1.40 also shows that net revenue estimates for a combined cycle unit continued to fall substantially below the annualized fixed cost estimate, shown by the solid yellow line. As noted above, fixed costs for existing and new units should be recoverable through a combination of long-term bilateral contracts and spot market revenues. The blue bars, equal to the ISO's soft offer cap price for the capacity procurement mechanism ($75.68/kW-yr), represent the potential additional contribution of a capacity payment up to the capacity procurement mechanism soft cap.

For 2020, the average net revenues were higher than the going-forward fixed cost estimate range, shown by transparent yellow bars in Figure 1.40. As shown in this chart, DMM estimates that annual going-forward fixed costs range from $26/kW-yr to $35/kW-yr for combined cycle resources.

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 1.4 with existing combined cycle resources in NP15 and SP15 as a benchmark. In the NP15 area, actual capacity factors in 2020 ranged between 3 and 73 percent with an average of 39 percent capacity factor. In the SP15 area, actual capacity factors ranged between 28 and 56 percent, with an average capacity factor of 40 percent. Our estimates ranged from 9 to 14 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 is 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.

Additionally, software limitations make shutdown instructions less frequent for these resources during the middle of the day because of the limited dispatch horizon used.[100] 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.[101]

1.3.2 Hypothetical combustion turbine unit

Table 1.5 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 estimated annualized fixed costs for a hypothetical combustion turbine unit.

Table 1.6 shows the optimization model results using the parameters specified in Table 1.5. 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 for 2020.

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[100] 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.

[101] 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.

Table 1.5 Assumptions for typical new combustion turbine [102]

Technical Parameters	
Maximum capacity	48.6 MW
Minimum operating level	24.3 MW
Heat rates (Btu/kWh)	
Maximum capacity	9,300 Btu/kWh
Minimum operating level	9,700 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 (2019)	$0
Minimum load major maintenance cost adder (2019)	$191
Minimum up time	60 minutes
Minimum down time	60 minutes
Ramp rate	50 MW/minute
Financial Parameters (2019)	
Financing costs	$105 /kW-yr
Insurance	$8 /kW-yr
Ad Valorem	$11 /kW-yr
Fixed annual O&M	$8 /kW-yr
Taxes	$10 /kW-yr
Total Fixed Cost Revenue Requirement	**$142/kW-yr**

102 Start-up and minimum load major maintenance adders are derived based on an aeroderivative GE LM6000 PH Sprint technology and costs reported in a NYISO study and adjusted each year for inflation: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B25745D07-C958-42EA-AC1A-A1BB0D80FF52%7D
The cost of actual new generators varies significantly due to factors such as ownership, location, and environmental constraints.

The remaining technical characteristics were assumed based on the manufacturer spec sheet based on the technology type and resource operational characteristics of a typical peaking unit within the ISO. https://www.ge.com/content/dam/gepower/global/en_US/documents/gas/gas-turbines/aero-products-specs/lm6000-fact-sheet-product-specifications.pdf

Table 1.6 Financial analysis of new combustion turbine (2020)

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	2.3%	$39.81	$12.85	$26.96
	15-minute prices and default energy bids without adder	2.8%	$42.63	$15.09	$27.54
	15-minute commitment with dispatch to 15-minute and 5-minute prices using default energy bids	2.5%	$41.43	$14.22	$27.21
SP15	15-minute prices and default energy bids	2.8%	$58.48	$17.39	$41.09
	15-minute prices and default energy bids without adder	3.3%	$61.15	$19.30	$41.85
	15-minute commitment with dispatch to 15-minute and 5-minute prices using default energy bids	3.4%	$63.88	$20.71	$43.17

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 2020 prices, net annual revenues were approximately $27/kW-yr with a 2 percent capacity factor. Similarly, in the SP15 area, net revenues were approximately $41/kW-yr with a 3 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.[103] Using this scenario, the hypothetical unit in NP15 earned net revenues of about $27.50/kW-yr with a 3 percent capacity factor. The hypothetical unit in SP15 earned net revenues of about $41.85/kW-yr with a capacity factor of 3.3 percent.

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 $27/kW-yr with a 2.5 percent capacity factor. In the SP15 area, net revenues were about $43/kW-yr with a 3.4 percent capacity factor.

Figure 1.41 shows how net revenue results from the optimization model compare to estimated annualized fixed costs of a hypothetical combustion turbine unit.[104] The green bars in this chart show estimated net revenues over the past five years.

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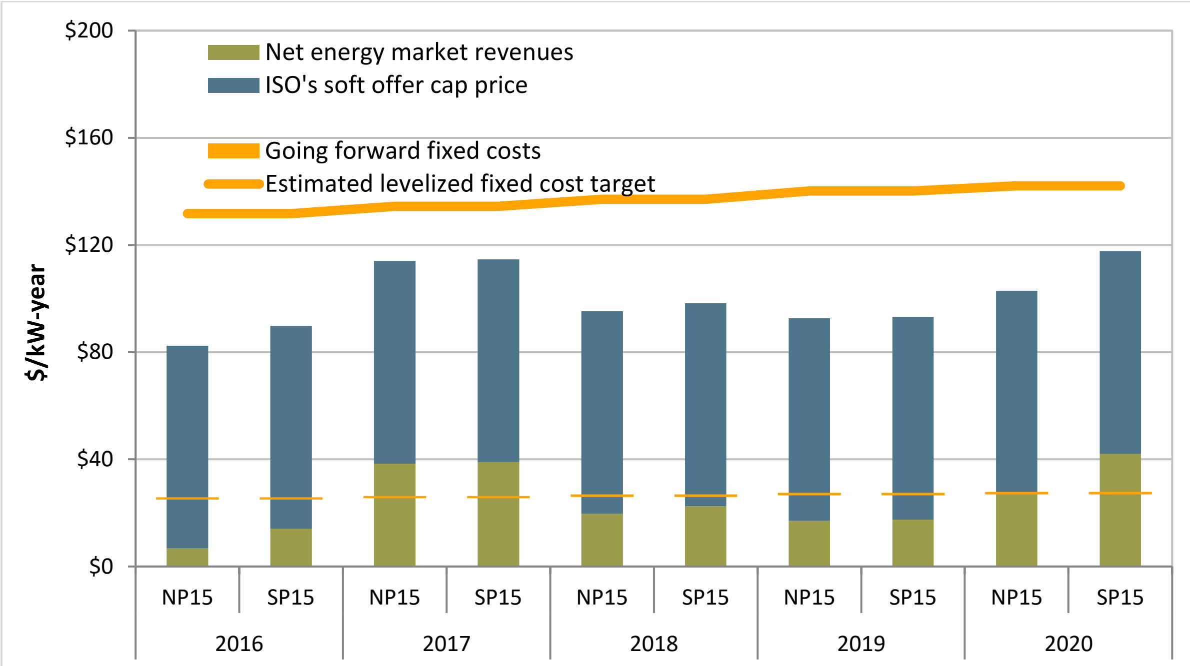
[103] As noted above, we frequently find resources that bid in excluding the full 10 percent adder in their incremental energy bids.

[104] 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-Sep28-2019.pdf

Figure 1.41 Estimated net revenues of new combustion turbine



As shown in Figure 1.41, net revenues for a hypothetical combustion turbine rose significantly in 2017 when compared to 2016. Net revenues then decreased in 2018 and 2019, but went up again in 2020. This is because of low gas prices and significantly high real-time prices in both NP15 and SP15 areas during some days in the third and fourth quarter of 2020.

Figure 1.41 shows that, from 2016 through 2020, net revenue estimates for a hypothetical combustion turbine unit in both the NP15 and the SP15 regions fall substantially below the annualized fixed cost estimate, shown by the solid yellow line. As noted above, fixed costs for existing and new units should be recoverable through a combination of long-term bilateral contracts and spot market revenues.

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 1.5 with existing combustion turbines in NP15 and SP15 as a benchmark. In the NP15 area, actual capacity factors in 2020 ranged between 0.8 and 7 percent, with an average capacity factor of 3 percent. In the SP15 area, actual capacity factors ranged between 0.1 and 11 percent, with an average capacity factor of 4 percent. DMM's estimates ranged from 2.3 to 3.4 percent and were relatively close to average actual capacity factors.

1.3.3 Hypothetical battery energy storage system

Table 1.7 shows the key assumptions used in the profit maximization model for a new fast-ramping typical lithium-ion battery energy storage system (BESS).

Table 1.7 Assumptions for typical new Li-ion battery energy storage system

Technical Parameters	
Maximum capacity	100 MW
Minimum capacity	-100 MW
Battery duration	4 hours
State-of-charge (SOC)	
Minimum SOC	0 MWh
Maximum SOC	400 MWh
Variable O&M costs	$30 /MWh
Round-trip efficiency	0.85

Table 1.8 shows the optimization model results using the parameters specified in Table 1.7. Results were calculated using two different scenarios for a battery unit located across 350 pricing nodes, separately. For each of these scenarios, net market revenues (revenues minus costs) across these nodes were grouped and averaged by local capacity area. As shown in Table 1.8, a battery unit offering regulation services in addition to participating in the energy market is significantly more profitable than a unit doing just energy price arbitrage.

Table 1.8 New battery energy storage net market revenues by LCA (2020)

Local capacity area	TAC area	Net market revenues ($/kW-yr)	
		Scenario 1	Scenario 2
		Energy arbitrage only	Energy and Regulation
Greater Bay Area	PG&E	$10.98	$102.41
North Coast & North Bay (NCNB)	PG&E	$16.58	$110.56
Greater Fresno	PG&E	$20.65	$118.86
Sierra	PG&E	$18.41	$108.38
Stockton	PG&E	$11.35	$103.79
Kern	PG&E	$12.59	$111.41
LA Basin	SCE	$27.52	$135.26
Big Creek/Ventura	SCE	$23.28	$132.08
San Diego/Imperial Valley	SDG&E	$24.93	$134.99
CAISO System		$16.20	$119.37

In the first scenario, we simulated the charging and discharging of a battery unit given day-ahead market prices at 350 pricing nodes, independently, using default energy bids as costs. In this energy price arbitrage scenario, the model optimally charges when electricity prices are low and discharges when the electricity prices are the highest, subject to the battery's state of charge (SOC) and other operational constraints. The state of charge is defined as a function of charging and discharging decision variables where round-trip efficiency (losses) is only applied while charging. In addition, state of charge is bound between minimum and maximum limits as shown in Table 1.7.

Figure 1.42 and Figure 1.43 show optimal hourly charging and discharging schedules averaged across pricing nodes located in the PG&E and SCE transmission access charge (TAC) area, respectively, for 2020. On average, the battery unit located in the PG&E TAC area was charging in about 3 percent of the hours and discharging in about 2.2 percent of the hours. The unit located in the SCE TAC area, on average, was charging in about 4 percent and discharging in about 3 percent of the hours. As shown in Table 1.8, net revenues averaged about $15/kW-yr in northern local capacity areas compared to $25/kW-yr in southern local areas.

Figure 1.42 Average hourly battery schedules across pricing nodes in PG&E area (2020)

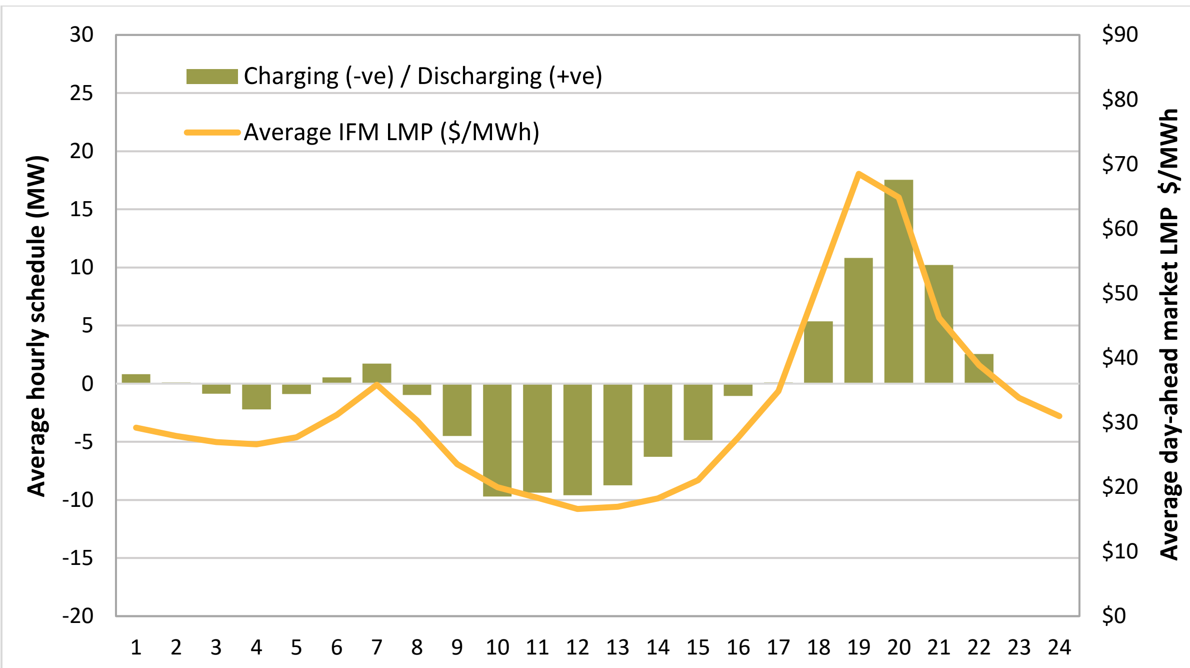
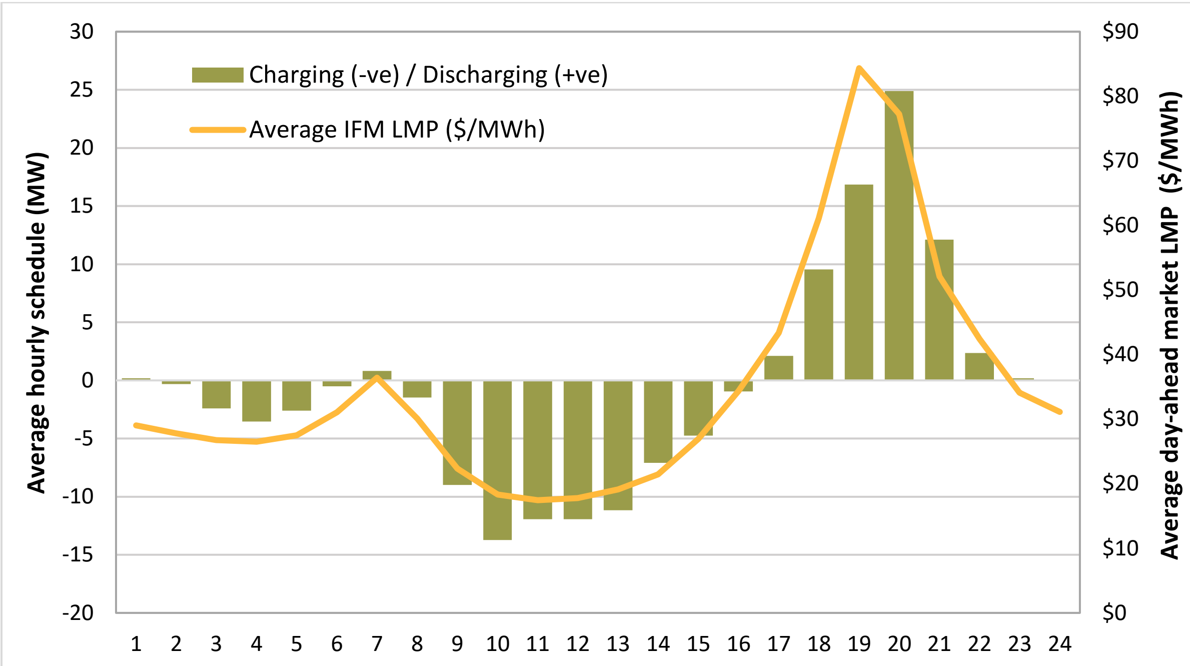


Figure 1.43 Average hourly battery schedules in SCE area (2020)



In the second scenario, the model calculates the maximum profit a battery unit can receive by participating in both energy arbitrage and regulation (ancillary services) markets. Revenues are calculated using day-ahead market prices and regulation up and down ancillary service marginal price (ASMP) at 350 pricing nodes, independently. Similar to the first scenario, default energy bids proposed under ESDER 4 initiative are used as bid costs. Revenues for regulation service include a capacity payment as well as any revenues from following automatic generation control (AGC) signals in the real-time market.

The model assumes that about 15 percent of the regulation up and down awards from the day-ahead market are deployed in real-time for frequency regulation. Hence, the model includes the costs and revenues associated with this fraction of regulation deployed in real-time in its profit maximization objective function. In order to quantify the change in state of charge (SOC) between hours from participating in the ancillary services market, the SOC function in this scenario also includes the fraction (15 percent) of regulation up and down deployed through AGC in real-time. Therefore, the quantities allocated to regulation up and regulation down reduce the maximum potential quantities allocated to arbitrage subject to the charge/discharge constraints of the battery unit.

Figure 1.44 and Figure 1.45 show optimal hourly awards for energy and regulation averaged across pricing nodes located in the PG&E and SCE TAC area, respectively, for 2020. On average, the battery unit located in the PG&E TAC area was charging in about 2 percent of the hours and discharging in less than about 1 percent of the hours. In the same area, regulation up award frequency was about 61 percent compared to 66 percent for regulation down. The unit located in the SCE TAC area, on average, was charging in about 1.8 percent and discharging in about 0.5 percent of the hours. Regulation up and regulation down award frequency averaged about 56 percent and 63 percent of hours, respectively. As shown in Table 1.8, net revenues averaged about $109/kW-yr in northern local capacity areas compared to $134/kW-yr in southern areas.

The results from this analysis show that net market revenues under the second scenario (energy and regulation) are significantly higher than the first scenario (energy arbitrage only). In addition, net revenues are greater in south regions compared to the north regions in both these scenarios.

The net revenue results from this model are benchmarked against battery resources providing energy and ancillary services in the ISO market. Based on 2020 settlements data, battery resources in the ISO have net revenues in the range of $107/kW-yr to $147/kW-yr. Results from the model's second scenario (energy and regulation), show estimated net revenues in the range of $102/kW-yr to $135/kW-yr which were relatively close to actual revenues earned by battery resources in 2020.

Figure 1.44 Average hourly battery energy and regulation awards in PG&E area (2020)

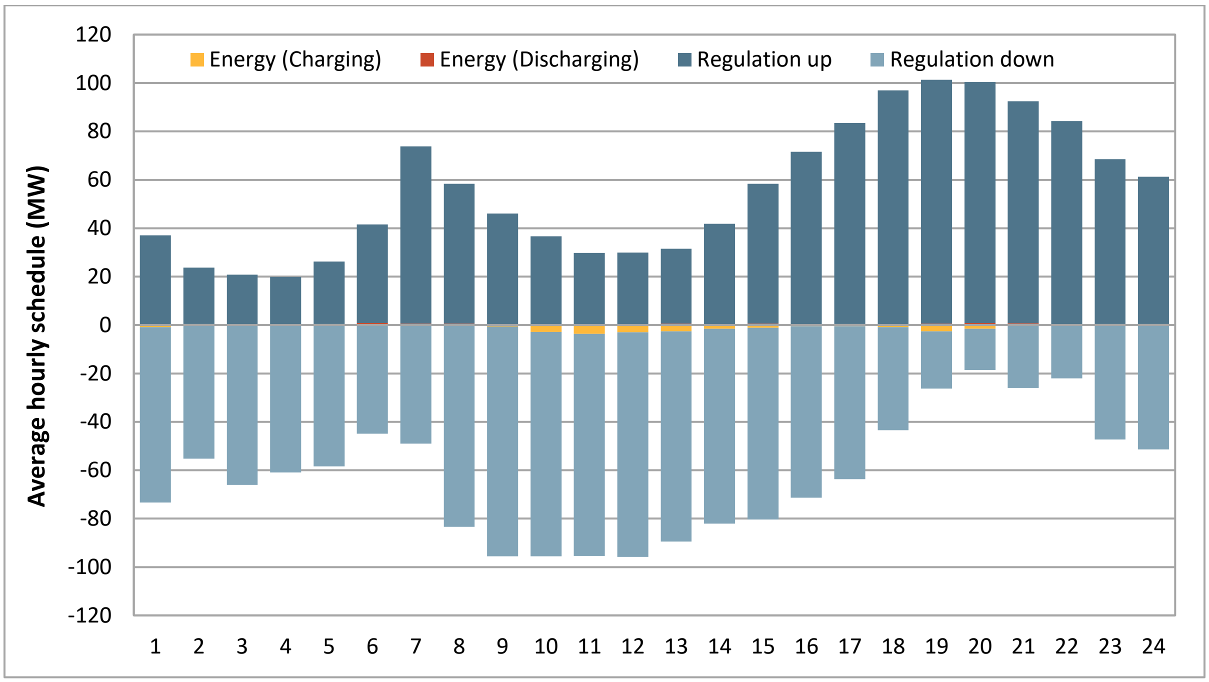
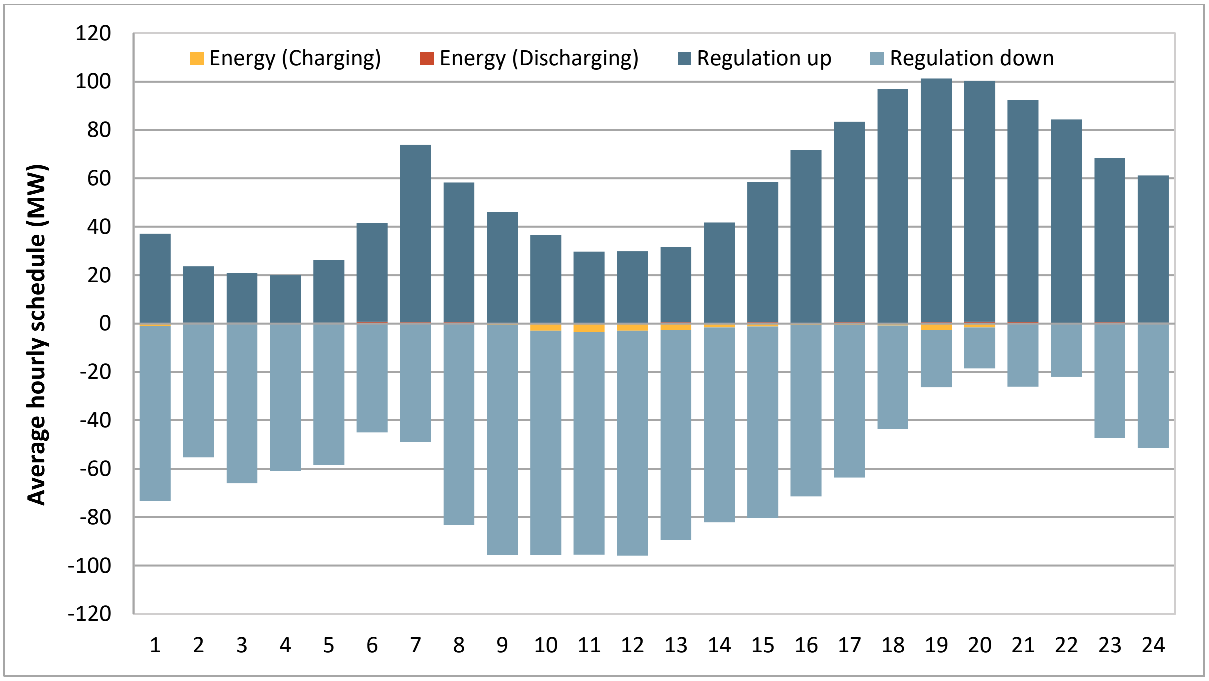


Figure 1.45 Average hourly battery energy and regulation awards across pricing nodes in SCE area (2020)



2 Overview of market performance

The ISO markets continued to perform efficiently and competitively in 2020.

- **Total wholesale electric costs increased by about 3 percent,** despite substantially lower natural gas prices. Controlling for both natural gas costs and greenhouse gas prices, wholesale electric costs increased by about 19 percent.
- **Energy market prices were competitive, with prices usually reflecting resources' marginal costs**. DMM estimates that the impact of import and gas resources bidding above reference levels, a conservative measure of average price-cost markup, was about $1/MWh or about 2.5 percent.
- **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.[105]
- **Bid cost recovery payments in the ISO increased to the second highest value since 2011**, totaling $126 million, or about 1.4 percent of total energy costs, the same percent as 2019, from $123 million in 2019 and $153 million in 2018. Payments in the three highest load months account for almost half or the total.
- **Bid cost recovery payments for units in the energy imbalance market totaled about $9 million** in 2019; about $1 million lower than in 2019. The cost of these payments is allocated back to the energy imbalance market balancing area in which the units receiving these payments is located.
- **Total ISO real-time imbalance offset costs increased by 69 percent to $177 million** compared to $105 million in 2019. Congestion offsets make up the bulk of the total at $117 million and were again attributable to significant reductions in constraint limits made by grid operators in the 15-minute market relative to limits used in the day-ahead market and network model changes.
- Following the load curtailment event in August, **the ISO revised the market algorithm to give the residual unit commitment process the ability to curtail exports**. The market change that went in place on September 5 was designed to address the treatment of economic and self-scheduled exports that cleared the day-ahead integrated forward market (IFM) run. With this change, the residual unit commitment process is able to curtail certain exports before relaxing the power balance constraint. These reduced exports no longer receive a real-time scheduling priority that exceeds real-time ISO load and can choose to re-bid in real-time or resubmit as self-schedules in real-time.[106]

105 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

106 The ISO provided details and examples of this change in the Market Performance and Planning Forum meeting on September 9, 2020: http://www.caiso.com/Documents/Presentation-MarketPerformance-PlanningForum-Sep9-2020.pdf#search=market%20performance%20and%20planning%20forum

2.1 Total wholesale market costs

The total estimated wholesale cost of serving load in 2020 was about $8.9 billion or about $42/MWh. This represents a 3 percent increase from about $41/MWh in 2019. After normalizing for natural gas prices and greenhouse gas compliance costs, using 2010 as a reference year, DMM estimates that total wholesale energy costs increased by about 19 percent.

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:

- Relatively high prices during the third quarter, related in part to warm temperatures increasing peak demand in the ISO and in the West which include the August heat wave;
- Increased prices during peak evening ramping periods; and
- Decreased production from hydroelectric resources.

Figure 2.1 shows total estimated wholesale costs per megawatt-hour of system load for the previous five years. 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.[107]

[107] For the wholesale energy cost calculation, an average of annual gas prices was used from the SoCal Citygate and PG&E Citygate hubs. Electricity costs tend to move with changes in gas costs, as illustrated by the ratio between the blue bar and the green line for 2016 and 2017. A gas cost factor of 80 percent has therefore been incorporated into the normalization calculations to account for this relation between electricity costs and gas prices. DMM validated the efficacy of this factor by using regression analysis to estimate the relationship between quarterly energy and gas prices from 2017 to 2020. Results showed a relationship that is not statistically different from the 80 percent factor and is robust to multiple specifications that control for quarterly and yearly influences.

Figure 2.1 Total annual wholesale costs per MWh of load (2016-2020)

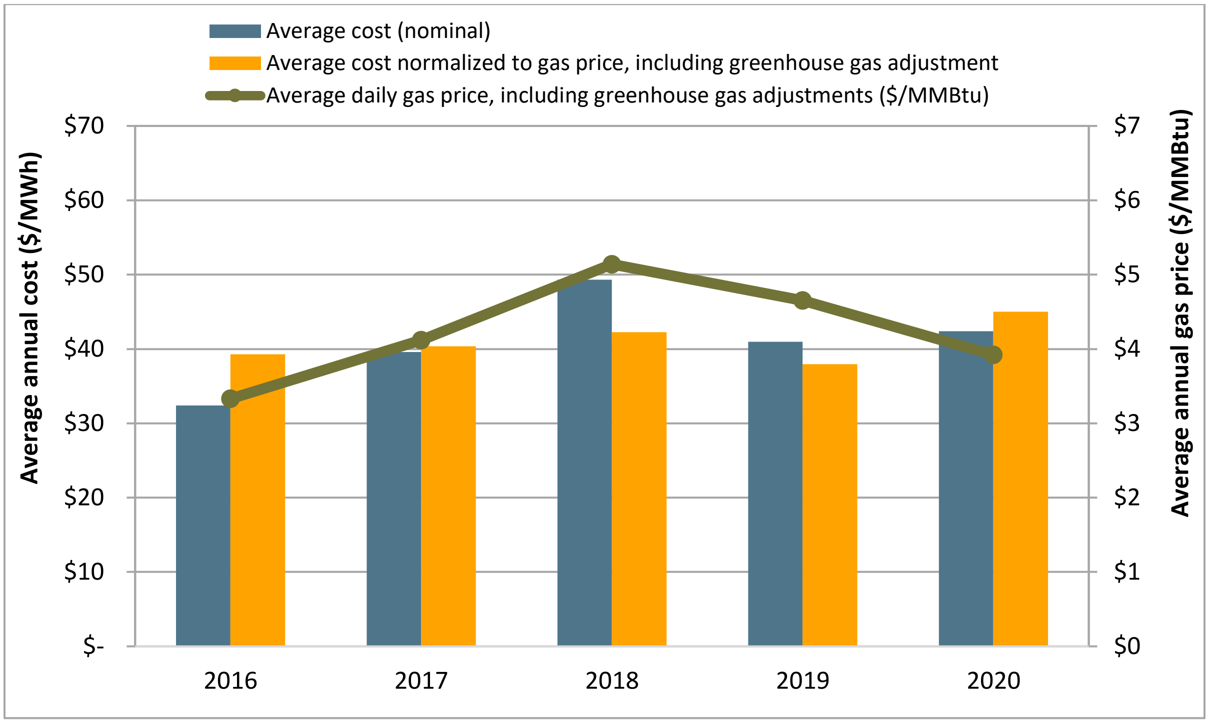


Table 2.1 provides annual summaries of nominal total wholesale costs by category for the previous five years.[108] The total wholesale energy cost also includes costs associated with ancillary services, convergence bidding, residual unit commitment, bid cost recovery, reliability must-run contracts, the capacity procurement mechanism, the flexible ramping constraint and product, and grid management charges.[109]

As shown in Table 2.1, the 3 percent increase in total cost in 2020 was from a modest overall increase in each cost category. Day-ahead energy costs, which increased by less than $1/MWh or roughly 1 percent from 2019, remain the largest proportion of wholesale costs at about 91 percent. Real-time energy costs increased to nearly 4 percent of wholesale costs, while the remaining components continue to represent a relatively small portion of the total.

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108 Values shown in this table represent cost to ISO load only and do not include costs to load in the energy imbalance market.

109 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. Costs reported prior to 2018 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.

Table 2.1 Estimated average wholesale energy costs per MWh (2016-2020)

	2016	2017	2018	2019	2020	Change '19-'20
Day-ahead energy costs	$ 30.49	$ 37.40	$ 46.05	$ 38.13	$ 38.61	$ 0.48
Real-time energy costs (incl. flex ramp)	$ 0.54	$ 0.73	$ 0.59	$ 1.02	$ 1.64	$ 0.62
Grid management charge	$ 0.42	$ 0.44	$ 0.46	$ 0.46	$ 0.46	$ 0.01
Bid cost recovery costs	$ 0.30	$ 0.41	$ 0.68	$ 0.56	$ 0.60	$ 0.04
Reliability costs (RMR and CPM)	$ 0.11	$ 0.10	$ 0.68	$ 0.06	$ 0.07	$ 0.01
Average total energy costs	**$ 31.86**	**$ 39.09**	**$ 48.47**	**$ 40.23**	**$ 41.39**	**$ 1.16**
Reserve costs (AS and RUC)	$ 0.53	$ 0.71	$ 0.87	$ 0.75	$ 1.02	$ 0.28
Average total costs of energy and reserve	**$ 32.39**	**$ 39.80**	**$ 49.34**	**$ 40.98**	**$ 42.41**	**$ 1.43**

2.2 Overall market competitiveness

The performance of California's wholesale energy markets remained competitive, with prices during most hours at or near the marginal cost of generation. DMM assesses the competitiveness of overall market prices 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.

DMM estimates these competitive baseline prices by re-simulating the day-ahead market after replacing bids or other market inputs using DMM's version of the day-ahead market software. Actual market prices were very close to these estimated competitive baseline prices, even during the heat wave period of August 14 to 19, indicating that replacing high-priced energy bids with cost-based bids did not lower prices. Resources that may be subject to mitigation, such as gas-fired and other resources, were generally infra-marginal during high-priced hours. When performing day-ahead market reruns using cost-based bids, high prices were set by demand response and other resources not subject to mitigation. System-wide mitigation of imports and gas-fired resources during this period would not have lowered prices.

Competitive baseline prices were calculated by re-running day-ahead market simulations under several different scenarios.[110] Each market simulation run is preceded by a base case rerun with all of the same inputs as the original day-ahead market run before completing the benchmark simulation, to screen for accuracy. 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.[111]

110 Detailed descriptions of these scenarios can be found in the *Q4 2020 Report on Market Issues and Performance*, April 28, 2021: http://www.caiso.com/Documents/2020-Fourth-Quarter-Report-on-Market-Issues-and-Performance-April-28-2021.pdf

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

As shown in Figure 2.2, average prices in the day-ahead market were very similar to or slightly above the estimated competitive baseline prices. This scenario shows competitive bidding by gas resources for energy and commitment costs, as well as competitive import bids. The red bars show the difference between baseline scenario prices and the base case price, indicating that average scenario prices were generally slightly below base case prices. The average price-cost markup for this competitive baseline scenario was about $1/MWh or 2.5 percent.[112] Very low price-cost markup values indicate that prices were competitive overall for the year.

Figure 2.2 Day-ahead market price-cost markup – default energy, commitment cost, and import bids scenario (2020)[113]

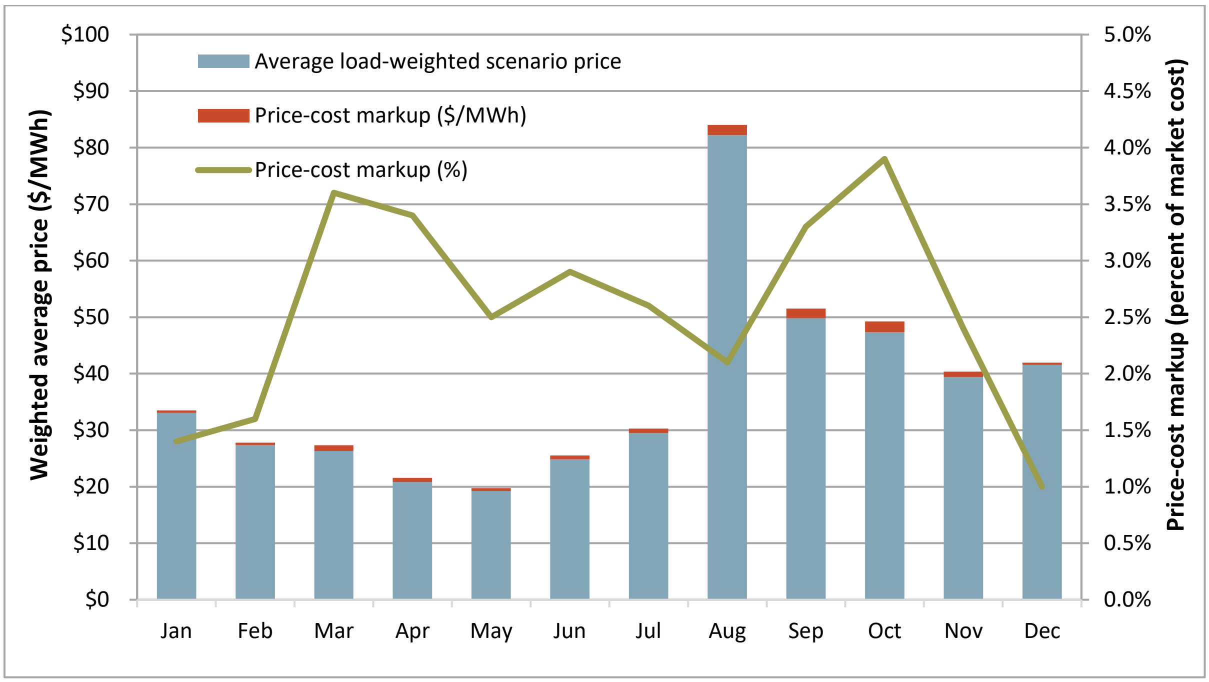


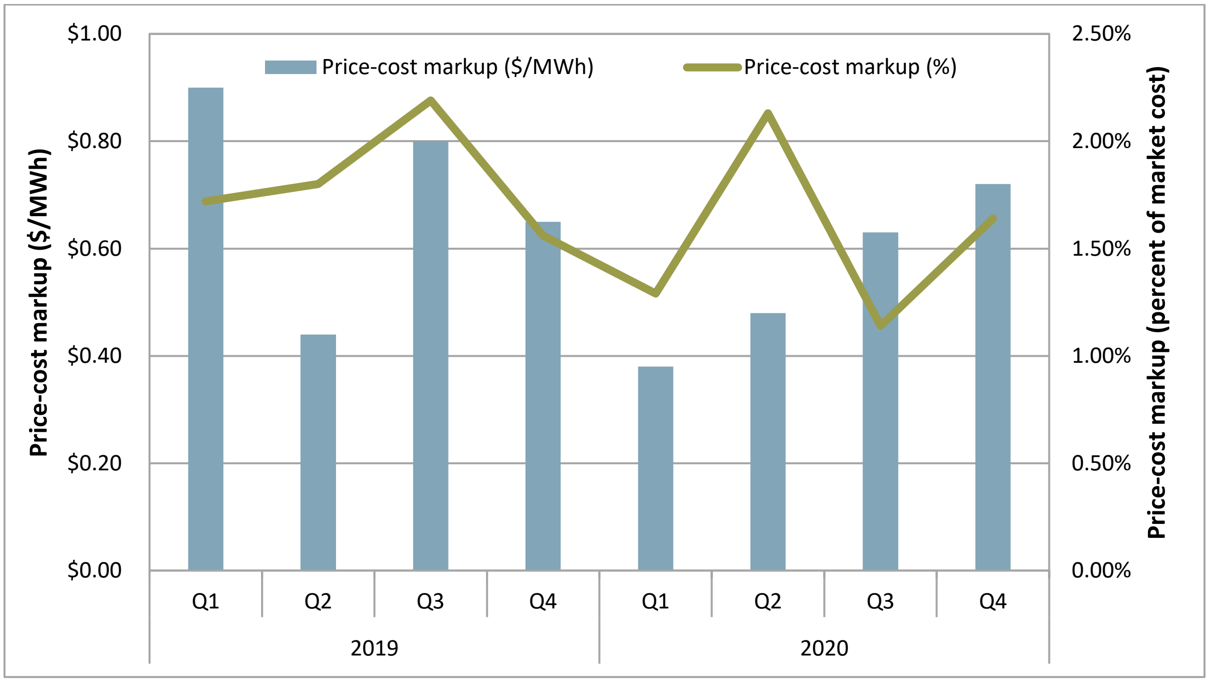
Figure 2.3 shows results for the scenario that caps energy bids for gas resources at the lower of their submitted bid or default energy bid. Price-cost markup for this scenario was slightly lower in 2020 at about $0.56/MWh or 1.4 percent compared with $0.70/MWh or 1.8 percent for the previous year. This scenario may be a low-end measure of system market power for several reasons. The only change in market inputs in this scenario was capping energy bids of gas-fired resources at their default energy bid, which includes a 10 percent adder above estimated marginal costs. All other bids are assumed to be

[112] For 2020, a limited number of startup bids for multi-segment startup costs were not changed during the scenario reruns. Although it was not possible to rerun all 2020 trade dates to correct this issue, a sample set of trade dates were rerun with the corrected substituted values. Average prices for these sample reruns were slightly lower than reported here, indicating the markup difference between the base case and scenario prices (shown in the red bars) would have been slightly higher.

[113] This figure shows the results for a scenario where bids for gas-fired units were set to the minimum of their submitted bid or default energy bid, bids for gas-fired resources' commitment costs were set to the minimum of their bid or 110 percent of proxy price, and import bids were set to the minimum of their bid or an estimated hydro default energy bid. In previous years, the competitive baseline was a scenario where bids for gas-fired generation were set to their default energy bids, convergence bids were removed, and system demand was set to actual system load. This tended to overestimate the competitive baseline price, because a significant amount of gas-fired supply is bid at prices lower than their default energy bids (which include a 10 percent adder), and the actual system load measure used was often greater than day-ahead cleared load.

competitive, including those of non-resource specific imports. In addition, this analysis does not change commitment cost bids for gas-fired resources which are capped at 125 percent of each resource's estimated start-up and minimum load bids.

Figure 2.3 Quarterly day-ahead market price-cost markup – default energy bid scenario (2019-2020)



2.3 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 third quarter of 2020 due in part to warm temperatures, including the August heat wave.
- Prices in the 5-minute market were lower than prices in both the 15-minute and day-ahead markets. Day-ahead prices averaged about $34.6/MWh, 15-minute prices were about $33.6/MWh, and 5-minute prices were about $29.9/MWh. Lower real-time prices is a persistent pattern that appears to be driven in part by systemic differences between load adjustments made by ISO grid operators in the 5 minute market.
- Average hourly prices generally moved in tandem with the average net load. The evening peak load was 9 percent higher than last year, while the morning peak was a bit lower. Peak prices were 20 percent higher this year, but occurred an hour earlier (during the ramping period).
- Similar to the previous year, negative average energy prices occurred in all three markets
- Price variability in all three markets was fairly similar to that of last year. Negative price spikes occur in the middle of the day when solar generation is highest. The yearly average of intervals

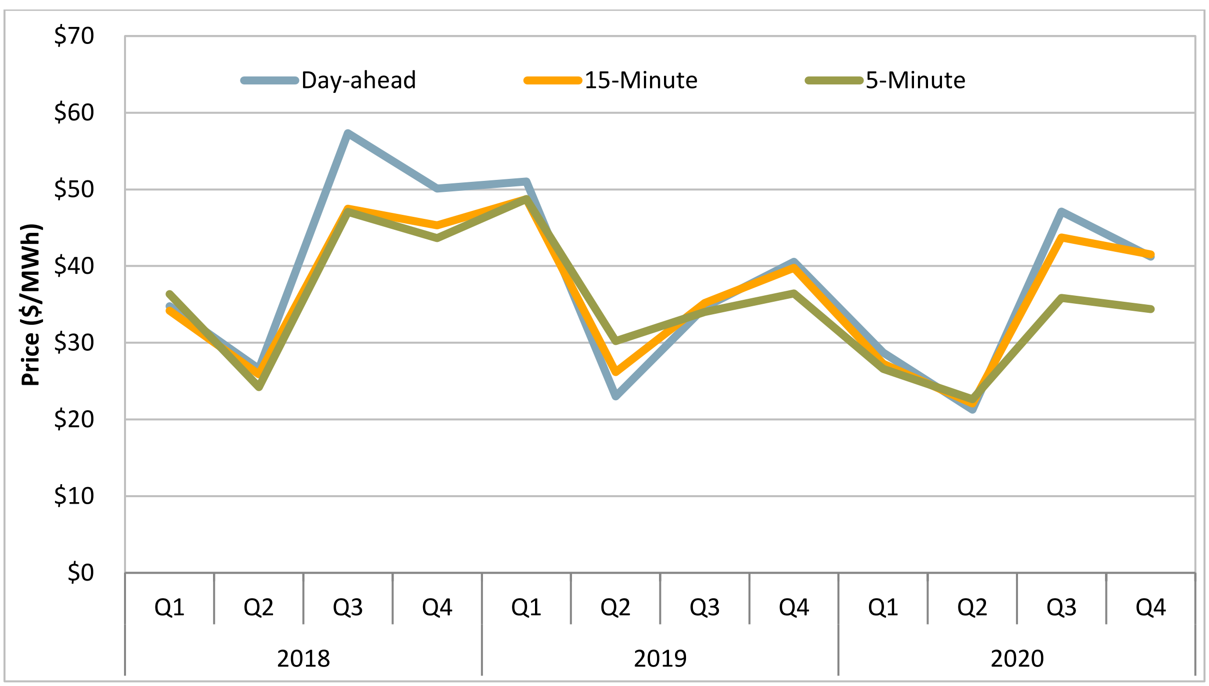
with prices below $0/MWh was 0.9 percent in the day-ahead market, 2.8 percent in the 15-minute market, and 4.2 percent in the 5-minute market. Positive price spikes happened in the late afternoon during the net peak load. High price spikes in the 5-minute and 15-minute market were similar to that of last year, but the frequency of high price spikes in the day-ahead market was high in 2020 compared to 2019.

Figure 2.4 shows the load-weighted average energy prices across the three largest aggregation points in the ISO (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric) during all hours for the day-ahead and real-time markets. Overall prices were lower in 2020 compared to 2019. Prices in all three markets were lower in the first and second quarter this year compared to last, particularly the first quarter where prices were about 45 percent lower in 2020. Prices in all three markets were higher in the third quarter of 2020, which includes the high demand days during the August heat wave.

Day-ahead energy prices averaged $35/MWh, a 7 percent decrease from 2019 but still higher than the 5-minute and 15-minute markets. Compared to last year, prices decreased 10 percent in the 15-minute market to an average of $34/MWh and 20 percent in the 5-minute market to an average of $30/MWh.

Although prices across the day-ahead and real-time markets converged closely the first two quarters of 2020, they diverged in the latter half of the year, with 5-minute prices being roughly 20 percent lower than prices in the 15-minute and day-ahead market.

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

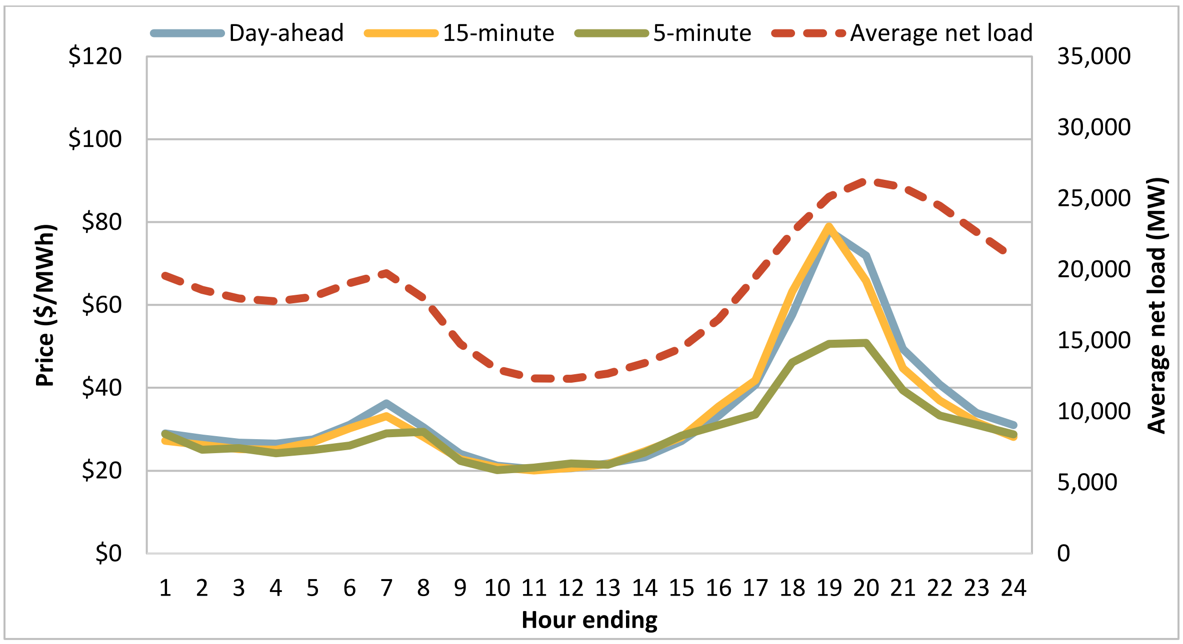


To analyze how prices vary throughout the day, on average, Figure 2.5 illustrates hourly load-weighted average energy prices in the ISO in the day-ahead and real-time markets as well as average hourly net load. Since the substantial increase in solar generation several years ago, net load and energy prices follow the same pattern. Net load and energy prices were lowest midday when low-priced solar generation was greatest. Energy prices and net load both peak during the early evening when demand is still high but solar generation has substantially decreased.

Average net load peaked in hour ending 20 at about 26,000 MW, 9 percent higher than that same hour in 2019. Although average price followed the shape of the net load curve, prices actually spiked during the ramp up period with the highest prices in all three markets during hour ending 19. In this hour day-ahead price averaged $78/MWh, 15-minute prices averaged $79/MWh, and 5-minute market prices averaged substantially lower at $51/MWh. This pattern is slightly different than 2019 where prices spike in hour ending 20, the same hour of the highest net load.

During the hours with highest net load, and highest energy prices, the divergence between the 5-minute market and the other two markets is the largest. In hours ending 17-20, prices in the 5-minute market were 20-35 percent lower than those in the day-ahead and 15-minute market.

Figure 2.5 Hourly load-weighted average energy prices (2020)



2.3.1 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 2.6 shows monthly average day-ahead peak 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 (ICE).

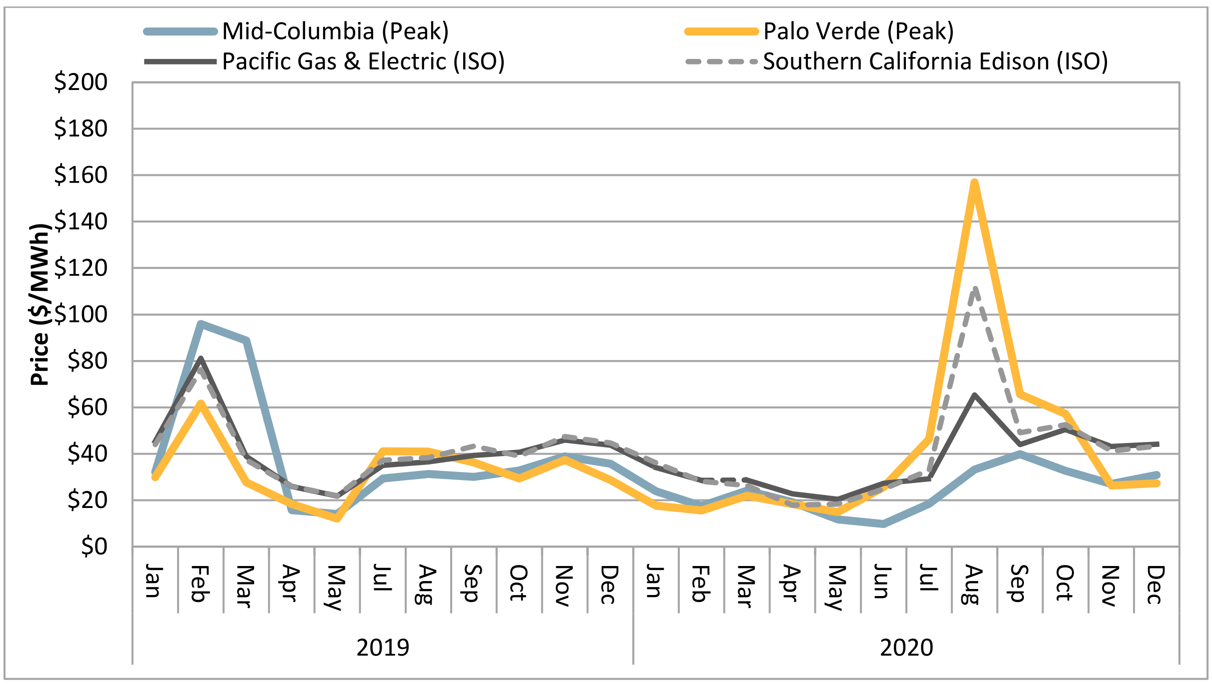
Prices in the ISO are represented in Figure 2.6 by prices at the Southern California Edison and Pacific Gas and Electric load aggregation points. As shown in the figure, average day-ahead market prices in the ISO across peak hours in the third quarter were greater than prices at Mid-Columbia hub and lower than the prices at Palo Verde electricity hub. The figure also shows significant price divergence between the ISO and these bilateral hubs during the heat wave conditions that existed in mid-August and early September. Prices at Mead, Palo Verde, and other bilateral power hubs exceeded the $1,000/MWh WECC soft offer cap, requiring sellers to submit cost justification for sales made above this cap to FERC.

DMM intervened in this cost justification proceeding and submitted comments on most of the company filings.[114,115]

Average day-ahead prices in the ISO were also compared to real-time hourly energy prices traded at Mid-Columbia and Palo Verde hubs for all hours of 2020 using data published by Powerdex. Day-ahead hourly prices in the Pacific Gas and Electric and Southern California Edison areas across all hours in 2020 were greater on average than prices at Mid-Columbia and Palo Verde by about $14/MWh and $8/MWh, respectively.

As mentioned earlier, 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. Prices between Pacific Gas and Electric and Southern California Edison tracked very closely in 2020 except in August 2020. The large price separation was due to the divergence in gas prices between SoCal Citygate and PG&E Citygate gas hubs. In addition, north-to-south congestion also contributed to increased prices in the south by preventing cheaper generation in the north to flow into the south.

Figure 2.6 Monthly average day-ahead and bilateral market prices



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[114] *Motion To Intervene and Comments of the Department of Market Monitoring of the California Independent System Operator Corporation*, Docket No. EL10-56-000, September 1, 2020: http://www.caiso.com/Documents/MotiontoInterveneandCommentsoftheDepartmentofMarketMonitoringWECCSoftOfferCap-Sept12020.pdf

[115] *DMM comments on WECC soft offer cap cost justification filings,* October 28, 2020: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=55CBE632-386E-470C-921E-B2F8C41AECE5

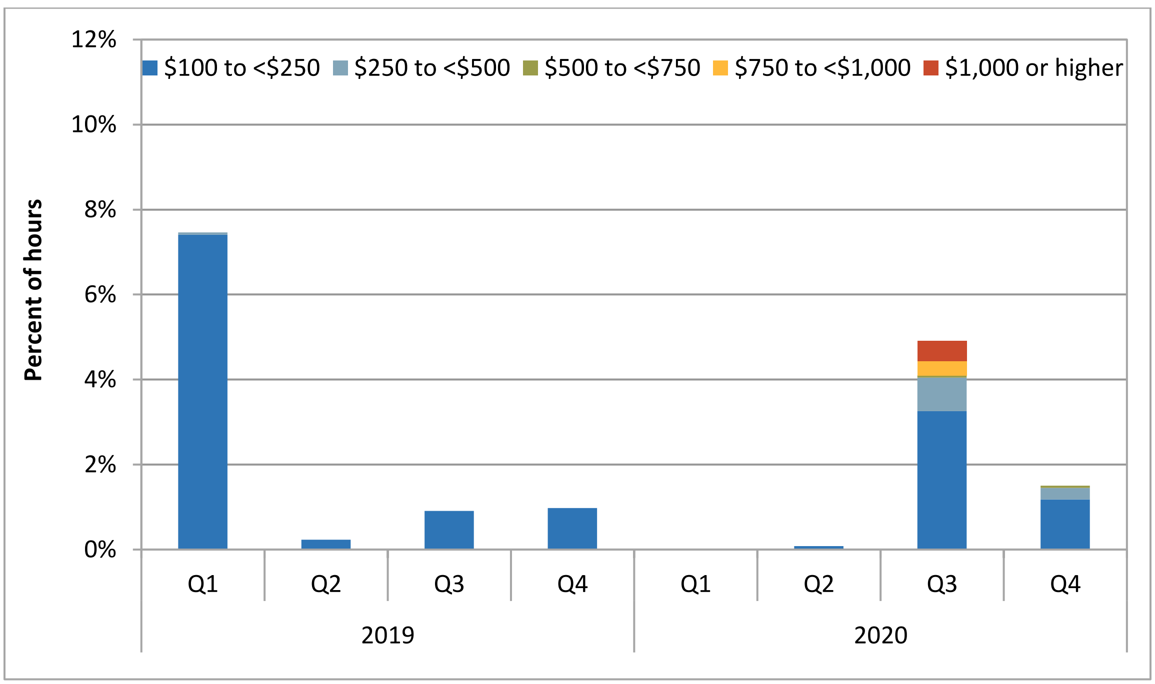
2.3.2 Day-ahead price variability

Variability in the day-ahead market was similar to last year. Positive price spikes happened in hours with high peak demand with 3 percent of hours ending 18 to 21 having prices above $200/MWh. Negative price spikes happened midday when solar generation was highest, where 3 percent of hours ending 11 through 15 had prices below $0/MWh.

High day-ahead market prices

High prices are common in the net peak load hours during the late afternoon when low cost solar generation has declined but demand for electricity remains high. Figure 2.7 shows the frequency of high prices in the day-ahead market. Prices in the day-ahead market were highest in the third quarter, with close to 2 percent of hours having prices over $250/MWh. High prices in the third quarter of 2020 reflect the tight conditions experienced in August and September during periods of extreme hot weather.

Figure 2.7 Frequency of positive day-ahead price spikes (ISO LAP areas)



Negative day-ahead market prices

Low prices were relatively frequent in the day-ahead market in 2020, similar to 2019. Figure 2.8 shows the frequency of prices near or below $0/MWh in the day-ahead market by quarter in 2019 and 2020. Similar to last year, negative prices only occurred in the first half of the year, primarily in the second quarter when net load is lower due to moderate temperatures and run of river hydro is highest.

Figure 2.9 shows the frequency of low and negative day-ahead prices by hour of the day. Low and negative prices in the day-ahead market occurred during midday hours when solar generation is highest.

Day-ahead prices were below $1 in 7.1 percent of hours during hours ending 11 through 15, with 40 percent of those hours being below zero.

Figure 2.8 Frequency of negative day-ahead price spikes (ISO LAP areas)

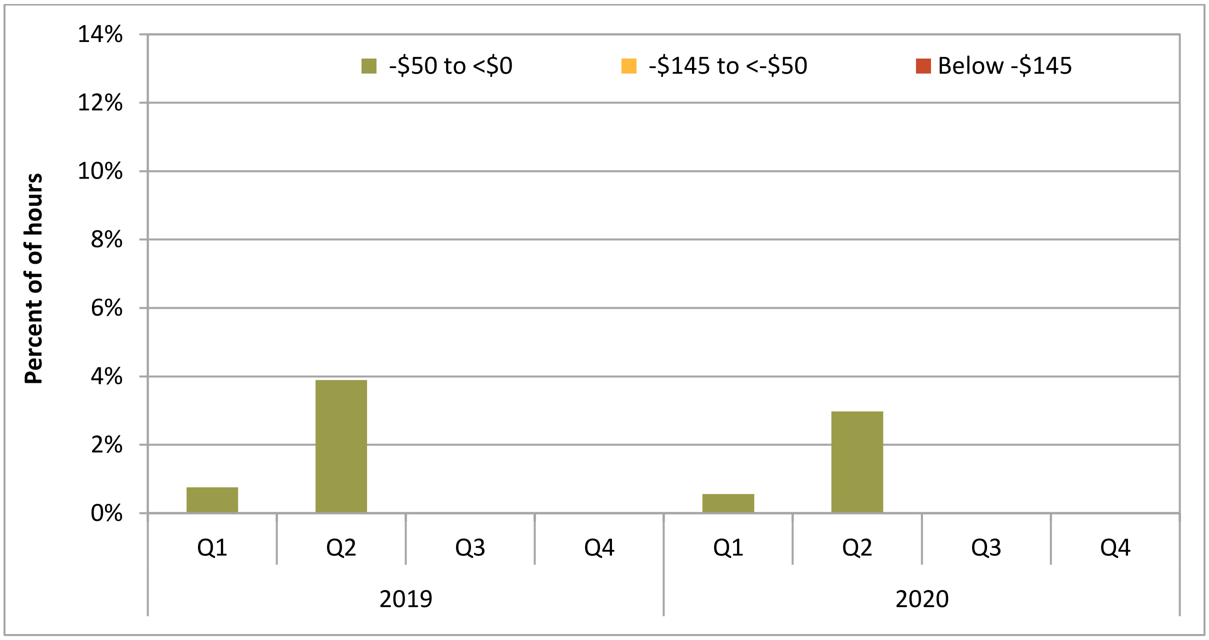
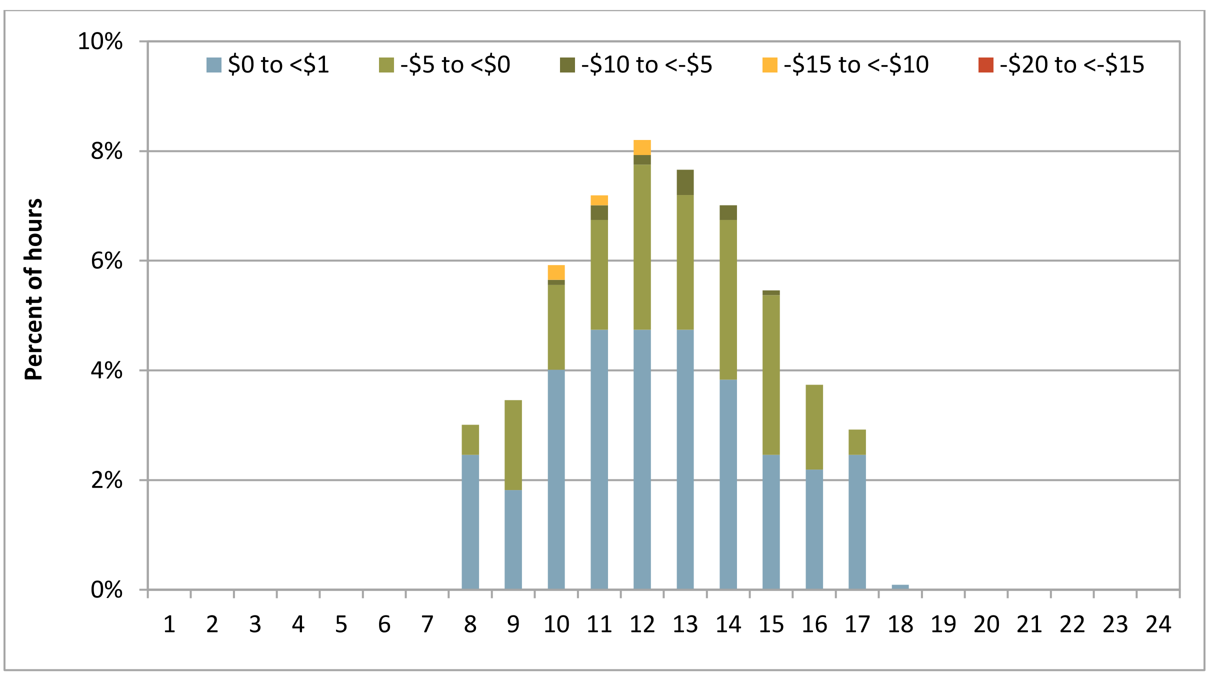


Figure 2.9 Hourly frequency of DA prices near or below $0/MWh



2.3.3 Real-time price variability

Variability in the 15-minute and 5-minute markets was fairly similar to last year. Compared to 2019, negative prices occurred at roughly the same frequency, while high prices were more frequent in the 15-minute market and less frequent in the 5-minute market. Most high real-time prices continued to occur in the morning and evening ramping hours.

High prices in the ISO area

Real-time market price spikes occurred most frequently in the third quarter, compared to last year when prices spiked most frequently in the second quarter. The high prices in 2019 were likely due to high bids and congestion since demand is relatively low in the second quarter; however, the high frequency of positive price spikes in the third quarter this year suggests these price spikes were due to high demand and more specifically high net load.

Figure 2.10 shows the frequency of prices above $250/MWh at load aggregation points (LAPs) within the ISO in the 15-minute market. This year, 0.6 percent of intervals in the 15-minute market had prices above $250/MWh. This is substantially higher than 2019 when the frequency was 0.3 percent. This increase in frequency is driven by the increase in positive price spikes in the second half of the year.

Figure 2.10 Frequency of positive 15-minute price spikes (ISO LAP areas)

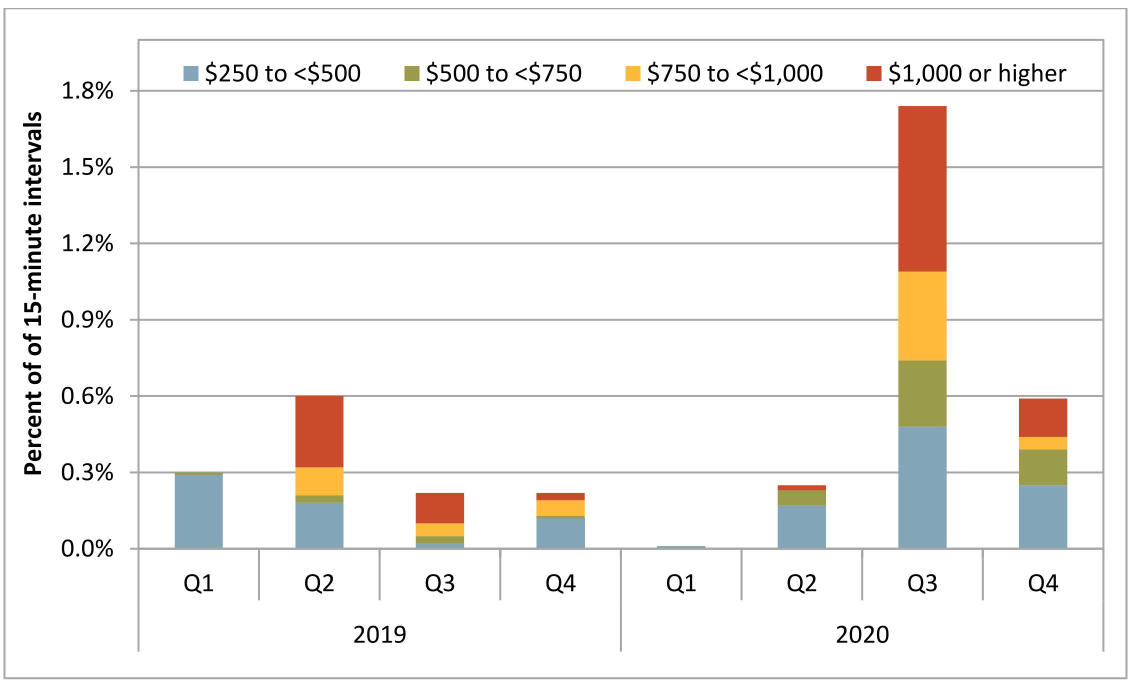


Figure 2.11 Frequency of positive 5-minute price spikes (ISO LAP areas)

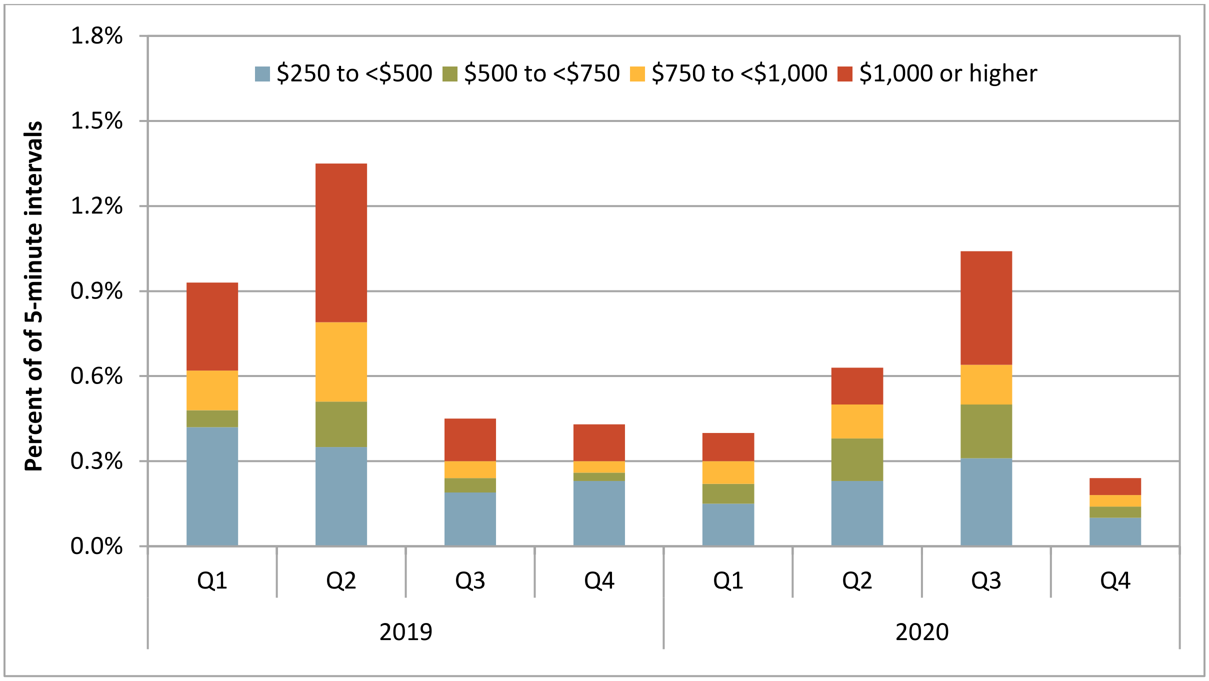


Figure 2.10 highlights how the frequency of high prices in the 15-minute market decreased in the first and second quarter of 2020 relative to 2019. This could be due to the lower loads associated with COVID-19 in the second quarter. However, there were substantially more intervals with high prices in the third quarter, increasing from 0.2 percent to almost 2 percent, likely due to very high temperatures.

Figure 2.11 shows the frequency of prices above $250/MWh in the 5-minute market. The frequency of these prices decreased from 0.8 percent of intervals in 2019 to 0.6 percent in 2020. Similarly, the frequency of extreme prices above $750/MWh declined from 0.4 percent in 2019 to 0.3 percent of intervals in 2020.

The higher frequency of 15-minute prices over $250/MWh and lower frequency of 5-minute prices over $250/MWh demonstrates the divergence of these two markets. In 2020, prices in the 5-minute market were often substantially lower than prices in the 15-minute and day-ahead markets.

Negative prices in the ISO area

The market arrives at a solution by matching supply with demand; when prices clear below a unit's bid, that resource may be dispatched down accordingly. During negatively priced intervals, the market continues to function efficiently and the least expensive generation serves load, while more expensive generation is dispatched down.

Figure 2.12 and Figure 2.13 show the frequency of negative prices at load aggregation points (LAPs) within the 15-minute and 5-minute markets, respectively.

Negative prices occurred with roughly the same frequency in both the 15-minute and 5-minute market during 2020 compared to the previous year. The distribution of negative prices across quarters was the same this year compared to 2019 as well, with the highest frequency of negative prices happening in the second quarter in both markets, followed by the first quarter. This is likely due to the lower demand for electricity in the first half of the year when weather is moderate.

Similar to the previous year, the frequency of prices near or below the -$150/MWh floor remained almost nonexistent in 2020. This result reflects the bidding flexibility of renewable resources and increased transfer capability in the real-time market from the energy imbalance market.

Figure 2.14 shows the annual frequency of negative prices in the 5-minute market since 2015. In 2020, roughly 4 percent of 5-minute intervals had negative prices, similar to 2019. Figure 2.15 shows the hourly frequency of negative 5-minute prices in the last four years. The figure illustrates that the majority of negative prices during 2020 generally occurred during midday hours when solar generation was highest and demand was low. In 2020 there was a slight increase in negative intervals in the morning, specifically hours ending 9 through 11. This could be due to the decrease in average loads during the morning peak caused by the stay-at-home orders associated with COVID-19.

Figure 2.12 Frequency of negative 15-minute prices (ISO LAP areas)

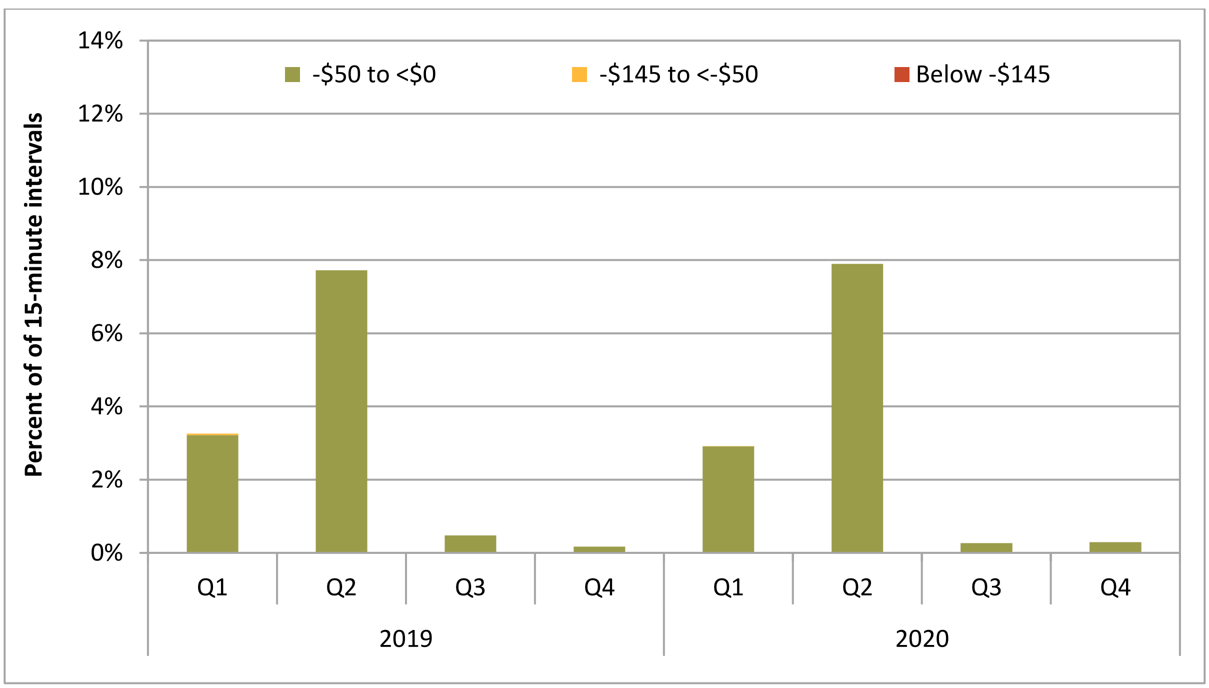


Figure 2.13 Frequency of negative 5-minute prices (ISO LAP areas)

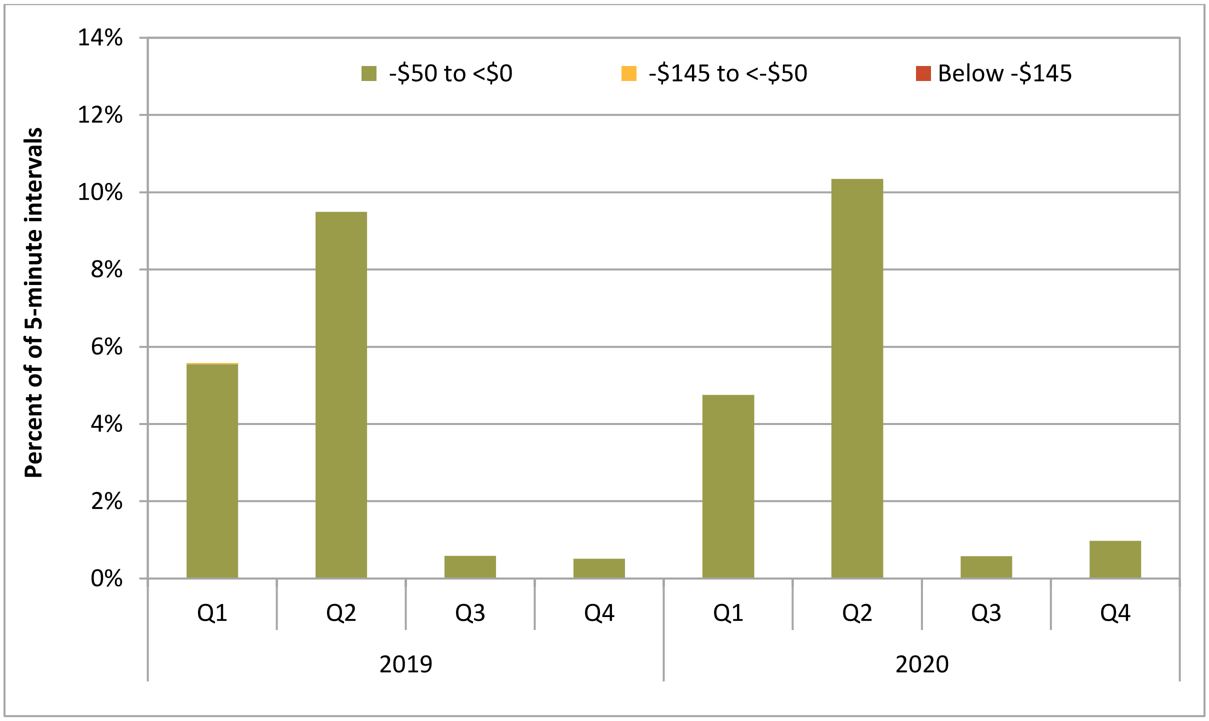


Figure 2.14 Frequency of negative 5-minute prices (ISO LAP areas)

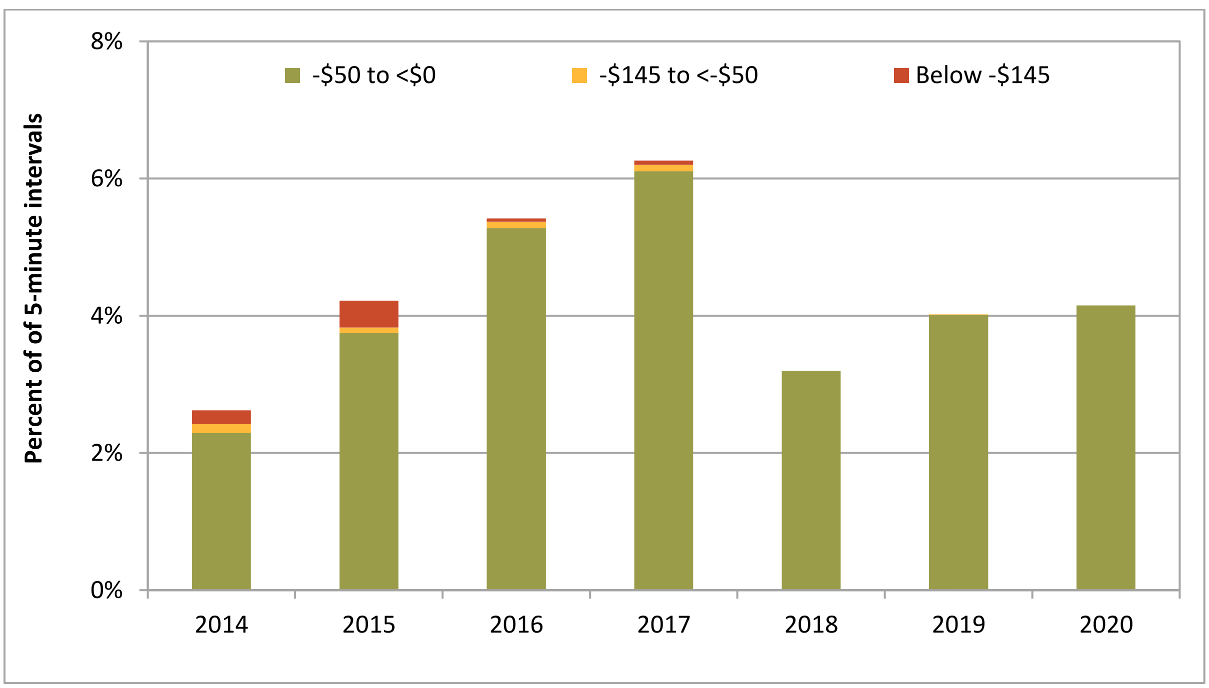
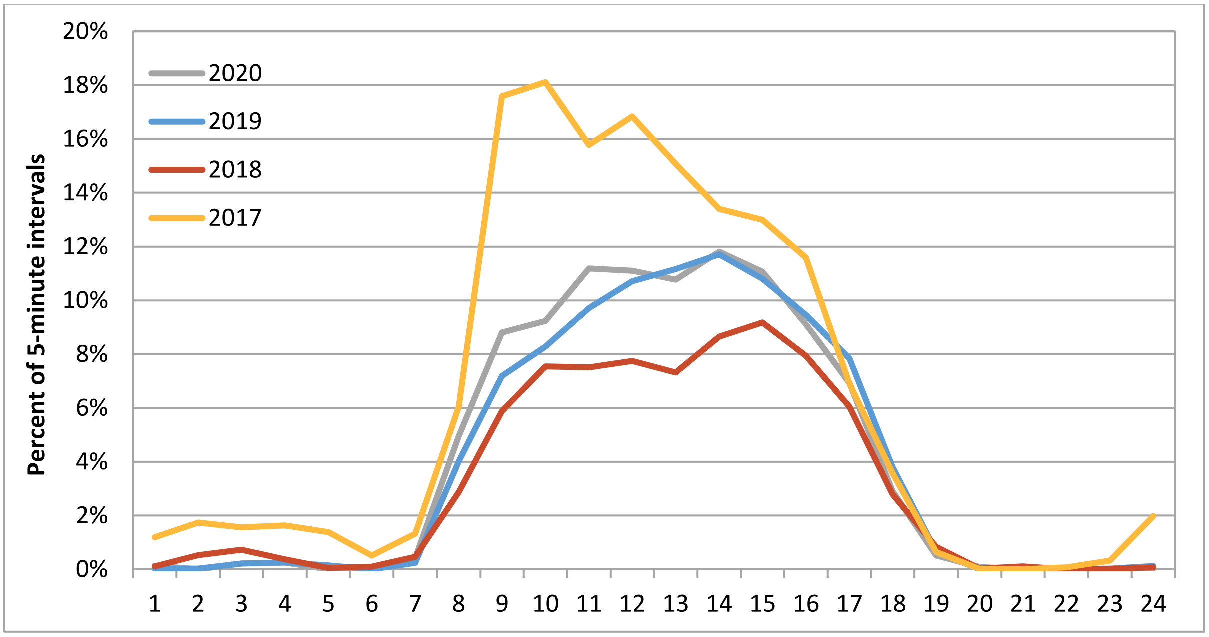


Figure 2.15 Hourly frequency of negative 5-minute prices by year (ISO LAP areas)



2.3.4 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.[116] 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).[117]

The load conformance limiter reduces the impact of an excessive load adjustment on market prices when it is considered to have caused a power balance constraint relaxation. If the limiter triggers, 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. The ISO implemented an enhancement to the load conformance limiter, effective February 27, 2019. With the enhancement, the load conformance limiter triggers by a measure based on the change in load adjustment from one interval to the next, rather than solely the magnitude of the load adjustment. This change significantly reduced the frequency in which the limiter triggers.

116 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.

117 On March 20, 2021 the penalty parameter for an under-supply infeasibility was scaled up to $2,000/MWh as part of FERC Order 831 compliance. For more information see DMM's *Q1 2021 Report on Market Issues and Performance*, pp.93-96: http://www.caiso.com/Documents/2021-First-Quarter-Report-on-Market-Issues-and-Performance-Jun-9-2021.pdf

System power balance constraint relaxations

The frequency of system power balance constraint relaxations in 2020, either valid or resolved by the load conformance limiter, were relatively low.

Figure 2.16 and Figure 2.17 show the quarterly frequency of under-supply infeasibilities in the 15-minute market and 5-minute market, respectively. The frequency of under-supply infeasibilities in the 15-minute market was relatively high during the third quarter, with shortages occurring during around 1 percent of intervals in August. Valid under-supply infeasibilities in the 5-minute market were less frequent compared to the previous year.

There continued to be no intervals during 2020 in either the 15-minute or the 5-minute markets in which the system power balance constraint was relaxed because of insufficient downward flexibility. Bidding flexibility from renewable resources and increased transfer capability from the energy imbalance market continued to contribute to reduced oversupply conditions.

Figure 2.16 Frequency of under-supply power balance constraint infeasibilities (15-minute market)

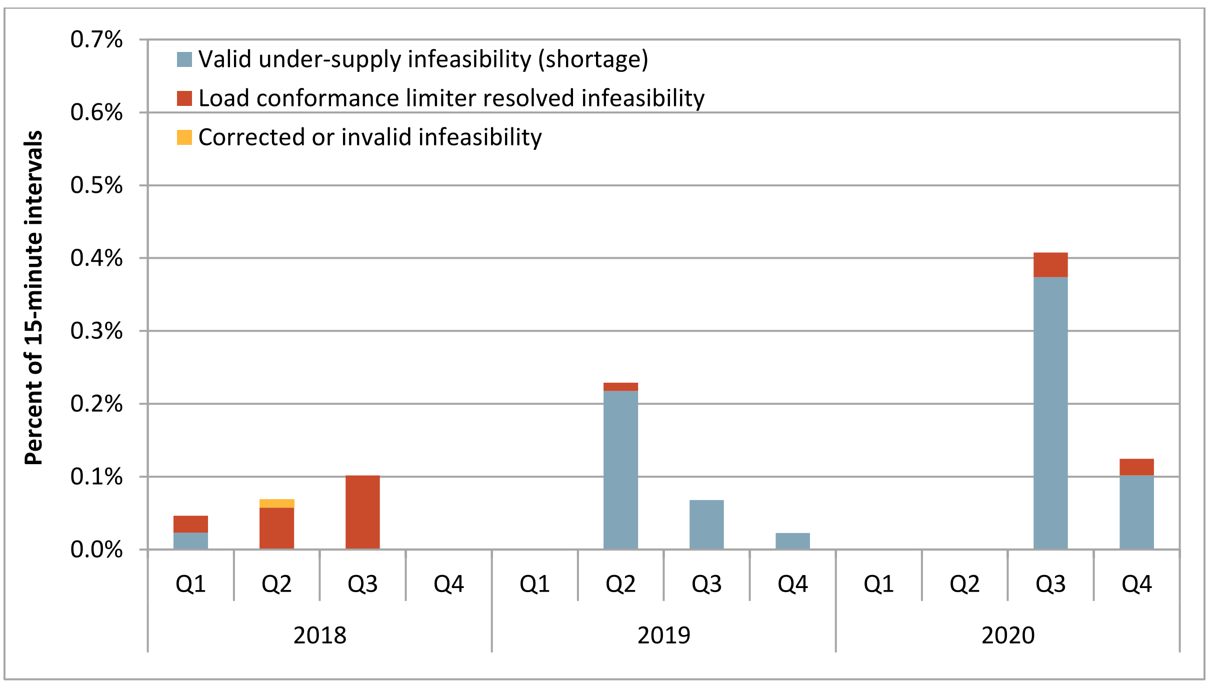
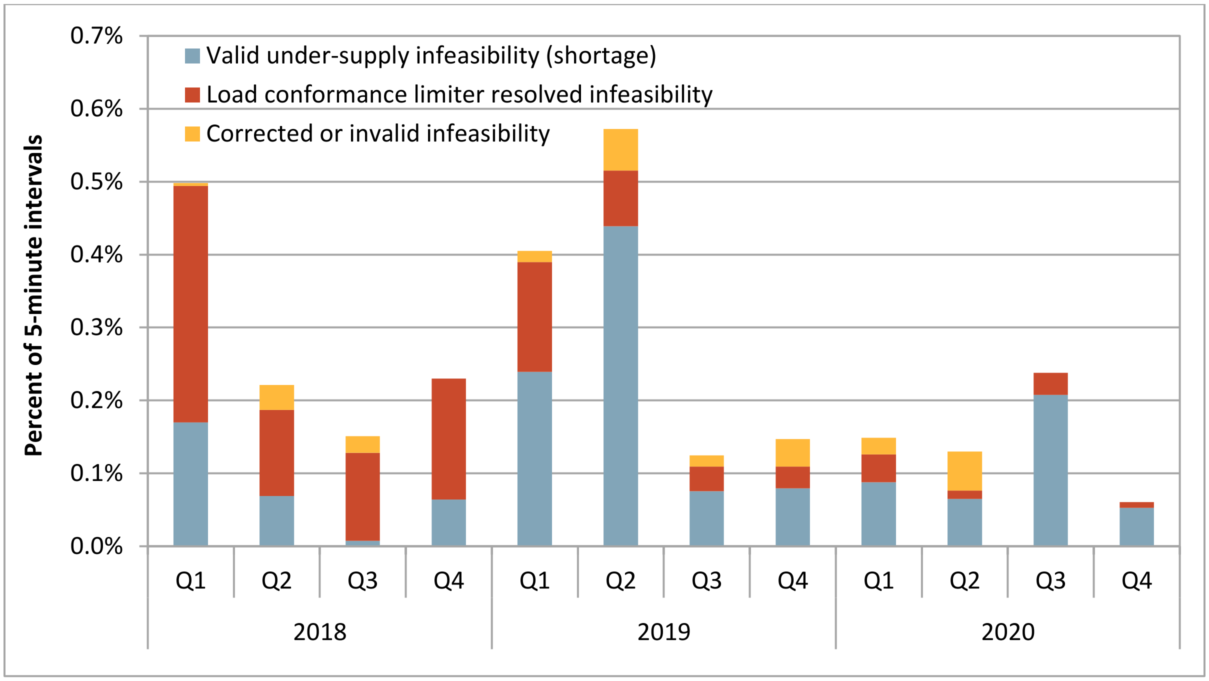


Figure 2.17 Frequency of under-supply power balance constraint infeasibilities (5-minute market)



As in prior years, most of the upward ramping shortages were very short in duration. Similar to 2019, about 84 percent of upward ramping capacity shortages in the 5-minute market during 2020 persisted for one to three 5-minute intervals (or 5 to 15 minutes). In the 15-minute market, about 75 percent of under-supply infeasibilities persisted for one to three 15-minute intervals (or 15 to 45 minutes).

2.4 Residual unit commitment

On average, the total volume of capacity procured through the residual unit commitment process in all quarters of 2020 was higher than 2019. As shown in Figure 2.18, when compared to 2019, this capacity almost doubled in the third quarter of 2020. In addition, ISO operators are able to increase the amount of residual unit commitment requirements for reliability purposes. In 2020, these operator adjustments increased significantly beginning in May and continued until October.[118]

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

During the period between mid-August to September 7, 2020, when regional high temperatures led to high demand across the entire western region, the ISO made two specific changes outlined below which

[118] See Section 8.3 for further discussion on operator adjustments in the residual unit commitment process.

impacted the residual unit commitment process, allowing that process to better align physical supply with demand.

- On August 16, the ISO announced the suspension of virtual bidding effective in the day-ahead market for operating day August 18, in part to prevent virtual supply bids from allowing additional exports to be scheduled in the day-ahead market which would ultimately need to be met by physical supply from within the ISO system.[119] The ISO reinstated virtual bidding in the day-ahead market for August 22.[120] By this time, system and market conditions had changed so that virtual bidding was again viewed as providing market benefits without presenting a risk to the system.
- Effective September 5, the ISO implemented several software modifications in the residual unit commitment process designed to reduce exports from being scheduled in the real-time market at high day-ahead penalty prices which could not be supported by available physical supply in the ISO system.[121]

DMM published a special report which includes detailed analysis of the impacts of these changes and provides recommendations on the residual unit commitment process.[122]

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119 Market Notice: *California ISO Suspends Convergence Bidding due to Current System Conditions*, August 16, 2020: http://www.caiso.com/Documents/CaliforniaISOSuspendsConvergenceBiddingCurrentSystemConditions.html

120 Market Notice: *California ISO Reinstates Convergence Bidding for 8/22/20 due to Updated System Conditions*, August 20, 2020: http://www.caiso.com/Documents/CaliforniaISOReinstatesConvergenceBiddingfor82220DuetoUpdatedSystemConditions.html

121 PRR 1282 Market Operations BPM, Emergency PRR, Scheduling of export resources in real time market, September 4, 2020: https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=1282&IsDlg=0

122 *Report on Market Conditions, Issues and Performance* – August and September 2020. http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

Figure 2.18 Residual unit commitment (RUC) costs and volume (2019 – 2020)

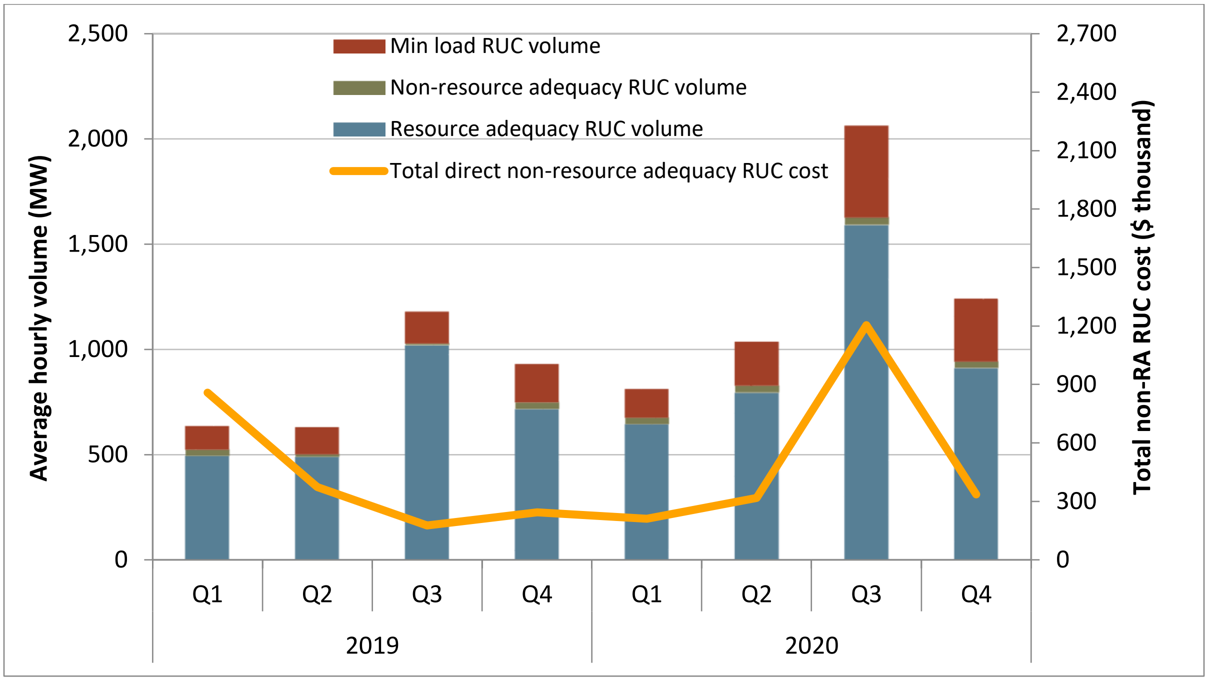

Figure 2.18 shows quarterly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. Total residual unit commitment procurement increased significantly to 1287 MW per hour in 2020 from an average of 845 MW in 2019. Specifically, the figure shows increased volumes due to high residual unit commitment requirements in the third and fourth quarters of 2020. The increased volumes in these quarters can be attributed to a combination of factors including relatively high operator adjustments, increase in amounts of cleared net virtual supply, and energy net short adjustments. When the day-ahead 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.[123] Most of the capacity procured 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.

Residual unit commitment capacity committed to operate at minimum load averaged 270 MW each hour. This was a significant increase of about 87 percent from the capacity that was procured and committed to operate at minimum load in 2019. In 2020, about 16 percent of this capacity was from long-start units compared to 9 percent in 2019.[124]

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[123] 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.

[124] 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.

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 process receive capacity payments.[125] As shown by the small green segment of each bar in Figure 2.18, the non-resource adequacy commitment averaged about 34 MW per hour in 2020, up from about 22 MW procured in 2019. The total direct cost of non-resource adequacy residual unit commitment, represented by the gold line in Figure 2.18, increased to about $2 million in 2020, up from a direct cost of about $1.6 million in 2019.

Figure 2.19 shows the same data presented in Figure 2.18 by energy type on an average hourly basis for 2020. As shown by the green bars in the figure, resource adequacy capacity scheduled in the residual unit commitment process was greatest during the off-peak hours of the day. The capacity procured from resource adequacy imports, shown by blue bars, was concentrated during hours ending 17 through 21.

Capacity procured from short-start and long-start resources tended to be greatest during the end of the day, as shown in the red bars in Figure 2.19. Long-start resources receiving residual unit commitment awards are committed to run at their minimum operating level and must bid this capacity into the real-time market. Short-start resources providing residual unit commitment capacity are not committed to run in real time, but have an obligation to bid into the real-time market.

Figure 2.19 Average hourly residual unit commitment (RUC) volume (2020)

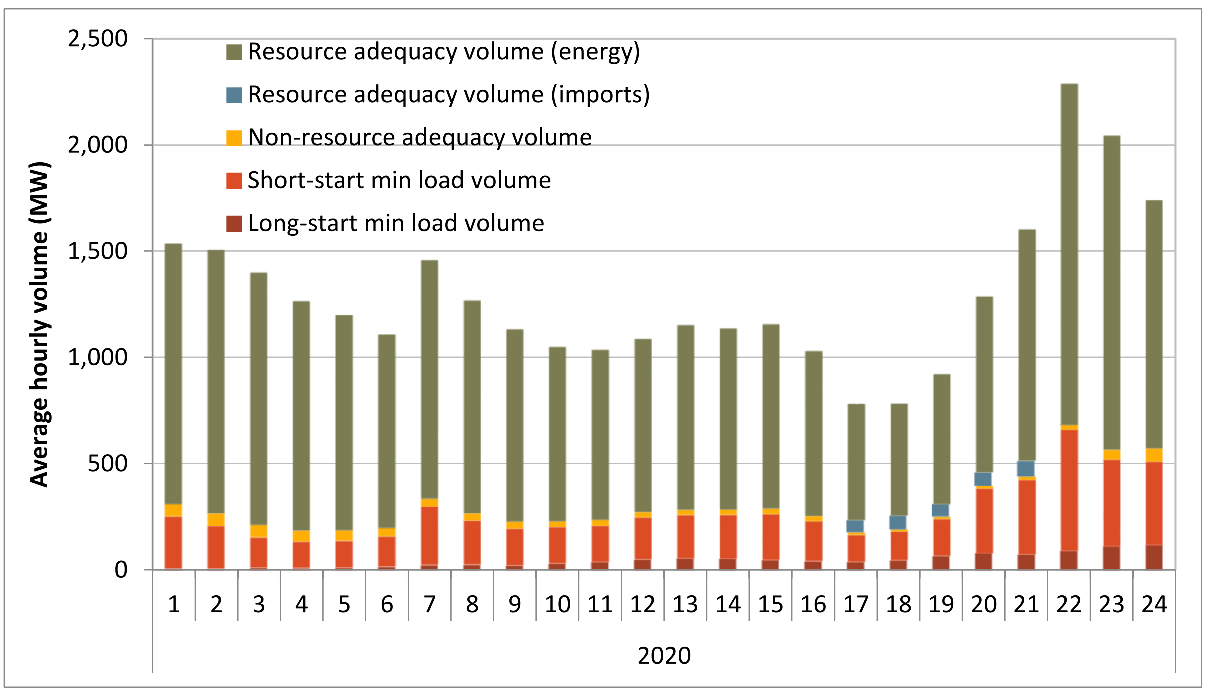
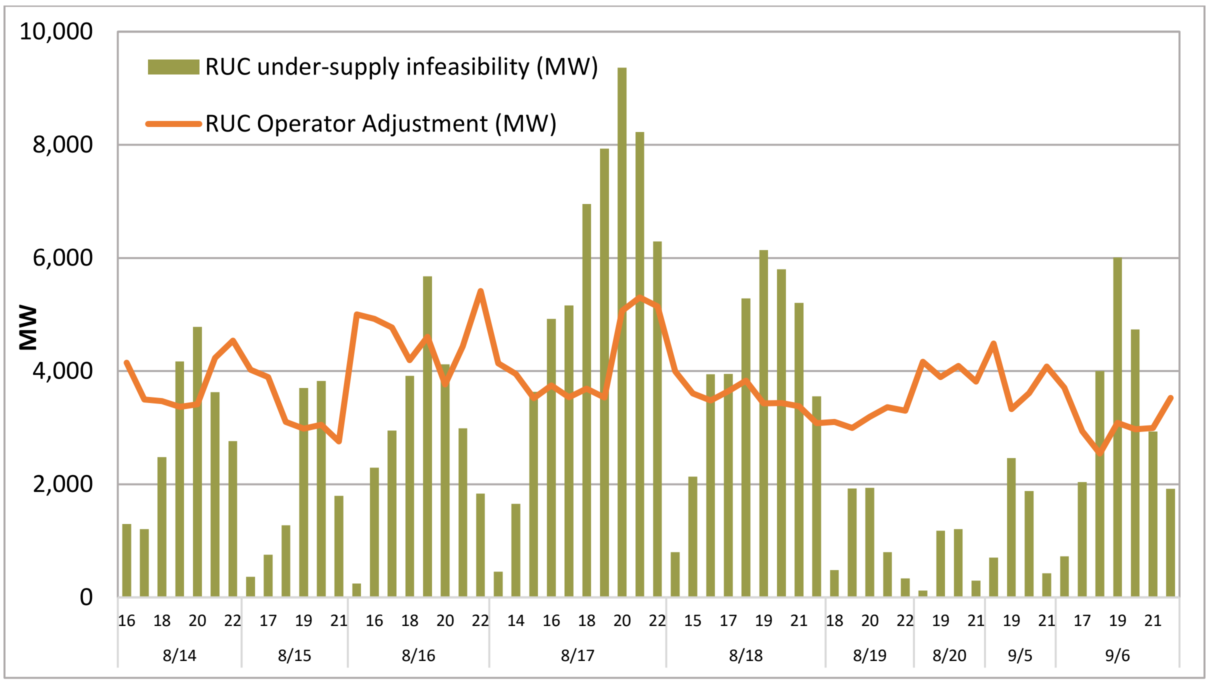


Figure 2.20 shows the residual unit commitment power balance constraint hourly under-supply infeasibility quantities that resulted during the heat wave conditions during mid-August and early

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

September. These infeasibilities resulted in prices being set around $250/MWh during those hours. The market change that went in place on September 5 was designed to address the treatment of economic and self-scheduled exports that cleared the day-ahead integrated forward market (IFM) run. With this change, the residual unit commitment process is able to curtail certain exports before relaxing the power balance constraint. These reduced exports no longer receive a real-time scheduling priority that exceeds real-time ISO load and can choose to re-bid in real-time or resubmit as self-schedules in real-time.[126] In 2020, there were 23 days with residual unit commitment power balance constraint under-supply infeasibilities during a total of 97 hours. In comparison, from 2016 through 2019 there were 10 days with a total of 27 hours with these infeasibilities.

Figure 2.20 Residual unit commitment under-supply infeasibilities (Aug 14 – 20 and Sep 5 – 6)



2.5 Bid cost recovery payments

Bid cost recovery payments for units in the ISO and energy imbalance market totaled around $126 million and $9 million, respectively, the second highest total since 2011. Bid cost recovery payments increased slightly in 2020 compared to 2019, when payments totaled $133 million.[127] The ISO's portion of these payments in 2020 represents 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,

126 The ISO provided details and examples of this change in the Market Performance and Planning Forum meeting on September 9, 2020: http://www.caiso.com/Documents/Presentation-MarketPerformance-PlanningForum-Sep9-2020.pdf#search=market%20performance%20and%20planning%20forum

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

residual unit commitment availability, day-ahead energy, and real-time energy. Excessively high bid cost recovery payments can indicate inefficient unit commitment or dispatch.

Figure 2.21 Bid cost recovery payments

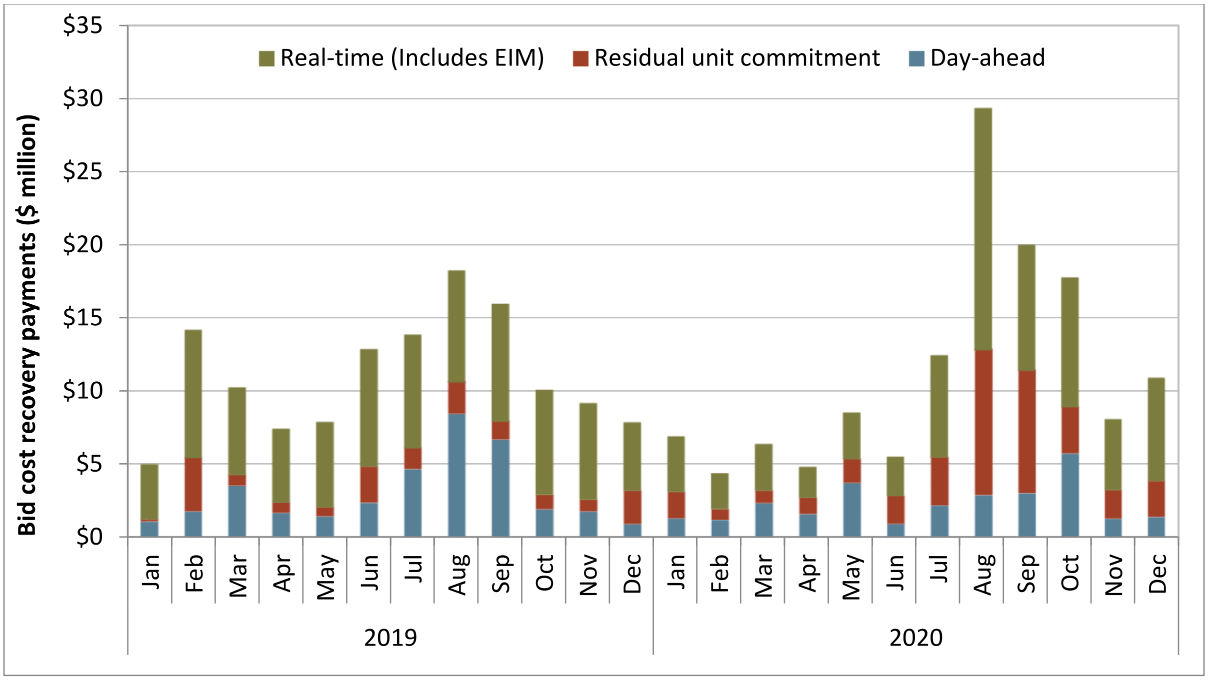


Figure 2.21 provides a summary of total estimated bid cost recovery payments in 2019 and 2020 by month and market. As shown in the figure, bid cost recovery payments in 2020 were highest during August through October. These significantly high payments can be attributed to higher loads experienced throughout the west during some days in those months.

Day-ahead bid cost recovery payments totaled $27 million in 2020, a decrease from $36 million in 2019. An estimated 43 percent of these payments can be attributed to resources effective at meeting the minimum online constraints enforced in the day-ahead market, compared to 68 percent in 2019.[128]

Real-time bid cost recovery payments were $71 million in 2020, down from about $80 million in 2019. Payments in August alone totaled about $16 million, because of high loads and prices experienced across the west. From August 14 to August 18, the ISO operators activated between 820 and 975 MW of reliability demand response resources (RDRR) during peak net load hours. In several hours, the ISO operators activated available RDRR out-of-market similar to exceptional dispatch instructions. These resources have minimum bids of $950/MWh. Because they were manually dispatched in many hours, they were often dispatched when prices were well below $950 and thus received significant bid cost

128 Minimum on-line constraints (MOCs) 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. Bid cost recovery payments attributed to resources committed to meet minimum online constraints in 2018 have been re-calculated based on an updated methodology.

recovery payments. Of the total $8.6 million in real-time bid cost recovery payments between August 14 and August 18, $4.8 million was paid to these RDRR resources.

Units committed through exceptional dispatches are eligible to receive real-time bid cost recovery payments. Exceptional dispatches are made by real-time operators to help ensure reliability across the system. DMM estimates these payments for resources committed to operate through exceptional dispatches totaled about $7 million in 2020, significantly down from $19 million in payments in 2019. Additional details regarding exceptional dispatches are covered in Section 8.1 of this report.

The real-time bid cost recovery amount also included payments for units in the energy imbalance market (EIM) which totaled $9 million in 2020; which is $1 million lower than payments in 2019. About $4 million of these payments were to units in Salt River Project (SRP) balancing authority and about $0.06 million to units in Seattle City Light (SCL) balancing area, both of which joined the EIM on April 1, 2020.

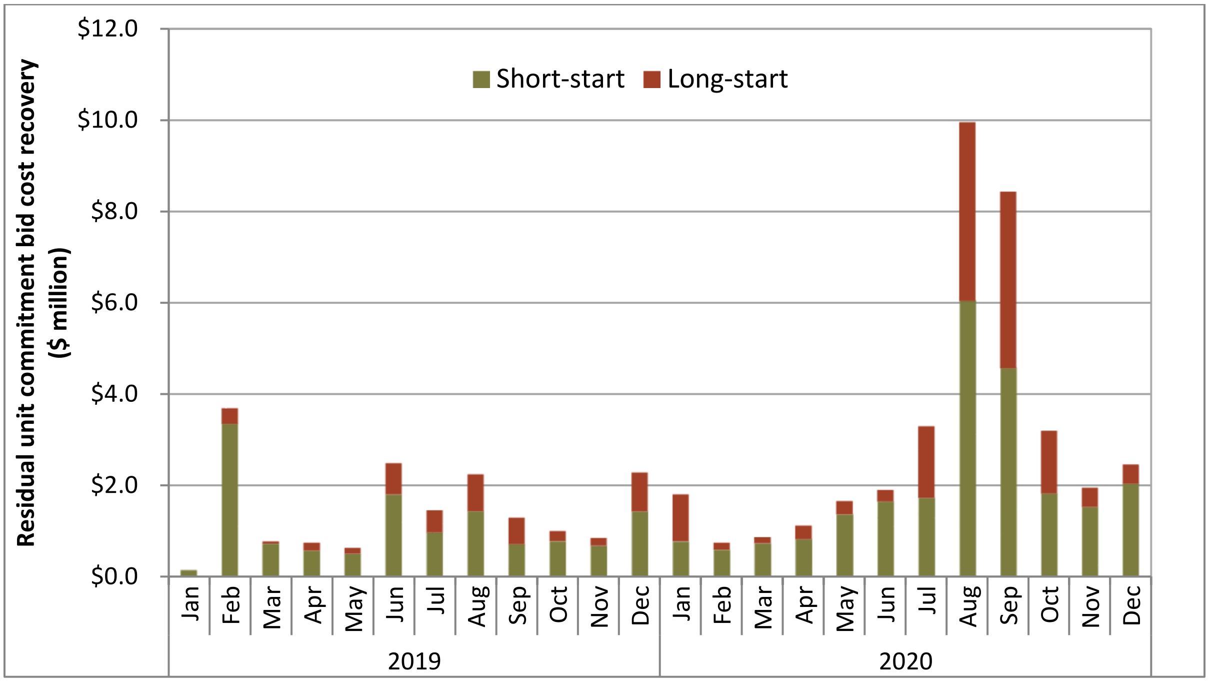
Bid cost recovery payments for units committed through the residual unit commitment process totaled about $37 million in 2020. This represents a 105 percent increase from about $18 million in 2019. The significant increase in residual unit commitment bid cost recovery payments can be attributed to periods of high loads in August and September along with manual operator adjustments causing the residual unit commitment process to procure more capacity.

Units committed by the residual unit commitment can be either long or short-start units. As shown in Figure 2.22, short-start units accounted for about $23 million in bid cost recovery payments, while long-start unit commitment accounted for $14 million. These totals represent all bid 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.

DMM estimates that about 60 percent of the ISO's total bid cost recovery payments, approximately $75 million, were allocated to resources that bid their commitment costs above 110 percent of their reference commitment costs. Commitment cost bids are capped at 125 percent of a reference proxy costs.[129] About 93 percent of these payments are for resources bidding at or near the 125 percent bid cap for proxy commitment costs.

[129] See Section 6.4 for additional information on commitment cost bid caps and bidding behavior.

Figure 2.22 Residual unit commitment bid cost recovery payments by commitment type



2.6 Real-time imbalance offset costs

Total real-time imbalance offset costs increased in 2020 to $177 million from $105 million in 2019 and $132 million in 2018 within the ISO. The bulk of the offset costs were $117 million in real-time congestion imbalance offset costs, up from $97 million in 2019 and equal to $117 million in 2018. Real-time imbalance energy offset costs increased to $64 million from $8 million and $17 million in 2019 and 2018, respectively.

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. The real-time offsets include imbalances from both the 15-minute market and 5-minute dispatch. 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).

Energy offset costs exceeded $2 million per day for many of the days during the high demand period.[130] These costs rose to almost $10 million on August 18 alone, more than the sum of energy offset in all of

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130 Based on current settlement data, days with energy offset costs greater than $2 million in the third quarter are: August 13 ($2.4 million), August 14 ($2.3 million), August 17 ($6.1 million), August 18 ($9.9 million), August 19 ($2.3 million), August 24 ($3.4 million), September 5 ($3.7 million), and September 6 ($4.9 million). Costs on these days account for $35 million of the total $54 million for the quarter.

2019. As on other similar days during this period, the ISO relied on out of market dispatches and other non-market measures to meet high demand. Large offset costs account for the revenue imbalance between real-time payment to the ISO by load and real-time market payments for generation on these days.

Like energy offset costs, congestion offset costs were concentrated on a few days.[131] As has been reported in previous reports, in the presence of significant real-time market congestion, constraint limit reductions between day-ahead and real-time can generate real-time congestion imbalance charges.[132]

As in 2018 and 2019, most congestion offset charges in 2020 were associated with network model differences and reductions in constraint limits in the 15-minute market from the day-ahead market.

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.[133]

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 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.[134] Congestion imbalances can also occur from differences in transmission modeling and the modeling of non-settled flows.

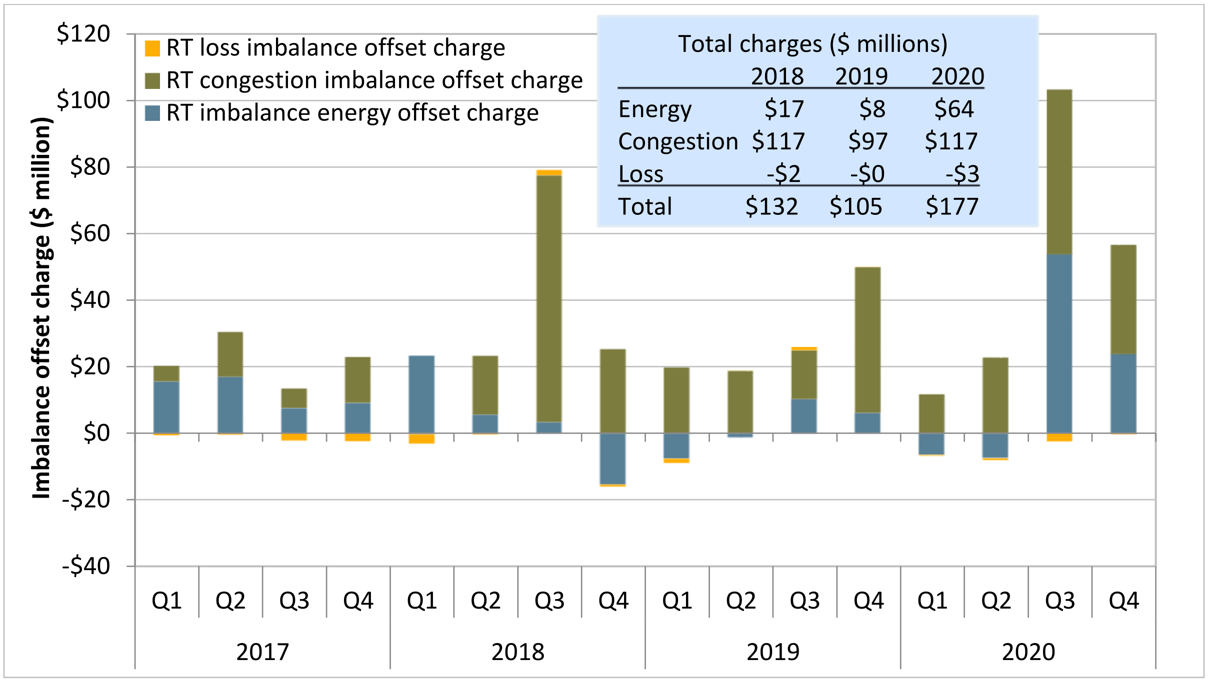
[131] Based on current settlement data, days with congestion offset costs greater than $2 million in the third quarter are: July 31 ($4.7 million), August 13 ($2.1 million), August 28 ($3.1 million), September 5 ($5.3 million), September 6 ($8.7 million), and September 18 ($2.3 million). Costs on these days account for $26 million of the total $49 million for the quarter.

[132] *Q3 2018 Report on Market Issues and Performance,* Department of Market Monitoring, November 1, 2018, pp. 23-27. http://www.caiso.com/Documents/2018ThirdQuarterReportonMarketIssuesandPerformance.pdf

[133] One is that flows increase causing a constraint to bind generating additional congestion rent.

[134] 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

Figure 2.23 Real-time imbalance offset costs



2.7 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 15minute 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.

Flexible ramping product requirement

There are separate demand curves calculated for each energy imbalance market area in addition to a system-level demand curve. The system-level demand curve for the entire footprint is always enforced in the market while the uncertainty requirement for the individual balancing areas is reduced in every interval by their transfer capability.[135] Previously, if the transfer capability for each area was sufficient, then only the system-level uncertainty requirement was active.

The flexible ramping product refinements stakeholder initiative introduced a new minimum flexible ramping product requirement. Effective in early November 2020, if a balancing authority area requirement individually is greater than 60 percent of the system requirement, then a minimum will be enforced equal to the balancing authority area's share of the diversity benefit.[136] The minimum requirement is intended to help mitigate some of the issues surrounding procurement of stranded flexible ramping product prior to the implementation of nodal procurement, expected in spring 2022.

A minimum requirement helps procure flexible ramping capacity within areas that contribute to a large portion of system-wide uncertainty. Figure 2.24 shows the frequency in which a minimum requirement was active for the ISO in the 15-minute market since the implementation of the minimum requirement in early November through the first quarter of 2021. Here, the ISO had a minimum upward requirement enforced in around 96 percent of intervals and a minimum downward requirement enforced in around 88 percent of intervals.

The minimum requirement was only implemented in the 15-minute market, and not in the 5-minute market. Procurement in the 5-minute market ensures that enough ramping capacity is available to manage uncertainty that may materialize between consecutive 5-minute market intervals. Without a minimum requirement in the 5-minute market, there can be cases where flexible ramping capacity procured internal to the ISO and settled in the 15-minute market is released in the 5-minute market in favor of undeliverable flexible ramping capacity stranded behind energy imbalance market transfer constraints. While the minimum requirement was intended as a temporary measure prior to implementation of nodal procurement, DMM believes that the minimum requirement should be included in the 5-minute market as an enhancement to improve the effectiveness of the flexible ramping product.

Figure 2.25 shows the frequency in which a minimum requirement was enforced for all other energy imbalance market areas.[137] Non-ISO areas, which exceed the 60 percent threshold in any interval, can similarly have a minimum requirement applied that will procure and price flexible ramping capacity in that area. In particular, PacifiCorp East had a minimum downward flexible ramping requirement during around 3 percent of intervals.

[135] In each interval, the upward uncertainty requirement for each area is reduced by net import capability while the downward uncertainty requirement is reduced by net export capability. If the area fails the sufficiency test in the corresponding direction, the uncertainty requirement will not include this reduction.

[136] For example, if a balancing authority area's upward requirement is greater than 60 percent of the system requirement at 1,000 MW and the diversity benefit factor (ratio of the system requirement to the sum of all area requirements) is 25 percent, then the minimum requirement for this area would be 250 MW. See *Flexible Ramping Product Refinements Final Proposal*, August 31, 2020. http://www.caiso.com/InitiativeDocuments/FinalProposal-FlexibleRampingProductRefinements.pdf

[137] Energy imbalance market areas which never had a minimum requirement applied during this period are not included in this figure.

Figure 2.24 California ISO frequency of enforced minimum requirement (15-minute market)

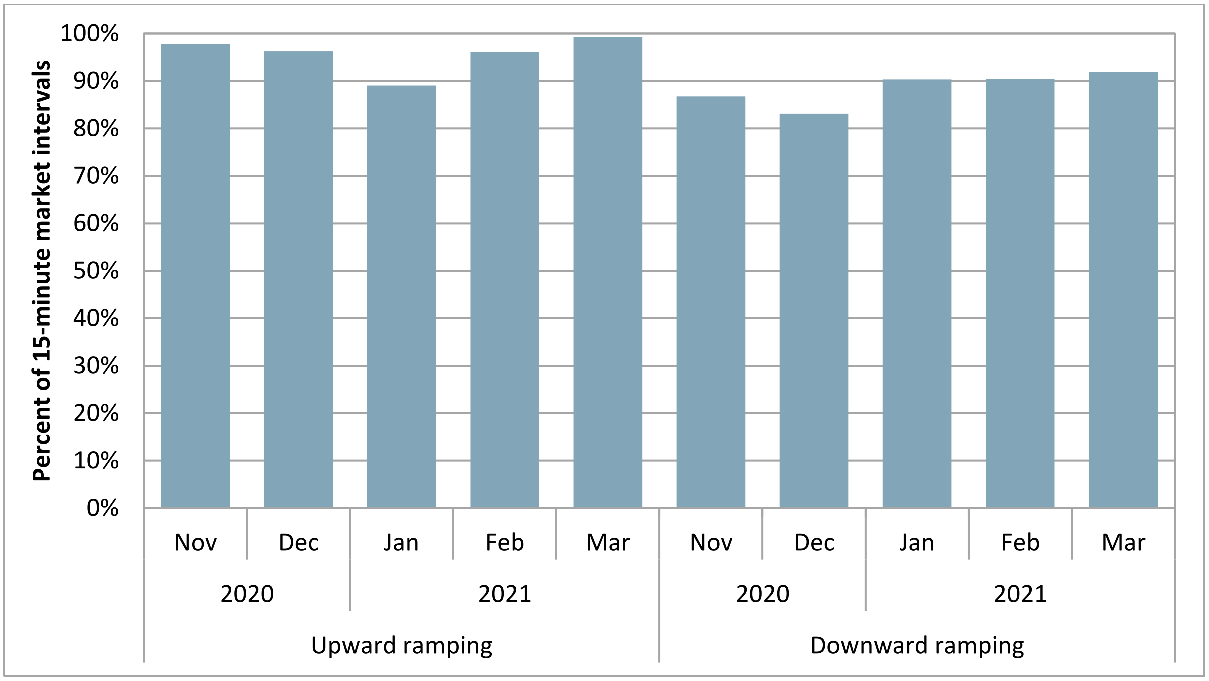
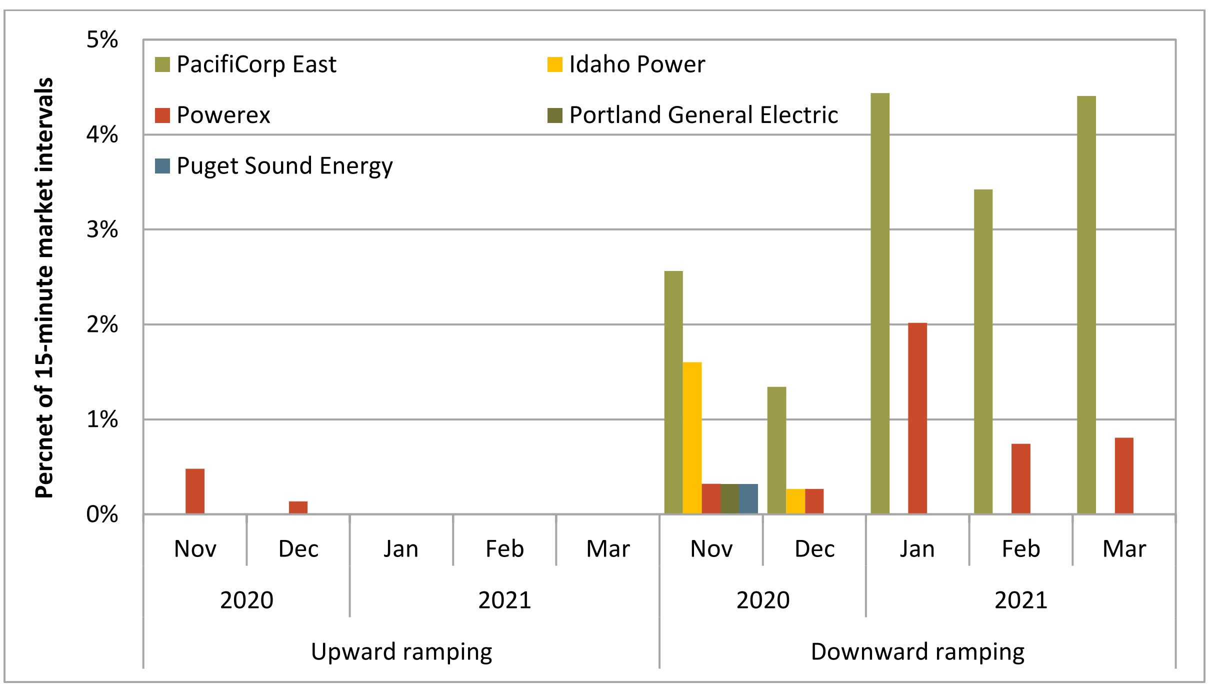


Figure 2.25 Energy imbalance market frequency of enforced minimum requirement (15-minute market)

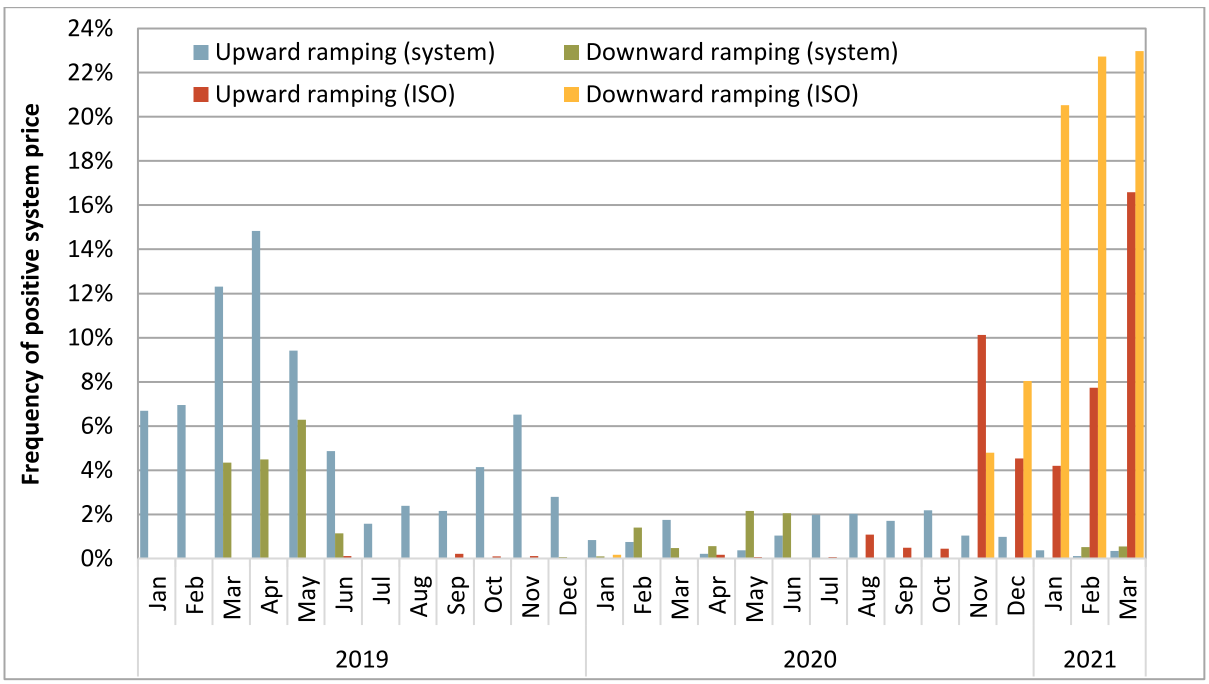


Flexible ramping product prices

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 is readily available relative to the need for it, such that there is no cost associated with the level of procurement.

Figure 2.26 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. Given the high frequency of the minimum requirement for the ISO, the percent of intervals in which the ISO demand curve bound at a positive shadow price is also shown and extended through the first quarter of 2021. The frequency of positive shadow prices for the system continued to be low overall during the year.

Figure 2.26 Monthly frequency of positive system or ISO flexible ramping shadow price (15-minute market)



Flexible ramping product costs

Flexible ramping capacity that satisfies the demand for upward or downward uncertainty receives payments based on the combined system and area-specific flexible ramping shadow price. In addition, the combined flexible ramping shadow price is used to pay or charge for forecasted ramping movements. This means a generator that was given an advisory dispatch by the market to increase output was paid the upward flexible ramping price and charged the downward flexible ramping price. Similarly, a generator that was forecast to decrease output was charged the upward flexible ramping price and paid the downward flexible ramping price.[138] The following section looks at flexible ramping

[138] 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.

product payments from three different perspectives: (1) by payment type, (2) by area, and (3) by fuel type.

Figure 2.27 shows the total monthly net payments to resources from the flexible ramping product, including both payments for flexible ramping capacity to meet upward and downward uncertainty as well as payments for forecasted movements. Payments associated with the flexible ramping product were $3.6 million during 2020 after accounting for forecasted movement, compared to around $8.7 million in 2019. Payments for only upward and downward uncertainty awards were $4.6 million during 2020, compared to around $6.3 million in the previous year.

Figure 2.27 Monthly flexible ramping product payments by type

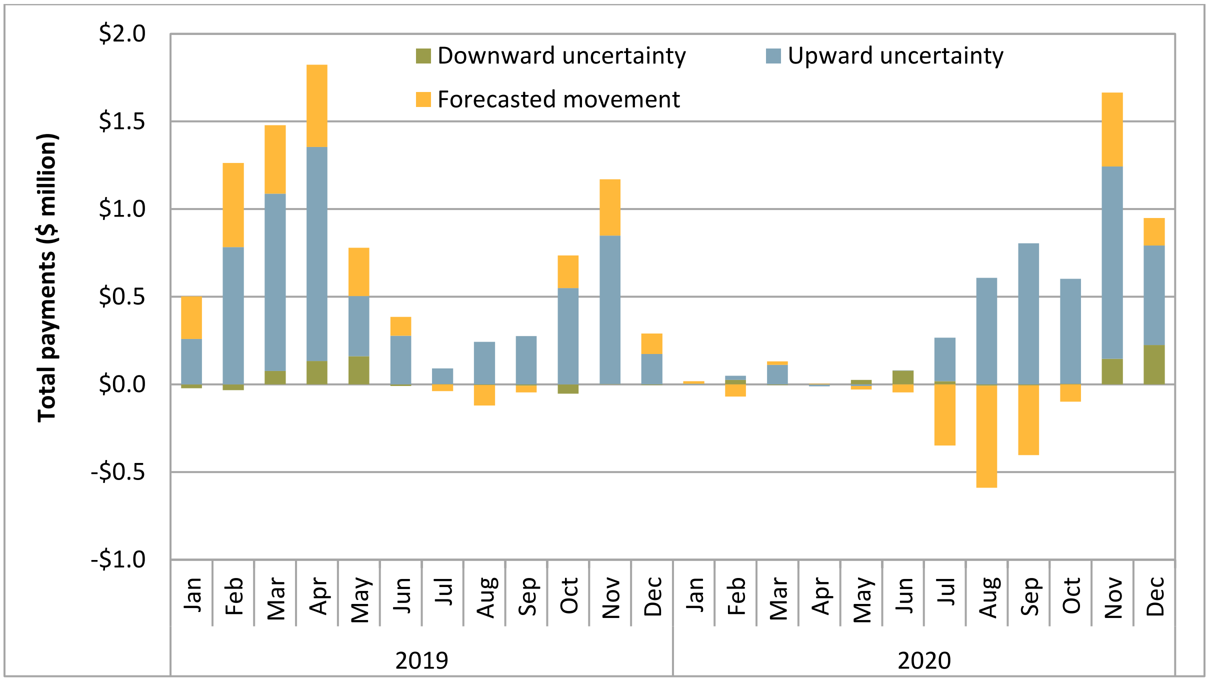


Figure 2.28 and Figure 2.29 do not include payments for forecasted movements and therefore only reflect payments to generators for upward and downward ramping capacity to meet uncertainty needs.

Figure 2.28 shows these payments by general geographic location. Payments for this capacity may have been procured to satisfy system-level demand, area-specific demand, or both. During 2020, 70 percent of payments for flexible ramping capacity have been to resources internal to the ISO while 21 percent of payments have been to areas in the Northwest region that includes PacifiCorp West, Puget Sound Energy, Portland General Electric, Powerex, and Seattle City Light. This reflects a significant difference from 2019 when 42 percent of payments were to resources internal to the ISO while 46 percent of payments were to resources in the Northwest region. This change was in part because of the implementation of the minimum requirement in November.

Figure 2.29 shows the same information by fuel type. In 2020, around 43 percent of flexible capacity payments for upward and downward uncertainty have been to gas generators while 39 percent of payments were to hydroelectric generators. Of note, 8 percent of payments have been to battery resources compared to less than 1 percent in the previous year.

Figure 2.28 Monthly flexible ramping product uncertainty payments by area

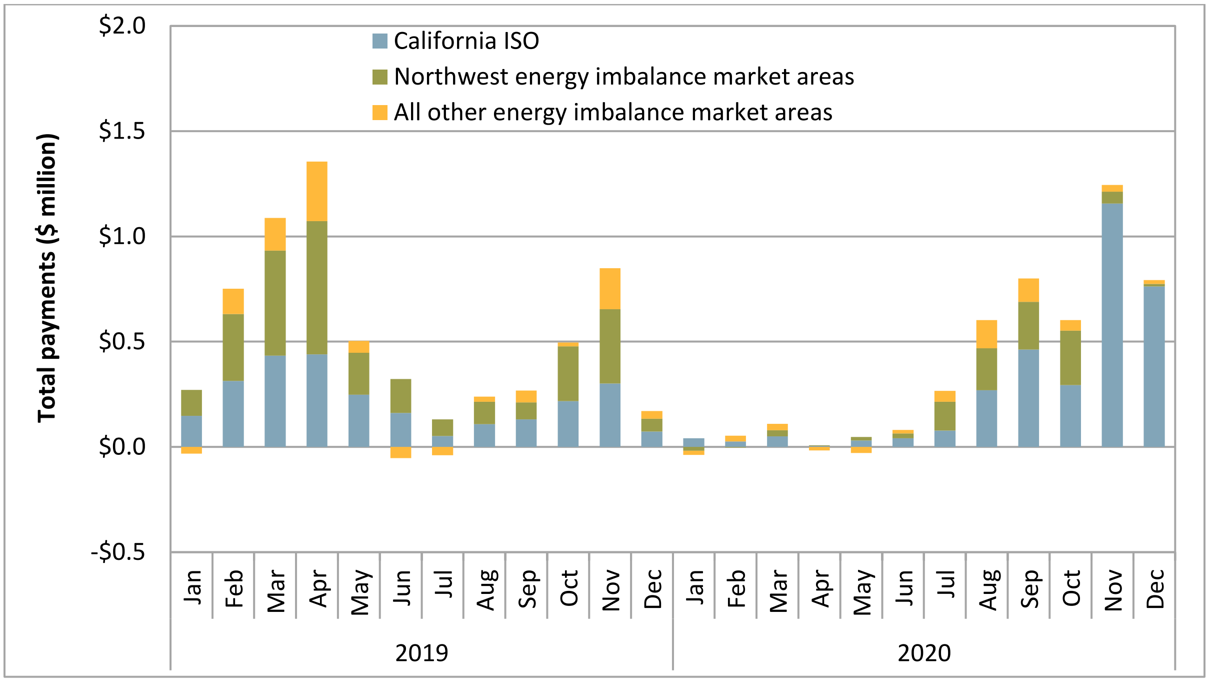
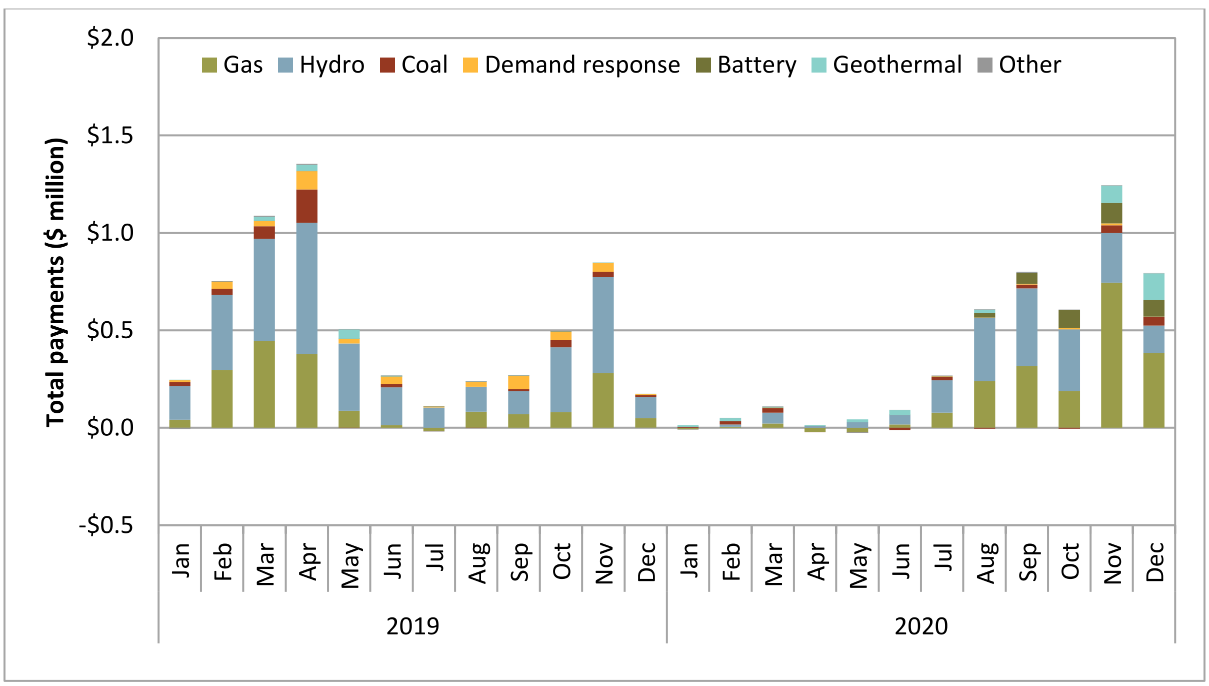


Figure 2.29 Monthly flexible ramping product uncertainty payments by fuel type

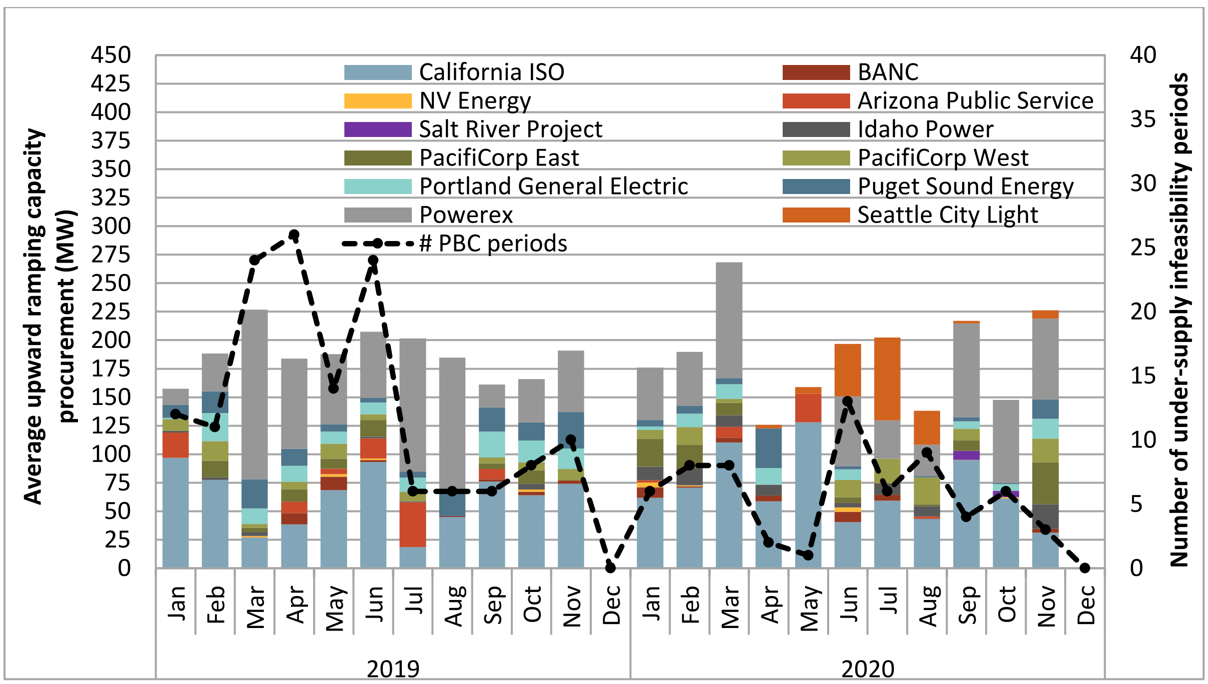


Flexible ramping product procurement

Figure 2.30 shows the average upward ramping capacity procured in the 5-minute market by area in the interval prior to any system under-supply infeasibility (or period of consecutive infeasibilities).[139] The dotted line shows the underlying number of under-supply infeasibility periods in each month. The bars show the average procurement of upward ramping capacity in the interval prior to these periods. During 2020, flexible ramping capacity awards to resources in the Northwest region made up 57 percent of procurement in the interval prior to under-supply infeasibility periods.

Procurement from resources stranded behind transfer constraints (particularly in the Northwest) can contribute to lower deliverability of flexible capacity at the system level and suppress the true opportunity cost of providing such capacity instead of energy.

Figure 2.30 Average 5-minute market upward ramping capacity procurement prior to under-supply infeasibility periods - by area



139 For under-supply infeasibility periods lasting longer in duration than one 5-minute interval, only procurement in the interval prior to these periods is summarized in these figures. There were no under-supply infeasibilities in December.

3 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 2020. Key elements highlighted in this chapter include the following:

- **The energy imbalance market continued to perform well and grow** by the addition of two new participants in 2020. 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 are now marked by distinct daily and seasonal patterns which reflect differences in regional supply conditions and transfer limitations.
- **Seattle City Light and Salt River Project joined the energy imbalance market** on April 1, adding an average of over 7,500 MW of export transfer capability and over 9,300 MW of import capability.
- **On average, prices in the ISO are higher than other energy imbalance market balancing areas**. 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.
- **In 2020, NV Energy had higher average prices during the spring and summer** than other EIM areas, peaking at $73.95/MWh in August. High prices in NV Energy correlate with months where a relatively high number of power balance constraint violations occurred. In many cases, these violations occurred in intervals where Western EIM imports into these areas were frozen due to failed resource sufficiency tests.
- **The ISO exports energy to other balancing areas in the energy imbalance market** during periods of relatively high solar production. By allowing the ISO to transfer energy out during these periods, the energy imbalance market has helped to reduce the need to curtail solar production.
- **During the morning and evening ramping hours, the ISO tends to import** from other balancing areas. Similarly, prices and transfers between other areas in the energy imbalance market reflect how the market allows entities to import when prices are lower and export when prices are high based on supply conditions in each area relative to the rest of the market.
- **Congestion imbalance deficits related to base schedules remained very low in 2020**. Balancing areas may allocate these imbalances to third party customers and others.
- **The decrease in supply that can be deemed delivered into California can be significant**. Beginning in 2019, there were intervals in which all eligible supply was imported, limiting energy imbalance market imports to California. In November 2018, the ISO implemented a revised energy imbalance market greenhouse gas bid design which limited greenhouse gas bid capacity. Following that change, the weighted average greenhouse gas cost increased as the delivered resources shifted from lower to higher greenhouse gas emissions.

3.1 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. Since then, transfer capacity between the ISO and the energy imbalance market areas has continued to increase. Puget Sound Energy and Arizona Public Service joined the market in October 2016. In 2017 and 2018, Portland General Electric, Powerex, and Idaho Power joined the market. The Balancing Authority of Northern California joined the energy imbalance market in 2019. The Balancing Authority of Northern California joined with the Sacramento Municipal Utility District as a member within the balancing area.

On April 1, 2020, Seattle City Light and Salt River Project joined the energy imbalance market. The 15-minute transfer limits for Seattle City Light and Salt River Project to the rest of the system have averaged 440 MW and 7,140 MW for export limits, respectively, while import limits have averaged 420 MW and 8,910 MW, respectively.[140]

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 are now marked by distinct daily and seasonal patterns which reflect differences in regional supply conditions and transfer limitations.

3.2 Energy imbalance market performance

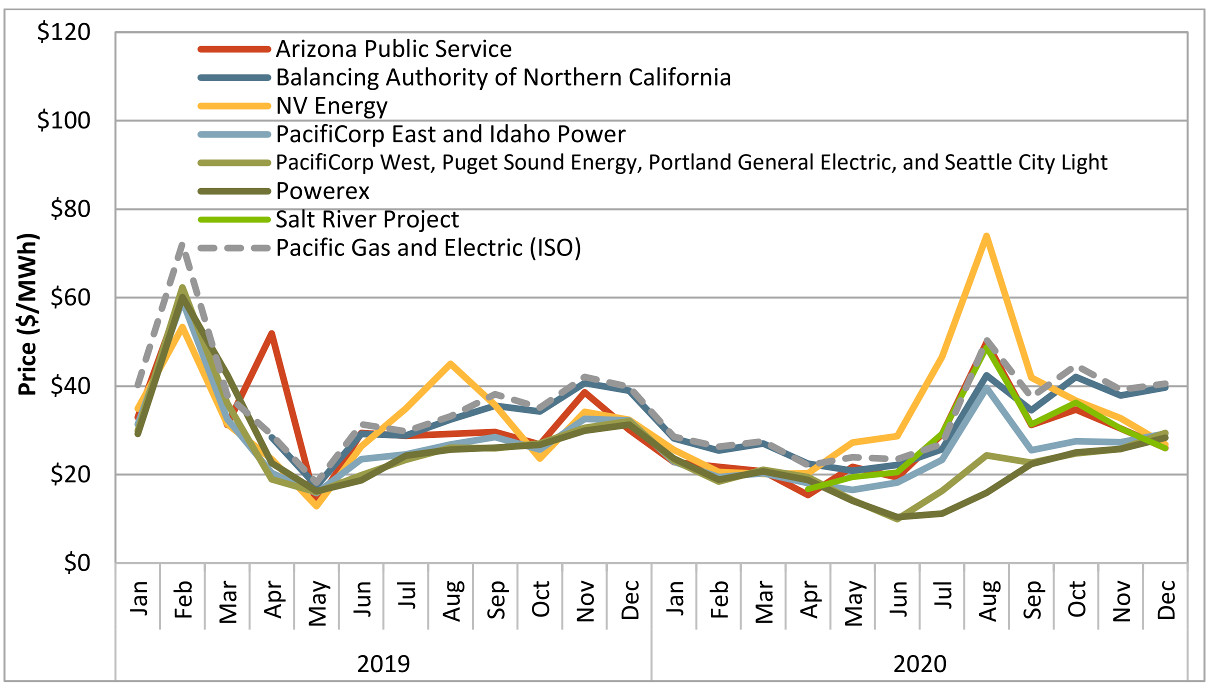
This section details the factors that influence prices in the Western EIM balancing authority and what causes price separation between entities. The Western EIM benefits participating balancing authorities by committing lower-cost resources across all areas to balance fluctuations in supply and demand in the real-time energy market. Since dispatch decisions are determined across the whole Western EIM

140 Average 15-minute transfer limits include all transfer limits between these new entities and all of the Western EIM.

system, prices within each balancing authority will be similar but can diverge from the system price when transfer capability constraints are binding, greenhouse gas compliance costs are enforced for imports into California, or power balance constraint violations within a single area are assigned penalty prices.

Figure 3.1 shows average monthly prices from the 15-minute market by balancing authority from January 2019 to December 2020. Several balancing areas are grouped together due to similar average monthly prices. Prices for the Balancing Authority of Northern California (dark blue line) begin in April 2019 and prices for Seattle City Light (included in the medium green line) and Salt River Project (light green line) begin in April 2020, when these entities joined the Western EIM. Prices for Pacific Gas and Electric (grey dashed line) are included in the figure as a point of comparison for this analysis. In 2020, NV Energy had higher average prices during the spring and summer than other EIM areas, peaking at $73.95/MWh in August. High prices in NV Energy correlate with months where a relatively high number of power balance constraint violations occurred. In many cases, these violations occurred in intervals where Western EIM imports into these areas were frozen due to failed resource sufficiency tests.

Figure 3.1 Monthly 15-minute market prices

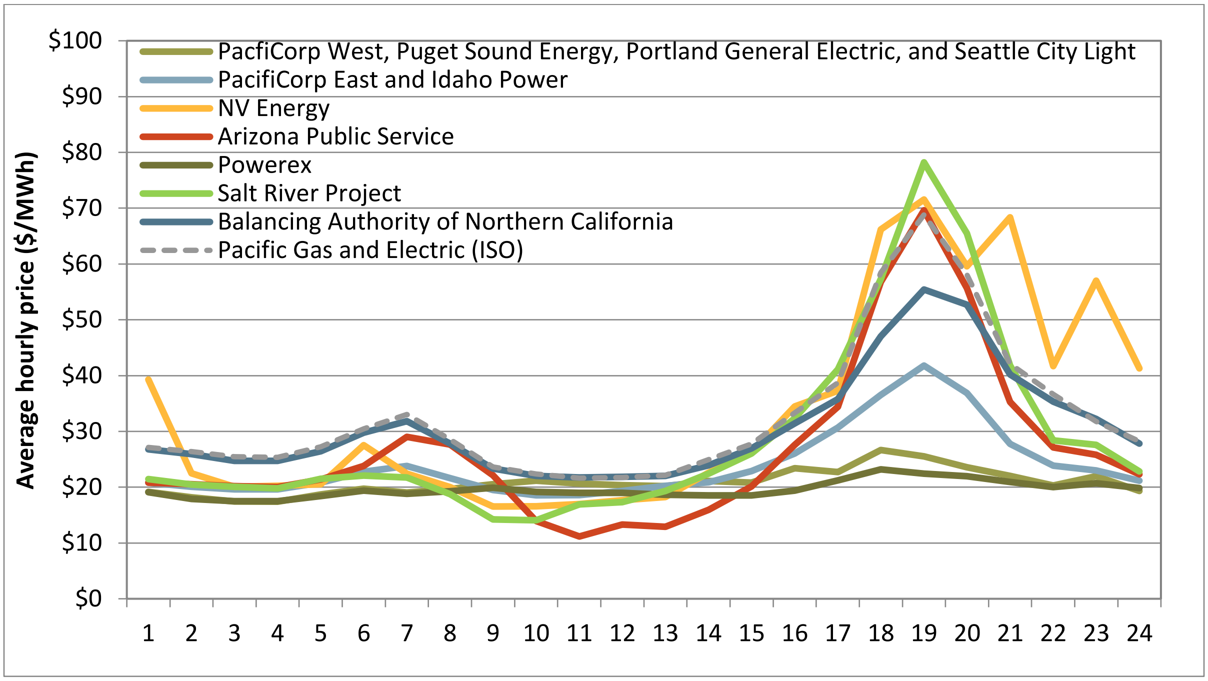


Price separation between Western EIM balancing authorities occurs for several reasons. ISO prices tend to be higher than the rest of the Western EIM due to both transmission constraints and greenhouse gas compliance cost for energy that is delivered to California.[141] In addition to this, average prices in the Northwest region (including PacifiCorp West, Puget Sound Energy, Portland General Electric, Seattle City Light, and Powerex) are regularly lower than the ISO and other balancing areas because of the availability of lower cost hydroelectric generation and limited transfer capability out of the region.

141 See Section 3.4 for more information about California's greenhouse gas compliance cost and its impact on the ISO and energy imbalance market.

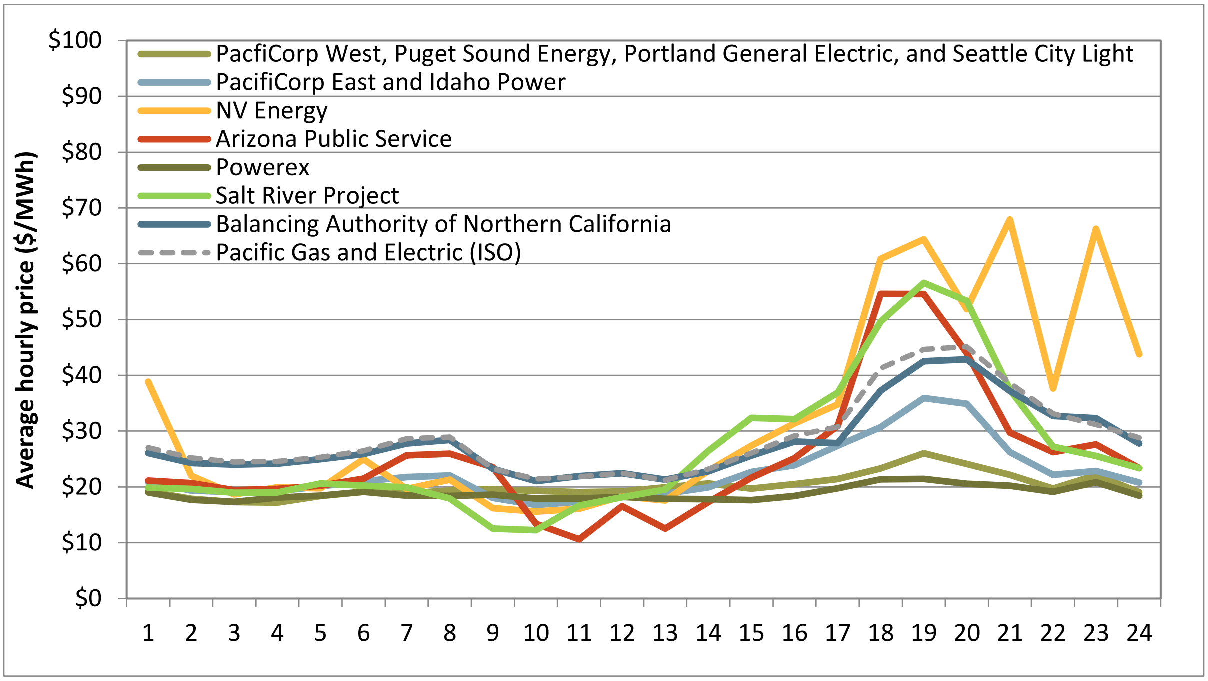
Figure 3.2 and Figure 3.3 show the average hourly variability between Western EIM area prices throughout the day in 2020.[142] Prices continue to follow the net load pattern with the highest energy prices during the evening peak net load hours. As in the previous analysis, several balancing areas are grouped together because of similar average hourly pricing. Prices at the Pacific Gas and Electric default load aggregation point are shown as a point of comparison.

Figure 3.2 Hourly 15-minute market prices



142 Prices for Seattle City Light and Salt River Project are the average of April 1, 2020 to December 31, 2020.

Figure 3.3 Hourly 5-minute market prices



Prices in entities outside of California tend to be lower than ISO prices throughout most hours. Price divergence is most pronounced during the evening net load peak when the ISO is typically importing energy that is subject to greenhouse gas compliance costs. Western EIM entity prices converge with ISO prices in the middle of the day when the ISO tends to export energy. The Balancing Authority of Northern California (BANC) is the exception to this rule due to its location in California.

Average prices in the Northwest region (PacifiCorp West, Puget Sound Energy, Portland General Electric, Seattle City Light, and Powerex) remain relatively flat throughout the day, with little increase during ramping hours. This reflects the limited transmission available in the Western EIM to support transfers from the Northwest to California and other balancing authorities in the Southwest.

Prices in the NV Energy, Arizona Public Service, and Salt River Project areas diverged from the rest of the Western EIM during the afternoon net load peak load hours. These areas experienced a relatively high number of flexible ramping sufficiency test failures that resulted in under-supply power balance constraint relaxations in the market software. The majority of these infeasibilities were not resolved by the enhanced load conformance limiter and were therefore priced at the penalty parameter.[143]

3.2.1 Power balance constraint

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 pricing is not in place.[144]

143 See Section 3.2.1 for further details on power balance constraint relaxations and changes to the penalty parameter.

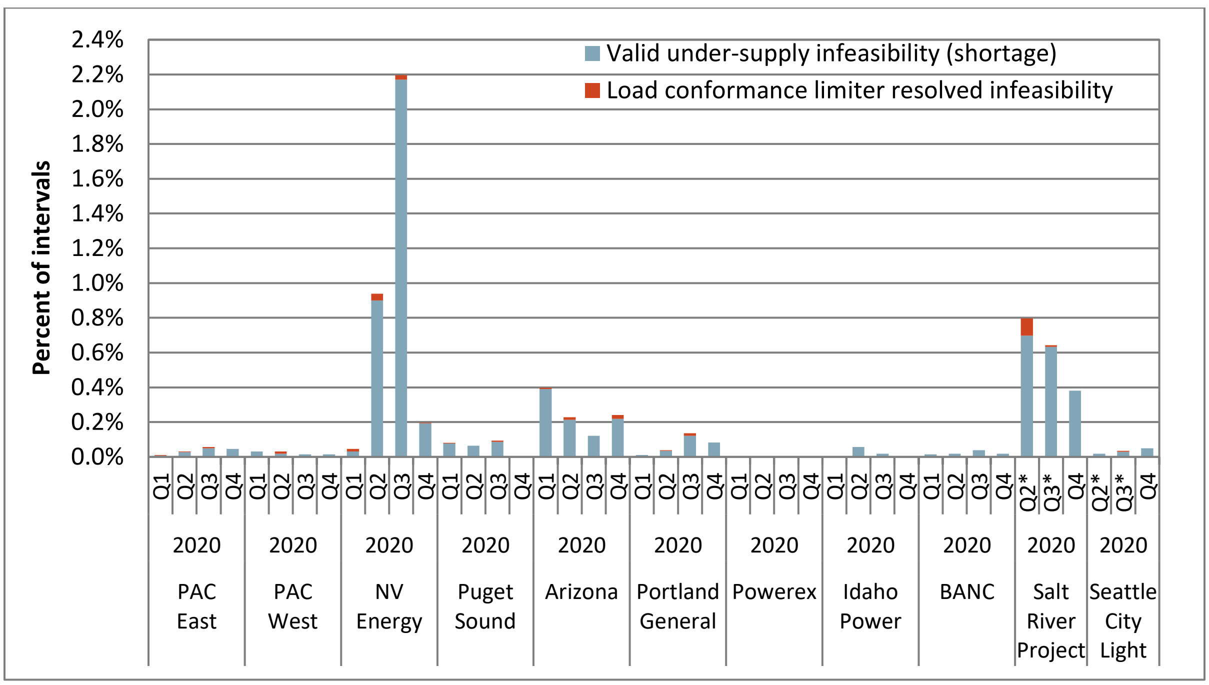
144 As of March 20, 2021 the penalty parameter for an under-supply infeasibility is scaled up to $2,000/MWh in certain conditions as part of FERC Order 831 compliance.

Transition period pricing sets prices for new balancing areas at the last dispatched economic bid rather than a penalty parameter when the power balance constraint is relaxed during the first six months after joining the energy imbalance market.

The load conformance limiter works the same way as it does in the ISO.[145] It reduces the impact of an excessive load adjustment on market prices when it is considered to have caused a power balance constraint relaxation. The 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 ISO implemented an enhancement to the load conformance limiter, effective February 27, 2019. With the enhancement, the load conformance limiter triggers by a measure based on the change in load adjustment from one interval to the next, rather than solely the magnitude of the load adjustment. This change significantly reduced the frequency in which the limiter triggers.

Figure 3.4 and Figure 3.5 show the frequency of power balance constraint relaxations in the 5-minute market by quarter for undersupply (shortage) and oversupply (excess) conditions.[146] The red bars in these figures show infeasibilities that were resolved by the load conformance limiter (or would have been without transition period pricing).

Figure 3.4 Frequency of power balance constraint undersupply (5-minute market)

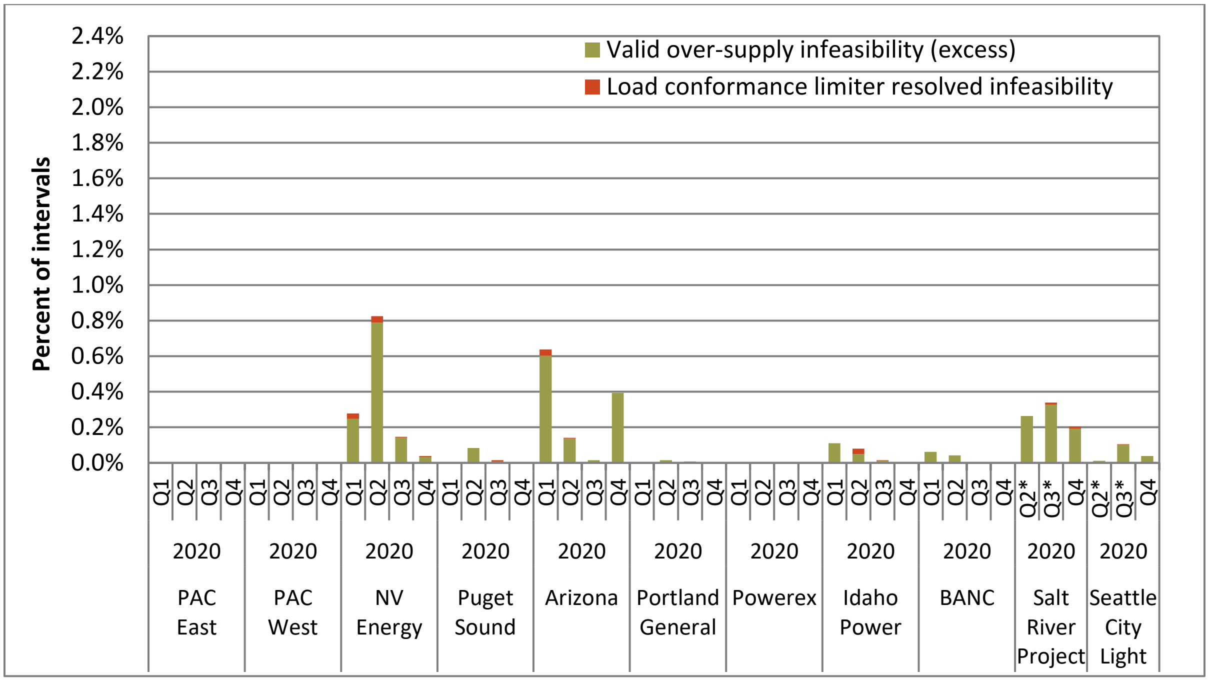


*Area under transition period pricing for the quarter

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

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

Figure 3.5 Frequency of power balance constraint oversupply (5-minute market)



*Area under transition period pricing for the quarter

3.2.2 Energy imbalance market congestion imbalance offset costs

Real-time congestion imbalances occur when payments made to schedules reducing flows on binding transmission constraints differ from payments collected from schedules increasing flows on constraints. A deficit is created when payments to flow reductions exceed collections from flow increases. When collections exceed payments there is a congestion surplus.

The ISO allocates real-time congestion imbalance deficits and surpluses to the balancing authority area in which the constraints are located. The balancing authority areas then allocate these imbalances based on their tariffs, which can include allocations to third party customers.

Western EIM base schedules can create flows above limits on constraints internal to a balancing authority area. If base schedule flows exceed internal constraint limits the 15-minute market must adjust schedules to reduce flows. The reduced flows would be paid without corresponding flow increases from which to collect payments, causing a congestion imbalance deficit. This leads to concerns that third party customers, who are not responsible for submitting base schedules or transmission limits to the ISO, will have to pay to offset deficits caused by base schedule flows that exceed internal constraint limits.

Table 3.1 shows estimated real-time congestion imbalance charges from internal transmission constraints in the 15-minute market. These estimates do not include congestion imbalances from the real-time dispatch or inter-balancing authority area transfer constraints. With the exception of the California ISO, which settles deviations from day-ahead market schedules, these data estimate the extent to which congestion imbalance deficits are the result of base schedule flows exceeding 15-minute market transmission limits. Negative values indicate a congestion imbalance deficit and positive values a surplus. Please note that these estimates are calculated from non-settlement quality data.

Table 3.1 Estimated 15-minute market EIM internal constraint congestion imbalances (million $)

	Annual				2020 Quarterly			
Balancing Authority Area	**2017**	**2018**	**2019**	**2020**	**Q1**	**Q2**	**Q3**	**Q4**
Arizona Public Service	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
BANC			$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Powerex	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
California ISO	-$26.2	-$70.4	-$92.3	-$114.5	-$12.7	-$23.2	-$49.1	-$29.5
Idaho Power Company		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
NV Energy	-$0.8	-$0.3	-$0.4	-$2.2	$0.0	-$0.4	-$0.4	-$1.4
PacifiCorp - East	-$18.1	-$2.0	$0.7	$0.5	-$0.7	-$0.1	-$0.2	$1.5
PacifiCorp - West	$0.0	-$0.1	$0.0	-$0.1	$0.0	$0.0	$0.0	$0.0
Portland General Electric	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Puget Sound Energy	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Seattle City & Light				$0.0	$0.0	$0.0	$0.0	$0.0
Salt River Project				$0.0	$0.0	$0.0	$0.0	$0.0

3.3 Energy imbalance market transfers

3.3.1 Energy imbalance market transfer limits

One of the key benefits of the energy imbalance market is the ability to transfer energy between areas in the 15-minute and 5-minute markets. Table 3.2 shows average 15-minute market limits between each of the areas after the addition of Salt River Project and Seattle City Light (April 3 to December 31, 2020).[147] The sum of each column reflects the average total import limit into each balancing area, while the sum of each row reflects the average total export limit from each area. For example, import transfer capacity into the ISO from areas in the Northwest region including PacifiCorp West, Portland General Electric, Puget Sound Energy, and Powerex, was around 180 MW on average during this period, or roughly 2 percent of total import capability. However, significant transfer capability between the ISO, NV Energy, Arizona Public Service, Salt River Project, and BANC allowed energy to flow between these areas with relatively little congestion.

[147] The blank cells indicate that the pair of areas have no energy transfer system resource (ETSR) defined between them. A cell with zero MW indicates that there is an ETSR defined between the pair of areas, but the limit was zero on average during the quarter.

Table 3.2 Average 15-minute market energy imbalance market limits (April 1 – December 31)

From Balancing Authority Area	To Balancing Authority Area: CISO	BANC	NEVP	AZPS	SRP	PACE	IPCO	PACW	PGE	PSEI	SCL	PWRX	*Total export limit*
California ISO		1,320	3,470	990	1,640			30	50	0		120	7,620
BANC	1,320												1,320
NV Energy	3,850			330		820	510						5,510
Arizona Public Service	2,240		260		7,270	740							10,510
Salt River Project	2,420			4,720		0							7,140
PacifiCorp East			620	400	0		1,040	230					2,290
Idaho Power			490			1,910		480		50	30		2,960
PacifiCorp West	130					390	370		320	250	20		1,480
Portland GE	50							340		20	30		440
Puget Sound Energy	0						0	250	20		340	150	760
Seattle City Light							30	30	20	360			440
Powerex	0									240			240
Total import limit	10,010	1,320	4,840	6,440	8,910	3,860	1,950	1,360	410	920	420	270	

3.3.2 Hourly energy imbalance market transfers

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

Figure 3.6 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.

Figure 3.7 through Figure 3.17 show the same information on imports and exports for all energy imbalance market areas in the 15-minute market. The amounts included in these figures are net of all base schedules and therefore reflect dynamic market flows between EIM entities.[148]

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

Figure 3.6 California ISO - average hourly 15-minute market transfer

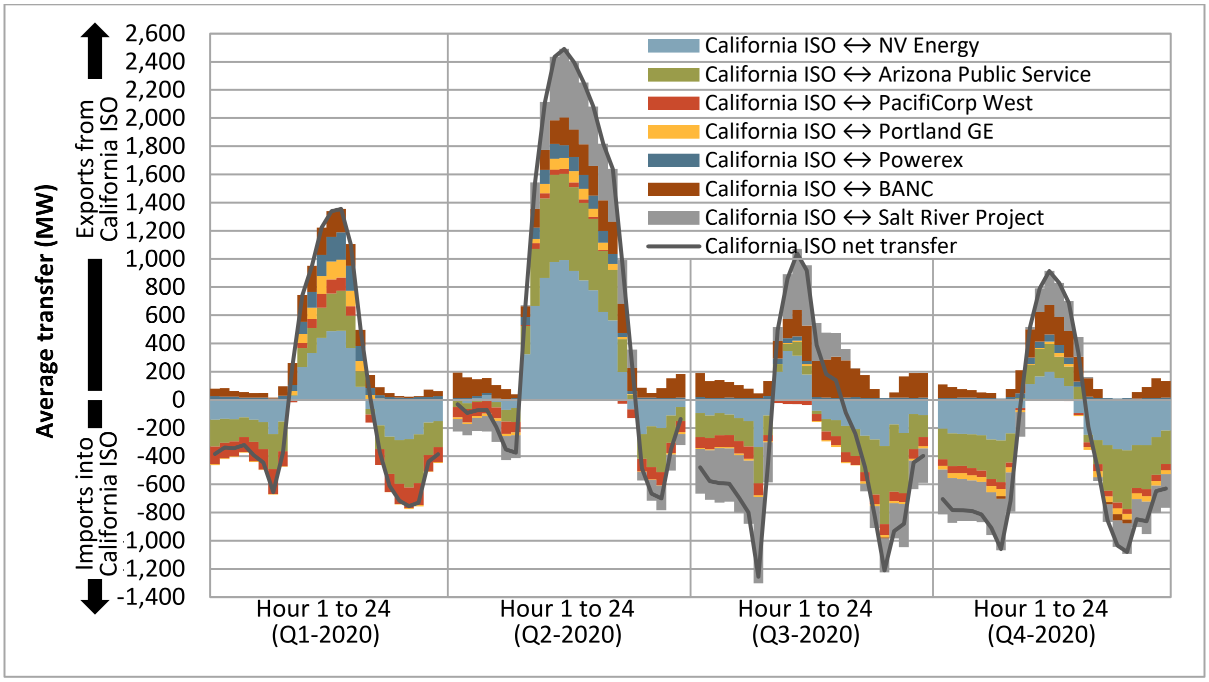


Figure 3.7 NV Energy – average hourly 15-minute market transfer

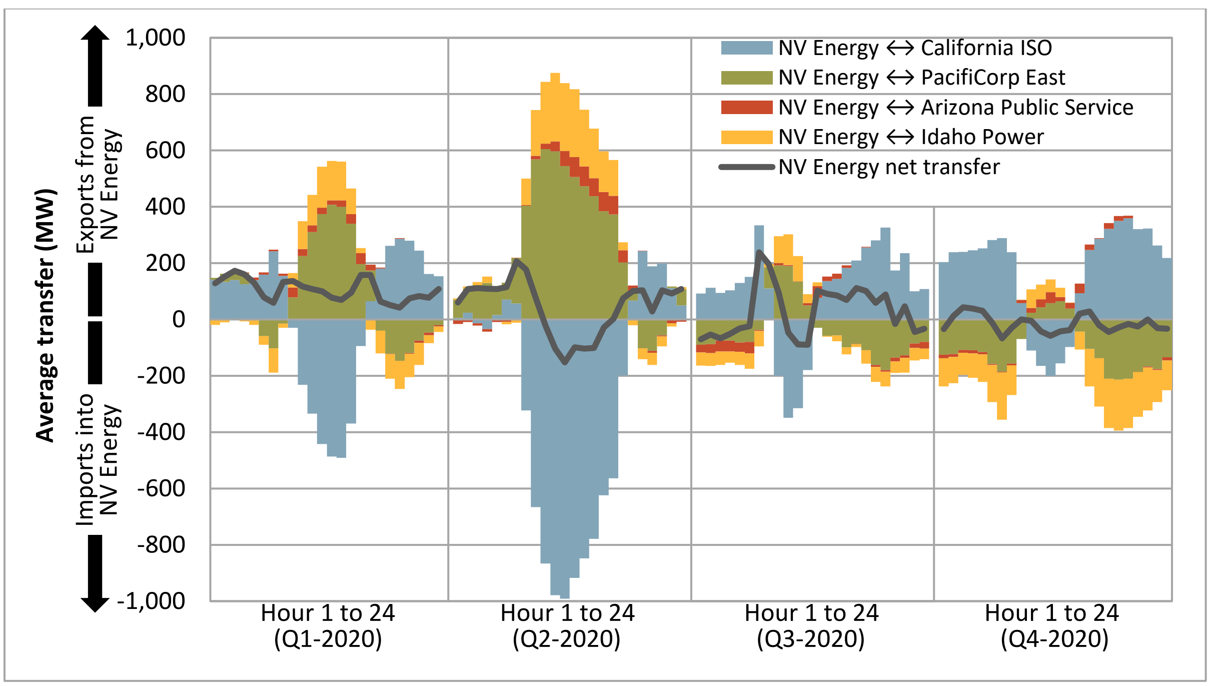


Figure 3.8 Arizona Public Service – average hourly 15-minute market transfer

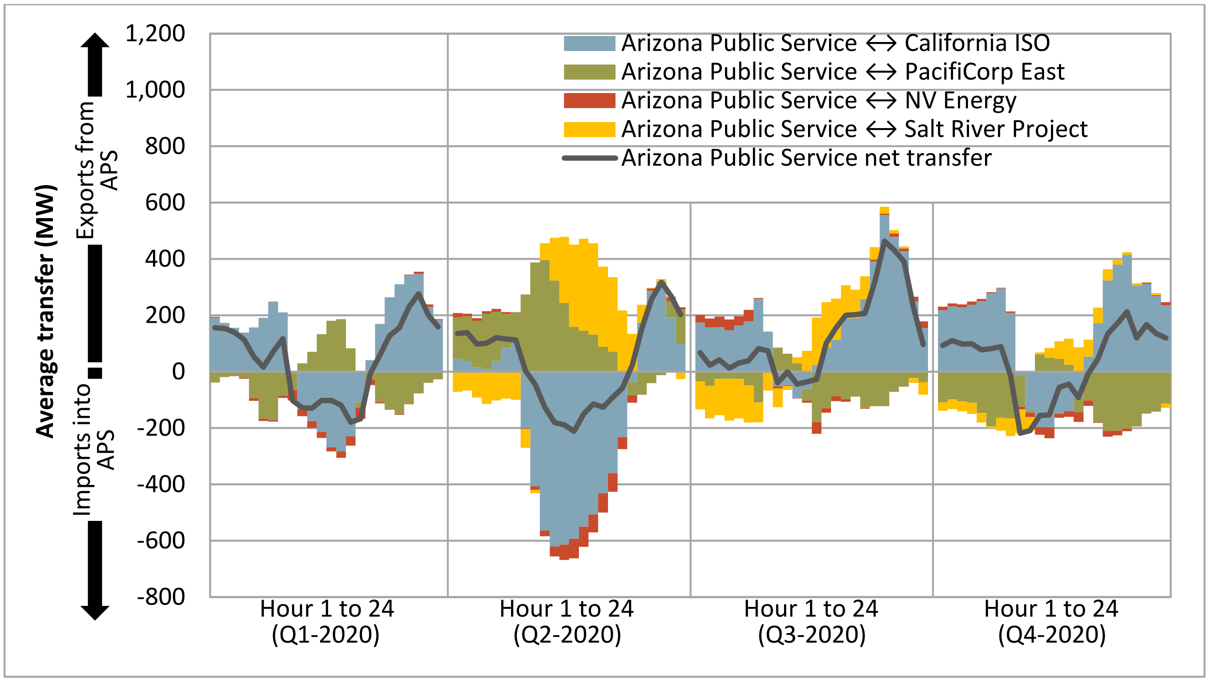


Figure 3.9 Idaho Power – average hourly 15-minute market transfer

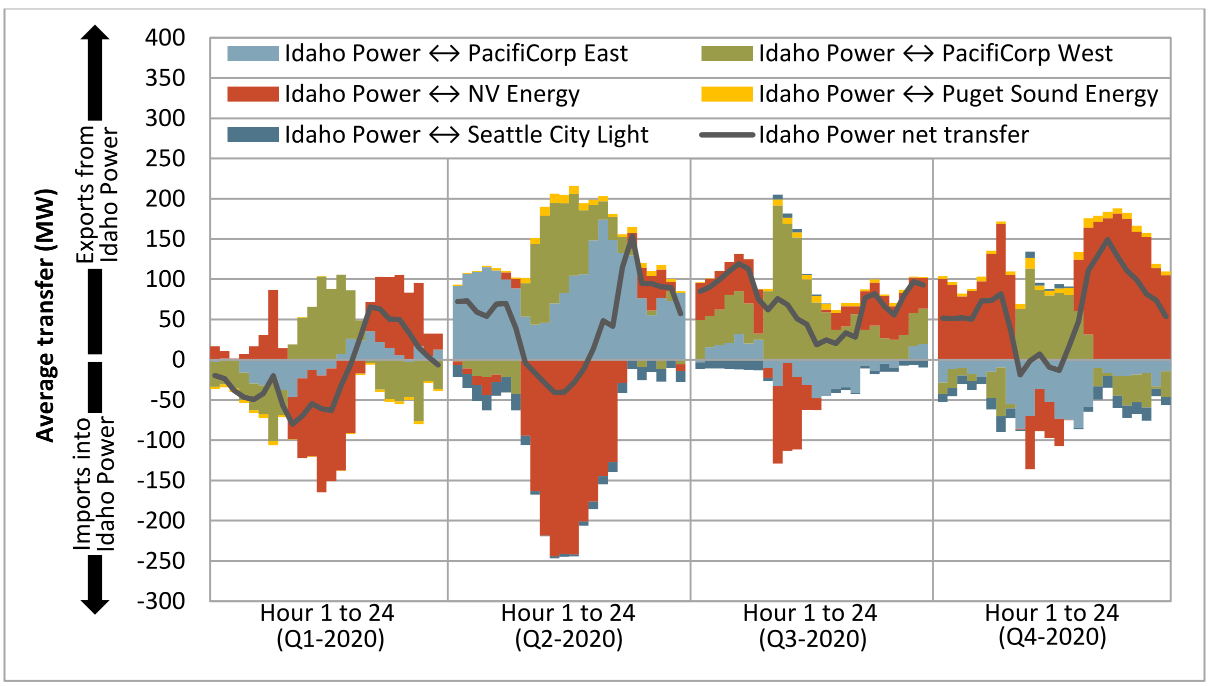


Figure 3.10 PacifiCorp East – average hourly 15-minute market transfer

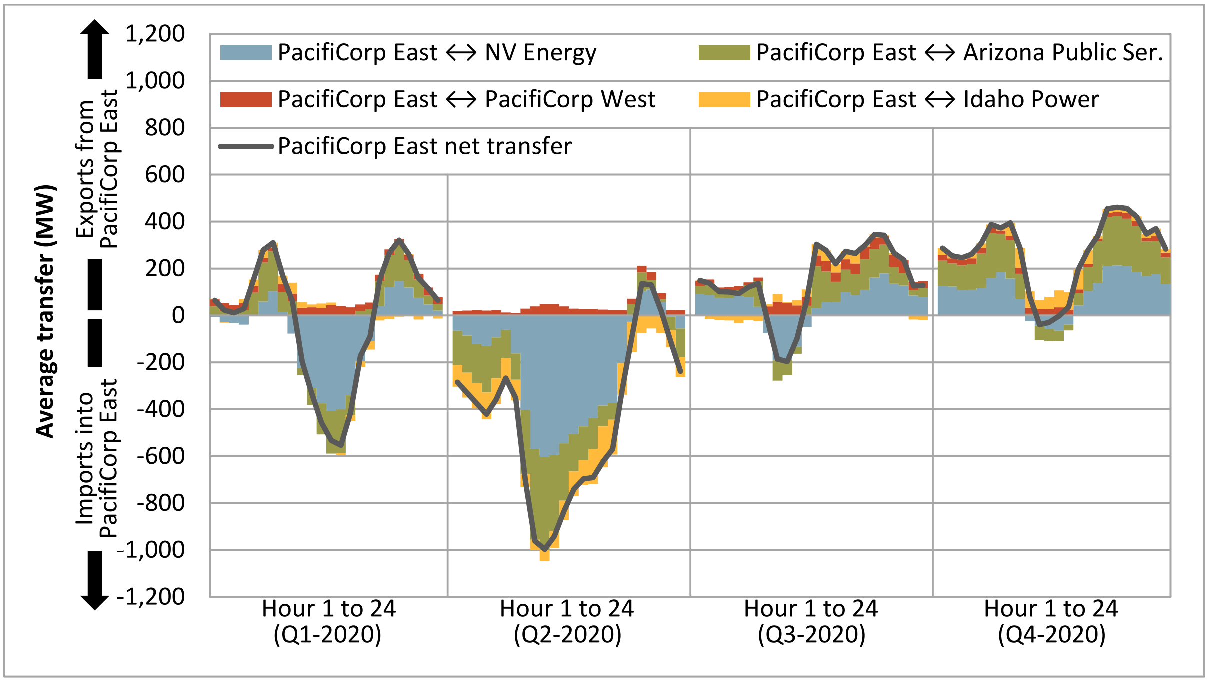


Figure 3.11 PacifiCorp West – average hourly 15-minute market transfer

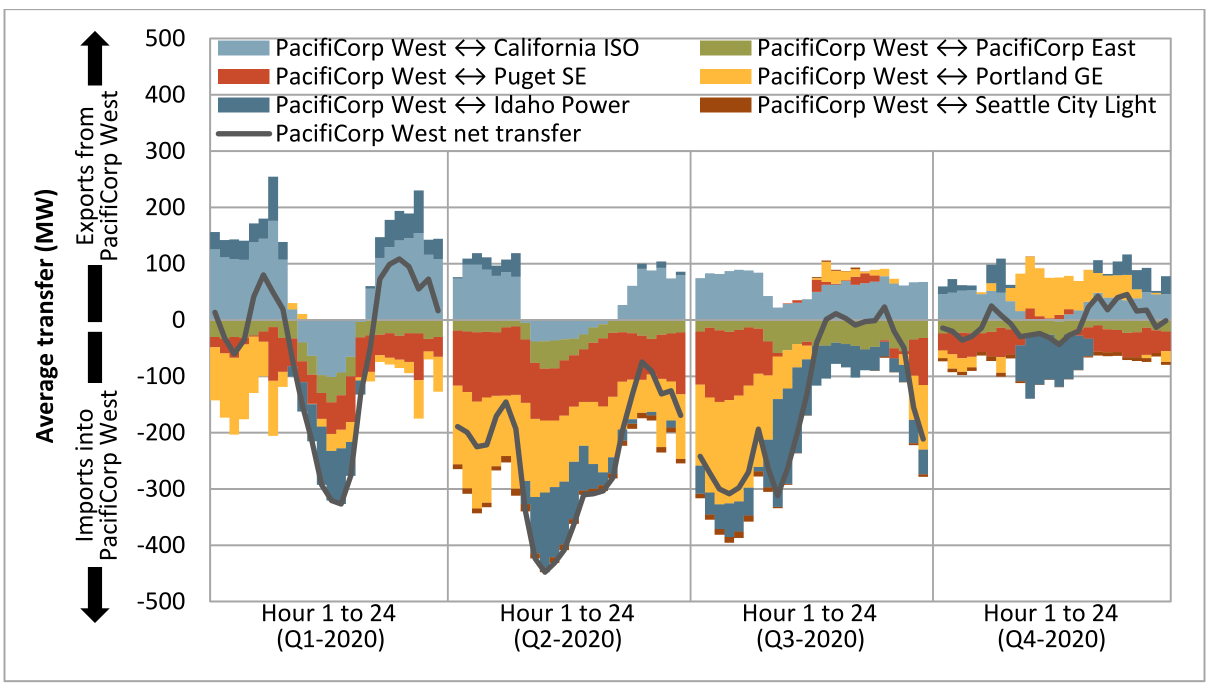


Figure 3.12 Puget Sound Energy – average hourly 15-minute market transfer

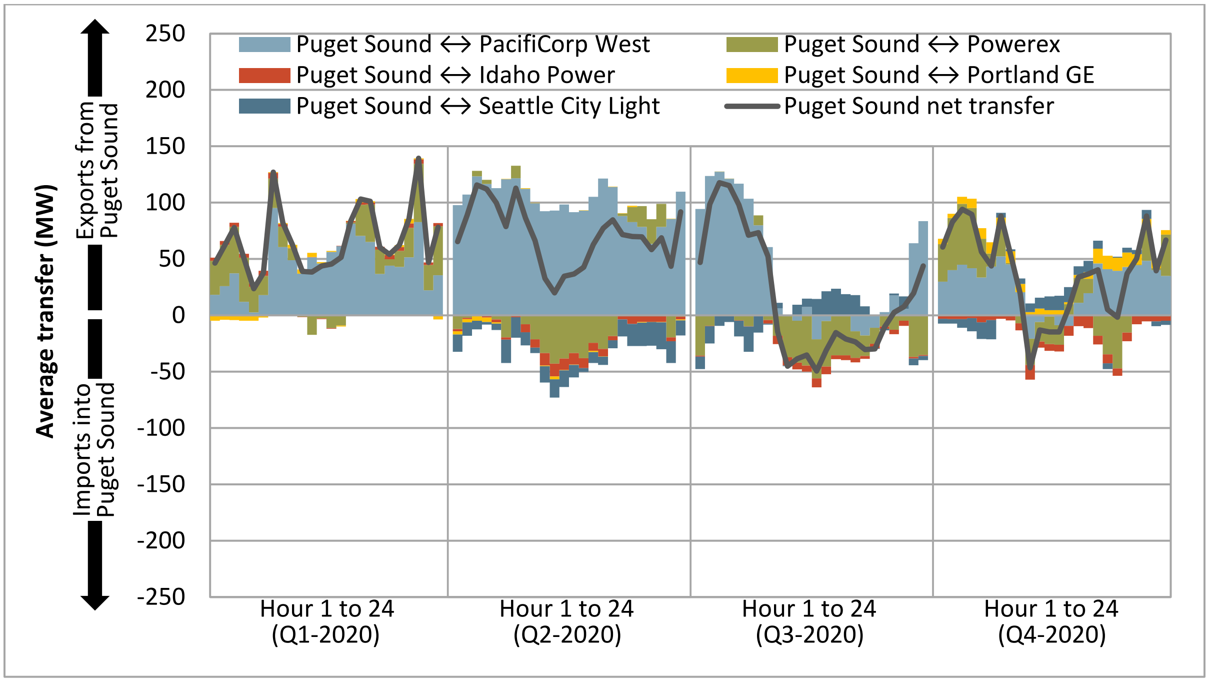


Figure 3.13 Powerex – average hourly 15-minute market transfer

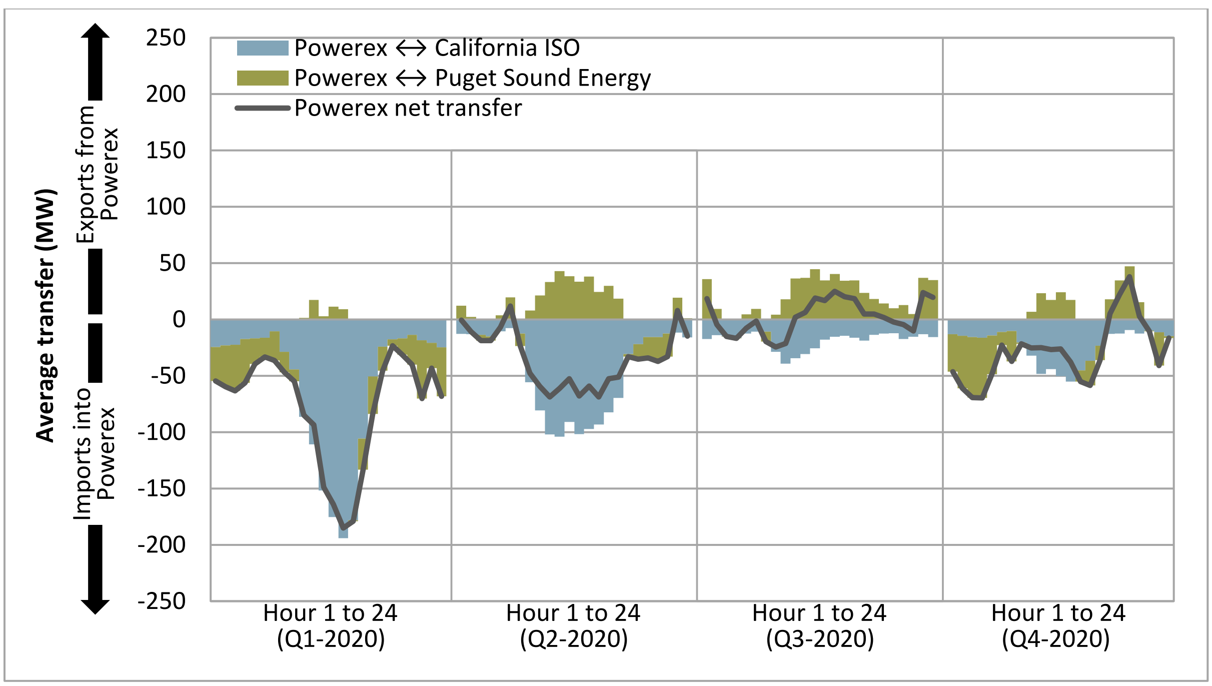


Figure 3.14 Portland General Electric – average hourly 15-minute market transfer

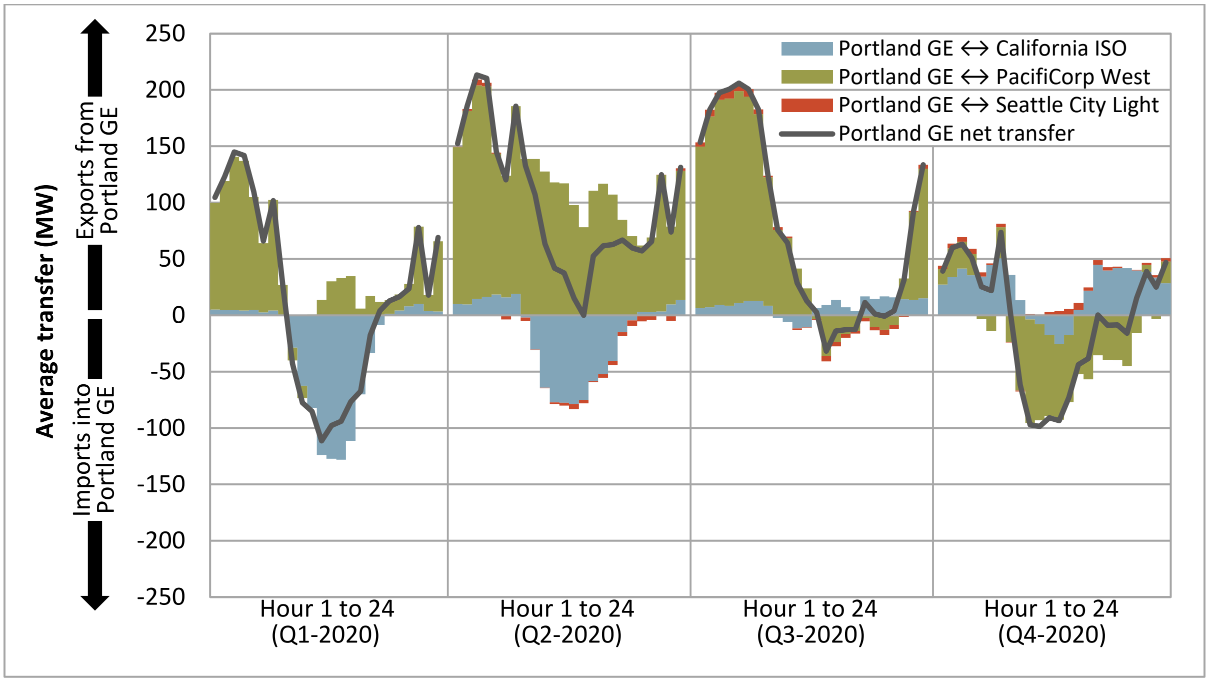


Figure 3.15 Balancing Authority of Northern California - average hourly 15-minute market transfer

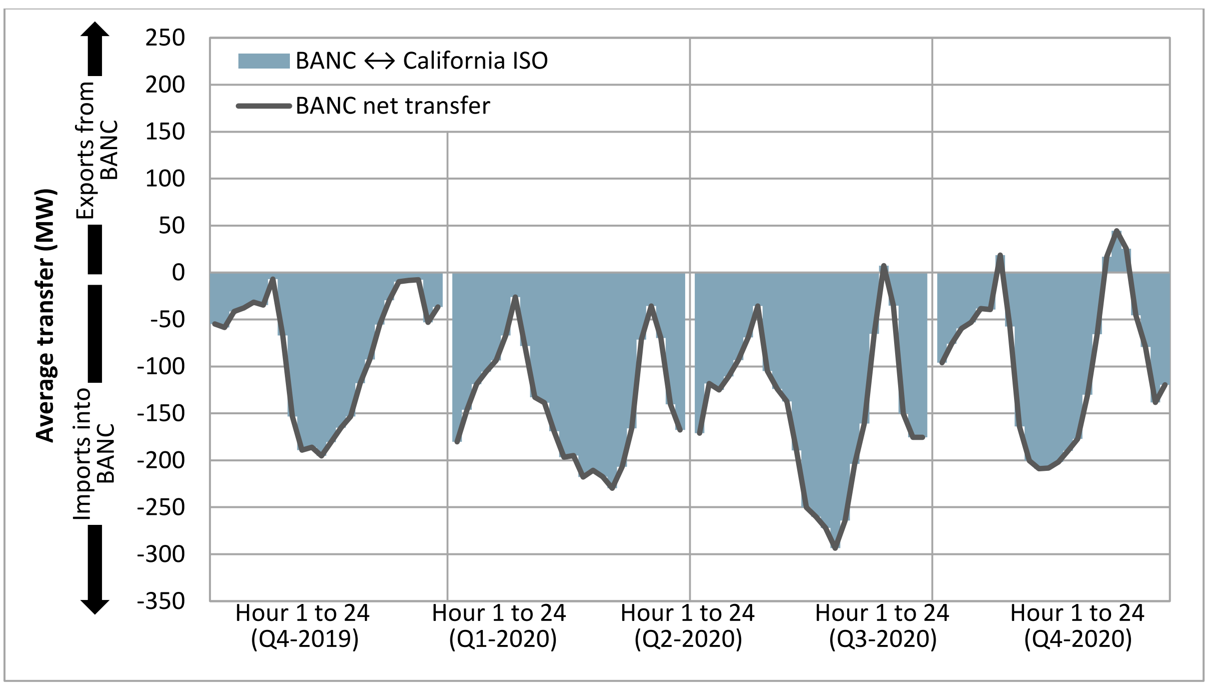


Figure 3.16 Salt River Project - average hourly 15-minute market transfer

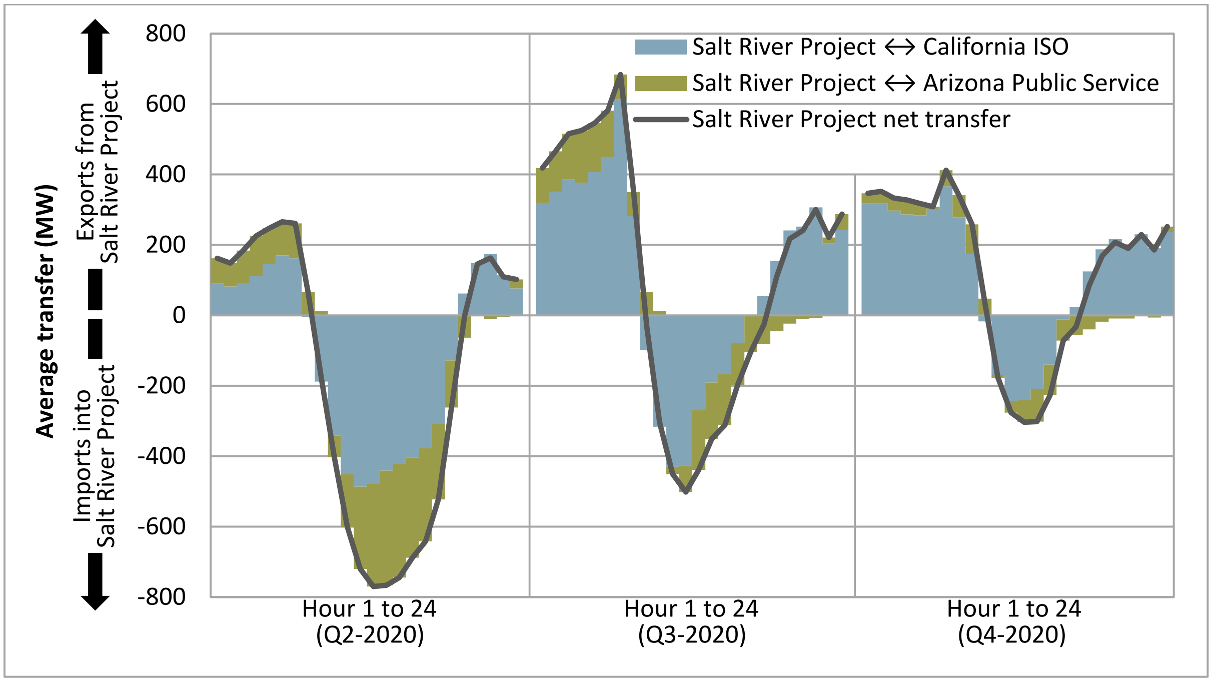
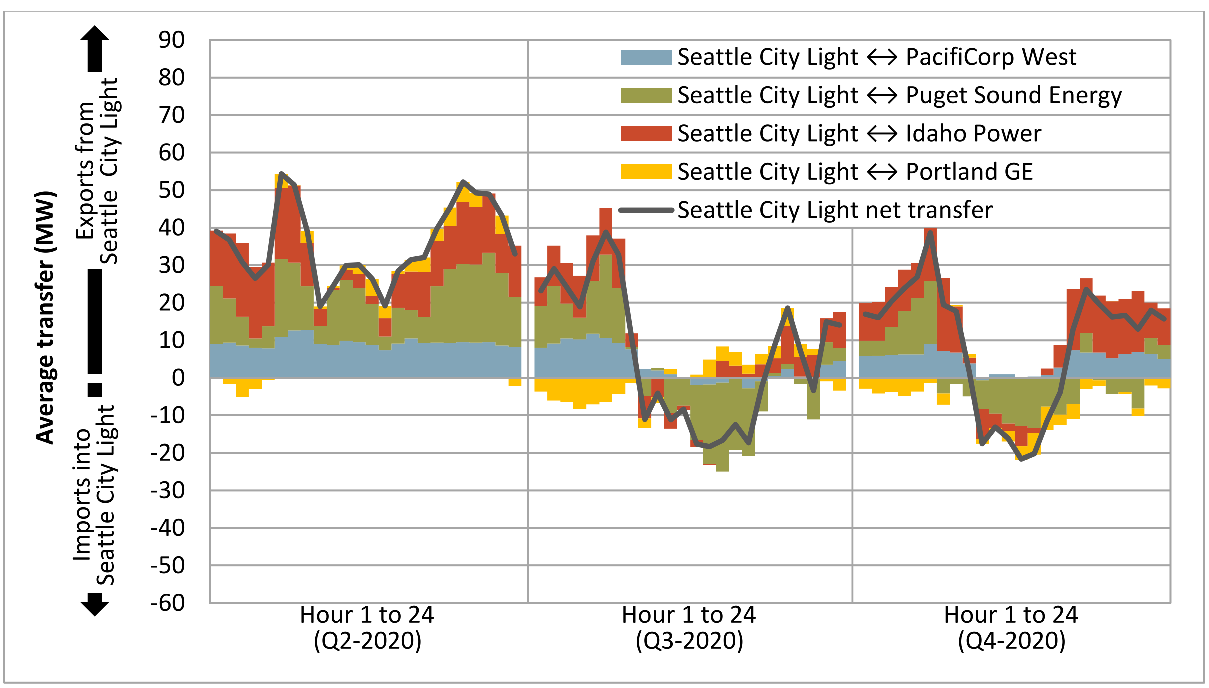


Figure 3.17 Seattle City Light - average hourly 15-minute market transfer



3.3.3 Impact of congestion between balancing areas on transfer capability

In 2020, congestion out of the Northwest areas increased significantly compared to the previous year. The highest frequency congestion into an area occurred in the Powerex area, where 39 percent of 15-minute market intervals and 33 percent of 5-minute market intervals were congested from the area over the course of the year.

Congestion between an energy imbalance market area and the rest of the system limits an area's import and export capability. In addition, during intervals when there is net import congestion into an energy imbalance market area, the market software triggers local market power mitigation for resources in that area.[149]

Table 3.3 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. This is calculated as the frequency of intervals where the shadow price on an area's transfer constraint was positive or negative, indicating higher or lower prices in an area relative to prevailing system prices.[150] When prices are lower relative to the system, this indicates congestion out of an area and limited export capability. Conversely, when prices are higher within an area, this indicates that congestion is limiting the ability for energy outside of an area to serve that area's load. The results of this section are the same as those found in Section 7.1.3 of this report on EIM transfers. Section 7.1.3 focused on the impact of congestion to EIM prices, whereas this section describes the same information in terms of the impact to import or export capability and the potential for market power mitigation.

The highest frequency of congestion in the energy imbalance market continued to be from the Northwest areas toward the larger energy imbalance market system. Congestion in the 15-minute market from PacifiCorp West, Portland General Electric, Puget Sound Energy, and Powerex occurred during an average of roughly 34 percent of intervals during the year.[151] This is significantly lower than the previous year when congestion occurred during an average of 21 percent of intervals from these areas.

Congestion in either direction for BANC, Arizona Public Service, NV Energy, PacifiCorp East, Idaho Power, and Salt River Project was relatively infrequent during the year. Congestion that did occur between these areas and the larger energy imbalance market system was often the result of a failed upward or downward sufficiency test, which limited transfer capability.

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149 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. The ISO area is not subject to market power mitigation under these conditions.

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

151 Seattle City Light belongs to this group of Northwest EIM areas; however, it was not included in this analysis as it joined the energy imbalance market in April of 2020.

Table 3.3 Frequency of congestion on the energy imbalance market transfer constraints (2020)

	15-minute market		5-minute market	
	Congested from area	Congested into area	Congested from area	Congested into area
BANC	1%	0%	0%	0%
Arizona Public Service	2%	2%	1%	2%
NV Energy	2%	2%	2%	2%
PacifiCorp East	5%	3%	3%	2%
Idaho Power	5%	3%	3%	3%
Salt River Project*	4%	6%	4%	6%
PacifiCorp West	31%	6%	20%	5%
Portland General Electric	34%	7%	24%	5%
Puget Sound Energy	34%	7%	26%	8%
Seattle City Light*	37%	7%	29%	6%
Powerex	39%	9%	33%	15%

*April 1 to December 31, 2020 only

3.4 Greenhouse gas compliance costs

Background

Under the current energy imbalance market design, all energy delivered to serve California load is subject to California's cap-and-trade regulation.[152] A participating resource must submit a separate bid representing the cost of compliance for energy attributed to the participating resource as serving California load. These bids are included in the optimization for energy imbalance market dispatch. Resource specific market results determined within the 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 optimization minimizes the cost of serving system load taking into account greenhouse gas compliance cost for all energy 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 deemed to serve California load. This price determined within the optimization is also included in the price difference between serving California and non-California energy imbalance market load, which can contribute to higher prices for energy imbalance market areas in California.[153] If all bids have been exhausted, the price may be set higher than the greenhouse gas bid of a marginal resource.

Scheduling coordinators who deliver energy receive revenue as compensation for compliance obligations. The revenue is equal to the cleared 15-minute market greenhouse gas quantity priced at the

152 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: https://ww2.arb.ca.gov/mrr-data

153 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

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 their resource. Because prices are set at or equal to the highest cleared bid, participating resources with low emissions are incentivized to export energy to California.

In November 2018, the ISO implemented a policy change to address concerns that the market design was not capturing the full greenhouse gas effect of energy imbalance market imports into California. The California Air Resources Board (ARB) 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 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 were 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 implemented changes that restrict capacity that can be deemed delivered to California from energy imbalance areas. Beginning in November 2018, the amount of capacity that can be deemed delivered to California is now limited to the difference between the upper economic bid limit of a resource and the resource's base schedule. Since the change, prices have increased, and both the resource mix of deliveries in to California and the energy imbalance entities being scheduled to deliver energy to California have changed, as discussed below. The decrease in supply that can be deemed as being imported into California has been significant. Beginning in 2019, there have been intervals in which all eligible supply was imported, limiting energy imbalance market imports into California.

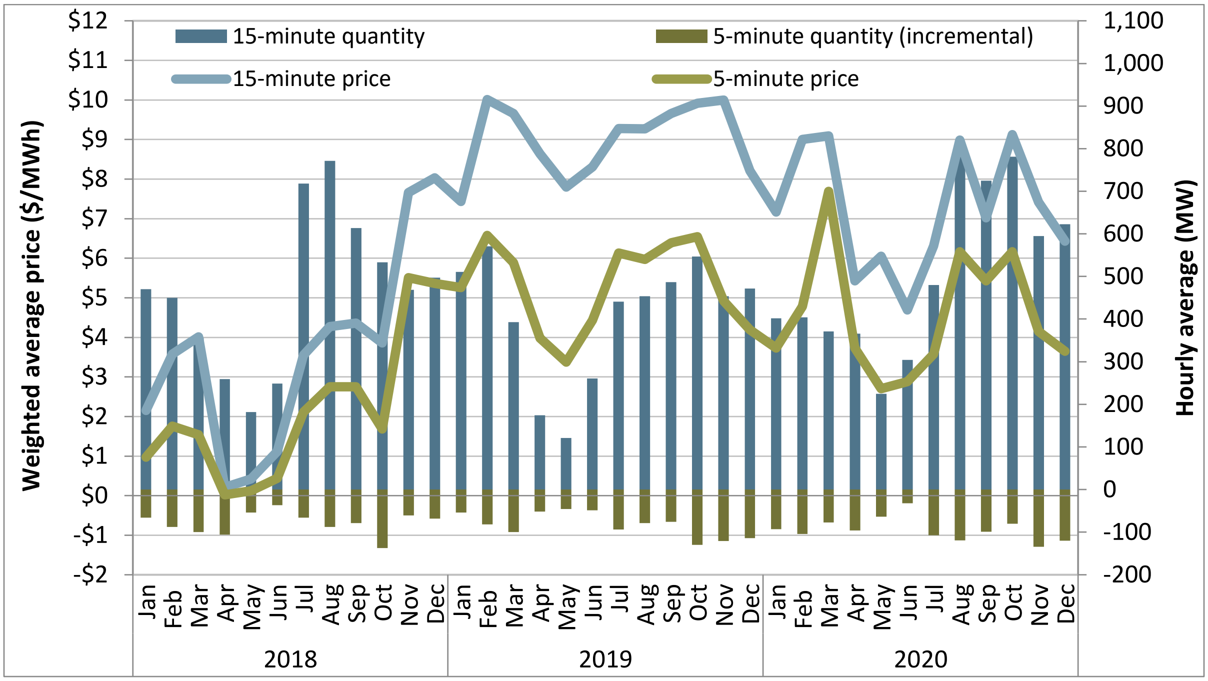
Greenhouse gas prices

Figure 3.18 shows monthly average cleared energy imbalance market greenhouse gas prices and hourly average quantities for energy delivered to California from 2018 to 2020. Weighted average prices are calculated using 15-minute 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 delivered quantities are represented by the blue and green bars in the chart, respectively.

In 2020, weighted 15-minute prices averaged around $7.20/MWh for each month of the year while 5-minute prices averaged around $4.50/MWh. Prices decreased from 2019 in both the 15-minute market and 5-minute market where weighted prices averaged $9.00/MWh and $5.30/MWh, respectively. In 2020, weighted average 15-minute prices were near the estimated greenhouse gas compliance costs for an efficient gas resource ($7.34/MWh) for every month of the year. This result occurred for the first time in November 2018 when the greenhouse gas policy change was implemented. Conversely, weighted average 5-minute prices were lower than the estimated greenhouse gas compliance cost for an efficient gas resource in every month.

Price differences between markets may occur if high emitting resources are procured in the 15-minute market and subsequently decrementally dispatched in the 5-minute market. Separation between 15-minute prices and 5-minute prices has increased since the policy change and the trend continued in 2020. Weighted average greenhouse gas prices in the 5-minute market were lower than 15-minute prices for each month of 2020, averaging about $2.70 less. In 2018, 15-minute prices were $1.49/MWh higher than 5-minute prices on average. This price separation is often correlated with operator load adjustments (described in Section 8.4), which are consistently higher in the 15-minute market than the 5-minute market. Operator load adjustments have been used for a number of years, but more recently contribute to accentuated differences in greenhouse gas prices due to the compressed bid stack.

Figure 3.18 Energy imbalance market greenhouse gas price and cleared quantity



Trends in these average prices can be further explained by the frequency of high and $0 prices. Figure 3.19 and Figure 3.20 illustrate the frequency of high prices for each market and quarter of the last three years. The charts also show the maximum price by quarter.

Historically, EIM greenhouse gas prices have not exceeded $7/MWh in either the 15-minute or 5-minute market. After November 2018, prices above $7/MWh occur frequently. In the 15-minute market, prices exceeded $10/MWh in 9 percent of intervals in 2020. In the 5-minute market, prices exceeded $10/MWh in 5 percent of intervals in 2020. The majority of these intervals were set by bids from emitting generators with compliance cost that bid a non-zero price to delivered energy to California. Some prices, however, were not set by bids.

As mentioned above, EIM greenhouse gas supply can be exhausted, limiting the total transfer of energy imported to California through the energy imbalance market, and setting greenhouse gas prices that exceed the highest cleared bid. In 2020, the highest 15-minute price was $708.86/MWh and the highest 5-minute price was $970.96/MWh. Prior to the fourth quarter of 2018, the highest 15-minute greenhouse gas price was $6.60/MWh and the highest 5-minute price was $6.69/MWh.

Figure 3.19 High 15-minute EIM greenhouse gas prices

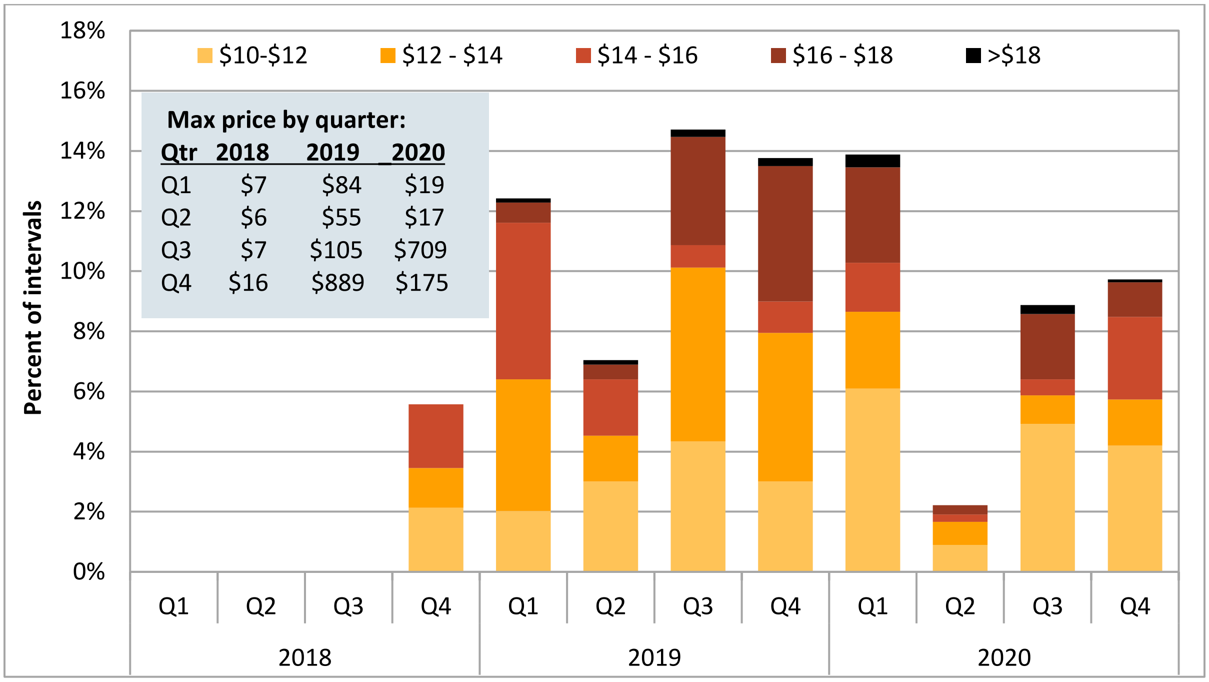
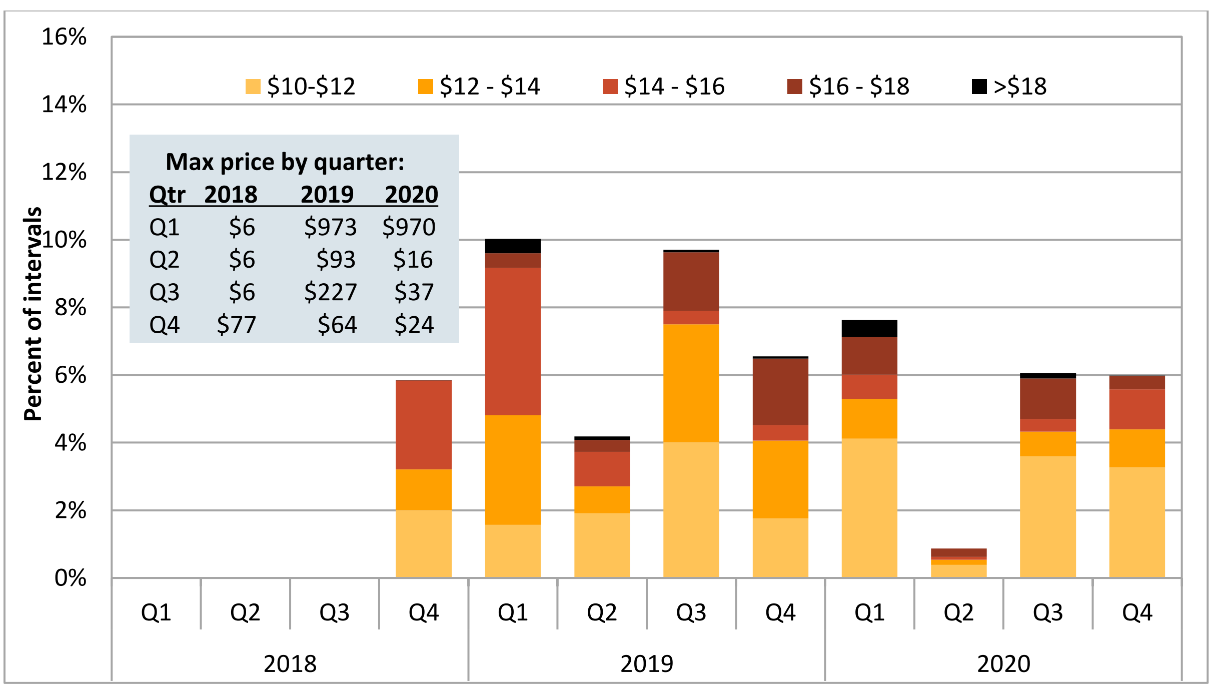


Figure 3.20 High 5-minute EIM greenhouse gas prices



Energy delivered to California by fuel type and balancing area

Figure 3.21 shows hourly average greenhouse gas energy by fuel type. In 2020, about 67 percent of EIM greenhouse gas compliance obligations were assigned to hydro resources, compared to about 51 percent in the previous year. The portion of energy delivered to California from natural gas resources was roughly 33 percent, down from around 46 percent in 2019. Delivery from coal resources accounted for about 1 percent for the year, a slight decrease compared to 2 percent in 2019.

Figure 3.22 shows the percentage of total greenhouse gas energy cleared by area. In 2020, most greenhouse gas energy came from entities in the northwest with large fleets of hydroelectric resources. About 73 percent of energy delivered to California from the energy imbalance market came from the northwestern balancing authority areas, while 34 percent came from PacifiCorp East, NV Energy, Arizona Public Service, and Salt River Project.

Figure 3.21 Percentage of energy delivered to California by fuel type (MW)

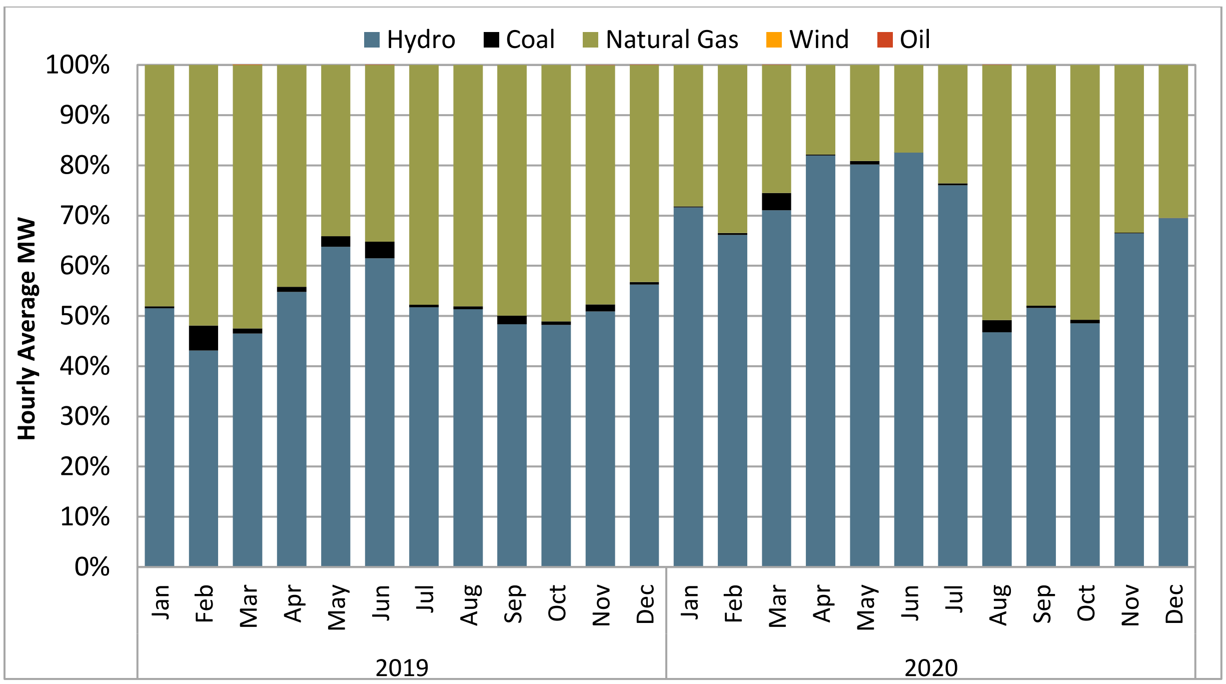
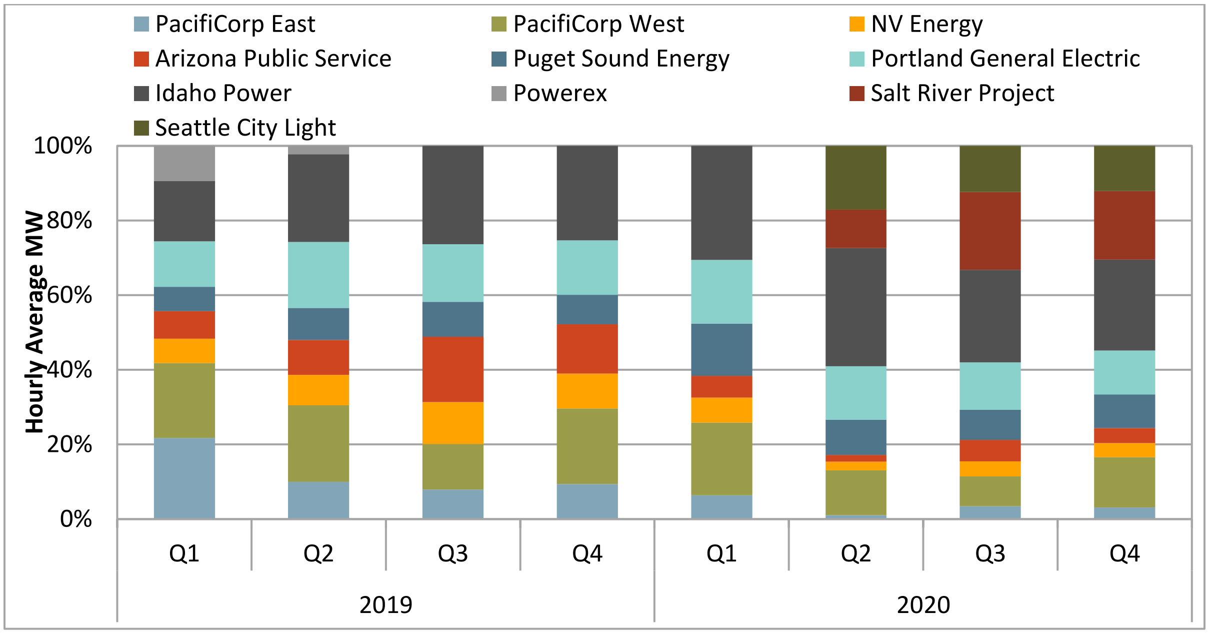


Figure 3.22 Energy delivered to California by area (MW)

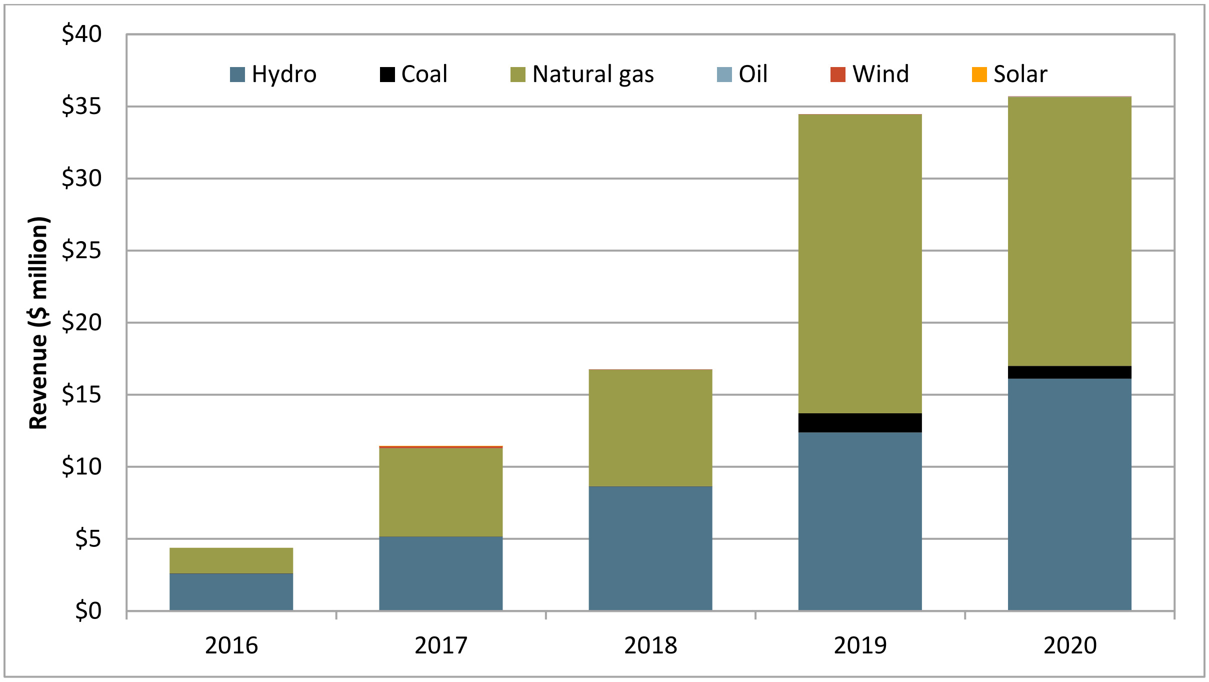


EIM greenhouse gas revenues

Figure 3.23 shows revenues accruing to energy imbalance market resources for energy delivered to California by fuel type. In 2020, revenues totaled roughly $35.7 million, about the same amount as the previous year.

Since the policy change in 2018, higher greenhouse gas prices in the energy imbalance market largely account for the increased revenues for energy deemed delivered to California. Natural gas and coal comprise the largest share of the change in revenues in the past two years. In 2020, natural gas revenues comprised 52 percent of revenues, while hydroelectric revenues comprised 45 percent, and coal revenues comprised about 3 percent.

Figure 3.23 Annual greenhouse gas revenues



3.5 Energy imbalance market resource sufficiency evaluation

As part of the energy imbalance market, each area including the ISO is subject to a resource sufficiency evaluation. The evaluation is performed prior to each hour to ensure that generation in each area is sufficient without relying on transfers from other balancing areas. The evaluation includes two tests:

- **The bid range capacity test (capacity test)** requires that each area provide incremental bid-in capacity to meet the imbalance between load, intertie, and generation base schedules.
- **The flexible ramping sufficiency test (sufficiency test)** requires that each balancing area has enough ramping flexibility over an hour to meet the forecasted change in demand as well as uncertainty.

If an area fails the bid range capacity test or flexible ramping sufficiency test, energy imbalance market transfers into that area cannot be increased.[154]

In January 2021, the ISO held a workshop to review the design of the resource sufficiency evaluation and its application to the ISO during the August heatwave.[155] The ISO identified two errors in the way the bid range capacity test was implemented:

- Resource derates and outages were not accounted for resulting in higher resource capacity relative to actual availability. This affected both the ISO and energy imbalance market areas.

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154 If an area fails either test in the upward direction, net EIM imports (negative) during the interval cannot exceed the lower of either the base transfer or optimal transfer from the last 15-minute interval.

155 *Resource Sufficiency Evaluation*, January 13, 2021. http://www.caiso.com/InitiativeDocuments/Presentation-MarketEnhancements-Summer2021ReadinessJan13,2021Workshop.pdf

- Mirror resources were incorrectly included for the ISO, impacting net scheduled interchange and the capacity test requirement.[156] This affected only the ISO.

The ISO corrected these issues effective February 4, 2021. On June 16, 2021, the ISO further added net load uncertainty to the requirement of the bid range capacity test as part of a package of market enhancements for Summer 2021 Readiness.[157] For more information on the impact of the implementation errors and proposed uncertainty on the bid range capacity test, see DMM's special report on the topic.[158]

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

Figure 3.24 and Figure 3.25 show the percent of intervals in which each EIM area failed the upward capacity and sufficiency tests, while Figure 3.26 and Figure 3.27 provide the same information for the downward direction.[159] The dash indicates that the area did not fail the test during the month.

The flexible ramping sufficiency test failures reported below now reflect ramping insufficiency independent of the bid-range capacity test. This is a change from prior DMM reports. Previously, reported sufficiency test failures reflected that either ramping capacity was insufficient or the bid-range capacity test failed causing the sufficiency test to fail automatically.

During 2020, across all areas:

- Of instances when transfers were capped because either test failed, only around 4 percent of upward failures and 9 percent of downward failures were caused entirely by failing the capacity test.
- During 46 percent of upward capacity test failures and 27 percent of downward capacity test failures, the sufficiency test failed regardless resulting in the same outcome.

During the year, EIM areas failed the sufficiency test infrequently. NV Energy failed the upward sufficiency test in around 2 percent of intervals while Arizona Public Service and Salt River Project failed in roughly 1 percent of intervals. In the downward direction, NV Energy failed the sufficiency test in around 2 percent of intervals while Arizona Public Service failed in around 1 percent of intervals. Energy imbalance market areas failed the capacity test very infrequently during the quarter. This was in large part because of the incorrect inclusion of derated or outage capacity in the test.

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156 Mirror resources are import and export schedules into or out of an EIM area to model power flow from the EIM area perspective at ISO intertie scheduling points. This allows the market to solve for both the California ISO and adjacent EIM areas simultaneously.

157 *Market Enhancements for Summer 2021 Readiness*, March 19, 2021. http://www.caiso.com/InitiativeDocuments/FinalProposal-MarketEnhancements-Summer2021Readiness.pdf .

158 *Resource Sufficiency Tests in the Energy Imbalance Market*, May 20, 2021: http://www.caiso.com/Documents/Report-on-Resource-Sufficiency-Tests-in-the-Energy-Imbalance-Market-May-20-2021.pdf.

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

Figure 3.24 Frequency of upward capacity test failures by month and area (percent of intervals)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
California ISO	—	—	—	0.1	0.2	—	—	—	—	—	—	—
BANC	—	—	—	—	—	—	0.0	0.0	—	0.1	0.0	—
NV Energy	—	—	—	0.0	0.0	—	—	—	—	0.1	0.2	—
Arizona PS	—	—	0.1	—	—	0.0	—	—	—	—	—	0.3
Salt River Project				0.2	—	—	—	—	—	0.1	0.1	—
Idaho Power	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	0.1	—
PacifiCorp West	—	0.1	—	—	—	—	—	—	—	—	0.1	—
Portland GE	—	—	—	—	—	—	—	—	—	—	—	—
Seattle City Light				—	0.1	—	0.2	0.1	—	—	—	—
Puget Sound En	—	0.1	—	—	—	—	—	—	—	—	—	—
Powerex	0.4	0.2	0.3	0.2	0.3	—	—	—	0.1	0.1	0.1	—

2020

Figure 3.25 Frequency of upward sufficiency test failures by month and area (percent of intervals)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
California ISO	—	—	—	—	—	—	0.1	1.1	0.5	0.4	0.5	—
BANC	—	0.2	—	—	—	—	—	0.2	0.0	0.1	—	0.1
NV Energy	—	0.6	0.1	0.7	2.6	2.3	4.5	7.1	2.6	1.4	0.8	—
Arizona PS	1.3	1.1	1.4	0.1	1.0	—	—	—	0.3	0.8	0.7	0.6
Salt River Project				1.8	0.1	0.5	0.7	1.8	1.1	1.7	0.9	0.3
Idaho Power	—	—	—	—	0.1	0.3	0.1	0.2	—	—	—	—
PacifiCorp East	0.0	0.0	0.1	0.0	0.2	0.1	0.2	0.2	0.1	0.5	0.0	—
PacifiCorp West	0.2	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.0	0.1
Portland GE	—	0.2	0.1	—	—	0.0	0.2	0.2	0.6	0.1	0.1	0.2
Seattle City Light				—	—	—	0.1	—	0.1	0.2	0.2	0.1
Puget Sound En	—	0.3	—	—	0.0	0.3	0.6	0.4	—	0.2	—	—
Powerex	0.4	0.2	0.1	—	0.5	0.2	0.2	0.1	0.3	0.1	0.6	0.2

2020

Figure 3.26 Frequency of downward capacity test failures by month and area (percent of intervals)

2020	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
California ISO	—	—	—	—	—	—	—	—	—	—	—	—
BANC	—	0.0	0.0	0.2	0.2	—	—	—	—	0.1	0.1	—
NV Energy	—	—	—	0.1	0.1	—	—	—	—	0.1	0.1	—
Arizona PS	—	—	0.3	0.3	0.1	—	—	—	—	0.1	0.1	—
Salt River Project				0.6	0.6	0.0	—	—	—	0.1	0.1	—
Idaho Power	—	—	—	0.1	0.1	—	—	—	—	0.1	0.1	—
PacifiCorp East	—	—	—	0.1	0.1	—	—	—	—	0.1	0.1	—
PacifiCorp West	—	—	—	0.1	0.1	—	—	—	—	0.1	0.1	—
Portland GE	—	—	—	0.1	0.1	—	—	—	—	0.1	0.1	—
Seattle City Light				0.1	0.1	—	—	—	—	0.1	0.1	—
Puget Sound En	—	—	—	0.1	0.1	—	—	—	—	0.1	0.1	—
Powerex	—	—	—	0.1	0.3	—	0.0	0.0	—	0.2	0.1	—

Figure 3.27 Frequency of downward sufficiency test failures by month and area (percent of intervals)

2020	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
California ISO	—	—	—	—	—	—	—	—	—	—	—	—
BANC	—	0.9	0.7	0.5	1.3	0.3	—	—	—	0.1	0.3	—
NV Energy	0.4	2.1	2.4	4.8	6.7	5.1	0.7	0.8	2.2	0.6	1.4	1.1
Arizona PS	3.0	1.3	2.7	0.9	0.5	2.3	0.1	—	0.1	1.9	0.9	2.5
Salt River Project				0.8	1.0	0.1	—	0.0	0.1	0.1	0.2	0.8
Idaho Power	—	0.1	0.2	—	0.7	—	0.0	—	—	0.0	0.0	—
PacifiCorp East	—	—	—	—	0.1	—	—	—	—	—	—	—
PacifiCorp West	—	—	—	—	—	—	—	—	—	—	—	—
Portland GE	0.1	—	—	—	0.2	0.1	—	—	—	—	—	—
Seattle City Light				0.5	—	—	0.1	0.2	0.2	0.2	0.1	0.1
Puget Sound En	—	—	—	—	0.5	0.8	0.1	—	—	—	—	—
Powerex	0.2	0.4	0.0	—	0.1	—	0.0	0.1	0.1	0.2	—	—

3.6 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 market, and prevents market infeasibilities that may arise without the availability of this capacity.[160]

Table 3.4 summarizes the quarterly frequency of upward and downward available balancing capacity offered and scheduled in each area during 2020.[161] Powerex, NV Energy, and BANC offered upward and downward balancing capacity during almost all hours. Table 3.4 also shows the average magnitude of the available balancing capacity when offered in their hourly resource plan. In particular, Powerex on average offered roughly 1,150 MW and 600 MW of upward and downward available balancing capacity during 2020.

The frequency of upward available balancing capacity offered by Portland General Electric and Arizona Public Service each increased significantly to around 97 percent of hours, up from around 47 percent of hours from the previous year. Upward and downward available balancing capacity offered by Puget Sound Energy decreased during the year, from around 99 percent of hours prior to June to less than 1 percent of hours in the second half of the year.

PacifiCorp East, PacifiCorp West, and Seattle City Light offered available balancing capacity in either direction infrequently, during less than 20 percent of hours during 2020. Idaho Power 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 2020. 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.

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160 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

161 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 is omitted from this table.

Table 3.4 Frequency of available balancing capacity offered and scheduled (2020)

	Offered		Scheduled	
	Percent of hours	Average MW	Percent of intervals (15-minute market)	Percent of intervals (5-minute market)
Upward ABC				
Powerex	100%	1,148	0.0%	0.1%
NV Energy	100%	53	1.6%	1.8%
BANC	100%	43	0.0%	0.1%
Portland General Electric	98%	30	0.0%	0.1%
Arizona Public Service	96%	103	0.2%	0.3%
Salt River Project*	93%	91	0.3%	0.6%
Puget Sound Energy	43%	35	0.0%	0.0%
Seattle City Light*	17%	20	0.0%	0.0%
PacifiCorp West	14%	99	0.0%	0.0%
PacifiCorp East	14%	80	0.0%	0.0%
Idaho Power	0%	N/A	0.0%	0.0%
Downward ABC				
Powerex	100%	-600	0.0%	0.1%
NV Energy	100%	-53	0.5%	0.8%
BANC	99%	-51	0.1%	0.1%
Portland General Electric	0%	-25	0.0%	0.0%
Arizona Public Service	95%	-59	0.3%	0.3%
Salt River Project*	91%	-47	0.1%	0.2%
Puget Sound Energy	43%	-45	0.0%	0.0%
Seattle City Light*	14%	-14	0.0%	0.0%
PacifiCorp West	7%	-54	0.0%	0.0%
PacifiCorp East	12%	-91	0.0%	0.0%
Idaho Power	0%	N/A	0.0%	0.0%

*April 1 to December 31, 2020, only

4 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 profits paid to convergence bidders totaled around $45 million**, an increase from about $37 million in 2019, after accounting for about $12 million in bid cost recovery charges allocated to virtual bids. Net profits before accounting for these charges rose to $57 million, the highest amount since 2012. This increase reflects both the profitability of virtual demand, particularly in the third quarter, and overall virtual supply bids with sustained day-ahead prices greater than real-time prices over much of the year.
- **Virtual supply exceeded virtual demand by an average of about 560 MW per hour**, compared to 660 MW in 2019. The percent of cleared virtual supply and demand was around 32 percent, a slight increase from about 29 percent in 2019.
- **Most profits from virtual bidding continue to be received by financial entities and marketers,** who received 72 percent and 26 percent of net revenues, respectively. Physical generators and load serving entities received about 2 percent of net virtual bidding 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* since it is intended to help decrease differences in day-ahead and real-time prices. 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.[162] 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.[163]

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.[164] In late September 2015, FERC issued an order requiring the ISO to remove tariff provisions that provided for reinstatement of convergence bids at interties.[165]

162 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.

163 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

164 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

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

4.1 Convergence bidding trends

In 2020 convergence bidding volumes decreased over 2019, with net cleared volumes of virtual supply slightly outweighing virtual demand for all quarters. This continues a trend of cleared virtual supply outweighing cleared virtual demand for all quarters since 2014. Figure 4.1 shows the quantities of both virtual supply and demand offered and cleared in the market. Figure 4.2 shows the average net cleared virtual positions for each operating hour.

Key convergence bidding trends include the following:

- On average, 32 percent of virtual supply and demand bids offered into the market cleared in 2020, compared to 29 percent in 2019.
- The average hourly cleared volume of virtual supply exceeded virtual demand for all quarters by about 560 MW per hour, a decrease from about 660 MW per hour the prior year.
- Average hourly cleared virtual supply was about 2,000 MW in 2020, compared to 2,160 MW in 2019. Average hourly cleared virtual demand remained stable at about 1,500 MW for the last two years.

Figure 4.1 Quarterly average virtual bids offered and cleared

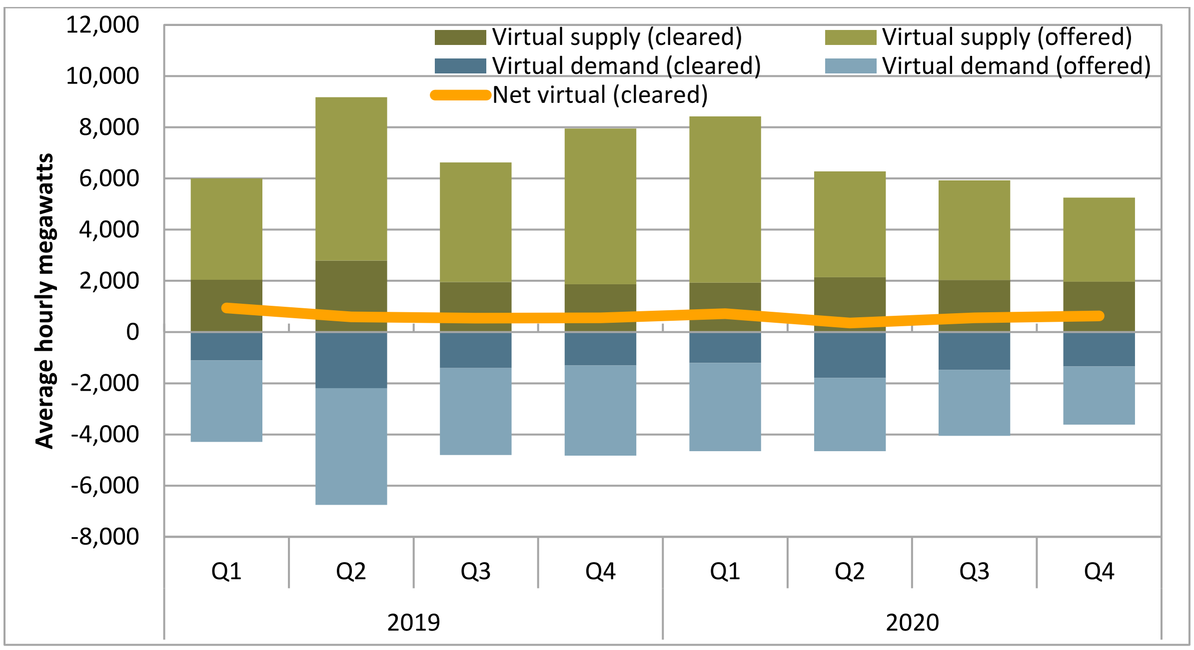
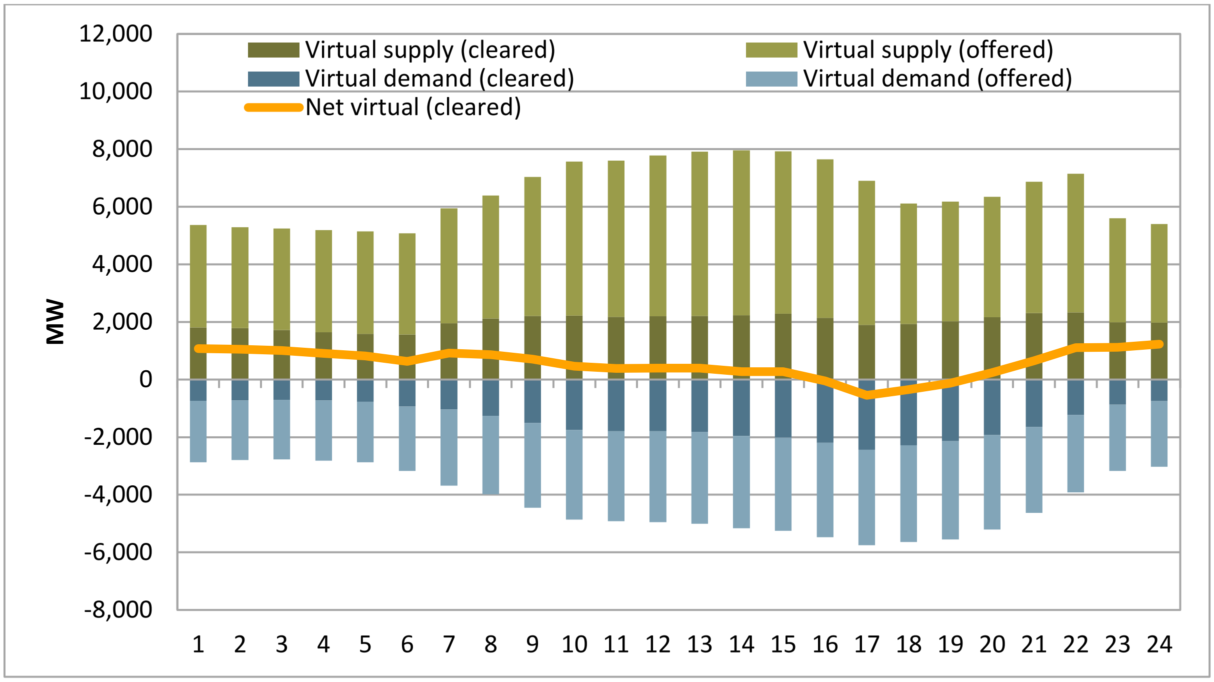


Figure 4.2 Average net cleared virtual bids in 2020



- Net virtual supply volumes were highest during the second quarter of the year when virtual supply exceeded virtual demand by around 350 MW per hour on average, a decrease from about 460 MW for the same period in 2019.
- Financial participants held about 72 percent of cleared virtual positions in 2020, continuing a multi-year trend, a slight increase from 70 percent in 2019. As with the previous year, financial participants bid more virtual supply than demand, which contributed to the increase in net virtual supply.
- Net virtual supply was negative during the evening peak hours 17 through 19; for all other hours, virtual supply outweighed virtual demand.

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 870 MW of virtual demand offset by 870 MW of virtual supply during each hour in 2020, an increase from about 790 MW in 2019. The share of these offsetting bids totaled about 50 percent of all cleared virtual bids in 2020, up slightly from about 48 percent in 2019. Offsetting bids made up 43 percent of cleared virtual supply and 60 percent of cleared virtual demand during 2020.

Consistency of price differences and volumes

Convergence bidding was 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. Similar to prior years, net convergence bidding volumes were generally less consistent with price differences between the day-ahead and real-time markets on average. Particularly, this can be seen, on average, with consistent virtual supply profitability punctuated by a relatively few instances of highly unprofitable days and hours which were inversely highly profitable for virtual demand.

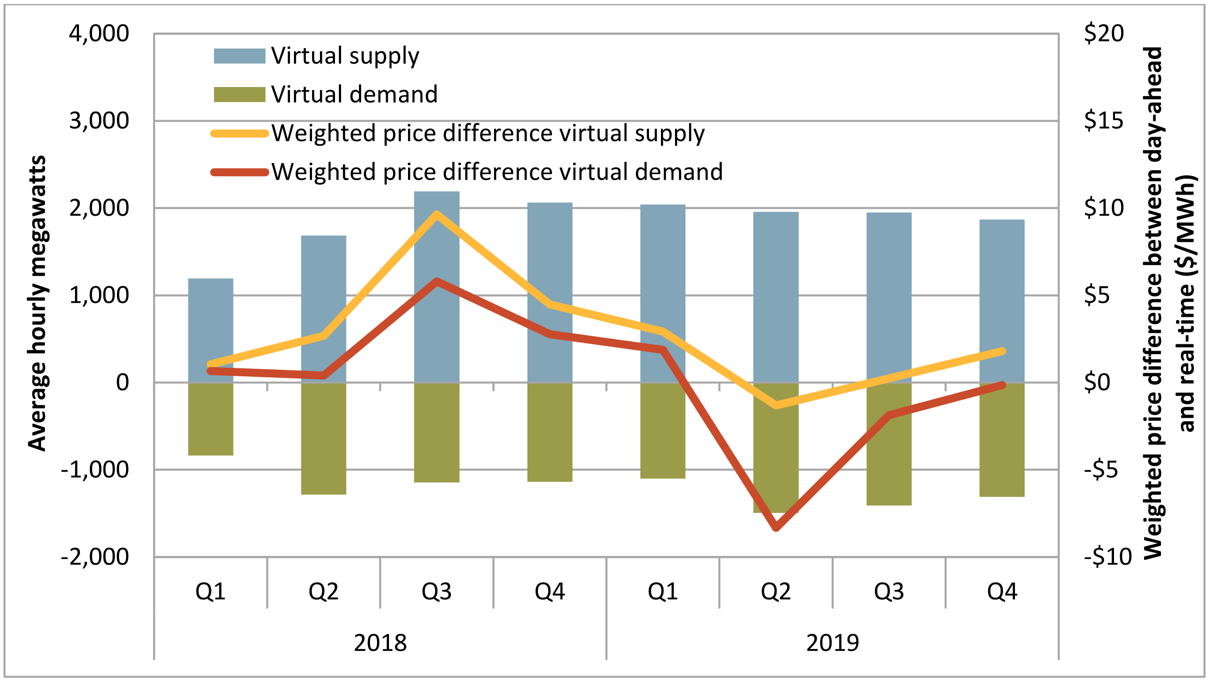
Figure 4.3 compares cleared convergence bidding volumes with the volume-weighted average price differences at which these virtual bids were settled. The difference between day-ahead and real-time prices shown in this figure represents the average price difference weighted by the amount of virtual bids 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 2020, virtual demand positions were profitable in all but the first quarter.

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 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. Virtual supply was profitable in all quarters of 2020. As shown in Figure 4.3, virtual supply and virtual demand bid volumes were generally consistent throughout the year.

Figure 4.3 Convergence bidding volumes and weighted price differences



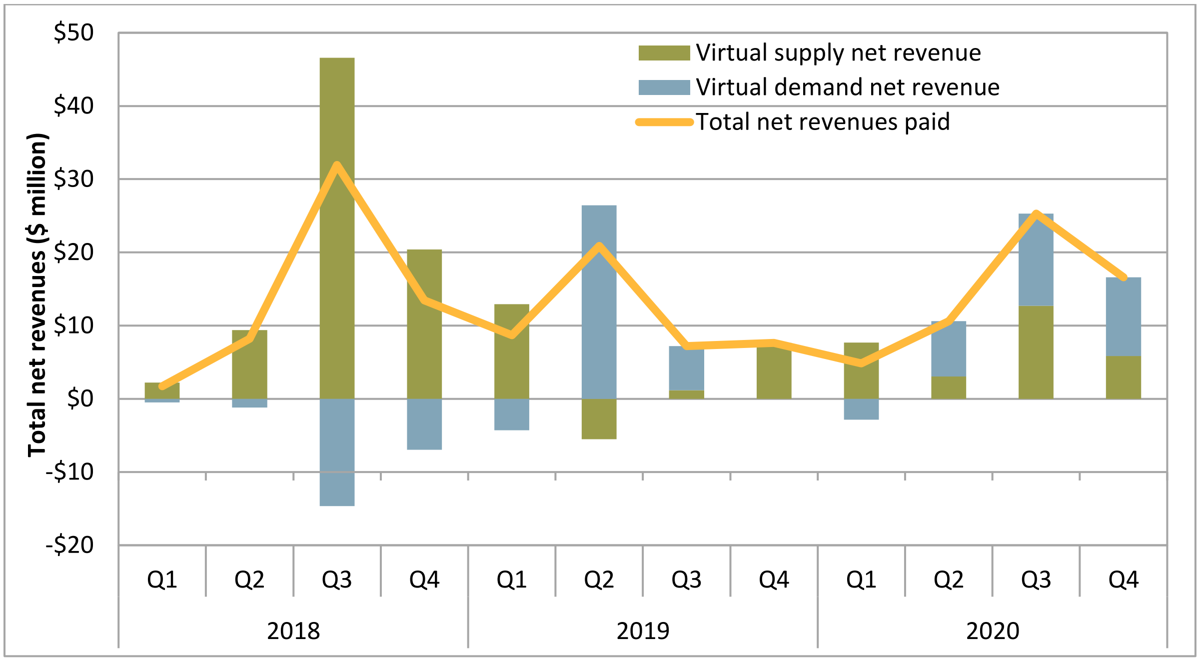
4.2 Convergence bidding payments

Net profits paid to virtual bidders (prior to any allocation of bid cost recovery payments) totaled about $57 million in 2020, an increase of about $13 million or about 29 percent from 2019. Similar to the prior year, day-ahead energy prices were consistently higher than in the real-time market, but there were a number of large real-time price spikes when virtual demand bids were highly profitable, particularly in May, July, September and October.

Figure 4.4 shows total quarterly net profits paid for accepted virtual supply and demand bids. As shown in Figure 4.4:

- Total net profits ($57 million) were paid to both cleared virtual supply and virtual demand, with about 51 percent of profits from virtual supply and 49 percent from virtual demand. In the previous year nearly two-thirds of total net profits were attributed to cleared virtual demand.
- Virtual supply positions were profitable in all quarters, totaling about $29 million for the year. This was primarily driven by sustained average day-ahead market prices higher than real-time market prices.
- Virtual demand positions were profitable in all but the first quarter, with relatively consistent net revenues in all other quarters, totaling about $32 million for the year. This is primarily the result of a few large positive price differences between the real-time and day-ahead markets.
- Total net revenues for virtual bidders peaked in the third quarter at about $25 million. Net revenues were positive in all quarters.

Figure 4.4 Total quarterly net revenues from convergence bidding



Net revenues and volumes by participant type

Most convergence bidding is typically conducted by entities engaging in purely financial trading that do not serve load or transact physical supply. These entities accounted for just under $57 million of the total convergence bidding revenues in 2020.

Table 4.1 compares the distribution of convergence bidding volumes and profits for different groups of convergence bidding participants. The trading volumes show cleared virtual positions along with the corresponding profits in millions of dollars.

Table 4.1 Convergence bidding volumes and revenues by participant type (2020)

Trading entities	Average hourly megawatts			Revenues\Losses ($ million)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	1,028	1,399	2,427	$17.7	$23.6	$41.2
Marketer	391	543	934	$9.8	$5.4	$15.2
Physical generation	24	1	25	$0.6	$0.0	$0.7
Physical load	0	24	24	$0.0	$0.3	$0.3
Total	**1,443**	**1,967**	**3,410**	**$28.1**	**$29.2**	**$57.3**

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 4.1, financial participants represent the largest segment of the virtual bidders, accounting for about 71 percent of cleared volume and about 72 percent of profits. Marketers represent about 27 and 26 percent of volume and profit, respectively. Load serving entities and generation owners account for the smallest share of both total revenues and volume at about 1.5 percent, respectively.

Table 4.1 shows that most participant types held significantly more virtual supply than virtual demand, similar to the prior year. However, total revenues for virtual supply increased to just under $30 million, compared to about $16 million the previous year.

Bid cost recovery charges to virtual bids

Virtual bids can influence unit commitment and therefore they share in associated costs. Specifically, virtual bids can be charged for bid cost recovery payments under two charge codes.[166]

- Integrated forward market bid cost recovery tier 1 allocation addresses costs associated with situations when the market clears with positive net virtual demand.[167] 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.[168] In this case, virtual supply leads to decreased unit commitment in the day-ahead market and increased unit commitment in the residual unit commitment, which may not be economic.

Figure 4.5 shows estimated total virtual bidding profit before and after bid cost recovery charges. Total convergence bidding bid cost recovery costs for the year were about $12.3 million, an increase from around $7.8 million in 2019. As noted earlier, the total estimated profits for convergence bidding in 2020 were around $57.4 million before accounting for these charges. After subtracting bid cost recovery costs allocated to virtual bids, net virtual bidding profits totaled about $44.6 million. This is a slight increase compared to about $36.7 million in net virtual bidding profits in 2019.

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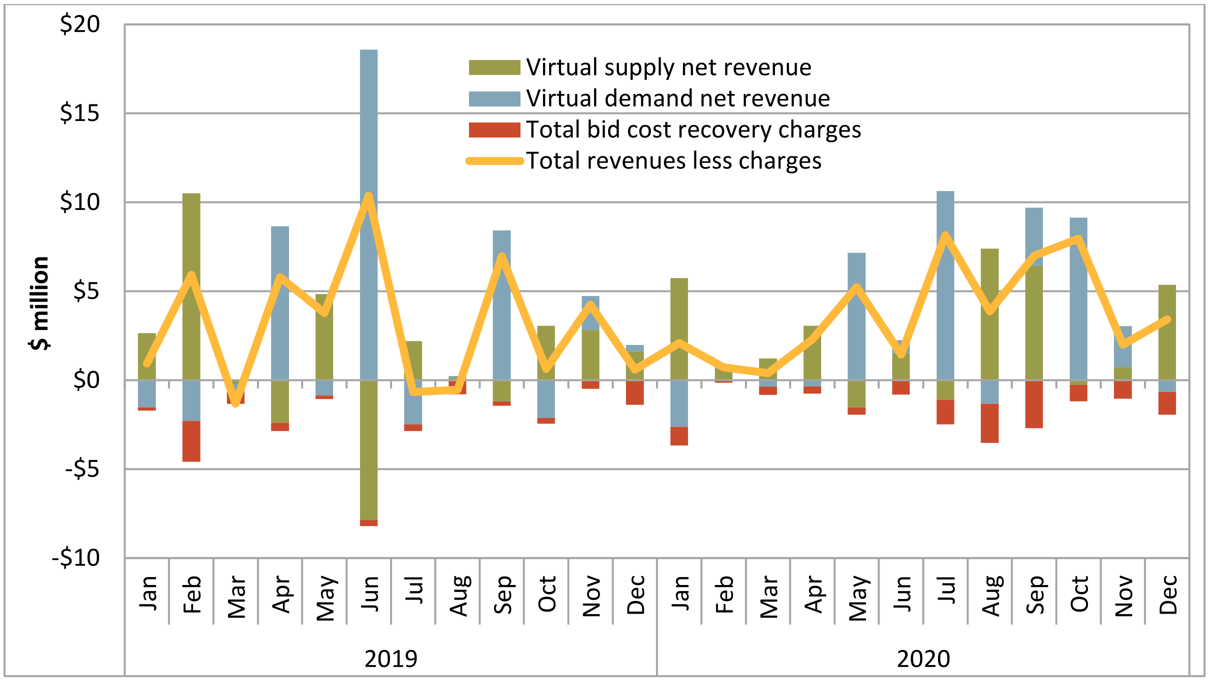
166 As previously noted, virtual supply and demand bids are treated similarly to physical supply and demand in the day-ahead market. However, virtual bids are excluded from the residual unit commitment process, which ensures sufficient capacity bids into the real-time market. When the ISO commits units in the residual unit commitment process, 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. Both charge codes are calculated by hour and charged on a daily basis.

167 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

168 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

Figure 4.5 Convergence bidding revenues and costs associated with bid cost recovery tier 1 and RUC tier 1



5 Ancillary services

This chapter provides a summary of the ancillary service market in 2020. Key trends highlighted in this chapter include the following:

- **Ancillary service costs increased to $199 million**, up from $148 million in 2019.
- **Regulation and operating reserve requirements increased**. Regulation down requirements increased 22 percent to 520 MW and regulation up requirements increased 12 percent to 390 MW, relative to 2019. Average combined requirements for spinning and non-spinning operating reserves also increased by 12 percent from the previous year to about 1,800 MW.
- **Provision of ancillary services from limited energy storage resources continued to increase**. Limited energy storage resources include batteries and other limited devices. Average hourly procurement from these resources for regulation increased from around 166 MW in 2019 to 191 MW in 2020, or around 21 percent of regulation requirements.
- **The frequency of ancillary service scarcity intervals decreased**. There were 129 intervals in the 15-minute market with ancillary service scarcity, compared to almost 200 scarcity instances in the previous year. The number of regulation scarcities decreased substantially. However, the number of non-spin scarcities increased from 2019 to 2020, particularly in August and September when the ISO faced very tight conditions.
- **Thirty percent of resources failed** ancillary service performance audits and unannounced compliance tests for spinning and non-spinning reserves in 2020, compared to 20 percent the previous year.
- **Five percent of resources failed performance audits for regulation.** In 2020, there were 181 performance audits for regulation with one failure resulting in a disqualification because of a successive failure.

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.[169]

5.1 Ancillary service costs

Costs for ancillary services totaled about $199 million in 2020. This is a significant increase from 2019 where total ancillary services were about $148 million, but similar to 2018 when ancillary costs were $177 million.

The costs reported in this section have been refined to account for rescinded ancillary service payments. Payments are rescinded when resources providing ancillary services do not fulfill the availability

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169 *2010 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2011, pp. 139-142: http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf

requirement associated with the awards. During 2020, about 7 percent of payments for ancillary service awards were rescinded.

Figure 5.1 shows ancillary service costs both as percentage of wholesale energy costs and per megawatt-hour of load from 2018 to 2020. Following a decrease in ancillary service costs in 2019, the cost per megawatt-hour increased to $0.95 in 2020. Ancillary service costs as a percent of energy cost increased substantially in 2020 to over 2.2 percent.

Figure 5.2 shows the total cost of producing ancillary service products by quarter and the total ancillary service cost for each megawatt-hour of load served. Similar to 2018, ancillary service costs were highest in the third quarter.

Payments increased for both regulation and operating reserves from 2019 to 2020, however the increase in operating reserves was much more pronounced. While payments for regulation up and down increased 10 percent to $98 million, payments for spinning and non-spinning reserves increased 70 percent to over $100 million. This increase was due in large part by the increase in payments for non-spin which increased from $6 million in 2019 to over $26 million in 2020.

Figure 5.1 Ancillary service cost as a percentage of wholesale energy costs (2018-2020)

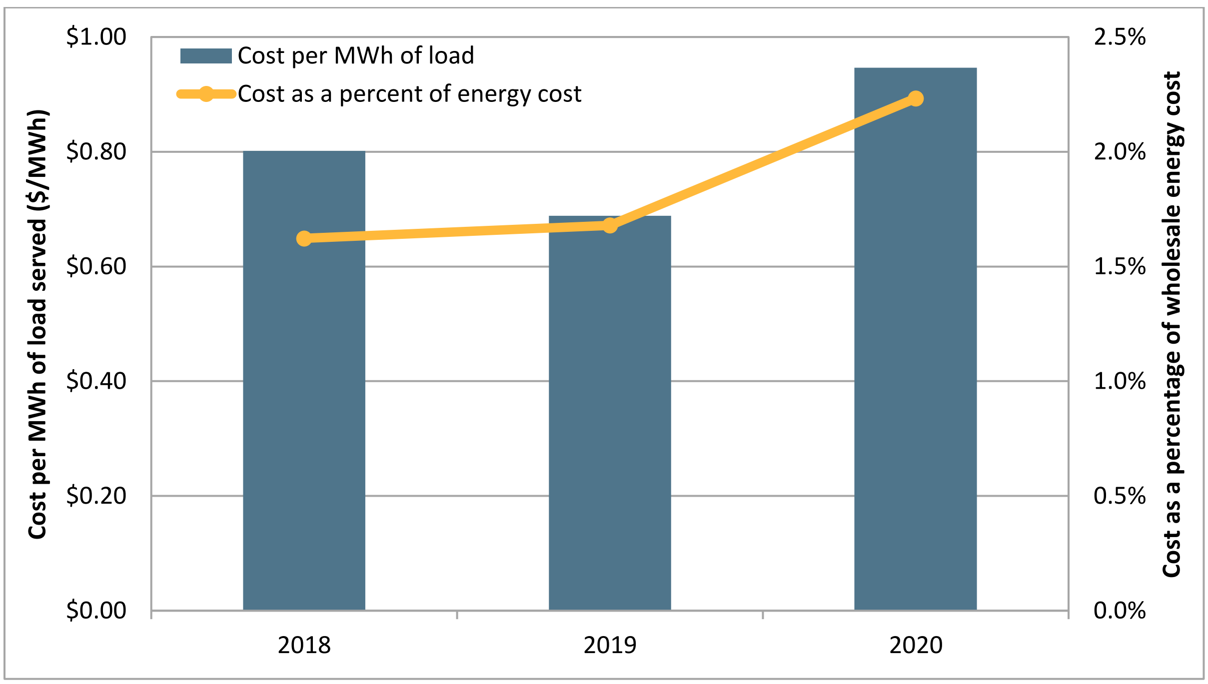
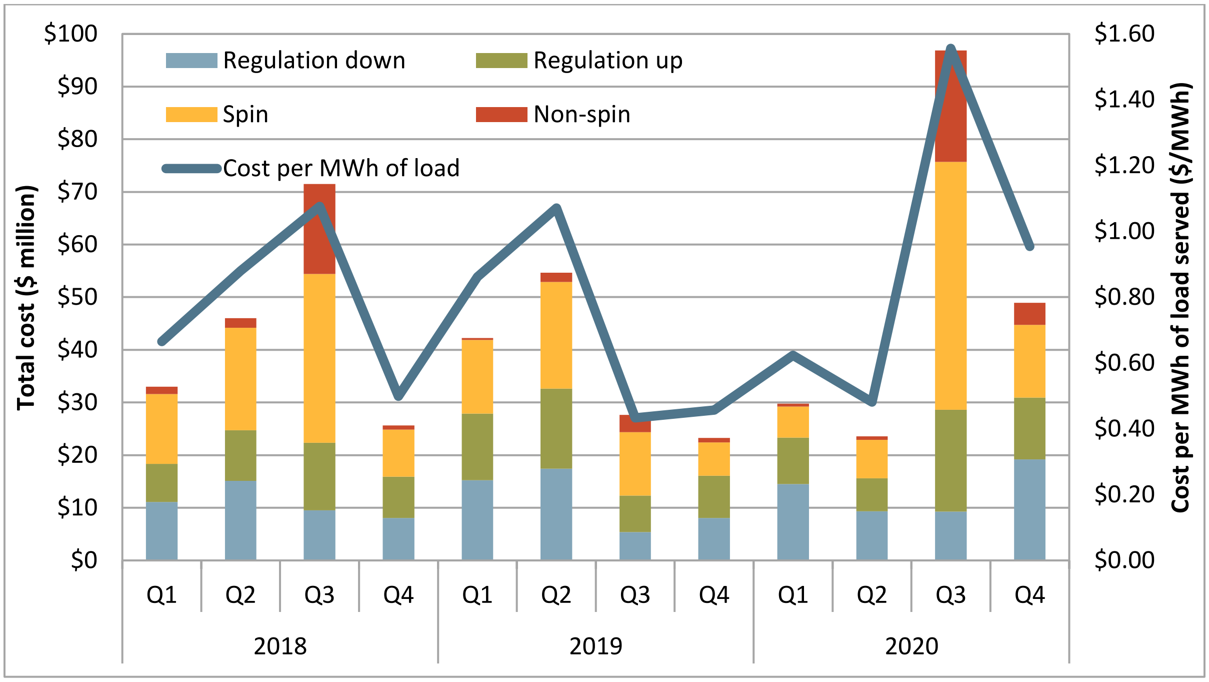


Figure 5.2 Total ancillary service cost by quarter and type



5.2 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.[170] 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.

Six of these regions are typically utilized: expanded system (or expanded ISO), internal system, expanded South of Path 26, internal South of Path 26, expanded North of Path 26, and internal North of Path 26.

[170] 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.

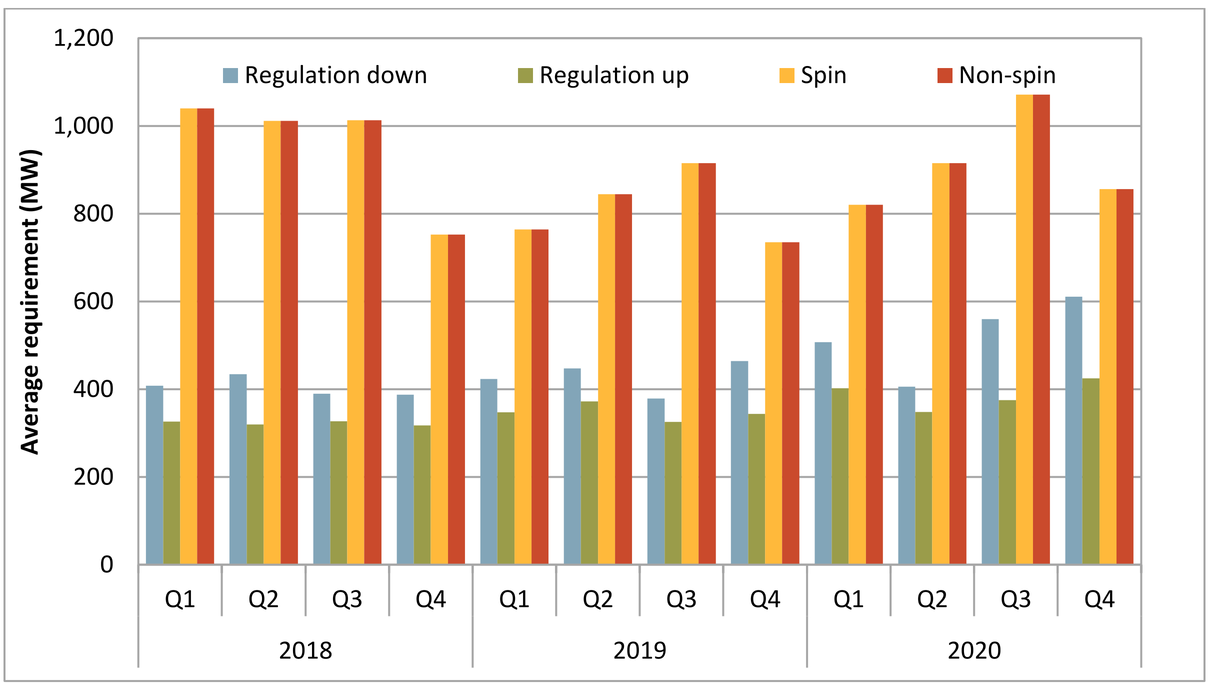
Operating reserve requirements

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.[171] 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 requirements in BAL-002-2, effective January 1, 2018, that required the ISO to reevaluate the most severe single contingency.[172] 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, 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 5.3 includes quarterly average day-ahead operating reserve requirements since 2018. Operating reserve requirements in the day-ahead market averaged about 1,800 MW in 2020, a 12 percent increase from last year.

Figure 5.3 Quarterly average day-ahead ancillary service requirements



171 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.

172 Further information on the NERC BAL-002-2 reliability standard is available here: http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-2.pdf

Regulation requirements

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 5.3 also shows average regulation requirements by quarter. During 2020, day-ahead requirements averaged around 520 MW for regulation down and 390 MW for regulation up, an increase from regulation requirements in 2019.

Figure 5.4 summarizes the average hourly profile of the day-ahead regulation requirements in 2020. Requirements for regulation down were higher than requirements for regulation up. Regulation up requirements are highest during midday hours, particularly in the early evening. Requirements for regulation down were highest from hour ending 8 to 21, particularly in the morning and evening hours where solar is either ramping on or off.

Figure 5.4 Hourly average day-ahead regulation requirements (2020)

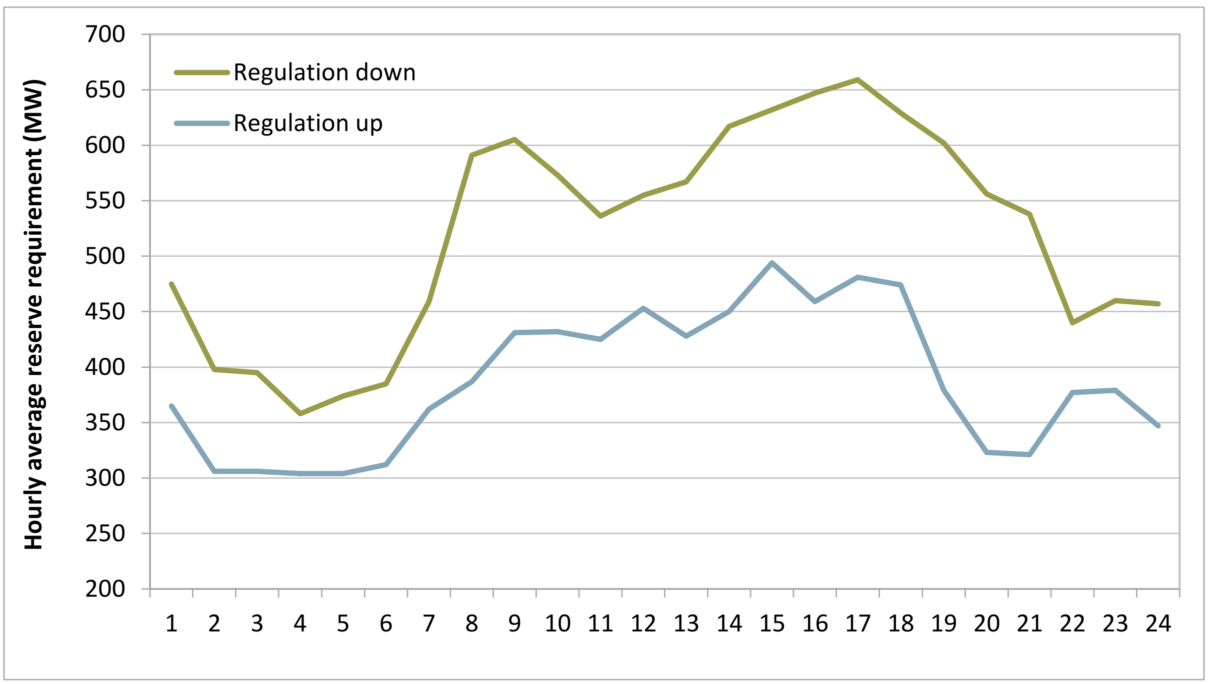
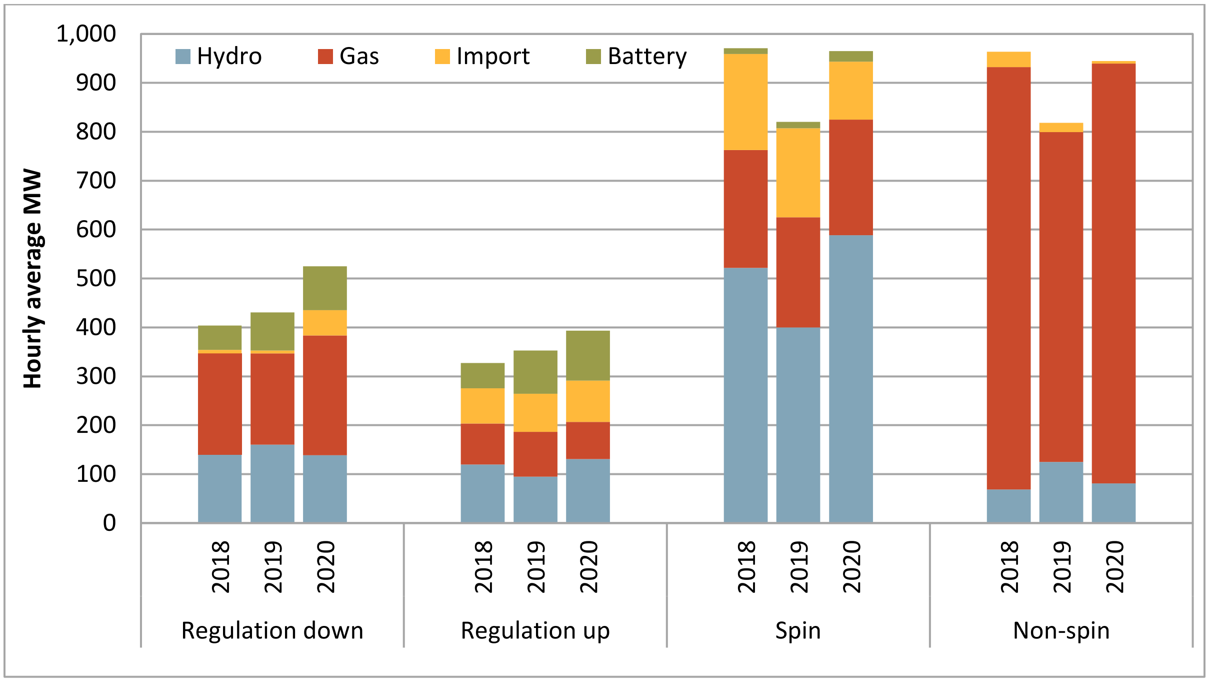


Figure 5.5 Procurement by internal resources and imports



Ancillary service procurement by fuel

Figure 5.5 shows the portion of ancillary services procured by fuel type from 2018 through 2020. Ancillary service requirements are met by both internal resource and imports (tie generation). 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 2020 increased 17 percent compared to 2019. This increase was met by an increase in procurement from gas resources (15 percent increase), batteries (15 percent) and imports (61 percent). Although there was an increase in imports used for regulation services, the average hourly procurement of all ancillary services from imports continued to decrease, from around 285 MW in 2019 to 260 MW this year.

The trend of ancillary service procurement has been similar the past three years, with an increasing share provided by batteries and less from imports. Average hourly procurement of ancillary services served by battery resource has been steadily increasing the past three years, growing from 113 MW in 2018 to 212 MW in 2020. The supply of batteries increased for each of the four types of ancillary services, especially spinning reserves where the average hourly procurement of batteries increased 62 percent.

As batteries have been increasing, the hourly average total procurement served by imports has been decreasing (7 percent decrease in 2019 and 9 percent decrease in 2020). The amount of spin and non-spin reserves served by imports decreased, while the average regulation served by imports increased.

Particularly there was a substantial increase the procurement of imports for regulation down, increasing from 6 MW in 2019 to 52 MW in 2020.

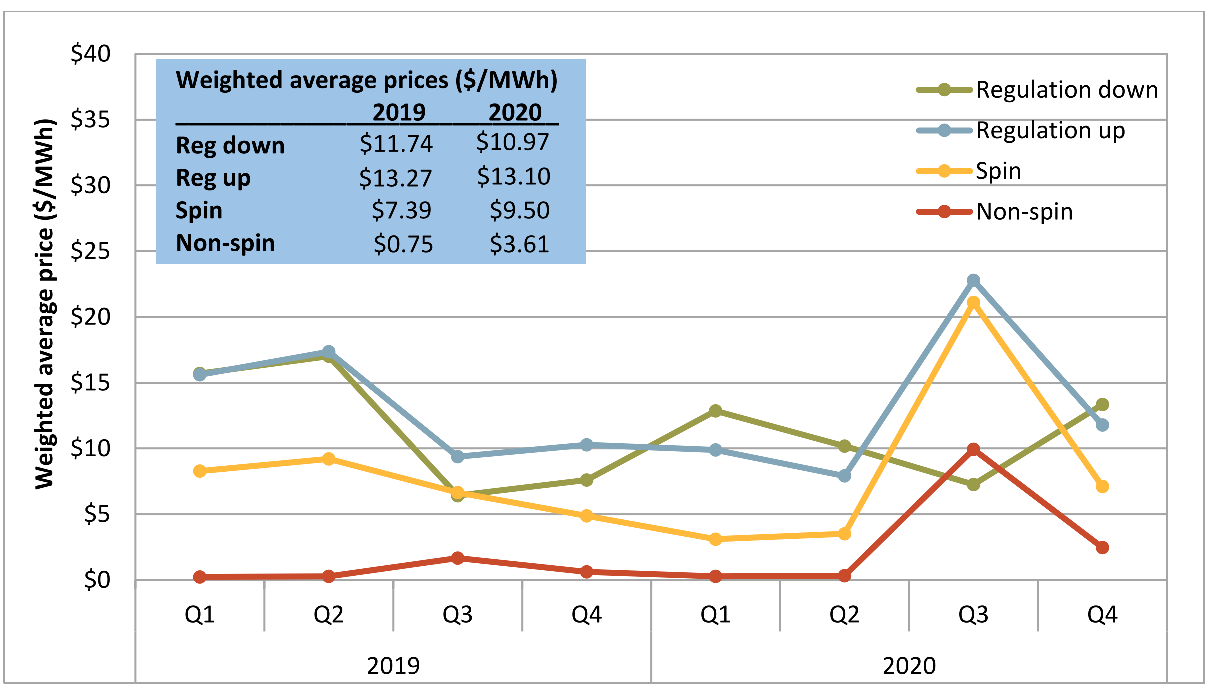
5.3 Ancillary service pricing

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 5.6 and Figure 5.7 show the weighted average market clearing prices for each ancillary service product by quarter in the day-ahead and real-time markets during 2019 and 2020, weighted by the quantity settled.[173]

As shown in Figure 5.6, weighted average day-ahead prices for spinning and non-spinning reserves increased from 2019 to 2020, especially the prices for non-spin. This is consistent with the increase in operating reserve requirements, particularly in the third and fourth quarter of 2020. Weighted average day-ahead prices for regulation up and down decreased slightly even though there was an increase in requirements.

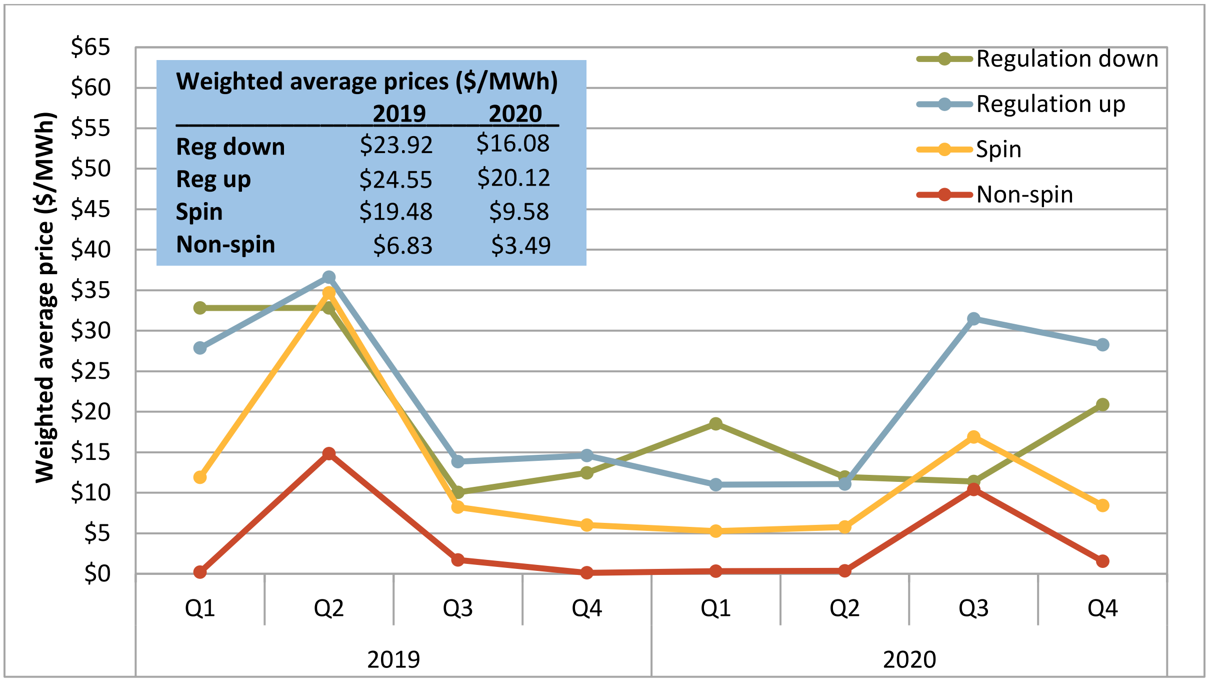
As shown in Figure 5.7, weighted average real-time prices for ancillary services decreased for both regulation and operating reserves. Prices for operating reserves in 2020 were roughly half of what they were in 2019, while the decline in prices for regulation was less extreme. However, overall real-time costs for ancillary services continued to be very low relative to day-ahead costs as only incremental real-time awards are settled at the 15-minute market price. As a result, real-time ancillary service costs accounted for only 9 percent of total costs during the year.

Figure 5.6 Day-ahead ancillary service market clearing prices



[173] Values reported here differ slightly from the previous year due to an update in the data source.

Figure 5.7 Real-time ancillary service market clearing prices



5.4 Special issues

5.4.1 Ancillary service scarcity

Ancillary service scarcity pricing occurs when there is insufficient supply to meet reserve requirements. Under the ancillary service scarcity price mechanism, 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.

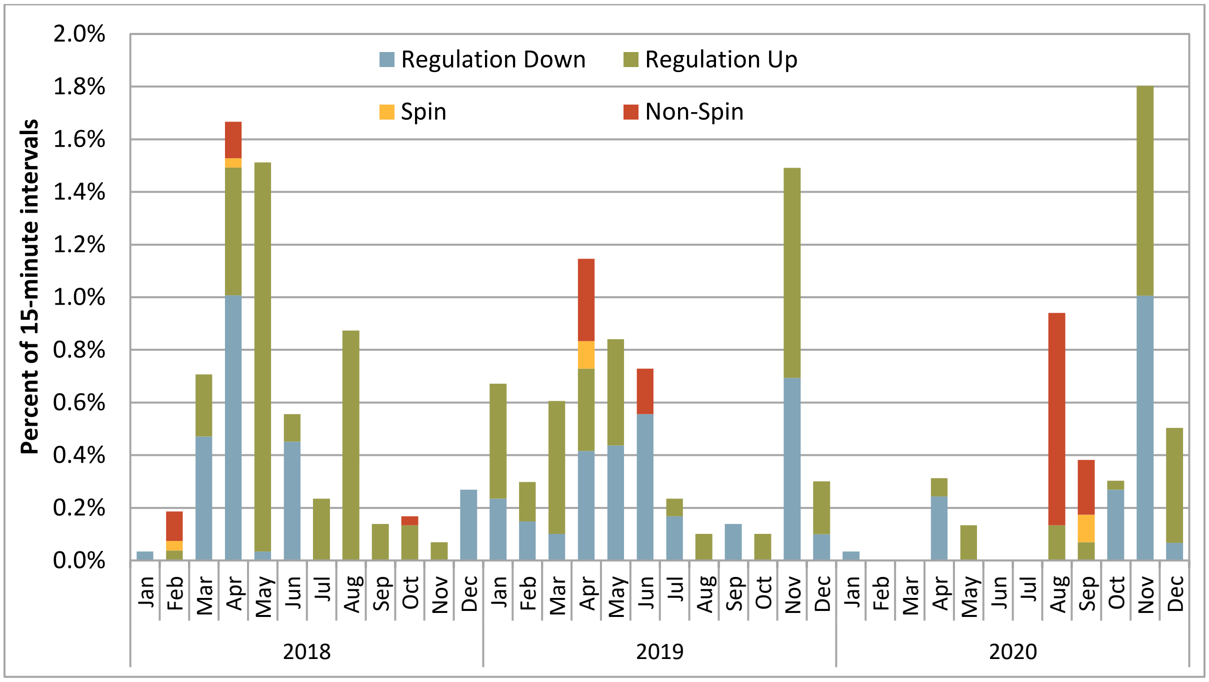
Figure 5.8 shows the monthly frequency of ancillary service scarcities in the 15-minute market by type. Similar to the previous year, there were no day-ahead market ancillary service scarcities during 2020. However, there were 129 valid scarcity intervals in the 15-minute market, which is lower than 2019 when there were almost 200 scarcity instances. The number of regulation scarcities decreased substantially, particularly in the first two quarters. Scarcities in regulation are most common during period of high variability in loads (spring and winter), and in 2020 there were significantly fewer regulation scarcities in the spring than in 2019 suggesting less variability in 2020 could have led to fewer scarcity issues. From Figure 5.8, we see that the number of non-spin scarcities increased from 2019 to 2020, particularly in August and September when the ISO faced very tight conditions.

Most of the ancillary services scarcities in 2020 were small, with around 67.4 percent under 5 MW. This is because ancillary services scheduled in the day-ahead market can be capped in real-time at the telemetry limits submitted by the plant.[174] This type of scarcity can occur with battery resources which

[174] More detailed description in 2019 Annual Report, page 171: http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf

have been increasingly used to support ancillary services. The majority of scarcities due to telemetry limits on batteries occurred during May and November of 2020.[175] By region, around 78 percent of scarcity events occurred in the expanded South of Path 26 region, 17 percent in the expanded system region, and 5 percent in the North of Path 26 region.

Figure 5.8 Frequency of ancillary service scarcities (15-minute market)



5.4.2 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. Failing a second test while a warning is in effect will immediately disqualify the resource from providing the concerned ancillary service. In addition, payments that were made to the resource for the impacted ancillary service will be rescinded.[176]

During 2020, the ISO performed a total of 257 performance audits and unannounced compliance tests for resources with spinning or non-spinning reserves, a drastic increase from the 163 tests performed in 2019. Some of this increase may be due to the increased need for contingency reserves during tight conditions this past summer, with almost 70 percent of the performance audits taking place in August and September. The failure rate increased this year from 20 percent in 2019 to around 30 percent in

175 Market Performance Planning Forum Dec 2015: http://www.caiso.com/Documents/Presentation-MarketPerformance-PlanningForum-Dec15-2020.pdf

176 For more information about the ISO's ancillary service testing procedures including updates to regulation performance audits, see Operating Procedure 5370: http://www.caiso.com/Documents/5370.pdf

2020. There were 11 failures for spinning and non-spinning reserves which 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.

The ISO adopted a new monthly process for performance audits of regulation, starting in February 2020. A resource providing regulation must pass at least 90 percent of qualifying tests in a month to pass, where each individual test requires the unit to reach an output threshold within the test period. Failing the monthly performance audit results in a warning. Failing a second test while a warning is in effect will immediately decertify the resource from providing the ancillary service. In 2020, there were 181 performance audits for regulation with a failure rate of roughly 5 percent. One failure resulted in disqualification of the unit.

6 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:

- **Overall prices in the ISO energy markets in 2020 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.[177]
- **The day-ahead energy market**, which accounts for most of the total wholesale market, **was structurally uncompetitive in more hours than in any of the last 5 years, but remained competitive during most hours in 2020.** Low hydroelectric availability and extreme summer loads in 2020 contributed to an increase in potentially non-competitive hours relative to previous years.
- **The market for capacity needed to meet local resource adequacy requirements was structurally uncompetitive in all local areas.** In the day-ahead and real-time energy markets, the potential for local market power is mitigated through bid mitigation procedures.
- **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 2020.
- **In the ISO, rates of both day-ahead and real-time mitigation increased.** The percent of constraints identified as non-competitive also increased relative to 2019 due to an increase in concentration of generation in the portfolios of net sellers and load in the portfolios of net buyers.
- **The ISO implemented an enhancement eliminating carryover mitigation in the real-time market in November 2019.** Following this, rates of mitigation fell in the Western EIM.
- **As rates of mitigation increased, more day-ahead bids were lowered due to mitigation** than in 2019. Most resources subject to mitigation submitted competitive offer prices, so that a low portion of bids were lowered as a result of the bid mitigation process; bids for an average of about 331 MW were changed in 2020 compared to 170 MW in 2019.
- **Capacity with bids lowered by mitigation in the 15-minute market also remained low**, averaging 95 MW per hour in the ISO and 90 MW per hour in the EIM. In the 5-minute market, capacity with bids lowered by mitigation averaged 238 MW per hour in the ISO and 90 MW in the EIM.
- **Local market power mitigation of exceptional dispatches for energy played a significant role** in limiting above-market costs in 2020, reducing above-market costs by about $5.5 million.
- **ISO operators continue to issue "RA Max" exceptional dispatches** to the maximum of resource adequacy contracts. These exceptional dispatches are issued to increase ramping capacity to meet the evening net load ramp and respond to real-time uncertainties, the issues that the flexible ramping product is designed to address. DMM recommended that the ISO change market rules so that RA Max exceptional dispatches are subject to bid mitigation, because there is a strong potential for suppliers to exercise market power and raise bids substantially over marginal cost.

[177] Further information on DMM's estimation of overall market competitiveness is available in Section 2.2.

6.1 Structural measures of competitiveness

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

- **Pivotal supplier test.** If supply is insufficient to meet demand with the supply of any individual supplier removed, then this supplier is pivotal. This is referred to as a single pivotal supplier test. The two-pivotal supplier test is performed by removing supply owned or controlled by the two largest suppliers. For the three-pivotal test, supply of the three largest suppliers is removed.

- **Residual supply index.** The residual supply index is the ratio of supply from non-pivotal suppliers to demand.[178] A residual supply index less than 1.0 indicates an uncompetitive level of supply.

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

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

6.1.1 Day-ahead system energy

The residual supply index analysis includes the following elements for accounting for supply and demand:

- Use of day-ahead input bids for physical generating resources (adjusted for outages and de-rates);

- Transmission losses were not explicitly added to demand. The day-ahead load forecast already factors in losses. This reflects a change from prior annual reports;

- Including self-scheduled exports as demand (combined with the day-ahead load forecast plus upward ancillary service requirements);

- Including ancillary services bids in excess of energy bids to account for this additional supply available to meet ancillary service requirements in the day-ahead market;

- Exclusion of CPUC jurisdictional investor-owned utilities as potentially pivotal suppliers;

- Accounting for the maximum availability of non-pivotal imports offered relative to import transmission constraint limits; and

- As in prior DMM analyses, virtual bids are excluded.

178 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.

During 2020, DMM observed more hours with an RSI less than one relative to any of the previous four years. Table 6.1 shows the annual number of hours with a residual supply index ratio less than one since 2016, based on the assumptions listed above. Figure 6.1 shows the same information graphically by quarter. During 2020, the number of hours with an RSI less than one increased significantly. For 2020, the residual supply index with the three largest suppliers removed (RSI_3) was less than one during 475 hours, and the index was less than one during 303 hours with the two largest suppliers removed (RSI_2). With the largest single supplier removed (RSI_1), there were 111 hours in 2020 with the index less than one. Low hydroelectric availability and extreme summer loads in 2020 were factors that contributed to an increase in potentially non-competitive hours relative to previous years.

2020 was less structurally competitive relative to the previous three years. Figure 6.2 shows the lowest 500 RSI_3 values for each year. During 2020, with the three largest suppliers removed, the RSI_3 was less than 0.9 in 216 hours, less than 0.8 in 57 hours, and less than 0.7 in 5 hours. At its lowest, the RSI_3 was around 0.67 in 2020, compared to around 0.87 in 2019, 0.75 in 2018, and 0.79 in 2017.

It is important to distinguish between scarcity conditions and non-competitive conditions. Scarcity conditions occur when calculated supply, prior to the removal of the largest supplier(s), is less than demand. Figure 6.3 plots each hour by its reserve margin (using the same assumptions as the residual supply index analysis except with no suppliers removed) against the day-ahead market system marginal energy cost. In 2020 there were 22 scarcity hours where the reserve margin was less than 100 percent. To demonstrate the distinction between scarcity hours and non-competitive conditions, Figure 6.3 also depicts the reserve margins (before removing pivotal suppliers) for hours that fail the one-, two-, and three-pivotal supplier test. Here, the chart shows a significant number of hours where the reserve margin is greater than 100 percent, but would be in a deficit with the largest pivotal supplier(s) removed, highlighting that there are many more non-competitive hours than the 22 scarcity hours.

Table 6.1 Hours with residual supply index less than one by year

Year	RSI_1	RSI_2	RSI_3
2016	4	36	76
2017	49	115	162
2018	26	82	269
2019	0	20	111
2020	111	303	475

Figure 6.1 Hours with residual supply index less than one by quarter

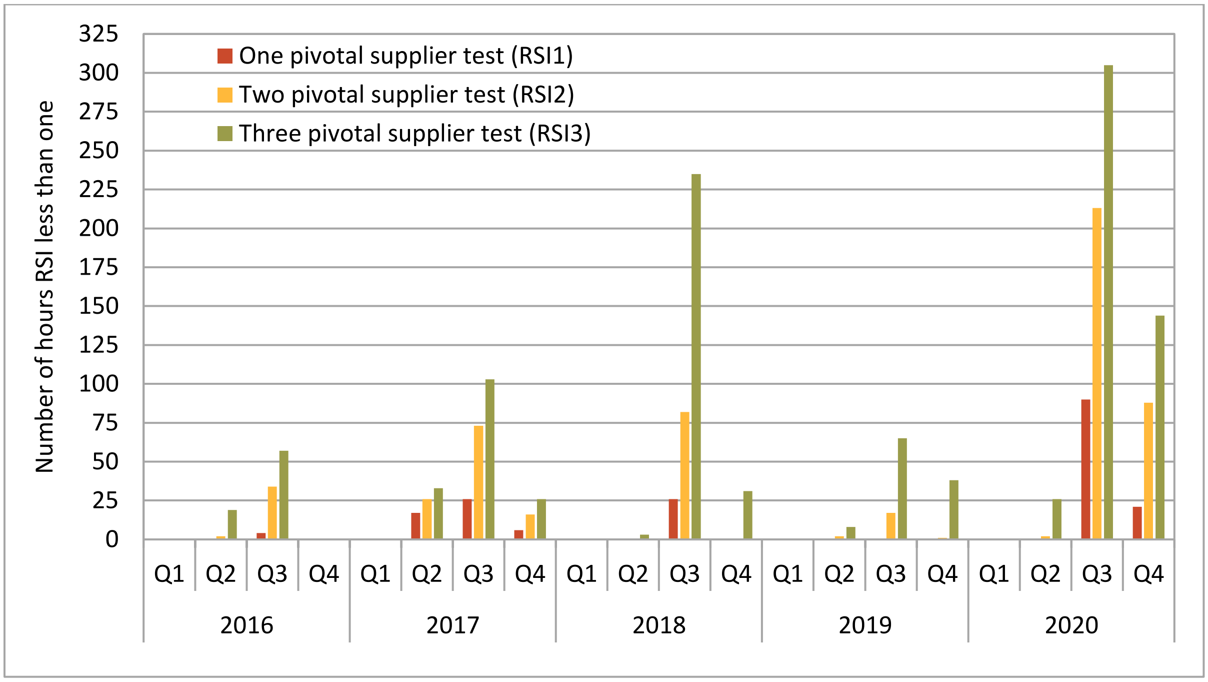


Figure 6.2 Residual supply index with largest three suppliers excluded (RSI_3) – lowest 500 hours

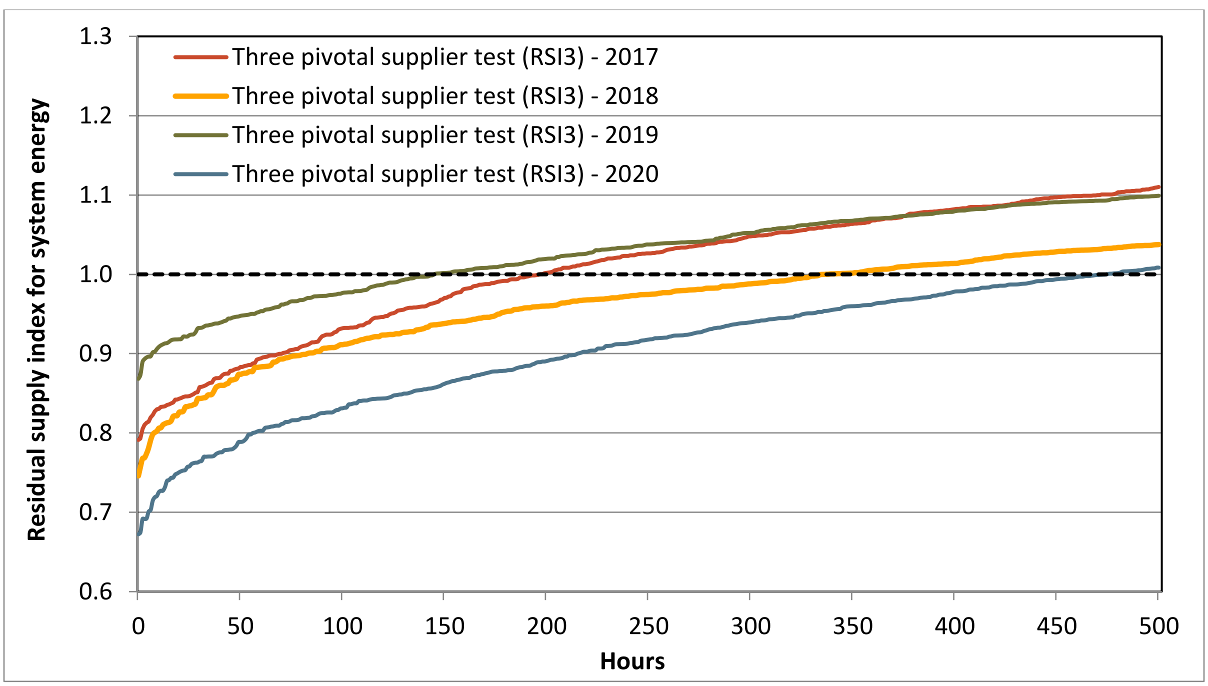
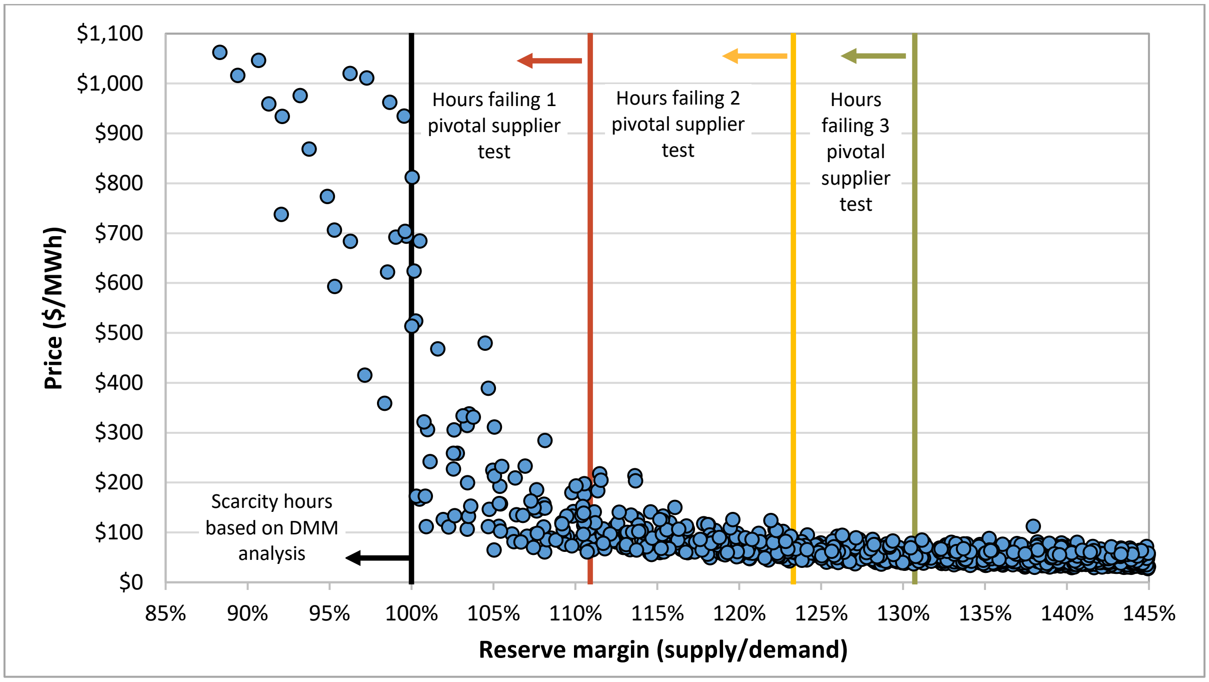


Figure 6.3 Comparison of potential scarcity and non-competitive hours



6.1.2 Local capacity requirements

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. In most local capacity areas, one or two entities own most of the generation needed to meet local capacity requirements.

Table 6.2 provides a summary of the residual supply index for local capacity areas in which the total local resource adequacy requirement exceeds capacity held by load serving entities. These areas have a net non-load serving entity capacity requirement, where load serving entities must procure capacity from other entities to meet local resource adequacy requirements.

Load serving entities meet local resource adequacy 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.[179]

Table 6.2 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. 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.

179 This analysis assumes load serving entities show resources at their net qualifying capacity on resource adequacy supply plans. However, based on actual resource availability, entities may show resources at less than net qualifying capacity values in a given month. Therefore, this analysis is likely a conservative assessment of competitiveness in local areas.

Key finding of this analysis include the following:

- The North Coast/North Bay, 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.
- Local capacity requirements for the Sierra and Stockton local areas decreased compared to 2019. In 2019, capacity in these areas was not sufficient to meet local requirements. The reduction in local requirements has resulted in capacity being sufficient to meet local requirements. However, Sierra remains structurally uncompetitive under a three pivotal supplier test, and Stockton remains structurally uncompetitive under a single pivotal supplier test.

In addition to the capacity requirements for each local area used in this analysis, additional reliability requirements exist for numerous sub-areas within local capacity areas. Some sub-areas require that capacity be procured from specific individual generating plants. Other sub-areas require various combinations of units that have different levels of effectiveness at meeting sub-area reliability requirements.

These sub-area requirements are not reflected in local capacity procurement requirements. However, these additional sub-area requirements represent 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.[180]

Table 6.2 Residual supply index for 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	1,215	3,577	2.94	1.25	0.27	0.10	0
North Coast/North Bay	612	712	1.16	0.02	0.00	0.00	1
Sierra	58	407	7.07	3.07	1.42	0.56	0
Stockton	34	38	1.13	0.59	0.09	0.02	2
SCE TAC area							
LA Basin	2,546	4,283	1.68	0.80	0.27	0.17	1
San Diego/Imperial Valley	1,389	1,665	1.20	0.76	0.34	0.11	3

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

[180] For further information on the capacity procurement mechanism, see Section 9.6.

constraints. Section 6.2 examines the actual structural competitiveness of transmission constraints when congestion occurred in the day-ahead and real-time markets.

6.2 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's 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 indicates local market power and resources that can supply counter-flow to a non-competitive constraint may be subject to bid mitigation.

6.2.1 Accuracy of transmission congestion assessment in ISO

Evaluating the performance of the ISO's local market power mitigation procedures involves examining both the accuracy with which the mitigation run predicts congestion in the same interval in the market run, as well as the portion of constraints congested in the mitigation or market run that are non-competitive. Table 6.3 shows the framework DMM uses to quantify overall accuracy of mitigation procedures.

All constraint-intervals defined by the *consistent* group in Table 6.3 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 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*. The dynamic competitive path assessment procedure does not evaluate uncongested constraints, and therefore does not establish the number of under-identified constraints that 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 6.3 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. For example, a total of 100 constraint-intervals 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, because 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 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 6.4 shows that 89 percent of congested constraint-hours were consistent in the mitigation and market runs in 2020, a 2 percent decrease from 2019. Congestion was present in the mitigation run but resolved in the market run during 5 percent of constraint-hours, and under-identified during 6 percent of constraint-hours.

The percent of consistent and competitive intervals fell slightly in the day-ahead market, but increased in the real-time markets relative to 2019. The percent of consistent and non-competitive constraints increased slightly in the day-ahead market but fell in the real-time markets relative to 2019. The day-ahead percent of non-competitive constraints increased from 32 percent in 2019 to 35 percent in 2020.

If the proportion of competitive to non-competitive constraint-hours was the same for under-identified as for constraints with predicted congestion, then about 2.1 percent of congested constraint-hours may represent missed mitigation in 2020. This is a modest increase over the 1.7 percent share of congested constraint-hours with potential missed mitigation in the previous year.

Real-time market

On November 13, 2019, the ISO implemented changes to real-time market power mitigation procedures. These changes resulted from the local market power mitigation enhancements (LMPME) stakeholder process, and modified the way mitigation in one interval impacts mitigation of future intervals. The 2019 data included a limited number of days following implementation of these changes, and showed results very similar to those of 2018. The 2020 data presented in Table 6.4 represent a full year of data after the implementation of LMPME. These data are generally consistent with earlier years. However, 2020 saw a notable increase in accurate congestion prediction in the 5-minute market, and a decrease in 5-minute market congestion resolved in the market run.

Results in the second panel of Table 6.4 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 91 percent of constraint-intervals, a 1 percent increase from 2019.

Under-identified congestion and congestion that was resolved in the market run were very similar in 2020 as in 2019. Under-identified congestion occurred in 4 percent of congested constraint-intervals and congestion that was resolved in the market run occurred in 5 percent of congested constraint-intervals.

Table 6.4 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 %
Day-ahead	Consistent	22,337	57%	12,497	32%	34,834	89%
	Resolved in Market Run	934	2%	984	3%	1,918	5%
	Under-identified	---	---	---	---	2,235	6%
	Total					**38,987**	**100%**
15-minute	Consistent	71,140	75%	16,116	17%	87,256	91%
	Resolved in Market Run	2,754	3%	1,886	2%	4,640	5%
	Under-identified	---	---	---	---	3,575	4%
	Total					**95,471**	**100%**
5-minute	Consistent	180,663	68%	64,887	24%	245,550	92%
	Resolved in Market Run	10,320	4%	5,053	2%	15,373	6%
	Under-identified	---	---	---	---	6,003	2%
	Total					**266,926**	**100%**

About 77 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, this would suggest that under-mitigation occurred in about 0.7 percent of the total number of congested constraint-intervals in 2020, down from 0.8 percent in 2019.

Results for the 5-minute market were largely similar in 2020 to 2019. However, 2020 saw a notable increase in accurate congestion prediction in the 5-minute market, and a decrease in 5-minute market congestion resolved in the market run. The third panel in Table 6.4 shows that the assessment run predicted congestion consistently with the binding 5-minute market run in about 92 percent of constraint-intervals, up from 83 percent in 2019. Constraints that were congested in the mitigation run but resolved in the market run fell to 6 percent in 2020 from 15 percent in 2019. Under predicted constraint-intervals were the same as 2019 levels at about 2 percent of the total in the 5-minute market.

6.2.2 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 currently a single pivotal suppler in each balancing area in the energy imbalance market. Results of this analysis for transfer constraints are shown in Table 6.5.

Table 6.5 Accuracy of congestion prediction on EIM transfer constraints

Market	Region	Consistent	Resolved in Market Run	Under identified
15-minute	PacifiCorp East	93%	5%	3%
	PacifiCorp West	90%	6%	4%
	Portland General Electric	90%	5%	5%
	Powerex	88%	7%	4%
	Puget Sound Energy	89%	6%	5%
	Idaho Power	92%	5%	4%
	Seattle City Light	90%	6%	4%
	NV Energy	96%	2%	1%
	Salt River Project	95%	2%	3%
	Arizona Public Service	90%	6%	3%
	BANC	97%	2%	1%
5-minute	PacifiCorp East	70%	24%	6%
	PacifiCorp West	72%	19%	9%
	Portland General Electric	71%	20%	9%
	Powerex	70%	20%	11%
	Puget Sound Energy	73%	18%	9%
	Idaho Power	71%	22%	7%
	Seattle City Light	73%	19%	8%
	NV Energy	71%	24%	5%
	Salt River Project	76%	19%	5%
	Arizona Public Service	71%	21%	8%
	BANC	65%	24%	11%

Performance of local market power mitigation on EIM transfer constraints in the 15-minute market in 2020 was very similar to 2019. Congestion on transfer constraints across all areas was accurately predicted in 91 percent of congested constraint-intervals. As shown in Table 6.5, congestion on transfer constraints for each energy imbalance market area was predicted with a similar degree of accuracy, with 88 percent to 97 percent of congested constraint-intervals being congested in both runs. Overall, across 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 remained high, but was slightly less than 2019 levels. As shown in the bottom half of Table 6.5, under prediction of congestion ranged from 5 to 11 percent of congested constraint-intervals for different transfer constraints, compared to a range of 3 to 8 percent in 2019.

6.3 Local market power mitigation

This section provides an assessment of the frequency and impact of the automated local market power mitigation procedures in the ISO and Western EIM balancing authority areas. 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.

6.3.1 Frequency and impact of automated bid mitigation

In the day-ahead and real-time markets, rates of mitigation increased significantly in 2020 relative to 2019. For the ISO's balancing authority area, incremental energy subject to mitigation has increased relative to prior years due, in part, to the increase in concentration of generation in the portfolios of net sellers and load in the portfolios of net buyers. In addition, heat wave conditions that existed across the west during August and September 2020 might have also contributed to increased rates of mitigation in 2020. In the Western EIM balancing authority areas, the elimination of carryover mitigation appears to have reduced mitigation rates beginning November 2019.

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 proposed the following enhancements to the local market power mitigation process for implementation in November 2019:[181]

1. Eliminate carryover mitigation by not mitigating a resource in subsequent market intervals only because the resource was mitigated in a prior interval of the same hour.
2. Allow an EIM entity balancing authority area in the real-time market to limit dispatch of incremental net exports when mitigation is triggered due to import congestion.
3. Introduce a new hydro default energy bid (hydro DEB) option that would apply to all hydroelectric resources with storage capability that participate in the ISO or in the Western EIM.

On September 30, 2019, FERC rejected the proposal to limit net exports by a Western EIM balancing authority area.[182] Subsequently, the ISO filed on October 30, 2019, a request for rehearing at FERC regarding the net export limit proposal.[183] The rest of the enhancements were implemented on

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

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

183 ISO's request for rehearing and alternative motion for clarification, October 30, 2019:

November 13, 2019. On June 18, 2020, FERC denied the request for rehearing but granted the motion for clarification.[184]

The impact on market prices of bids that were mitigated can only be assessed precisely by re-running the market software without bid mitigation. Currently, DMM does not have the ability to re-run the day-ahead and real-time market software under this scenario. Instead, DMM developed a variety of metrics to estimate the frequency with which mitigation is triggered and the effect of this mitigation on each unit's energy bids and dispatch levels. These metrics identify bids lowered from mitigation each hour and estimate the additional energy dispatched from these price changes.[185]

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

Day-ahead market

As shown in Figure 6.4, in 2020, the average incremental energy subject to mitigation increased significantly relative to 2019. This is due, in part, to the increase in concentration of generation in the portfolios of net sellers and load in the portfolios of net buyers. Heat wave conditions that existed across the west during August and September might have also contributed to increased rates of mitigation in the third quarter.

- Bids for an average of 1,183 MW per hour were subject to mitigation but not lowered in 2020, a significant increase from 477 MW in 2019.
- Bids for an average of about 331 MW per hour were changed in 2020, almost doubled when compared to 2019.
- Figure 6.5 shows day-ahead dispatch instructions from bid mitigation increased by about 26 MW per hour in 2020, compared to 16 MW per hour in 2019. This potential increase in dispatch due to mitigation is concentrated mostly during evening peak hours in 2020.

http://www.caiso.com/Documents/Oct302019_RequestforRehearingorClarification-LocalMarketPowerMitigationER19-2347.pdf

[184] FERC order denying rehearing and granting clarification, ER19-2347-001, June 18, 2020: https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14869989

[185] The methodology has been updated to show incremental energy instead of units that have been subject to automated bid mitigation. Prior to the local market power mitigation enhancements in November 2019, this metric also captures carryover mitigation (balance of hour mitigation) in 15-minute and 5-minute markets by comparing the market participant submitted bid at the top of each hour (in the 15-minute market) to the bid used in each interval of 15-minute and 5-minute market runs.

Figure 6.4 Average incremental energy mitigated in day-ahead market

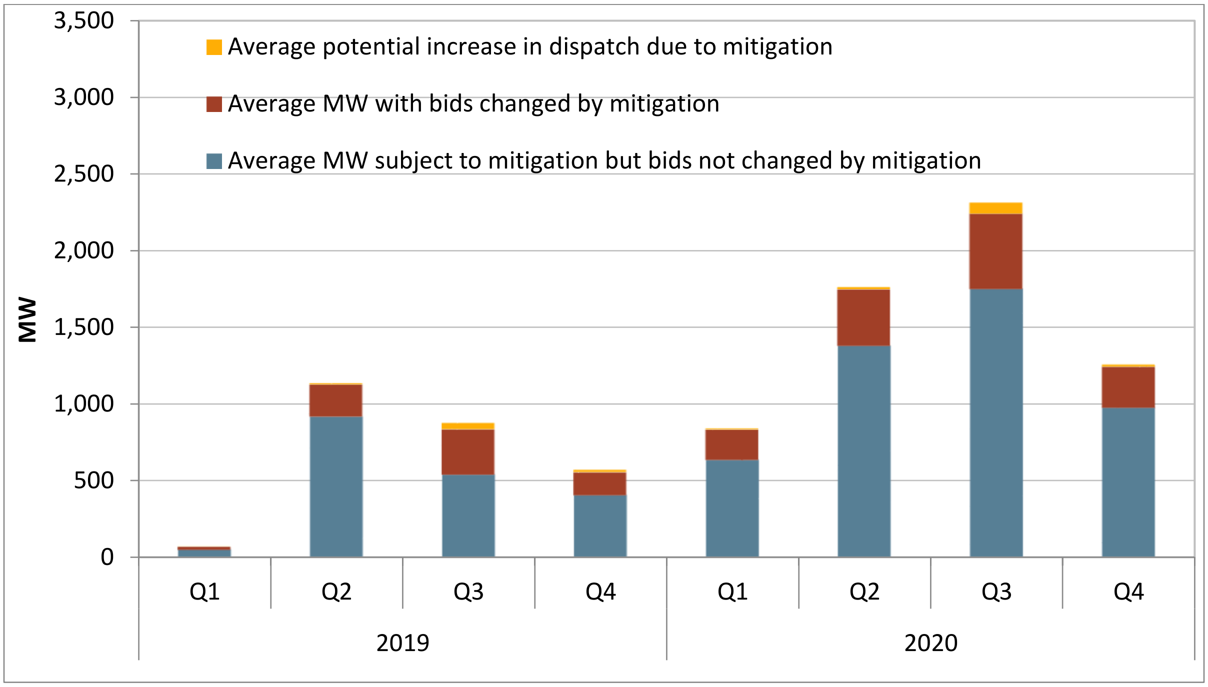
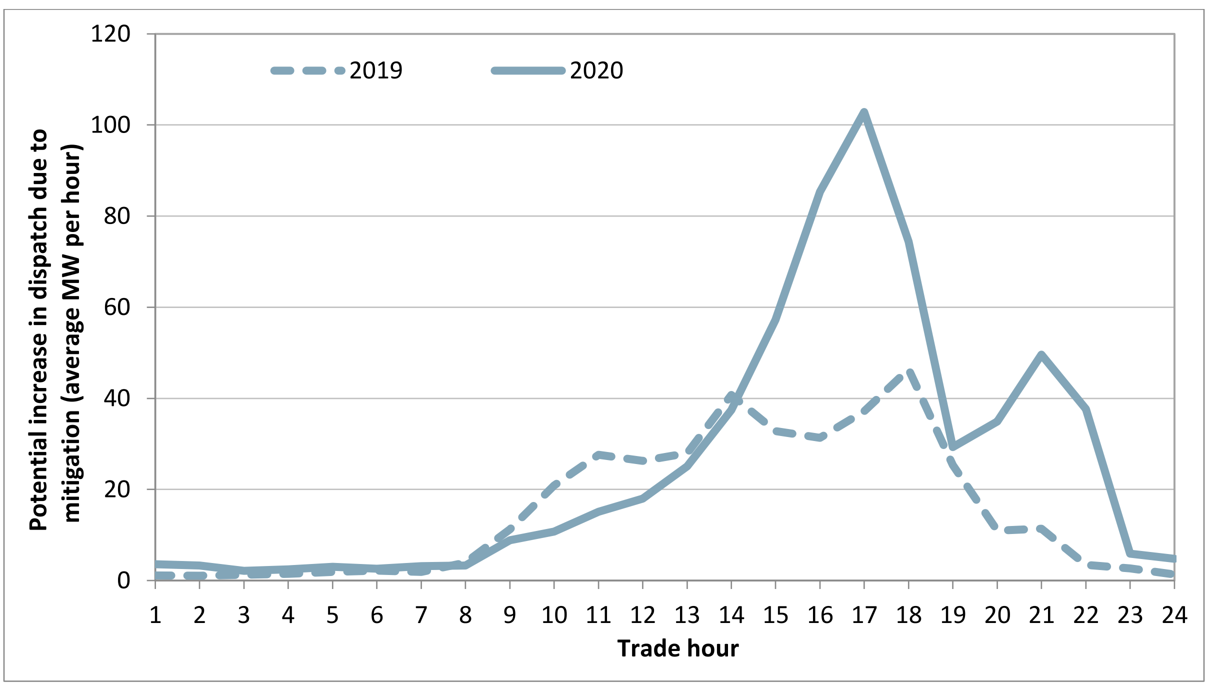


Figure 6.5 Potential increase in day-ahead dispatch due to mitigation (hourly averages)



Real-time market

Figure 6.6 through Figure 6.8 highlight the frequency and volume of 15-minute and 5-minute market mitigation in the ISO. As shown in these figures, average incremental energy subject to mitigation in the ISO is consistently higher in the 5-minute than in the 15-minute market.

- In the 15-minute market, bids for about 572 MW of incremental energy were subject to mitigation in 2020, more than double when compared to 2019. Of this energy, bids for about 477 MW were not lowered compared to 95 MW which were lowered due to mitigation. Similarly, in the 5-minute market, bids for about 1,331 MW were unchanged due to mitigation compared to 238 MW which were lowered.
- On average, the potential increase in 15-minute dispatch due to bid mitigation was similar in 2020 compared to 2019. On the other hand, potential increase in 5-minute dispatch from bid mitigation increased to 38 MW per hour in 2020 compared to 22 MW per hour in 2019.

Figure 6.6 Average incremental energy mitigated in 15-minute real-time market (ISO)

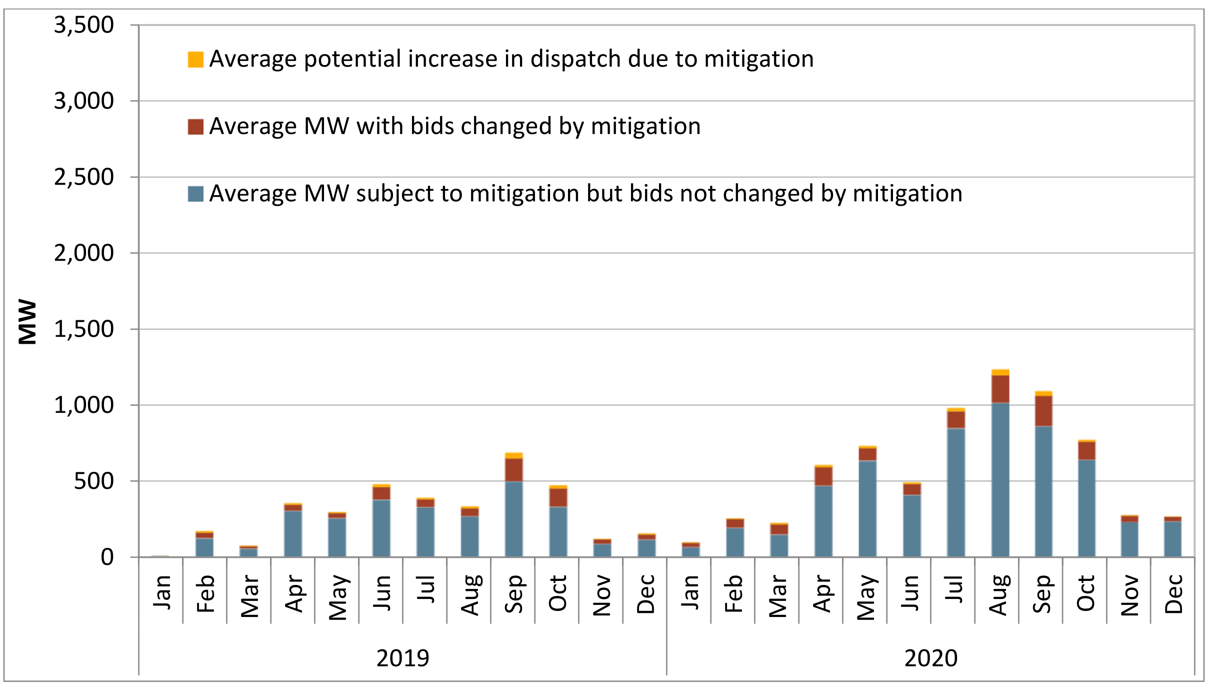


Figure 6.7 Average incremental energy mitigated in 5-minute real-time market (ISO)

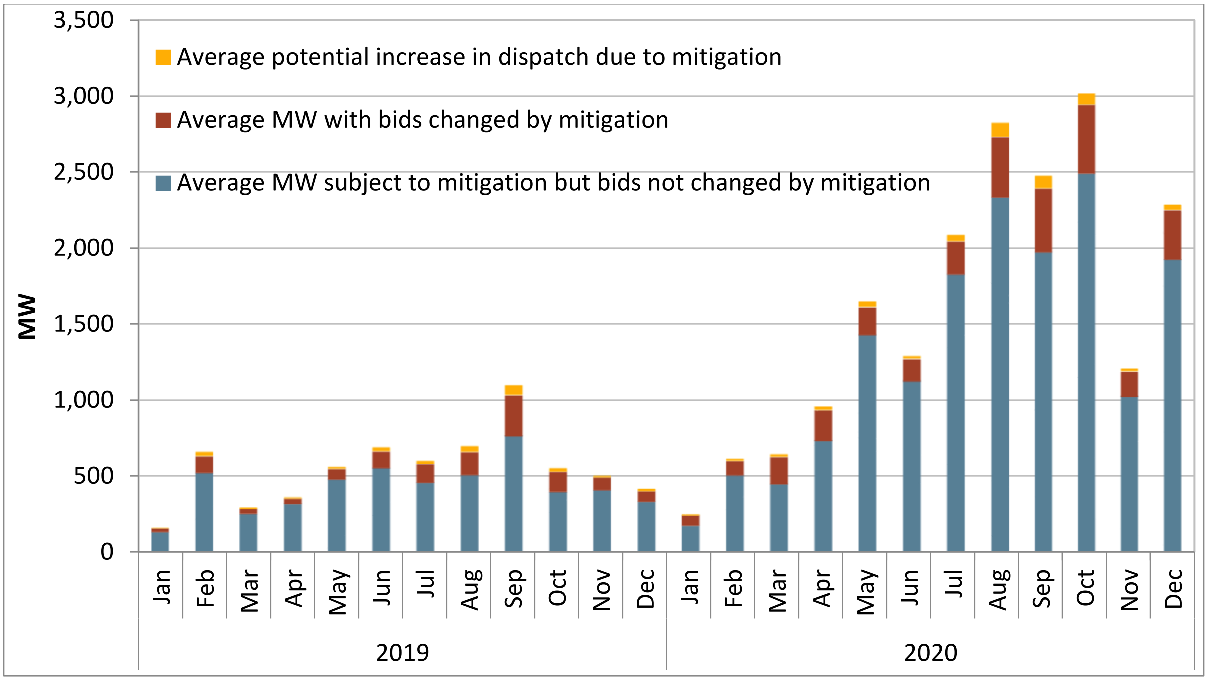


Figure 6.8 Potential increase in 15-minute and 5-minute dispatch due to mitigation (ISO)

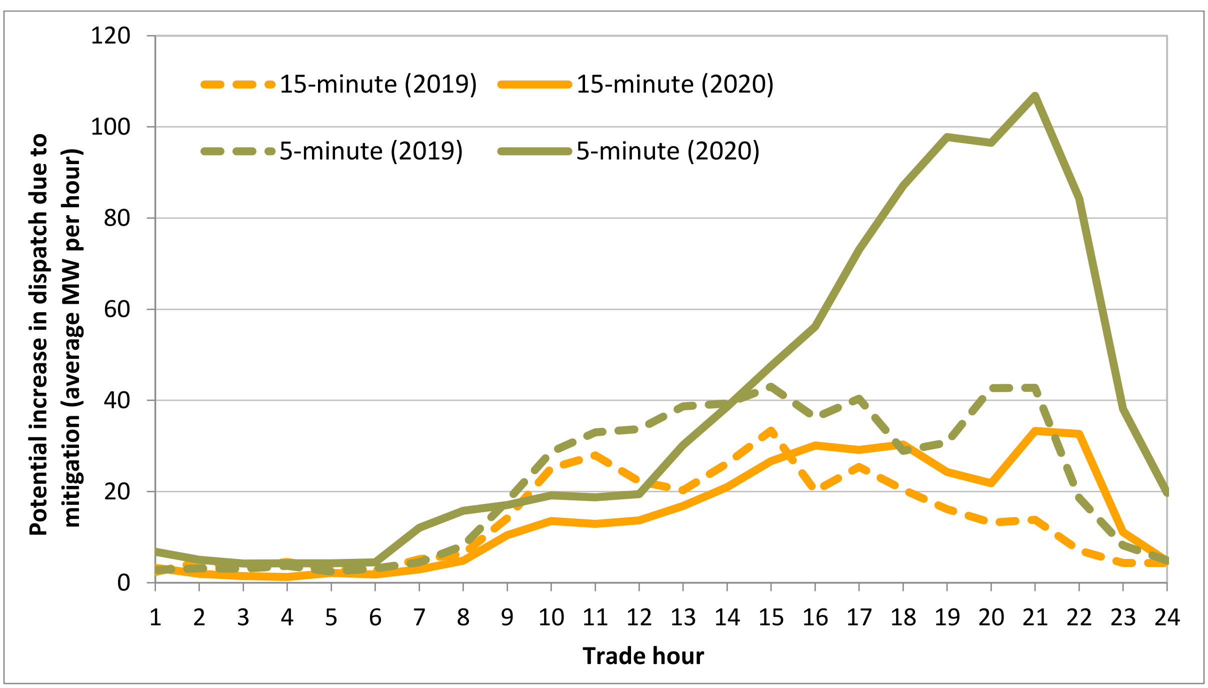


Figure 6.9 through Figure 6.11 highlight the frequency and volume of 15-minute and 5-minute market mitigation in all the balancing authority areas in the Western EIM. The elimination of carryover mitigation in November 2019 appears to have reduced mitigation rates in the Western EIM.

- As shown by blue bars in the figures, in the 15-minute market, bids for an average of 613 MW were subject to mitigation but not lowered in 2020 compared to 575 MW in 2019. In the 5-minute market, bids for about 512 MW were subject to mitigation but not lowered in 2020 compared to 540 MW in 2019.
- Red bars in the figure show that average incremental energy with bids lowered as a result of mitigation decreased in 2020 relative to 2019. In both 15-minute and 5-minute markets, average MW with bids lowered decreased to 90 MW in 2020 when compared to 220 MW in 2019.
- As shown in Figure 6.11, as a result of decreased bid mitigation in 2019, the average megawatts potentially increased in both 15-minute and 5-minute markets also decreased in the energy imbalance market areas.

Figure 6.9 Average incremental energy mitigated in 15-minute real-time market (Western EIM)

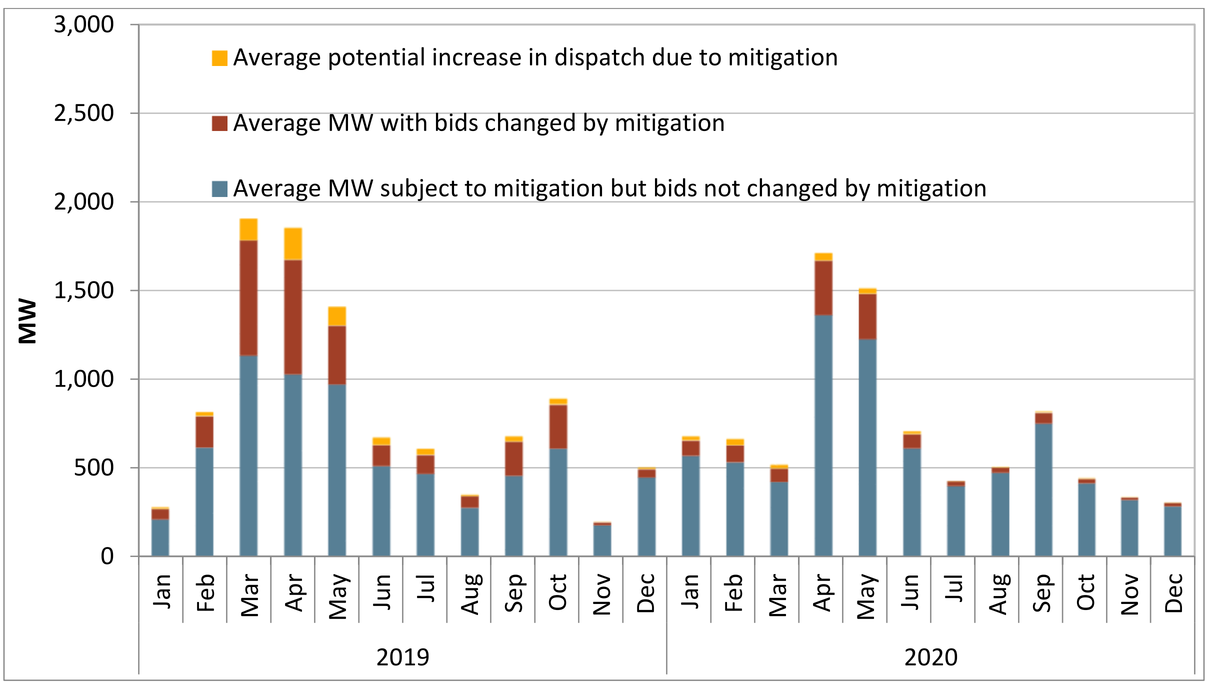


Figure 6.10 Average incremental energy mitigated in 5-minute real-time market (Western EIM)

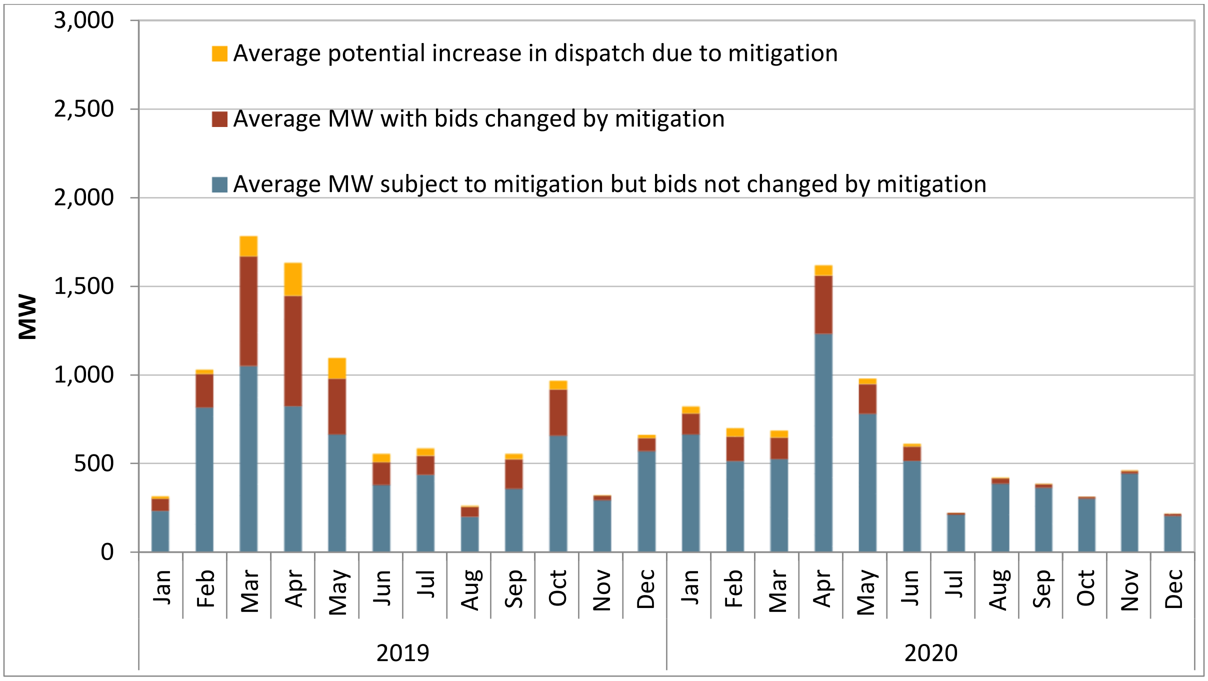
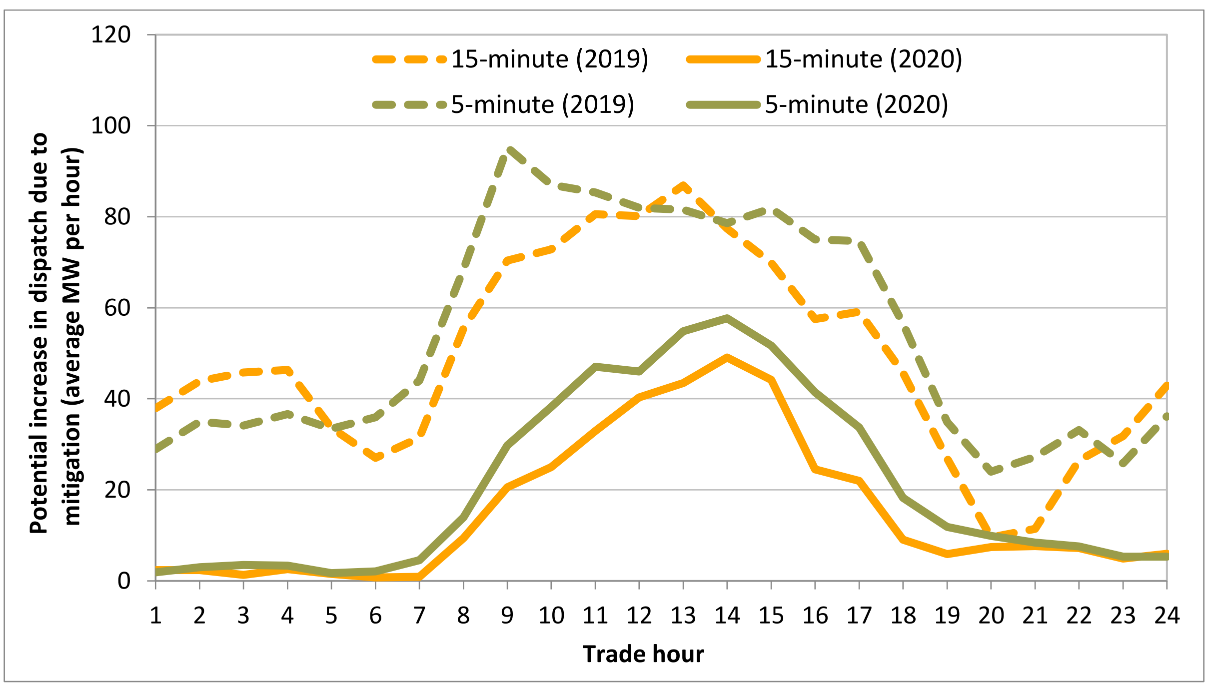


Figure 6.11 Potential increase in 15-minute and 5-minute dispatch due to mitigation (Western EIM)



6.3.2 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.[186] Total energy from exceptional dispatches decreased in 2020. The above-market costs associated with these exceptional dispatches decreased as well, totaling $16 million in 2020 compared to $26 million in 2019. The cost associated with exceptional dispatch commitments to minimum load versus out-of-market costs for exceptional dispatch incremental energy were roughly the same in 2020.

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*.

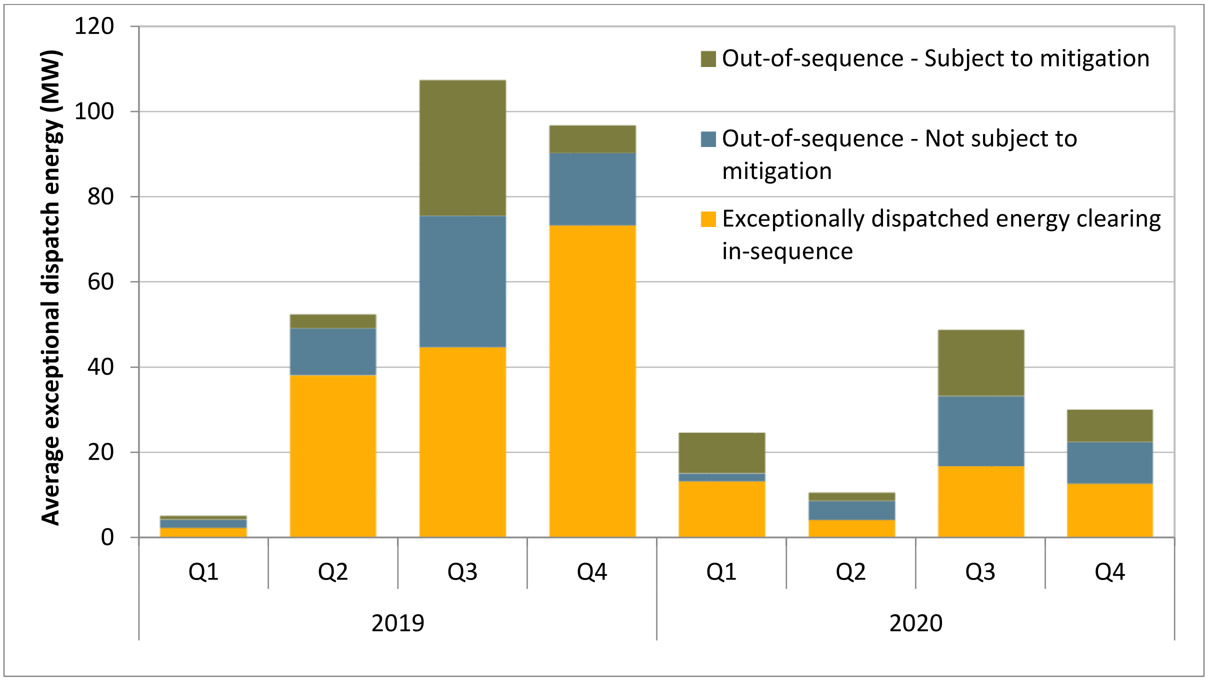
In 2020, local market power mitigation played a substantial role in limiting above-market costs for exceptional dispatches for energy, reducing these costs by $5.5 million.

Volume and percent of exceptional dispatches subject to mitigation

As shown in Figure 6.12, the overall volume of exceptional dispatch energy above minimum load decreased in 2020 when compared to 2019. This decrease was largely attributed to less exceptional dispatches issued for unit testing of new resources coming online, discussed in Chapter 8. Out-of-sequence energy is energy with bid prices or default energy bids above the market clearing price. Out-of-sequence exceptional dispatches not subject to mitigation decreased by about half in 2020 compared to 2019. Out-of-sequence exceptional dispatches subject to mitigation decreased by about 19 percent in 2020 compared to 2019.

[186] A more detailed discussion of exceptional dispatches is provided in Section 8.1.

Figure 6.12 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.

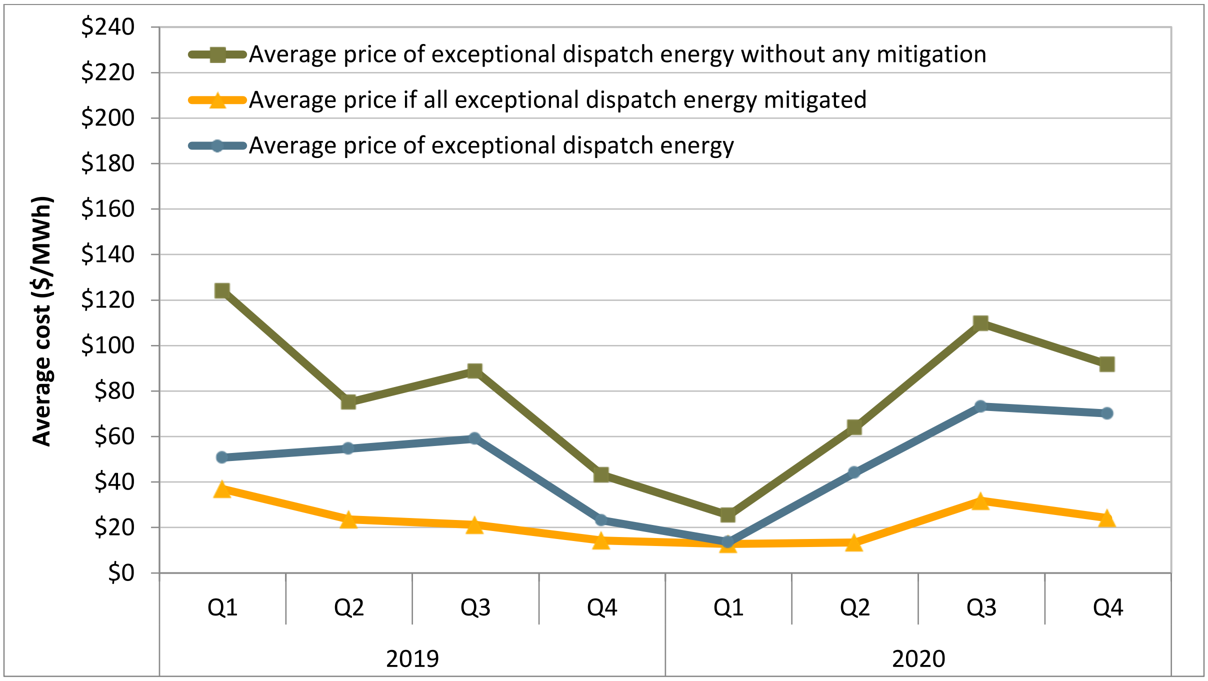
Using the value of out-of-sequence costs with the corresponding megawatt quantities of out-of-sequence exceptional dispatch energy, one can calculate the average price of out-of-sequence exceptional dispatch energy. This price is the amount per megawatt-hour by which out-of-sequence exceptional dispatch energy exceeds the locational marginal price.

Figure 6.13 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 6.13 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 6.13 shows, this price difference increased slightly in 2020 compared to 2019.

The yellow line in Figure 6.13 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 2020 and was greater than the same quarter in 2019.

The average price of out-of-sequence exceptional dispatch energy increased slightly in 2020 at $50/MWh from $47/MWh in 2019. Average prices for exceptional dispatch energy was highest during the third and fourth quarters in 2020, at $73/MWh and $70/MWh, respectively. The exceptional dispatches driving these values were predominately issued to provide ramping capacity to meet the evening net load peak.

Figure 6.13 Average prices for out-of-sequence exceptional dispatch energy



RA Max exceptional dispatches

Beginning in the third quarter of 2019, ISO operators started to issue exceptional dispatches to manually commit and dispatch resources to the maximum of their resource adequacy contracts. These are referred to as "RA Max" exceptional dispatches and were typically issued to a number of slow-ramping, gas generator resources located in the Los Angeles basin. The intention of RA Max exceptional dispatches is to increase the amount of ramping capacity available to meet the evening net load ramp and respond to other uncertainties in real-time.

Exceptional dispatches to RA Max are not subject to energy bid mitigation, and are paid the higher of the unit's energy bid or the market price. However, there is a strong potential for units being dispatched out-of-market via RA Max exceptional dispatches to exercise market power and raise bids substantially over marginal cost. DMM recommended in its 2019 annual report that RA Max exceptional dispatch energy should be subject to mitigation as there is a strong potential for suppliers to exercise market power and raise bids substantially over marginal cost.[187]

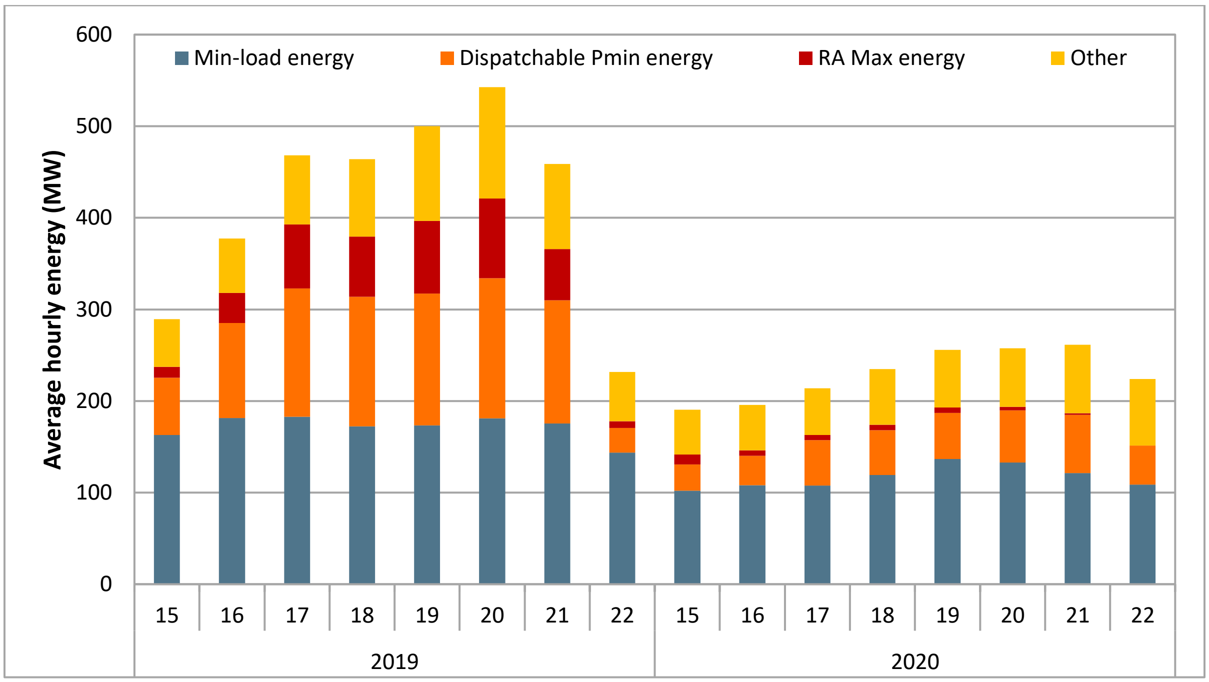
Since then, the ISO indicated it would monitor the frequency of RA Max exceptional dispatches and take actions if costs become excessive. The ISO had also indicated it would develop procedures to help

[187] *2019 Annual Report on Market Issues and Performance,* June 2020, pp. 308-309 http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf

ensure that RA Max exceptional dispatches are only issued when needed to ensure reliability. This has largely been the case as RA Max exceptional dispatch energy decreased significantly in 2020.

Figure 6.14 shows the average volume of energy from exceptional dispatches to gas-fired resources by hour in the third quarter of 2019 and 2020. In total, RA Max exceptional dispatches accounted for around 3 percent of the total exceptional dispatch energy, down from about 16 percent in prior year. In total, RA Max exceptional dispatches were only issued during three trade dates in 2020.

Figure 6.14 Average hourly exceptional dispatch energy by type (July – September)



6.4 Start-up and minimum load bids

This section analyzes commitment cost bid behavior for ISO gas capacity – excluding use-limited resources – under the proxy cost option. For 2020, DMM estimates that about 60 percent of the ISO's total bid cost recovery payments, approximately $75 million, was allocated to gas resources that bid their commitment costs above 110 percent of their reference commitment costs. Commitment cost bids are capped at 125 percent of reference proxy costs. About 93 percent of these payments were for resources bidding at or near the 125 percent bid cap for proxy commitment costs.

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.[188] The ISO modified this option to capture the fluctuations of daily fuel prices for natural gas-fired resources and 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.[189] However, the registered costs continued to remain fixed for a period of 30 days.[190] 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 cost enhancement phase 3 (CCE3) initiative, the ISO implemented 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.[191] This initiative phased out the registered cost option and limited the use of that option to resources which do not have sufficient data to calculate an opportunity cost adder.

Effective February 16, 2021, the ISO implemented Commitment Cost and Default Energy Bid Enhancements Phase 1 (CCDEBE).[192] Under this market design, resources can submit automated and manual adjustments to commitment cost and default energy bid reference levels.

Day-ahead and real-time ISO gas capacity under the proxy cost option

Figure 6.15 and Figure 6.16 highlight how proxy commitment costs were bid into the day-ahead and real-time markets in 2020 compared to 2019.[193] As shown in Figure 6.15, in the day-ahead market about 32 percent of capacity submitted start-up bids at or below the proxy cost compared to 31 percent in 2019. About 37 percent of the capacity submitted start-up bids at or near the proxy cost cap in 2020

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188 For more information, see the following FERC order accepting the tariff revisions: https://www.caiso.com/Documents/Dec302014_OrderAcceptingCommitmentCostEnhancementsTariffRevision_ER15-15-001.pdf

189 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.

190 Updated use-limited resource definition, CAISO tariff, pp 10-11: http://www.caiso.com/Documents/Section30-Bid-Self-ScheduleSubmission-CAISOMarkets-asof_Apr1-2019.pdf

191 Commitment costs enhancements stakeholder process: http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostEnhancements.aspx

192 Market Notice - Commitment Cost and Default Energy Bid Enhancements Phase 1: Deployment Effective for Trade Date 2/16/21: https://e.caisocommunications.com/public/viewmessage/html/36997/jxzquzt9ntc6d6xbtofvglxbdylj3/0bbe03eb000000000000000000000008bbc8

193 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.

compared to 38 percent in 2019. In the real-time market, in 2020, about 37 percent of the startable capacity submitted bids at or near the proxy cost cap, about 2 percent higher when compared to 2019.

As shown in Figure 6.16, in both the day-ahead and real-time markets, the percent of minimum load capacity bidding at or near the proxy cost cap is similar in all quarters of 2019 and 2020.

Figure 6.15 Day-ahead and real-time gas-fired capacity under the proxy cost option for start-up cost bids (percentage)

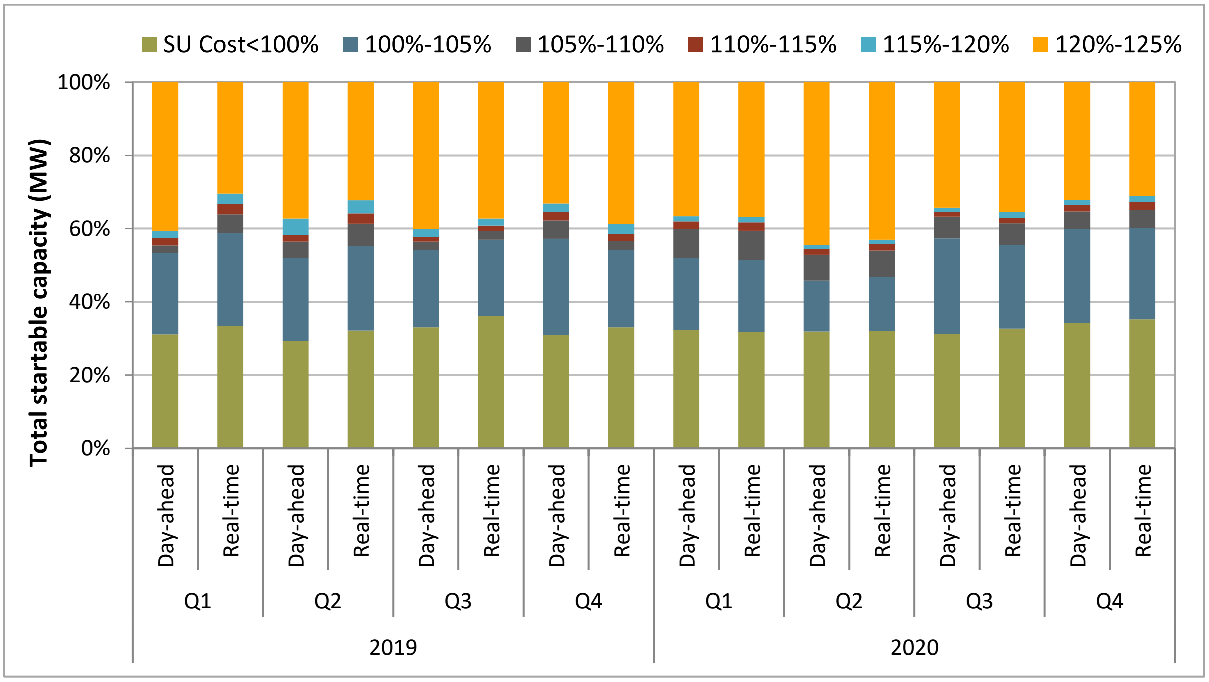
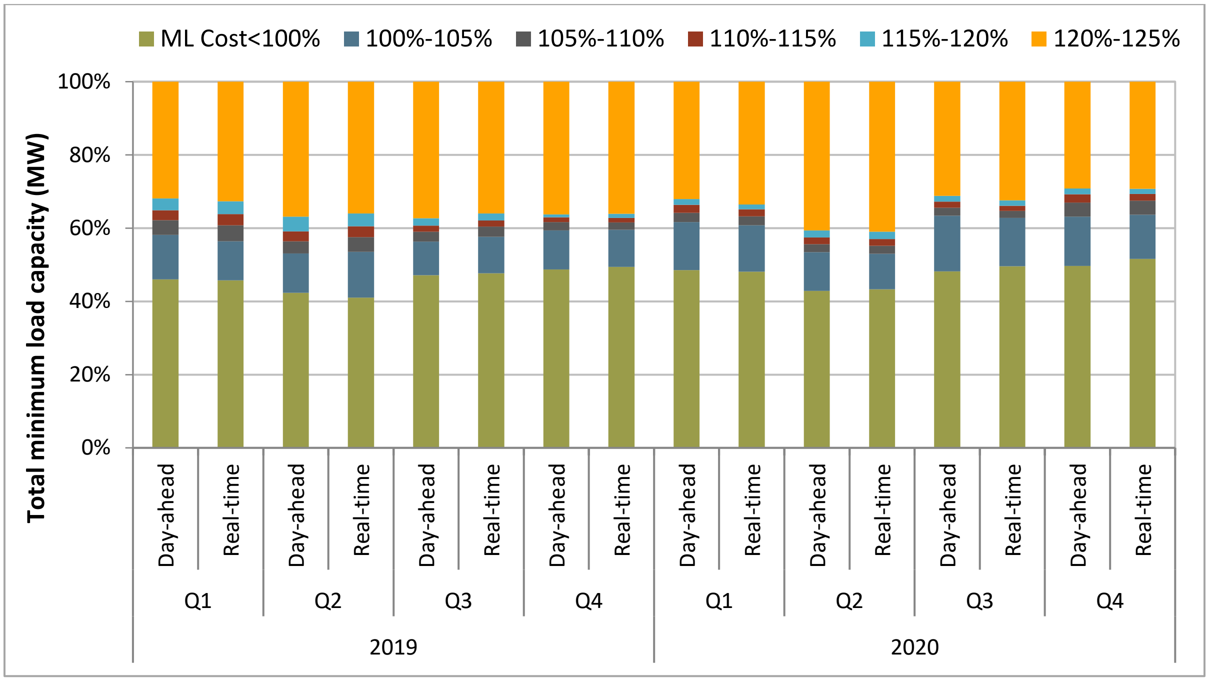


Figure 6.16 Day-ahead and real-time gas-fired capacity under the proxy cost option for minimum load cost bids (percentage)



6.5 Market based rate authority in the energy imbalance market

Energy imbalance market participants that are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) must seek authority from FERC to sell at market based rates in the energy imbalance market. Once granted, each entity's authority to continue selling at market based rates in the energy imbalance market and other markets is reviewed by FERC on a triennial basis. Currently, all FERC jurisdictional energy imbalance market participants have authority to sell in the energy imbalance market at market based rates. This includes participants that were granted market based rate authority at the beginning of their participation in the energy imbalance market, as well as participants that have since undergone triennial review by FERC and retained this authority.

7 Congestion

This chapter provides a review of congestion and the congestion revenue rights auction in 2020.[194] Findings from this chapter include the following:

- **Day-ahead market congestion increased.** Both the frequency and the magnitude of congestion impacting load area prices was higher in 2020 relative to 2019. The primary constraints impacting price separation in the day-ahead market were a Path 26 nomogram, the Midway-Vincent #2 500 kV line, and the Quinto-Los Banos 230 kV line. In 2020 day-ahead congestion revenues totaled about 6.0 percent of total day-ahead market energy costs, compared to about 4.3 percent in 2019.

- **Real-time market congestion increased**. Both the 15-minute and 5-minute markets had patterns of congestion that were similar to the day-ahead market. The primary constraints impacting price separation in the real-time market were the Midway-Vincent #2 500 kV line, the Malin-Round Mountain 500 kV line, and the constraints associated with the Round Mountain-Table Mountain nomogram.

- **The frequency and impact of transfer constraint congestion increased**. Similar to prior years, the frequency of congestion was highest among the load areas located in the Pacific Northwest. Transfer constraint congestion decreased prices for these balancing areas with a higher average magnitude than 2019.

- **Intertie congestion increased**. Overall import congestion on interties totaled about $263 million, a 74 percent increase compared to the $152 million of 2019. The increase from the previous year was largely driven by increased congestion on the two major interties linking the ISO with the Pacific Northwest: the Nevada/Oregon Border (NOB) and MALIN 500 (PACI/Malin 500).

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:

- In 2019, the ISO implemented two sets of changes to the congestion revenue rights auction process. The first reduced the number and pairs of nodes at which congestion revenue rights can be purchased in the auction (Track 1A). The second reduced 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). DMM continues to support 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.

- **Payouts to congestion revenue rights sold in the ISO's auction exceeded auction revenues by over $70 million in 2020**. About $36 million of the $70 million in ratepayer losses was from small load serving entities selling allocated rights at a loss in the third quarter. These losses are borne by transmission ratepayers who pay for the full cost of the transmission system through the transmission access charge (TAC). Losses from congestion revenue rights sold in the auction totaled about $100 million in 2017, $131 million in 2018, and fell to $22 million in 2019.

[194] For a detailed background of congestion, from how it is calculated to how it interacts with other market elements, please see Section 8.1 of DMM's 2019 annual report.

- Transmission ratepayers received about 56 cents in auction revenue per dollar paid out to these rights purchased in the auction in 2020. Track 1B revenue deficiency offsets reduced payments to auctioned CRRs by about $47 million. Losses from auctioned congestion revenue rights totaled about 14 percent of total day-ahead congestion rent in 2020 compared to about 6 percent in 2019 and 21 percent in 2018.
- DMM believes the current auction is unnecessary and could be eliminated.[195,196] If the ISO believes it is beneficial to the market to facilitate hedging, DMM believes the current auction format could 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.

7.1 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 real-time 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 Southern California Edison and San Diego Gas and Electric areas, but decreases prices in the Pacific Gas and Electric area. Similarly, congestion within Northern California increases prices in the Pacific Gas and Electric area, and decreases prices in Southern California.

Highlights of congestion in 2020 include the following:

- In the day-ahead market, both the frequency and magnitude of congestion impacting load area prices in 2020 increased relative to 2019. The constraints that had the greatest impact on price separation throughout the year were a Path 26 nomogram, the Midway-Vincent #2 500 kV line, and the Quinto-Los Banos 230 kV line.
- In the 15-minute market, patterns of congestion followed a similar pattern to the day-ahead market. The constraints that had the greatest impact on price separation in the 15-minute market were the Midway-Vincent #2 500 kV line, the Malin-Round Mountain 500 kV line, and the constraints associated with the Round Mountain-Table Mountain nomogram.
- In the real-time market, EIM transfer constraint congestion decreased prices in the majority of the energy imbalance market, while it increased prices in the Arizona Public Service and NV Energy areas. Transfer constraint congestion had a greater impact on prices than internal constraints in EIM areas located in the Pacific Northwest.

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[195] 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

[196] 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

7.1.1 Day-ahead congestion

Congestion rent and loss surplus

In the day-ahead market, hourly congestion rent collected on a constraint is equal to the product of the shadow price and the megawatt flow on that constraint. The daily congestion rent is the sum of hourly congestion rents collected on all constraints for all trading hours of the day. The daily marginal loss surplus is computed as the difference between daily net energy charge and daily congestion rent. The loss surplus is allocated to measured demand.[197]

Congestion rents were higher while loss surplus was lower overall in 2020 compared to 2019. At $488 million, day-ahead congestion revenues totaled about 6.0 percent of total day-ahead market energy costs, compared to about 4.3 percent in 2019. The variation between quarters was considerably higher in 2020 compared to the previous year. The peak for both congestion rents and loss surplus occurred in the third quarter, reaching about $220 million and $63 million, respectively. This increase is in large part due to increased congestion from fires and the August and September heat waves.[198]

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 2020 reflect this overall trend. Figure 7.2 shows price separation resulting from congestion by quarter for the current and previous year.

Figure 7.3 shows the frequency of congestion.

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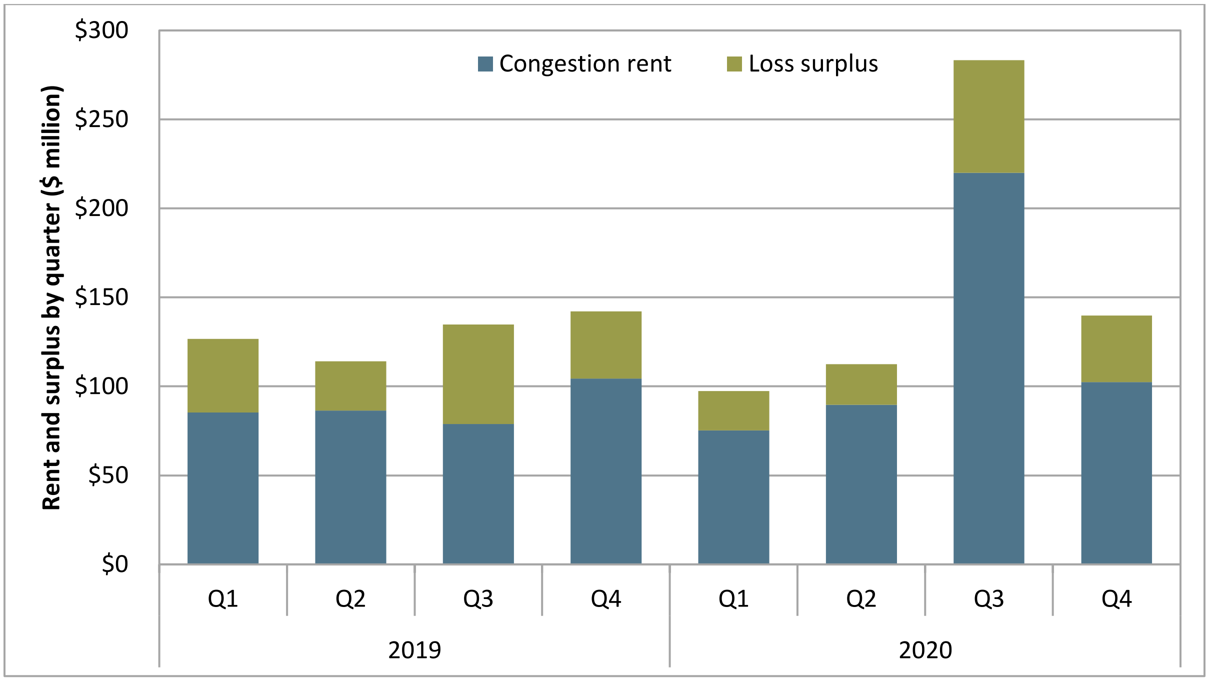
197 For more information on marginal loss surplus allocation refer to ISO's business practice manual for Settlements and Billing, CG CC6947 IFM Marginal Losses Surplus Credit Allocation: https://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing

198 For more detailed information on the effects of the August heat storm on congestion, refer to Section 1.10 of DMM's 2020 third quarter report: http://www.caiso.com/Documents/2020ThirdQuarterReportonMarketIssuesandPerformance-Feb4-2021.pdf

Figure 7.1 Congestion rent and loss surplus by quarter (2019 – 2020)



Congestion impact in the day-ahead market from internal, flow-based constraints

The overall impact of day-ahead congestion on price separation increased in 2020 relative to 2019. In both years, congestion increased average prices in the San Diego Gas & Electric and Southern California Edison areas and decreased average prices in the Pacific Gas and Electric area. The following summary values can be seen in Table 7.1:

- For San Diego Gas and Electric, congestion increased average prices above the system average by about $1.66/MWh (3.3 percent), compared to about $1.20/MWh (3.8 percent) in 2019.
- For Southern California Edison, congestion drove prices up by about $0.94/MWh (1.2 percent), compared to $0.04/MWh (0.2 percent) in the previous year.
- For Pacific Gas and Electric, congestion reduced prices below the system average by about $1.46/MWh (3.2 percent), compared to a decrease of $0.07/MWh (0.4 percent) in 2019.

Figure 7.2 Overall impact of congestion on price separation in the day-ahead market

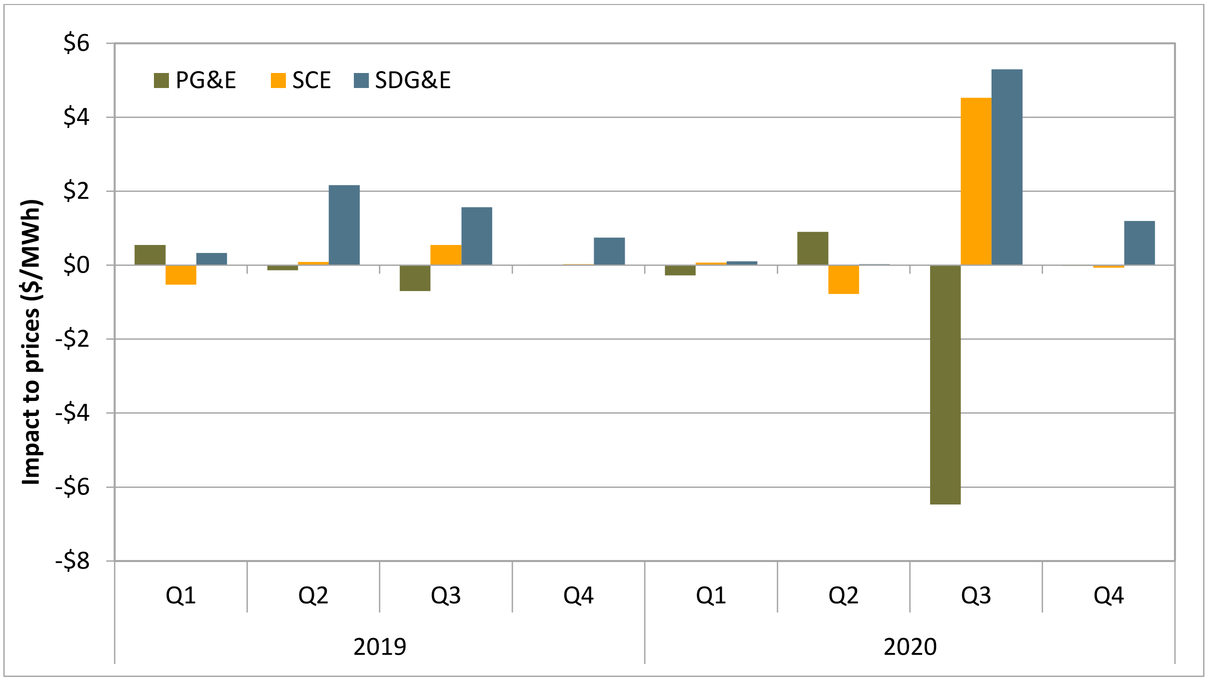
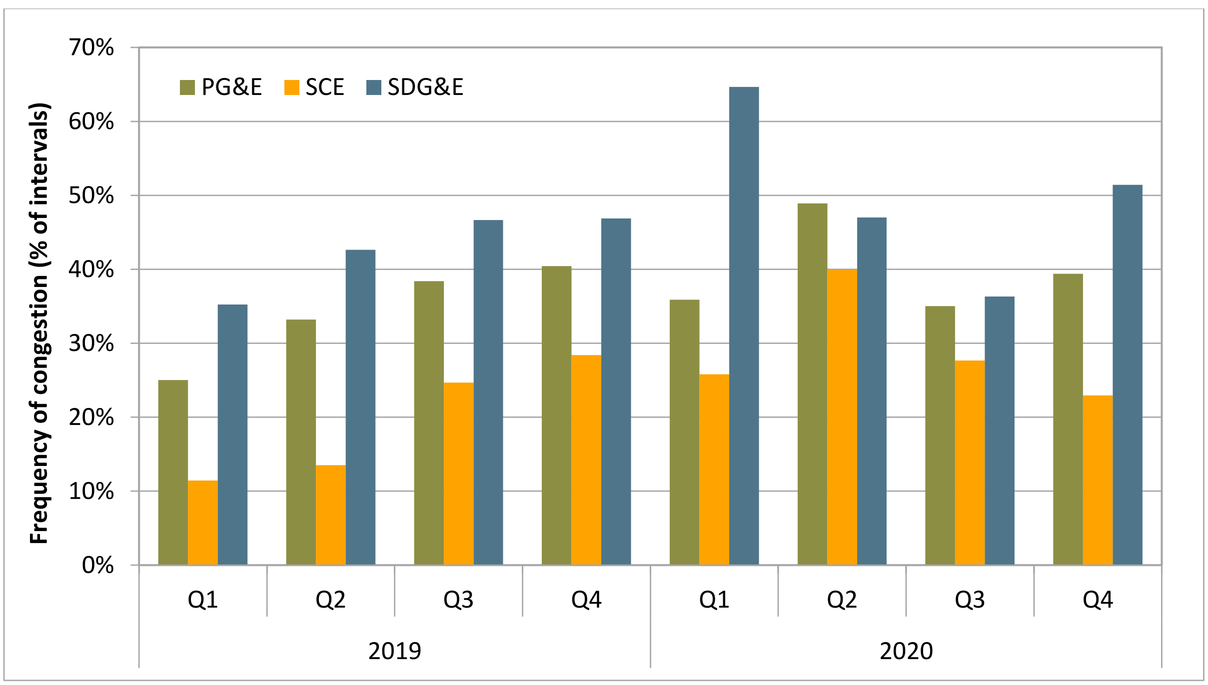


Figure 7.3 Percent of hours with congestion impacting prices by load area



The frequency of congestion increased in 2020 relative to 2019. This frequency impacting San Diego Gas and Electric area prices peaked during the first quarter, while Pacific Gas and Electric and Southern California Edison areas peaked during the second quarter.

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 prices in the San Diego Gas and Electric area in the first quarter of 2020 was very low, despite having the highest quarterly frequency of congestion for the year. 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. This offsetting congestion can be observed, to some extent, in all quarters of 2020.

Information regarding the impact of congestion from individual constraints shown below, with additional detail on the cause of congestion for constraints with the largest impact on prices.

Table 7.1 shows the overall impact of congestion from different constraints on average prices in each load aggregation area in 2020. Additionally, the table shows the frequency with which each constraint was binding in each quarter.[199] The constraints that had the greatest impact on price separation throughout the year were a Path 26 nomogram, the Midway-Vincent #2 500 kV line, and the Quinto-Los Banos 230 kV line.

Path 26 Nomogram

The Path 26 nomogram (6410_CP6_NG) was not binding frequently but did impact average prices across the CAISO balancing area. Overall for the year, it increased prices in the Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E) areas by $0.64/MWh (1.8 percent) and $0.60/MWh (1.6 percent), respectively. It decreased prices in the Pacific Gas and Electric (PG&E) area by $0.90/MWh (2.7 percent). The nomogram is enforced to mitigate an overload when two Path 26 lines are out of service. It was used in the third quarter when the Lake Fire forced multiple lines to be de-energized.

Midway-Vincent #2 500 kV line

The Midway-Vincent #2 500 kV line (30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3) increased prices in SCE and SDG&E areas by about $0.56/MWh (1.6 percent) and $0.54/MWh (1.5 percent), respectively. Conversely, congestion on this line decreased average prices in PG&E by about $0.80/MWh (2.4 percent). This line was congested throughout the year and was heavily impacted by the August heat wave in the third quarter.

Quinto-Los Banos 230 kV line

The Quinto-Los Banos 230 kV line (30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1) increased prices in PG&E by about $0.21/MWh (0.6 percent), while it decreased prices in both SCE and SDG&E by about $0.18/MWh (0.5 percent) and $0.16/MWh (0.4 percent), respectively. This line bound primarily due to maintenance on the Tesla-Los Banos 500 kV line.

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199 To see the breakdown of each individual constraint's impact on prices during the respective quarter, 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

Table 7.1 Impact of constraint congestion on overall day-ahead prices during all hours (2020)

Constraint Location	Constraint	Frequency				PG&E		SCE		SDG&E	
		Q1	Q2	Q3	Q4	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
PG&E	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	4.9%	21.9%	0.2%	5.7%	$0.21	0.63%	-$0.18	-0.50%	-$0.16	-0.43%
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	4.7%	28.8%	2.6%	1.9%	$0.11	0.34%	-$0.09	-0.24%	-$0.08	-0.21%
	40687_MALIN _500_30005_ROUND MT_500_BR_1 _3	0.0%	0.0%	1.2%	4.2%	$0.06	0.16%	-$0.04	-0.11%	-$0.05	-0.13%
	OMS 6196189 Moss Landing PP	0.3%	2.3%	0.0%	0.0%	$0.02	0.05%	-$0.02	-0.04%	-$0.02	-0.04%
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	0.0%	0.5%	1.9%	0.0%	$0.02	0.05%	-$0.01	-0.03%	-$0.02	-0.04%
	7440_MetcalfImport_Tes-Metcalf	0.0%	0.0%	1.4%	0.8%	$0.01	0.03%	-$0.01	-0.02%	-$0.01	-0.02%
	30735_METCALF _230_30042_METCALF _500_XF_12	1.2%	0.0%	0.0%	0.0%	$0.01	0.02%	-$0.01	-0.01%	-$0.01	-0.01%
	30735_METCALF _230_30042_METCALF _500_XF_13	0.0%	1.0%	0.0%	0.0%	$0.00	0.01%	$0.00	-0.01%	$0.00	-0.01%
	30055_GATES1 _500_30900_GATES _230_XF_11_S	0.0%	0.0%	0.0%	0.5%	$0.00	0.01%	$0.00	-0.01%	$0.00	-0.01%
	30005_ROUND MT_500_30015_TABLE MT_500_BR_2 _2	0.0%	0.0%	0.3%	0.0%	$0.00	0.01%	$0.00	-0.01%	$0.00	-0.01%
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	0.0%	0.6%	0.0%	0.0%	-$0.01	-0.02%	$0.01	0.01%	$0.01	0.01%
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	0.6%	0.1%	0.5%	0.5%	-$0.01	-0.02%	$0.00	0.01%	$0.00	0.01%
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	0.0%	0.2%	0.4%	0.3%	-$0.01	-0.04%	$0.01	0.03%	$0.01	0.03%
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	2.2%	0.2%	17.3%	1.5%	-$0.80	-2.41%	$0.56	1.58%	$0.54	1.46%
SCE	6410_CP6_NG	0.0%	0.0%	2.2%	0.0%	-$0.90	-2.70%	$0.64	1.79%	$0.60	1.63%
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	0.1%	0.1%	1.9%	4.7%	-$0.02	-0.06%	$0.02	0.06%	$0.01	0.04%
	24084_LITEHIPE_230_24091_MESA CAL_230_BR_1 _1	3.1%	0.0%	0.0%	0.0%	-$0.02	-0.06%	$0.02	0.05%	$0.02	0.05%
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	0.6%	1.2%	1.6%	1.0%	-$0.01	-0.04%	$0.02	0.05%	$0.00	0.00%
	25201_LEWIS _230_24137_SERRANO _230_BR_2 _1	2.3%	0.0%	0.0%	0.0%	-$0.01	-0.02%	$0.01	0.02%	$0.00	0.00%
	24091_MESA CAL_230_24076_LAGUBELL_230_BR_1 _1	0.0%	1.1%	0.0%	0.0%	-$0.01	-0.03%	$0.01	0.02%	$0.00	0.01%
	6410_CP5_NG	0.0%	0.0%	0.0%	0.5%	$0.00	-0.01%	$0.00	0.01%	$0.00	0.01%
	OMS 9076082 ELD-MHV_NG	0.0%	0.0%	0.0%	9.1%	$0.00	0.01%	$0.00	0.00%	-$0.03	-0.08%
	24114_PARDEE _230_24147_SYLMAR S_230_BR_2 _1	0.0%	0.0%	0.0%	2.7%	$0.01	0.01%	$0.00	0.00%	-$0.02	-0.05%
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	3.0%	0.0%	0.4%	4.1%	$0.00	0.00%	$0.00	0.00%	$0.01	0.02%
	OMS 8220388_N2_DV2_N1SV500	0.0%	5.1%	0.0%	0.0%	$0.01	0.01%	$0.00	-0.01%	$0.00	0.00%
	OMS 8095129_D-SBLR_OOS_N1SV500	4.0%	5.5%	0.0%	0.0%	$0.01	0.02%	-$0.01	-0.02%	$0.00	0.00%
	6410_CP10_NG	0.6%	0.0%	0.0%	2.8%	$0.04	0.11%	-$0.03	-0.09%	-$0.03	-0.08%
SDG&E	7820_TL 230S_OVERLOAD_NG	11.2%	8.1%	2.4%	4.8%	-$0.02	-0.05%	$0.00	0.00%	$0.17	0.46%
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	1.4%	0.1%	0.0%	3.8%	-$0.03	-0.08%	$0.00	0.00%	$0.16	0.42%
	24138_SERRANO _500_24137_SERRANO _230_XF_3	8.5%	0.0%	0.0%	0.0%	-$0.08	-0.25%	$0.05	0.14%	$0.15	0.40%
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	0.0%	0.0%	1.6%	4.3%	-$0.02	-0.07%	$0.00	0.00%	$0.14	0.37%
	7820_TL23040_IV_SPS_NG	0.1%	0.4%	2.7%	0.0%	-$0.01	-0.02%	$0.00	0.00%	$0.10	0.26%
	22886_SUNCREST_230_92861_SUNC TP2_230_BR_2 _1	0.0%	0.0%	3.8%	0.1%	$0.00	0.00%	$0.00	0.00%	$0.08	0.21%
	OMS 8447302 ML_BK80_NG	0.0%	3.7%	0.0%	0.0%	-$0.01	-0.02%	$0.00	0.00%	$0.05	0.15%
	OMS 8701994_50001_OOS_NG	0.0%	0.0%	0.0%	0.4%	$0.00	-0.01%	$0.00	0.00%	$0.04	0.12%
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	0.0%	3.7%	0.0%	0.0%	-$0.02	-0.07%	$0.01	0.03%	$0.04	0.12%
	OMS 8701990_50001_OOS_NG	0.0%	0.0%	0.0%	0.3%	$0.00	-0.01%	$0.00	0.00%	$0.04	0.11%
	OMS 9300871_50001_OOS_NG	11.2%	8.1%	2.4%	4.8%	$0.00	-0.01%	$0.00	0.00%	$0.03	0.08%
	MIGUEL_BKs_MXFLW_NG	1.4%	0.1%	0.0%	3.8%	$0.00	-0.01%	$0.00	0.00%	$0.03	0.08%
	OMS 8701965_50001_OOS_NG	8.5%	0.0%	0.0%	0.0%	$0.00	-0.01%	$0.00	0.00%	$0.02	0.05%
	OMS 8618881 MG_BK81_NG	0.0%	0.0%	1.6%	4.3%	$0.00	-0.01%	$0.00	0.00%	$0.02	0.05%
	OMS 8092833 MG-BK81_NG	0.1%	0.4%	2.7%	0.0%	$0.00	-0.01%	$0.00	0.00%	$0.02	0.04%
	OMS 8573611 SUNCREST BK81_NG	0.0%	0.0%	3.8%	0.1%	$0.00	0.00%	$0.00	0.00%	$0.02	0.04%
	OMS 8098960_TL50003_NG	0.0%	3.7%	0.0%	0.0%	$0.00	-0.01%	$0.00	0.00%	$0.02	0.04%
	OMS 8286163_50001_OOS_NG	0.0%	0.0%	0.0%	0.4%	$0.00	0.00%	$0.00	0.00%	$0.01	0.04%
	OMS 8286167_50001_OOS_NG	0.0%	3.7%	0.0%	0.0%	$0.00	0.00%	$0.00	0.00%	$0.01	0.04%
	OMS 8286176_50001_OOS_NG	0.0%	0.0%	0.0%	0.3%	$0.00	0.00%	$0.00	0.00%	$0.01	0.03%
	OMS 8247851_50001_OOS_NG	0.0%	0.0%	0.0%	0.5%	$0.00	0.00%	$0.00	0.00%	$0.01	0.03%
	22644_PENSQTOS_69.0_22164_DELMARTP_69.0_BR_1 _1	0.4%	0.3%	0.0%	0.5%	$0.00	0.00%	$0.00	0.00%	$0.01	0.03%
	OMS 8420328_50004_OOS_NG	0.0%	0.0%	0.0%	0.3%	$0.00	0.00%	$0.00	0.00%	$0.01	0.03%
	OMS 8098953_TL50003_NG	0.0%	0.0%	1.9%	0.0%	$0.00	0.00%	$0.00	0.00%	$0.01	0.03%
	OMS 8523747_TL50003_NG	0.6%	0.0%	0.0%	0.0%	$0.00	0.00%	$0.00	0.00%	$0.01	0.03%
	OMS 8092823 MG-BK81_NG	0.0%	1.3%	0.0%	0.0%	$0.00	0.00%	$0.00	0.00%	$0.01	0.02%
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	0.5%	0.0%	0.0%	0.0%	$0.00	-0.01%	$0.00	0.01%	$0.01	0.01%
	OMS 8929209_D-SBLR_OOS_CP3	0.5%	0.0%	0.0%	0.0%	$0.02	0.04%	$0.00	-0.01%	-$0.02	-0.06%
	22644_PENSQTOS_69.0_22492_MIRAMRTP_69.0_BR_1 _1	0.6%	0.0%	0.0%	0.0%	$0.00	0.00%	$0.00	0.00%	-$0.08	-0.21%
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	0.4%	0.0%	0.0%	0.0%	$0.00	0.00%	$0.00	0.00%	-$0.28	-0.77%
Other	Other					$0.04	0.13%	-$0.01	-0.04%	$0.05	0.14%
Total	**Total**					**-$1.47**	**-4.41%**	**$0.95**	**2.66%**	**$1.67**	**4.53%**

7.1.2 Real-time congestion

Congestion in the 15-minute real-time market was similar to the 5-minute market, but had a lower impact on locational price differences.[200] Below is an analysis of the frequency and effects of congestion in each of these real-time markets.

Congestion in the 15-minute market from internal, flow-based constraints

Figure 7.4 shows price separation resulting from internal congestion on load areas in the ISO and energy imbalance market by quarter. Figure 7.5 shows the percent of hours with internal congestion increasing versus decreasing 15-minute prices by more than $0.05/MWh in 2020.

In 2019, DMM enhanced the congestion frequency and impact metrics by removing the energy imbalance market greenhouse gas (GHG) component, removing energy imbalance market transfer constraint congestion, correcting for market interruptions, and adjusting for price corrections. These changed the focus of these metrics on the impact of internal transmission constraint congestion alone.[201]

Over the entire year, in the ISO, congestion resulted in a net increase to prices for Southern California Edison, San Diego Gas and Electric areas; while resulting in a net decrease to prices in Pacific Gas and Electric area. In the EIM, congestion due to internal constraints resulted in a net decrease to prices in all of the balancing areas.

On a quarterly basis, net price separation due to internal congestion was greatest in the third quarter. During this quarter, San Diego Gas and Electric experienced the largest price impact, with prices increasing by $8.44/MWh. Price impacts in PacifiCorp West, Portland General Electric, Puget Sound Energy, Powerex, and Seattle City Light were very similar in each quarter, leading to prices in these areas decreasing by an average of 27 percent due to internal congestion during the third quarter of 2020.

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 fourth quarter, followed by the third quarter. In each quarter, congestion decreased prices more than it increased prices. For 2020, PacifiCorp East had the largest average frequency of congestion, as shown in Figure 7.5. This congestion in PacifiCorp East primarily decreased prices (50 percent of intervals) rather than increased prices (less than 1 percent of intervals).

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.

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200 In 2020, as in previous years, 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.

201 These factors were included in reports prior to the 2019 annual report, and mainly manifested themselves in the "Other" category.

Figure 7.4 Overall impact of internal congestion on price separation in the 15-minute market

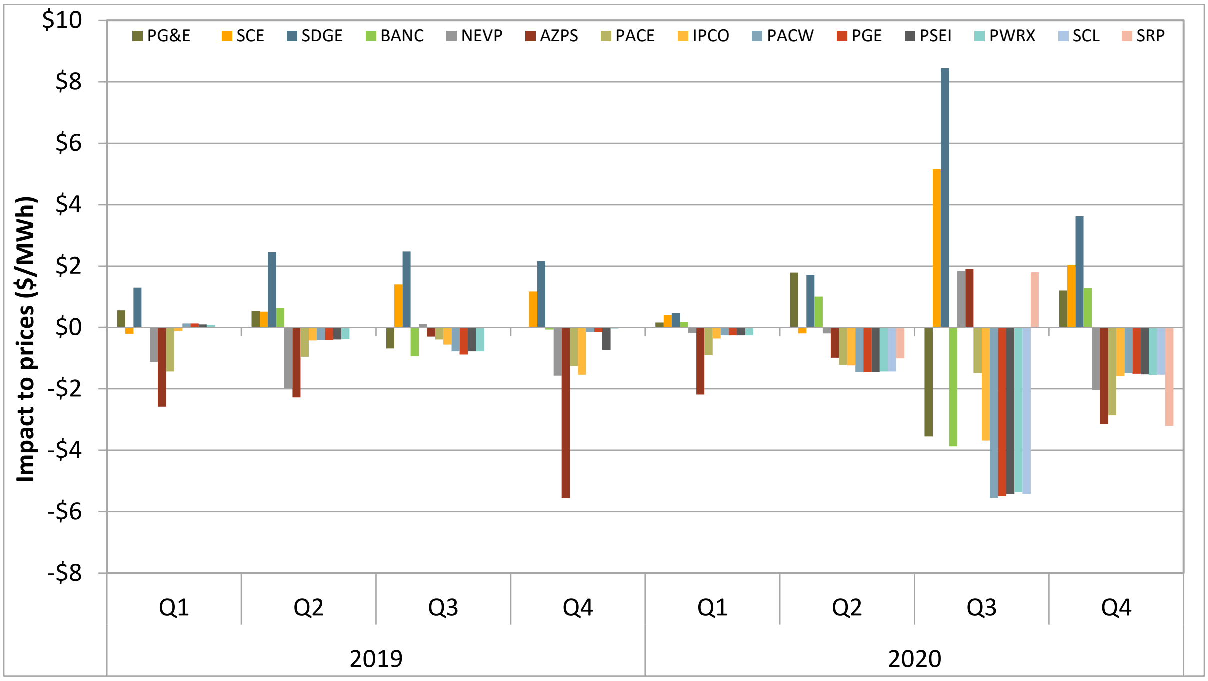


Figure 7.5 Average percent of hours with internal congestion increasing versus decreasing 15-minute prices in 2020 (>$0.05/MWh)

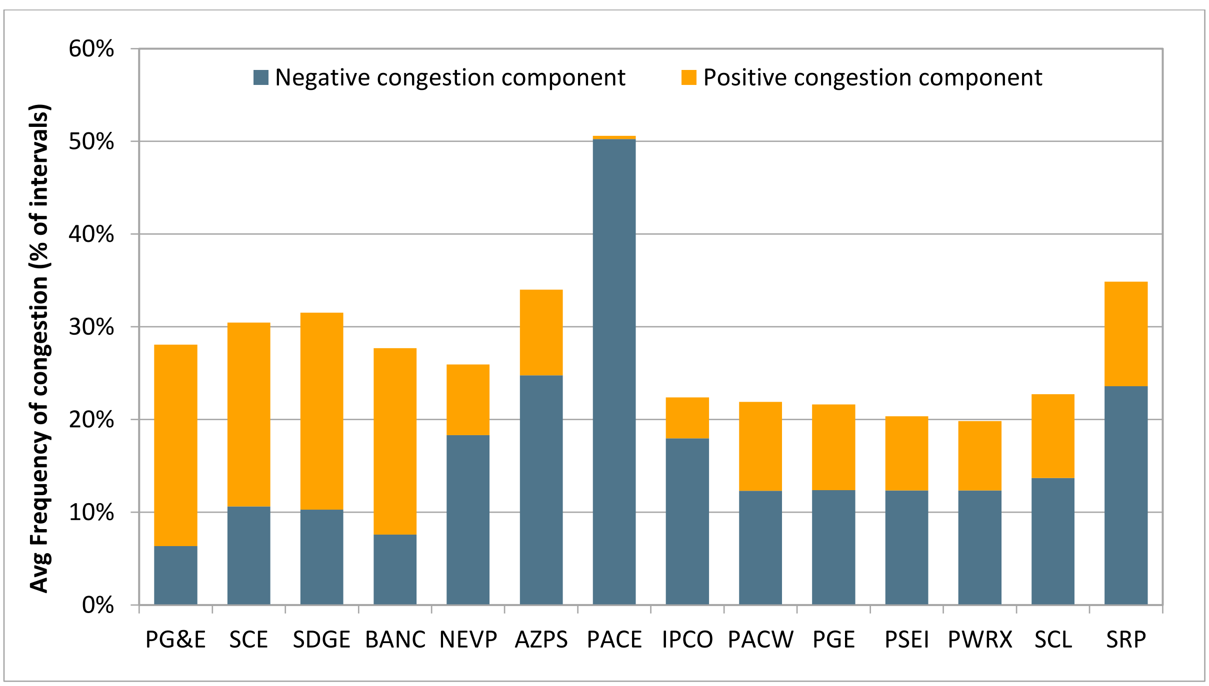


Table 7.2 shows the overall impact of 15-minute congestion from individual constraints on prices in each load area in 2020. The color scales in the table below help to highlight congestion that was particularly impactful. The impact from transfer constraints are included at the bottom of the table and are discussed in greater depth in Section 7.1.3. This section focuses on individual flow-based constraints that are internal to balancing authority areas, rather than schedule-based constraints between areas.

The constraints that had the greatest impact on price separation in the 15-minute market were the Midway-Vincent #2 500 kV line, the Malin-Round Mountain 500 kV line, and the constraints associated with the Round Mountain-Table Mountain nomogram.

Midway-Vincent #2 500 kV line

The Midway-Vincent #2 500 kV line (30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3) had the greatest impact on average 15-minute prices for the year. Congestion on the line increased average prices in areas south of the line by about $0.72/MWh and decreased prices north of the line by $0.65/MWh. Similar to the day-ahead market, this line was heavily impacted by the August heat wave in the third quarter, as well as outages on the Midway-Whirlwind 500 kV line.

Malin-Round Mountain 500 kV line

The second most impacted constraint overall was the Malin-Round Mountain 500 kV line (40687_MALIN _500_30005_ROUND MT_500_BR_1 _3). Over the course of the year, it increased average prices in areas south of the line by $0.17/MWh, while it decreased prices north of the line by $0.42/MWh on average. The line was impacted by scheduled maintenance and high unscheduled flows throughout the latter part of 2020.

Round Mountain-Table Mountain nomogram

The Round Mountain-Table Mountain nomogram (RM_TM21_NG) had the third largest overall impact on price separation in 2020. Congestion on the constraints associated with the nomogram increased prices south of the line by an average of $0.12/MWh, and decreased average prices north of the line by $0.38/MWh. This constraint was impacted by outages on the Round Mountain-Table Mountain #1 500 kV line.

Table 7.2 Impact of internal constraint congestion on overall 15-minute prices during all hours

Constraint Location	Constraint	PGAE	SCE	SDGE	BANC	NEVP	AZPS	SRP*	PACE	IPCO	PACW	PGE	PSEI	PWRX	SCL*
NEVP	CAL-DRM_2 120	-$0.01	$0.00	$0.00	-$0.03	$0.09	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
PACE	TOTAL_WYOMING_EXPORT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.09	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	WYOMING_EXPORT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.22	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
PG&E	40687_MALIN _500_30005_ROUND MT_500_BR_1 _3	$0.32	$0.16	$0.14	$0.32	$0.01	$0.10	$0.12	-$0.18	-$0.33	-$0.46	-$0.46	-$0.46	-$0.45	-$0.58
	RM_TM21_NG	$0.25	$0.13	$0.11	$0.18	$0.00	$0.08	$0.10	-$0.17	-$0.31	-$0.42	-$0.42	-$0.41	-$0.41	-$0.54
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	$0.17	$0.10	$0.09	$0.11	$0.02	$0.06	$0.08	-$0.12	-$0.21	-$0.28	-$0.28	-$0.28	-$0.27	-$0.36
	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.15	-$0.34	-$0.32	$0.38	-$0.16	-$0.28	-$0.29	$0.00	$0.12	$0.24	$0.24	$0.23	$0.23	$0.25
	OMS 6196189 Moss Landing PP	$0.10	-$0.04	-$0.04	$0.00	-$0.04	-$0.04	-$0.05	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.09	-$0.04	-$0.02	$0.00	$0.00	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30640_TESLA C _230_30040_TESLA _500_XF_6	$0.05	-$0.02	-$0.02	$0.00	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02
	7440_MetcalfImport_Tes-Metcalf	$0.02	-$0.01	-$0.01	$0.01	-$0.01	-$0.01	-$0.02	$0.00	$0.00	$0.01	$0.00	$0.00	$0.00	$0.01
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _2	$0.01	-$0.01	-$0.01	$0.01	-$0.01	-$0.01	-$0.02	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.01	-$0.01	-$0.01	$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
	30005_ROUND MT_500_30015_TABLE MT_500_BR_2 _2	$0.01	$0.00	$0.00	$0.01	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02
	30050_LOSBANOS_500_30055_GATES1 _500_BR_3 _1	$0.01	-$0.01	-$0.01	$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	$0.01	-$0.01	-$0.01	$0.01	$0.00	-$0.01	-$0.01	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.00
	SUMMIT2-DRUM	-$0.01	$0.00	$0.00	-$0.03	$0.06	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	-$0.07	$0.06	$0.06	-$0.07	$0.03	$0.05	$0.07	$0.00	-$0.03	-$0.05	-$0.05	-$0.05	-$0.05	-$0.07
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	-$0.07	$0.05	$0.05	-$0.07	$0.03	$0.05	$0.06	-$0.01	-$0.03	-$0.06	-$0.06	-$0.05	-$0.05	-$0.07
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	-$0.10	$0.09	$0.09	-$0.09	$0.05	$0.07	$0.10	$0.00	-$0.04	-$0.07	-$0.07	-$0.07	-$0.07	-$0.09
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.99	$0.81	$0.78	-$0.92	$0.46	$0.67	$0.87	-$0.01	-$0.39	-$0.69	-$0.70	-$0.66	-$0.65	-$0.87
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1	$0.00	$0.00	$0.00	-$0.02	$0.21	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SCE	6410_CP1_NG	-$0.22	$0.18	$0.18	-$0.21	$0.10	$0.16	$0.21	$0.00	-$0.09	-$0.16	-$0.16	-$0.16	-$0.15	-$0.21
	OMS 9076082 ELD-MHV_NG	$0.15	$0.15	$0.04	$0.13	-$0.34	-$0.30	-$0.40	-$0.17	-$0.06	$0.01	$0.01	$0.01	$0.00	$0.01
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.06	$0.11	$0.06	$0.05	-$0.18	-$0.16	-$0.22	-$0.09	-$0.03	$0.01	$0.00	$0.00	$0.00	$0.00
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.02	$0.08	$0.08	-$0.02	-$0.02	-$0.03	-$0.02	-$0.03	-$0.03	-$0.02	-$0.02	-$0.02	-$0.02	-$0.01
	24156_VINCENT _500_24155_VINCENT _230_XF_4 _P	-$0.06	$0.08	$0.05	-$0.06	$0.00	$0.02	$0.02	-$0.01	-$0.03	-$0.05	-$0.05	-$0.05	-$0.05	-$0.06
	29400_ANTELOPE_500_29402_WIRLWIND_500_BR_1 _1	-$0.06	$0.06	$0.06	-$0.06	$0.03	$0.05	$0.07	$0.00	-$0.02	-$0.04	-$0.04	-$0.04	-$0.04	-$0.05
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	$0.00	$0.05	$0.00	$0.00	-$0.02	-$0.02	-$0.02	-$0.02	-$0.01	$0.00	$0.00	$0.00	$0.00	-$0.01
	6410_CP6_NG	-$0.06	$0.05	$0.05	-$0.06	$0.03	$0.04	$0.06	$0.00	-$0.02	-$0.04	-$0.04	-$0.04	-$0.04	-$0.05
	SYLMAR-AC_BG	$0.00	$0.03	$0.00	$0.00	-$0.03	-$0.03	-$0.03	-$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	24025_CHINO _230_24093_MIRALOM _230_BR_3 _1	-$0.02	$0.02	$0.05	-$0.02	-$0.01	$0.00	$0.00	-$0.01	-$0.01	-$0.02	-$0.02	-$0.01	-$0.01	-$0.01
	24114_PARDEE _230_24147_SYLMAR S_230_BR_2 _1	$0.03	$0.00	-$0.03	$0.02	-$0.05	-$0.05	-$0.07	-$0.02	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
	8705726_Devers VISTA1_NG	$0.01	$0.00	$0.00	$0.00	$0.00	-$0.02	-$0.03	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	6410_CP10_NG	$0.01	-$0.02	-$0.02	$0.01	-$0.01	-$0.01	-$0.02	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
	OMS 8220388_N2_DV2_N1SV500	$0.02	-$0.02	$0.00	$0.02	$0.00	-$0.04	-$0.06	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
SDG&E	7820_TL 230S_OVERLOAD_NG	$0.00	$0.03	$0.50	$0.00	-$0.04	-$0.11	-$0.08	-$0.04	-$0.02	$0.00	$0.00	$0.00	$0.00	$0.00
	MIGUEL_BKs_MXFLW_NG	$0.00	$0.00	$0.44	$0.00	$0.00	-$0.14	-$0.18	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	$0.00	$0.04	$0.40	$0.00	-$0.04	-$0.13	-$0.15	-$0.04	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	22468_MIGUEL _500_22472_MIGUELMP_ 1.0_XF_80	$0.00	$0.00	$0.36	$0.00	-$0.02	-$0.11	-$0.14	-$0.03	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 8573611 SUNCREST BK81_NG	$0.00	$0.00	$0.29	$0.00	-$0.01	-$0.09	-$0.12	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	22886_SUNCREST_230_92861_SUNC TP2_230_BR_2 _1	$0.00	$0.00	$0.21	$0.00	$0.00	-$0.07	-$0.09	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.03	$0.06	$0.15	-$0.03	-$0.01	-$0.02	$0.00	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.03	-$0.01
	OMS 8447302 ML_BK80_NG	$0.00	$0.00	$0.04	$0.00	$0.00	-$0.01	-$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	24138_SERRANO _500_24137_SERRANO _230_XF_3	-$0.01	$0.02	$0.03	-$0.01	$0.00	-$0.01	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	$0.00
	25201_LEWIS _230_24137_SERRANO _230_BR_2 _1	-$0.01	$0.03	$0.02	-$0.01	-$0.01	-$0.01	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	$0.00
	OMS 8421617_D-VST2_OOS_CP3	$0.01	-$0.01	$0.00	$0.01	-$0.01	-$0.03	-$0.04	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	24132_SANBRDNO_230_24804_DEVERS _230_BR_1 _1	$0.00	$0.00	-$0.01	$0.00	$0.00	-$0.27	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 8929209_D-SBLR_OOS_CP3	$0.04	-$0.03	-$0.01	$0.04	-$0.01	-$0.14	-$0.20	-$0.01	$0.00	$0.02	$0.01	$0.01	$0.01	$0.01
	22644_PENSQTOS_69.0_22492_MIRAMRTP_69.0_BR_1 _1	$0.00	$0.00	-$0.15	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	$0.00	$0.00	-$0.33	$0.00	$0.00	-$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Other	$0.11	$0.03	$0.26	$0.00	-$0.20	-$0.23	-$0.23	-$0.19	-$0.07	-$0.06	-$0.03	-$0.07	-$0.07	-$0.06
	Internal Total	**-$0.10**	**$1.85**	**$3.58**	**-$0.36**	**-$0.14**	**-$1.10**	**-$0.80**	**-$1.62**	**-$1.72**	**-$2.19**	**-$2.18**	**-$2.17**	**-$2.16**	**-$2.80**
	Transfers				-$1.02	$5.55	$0.34	-$0.17	-$1.52	-$1.61	-$4.54	-$4.53	-$4.60	-$5.77	-$5.94
	Grand Total	**-$0.10**	**$1.85**	**$3.58**	**-$1.38**	**$5.41**	**-$0.76**	**-$0.97**	**-$3.14**	**-$3.33**	**-$6.73**	**-$6.71**	**-$6.77**	**-$7.93**	**-$8.74**

**April 1 to December 31, 2020 only*

Congestion in the 5-minute market from internal, flow-based constraints

Figure 7.6 shows the average price separation resulting from congestion between ISO area and energy imbalance market area prices in the 5-minute market by quarter. Figure 7.7 shows the average percent of hours with congestion increasing versus decreasing 5-minute prices by more than $0.05/MWh in 2020.

Congestion frequency in the 5-minute market was very similar to that of the 15-minute market. The most notable difference between the two markets is that price impacts were higher in the 15-minute market. Internal congestion in the 5-minute market resulted in a net increase to prices in Southern California Edison, San Diego Gas and Electric, and NV Energy; while resulting in a net decrease to prices in Pacific Gas and Electric as well as the rest of the Western EIM. The greatest net increase to average prices occurred in the San Diego Gas and Electric area, while the greatest net decrease occurred in the Portland General Electric balancing area.

On a quarterly basis, net price separation due to congestion was greatest in the third quarter. During which, San Diego Gas and Electric experienced the largest price impact, with prices increasing by $6.91/MWh. Price impacts in PacifiCorp West, Portland General Electric, Puget Sound Energy, Powerex, and Seattle City Light were very similar for each quarter, averaging a net decrease of $1.85/MWh over the year.

The frequency of congestion steadily increased over the course of the year, with the highest average frequency occurring during the fourth quarter. In each quarter, congestion more frequently decreased prices than increased prices across energy imbalance market areas. For 2020, PacifiCorp East was most frequently impacted by congestion from internal constraints in the 5-minute market. Most of this congestion in the PacifiCorp East area drove prices down (45 percent of intervals) rather than increasing prices (less than 1 percent of intervals).

Figure 7.6 Overall impact of internal congestion on price separation in the 5-minute market

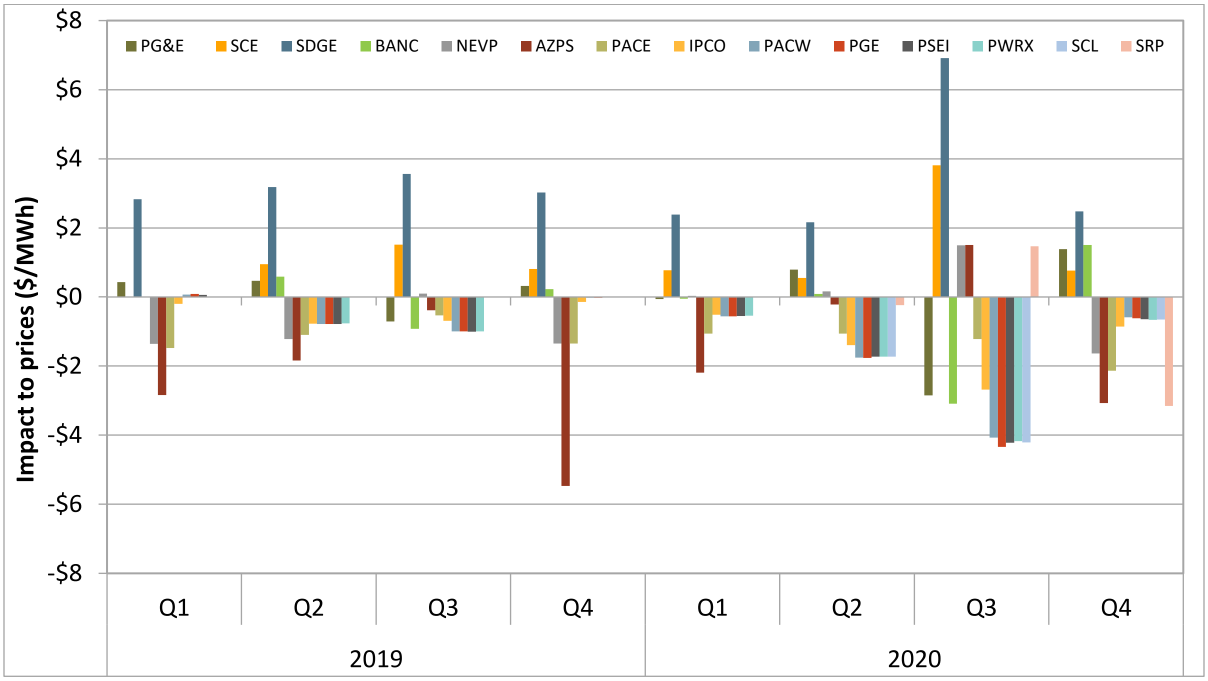
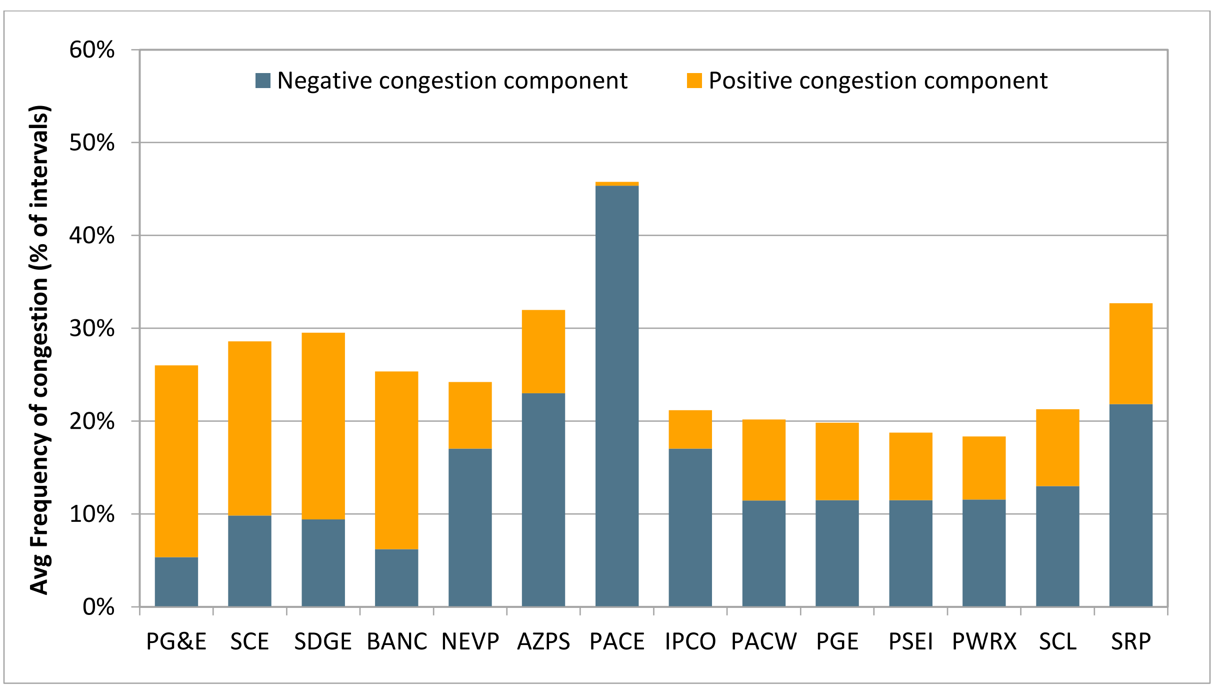


Figure 7.7 Average percent of hours with internal congestion increasing versus decreasing 5-minute prices in 2020 (>$0.05/MWh)



7.1.3 Congestion on EIM transfer constraints

This section focuses on price impact due to congestion on schedule-based transfer constraints. In the 15-minute market, the total impact of congestion on a specific energy imbalance market (EIM) area is equal to the sum of price impact of flow-based (listed in Table 7.2) and schedule-based constraints (listed in Table 7.3).[202]

The results of this section are the same as those found in Section 3.3.3 of this report. Both sections analyze transfer constraint congestion in the EIM; however, each focuses on different aspects. Section 3.3.3 focuses on the impact of transfer constraint congestion to transfer capability. Thus, Section 3.3.3 discusses congestion frequency split by the direction of congestion into (import congestion) or out of (export congestion) an energy imbalance market area. Conversely, this section discusses the same data as an increase or decrease to prices. When congestion decreases prices in an energy imbalance market area relative to the system, this indicates congestion out of an area and limited export capability. Conversely, when prices are higher within an area relative to the system, this indicates that congestion is limiting the ability for energy outside of an area to serve that area's load (i.e., import capability is limited).

Table 7.3 shows the frequency of transfer constraint congestion and average price impact in the 15-minute and 5-minute markets for 2020. As shown in the figure, the highest frequency occurred either into or away from the EIM load areas located in the Pacific Northwest. On average, this congestion typically reduced prices in those areas. Notably in Salt River Project, the average price impact from transfer congestion in the 15-minute market was negative, while it was positive in the 5-minute market.

Table 7.3 Average price impact and congestion frequency on EIM transfer constraints (2020)

	15-minute market		5-minute market	
	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)
BANC	1%	-$1.02	1%	-$0.15
Arizona Public Service	4%	$0.34	3%	$1.54
NV Energy	4%	$5.55	3%	$7.24
PacifiCorp East	8%	-$1.52	5%	-$0.38
Idaho Power	8%	-$1.61	5%	-$0.63
Salt River Project*	10%	-$0.17	10%	$1.34
PacifiCorp West	37%	-$4.54	25%	-$2.75
Portland General Electric	41%	-$4.53	29%	-$2.59
Puget Sound Energy	41%	-$4.60	33%	-$2.79
Seattle City Light*	44%	-$5.94	35%	-$3.86
Powerex	48%	-$5.77	48%	-$4.09

**April 1 to December 31, 2020 only*

[202] The marginal congestion component at each energy imbalance market load area is adjusted to remove the impact due to greenhouse gas price.

Transfer congestion in the 15-minute market

Figure 7.8 shows the frequency of congestion on transfer constraints by quarter for 2019 and 2020. Figure 7.9 shows the average impact to prices in the 15-minute market by quarter over the same time period.

In 2020, the frequency of congestion was highest among the load areas located in the Pacific Northwest. Since entering the market in the second quarter of 2020, transfer constraint congestion into and out of Seattle City Light area bound with a similar frequency to that of other Pacific Northwest EIM entities. In contrast, transfer constraint congestion into and out of Salt River Project bound with a higher frequency than other Southwest EIM entities.

As shown in Figure 7.9, transfer congestion had a significant impact on price separation in the third quarter; during which time, it increased prices in NV Energy by an average of $15.06/MWh. Transfer congestion also decreased prices in balancing areas located in the Pacific Northwest with a higher than average magnitude than 2019.

Figure 7.8 EIM transfer constraint congestion frequency in the 15-minute market (>$0.01/MWh)

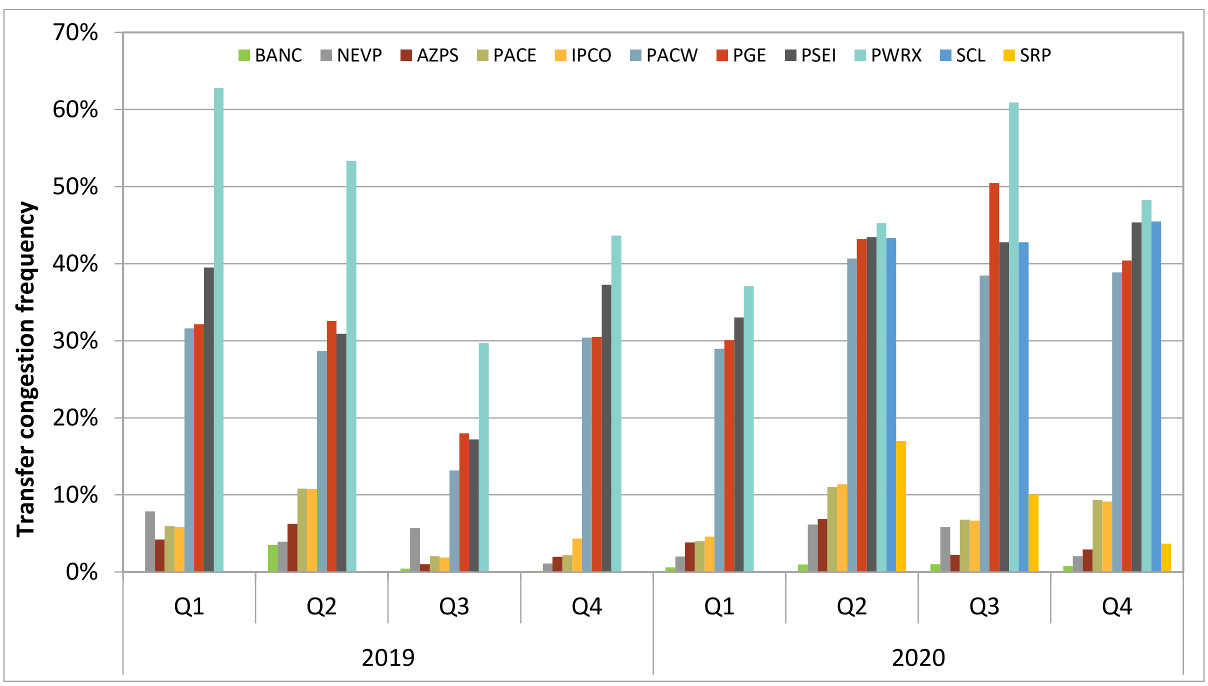
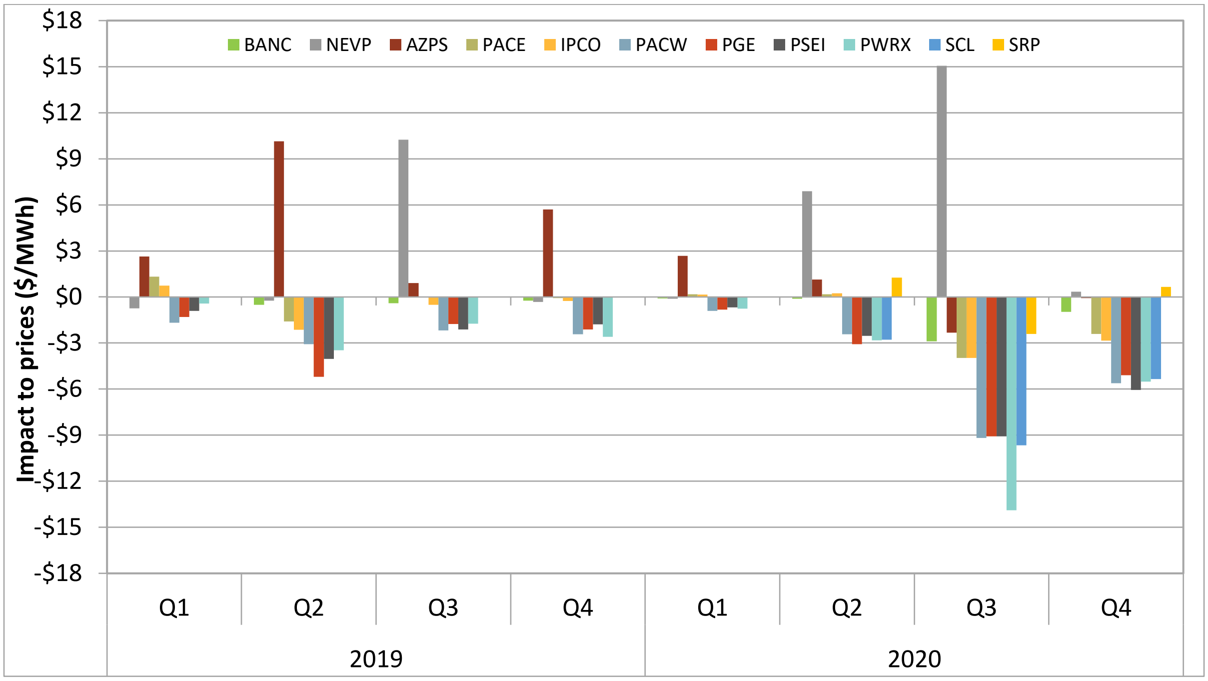


Figure 7.9 EIM transfer constraint congestion average impact on prices in the 15-minute market



Transfer congestion in the 5-minute market

Figure 7.10 shows the frequency of congestion on transfer constraints in the 5-minute market by quarter for 2019 and 2020. Figure 7.11 shows the average impact on price in the 5-minute market by quarter over the same time period.

Similar to previous years, the frequency of congestion was highest among the load areas located in the Pacific Northwest. The net impact of congestion reduced prices in those areas by an average of $3.18/MWh over the course of 2020. Similar to the 15-minute market, transfer congestion frequency was relatively low for the Arizona Public Service and NV Energy load areas but the impact was large, raising prices on average by $1.55/MWh and $7.22/MWh, respectively.

Figure 7.10 EIM transfer constraint congestion frequency in the 5-minute market

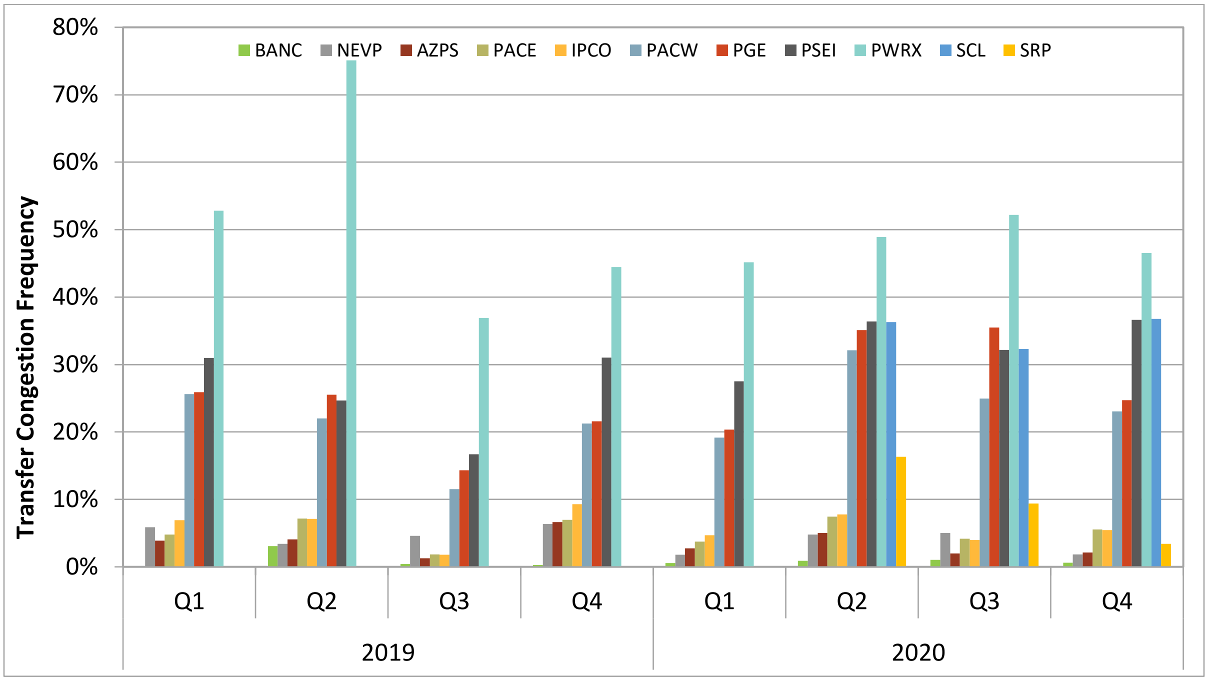
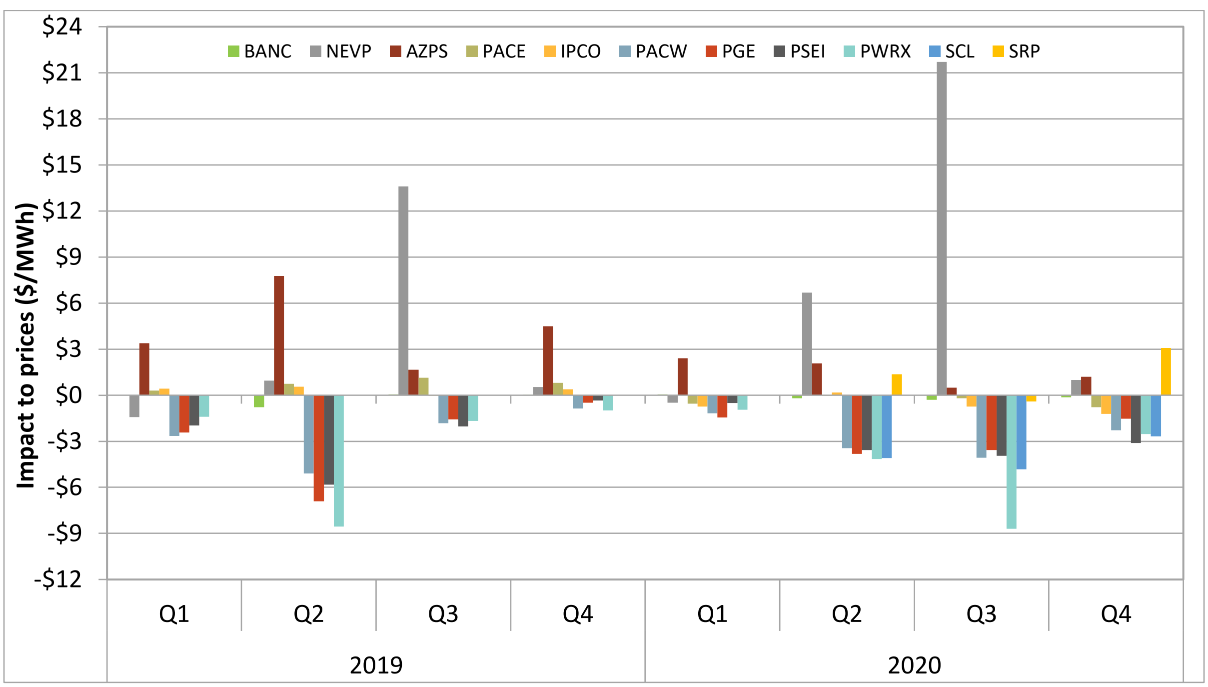


Figure 7.11 EIM transfer constraint congestion average impact on prices in the 5-minute market



7.2 Congestion on interties

The frequency and financial impact of congestion on most interties connecting the ISO with other balancing authority areas increased in 2020 compared to 2019, particularly for interties connecting the ISO to the Pacific Northwest.

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 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.

Table 7.4 provides a summary of congestion frequency on interties including average day-ahead congestion charges and the total congestion charges from the day-ahead, 15-minute, and 5-minute market. The congestion price reported in Table 7.4 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 7.12 compares the percentage of hours that major interties were congested in the day-ahead market during the last three years. Figure 7.13 provides a graphical comparison of total congestion charges on major interties in each of the last three years. Figure 7.13 also includes intertie congestion charges as a percentage of total day-ahead congestion rent.

Trends in impact of congestion on interties

Overall, congestion on interties across all markets (day-ahead, 15-minute, and 5-minute) reached about $263 million, compared with $152 million in 2019 and $205 million in 2018. The increase from 2019 was largely driven by increased congestion on the two major interties linking the ISO with the Pacific Northwest: the MALIN 500 (PACI/Malin 500) and Nevada/Oregon Border (NOB).[203] On these interties, total congestion charges nearly tripled in 2020 to a combined $236 million from about $79 million in 2019. This was mostly driven by increased frequency of import congestion on both interties during the third quarter. On the IPP DC Adelanto intertie, total congestion charges returned to 2018 levels, decreasing to $3 million from about $40 million in 2019.

In the 15-minute and 5-minute markets, import congestion charges on interties are up from 2019. The 15-minute market increased from $29 million in 2019 to $45 million in 2020, while the 5-minute market increased from roughly $32 million in 2019 to $36 million in 2020. Total import congestion charges were higher in the 15-minute than the 5-minute market for most interties except Palo Verde and IPP DC Adelanto.

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[203] 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 7.4 Summary of import congestion (2018-2020)

Import region	Intertie	Day-ahead frequency of import congestion			Day-ahead average congestion charge ($/MW)			Total import congestion charges* (thousands)		
		2018	2019	2020	2018	2019	2020	2018	2019	2020
Northwest	Malin 500	19.0%	21.5%	35.4%	$10.67	$12.76	$10.16	$119,814	$65,103	$140,802
	NOB	21.5%	7.6%	26.4%	$12.24	$8.40	$13.45	$44,844	$14,051	$95,249
	COTPISO	1.7%	1.1%	8.3%	$33.94	$25.60	$16.39	$215	$90	$518
	Cascade	0.3%	0.8%	0.1%	$7.98	$16.90	$21.40	$24	$197	$88
	Marble		0.2%	0.1%		$181.83	$153.44		$18	$19
	Summit		0.3%	0.1%		$59.81	$28.95		$33	$7
Southwest	Palo Verde	6.0%	7.4%	2.5%	$13.82	$11.69	$12.10	$24,473	$21,716	$10,239
	IPP DC Adelanto	1.5%	11.3%	0.1%	$11.15	$17.85	$23.56	$2,637	$39,645	$2,813
	IPP Utah	17.2%	11.4%	9.0%	$7.61	$7.92	$11.87	$3,370	$3,436	$2,757
	Mead	0.4%	0.7%	0.8%	$5.39	$24.25	$26.61	$323	$1,673	$1,398
	MeadTMead	0.1%	0.2%	0.1%	$326.93	$12.79	$644.63	$437	$140	$985
	West Wing Mead	0.8%	0.9%	0.1%	$13.99	$25.04	$12.66	$171	$779	$30
	Other							$8,974	$4,664	$8,337
Total								***$205,281***	***$151,544***	***$263,243***

* Total import congestion charges is the combined total from the day ahead, 15-minute, and 5-minute markets.

Figure 7.12 Percent of hours with day-ahead congestion on major interties (2018-2020)

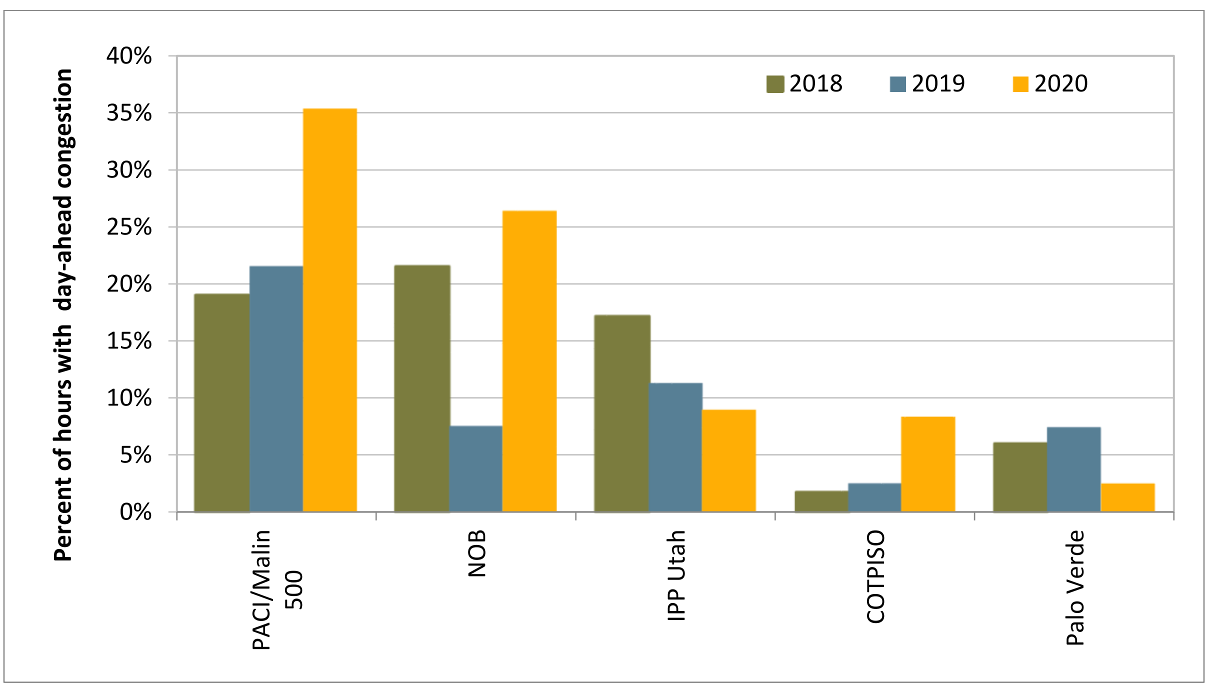
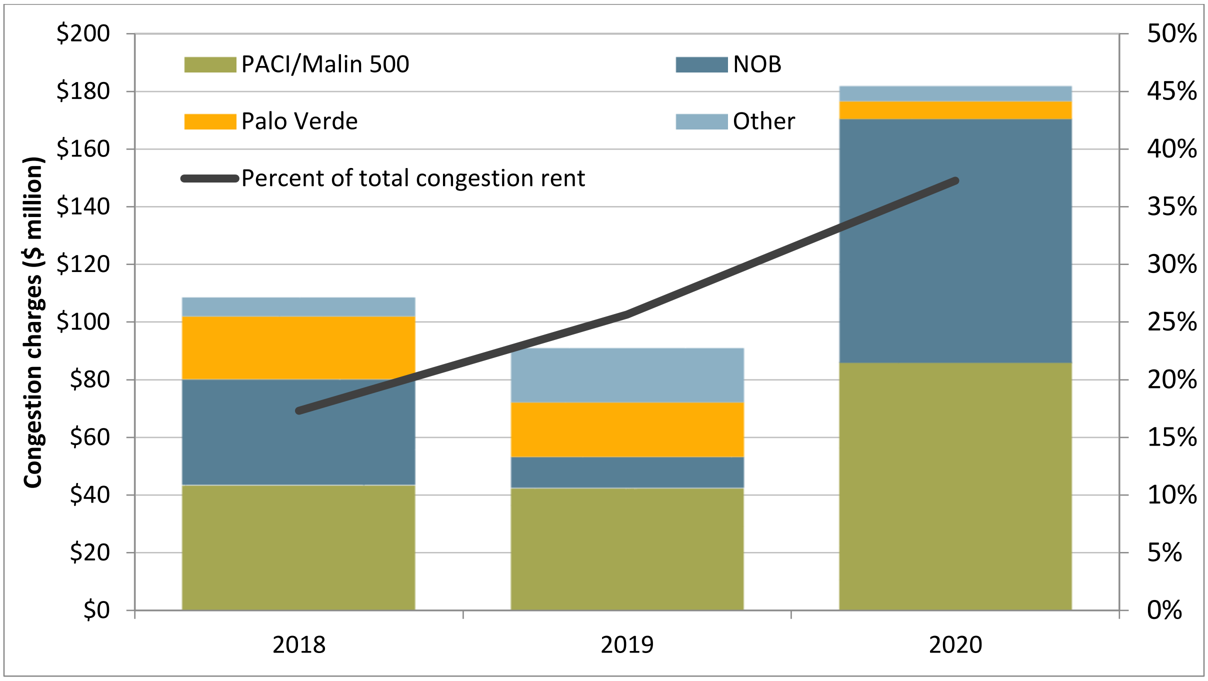


Figure 7.13 Day-ahead import congestion charges on major interties (2018-2020)



7.3 Congestion revenue rights

Congestion revenue rights sold in the auction consistently pay more to purchasers than they cost 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 2009 through 2018, transmission ratepayers received about 48 percent of the value of their congestion revenue rights sold at auction, with a total shortfall of more than $860 million.

In response to these systematic losses from congestion revenue right auction sales, the ISO instituted significant changes to the congestion revenue right auction starting in the 2019 settlement year. These changes include the following:

- Track 0 – Increasing the number of constraints enforced by default in the congestion revenue right models, identifying potential enforcement of “nomogram” constraints in the day-ahead market to include in the congestion revenue right models, and other process improvements.[204]
- Track 1A – Limiting allowable source and sink pairs to “delivery path” combinations.[205]

[204] California ISO, *Congestion Revenue Rights Auction Efficiency Track 1B Straw Proposal*, April 19, 2018: http://www.caiso.com/InitiativeDocuments/StrawProposal-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

[205] California ISO, *Congestion Revenue Rights Auction Efficiency Track 1A Draft Final Proposal Addendum*, March 8, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalAddendum-CongestionRevenueRightsAuctionEfficiency-Track1.pdf

- Track 1B – Limiting congestion revenue right payments to not exceed congestion rents actually collected from the underlying transmission constraints.[206]

In 2020, transmission ratepayer losses from congestion revenue right auctions totaled over $70 million. About $38 million of the $70 million in losses occurred in the third quarter. Transmission ratepayers received about 56 cents in auction revenue per dollar paid out to these rights purchased in the auction in 2020.

Section 7.3.1 provides an overview of allocated and auctioned congestion revenue rights holdings. Section 7.3.2 provides more details on the performance of the congestion revenue rights auction.

7.3.1 Allocated and auctioned congestion revenue rights

Background

Congestion revenue rights are paid (or charged), for each megawatt held, based on 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.[207]

Ratepayers own the day-ahead transmission rights not held by merchant transmission or long-term rights holders. Allocating congestion revenue rights is a means of distributing the revenue from the sale of these rights, also known as congestion rent, to entities serving load to then be passed on 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 auctions. In exchange for backing the auctioned rights, ratepayers receive the net auction revenue which is allocated by load share.

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, 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.

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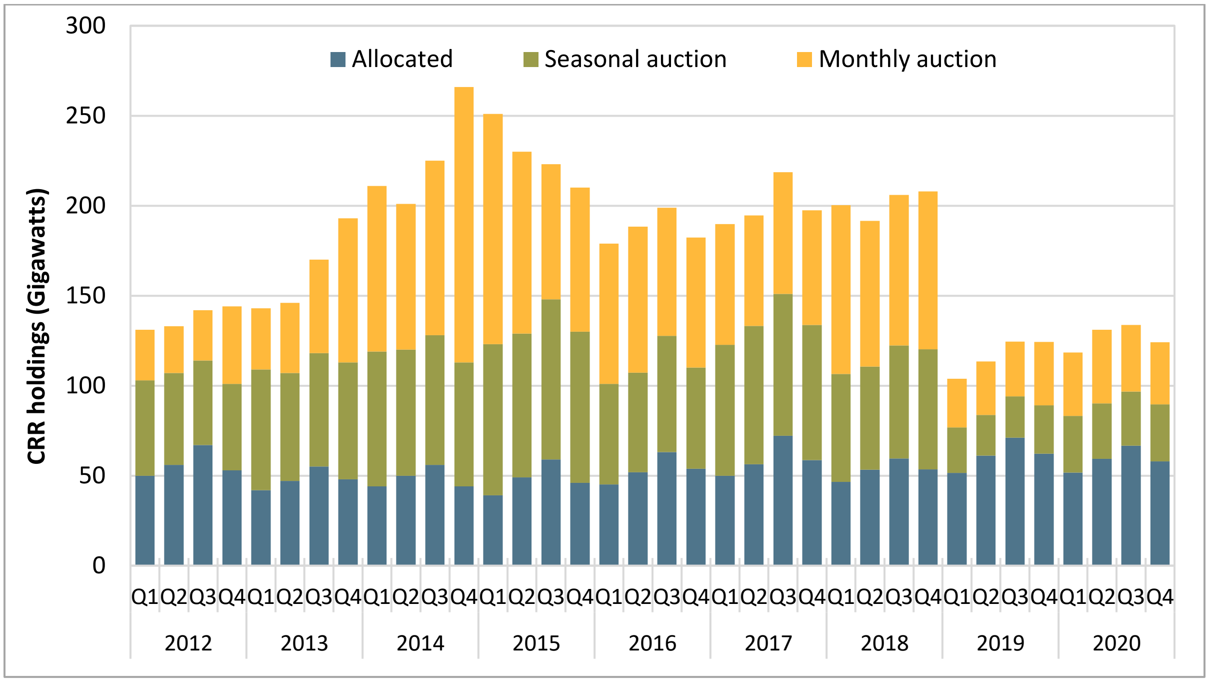
206 California ISO, *Congestion Revenue Rights Auction Efficiency Track 1B Draft Final Proposal Second Addendum*, June 11, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalSecondAddendum-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

207 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.

Figure 7.14 shows the congestion revenue right megawatts held by allocated, seasonally auctioned, and monthly auctioned rights. This figure includes all peak and off-peak rights. In 2020, the share of allocated congestion revenue rights was about 46 percent of the total megawatts held. Auctioned rights share was about 54 percent of the total. As shown in the figure, the change in trend from 2019 is because of the Track 1A changes implemented beginning 2019 auction which limited allowable source and sink pairs to "delivery path" combinations.

Figure 7.14 Congestion revenue rights held by procurement type (2012 – 2020)[208]



7.3.2 Congestion revenue right auction returns

The CRR auction returns compares the auction revenues that ratepayers receive for rights sold in the ISO's auction to the payments made to these auctioned rights based on day-ahead market prices. In response to persistent ratepayer losses since the auction began,[209] the ISO instituted significant changes to the auction starting in the 2019 settlement year. These changes include the following:

- Track 0 – Increasing the number of constraints enforced by default in the congestion revenue right models, identifying potential enforcement of "nomogram" constraints in the day-ahead market to include in the congestion revenue right models, and other process improvements.[210]

208 Allocated CRR holdings also include existing transmission rights (ETCs) and transmission ownership rights (TORs)

209 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.

210 California ISO, *Congestion Revenue Rights Auction Efficiency Track 1B Straw Proposal*, April 19, 2018: http://www.caiso.com/InitiativeDocuments/StrawProposal-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

- Track 1A – Limiting allowable source and sink pairs to "delivery path" combinations.[211]
- Track 1B – Limiting congestion revenue right payments to not exceed congestion rents actually collected from the underlying transmission constraints.[212]

DMM believes the current auction is unnecessary and could be eliminated.[213] 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.

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 revenues received for auctioning transmission rights to the day-ahead congestion payments to these rights. Figure 7.15 compares the following for each of the last several years:

- Auction revenues received by ratepayers from congestion revenue rights sold in auction (blue bars).[214]
- Net payments made to the non-load serving entities purchasing congestion revenue rights in auction (green bars).
- Total ratepayers losses are the difference between auction revenues received and payments made to non-load serving entities (yellow line).

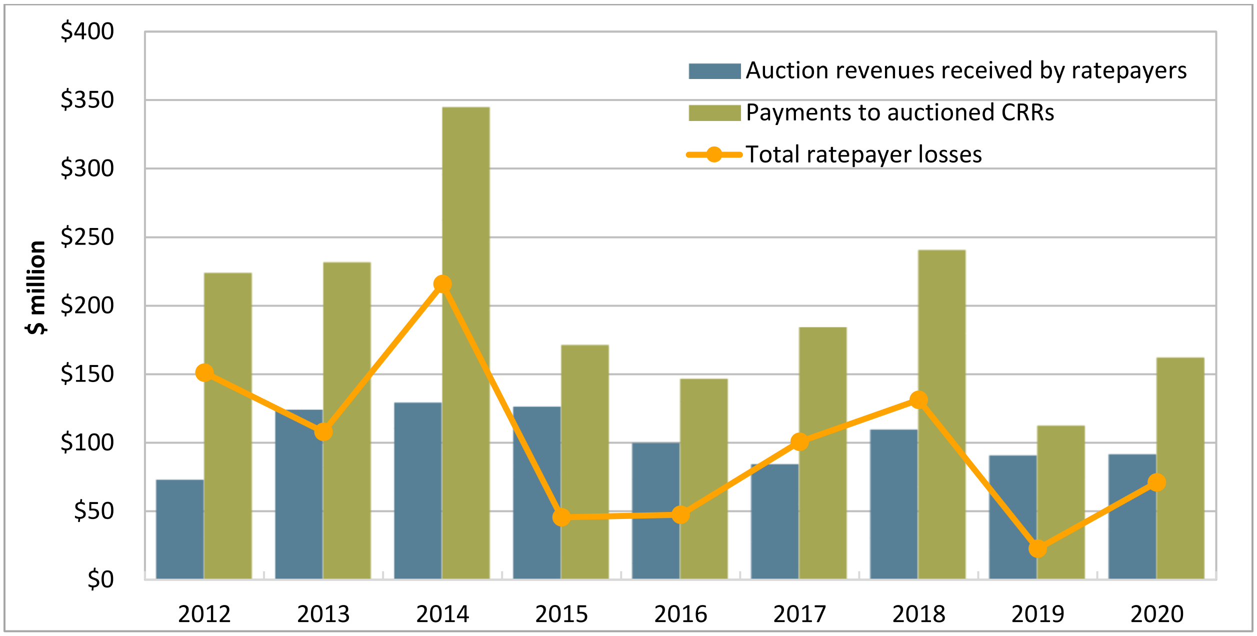
[211] California ISO, *Congestion Revenue Rights Auction Efficiency Track 1A Draft Final Proposal Addendum*, March 8, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalAddendum-CongestionRevenueRightsAuctionEfficiency-Track1.pdf

[212] California ISO, *Congestion Revenue Rights Auction Efficiency Track 1B Draft Final Proposal Second Addendum*, June 11, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalSecondAddendum-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

[213] 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

[214] 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 7.15 Ratepayer auction revenues compared with congestion payments for auctioned CRRs



Between 2012 and 2018, prior to the auction modifications, 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 or about 28 percent of day-ahead congestion rent.

In 2020, ratepayer auctions losses were about $70 million, about 14 percent of day-ahead market congestion rent. Ratepayers received an average of 56 cents in auction revenue per dollar paid to auctioned congestion revenue rights holders. Track 1B revenue deficiency offsets reduced payments to non-load serving entity auctioned rights by about $47 million. Over half the losses occurred in the third quarter.

In 2019, losses were about $22 million, about 6 percent of day-ahead market congestion rent. Ratepayers received an average of 80 cents in auction revenue per dollar paid out. Track 1B revenue deficiency offsets reduced payments to auctioned rights by about $44 million.

With the implementation of the constraint specific allocation of revenue inadequacy offsets to congestion revenue right holders, under the Track 1B changes, it is not possible to know precisely how much of the ratepayers losses are from ISO sales (through the auction transmission model) versus load serving entity trades. This is because it is not possible to directly tie the offsets actually paid by congestion revenue rights purchasers to the sales of specific congestion revenue rights. DMM created a simplified estimate of these offsets by estimating the notional revenue that would have been paid to the sold rights had they been kept and applying the average ratio of offsets to notional revenues.

Figure 7.16 shows the estimated breakout of ratepayer auction losses by ISO sales (the blue bars) and load serving entity trades (the green bars). With the exception of the third quarter of 2020, the losses are mostly from ISO sales. On net, excluding the third quarter of 2020, we estimate that load serving entities made a small amount on their trades in the auction since the start of 2019. The losses in the third quarter of 2020 are mostly from the sale of allocated rights made by several small load serving entities.

Figure 7.16 Estimated CRR auction loss breakout ISO and load serving entity

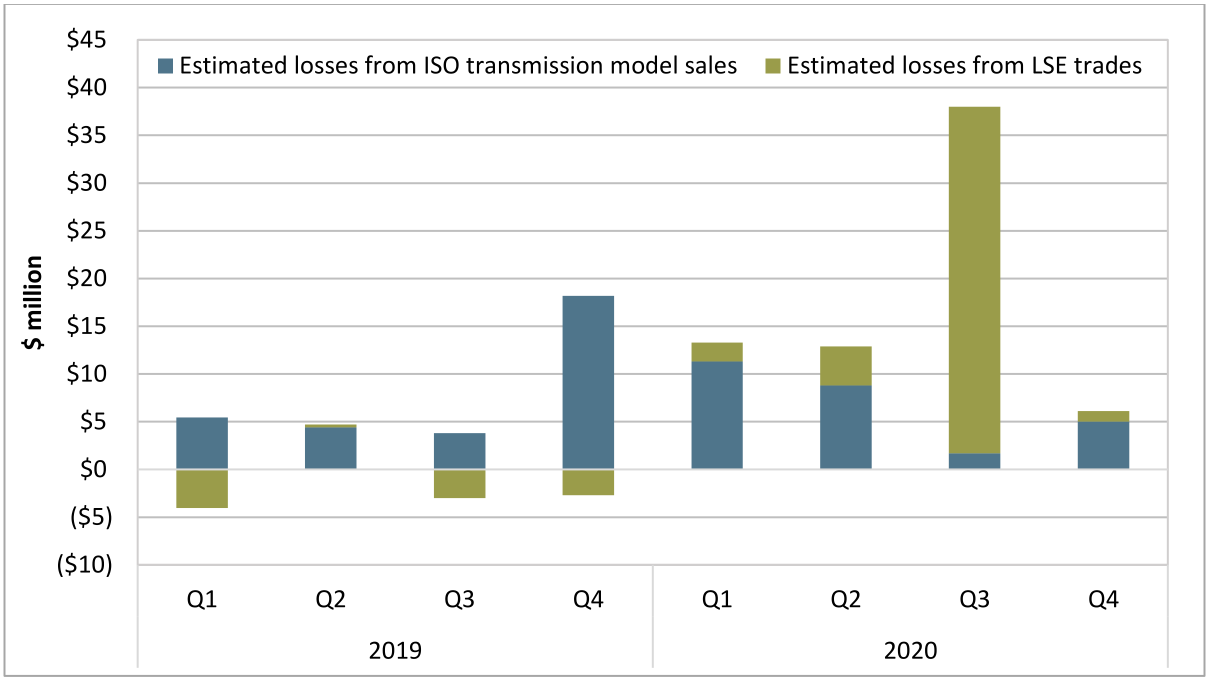


Figure 7.17 through Figure 7.19 compare the auction revenues paid for and payments received from congestion revenue rights traded in the auction by market participant type.[215] The difference between auction revenues and the payments to congestion revenue rights are the profits for the entities holding the auctioned rights. These profits are losses to ratepayers.

- Financial entities received net revenue nearly $24 million in in 2020, about the same as the $23 million in 2019. Total revenue deficit offsets were about $27 million.
- Marketers received net revenues of nearly $34 million from auctioned rights in 2020, up significantly from $3 million in 2019. Total revenue deficit offsets were nearly $13 million.
- Physical generation entities received about $13 million in net revenue from auctioned rights in 2020 up from losses over $3 million in 2019. Total revenue deficit offsets were about $8 million.

One of the benefits of auctioning congestion revenue rights is to allow day-ahead market participants to hedge congestion costs. However, in both 2019 and 2020, physical generators as a group continued to

[215] 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.

account for a relatively small portion of congestion revenue rights held. As a group, generators received the lowest overall payments from congestion revenue rights.

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, load serving entities face significant technical and regulatory hurdles to purchasing 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.

Figure 7.17 Auction revenues and payments (financial entities)

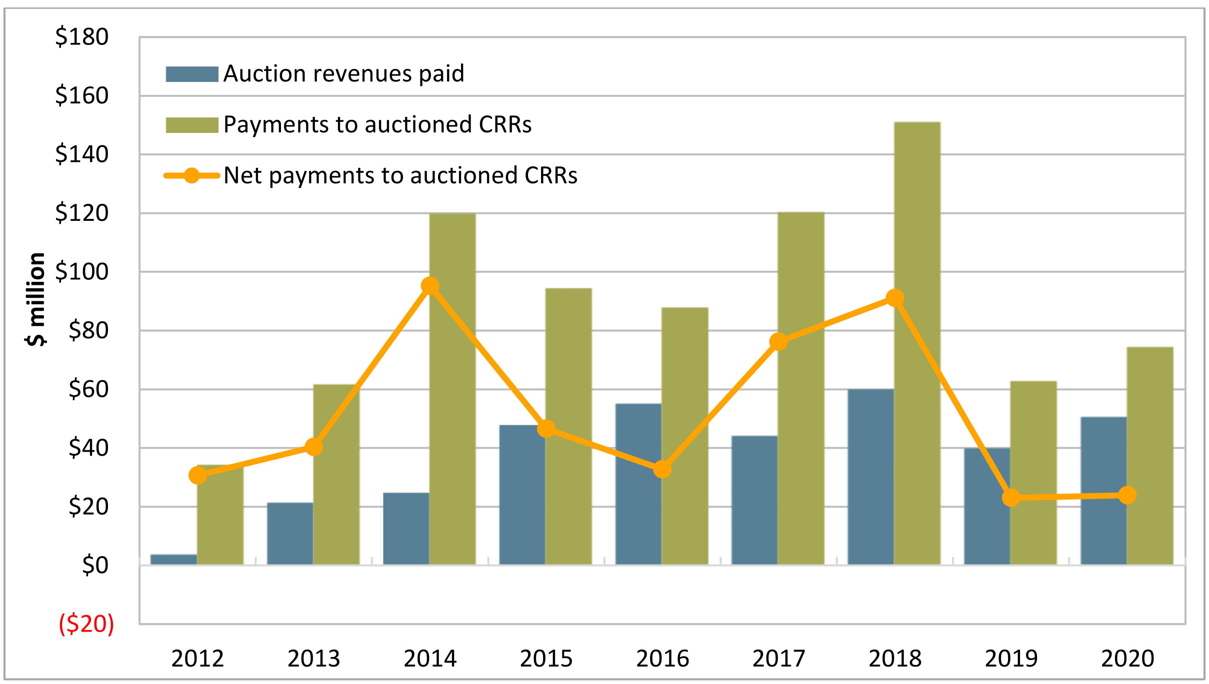


Figure 7.18 Auction revenues and payments (marketers)

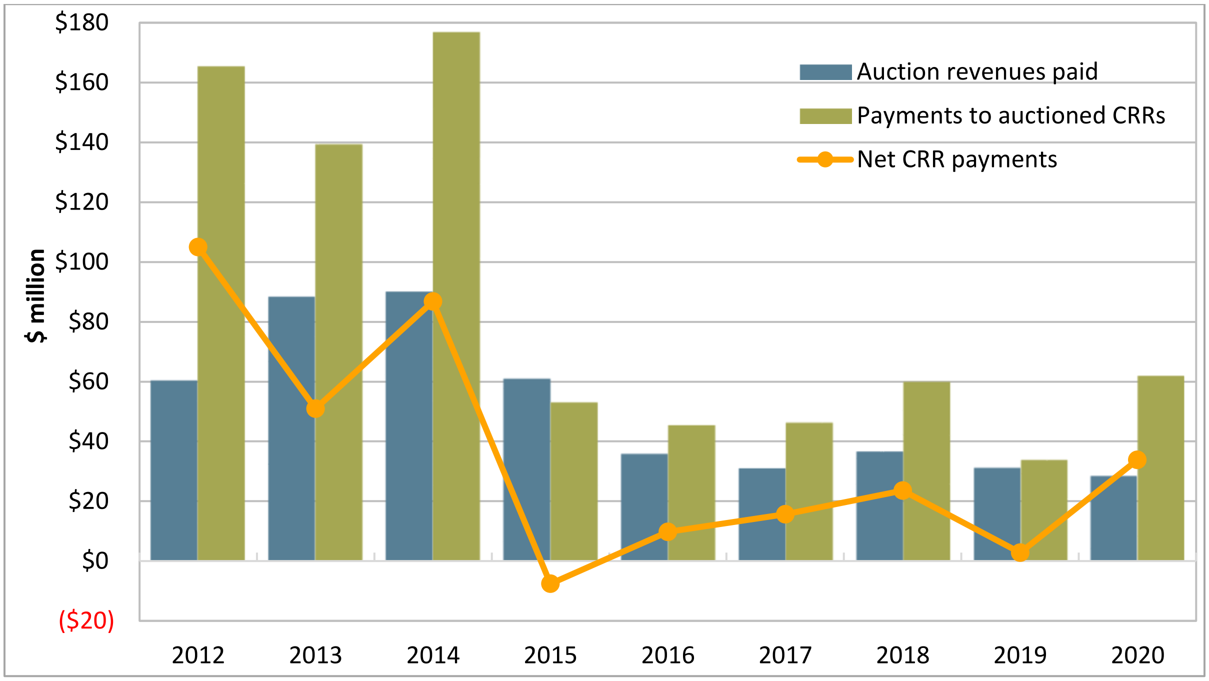
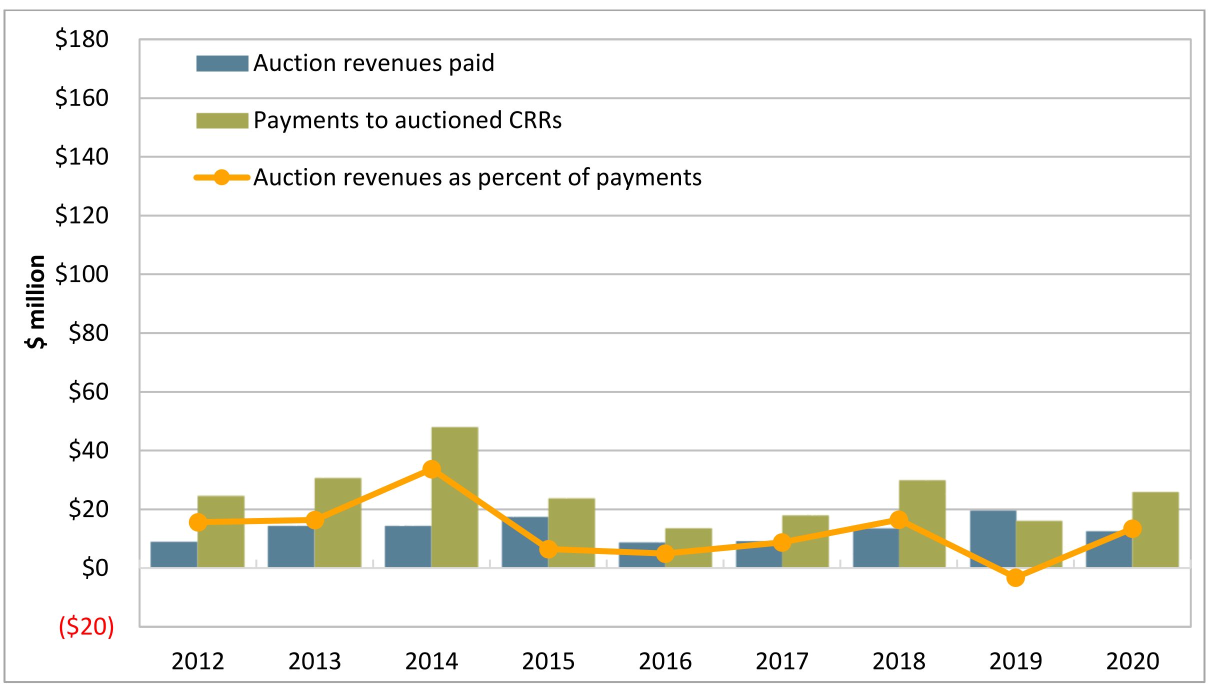


Figure 7.19 Auction revenues and payments (generators)



8 Market adjustments

Given the complexity of market models and systems, all ISO operators make some adjustments to the inputs and outputs of their standard market models and processes. For example, transmission limits may 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 key market adjustments made by grid operators, 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 decreased in 2020** and continued to account for a relatively low portion of total system load, or 0.5 percent compared to 0.7 percent in 2019. The decrease in total energy from exceptional dispatches in 2020 was driven by less exceptional dispatch energy above minimum load, while minimum load energy from exceptional dispatch unit commitments largely stayed the same.
- **Total above-market costs due to exceptional dispatch decreased** to about $15.8 million in 2020 from $26.4 million in 2019. Although exceptional dispatches to commit units to operate at minimum load stayed about the same, the cost of this category fell from $15 million in 2019 to $6.9 million in 2020.
- **Manual adjustments to ISO system loads remained high at about 1,000 MW in peak net load ramp hours** in the hour-ahead and 15-minute markets, continuing a dramatic increase over 2018 and 2017, which were both substantially above previous years. High hour-ahead load adjustments tend to increase imports in the ISO's hour-ahead market.
- **ISO operator adjustments added an average of 372 MW per hour to residual unit commitment requirements**, an increase from 210 MW in 2019. In the third quarter, the average adjustment was over 1000 MW per hour. In 2020 these manual adjustments were primarily issued to address reliability concerns and to account for load forecast errors.

8.1 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 0.5 percent of system loads in 2020, compared to 0.7 percent in 2019.

Exceptional dispatch energy above minimum load decreased by approximately 23 percent in 2020 from 2019, while minimum load energy from unit commitments stayed about the same. As shown in Figure 8.1[216] minimum load energy from units committed via exceptional dispatch accounted for 77 percent of all exceptional dispatch energy in 2020. About 14 percent of energy from exceptional dispatches was from out-of-sequence energy (to operate above minimum load), and the remaining 9 percent was from in-sequence energy.

The decrease in above minimum load energy from exceptional dispatches in 2020 is likely due to a number of factors. First, exceptional dispatches for unit testing occurred much more frequently in 2019 than in 2020. As shown in Figure 8.1, the in-sequence exceptional dispatch energy (green bars) decreased significantly year to year which can largely be attributed to the decrease of unit testing exceptional dispatches for new units coming online.

In addition, the decrease of out-of-sequence exceptional dispatch energy is likely due to higher average prices in both the real-time and day-ahead markets in the summer months when exceptional dispatches are used most frequently by the ISO operators. As a result, resources that were typically relied upon last summer to provide additional ramping capacity were dispatched by the market instead of an exceptional dispatch more often in 2020 than in 2019. However, the ISO operators increased the use of unit commitment exceptional dispatches for many of these resources to stay online at minimum load for several days at a time during the summer months.

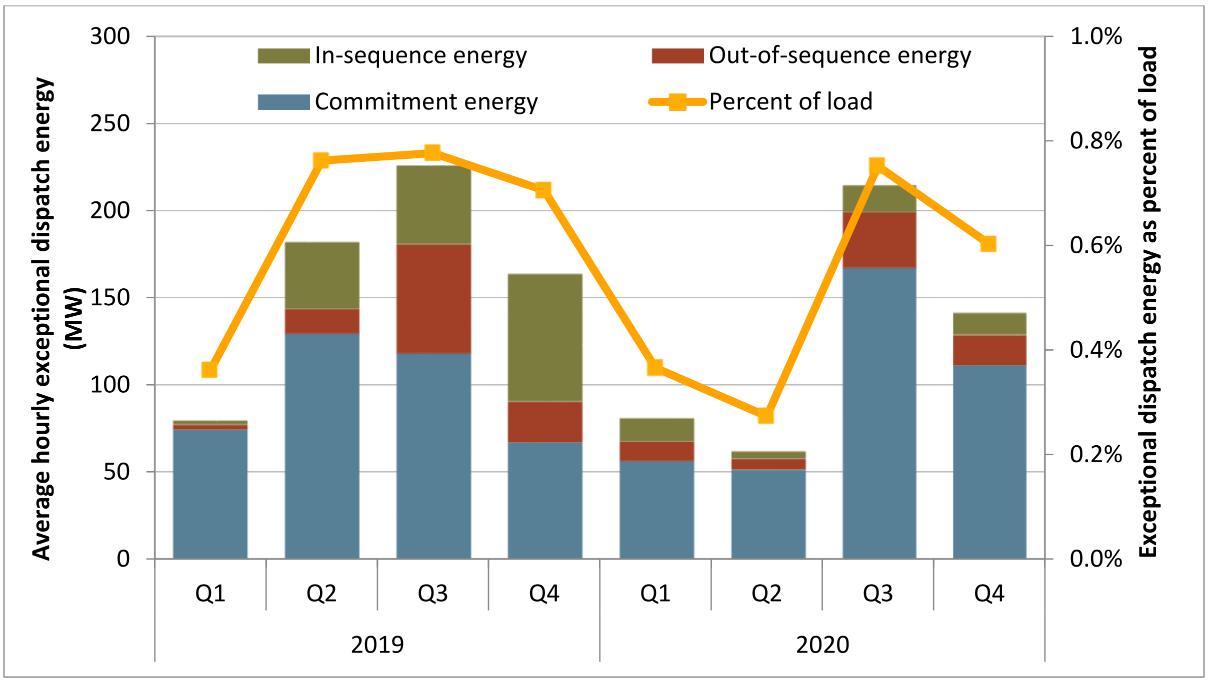
Although most exceptional dispatches are not priced and paid based on market clearing energy prices, they can affect the market clearing price for energy. Energy resulting from exceptional dispatch effectively reduces the remaining load to be met by other supply. This can reduce market prices relative

[216] 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.

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.

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 most 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 8.1 Average hourly energy from exceptional dispatch

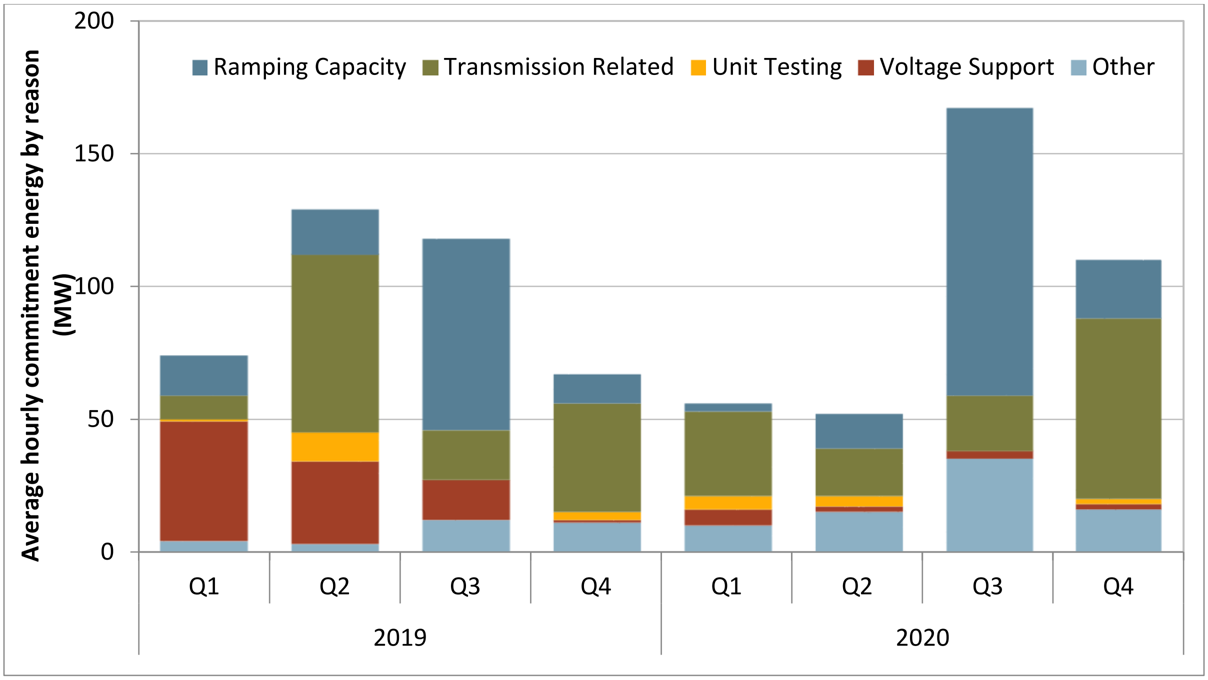


Exceptional dispatches for unit commitment

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 remained about the same in 2020 compared to 2019, with most occurring in the third and fourth quarters of 2020. Exceptional dispatch unit commitments in the third quarter of 2020 were predominately issued to provide additional ramping capacity to the grid. These exceptional dispatches are issued to increase the amount of ramping capacity available to meet the evening net load ramp and respond to other uncertainties in real time. In the fourth quarter, exceptional dispatch unit commitments were predominately issued for transmission related modeling limitations. Most of these exceptional dispatches were issued to address congestion related to planned transmission outages which generally occur outside of the summer months.

Figure 8.2 Average minimum load energy from exceptional dispatch unit commitments



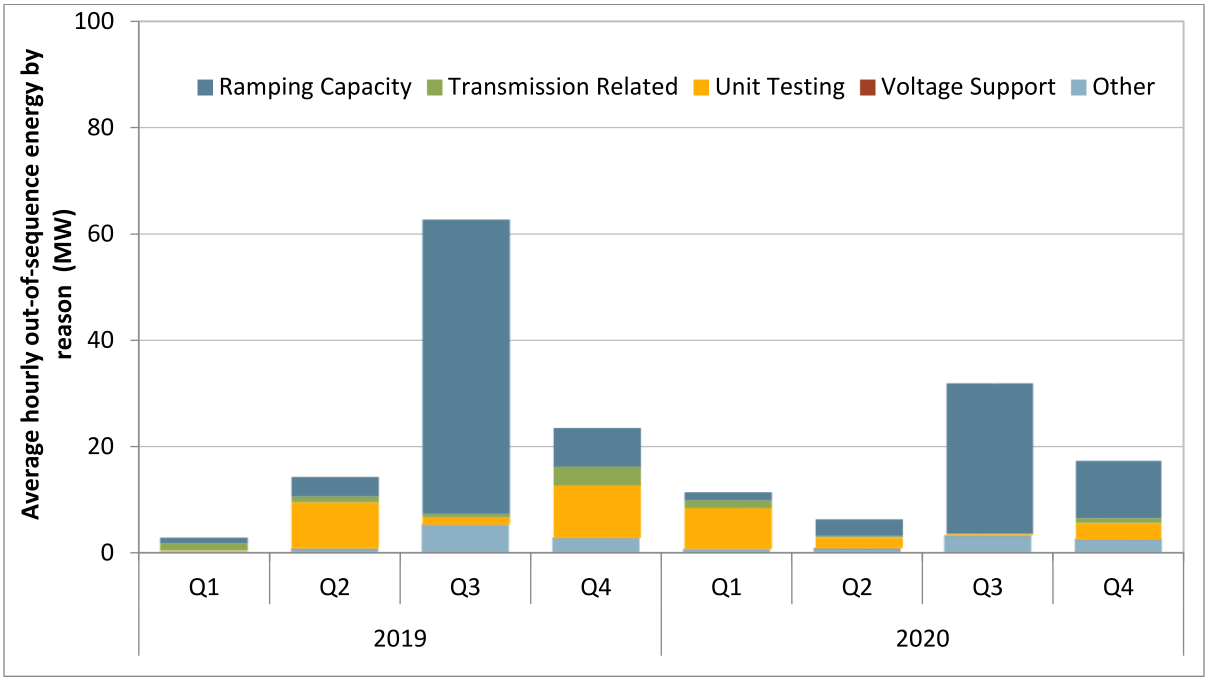
Exceptional dispatches for energy

Energy from real-time exceptional dispatches to ramp units above minimum load or to ensure they do not operate below their regular market dispatch decreased by 57 percent in 2020. As illustrated in Figure 8.1, about 60 percent of this type of exceptional dispatch was out-of-sequence, meaning the bid price was greater than the locational market clearing price.[217] While the level of exceptional dispatch energy from unit commitments did not change in 2020, the portion of exceptional dispatch for out-of-sequence energy decreased compared to previous years.

Figure 8.3 shows the change in out-of-sequence exceptional dispatch energy by quarter for 2019 and 2020. Out-of-sequence exceptional dispatch energy followed a similar trend to the previous year, with most occurring in the third quarter. The primary reason logged for out-of-sequence energy exceptional dispatches was for ramping capacity. Many of these exceptional dispatches were used to ramp thermal resources to their minimum dispatchable level – a higher operating level with a faster ramp rate which allows these units to be more available to meet reliability requirements and other uncertainties in real time.

[217] 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 8.3 Out-of-sequence exceptional dispatch energy by reason



Exceptional dispatch costs

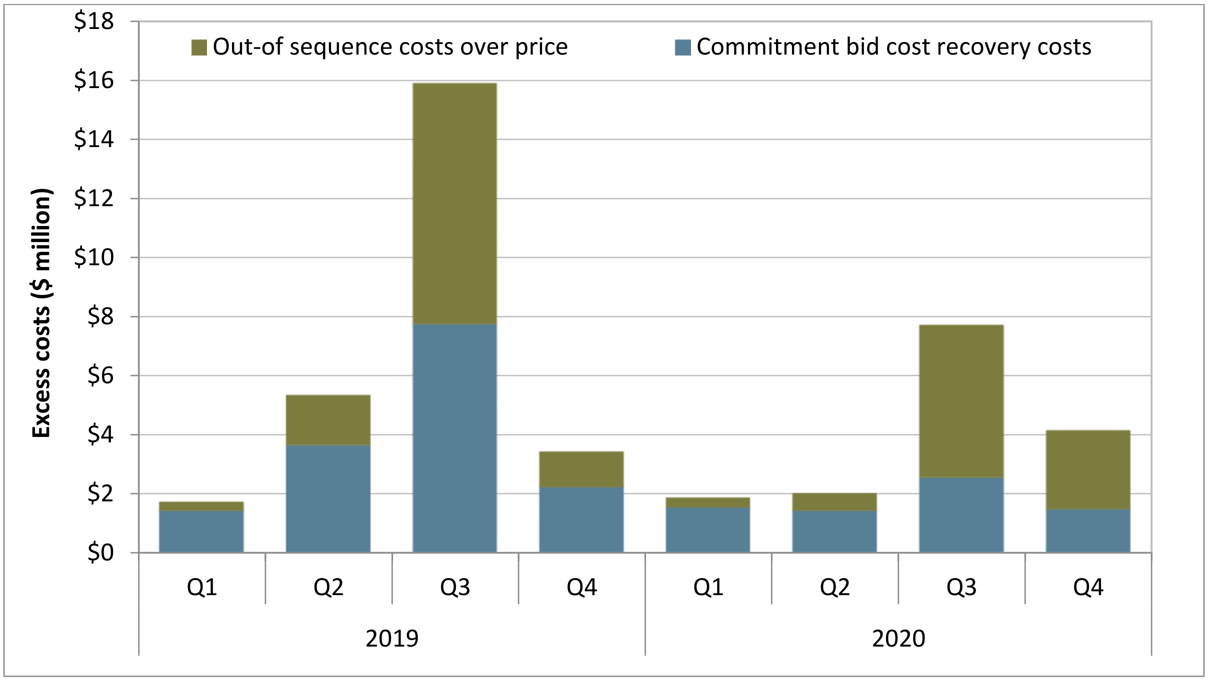
Exceptional dispatches can create two types of additional costs not recovered through the market clearing price of energy.

- 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 8.4 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 decreased from $15 million to $6.9 million and out-of-sequence energy costs decreased from $11.3 million to $8.8 million in 2020.[218] Total above-market costs decreased by 40 percent to about $15.8 million in 2020 from $26.4 million in 2019.

[218] 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 8.4 Excess exceptional dispatch cost by type



8.2 Manual dispatches

Manual dispatch on the interties

Exceptional dispatches on the interties are instructions issued by ISO operators when the market optimization is not able to address a particular reliability requirement or constraint. Energy dispatches issued by ISO operators are sometimes referred to as manual or out-of-market dispatches. During periods of extreme temperature and energy demand, the ISO may call upon neighboring balancing authority areas to provide emergency assistance on the interties in the real-time markets.

Figure 8.5 shows the total hourly megawatts from all manual dispatch and emergency assistance over the past two years. Imports coming from emergency assistance reflect energy imported from balancing authority areas with whom the ISO has contractual agreements during emergency conditions. All other manual dispatches reflect energy from offers made by ISO operators for imports from neighboring balancing areas for imports in the real-time market. These types of imports are often paid a negotiated price, typically for 'bid or better'.[219]

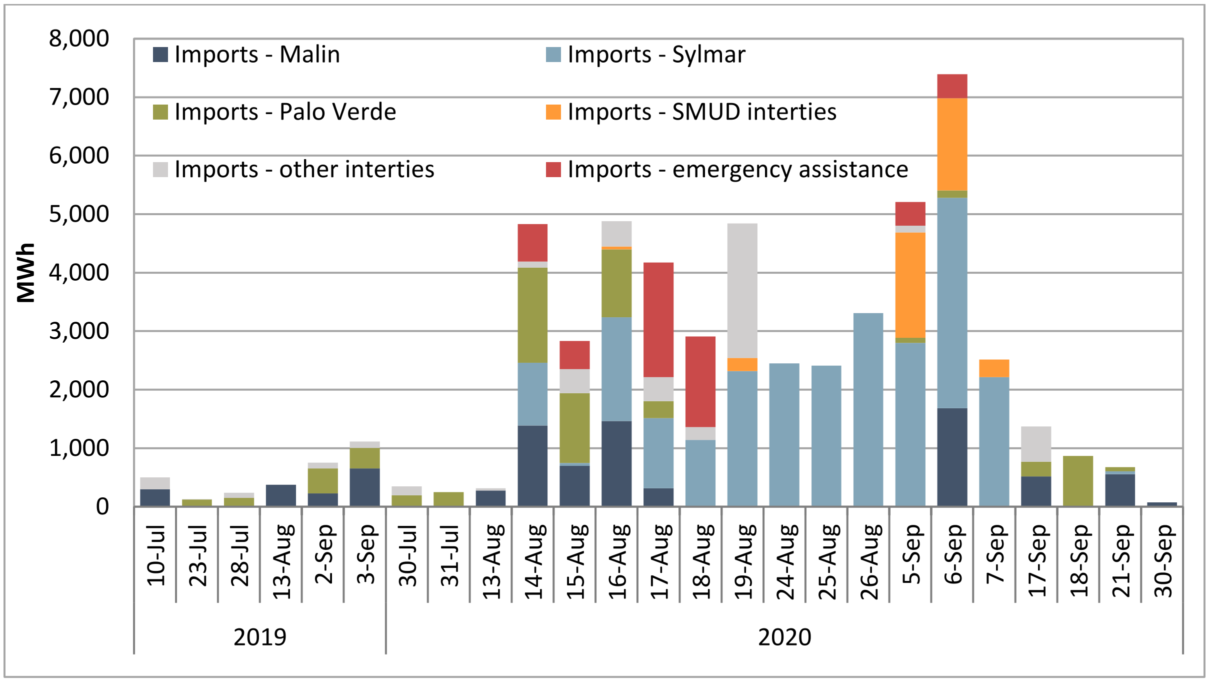
Out-of-market dispatches of both imports and emergency assistance increased substantially from 2019 to 2020. In 2020, the ISO imported about 47,000 MWh of non-emergency assistance out-of-market dispatches on the ties, an increase from about 3,100 MWh in 2019. About 80 percent of the total non-emergency out-of-market dispatches for the year occurred over the regional heat wave in the west from mid-August to early September. Nearly 6,000 MWh of emergency assistance was received from

[219] DMM's 2017 annual report (pp. 206-207) provides more detail on manual dispatch types and prices paid for out-of-market imports, http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf

neighboring balancing authority areas during the same period in 2020. In 2019, no emergency assistance was imported in to the ISO.

In addition to emergency assistance imported in to the ISO, the ISO also can also provide export emergency assistance to neighboring balancing authorities. In 2020, export dispatches for emergency assistance totaled around 1,400 MWh with over 80 percent being attributed to one balancing authority. This is a decrease from the previous year with nearly 6,000 MWh of export emergency assistance dispatched.

Figure 8.5 Manual dispatch and emergency assistance on the ISO interties (July-September)



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. 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 8.6 through Figure 8.7 summarize monthly manual dispatch activity of participating and non-participating resources for energy imbalance market areas with incremental or decremental volume above 10 MW in any month. The volume of manual dispatches in energy imbalance market areas can peak in the first few months that a new market participant is active in the market, such as in Salt River Project balancing area in 2020.

Figure 8.6 EIM manual dispatches – Arizona Public Service area

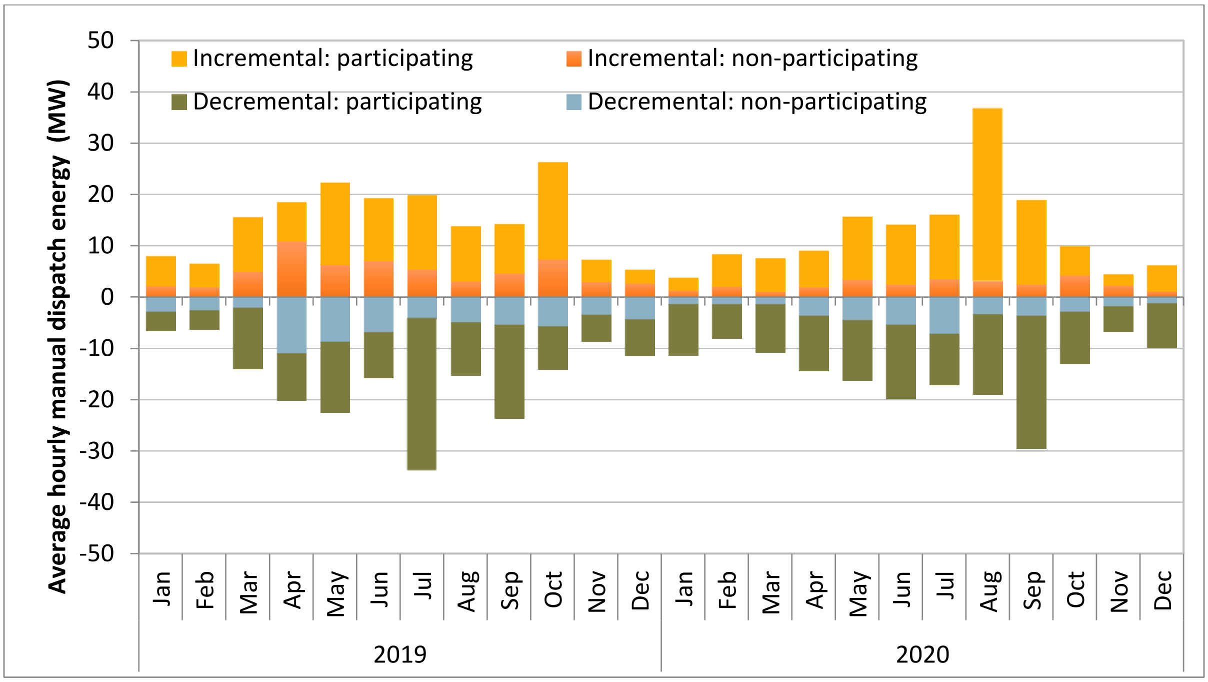


Figure 8.7 EIM manual dispatches – Idaho Power Company area

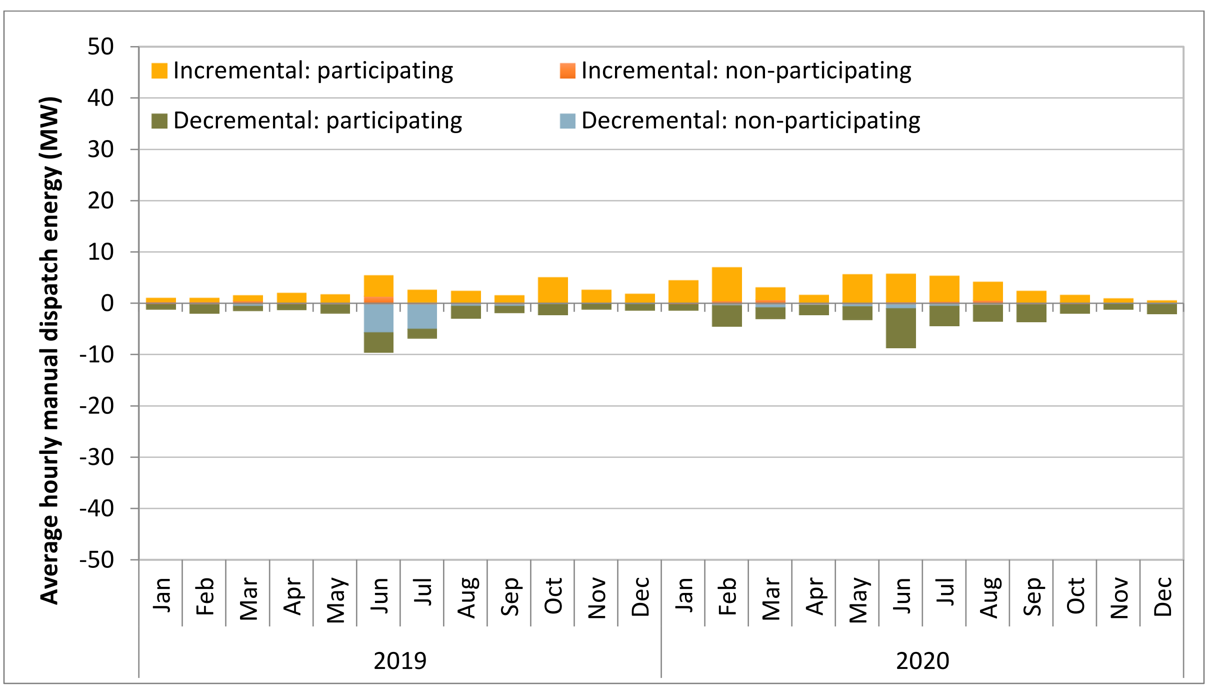
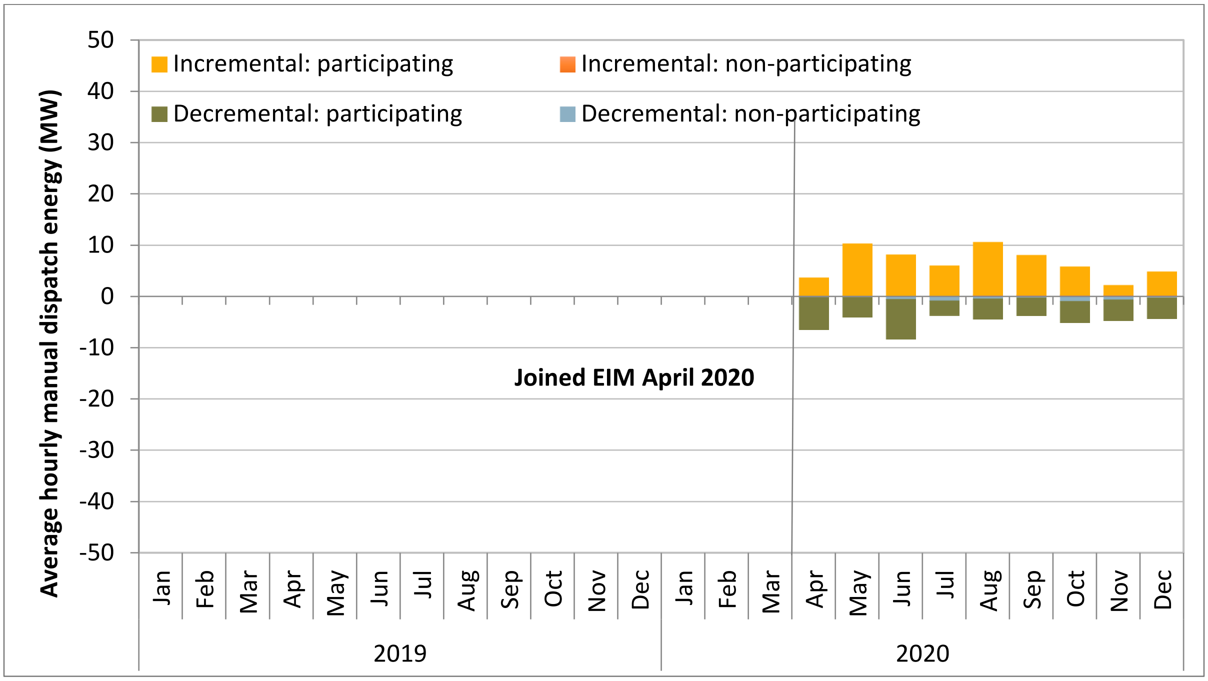


Figure 8.8 EIM manual dispatches – Salt River Project area



8.3 Residual unit commitment adjustments

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 May 2020.

As noted in Section 2.4, 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 integrated forward market (IFM) run of the day-ahead market and procures capacity to bridge the gap between the amount of load cleared in the IFM run and the day-ahead forecast load.

Figure 8.9 shows the average hourly determinants of capacity requirements used in residual unit commitment process by quarter in 2019 and 2020.

The residual unit commitment process includes an automated adjustment to account for the need to replace net virtual supply clearing in the IFM run of the day-ahead market, which can offset physical supply in that run. In 2020, this automated adjustment, shown in the green bars in Figure 8.9, was the primary driver of positive residual unit commitment requirement. The average increase in residual unit commitment requirements due to net virtual supply decreased from 626 MW in 2019 to 555 MW in 2020.

ISO operators can also make manual adjustments to increase the amount of residual unit commitment requirements. These manual adjustments, shown in the red bar in Figure 8.9, contributed an average of 372 MW per hour to requirements, an increase from about 210 MW per hour in 2019. The figure also shows that these adjustments were most frequent during the third quarter. The operators used this tool on 64 days (out of 92 days) and the adjustment averaged about 1,158 MW per hour compared to about 688 MW per hour in the same quarter of 2019. These manual adjustments were primarily to address reliability concerns and to account for load forecast errors.

The blue bars in Figure 8.9 show the portion of the residual unit commitment requirement that is calculated based on the difference between cleared supply (both physical and virtual) in the integrated forward market (IFM) run of the day-ahead market and the ISO's day-ahead load forecast. This difference increased residual unit commitment requirements by 371 MW on a yearly average basis in 2020. During the heat wave conditions that existed during August, this factor contributed towards increased residual unit commitment requirements on average by about 1,160 MW per hour.

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 8.9.

Figure 8.9 Determinants of residual unit commitment procurement

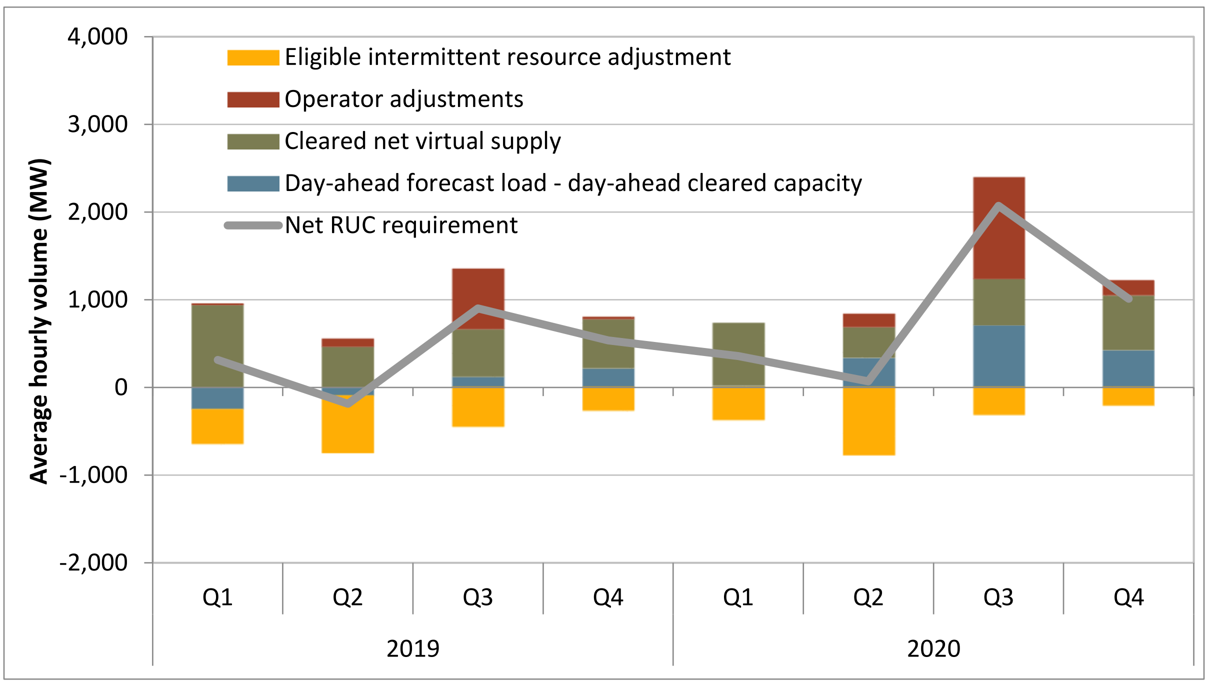
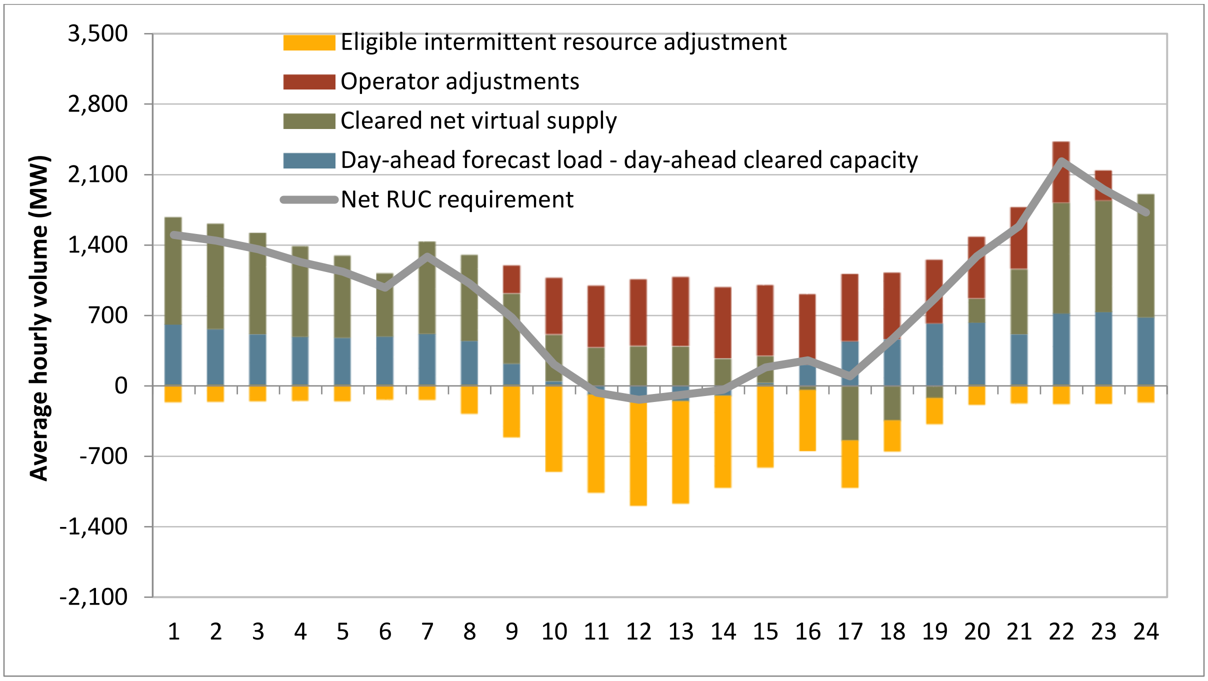


Figure 8.10 shows these same four determinants of the residual unit commitment requirements for 2020 for each operating hour of the day. As shown by the red bars in Figure 8.10, manual adjustments by grid operators tended to be greatest between the peak load hours ending 9 through 22. During the third quarter of 2020, operators increased the residual unit commitment requirement by about 1,850 MW on average for hours ending 9 through 23.

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 load forecast was greater than day-ahead cleared capacity during all hours except 11 through 14 in 2020. Similar to 2019, the bulk of the intermittent resource adjustments occurred in hours ending 9 to 18.

Figure 8.10 Average hourly determinants of residual unit commitment procurement (2020)



8.4 Real-time imbalance conformance

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*. The ISO has begun using the term *imbalance conformance* to describe these adjustments. 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.

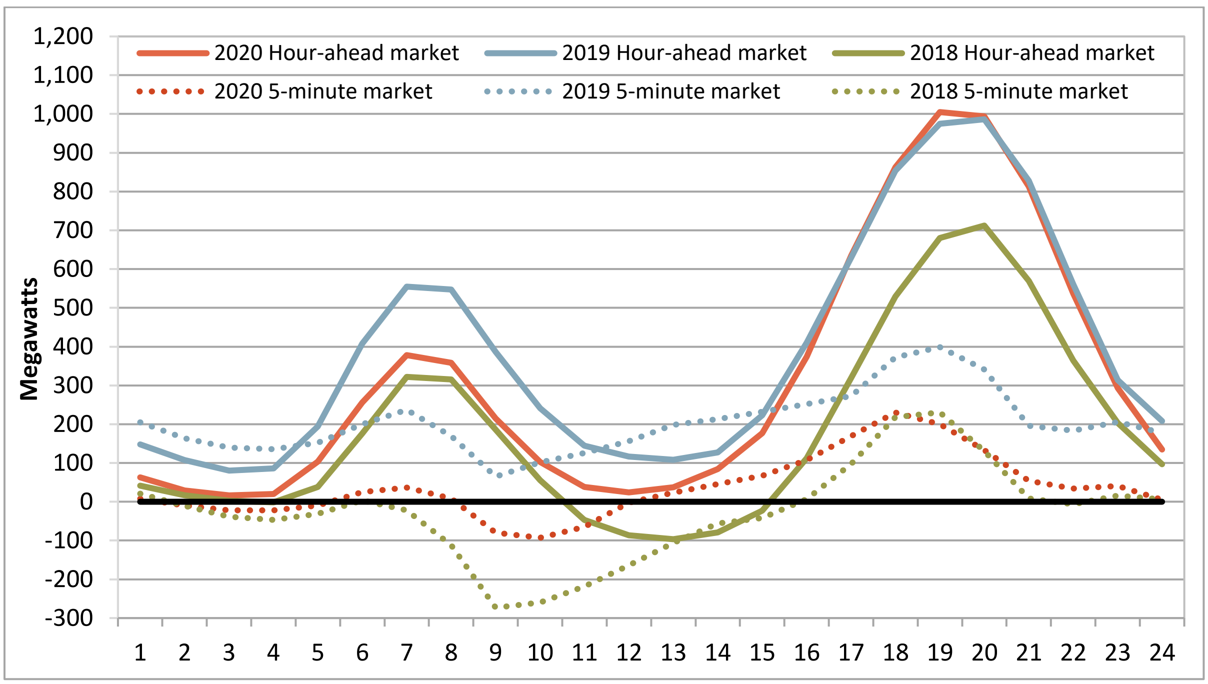
Real-time market load adjustments by the ISO

Beginning in 2017, there was a large increase in load forecast adjustments in the steep morning and evening net load ramp periods in the ISO's hour-ahead and 15-minute markets. This large increase continued in 2020, with average hourly load adjustments in the hour-ahead and 15-minute markets peaking at almost 1,000 MW, almost a two-fold increase from the peak in 2016 (460 MW).

Figure 8.11 shows the average hourly load adjustment profile for the hour-ahead and 5-minute markets for 2018 to 2020.[220] As in prior years, the general shape and direction of load adjustments were similar for hour-ahead and 15-minute adjustments. However, the 2020 morning adjustments dropped from the 2019 maximum level of about 550 MW to close to the 2018 levels of 380 MW. As shown in Figure 8.11 average hour-ahead load forecast adjustments in 2020 mirror the pattern of net loads over the course of the day, averaging 310 MW over the entire day with a maximum of about 380 MW in the morning ramp hours and nearly 1,000 MW during the evening ramping hours.

The load adjustments in the 5-minute market have a similar shape as the hour-ahead market, but less pronounced. In 2020 the 5-minute market more closely resembles the shape of 2018 with little adjustment prior to early morning ramp and after the evening ramp. However, adjustments were negative just after the morning peak and then positive just prior to afternoon ramp. 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 800 MW.

Figure 8.11 Average hourly load adjustment (2018 - 2020)



Adjustments are often associated with over- or under-forecasted load, changes in expected renewable generation, and morning or evening net load ramp periods. The ISO also adjusts loads in the 15-minute and 5-minutae 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 (e.g., exceptional dispatches), between the executions of different real-time markets.[221] Operators have

[220] 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.

[221] 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

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.

High real-time market load adjustments in peak net load hours are associated with increasing hourly import bids in morning and evening ramping hours. Increasing imports in these hours increases the supply of internal generation that could be ramped up or down in the real-time market.

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 make additional generation available within the ISO during the morning and evening ramping hours.

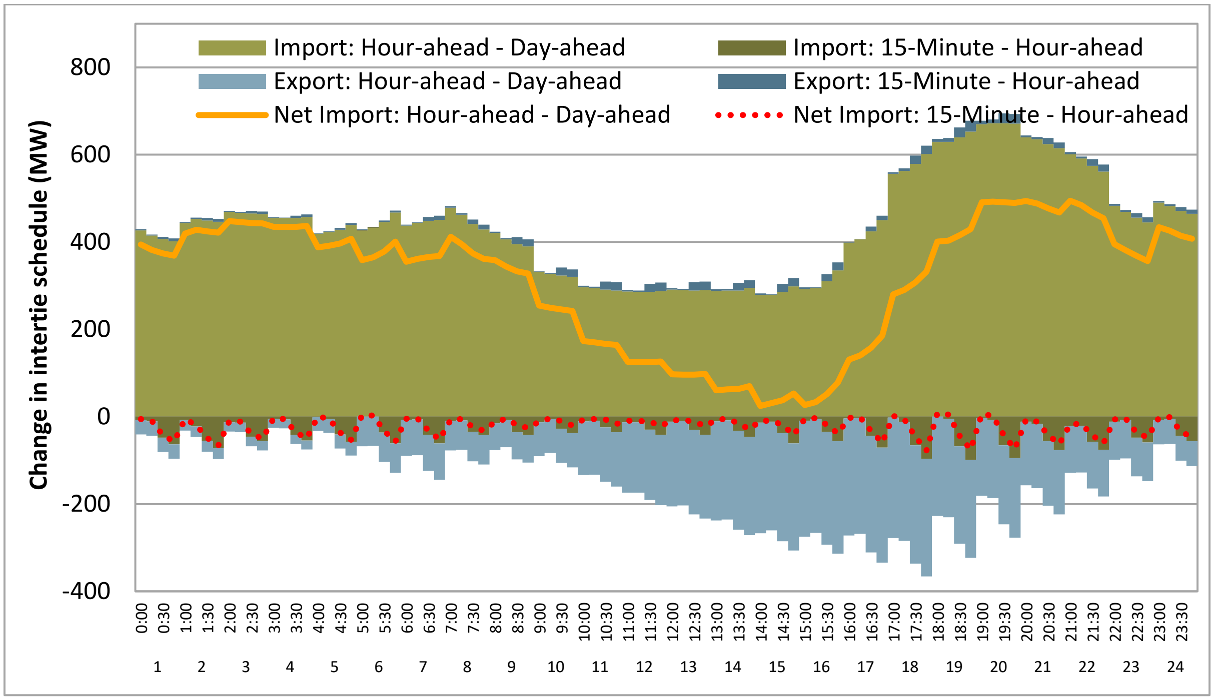
The impact of the hour-ahead load bias on real-time imports is reflected in Figure 8.12, which shows the incremental change in gross and net imports in the real-time market. The light green area in Figure 8.12 shows the average incremental increase in imports between the day-ahead and hour-ahead markets. 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 8.12 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 8.12, most incremental commitment of imports occurs in the hour-ahead market outside the mid-day hours in two periods, hours ending 1 to 10 and hours ending 17 to 24. During these hours in 2020, net interchange averaged about 380 MW, an increase from an average of 320 MW during these hours in 2019. Similar to 2020, the highest average net interchange was in hours ending 19 to 22, reaching a peak in hour ending 21 at 490 MW.

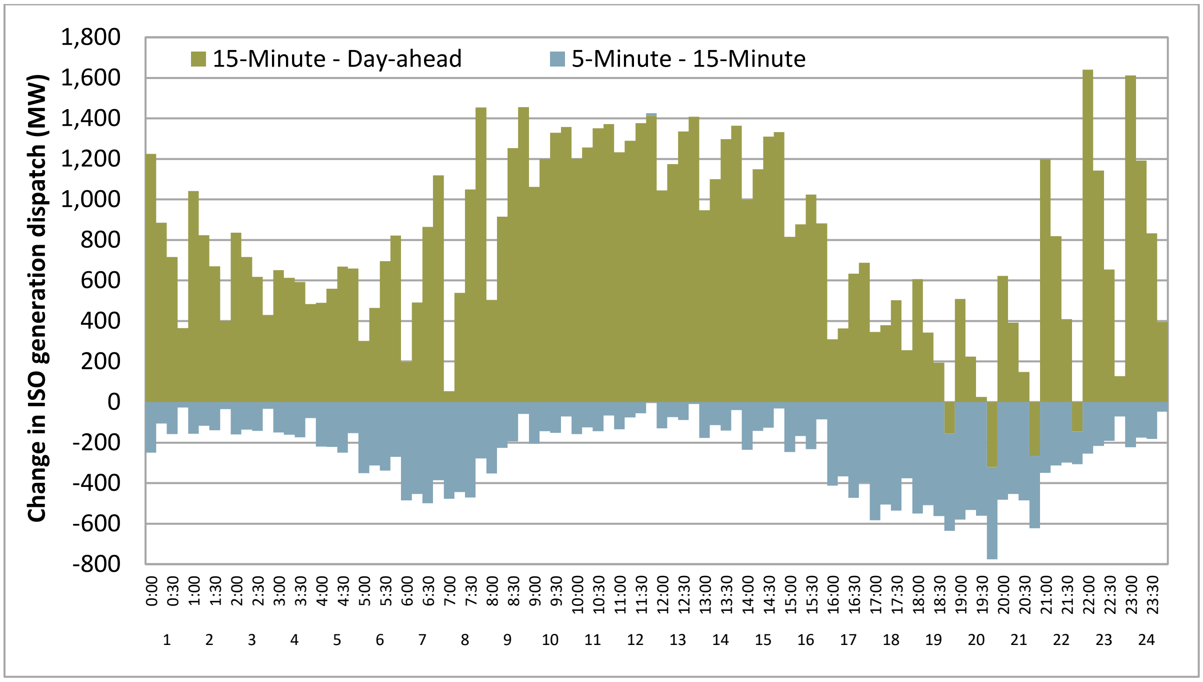
As with the previous year, there was also a noticeable increase in both imports and exports in 2020 between the hour-ahead and day-ahead markets during mid-day solar peak periods, compared to the prior three years. Net imports fell between the day-ahead and hour-ahead markets in these hours, similar to prior years. This appears to be associated with rebidding of energy that did not clear the day-ahead market that then often cleared at price-taker bid floor levels associated with self-schedules in the real-time markets.

Figure 8.12 Net interchange dispatch volume



Meanwhile, the 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, similar to the previous year. Figure 8.13 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 8.12.

Figure 8.13 Imbalance generation dispatch volume



Load adjustments in the energy imbalance market

Energy imbalance market operators can also make load adjustments in their respective balancing areas. Figure 8.14 and Figure 8.15 show the frequency of positive and negative load forecast adjustments for the ISO and different energy imbalance market areas during 2020 for the 15-minute and 5-minute markets, respectively.

For much of 2020, in the 15-minute market, positive and negative load adjustments were most frequent in Arizona Public Service.

Overall, load adjustments in the 5-minute market were more frequent than load adjustments in the 15-minute market for most balancing areas and quarters during the year. This trend was particularly notable in all except for BANC SMUD and Salt River Project. In Arizona Public Service, the frequency of 5-minute load adjustment was similar to the 15-minute adjustment.

Figure 8.14 Average frequency of positive and negative load adjustments (15-minute market)

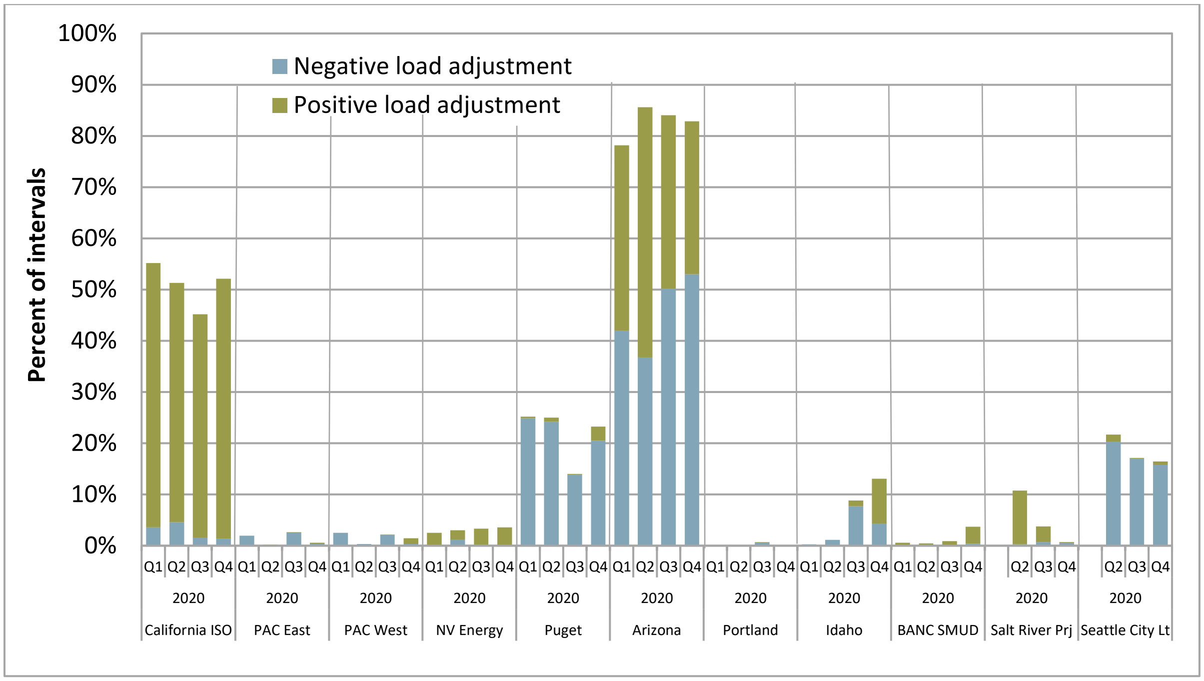
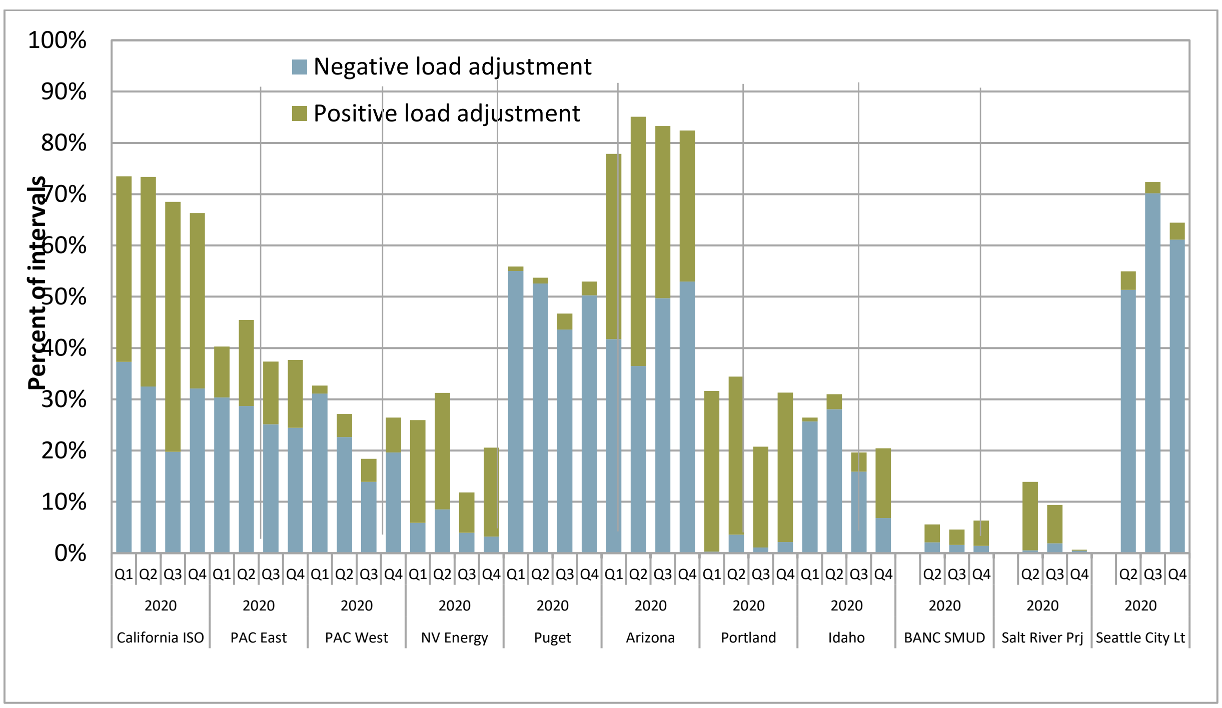


Figure 8.15 Average frequency of positive and negative load adjustments (5-minute market)



8.5 Blocked instructions and dispatches

Instructions

The 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.[222] 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, telemetry data is an input to the real-time market system. If that 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.

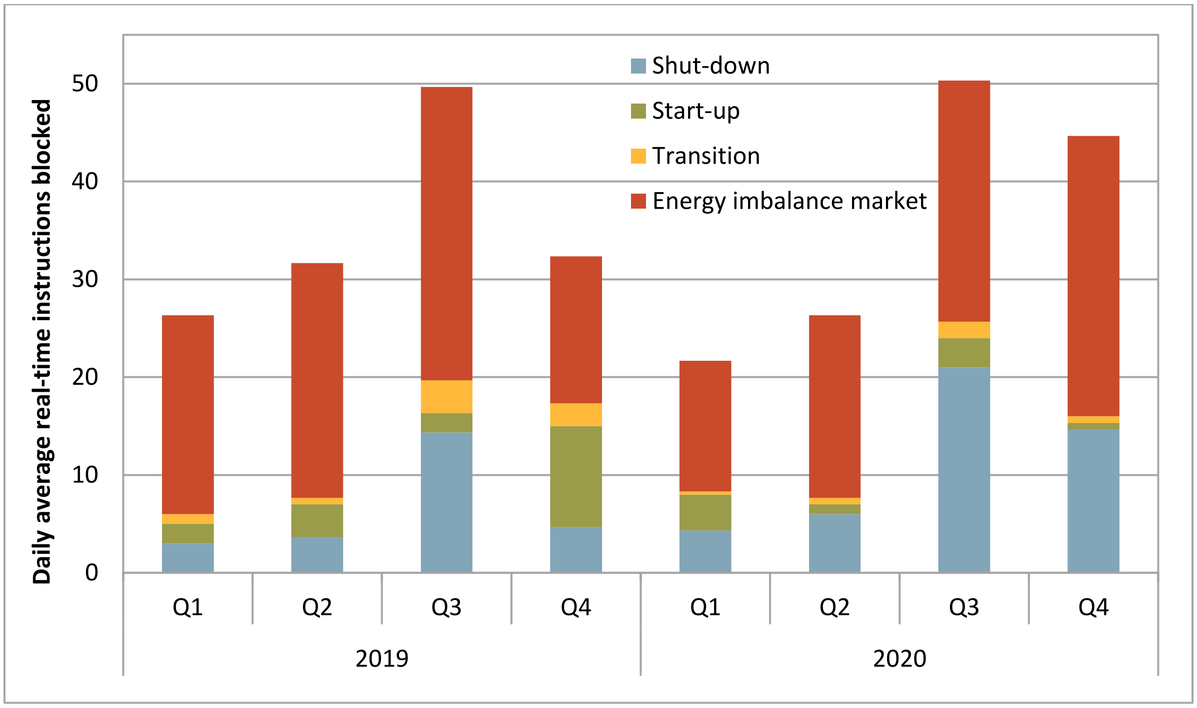
- **Information systems and processes.** In some cases, problems occur in the complex combination of information systems and processes needed to operate the real-time market on a timely and accurate basis. In such cases, operators may need to block commitment or dispatch instructions generated by the real-time market model.

Within the ISO, blocked instructions slightly increased from a daily average of 13 in 2019 to 14 in 2020 (blue, green, and gold bars in the figure). Figure 8.16 shows the frequency of blocked real-time commitment start-up, shut-down, and multi-stage generator transition instructions. Blocked shut-down instructions continued to be the most common reason for blocked instructions at about 80 percent in 2020, an increase from about 50 percent the previous year.

Blocked start-up instructions accounted for about 15 percent of blocked instructions within the ISO in 2020, a decrease from nearly 35 percent in 2019. Blocked transition instructions to multi-stage generating units also increased to about 6 percent from 15 percent in 2019. The average number of instructions blocked by western energy imbalance market operators was 22 per day in 2020 and 21 in 2019 (red bars in Figure 8.16).

[222] 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 8.16 Frequency of blocked real-time commitment instructions



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.

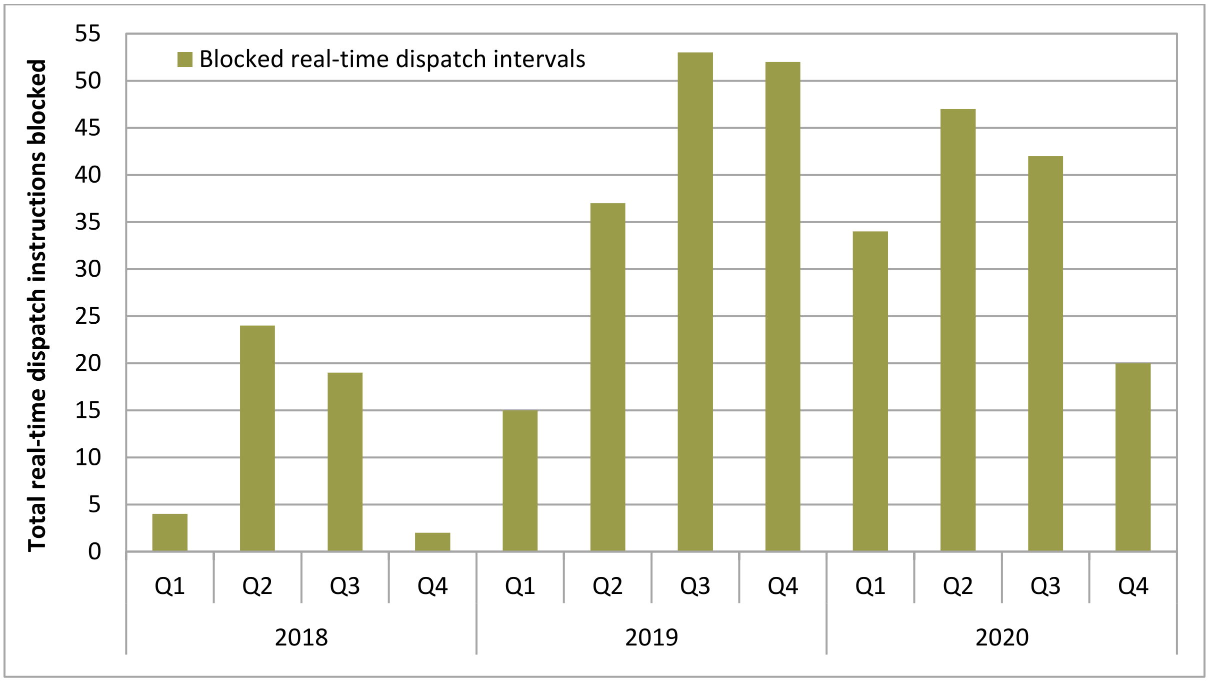
The ISO began blocking dispatches in 2011 as both market participants and ISO staff were concerned that inappropriate price signals were being sent to the market even when they were known to be problematic. These inappropriate dispatches would often have caused participants to exacerbate issues with 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.[223]

Figure 8.17 shows the frequency that operators blocked price results in the real-time dispatch from the first quarter 2018 through 2020. The total number of blocked intervals in 2020 decreased about 9 percent from the previous year.

[223] For example, if the load were to drop by 50 percent in one interval, the software can automatically block results.

Figure 8.17 Frequency of blocked real-time dispatch intervals



9 Resource adequacy

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. Key findings in this chapter include:

- **Most system resource adequacy capacity was procured by investor-owned utilities**. Investor-owned utilities accounted for about 66 percent of procurement, community choice aggregators procured 19 percent, municipal entities contributed 8 percent, and direct access providers accounted for 7 percent.
- **Over half of resource adequacy capacity was classified as use-limited** and thus exempt from ISO bid insertion in all hours.
- **On high load days, resource adequacy resources bid in enough capacity to meet average hourly load**. During the evening load ramp, however, changes in bids from RAAIM exempt solar causes increased reliance on RAAIM exempt gas, demand response, and imports to meet system needs.
- **In the real-time market, less than 90 percent of system resource adequacy capacity was bid or self-scheduled during high load hours.** During the top 210 load hours of the year, 95 percent of system resource adequacy capacity was available in the day-ahead market after outages; 90 percent was offered in the day-ahead market; 94 percent was available after outages in the real-time market; and 88 percent was offered in the real-time market. Resource adequacy availability during the load curtailment event was similar in the 6 to 7 p.m. hour but lower in the 7 to 8 p.m. hour.[224]
- **Overall, total local resource adequacy capacity exceeded requirements in local capacity areas**. Significant amounts of energy, beyond requirements, were available in the day-ahead market for several local capacity areas, but procurement in other local capacity areas was significantly lower than the local area requirements.
- **Flexible resource adequacy requirements exceeded the actual net load ramp** during the maximum net load ramp in all months except November. In November the maximum net load occurred on a Sunday and began an hour before some flexible resource adequacy category requirements.
- **Most resource adequacy availability incentive mechanism (RAAIM) charges and payments are attributed to generic resource adequacy resources.** In 2020, there was about $37 million in RAAIM charges and $27 million in incentive payments. Most accrued in the third and fourth quarters.
- **Intra-monthly capacity procurement mechanism (CPM) designations cost about $2.1 million in 2020**. Intra-monthly significant event designations were issued in August and September to meet high regional demand and ensure that the ISO could meet NERC reliability standards for load and reserve obligations.

[224] An in-depth analysis and report of these factors may be found in the Department of Market Monitoring's *Report on Market Conditions, Issues and Performance – August and September 2020*. http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

9.1 Background

The purpose of the resource adequacy program is to ensure the ISO system has enough capacity to reliably operate the grid, and to provide incentives for the siting and construction of new resources. In conjunction with the ISO and the California Energy Commission (CEC), the California Public Utilities Commission (CPUC) and other local regulatory authorities (LRAs) establish resource adequacy procurement obligations for all load serving entities within their respective jurisdictions.

The bilateral transactions between load serving entities and electricity suppliers that result from resource adequacy 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 requirements and processes adopted by the CPUC and other local regulatory authorities.

The resource adequacy program includes procurement 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.

9.2 System resource adequacy

Analysis in this section focuses on the availability of system resource adequacy resources throughout the year with 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 CEC, CPUC, and other local regulatory authorities to set system resource adequacy 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.[225] Load serving entities then procure capacity to meet

[225] The planning reserve margin is designed to reflect operating reserve requirements and additional capacity that may be needed to cover forced outages and potential load forecast error.

these requirements and demonstrate this procurement through the filing of annual and monthly supply plans to the ISO.

For annual supply plan 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 supply plan showings, CPUC-jurisdictional entities must demonstrate they have procured 100 percent of their monthly system obligation.

Bidding and scheduling obligations

Scheduling coordinators for resource adequacy resources must make the capacity listed in monthly supply plans 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 market. Resources certified for ancillary services must offer this capacity into the day-ahead 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- and medium-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. 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.

In 2020, about 43 percent of the capacity procured to meet resource adequacy requirements was from resources that are not use-limited and bid into ISO markets 24x7, unless reported to the ISO as unavailable due to outages. This capacity primarily includes most gas-fired resources. If a market participant does not submit bids, the ISO automatically creates and inserts bids for these resources.

The remaining capacity counted toward meeting system resource adequacy requirements in 2020 are generally only 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.

Bid data processing for generic resource adequacy

For the following generic resource adequacy bid availability analysis, day-ahead market bids include energy bids and non-overlapping ancillary service bids while real-time market bids include energy bids only.[226] Bids are capped at the resource adequacy capacity values shown for individual resources to

[226] To calculate hourly real-time bid amounts, bids from variable energy resources were averaged over the hour. Bids from non-VER resources reflect the maximum hourly bid in the hour-ahead, 15-minute, and 5-minute markets adjusted for derates, due to data issues.

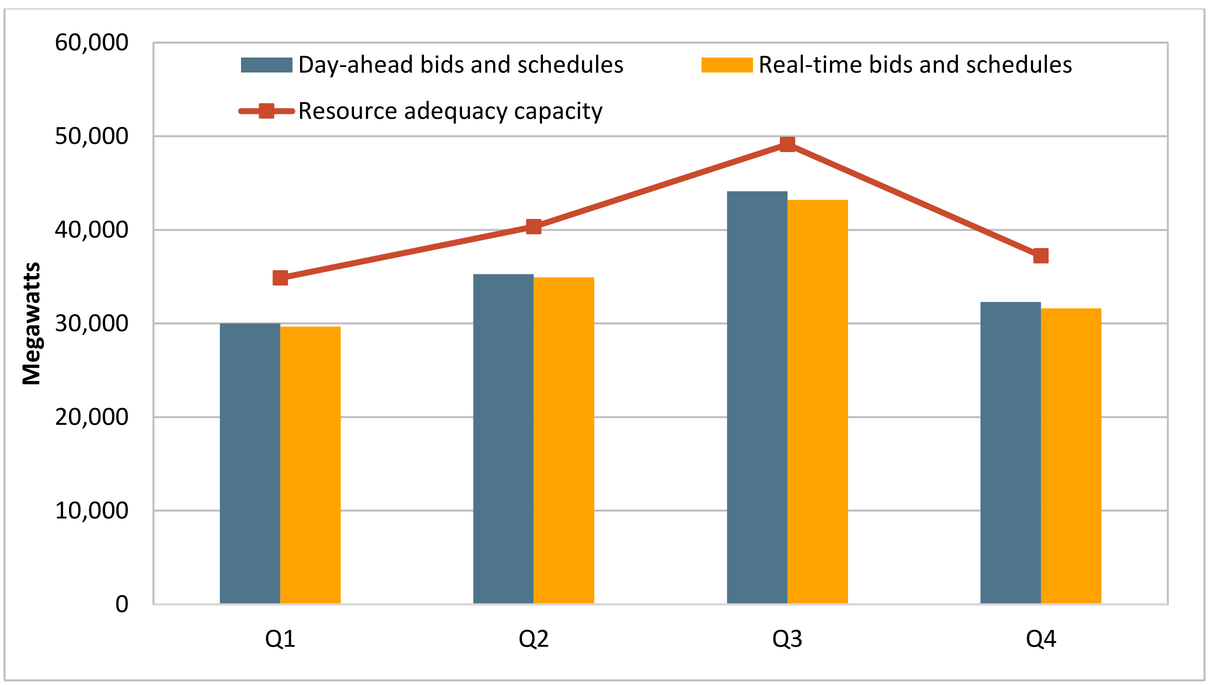
measure the availability of capacity that was secured during the planning timeframe. Bids are also capped according to individual resource outages and derates.[227]

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 2020 the availability assessment hours were hours ending 17 through 21 of non-holiday weekdays.[228]

Figure 9.1 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 into the day-ahead and real-time markets during the availability assessment hours.

Figure 9.1 Quarterly resource adequacy capacity scheduled and bid into ISO markets (2020)



[227] In addition, long-start resources that bid into the day-ahead but do not have a day-ahead or residual unit commitment schedule are no long filtered out of real-time analysis.

[228] Non-holiday weekdays are weekdays that are not a FERC holiday.

Key findings of this analysis include:

- ***On average, bids and schedules were lower than total capacity in each quarter***. Between 86 and 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 44,000 MW out of about 49,000 MW of procured resource adequacy capacity (or 90 percent) was available in the day-ahead market. Availability was similar for the remaining quarters at about 86 to 87 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 2020.*** 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

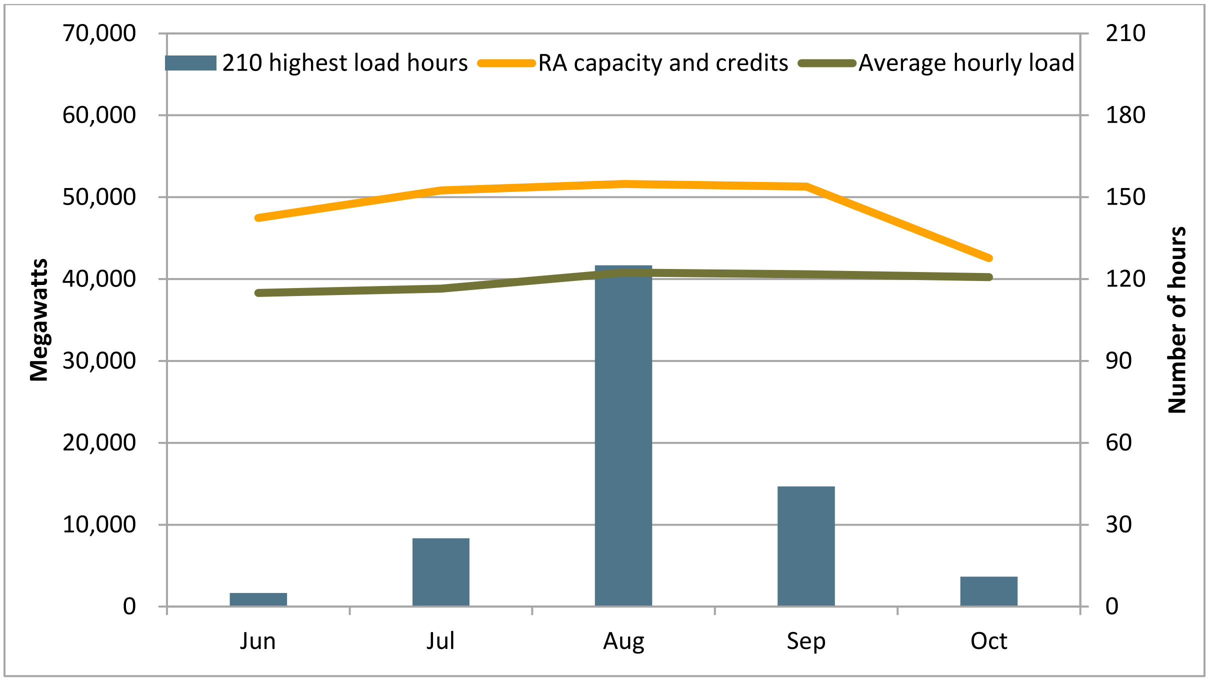
California's resource adequacy program recognizes that a portion of the state's generation is only available during limited hours. To accommodate this, load serving entities are allowed to meet a portion of their resource adequacy requirements with availability-limited generation. This element of the program reflects assumptions that generation will generally be available and used during hours when peak loads are highest. Therefore, the CPUC's resource adequacy program is designed to ensure that the highest load hours are met by requiring that all resource adequacy capacity be available at least 210 hours across summer months.[229] It is assumed that use-limited resources are managed such that they will be available during the peak load hours.

Figure 9.2 provides an overview of resource adequacy capacity during the 210 highest load hours in 2020. The green line shows average hourly load during these hours. The yellow line includes average monthly procured resource adequacy supply, legacy reliability must-run capacity, and additional capacity that the CPUC credits towards load serving entity resource adequacy obligations.[230] In addition, the blue bars show the number of hours in each month that belong to the 210 highest load hours during the year.

[229] 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 in a year regardless of month, the MCC bucket construct specifies minimum required availability in each month, May through September.

[230] These credits include capacity from utility demand response programs with a PRM adder as well as liquidated damage credits.

Figure 9.2 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 2020***. Average hourly load was around 40,400 MW for these hours, while average resource adequacy capacity was around 49,000 MW.
- ***During 2020, load during the 210 highest load hours was greater than 38,000 MW.*** These hours were typically concentrated in high temperature days during July, August, and September but also included some days in June and October.

Load serving entities can contract with multiple types of resources to fulfill their resource adequacy obligations. Table 9.1 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 2020.[231] 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).

[231] Bids and self-schedules in the day-ahead and real-time markets are now reported as the proportion of total resource adequacy capacity. This is a change from previous reports which presented bids and self-schedules as the proportion of capacity after adjusting for outages and availability.

Table 9.1 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 total RA Cap.	MW	% of total RA Cap.	MW	% of total RA Cap.
Must-Offer:									
Gas-fired generators	19,641	18,512	94%	18,511	94%	18,112	92%	18,077	92%
Other generators	1,437	1,350	94%	1,350	94%	1,339	93%	1,339	93%
Subtotal	**21,078**	**19,862**	**94%**	**19,861**	**94%**	**19,451**	**92%**	**19,416**	**92%**
Other:									
Imports	4,699	4,660	99%	4,155	88%	4,687	100%	3,827	81%
Use-limited gas units	8,164	7,856	96%	7,820	96%	7,728	95%	7,672	94%
Hydro generators	6,385	5,682	89%	5,385	84%	5,573	87%	5,279	83%
Nuclear generators	2,740	2,698	98%	2,691	98%	2,698	98%	2,691	98%
Solar generators	2,790	2,777	100%	1,950	70%	2,761	99%	1,969	71%
Wind generators	1,160	1,144	99%	770	66%	1,141	98%	756	65%
Qualifying facilities	969	959	99%	806	83%	949	98%	818	84%
Other non-dispatchable	743	733	99%	587	79%	720	97%	521	70%
Subtotal	**27,650**	**26,509**	**96%**	**24,164**	**87%**	**26,257**	**95%**	**23,533**	**85%**
Total	**48,728**	**46,371**	**95%**	**44,025**	**90%**	**45,708**	**94%**	**42,949**	**88%**

Key findings of this analysis include:

- ***About 57 percent of resource adequacy capacity was procured from gas-fired generators***. Gas-fired resources supplied 27,800 MW of resource adequacy capacity during the 210 highest load hours of 2020.

- ***Just 43 percent of resource adequacy capacity for the 210 highest load hours was procured from resources that are not availability-limited and are subject to ISO bid insertion***. About 21,100 MW of system resource adequacy capacity was not classified as use-limited and was subject to ISO bid insertion 24x7.[232] Gas-fired generation in this category made up about 19,600 MW (40 percent) of total resource adequacy capacity. Other generators accounted for 3 percent.

- ***Use-limited gas units made up the largest portion of resource adequacy capacity with limited availability not subject to ISO bid insertion***. These resources contributed about 8,200 MW of total capacity (17 percent), hydro generators contributed 13 percent, imports contributed 10 percent, solar resources contributed 6 percent, nuclear resources contributed 6 percent, wind resources contributed 2 percent, qualifying facility resources contributed 2 percent, and other non-dispatchable resources (e.g., demand response) contributed 2 percent of system capacity.[233]

232 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.

233 Energy storage is included in the "other non-dispatchable" category in this report. DMM plans on giving it a separate category in future reports.

- ***Capacity available after reported outages and de-rates continued to be significant***. Average resource adequacy capacity was around 49,000 MW during the 210 highest load hours in 2020, about 700 MW less than in 2018. After adjusting for outages and de-rates, the remaining capacity available in the day-ahead market was about 95 percent of the overall resource adequacy capacity, which was about 2 percent lower than in 2019.

- ***Day-ahead market availability was high for all resource types***. About 94 percent of must-offer and 96 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 91 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 de-rates***. The last four columns of Table 9.1 show how potentially available resource adequacy capacity and actual bids in the real-time market compare with total resource adequacy capacity. This capacity has been adjusted for outages and de-rates. About 88 percent of the total resource adequacy capacity was scheduled or bid in the real-time market.

- ***Most use-limited gas capacity was bid into the day-ahead market***. Around 8,200 MW of use-limited gas resources were used to meet resource adequacy requirements. About 96 percent of this capacity was bid in the day-ahead market during the highest 210 load hours. In real-time, about 7,700 MW (94 percent) of this capacity was scheduled or bid in the real-time market.

Table 9.2 shows the availability of resources in ISO markets aggregated by the type of load serving entity that the resources were contracted with. In this analysis, supply plans were used to proportionally assign resource bid availability to load serving entities based on corresponding contracted capacity.[234] 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.

[234] 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.

Table 9.2 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 total RA Cap.	MW	% of total RA Cap.	MW	% of total RA Cap.
CCA	9,038	8,696	96%	8,394	93%	8,589	95%	8,015	89%
DA	3,439	3,295	96%	3,155	92%	3,251	95%	3,125	91%
IOU	31,921	30,193	95%	28,749	90%	29,735	93%	28,111	88%
Muni	3,979	3,843	97%	3,387	85%	3,792	95%	3,366	85%
Substituted capacity	352	344	98%	340	97%	339	96%	330	94%
Total	**48,729**	**46,371**	**95%**	**44,025**	**90%**	**45,706**	**94%**	**42,947**	**88%**

Key findings of this analysis include:

- ***Most system capacity was procured by investor-owned utilities.*** Investor-owned utilities accounted for about 32,000 MW (or 66 percent) of system resource adequacy procurement, community choice aggregators contributed 19 percent, municipal utilities contributed 8 percent, and direct access services contributed 7 percent. This is similar to 2019, when investor-owned utilities and community choice aggregators accounted for 66 percent and 18 percent of procurement, respectively.

- ***Day-ahead availability was high for all load types***. About 97 percent of resource adequacy capacity was available from resources contracted with municipal utilities, 96 percent of resource adequacy capacity was available from resources contracted with direct access, 96 percent of resource adequacy capacity was available from resources that contracted with community choice aggregators, and 95 percent was available from investor-owned utilities.

- ***All load serving entity types contracted with a majority of resources with availability limitations that are not subject to ISO bid insertion.*** Community choice aggregators procured 54 percent of their resource adequacy capacity from these resources, while direct access services procured 51 percent, investor-owned utilities procured 57 percent, and municipal utilities procured 67 percent.

- ***All load types continue to procure a significant amount of imports to meet system resource adequacy requirements.*** Community choice aggregators procured 22 percent of their resource adequacy capacity from imports, while municipal utilities procured 16 percent, direct access services procured 10 percent, and investor-owned utilities procured 5 percent.

- ***Most capacity was available to be bid into the real-time market for each load type***. Real-time resource adequacy capacity availability ranged from 93 percent to 96 percent for each load type. Availability of resources contracted with investor-owned utilities was slightly lower than for the other load types. This was primarily due to lower availability from hydro resources during high load periods.

- ***Substitute capacity had high rates of availability and market participation.*** An average of about 352 MW of resource adequacy capacity came from substituted capacity during the 210 highest load hours.

Table 9.3 shows the availability of resource adequacy capacity in the ISO markets based on whether the capacity was exempt from charges under the resource adequacy availability incentive mechanism. For this analysis, settlements data was used to identify resources that were exempt from RAAIM charges if they were unavailable during the availability assessment hours.[235]

Table 9.3 Average system resource adequacy capacity and availability by RAAIM category (210 highest load hours)

RAAIM Category	RA capacity by RAAIM group (MW)	% of total RA capacity	Day-ahead: Adjusted for outages MW	Day-ahead: Adjusted for outages % of total RA Cap.	Day-ahead: Bids and self-schedules MW	Day-ahead: Bids and self-schedules % of total RA Cap.	Real-time: Adjusted for outages/availability MW	Real-time: Adjusted for outages/availability % of total RA Cap.	Real-time: Bids and self-schedules MW	Real-time: Bids and self-schedules % of total RA Cap.
Non-RAAIM exempt	38,735	79%	36,621	95%	35,736	92%	36,073	93%	34,817	90%
RAAIM exempt	9,994	21%	9,749	98%	8,289	83%	9,634	96%	8,129	81%
Total	**48,729**	**100%**	**46,370**	**95%**	**44,025**	**90%**	**45,707**	**94%**	**42,946**	**88%**

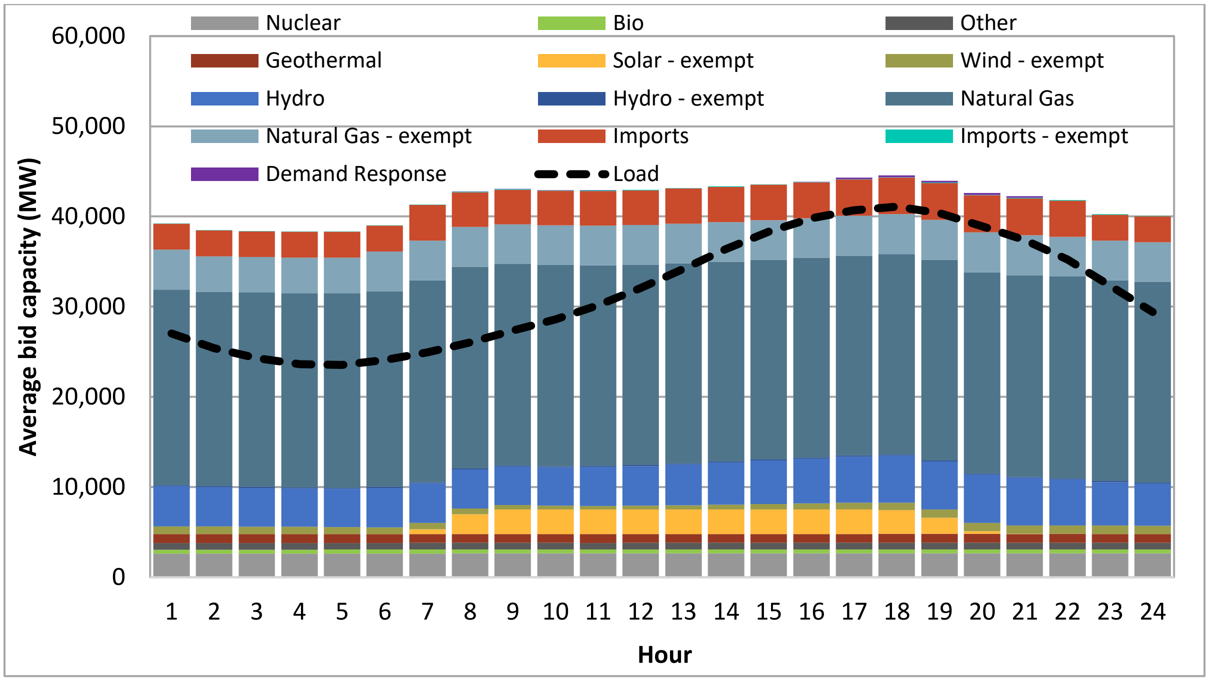
Key findings of this analysis include:

- ***Capacity exempt from RAAIM charges accounted for about 21 percent of overall resource adequacy capacity*** during the 210 highest load hours of 2020. This was mostly made up of gas, solar, and wind resources.
- ***Capacity subject to RAAIM was adjusted more for outages and availability, but bid a higher percentage of available capacity in the markets***. About 93 percent of resource adequacy capacity subject to RAAIM was available in the real-time market on average. Reduced availability was mainly driven by gas and hydro units that were adjusted for outages and availability.
- ***Capacity exempt from RAAIM bid a lower percentage in the markets***. Capacity exempt from RAAIM was adjusted for outages less often, but only 81 to 83 percent of their capacity was bid into the markets during high load hours. Reduced availability was mainly driven by solar and wind resources that are typically not able to generate to resource adequacy values when loads are highest.

Figure 9.3 shows the average hourly resource adequacy capacity that was bid into the day-ahead market during the days that contained the 210 highest load hours in 2020. Capacity is grouped by fuel type and RAAIM exemption status. Average hourly load is also represented on the graph as a point of reference.

[235] There are many reasons why a resource may be exempt from RAAIM charges in general or on any particular day. This includes the resource's maximum generation capacity, generation type, or outage type, among others. For more information on RAAIM exemptions, refer to Section 40.9 of the ISO tariff.

Figure 9.3 Average hourly bids by fuel type and RAAIM category (Days with 210 highest load hours)



Key findings of this analysis include:

- ***There was enough bid-in capacity in the day-ahead market from resource adequacy resources on average to cover average hourly load across the day; however, this was not true for all high load days in 2020***. On average, bids in the day-ahead market exceeded load by a minimum of about 3,500 MW in hour-ending 18 to a maximum of about 17,000 MW in hour-ending 8.

- ***Contrary to the average values, day-ahead bids from resource adequacy capacity were insufficient to cover average hourly load during some hours in 2020.*** Day-ahead bids from resource adequacy resources were not sufficient to meet the day-ahead load forecast during several peak net load hours on August 17-20. After adding non-spin reserve requirements, regulation up requirements, and the amount of self-scheduled exports to the load forecast, bid insufficiency from resource adequacy resources increased for most peak net load hours from August 14-20.[236]

- ***Availability-limited capacity plays a significant role in meeting demand during peak load hours***. After hour-ending 17, a reduction in the availability of solar capacity causes increased reliance on RAAIM exempt gas resources, demand response, and imports to meet system demand.

[236] For more information, refer to *Report on system and market conditions, issues and performance: August and September 2020*, DMM, November 24, 2020, pp/22-35: http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

Resource adequacy imports

Load serving entities are allowed to use non-resource specific imports to meet system resource adequacy requirements. Imports can be bid at any price up to the $1,000/MWh bid cap as they are not subject to market power mitigation and do not have any further bid obligation in the real-time market if not scheduled in the day-ahead energy or residual unit commitment process.[237]

DMM 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 2020, the availability of imports in the real-time market is relatively low compared to other resources like must-offer gas units, however the energy bid prices for imports have been declining over time compared to other resources.

In June 2020, the CPUC issued a decision specifying that non-resource-specific import resource adequacy resources must be bid into ISO markets at or below $0/MWh, at minimum in the availability assessment hours.[238] These rules became effective at the beginning of 2021.

Table 9.1 shows that load serving entities used about 4,700 MW of imports (or about 10 percent of total resource adequacy capacity) to meet system requirements during the top 210 load hours of 2020. These resources had moderate participation rate in the day-ahead market with about 88 percent of available capacity submitting bids and self-schedules. In the real-time market, however, imports had the second lowest participation rate of non-variable energy resources with 81 percent of capacity available through bids or self-schedules.

Figure 9.4 summarizes the bid prices and volume of self-scheduled and economic bids for import resources in the day-ahead market during peak hours on a quarterly basis.[239] 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 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.

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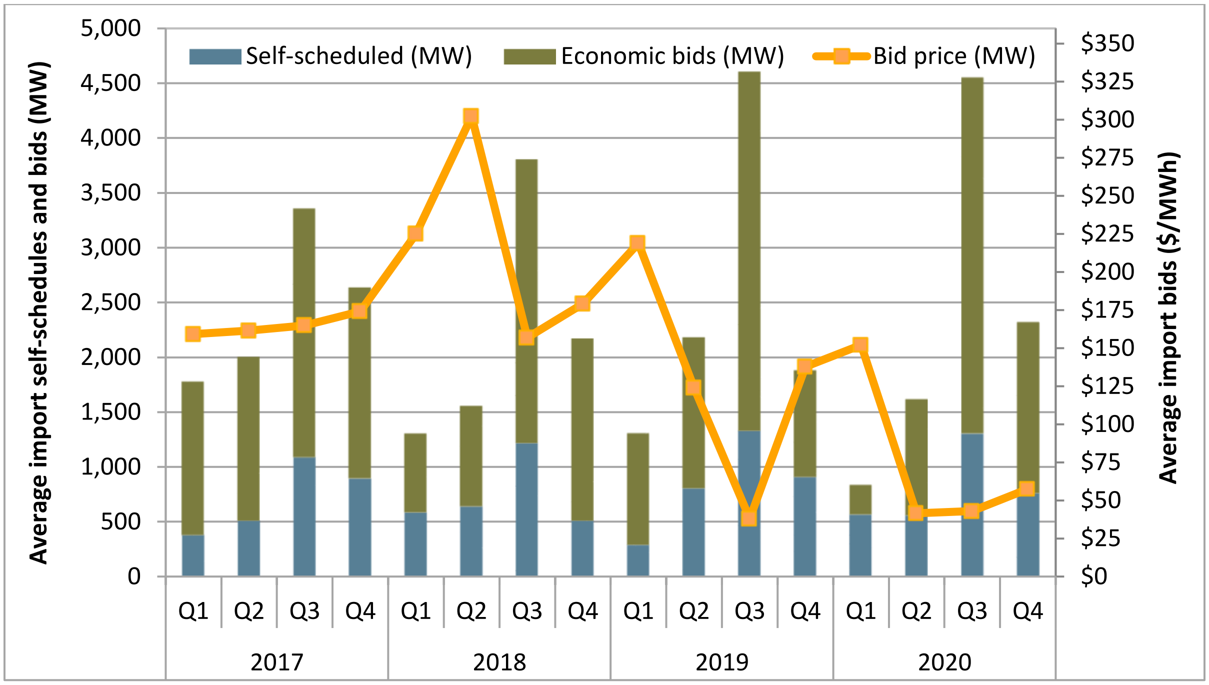
[237] In 2021 Phases 1 (March 20) and 2 (June 13) of the FERC Order 831 Compliance Tariff Amendment were implemented. Phase 1 allows RA-imports to bid over the soft offer cap of $1,000/MWh when the Maximum Import Bid Price (MIPB) is over $1,000/MWh or the ISO has accepted a cost-verified bid over $1,000/MWh. Phase 2 imposed bidding rules capping RA-import bids over $1,000/MWh at the greater of MIBP or highest cost-verified bid up to the hard offer cap of $2,000/MWh.

[238] *Decision Adopting Resource Adequacy Import Requirements (D.20-06-028)*, R.17-09-020, CPUC, June 25, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K516/342516267.PDF

[239] Peak hours are defined as Monday through Saturday, excluding North American Electric Reliability Council holidays, from hour-ending 7 to hour-ending 22.

Figure 9.4 Resource adequacy import self-schedules and bids (Quarterly peak hours)



Key findings of this analysis include:

- ***Overall volume of resource adequacy import bids in high load hours decreased slightly in 2020 compared to 2019***. Quarterly averages for import bids and self-schedules ranged from about 800 MW to 4,500 MW in 2020 compared to 1,300 MW to 4,600 MW in 2019.
- ***Weighted average prices for energy bids from resource adequacy imports for 2020 were highest in the first quarter***. Energy bid prices averaged over $150/MWh in this quarter before decreasing over successive quarters. Energy bid prices averaged about $50/MWh for 2020. This is the lowest yearly average since 2015.
- ***There were more economic bids for imports than self-schedules in three quarters***. Self-scheduled resource adequacy imports accounted for about 34 percent of total bids from these resources in the day-ahead market, about the same as in 2019.

9.3 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 energy supply is the tightest in California. The goal of local resource adequacy requirements is to ensure reliability in specific transmission constrained load pockets. Load serving entities are required to procure resource adequacy capacity within certain local areas that have limited import capability.

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 all contingencies required by the mandatory reliability standards (NERC, WECC, and ISO). The ISO allocates local capacity area obligations to the CPUC, commensurate with the total CPUC jurisdictional load share, and directly 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. For CPUC-jurisdictional load serving entities, the CPUC re-allocates local requirements to load serving entities 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.

On an annual basis, CPUC-jurisdictional load serving entities are required to demonstrate that they have procured 100 percent of their local resource adequacy requirements for each month of the compliance year.[240] Load serving entities must also demonstrate that they have met revised local obligation on a monthly basis from May through December due to load migration.

Local market power exists in most local capacity areas due to a lack of competition and insufficient supply to meet local resource adequacy requirements in some local areas.[241]

Bidding and scheduling obligations

Scheduling coordinators representing resource adequacy capacity that satisfies local requirements must make the capacity listed in resource adequacy supply plans 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 9.4 shows an analysis similar to the availability analysis for system resource adequacy. This table compares the local area capacity requirements established by the ISO to the amount of capacity that was procured and actually bid into both the day-ahead and real-time markets during the highest 210 load hours in 2020.[242]

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240 Under the CPUC's Decision (D.) 19-02-022, local resource adequacy requirements will be three-year forward requirements starting in the 2021 compliance year. CPUC-jurisdictional load serving entities will be required to procure capacity to meet 100 percent of local requirements for the upcoming compliance year, 100 percent of requirements for the following year, and 50 percent of local requirements for the third year. Under the CPUC's Decision (D.) 20-06-002, PG&E and SCE will serve as central procurement entities for local capacity in their respective distribution service areas starting with the 2023 compliance year.

241 For more information on competitiveness in local capacity areas, refer to Chapter 6.

242 Local capacity area resource adequacy requirements obtained from the *2020 Local Capacity Technical Analysis*, May 1, 2019, pg. 24, Table 3.1-1: http://www.caiso.com/Documents/Final2020LocalCapacityTechnicalReport.pdf.

Table 9.4 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	6,498	4,550	6,264	138%	6,156	98%	6,204	136%	6,068	98%
Greater Fresno	PG&E	2,704	1,694	2,645	156%	2,526	96%	2,617	154%	2,498	95%
Sierra	PG&E	1,862	1,764	1,479	84%	1,424	96%	1,471	83%	1,432	97%
North Coast/North Bay	PG&E	822	742	759	102%	739	97%	750	101%	749	100%
Stockton	PG&E	612	629	595	95%	581	98%	588	93%	575	98%
Kern	PG&E	404	465	394	85%	374	95%	389	84%	362	93%
Humboldt	PG&E	162	130	156	120%	152	97%	154	118%	152	99%
LA Basin	SCE	8,610	7,364	7,995	109%	7,907	99%	7,724	105%	7,627	99%
Big Creek/Ventura	SCE	4,302	2,410	3,994	166%	3,888	97%	3,782	157%	3,659	97%
San Diego	SDG&E	3,954	3,895	3,751	96%	3,589	96%	3,743	96%	3,553	95%
Total		**29,930**	**23,643**	**28,032**	**119%**	**27,336**	**98%**	**27,422**	**116%**	**26,675**	**97%**

Key findings of this analysis include:

- ***Overall, total resource adequacy capacity exceeded requirements in local capacity areas***. Load serving entities procured almost 30,000 MW of capacity in local areas in 2020, compared to about 24,000 MW of required capacity. Even after controlling for outages, the overall available capacity exceeded local requirements in the day-ahead (119 percent of requirements) and real-time (116 percent of requirements) markets.

- ***Procurement in some local capacity areas was significantly lower than the local area requirement***. Total resource adequacy capacity was below the local requirements in the Stockton and Kern local areas.[243]

- ***Significant amounts of energy, beyond requirements, were available in the day-ahead market for several local capacity areas***. Capacity in the Greater Bay Area, Greater Fresno, North Coast/North Bay, Humboldt, LA Basin, and Big Creek/Ventura was available between 102 percent and 156 percent of the local area requirement, after accounting for outages and de-rates. This offsets lower availability rates from capacity in Sierra, Stockton, Kern, and San Diego. Overall, about 119 percent of local capacity area requirements were available in the day-ahead market.

- ***Available capacity was generally lower in the real-time market compared to the day-ahead market***. About 116 percent of local capacity area requirements was bid into the day-ahead market, while 113 percent of local area requirements was bid into the real-time market.

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 2020 are described in depth in Section 9.6.

243 Under the CPUC's Decision (D.) 19-02-022, starting 2020, the local capacity requirements in the Fresno, Humboldt, North Coast/North Bay, Sierra, and Stockton local areas are no longer aggregated to a "PG&E Other" local area requirement.

Table 9.5 shows 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 9.5 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 total RA Cap.	MW	% of total RA Cap.	MW	% of total RA Cap.
PG&E	CCA	3,684	3,535	96%	3,456	94%	3,499	95%	3,422	93%
	DA	843	812	96%	802	95%	804	95%	792	94%
	IOU	7,547	7,033	93%	6,861	91%	6,972	92%	6,805	90%
	Muni	926	855	92%	775	84%	841	91%	759	82%
	Substituted Capacity	63	59	94%	57	90%	58	92%	57	90%
	Subtotal	**13,063**	**12,294**	**94%**	**11,951**	**91%**	**12,174**	**93%**	**11,835**	**91%**
SCE	CCA	1,143	1,072	94%	1,048	92%	1,031	90%	1,009	88%
	DA	546	484	89%	471	86%	461	84%	446	82%
	IOU	10,018	9,265	92%	9,177	92%	8,880	89%	8,758	87%
	Muni	1,061	1,023	96%	956	90%	991	93%	936	88%
	Substituted Capacity	145	145	100%	144	99%	143	99%	136	94%
	Subtotal	**12,913**	**11,989**	**93%**	**11,796**	**91%**	**11,506**	**89%**	**11,285**	**87%**
SDG&E	CCA	98	93	95%	93	95%	88	90%	87	89%
	DA	431	421	98%	421	98%	419	97%	418	97%
	IOU	3,425	3,237	95%	3,075	90%	3,236	94%	3,049	89%
	Muni	-	-	-	-	-	-	-	-	-
	Substituted Capacity	0	0	100%	0	100%	0	100%	0	100%
	Subtotal	**3,954**	**3,751**	**95%**	**3,589**	**91%**	**3,743**	**95%**	**3,554**	**90%**
	Total	**29,930**	**28,034**	**94%**	**27,336**	**91%**	**27,423**	**92%**	**26,674**	**89%**

Key findings of this analysis include:

- ***Most local resource adequacy capacity was procured by investor-owned utilities***. Investor-owned utilities accounted for about 21,000 MW (or about 70 percent) of local resource adequacy procurement, community choice aggregators contributed 16 percent, direct access services contributed 6 percent, and municipal utilities contributed 7 percent.

- ***Most local resource adequacy capacity procurement by community choice aggregators occurred in the Pacific Gas and Electric TAC area***. Community choice aggregators procured about 28 percent of total resource adequacy capacity in the Pacific Gas and Electric area, mostly in the Greater Bay Area, Greater Fresno, and Sierra local capacity areas.

- ***Day-ahead availability was high for all load types in each TAC area***. Availability in the day-ahead market ranged from 93 percent to 95 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 92 percent of the total local resource adequacy capacity was available to the real-time market. Resources in the Southern California Edison TAC area had the lowest availability in the real-time market out of the three areas with 89 percent availability. This was mainly due to outages of resources that contracted with the investor-owned utilities and community choice aggregators.

9.4 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.[244]

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.[245,246] Because the grid commonly faces two pronounced upward net load ramps per day, flexible resource adequacy categories were designed to address both the maximum primary and secondary net load ramp.[247]

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

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244 For more information, see the following FERC order: http://www.caiso.com/Documents/Oct16_2014_OrderConditionallyAcceptingTariffRevisions-FRAC-MOO_ER14-2574.pdf

245 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.

246 Net load is defined as total load less wind and solar production.

247 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. The must-offer obligation hours vary seasonally based on this pattern for Category 2 and 3 flexible resource adequacy.

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 9.5 investigates how well flexible resource adequacy requirements addressed system load ramping needs in 2020 by comparing the requirements and the actual maximum three-hour net load ramp on a monthly basis.[248] 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.

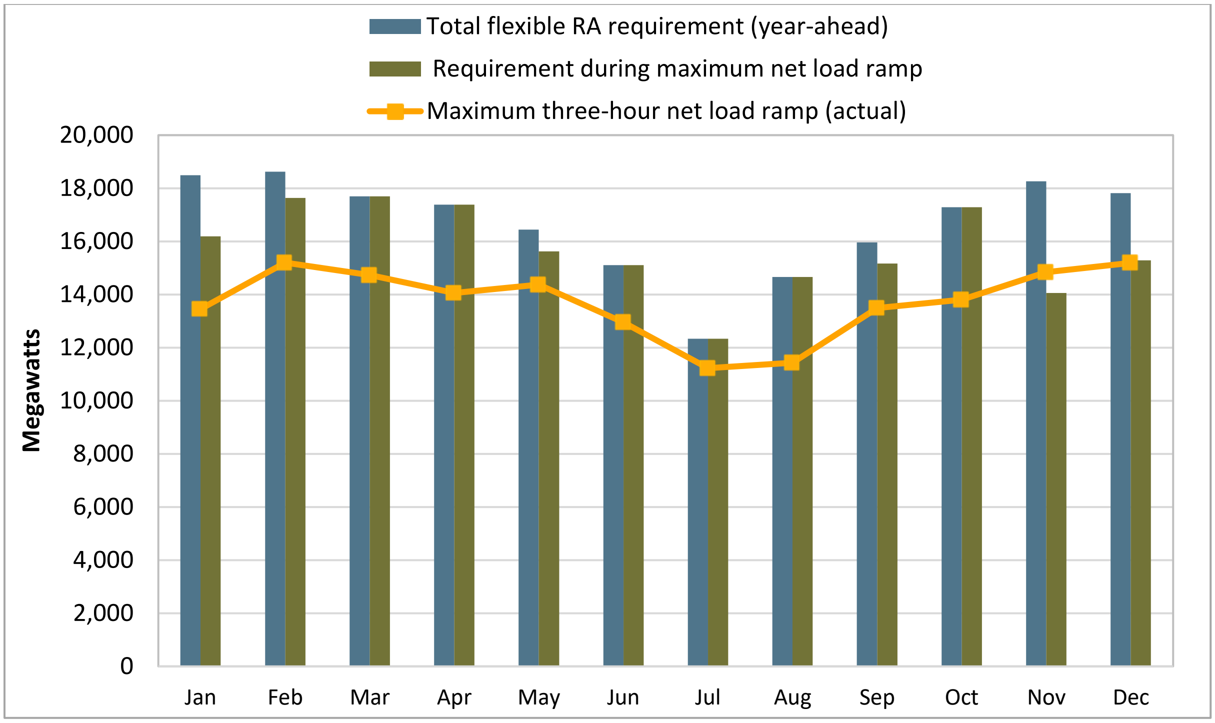
Because each category of flexible resource capacity has different must-offer hours, the requirement will effectively differ from day-to-day and hour-to-hour.[249] Figure 9.5 was therefore calculated by first

[248] 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.

[249] 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.

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 9.5 Flexible resource adequacy requirements during the actual maximum net load ramp



Key findings of this analysis include:

- ***Year-ahead flexible resource adequacy requirements were sufficient to meet the actual maximum three-hour net load ramp for all months in 2020.*** This is shown where the blue bars are higher than the gold line.
- ***Actual flexible resource adequacy requirements set at the time of the peak ramp were sufficient to meet actual maximum three-hour net load ramps for most months***. This is shown when the green bars are higher than the gold line. Average requirements were not sufficient to meet the actual three-hour net load ramp in November.

The effectiveness of flexible resource adequacy requirements and must-offer rules in addressing supply during maximum load ramps is 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 2020 requirements and must-offer hours were sufficient in reflecting actual ramping needs in most cases.

Table 9.6 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 9.6 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	13,458	18,493	16,194	1/13/2020	14:20	Y	
Feb	15,199	18,623	17,631	2/4/2020	14:40	Y	
Mar	14,734	17,702	17,702	3/2/2020	15:05	Y	
Apr	14,054	17,384	17,384	4/14/2020	16:45	Y	
May	14,375	16,445	15,625	5/3/2020	16:50	Y	
Jun	12,950	15,109	15,109	6/16/2020	16:55	Y	
Jul	11,228	12,333	12,333	7/1/2020	16:50	Y	
Aug	11,427	14,664	14,664	8/11/2020	15:55	Y	
Sep	13,491	15,959	15,161	9/27/2020	14:55	Y	
Oct	13,808	17,284	17,284	10/26/2020	15:05	Y	
Nov	14,845	18,265	14,062	11/29/2020	14:00	N	Ramp start time occurred before Category 2 requirement; max ramp occurred on a Sunday.
Dec	15,186	17,817	15,286	12/29/2020	14:15	Y	

Key results of this analysis include:

- ***The average requirement during the maximum net load ramp was sufficient to meet the actual maximum three-hour net load ramps in most months***. The average requirement was at least 1,000 MW greater than the maximum 3-hour net load ramp in most months. The only month where average requirements were less than the net load ramp was November.
- ***In November, the maximum net load ramp occurred at least partially outside of Category 2 and Category 3 must-offer hours***. The maximum net load occurred on a Sunday when Category 3 resources do not have must-offer obligations. In addition, the net load ramp began an hour before Category 2 must-offer obligations.

Procurement

Table 9.7 shows what types of resources provided flexible resource adequacy and details the average monthly flexible capacity procurement in 2020 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, the majority of flexible ramping procurement continued to be composed of natural gas-fired generation in 2020.

Table 9.7 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	11,283	65%	27	4%	0	0%
Use-limited gas units	4,136	24%	637	95%	2	6%
Use-limited hydro generators	1,734	10%	3	0%	0	0%
Other hydro generators	128	1%	3	0%	0	0%
Geothermal	181	1%	0	0%	0	0%
Biomass	17	0%	0	0%	0	0%
Use-limited biomass	2	0%	0	0%	0	0%
Energy Storage	8	0%	0	0%	30	91%
Other	0	0%	0	0%	1	3%
Total	**17,489**	**100%**	**670**	**100%**	**33**	**100%**

Key findings of this analysis include:

- ***Most flexible resource adequacy capacity was procured from non-use-limited gas-fired generators***. About 11,300 MW (or 62 percent) of total flexible capacity came from these resources. This is a proportional decrease from 2019 when gas-fired generators accounted for about 66 percent of total flexible capacity. Almost all (99 percent) of the capacity supplied by gas-fired generators served as Category 1 resources in 2020.
- ***Use-limited gas units made up the second largest volume of flexible resource adequacy capacity***. These generators made up about 24 percent of Category 1 capacity and 26 percent of overall flexible capacity.
- ***Use-limited hydroelectric generators made up the third largest volume of Category 1 flexible resource adequacy capacity***. These generators accounted for about 10 percent of Category 1 capacity, up from about 9 percent in 2019.
- ***Load serving entities procured significantly less than the maximum allowed amount of Category 3 flexible capacity in 2020***. Load serving entities procured a monthly average of 34 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 and other non-dispatchable resources (e.g., demand response) comprised a significant proportion of Category 3 flexible resource adequacy capacity***. These resources accounted for a small amount of total flexible capacity, but together they made up about 93 percent of Category 3 capacity in 2020.

Table 9.8 shows what types of load serving entities procured flexible resource adequacy by category in 2020. Supply plans were used to determine monthly LSE procurement and averaged over the year by flexible resource adequacy category.

Table 9.8 Average monthly flexible resource adequacy procurement by load type and flex category

Load Type	Category 1		Category 2		Category 3	
	Average MW	Total %	Average MW	Total %	Average MW	Total %
CCA	3,388	19%	0	0%	8	24%
DA	1,640	9%	0	0%	0	0%
IOU	11,847	68%	614	92%	23	70%
Muni	613	4%	56	8%	2	6%
Total	**17,488**	**100%**	**670**	**100%**	**33**	**100%**

Key findings of this analysis include:

- ***Investor-owned utilities procured the highest proportion of each flexible resource adequacy category***. Investor-owned utilities procured 69 percent of total flexible capacity, community choice aggregators procured 19 percent, direct access services procured 9 percent, and municipal utilities procured 4 percent. Investor-owned utilities procured at least 68 percent of the capacity of each category.

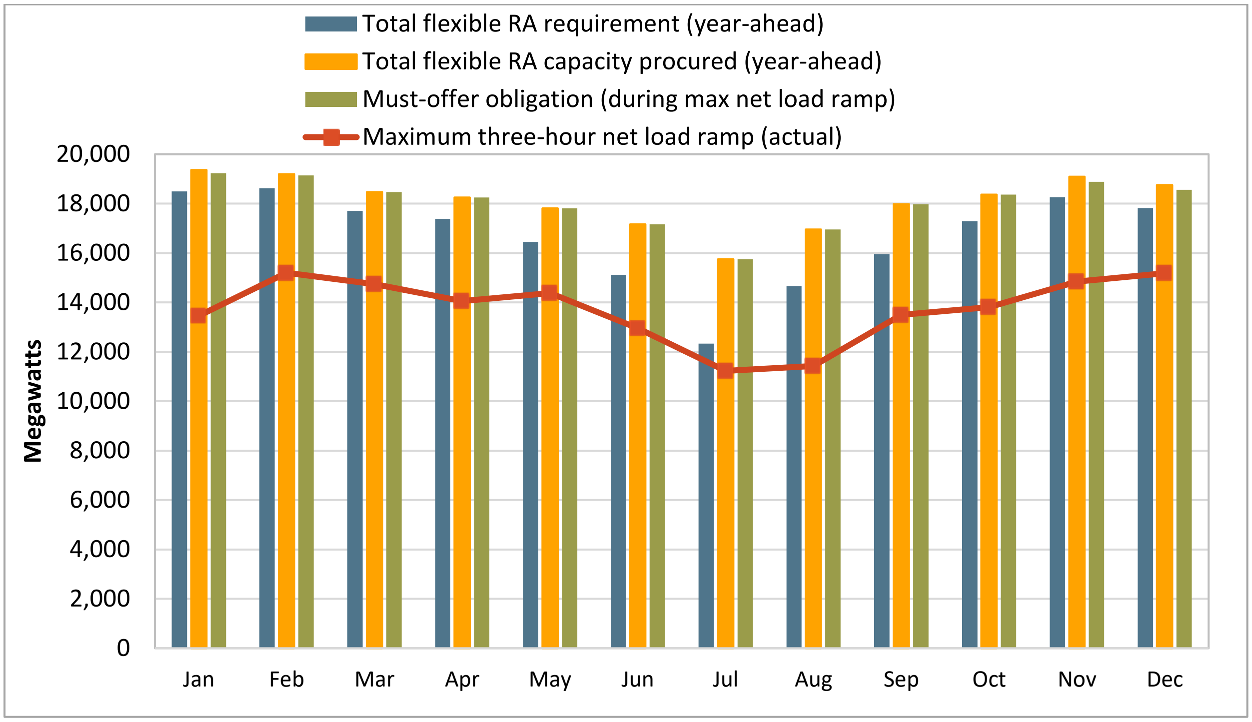
- ***Most load types procured resources for multiple flexible resource adequacy category***. Investor-owned utilities and municipal utilities procured Category 1, 2, and 3 flexible resource adequacy resources. Community choice aggregators and direct access services did not procure any Category 2 capacity.

- ***Community choice aggregators procured the second highest proportion of Category 3 flexible capacity***. CCAs procured most of their flexible capacity from Category 1 resources, but their procurement also contributed to a portion of total Category 3 (24 percent) capacity.

Due in part to greater amounts of Category 1 capacity, total flexible resource adequacy procurement exceeded requirements for all months in 2020. Figure 9.6 builds upon the information presented in Figure 9.5 by adding more information to the graph. Figure 9.6 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.[250] 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.

[250] 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 9.6 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 the same as total procurement (gold bars) from March to October. For every other month, the must-offer obligation is about 50 to 200 MW lower than the amount procured.
- ***The must-offer obligation for procured capacity was sufficient to meet the maximum net load ramp in all 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 in 2020.

Availability

Table 9.9 presents an assessment of the availability of flexible resource adequacy capacity in 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, an extra-long-start resource is considered 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 2020. This analysis is not intended to replicate how availability is measured under the resource adequacy availability incentive mechanism.[251]

Table 9.9 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 DA Capacity		MW	% of RT Capacity
January	18,845	16,747	89%	13,081	11,421	87%
February	18,695	15,601	83%	13,332	10,739	81%
March	17,857	14,289	80%	12,566	9,948	79%
April	17,712	13,561	77%	11,757	10,005	85%
May	17,210	13,913	81%	10,841	9,712	90%
June	16,688	14,257	85%	11,155	10,127	91%
July	15,266	13,784	90%	10,824	9,557	88%
August	16,513	14,845	90%	12,243	10,182	83%
September	17,476	15,453	88%	13,011	10,785	83%
October	17,709	14,822	84%	14,362	11,290	79%
November	18,628	15,616	84%	13,880	10,749	77%
December	18,128	15,284	84%	13,364	11,235	84%
Total	**17,561**	**14,848**	**85%**	**12,535**	**10,479**	**84%**

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 2020***. Average availability in the day-ahead market was 85 percent and ranged from 77 percent to 90 percent. This is similar to 2019 when average availability in the day-ahead market was about 86 percent with a range from 80 percent to 91 percent. Average availability in the real-time market was 84 percent and ranged from 77 percent to 91 percent. This is slightly lower than 2019 when average real-time availability was 88 percent and ranged from 83 percent to 90 percent.

- ***The real-time average must-offer obligation is much lower than the day-ahead obligation***. Flexible capacity must-offer requirements were about 14,848 MW in the day-ahead market and only about 10,479 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

[251] The resource adequacy availability incentive mechanism was implemented by the ISO in November 2016.[251] Resource adequacy availability incentive mechanism penalties became financially binding on April 1, 2017.

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 9.10 is based on the same data summarized in Table 9.9, 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 9.10 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 DA Capacity		MW	% of RT Capacity
CCA	3,386	2,727	81%	2,513	2,189	87%
DA	1,644	1,379	84%	1,221	1,046	86%
IOU	11,901	10,198	86%	8,238	6,780	82%
Muni	630	545	87%	564	464	82%
Total	**17,561**	**14,848**	**85%**	**12,535**	**10,480**	**84%**

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 community choice aggregators had about 81 percent availability in the day-ahead market, those that contracted with direct access services had about 84 percent availability, and those that contracted with investor-owned utilities and municipalities had 86 to 87 percent availability. In the real-time market, these resources were available between 82 and 87 percent of the time, depending on load type.

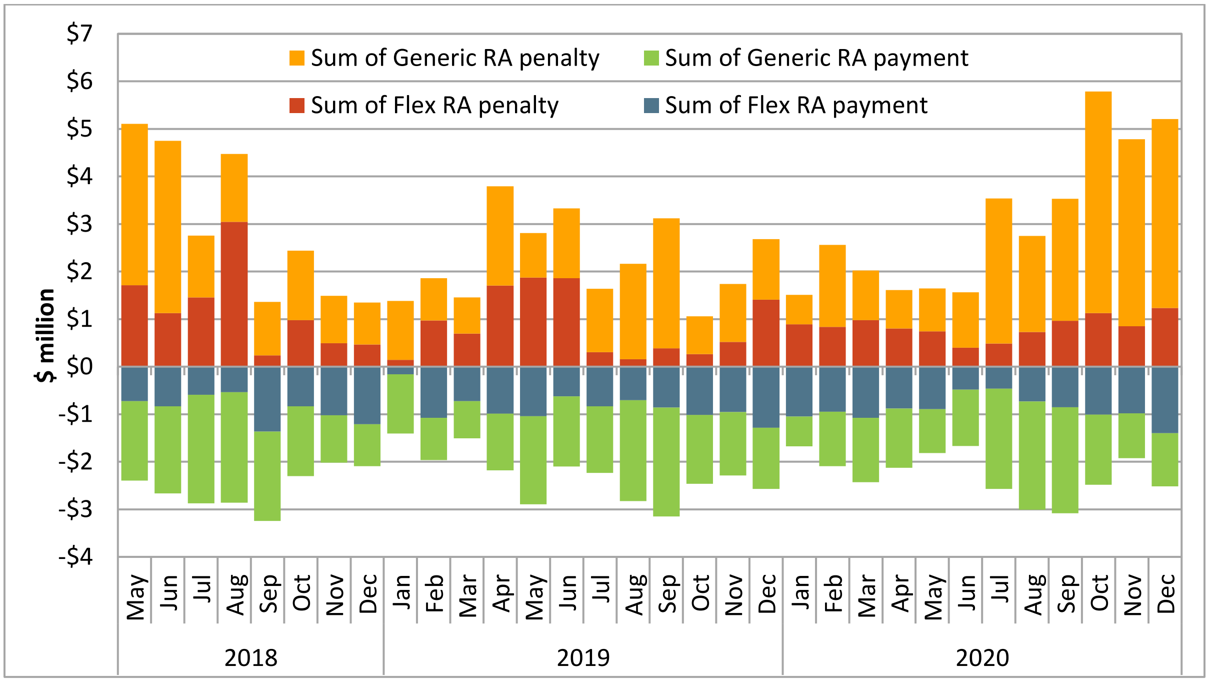
9.5 Incentive mechanism payments

The purpose of the resource adequacy availability incentive mechanism (RAAIM) is to provide an incentive for resource adequacy resources to meet their bidding obligations and provide energy bids to the market. Resources that are designated as system, local, or flexible resource adequacy capacity are subject to RAAIM. The monthly performance of these resources are measured by the availability of bids and self-schedules in the market during designated availability assessment hours. The 2020 availability assessment hours for system and local resource adequacy resources were hours ending 17 to 21. The 2020 availability assessment hours for flexible resource adequacy resources were hours ending 6 to 22 for base ramping resources, hours ending 16 to 20 for peak ramping resources, and hours ending 16 to 20 on non-holiday weekdays for super-peak ramping resources.

Resources that provide local, system, or flexible resource adequacy are either charged or paid each month depending on their average capacity availability during the availability assessment hours. Resources whose average monthly capacity availability is less than the availability standard of 94.5 percent are charged a non-availability charge for the month. Resources whose average capacity availability is greater than the availability standard of 98.5 percent are paid an incentive payment for the month. The RAAIM price is set at 60 percent of the CPM soft-offer cap price, or about $3.79/kW-month.[252]

Figure 9.7 summarizes monthly RAAIM charges and payments to resource adequacy resources from May 2018 to December 2020. Financial sums are presented in relation to how money flows through the ISO; RAAIM penalties that resources pay the ISO are in the positive direction on the graph while RAAIM payments where the ISO pays resources are in the negative direction. Charges and payments are presented for both generic and flex resource adequacy resources.

Figure 9.7 Flexible resource adequacy procurement during the maximum net load ramp



Key findings from this analysis include:

- ***Most RAAIM charges and payments are attributed to generic resource adequacy resources.*** In 2020, there was about $37 million in RAAIM charges and $27 million in incentive payments. About 72 percent of penalties and 61 percent of payments were to generic resource adequacy resources.
- ***In 2020, most RAAIM charges occurred during the second half of the year.*** RAAIM charges averaged over $4 million per month in the third and fourth quarter compared to almost $2 million in the first two quarters. This aligns with the period during and after the heat wave conditions that occurred in the third quarter of 2020 when operating conditions were extremely tight.

[252] These payments (charges) are set at the resource's monthly average resource adequacy capacity multiplied by the difference between the lower (upper) bound of the monthly availability standard of 94.5 (98.5) percent and the resource's monthly availability percentage multiplied by the RAAIM price.

9.6 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.

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.

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.

Annual designations

There were no annual capacity procurement designations in 2020. Since the implementation of the current capacity procurement mechanism framework in 2016, the only annual designations were made in 2018.

Monthly designations

There were no monthly capacity procurement mechanism designations made in 2020, and there have not been any since the program was implemented in 2016.

Intra-monthly designations

Table 9.11 shows the intra-monthly capacity procurement mechanism designations that occurred in 2020. 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.

Table 9.11 Intra-monthly capacity procurement mechanism costs

Resource	Designated MW	CPM Start Date	CPM End Date	CPM Type	Price ($/kW-mon)	Estimated cost ($ mil)	Local capacity area	CPM designation trigger
DUANE_1_PL1X3	9	8/16/20	8/31/20	ED	$6.31	$0.03	SYS	Significant Event CPM Designation
BARRE_6_PEAKER	47	8/17/20	8/31/20	SIGEVT	$6.31	$0.14	SYS	Significant Event CPM Designation
GATEWY_2_GESBT1	24	8/17/20	8/31/20	SIGEVT	$6.31	$0.07	SYS	Significant Event CPM Designation
MNDALY_6_MCGRTH	47	8/17/20	8/31/20	SIGEVT	$6.31	$0.14	SYS	Significant Event CPM Designation
SBERDO_2_PSP4	20	8/17/20	8/31/20	SIGEVT	$6.31	$0.06	SYS	Significant Event CPM Designation
SNCLRA_6_PROCGN	27	8/17/20	8/31/20	SIGEVT	$6.31	$0.08	SYS	Significant Event CPM Designation
SUTTER_2_CISO	250	8/17/20	8/31/20	SIGEVT	$6.31	$0.74	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 1	3	8/17/20	8/31/20	SIGEVT	$6.31	$0.01	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 2	2	8/17/20	9/15/20	SIGEVT	$6.31	$0.01	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 3	2	8/17/20	9/15/20	SIGEVT	$6.31	$0.01	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 4	3	8/17/20	9/15/20	SIGEVT	$6.31	$0.02	SYS	Significant Event CPM Designation
GATEWY_2_GESBT1	20	8/17/20	8/31/20	ED	$6.31	$0.06	SYS	Significant Event CPM Designation
GATEWY_2_GESBT1	8	8/18/20	9/16/20	SIGEVT	$6.31	$0.05	SYS	Significant Event CPM Designation
BIGCRK_2_EXESWD	15	8/19/20	9/17/20	SIGEVT	$6.31	$0.09	SYS	Significant Event CPM Designation
GATEWY_2_GESBT1	25	9/1/20	9/15/20	SIGEVT	$6.31	$0.07	SYS	Significant Event CPM Designation
SBERDO_2_PSP4	10	9/1/20	9/15/20	SIGEVT	$6.31	$0.03	SYS	Significant Event CPM Designation
SNCLRA_6_PROCGN	3	9/1/20	9/15/20	SIGEVT	$6.31	$0.01	SYS	Significant Event CPM Designation
SUTTER_2_CISO	155	9/1/20	9/15/20	SIGEVT	$6.31	$0.46	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 1	3	9/1/20	9/15/20	SIGEVT	$6.31	$0.02	SYS	Significant Event CPM Designation
HUMBPP_1_UNITS3	16	9/1/20	9/30/20	ED	$6.31	$0.00	PGE	Potential thermal overload
ARCOGN_2_UNITS	12	9/6/20	10/5/20	SIGEVT	$6.31	$0.00	SYS	Significant Event CPM Designation
SUTTER_2_CISO	250	10/1/20	10/30/20	SIGEVT	$6.31	$0.00	SYS	Significant Event CPM Designation
Total	950					$2.09		

Key findings of this analysis include:

- ***About 950 MW of capacity was procured with an estimated cost of about $2.1 million in 2020.*** The ISO issued a capacity procurement mechanism significant event, which designated about 685 MW of backstop capacity for system reliability needs. The designations were made initially for the month of August with extensions and increased procurement through October. The event was issued to meet the need of the summer heat waves in California and the rest of the West so that the ISO could meet NERC reliability standards for load and reserve obligations. These heat waves created load conditions that were significantly above the projected loads that set the resource adequacy requirements during the planning stage.

- ***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 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, state regulators, market participants, and other interested entities.[253]

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. This chapter summarizes DMM's current recommendations on key market design initiatives and issues. Additional details on many of DMM's recommendations are provided in comments and other reports posted on DMM's page on the ISO website.[254] A summary of key recommendations is provided in the Executive Summary of this report.

10.1 Resource adequacy

California has relied upon the state's long-term bilateral procurement process and resource adequacy program to maintain adequate system capacity and help mitigate market power for over 16 years. However, as noted in the discussion of system market power in Section 10.3, numerous regulatory and structural market changes have occurred in recent years which create the need for significant changes in the state's resource adequacy framework.

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 more detailed market design options and decisions. These include:

- Strengthening requirements for the use of imports to meet system level resource adequacy requirements.
- Developing resource adequacy requirements and resource capacity ratings that ensure sufficient flexible capacity needed to integrate a high level of renewable resource capacity.
- Adopting a multi-year framework for local resource adequacy requirements and procurement by load serving entities.
- Developing a central buyer framework for meeting any local resource adequacy requirements not met by resource adequacy capacity procured by CPUC-jurisdictional load serving entities.
- Developing resource adequacy requirements that consider both energy and capacity needs across all hours of the day, including the peak net load hours.

DMM supports these efforts and views the options being considered by the CPUC as potentially effective steps in addressing the current gaps in the state's resource adequacy framework.

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

254 DMM reports, presentations, and stakeholder comments can be found on the ISO's website here: http://www.caiso.com/market/Pages/MarketMonitoring/MarketMonitoringReportsPresentations/Default.aspx#CommentsRegulatory

DMM also recommends that the ISO and local regulatory authorities consider developing stronger resource adequacy mechanisms tied to resource performance that could better ensure that resource adequacy capacity is available and is incentivized to perform on critical operating days.

CPUC requirements for resource adequacy imports

DMM warned that existing ISO 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 instance, under ISO resource adequacy rules, imports can be routinely bid significantly above projected prices in the day-ahead market to help ensure they do not clear, thus relieving the imports of any further offer obligations in the real-time market.[255]

The CPUC has sought to address this concern though rules applicable to CPUC jurisdictional entities using imports to meet resource adequacy requirements. In 2020, the CPUC issued a decision specifying that non-resource specific import resource adequacy resources must be self-scheduled or bid into ISO markets at or below $0/MWh during peak net load hours of 4 to 9 pm.[256] DMM supported the CPUC's approach as an interim measure to better ensure delivery of import resource adequacy in peak net load hours, while the CPUC and stakeholders considered alternative solutions that would allow resource adequacy imports to participate more flexibly in the market.[257]

In May 2021, the CPUC issued another decision deferring adoption of a replacement framework for import resource adequacy requirements, noting a need for further discussion on key issues including firm transmission requirements and ensuring that the energy supporting import resource adequacy contracts cannot be recalled by the source balancing area.[258]

DMM supported development of a source-specific framework for resource adequacy imports which ensures that import energy cannot be recalled to other balancing areas, particularly when other balancing areas also face supply shortages. Solutions to both improve the reliability of import resource adequacy and address system market power concerns should continue to be developed and considered by the ISO and CPUC.

ISO initiative on resource adequacy imports

The ISO is also considering changes to requirements for resource adequacy imports through an ongoing initiative on resource adequacy enhancements. The ISO acknowledged DMM's concern about resource adequacy imports at the start of this initiative, noting that "current RA import provisions may allow some RA import resources to be shown to meet RA obligations while also representing speculative

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[255] *DMM Special Report: Import Resource Adequacy*, September 10, 2018, pp. 1-2: http://www.caiso.com/Documents/ImportResourceAdequacySpecialReport-Sept102018.pdf

[256] *Decision adopting resource adequacy import requirements (D.20-06-028)*, CPUC, June 5, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K516/342516267.PDF

[257] *Comments on Proposed Decision Clarifying Resource Adequacy Import Rules*, R.17-09-020, September 26, 2019. http://www.caiso.com/Documents/CommentsofDepartmentofMarketMonitoringonProposedDecisionClarifyingRAImportRules-R17-09-020-Sept262019.pdf

[258] *Decision adopting Local Capacity Obligations for 2022 – 2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program (D.21-06-029)*, CPUC, June 24, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.PDF

supply (*i.e.,* no true physical resource or contractual obligation backing the RA showing) or being committed to other regions and double counted."[259]

The ISO's latest proposal would require specification of a physical source backing resource adequacy import showings which may include a specific resource, aggregation of resources, or balancing area.[260] The ISO has also proposed to extend the real-time must-offer obligation to resource adequacy imports as recommended by DMM, and has proposed to require that import resource adequacy be backed by firm transmission on the last leg of transmission to the ISO border.

DMM agrees that a source-specific framework for resource adequacy imports which ensures that import energy cannot be recalled to other balancing areas could better ensure that import capacity is dedicated to the CAISO. However, some details regarding a source-specific framework could benefit from further discussion and development.

DMM noted that the ISO's proposal may still not ensure that the energy supporting import resource adequacy will not be recalled by other balancing areas, particularly when energy is scarce throughout the west.[261] DMM recommends that the ISO work with neighboring balancing areas to formalize operating practices to ensure that the energy backing import capacity that balancing areas rely on cannot be curtailed by other balancing areas. This type of coordination may become increasingly important as the ISO considers resource sufficiency requirements for an expanded day-ahead market, and as resource adequacy constructs expand across the west.

DMM also recommends that rules regarding transmission requirements to support import resource adequacy be developed further. DMM has some concern that the ISO's proposal to require that import resource adequacy be supported by firm transmission on the last leg to the ISO border and to require that the load serving entity attest that this requirement will be met in the month-ahead timeframe could create potential market power concerns with limited commensurate reliability benefit. DMM suggests that transmission requirements be developed further in ongoing ISO stakeholder processes.

Energy and availability limited resources

In 2019, DMM began to provide analysis and express concern about the cumulative impacts of various energy-limited or availability-limited resources which are being relied upon to meet an increasing portion of resource adequacy requirements.[262] These resources include solar, imports, demand response, and battery capacity in peak net load hours. Each of these resource types have generally had

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[259] *Resource Adequacy Enhancements Straw Proposal – Part 1*, December 20, 2018, p. 9: http://www.caiso.com/Documents/StrawProposalPart1-ResourceAdequacyEnhancements.pdf.

[260] *Resource Adequacy Enhancements Draft Final Proposal – Phase 1 and Sixth Revised Straw Proposal*, CAISO, December 17, 2020: http://www.caiso.com/InitiativeDocuments/DraftFinalProposal-SixthRevisedStrawProposal-ResourceAdequacyEnhancements.pdf

[261] *Comments on Resource Adequacy Enhancements Fourth Revised Straw Proposal,* Department of Market Monitoring, April 21, 2020. http://www.caiso.com/InitiativeDocuments/DMMComments-ResourceAdequacyEnhancements-FourthRevisedStrawProposal.pdf

[262] *Reply Comments of the Department of Market Monitoring*, 16-02-007, August 12, 2019: http://www.caiso.com/Documents/CPUC-DMMReplyCommentsonRulingInitiatingProcurementTrackandSeekingCommentonPotentialReliabilityIssues-Aug122019.pdf

limited availability during peak net load hours when the ISO counts on resource adequacy capacity to be available the most.

In 2020, the cumulative impact of increased reliance on energy-limited or availability-limited resources to meet resource adequacy requirements became apparent during heat waves occurring in late August to early September, when the ISO needed to curtail uninterruptible load for the first time in 20 years during two hours. Reports by DMM and the ISO both found that a key factor contributing to these outages were current rules for counting the resource adequacy capacity provided by different resources, which significantly overstate the actual available capacity of these resources during critical peak net load hours.[263]

To limit the potential for similar conditions in future years, DMM recommended that system level resource adequacy requirements should be modified to ensure more of this capacity is available during net load peak hours. In July 2021, the CPUC issued a decision directing further development of a reformed resource adequacy framework that considers both capacity and energy needs across all hours of the year.[264] DMM supports the CPUC's decision which could result in significant, but important, changes to the CPUC resource adequacy program including ensuring that the resource adequacy fleet can meet demand across all hours of the day, including energy required to charge storage resources.

In addition, DMM recommended that capacity counting rules for different resource types should be modified to more accurately reflect the actual availability of these resources during the peak net load hours. To address capacity counting concerns, the CEC in conjunction with the CPUC and ISO will begin to develop new capacity counting methodologies for demand response resources with variable availability.[265]

The CPUC will also remove 6 percent of the 15 percent planning reserve margin capacity adder applied to utility demand response capacity values and will further evaluate retaining the remaining 9 percent beyond 2022.[266] DMM supports these efforts which could more accurately measure the capacity contribution of demand response resources.

While the CPUC did not make changes to solar capacity counting methodologies in 2020, in February 2021, the CPUC issued a decision directing investor-owned utilities to procure additional capacity for summer 2021 that can be available in net peak demand hours.[267] DMM believes this additional procurement can help ensure additional capacity is available during peak net load hours when solar production drops off. However, DMM continues to support larger scale changes to the resource

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263 *Report on system and market conditions, issues and performance: August and September 2020,* pp. 1-3.

264 *Decision on Track 3B.2 Issues: Restructure of the Resource Adequacy Program (D.21-07-014),* CPUC, July 15, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M393/K334/393334426.PDF

265 *Decision adopting Local Capacity Obligations for 2022 – 2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program (D.21-06-029)*, CPUC, June 24, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.PDF

266 *Ibid.*

267 *Decision directing PG&E, SCE, and SDG&E to Take Actions to Prepare for Potential Extreme Weather in Summers of 2021 and 2022 (D.21-03-056),* CPUC, March 26, 2021: https://docs.cpuc.ca.gov/publisheddocs/published/g000/m373/k745/373745051.pdf

adequacy program discussed above which could better capture the temporal contribution of different resource types towards meeting energy and capacity requirements.

Resource adequacy performance incentives

The ISO's current mechanism for incentivizing the availability of resource adequacy capacity is its resource adequacy availability incentive mechanism (RAAIM). This mechanism is based solely on resource availability, not performance. Potential financial penalties associated with RAAIM are based on 60 percent of the ISO's CPM soft offer cap which is currently $6.31/kW-month.[268]

As capacity becomes more limited across the west and as capacity prices increase, the difference between capacity payments and potential RAAIM penalties also increases. Additionally, starting 2021, the CPUC's penalty costs for system resource adequacy showing deficiencies for summer months will increase from $6.66/kW-month to $8.88/kW-month.[269] Starting in 2022, these penalties could become much higher for load serving entities with repeated deficiencies.[270]

DMM is concerned that if the ISO's RAAIM penalties become insignificant compared to potential resource adequacy payments, suppliers may be willing to sell resource adequacy capacity that is more likely to be unavailable or to incur forced outage for a significant portion of the month. Suppliers could have a significant incentive to sell unreliable resource adequacy to load serving entities who are willing to pay high prices for system capacity (up to the CPUC's penalty prices plus potential costs associated with potential ISO backstop procurement). A supplier could also avoid penalties by offering capacity into the ISO market even though this capacity fails to perform when called upon by the ISO.

DMM observed during the 2020 heatwaves that when resources were available but did not perform in real-time, these resources generally faced little financial consequences as real-time energy market prices were often lower than day-ahead prices. While the ISO's recent summer readiness enhancements may enhance real-time pricing during tight system conditions and create stronger financial incentives for resources to deliver expected energy, DMM still has some concerns that if capacity payments are very high, there could be limited incentives for resources receiving these payments to actually perform when needed by the ISO.

DMM recommends that the ISO and local regulatory authorities consider developing a resource adequacy incentive mechanism that is based on resource performance which could result in potentially very high penalties that act as a claw back of a very large portion of capacity payments when resources do not deliver on critical days. This type of incentive mechanism could become increasingly important for incentivizing availability and performance of resource adequacy capacity as resource adequacy payments increase compared to the magnitude of potential RAAIM charges from the ISO. This type of mechanism could also better incentivize suppliers to sell highly available and dependable capacity up front.

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268 ISO Tariff Section 40.9.6.1(c)

269 *Decision adopting Local Capacity Obligations for 2021 – 2023, Flexible Capacity Obligations for 2021, and Refinements to the Resource Adequacy Program (D.20-06-031)*, CPUC, June 24, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K083/342083913.PDF

270 *Decision adopting Local Capacity Obligations for 2022 – 2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program (D.21-06-029)*, CPUC, June 25, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.PDF

Centralized procurement

In 2018, the CPUC initiated a proceeding to develop and consider options for establishing one or more *central procurement entities* authorized to procure capacity needed to meet local area reliability requirements assigned to CPUC-jurisdictional load serving entities. The central procurement entity would be authorized to procure local resource adequacy capacity through multi-year contracts, with costs being allocated to entities serving load within each distribution service area.

In June 2020, the CPUC adopted a decision that establishes central procurement of multi-year local resource adequacy capacity beginning with the 2023 compliance year.[271] Under the CPUC decision, the state's two major investor-owned utilities (Pacific Gas and Electric and Southern California Edison) will serve as the central procurement entities for local areas in their respective distribution service areas. The decision does not adopt a central procurement framework for the San Diego Gas and Electric area at this time. With this approach, the central procurement entities will secure a portfolio of the most effective local resources to meet local capacity requirements and potentially mitigate the need for CAISO backstop procurement in certain local areas.

As noted in our 2018 annual report, DMM supports the CPUC decision to adopt a multi-year framework for local resource adequacy through a central buyer framework.[272] The adopted framework should help avoid unnecessary reliance on the ISO's two backstop procurement mechanisms: the capacity procurement mechanism and reliability must-run contracts.

10.2 Flexible ramping product

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.

Prior to the initial implementation of the flexible ramping product in 2016, DMM recommended that the ISO start another stakeholder initiative to work on other important enhancements to the product's basic design.[273] Since 2016, two key enhancements that DMM recommended include the following:[274]

- More locational procurement of flexible ramping capacity to decrease the likelihood that the product is not deliverable (or *stranded*) because of transmission constraints. The ISO implemented interim changes to address this issue in the fifteen-minute market in 2020.
- Increase the time horizon of real-time flexible ramping product beyond the 5-minute and 15-minute timeframe of the current product to address expected ramping needs and net load uncertainty over

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271 *Decision on Central Procurement of the Resource Adequacy Program*, R.17-09-020, June 11, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M340/K671/340671902.PDF

272 *2018 Annual Report on Market Issues and Performance*, Department of Market Monitoring, p. 268: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

273 *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

274 DMM also highlighted these two recommendations in DMM's 2018 annual report and in more recent comments in the ISO's stakeholder process. *2018 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2019, pp. 269-270: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

a longer time frame (e.g., 30, 60, and 120 minutes out from a given real-time interval) and appropriately price procurement of capacity to meet longer time horizons.

DMM continues to recommend these enhancements, as described in more detail below.

Locational procurement

Analyses by DMM and the ISO have shown that the current real-time flexible ramping product may not be deliverable because of transmission constraints.[275] The ISO is addressing undeliverable or stranded flexible ramping capacity through nodal procurement starting in the spring of 2022.[276] Locational procurement that accounts for transmission constraints should result in deliverable reserves which will significantly increase the efficiency of the ISO's market awards and dispatches.

Real-time product for uncertainty over longer time horizons

DMM continues to recommend that the ISO begin to develop an approach for extending the time horizon of the flexible ramping product to account for uncertainty over longer time horizons. The range of likely outcomes narrows as the time between the uncertain outcome and the evaluation of that uncertain outcome narrows; there is less uncertainty between the 15- and 5-minute markets than over a longer interval.[277] 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).

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 already face significant uncertainty over load and the future availability of resources to meet that load. This uncertainty is the primary reason operators need to systematically enter the large positive load adjustments during the morning and evening ramping hours, as described in Section 8.4 of this report. Operators also take other out-of-market actions to ensure sufficient ramping capacity is available in the peak ramping hours, including exceptional dispatches to commit additional gas-fired units and to begin ramping these resources up in the peak ramping hours. Extending the time horizon of the flexible ramping product should significantly reduce the need for manual load adjustments and out-of-market dispatches of gas resources.

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

Q3 Report on Market Issues and Performance, December 5, 2019, pp.84-86. http://www.caiso.com/Documents/2019ThirdQuarterReportonMarketIssuesandPerformance.pdf

276 *Flexible Ramping Product Refinements Issue Paper and Straw Proposal*, November 14, 20019, pp.6-8. http://www.caiso.com/InitiativeDocuments/IssuePaper-StrawProposal-FlexibleRampingProductRefinements.pdf

277 Illustrations of this concept as applied to the flexible ramping product are available here: *Real-time Flex Ramp Product Enhancements – Western EIM Body of State Regulators*, June 12, 2020. http://www.caiso.com/Documents/Presentation-Real-TimeFlexRampProductEnhancements-WesternEIMBodyofStateRegulators-June122020.pdf

Further, to the extent that the power balance and flexible ramping constraints in advisory intervals do cause capacity procurement by changing binding interval schedules, this capacity may not be appropriately paid because the advisory interval prices are not used for market settlements. Creating flexible ramping products with longer time-horizons would move the prices of procuring capacity into the binding market interval for settlements.

In the ISO's new day-ahead market enhancements initiative, the ISO is proposing a new imbalance reserve product that would be procured in the day-ahead market based on the ISO's net load forecast. The real-time flexible ramping products may inefficiently release and not replace this capacity. Extending the real-time flexible ramping product horizons will help ensure that imbalance reserves procured in the day-ahead market are not inefficiently released.

10.3 System level market power

The ISO has tariff provisions and automated procedures for mitigating local market power in congested areas within the balancing area. However, ISO rules do not provide for mitigating potential market power at a system level (or across the entire ISO balancing area).

Despite the lack of any bid mitigation for system market power, the ISO's energy markets have been highly competitive at a system level since the early 2000s due to a high level of forward bilateral energy contracting by the ISO's load serving entities, relatively high supply margins, and access to imports from other balancing areas. The long-term procurement framework and resource adequacy requirements developed by the CPUC and other local regulatory authorities have played a key role in making the ISO's energy market competitive at a system level for more than 15 years.

In recent years, a number of regulatory and structural market changes have occurred which have increased the potential for system level market power in the ISO balancing area. These include the following:

- Reliance on a growing amount of capacity from intermittent renewable resources, which has limited the 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 resource adequacy requirements by load serving entities.
- Fewer energy tolling contracts between gas units within the ISO and load serving entities without an incentive to exercise market power.
- Regional supply and demand conditions appear to be tightening as well, so that the supply of imported power to the ISO may be reduced under high load conditions.

In 2018, DMM recommended that the ISO begin to consider actions to reduce the likelihood of uncompetitive system conditions and to mitigate the potential impacts of system market power on energy market costs and reliability. Specific recommendations provided by DMM and the actions that have been taken that address these recommendations are summarized below:

- Begin to discuss and develop an approach that could be implemented to provide some degree of system level market power mitigation. *The ISO launched an initiative in 2019 to begin designing a system-level market power mitigation process, and has developed a proposal that could be approved and implemented as soon as summer of 2021. This stakeholder process is scheduled to resume in late 2021.*

- Set local and system resource adequacy requirements sufficiently high to ensure reliability and reduce the potential frequency of non-competitive market outcomes**.** *In February 2021, the CPUC issued a decision directing investor-owned utilities to procure additional capacity starting summer 2021 that can be available in net peak demand hours, effectuating an increase in the system planning reserve margin from 15 percent to 17.5 percent of peak demand.*[278]

- Consider options for increasing the supply and availability of energy from resource adequacy imports beyond the day-ahead market into real-time. These options include extending a must-offer requirement for all or some resource adequacy imports into the real-time market. Options may also include scheduling and bidding requirements and limitations designed to increase the amount of resource adequacy imports clearing the day-ahead market in tight supply conditions or high load uncertainty. *Starting in January 2021, the CPUC implemented new rules to address this issue by requiring that resource adequacy imports be offered at prices at or below $0/MWh in peak net load hours in the day-ahead and real-time markets. The ISO has also developed a proposed change to its rules that would require resource adequacy imports to be backed by a specific set of physical resources, and would extend a must-offer requirement for some resource adequacy imports into the real-time market*.

- When implementing FERC Order No. 831, require that import bids over $1,000/MWh are subject to *ex ante* cost justification and do not raise penalty prices up to $2,000/MWh except when bids over $1,000/MWh which have been cost justified are actually dispatched. *The ISO filed for approval of changes to address these recommendations in early 2021 and implemented these requirements in early summer 2021.*

- 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 incentives and sanctions for failing to meet 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.

As noted above, several of these recommendations are being addressed in different ISO stakeholder initiatives and CPUC proceedings.

[278] *Decision directing PG&E, SCE, and SDG&E to Take Actions to Prepare for Potential Extreme Weather in Summers of 2021 and 2022 (D.21-03-056),* CPUC, March 26, 2021: https://docs.cpuc.ca.gov/publisheddocs/published/g000/m373/k745/373745051.pdf

System market power bid mitigation

In 2020, the ISO completed development of potential system market power mitigation measures for the real-time market only. The proposed measures would be triggered when the ISO, or the ISO with a larger sub-area of the western interconnection, may be import constrained.[279,280] In early 2021, the ISO decided to defer further work on approving and implementing a final proposal that could be approved and implemented before summer of 2021.

DMM supports the ISO's efforts to design and implement system market power mitigation and is generally supportive of the proposal being developed. Despite some limitations of the ISO's current proposal, DMM believes that the ISO's proposal may mitigate real-time market power in some situations. Mitigation of market power in the real-time market may also help mitigate market power in the day-ahead market to some degree. DMM supports the ISO's continued development of system-level market power mitigation measures for the day-ahead and real-time markets in the second phase of the initiative.

The ISO is scheduled to resume consideration of its system market power mitigation proposal in late 2021, as part of an initiative that will include consideration of changes to the ISO's scarcity pricing provisions. DMM cautioned that if scarcity pricing provisions are not well designed and do not accurately account for all available capacity, such provisions could encourage withholding of supply in order to trigger scarcity pricing.

Resource adequacy imports

DMM has longstanding concerns that existing rules 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.[281] If resource adequacy import capacity is not scheduled in the day-ahead market or residual unit commitment process, these resources have no further obligation to bid into the real-time market. Thus, by simply bidding at or near the $1,000/MWh bid cap in the day-ahead market, resource adequacy imports can receive capacity payments while providing no real benefits in terms of either system reliability or market competitiveness.

To address this issue, in 2020, the CPUC issued a decision specifying that non-resource specific import resource adequacy resources must be self-scheduled or bid into ISO markets at or below $0/MWh during peak net load hours of 4 to 9 pm, starting in 2021.[282]

DMM suggested that resource adequacy imports could be subject to some type of lower bidding limits when potential system market power exists. Unlike other imports, resource adequacy imports receive

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279 *System Market Power Mitigation Straw Proposal*, California ISO, December 11, 2019: http://www.caiso.com/InitiativeDocuments/StrawProposal-SystemMarketPowerMitigation.pdf

280 *System Market Power Mitigation Revised Straw Proposal*, California ISO, April 7, 2020: http://www.caiso.com/InitiativeDocuments/RevisedStrawProposal-SystemMarketPowerMitigation.pdf

281 *2018 Annual Report on Market Issues and Performance*, Department of Market Monitoring, May 2019, p. 269: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

Import Resource Adequacy, Department of Market Monitoring, September 10, 2018: http://www.caiso.com/Documents/ImportResourceAdequacySpecialReport-Sept1020

282 *Decision adopting resource adequacy import requirements (D.20-06-028)*, CPUC, June 5, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K516/342516267.PDF

capacity payments and can be subject to must-offer obligations. The ISO contends that subjecting resource adequacy imports to any type of bid mitigation would be "ineffective and inappropriate."[283]

DMM also recommended that the ISO consider options for increasing the supply and availability of energy from resource adequacy imports beyond the day-ahead market into real-time.

10.4 FERC Order No. 831

FERC Order No. 831 requires that all ISOs allow submission of bids of up to $2,000/MWh. If the ISO can verify that bids over the current $1,000/MWh bid cap within the ISO's balancing area are cost justified before the market runs (*ex ante*), these bids may set market clearing prices. If the ISO cannot verify that bids over $1,000/MWh are cost justified *ex ante*, these bids are capped at $1,000/MWh but may apply for *ex-post* cost recovery if dispatched.

Order No. 831 found that although cost justification for import bids can be difficult, ISOs may file tariff changes with the Commission which would also require imports to be cost justified *ex ante* in order to set market clearing prices. If the ISO cannot verify that import bids over $1,000/MWh are cost justified *ex ante*, these bids could be capped at $1,000/MWh but may apply for *ex-post* cost recovery if dispatched.

In 2019, DMM recommended that before implementing Order No. 831, the ISO should file tariff changes with FERC to subject import bids over $1,000/MWh to *ex ante* cost justification similar to resources within the ISO system.[284] DMM also recommended that the ISO should develop an approach that would allow any cost-verified bids over $1,000/MWh to set market prices when dispatched without setting the power balance constraint penalty price from $1,000/MWh to $2,000/MWh during all hours, as was proposed by the ISO.

In 2021, the ISO filed the necessary Section 205 tariff amendments to address the recommendations raised by DMM.[285] The ISO implemented these changes in early summer 2021.

10.5 Scarcity pricing

The ISO is scheduled to resume consideration of its system market power mitigation proposal in late 2021, as part of an initiative that will include consideration of changes to the ISO's scarcity pricing provisions. DMM cautioned that if scarcity pricing provisions are not well designed and do not accurately account for all available capacity, such provisions could encourage withholding of supply in order to trigger scarcity pricing.

[283] *System Market Power Mitigation Straw Proposal*, California ISO, December 11, 2019, pp.30-32: http://www.caiso.com/InitiativeDocuments/StrawProposal-SystemMarketPowerMitigation.pdf

[284] *Comments on Issue Paper and Straw Proposal Requirements for Import Bids Greater than $1,000 under FERC Order No. 831*, Department of Market Monitoring, May 30, 2019. http://www.caiso.com/Documents/DMMcomments-ImportBidCostVerification_IssuePaperandStrawProposal.pdf

[285] Tariff Amendment to Enhance Market Parameters and Import Bidding Related to Order No. 831, February 22, 2021: http://www.caiso.com/Documents/Feb22-2021-TariffAmendment-PricingParameters-OrderNo831-ER21-1192.pdf

DMM also notes that the ISO has already implemented numerous changes in 2021 that feature steps that will allow prices to rise and increase compensation for imports during tight supply conditions. First, the ISO's FERC Order No. 831 compliance filing includes the following two provisions:

- Bids can now be submitted at prices above the $1,000/MWh soft offer cap up to $2,000/MWh. These bids can set market prices if they are cost-justified prior to market operation.
- When a bid over $1,000/MWh is cost-justified prior to market operation, the ISO will set the power balance constraint penalty price at the highest cost-justified bid (i.e., up to $2,000/MWh). Prices are set based on this penalty price when supply/demand infeasibilities occur in the market software.

In addition, in 2021 the ISO developed and implemented the following changes on an expedited basis in order to improve pricing and compensation of needed supply under tight conditions:

- Hourly imports will receive the higher of their bid price or the 15-minute market price during tight system conditions. This removes the risk that hourly imports could get paid below their offer price in any given hour during tight system conditions.
- When the ISO arms load (i.e., prepares to shed load in a controlled manner if needed) to serve as operating reserves and then releases generation that was serving as reserves into the energy supply stack, the ISO will set the bid price of the reserves added to the energy supply stack at the energy bid cap. This will help ensure that prices are relatively high when system conditions are extremely tight, such that controlled dropping of load needs to be relied upon for operating reserve.
- When reliability demand response resources (RDRR) are deployed in the real-time market, these resources will be included in the market dispatch and pricing. Adding the expected load curtailment from these dispatches onto the load forecast in each market should help to prevent them from inappropriately suppressing market prices.

DMM supported all these changes and believes they will improve the functioning of the CAISO markets during tight system conditions.[286] The combined effect of these changes should increase the frequency of very high prices at or near the $1,000/MWh price cap under tight conditions when scarcity is most likely to occur. Thus, DMM recommends the ISO review and consider market performance with these changes in effect as it considers adding additional scarcity pricing provisions.

10.6 WECC soft offer cap

During several days in August 2020, at least 18 entities made bilateral spot market sales at prices over $1,000/MWh in the Western Electricity Coordinating Council (WECC) outside of the CAISO balancing area. These sales exceeded the soft cap of $1,000/MWh which was established by FERC in 2011 and are subject to cost justification by FERC.

DMM intervened and submitted comments in these cost justification proceedings, noting that "the Commission's decisions on these cost justification proceedings will establish important future precedent and market expectations in bilateral markets throughout the WECC and the CAISO's organized day-

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286 *Motion To Intervene and Comments of the Department of Market Monitoring of the California Independent System Operator Corporation*, Docket No. ER21-1536-000, EL10-56-000, April 16, 2021: http://www.caiso.com/Documents/DMM-Comments-on-ER21-1536-Summer-2021-Readiness-Apr-16-2021.pdf

ahead and real-time energy markets."[287] DMM recommended that the Commission develop and provide clear guidance and precedent on what constitutes valid cost justification through these proceedings. DMM's comments also noted that:

> DMM is concerned that accepting cost-justification for sales over the $1,000/MWh soft cap simply based on a seller's reported purchase price or its assessment of "prevailing market prices" or conditions would essentially render the soft cap meaningless – and undermine market power mitigation provisions in the CAISO markets. Moreover, any criteria adopted by the Commission in these proceedings (and subsequently by the CAISO) could even create adverse incentives for some participants to circumvent market power mitigation measures approved by the Commission in the CAISO and the rest of the WECC (e.g., through various forms of "megawatt laundering", wash trades, etc.)

In June 2021, FERC issued an order indicating that justification for sales above the $1,000/MWh soft price cap may be based on, but are not limited to, demonstrations from at least one of three frameworks: (1) a production cost-based framework; (2) an index-based framework; and (3) an opportunity cost-based framework. FERC has not ruled on any of the cost justification filings submitted, and provided sellers the opportunity to supplement or amend their filings consistent with the guidance described in FERC's order.

DMM will continue to review and comment on these cost justification proceedings due to the impact that FERC's ultimate rulings will have on bilateral markets throughout the WECC and the CAISO's organized day-ahead and real-time energy markets.

10.7 Export and wheeling schedules

The summer 2020 heat wave also highlighted the need to review the ISO's procedures and policies for curtailing load vs. curtailing exports and wheeling schedules. During the hours in August when California ISO grid operators curtailed ISO balancing area load, operators did not also curtail any exports or wheeling schedules. In the following days and weeks the ISO took several steps to modify its software and procedures so that some exports would be curtailed before curtailment of ISO area load.

In addition, the ISO conducted an expedited stakeholder process to consider other changes in the transmission scheduling priority provided to export and wheeling schedules when load curtailments might occur. This process resulted in tariff changes which provide for curtailment of some exports and wheeling schedules before curtailment of ISO area load. These interim rules were only approved by FERC for a one year period, during which the ISO will work with stakeholders to develop more comprehensive longer term rules for transmission scheduling priority.

DMM supports the interim tariff revisions as incremental improvements that should enhance the reliability of the California ISO balancing authority area for summer 2021, while better aligning the ISO market rules and practices with those of other balancing areas, ISOs, and RTOs. Over the longer term, DMM recommends that the California ISO develop an approach for transmission scheduling priority that is more similar that of other ISOs.

[287] *Comments of the Department of Market Monitoring of the California Independent System Operator*, ER51-57-000, October 28, 2020. http://www.caiso.com/Documents/CommentsoftheDepartmentofMarketMonitoring-WECCSoftOfferCap-ShellEnergy-ER21-57-000-Oct282020.pdf

DMM's understanding is that transmission providers in other western balancing areas only sell long-term firm or additional network transmission service to the extent that there is sufficient excess capacity on the system to provide that service, after the needs of the balancing area's native load and other existing firm uses have been met. California ISO currently has no process to account for the needs of ISO balancing area load as an existing firm use, or to determine the long-term availability of excess transmission that could be sold to other entities at priority equal to ISO load.

Based on DMM's understanding of rules and practices in other balancing areas, making California ISO rules consistent with that of other ISOs and balancing areas would involve the following additional changes:

- Establish a process to determine excess available transmission capacity on the ISO system;
- Establish an option for wheel-through transactions to purchase excess firm or similar quality transmission service on a long-term basis; and
- Develop clear priority access to transmission for ISO area load, and other network-quality transmission customers, relative to hourly wheeling schedules (which have not purchased firm transmission on a long-term basis).

DMM supports the ISO's recent commitment to address these issues through the External Load Forward Scheduling Rights Process stakeholder initiative launched in July 2021.

10.8 EIM resource sufficiency tests

During the 2020 heat wave, the California ISO balancing authority area passed the EIM capacity test during hours where ISO area resources were insufficient to meet total demand. After detailed review of the capacity test during these hours, the ISO determined that the software was incorrectly including capacity that was unavailable due to outages and de-rates as part of the available capacity in each balancing area. This resulted in the ISO and other EIM balancing areas passing the capacity test during a significant number of hours when the actual available capacity offered was less than the requirement. The ISO corrected this issue in February 2021.

The ISO implemented additional changes to the capacity test in June 2021 which increase the requirement for each balancing area to include an extra margin for load and renewable uncertainty. However, these changes were limited to what could be feasibly implemented given the compressed timeframe of the initiative. Therefore, the ISO opened an initiative to explore more comprehensive changes to the EIM capacity, flexible ramping, and balancing sufficiency tests.[288]

DMM recommends that the ISO consider eliminating additional capacity from the bid range capacity test, specifically capacity which is unavailable because of various operating limitations and independent of any displacement from energy imbalance market transfers. In other words, this is capacity that is

288 EIM resource sufficiency evaluation enhancements: https://stakeholdercenter.caiso.com/StakeholderInitiatives/EIM-resource-sufficiency-evaluation-enhancements

restricted by intertemporal and resource-level constraints that exist regardless of how EIM transfers positioned the resource.[289]

DMM supports the ISO and stakeholders exploring broader changes to the capacity test that would better disincentivize balancing areas from leaning on each other while still enabling the efficiency of inter-balancing area trades. For example, DMM continues to recommend that changes to the consequence of failing the tests be considered. Currently, when an EIM area fails either the capacity or flexible ramping test, EIM transfers into the balancing area are not allowed to increase beyond the level of supply being transferred into the area just prior to the test failure. DMM previously recommended that the ISO and stakeholders consider other options such as imposing a capacity charge or other financial charge.

10.9 Demand response resources

In August and September 2020, the ISO relied on demand response to curtail load more frequently and at much higher levels than in nearly two decades. Demand response resources met about 4 percent of total system resource adequacy capacity requirements in August and September 2020. This capacity is comprised of utility demand response programs that are credited towards reducing resource adequacy requirements, along with demand response capacity that is scheduled by third parties and shown on resource adequacy supply plans.

As summarized in DMM's report on the summer 2020 heatwave, a large portion of demand response resource adequacy capacity was not available for dispatch.[290] In early 2021, DMM issued a more detailed follow-up report on demand response resource issues and performance.[291] As noted in that report:

> About one-third of the 1,847 MW of resource adequacy capacity requirement met by demand response in August was not available or directly accessible to the ISO in real-time during periods of firm load curtailment. Utility demand response resource adequacy appeared to be over-counted compared to its actual contribution, particularly in peak net load hours. Additionally, in 2020, the percentage of supply plan demand response with long-start operating characteristics more than doubled from 2019. Long-start demand response capacity is not available to the ISO in the residual unit commitment process or in real-time unless committed in the day-ahead market.

DMM's 2019 annual report identified several issues regarding the performance and operation of demand response resources and included the following recommendations to address these issues:[292]

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289 Examples of this capacity are available in DMM's special report on resource sufficiency tests in the Energy Imbalance Market: http://www.caiso.com/Documents/Report-on-Resource-Sufficiency-Tests-in-the-Energy-Imbalance-Market-May-20-2021.pdf, p. 7.

290 *Report on market conditions, issues, and performance: August and September 2020*, Department of Market Monitoring, November 20, 2020: http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

291 *Report on demand response issues and performance*, Department of Market Monitoring, February 25, 2021: http://www.caiso.com/Documents/ReportonDemandResponseIssuesandPerformance-Feb252021.pdf

292 2019 annual report, pp. 303-306.

- The ISO should proactively monitor demand response resource master file parameters to ensure these resources can actually provide the capacity and resource attributes that have been reflected to the ISO and local regulatory authorities.
- The ISO should also proactively validate demand response performance values which are self-submitted by scheduling coordinators to ensure resources are able to operate and perform consistent with their resource attributes. These assessments will require a review of both underlying load data and the statistical methodologies used to calculate baseline load values.
- The ISO should continue to work with local regulatory authorities to ensure that demand response capacity credits accurately reflect the reliability value that underlying demand response resources provide to the system.

The ISO has taken steps to validate demand response performance values under its authority to audit demand response provider data. The ISO also took steps in 2020 to ensure that demand response resources that cannot respond to 5-minute dispatches are registered under hourly or 15-minute dispatch options and developed additional guidance for demand response providers submitting commitment cost parameters to the master file.

Regarding demand response credits, the CEC in conjunction with the CPUC and ISO will begin to develop new capacity counting methodologies for demand response resources with variable availability.[293] Further, the CPUC will remove 6 percent of the 15 percent planning reserve margin capacity adder applied to utility demand response capacity values and will further evaluate retaining the remaining 9 percent beyond 2022.[294] DMM's 2021 report on demand response resource issues and performance included the following additional and more specific recommendations.

- ***Consider removing the exemption for long-start proxy demand response to be available in the residual unit commitment process***. This exemption does not exist for other types of long-start resources. The percentage of supply plan proxy demand response considered long-start based on registered start-up times in the ISO's master file increased from 38 percent in August 2019 to 71 percent in August 2020. If this capacity does not clear the day-ahead energy market, this capacity currently has no tariff obligation to be available in the residual unit commitment process.
- ***Consider developing a performance-based penalty or incentive structure for resource adequacy resources***. Under ISO market rules, demand response resources which are not offered and/or do not perform do not face any penalty or significant financial risk.[295] Meanwhile, most of the compensation for demand response resources comes from the capacity payment or credit that comes from being used to meet resource adequacy requirements. Thus, DMM suggests that stronger performance-based penalty or incentive mechanisms should be considered.

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293 *Decision adopting Local Capacity Obligations for 2022 – 2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program*, CPUC, June 24, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.PDF

294 *Ibid.*

295 *Report on demand response issues and performance*, Department of Market Monitoring, February 25, 2021, pp. 27-30.

Other recommendations in the report include the following:

- ***Adopt a process to manually dispatch available demand response counted towards meeting resource adequacy requirements before issuing exceptional dispatches to non-resource adequacy capacity and curtailing firm load.*** DMM observed that in summer 2020 some demand response resource adequacy capacity that did not clear the day-ahead was not subsequently manually dispatched in the day-ahead timeframe and thus was not available in real-time. Furthermore, some demand response capacity that was available but was not economic in real-time (and was not ramp limited) was not manually dispatched by the ISO in peak net load hours on high load days in August and September.

- ***Consider refinements to the demand response hourly dispatch model.*** DMM observed that a combination of slow ramp rates and hourly block constraints limited the amount of proxy demand response capacity that the ISO could access in real-time on high load days. The ISO has taken steps to review resource ramp rates and validate these parameters with demand response providers. To the extent that demand response resources remain slow-ramping, DMM suggests that the ISO could also consider modifying the hourly dispatch option by lifting or making the block schedule requirement optional under the hourly dispatch option, so that the ISO could access more capacity from these slow-ramping resources.

- ***Ensure that non-CPUC jurisdictional load serving entities that manage utility demand response programs credited against resource adequacy requirements communicate the available capacity to the ISO*** on a daily basis so that the ISO is aware of and can call this capacity when needed. Non-CPUC jurisdictional demand response programs accounted for about 122 MW of resource adequacy capacity in August and September 2020. However, this capacity was not registered in the ISO market, and the ISO did not have operational insight into this capacity. DMM understands that the ISO has reached out to non-CPUC jurisdictional load serving entities using demand response crediting to ensure that the ISO has more visibility into these demand response programs going forward.

10.10 Energy storage resources

While the amount of energy storage resources on the ISO system is currently limited compared to other resource types, the amount of new battery energy storage capacity is projected to increase rapidly in coming years and is being relied upon to play a key role in the integration of renewable resources. Consequently, DMM has played an active role in efforts to develop new market and software enhancements to facilitate use of energy storage resources.

While battery resources are generally very fast-responding and flexible, the availability of these resources depends of their state of charge levels. DMM observed that battery resources providing resource adequacy often do not have sufficient charge to provide resource adequacy values for four consecutive hours across peak net load periods. DMM suggested potential changes to CPUC and ISO rules that could help mitigate availability concerns related to battery resources. These recommendations include developing default energy bids and subjecting battery resources participating under the ISO's non-generator resource (NGR) model to local market power mitigation.[296] DMM also

[296] *2018 Annual Report on Market Issues and Performance*, p. 24: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

recommends that the ISO consider whether resource adequacy availability incentives should consider limits on resources' state of charge values or limits to resources' charging capability.

DMM also observed that exceptional dispatch (ED) instructions sent to battery resources have sometimes resulted in inefficient outcomes on days where system conditions have been very tight. DMM recommends that the ISO consider enhancing processes for issuing exceptional dispatches to battery resources by issuing these dispatches as state of charge values instead of megawatt values.

Modeling energy storage costs

Energy storage resources face unique costs and operating parameters that may not align with current market mechanisms designed for traditional generators. DMM recommended that the ISO and the energy storage community continue working together in the energy storage and distributed energy resources phase 4 (ESDER 4) stakeholder initiative to identify and develop modeling of unique energy storage resource costs in both market optimization and default energy bids used in local market power mitigation. A detailed discussion of this issue was included in DMM's 2019 annual report.[297]

The ISO and DMM have made significant progress in understanding costs of batteries through the ESDER 4 stakeholder process. This information has helped in developing a proposal for a default energy bid for energy storage resources, as well as proposals to model different operational limitations of these resources. DMM supports these efforts, as well as the ISO's proposal to apply local market power mitigation procedures to energy storage resources.

The ISO's October 2020 proposal indicates that the ISO will model three cost components in default energy bids for energy storage resources – energy costs, variable operations costs including cycling and cell degradation costs, and opportunity costs. The ISO would calculate a static default energy bid value over the day for each battery resource.[298]

DMM is supportive of the proposal, but has recommended several additional refinements.[299] DMM recommends that the ISO continue to enhance the proposed default energy bid for energy storage resources to:

- Allow the default energy bid value to vary throughout the day to capture costs that may differ based on resource operation over the day;
- More precisely clarify which costs are included in the default energy bid and whether some components, such as sunk costs from intraday charging, are included for the purpose of increasing the default energy bid to approximate different costs that are not otherwise captured;

[297] *2019 Annual Report on Market Issues and Performance*, p. 306 – 307: http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf

[298] *Energy Storage and Distributed Energy Resources – Storage Default Energy Bid Final Proposal*, California ISO, October 22, 2020: http://www.caiso.com/InitiativeDocuments/FinalProposal-EnergyStorageDistributedEnergyResourcesPhase4-DefaultEnergyBid.pdf

[299] *Comments on Energy Storage and Distributed Energy Resources Phase 4 (ESDER 4) – Storage Default Energy Bid Final Proposal*, Department of Market Monitoring, November 12, 2020. http://www.caiso.com/Documents/DMMComments-EnergyStorageandDistributedEnergyResources-StorageDefaultEnergyBidFinalProposal-Nov122020.pdf

- Reconsider the use of day-ahead local market power mitigation run prices as an input to the day-ahead storage default energy bid; and
- Ultimately, develop a more robust framework to allow for estimation of opportunity costs outside of the market optimization horizon, and that accurately accounts for those opportunity costs by considering the ability of storage resources to discharge and recharge before reaching distant intervals.

Resource adequacy battery capacity

Batteries are part of a more general category of energy-limited or availability-limited resources which are being relied upon to meet an increasing portion of resource adequacy requirements. A battery resource's ability to deliver energy across peak net load hours depends on the resource's state of charge and thus its market awards in preceding hours. DMM observed that battery resources providing resource adequacy often do not have sufficient charge to provide resource adequacy values for three or four consecutive hours across peak net load periods.

While a longer real-time look ahead horizon could help position storage resources to be able to meet demand in peak net load hours, resources should also be incentivized to be charged for peak net load hours when the ISO will rely on storage capacity the most.

Today, storage resources can avoid exposure to the ISO resource adequacy availability incentive mechanism (RAAIM) if discharge bids are in place up to resource adequacy values in availability assessment hours. However, there are other means by which storage resources may limit availability across peak net load hours. DMM recommends that the ISO consider resource adequacy batteries' use of the following parameters that could limit resource availability in RAAIM calculations:

- De-rates to maximum state of charge values below a resource's 4 hour resource adequacy value
- De-rates to minimum state of charge such that (maximum SOC – minimum SOC) is less than a resource's 4 hour resource adequacy value
- De-rates to Pmin or not offering charging bid range such that resources are unable to charge for later hours.

Exceptional dispatch of battery resources

DMM observed that exceptional dispatch instructions sent to battery resources have sometimes resulted in inefficient outcomes on days where system conditions have been very tight. Batteries have sometimes been sent exceptional dispatch instructions to charge significantly when resources are already at or near a full state of charge. In some of these cases, resources could not feasibly meet these instructions to charge. In other cases, these instructions caused batteries to discharge uneconomically prior to the instruction to charge, in order to reduce the resource's state of charge and create headroom so that the resource could meet the charge instruction.

Additionally, because exceptional dispatches are often issued as fixed megawatt instructions today, when operators have issued exceptional dispatches to batteries with existing ancillary service awards, the existing awards have become infeasible in real-time. Ancillary services must then be procured from other resources in real-time on short notice when the system may already be very constrained.

Exceptional dispatch instructions that do not consider existing state of charge can also drive inefficient outcomes such as impacting prices in earlier intervals if resources are forced to discharge out of economic merit to meet the instruction, and adding charging demand on the system when it is not needed.

DMM believes that processes for issuing exceptional dispatches to batteries could be significantly improved if these instructions were issued as state of charge values instead of megawatt values. Dispatch instructions that consider resources' existing state of charge could allow resources to better maintain operating reserve awards and could help avoid unnecessary charging and discharging of storage resources.

State of charge deviations between day-ahead and real-time markets

In the day-ahead market, battery resources submit an initial state of charge value which the day-ahead interprets as the level of charge that a battery has at the start of a market day. However, in real-time, a battery's actual state of charge may be different from the initial state of charge value submitted to the day-ahead market.

DMM observed that day-ahead initial state of charge and actual state of charge values at the start of a day sometimes diverge significantly for certain battery resources. When these values diverge significantly, the real-time market may schedule a battery much differently than was predicted in the day-ahead market. DMM observed instances where resources reflect a much higher state of charge in the day-ahead market than what materializes in real-time requiring resources to be backed down from day-ahead discharge awards. DMM also observed cases where resources reflect a much lower state of charge in the day-ahead market than what materializes in real-time requiring resources to be backed down from day-ahead charging awards. In many of these cases, resources receive significant real-time bid cost recovery when they must either buy back day-ahead awards or are paid back for day-ahead charging at a net loss.

DMM is concerned that significant deviations between day-ahead and real-time state of charge values can create opportunities for potential gaming of bid cost recovery payments. Early in the ESDER stakeholder processes, DMM recommended the ISO consider the implications of a day-ahead submitted state of charge as a new and unique intertemporal constraint between markets.[300] DMM recommended that the ISO revisit this topic in future initiatives to address potential settlement implications.

In light of DMM's recent observations and the significant and growing volume of battery resources in the ISO market, DMM recommends that the ISO consider developing rules in the current Energy Storage Enhancements initiative to mitigate potential gaming opportunities when entities submit initial day-ahead state of charge values that deviate significantly from actual state of charge values in real-time.

10.11 Congestion revenue rights

Since the start of the ISO's congestion revenue rights (CRR) auction in 2009 through 2020, payouts to non-load serving entities purchasing congestion revenue rights have exceeded the auction revenues by about $960 million. If the ISO did not auction these congestion revenue rights, these congestion

[300] *Stakeholder Comments: Energy Storage and Distributed Energy Resources (ESDER) – Revised Draft Final Proposal*, Department of Market Monitoring, February 2, 2016. http://www.caiso.com/InitiativeDocuments/DMMComments-EnergyStorageDistributedEnergyResources-RevisedDraftFinalProposal.pdf

revenues would be credited back to transmission ratepayers who pay for the cost of the transmission system through the transmission access charge (TAC). Thus, this $960 million represents profits to the entities purchasing these financial rights in the auction, but represents revenue losses to transmission ratepayers. Most of these losses have resulted from profits received by purely financial entities which purchase congestion revenue rights but do not schedule power or load in the ISO.

In response to the large and systematic losses from sales of congestion revenue rights, the ISO instituted significant changes to the auction starting in the 2019 settlement year.[301] These changes include the following:

- Track 0 – Increasing the number of constraints enforced by default in the congestion revenue rights models, identifying potential enforcement of "nomogram" constraints in the day-ahead market to include in the congestion revenue rights models, and other process improvements.[302]
- Track 1A – Limiting congestion revenue rights sold in the auction to pairs of sources and sinks corresponding to potential "delivery paths" for energy to load.[303]
- Track 1B – Limiting congestion revenue rights payments to not exceed congestion rents actually collected from the underlying transmission constraints.[304]

As discussed in Chapter 7 of this report (Section 7.2), while changes implemented by the ISO in 2019 reduced losses from the congestion revenue rights auction, losses to ratepayers from the auction were still significant in 2019 and 2020.

DMM believes that under current rules it remains likely that the congestion revenue rights auction will continue to result in significant losses to transmission ratepayers. DMM continues to recommend that the ISO take steps to discontinue auctioning congestion revenue rights and instead reallocate all congestion revenues back to ratepayers who pay for the cost of the transmission system through the transmission access charge. If the ISO believes it is highly beneficial for the ISO to actively facilitate hedging of congestion costs by suppliers, DMM recommends that the ISO modify the auction into a market for financial hedges based on clearing of bids from willing buyers and sellers.

10.12 Capacity procurement mechanism

In early 2020, the ISO filed at FERC to make limited changes to compensation of any capacity procured at prices in excess of the capacity procurement mechanism soft cap. DMM supports these changes as an incremental improvement to current market rules. However, DMM believes that the ISO's proposal does

301 2019 annual report, pp. 230-234.

302 *Congestion Revenue Rights Auction Efficiency Track 1B Straw Proposal*, California ISO, April 19, 2018: http://www.caiso.com/InitiativeDocuments/StrawProposal-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

303 *Congestion Revenue Rights Auction Efficiency Track 1A Draft Final Proposal Addendum*, California ISO, March 8, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalAddendum-CongestionRevenueRightsAuctionEfficiency-Track1.pdf

304 *Congestion Revenue Rights Auction Efficiency Track 1B Draft Final Proposal Second Addendum*, California ISO, June 11, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalSecondAddendum-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

not address the key concerns with the current backstop procurement mechanisms that are needed as part of a comprehensive reform.

DMM submitted an extensive review of different cost studies showing that the current $76/kW-year soft cap is based on an inaccurately high estimate of the annual going forward fixed costs (GFFC) of gas-fired units.[305] Based on this review, DMM recommended the ISO perform its own review of cost estimates used by the ISO to set the soft cap. DMM also recommended that the ISO continue to consider establishing a structural market power test to any capacity procured on an annual basis under the capacity procurement mechanism.

10.13 Day-ahead market enhancements

In 2018 the ISO initiated a process to develop a proposal for day-ahead market enhancements. The ISO will continue developing the proposal in 2021.[306]

Day-ahead imbalance reserve product

A key element of the ISO's initial proposal is the introduction of a day-ahead imbalance reserve product intended to ensure sufficient ramping capacity is available in the real-time market. DMM supports development of such a product. The new day-ahead imbalance reserve product will increase day-ahead market costs through the direct payments for this new product as well as through increases to day-ahead market energy prices resulting from procurement of this product.

However, if the ISO does not extend the uncertainty horizon of the real-time flexible ramping product, DMM is concerned that the imbalance reserves that are procured in the day-ahead market will provide limited benefit in terms of increased ramping capacity in real-time or reduced real-time market costs. Thus, DMM continues to recommend that the ISO take steps to extend the time horizon of the real-time flexible ramping product to enable the market software to commit and position resources to address uncertainty in net load forecasts further out in the future.

10.14 Extended day-ahead energy market

In 2019 the ISO also initiated a process to develop a proposal for extending the day-ahead market to include other entities in the Western EIM.[307] This initiative is designed to build on market design changes made as part of the ISO's initiative on day-ahead market enhancements.

DMM strongly supports extending participation in the day-ahead market to more entities across the west. An extended day-ahead market would increase trading opportunities across the west and allow

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305 DMM Comments on CPM Tariff Filing ER20-1075, April 3, 2020: http://www.caiso.com/Documents/AnswerandMotionforLeavetoAnswer-DMMCommentsonCPMTariffFilingER20-1075-Apr32020.pdf

306 Day-Ahead Market Enhancements Initiative webpage: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements

307 *Extending the Day-Ahead Market to EIM Entities Issue Paper*, California ISO, October 10, 2019: http://www.caiso.com/Documents/IssuePaper-ExtendedDayAheadMarket.pdf

entities throughout the Western EIM to more efficiently meet their needs as the western electric grid continues to evolve and reliance on renewable energy increases.

In the first phase of this stakeholder process, the ISO is addressing the following three areas: (1) resource sufficiency, (2) provision of transmission, and (3) allocation of congestion rents. These three areas are being addressed first because they are expected to be the most controversial. Several key issues and concerns highlighted in DMM's initial comments on these issues are briefly summarized below.[308]

Resource sufficiency

The extended day-ahead market design clearly needs to allow entities to meet resource sufficiency obligations with power from resources that must schedule over another balancing authority area's transmission. Western EIM entities proposed requiring a resource to have firm (or equivalent quality) transmission service to a balancing area before the day-ahead market closes in order for the resource to count towards meeting the area's resource sufficiency requirement for the extended day-ahead market.

DMM expressed concern that in the absence of changes to existing timelines and protocols for releasing firm transmission, the proposed firm transmission requirement proposed by EIM entities for resource sufficiency qualification could significantly restrict the amount of transmission that load serving entities can rely on for utilizing the most efficient resources to meet resource sufficiency requirements for the extended day-ahead market. This is because third party entities can purchase long-term firm transmission rights at regulated rates on critical paths between generation and load centers when transmission operators first offer the firm rights far in advance of the day-ahead market timeframe. DMM's understanding is that current open access protocols for transmission in WECC only require long-term firm rights holders to release unused transmission capacity after the ISO's day-ahead market closes.

Provision of transmission

The Western EIM has been designed as a voluntary market. Energy imbalance market entities have proposed that transmission operators could offer additional unreserved transmission to the extended day-ahead market in the form of unsold, unreserved firm (or equivalent quality) capacity at the time the extended day-ahead market is initiated. On one hand, this approach may increase transmission that is made available in the extended day-ahead market. However, some participants have raised concerns that reservation of transmission capacity could have the effect of reducing competitive access to transmission (and energy) in the extended day-ahead market. DMM believes that mechanisms to ensure competitive access to transmission in the extended day-ahead market warrant further consideration.

Congestion revenues

How congestion rents are allocated will have a major impact on the incentives for entities to provide transmission rights to the extended day-ahead market. To create incentives to make transmission available, congestion rents would be allocated to transmission owners. However, if the allocation of

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308 *Comments on Extended Day-Ahead Market: February 11-12, 2020 Stakeholder Workshop Bundle 1 Topics: Resource Sufficiency, Transmission, and Congestion Revenue*, Department of Market Monitoring, February 26, 2020: http://www.caiso.com/InitiativeDocuments/DMMComments-ExtendedDay-AheadMarketTechnicalWorkshop-Feb11-12-2020.pdf

congestion rents creates incentives for entities to reduce the available transmission for the purpose of receiving increased congestion rents, this would adversely affect the extended day-ahead market as well as bilateral markets.