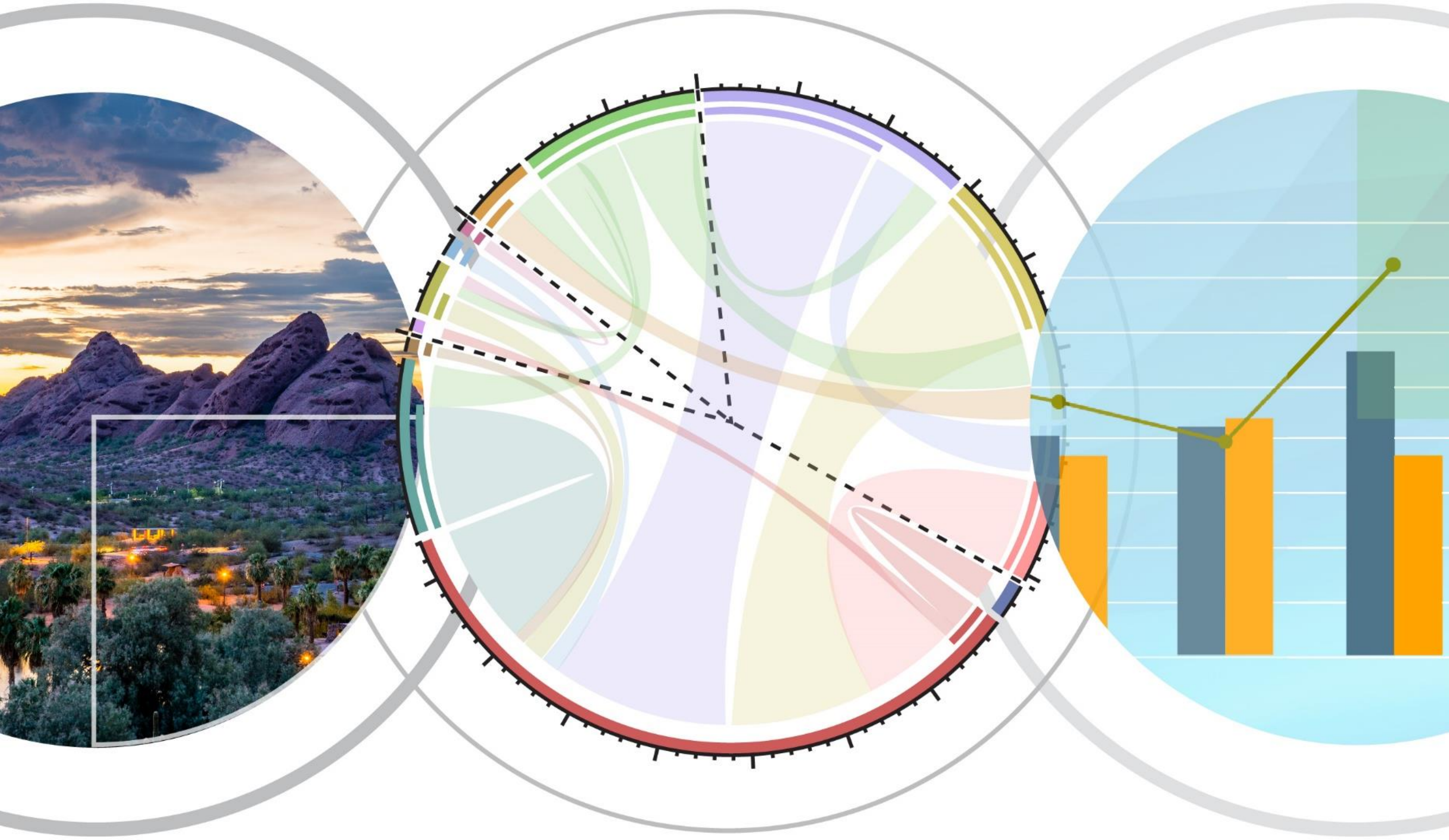
2021
ANNUAL REPORT ON MARKET ISSUES & PERFORMANCE



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 (WEIM). The CAISO and WEIM continued to perform efficiently and competitively in 2021. Key highlights include the following:

- **The total estimated wholesale cost of serving California ISO area load in 2021 rose by 33 percent, due to substantially higher natural gas prices**. Total wholesale costs for the CAISO footprint were about $12.6 billion, or about $56/MWh. After adjusting for higher natural gas costs and changes in greenhouse gas prices, wholesale electric costs per megawatt-hour decreased by about 10 percent.

- **Natural gas prices increased across the West and in the California spot market**, more than doubling at the SoCal Citygate hub. Natural gas demand growth exceeded supply growth, particularly for liquefied natural gas exports, driving electricity prices up across the market.

- **California ISO load continued to decrease in 2021,** due in part to increases in behind-the-meter solar generation. California ISO loads peaked at 43,982 MW, lower than the median forecast and the lowest peak load since 2003.

- **Expansion of the Western Energy Imbalance Market helped improve the overall structure and performance of the real-time market** in the CAISO and other participating balancing areas. In 2021, four new balancing areas (Turlock Irrigation District, Public Service Company of New Mexico, Los Angeles Department of Water and Power, and NorthWestern Energy) joined the Western Energy Imbalance Market. Participation by the Balancing Authority of Northern California (BANC) expanded with the addition of Modesto Irrigation District, City of Redding, and City of Roseville.

- **Summer supply margins were bolstered by significant market design changes and the integration of additional capacity**. More than 4 GW of planned retirement was postponed before the summer of 2020; over 3 GW of capacity was added for the summer of 2021; and over 4.5 GW was added before the summer of 2022, 3.5 GW of which was storage capacity.

- **Overall prices in the California ISO 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.

- **Drought conditions persisted across the West, decreasing available hydroelectric supply and increasing fire risk**. In July, the Bootleg Fire in southern Oregon threatened transmission lines and reduced import energy from the Pacific Northwest.

- **Total energy from all types of exceptional dispatch was similar to 2020** and continued to account for a relatively low portion of total system load. Total above-market costs from exceptional dispatch increased by 73 percent to $27.4 million from $15.8 million in 2020. Bid mitigation, which was applied to some exceptional dispatches for energy, avoided about $1.1 million in 2021 down from $5.5 million in avoided out-of-market costs in 2020.

Some market costs decreased or grew at a lower rate than wholesale energy costs:

- **Total CAISO real-time imbalance offset costs totaled $177 million this year,** compared to $176 million in 2020. Congestion offsets made up most of the total and were largely generated by significant reductions in constraint limits between the day-ahead and 15-minute markets.
- **Ancillary service costs decreased to $165 million,** down from $199 million in 2020. Costs decreased as operating reserve requirements fell and regulation requirements increased.
- **Bid cost recovery payments in the California ISO rose to $158 million, the highest value since 2011**. These uplift payments were about 1.2 percent of total energy costs, down from 1.4 percent in 2020. Uplift payments for units in the WEIM totaled about $22 million up from $9 million in 2020.
- **Locational price differences due to congestion decreased in the day-ahead and real-time markets.** Day-ahead congestion rents totaled $613 million, about 5.2 percent of the day-ahead market energy costs, compared to 6 percent in 2020. The frequency and impact of WEIM transfer constraints decreased, along with congestion on interties connecting the CAISO with other balancing areas.
- **Payouts to congestion revenue rights sold in the California ISO auction exceeded auction revenues by $43 million in 2021.** These losses are borne by transmission ratepayers who pay for the full cost of the transmission system through the transmission access charge (TAC). Changes to the auction implemented in 2019 have reduced, but not eliminated, losses to transmission ratepayers from the auction. Ratepayer losses have averaged about $45 million per year after the changes, compared to average losses of $114 million per year in the seven years before the reforms.
- **Net profits paid to convergence bidders decreased to about $38 million in 2021 from $45 million in 2020**. Overall, virtual demand bids were not profitable while virtual supply bids were due to hours in which day-ahead prices were higher than real-time prices.
- **Flexible ramping product system-level prices were zero for over 99 percent of intervals** in the 15-minute market, and 99.9 percent of intervals in the 5-minute market for both upward and downward flexible ramping capacity. The California ISO is implementing nodal procurement for the flexible ramping product in fall of 2022. This should resolve several issues that are lowering prices for the flexible ramping product.

Factors helping to lower market costs and offset the impact of higher gas costs included:

- **Lower net load.** As California ISO load fell, generation from utility scale wind and solar increased**.** Non-hydro renewable generation accounted for about 31 percent of total supply in 2021, up from 28 percent in 2020. Solar generation increased by about 13 percent and accounted for around 16 percent of total supply. The increase was driven by the addition of new solar generation capacity and increased ability for the market to export during the peak solar hours.
- **There were significantly fewer structurally uncompetitive hours** in the day-ahead energy market, which accounts for most of the California ISO total wholesale energy market**.** Both the significant increase in battery capacity and milder peak summer demand contributed to the decrease in non-competitive hours despite continual low hydroelectric availability.

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 California ISO anticipates a continued increase in renewable generation to meet state goals.
- Since 2016, total battery capacity participating in the CAISO balancing area has increased significantly and totaled about 2,500 MW of discharge capacity by the end of 2021. Most battery capacity participating in CAISO 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.

Total wholesale market costs

The total estimated wholesale cost of serving load in 2021 was about $12.6 billion, or about $56/MWh. This represents a 33 percent increase from about $42/MWh, or $8.9 billion in 2020. After normalizing for natural gas prices and greenhouse gas compliance costs, DMM estimates that total wholesale energy costs decreased by about 10 percent from about $44/MWh in 2020 to just under $40/MWh in 2021.

As highlighted elsewhere in this report, conditions that contributed to higher nominal wholesale costs include the following:

- **Higher energy prices due to the large increase in natural gas prices.** Spot market natural gas prices increased about 83 percent from 2020 (Section 1.2.6).
- **Natural gas production increased**, substituting for lower imports and less hydroelectric production.
- **Hydroelectric production decreased** about 26 percent from 2020 (Section 1.2.2).

After adjusting for changes in natural gas prices as well as greenhouse gas compliance costs, conditions that contributed to lower normalized wholesale costs include the following:

- **Average net load decreased 5 percent** (Section 2.3); partly as a result of increased solar and wind generation (Section 1.2.2).
- **Relatively mild weather conditions led to lower load in peak hours** (Section 1.1.1); the markup of prices during peak hours compared to off-peak hours decreased from 2020 to 2021.
- **Hours with high load across all WEIM entities decreased;** the lack of region-wide heat waves helped keep prices in all areas lower after adjusting for gas prices.

Figure E.1 Total annual wholesale costs per MWh of load (2017-2021)

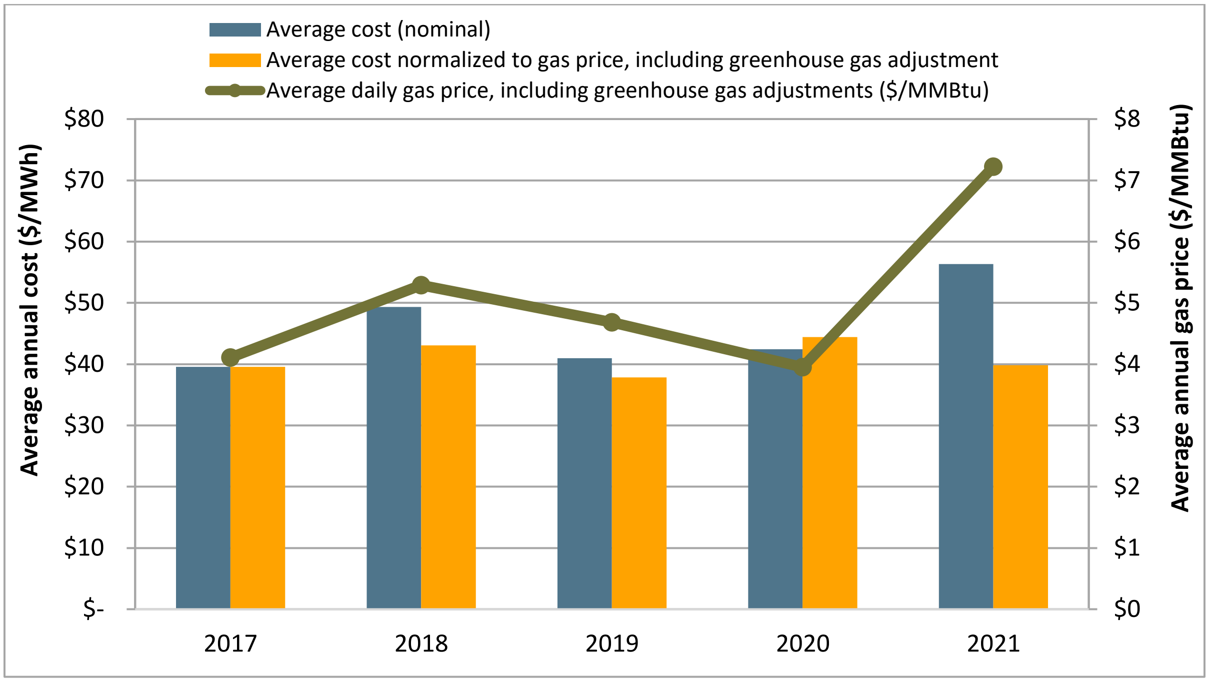


Figure E.1 shows total estimated wholesale costs per megawatt-hour of system load from 2017 to 2021. Wholesale costs are provided in nominal terms (blue bar), and after being normalized for changes in natural gas prices and greenhouse gas compliance costs (gold bar). The green line represents the annual 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

California ISO day-ahead and real-time market prices increased in 2021, driven primarily by an increase in natural gas prices despite lower load, higher renewable generation, and moderate system conditions in most hours. Figure E.2 and Figure E.3 highlight the following:

- Electricity prices in the western states typically follow natural gas price trends. This is because natural gas units are often the marginal source of generation in the California ISO and other regional markets. Figure E.2 shows both electricity prices and the gas price at a major hub in Southern California.
- Prices in the California ISO's day-ahead market were slightly higher than 15-minute real-time prices, but significantly higher than 5-minute prices. Day-ahead prices averaged $53/MWh, 15-minute prices were about $51/MWh, and 5-minute prices were about $45/MWh. Convergence bidding provides incentives for financial arbitrage to converge day-ahead and 15-minute prices. Lower 5-minute prices reflect the difference between 15-minute and 5-minute load adjustments made by the CAISO grid operators.
- 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 gas prices with load-weighted average energy prices

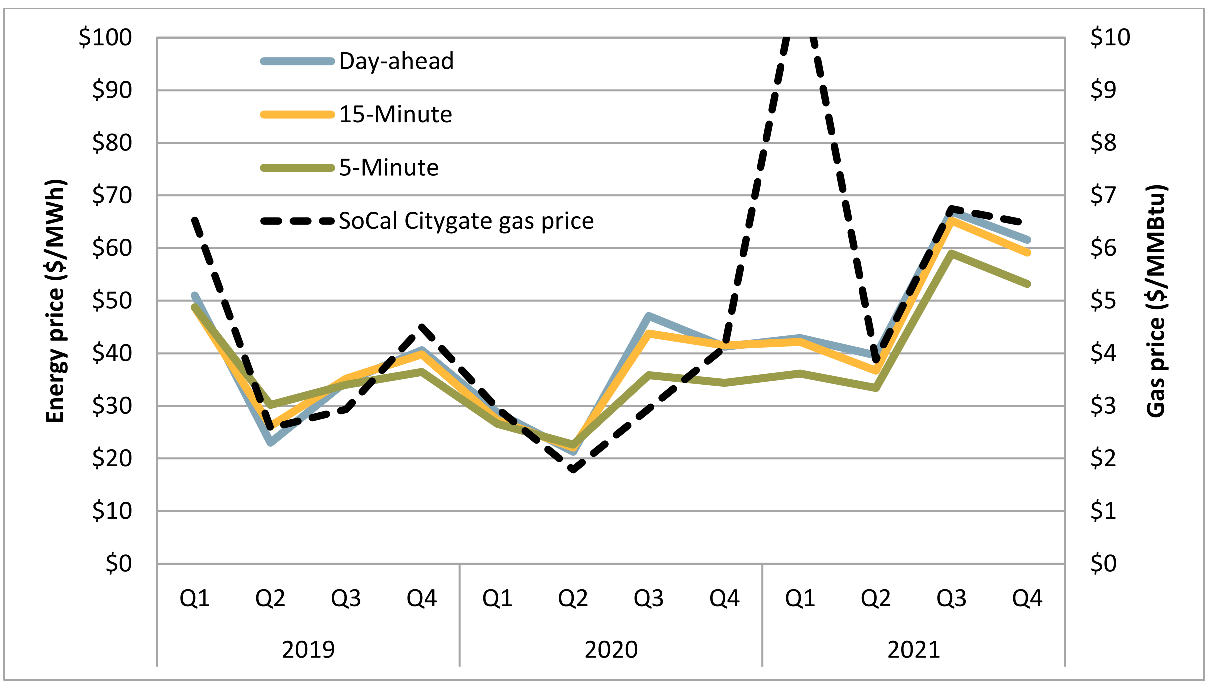
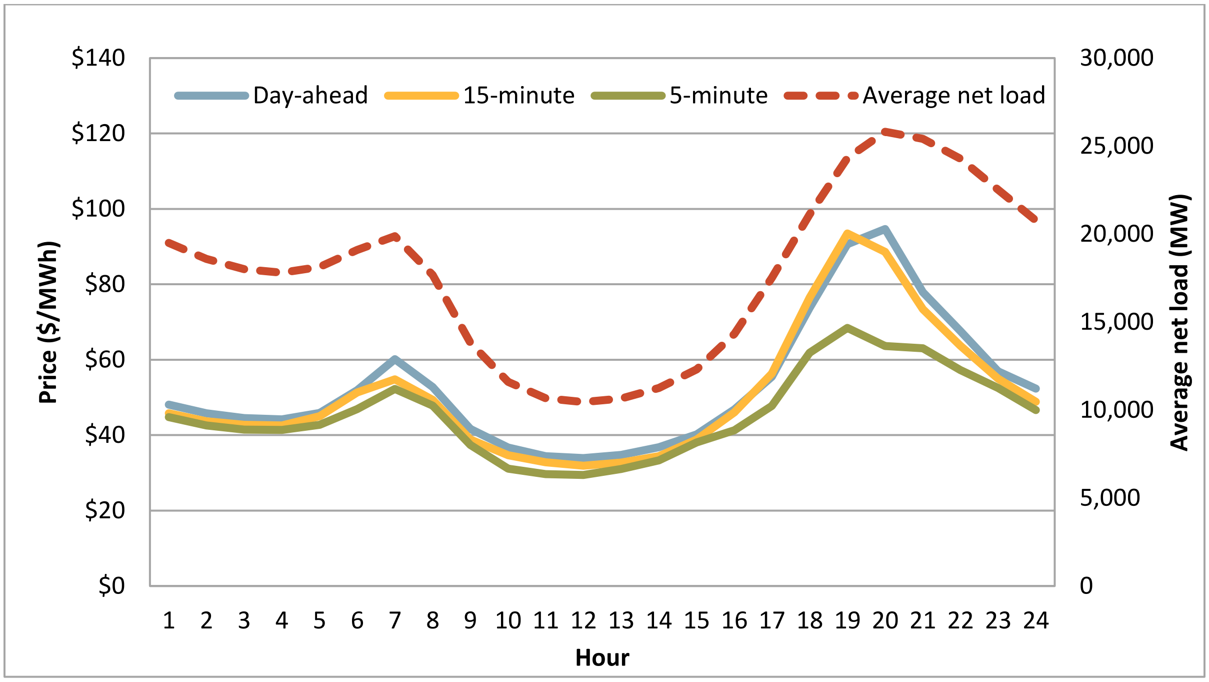


Figure E.3 Hourly system energy prices (2021)



Market competitiveness

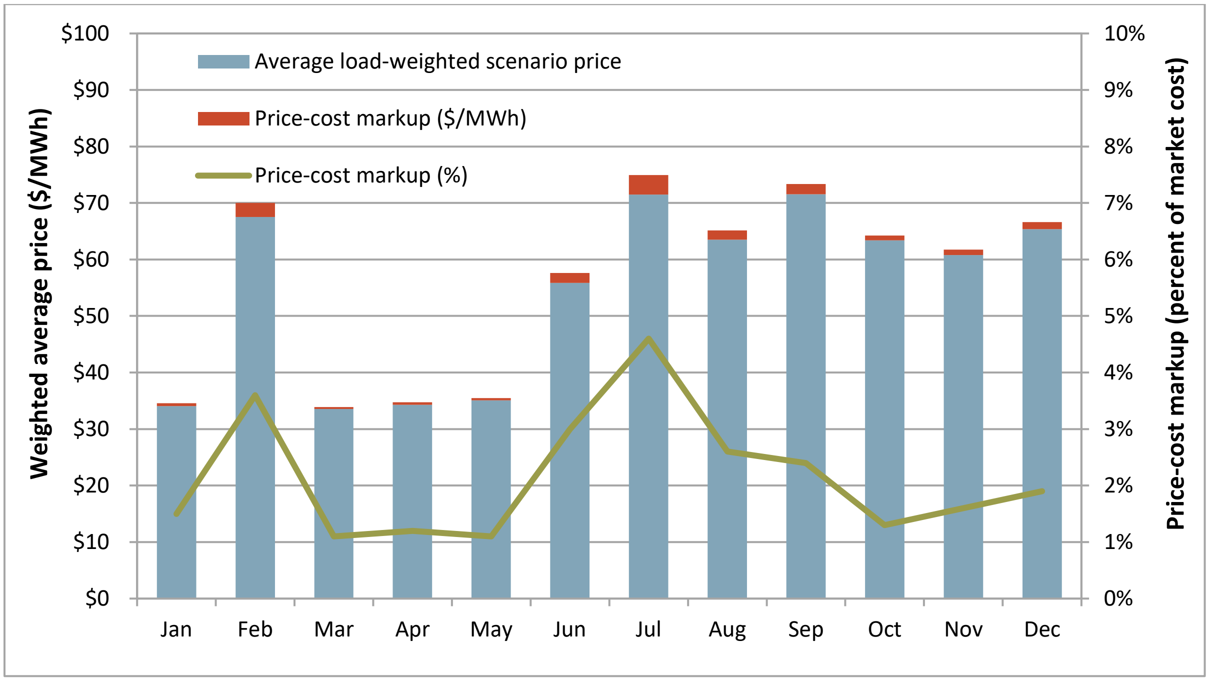
Prices in the California ISO energy markets were competitive in 2021. Overall, wholesale energy prices were about equal to competitive baseline prices DMM estimates would result under perfectly competitive conditions.

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.

DMM estimates an average price-cost markup of $1.41/MWh, or about 2.5 percent, as shown in Figure E.4. This slight positive markup indicates that prices have been very competitive, overall, for the year.[1]

[1] 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 (2021)



Market changes

The CAISO implemented multiple changes to both the day-ahead market and the real-time Western Energy Imbalance Market. Some of the most notable changes are summarized below.

- **Residual unit commitment process export prioritization (September 2020**). These changes to the residual unit commitment (RUC) process allow exports to be curtailed when procurement of physical energy and capacity in the residual unit commitment fails to bridge the gap between physical supply cleared in the day-ahead and the day-ahead forecasted load. Because of these changes, significant volumes of exports clearing the day-ahead market were identified as unsupportable through the residual unit commitment process on the highest load days in 2021. The residual unit commitment undersupply power balance constraint was infeasible during 11 hours on four days in 2021. Significant volumes of economic exports and low-priority self-schedule exports were cut in the residual unit commitment process prior to relaxing the power balance constraint.[2] On some high load days more than 2.5 GW of exports that cleared in the day-ahead market were cut in the residual unit commitment process. On these days, some exports that rebid into the real-time market cleared, ultimately meeting high demand in other regions.

[2] More information on the magnitude of export curtailment in the residual unit commitment process can be found in DMM's third quarter report.
Department of Market Monitoring, *Q3 2021 Report on Market Issues and Performance,* December 9, 2021 p. 96
http://www.caiso.com/Documents/2021-Third-Quarter-Report-on-Market-Issues-and-Performance-Dec-9-2021.pdf

- **Minimum flexible ramping product requirement (November 2020).** If an individual balancing authority area requirement is greater than 60 percent of the system requirement, then a minimum requirement will be enforced, equal to the balancing authority area's share of the diversity benefit.[3] 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 Fall 2022. The minimum requirement was initially implemented in the 15-minute market only. DMM recommended that the minimum requirement be included in the 5-minute market as an enhancement to improve the effectiveness of the flexible ramping product until nodal procurement implementation.[4] The California ISO implemented the 5-minute market minimum requirement on February 16, 2022.

- **WEIM resource sufficiency evaluation error correction (February 2021)**. The California ISO corrected two errors effective February 4, 2021.[5] These errors caused the incorrect accounting of resource de-rates/outages, as well as mirror resources, which made it easier to pass the test.

- **Default energy bid and commitment cost bid cap real-time adjustment (February 2021).** The commitment costs and default energy bid enhancements (CCDEBE) phase 1 was implemented on February 16, in response to national gas price volatility as a result of winter storm Uri. This functionality allows market participants to submit reference level adjustment requests above bid caps in the market. Since its implementation, this additional flexibility was utilized during a limited number of days when there was gas price volatility by a small number of market participants.

- **Bidding above the $1,000/MWh energy bid cap (March 2021).** This first phase of FERC Order No. 831 compliance established a hard bid cap of $2,000/MWh along with a soft bid cap of $1,000/MWh.[6] This allows resources to bid above the soft bid cap when either the maximum import bid price (MIBP) or a cost-verified energy bid from a resource-specific resource is greater than the $1,000/MWh bid cap. The MIBP is a reference point for import bids that is based on the prices at Mid-Columbia and Palo Verde. There were seven days in 2021 with hours that had a MIBP over the $1,000/MWh bid cap. This allowed non-resource adequacy imports to bid over the $1,000/MWh

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3 For example, if a balancing authority area's upward requirement is 1,000 MW and is greater than 60 percent of the system requirement, 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 California ISO, *Flexible Ramping Product Refinements Final Proposal*, August 31, 2020:
http://www.caiso.com/InitiativeDocuments/FinalProposal-FlexibleRampingProductRefinements.pdf

4 Procurement in the 5-minute market helps maintain available ramping capacity 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 within the California ISO and settled in the 15-minute market, is released in the 5-minute market in favor of undeliverable flexible ramping capacity stranded behind WEIM transfer constraints.

5 For additional information on these errors and the impact on bid range capacity test failures, see:
Department of Market Monitoring, *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

6 For additional details, see DMM's 2021 first and second quarter reports.
Department of Market Monitoring, *Q1 2021 Report on Market Issues and Performance,* June 9, 2021 pp. 93-96
http://www.caiso.com/Documents/2021-First-Quarter-Report-on-Market-Issues-and-Performance-Jun-9-2021.pdf
Department of Market Monitoring, *Q2 2021 Report on Market Issues and Performance*, October 5, 2021, pp. 101-103
http://www.caiso.com/Documents/2021-Second-Quarter-Report-on-Market-Issues-and-Performance-Oct-5-2021.pdf

soft bid cap during those specific hours. There were no other instances of cost-verified energy bids over the bid cap.

- **Gas burn constraint shaping and addition to market power mitigation (May 2021).** On May 20, the California ISO implemented DMM's recommendations on better shaping the maximum gas burn constraint limit using the net load approach. If needed, the shaping will also be based on estimated gas burn resulting from the two-day-ahead runs of the market software.[7,8] In addition, maximum gas burn constraints have been added to the automated assessment of the competitiveness of transmission constraint congestion in the local market power mitigation process, replacing a manual process.[9]

- **Addition of net load uncertainty to the bid range capacity test (June 2021)**. As part of a set of refinements to the WEIM resource sufficiency evaluation, the net load uncertainty measure used in the flexible ramping test was added to the bid range capacity test. This addition of uncertainty significantly increased test failures in multiple areas. Test failures cap transfer capacity, increasing the likelihood of prices set by a violation of the power balance constraint at $1,000/MWh. Since the implementation of uncertainty, 66 percent of upward test failures in 2021 *would* have passed without the additional requirement component. Net load uncertainty was removed from the requirement on February 15, 2022.

- **FERC Order 831 compliance, phase 2 (June 2021)**. This phase imposed bidding rules capping California resource adequacy import bids over $1,000/MWh at the greater of MIBP or the highest cost-verified bid up to the hard offer cap of $2,000/MWh. The MIBP is a reference point for import bids that is based on the prices at Mid-Columbia and Palo Verde. In 2021, bids from CPUC jurisdictional import resource adequacy resources exceeded $0/MWh only during a few peak hours in 2021. This is a result of CPUC Decision D.20-06-028, which requires non-resource-specific resource adequacy imports to self-schedule or bid at or below $0/MWh during availability assessment hours beginning in 2021. Procurement of import capacity also declined compared to previous years.

- **Market enhancements for summer readiness (June 2021).** The California ISO developed and implemented these changes to improve pricing and compensation of supply under tight conditions. First, 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 be paid below their offer price in any given hour during tight system conditions. Second, when the CAISO arms load to serve as operating reserves (i.e., prepares to shed load in a controlled manner, if needed), and then releases generation that was serving as reserves into the energy supply stack, the CAISO 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

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7 Department of Market Monitoring, *Motion to Intervene and Comments on Aliso Canyon Gas-Electric Coordination Phase 5, FERC Docket No. ER20-273*, November 21,2019: http://www.caiso.com/Documents/MotiontoInterveneandCommentsoftheDepartmentofMarketMonitoring-Aliso5-ER20-273-000-Nov212019.pdf

8 California ISO, Proposed Revision Request Detail, PRR# 1262, Aliso Canyon gas-electric coordination Phase 5 https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=1262&IsDlg=0

9 California ISO, *Business Requirements Specifications for Aliso Canyon Phase 5,* May 5, 2020: http://www.caiso.com/Documents/BusinessRequirementsSpecification-AlisoCanyonPhase5.pdf

controlled dropping of load needs to be relied upon for operating reserve. Third, 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. 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.

- **Self-scheduled export priority changes (August 2021).** Effective August 4, further changes were implemented to designate self-schedule exports as either a low or high priority export. High priority price taking (PT) exports are those supported by non-resource adequacy capacity, while low-priority price taking (LPT) exports are not.[10] All low-priority exports that clear the residual unit commitment process will be prioritized below internal load. In addition, the California ISO will prioritize exports that bid into the day-ahead market and clear the residual unit commitment process over new exports that self-schedule into the real-time market.

- **Wheeling priority changes (August 2021).** These changes established two categories of self-scheduled wheel-through transactions. The California ISO now designates high-priority (PT) and low-priority (LPT) self-scheduled wheels. High-priority wheels are required to register with the California ISO ahead of time and must be supported by a firm power supply contract to serve the load of an external load serving entity, as well as monthly firm transmission to the California ISO balancing area border. High-priority wheels will have priority equal to or above CAISO native load while low-priority wheels will have priority below native load.[11]

- **Ancillary service testing changes (September 2021).** The CAISO implemented a change to allow successful non-spin tests to constitute as passing performances for spin tests as well. For resources registered as battery or other (hybrid, hydro), a successful spin test will also constitute a passing performance for non-spin tests.[12]

- **Battery energy storage resource mitigation (November 2021).** Battery energy storage resources became subject to mitigation in the local market power mitigation process.[13]

- **WEIM resource sufficiency evaluation enhancements (June 2022)**. The California ISO implemented a number of changes to the resource sufficiency evaluation as part of the resource sufficiency

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10 Additional information and analysis on market changes implemented in August 2021 is provided in DMM's 2021 third quarter report.
Department of Market Monitoring, *Q3 2021 Market Issues and Performance,* September 9, 2021, pp. 94-102: http://www.caiso.com/Documents/2021-Third-Quarter-Report-on-Market-Issues-and-Performance-Dec-9-2021.pdf

11 Due to the additive nature of penalty prices, the combined penalty price for the import and export wheel of a high-priority wheel exceeds that of California ISO balancing area native load; however, the combined penalty price of self-scheduled imports and California ISO native load is equal to that of a high-priority wheel. This implies that California ISO load served by self-scheduled imports has equal priority to a high-priority wheel, but California ISO load served by other types of supply will have priority below a high-priority wheel.

12 For more information about the California ISO ancillary service testing procedures including updates to regulation performance audits, see: California ISO, *Operating Procedure 5370*: http://www.caiso.com/Documents/5370.pdf, p. 14.

13 California ISO Market Notice*: ESDER Phase 4 Initiative: Deployment Effective for Trade Date 11/1/21,* October 29, 2021: http://www.caiso.com/Documents/ESDERPhase4Initiative-DeploymentEffectiveforTradeDate-11121.html

evaluation enhancements phase 1.[14] This phase includes changes to the capacity test that will exclude some capacity that is unavailable because of various operating limitations. It also includes the suspension of intertie and net load uncertainty in the capacity test, while the California ISO continues its efforts to develop a better approach for incorporating uncertainty into the requirement in phase 2. DMM supported both of these changes.[15]

Ancillary services

Ancillary service costs decreased to $0.78/MWh from $0.95/MWh in 2020 and from 2.2 to 1.3 as a percent of total wholesale energy cost, as shown in Figure E.5. Total ancillary service costs decreased to $165 million, down from $199 million in 2020. Lower operating reserve requirements and the growing fleet of non-gas resources within the California ISO capable of providing ancillary services both contributed to lower ancillary service costs, despite higher gas prices and total wholesale energy cost.

Operating reserve requirements decreased as regulation requirements increased, with adjustments for net load variability. Regulation down requirements increased 30 percent to 684 MW and regulation up requirements increased 4 percent to 404 MW. Average combined requirements for spinning and non-spinning operating reserves decreased by 3 percent from the previous year to about 1,770 MW.

Thirty percent of resources failed ancillary service performance audits and unannounced compliance tests for spinning and non-spinning reserves, compared to 30 percent in 2020 and 20 percent in 2019. The frequency of ancillary service scarcity intervals continued to decrease, remaining very low. There were 55 intervals in the 15-minute market with ancillary service scarcity, compared to 129 in 2020 and almost 200 in 2019.

Provision of ancillary services from limited energy storage resources continued to increase, replacing procurement from imports. Average hourly procurement of ancillary services served by battery resources has been steadily increasing the past three years, growing from 179 MW in 2019 to 400 MW in 2021.

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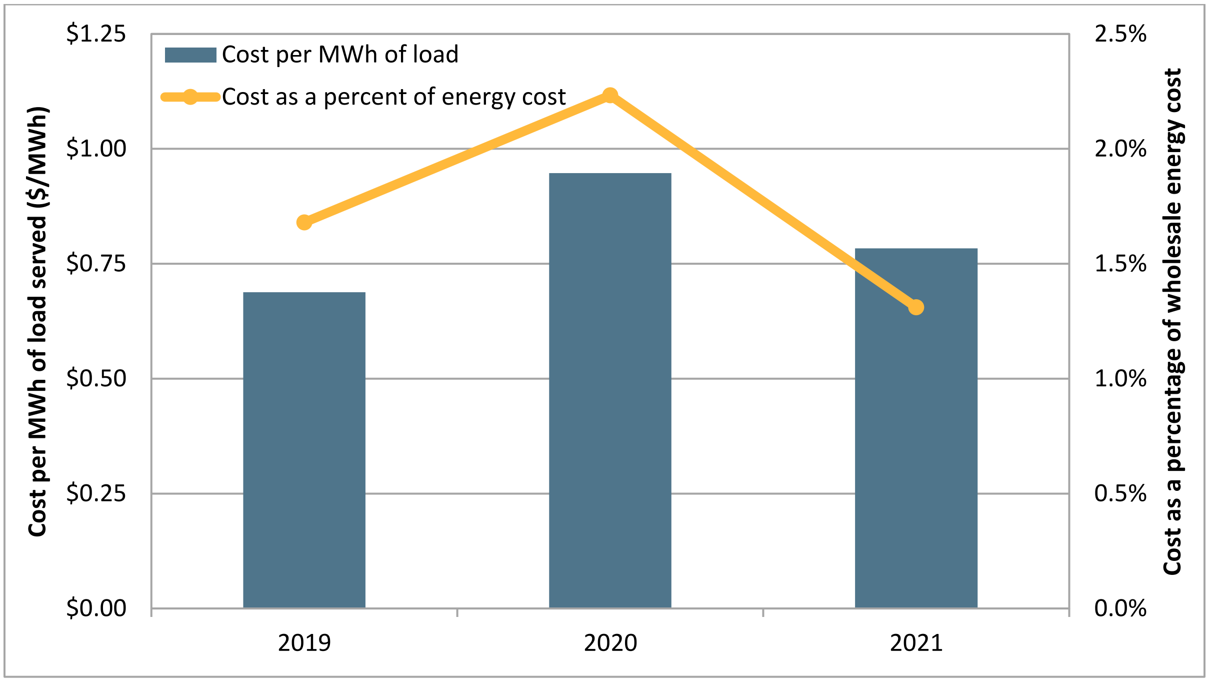
14 California ISO Initiative, *WEIM resource sufficiency evaluation enhancements*: https://stakeholdercenter.caiso.com/StakeholderInitiatives/EIM-resource-sufficiency-evaluation-enhancements

15 Department of Market Monitoring, *Comments on EIM Resource Sufficiency Evaluation Enhancements Phase 1 Revised Draft Final Proposal*, January 11, 2022. http://www.caiso.com/Documents/DMM-Comments-EIM-Resource-Sufficiency-Evaluation-Enhancements-Phase-1-Revised-Draft-Final-Proposal-Jan-11-2022.pdf

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



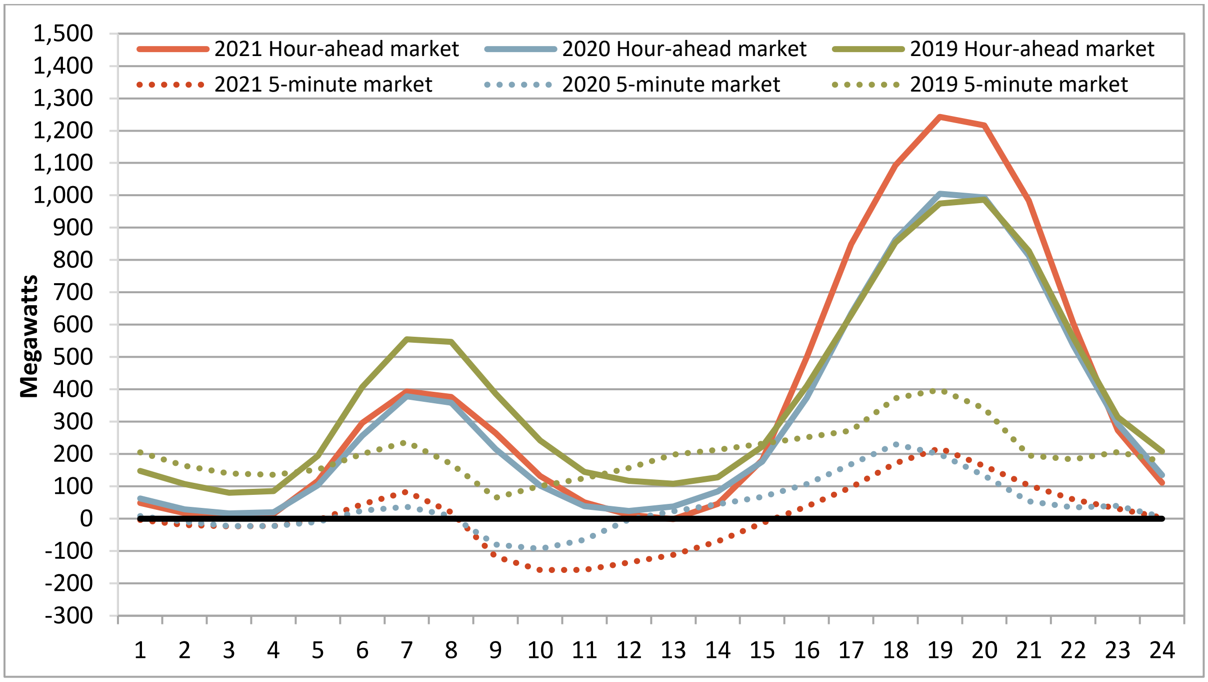
Load forecast adjustments

Operators in the California ISO and Western 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 CAISO uses the term imbalance conformance to describe the adjustments that are used to account for potential modeling inconsistencies and inaccuracies.

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

As shown in Figure E.6, load forecast adjustments in the hour-ahead routinely mirror the pattern of net loads over the course of the day, averaging 400 MW to about 1,200 MW during the morning and evening ramping hours respectively; 15-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 CAISO to be available for dispatch in the 15-minute and 5-minute markets. California ISO operator adjustments added over 600 MW per hour to residual unit commitment requirements, on average, in peak net load hours.

Figure E.6 Average hourly load adjustment (2019 - 2021)



Real-time imbalance offset costs

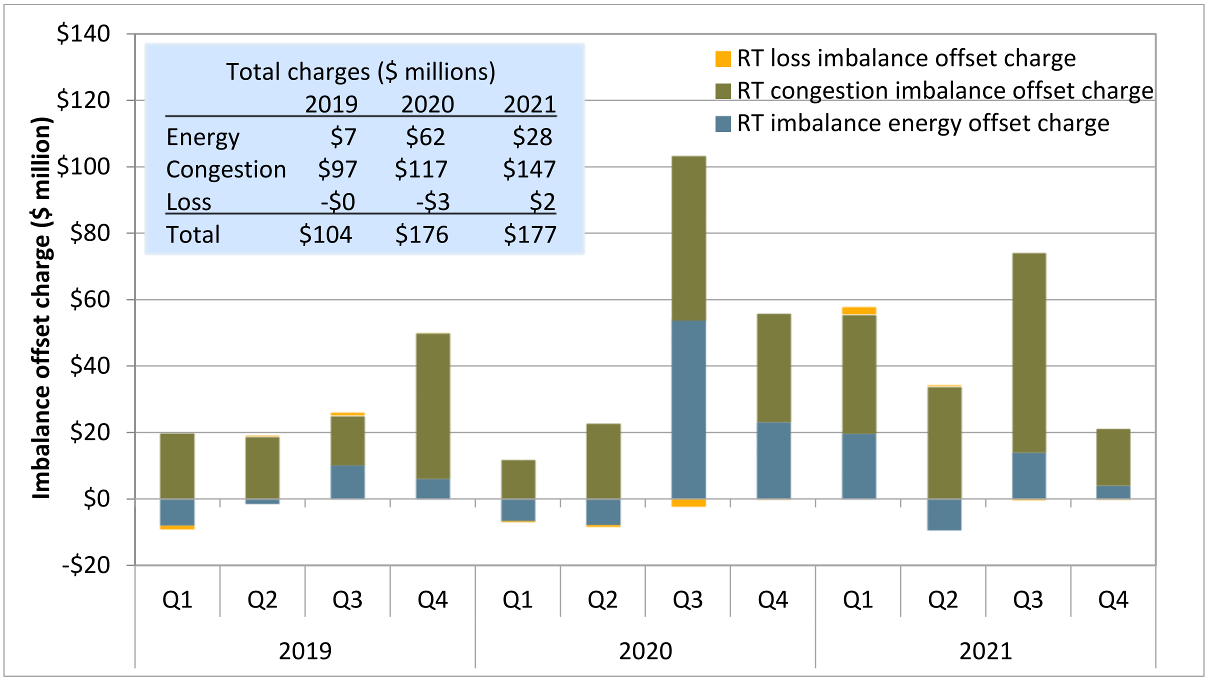
The real-time imbalance offset charge is the difference between the total money paid by the CAISO and the total money collected by the CAISO for energy settled at real-time prices. The charge is allocated as an uplift to load serving entities and exporters based on measured system demand.

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

Total real-time imbalance offset costs within the CAISO were $177 million in 2021, which was about the same as the $176 million in 2020, but still significantly higher than the $104 million in 2019. The majority of the offset costs were from real-time congestion imbalance offsets ($147 million), up from $117 million in 2020 and $97 million in 2019. Real-time imbalance energy offset costs fell to $28 million from $62 million in 2020, still higher than the $7 million in 2019.

As in each year since 2018, 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.

Figure E.7 Real-time imbalance offset costs



Congestion

Locational price differences due to congestion in both the day-ahead and 15-minute markets decreased in 2021, particularly on constraints associated with major transmission line limits separating Northern and Southern California as well as those connecting the California ISO and the Pacific Northwest. Key congestion trends during the year include the following:

- **Day-ahead market congestion decreased.** Both the frequency and the price impact of day-ahead congestion were lower in 2021 than in 2020. In 2021, day-ahead congestion revenues totaled about 5.2 percent of total day-ahead market energy costs, compared to about 6 percent in 2020.
- **Real-time market congestion decreased**. Both the 15-minute and 5-minute markets had patterns of congestion that followed seasonal trends in both solar production and load.
- **The frequency and impact of WEIM transfer constraint congestion decreased.** As in prior years, the frequency of congestion was highest for areas in the Pacific Northwest, where it decreased prices.
- **Intertie congestion decreased**. Congestion on interties across all markets (day-ahead, 15-minute, and 5-minute) reached about $164 million, down from $263 million in 2020. This decrease was largely driven by decreased congestion on the two major interties linking the CAISO with the Pacific Northwest: the Malin 500 and the Nevada/Oregon Border (NOB).

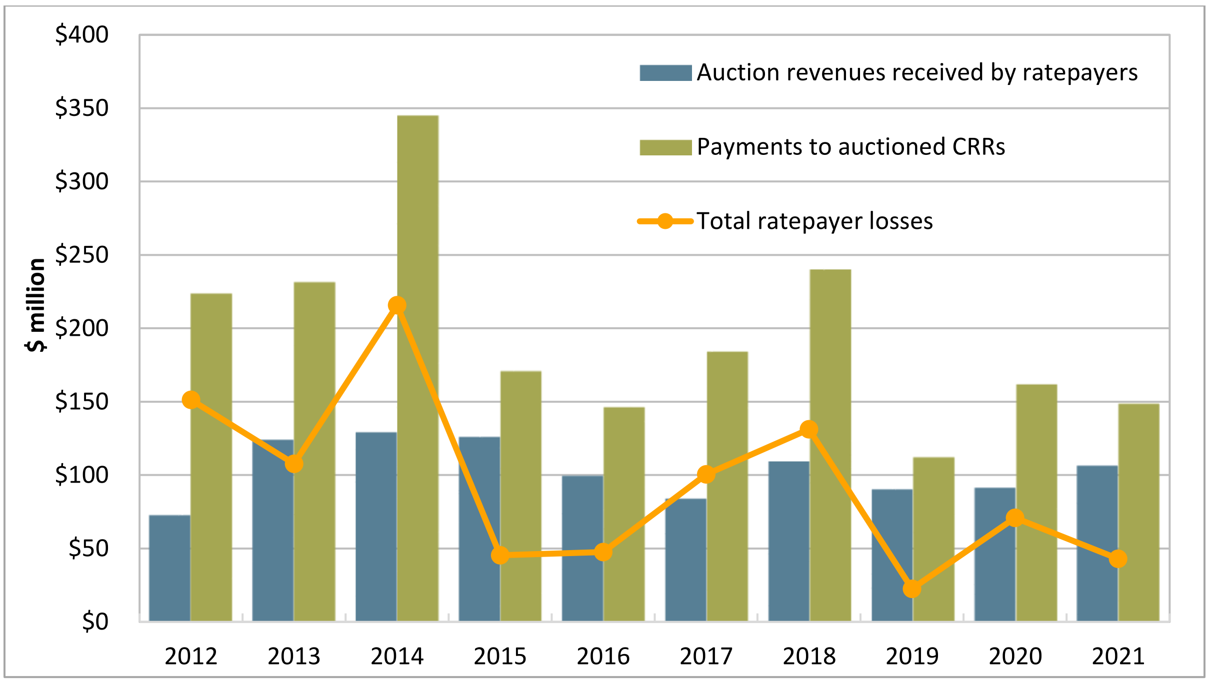
Congestion revenue rights

As shown in Figure E.8, in 2021 ratepayer losses from the auctions totaled $43 million, down from over $70 million in 2020. These losses are borne by transmission ratepayers who pay for the full cost of the transmission system through the transmission access charge (TAC).

Transmission ratepayers received about 71 cents in auction revenue per dollar paid out to these rights purchased in the auction in 2021. Track 1B revenue deficiency offsets reduced payments to auctioned CRRs by about $81 million. Losses from auctioned congestion revenue rights totaled about 7 percent of total day-ahead congestion rent in 2021, compared to about 14 percent in 2020, 6 percent in 2019, and 21 percent in 2018.

DMM believes the current auction is unnecessary and could be eliminated.[16,17] If the CAISO 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.8 Ratepayer auction revenues compared with congestion payments for auctioned CRRs



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 CAISO tariff requirements that

16 Department of Market Monitoring, *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

17 Department of Market Monitoring, *Market alternatives to the congestion revenue rights auction*, November 27, 2017: http://www.caiso.com/Documents/DMMWhitePaper-Market_Alternatives_CongestionRevenueRightsAuction-Nov27_2017.pdf

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, which is coincidentally the year the CAISO 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.[18] These investor-owned utilities bid this capacity into the market at cost, under least-cost bidding requirements set by the CPUC.

Over the last six 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.[19] 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 CAISO market competitiveness. Despite the lack of any bid mitigation for system market power, the CAISO 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 CAISO 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 CAISO energy market competitive at a system level.

The California 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 (PRM), which the CPUC recently increased from 15 percent to 17.5 percent of peak load.[20]

Analysis in this report shows that:

- **Most system resource adequacy capacity was procured by investor-owned utilities**. Investor-owned utilities accounted for about 60 percent of procurement (down from 66 percent in 2020), community choice aggregators procured 23 percent, municipal entities contributed 8 percent, and direct access providers accounted for 8 percent.

- **Over half of resource adequacy capacity was classified as use-limited** and thus exempt from CAISO bid insertion in all hours.

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18 CPUC Docket No. R.19-11-009, *Decision on Track 3B.2: Restructure of the Resource Adequacy Program (Decision 21-07-014),* July 16, 2021, pp. 5-6: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M393/K334/393334426.PDF

19 Ibid. p6.

20 The planning reserve margin reflects operating reserve requirements and additional capacity that may be needed to cover forced outages and potential load forecast error.

- **During system emergency hours, less than 90 percent** of system resource adequacy capacity was bid or self-scheduled in the real-time market. In the day-ahead market, 93 percent was available during these hours.
- **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 CAISO system.

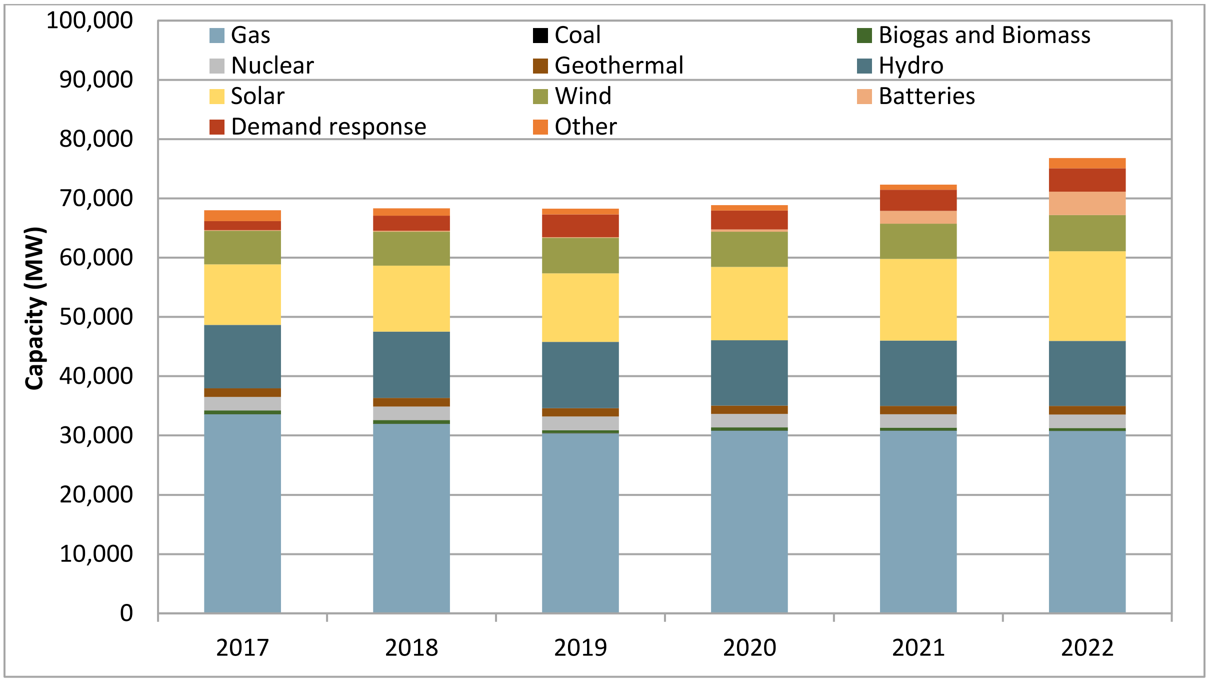
In February 2021, the CPUC issued a decision directing investor-owned utilities to procure additional capacity for summer 2021 that can be available in net peak demand hours.[21] DMM believes this additional procurement can help ensure additional capacity is available during peak net load hours when solar production drops off. However, DMM continues to support larger scale changes to the resource adequacy program discussed in the recommendations section below which could better capture the temporal contribution of different resource types towards meeting energy and capacity requirements.

Figure E.9 summarizes the trends in available nameplate capacity from June of 2017 through 2022. Since 2017, there has been a decrease in gas capacity, falling from 33.6 GW in June 2017 to 30.8 GW in June 2022. This capacity was replaced by solar, which grew from 10.2 GW to 15.1 GW; by wind, which grew from 5.7 GW to 6.1 GW; and by demand response, which grew from 1.5 GW to 3.9 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.[22]

[21] CPUC Docket No. R.20-11-003, *Decision Directing PG&E, SCE, and SDG&E to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2021 and 2022 (D.21-03-056),* March 26, 2021: https://docs.cpuc.ca.gov/publisheddocs/published/g000/m373/k745/373745051.pdf

[22] In contrast to gas and nuclear capacity, the resource adequacy contribution or qualifying capacity (QC) of wind and solar resources in the California 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.9 Total CAISO participating capacity by fuel type and year (as of June 1)



The California 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 California ISO 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 CAISO 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 independent system operators and the Federal Energy Regulatory Commission.

DMM estimates net revenues for new gas-fired generating resources using market prices for gas and electricity. In 2021, estimated net revenues for both combined cycles and combustion turbines in Southern California were less than estimated going-forward fixed costs. Estimated net revenues for new combined cycle gas resources in Northern California rose, exceeding estimated going-forward fixed costs, but 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 current California ISO market design. Net revenues summed with a generous capacity payment ($76/kW-yr, the CAISO 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.

Figure E.10 Estimated net revenue of hypothetical combined cycle unit

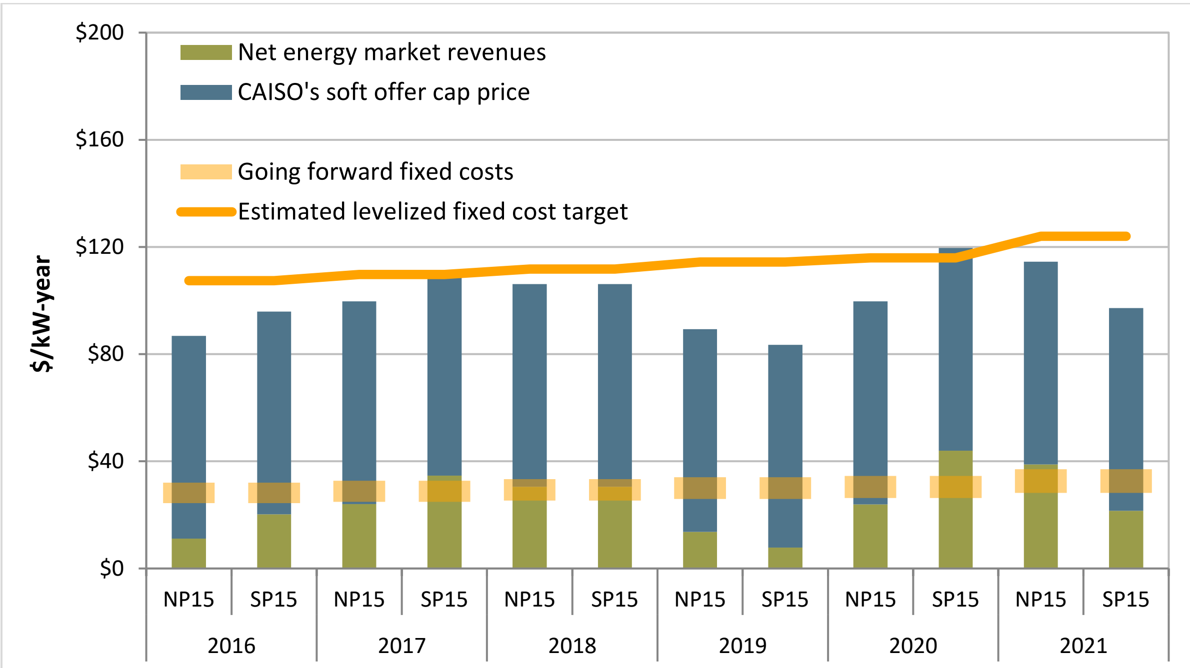
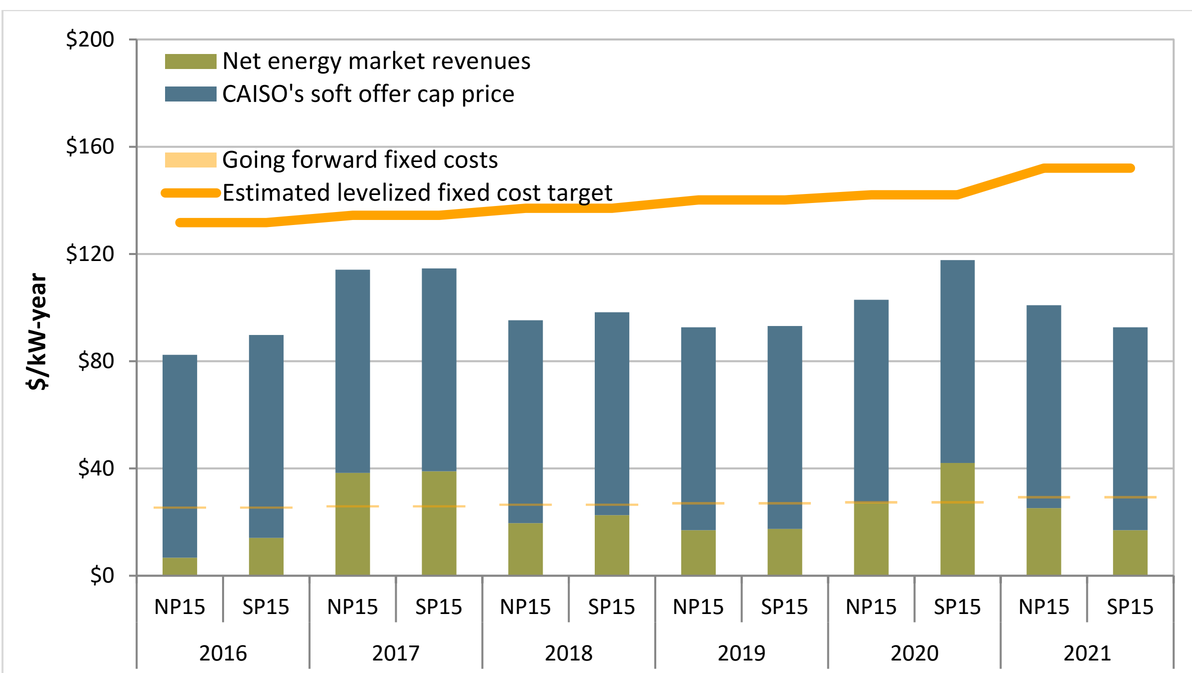


Figure E.11 Estimated net revenues of hypothetical combustion turbine



Starting in 2020, this analysis 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.

Table E.1 New battery energy storage net market revenues by LCA (2020-2021)

Local capacity area	TAC area	Net market revenues ($/kW) Scenario 2 Energy and Regulation									
		2020 Q1	2020 Q2	2020 Q3	2020 Q4	2021 Q1	2021 Q2	2021 Q3	2021 Q4	2020 $/kW-yr	2021 $/kW-yr
Greater Bay Area	PG&E	$23.55	$24.82	$31.15	$22.88	$42.30	$32.89	$24.64	$14.32	$102.41	$114.14
North Coast & North Bay (NCNB)	PG&E	$25.12	$28.18	$33.87	$23.39	$42.25	$32.86	$24.61	$14.16	$110.56	$113.88
Greater Fresno	PG&E	$25.65	$32.50	$34.87	$25.84	$44.34	$42.60	$35.19	$20.61	$118.86	$142.74
Sierra	PG&E	$23.75	$26.10	$35.22	$23.30	$42.02	$33.98	$24.48	$14.17	$108.38	$114.65
Stockton	PG&E	$23.50	$25.98	$31.30	$23.01	$42.33	$33.21	$25.01	$14.64	$103.79	$115.19
Kern	PG&E	$25.28	$28.60	$33.20	$24.34	$43.34	$37.79	$27.50	$18.93	$111.41	$127.55
LA Basin	SCE	$27.16	$23.30	$53.35	$31.45	$42.03	$25.36	$17.73	$15.65	$135.26	$100.77
Big Creek/Ventura	SCE	$26.14	$23.32	$53.11	$29.52	$41.57	$25.71	$17.93	$15.81	$132.08	$101.02
San Diego/Imperial Valley	SDG&E	$29.01	$22.85	$53.28	$29.85	$40.99	$26.60	$18.05	$14.59	$134.99	$100.23
CAISO System		$25.99	$25.65	$40.96	$26.77	$42.60	$31.09	$22.37	$16.92	$119.37	$112.97

Recommendations

As the California 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 California ISO, the California ISO Governing Board, FERC staff, state regulators, market participants, and other interested entities.[23] DMM provides written comments and recommendations in the California ISO stakeholder process and in quarterly, annual, and other special reports.[24] DMM's current recommendations on key market design initiatives are summarized below and in Chapter 10.

Western Energy Imbalance Market resource sufficiency tests

The resource sufficiency tests for both capacity and flexible ramping capacity are key elements of the Western Energy Imbalance Market design. These tests are intended to ensure that enough resources are available to meet reliability needs and prevent one balancing area from leaning on other WEIM areas.

The California ISO implemented a number of changes to the resource sufficiency evaluation in June 2022. These changes include the exclusion of some capacity that is unavailable because of various operating limitations. The ISO also suspended inclusion of intertie and net load uncertainty in the capacity test.[25] DMM supported these changes. As part of this ongoing initiative, DMM is providing

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23 California ISO, *Tariff Appendix P, ISO Department of Market Monitoring, Section 5.1*, April 1, 2017: http://www.caiso.com/Documents/AppendixP_CAISODepartmentOfMarketMonitoring_asof_Apr1_2017.pdf

24 Department of Market Monitoring, Market Monitoring Reports and Presentations: http://www.caiso.com/market/Pages/MarketMonitoring/MarketMonitoringReportsPresentations/Default.aspx#CommentsRegulatory

25 Department of Market Monitoring, *Comments on EIM Resource Sufficiency Evaluation Enhancements Phase 1 Revised Draft Final Proposal*, January 11, 2022. http://www.caiso.com/Documents/DMM-Comments-EIM-Resource-Sufficiency-Evaluation-Enhancements-Phase-1-Revised-Draft-Final-Proposal-Jan-11-2022.pdf

additional information and analysis about resource sufficiency evaluation performance, accuracy, and impacts in regular monthly reports.[26]

Phase 2 of the initiative continues to explore other enhancements to make the tests more accurate and to modify the consequences of test failures. DMM supports exploring broader changes to the resource sufficiency evaluation that would provide better incentives to deter balancing areas from leaning on the Western Energy Imbalance Market, while still allowing for efficient transfers of energy between different balancing areas through the WEIM.

Before resuming inclusion of any uncertainty in test requirements, DMM recommends the California ISO re-consider the uncertainty requirements that have been used in the resource sufficiency tests. These uncertainty requirements are set based on the same measure of uncertainty used in the real-time market flexible ramping product. DMM has suggested that a simpler and more transparent approach might be more appropriate for use in the resource sufficiency evaluation.

DMM continues to recommend that changes to the consequences of test failure be considered. Currently, when a WEIM area fails either the capacity test or flexible ramping test, WEIM 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 has recommended that both the California ISO and stakeholders consider other options, such as imposing a capacity charge or other financial charge.

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 CAISO has implemented numerous improvements to this product since its introduction in 2016, CAISO 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.

Since 2016, DMM has recommended the following two key enhancements:[27]

- Increase the locational procurement of flexible ramping capacity to decrease the likelihood that the product is not deliverable (or *stranded*) because of transmission constraints. The CAISO is hoping to address this issue by implementing nodal procurement of flexible ramping capacity in fall 2022.
- 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 a longer time frame (e.g., 30, 60, and 120 minutes out from a given real-time interval) and

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[26] Department of Market Monitoring, *2022 Western Energy Imbalance Market resource sufficiency evaluation reports:* http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=1571AD84-67B2-4641-BA7D-4499082910E5

[27] DMM highlighted these two recommendations in their 2018 annual report as well as in recent comments in the California ISO stakeholder process.
Department of Market Monitoring, *2018 Annual Report on Market Issues and Performance*, May 2019, pp. 269-270: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

appropriately price procurement of capacity to meet longer time horizons. The ISO has not yet examined this change through the market design and stakeholder process.

DMM believes both these changes are needed to make the flexible ramping product effective at meeting ramping needs through the market, rather than through the various manual interventions currently used by grid operators. These manual interventions have the effect of reducing real time prices. These changes would decrease the need for manual interventions, and would increase market prices for energy and ramping capacity received by flexible resources helping to meet ramping needs during the net peak hours.

Day-ahead market enhancements

In 2018, the California ISO initiated a process to develop a proposal for day-ahead market enhancements.[28] This initiative is intended to feed into a separate ongoing initiative to develop an extended (regional) day-ahead market that includes balancing areas participating in the real-time Western Energy Imbalance Market.

A key element of the 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 the procurement of this product.

However, if the California 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.

Extended day-ahead market

In 2019, the California ISO initiated a process to develop a proposal for extending the day-ahead market to include other entities in the Western Energy Imbalance Market.[29] DMM supports the CAISO's efforts to extend the day-ahead market to other balancing areas across the west. This has the potential to provide significant efficiency benefits by facilitating trade between diverse areas and resource types.

As noted above, DMM views the day-ahead imbalance reserve product proposed in the day-ahead market enhancements initiative as being a key element of an extended regional day-ahead market.

Several areas of the proposed design warrant substantial development or clarification in order to produce a feasible design.[30] The California ISO needs to define clearly how the core elements of the

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[28] California ISO Initiative, *Day-Ahead Market Enhancements:* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements

[29] California ISO, *Extending the Day-Ahead Market to EIM Entities Issue Paper*, October 10, 2019: http://www.caiso.com/Documents/IssuePaper-ExtendedDayAheadMarket.pdf

[30] Department of Market Monitoring, *Comments on Extended Day-Ahead Market Straw Proposal,* June 17, 2022: http://www.caiso.com/Documents/DMM-Comments-Extended-Day-Ahead-Market-Straw-Proposal-June-17-2022.pdf

extended day-ahead market design will work together during the critical hours each year when the potential exists for a supply shortfall in the extended day-ahead market footprint.

For example, the California ISO has verbally indicated that the extended day-ahead market design is intended to have all participating balancing areas that pass the day-ahead resource sufficiency evaluation share the consequences of any real-time supply shortfall in the extended day-ahead market footprint. DMM agrees that this high-level design would be ideal. However, other elements of the California ISO's April straw proposal suggest that this principle may not be applied in real-time.

Congestion revenue rights

Congestion revenue rights sold in the ISO 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. These losses are borne by transmission ratepayers who pay for the full cost of the transmission system through the transmission access charge (TAC).

In response to these systematic losses from the congestion revenue right auction sales, the CAISO instituted significant changes to the auction starting in the 2019 settlement year. Changes to the auction implemented in 2019 have reduced, but not eliminated, losses to transmission ratepayers from the auction. Ratepayer losses have averaged about $45 million per year after the changes, compared to average losses of $114 million per year in the seven years before the reforms. Most of these losses have resulted from profits received by purely financial entities that purchase congestion revenue rights but do not schedule power or load in the California ISO.

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 CAISO 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 California ISO believes it is highly beneficial for them to actively facilitate hedging of congestion costs by suppliers, DMM recommends that the CAISO replace the auction with a market for financial hedges based on clearing of bids from willing buyers and sellers.

Pricing under tight supply conditions

In 2021, the California ISO implemented numerous changes that feature steps to allow prices to rise and increase compensation for imports during tight supply conditions. DMM supports these changes and believes they will improve the functioning of the CAISO markets during tight system conditions.[31] 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.

DMM recommends the California ISO review and consider market performance, with these changes in effect, as it considers adding additional scarcity pricing provisions. DMM has cautioned that if scarcity

31 Department of Market Monitoring, *Motion To Intervene and Comments (FERC 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

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.[32] The CPUC took steps to address this issue in 2020 by requiring that non-resource-specific import resource adequacy resources, procured by CPUC-jurisdictional participants, must be self-scheduled or bid into the CAISO markets at or below $0/MWh during the peak net load hours of 4-9 p.m., starting in 2021.[33]

DMM has suggested that the CAISO market rules could be modified so the resource adequacy imports would 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. The California ISO contends that subjecting resource adequacy imports to any type of bid mitigation would be “ineffective and inappropriate.”[34]

DMM has also suggested that the California ISO consider options for increasing the supply and availability of energy from resource adequacy imports beyond the day-ahead market into real-time.

Export and wheeling schedules

The summer 2020 heat wave highlighted the need to review the California ISO policies and procedures for curtailing load versus curtailing exports and wheeling schedules. In late summer 2020, the CAISO took several steps to modify its software and procedures so that some exports would be curtailed before curtailment of CAISO area load.

In 2021, the CAISO 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.[35] This process resulted in tariff changes that provide for curtailment of some exports and wheeling schedules before curtailment of CAISO area load which were initially approved by FERC for a one year period through 2022.

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[32] Department of Market Monitoring, *2018 Annual Report on Market Issues and Performance*, May 2019, p. 269: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

Department of Market Monitoring, *Import Resource Adequacy*, September 10, 2018: http://www.caiso.com/Documents/ImportResourceAdequacySpecialReport-Sept102018.pdf

[33] CPUC Docket No. R.17-09-020, *Decision adopting resource adequacy import requirements (D.20-06-028)*, June 5, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K516/342516267.PDF

[34] California ISO, *System Market Power Mitigation Straw Proposal*, December 11, 2019, pp. 30-32: http://www.caiso.com/InitiativeDocuments/StrawProposal-SystemMarketPowerMitigation.pdf

[35] California ISO Initiative, *Market enhancements for summer 2021 readiness:* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Market-enhancements-for-summer-2021-readiness

In fall 2021, the California ISO began the transmission service and market scheduling priorities initiative.[36] The first phase of this initiative extended the interim rules until 2024. Through the second phase of this initiative, the CAISO continues to 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 CAISO balancing authority area, while better aligning the CAISO market rules and practices with those of other balancing areas, independent system operators, and regional transmission organizations.

Over the longer term, DMM continues to recommend that the California ISO develop an approach for transmission scheduling priority that is more similar to that of other independent system operators.

Based on DMM's understanding of the rules and practices in other balancing areas, making the California ISO rules consistent with that of other independent system operators and balancing areas would involve the following additional changes:

- Establish a process to determine excess available transmission capacity on the CAISO 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 the CAISO 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 California ISO's commitment to work with stakeholders in the ongoing transmission services and market scheduling priorities initiative to develop more comprehensive longer-term rules for transmission scheduling priorities by summer 2024.

Resource adequacy

California relies on the state's long-term bilateral procurement process and resource adequacy program to maintain adequate system capacity and help mitigate market power through forward energy contracting. 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 made two important changes to resource adequacy in 2020:

- Adopt a multi-year framework for local resource adequacy requirements and procurement by load serving entities.
- Develop a central buyer framework development for meeting any local resource adequacy requirements not met by resource adequacy capacity procured by CPUC-jurisdictional load serving entities.

[36] California ISO Initiative, *Transmission service and market scheduling priorities:* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Transmission-service-and-market-scheduling-priorities

The CPUC has identified additional options for addressing these issues and is currently working with the California ISO and stakeholders on moving forward with more detailed market design options and decisions. These options include the following:

- Strengthen requirements for the use of imports to meet system-level resource adequacy requirements.
- Develop resource adequacy requirements and resource capacity ratings that ensure sufficient flexible capacity needed to integrate a high level of renewable resource capacity.
- Develop 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 under consideration by the CPUC as potentially effective steps in addressing the current gaps in the state's resource adequacy framework.

DMM also recommends the California 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. The current California ISO *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.

Demand response

In the last two years, the California ISO has increasingly relied on demand response to curtail load during peak summer hours. DMM's analysis of how demand response resources participated and performed in the CAISO market on high load days, in summer 2020 and 2021, shows that a large portion of demand response resource adequacy capacity was not available for dispatch, or performed significantly below dispatched levels during key peak net load hours.[37] This results from a combination of how demand response resources are counted toward resource adequacy requirements, as well as by the performance of some demand response programs after being dispatched.

Resource adequacy payments, or the value of reduced resource adequacy requirements, are the primary revenue sources for demand response resources. Even when demand response resources are frequently dispatched, the energy market revenues from actually performing (or charges for failing to perform) represent a relatively small portion of the overall compensation or value of these resources. This current market framework does not provide a strong financial incentive for most demand response resources to perform when needed most under critical system conditions.

In prior reports, DMM has highlighted some recommendations that the CAISO and CPUC could consider to enhance the availability and performance of demand response resources, especially before increasing

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[37] Department of Market Monitoring, *Demand Response Issues and Performance 2021*, January 12, 2022: http://www.caiso.com/Documents/Demand-Response-Issues-Performance-Report-Jan-12-2022.pdf

Department of Market Monitoring, *2020 Annual Report on Market Issues and Performance,* August 2021, pp. 21-22: http://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf reliance on demand response towards meeting resource adequacy requirements.[38] The California ISO, CPUC, and CEC are currently working on addressing some important issues pertaining to demand response. DMM's major recommendations include the following:

- ***Re-examine demand response counting methodologies.*** The California ISO, CPUC, and CEC are currently examining different counting methodologies for demand response, including methodologies which would better capture the variable nature of demand response availability.[39] Counting methodologies should better capture the capacity contribution of demand response resources with load reduction capabilities that vary across the day and may have limited output in general.

- ***Adopt the California ISO's recommendation to remove the planning reserve margin adder applied to demand response capacity counted towards system resource adequacy requirements under the CPUC jurisdiction.*** The CAISO has recommended that the CPUC discontinue applying a planning reserve margin adder to demand response capacity values.[40] Starting in 2022, the CPUC will remove 6 of the 15 percent planning reserve margin adder applied to demand response capacity credits, and the CEC will examine whether the remaining 9 percent of the adder should be retained.[41] The CAISO and DMM recommend that the CPUC consider removing the remaining 9 percent of the planning reserve margin adder, as this adder contributes to overestimating the actual resource adequacy value of utility demand response programs on high load days.

- ***Make demand response available on Saturdays.*** In 2021, the CPUC also approved rules that would require demand response programs counted towards resource adequacy to be available on Saturdays, which DMM supported as high load days in recent years have not been limited to weekdays.[42]

- ***Consider developing a performance-based penalty or incentive structure for resource adequacy resources***. A performance-based penalty or incentive mechanism could be particularly relevant for demand response resources because of the difficulty of determining, in advance, whether or not a new demand response resource—or an existing provider that is selling additional new capacity—is

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38 Department of Market Monitoring, *Demand response, issues and performance*, February 25, 2021, pp. 3-4: http://www.caiso.com/Documents/ReportonDemandResponseIssuesandPerformance-Feb252021.pdf

Department of Market Monitoring, *2020 Annual Report on Market Issues and Performance*, August 2021, pp. 21-22: http://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf

39 California Energy Commission, *CEC Docket Log for Docket 21-DR-01:* https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=21-DR-01

40 CPUC Docket R-19-11-009, *California Independent System Operator Corporation Consolidated Comments on all Workshops and Proposals*, March 23, 2020, pp. 10-11: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M330/K052/330052136.pdf

41 CPUC Docket R19-11-009, Decision adopting Local Capacity Obligations for 2022 – 2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program, June 25, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.pdf

42 CPUC Docket No. R.19-11-009, *Decision Adopting Local Capacity Obligations for 2022-2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program, (D.21-06-029),* June 25, 2021, pp. 9-10: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.PDF

capable of delivering load curtailment in critical hours equal to the quantity of resource adequacy capacity that the resource has been paid to provide.

Energy storage resources

The amount of energy storage resources on the CAISO system has increased significantly in recent years. Battery energy storage capacity is projected to continue increasing in coming years and is being relied upon to play a key role in the integration of renewable resources. While battery resources are generally very fast responding and flexible, the availability of these resources depends on their state of charge levels. For example, battery resources providing resource adequacy sometimes do not have sufficient charge to provide resource adequacy values for four consecutive hours across peak net load periods. Consequently, DMM has played an active role in efforts to develop new market rules and software enhancements to facilitate use of energy storage resources.

DMM has suggested potential changes to CPUC and CAISO 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 CAISO's non-generator resource (NGR) model to local market power mitigation, and developing methods to better reflect costs of energy storage resources in market models.[43] Battery energy storage resources became subject to mitigation in the local market power mitigation process in November 2021.[44]

DMM also recommends that the CAISO consider whether resource adequacy availability incentives should consider limits on resources' state of charge values or limits to resources' charging capability.

DMM has previously recommended new bid cost recovery (BCR) rules for energy storage resources. New BCR rules are needed to mitigate inefficiencies and potential gaming opportunities that may result from differences between day-ahead and real-time state of charge. Recently observed market outcomes and the growing capacity of energy storage resources on the CAISO system continue to underscore the need to address BCR for energy storage resources. DMM continues to recommend that the CAISO develop these revised bid cost recovery rules as soon as practicable.

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43 Department of Market Monitoring, *2018 Annual Report on Market Issues and Performance*, May 2019, p. 24: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

44 California ISO Market Notice*: ESDER Phase 4 Initiative: Deployment Effective for Trade Date 11/1/21,* October 29, 2021: http://www.caiso.com/Documents/ESDERPhase4Initiative-DeploymentEffectiveforTradeDate-11121.html

Organization of report

The remainder of this report is organized as follows:

- **Loads and resources.** Chapter 1 summarizes load and supply conditions that impact market performance. This chapter includes an updated analysis of net operating revenues earned by hypothetical new gas-fired generation from the CAISO markets.
- **Overall market performance.** Chapter 2 summarizes overall market performance.
- **Western Energy imbalance market.** Chapter 3 highlights the growth and performance of the Western 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 services market.
- **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 CAISO 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 2021, California ISO wholesale electricity prices were higher due to an increase in gas prices and a decrease in hydroelectric supply, despite lower load and an increase in solar generation.

Specific trends highlighted in this chapter include the following:

- **California ISO load continued to decrease in 2021**, due in part to increases in behind-the-meter solar generation and continued initiatives to improve energy efficiency. However, this effect was offset during morning peak hours as demand increased with the lifting of COVID-19 related public health measures.
- **California ISO loads peaked at 43,982 MW**, lower than the median forecast and the lowest peak load for the California ISO since 2003.
- **The average price of natural gas increased across the West and in the California spot market by about 141 percent at SoCal Citygate and 67 percent at PG&E Citygate**. Natural gas demand growth exceeded supply growth, particularly for liquefied natural gas exports, driving electricity prices up across the market.
- **Hydroelectric generation decreased to 6 percent of supply in 2021.** California ISO hydroelectric generation in 2021 was about 26 percent lower than in 2020, the third lowest year since 2011, as drought conditions persist across the West.
- **Net imports accounted for 19 percent of generation, a decrease by 1,100 MW from 2020**, as non-Western Energy Imbalance Market imports fell from both the Southwest and Northwest.
- **Non-hydro renewable generation accounted for about 31 percent of total supply in 2021**, up from 28 percent in 2020.[45] Solar generation increased by about 13 percent and accounted for around 16 percent of total supply. The increase was driven by the addition of new solar generation capacity and increased ability for the market to export during the peak solar hours.
- **Over 4,000 MW of gas capacity was scheduled to retire before the summer of 2021,** but instead remains operational. The California ISO took steps to prevent these retirements to keep necessary capacity online to maintain reliability during the summer peak.
- **Demand response resource capacity increased** from 2020 to 2021, particularly utility demand response. Aggregate reported performance of demand response resources averaged 65 percent, an increase from last summer. The self-reported performance of utility demand response increased from 75 percent to almost 90 percent during peak hours this summer.
- **Capacity from battery storage resources grew dramatically** from 400 MW in June 2020 to 3.9 GW as of June 2022. In addition, the California ISO added over 700 MW of capacity from either co-located or hybrid resources, including storage resources prohibited from charging from the grid.

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45 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 2021 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, estimated net revenues for combined cycles exceeded going-forward fixed costs.
- **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 and 2021 once ancillary service payments were included, averaging about $114/kW-yr in 2021, which is slightly down from $118/kW-yr in 2020.

1.1 Load conditions

1.1.1 System loads

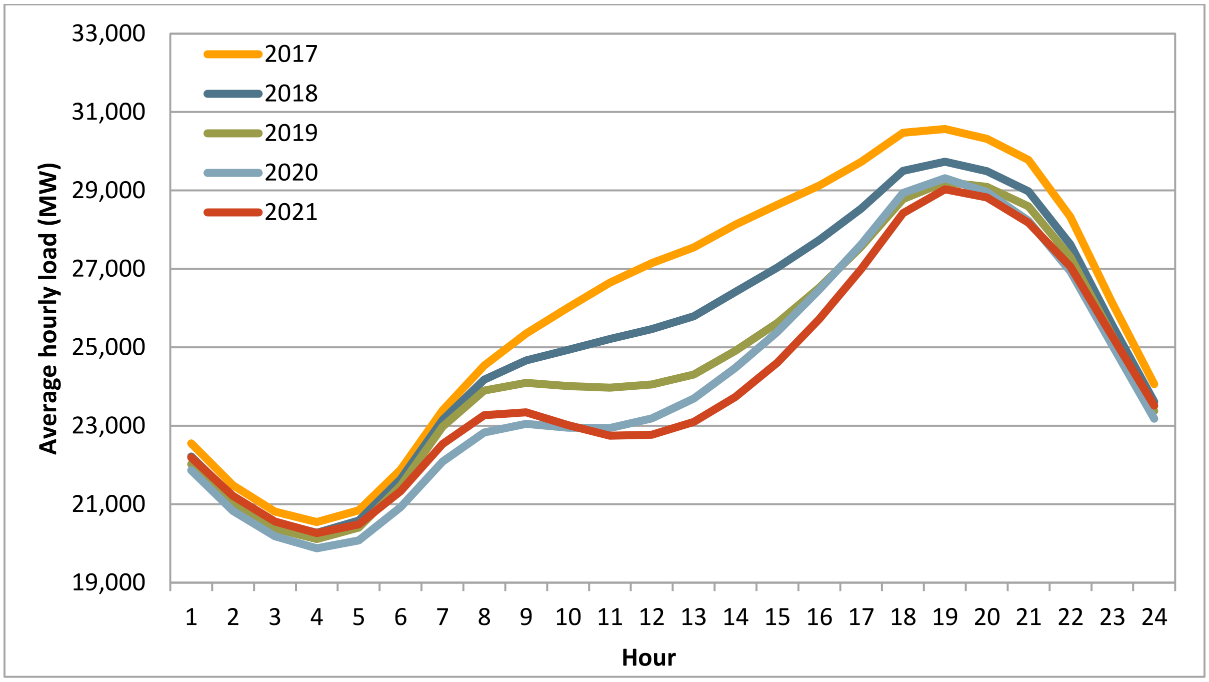
California ISO (CAISO) load decreased in 2021 and was the lowest since 2003. Peak load decreased significantly compared to 2020, with the total and average load decreasing as well. Over the last two decades, peak load has shifted to being later in both the day and the time of year. For example, peak load in 2002 occurred on July 10 just after 3 p.m., but occurred on September 8 at nearly 6 p.m. in 2021. Table 1.1 summarizes annual system peak loads and energy use since 2017. Although total load decreased between 2020 and 2021, it fell at a slower rate than it had since 2017.

Table 1.1 Annual system load in CAISO: 2017 to 2021

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%
2021	211,020	24,092	-0.1%	43,982	-6.7%

Figure 1.1 shows average hourly load by year along with how the overall load shape has changed since 2017. Lower loads are due, in part, to the growth of 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 shows the effect of increased behind-the-meter solar generation on load in California.

Figure 1.1 Average hourly load (2017-2021)



Seasonal load trends

Figure 1.2 and Figure 1.3 show the average load by quarter and month between 2017 and 2021, respectively. Average load was higher in the second quarter than in 2020, but lower in each of the other quarters. Higher second quarter load was due in part to warmer weather that caused higher peak loads, as well as reduced COVID-19 restrictions, which allowed the morning peak load to rebound to near 2019 levels. A number of factors influence load trends; however, load tends to follow statewide temperatures on average.[46]

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

Figure 1.2 Average load by quarter (2017-2021)

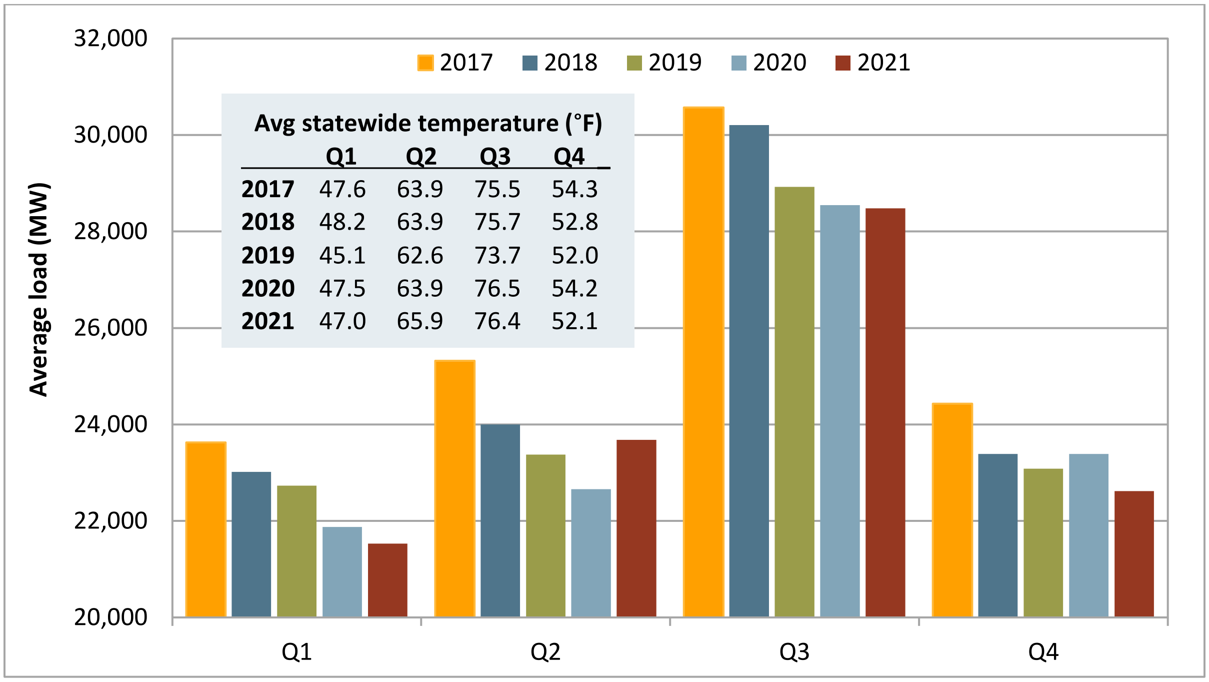
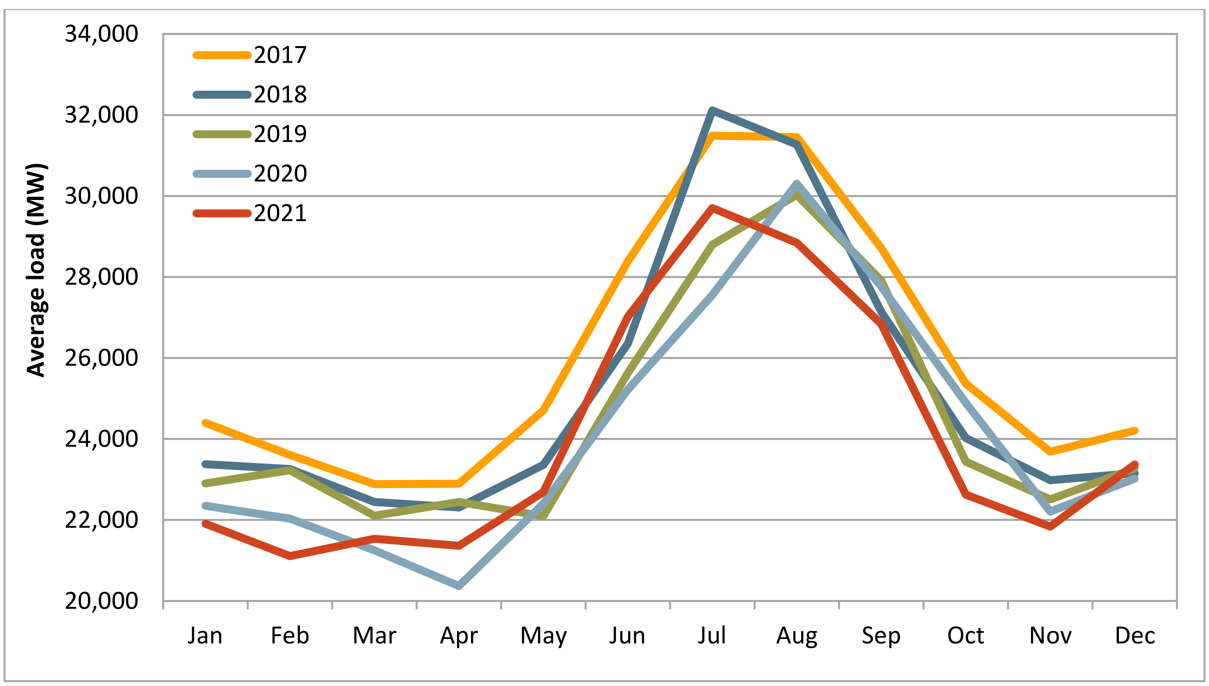


Figure 1.3 Average load by month (2017-2021)

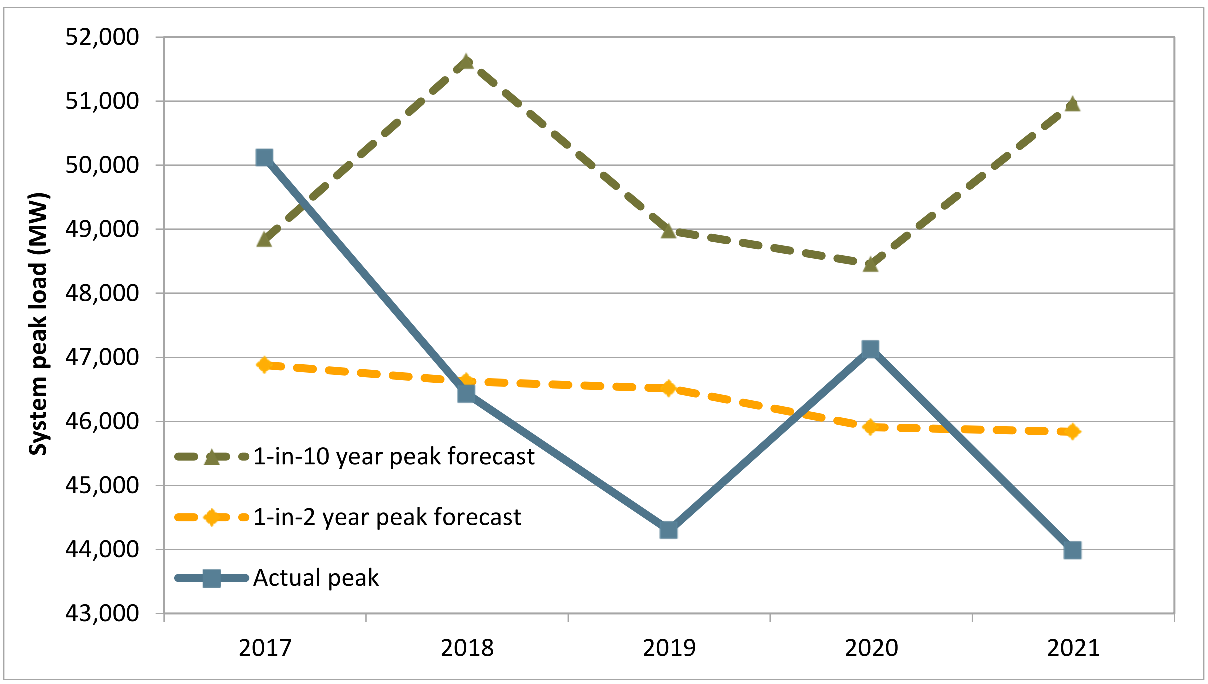


Peak load

Summer loads peaked at 43,982 MW on September 8, about 7 percent lower than the 2020 peak. Peak load in 2021 was lower than both the *1-in-2* and *1-in-10 year* forecast, and was also the lowest peak load for the California ISO since 2003.[47] System demand during the single highest load hour often varies substantially year-to-year based on the weather conditions. The potential for extreme heat-related peak loads creates a continued threat to operational reliability and drives many of the California ISO reliability planning requirements.

The peak load in 2021 was about 4 percent lower than the CAISO *1-in-2 year* load forecast (45,837 MW) and about 14 percent lower than the *1-in-10 year* forecast (50,968 MW) as shown in Figure 1.4. The California 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



1.1.2 Local transmission constrained areas

The California 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

47 California ISO Peak Load History, 1998 – 2021: https://www.caiso.com/documents/californiaisopeakloadhistory.pdf

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.[48] The local capacity requirement is defined as the resource capacity needed to serve load within a local capacity area reliably. Dependable generation is the net qualifying capacity of available resources within the locally constrained area.

Table 1.2 Load and supply within local capacity areas in 2021[49]

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	10,780	23%	7,418	6,353	86%
Greater Fresno	PG&E	3,189	7%	3,392	1,694	50%*
Sierra	PG&E	1,865	4%	2,108	1,821	86%*
North Coast/North Bay	PG&E	1,456	3%	842	842	100%*
Stockton	PG&E	1,113	2%	596	596	100%*
Kern	PG&E	1,285	3%	413	413	100%*
Humboldt	PG&E	153	0.3%	191	130	68%
LA Basin	SCE	18,930	40%	9,664	6,127	63%
Big Creek/Ventura	SCE	4,451	9%	5,128	2,296	45%
San Diego	SDG&E	4,523	9%	4,361	3,888	89%
Total		**47,745**		**34,113**	**24,160**	

*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.

Local capacity requirements increased to 24,160 MW for 2021 compared to 23,643 MW in 2020. Dependable generation and peak load decreased slightly overall in these areas. Table 1.2 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.[50] One or two entities own the bulk of generation in each of these areas. As a result, the potential for locational market power in these load pockets is significant. Of the local capacity areas, the Los Angeles Basin and the Greater Bay Area have the highest local capacity requirements, due in part to high *1-in-10 year* peak load forecasts. Requirements increased significantly in the Greater Bay Area (1,803 MW), although the peak load

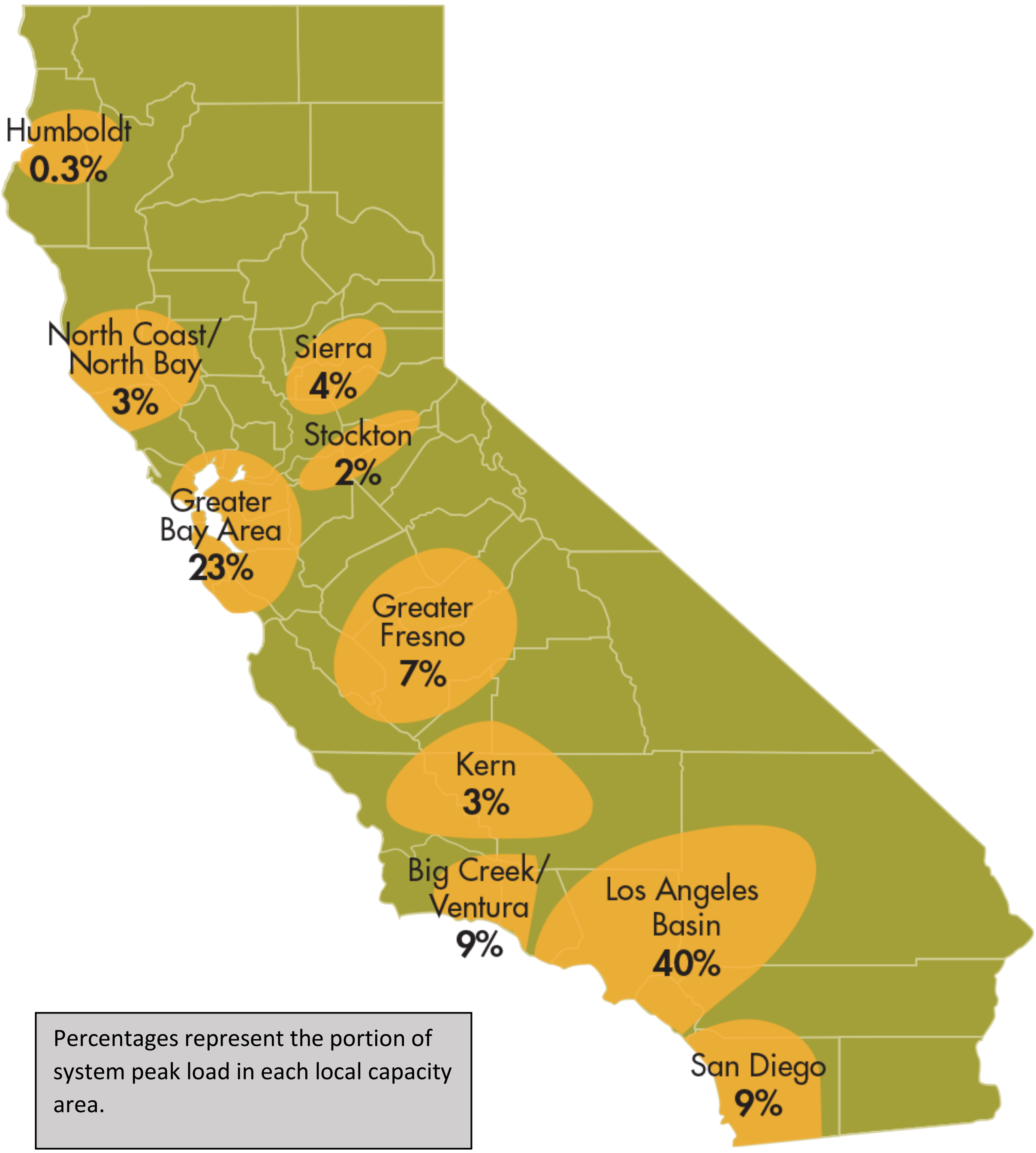
48 Note that the total local area peak load figure, as well as proportion of each local capacity area's load of the total, is illustrative. Each local area's load will peak at a different time from one another and from the system-coincident peak load.

49 California ISO, *2021 Local Capacity Technical Analysis*, May 1, 2020, p. 26, Table 3.1-1: http://www.caiso.com/Documents/Final2021LocalCapacityTechnicalReport.pdf

50 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.

projections remained similar. Conversely, requirements decreased in the LA Basin (1,237 MW) and Big Creek/Ventura (114 MW) areas, which correspond to the lower peak load projections in those areas.

Figure 1.5 Local capacity areas



1.2 Supply conditions

1.2.1 Generation mix

Natural gas and non-hydro renewable generation were the largest sources of energy in the CAISO energy mix in 2021, together comprising 66 percent of total system energy. Battery generation increased during peak net load hours as new battery resources came online. Hydroelectric generation and net imports decreased during all hours compared to 2020.

Monthly generation by fuel type

Figure 1.6 provides a profile of average generation by month and fuel type. Figure 1.7 illustrates the same data on a percentage basis. These figures show the following:

- Natural gas and non-hydro renewables were the largest sources of generation in 2021, together representing 66 percent of total generation in the CAISO.
- Natural gas generation accounted for 34 percent of total supply, an increase from 32 percent in 2020. This was driven primarily by reduced hydroelectric generation, which decreased to just 6 percent of supply.
- Import generation represented 17 percent of total supply, a decrease from 21 percent in 2020. On an average hourly basis, import generation was about 1,100 MW lower across all hours than 2020.
- Nuclear generation provided 10 percent of supply, roughly the same as previous years.

Figure 1.6 Average generation by month and fuel type in 2021

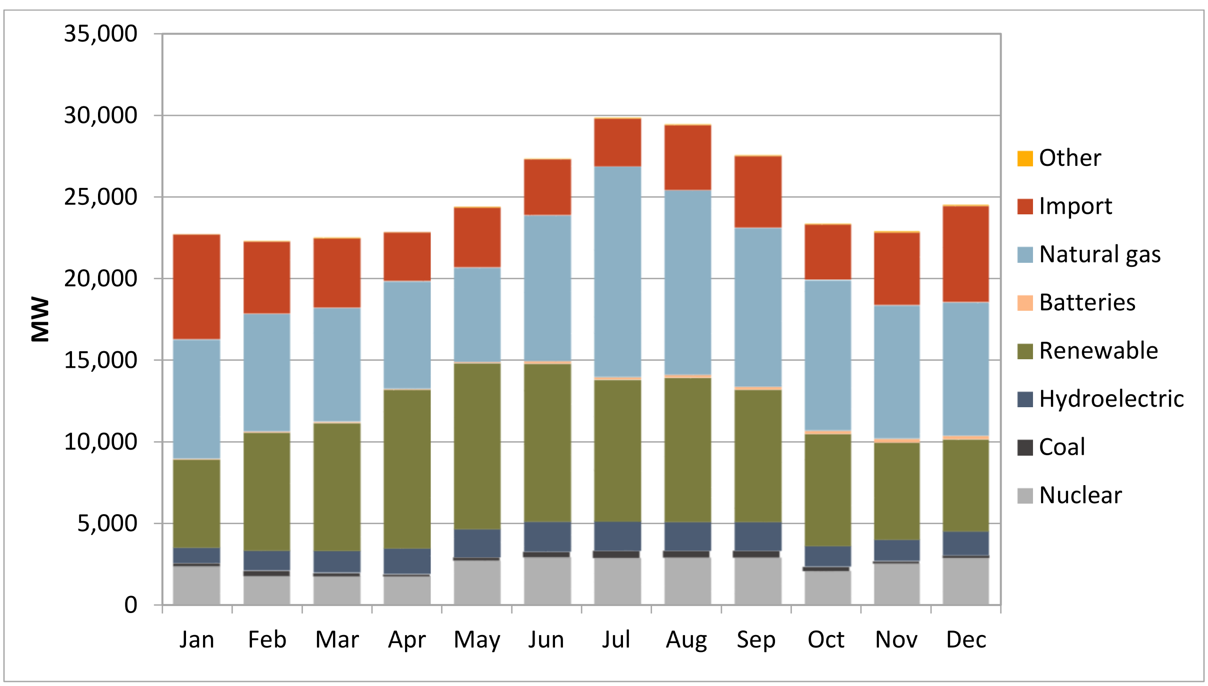
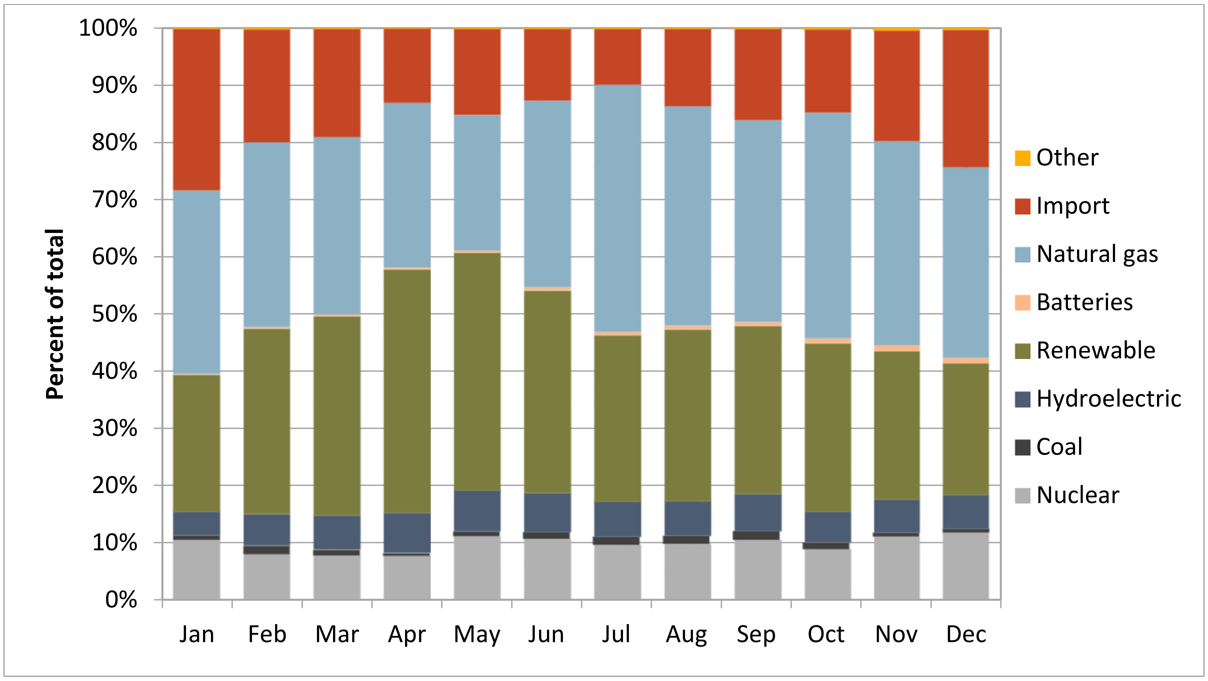


Figure 1.7 Average generation by month and fuel type in 2021 (percentage)



Generation by fuel type

Figure 1.8 shows average hourly generation by fuel type over the year.[51] Overall, for 2021, hour ending 19 averaged the highest amount of generation at about 29,450 MW, while hour ending 4 averaged the lowest at about 20,575 MW. Generation from nuclear, coal, biogas-biomass, and geothermal resources comprised about 4,200 MW of inflexible base generation, or about 50 MW more than 2020. Generation from battery storage resources averaged about 375 MW during the peak net load hours of 17-21.

Figure 1.9 shows the change in hourly generation by fuel type between 2020 and 2021. In the chart, positive values represent increased generation over the course of the year compared to 2020, while negative values represent a decrease in generation.

Overall, the net change shows that there was an increase in average hourly generation in the morning hours and a decrease during evening peak net load hours. During all hours of the day, hydroelectric generation and imports were lower than 2020. These reductions were matched by increased natural gas generation in off-peak hours and renewable generation in the middle of the day. Generation from battery storage resources increased during the peak net load hours of 17-21.

51 Batteries and Coal were previously included in the Other category.

Figure 1.8 Average hourly generation by fuel type (2021)

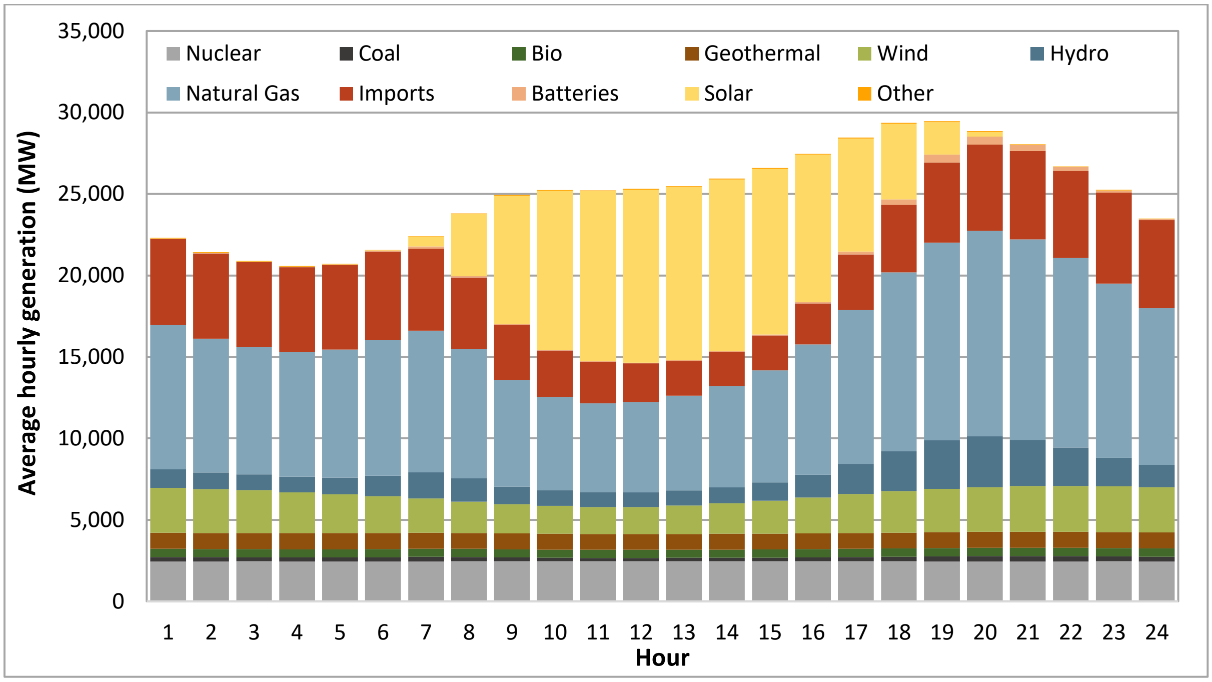
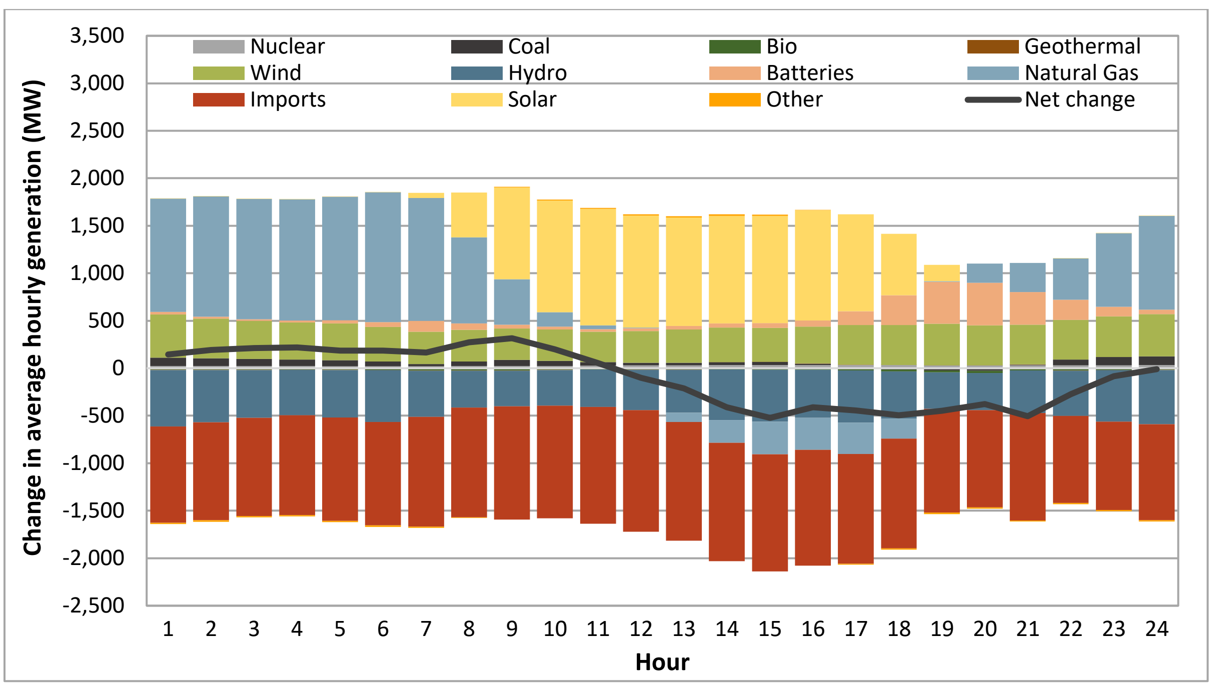


Figure 1.9 Change in average hourly generation by fuel type (2020 to 2021)



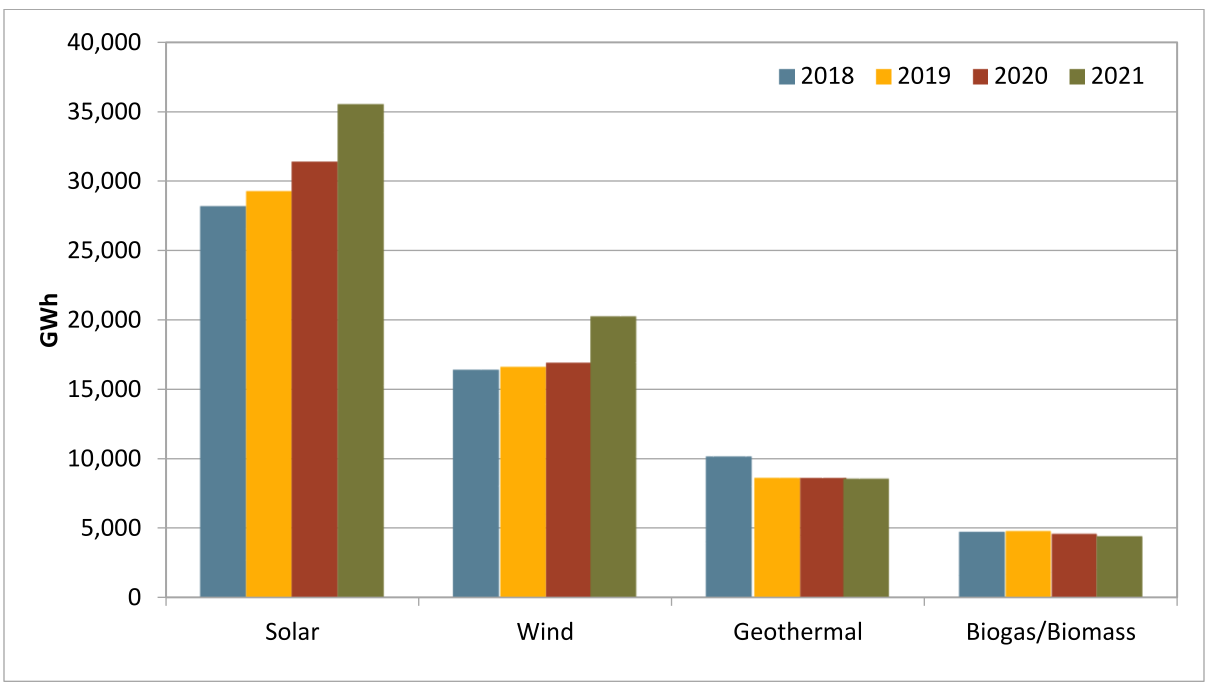
1.2.2 Renewable generation

In 2021, about 31 percent of CAISO generation was from non-hydro renewable resources and about 6 percent was from hydroelectric generation. This section provides additional detail about trends in renewable generation and the factors influencing renewable resource availability.

Figure 1.10 provides a detailed breakdown of non-hydro renewable generation including imports that are specifically identified as wind and solar resources.[52] Figure 1.10 also illustrates:

- Overall solar generation increased by about 13 percent compared to 2020 and accounted for 16 percent of total supply. The increase was primarily driven by the addition of new solar resources. The rate of increase in generation from solar rose to 13 percent from 7 percent in 2020, which marks a deviation from the trend as the rate of increase had begun to slow in recent years.
- Generation from wind resources increased by 20 percent and contributed to 9 percent of total system energy.
- The overall output from geothermal generation decreased less than 1 percent compared to 2020, and continued to provide 4 percent of system energy.
- Biogas, biomass, and waste generation decreased about 4 percent. Together they accounted for 2 percent of system energy.

Figure 1.10 Total renewable generation by type (2018-2021)

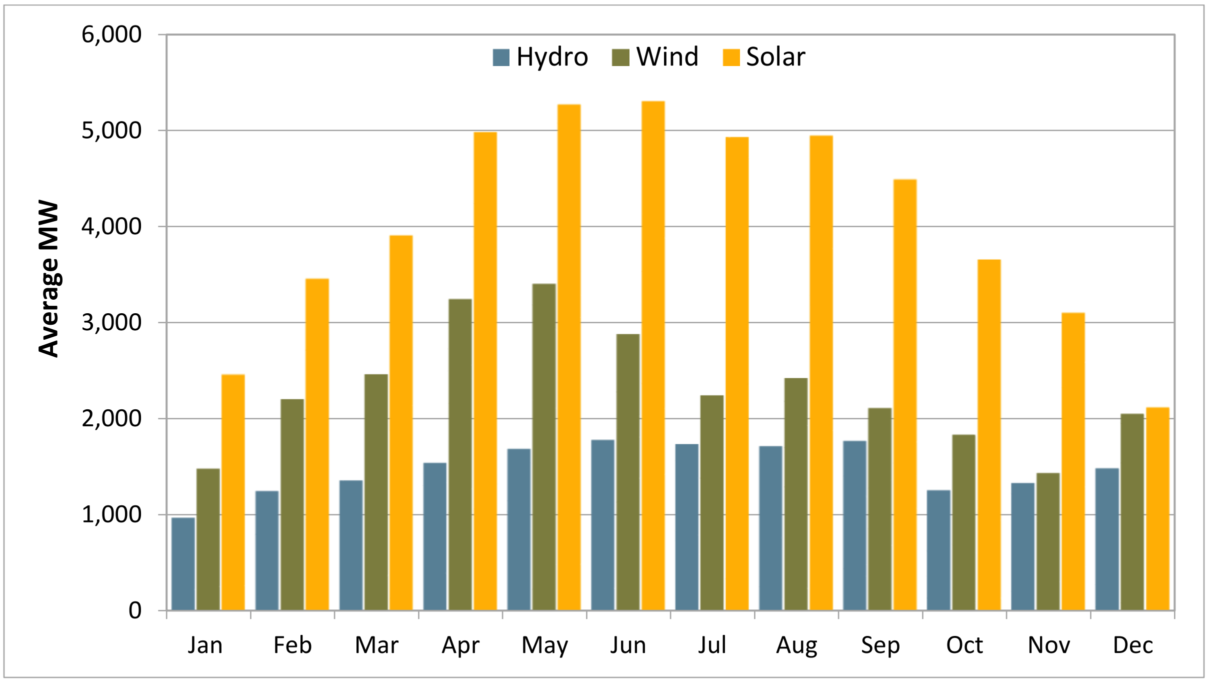


52 In addition to values reported here, renewable and hydro resource generators provide energy through imports and behind-the-meter generation. These values are excluded due to lack of input data.

Figure 1.11 compares average monthly generation of hydro, wind, and solar resources. Due to low snowpack levels, the amount of energy produced by hydroelectric resources was below that of wind resources.

In 2021, average hourly solar generation peaked at 13,452 MW on May 27 during hour ending 12, wind generation peaked in May, and hydroelectric resources peaked in June. Non-hydro renewable generation made up the greatest portion of system generation during April, when it accounted for 43 percent of total generation.

Figure 1.11 Monthly comparison of hydro, wind, and solar generation (2021)



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 California ISO. Curtailments fall into six categories:

- **Economic downward dispatch**, in which an economically bid resource is dispatched down and the market price falls below or within one dollar of a resource's bid or the resource's upper limit is binding;[53]
- **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;
- **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 California ISO was solar resources, rather than wind, because solar resources typically bid more economic downward capacity than wind resources.

In the California ISO, total curtailment was 6 percent lower than 2020. Economic downward dispatch accounted for about 1,524 GWh (96 percent) of curtailment during the year, while self-scheduled curtailment accounted for about 34 GWh (2 percent). Exceptional dispatch curtailments for both self-scheduled and economic bid resources fell sharply and were about 2 GWh, less than 1 percent. The roughly 35 GWh (2 percent) of remaining curtailment came from "other" economic and self-scheduled curtailment.

Figure 1.13 shows downward dispatch of WEIM wind and solar resources. As defined above, curtailments fall into four categories: economic downward dispatch, other economic downward dispatch, self-schedule curtailment, and other self-schedule curtailment. In the WEIM, total curtailment of wind and solar resources was 70 percent higher than 2020. Economic downward dispatch in the WEIM during 2021 accounted for roughly 134 GWh (95 percent) of total curtailment, and saw a large uptick in the fourth quarter. Over 75 percent of the WEIM generation curtailed down in the fourth quarter came from resources that were impacted by congestion on the Wyoming Export constraint.[54]

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

54 The Wyoming Export constraint (*Total_Wyoming_Export*) was congested during 59.1 percent of intervals during the fourth quarter of 2021.

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

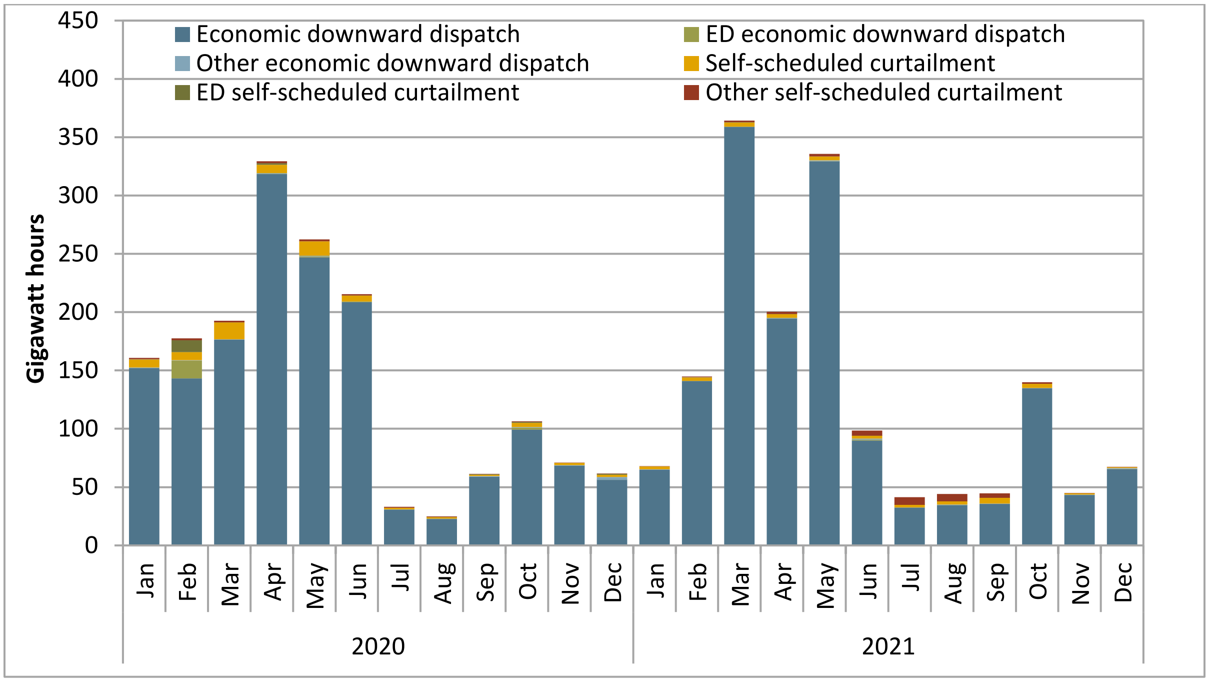
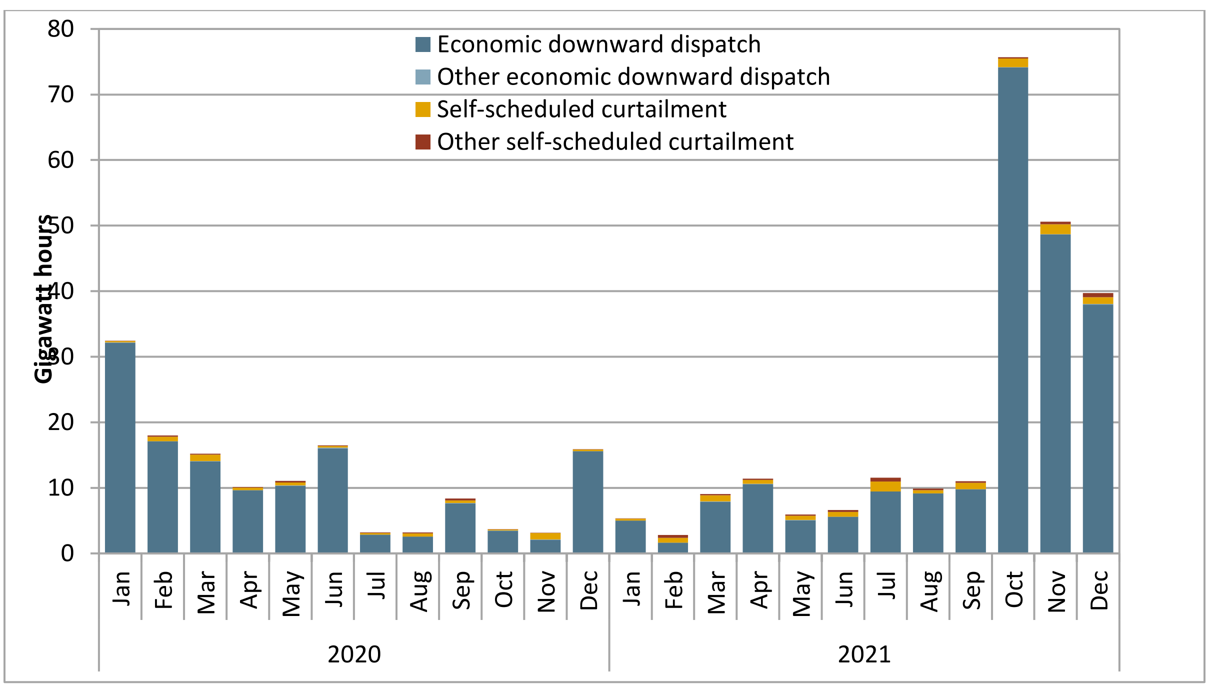


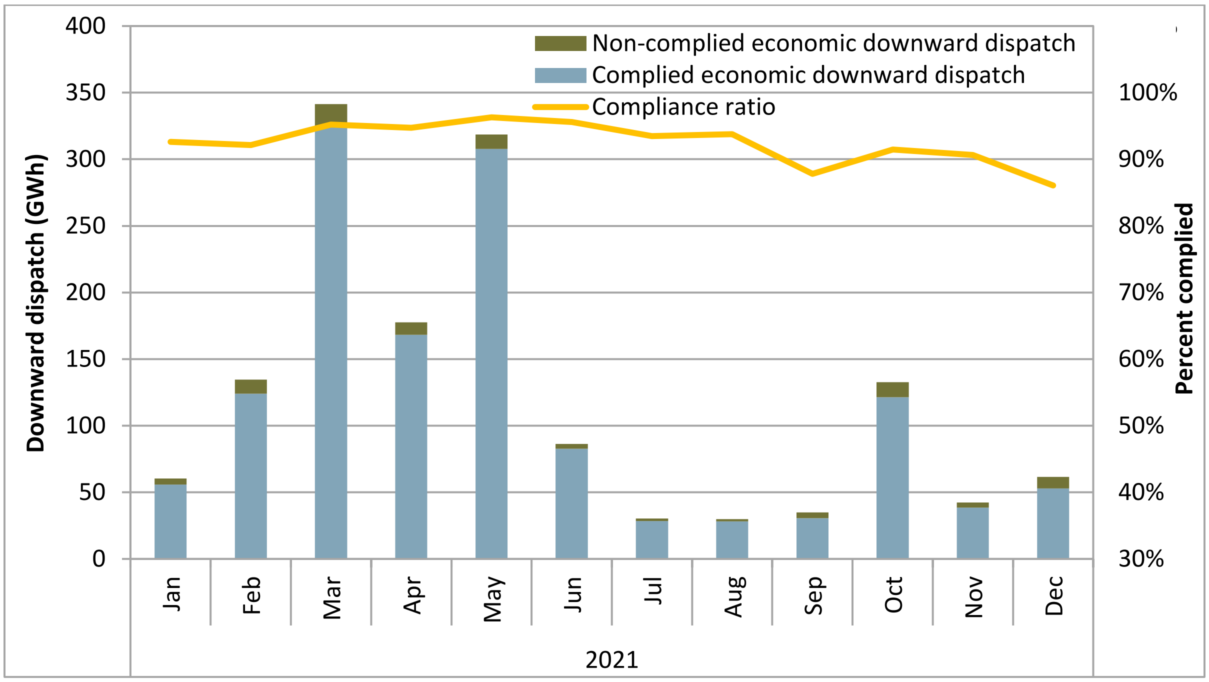
Figure 1.13 Reduction of wind and solar generation by month (WEIM)



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 output. Figure 1.14 and Figure 1.15 show monthly solar and wind compliance with economic downward dispatch instructions during the year.[55] 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.

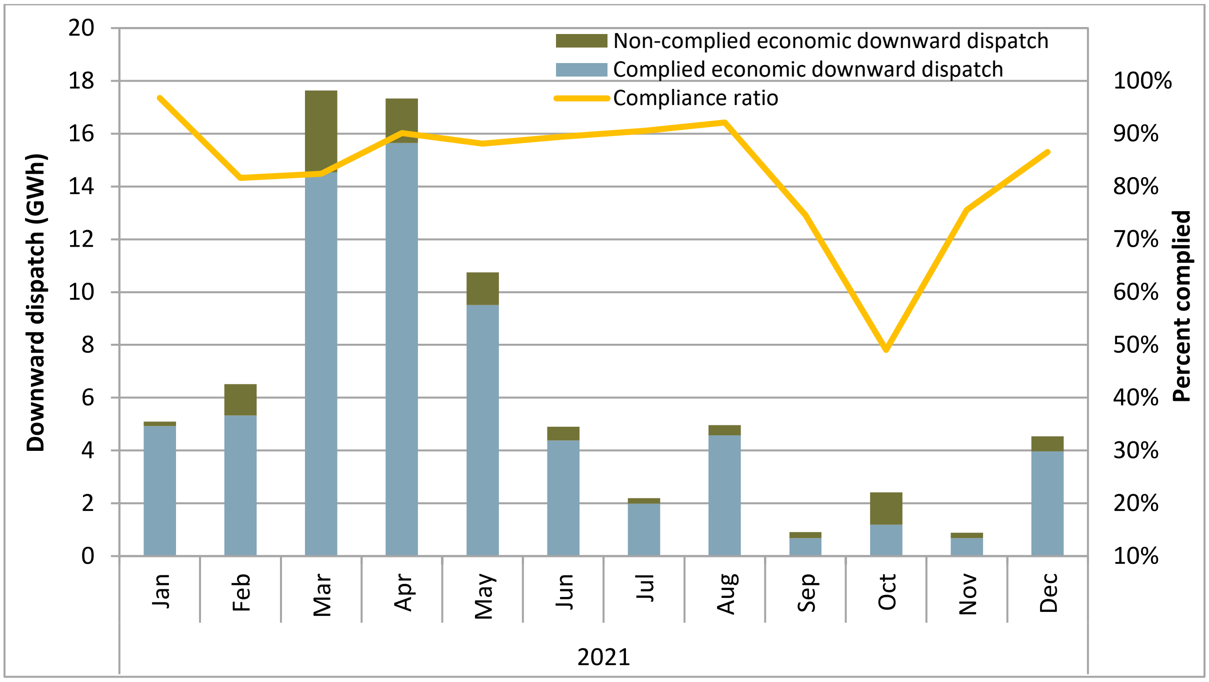
The quantity and performance of solar and wind resources that complied with economic downward dispatch decreased over the year. Solar resources were about 94 percent compliant, while wind resources were 86 percent compliant with downward dispatch instructions. Under market rules, all market participants and resources are expected to follow dispatch instructions.

Figure 1.14 Compliance with dispatch instructions – solar generation



55 This analysis includes variable energy resources in the CAISO balancing area only.

Figure 1.15 Compliance with dispatch instructions – wind generation



Hydroelectric supplies

Total hydroelectric production in 2021 decreased 26 percent from 2020.[56] Statewide snowpack, as measured on April 1, 2021, was 62 percent of the long-term average.[57]

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. Almost all hydroelectric resources in the California ISO area are owned by CPUC-jurisdictional investor-owned utilities.

Figure 1.17 compares monthly hydroelectric output from resources within the California ISO system for each month during the last three years and 2015. The hydroelectric generation pattern in 2021 is more similar to 2015 than recent years. Hydro generation followed a seasonal pattern, but remained relatively flat over the year. On average, monthly generation in 2021 was about 26 percent lower than in 2020, and was the third lowest year since 2011. As drought conditions persist in California, hydroelectric generation will likely continue to decrease.

56 Annual hydroelectric production includes all tie generators.

57 For snowpack information, please see: California Department of Water Resources, *California Data Exchange Center for Snow*, Snow Sensor Information/Course Measurements: https://cdec.water.ca.gov/cgi-progs/prevsnow/COURSES

Figure 1.16 Annual hydroelectric production (2011-2021)

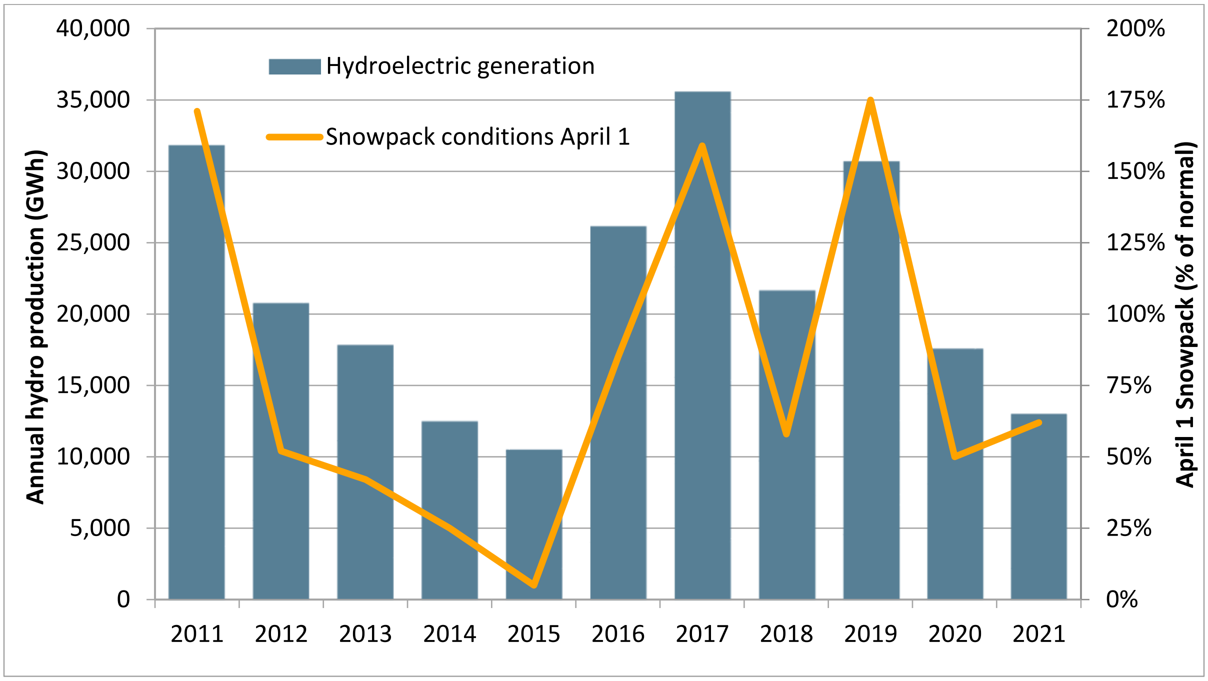
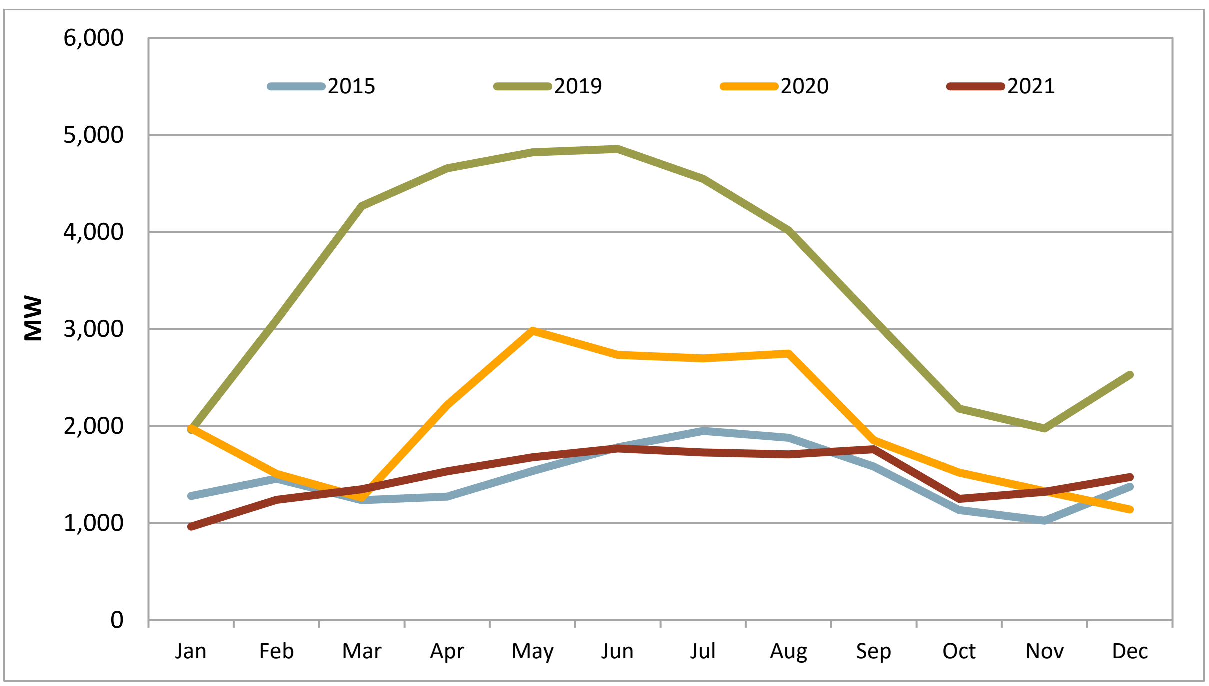


Figure 1.17 Average hydroelectric production by month (2015-2021)



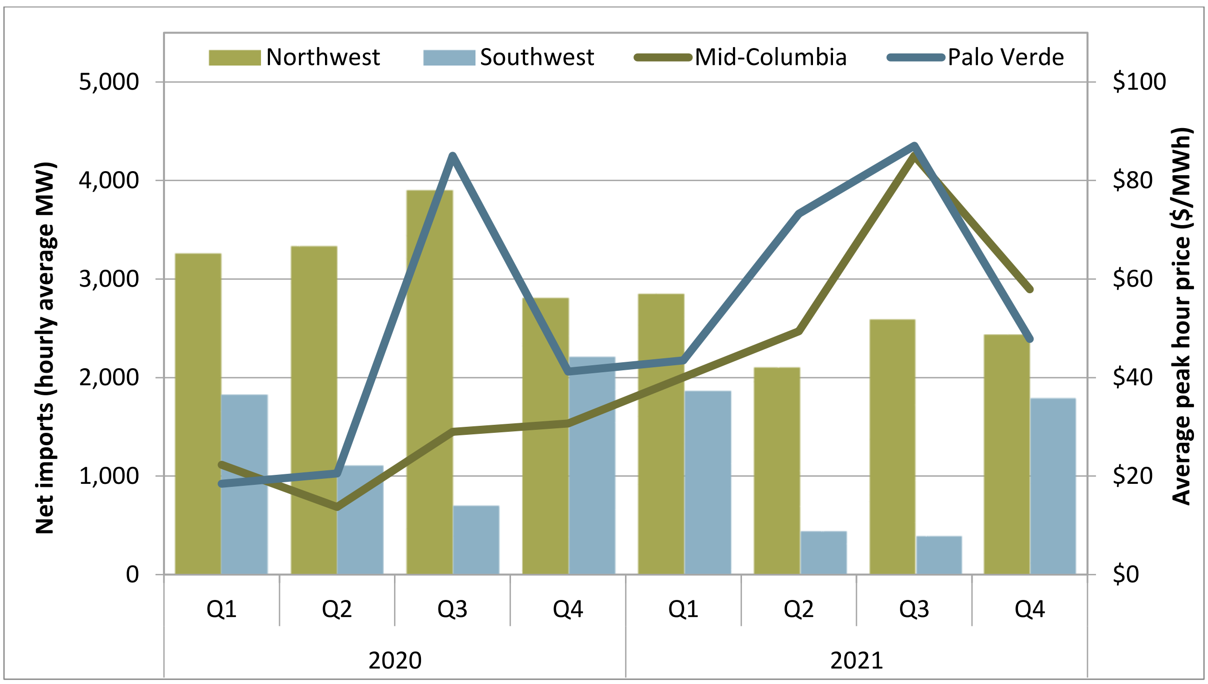
1.2.3 Net imports

Peak hours and average prices

Total generation from net imports in 2021 decreased compared to 2020.[58] As shown in Figure 1.18, net imports from sources in the Northwest decreased by 25 percent, while net imports from the Southwest decreased by about 23 percent.

Figure 1.18 also shows the quarterly average bilateral prices at Mid-Columbia (Mid-C) and Palo Verde. In the second quarter of 2021, prices at Palo Verde were substantially higher than Mid-Columbia, clearing above the $1,000/MWh WECC soft offer cap during a regional heat wave in June.[59] Bilateral prices in other quarters of the year were similar. Net imports from the Northwest decreased in all quarters over the previous year, while net imports from the Southwest were lower in all but the first quarter.

Figure 1.18 Net imports and average day-ahead price (peak hours, 2020-2021)



Net interchange – CAISO imports and exports with WEIM transfers

The Western Energy Imbalance Market (WEIM) provides additional interchange between the CAISO and other balancing authority areas in both the import and export directions. The net quantity of imports *to* and exports *from* the CAISO, as well as WEIM transfers, is the CAISO system net interchange.

[58] Net imports are equal to scheduled imports minus scheduled exports in any period. These net imports exclude any transfers associated with the Western Energy Imbalance Market.

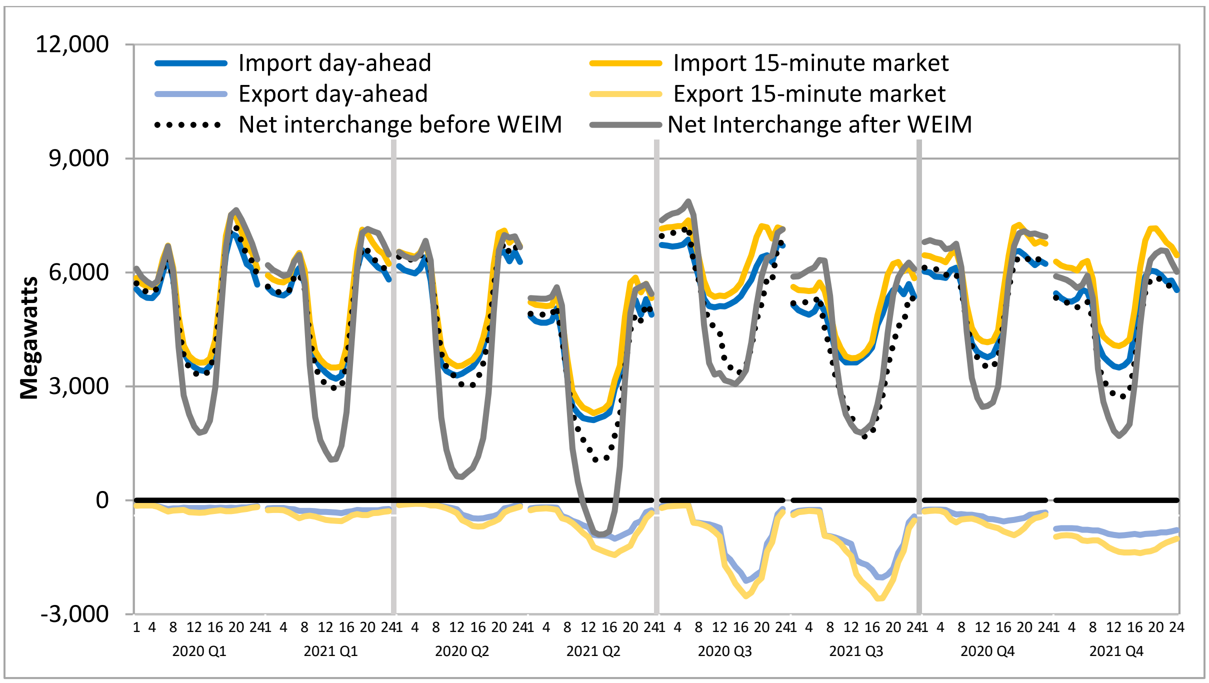
[59] Further coverage of bilateral prices relative to prices within the California ISO balancing area is available in Section 2.3.1 of this report.

As shown in Figure 1.19, average hourly net interchange continued to follow CAISO net load and average prices, falling in the mid-day hours, as solar generation peaks and rising in the peak net load hours. Cleared imports (shown in dark blue and dark yellow) peaked at lower volumes but a similar hour as in 2020. The observation of higher volumes just before the morning and after the evening peak periods continued.

Exports increased in each quarter (shown as negative numbers below the horizontal axis in pale blue and yellow) and were the highest in the third quarter, peaking at about 2,600 MW in hour ending 17.

Average net interchange fell in 2021, on average, in each quarter. The average net interchange, excluding WEIM transfers (shown in dashes), is based on meter data, and averaged by hour and quarter. The solid grey line adds incremental WEIM interchange; the lowest point occurred in the second quarter at about negative 900 MW in hour ending 14.

Figure 1.19 Average hourly net interchange by quarter



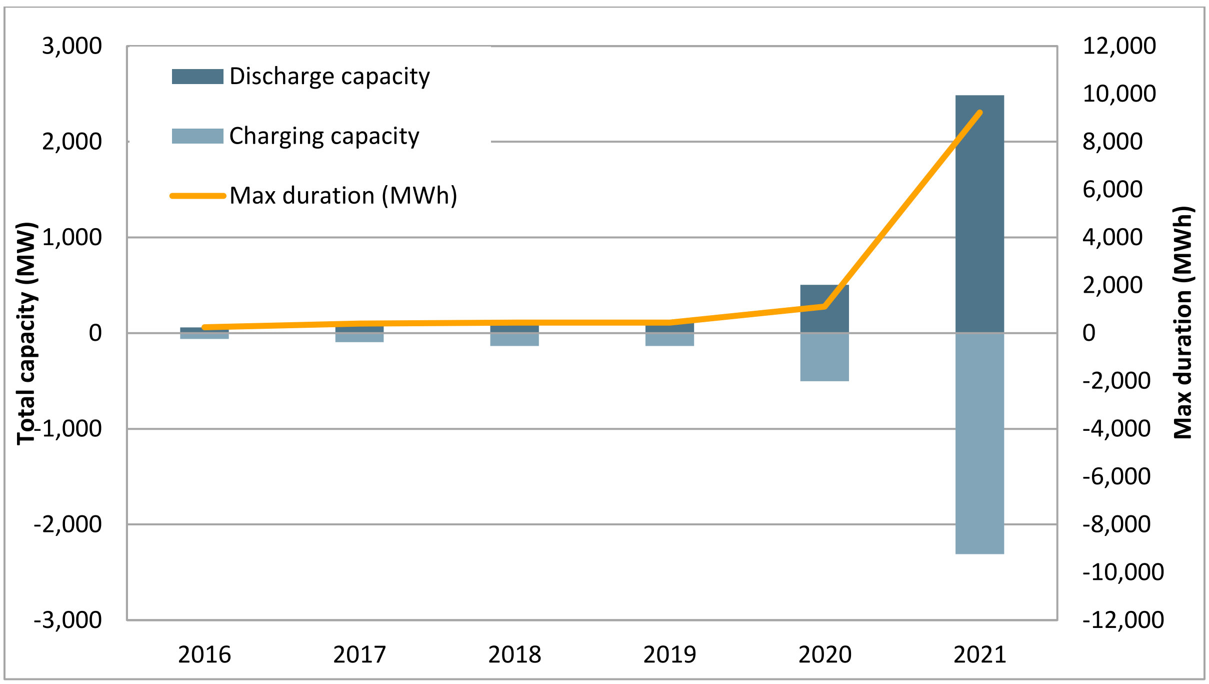
1.2.4 Energy storage and distributed energy resources

Batteries

The amount of battery storage capacity participating in the California ISO balancing area increased significantly in 2021. With the increase in capacity, batteries shifted to provide more energy than ancillary services when compared to 2020. Battery resources currently participate in the market through the non-generator resource (NGR) model, or as demand response resources.[60]

Figure 1.20 shows the total capacity of standalone battery storage participating as non-generator resources, both represented in terms of maximum output (megawatt) and maximum duration (megawatt-hour).[61] Since 2016, total battery capacity participating in the CAISO balancing area has increased significantly and totaled about 2,500 MW of discharge capacity by the end of 2021.

Figure 1.20 Battery capacity (2016-2021)



In 2021, about 1,413 MW of standalone storage was shown as resource adequacy capacity in September 2021, compared to 149 MW in September 2020.[62] Battery storage resources are eligible to receive bid cost recovery or make-whole payments. In 2021, these payments totaled about $4 million.

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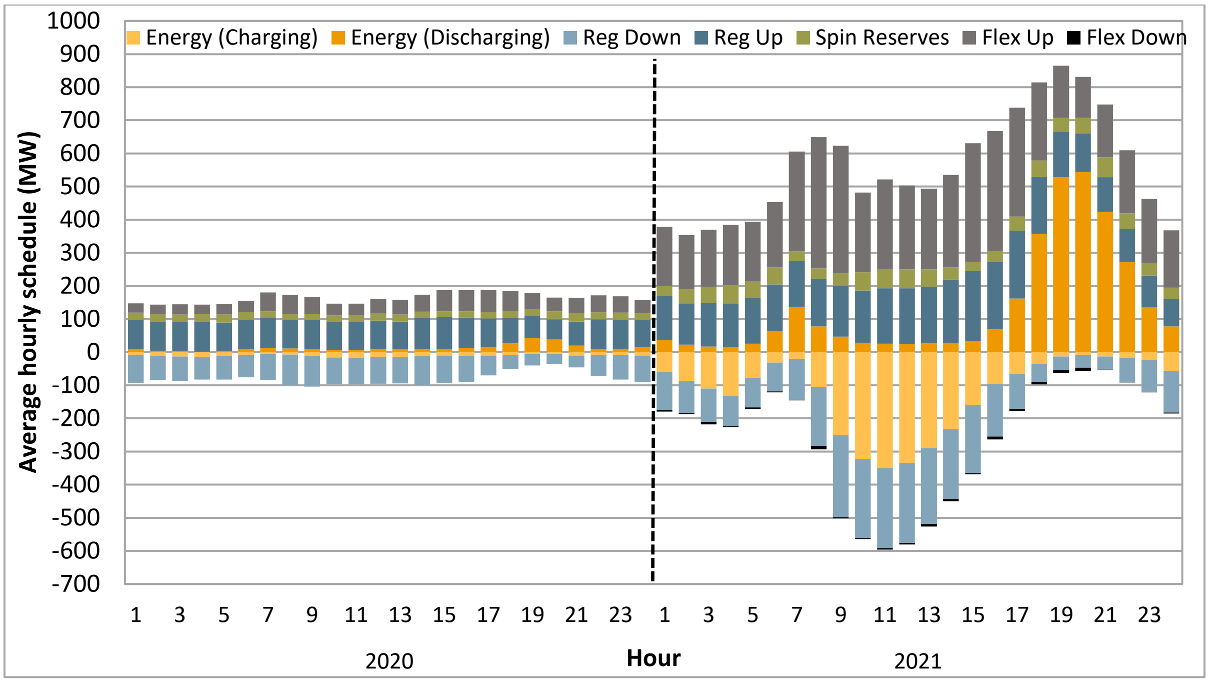
60 The California ISO is proposing a new model, the energy storage resource (ESR) model. California ISO, *Energy Storage Enhancements Revised Straw Proposal*, March 9, 2022: http://www.caiso.com/InitiativeDocuments/RevisedStrawProposal-EnergyStorageEnhancements.pdf

61 These values may differ from other battery capacity measures. This metric only includes the capacity of participating batteries, defined here as being scheduled at least once in the respective year.

62 Resource adequacy capacity is usually offered at $0/MWh in the residual unit commitment (RUC) process; however, none of the battery capacity is currently considered in RUC.

Figure 1.21 shows average hourly real-time (15-minute market) schedules of standalone battery resources. Battery schedules across all products increased dramatically. The average schedule for energy was ten times higher in 2021, compared to 2020. Ancillary services awards were twice as high, and flexible ramping up capacity provided by batteries was five times higher. Battery discharge energy remains the highest during evening ramping hours, averaging 544 MW in hour ending 20. Batteries are often charging during off-peak and mid-day hours when prices are lowest.

Figure 1.21 Average hourly battery schedules (2020-2021)



Historically, batteries have been scheduled primarily to provide ancillary services. However, in 2021 there was a significant increase in energy provided by battery resources, as seen in Figure 1.21. While the amount of ancillary service requirements met by battery resources increased, the increase in ancillary service awards for batteries is not proportional to the increase in battery capacity.[63]

Figure 1.22 shows the percent of battery storage capacity (total charge and discharge range) available to the real-time market that was scheduled for ancillary services (regulation up, regulation down, and spinning reserve) by quarter. Ancillary service awards, as a percent of battery capacity offered, have decreased since 2020, and significantly decreased to about 10 percent in the third and fourth quarter of 2021.

This trend is attributed in part to new storage resources coming online in summer 2021, which were not yet certified to provide ancillary services, and thus could only provide energy. However, the battery capacity eligible to provide regulation up and down also began to offer these services at higher prices, resulting in a lower percentage of total battery capacity clearing to provide regulation.

63 Section 5.1 includes more information regarding ancillary service procurement.

Figure 1.22 Percent of battery capacity scheduled for ancillary services

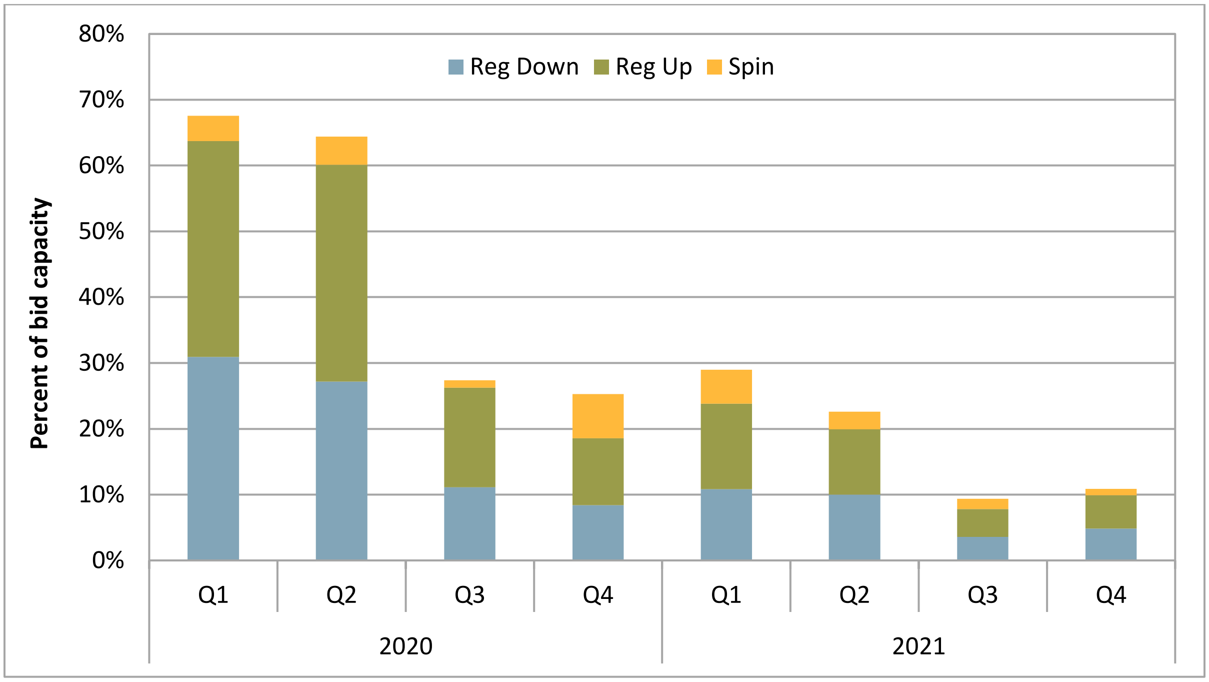


Figure 1.23 shows the amount of day-ahead regulation requirements (expanded system requirements) met by battery resources and the total battery capacity offered and cleared to provide regulation. In addition, it depicts the average bid prices of batteries providing regulation as well as the average regulation prices weighted by volume of regulation bids at each battery resource node. This weighting reflects the average clearing price of regulation for battery resources specifically.

While regulation capacity schedules on battery resources increased, the amount of regulation scheduled did not increase proportionally to the increase in battery capacity. From 2020 to 2021, the average percent of regulation that cleared decreased from about 37 percent to 23 percent, as shown in Figure 1.23. This is due in part to an increase in regulation bid prices from battery resources, which averaged higher than the clearing price.

Figure 1.23 Day-ahead regulation requirements met by battery storage

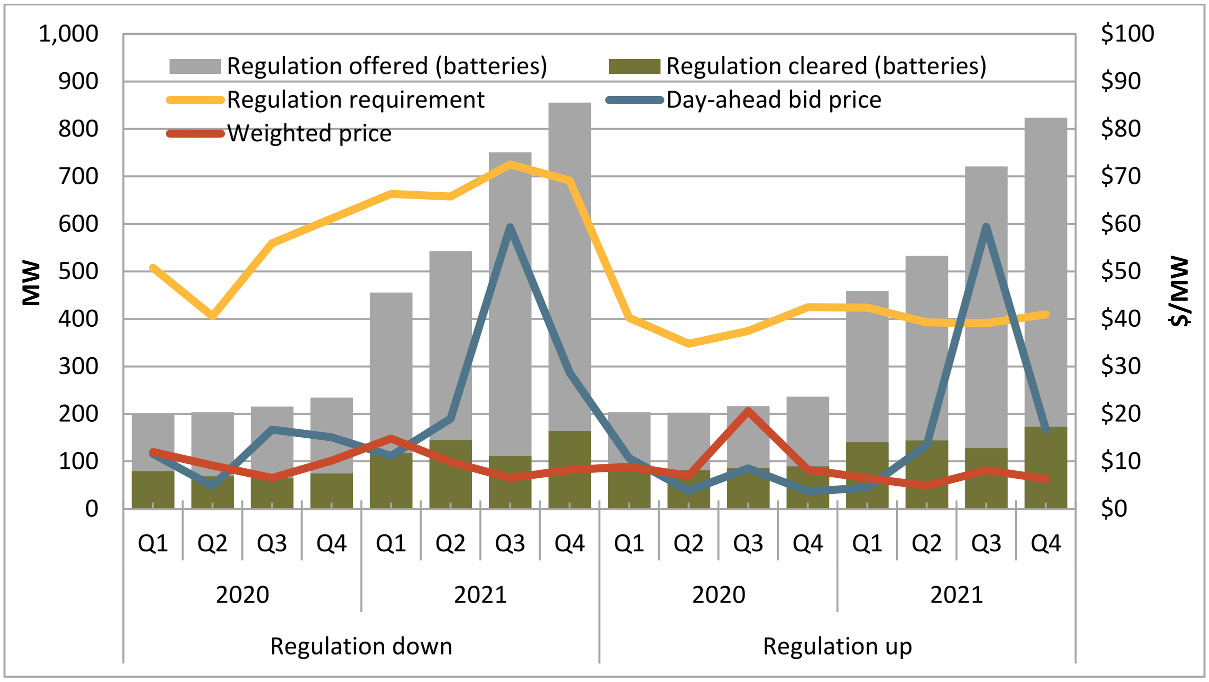


Figure 1.24 and Figure 1.25 show average energy bids of battery resources compared to average nodal prices by quarter in both the day-ahead and real-time market, respectively.[64] Under the non-generator resource model, batteries submit a single energy bid curve, which reflects both willingness to charge and discharge. Compared to 2020, average discharge bid prices increased while average charge bids decreased. This implies an increase in the average price spread (the difference between willingness to charge and discharge).

As seen in Figure 1.24, the price spread of average energy bids of batteries increased substantially in the day-ahead market. On average, charge prices were $45 lower and discharge prices were $138 higher than the nodal price, averaging a price spread of about $190. Average charge bids were closer to nodal prices during the middle of the day. The average bid to discharge in the day-ahead market was consistently higher than the clearing price throughout 2021.

Figure 1.25 shows average real-time bids of battery resources for the portion of a resource 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). The average price spread in battery bids in the real-time market increased to $120, but was lower than the $190 price spread in the day-ahead market. Comparing bid behavior across the day-ahead and real-time markets suggests that bids from batteries are more competitive in the real-time market.

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

Figure 1.24 Average day-ahead battery bids and nodal prices (Q3 2020 – 2021)

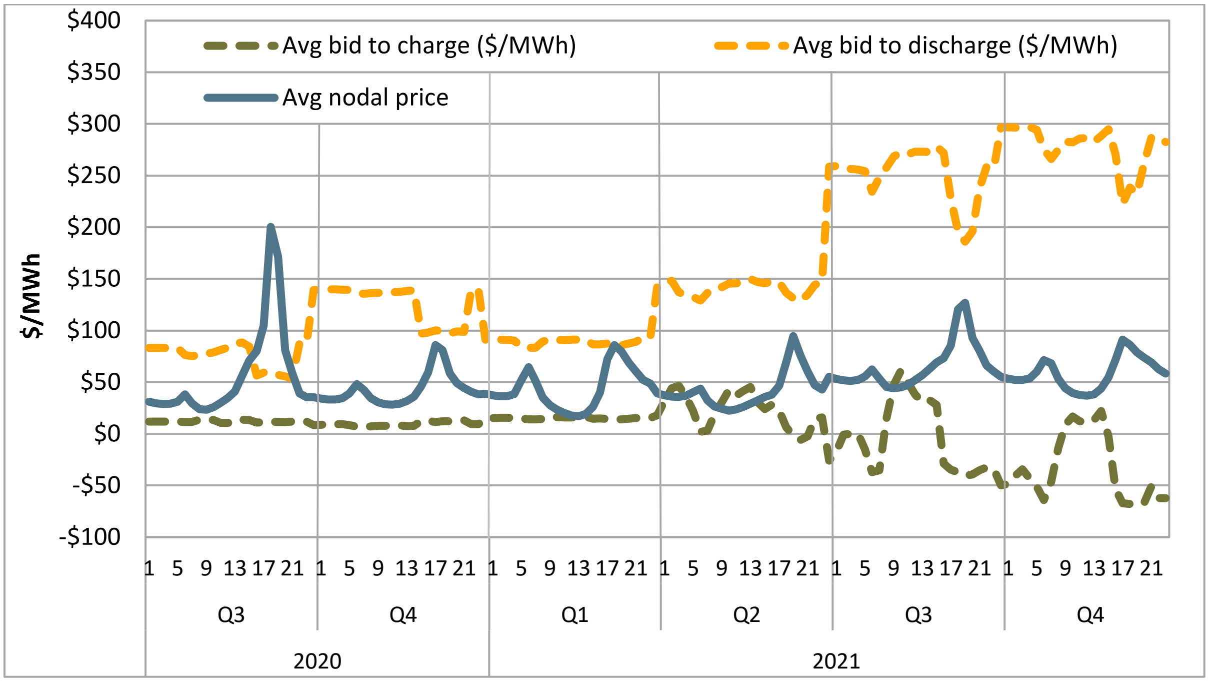
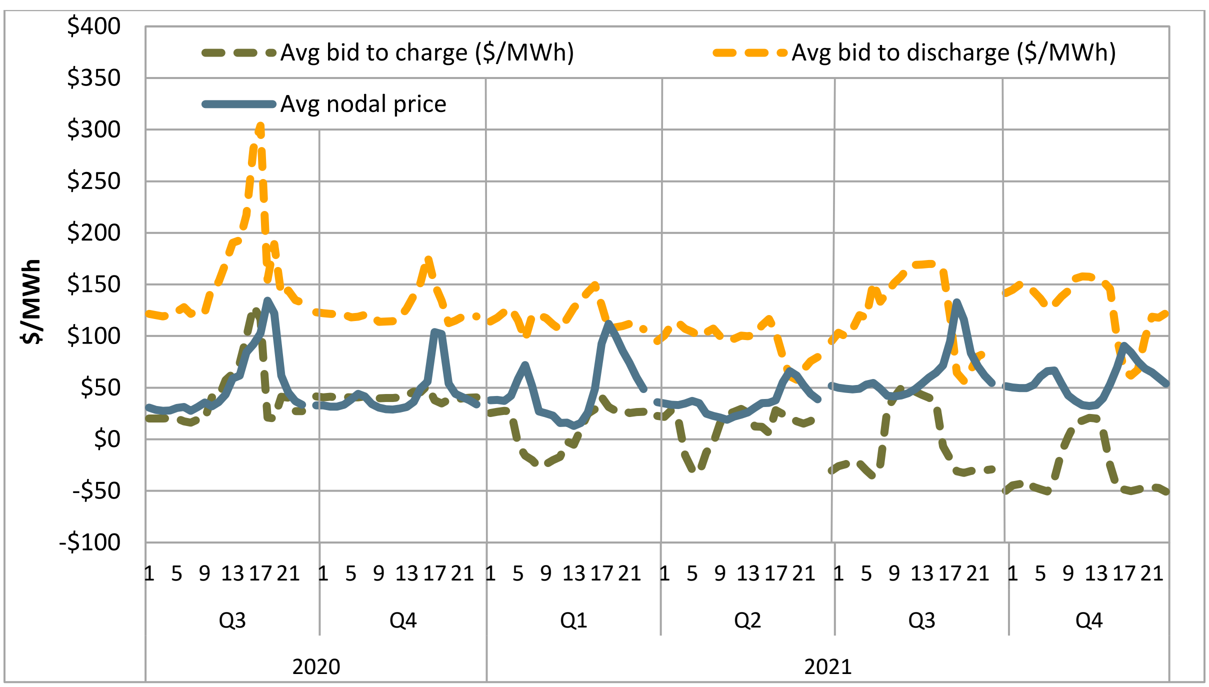


Figure 1.25 Average real-time battery bids and nodal prices (Q3 2020 – 2021)



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.

Utility demand response increased around 20 percent from 2020. Self-reported performance of utility demand response exceeded that of third-party demand response resources. Self-reported performance averaged 88 percent for utility proxy demand response, 65 percent for utility reliability demand response, and 53 percent for third-party proxy demand response.

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 California 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 2021, the California ISO declared Flex Alerts on several days between June and September in response to reliability concerns related to high temperatures and high system demand in California.[65]

Figure 1.26 shows the total third-party demand response resource adequacy capacity shown on monthly supply plans in 2020 and 2021.[66] Third-party demand response participating in the California ISO market has increased significantly since 2016, averaging about 187 MW across 2021.

Some demand response resources shown on resource adequacy supply plans continued to be sized less than 1 MW in 2021, which exempts these resources from the California ISO resource adequacy availability incentive mechanism (RAAIM). In the summer months, about 41 percent of demand response resources shown on resource adequacy supply plans were sized less than 1 MW, a slight decrease from 47 percent in 2020. Additionally, about 63 percent of this capacity qualified as long-start in summer 2021 compared to about 70 percent in 2020. 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.

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65 Flex Alerts were issued on June 17-18, July 9-10, July 12, July 28, and September 8-9.

66 Note that third-party demand response was no longer able to supply RDRR capacity after a decision by the CPUC. CPUC Docket No. A.17-01-018, *Decision Addressing Auction Mechanism, Baselines, and Auto Demand Response for Battery Storage (D.19-07-009)*, July 11, 2019, pp. 45-46: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M309/K713/309713644.PDF

Figure 1.26 Third-party demand response shown on monthly resource adequacy supply plans

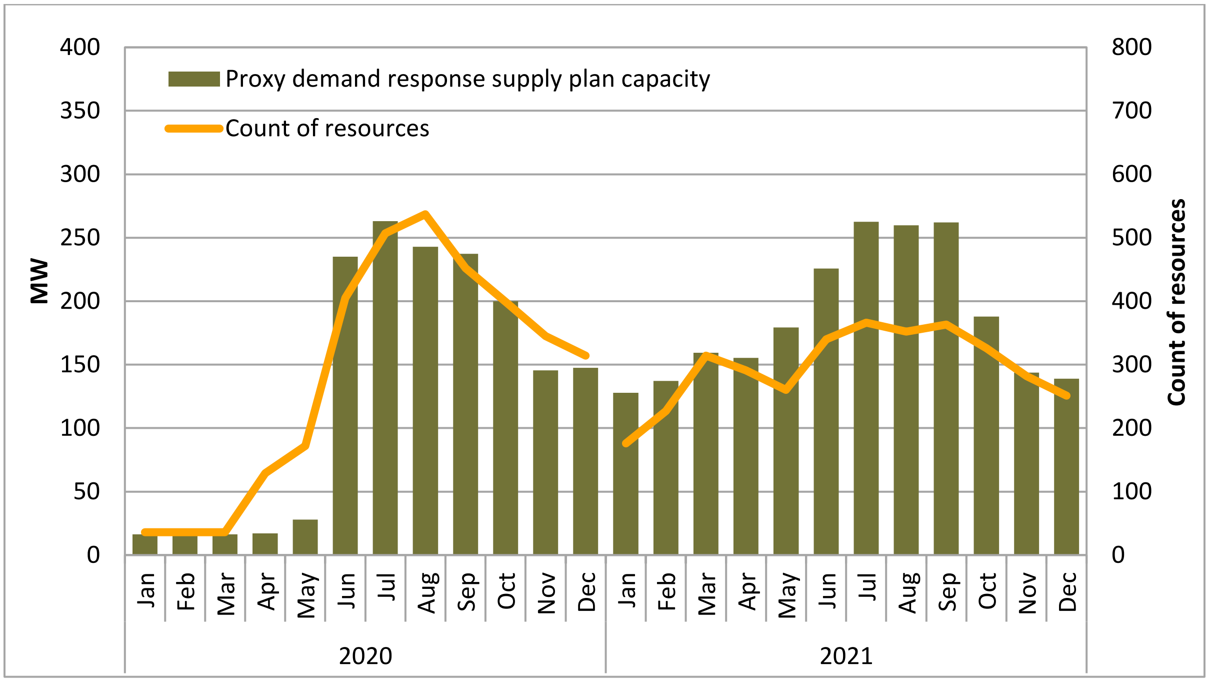


Figure 1.27 CPUC-jurisdictional utility demand response resource adequacy credits

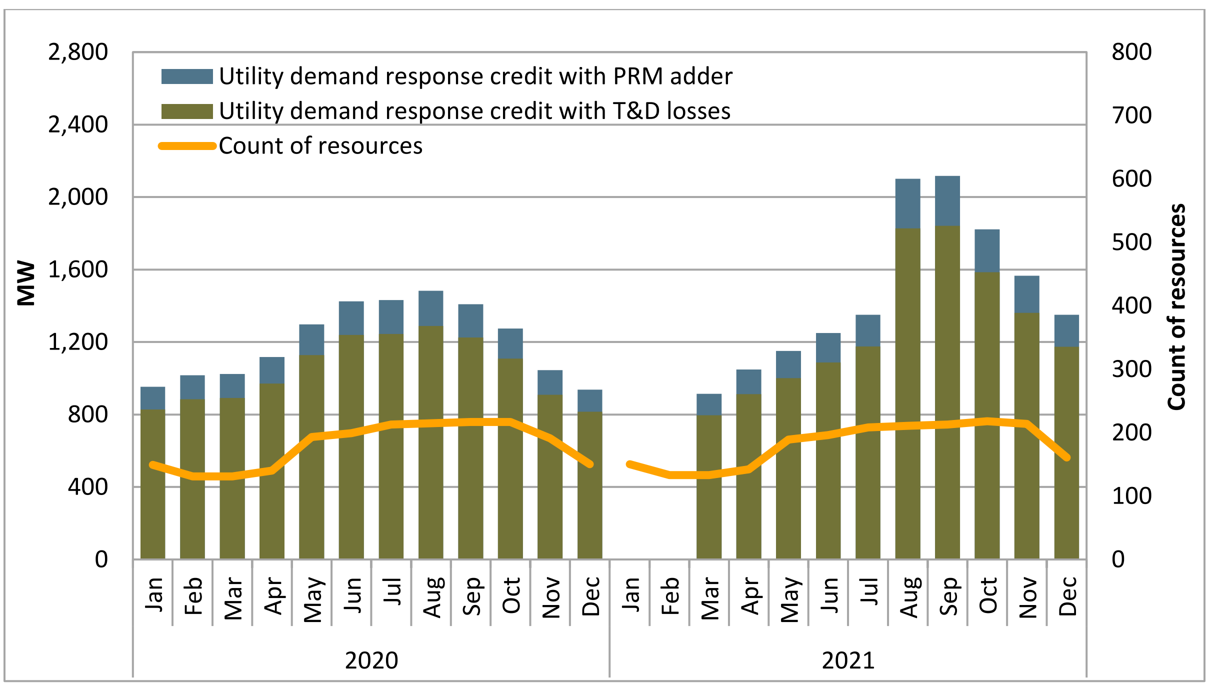
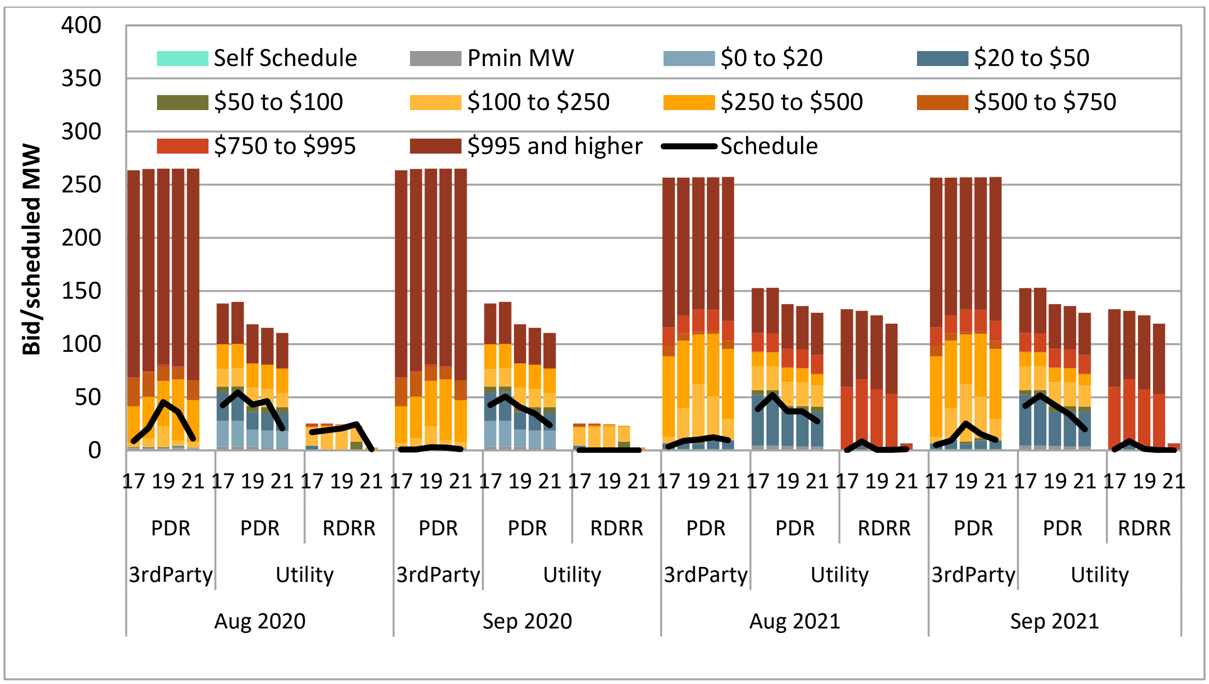


Figure 1.27 shows the total demand response resource adequacy capacity (proxy demand response and reliability demand response resources) associated with CPUC-jurisdictional utility demand response

programs.[67] 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 California ISO must-offer obligations or resource adequacy availability incentive mechanism.

Figure 1.28 shows the day-ahead bids and schedules of both utility and third-party demand response resource adequacy resources in peak net load hours (not capped at individual resources' resource adequacy values) for both August and September of 2020 and 2021. The figure also reflects bids in the California ISO availability assessment hours (between 4-9 p.m. 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 1.28 Demand response resource adequacy day-ahead bids August and September



The quantity of third-party demand response that bid into the day-ahead market remained about the same, although, in 2021, about 50 percent was offered at or near the $1,000/MWh bid cap, compared to 76 percent in 2020. While there was a higher amount of competitive bidding in the market, there was not a substantial increase in the amount of demand response scheduled. The quantity bid in from utility

67 There were no demand response (or other local regulatory authority) credits for January and February 2021 due to a business practice manual change that eventually was withdrawn by the California ISO.
California ISO, *Brief – PRR 1280 Appeal,* August 27, 2020
http://www.caiso.com/Documents/ISOAnsweringBrief-PRR1280-Nov23-2020.pdf
California ISO, *Staff Statement on Withdrawing PRR 1280*
http://www.caiso.com/Documents/ISOStaffStatement-WithdrawingPRR1280.pdf

demand response resources increased from 2020 to 2021, particularly from reliability demand response resources, which were four times higher this year compared to last.

Dispatch and performance of demand response

The CAISO relied on demand response resources, including reliability demand response, during high load days in July and September 2021. The CAISO economically scheduled proxy demand response resources and issued manual dispatches to reliability demand response on July 9. However, outside of these heatwave periods, demand response resource adequacy resources were rarely scheduled in the CAISO markets.

DMM reported on demand response performance during the July and September heatwaves and found that aggregate demand response performance improved this summer from 53 percent in 2020 to 64 percent in 2021.[68] Figure 1.29 shows the expected load curtailment (schedule) of demand response resource adequacy resources compared to reported performance from July 2019 to September 2021 in peak net load hours (4-9 p.m.). Real-time schedules are not capped at resource adequacy values.[69] Self-reported performance has continually increased for utility proxy demand response, averaging 40 percent across July, August, and September of 2019, 75 percent in 2020, and almost 90 percent in 2021.

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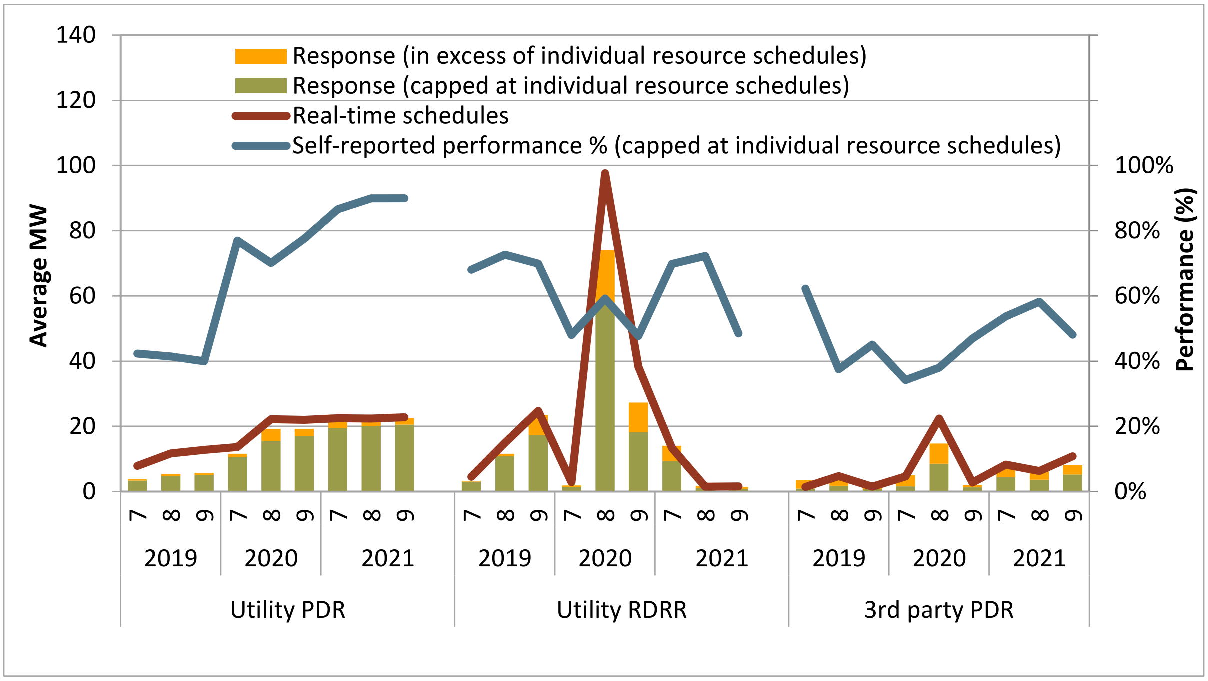
68 Department of Market Monitoring, *Demand Response Issues and Performance 2021,* January 12, 2022: http://www.caiso.com/Documents/Demand-Response-Issues-Performance-Report-Jan-12-2022.pdf

69 Of note, 2019 third-party demand response average performance decreased, compared to July/August performance reported in DMM's 2019 annual report. This change is due to some scheduling coordinators submitting updated performance data that was picked up in settlement recalculations issued 9 months (T+9M) after relevant 2019 market dates.
Department of Market Monitoring, *2019 Annual Report on Market Issues and Performance,* June 2020, pp. 55-56: http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf

Figure 1.29 Demand response resource adequacy performance - July to September (4-9 p.m.)



1.2.5 Generation outages

The quantity of generation on outage increased 13 percent from 2020 and 29 percent from 2019. Generation outages typically follow a seasonal pattern with the majority of outages taking place in the non-summer months; 2021 followed this trend. There has been a steady increase in forced outages from 2019 to 2021, which may be due in part to an aging thermal resource fleet.

Under the current California ISO outage management system, known as WebOMS, all outages are categorized as either planned or forced. WebOMS has a menu of subcategories indicating the reason for the outage. Examples of these 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:

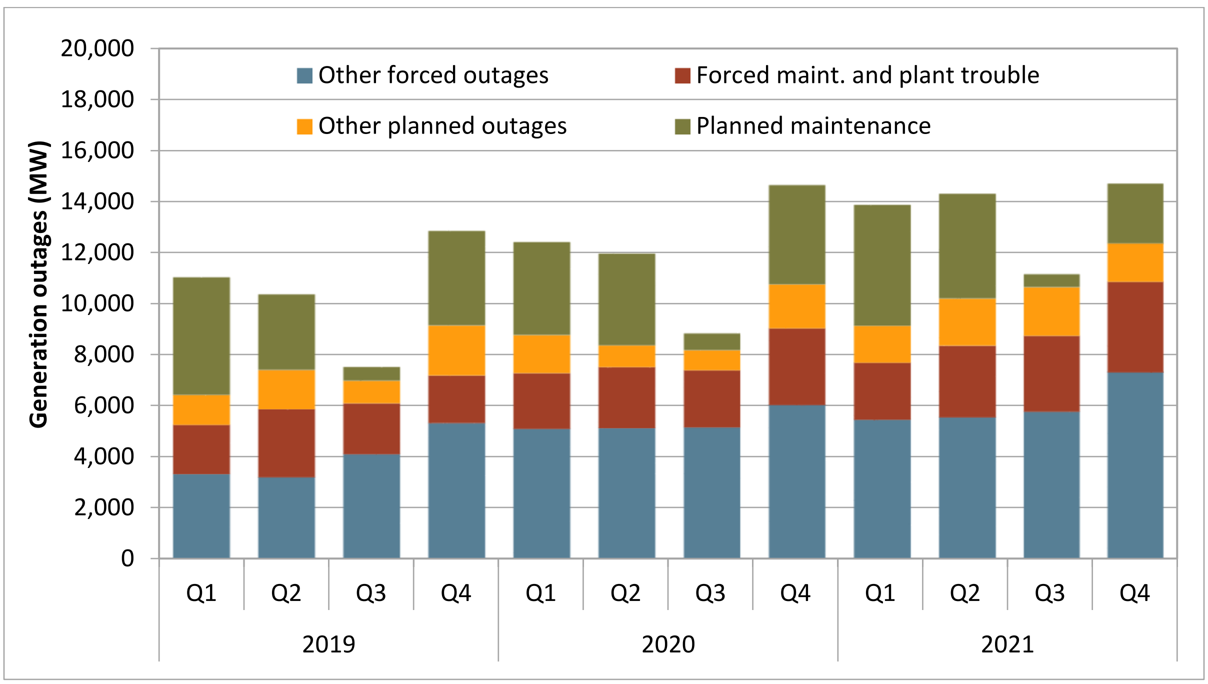
- **Planned maintenance**, which includes plant maintenance that has been submitted more than 7 days prior;
- **Other planned outages**, which includes other types of de-rates that have been submitted more than 7 days prior;
- **Forced maintenance and plant trouble**, which includes plant maintenance 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 1.30 shows the quarterly averages of maximum daily outages by type during peak hours. Generation outages follow a seasonal pattern, with most taking place in the non-summer months. This pattern is driven by planned outages as maintenance is performed in preparation for the higher summer load period.

Average total generation outages in the California ISO balancing area were about 13,500 MW, up from 12,000 MW in 2020.[70] Outages for planned maintenance averaged about 2,900 MW during peak hours, while all other types of planned outages averaged about 1,700 MW. Some common types of outages in this category are ambient de-rates (both due to temperature and not due to temperature) and transmission outages.

Forced outages for plant maintenance or trouble averaged about 2,900 MW per quarter, while all other types of forced outages averaged about 6,000 MW. 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 2021 may be due in part to the California ISO keeping older thermal resources online to maintain adequate capacity for system reliability.

Figure 1.30 Average of maximum daily generation outages by type – peak hours



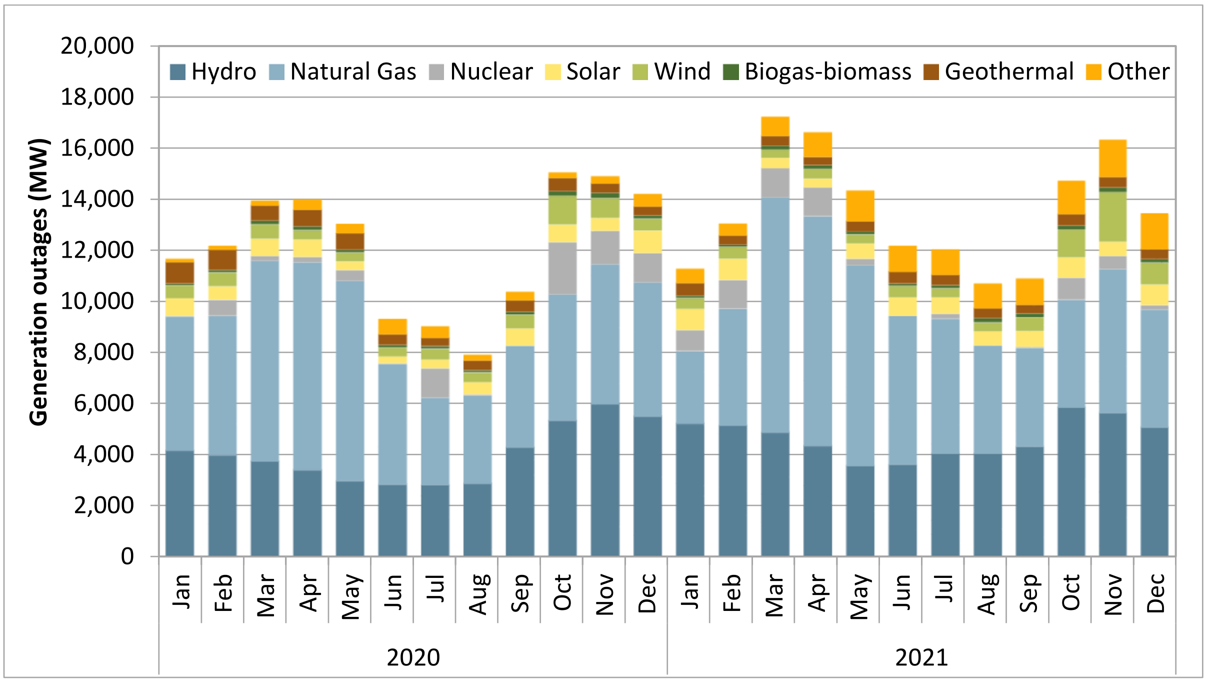
70 This average is calculated as the average of the daily maximum level of outages, excluding off-peak hours. Values reported here only reflect generators in the California ISO balancing area and do not include WEIM outages.

Generation outages by fuel type

Natural gas and hydroelectric generation averaged 5,600 MW and 4,600 MW on outage during 2021. Together, these two fuel types accounted for 75 percent of the generation on outage for the year.

Figure 1.31 shows the monthly average generation on outage by fuel type during peak hours. March experienced the highest monthly average generation on outage at 17,200 MW in total, in large part due to an increase in natural gas generation outages. These natural gas generation outages gradually tapered down through the summer.

Figure 1.31 Monthly average of maximum daily generation outages by fuel type – peak hours



1.2.6 Natural gas prices

Electricity prices in the western states typically follow natural gas price trends. This is because natural gas units are often the marginal source of generation in the California ISO and other regional markets.

Across key delivery points in the west, the average price of natural gas in the daily spot markets increased significantly in 2021 compared to 2020. At the PG&E Citygate and SoCal Citygate gas hubs, the price rose by 67 percent and 141 percent, respectively. At other major gas trading hubs, such as Henry Hub, El Paso Permian, and Northwest Sumas gas hubs, the prices rose by 92 percent, 264 percent, and 89 percent, respectively. This increase in natural gas prices resulted in higher system marginal energy prices across the CAISO footprint in 2021.

Figure 1.32 shows monthly average natural gas prices at PG&E Citygate, SoCal Citygate, Northwest Sumas, and El Paso Permian, as well as 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 February and reached a high of $136.00/MMBtu in the next-day trading window for the Feb 15-16 gas days. This is because of the winter freeze-offs which significantly affected the Permian supply basin in West Texas. By comparison, the spot price at PG&E Citygate was considerably lower at $6.25/MMBtu because of access to natural gas from the Rocky Mountain region and Western Canada. The figure also shows prices at both hubs remained elevated for the rest of the year, particularly at SoCal Citygate; this is due to ongoing pipeline constraints since mid-August 2021 on the El Paso system. These constraints restricted access to the Permian basin gas supply. Overall, for 2021, the price at SoCal Citygate averaged $7.10/MMBtu compared to $2.95/MMBtu in 2020.

The Aliso Canyon protocol remained in effect in 2021 making the facility available for withdrawals for Stage 2 or above low operational flow orders (OFO). These protocols exist to mitigate gas price spikes and maintain system reliability.[71] On November 4, 2021, the California Public Utilities Commission (CPUC) issued a temporary order increasing the inventory limit for the Aliso Canyon Storage Field from 34 Bcf to 41.16 Bcf.[72] In 2021, SoCalGas withdrew gas from the Aliso Storage facility on 73 gas days compared to 57 gas days in 2020.

Consistent with the CPUC's ruling on April 29, 2019, SoCalGas Company made changes to its OFO stages and associated non-compliance penalty structure.[73] 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.

The revisions from the CPUC's ruling expired on October 31, 2021. DMM submitted comments on the CPUC ruling to revise the existing penalty structure.[74] Until a final decision on this new ruling is reached, the CPUC has temporarily extended the 8-stage winter OFO structure until May 1, 2022.[75] Finally, on

71 CPUC Docket No. I.17-0-002, A.18-07-024, A.17-10-007, *Aliso Canyon Withdrawal Protocol*, July 23, 2019: https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/news_room/newsupdates/2020/withdrawalprotocol-revised-april12020clean.pdf

72 CPUC Docket No. I.17-02-002, *Decision setting the interim range of Aliso Canyon Storage Capacity at 0 to 41.16 Bcf (D.21-11-008)*, November 4, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M421/K086/421086399.PDF

73 CPUC's Proposed Decision, *Granting In Part and Denying In Part for Modification Filed by Southern California Edison and Southern California Generation Coalition of Commission Decisions D.15-06-004 and 16-06-039 as Modified by D.16-12-016,* April 29, 2019, pp. 31-32: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M285/K085/285085989.PDF

74 Department of Market Monitoring, *Response to Judge's Ruling Seeking Comments on Safe and Reliable Gas System, CPUC R.20-01-007,* Aug 14, 2020: http://www.caiso.com/Documents/CPUC-ResponsetoJudgesRulingSeekingComments-SafeandReliableGasSystems-R20-01-007-Aug142020.pdf

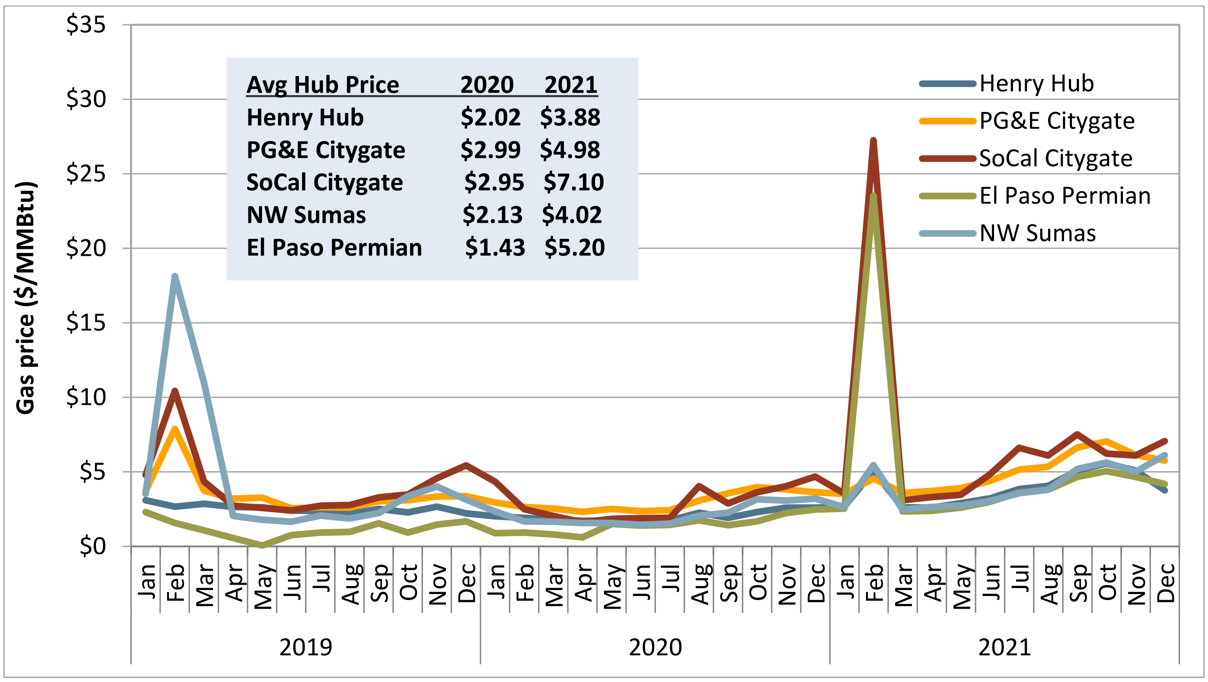
75 CPUC Docket No. R.20-1-007, *Proposed Decision Ordering Southern California Gas Company and San Diego Gas & Electric Company to Implement Rule 30 Operational Flow Order Noncompliance Charge Structure for the Six Months Commencing November 1, 2021,* October 29, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M423/K447/423447100.PDF

March 18, 2022, a proposed decision was issued to extend SoCalGas' 8-stage winter OFO penalty structure "year-round." These changes will also be applicable to PG&E and SDG&E service territories.[76] In 2021, SoCalGas declared 57 low OFOs, primarily stage 1 or 2. This is in comparison to 53 low OFOs in 2020, which were also primarily stage 1 or 2.

As mentioned earlier, prices at other gas trading hubs in the west also increased in 2021 relative to 2020. The spot price at the Permian hub reached a record high of $220/MMBtu for the February 17 gas day. Overall, the average gas price for 2021 was $5.20/MMBtu which is significantly higher than $1.43/MMBtu during 2020.

Price increases are associated with the growth of demand for natural gas, both domestically and exported as liquefied natural gas.[77]

Figure 1.32 Monthly average natural gas prices (2020-2021)



[76] CPUC Docket No. R.20-01-*007, Decision Implementing Southern California Gas Company Rule 30 Operational Flow Order Winter Noncompliance Penalty Structure Year-Round for Southern California Gas Company, San Diego Gas & Electric Company, and Pacific Gas And Electric Company,* March 18, 2022: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M460/K301/460301154.PDF

[77] FERC Report, *Summer Energy Market and Reliability Assessment*, May 19, 2022, pp. 6-12: https://www.ferc.gov/media/report-summer-assessment-2022

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

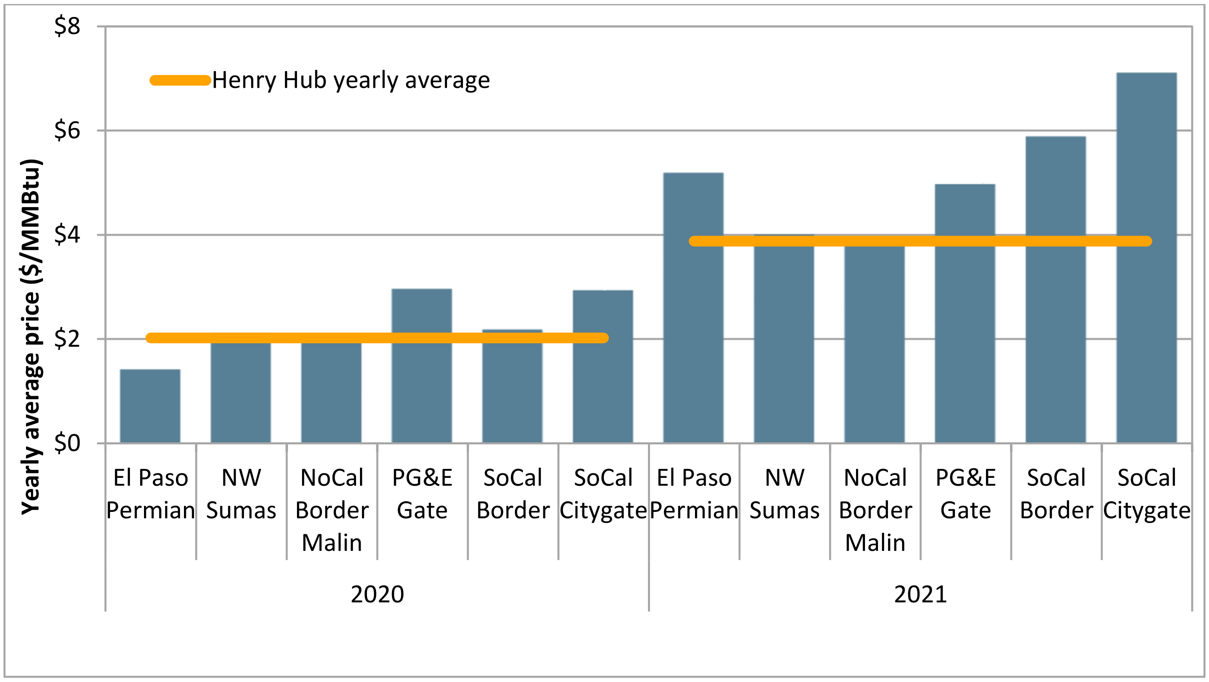


Figure 1.33 compares yearly average natural gas prices at six major western trading points to the Henry Hub reference average for 2020 and 2021. The yearly average prices in 2021 exceeded the Henry Hub reference price at all the trading hubs. On average, the yearly price at SoCal Citygate exceeded the Henry Hub average by 83 percent. Similarly, PG&E Citygate and Northwest Sumas exceeded the Henry Hub average by 28 percent and 4 percent, respectively. The average Permian price exceeded the Henry Hub average by 34 percent.

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. In addition, these restrictions affected the real-time flexibility of natural gas-fired electric generators in Southern California. These primarily impacted resources operated in the Southern California Gas Company (SoCalGas) and San Diego Gas & 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.[78]

In response to the gas supply restrictions stemming from the Aliso Canyon natural gas leak, the California ISO received temporary authority to implement numerous measures to improve gas-electric coordination. These measures provided operators the ability to maintain electric reliability while limiting gas usage by generators in the SoCalGas system. Beginning in 2020, FERC granted the California 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 California ISO has developed to manage potential gas system limitations is a set of constraints (or nomograms). This tool allows operators to restrict the gas burn of groups of natural gas-fired generating units through the market dispatch. 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.[79]

In 2021, the operators enforced the maximum gas burn constraint in both the day-ahead and real-time markets; this constraint was enforced in selected sub-regions of the SoCalGas service area during July 15 through 18. It was enforced to facilitate pipeline maintenance work in the southern system of the SoCalGas area. During this period, the constraint was binding in about 5 percent of day-ahead intervals and none in the real-time market.

On October 31, 2019, the California ISO filed tariff amendments to extend Aliso Canyon provisions permanently.[80] One of proposals was to refine the shaping of the maximum gas burn limit using net load rather than gross load.

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.[81] Beginning in 2020, FERC approved these tariff

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78 CPUC Order Instituting Investigation; I.17-02-002, *Aliso Canyon Well Failure Order Instituting Investigation*, Feb 9, 2017: https://www.cpuc.ca.gov/regulatory-services/safety/pipeline-safety/aliso-canyon-well-failure/aliso-canyon-well-failure-order-instituting-investigation

79 Refer to California ISO, *Operating Procedure 4120, Gas Transmission Pipeline System Limitations or Outages*: https://www.caiso.com/Documents/4120.pdf

80 California ISO, *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

81 Department of Market Monitoring, *2018 Annual Report on Market Issues and Performance*, May 2019, pp. 261-262: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

amendments. FERC also directed the California ISO to file annual informational filings relating to the performance of the enforced nomograms.[82,83]

Effective May 20, 2021, the California ISO implemented DMM's recommendations on better shaping the maximum gas burn constraint limit using the net load approach. If needed, the shaping will also be based on estimated gas burn resulting from the two-day-ahead runs of the market software.[84,85] In addition, DMM continues to recommend that the California 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 this process is manual and cumbersome for the operators to use in real-time. Hence, the operators opt for out-of-market actions such as exceptional dispatches to manage gas limitations instead.

Figure 1.34 shows the nomogram limits in day-ahead and real-time based on a net load approach on July 16, 2021. DMM believes that incorporating maximum gas constraints into the market software could be more effective and efficient at managing gas limitations than the use of manual dispatches made by system operators. Effective May 20, 2021, the California ISO started including maximum gas burn constraint as part of the local market power mitigation (LMPM) process to automatically designate a constraint as competitive or not.[86]

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82 FERC Report, *Order Accepting Tariff Revisions* (ER20-273), December 30, 2019: http://www.caiso.com/Documents/Dec30-2019-OrderAcceptingTariffRevisions-AlisoCanyonGasElectricCoordination-MaximumGasConstraint-ER20-273.pdf

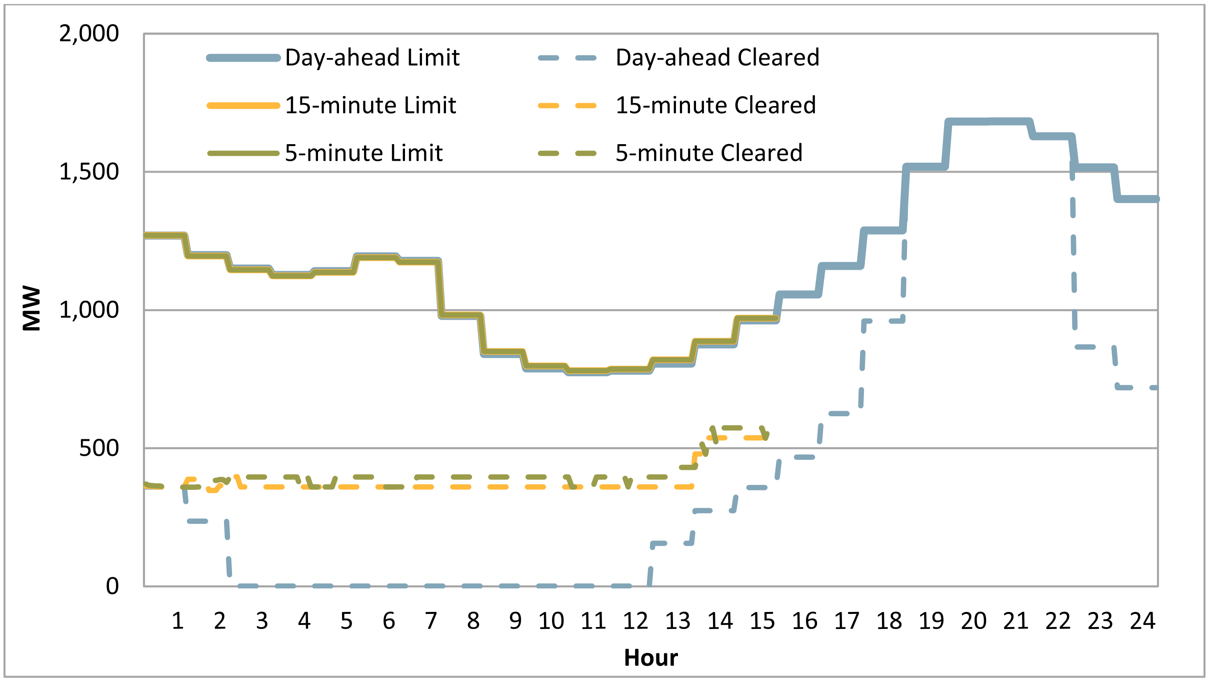
83 California ISO, *Annual Report on Use of the Maximum Gas Burn Constraint, FERC Docket No. ER20-273*, June 30, 2021: http://www.caiso.com/Documents/Jun30-2021-AnnualInformationalFiling-UsageofMaximumGasBurnConstraint-ER20-273.pdf

84 Department of Market Monitoring, *Motion to Intervene and Comments on Aliso Canyon Gas-Electric Coordination Phase 5, FERC Docket No. ER20-273*, November 21,2019: http://www.caiso.com/Documents/MotiontoInterveneandCommentsoftheDepartmentofMarketMonitoring-Aliso5-ER20-273-000-Nov212019.pdf

85 California ISO, Proposed Revision Request Detail, PRR# 1262, Aliso Canyon gas-electric coordination Phase 5 https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=1262&IsDlg=0

86 California ISO, *Business Requirements Specification* for *Aliso Canyon Phase 5*, May 5, 2020: http://www.caiso.com/Documents/BusinessRequirementsSpecification-AlisoCanyonPhase5.pdf

Figure 1.34 Aliso gas nomogram binding status in day-ahead and real-time market (Jul 16, 2021)



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.[87] 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 for resources located in the California ISO balancing area or other California balancing areas in the WEIM.

In addition, greenhouse gas compliance costs are attributed to resources who participate in the WEIM and serve California load, which is defined as load within the California ISO, Turlock Irrigation District, the Balancing Area of Northern California, or Los Angeles Department of Water and Power. This facilitates compliance with California's cap-and-trade program and mandatory reporting regulations. Resource specific compliance obligations are determined by the market optimization based on energy bids and greenhouse gas bid adders; they are reported to participating resource scheduling coordinators for compliance. Further detail on greenhouse gas compliance in the Western Energy Imbalance Market is provided in Section 3.3 of this report.

87 A more detailed description of the cap-and-trade program and its impact on wholesale electric prices was provided in DMM's 2015 annual report.
Department of Market Monitoring, *2015 Annual Report on Market Issues and Performance*, 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 market software, a calculated greenhouse gas allowance index price is used as a daily measure for greenhouse gas allowance costs. The index price is calculated as the average of two market-based indices.[88] Daily values of this greenhouse gas allowance index are plotted in Figure 1.35.

Figure 1.35 California ISO greenhouse gas allowance price index

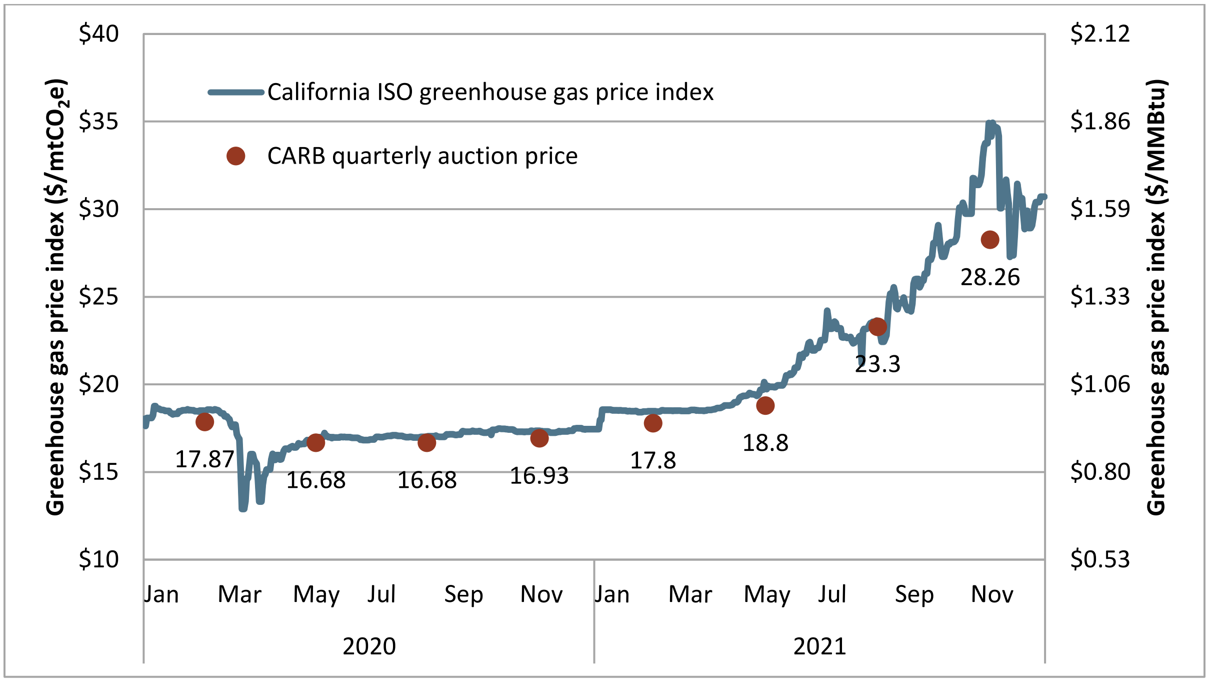


Figure 1.35 also shows market clearing prices in the California Air Resources Board's quarterly auctions of emission allowances that can be used for the 2020 or 2021 compliance years. The values displayed on the right axis convert the greenhouse gas allowance price into an incremental gas price adder, 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.[89]

As shown in Figure 1.35, the average cost of greenhouse gas allowances in bilateral markets increased 35 percent from a load-weighted average of \$17.16/mtCO_2e in 2020 to \$23.14/mtCO_2e in 2021. In 2021, each of the California Air Resources Board's quarterly allowance auctions sold a fraction of allowances

[88] The indices are from ICE and ARGUS Air Daily. As the California 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 California ISO notice: http://www.caiso.com/Documents/GreenhouseGasAllowancePriceSourcesRevisedMay8_2013.htm

[89] 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 Code of Federal Regulations, *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

offered and thus cleared at an average auction reserve price of \$22/mtCO_2e, compared to \$17/mtCO_2e last year.

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.[90] The greenhouse gas compliance cost expressed in dollars per MMBtu in 2021 ranged from about \$1.00/MMBtu to almost \$2.00/MMBtu.

The \$23.14/mtCO_2e average in 2021 would represent an additional cost of about \$9.83/MWh for a relatively efficient gas unit.[91] This is an increase from 2020 when the average price was \$17.16/mtCO_2e, or about \$7.29/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 California ISO identified several upcoming challenges to meeting summer evening peak load including capacity shortfall in 2020 and 2021.[92] In response, the California 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.[93]

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

91 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 89.

92 Board of Governors Meeting, *Briefing on Post 2020 Grid Operational Outlook,* presented by Mark Rothleder, September 18, 2019: https://www.caiso.com/Documents/Briefing-Post-2020-GridOperationalOutlook-Presentation-Sep2019.pdf

93 There has been a significant increase in the number of storage resources requesting interconnection to the California ISO balancing area. Board of Governors Meeting, *Briefing on Renewables and Energy Storage in the ISO Generator Interconnection Queue,* presented by Bob Emmert, July 15, 2021: http://www.caiso.com/Documents/Briefing-Renewables-Generator-Interconnection-Queue-Presentation-July-2021.pdf

The CPUC took numerous measures to promote adequate capacity for 2021, which included an order of 3,300 MW of additional capacity procurement and implementation of an effective 17.5 percent planning reserve margin (PRM).[94] Large electric investor-owned utilities are required to meet their 15 percent system PRM requirements and are directed to target an additional 2.5 percent of incremental resources that are available at the net peak starting summer 2021.[95]

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 the California ISO markets and no longer participates. In addition to decommissioned units, withdrawals may include resources that exit the market for a short period before returning (also known as mothballing), resources that withdraw to upgrade the unit and then repower, and resources whose contracts have expired with the California ISO regardless of the units' capability to provide power.

Graphs reflect nameplate capacity and changes between Junes of one year to the next to reflect changes to peak summer capacity.[96]

Total California ISO registered and participating capacity

Figure 1.36 summarizes the trends in available nameplate capacity from June 2017 through June 2022. Since 2017, there has been a decrease in gas capacity, falling from 33.6 GW in June 2017 to 30.8 GW in June 2022. This capacity was replaced by solar, which grew from 10.2 GW to 15.1 GW; by wind, which grew from 5.7 GW to 6.1 GW; and by demand response, which grew from 1.5 GW to 3.9 GW.

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.[97] Batteries, which can be more flexible than the three previous resource types, are currently the fastest growing resource type, growing from 400 MW in June 2020 to 3.9 GW as of June 2022.[98]

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94 The CPUC also approved seven clean energy contracts for PG&E to meet procurement requirements and authorized procurement of 770 MW of energy storage for SCE.
CPUC Press Release Docket #:R.20-11-003, March 5, 2021:
https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M369/K653/369653557.PDF

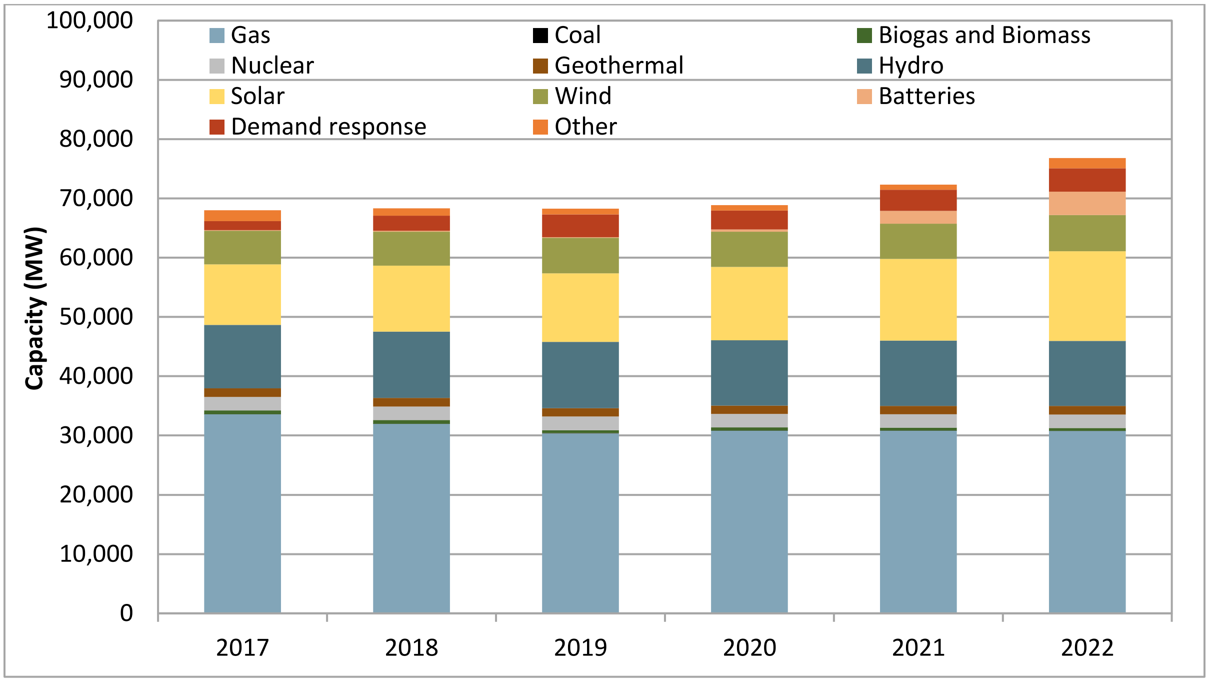
95 CPUC Docket No. R.20-1-03, *Decision Directing PG&E, SCE, and SDG&E to Take Actions to Prepare for Potential Extreme Weather in Summers of 2021 and 2022 (D.21-03-056)*, March 25, 2021:
https://docs.cpuc.ca.gov/publisheddocs/published/g000/m373/k745/373745051.pdf

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

97 In contrast to gas and nuclear capacity resource adequacy contributions, qualifying capacity (QC) of wind and solar resources in the California ISO balancing area 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.

98 Some battery resources are counted in the "other" category based off how the resource is registered in Master File. The "other" category also includes hybrid resources and some demand response resources.

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



Withdrawal and retirement of California ISO participating capacity

Figure 1.37 and Figure 1.38 summarize the trends in withdrawal and retirement of capacity from June of 2017 through 2022.

Since June 2017, almost 6.5 GW of capacity withdrew from market participation, about 90 percent of which was gas-fired capacity. Until summer of 2020, there was substantial retirement of natural gas plants, averaging about 2,000 MW each year. After the load curtailment event of 2020, the California ISO took necessary steps to keep capacity online and maintain reliability during the summer peak. This included a request to extend the State Water Resource Control Board's once-through cooling regulation compliance dates for gas-fired generating units, as well as the use of reliability must-run (RMR) contracts.[99]

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99 The State Water Resource Control Board's regulations were to phase out once-through cooling technology at coastal plants that utilize marine water for cooling. These resources were set to retire by the end of 2020, but the board extended the closure date until the end of 2023.
State Water Resources Control Board, *Final Amendment to the Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plan Cooling.* October 19, 2021: https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc_policy_2021/final_amdmt.pdf

Figure 1.37 Withdrawals from California ISO market participation by fuel type[100]

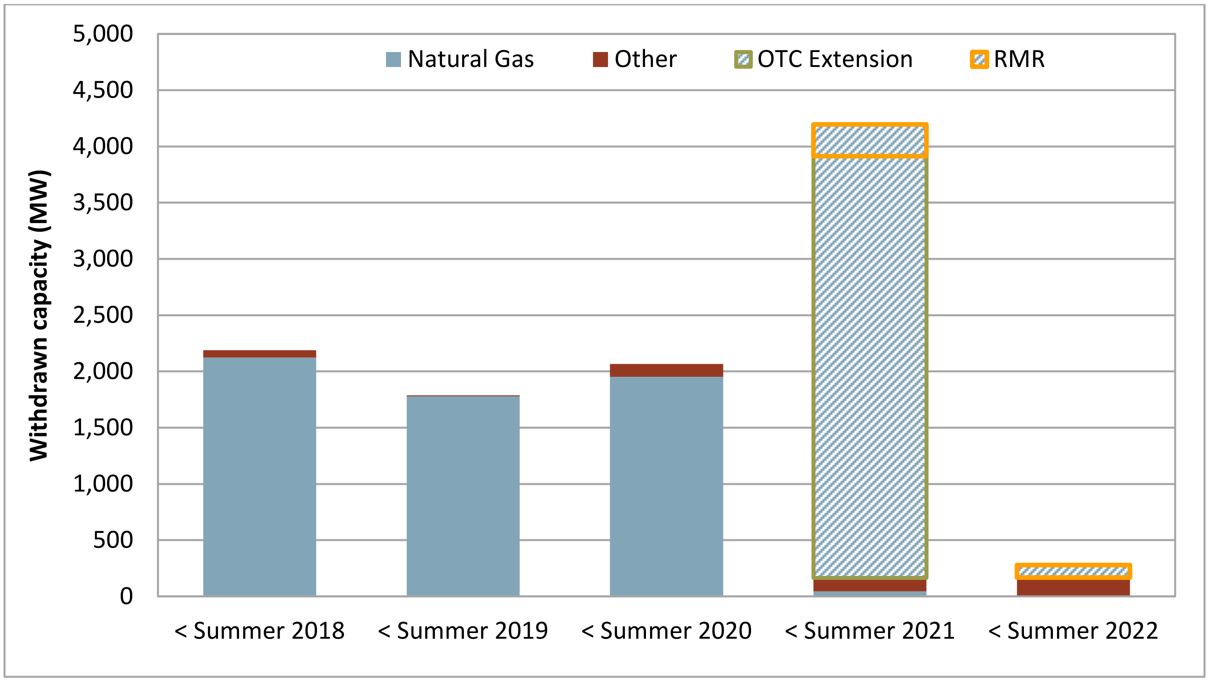

Figure 1.38 shows withdrawals by local area according to local resource adequacy showings. Resources just shown for system resource adequacy are labeled as CAISO System. The chart shows that withdrawals from California ISO market participation have largely come from the state's four largest local areas: Bay Area, LA Basin, San Diego-Imperial Valley, and Big Creek-Ventura. With the extension of the once-through cooling regulations and reliability must-run contracts, there was a substantial decrease in withdrawals for the last two years, as seen in the striped segment of the figure above.[101] From June 2021 to June 2022, only 173 MW of capacity withdrew from the market, 68.5 MW of which was in the LA Basin.

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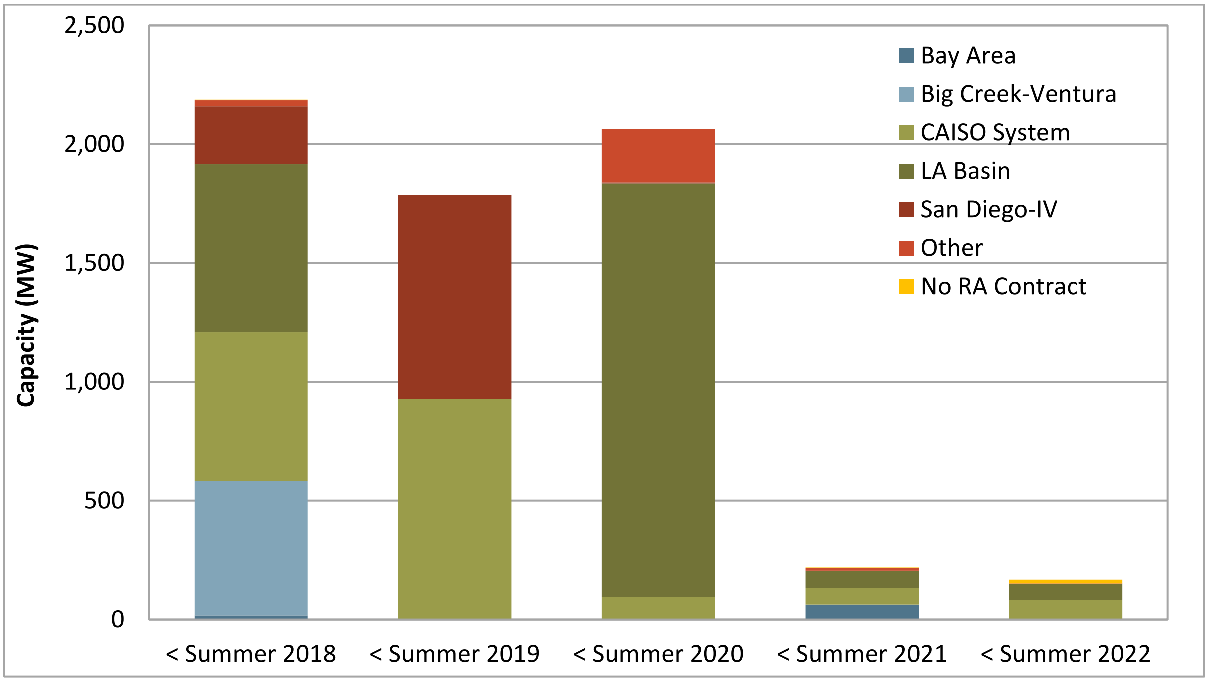
100 Please note that this is not a complete picture of capacity changes and resource availability in the California ISO system. Other changes in available capacity that are not included in this metric include: 1) generation outages, 2) increases and decreases to capacity without changes in participation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

101 Before summer 2021, the California ISO approved reliability must-run contracts for Midway Sunset Cogeneration and Kingsbury Cogeneration. On September 23, 2021, the California ISO Board of Governors approved extension of Oakland Power Plant. See California ISO, *Motion to Intervene and Protest for FERC Docket No. ER22-290, Oakland Power Company, LLC.,* November 18, 2021: http://www.caiso.com/Documents/Nov18-2021-CAISOMotiontoInterveneandProtest-OaklandPower-ReliabilityMustRunRMRAgrmt-ER22-290.pdf

Figure 1.38 Withdrawals from California ISO market participation by local area



Additions to participating capacity

Figure 1.39 shows additions to California 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.[102]

From June 2016 to June 2022, 7,000 MW of solar, 2,000 MW of gas capacity, 1,000 MW of wind, and 4,000 MW of battery capacity were added or returned to the market.[103] The majority of the increase in battery capacity happened within the last two years, with 3,500 MW of capacity added since June 2020. Other additions between June 2021 and June 2022 include 5 MW of biomass, 40 MW of geothermal, and 740 MW of hybrid resources.

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

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

Figure 1.39 Additions to California ISO market participation by fuel type[104]

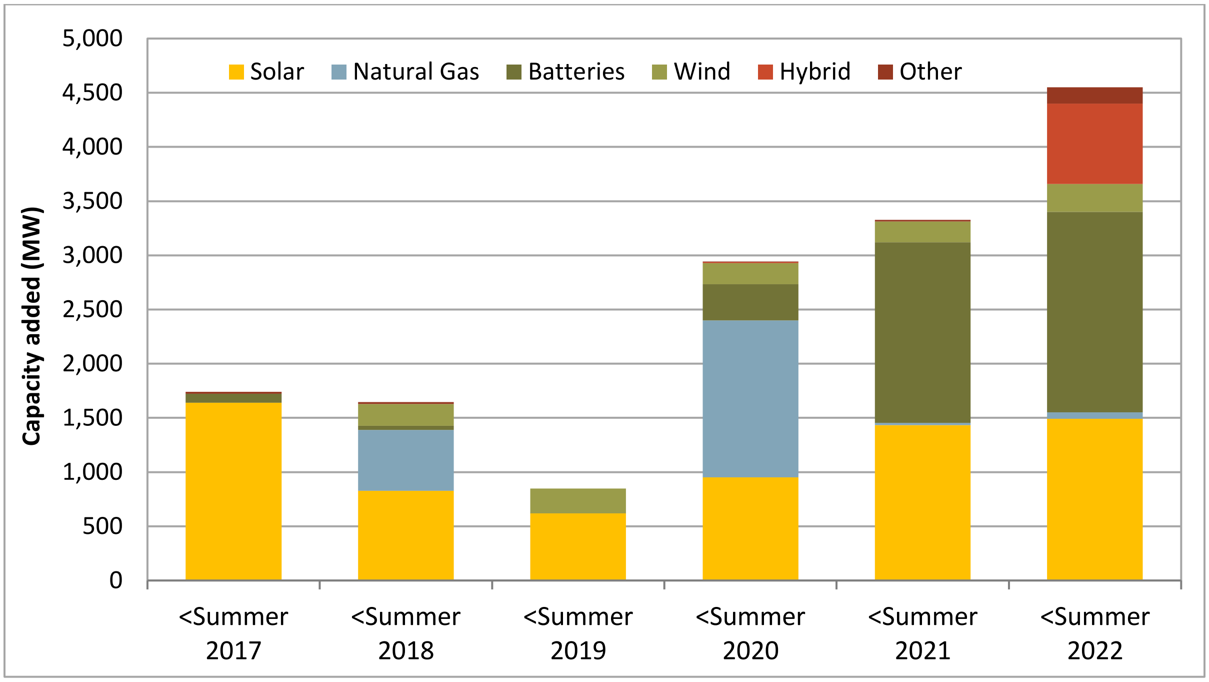
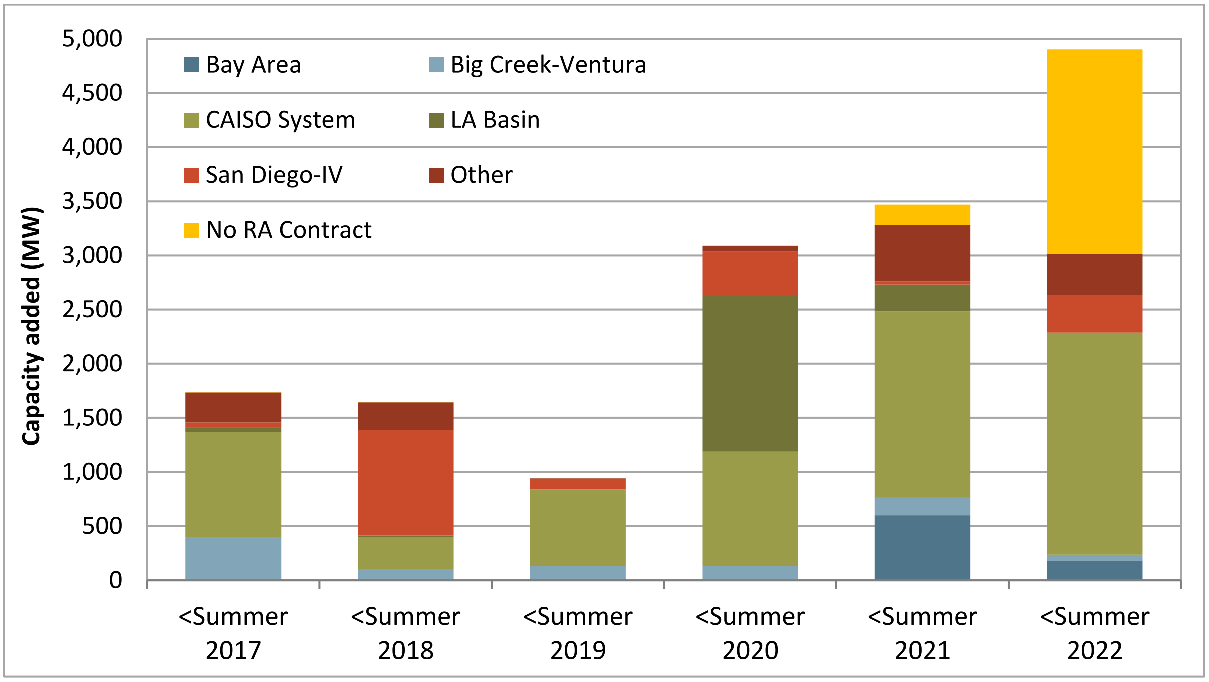


Figure 1.40 shows additions by local area according to local resource adequacy showings. Resources just shown for system resource adequacy (RA) are labeled as CAISO System.[105] In the last couple of years, a significant amount of the new capacity came in as system RA, with around 1,700 MW added from June 2020 to June 2021, and over 2,000 MW added from June 2021 to June 2022. Almost all of the capacity added to local areas defined as "other" in Figure 1.40 was capacity added to the Fresno area.

[104] Please note that this is not a complete picture of capacity changes and resource availability in the California 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.

[105] New resources are unable to sell resource adequacy until they receive net qualifying capacity. Many of the new resources do not have resource adequacy contracts, and are therefore not assigned to the designated local areas.

Figure 1.40 Additions to California ISO market participation by local area



1.3 Net market revenues of new generation

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

Each year, DMM examines the extent to which revenues from the California ISO 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. Starting in 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 markets is significantly higher than just participating in energy price arbitrage. In addition, net revenues in 2021 are higher in northern local capacity areas than southern areas under these scenarios.

For new gas-fired units, net revenues earned through the California ISO energy market continued to be lower than DMM's estimate of levelized fixed costs. For 2021, DMM estimates that net energy market revenues for a typical gas combined cycle unit ranged from $20 to $41/kW-yr compared to total annualized fixed costs of about $124/kW-yr. For a typical combustion turbine unit, DMM estimates net energy market revenues of about $16 to $26/kW-yr compared to total annualized fixed costs of about $152/kW-yr.

In addition, estimated net energy market revenues of gas units in 2021 were, on average, lower 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 $28 to $37/kW-yr, compared to net energy market revenues of $20 to $41/kW-yr. For a typical combustion turbine unit, DMM estimates net energy market revenues of about $16 to $26/kW-yr in 2021 compared to estimated annualized going-forward fixed costs of about $29 to $30/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.

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 capacity procurement mechanism (CPM), or a reliability must-run contract. The California ISO soft cap for CPM 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.

On December 17, 2021, in response to a CPUC challenge of a FERC order, the U.S. Court of Appeals determined that FERC's reliance on an earlier order approving a 20 percent adder for bids at or below the CPM soft offer cap was misplaced. In addition, the court also determined that FERC failed to justify its decision adequately to allow a 20 percent adder for bids above the CPM soft offer cap.[106] On April 22, 2022, FERC issued an order reversing its original determination and finding that the California ISO has not demonstrated that the proposed 20 percent adder is just and reasonable.[107] On May 23, 2022, the California ISO submitted a compliance filing excluding the 20 percent adder from the compensation methodology.[108]

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.[109] Incremental energy costs are calculated using default energy bids used in local market power

106 U.S. Court of Appeals, Order No. 20-1388 on *Petition for Review of Order Regarding Bids Above CPM Soft Offer Cap*, December 17, 2021: https://www.cadc.uscourts.gov/internet/opinions.nsf/A7E4F1659200B2B4852587AE0054513A/$file/20-1388-1927124.pdf

107 FERC Docket No. ER20-1075-002, *Order on Remand on Compensation for Resources with Bids Above CPM Soft Offer Cap,* April 22, 2022: http://www.caiso.com/Documents/Apr22-2022-Order-on-Remand-CPM-Soft-Offer-Cap-ER20-1075.pdf

108 California ISO, *Compliance Filing to Enhance the Capacity Procurement Mechanism (ER20-1075)*, May 23, 2022: http://www.caiso.com/Documents/May23-2022-ComplianceFiling-CapacityProcurementMechanism-CPM-above-SoftOfferCap-ER20-1075.pdf

109 Net revenues due to ancillary services and flexible ramping capacity are not modeled in the optimization model. For a combined cycle unit in the California ISO area, 2021 total average annual net revenues for regulation (up and down), and spinning reserves were approximately $1.15/kW-yr and payments for flexible ramping capacity were around $0.27/kW-yr. Similarly, for a combustion turbine unit, 2021 total average net revenues for spin and non-spinning reserve were $3/kW-yr while average flexible ramping payments were $0.25/kW-yr. Therefore, ancillary service and flexible ramping revenues would have had a small impact on the overall net revenues for both the combined cycle and combustion turbine units.

mitigation.[110] Commitment costs are calculated using proxy start-up and minimum load cost methodology.[111]

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 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 valorem*).[112] 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.[113] DMM's analysis indicates that the annual fixed O&M from the CEC report, which is used to set the California ISO 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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110 Default energy bids are calculated using the variable cost option as described in:
California ISO, *Business Practice Manual Change Management, Market Instruments, Appendix F, Example of Variable Cost Option Bid Calculation*: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments

111 Start-up and minimum load costs are calculated using the proxy cost option as described in:
California ISO, *Business Practice Manual Change Management, Market Instruments, Appendix G.2, Proxy Cost Option:* https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments

The energy price index used in the proxy start-up costs is calculated using the retail rate option described in:
California ISO, *Business Practice Manual Change Management, Market Instruments, Appendix M.2, Retail Region Price:* https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments

112 The annual fixed costs used by DMM represent the average between IOU, POU, and Merchant fixed costs reported by the CEC. See CEC Staff Report, *Estimated Cost of New Utility-Scale Generation in California: 2018 Update, Appendix D, Levelized Cost by Developer Type*, May 2019 | CEC-200-2019-500:
https://www.energy.ca.gov/sites/default/files/2021-06/CEC-200-2019-005.pdf

113 Department of Market Monitoring, *Answer and Motion for Leave to Answer, Comments on CPM Tariff Filing (ER20-1075)*, Apr 3, 2020:
http://www.caiso.com/Documents/AnswerandMotionforLeavetoAnswer-DMMCommentsonCPMTariffFilingER20-1075-Apr32020.pdf

FERC Docket No. ER18-240, *Metcalf RMR Agreement Filing, Schedule F, Article II Part B*, November 2, 2017, pp. 140-142:
https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20171102-5246&optimized=false

FERC Docket No. ER18-230, *Gilroy RMR Agreement Filing, Schedule F, Article II Part B,* November 2, 2017, pp. 140-147:
https://elibrary.ferc.gov/eLibrary/docfamily?accessionnumber=20171102-5142&optimized=false

S&P Global Average (2019). Data downloaded from S&P Global online screener tool. S&P Global Market Intelligence (*subscription required*): https://platform.mi.spglobal.com range from $28 to $37/kW-yr for a typical combined cycle resource and $29 to $30/kW-yr for a typical combustion turbine.[114]

For a battery energy storage system, potential revenue streams are evaluated under two scenarios using a profit maximization optimization model. The first scenario considers energy price arbitrage in the day-ahead market across more than 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 year's 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.[115] 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 and 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

114 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.

115 California ISO, *Business Requirements Specification, Energy Storage and Distributed Energy Resources (ESDER), Phase* 4, October 11, 2021, Section 7.2, Appendix B – Storage Default Energy Bid Calculation Examples, p. 50: http://www.caiso.com/Documents/BusinessRequirementsSpecification-EnergyStorageandDistributedEnergyResourcesPhase4.pdf

Southern California (SP15), separately. These scenarios show how different assumptions would change net revenues for 2021.

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 2021, for a unit located in NP15 with the above assumptions, net revenues were $37/kW-yr with a 17 percent capacity factor.[116] Using the same assumptions for a hypothetical unit located in SP15, net revenues were $20/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 that 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.[117] Many resources do not include the full adder as part of their typical energy bid. Under this scenario, net revenues in 2021 for a hypothetical unit in the NP15 area were $41/kW-yr with a 20 percent capacity factor. In the SP15 area, net annual revenues were $23/kW-yr with a 14 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 based 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 reflected how after the day-ahead market gas units can re-bid and be re-dispatched in the real-time market. Under this scenario, net revenues for a hypothetical unit located in the NP15 area were $39/kW-yr with a 20 percent capacity factor. In the SP15 area, net annual revenues were $21/kW-yr with an 11 percent capacity factor.

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

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

Table 1.3 Assumptions for typical new 2x1 combined cycle unit[118]

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 $mtCO_2e$/MMBtu	0.053165 $mtCO_2e$/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 (2021)	$6,200	$12,400
Minimum load major maintenance cost adder (2021)	$310	$620
Minimum up time	60 minutes	60 minutes
Minimum down time	60 minutes	60 minutes
Ramp rate	40 MW/minute	40 MW/minute
Financial Parameters (2021)		
Financing costs		$86 /kW-yr
Insurance		$7 /kW-yr
Ad Valorem		$9 /kW-yr
Fixed annual O&M		$12.7 /kW-yr
Taxes		$10 /kW-yr
Total Fixed Cost Revenue Requirement		**$124 /kW-yr**

118 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. See Analysis Group Inc. Lummus Consultants International, Inc. *Study to Establish New York Electricity Market ICAP Demand Curve Parameters*, September 13, 2016: 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 California ISO balancing area. https://assets.siemens-energy.com/siemens/assets/api/uuid:a42b9bc4-dc1e-4205-a27e-afa3de31b6f3/familybrochure-gasturbines-sev11-medium144dpi.pdf?ste_sid=cb8e656f6c97db539e71f012c79be3f5

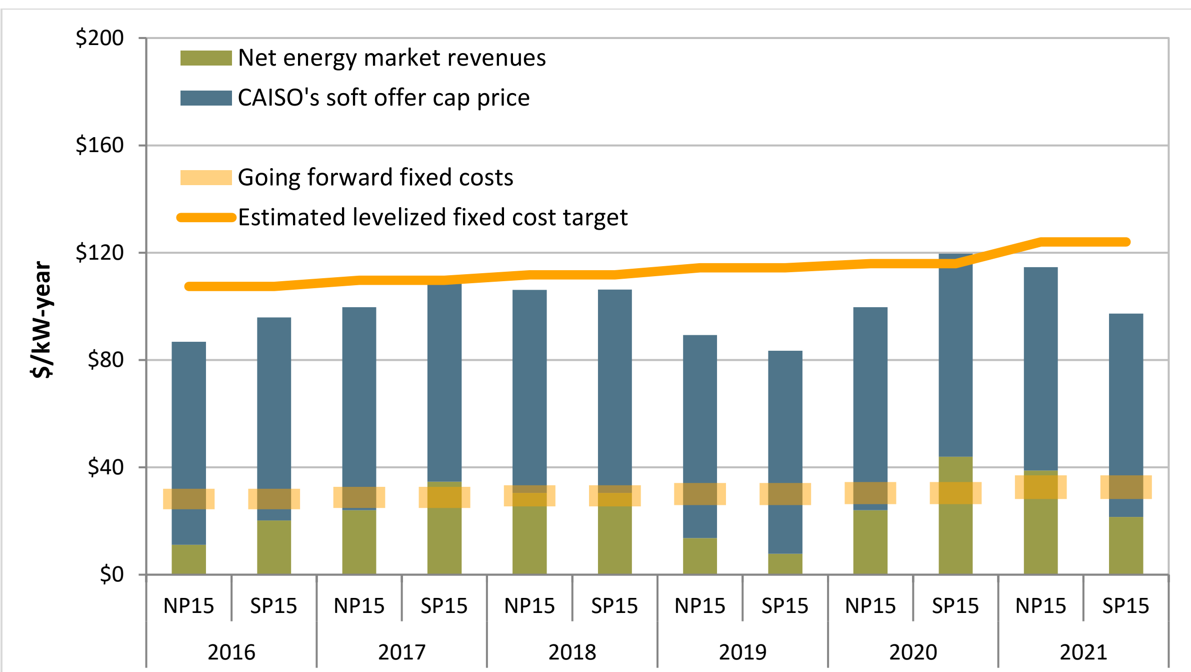
Maximum number of start-up and run-hours constraint has been relaxed in the annual optimization problem.

Table 1.4 Financial analysis of new combined cycle unit (2021)

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	17%	$134.91	$98.07	$36.84
	Day-ahead prices and default energy bids without adder	20%	$156.19	$115.15	$41.04
	Day-ahead commitment with dispatch to day-ahead and 5-minute prices using default energy bids	20%	$154.34	$115.59	$38.75
SP15	Day-ahead prices and default energy bids	10%	$89.29	$69.21	$20.09
	Day-ahead prices and default energy bids without adder	14%	$114.28	$91.02	$23.26
	Day-ahead commitment with dispatch to day-ahead and 5-minute prices using default energy bids	11%	$95.00	$73.64	$21.36

Figure 1.41 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 six 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 California ISO soft offer cap price for the capacity procurement mechanism ($75.68/kW-yr).

Figure 1.41 Estimated net revenue of hypothetical combined cycle unit



As shown in Figure 1.41, compared to 2020, net revenues in 2021 for the SP15 area are lower and are higher for the NP15 area. This is primarily because of relatively lower gas prices and high day-ahead prices in the NP15 area. This in turn led to increased unit commitment, low operating costs, and hence increased net energy market revenues for NP15.

Figure 1.41 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 California ISO 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 2021, the average net revenues were, on average, slightly lower than the going-forward fixed cost estimate range, shown by transparent yellow bars in Figure 1.41. As shown in this chart, DMM estimates that annual going-forward fixed costs range from $28 to $37/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 2021 ranged between 2 and 81 percent with an average of 42 percent capacity factor. In the SP15 area, actual capacity factors ranged between 19 and 55 percent, with an average capacity factor of 38 percent. Our estimates ranged from 10 to 20 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 mid-day 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.[119] This can result in a resource staying on in the mid-day 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.[120]

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 2021.

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119 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.

120 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[121]

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)	$199
Minimum up time	60 minutes
Minimum down time	60 minutes
Ramp rate	50 MW/minute
Financial Parameters (2021)	
Financing costs	$112 /kW-yr
Insurance	$9 /kW-yr
Ad Valorem	$11.4 /kW-yr
Fixed annual O&M	$8.5 /kW-yr
Taxes	$11 /kW-yr
Total Fixed Cost Revenue Requirement	**$152 /kW-yr**

121 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.
NERA Economic Consulting, *Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator,* September 3, 2010:
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 California ISO area.
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 (2021)

Zone	Scenario	Capacity factor	Real-time energy revenues ($/kW-yr)	Operating costs ($/kW-yr)	Net revenue ($/kW-yr)
NP15	15-minute prices and default energy bids	3.8%	$55.20	$30.63	$24.57
	15-minute prices and default energy bids without adder	4.9%	$63.42	$37.38	$26.04
	15-minute commitment with dispatch to 15-minute and 5-minute prices using default energy bids	4.3%	$59.13	$33.98	$25.14
SP15	15-minute prices and default energy bids	2.4%	$39.50	$23.07	$16.43
	15-minute prices and default energy bids without adder	2.8%	$42.88	$25.42	$17.46
	15-minute commitment with dispatch to 15-minute and 5-minute prices using default energy bids	2.7%	$42.24	$25.25	$16.99

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 2021 prices, net annual revenues were approximately $25/kW-yr with a 4 percent capacity factor. Similarly, in the SP15 area, net revenues were approximately $16/kW-yr with a 2.4 percent capacity factor.

The second scenario assumes that 15-minute prices are used for commitment and dispatch instructions, but does not factor the 10 percent scalar into the default energy bids as a measure of incremental energy costs.[122] Using this scenario, the hypothetical unit in NP15 earned net revenues of about $26/kW-yr with a 5 percent capacity factor. The hypothetical unit in SP15 earned net revenues of about $17.50/kW-yr with a capacity factor of 2.8 percent.

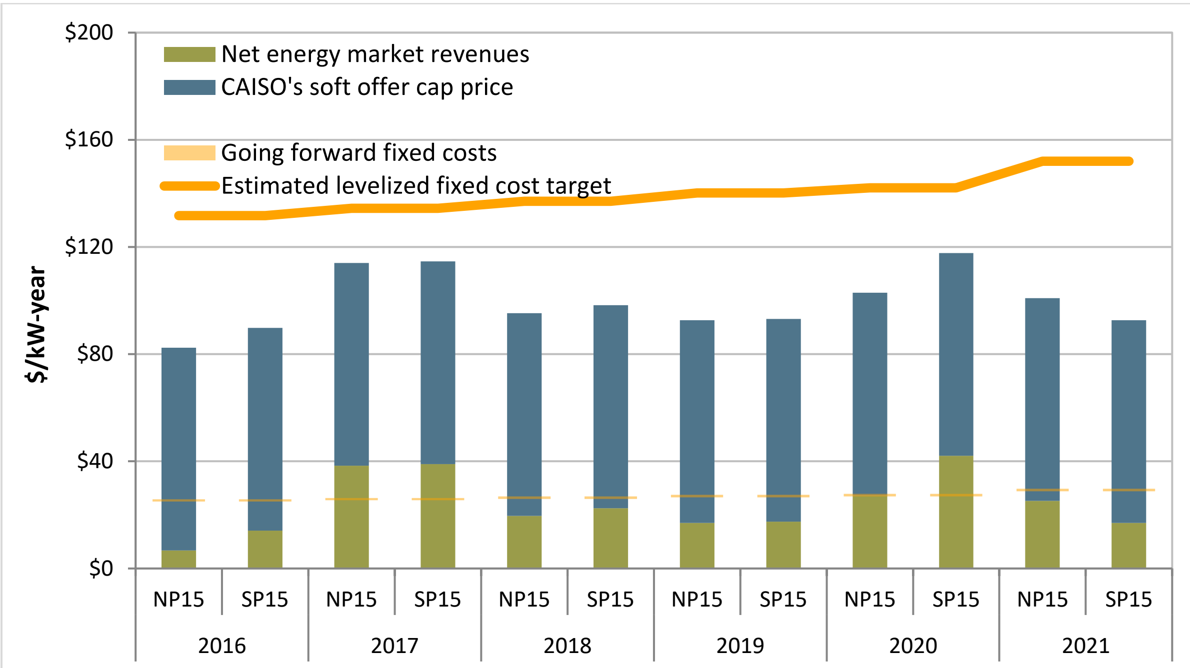
The third scenario includes all of the unit assumptions made in the first scenario, but also includes 5-minute prices for calculating unit revenues in addition to 15-minute prices. Specifically, this methodology commits the resource based on 15-minute market prices and then re-optimizes the dispatch 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 $25/kW-yr with a 4 percent capacity factor. In the SP15 area, net revenues were about $17/kW-yr with a 2.7 percent capacity factor.

Figure 1.42 shows how net revenue results from the optimization model compare to estimated annualized fixed costs of a hypothetical combustion turbine unit.[123] The green bars in this chart show estimated net revenues over the past six years.

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

123 More information on the capacity procurement mechanism can be found in Section 43A of the California ISO tariff: http://www.caiso.com/Documents/Section43A-CapacityProcurementMechanism-asof-Sep28-2019.pdf

Figure 1.42 Estimated net revenues of new combustion turbine



As shown in Figure 1.42, 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. In 2021, net revenues in SP15 were 60 percent lower when compared to 2020. This is because gas prices in this area increased by $4/MMBtu thereby increasing operating costs and overall lowering net revenues. For the NP15 area, the net revenues were about the same as they were in 2020.

Figure 1.42 shows that, from 2016 through 2021, net revenue estimates for a hypothetical combustion turbine unit in both the NP15 and 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 2021 ranged between 1 and 19 percent, with an average capacity factor of 6 percent. In the SP15 area, actual capacity factors ranged between 0.02 and 9 percent, with an average capacity factor of 3 percent. DMM's estimates ranged from 2.4 to 5 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

Net revenues were calculated using two different scenarios for a battery unit located across 360 pricing nodes, separately.[124] Table 1.8 and Table 1.9 show the optimization model results under these two scenarios using the parameters specified in Table 1.7. 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 1.9, 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).[125]

In the first scenario (Table 1.8), we simulated the charging and discharging of a battery unit given day-ahead market prices at 360 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. As shown in Table 1.8, net revenues in 2021 under the energy price arbitrage scenario averaged $13.53/kW-yr and are down by 26 percent compared to 2020.

124 For 2020, the model was run across 350 pricing nodes that had available data.

125 More information on market performance of existing battery storage resources is provided in Section 1.2.4.

Table 1.8 New battery energy storage net market revenues by LCA (Scenario 1)

Local capacity area	TAC area	Net market revenues ($/kW) Scenario 1 Energy arbitrage only									
		2020 Q1	2020 Q2	2020 Q3	2020 Q4	2021 Q1	2021 Q2	2021 Q3	2021 Q4	2020 $/kW-yr	2021 $/kW-yr
Greater Bay Area	PG&E	$0.02	$0.34	$9.05	$1.56	$5.86	$1.10	$1.41	$0.04	$10.98	$8.40
North Coast & North Bay (NCNB)	PG&E	$0.08	$0.82	$13.54	$2.14	$5.96	$0.97	$1.37	$0.00	$16.58	$8.30
Greater Fresno	PG&E	$0.09	$5.21	$12.53	$2.83	$7.56	$10.38	$11.64	$4.18	$20.65	$33.77
Sierra	PG&E	$0.10	$1.48	$15.05	$1.77	$5.47	$1.84	$1.61	$0.00	$18.41	$8.92
Stockton	PG&E	$0.02	$0.34	$9.45	$1.53	$4.91	$1.06	$1.64	$0.04	$11.35	$7.64
Kern	PG&E	$0.02	$0.72	$10.38	$1.47	$6.78	$2.95	$3.97	$1.41	$12.59	$15.11
LA Basin	SCE	$2.13	$0.68	$20.80	$3.91	$9.20	$1.98	$1.65	$0.47	$27.52	$13.30
Big Creek/Ventura	SCE	$0.07	$0.52	$20.69	$1.99	$8.39	$2.49	$1.75	$0.67	$23.28	$13.30
San Diego/Imperial Valley	SDG&E	$1.54	$0.59	$20.67	$2.14	$7.66	$3.97	$1.84	$0.25	$24.93	$13.73
CAISO System		$0.58	$0.60	$13.26	$1.76	$7.22	$2.40	$2.15	$1.01	$16.20	$12.78

Figure 1.43 and Figure 1.44 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 2021. On average, the battery unit located in the PG&E TAC area was charging in about 4.4 percent of the hours and discharging in about 3.4 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.

Figure 1.43 Average hourly battery schedules across pricing nodes in PG&E area (2021)

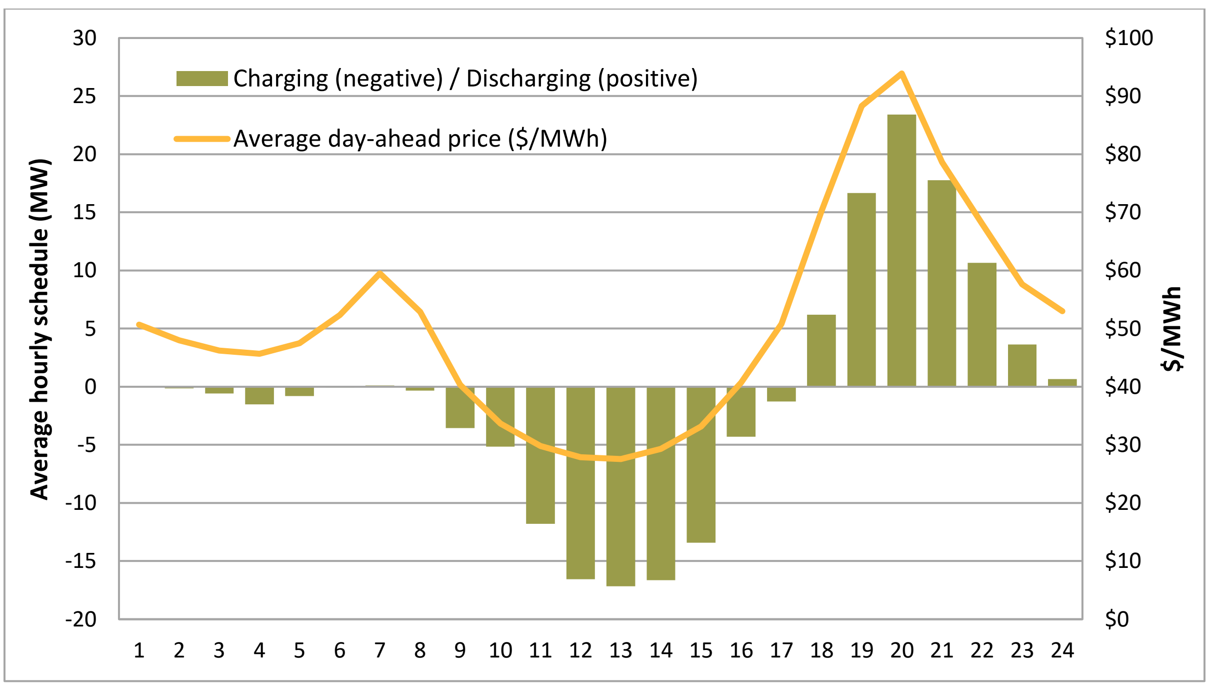
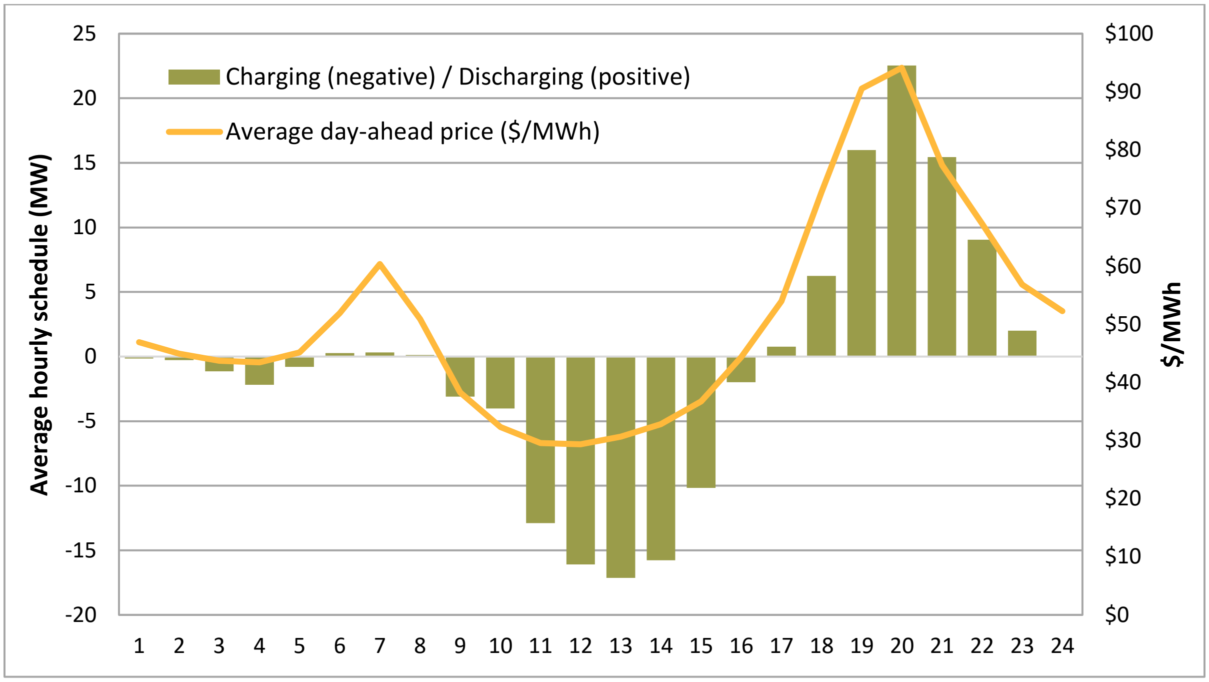


Figure 1.44 Average hourly battery schedules in SCE area (2021)



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 360 pricing nodes, independently. Similar to the first scenario, default energy bids proposed under the 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 10 percent of the regulation up and regulation down awards from the day-ahead market are deployed in real-time for frequency regulation.[126] 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 (10 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.

As shown in Table 1.9, net revenues in the third quarter of 2021 are significantly lower when compared to the same quarter of 2020. This is because of a significant drop in regulation up prices during the peak hours of the quarter in 2021 compared to 2020. In addition, the charge and discharge bid costs for the third quarter of 2021 rose by 94 percent and 40 percent, respectively, from the third quarter of 2020, thereby reducing the net revenues. Overall, for 2021, the net revenues averaged $114/kW-yr, which is slightly down from $118/kW-yr in 2020. The results from this analysis show that net market revenues

126 Fifteen-minute AGC signal data is used to estimate the percentage of awarded regulation range in the day-ahead, which is utilized in real-time regulation movement. For 2020, the model uses a 12 percent estimate based on 2020 AGC data.

under the second scenario (energy and regulation) are significantly higher than the first scenario (energy arbitrage only). In addition, net revenues in 2021 are greater in northern regions compared to the southern regions in this scenario.

Table 1.9 New battery energy storage net market revenues by LCA (Scenario 2)

Local capacity area	TAC area	Net market revenues ($/kW) Scenario 2 Energy and Regulation									
		2020 Q1	2020 Q2	2020 Q3	2020 Q4	2021 Q1	2021 Q2	2021 Q3	2021 Q4	2020 $/kW-yr	2021 $/kW-yr
Greater Bay Area	PG&E	$23.55	$24.82	$31.15	$22.88	$42.30	$32.89	$24.64	$14.32	$102.41	$114.14
North Coast & North Bay (NCNB)	PG&E	$25.12	$28.18	$33.87	$23.39	$42.25	$32.86	$24.61	$14.16	$110.56	$113.88
Greater Fresno	PG&E	$25.65	$32.50	$34.87	$25.84	$44.34	$42.60	$35.19	$20.61	$118.86	$142.74
Sierra	PG&E	$23.75	$26.10	$35.22	$23.30	$42.02	$33.98	$24.48	$14.17	$108.38	$114.65
Stockton	PG&E	$23.50	$25.98	$31.30	$23.01	$42.33	$33.21	$25.01	$14.64	$103.79	$115.19
Kern	PG&E	$25.28	$28.60	$33.20	$24.34	$43.34	$37.79	$27.50	$18.93	$111.41	$127.55
LA Basin	SCE	$27.16	$23.30	$53.35	$31.45	$42.03	$25.36	$17.73	$15.65	$135.26	$100.77
Big Creek/Ventura	SCE	$26.14	$23.32	$53.11	$29.52	$41.57	$25.71	$17.93	$15.81	$132.08	$101.02
San Diego/Imperial Valley	SDG&E	$29.01	$22.85	$53.28	$29.85	$40.99	$26.60	$18.05	$14.59	$134.99	$100.23
CAISO System		$25.99	$25.65	$40.96	$26.77	$42.60	$31.09	$22.37	$16.92	$119.37	$112.97

Figure 1.45 and Figure 1.46 show optimal hourly awards for energy and regulation averaged across pricing nodes located in the PG&E and SCE TAC area, respectively, for 2021. On average, the battery unit located in the PG&E TAC area was charging in about 3 percent of the hours and discharging in less than about 3.5 percent of the hours. In the same area, regulation up award frequency was about 52 percent compared to 66 percent for regulation down. The unit located in the SCE TAC area, on average, was charging in around 0.5 percent, and discharging in around 1 percent of the hours. Regulation up and regulation down award frequency averaged about 42 percent and 52 percent of hours, respectively.

The net revenue results from this model are benchmarked against battery resources providing energy and ancillary services in the California ISO market. Based on 2021 settlements data, existing battery resources have net revenues in the range of $47/kW-yr to $137/kW-yr, averaging about $104/kW-yr. Results from the model's second scenario (energy and regulation) show estimated net revenues in the range of $100/kW-yr to $143/kW-yr, averaging $114/kW-yr, which were relatively close to actual revenues earned by battery resources in 2021.

Figure 1.45 Average hourly battery energy and regulation awards in PG&E area (2021)

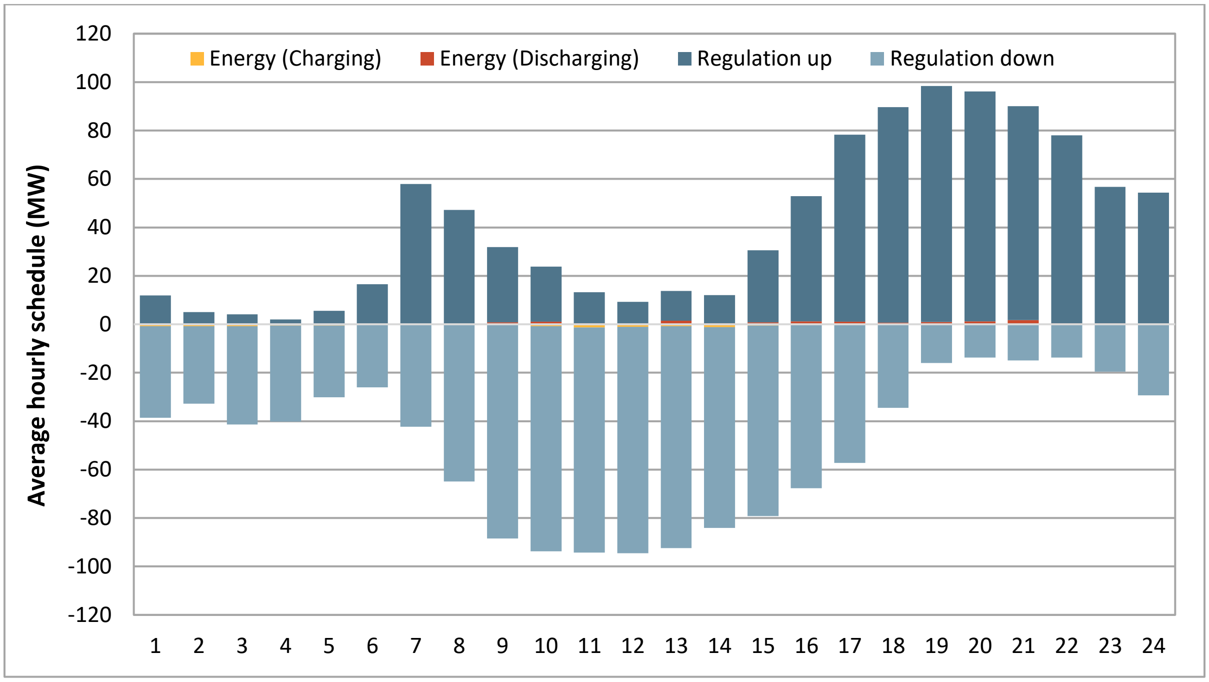
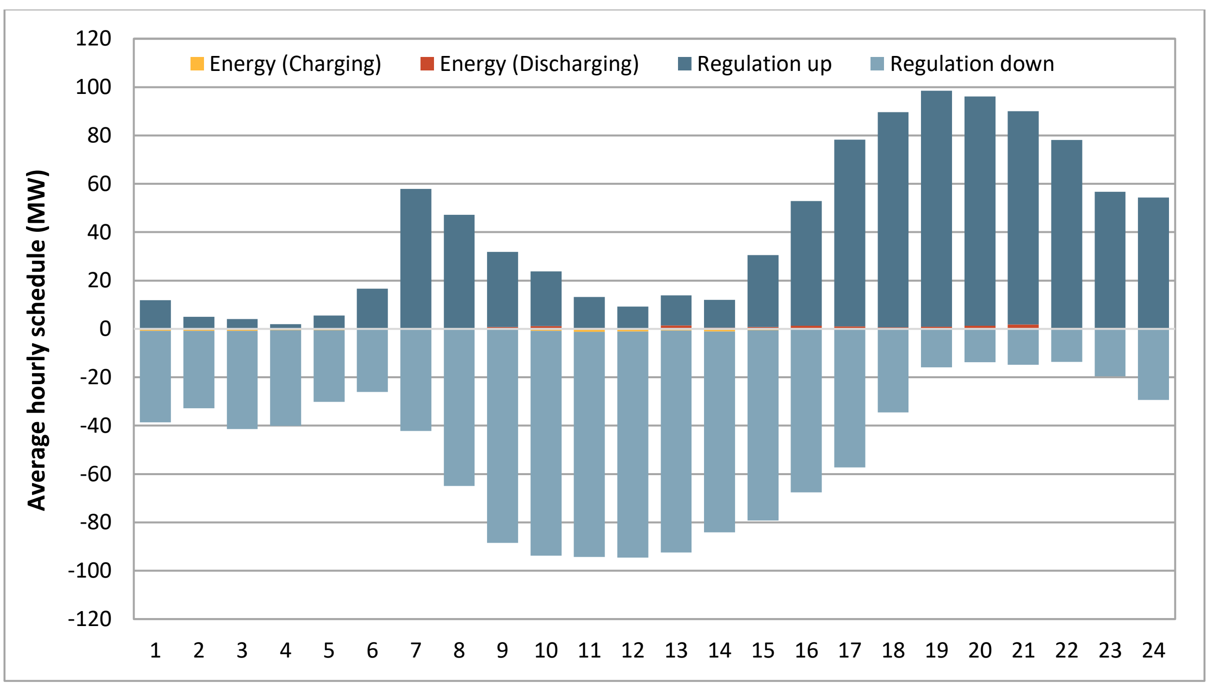


Figure 1.46 Average hourly battery energy and regulation awards across pricing nodes in SCE area (2021)



2 Overview of market performance

The California ISO markets continued to perform efficiently and competitively in 2021.

- **Total wholesale costs increased by about 33 percent** to $12.6 billion due to substantially higher natural gas prices. Controlling for both natural gas costs and greenhouse gas prices, wholesale electric costs decreased by about 10 percent.
- **Energy market prices were competitive, with prices usually reflecting resources' marginal costs**. DMM estimates the impact of import and gas resources bidding above reference levels, a conservative measure of average price-cost markup, was about $1.41/MWh, or about 2.5 percent.
- **Energy market prices were about 50 percent higher in 2021 compared to 2020,** primarily due to higher natural gas prices. Prices in the 5-minute market were lower than prices in the day-ahead and 15-minute markets due to manual adjustments to the hour-ahead load forecast and additional energy from out-of-market commitments and dispatches issued after the day-ahead market.[127]
- **Bid cost recovery payments in the California ISO increased to the highest value since 2011,** totaling $158 million, or about 1.2 percent of total energy costs. This 25 percent increase from 2020, when payments to units in the CAISO were $126 million, was less than the increase in wholesale costs.
- **Bid cost recovery payments for units in the Western Energy Imbalance Market totaled about $22 million** in 2021; about $13 million lower than in 2020. The cost of these payments is allocated back to the balancing area where the units receiving these payments are located.
- **Total CAISO real-time imbalance offset costs totaled $177 million this year,** compared to $176 million in 2020. Congestion offsets made up for most of the total and were largely generated by significant reductions in constraint limits between the 15-minute and day-ahead markets.
- **Recent changes to the residual unit commitment (RUC) process** allow exports to be curtailed when procurement alone fails to bridge the gap between physical supply cleared in the day-ahead and the day-ahead forecast load.
- **Significant volumes of exports clearing the day-ahead market were curtailed through the residual unit commitment process on the highest load days.** On some high load days more than 2.5 GW of exports cleared in the day-ahead market were cut in the residual unit commitment process.
- **Flexible ramping product** system-level prices were zero for over 99 percent of intervals in the 15-minute market, and 99.9 percent of intervals in the 5-minute market for each of upward and downward flexible ramping capacity. The California ISO is implementing nodal procurement for the flexible ramping product in fall of 2022. This is expected to resolve two issues lowering prices (1) stranded flexible ramping capacity and (2) the undesirable interplay between local and system requirements.

[127] The California ISO is investigating factors contributing to a day-ahead price premium in an on-going stakeholder process. See initial findings here. California ISO, *Price Performance in the CAISO's Energy Markets*, April 3, 2019: http://www.caiso.com/Documents/WhitePaper-PricePerformanceAnalysis-Apr3-2019.pdf

- **Market changes were enacted to comply with FERC Order No. 831,** which increased the bid cap to $2,000/MWh but enforces a soft bid cap of $1,000/MWh. This allows resources to bid above the soft bid cap under certain market conditions, which happened very rarely in 2021.[128]

2.1 Total wholesale market costs

The total estimated wholesale cost of serving load in 2021 was about $12.6 billion, or about $56/MWh. This represents a 33 percent increase from about $42/MWh, or $8.9 billion in 2020. After normalizing for natural gas prices and greenhouse gas compliance costs, using 2017 as a reference year, DMM estimates that total wholesale energy costs decreased by about 10 percent from about $44/MWh in 2020 to just under $40/MWh in 2021.

A variety of factors contributed to the changes in both nominal and normalized wholesale costs in 2021. Higher gas prices pushed nominal prices up in 2021, but after adjusting for both gas prices and greenhouse gas compliance costs, a trend of lower loads in both the California ISO and region-wide reduced prices below 2020 prices.

As highlighted elsewhere in this report, conditions that contributed to higher nominal wholesale costs include the following:

- **Higher energy prices due to the large increase in natural gas prices.** Spot market natural gas prices increased about 83 percent from 2020 (Section 1.2.6).
- **Natural gas production increased**, substituting for lower imports and less hydroelectric production.
- **Hydroelectric production decreased** about 26 percent from 2020 (Section 1.2.2).

After adjusting for changes in natural gas prices as well as greenhouse gas compliance costs, conditions that contributed to lower normalized wholesale costs include the following:

- **Average net load decreased 5 percent** (Section 2.3); partly as a result of the increase in solar and wind generation (Section 1.2.2).
- **Relatively mild weather conditions led to lower load in peak hours** (Section 1.1.1); the markup of prices during peak hours compared to off-peak hours decreased from 2020 to 2021.
- **Hours with high load across all WEIM entities decreased;** the lack of region-wide heat waves helped keep prices lower after adjusting for gas prices.

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

[128] See Section 2.3.2 and 10.4 for more details on the FERC Order No. 831 tariff amendment and its impact.

cap-and-trade program. The green line represents the annual average daily natural gas price including greenhouse gas compliance.[129]

Figure 2.1 Total annual wholesale costs per MWh of load (2017-2021)

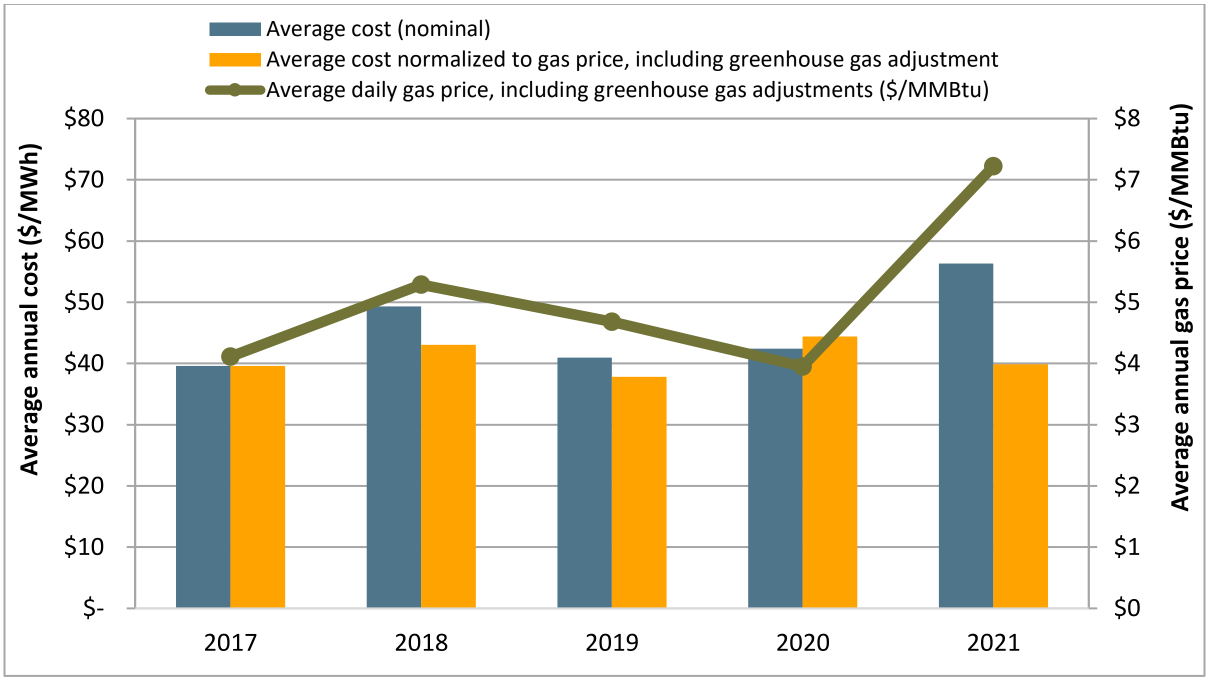


Table 2.1 provides annual summaries of nominal total wholesale costs by category for the previous five years.[130] The total wholesale energy cost also includes costs associated with ancillary services, convergence bidding, residual unit commitment, bid cost recovery, reliability must-run contracts, the capacity procurement mechanism, the flexible ramping constraint and product, and grid management charges.[131]

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129 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 2017 and 2018. A gas cost factor of 80 percent has historically been incorporated into the normalization calculations to account for this relation between electricity costs and gas prices. For this report, DMM used time-series regression analysis to estimate the relationship between daily energy and gas prices each year from 2018 to 2021. In addition to gas prices, the models also control for load, VER, and hydro conditions, as well as seasonal indicators and autoregressive terms. Yearly gas price estimates are 0.6 for 2018, 0.6 for 2019, 1 for 2020, and 0.7 for 2021.

130 Values shown in this section represent cost to California ISO load only and do not include costs to load in the WEIM.

131 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*. 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.
Department of Market Monitoring, *2009 Annual Report on Market Issues and Performance,* April 2010: http://www.caiso.com/2777/27778a322d0f0.pdf

As shown in Table 2.1, the 33 percent increase in total nominal cost in 2021 was largely from changes in day-ahead energy costs, which increased by over $14/MWh or roughly 37 percent. Real-time energy costs decreased about 30 percent as real-time prices fell, as discussed in more detail in Section 2.3.

Day-ahead energy costs remain the largest proportion of wholesale costs at about 94 percent. The remaining components continue to represent a relatively small portion of the total. Overall reliability costs increased due to significant increases in the costs of capacity procurement mechanism (CPM) and reliability must-run (RMR) contracts.[132] Bid cost recovery costs increased slightly, although less than the increase in day-ahead energy costs and nominal wholesale costs. The grid management charge costs decreased 6 percent because of reduced revenue requirement in 2021.[133] Reserve costs decreased about 20 percent in 2021, due to lower ancillary service costs caused by lower ancillary service prices.[134]

Table 2.1 Estimated average wholesale energy costs per MWh (2017-2021)

	2017	2018	2019	2020	2021	Change '20-'21
Day-ahead energy costs	$ 37.40	$ 46.05	$ 38.13	$ 38.61	$ 53.02	$ 14.41
Real-time energy costs (incl. flex ramp)	$ 0.73	$ 0.59	$ 1.02	$ 1.65	$ 1.19	$ (0.46)
Grid management charge	$ 0.44	$ 0.46	$ 0.46	$ 0.46	$ 0.43	$ (0.04)
Bid cost recovery costs	$ 0.41	$ 0.68	$ 0.56	$ 0.60	$ 0.69	$ 0.09
Reliability costs (RMR and CPM)	$ 0.10	$ 0.68	$ 0.06	$ 0.07	$ 0.21	$ 0.13
Average total energy costs	**$ 39.09**	**$ 48.47**	**$ 40.23**	**$ 41.40**	**$ 55.52**	**$ 14.12**
Reserve costs (AS and RUC)	$ 0.71	$ 0.87	$ 0.75	$ 1.02	$ 0.79	$ (0.23)
Average total costs of energy and reserve	**$ 39.80**	**$ 49.34**	**$ 40.98**	**$ 42.42**	**$ 56.31**	**$ 13.89**

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 calculates these estimated 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, indicating that

132 The California ISO issued a capacity procurement mechanism significant event designation starting July 9, 2021, and procured almost 2,000 MW of additional capacity at an estimated cost of $9.8 million (Section 9.6). Costs for reliability must-run contracts also increased to about $38 million in 2021 from $13 million in 2020 (Section 9.7).

133 The grid management charge was reduced in 2021 because revenue requirements decreased by 3 percent from 2020, and were the lowest since 2006.
California ISO, *2021 Budget and Grid Management Charge Rates,* December 17, 2020, p. 3:
http://www.caiso.com/Documents/2021Budget-GMCRatesBook-Final.pdf

134 Additional information on bid cost recovery and ancillary service costs is included in Sections 2.6 and 5.1.

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 re-runs 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.[135] Each market simulation run is preceded by a base case re-run 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.[136]

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 $1.41/MWh or 2.5 percent.[137] Very low price-cost markup values indicate that prices were competitive overall for the year.

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[135] Detailed descriptions of these scenarios can be found in the DMM *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

[136] 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.

[137] For 2021, a limited number of dates included adjustments to default energy bid values in the day-ahead market under the new commitment cost and default energy bid enhancement rules that went into effect in February 2021. Because of software limitations, these adjusted values could not be captured in the scenario simulation runs. However, because the resources with these adjusted values were not subject to mitigation during that timeframe, there was no impact observed in the scenario results.

Figure 2.2 Day-ahead market price-cost markup – default energy, commitment cost, and import bids scenario (2021)[138]

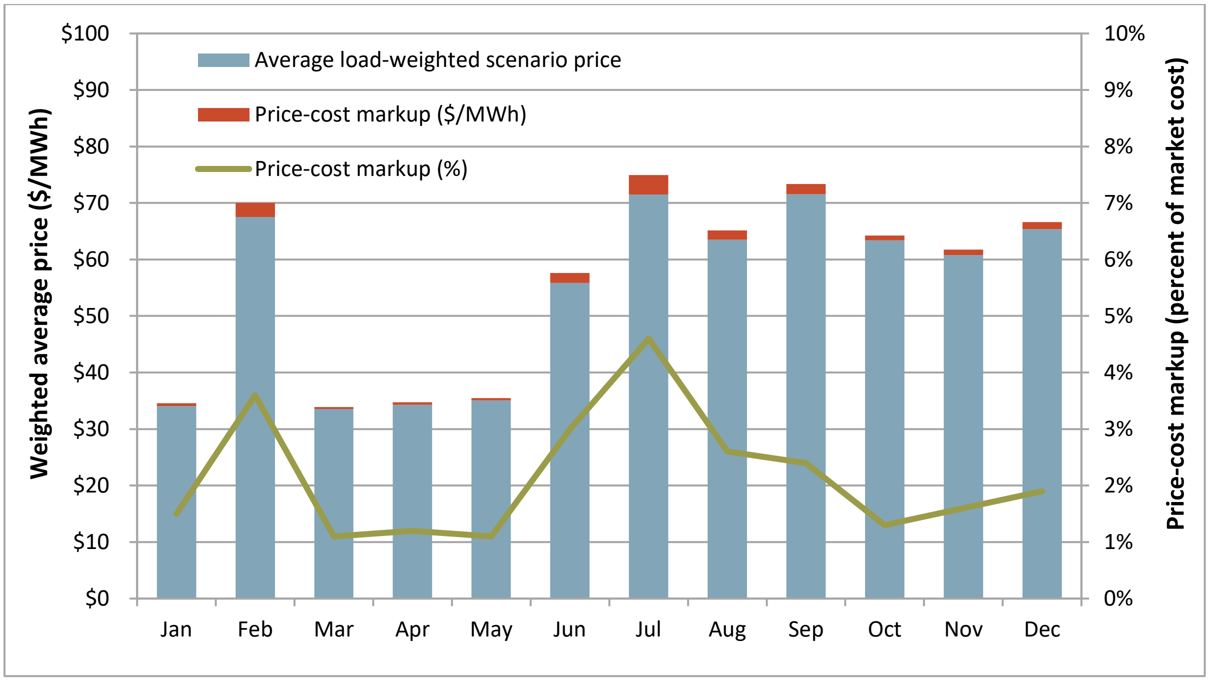
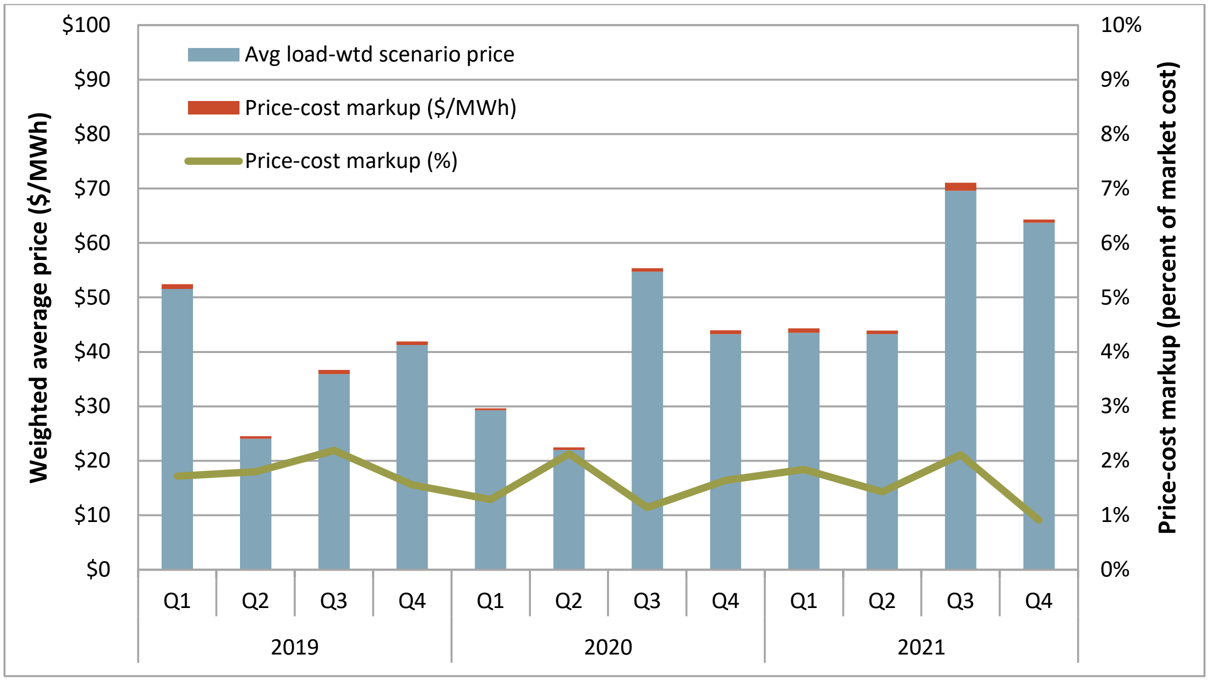


Figure 2.3 shows results for the scenario that caps energy bids for gas resources at the lower of their submitted bid or default energy bid. Price-cost markup for this scenario was slightly higher in 2021 at about $0.94/MWh, or 1.6 percent compared with $0.56/MWh, or 1.4 percent for 2020. This scenario may be a low-end measure of system market power for the following 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 were assumed to be competitive, including those of non-resource specific imports. In addition, this analysis did 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.

138 This figure shows results for a scenario where: 1) bids for gas-fired units were set to the minimum of their submitted bid or default energy bid; (2) bids for gas-fired resources' commitment costs were set to the minimum of their bid or 110 percent of proxy price; and (3) 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: 1) bids for gas-fired generation were set to their default energy bids; 2) convergence bids were removed; and 3) 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.

Figure 2.3 Quarterly day-ahead market price-cost markup – default energy bid scenario (2019-2021)



2.3 Energy market prices

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

- Average energy market prices were about 50 percent higher than in 2020. 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 California ISO and other regional markets. Gas prices were much higher in 2021 than 2020.

- Prices in the 5-minute market were lower than prices in both the 15-minute and day-ahead markets. Day-ahead prices averaged $53/MWh, 15-minute prices were about $51/MWh, and 5-minute prices were about $45/MWh. Convergence bidding provides incentives for financial arbitrage to converge day-ahead and 15-minute prices. Lower 5-minute prices reflect the difference between 15-minute and 5-minute load adjustments made by the CAISO grid operators.

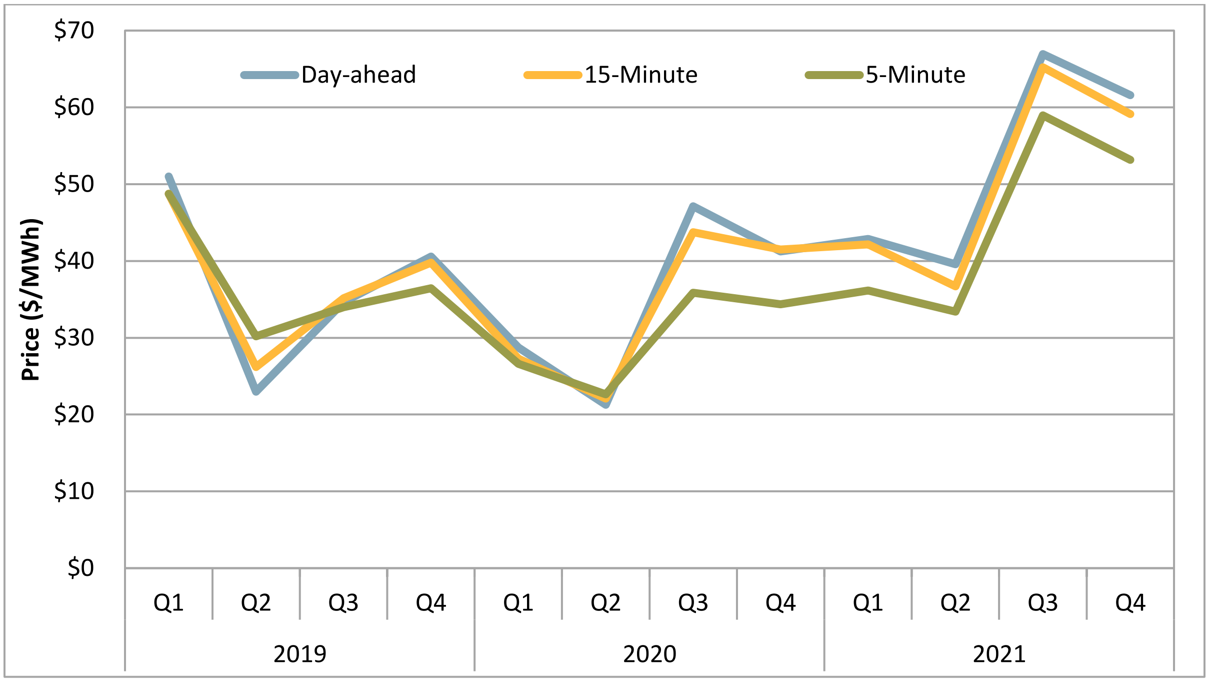
- Average hourly prices generally moved in tandem with the average net load. The evening peak net load was 2 percent lower than in 2020. Peak prices were higher in 2021, and occurred during the highest net load hour in the day-ahead market, but an hour earlier (during ramping period) in the real-time markets.

Figure 2.4 shows the load-weighted average energy prices across the three largest aggregation points in the California ISO (Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric) during all hours for the day-ahead and real-time markets. Overall prices were substantially higher in

2021. Across all three markets, prices were roughly 50 percent higher in 2021 compared to 2020. These higher prices are due in part to less hydroelectric generation and higher gas prices.[139]

The day-ahead and 15-minute market energy prices averaged $53/MWh and $51/MWh respectively. Prices in the 5-minute market averaged $45/MWh, substantially lower, but a 52 percent increase compared to the 5-minute market prices in 2020.

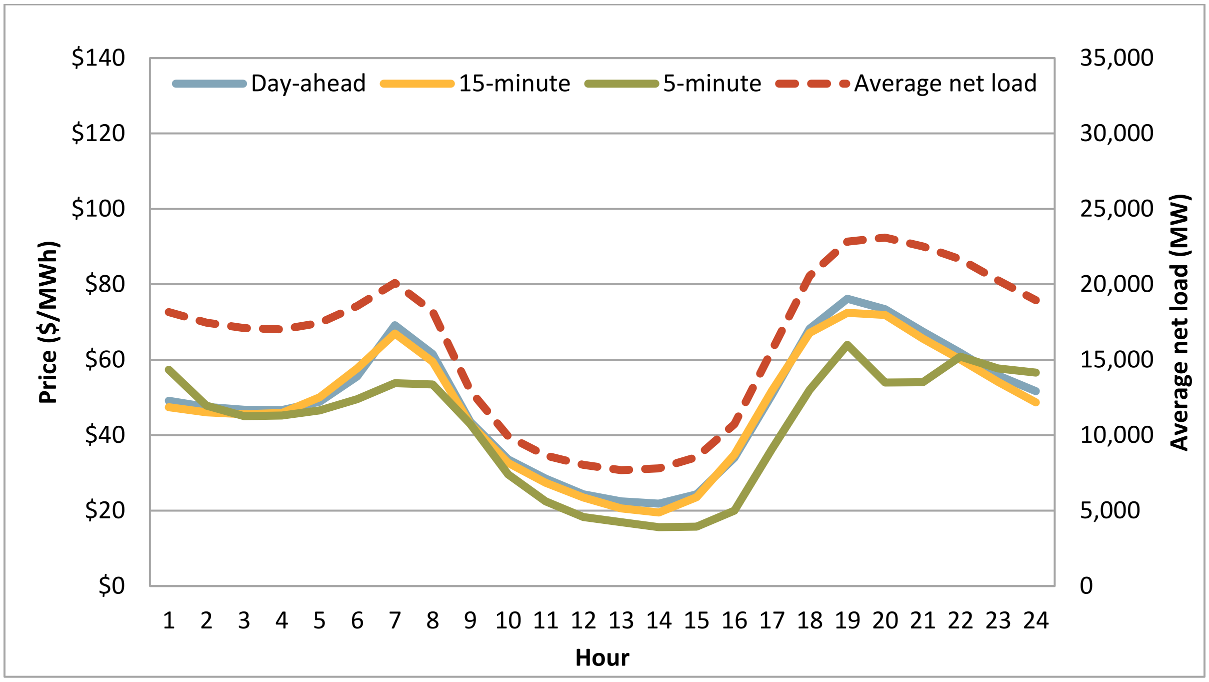
Figure 2.4 Average quarterly prices (all hours) – load-weighted average energy prices



To analyze how prices vary throughout the day, Figure 2.5 illustrates hourly load-weighted average energy prices in the California ISO in the day-ahead and real-time markets, as well as average hourly net load. As both utility scale and behind the meter solar generation have increased, energy prices have followed net load more closely. Net load and energy prices were lowest mid-day when low-priced solar generation was the greatest. Energy prices and net load both peak during the early evening when demand is still high but solar generation has substantially decreased. Day-ahead market prices in peak hours (4-10 p.m.) were about 70 percent higher than off-peak hours, compared to 2020 when peak prices in the day-ahead were over twice as high as off-peak. 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 17-22, prices in the 5-minute market was roughly 20-50 percent lower than those in the day-ahead and 15-minute market.

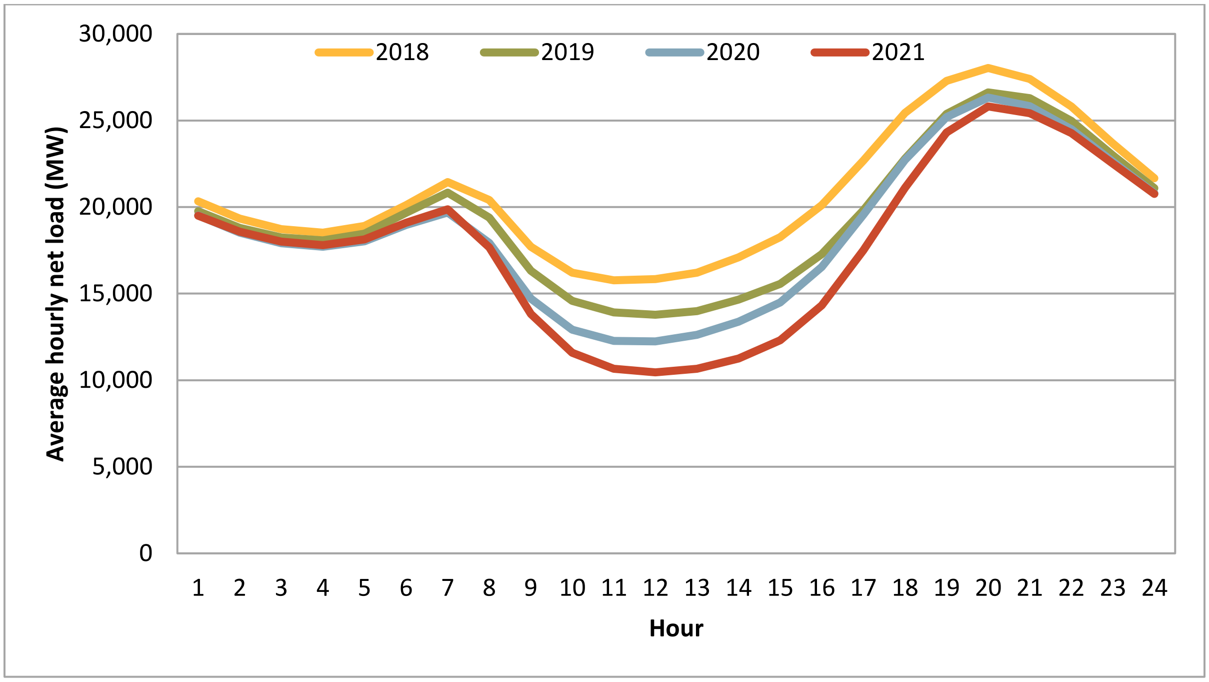
139 See Sections 1.2.1 and 1.2.6 about hydroelectric production and natural gas price trends.

Figure 2.5 Hourly load-weighted average energy prices (2021)



Average net load peaked in hour ending 20 at about 25,800 MW, or about 2 percent lower than the same hour last year. Figure 2.6 shows the change in net load from 2018 to 2021. On average, net load was roughly 5 percent lower in 2021, compared to 2020. The decrease in net load was most pronounced during the morning through afternoon (9 a.m. to 5 p.m.), when net load was around 10-15 percent lower in 2021. Prices in the day-ahead market were highest during the peak net load hour, averaging $95/MWh, which is 20 percent higher than the peak price last year. Prices in the real-time market spiked during the ramp up period with the highest prices in both the 15-minute and 5-minute markets during hour ending 19. In this hour, 15-minute prices averaged $93/MWh, and 5-minute market prices averaged $68/MWh, which was substantially lower.

Figure 2.6 Hourly average net load (2018-2021)

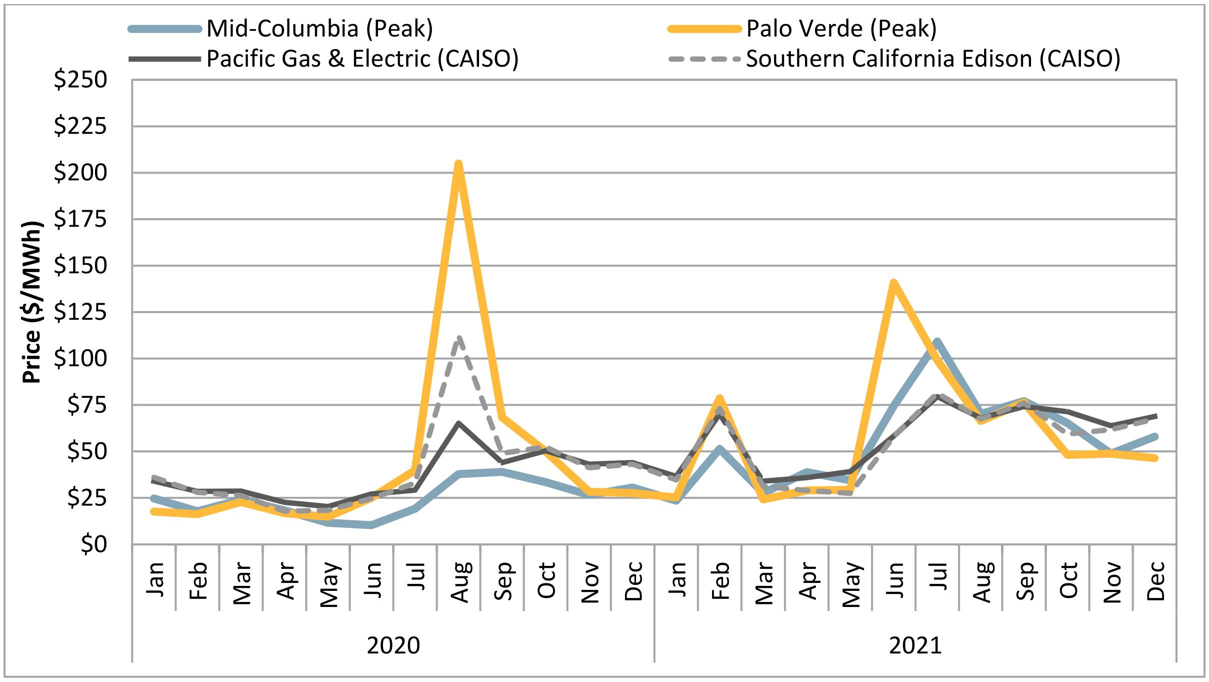


2.3.1 Comparison to bilateral prices

During the summer of 2021, day-ahead peak prices at Mid-Columbia and Palo Verde exceeded the average day-ahead peak prices in the California ISO (CAISO). Figure 2.7 shows monthly average day-ahead peak prices in the CAISO balancing area 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 CAISO balancing area are also represented in the figure by prices at the Southern California Edison and Pacific Gas and Electric load aggregation points.

As shown in the figure, during the February 2021 high gas price event across the west, average day-ahead market prices in California ISO across peak hours were greater than prices at Mid-Columbia and slightly lower than Palo Verde. The California ISO prices were significantly lower than both bilateral hubs during the heat wave conditions that existed in the Northwest and Southwest during mid and late-June.

Figure 2.7 Monthly average day-ahead and bilateral market prices



On June 17, 2021, prices at Mead and Palo Verde exceeded the $1,000/MWh WECC soft offer cap, requiring sellers to submit cost justification for sales made above the cap to FERC. DMM has intervened in this proceeding and submitted comments on most filings.[140,141] FERC also issued guidance responsive to the August 2020 cost justification filings for sales above the WECC soft cap.[142]

On April 8, 2022, FERC began issuing orders on cost justification filings for sales above the WECC soft offer cap during the August 2020 heat wave event. Several sellers have been ordered to refund the

140 Department of Market Monitoring, *Motion To Intervene* (FERC Docket No. ER21-2370, *et al*), July 28, 2021: http://www.caiso.com/Documents/Motion-to-Intervene-of-the-Department-of-Market-Monitoring-WECC-Soft-Offer-Cap-ER21-2370-et-al-Jul-28-2021.pdf

141 Department of Market Monitoring, *Comments on WECC Soft Offer Cap Cost Justification* (FERC Docket No. ER21-2453, et al), August 9, 2021: http://www.caiso.com/Documents/Comments-of-the-Department-of-Market-Monitoring-ER21-2453-et-al-WECC-Soft-Offer-Cap-Aug-9-2021.pdf
Department of Market Monitoring, *Motion to File Comments Out of Time on WECC Soft Offer Cap Cost Justification* (FERC Docket No. ER21-2370, et al), August 9, 2021: http://www.caiso.com/Documents/Motion-to-File-Comments-Out-of-Time-of-the-Department-of-Market-Monitoring-ER21-2370-et-al-WECC-Soft-Offer-Cap-Aug-9-2021.pdf

142 FERC Docket No. ER21-40-000, et al, *175 FERC ¶ 61,226, Order Approving Guidance for $1000/MWh soft price cap in the WECC.* June 17, 2021: https://www.ferc.gov/media/e-3-061721

premium charged above the index price used to justify the sale. A motion is pending at FERC to raise the soft offer cap from $1,000/MWh to $2,000/MWh for spot sales in WECC's bilateral markets.[143]

Average day-ahead prices in the CAISO balancing area and bilateral hubs (from ICE) were also compared to real-time hourly energy prices traded at Mid-Columbia and Palo Verde hubs for all hours of 2021 using data published by Powerdex. Day-ahead hourly prices in the Pacific Gas and Electric and Southern California Edison areas, across all hours in 2021, were lower on average than prices at Mid-Columbia and Palo Verde by about $7/MWh and $10/MWh, respectively. Average day-ahead prices at Mid-Columbia (from ICE) were greater than the average real-time prices at Mid-Columbia (from Powerdex) by $10/MWh. At Palo Verde, the average day-ahead price (from ICE) was higher than the real-time price (from Powerdex) by $6/MWh.

2.3.2 Price variability

Although average real-time prices were lower than day-ahead prices, real-time prices can exhibit greater volatility. This volatility is often driven by brief periods when the market software has exhausted upward and downward flexibility, requiring relaxation of the system power balance constraint.

Price variability in 2021 was similar to 2020, with the exception of high prices in February 2021 due to extremely high gas prices.

High prices

Higher prices tend to occur when conditions are tight due to limited supply. Figure 2.8 shows the frequency of high prices in the day-ahead, 15-minute, and 5-minute markets in both 2020 and 2021. Positive price spikes were most common in the first and third quarters in 2021. High prices in the first quarter were due to the gas price spike in February, caused by winter storm Uri. Prices tend to be higher in the third quarter due to warmer temperatures that lead to increased demand. Although there were some price spikes in the third quarter of 2021, the frequency was lower than the third quarter in 2020. This is due in part to the milder summer conditions in 2021.[144]

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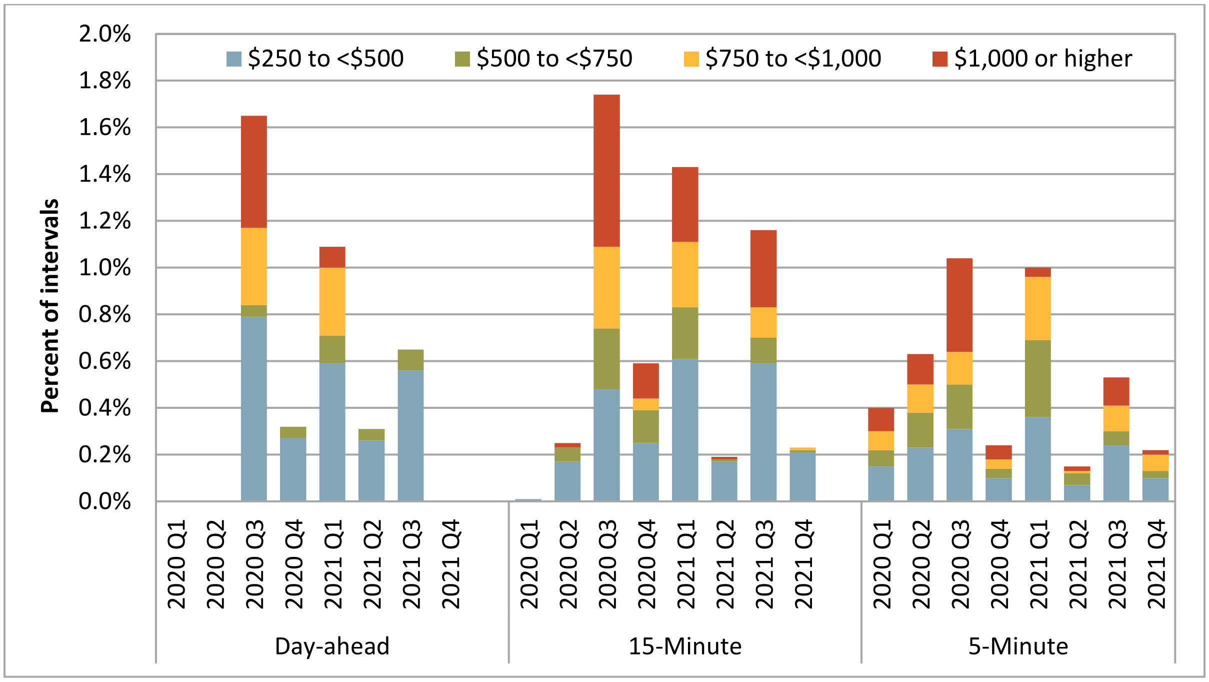
[143] FERC Docket No. ER21-64*, Macquarie Energy, LLC submits Explanation for Bilateral Spot Sales in Western Electricity Coordinating Council:* eLibrary | Docket Search Results (ferc.gov)
FERC Docket No. ER21-46, *Mercuria Energy America, LLC submits Tariff Filing per 35: Explanation for Bilateral Spot Sales in the West:* eLibrary | Docket Search Results (ferc.gov)
FERC Docket No. EL10-56*, Macquarie Energy and Mercuria Energy filings, July 19, 2021:* eLibrary | Docket Search Results (ferc.gov)

[144] Department of Market Monitoring, *Q3 2021 Report on Market Issues and Performance,* December 9, 2021, pp. 23-27: http://www.caiso.com/Documents/2021-Third-Quarter-Report-on-Market-Issues-and-Performance-Dec-9-2021.pdf

Figure 2.8 Frequency of positive price spikes (California ISO areas)



FERC Order No. 831

In March 2021, the first phase of the FERC Order No. 831 tariff amendment was implemented.[145] This new market rule established a hard bid cap of $2,000/MWh along with a soft bid cap of $1,000/MWh. This allows resources to bid above the soft bid cap under certain circumstances, specifically when either the maximum import bid price (MIBP) or a cost-verified energy bid from a resource-specific resource is greater than the $1,000/MWh bid cap. The MIBP is a reference point for import bids that is based on the prices at Mid-Columbia and Palo Verde. There were seven days with hours that had an MIBP over the $1,000/MWh bid cap. This allowed non-resource adequacy imports to bid over the soft bid cap during those specific hours. There were no instances of a cost-verified energy bid over the bid cap. Overall, there were few instances with bids over $1,000/MWh after the implementation of this tariff amendment.

Negative prices

Low or negative prices may occur during hours with an abundance of supply. 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 generation that is more expensive is dispatched down.

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145 For additional details, see DMM's 2021 Q1 and Q2 reports.
Department of Market Monitoring, *Q1 2021 Report on Market Issues and Performance,* June 9, 2021 pp. 93-96
http://www.caiso.com/Documents/2021-First-Quarter-Report-on-Market-Issues-and-Performance-Jun-9-2021.pdf
Department of Market Monitoring, *Q1 2021 Report on Market Issues and Performance*, October 5, 2021, pp. 101-103
http://www.caiso.com/Documents/2021-Second-Quarter-Report-on-Market-Issues-and-Performance-Oct-5-2021.pdf

Similar to last year, negative prices were infrequent across all three markets. Figure 2.9 shows the frequency of prices near or below $0/MWh in the day-ahead, 15-minute, and 5-minute markets in 2020 and 2021. Overall, negative prices are more frequent in the 15-minute and 5-market markets, compared to the day-ahead market. There were about 55 hours when the day-ahead prices were negative, or less than one percent of total hours. This is a decrease from 2020 when there were around 130 hours with negative day-ahead prices. The frequency of negative prices in the 15-minute and 5-minute markets was similar to 2020, although there were fewer negative price spikes in the second quarter of 2021.

Similar to the previous year, the frequency of prices near or below the -$150/MWh floor remained very close to zero in 2021. This result reflects the bidding flexibility of renewable resources and increased transfer capability in the real-time market from the Western Energy Imbalance Market.

Figure 2.9 Frequency of negative price spikes California ISO areas

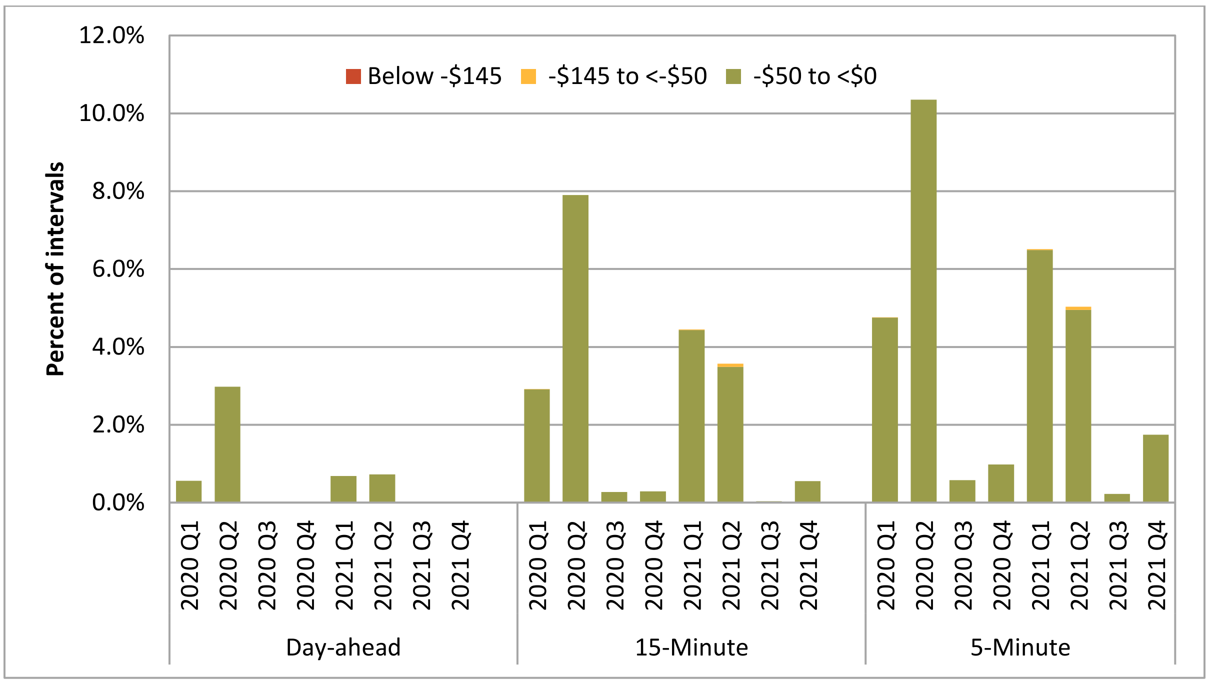


Figure 2.10 shows the annual frequency of negative prices in the 5-minute market since 2015. In 2021, roughly 3.5 percent of 5-minute intervals had negative prices, a slight decrease from 2020.
Figure 2.11 shows the hourly frequency of negative 5-minute prices in the last four years. The figure illustrates that the majority of negative prices during 2021 generally occurred during mid-day hours when solar generation was highest.

Figure 2.10 Frequency of negative 5-minute prices (CAISO LAP areas)

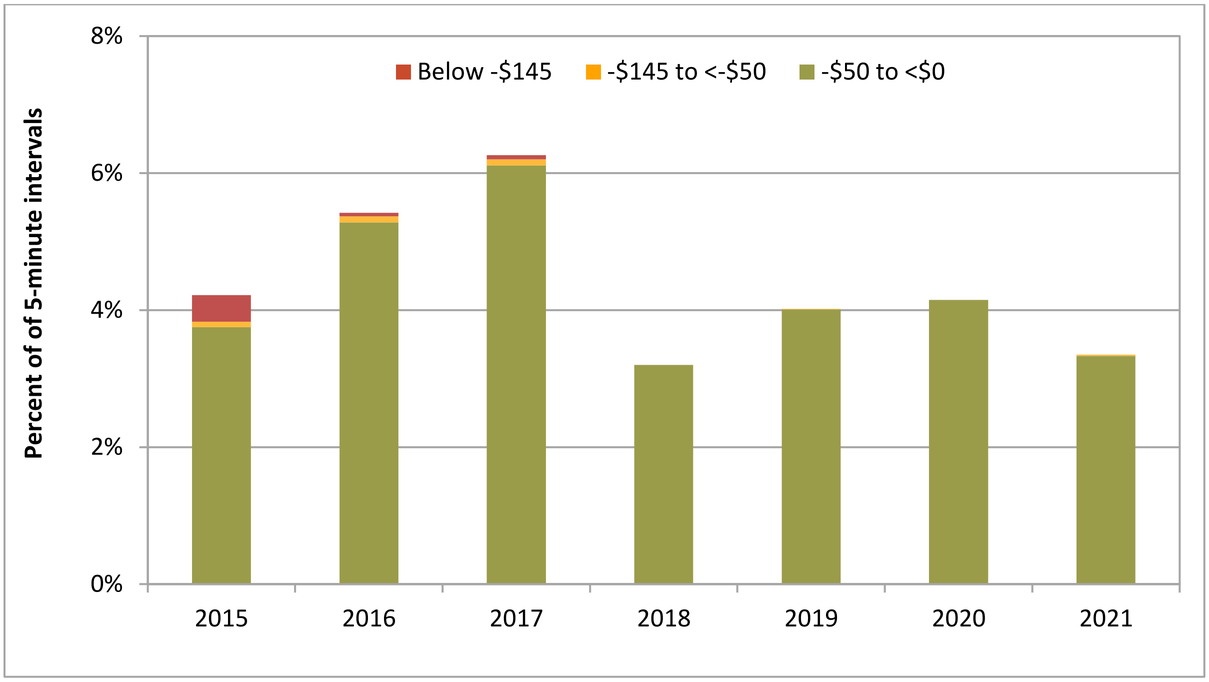
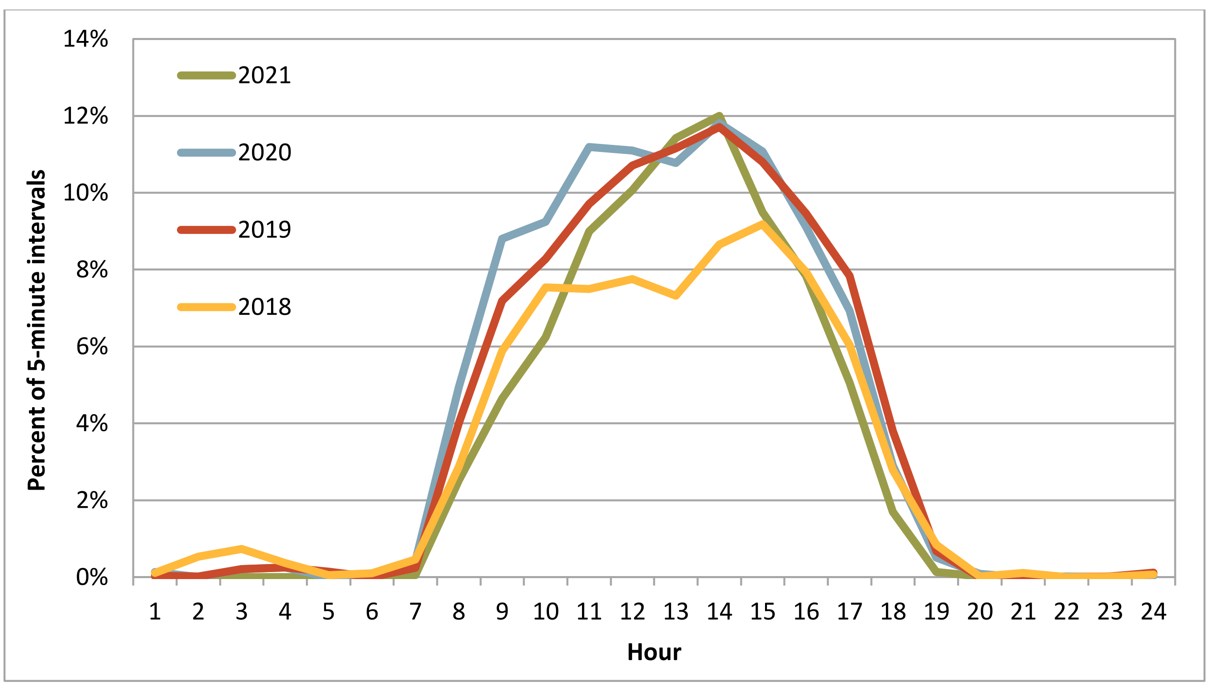


Figure 2.11 Hourly frequency of negative 5-minute prices by year (CAISO LAP areas)



2.3.3 Power balance constraint

The CAISO and Western 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.[146] When this occurs, prices can be set at the $1,000/MWh penalty parameter while relaxing the constraint for shortages (undersupply infeasibility), or the -$155/MWh penalty parameter while relaxing the constraint for excess energy (oversupply infeasibility). After the implementation of the FERC Order 831 Tariff Amendment, there are certain market conditions where the penalty parameter for undersupply can be set above $1,000/MWh.[147]

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 is triggered, 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.

System power balance constraint relaxations

The frequency of system power balance constraint relaxations, both set at the penalty price or resolved by the load conformance limiter, were relatively low in 2021.

Figure 2.12 shows the quarterly frequency of undersupply and oversupply infeasibilities in the 15-minute and 5-minute markets. The frequency of undersupply infeasibilities in the 15-minute market was highest during the third quarter. Undersupply infeasibilities in the 5-minute market were less frequent compared to 2020.

There continued to be no intervals during 2021 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, in addition to increased transfer capability from the energy imbalance market, continued to contribute to reduced oversupply conditions.

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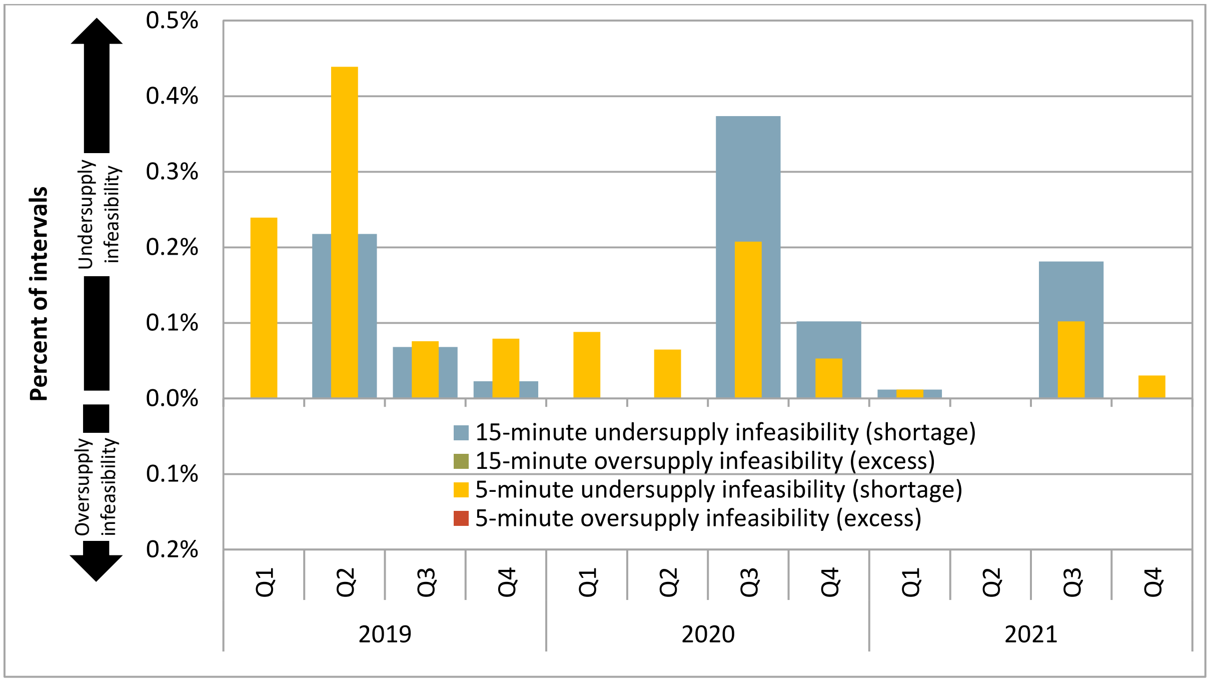
[146] Please refer to DMM's *2016 Annual* Report for a detailed description of the power balance constraint and load bias limiter. Department of Market Monitoring, *2016 Annual Report on Market Issues and Performance,* May 2017, pp. 101-103: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf

[147] On March 20, 2021, the penalty parameter for an undersupply infeasibility was scaled up to $2,000/MWh as part of FERC Order No. 831 compliance. On June 13, 2021, the California ISO implemented the second phase of the tariff amendment which limited the conditions for when the penalty parameter will be set over the soft bid cap of $1,000/MWh.

For more information see Department of Market Monitoring, *Q1 2021 Report on Market Issues and Performance*, June 9, 2021, Table 3.2: http://www.caiso.com/Documents/2021-First-Quarter-Report-on-Market-Issues-and-Performance-Jun-9-2021.pdf

Figure 2.12 Frequency of power balance constraint infeasibilities by market



2.4 Residual unit commitment

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.

On average, the total volume of capacity procured through the residual unit commitment process in all quarters of 2021 was 18 percent lower than 2020, as shown in Figure 2.13. California ISO operators are able to increase the amount of residual unit commitment requirements for reliability purposes. In 2021, these operator adjustments declined by 36 percent compared to 2020.[148]

Figure 2.13 also shows quarterly average hourly residual unit commitment procurement, categorized as non-resource adequacy, resource adequacy, or minimum load. Total residual unit commitment procurement decreased to 1,054 MW per hour in 2021 from an average of 1,287 MW in 2020. The figure shows that in 2021 the volume of residual unit commitment requirements was highest in the third quarter. Factors contributing to high third quarter volume included relatively high operator adjustments, higher cleared net virtual supply, and larger gaps between day-ahead load forecast and cleared supply. When the day-ahead market clears with net virtual supply, residual unit commitment capacity is needed to replace net virtual supply with physical supply.

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

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.[149] Most of the capacity procured is from units that 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 216 MW each hour. This was a 20 percent decrease from the capacity that was procured and committed to operate at minimum load in 2020. In 2021, about 17 percent of this capacity was from long-start units similar to 2020.[150]

In September 2020, the California ISO revised the residual commitment to address the treatment of economic and self-scheduled exports that clear the day-ahead integrated forward market (IFM) run. With this change, the residual unit commitment process is able to curtail economic and lower priority self-scheduled exports before relaxing the power balance constraint. These reduced exports no longer receive a real-time scheduling priority that exceeds the California ISO real-time load and can choose to re-bid in real-time or resubmit as self-schedules in real-time.[151] Effective August 4, 2021, further changes were implemented to designate self-schedule exports as either a low or high priority export. High priority price taking (PT) exports are those supported by non-resource adequacy capacity, while low-priority price taking (LPT) exports are not.[152] All low-priority exports that clear the residual unit commitment process will be prioritized below internal load. In addition, the California ISO will prioritize exports that bid into the day-ahead market and clear the residual unit commitment process over new exports that self-schedule into the real-time market.

In 2021, the *residual unit commitment undersupply power balance constraint* was infeasible on four days, June 17 (hours ending 19-22), July 9 (hour ending 20), and July 28-29 (hours ending 19-21). These infeasibilities resulted in prices being set around $250/MWh during those hours. In addition, significant volumes of economic exports and low-priority self-schedule exports were cut in the residual unit commitment process prior to relaxing the power balance constraint.[153]

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149 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.

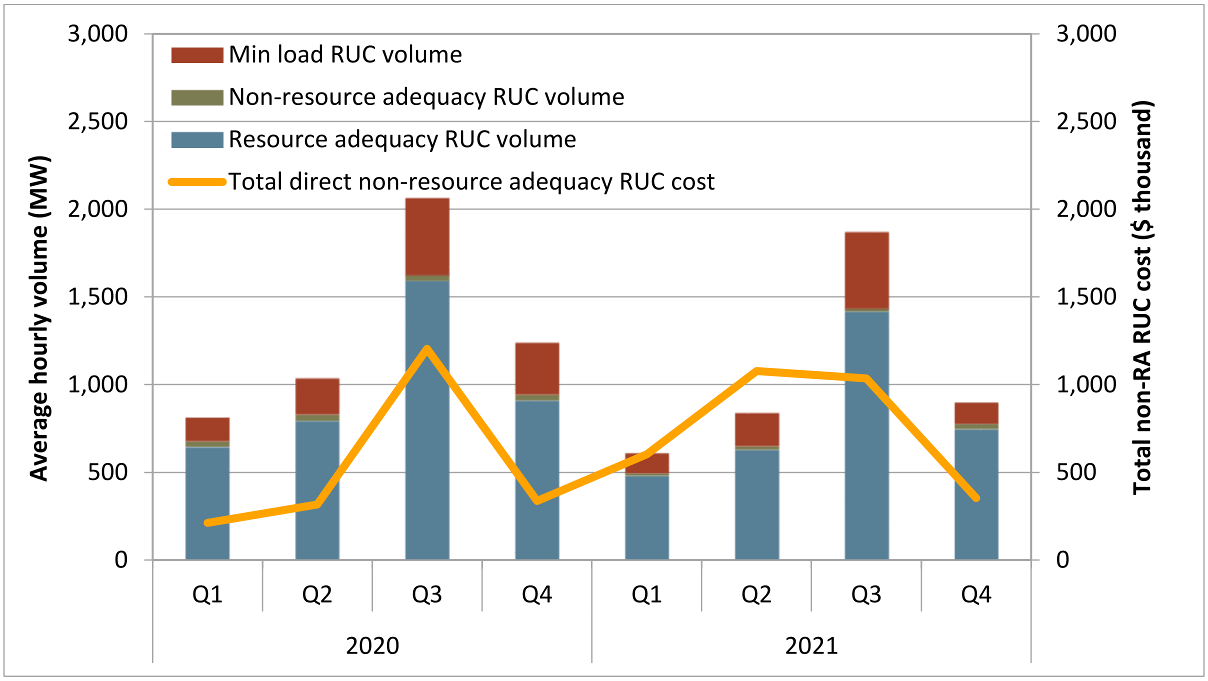
150 Long-start commitments are resources that require 300 or more minutes to start up. These resources receive binding commitment instructions from the residual unit commitment process. Short-start units receive an advisory commitment instruction in the residual unit commitment process, but the actual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

151 The California 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

152 Additional information and analysis on market changes implemented in August 2021 is provided in:
Department of Market Monitoring, *Q3 2021 Market Issues and Performance,* September 9, 2021, pp. 94-102:
http://www.caiso.com/Documents/2021-Third-Quarter-Report-on-Market-Issues-and-Performance-Dec-9-2021.pdf

153 More information on magnitude of export curtailment in residual unit commitment process can be found in DMM's third quarter report.
Ibid, p. 96

Figure 2.13 Residual unit commitment (RUC) costs and volume (2020 – 2021)



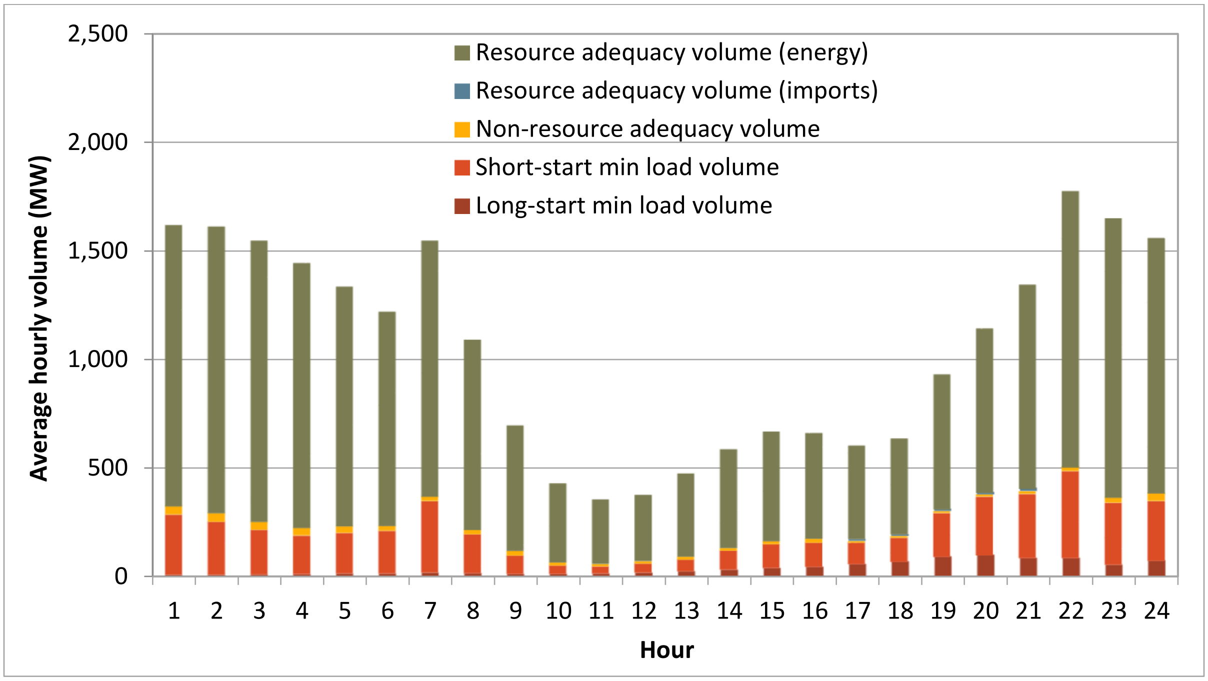
Most of the capacity procured in the residual unit commitment market does not incur any direct costs from residual unit capacity payments because only non-resource adequacy units committed in the process receive capacity payments.[154] As shown by the small green segment of each bar in Figure 2.13, the non-resource adequacy commitment averaged about 21 MW per hour in 2021, down from about 34 MW procured in 2020. The total direct cost of non-resource adequacy residual unit commitment, represented by the gold line in the same figure, increased to about $3 million in 2021, up from a direct cost of about $2 million in 2020.

Figure 2.14 shows the same data presented in Figure 2.13 by resource type on an average hourly basis. As shown by the green bars, resource adequacy capacity scheduled in the residual unit commitment process was greatest during the off-peak hours of the day. Requirements in these hours are driven by the need to replace cleared net virtual supply with physical supply. The capacity procured from resource adequacy imports, shown by blue bars, on average ranged from 7 MW to 14 MW, and 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 2.14. 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.

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

Figure 2.14 Average hourly residual unit commitment (RUC) volume (2021)



2.4.1 Exports and wheels

The residual unit commitment process is designed to procure additional capacity, and if necessary, curtail certain exports when physical supply cleared in the day-ahead market fails to meet the day-ahead forecasted load. As noted in DMM's report regarding the August 2020 load curtailment event, the large volume of exports clearing the day-ahead market contributed to the supply shortfall.[155] Those exports were passed into the real-time market with a higher scheduling priority than internal load, and were therefore not curtailed during the hours when the California ISO curtailed internal load. To address concerns raised after the load curtailment event, the California ISO implemented changes to export priorities on an expedited basis in early September 2020, and implemented additional changes on August 4, 2021.

September 2020 changes influence 2021 high load days

The market rule changes implemented in September 2020 limited the quantity of exports entering the real-time market with a scheduling priority above native load to the quantity deemed feasible by the residual unit commitment (RUC) process. This allowed the RUC process to curtail economic and lower priority self-scheduled exports before curtailing native load. As a result, significant volumes of exports clearing the day-ahead market were curtailed through the residual unit commitment process on most of the highest load days of June and July of 2021. As shown in Figure 2.15, on some high load days in 2021

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[155] Department of Market Monitoring, *Report on System and Market Conditions Issues and Performance: August and September 2020*, November 24, 2020: http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

more than 2.5 GW of exports cleared in the day-ahead market were dropped in the residual unit commitment process.

Figure 2.15 Cleared day-ahead exports in peak hours on high load days

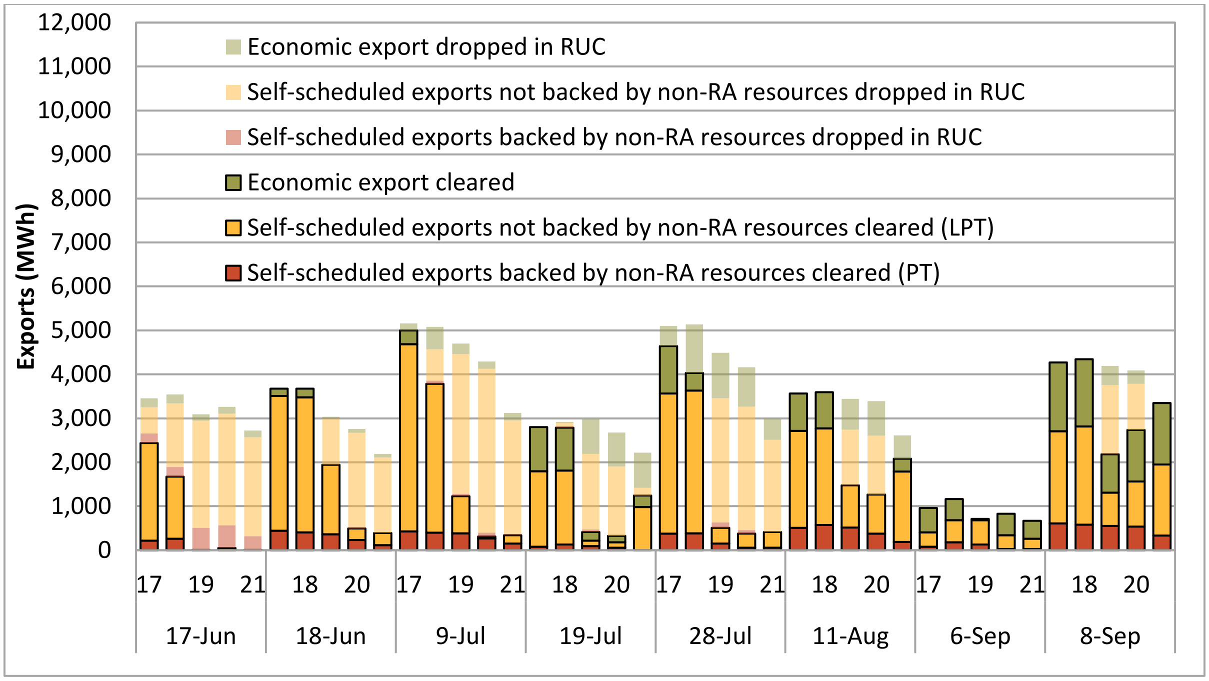
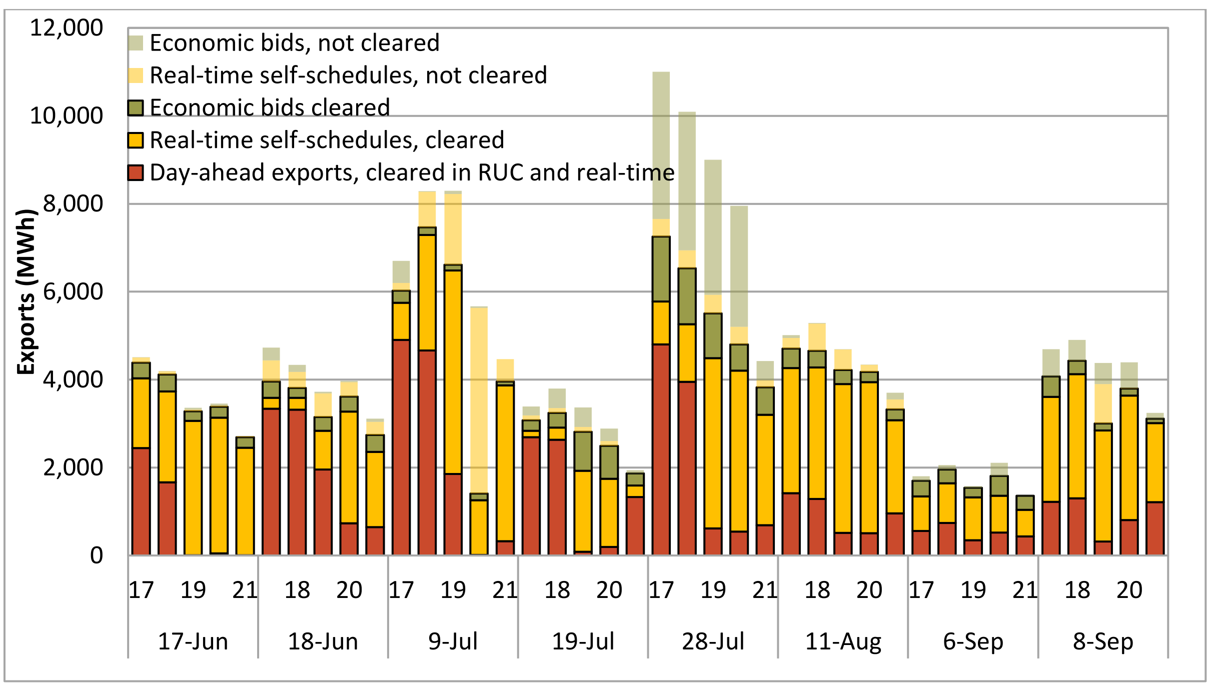


Figure 2.16 Real-time export bids in peak hours on high load days



Exports that clear the day-ahead process are automatically scheduled in the real-time market with a relatively high scheduling priority, while exports that do not clear the residual unit commitment process are not. Some day-ahead market exports that did not clear the residual unit commitment process were re-bid into the real-time market and cleared, ultimately meeting high demand in other regions. As shown in Figure 2.16 real-time exports on these days included exports with day-ahead priority as well as lower priority self-schedules and economic bids that entered in the real-time market.

2.5 August 2021 changes to self-scheduled export and wheel priority

The California ISO implemented tariff changes in August 2021 clarifying scheduling priorities of the California ISO load, self-scheduled exports, and self-scheduled wheel-through transactions. Under the load, export, and wheeling priorities tariff amendment, a scheduling coordinator self-scheduling an export into the California ISO market shall designate it as either a low-priority or high-priority export.[156] High-priority price taking (PT) exports are those supported by non-resource adequacy capacity, while low-priority price taking (LPT) exports are not.[157]

Under the August 2021 tariff changes, all low-priority exports that clear the residual unit commitment process are prioritized below internal load.[158] In addition, the California ISO now prioritizes exports that bid into the day-ahead market and clear the residual unit commitment process over new exports that self-schedule into the real-time market. The goal of this is to incentivize bidders to procure resources in the day-ahead timeframe to allow the market to set reliable schedules. Several new measures were also implemented to ensure high-priority exports are supported by non-resource-adequacy capacity.[159]

The tariff changes also established two categories of self-scheduled wheel-through transactions. The California ISO now designates high-priority (PT) and low-priority (LPT) self-scheduled wheels. High-priority wheels are required to register with the California ISO ahead of time and must be supported by a firm power supply contract to serve the load of an external load serving entity, as well as monthly firm transmission to the California ISO balancing area border. High-priority wheels will have

156 California ISO, *Tariff Amendment to Implement Market Enhancements for Summer 2021 – Load, Export, and Wheeling Priorities, filed at FERC.* April 28, 2021: http://www.caiso.com/Documents/Apr28-2021-Tariff-Amendment-Load-Exports-and-Wheeling-Tariff-Amendment-ER21-1790.pdf

157 California ISO, *Fifth Replacement Electronic Tariff,* August 4, 2021, p. 25: http://www.caiso.com/Documents/Section34-Real-TimeMarket-asof-Aug4-2021.pdf

158 Previously all exports that cleared the residual unit commitment process would be self-scheduled into the real-time with a priority above load.

159 DMM noted several instances in which high-priority exports were not supported by non-resource adequacy capacity. The California ISO has resolved some of these issues with market software fixes. Other refinements necessary to ensure that the non-resource adequacy capacity supporting a high-priority export is available in real-time may be addressed in the California ISO external load forward scheduling rights initiative.

California ISO, *Tariff Amendment to Implement Market Enhancements for Summer 2021 – Load, Export, and Wheeling Priorities, filed at FERC.* April 28, 2021, p. 5: http://www.caiso.com/Documents/Apr28-2021-Tariff-Amendment-Load-Exports-and-Wheeling-Tariff-Amendment-ER21-1790.pdf priority equal to or above ISO native load[160] while low-priority wheels will have priority below native load.

The load, export, and wheeling priorities revisions were implemented on August 4, 2021.[161] High-priority wheels are required to register monthly and 45 days before each month except for August.[162] Figure 2.17 shows the total amount of high priority wheeling capacity registered in August and September, along with the portion of this capacity that was actually scheduled in the day-ahead market during the next peak hours of each day (7 to 22).

- In August 2021, 1,021 MW was registered as high-priority wheel-through transactions. However, this capacity was scheduled in the day-ahead market on only seven days; 346 MW was scheduled on August 28 and 29, with about 96 MW per hour scheduled on five other days.
- In September, 687 MW of high-priority wheels were registered.[163,164] Only 96 MW of this capacity was scheduled in the net peak hours of the month.

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160 Due to the additive nature of penalty prices, the combined penalty price for the import and export wheel of a high-priority wheel exceeds that of California ISO balancing area native load; however, the combined penalty price of self-scheduled imports and California ISO native load is equal to that of a high-priority wheel. This implies that California ISO load served by self-scheduled imports has equal priority to a high-priority wheel, but California ISO load served by other types of supply will have priority below a high-priority wheel.

161 California ISO, *Informational Filing of Effective Date of Load, Exports, and Wheeling Tariff Amendment on FERC Docket No. ER21-1790,* August 11, 2021: http://www.caiso.com/Documents/Aug11-2021-InformationalFiling-EffectiveDate-Load-Export-Wheeling-ER21-1790.pdf

162 The only exception was the first applicable month, when they were able to register until June 29

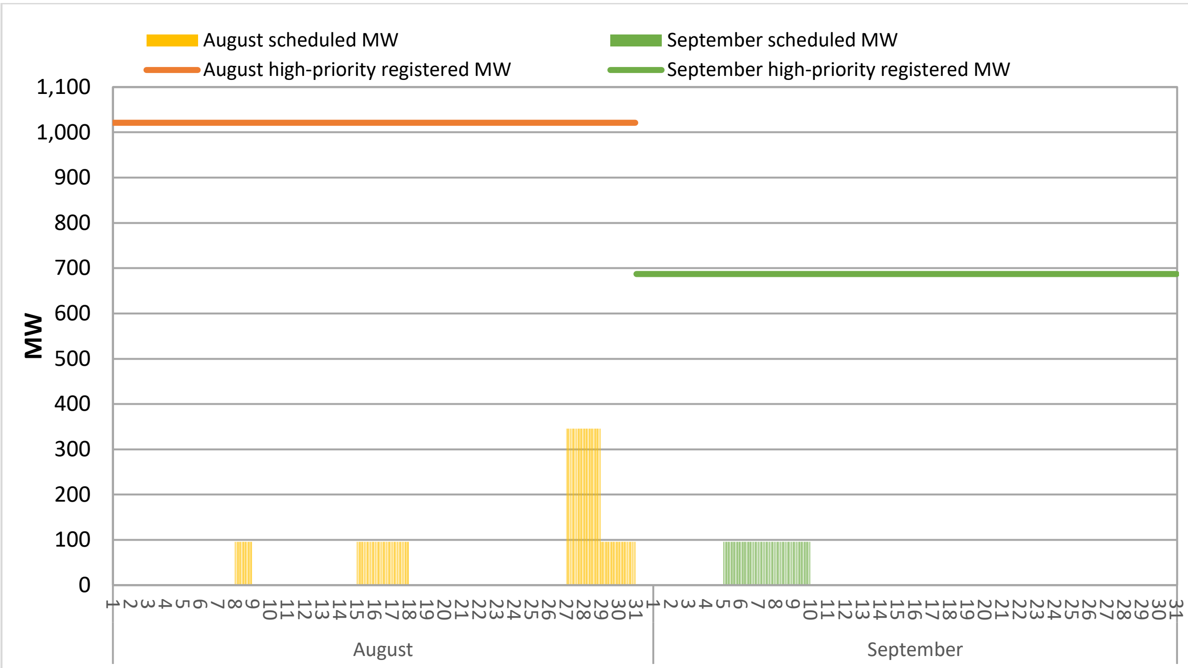
163 California ISO, Market Analysis and Forecasting, *Summer Market Performance Report August 2021,* revised October 11, 2021: http://www.caiso.com/Documents/SummerMarketPerformanceReportforAug2021.pdf

California ISO, Market Analysis and Forecasting, *Summer Market Performance Report September 2021,* October 21, 2021: http://www.caiso.com/Documents/SummerMarketPerformanceReport-Sep2021.pdf

164 The CAISO has identified issues with the process of priority for registered wheels. California ISO, *Summer Readiness August's Performance,* presented by Guillermo Bautista Alderete, October 6, 2021, slide 14: http://www.caiso.com/Documents/Presentation-SummerMarketPerformanceReport-Aug2021-Oct6-2021.pdf

California ISO, *Summer Readiness September 2021 Market Performance,* presented by Guillermo Bautista Alderete, November 3, 2021, slide 15: http://www.caiso.com/Documents/Presentation-Sep2021SummerMarketPerformanceReport-Nov3-2021.pdf

Figure 2.17 High-priority wheels (HE07-HE22 between August 1 and September 31)



While these enhancements are an important incremental improvement, they represent an interim step. Additional refinements are needed for high-priority export rules and a more robust, long-term process for transmission procurement by high-priority wheel-through transactions.[165] These efforts are currently underway in the California ISO's External Load Forward Scheduling Rights stakeholder initiative.[166]

2.6 Bid cost recovery payments

Bid cost recovery payments totaled $180 million, the highest total since 2011 and a significant increase from 2020 when payments were $135 million. Around $158 million of bid cost recovery payments in 2021 were for units in the California ISO (CAISO), and $22 million for units in the Western Energy Imbalance Market (WEIM).[167] The CAISO portion of these payments represents about 1.2 percent of total CAISO wholesale energy costs, which is down from 1.4 percent in 2020.

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

165 Department of Market Monitoring, *Comments on Market Enhancements for Summer 2021 Readiness Final Proposal,* April 2, 2021: http://www.caiso.com/Documents/DMM-Comments-on-Summer-2021-Readiness-Final-Proposal-Apr-2-2021.pdf

166 California ISO initiative, *Transmission service and market scheduling priorities:* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Transmission-service-and-market-scheduling-priorities

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

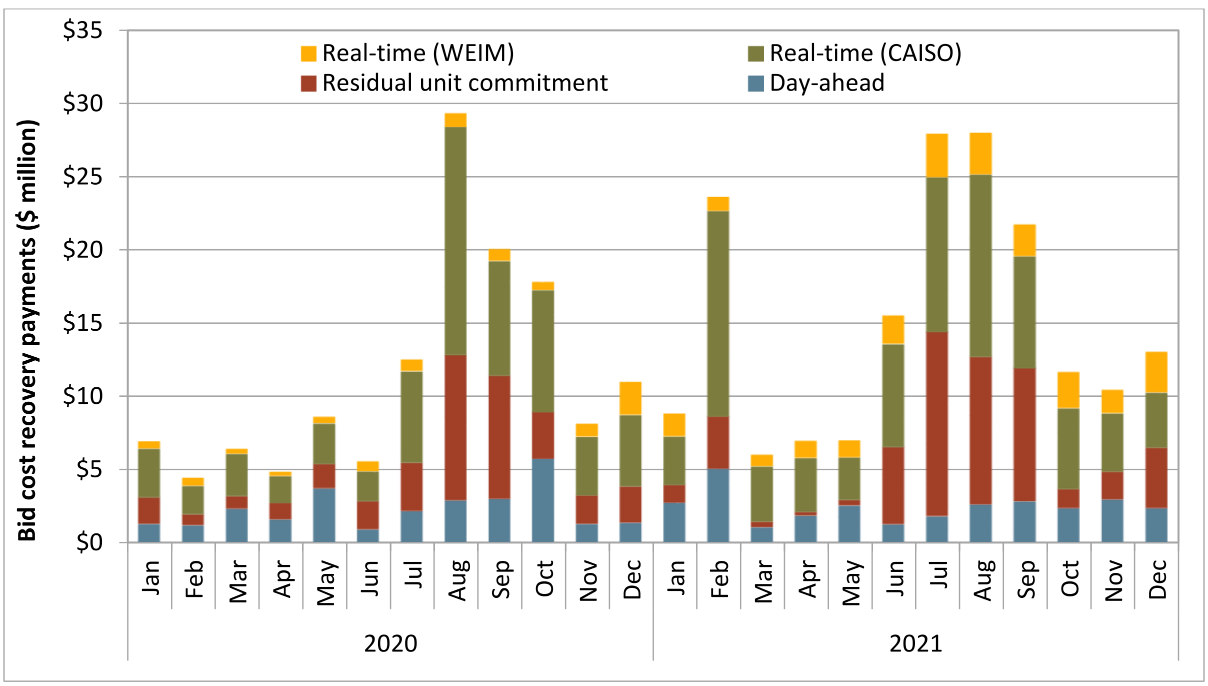
or dispatch. Over 90 percent of these payments, or about $164 million, were to gas resources, followed by $7.2 million to hydro resources, and about $4 million to battery energy storage resources.

The almost 35 percent increase in bid cost recovery payments can be attributed to the significant increase in gas prices. As mentioned in Section 1.2.6, gas prices at PG&E Citygate and SoCal Citygate gas hubs rose by 67 percent and 141 percent, respectively. At other major gas trading hubs such as El Paso Permian, and Northwest Sumas, the prices rose by 264 percent, and 89 percent, respectively.

DMM estimates that about 62 percent of the California ISO total bid cost recovery payments, or approximately $98 million, were allocated to resources that bid their commitment costs above 110 percent of their reference commitment costs. About 95 percent of these payments are for resources bidding at or near the 125 percent bid cap for proxy commitment costs, similar to 2020.

Commitment cost bids are capped at 125 percent of a reference proxy costs.[168] Additional bidding flexibility for commitment costs is provided through reference level adjustment requests. This functionality was implemented as part of commitment costs and default energy bids enhancements (CCDEBE) initiative processes. These requests, if accepted, are used in the market commitment process and can impact bid cost recovery by increasing the bid costs used in the calculation. In 2021, this feature was only used on a few occasions and had minimal impact to bid cost recovery payments.

Figure 2.18 Bid cost recovery payments



[168] See Section 6.3 for more information on commitment cost bid caps and bidding behavior.

Figure 2.18 provides a summary of total estimated bid cost recovery payments in 2020 and 2021 by month and market. As shown in the figure, bid cost recovery payments in 2021 were highest during February as well as June through September. These significantly high payments can be attributed to higher gas prices, particularly in February, and relatively high loads in June through September.

Day-ahead bid cost recovery payments totaled $29 million in 2021, a slight increase from $27 million in 2020. An estimated 35 percent of these payments can be attributed to resources effective at meeting the minimum online constraints enforced in the day-ahead market, compared to 43 percent in 2020.[169]

Real-time bid cost recovery payments were $101 million in 2021, about $30 million higher than payments in 2020. Out of the $101 million in real-time payments, about 22 million was allocated to resources (non-California ISO) participating in the WEIM, which is $13 million higher than payments in 2020. About $5.5 million of these payments were to units in balancing areas that joined the WEIM in 2021.

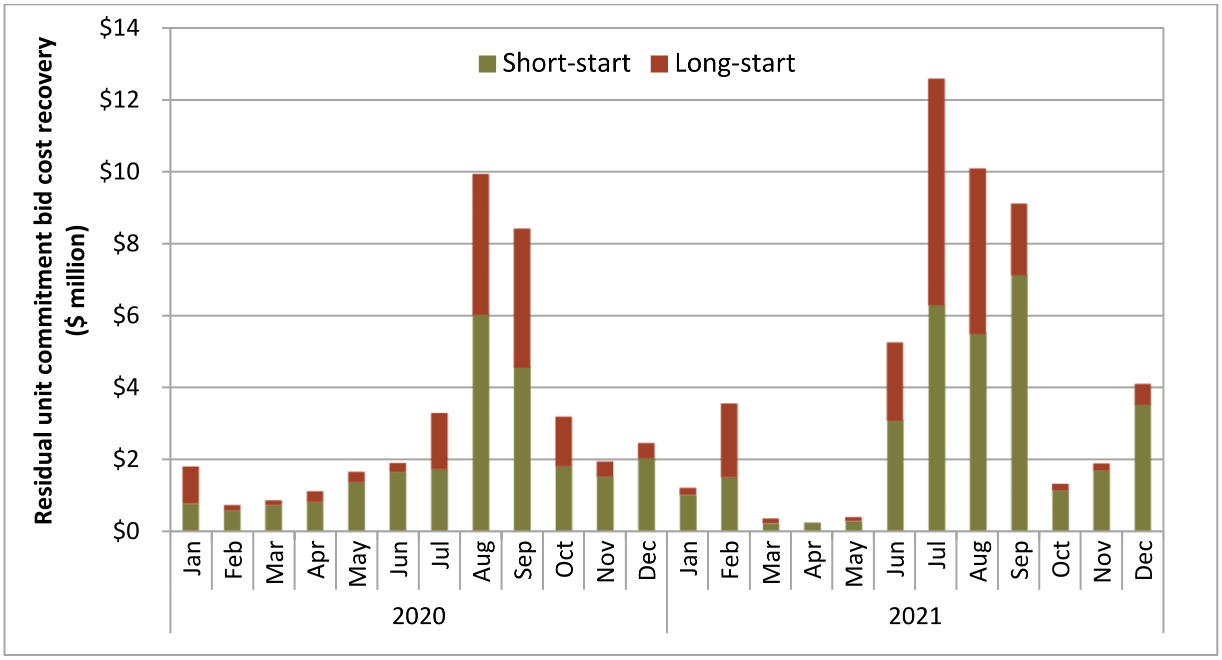
Units committed through exceptional dispatches are eligible to receive real-time bid cost recovery payments. Exceptional dispatches are made by real-time operators to help ensure reliability across the system. DMM estimates these payments for resources committed to operate through exceptional dispatches totaled about $24 million in 2021, significantly up from $7 million in 2020. Additional details regarding exceptional dispatches are covered in Section 8.1 of this report.

Bid cost recovery payments for units committed through the residual unit commitment process totaled about $50 million in 2021. This represents a $13 million increase in payments from 2020. This increase is due in part to higher gas prices this year. Average procurement in the residual unit commitment process was less than the previous year, as stated in Section 2.4. However, gas prices were substantially higher this year, and the majority of bid cost recovery payments for units committed through the residual unit commitment process are received by gas-fired resources.

Units committed by the residual unit commitment can be either long or short-start units. As shown in Figure 2.19, short-start units accounted for about $32 million in bid cost recovery payments, while long-start unit commitment accounted for $18 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.

[169] 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.

Figure 2.19 Residual unit commitment bid cost recovery payments by commitment type



2.7 Real-time imbalance offset costs

Total real-time imbalance offset costs within the CAISO were $177 million in 2021, which was about the same as the $176 million in 2020, but still significantly higher than the $104 million in 2019. The majority of the offset costs were from real-time congestion imbalance offsets ($147 million), up from $117 million in 2020 and $97 million in 2019. Real-time imbalance energy offset costs fell to $28 million from $62 million in 2020, still higher than the $7 million in 2019.

The real-time imbalance offset cost is the difference between the total money paid and the total money collected by the California 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 CAISO 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 made 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).

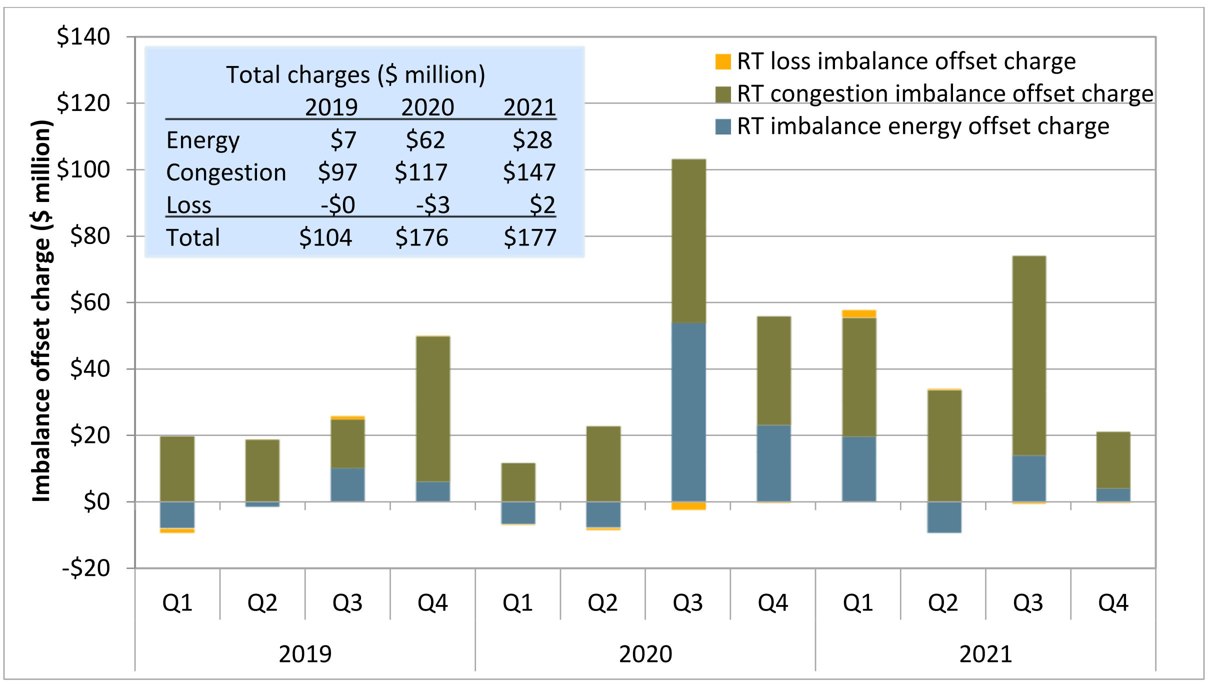
Energy offset deficits totaled $21 million in February 2021, with most of that coming in between February 13 and 19, and during winter storm Uri, when gas prices spiked. July and September also saw significant energy imbalance deficits of about $7 million each.

All months in 2021 saw congestion offset deficits. The two highest months were February with $26 million, and July with just below $36 million.

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 California ISO enough to cover the payments to the schedule that reduced flows—and the California ISO congestion accounts would remain balanced. As 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.[170]

However, there are several reasons the congestion payments will not balance. One reason is that flows increase causing a constraint to bind generating additional congestion rent. Another 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 binding constraint without a corresponding flow increase. The California ISO will pay the flow reduction but cannot balance this payment with collections from a flow increase. To maintain revenue balance, the California ISO charges an uplift to measured demand to offset the imbalance. Congestion imbalances can also occur from differences in transmission modeling and the modeling of non-settled flows.

Figure 2.20 Real-time imbalance offset costs



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

2.8 Flexible ramping product

Background

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

The flexible ramping product procures both upward and downward flexible capacity, in both the 15-minute and 5-minute markets. Procurement in the 15-minute market is intended to ensure that enough ramping capacity is available to meet the needs of both the upcoming 15-minute market run and the three corresponding 5-minute market runs. 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

The end of the demand curve is implemented in the California ISO market optimization as a soft requirement that can be relaxed in order to balance the cost and benefit of procuring more or less flexible ramping capacity. This requirement for rampable capacity reflects the upper end of uncertainty that might materialize.[171] Therefore, it is sometimes referred to as the *flex ramp requirement* or *uncertainty requirement*.

There is separate demand curves calculated for each WEIM area, in addition to a system-level demand curve. The system uncertainty requirement 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.[172] 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. Beginning in November 2020, if an individual balancing authority area requirement 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.[173] The minimum requirement is

171 Based on a 95 percent confidence interval from historical data for the same hour. Weekdays use data from the last 40 weekdays. For weekends, the last 20 weekend days are used.

172 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.

173 For example, if a balancing authority area's upward requirement is 1,000 MW and is greater than 60 percent of the system requirement, 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 California ISO, *Flexible Ramping Product Refinements Final Proposal*, August 31, 2020: http://www.caiso.com/InitiativeDocuments/FinalProposal-FlexibleRampingProductRefinements.pdf

intended to help mitigate some of the issues surrounding procurement of stranded flexible ramping product prior to the implementation of nodal procurement, expected in fall 2022.

A minimum requirement helps procure flexible ramping capacity within areas that contribute to a large portion of system-wide uncertainty. This is typically only the CAISO area, which had a minimum upward requirement enforced in around 90 percent of intervals, and a minimum downward requirement enforced in around 74 percent of intervals during 2021. For Non-CAISO areas, PacifiCorp East notably had a minimum downward flexible requirement in around 12 percent of intervals during the year.

The minimum requirement was initially implemented in the 15-minute market only. DMM recommended that the minimum requirement be included in the 5-minute market as an enhancement to improve the effectiveness of the flexible ramping product until nodal procurement implementation.[174] The California ISO implemented the 5-minute market minimum requirement on February 16, 2022.

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 2.21 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. The percent of intervals in which the CAISO demand curve bound at a positive shadow price is also shown. This was frequent during 2021 because of the minimum requirement, which typically necessitated a portion of flexible ramping capacity to be procured within CAISO.

The frequency of positive shadow prices for the *system* continued to be low overall. During the year, the 15-minute market system-level demand curve for upward ramping bound in less than 1 percent of intervals. For downward ramping capacity, the shadow price was zero from May to December.

Following a review by the California ISO on intermittent resources and flexible ramping product eligibility, the California ISO implemented a change effective May 9 to set all 5-minute dispatchable resources with economic bids as eligible to receive flexible ramping product awards. In particular, additional flexible ramping capacity from wind and solar resources (which were previously ineligible to receive these awards) contributed to the decreased frequency of positive flex ramp prices, particularly for downward ramping. Since the change, the shadow price for downward flexible ramping capacity has been zero in all intervals.

In the 5-minute market, the system-level and California ISO-specific demand curves for upward and downward ramping capacity, bound in less than 0.1 percent of intervals.

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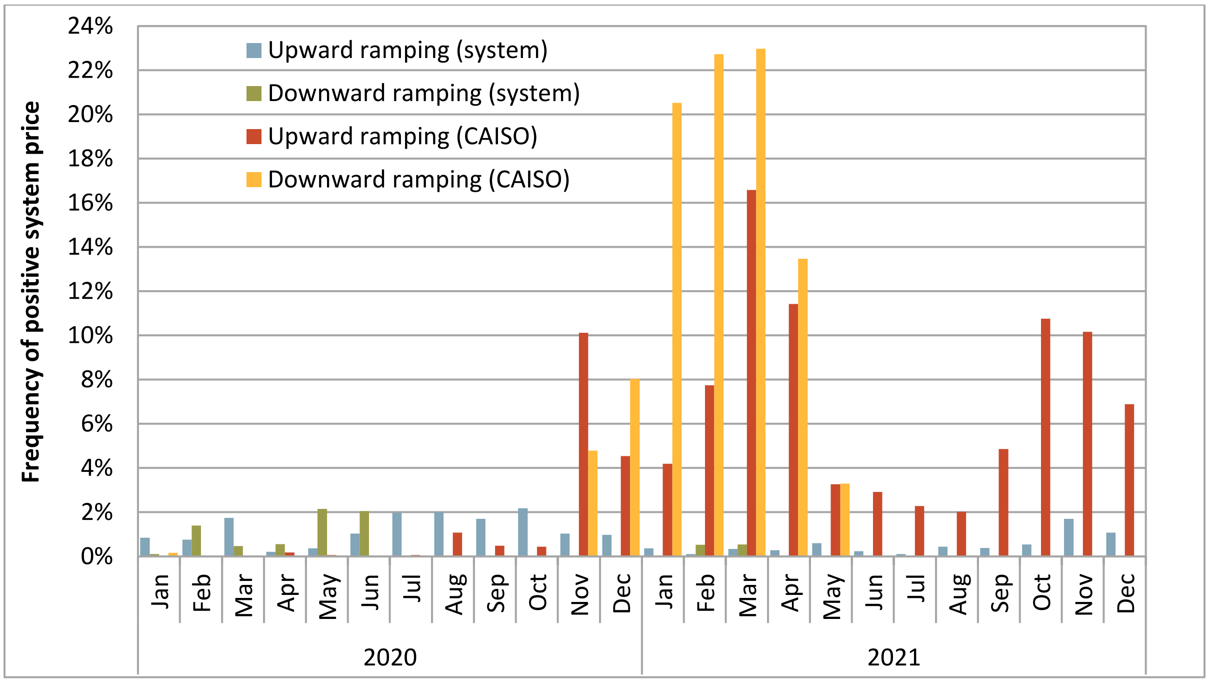
174 Procurement in the 5-minute market helps maintain available ramping capacity to manage uncertainty that may materialize between consecutive 5-minute market intervals. Without a minimum requirement in the 5-minute market, there can be cases where flexible ramping capacity, procured within the California ISO and settled in the 15-minute market, is released in the 5-minute market in favor of undeliverable flexible ramping capacity stranded behind WEIM transfer constraints.

The following sections look at some of the reasons the system-level flexible ramping product prices have often been zero.

Figure 2.21 Monthly frequency of positive system or CAISO flexible ramping shadow price (15-minute market)



Stranded flexible ramping capacity

Flexible ramping capacity procured in the WEIM can be stranded behind transfer constraints. The system-level demand curve for the entire CAISO and WEIM footprint is always enforced in the market and can be met from ramping capacity in any area. In addition, there is a constraint that caps upward ramping procurement in each area by the sum of its local uncertainty requirement and net export capability.[175]

However, even with this constraint, there is the potential for stranded flexible ramping capacity. While this issue can occur in other areas, it is most prominent in the Northwest region, which includes PacifiCorp West, Puget Sound Energy, Portland General Electric, Seattle City Light, and Powerex; this is because of limited transfer capability out of the Northwest region. For example, in cases when supply conditions are tight in the CAISO and surrounding system but export capability out of the Northwest region is zero, these areas may still have export capability to each other within the Northwest region. As a result, the export capability cap on upward flexible ramping capacity will often do little to prevent procurement that is stranded in this region. Further, when supply conditions are tight, it can often be most economic under the current structure to procure more flexible ramping capacity from the Northwest region than from the surrounding system as the opportunity cost of providing that ramping capacity in lieu of energy would then be lower in the Northwest.

175 Net export capability is the sum of export WEIM transfer limits in excess of the net WEIM transfer. Downward ramping capacity is instead capped by the sum of the area-specific downward uncertainty requirement and net import capability.

Figure 2.22 illustrates this interaction with an example interval from September 7, 2021. The figure shows dynamic (non-base) export limits and remaining export capability out of each area in the Northwest region. Transfers that are dedicated exclusively for base schedules (fixed bilateral transactions between WEIM entities) or have transmission limits set at zero MW, could not support any upward flexible ramping capacity and were omitted from the figure. The red and green arrows show the direction of the transfer flows and whether it is fully constrained (red) or not (green).[176] In this interval, there was 649 MW of upward ramping capacity (or 65 percent of the system requirement) awarded to resources in the Northwest region, but 0 MW of actual export capability out of the region. Here, export capability to each other within the Northwest region allowed for higher procurement of upward flexible than was actually accessible for the surrounding system.

Figure 2.23 shows the potential for stranded upward flexible ramping capacity in the Northwest during 2021 and highlights how the outcome illustrated in the example interval in Figure 2.22 can persist throughout the year. The figure summarizes only *dynamic* (non-base) export limits out of the Northwest region since base scheduled transfers are neither optimized in the market nor able to support flexible ramping capacity out of the region. So, while there is often significant export flows out of the Northwest region to PacifiCorp East and NorthWestern Energy, these are base scheduled, so there is never dynamic export capability here (as shown by the green and yellow circles). Further, Figure 2.23 shows that the export limits depicted in Figure 2.22 were within typical levels for September (between 130 and 440 MW). Instead, looking at the whole year, total dynamic export limits out of the region were typically between 300 and 560 MW.

[176] The gray arrows indicate that there is two-way transfer capability, but the flow is not going in that direction.

Figure 2.22 Example interval — Stranded upward ramping capacity in the Northwest (September 7, 2021)

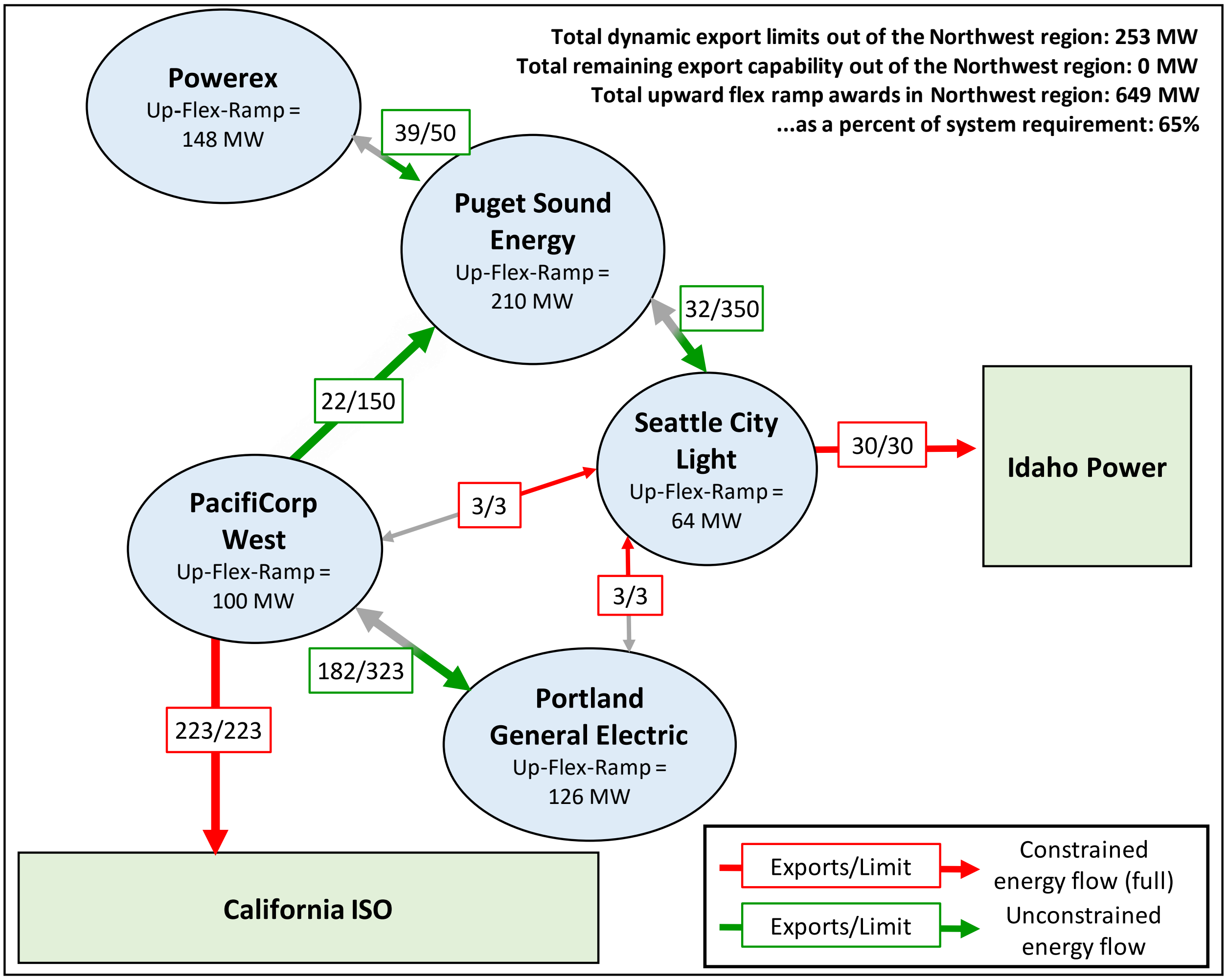


Figure 2.23 Distribution of dynamic export limits out of the Northwest region

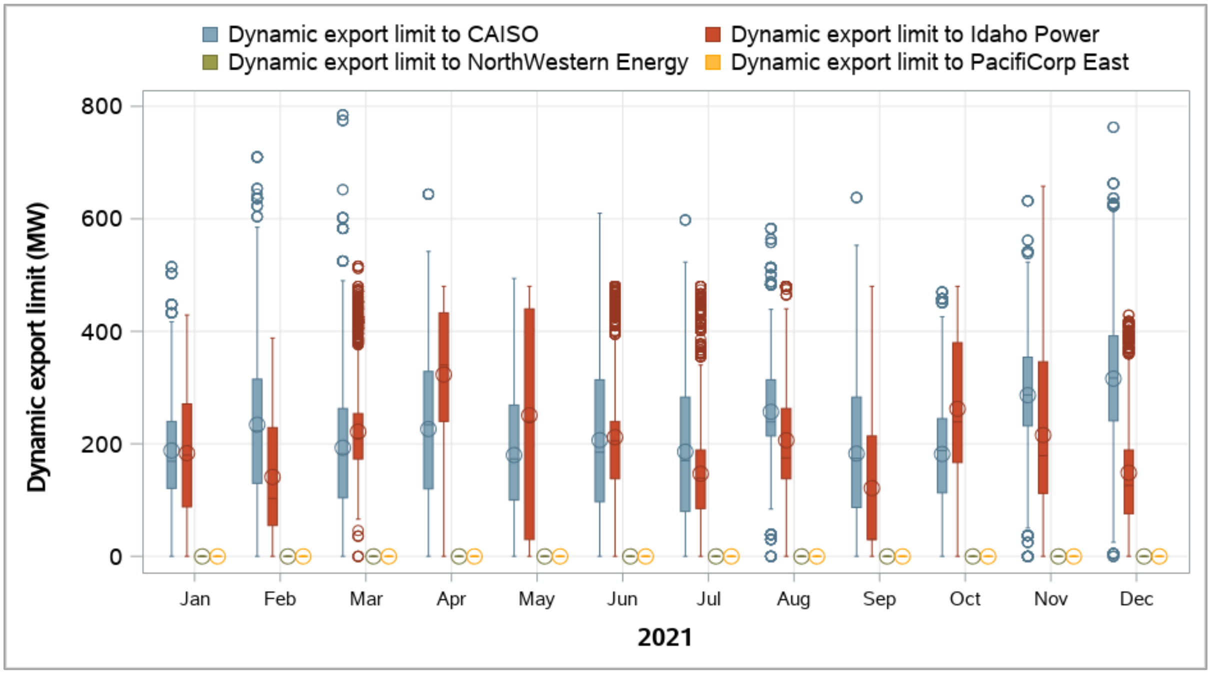


Figure 2.24 Average hourly stranded flexible ramping capacity by area (2021)

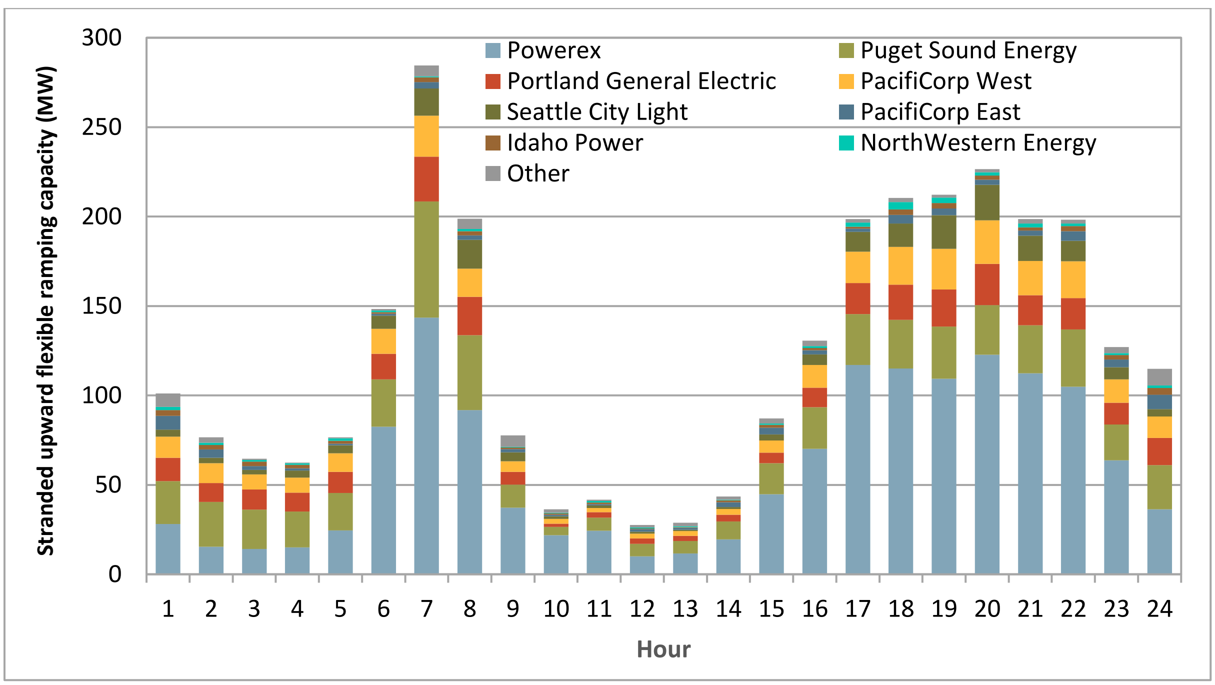


Figure 2.24 summarizes stranded flexible ramping capacity on average for each hour during the year.[177] During peak-load hours, dynamic export limits out of the Northwest region often become constrained resulting in higher quantities of upward flexible ramping capacity that is undeliverable to the greater WEIM footprint. Between evening hours 17 and 22, stranded flexible ramping capacity averaged around 210 MW during 2021. Across all hours in the year, stranded flexible ramping capacity is often low, between 6 and 36 percent of the system requirement. However, during some of the more extreme summer hours, it has at times made up more than half of the requirement. Flexible ramping capacity awards to 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. This makes flexible ramping capacity appear more available and cheaper than it actually is.

WEIM transfer constraints are not the only source of deliverability issues with the flexible ramping product. Ramping capacity can also be stranded behind internal congestion or be undeliverable because of certain resource constraints.

Local relaxations effectively reduce system uncertainty requirements

There is separate local demand curves calculated for each WEIM area in addition to a system-level demand curve. Flexible ramping capacity procured in one balancing area can be used to meet local or system uncertainty needs (or both). The system uncertainty requirement for the entire footprint is always enforced in the market and a relaxation from this requirement will price flexible ramping capacity at the system level.

Each area also has a local uncertainty requirement that is reduced in every interval by their transfer capability. Previously, if the transfer capability for each area was sufficient, then only the system uncertainty requirement was active. However, with the implementation of the minimum requirement in 2020, areas that contribute to a significant portion of system uncertainty (typically only CAISO) will still have a nonzero local requirement even with sufficient transfer capability.

Any relaxation from a local requirement will meet the system-level requirement, reducing the footprint demand for flexibility across all areas, but only price flexible ramping capacity for that particular local area. System flexible ramping needs are typically smaller than the sum of the needs of individual areas because of reduced uncertainty across a larger footprint. As a result, a relaxation for a local requirement can disproportionately reduce the system requirement by an amount that exceeds the area's expected share of system uncertainty. This reduction in demand for system-level flexibility will therefore reduce the cost for providing that flexibility.

With the minimum requirement enhancement, a local flex ramp requirement is typically enforced for the CAISO area because of significant load and variable energy resources that contribute to a large share of system-wide uncertainty. This resolves some of the issues surrounding stranded flexible ramping capacity by ensuring that a nonzero quantity of flexible ramping capacity is procured within CAISO. When conditions across the system (including CAISO) are tight, the market will often relax the minimum local requirement for CAISO, reducing system flexibility needs, while pricing flexible ramping capacity in the CAISO area only. As upward flexibility in CAISO becomes scarcer and more expensive, prices for

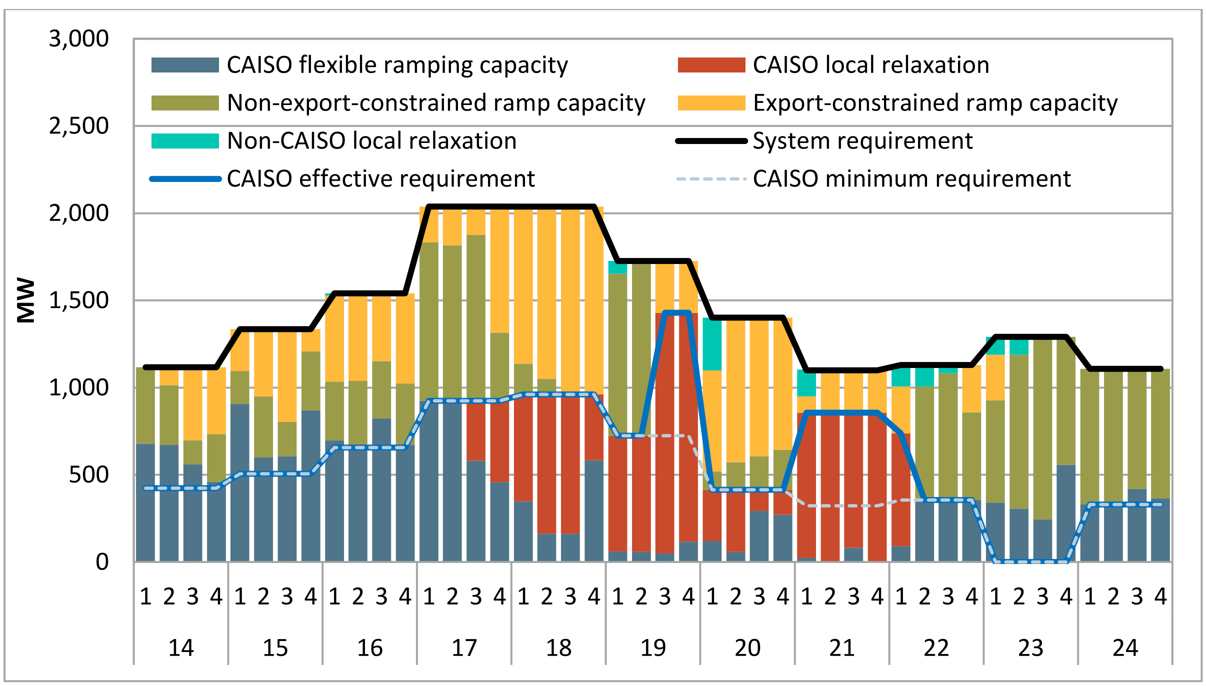
177 Stranded flexible ramping capacity is flagged when the shadow price on a WEIM area's transfer constraint (net of any greenhouse gas prices) was negative; indicating that the area is export constrained relative to prevailing system conditions.

system-level flexible ramping capacity typically remain low even though flexible ramping capacity external to CAISO may be physically able to meet CAISO flexibility needs.

As an example, Figure 2.25 shows how the 15-minute market system requirement for upward flexibility was met during the peak hours of July 9, 2021. On this day, system prices for flexible ramping capacity remained mostly at zero despite very tight system conditions and high energy prices. The bars show either flexible ramping capacity or local relaxation that effectively met the system requirement. The ramping capacity is then split out by whether it is to resources in CAISO or another WEIM area (and whether that area is stranded behind WEIM transfer constraints or not). The blue lines show the minimum and effective requirement for CAISO. During the periods in which the effective requirement exceeded the minimum requirement, CAISO failed the resource sufficiency evaluation such that the full quantity of its local uncertainty requirement was enforced.

As shown in Figure 2.25, the system uncertainty requirement (black line) is met in every interval without any system relaxation such that the system-wide price for flexible ramping capacity was zero. Alternatively, relaxation of the CAISO local requirement (red bars) can meet a significant portion of the system requirement, which will price flexible ramping capacity in CAISO, but not in the surrounding WEIM areas (even if these areas can provide flexibility). The yellow bars also highlight substantial flexible ramping capacity awards to resources within balancing areas that are export constrained relative to the greater WEIM system.

Figure 2.25 System flexible ramping product requirement, procurement, and relaxation (July 9, 2021)



The California ISO is implementing nodal procurement for the flexible ramping product in fall of 2022, as part of the flexible ramping product refinements stakeholder initiative.[178] This is expected to resolve both (1) stranded flexible ramping capacity and (2) the undesirable interplay between local and system requirements. Locational procurement, accounting for transmission constraints, would result in deliverable reserves, which could significantly increase the efficiency of the CAISO market awards and dispatches. This change should also help to address the very low prices for flexible ramping capacity and instead allow this capacity to be priced based on the relative availability and actual tradeoff between providing that flexibility in lieu of energy.

[178] California ISO, *Flexible Ramping Product Refinements Final Proposal,* August 31, 2020. http://www.caiso.com/InitiativeDocuments/FinalProposal-FlexibleRampingProductRefinements.pdf

3 Western Energy Imbalance Market

The Western Energy Imbalance Market (WEIM) allows balancing authority areas outside of the California ISO balancing area to participate in the California ISO real-time market. This chapter provides a summary of WEIM performance during 2021.

Key elements highlighted in this chapter include the following:

- **The Western Energy Imbalance Market continued to perform well**. The growth of the WEIM and increase in available transmission has increased economic transfers between balancing areas, displacing higher cost generation in favor of lower cost generation.
- **The Western Energy Imbalance Market continued to grow with the addition of four new participants in 2021.** Turlock Irrigation District joined the WEIM on March 25; Public Service Company of New Mexico and Los Angeles Department of Water and Power joined on April 1; and NorthWestern Energy joined on June 15, bringing the total number of participants up to 15. Participation by the Balancing Authority of Northern California (BANC) also expanded in 2021 with the addition of Modesto Irrigation District, City of Redding, and City of Roseville.
- **The California ISO exports significant energy to other balancing areas in the Western Energy Imbalance Market, in periods of relatively high solar production.** By allowing the CAISO to transfer energy out during these periods, the WEIM has reduced the need to curtail solar and other low cost renewable production.
- **During peak evening hours in the summer, the California ISO tends to import significantly from other balancing areas.** This reflects regional supply conditions and transfer capacity across the market footprint that can best meet system-wide demand during this period.
- **The addition of uncertainty in the bid range capacity test significantly increased test failures.** Net load uncertainty was added on June 16, 2021 and removed on February 15, 2022.
- **Western Energy Imbalance Market participants in the Pacific Northwest continued to be in the most frequently congested region**, separating this region from the greater market footprint.
- **A transmission outage significantly limited Western Energy Imbalance Market transfer capability for NorthWestern Energy in the fall.** This contributed to higher flexible ramping product prices, higher energy prices, and more frequent power balance constraint relaxations in this area during this period.
- **Greenhouse gas prices increased significantly in 2021**, in part due to increased greenhouse gas allowance prices. Greenhouse gas compliance costs for energy delivered within California contributed to higher prices for WEIM entities within the state. Prices may have also been affected by an issue with the greenhouse gas obligation calculation after Los Angeles Department of Water and Power joined the WEIM in April. In 2021, about 50 percent of the WEIM greenhouse gas compliance obligations were assigned to each of gas and hydroelectric resources, for energy deemed delivered to California.

3.1 Background

The Western Energy Imbalance Market (WEIM) allows balancing authority areas outside of the California ISO (CAISO) balancing area to voluntarily take part in the CAISO real-time market. The WEIM was designed to provide benefits from increased regional integration by enhancing the efficiency of dispatch instructions, reducing renewable curtailment, and reducing total requirements for flexible reserves.

The California ISO real-time market software solves a cost minimization problem for dispatch instructions to generation considering all of the resources available to the market, including both the WEIM and CAISO areas. This can allow the market to increase efficiency by re-optimizing dispatches and manage congestion within each WEIM area as well as optimize *energy transfers* economically in real-time between WEIM areas by balancing supply and demand across the footprint with lower-cost generation. Energy transfers between balancing areas also helps to reduce curtailment of low cost renewables in one area during times of excess generation.

A key element of the WEIM is the *resource sufficiency evaluation*, which checks whether each area is independently sufficient without relying on transfers from other balancing areas. Failing the evaluation, either from an insufficient capacity or flexibility perspective, will limit the ability of an area to participate fully in the market. This allows the WEIM to realize a lower cost solution across a larger footprint, while addressing the potential for leaning by one area on another.

The Western Energy Imbalance Market has expanded significantly since its implementation in November 2014, when it only optimized the California ISO and PacifiCorp balancing authority areas. Since then, NV Energy (NVE) was integrated in the market in December 2015, Puget Sounded Energy (PSE) and Arizona Public Service (APS) joined in October 2016, Portland General Electric (PGE) began participation in 2017, Idaho Power and Powerex joined in 2018, the Balancing Authority of Northern California (BANC) joined in 2019,[179] and Seattle City Light and Salt River Project joined the market in 2020.

In 2021, the Western Energy Imbalance Market continued to expand with four new participants. Turlock Irrigation District (TID) joined March 25, both Los Angeles Department of Water and Power (LADWP) and Public Service Company of New Mexico (PNM) joined on April 1, and NorthWestern Energy (NWMT) joined on June 15, bringing the total number of participants up to 15, including CAISO.

Both the growth of the Western Energy Imbalance Market since 2015 and the increase in available transmission have increased economic transfers between balancing areas, displacing higher cost generation in favor of lower cost generation that can meet system-wide needs. Prices and transfers now highlight distinct daily and seasonal patterns that reflect regional supply conditions and transfer limitations.

3.2 Regional load

Non-California ISO load served in the WEIM increased significantly between 2017 and 2021. Average hourly load in 2021 peaked at 49,400 MW in July, which is a 69 percent increase from the 2017 peak.

[179] The Balancing Authority of Northern California initially began participation in 2019 with only the Sacramento Municipal Utility District participating as a member within the balancing authority area (phase 1). On March 25, 2021, three other members including Modesto Irrigation District, City of Redding, and City of Roseville began participation (phase 2).

The increase in load, year over year, is primarily due to new areas joining the market, as there were five non-CAISO participating WEIM entities in 2017 and 14 by the end of 2021.

Figure 3.1 shows the average load by month in the WEIM between 2017 and 2021. This figure includes all non-CAISO WEIM areas. Peak average load in the WEIM generally occurs during the summer months of July and August, with a smaller secondary peak in December. In 2021, average load reached 49,400 MW in July and 44,150 MW in December. This dual peak trend corresponds with the large WEIM footprint as some areas see high loads in summer and others in winter.

Table 3.1 shows the individual peak load hour for each balancing authority and load by balancing authority area during the WEIM system peak load interval. The total load across the WEIM footprint peaked on July 9 at 109,450 MW. Load peaked in balancing areas in the Southwest in mid-June. Peak load in Powerex, Puget Sound Energy, and Seattle City Light occurred on December 27.

Figure 3.1 Average WEIM load by month

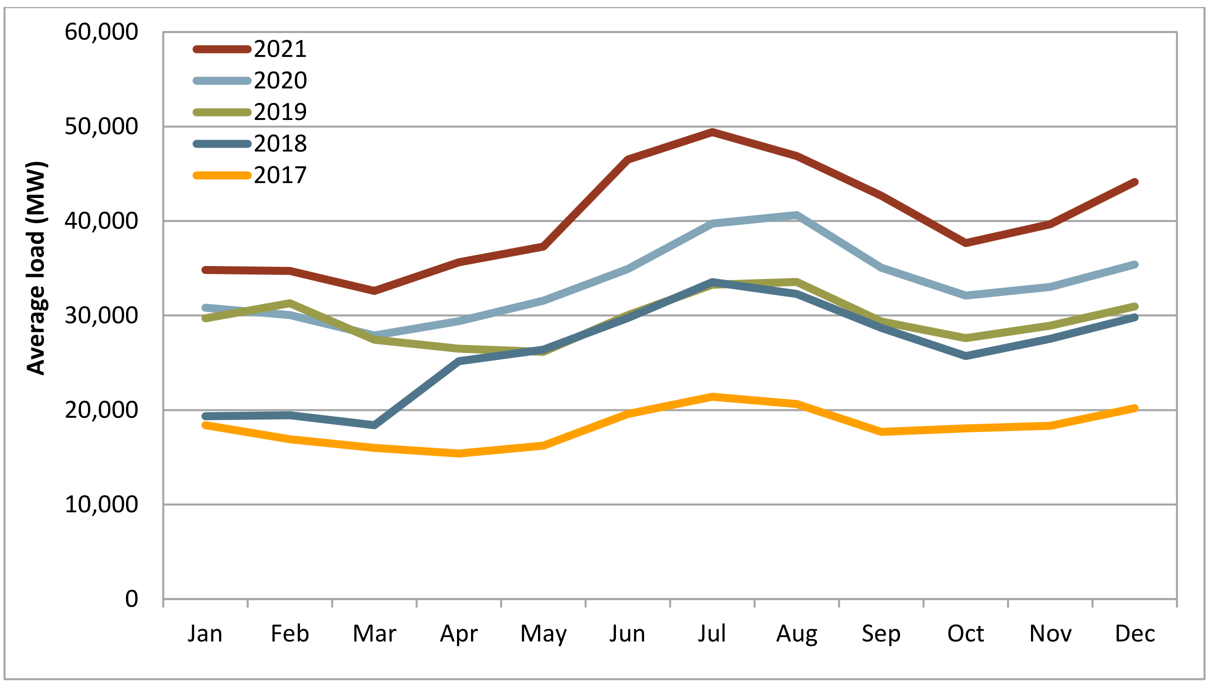


Table 3.1 System peak load by BAA

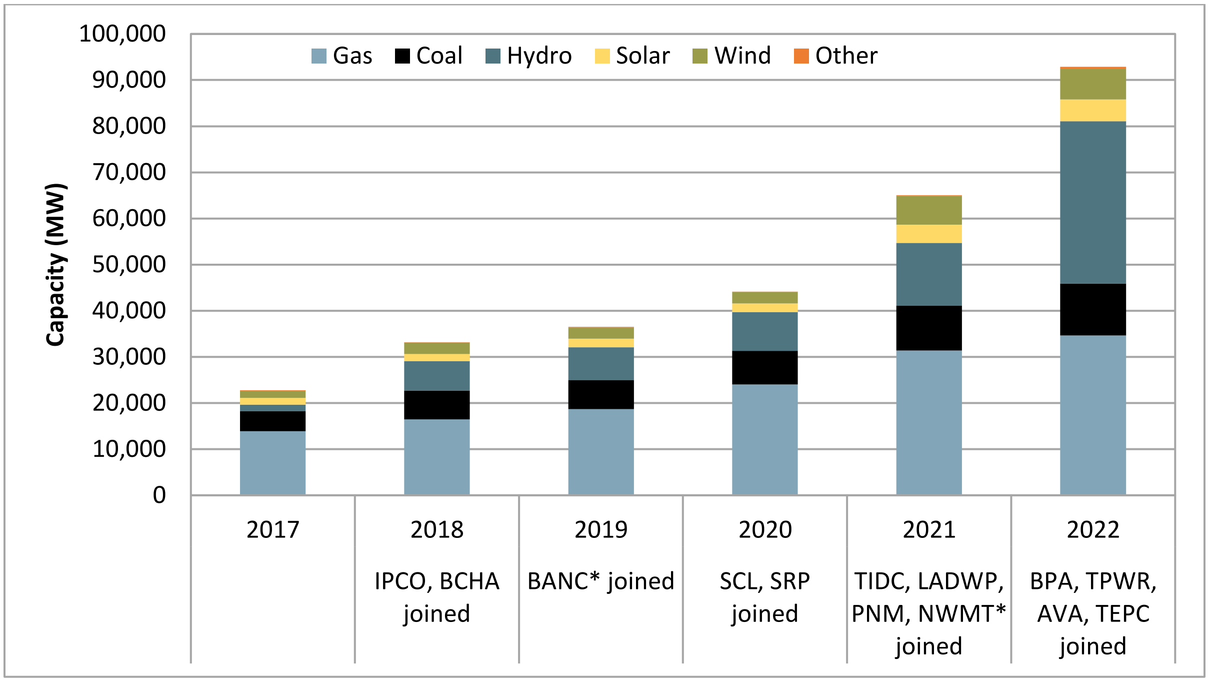
	Peak load		Load during WEIM system peak (09-Jul-21)	
BAA	**Date**	**Load (MW)**	**Load (MW)**	**Percentage**
CISO	8-Sep-21	43,982	42,299	38.7%
NEVP	9-Jul-21	9,301	9,160	8.4%
PACE	8-Jul-21	9,041	8,623	7.9%
BCHA	27-Dec-21	11,769	7,630	7.0%
SRP	17-Jun-21	7,495	7,338	6.7%
AZPS	18-Jun-21	7,386	6,995	6.4%
LADWP	9-Sep-21	4,790	4,526	4.1%
BANC	18-Jun-21	4,342	4,206	3.8%
IPCO	30-Jun-21	3,941	3,478	3.2%
PACW	28-Jun-21	3,997	3,402	3.1%
PGE	28-Jun-21	4,410	3,210	2.9%
PSEI	27-Dec-21	4,893	3,081	2.8%
PNM	14-Jun-21	2,476	2,246	2.1%
NWMT	27-Jul-21	1,857	1,496	1.4%
SCL	27-Dec-21	1,810	1,089	1.0%
TIDC	13-Jul-21	1,067	671	0.6%
Total			**109,450**	

3.3 Participating capacity and generation

Figure 3.2 shows the total participating WEIM nameplate capacity from June 2017 through June 2022.[180] These amounts only reflect participating capacity and therefore do not include capacity from non-participating resources, which are neither bid nor optimized in the market. The total amount of participating WEIM capacity has grown significantly in recent years as new areas join the WEIM. In the last five years, roughly 70,000 MW of capacity has been added to the Western Energy Imbalance Market; 50 percent of which was hydro and about 30 percent was natural gas. Natural gas and coal capacity represent 49 percent of total participating capacity, but represent over 76 percent of participating generation. Hydroelectric capacity more than doubled between June 2021 and June 2022 with the addition of the new entities.

[180] Data for 2022 includes all participating WEIM capacity as of June 1, 2022.

Figure 3.2 Total WEIM participating capacity by fuel type and year (as of June 1, 2022)[181]



The change in capacity, year over year, is due to new balancing authority areas (BAAs) joining the Western Energy Imbalance Market and the fuel mix of their participating generation. Figure 3.3 shows the fuel mix of participating capacity for each BAA in the WEIM as of June 1, 2022. This figure highlights that the increase in hydroelectric capacity in 2022 was driven by the addition of Bonneville Power Administration, which adds about 20,000 MW of hydro capacity to the WEIM.

[181] BANC joined in two phases; the first was in April 2019 and the second was in 2021. NWMT joined shortly after June 1, 2021 but is included in the 2021 bar.

Figure 3.3 Fuel mix of WEIM participating capacity by BAA (as of June 1, 2022)

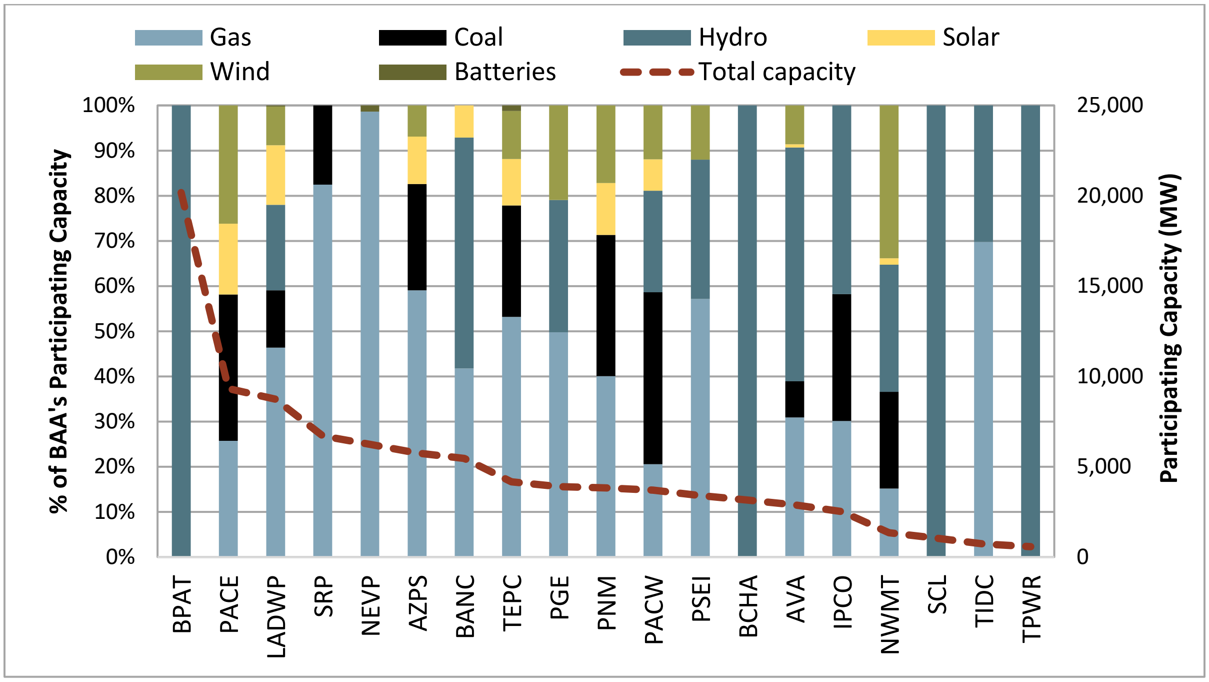


Figure 3.4 provides a profile of average monthly participating WEIM generation by fuel type.[182] Figure 3.5 illustrates the same data on a percentage basis. These two figures show the following:

- Natural gas and coal were the largest sources of participating WEIM generation in 2021, representing 53 and 23 percent of total generation, respectively.
- Compared to 2019, the share of energy from renewables doubled and accounted for 13 percent of participating WEIM generation in 2021.[183]

182 Changes in monthly generation are due in part to new WEIM entities joining the market.

183 In this analysis, non-hydro renewables do not include behind-the-meter generation such as rooftop solar.

Figure 3.4 Average monthly participating WEIM generation by fuel type in 2021

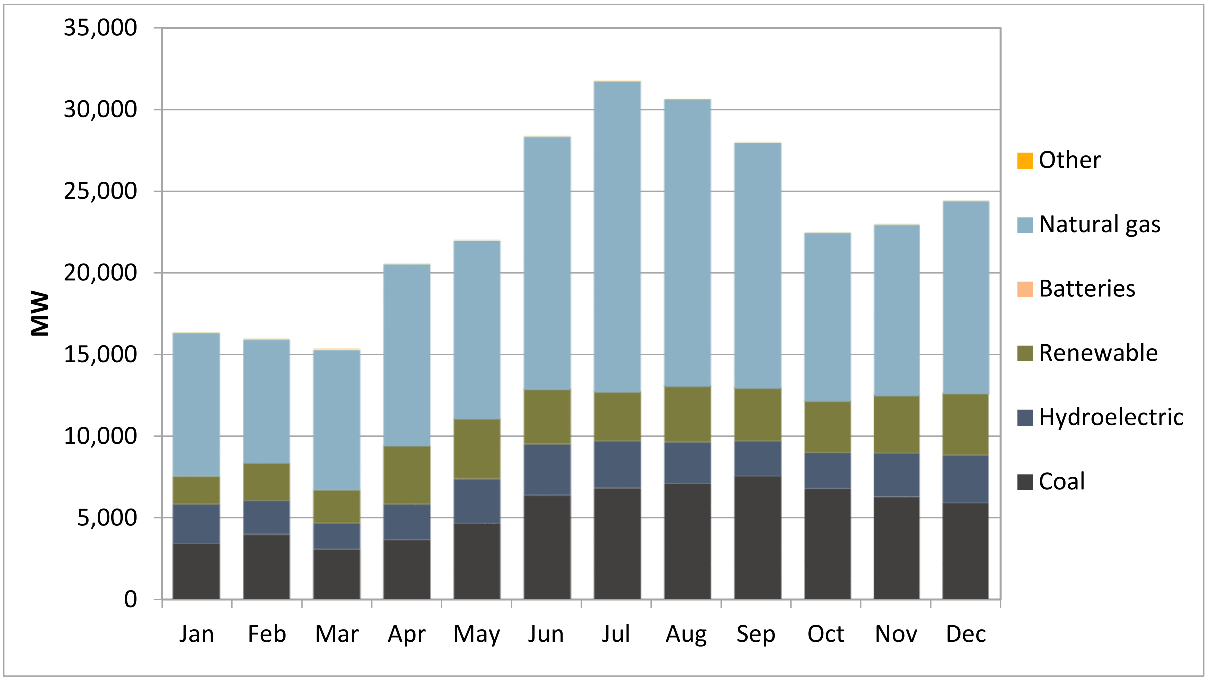


Figure 3.5 Average monthly participating WEIM generation by fuel type in 2021 (percentage)

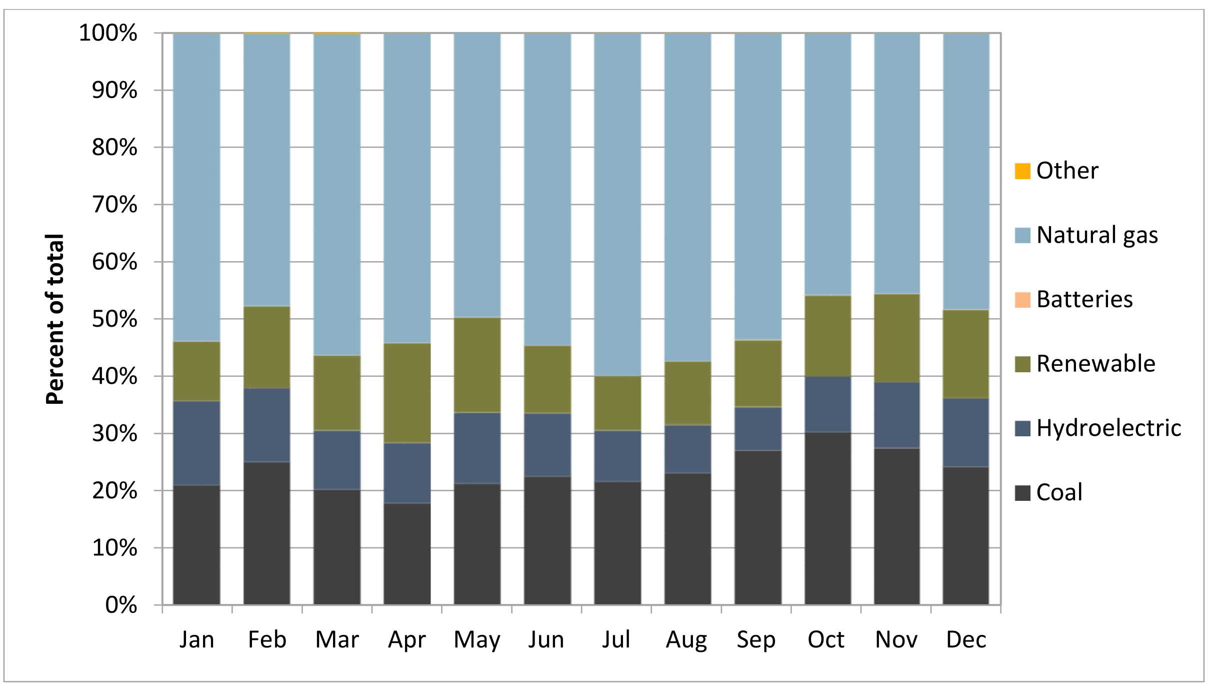
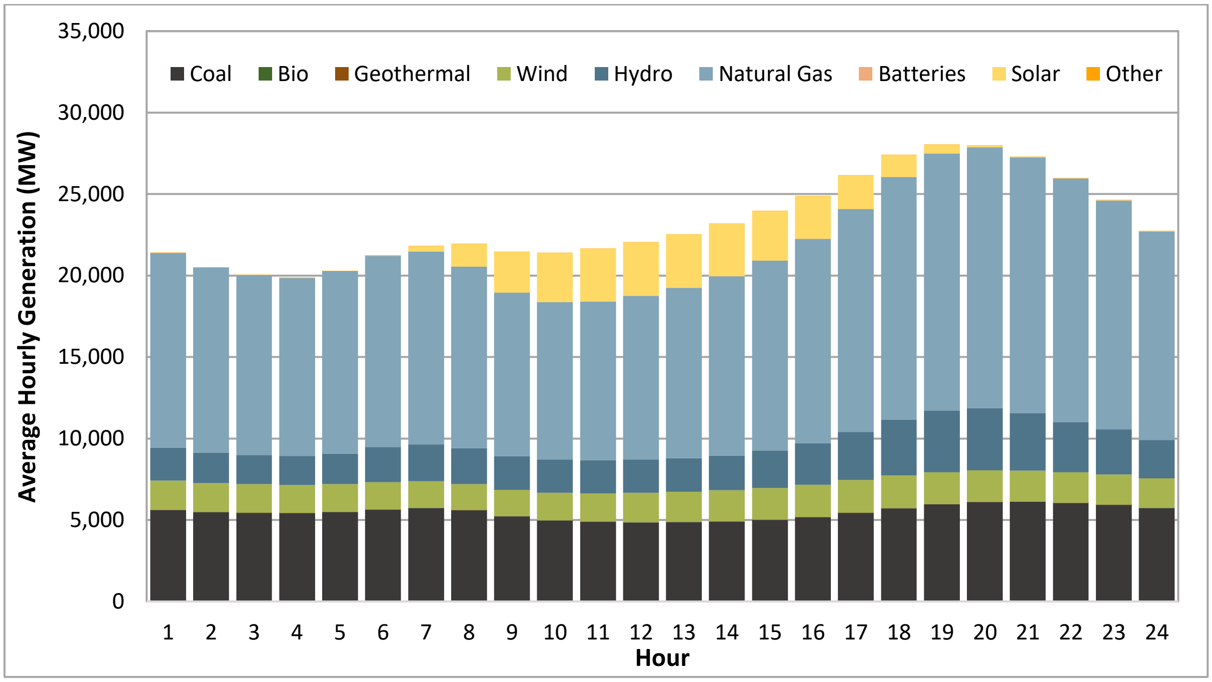


Figure 3.6 shows average hourly participating WEIM generation by fuel type over the year.[184] Overall, for 2021, hour ending 19 averaged the highest amount of generation at about 28,050 MW, while hour ending 4 averaged the lowest at about 19,875 MW. Figure 3.7 shows the change in average hourly participating WEIM generation by fuel type from 2020 to 2021.[185] Generation from solar resources more than doubled in 2021, and has started to resemble the duck curve observed in the California ISO hourly generation.[186] The overall increase in generation by all fuel types is due primarily to new entities joining the WEIM.

Figure 3.6 Average hourly participating WEIM generation by fuel type (2021)

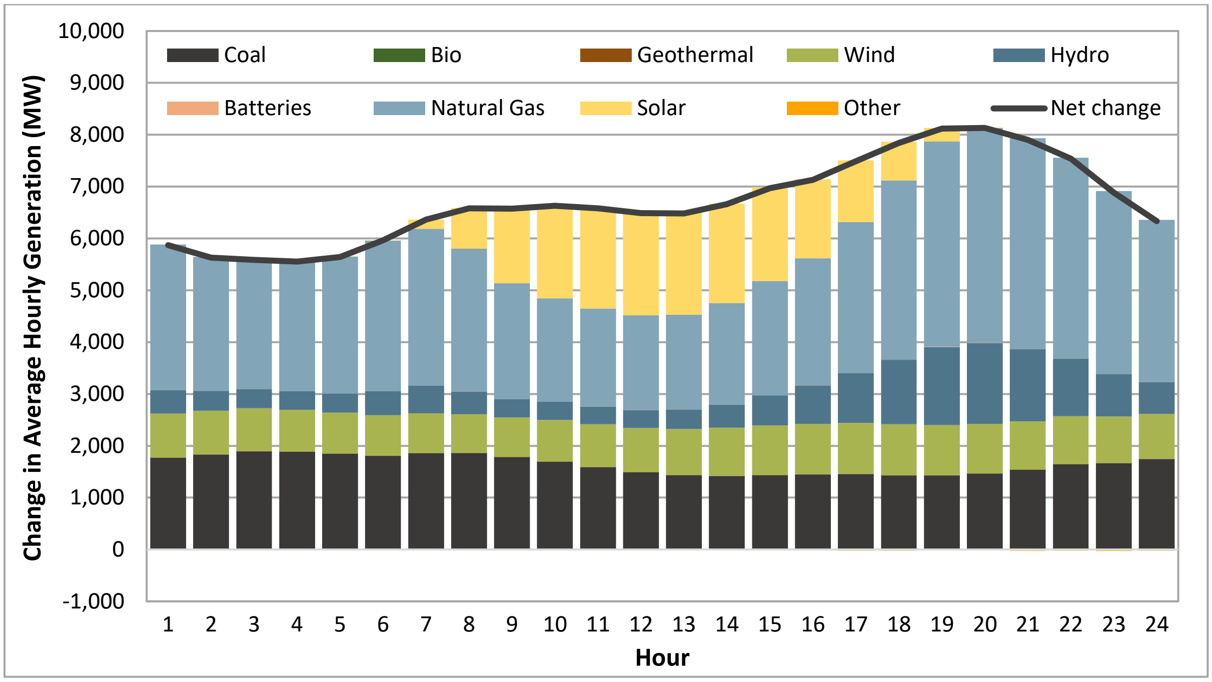


184 Participating capacity includes resources that are bid-in and optimized in the real-time market. These charts therefore show lower values than total capacity, which also includes non-participating resources.

185 In this chart, positive values represent higher average hourly generation by a fuel type during the hour, while negative values represent a decrease in hourly generation.

186 For more information on the duck curve and its implications on grid management, please see California ISO, *Fast Facts:* https://www.caiso.com/documents/flexibleresourceshelprenewables_fastfacts.pdf

Figure 3.7 Change in average hourly participating WEIM generation by fuel type (2020 to 2021)



3.4 Transfers, limits, and congestion

Transfers

One of the key benefits of the Western Energy Imbalance Market is the ability to transfer energy between areas in the 15-minute and 5-minute markets. These transfers are the result of regional supply and demand conditions in the market, as lower cost generation is optimized to displace expensive generation and meet load across the footprint. WEIM transfers are also constrained by *transfer limits* between the WEIM balancing authority areas, which are discussed in the next section.

Figure 3.8 and Figure 3.9 highlight typical transfer patterns during two key periods that produce a high volume of transfers.[187] First, Figure 3.8 shows average dynamic 15-minute market exports out of each area during mid-day hours in April and May 2021.[188] The curves show the path and size of exports where the color corresponds to the area the transfer is coming from. The inner ring, at the origin of each curve, measures average exports from each area. The outer ring instead shows total exports and imports for each area. Each small tick is 50 MW and each large tick is 250 MW.

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187 WEIM transfer paths less than 25 MW, on average, are excluded from the figures.

188 These figures exclude the fixed bilateral transactions between WEIM entities (base WEIM transfer schedules) and therefore reflect only *dynamic* market flows optimized in the market.

In particular, Figure 3.8 shows that the CAISO exported just over 2,000 MW, on average during these mid-day spring hours, out to neighboring areas including BANC, LADWP, Portland General Electric, Powerex, NV Energy, Salt River Project, and Arizona Public Service. These areas each remained a net importer on average, despite having some exports out to other connecting areas in the WEIM footprint (which can be followed around in the chart). The mid-day hours of April and May typically contain the highest levels of exports out of the CAISO area because of significant renewable production (particularly solar), as well as modest loads.

Figure 3.9 shows average dynamic transfers during peak load hours between the months of June and September 2021. During these hours, when supply conditions across the footprint are typically tightest, imports into the CAISO are often high. The figure shows, on average, 1,700 MW of exports out of Arizona Public Service, LADWP, NV Energy, PacifiCorp West, Portland General Electric, Salt River Project, and Turlock Irrigation District, going into the CAISO during these hours (CAISO import). In addition, the CAISO is then exporting out to Powerex and BANC, which were also net importers on average for this period.

Figure 3.8 Average 15-minute market WEIM exports (mid-day hours, April – May, 2021)

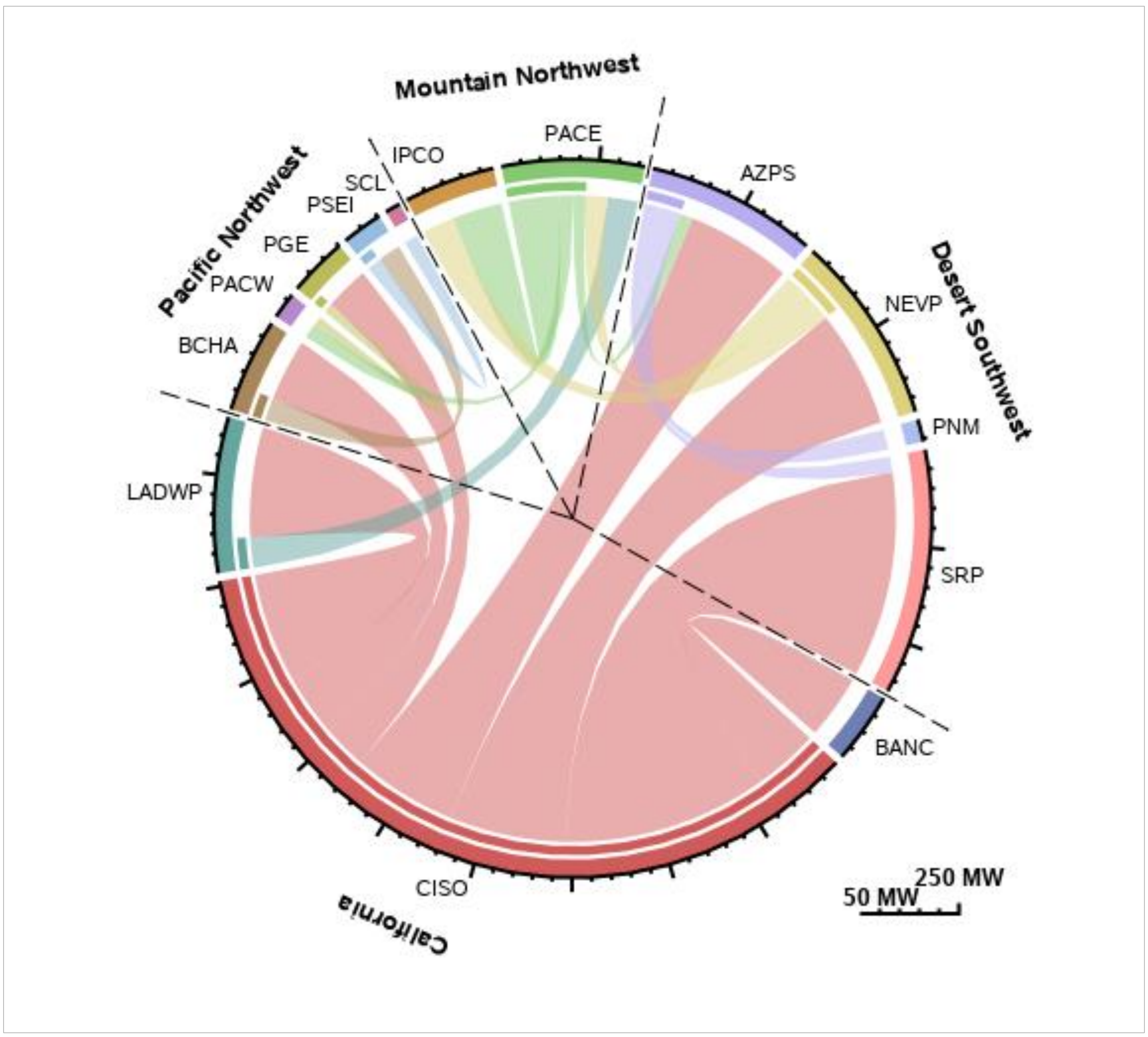
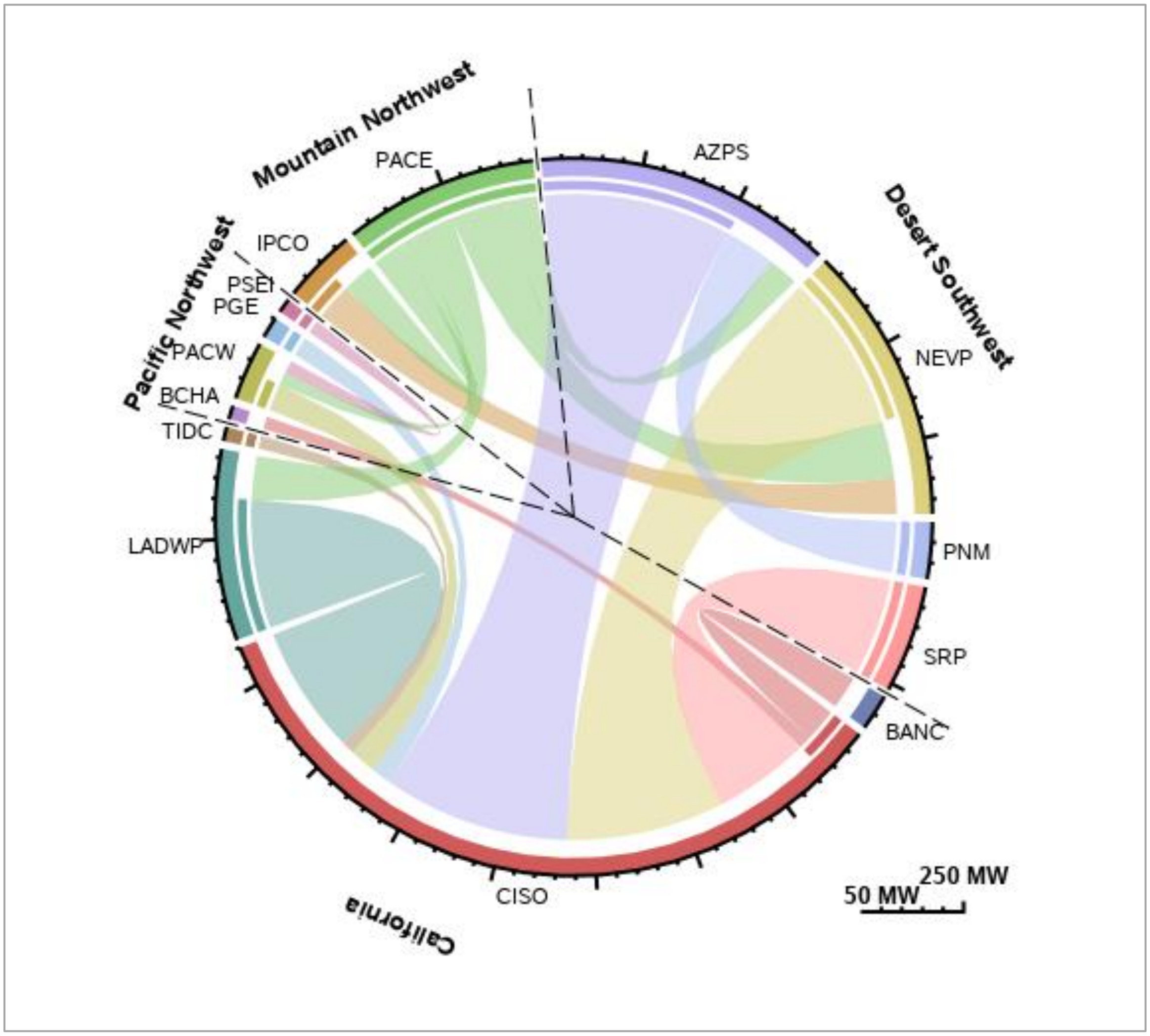


Figure 3.9 Average 15-minute market WEIM exports (peak load hours, June – September, 2021)



Transfer limits

WEIM transfers between areas are constrained by *transfer limits*. These largely reflect transmission and interchange rights made available to the market by participating WEIM entities.[189] Table 3.2 shows average 15-minute market limits between each of the areas over the year.[190] These amounts exclude base transfer schedules and therefore reflect only the transfer capability made available by WEIM entities to optimally transfer energy between areas. The sum of each column reflects the average total

189 The exception to this is PacifiCorp West and Portland General Electric 5-minute market transfer limits with CAISO, which are based on the allocated dynamic transfer capacity driven by system operating conditions.

190 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 year.

import limit into each balancing area, while the sum of each row reflects the average total export limit from each area.

Import transfer capacity into the CAISO from the Pacific Northwest (including PacifiCorp West, Portland General Electric, Puget Sound Energy, Seattle City Light, and Powerex) was around 230 MW on average, or roughly 1 percent of total import capability. Significant transfer capability, between the CAISO and the neighboring Southwest and WEIM areas within California, allowed energy to flow between these areas with relatively little congestion.

Table 3.2 Average 15-minute market WEIM transfer limits (2021)

From Balancing Authority Area	To Balancing Authority Area																*Total*
	CAISO	BANC	TIDC*	LADWP*	NEVP	AZPS	SRP	PNM*	PACE	IPCO	NWMT*	PACW	PGE	PSEI	SCL	PWRX	*export limit*
California ISO		3,350	1,160	5,000	3,500	1,190	1,560					20	60			230	16,070
BANC	3,310		510														3,820
Turlock Irrig. District*	1,200	760															1,960
LADWP*	7,970				1,480	330			200								9,980
NV Energy	3,940			1,080		300			780	420							6,520
Arizona Public Service	2,550			360	330		3,520	520	590								7,870
Salt River Project	2,550					2,780		70									5,400
PSC New Mexico*						440	60										500
PacifiCorp East				180	430	400				650	170	130					1,960
Idaho Power					420				1,590		190	320		80	30		2,630
NorthWestern Energy*									90	140							230
PacifiCorp West	120								0	170			340	150	10		790
Portland GE	110											360		130	10		610
Puget Sound Energy										10		120	130		350	80	690
Seattle City Light										30		20	10	350			410
Powerex	0													130			130
Total import limit	21,750	4,110	1,670	6,620	6,160	5,440	5,140	590	3,250	1,420	360	970	540	840	400	310	

*Since joining the WEIM in 2021

Congestion on transfer constraints

WEIM participants in the Pacific Northwest continued to be the most frequently congested region relative to the greater market footprint.[191] WEIM areas within California experienced the lowest frequency of congestion, with BANC experiencing less than 1 percent in both the 15-minute and 5-minute markets.

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 a WEIM area. This is calculated as the percent of intervals when 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.[192] When prices are lower relative to the system, this indicates congestion out of an area (or region) and limited export capability. Conversely, when prices are higher within an area, this indicates that congestion is limiting the ability for outside energy to serve that area's load. The results of this section are the same as those found in Section 7.1.3 of this

[191] Pacific Northwest areas include Powerex, Puget Sound Energy, Seattle City Light, Portland General Electric, and PacifiCorp West.

[192] Greenhouse gas prices can contribute to lower prices relative to those inside the CAISO. This calculation uses the WEIM greenhouse gas prices in each interval to account for and omit price separation that is the result of greenhouse gas prices only.

report on congestion. Section 7.1.3 focuses on the impact of congestion on prices, whereas this section describes the same information in terms of the impact to WEIM import or export capability.

The highest frequency of congestion occurred with areas located in the Pacific Northwest. WEIM *exports* were congested from this region during around 30 percent of the 15-minute market intervals and 25 percent of the 5-minute market intervals. WEIM *imports* into the Pacific Northwest region were also frequently congested, typically during mid-day hours. PacifiCorp West, Portland General Electric, Seattle City Light, and Puget Sound Energy were import congested during around 10 percent of both the 15-minute and 5-minute market intervals. Powerex was congested for imports into the area during around 21 percent of the 5-minute market intervals.

In Table 3.3, the relatively high frequency of congestion for NorthWestern Energy was largely due to outages on the Brady transmission in the fall. This line, with connections to Idaho Power and PacifiCorp East, supported most of NorthWestern Energy's dynamic transfer capability in the WEIM. On September 14, the transmission line relayed and was out until September 16. The line then went on outage for scheduled maintenance on September 20 until November 1. Prior to these events, total WEIM dynamic transfer capability for NorthWestern Energy averaged around 260 MW for exports and 490 MW for imports. During the outages, transfer capability averaged only 70 MW for exports and 0 MW for imports. This congestion contributed to higher flexible ramping product prices, higher energy prices, and more frequent power balance constraint relaxations for NorthWestern Energy.

Congestion in either direction for BANC, Turlock Irrigation District, Arizona Public Service, LADWP, and NV Energy was relatively infrequent during the year. However, congestion that did occur between these areas and the larger WEIM system was often the result of a failed upward or downward resource sufficiency evaluation, which limited transfer capability.

Table 3.3 Frequency of congestion on WEIM area transfer constraints (2021)

	15-minute market		5-minute market	
	Congested from area	Congested into area	Congested from area	Congested into area
BANC	0%	0%	0%	0%
Turlock Irrigation District*	1%	0%	0%	1%
Arizona Public Service	1%	0%	1%	2%
L.A. Dept. of Water and Power*	1%	1%	1%	2%
NV Energy	2%	0%	2%	2%
Public Service Company of NM*	4%	1%	3%	2%
PacifiCorp East	5%	1%	4%	2%
Idaho Power	4%	3%	3%	4%
Salt River Project	7%	3%	6%	4%
NorthWestern Energy*	15%	15%	14%	12%
PacifiCorp West	25%	9%	16%	8%
Portland General Electric	25%	11%	17%	9%
Seattle City Light	33%	9%	29%	11%
Puget Sound Energy	33%	9%	29%	11%
Powerex	30%	9%	33%	21%

*Since joining the WEIM in 2021

3.5 Resource sufficiency evaluation

As part of the Western Energy Imbalance Market (WEIM), each area, including the California ISO, is subject to a resource sufficiency evaluation. The resource sufficiency evaluation allows the market to optimize transfers between participating WEIM entities while preventing leaning by one area on another. 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 is made up of four tests: the power flow feasibility test, the balancing test, the bid range capacity test, and the flexible ramping sufficiency test. Failures of two of the tests constrain transfer capability:

- **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 (flexibility test)** requires that each balancing area have enough ramping flexibility over an hour to meet the forecasted change in demand as well as uncertainty.

If an area fails either the bid range capacity test or flexible ramping sufficiency test in the upward direction, transfers into that area cannot be increased.[193] Similarly, if an area fails either test in the downward direction, transfers out of that area cannot be increased.

[193] If an area fails either test in the upward direction, net WEIM imports during the hour cannot exceed the greater of either the base transfer or the optimal transfer from the last 15-minute interval prior to the hour.

Bid range capacity and flexible ramping sufficiency test results

Figure 3.10 and Figure 3.11 show the percent of intervals in which each WEIM area failed the upward capacity or flexibility tests, while Figure 3.12 and Figure 3.13 provide the same information for the downward direction.[194] The dash indicates the area did not fail the test during the month.

Failures of the upward capacity test increased significantly in the summer of 2021 relative to the previous year. This increase was driven by several changes implemented by the California ISO in 2021. The California ISO corrected two errors effective February 4, 2021.[195] These errors incorrectly accounted for resource de-rates/outages as well as mirror resources, making it easier to pass the test. Next, the California ISO added net load uncertainty as a requirement of the bid range capacity test on June 16, 2021. The impact of adding uncertainty is summarized in the following section.

Overall, WEIM areas failed the resource sufficiency evaluation infrequently during the year. Of note, NorthWestern Energy failed the upward capacity test in around 1.8 percent of intervals as well as the upward flexibility test in around 2.3 percent of intervals since joining the market. These failures occurred most frequently in October. However, this did not have any direct impact on the rest of the WEIM because NorthWestern Energy did not have any incremental import capacity in the market during this period, as discussed in the previous section.

Salt River Project failed the upward capacity test in around 1.4 percent of intervals and the upward flexibility test in around 1.3 percent of intervals. In the downward direction, NV Energy failed the flexibility test in around 2 percent of intervals.

A failure of the capacity test does not always overlap with a failure of the flexibility test. Of the resource sufficiency evaluation failures across all areas during 2021, the capacity test alone failed 45 percent and the flexibility test alone failed 33 percent; in the remaining 22 percent of the evaluation failures, both tests were failed.

194 Results exclude known invalid test failures. These can occur because of a market disruption, software defect, or other error.

195 For additional information on these errors and the impact on bid range capacity test failures, see: Department of Market Monitoring, *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

Figure 3.10 Frequency of upward capacity test failures by month and area (15-minute intervals)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arizona PS	5	10	—	—	8	—	5	8	5	—	9	1
BANC	—	—	3	—	—	—	7	—	1	—	—	—
California ISO	—	—	—	—	—	4	6	1	5	—	—	—
Idaho Power	—	—	—	—	—	—	13	25	3	—	—	—
LADWP				—	—	2	—	—	—	8	5	2
NorthWestern						9	36	18	6	253	34	7
NV Energy	—	9	—	1	14	22	15	6	7	8	—	—
PacifiCorp East	—	—	—	—	—	10	9	4	6	4	—	—
PacifiCorp West	—	—	2	—	1	4	7	2	3	2	14	11
Portland GE	—	4	—	11	—	21	25	30	41	13	6	11
Powerex	4	1	—	—	—	1	1	—	2	15	6	6
PSC New Mexico				—	—	—	11	—	5	—	—	—
Puget Sound En	—	2	17	29	18	45	16	21	17	29	18	10
Salt River Proj.	—	215	—	2	4	19	90	76	56	3	20	—
Seattle City Light	—	—	—	—	—	—	—	1	14	4	—	4
Turlock ID			—	—	1	—	—	33	22	46	—	—

2021

Figure 3.11 Frequency of upward flexibility test failures by month and area (15-minute intervals)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arizona PS	15	13	7	—	19	—	1	—	7	—	10	1
BANC	—	—	—	—	—	—	—	—	—	—	—	—
California ISO	—	—	—	—	—	1	10	3	11	—	3	—
Idaho Power	—	4	—	—	—	—	—	—	—	—	—	1
LADWP				1	3	—	4	—	—	1	1	10
NorthWestern						18	108	20	46	247	14	14
NV Energy	4	13	11	12	20	27	12	15	4	8	1	1
PacifiCorp East	4	2	4	4	1	2	1	—	4	—	2	1
PacifiCorp West	1	5	3	4	1	—	1	2	—	—	16	7
Portland GE	10	15	3	7	7	8	14	5	—	1	—	5
Powerex	7	4	4	4	—	4	15	—	—	7	5	8
PSC New Mexico				11	1	3	15	—	2	—	2	—
Puget Sound En	—	—	—	—	4	2	1	1	—	—	2	—
Salt River Proj.	5	192	8	15	6	26	57	49	24	5	36	1
Seattle City Light	—	—	—	—	—	—	1	—	4	—	—	—
Turlock ID			—	—	9	—	—	—	2	5	—	—

2021

Figure 3.12 Frequency of downward capacity test failures by month and area (15-minute intervals)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arizona PS	—	—	—	—	1	—	—	—	—	—	5	—
BANC	—	1	2	—	—	—	—	—	—	—	—	—
California ISO	—	—	—	—	—	—	—	—	—	—	—	—
Idaho Power	—	—	—	—	—	—	—	—	—	—	4	—
LADWP				—	—	2	—	—	—	5	—	—
NorthWestern						—	—	—	—	29	—	—
NV Energy	—	—	—	—	—	1	—	—	—	—	—	—
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	—	—	—	—	—	—	—	—	—	—	—	—
Portland GE	—	—	—	—	—	—	—	—	—	—	—	—
Powerex	—	—	—	1	—	8	3	—	24	9	1	—
PSC New Mexico				—	—	—	—	—	—	7	4	—
Puget Sound En	—	—	—	—	—	—	—	—	—	1	—	—
Salt River Proj.	—	—	—	1	—	1	—	—	—	—	—	1
Seattle City Light	—	—	—	—	—	—	1	1	1	—	7	5
Turlock ID			—	—	8	6	1	6	5	20	3	1

2021

Figure 3.13 Frequency of downward flexibility test failures by month and area (15-minute intervals)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arizona PS	64	61	129	55	8	4	—	4	2	3	15	11
BANC	—	17	10	—	—	—	—	—	—	—	—	4
California ISO	—	—	—	—	—	—	—	—	—	—	—	—
Idaho Power	—	—	—	—	1	—	—	—	—	—	8	1
LADWP				—	—	2	—	—	—	2	—	—
NorthWestern						10	18	11	33	68	4	1
NV Energy	6	163	42	15	127	58	88	74	48	34	11	13
PacifiCorp East	—	—	—	—	—	—	—	—	—	—	—	—
PacifiCorp West	—	—	2	—	—	4	—	—	—	—	1	—
Portland GE	1	—	—	—	—	—	—	—	—	—	—	—
Powerex	12	—	42	6	27	36	12	6	29	12	1	4
PSC New Mexico				39	—	1	—	—	4	11	20	4
Puget Sound En	—	—	—	—	—	—	—	—	—	—	1	—
Salt River Proj.	33	43	35	5	2	5	—	2	1	2	1	2
Seattle City Light	—	—	—	—	—	—	6	—	—	—	1	1
Turlock ID			3	4	16	—	—	1	—	18	3	5

2021

Impact of adding uncertainty to the bid range capacity test

On June 16, 2021, the California ISO added net load uncertainty to the requirement of the bid range capacity test. At the end of 2021, the CAISO stated its intention to remove both the net load and intertie uncertainty components from the capacity test while these adders are further refined as part of the resource sufficiency evaluation enhancements stakeholder initiative.[196] Net load uncertainty was removed from the bid range capacity test on February 15, 2022. Intertie uncertainty was removed on June 1, 2022. Once the calculations are improved, these adders are expected to return as part of the next phase of the initiative.

Figure 3.14 shows the impact of adding net load uncertainty by showing actual capacity test failure intervals that *would* have passed the test without the extra requirement component. Since the outcome of failing either the capacity test or the flexibility test is the same, intervals in which the flexibility test *also* failed in that interval were excluded. The figure therefore summarizes additional intervals in which transfers were capped because of the additional uncertainty component in the capacity test. Since the implementation of uncertainty, 66 percent of upward test failures in 2021 *would* have passed without the additional requirement component.

Figure 3.14 Additional capacity test failures with net load uncertainty <u>excluding</u> flexibility test failures (15-minute intervals)

	Upward capacity test							Downward capacity test						
	Jun*	Jul	Aug	Sep	Oct	Nov	Dec	Jun*	Jul	Aug	Sep	Oct	Nov	Dec
Arizona PS	—	3	7	2	—	1	1	—	—	—	—	—	—	—
BANC	—	3	—	1	—	—	—	—	—	—	—	—	—	—
California ISO	3	2	—	2	—	—	—	—	—	—	—	—	—	—
Idaho Power	—	13	21	3	—	—	—	—	—	—	—	—	—	—
LADWP	—	—	—	—	—	1	1	—	—	—	—	2	—	—
NorthWestern	2	9	9	—	105	23	5	—	—	—	—	13	—	—
NV Energy	2	9	6	5	6	—	—	—	—	—	—	—	—	—
PacifiCorp East	7	8	4	4	4	—	—	—	—	—	—	—	—	—
PacifiCorp West	4	6	2	2	2	11	5	—	—	—	—	—	—	—
Portland GE	17	19	25	34	13	4	11	—	—	—	—	—	—	—
Powerex	1	1	—	2	6	1	2	3	1	—	2	4	1	—
PSC New Mexico	—	1	—	2	—	—	—	—	—	—	—	7	—	—
Puget Sound En	7	8	10	8	19	13	8	—	—	—	—	1	—	—
Salt River Proj.	5	34	15	27	2	14	—	—	—	—	—	—	—	1
Seattle City Light	—	—	1	3	—	—	1	—	—	—	1	—	2	2
Turlock ID	—	—	9	10	18	—	—	4	—	1	2	1	1	—

*June 16-30, 2021 only (implementation of uncertainty in the capacity test)

[196] California ISO, *EIM Resource Sufficiency Evaluation Enhancements Phase 1 Revised Draft Final* Proposal, December 16, 2021. http://www.caiso.com/InitiativeDocuments/RevisedDraftFinalProposal-EIMResourceSufficiencyEvaluationEnhancements.pdf

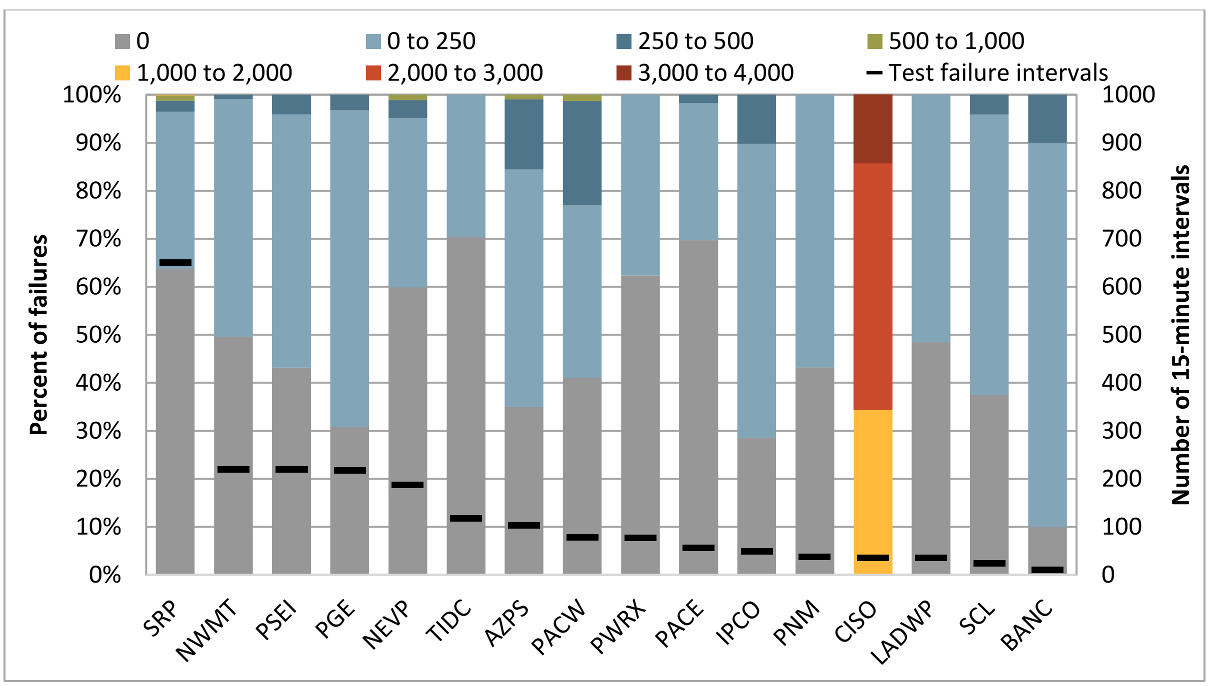
WEIM import limits and transfers following a test failure

This section summarizes the import limits that are imposed when a WEIM entity fails either the bid range capacity test or flexible ramping sufficiency test in the upward direction. When either test fails, imports will be capped at the greater of the base transfer or the optimal transfer from the last 15-minute market interval. These limits are also compared against actual WEIM transfers during these insufficiency periods in this section.

Figure 3.15 summarizes dynamic import limits excluding base transfers (fixed bilateral transactions between entities) imposed after failing either test during the year. From this perspective, the dynamic import limit after a test failure is set by the greater of (1) zero or (2) the transfer from the last 15-minute market interval *minus* the current base transfer. The dynamic import limit therefore shows the incremental flexibility that is available through the WEIM after a resource sufficiency evaluation failure. The black horizontal line (right axis) shows the number of 15-minute intervals with an import limit imposed after a test failure, while the bars (left axis) show the frequency of various quantity ranges.[197]

The figure also shows that the dynamic import limit for the CAISO following a resource sufficiency evaluation failure is typically large, between 1,000 and 4,000 MW. The CAISO does not have base transfers and often has a high volume of dynamic imports prior to any upward test failure, which will set the import limit during the failure interval. Substantial imbalance conformance adjustments entered by the CAISO operators can further contribute to this outcome. Here, the optimal transfer in the last 15-minute interval increases as the optimization solves for load plus imbalance conformance, potentially setting a higher import limit than would have existed otherwise.

Figure 3.15 Imposed dynamic import limit following upward test failure (2021)



197 Test failure intervals in which an import limit was not imposed because it was at or above the unconstrained total import capacity were excluded from this summary.

Figure 3.16 summarizes transfers optimized in the real-time market following an upward resource sufficiency evaluation failure. The black horizontal line (right axis) shows the number of 15-minute intervals with either a capacity test or a flexibility test failure, while the bars (left axis) show the percent of failure intervals in which the balancing area was a net importer or net exporter in the corresponding real-time market interval. Figure 3.17 summarizes the same information with the net transfer quantity categorized by various levels. These figures summarize dynamic WEIM transfers only and therefore base transfers are again excluded.

As shown by Figure 3.16, balancing areas were commonly optimized as net exporters in 2021, despite failing the resource sufficiency evaluation for that interval. This result is in part driven from *uncertainty* that is included in both the capacity and the flexibility tests. During much of this period, the capacity test included both intertie and net load uncertainty in the requirement.[198] The flexibility test also includes net load uncertainty in the requirement. In some cases, the balancing area would fail the resource sufficiency evaluation in part because of the uncertainty component in either test, but then in the real-time market it could then be economically optimal to export if that uncertainty does not materialize.

Other factors can also contribute to this outcome as a net exporter. A decrease in the load forecast (or an increase in wind or solar forecasts) from the resource sufficiency evaluation to the real-time market can lead to greater resource sufficiency and WEIM exports. A negative imbalance conformance adjustment entered by the WEIM operators can also be included in the market run to effectively lower load, but will not be included in the resource sufficiency evaluation.

[198] Net load uncertainty was added to the capacity test on June 16, 2021 and was removed on February 15, 2022.

Figure 3.16 Dynamic WEIM transfer status during upward test failure (2021)

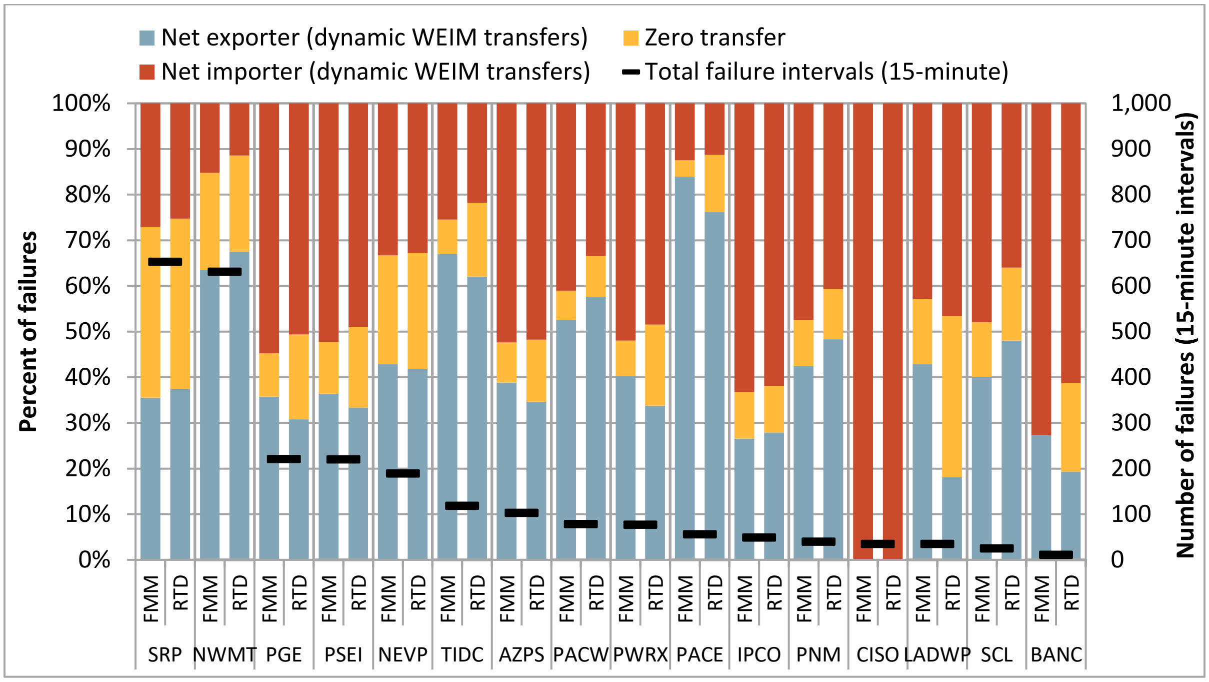
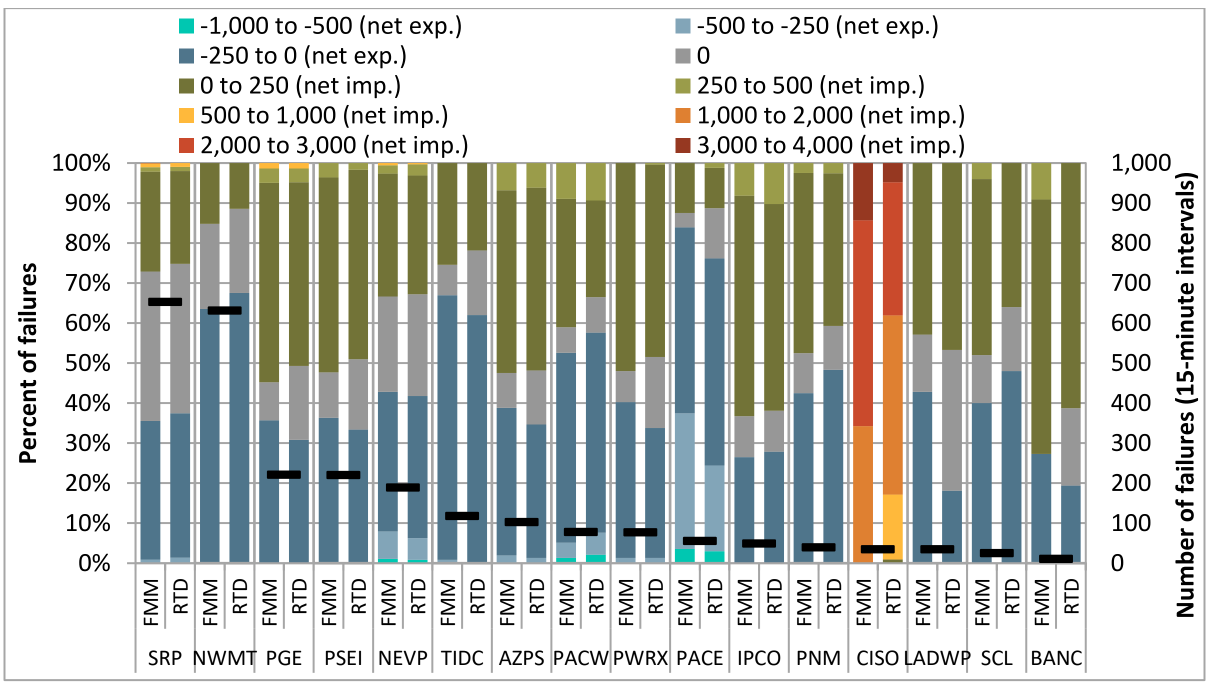


Figure 3.17 Dynamic WEIM transfer amount during upward test failure (2021)



Resource sufficiency evaluation monthly reports

As an outcome of the WEIM resource sufficiency evaluation stakeholder initiative, DMM is providing additional transparency surrounding test accuracy and performance in monthly reports specific to this topic.[199] These reports include many metrics and analyses not included in this annual report, such as the impact of several changes proposed or adopted through the stakeholder process, as well as a detailed look at the net load uncertainty adders used in the tests.

3.6 Market performance

This section describes prices in the Western Energy Imbalance Market and some of the factors that contribute to price separation between participating areas. The WEIM lowers costs by committing and ramping less expensive generation across all areas to meet system-wide load. When transfer constraints do not limit the ability for energy to move between areas, prices within each balancing authority area often converge. In contrast, prices can diverge on each side of a transfer constraint when energy flow is limited from the lower-priced region to the higher priced region. When transfer constraints become binding and an area runs out of upward or downward ramping capability to balance internal supply and demand, the market can relax the power balance constraint, setting prices at penalty parameters. A failed resource sufficiency evaluation can also lead to this outcome and have a significant impact on prices by limiting an area's transfer capability, and consequently its ability to balance load.

Greenhouse gas compliance costs, enforced for imports into California, can also contribute to price separation between WEIM areas. These costs are discussed in Section 3.7. Congestion on internal constraints, as discussed in Section 7.1.2, can also impact WEIM prices.

3.6.1 Energy market prices

Figure 3.18 and Figure 3.19 show average hourly market prices throughout the day in 2021.[200] The color gradient highlights deviation from the average hourly system marginal energy cost (SMEC), shown in the top row. Here, blue represents prices below that hour's average system price, and orange indicates prices above. The CAISO prices in the Pacific Gas and Electric (PG&E) and Southern California Edison (SCE) areas are included as a point of comparison.

CAISO prices in California tend to be higher than prices in balancing areas outside of California because of the greenhouse gas compliance cost for energy that is delivered within the state.[201] In addition, average prices in the Pacific Northwest (including PacifiCorp West, Puget Sound Energy, Portland General Electric, Seattle City Light, and Powerex) are regularly lower than in CAISO and other balancing areas because of limited transfer capability out of the region and high availability of lower cost hydroelectric generation within the region. Other differences in prices reflect congestion and transfer limitations between the different areas. Prices followed the CAISO net load pattern with the lowest

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[199] Department of Market Monitoring Reports and Presentations, *WEIM resource sufficiency evaluation reports:* http://www.caiso.com/market/Pages/MarketMonitoring/MarketMonitoringReportsPresentations/Default.aspx

[200] Prices for Turlock Irrigation District, Public Service Company of New Mexico, Los Angeles Department of Water and Power, and NorthWestern Energy are the average from their respective WEIM go-live dates to December 31, 2021.

[201] See Section 3.7 for more information about California's greenhouse gas compliance cost and its impact on both the California ISO and the Western Energy Imbalance Market.

energy prices during the mid-day hours and the highest energy prices during the evening peak net load hours.

Figure 3.20 shows average monthly prices in the 15-minute market, by area, from 2020 through 2021. High prices in NorthWestern Energy during October were driven by a transmission outage that limited transfer capacity *into* and *out of* the area. The limited transfer capacity then meant that a local flexible ramping capacity requirement to meet uncertainty in this area was frequently enforced.[202] During October, this requirement was frequently relaxed at a positive shadow price based on the availability of flexible capacity and trade-off between procuring additional flexibility in lieu of energy. This contributed to higher average energy prices for that month.

Figure 3.18 Average hourly 15-minute market prices ($/MWh)

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SMEC	$44	$42	$41	$41	$43	$49	$52	$47	$38	$34	$33	$32	$33	$34	$38	$45	$54	$72	$88	$83	$69	$60	$52	$47
PG&E (CAISO)	$47	$44	$43	$43	$45	$50	$53	$51	$42	$39	$37	$36	$37	$38	$42	$49	$57	$73	$90	$86	$71	$62	$54	$49
SCE (CAISO)	$45	$43	$42	$42	$45	$52	$56	$48	$35	$31	$29	$28	$29	$31	$36	$43	$55	$79	$96	$91	$75	$65	$56	$49
Arizona PS	$34	$32	$31	$31	$34	$40	$43	$40	$27	$23	$20	$20	$22	$24	$28	$34	$47	$65	$75	$72	$59	$49	$43	$37
BANC	$50	$47	$45	$45	$47	$51	$53	$51	$46	$43	$43	$43	$44	$46	$52	$58	$65	$79	$89	$90	$72	$65	$57	$51
Idaho Power	$34	$32	$31	$31	$33	$37	$40	$38	$34	$32	$32	$32	$33	$34	$37	$41	$47	$60	$69	$66	$52	$46	$41	$36
LADWP*	$47	$45	$43	$43	$44	$49	$51	$46	$38	$34	$32	$32	$34	$37	$43	$50	$59	$73	$85	$86	$69	$61	$54	$48
NorthWestern*	$42	$37	$39	$37	$36	$41	$44	$49	$50	$44	$44	$46	$46	$50	$52	$57	$64	$72	$76	$75	$58	$56	$55	$44
NV Energy	$35	$35	$31	$31	$33	$39	$40	$38	$28	$25	$26	$24	$24	$27	$31	$37	$46	$67	$78	$75	$72	$52	$49	$40
PacifiCorp East	$31	$29	$28	$28	$30	$34	$38	$35	$29	$27	$26	$26	$26	$28	$31	$36	$43	$56	$66	$63	$50	$43	$38	$33
PacifiCorp West	$33	$31	$30	$30	$31	$34	$32	$35	$34	$34	$34	$34	$35	$35	$36	$39	$42	$48	$52	$49	$43	$39	$40	$35
Portland GE	$34	$31	$30	$30	$31	$33	$32	$35	$34	$35	$34	$34	$34	$36	$37	$39	$44	$48	$54	$50	$44	$39	$43	$35
Powerex	$31	$30	$29	$29	$30	$32	$32	$33	$35	$33	$32	$32	$32	$33	$34	$35	$39	$43	$42	$41	$39	$38	$37	$33
PSC New Mexico*	$34	$31	$30	$30	$31	$35	$37	$33	$29	$25	$25	$26	$28	$30	$35	$41	$47	$58	$69	$67	$52	$45	$40	$35
Puget Sound Energy	$34	$29	$28	$29	$30	$32	$30	$35	$35	$33	$34	$33	$34	$34	$35	$38	$40	$45	$46	$45	$39	$37	$38	$33
Salt River Project	$32	$31	$30	$30	$33	$36	$41	$40	$29	$27	$22	$23	$24	$26	$29	$40	$53	$69	$85	$75	$63	$52	$45	$35
Seattle City Light	$32	$29	$29	$29	$30	$32	$30	$33	$33	$33	$34	$33	$34	$35	$37	$39	$40	$45	$46	$45	$39	$37	$37	$33
Turlock ID*	$50	$47	$45	$45	$47	$52	$53	$51	$47	$45	$45	$45	$47	$49	$53	$59	$65	$79	$88	$90	$73	$64	$58	$52

*Since joining the WEIM

202 A local flexible ramping capacity requirement for each balancing area is reduced by the area's transfer capability (import capability reduces the local upward requirement and export capability reduces the local downward requirement). When transfer capability is sufficient, then only the system-wide flexible ramping requirement remains.

Figure 3.19 Average hourly 5-minute market prices ($/MWh)

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SMEC	$43	$41	$40	$40	$41	$45	$50	$46	$36	$31	$30	$29	$31	$33	$37	$40	$46	$58	$64	$60	$58	$54	$50	$44
PG&E (CAISO)	$46	$44	$42	$42	$44	$47	$51	$50	$41	$36	$34	$34	$35	$37	$41	$43	$48	$59	$65	$62	$60	$57	$53	$47
SCE (CAISO)	$43	$41	$41	$40	$42	$47	$53	$45	$33	$26	$25	$25	$27	$30	$35	$39	$47	$64	$70	$65	$64	$58	$52	$46
Arizona PS	$33	$31	$31	$31	$32	$36	$42	$40	$28	$20	$20	$19	$21	$24	$28	$33	$41	$55	$63	$55	$52	$45	$40	$38
BANC	$49	$46	$44	$45	$45	$48	$51	$53	$45	$41	$40	$41	$43	$46	$51	$53	$55	$64	$70	$67	$63	$60	$55	$50
Idaho Power	$34	$32	$30	$30	$32	$35	$38	$37	$33	$30	$30	$30	$32	$33	$36	$38	$41	$51	$54	$49	$46	$42	$40	$35
LADWP*	$48	$46	$42	$42	$43	$47	$49	$45	$34	$29	$28	$29	$33	$36	$42	$46	$49	$58	$68	$64	$61	$56	$52	$46
NorthWestern*	$37	$35	$34	$34	$35	$37	$40	$46	$41	$38	$37	$38	$41	$45	$49	$49	$48	$52	$54	$48	$46	$40	$41	$39
NV Energy	$38	$32	$30	$29	$32	$35	$39	$35	$24	$21	$22	$22	$22	$26	$29	$36	$41	$57	$64	$64	$70	$51	$50	$39
PacifiCorp East	$30	$28	$27	$27	$29	$32	$36	$34	$27	$24	$23	$24	$25	$28	$31	$34	$38	$50	$56	$46	$45	$39	$37	$32
PacifiCorp West	$32	$31	$30	$29	$31	$33	$33	$34	$33	$32	$32	$32	$32	$34	$34	$36	$38	$42	$44	$43	$40	$38	$39	$34
Portland GE	$34	$30	$29	$29	$31	$33	$32	$34	$33	$31	$32	$32	$32	$33	$36	$39	$38	$42	$47	$44	$40	$37	$41	$33
Powerex	$31	$29	$29	$29	$29	$32	$32	$32	$31	$30	$30	$30	$30	$31	$31	$33	$35	$38	$40	$39	$37	$36	$36	$32
PSC New Mexico*	$32	$30	$29	$29	$31	$35	$34	$33	$26	$21	$22	$23	$26	$29	$35	$38	$44	$50	$57	$51	$49	$41	$38	$32
Puget Sound Energy	$35	$29	$28	$28	$29	$31	$30	$32	$35	$31	$32	$31	$31	$32	$33	$39	$38	$39	$40	$41	$36	$33	$44	$34
Salt River Project	$30	$29	$29	$29	$31	$35	$38	$37	$26	$23	$19	$23	$25	$29	$29	$41	$52	$67	$76	$62	$55	$48	$44	$34
Seattle City Light	$32	$29	$28	$28	$29	$31	$30	$31	$31	$31	$31	$31	$33	$34	$33	$37	$35	$39	$40	$41	$36	$34	$36	$31
Turlock ID*	$49	$47	$45	$45	$46	$49	$51	$53	$46	$44	$43	$43	$46	$48	$53	$54	$55	$63	$67	$66	$62	$59	$56	$50

*Since joining the WEIM

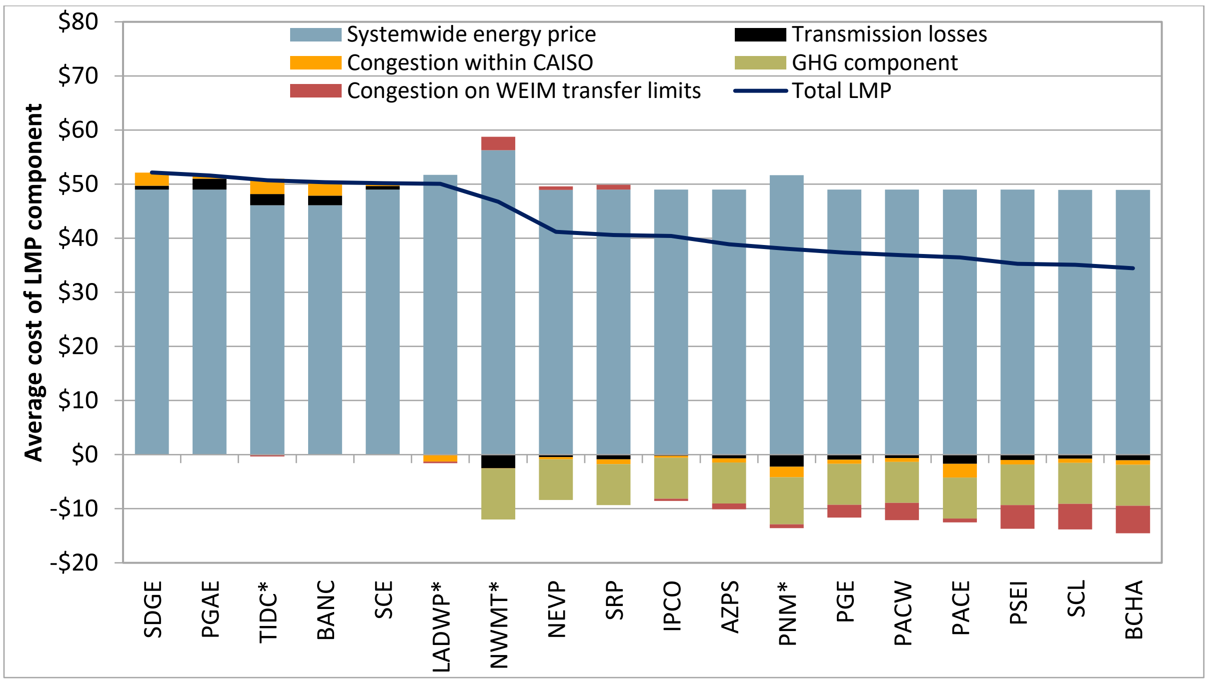
Figure 3.20 Average monthly 15-minute market prices ($/MWh)

	2020 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2021 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SMEC	$28	$25	$26	$20	$20	$22	$29	$54	$40	$43	$37	$37	$31	$61	$31	$33	$32	$42	$64	$54	$68	$61	$54	$57
PG&E (CAISO)	$29	$26	$28	$22	$24	$23	$27	$50	$38	$45	$39	$41	$33	$49	$34	$37	$37	$45	$70	$57	$72	$67	$58	$60
SCE (CAISO)	$29	$26	$25	$19	$21	$23	$33	$60	$48	$47	$39	$40	$31	$78	$30	$30	$28	$44	$67	$56	$70	$56	$55	$58
Arizona PS	$23	$22	$21	$15	$22	$19	$29	$50	$31	$35	$30	$26	$23	$63	$20	$23	$24	$37	$54	$44	$57	$42	$39	$41
BANC	$28	$25	$27	$22	$21	$22	$26	$42	$35	$42	$38	$40	$33	$48	$35	$38	$39	$44	$69	$56	$70	$71	$57	$60
Idaho Power	$24	$20	$21	$19	$16	$19	$22	$39	$25	$27	$29	$32	$26	$51	$27	$28	$26	$36	$49	$45	$57	$55	$40	$46
LADWP																$30	$29	$42	$63	$52	$66	$56	$54	$57
NorthWestern																		$37	$41	$41	$66	$79	$38	$44
NV Energy	$26	$21	$20	$20	$27	$29	$47	$74	$42	$37	$33	$27	$26	$63	$26	$29	$27	$41	$54	$42	$56	$45	$40	$45
PacifiCorp East	$22	$19	$20	$17	$17	$18	$24	$40	$26	$28	$25	$27	$24	$52	$25	$26	$24	$34	$47	$38	$51	$42	$37	$38
PacifiCorp West	$23	$18	$21	$20	$15	$10	$17	$24	$22	$25	$26	$30	$22	$34	$24	$29	$29	$30	$40	$42	$56	$53	$40	$44
Portland GE	$23	$18	$22	$19	$14	$9	$16	$24	$23	$25	$27	$29	$22	$34	$24	$30	$28	$31	$41	$46	$57	$53	$38	$43
Powerex	$24	$19	$21	$19	$14	$10	$11	$16	$22	$25	$26	$28	$22	$35	$26	$29	$27	$29	$35	$38	$44	$50	$40	$39
PSC New Mexico																$24	$23	$34	$51	$41	$54	$42	$38	$36
Puget Sound Energy	$23	$19	$21	$19	$14	$11	$17	$24	$22	$25	$25	$29	$21	$34	$26	$29	$29	$30	$39	$41	$48	$48	$39	$41
Salt River Project				$17	$19	$21	$29	$49	$31	$36	$30	$26	$23	$66	$22	$25	$24	$41	$60	$50	$55	$42	$43	$37
Seattle City Light				$19	$14	$10	$16	$24	$23	$25	$26	$30	$21	$34	$24	$29	$28	$29	$39	$40	$50	$47	$38	$41
Turlock ID																$38	$41	$45	$67	$56	$71	$75	$57	$61

Figure 3.21 and Figure 3.22 show the average 15-minute and 5-minute market price by component for each balancing authority area in 2021.[203] The system marginal energy price is the same for all entities in each hour.[204] The price difference between balancing authority areas is determined by area specific elements including transmission losses, greenhouse gas compliance costs, congestion, and power balance constraint violations.

Congestion on WEIM transfer constraints often drives price separation between areas. In some cases, the power balance constraint may be relaxed within the constrained region at a high penalty parameter. The red segments in the figures reflect price differences caused by congestion on transfer constraints, including any power balance constraint relaxations that increase the price in a single area.

Figure 3.21 Annual average 15-minute price by component (2021)

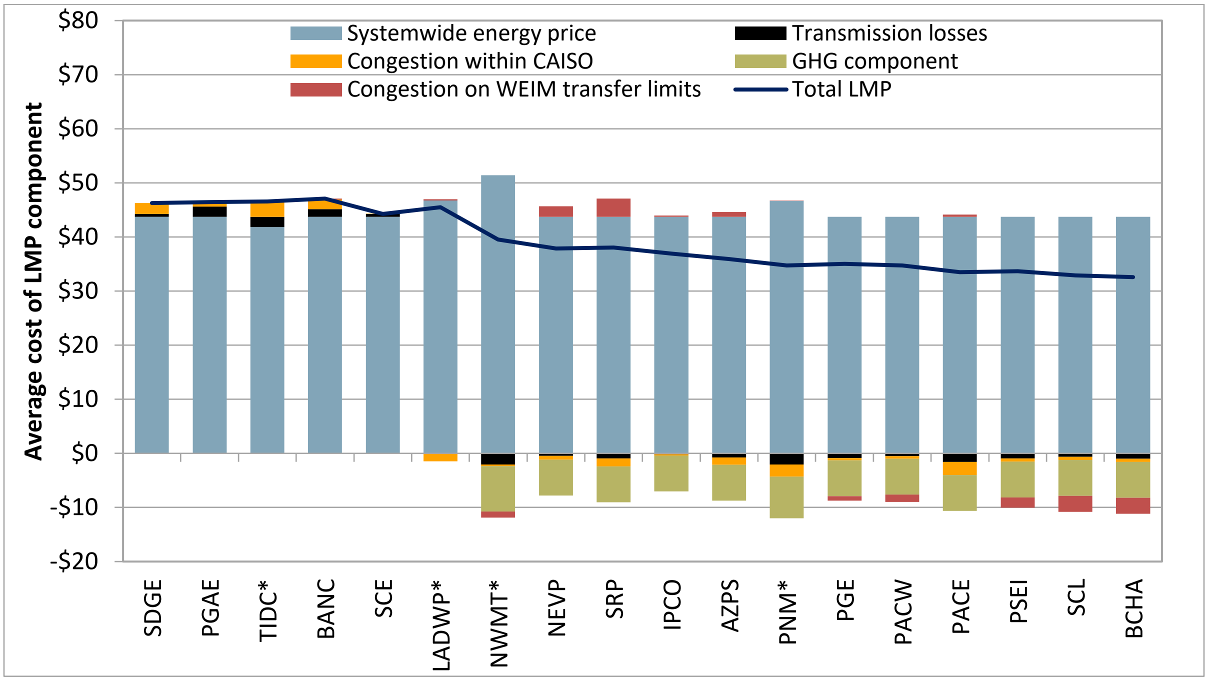


*Since joining the WEIM

[203] The 'Congestion within the CAISO' component represents all congestion on internal constraints, including those within the California ISO and WEIM. California ISO-specific internal constraints make up the large majority of this category.

[204] Areas that joined the WEIM part-way through the year will have a different average system marginal energy price than other areas as their respective averages are only from the time they joined.

Figure 3.22 Annual average 5-minute price by component (2021)



*Since joining the WEIM

3.6.2 Power balance constraint

WEIM area prices can be significantly impacted by the frequency in which the power balance constraint is relaxed, also referred to as a *power balance infeasibility*. When the power balance constraint is relaxed for undersupply conditions in an area, prices are set using the $1,000/MWh penalty price for this constraint in the pricing run of the market model.[205] During the first six months after joining the Western Energy Imbalance Market, *transition period pricing* instead sets prices for new WEIM balancing areas at the highest dispatched economic bid, rather than a penalty parameter when the power balance constraint is relaxed.

Figure 3.23 shows the frequency of power balance constraint relaxations in the 15-minute and 5-minute markets by quarter for undersupply (shortage) and oversupply (excess) conditions.[206] The frequency of undersupply infeasibilities are shown in the upward direction, while the frequency of oversupply infeasibilities are shown in the downward direction. NorthWestern Energy had the highest frequency of undersupply infeasibilities in 2021. This outcome was driven from a transmission outage in September and October, which limited the area's transfer capability and ability to balance load. However, the area

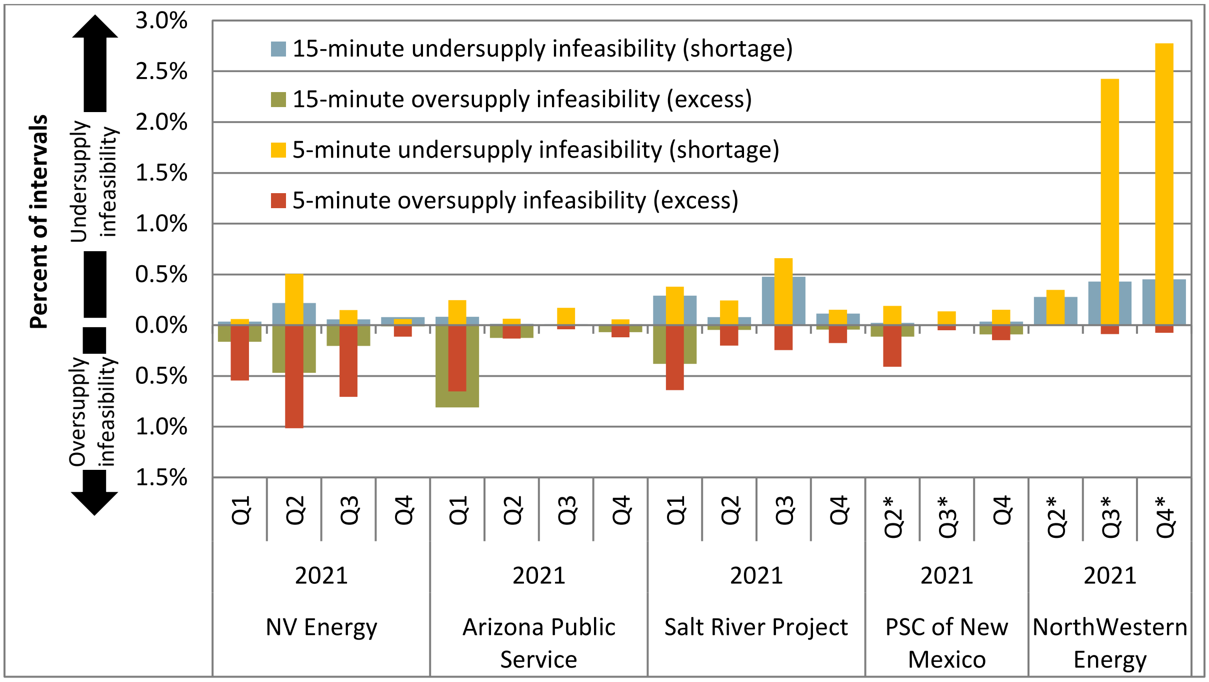
205 From March 20, 2021 to June 13, 2021, the penalty price for power balance constraint relaxation was increased from $1,000/MWh to $2,000/MWh. After June 13, the penalty price is only set over $1,000/MWh under certain circumstances. For additional details, see Department of Market Monitoring, *Q2 2021 Report on Market Issues and Performance,* October 5, 2021, pp. 101-103: http://www.caiso.com/Documents/2021-Second-Quarter-Report-on-Market-Issues-and-Performance-Oct-5-2021.pdf

206 Areas that did not incur undersupply or oversupply infeasibilities in at least 0.1 percent of 15-minute market intervals for any quarter during the year were excluded from the chart. Infeasibilities that were either invalid or resolved by the imbalance conformance limiter were omitted.

was under transition period pricing during this outage period such that prices were not impacted by relaxing the power balance constraint.

Balancing authority areas in the Southwest region, including NV Energy, Arizona Public Service, Salt River Project, and Public Service Company of New Mexico, also had a relative high frequency of power balance constraint relaxation. Most of these occurred following a resource sufficiency evaluation failure. Here, reduced transfer capability as a result of failing the test, can affect an area's ability to balance load as there is less flexibility to import or export to neighboring areas. This contributed to a higher frequency of power balance constraint relaxations.

Figure 3.23 Frequency of power balance constraint relaxations by market



*Area under transition period pricing for the quarter

3.6.3 Available balancing capacity

Available balancing capacity (ABC) allows for market recognition and accounting of capacity that WEIM participants 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 WEIM entity in their hourly resource plans. The available balancing capacity mechanism enables the CAISO system software to deploy such capacity through the market, and prevents market infeasibilities that may arise without the availability of this capacity.[207]

[207] FERC Docket No. ER15-861-*006, Order on Compliance Filing – Available Balancing Capacity*, December 17, 2015: http://www.caiso.com/Documents/Dec17_2015_OrderAcceptingComplianceFiling_AvailableBalancingCapacity_ER15-861-006.pdf

Table 3.4 summarizes the annual frequency of upward and downward available balancing capacity, both offered and scheduled, in each area during 2021.[208] Powerex, NV Energy, BANC, Turlock Irrigation District, Salt River Project, NorthWestern Energy, and Arizona Public Service offered both upward *and* downward balancing capacity during most hours; Portland General Electric only offered *upward* balancing capacity during most hours. The table also shows the average magnitude of the available balancing capacity when offered in their hourly resource plan. In particular, Powerex, on average, offered roughly 1,060 MW and 600 MW of upward and downward available balancing capacity, respectively, during 2021.

PacifiCorp West, Seattle City Light, and Puget Sound Energy offered available balancing capacity in either direction infrequently. Idaho Power did not offer upward or downward available balancing capacity for any hour during the year.

Overall, available balancing capacity was dispatched infrequently for scarcity conditions during 2021. Upward and downward available balancing capacity offered by NV Energy, Salt River Project, and NorthWestern Energy were dispatched most frequently during the year compared to other balancing areas. In particular, the 5-minute market available balancing capacity in NorthWestern Energy was dispatched in around 3.5 percent of intervals since joining the WEIM in June because of a high frequency of power balance constraint infeasibilities.

[208] Dispatched available balancing capacity without scarcity pricing in the scheduling run is omitted from this table. In some cases, a resource may be required to cross the operational range where available balancing capacity is defined, therefore "scheduling" it in the real-time market without scarcity conditions.

Table 3.4 Frequency of available balancing capacity offered and scheduled (2021)

	Offered		Scheduled	
	Percent of hours	Average MW	Percent of intervals (15-minute market)	Percent of intervals (5-minute market)
Upward ABC				
Powerex	100%	1,059	0.0%	0.0%
NV Energy	100%	53	0.2%	0.3%
BANC	100%	69	0.0%	0.1%
Turlock Irrigation District*	100%	11	0.1%	0.1%
Salt River Project	99%	91	0.6%	0.8%
Portland General Electric	98%	30	0.0%	0.1%
NorthWestern Energy*	98%	13	0.8%	3.5%
Arizona Public Service	95%	20	0.0%	0.1%
PSC New Mexico*	67%	27	0.0%	0.0%
LADWP*	37%	80	0.0%	0.0%
PacifiCorp East	28%	84	0.0%	0.0%
PacifiCorp West	4%	59	0.0%	0.0%
Seattle City Light	4%	42	0.0%	0.0%
Puget Sound Energy	0.1%	29	0.0%	0.0%
Idaho Power	0%	N/A	0.0%	0.0%
Downward ABC				
Powerex	100%	600	0.1%	0.1%
NV Energy	99%	53	0.5%	0.8%
BANC	100%	73	0.0%	0.0%
Turlock Irrigation District*	100%	5	0.1%	0.0%
Salt River Project	96%	48	0.2%	0.3%
Portland General Electric	0%	N/A	0.0%	0.0%
NorthWestern Energy*	94%	13	0.0%	0.3%
Arizona Public Service	92%	20	0.1%	0.1%
PSC New Mexico*	38%	33	0.0%	0.0%
LADWP*	9%	79	0.0%	0.0%
PacifiCorp East	16%	81	0.0%	0.0%
PacifiCorp West	11%	55	0.0%	0.0%
Seattle City Light	0%	N/A	0.0%	0.0%
Puget Sound Energy	0%	N/A	0.0%	0.0%
Idaho Power	0%	N/A	0.0%	0.0%

*Since joining the WEIM in 2021.

3.7 Greenhouse gas compliance costs

Background

Under the current Western Energy Imbalance Market design, all energy delivered to serve California load is subject to California's cap-and-trade regulation.[209] 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 WEIM 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. In November 2018, the California ISO implemented a policy change to address concerns regarding secondary dispatch. Secondary dispatch is defined as low-emitting resources that are outside of California scheduling as imports into California, as opposed to meeting their own demand, and in turn, these areas outside of California must dispatch higher-emitting resources to account for the difference. The policy change limited the amount of capacity that can be deemed delivered in to California to the difference between a resource's base schedule and their upper economic bid limit.

The 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 both California and non-California WEIM load, which can contribute to higher prices for WEIM areas in California.[210] 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 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 in to California.

Greenhouse gas prices

Figure 3.24 shows monthly average cleared WEIM greenhouse gas prices and hourly average quantities for energy delivered to California from 2019 to 2021. Average 15-minute market prices are weighted by greenhouse gas delivered in the 15-minute market. Alternatively, average 5-minute market prices are weighted by the absolute incremental megawatts delivered in the 5-minute market. Hourly average

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209 Further information on Western 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

210 Further detail on the determination of deemed delivered greenhouse gas megawatts within the WEIM optimization is available in the Western Energy Imbalance Market Business Practice Manual Change Management, Energy Imbalance Market: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Energy%20Imbalance%20Market

15-minute and 5-minute delivered quantities are represented by the blue and green bars in the chart, respectively.

In 2021, weighted 15-minute greenhouse gas prices averaged $10.90/MWh, while 5-minute prices averaged $7.50/MWh. This is a substantial increase from 2020 when 15-minute market and 5-minute market prices averaged $7.20/MWh and $5.30/MWh, respectively. These higher prices can be explained in part by the increase in the cost of greenhouse gas allowances. The average cost of greenhouse gas allowances in bilateral markets increased 35 percent to $23.14/ mt$CO_2$e, which translates to about $9.83/MWh for a relatively efficient gas unit.[211]

Weighted average greenhouse gas prices in the 5-minute market averaged 32 percent lower than 15-minute prices for each month in 2021, similar to 2020. Price differences between markets may occur if resources are procured in the 15-minute market and then subsequently decrementally dispatched in the 5-minute market. This price separation is often correlated with operator imbalance conformance adjustments, described in Section 8.4, which are consistently higher in the 15-minute market than the 5-minute market.

Prices may have also been affected by an issue with the CAISO greenhouse gas obligation calculation. After Los Angeles Department of Water and Power (LADWP) joined the WEIM on April 1, 2021, the market was incorrectly including LADWP's base schedule transfers as market transfers in the real-time imbalance energy market. This led to higher attribution of greenhouse gas quantities, which affected both the real-time energy transfers attributed to resources and the payments made to those resources. The California ISO fixed this issue on January 27, 2022.[212]

211 Discussed further in Section 1.2.8.

212 Market Performance and Planning Forum, June 16, 2022, slides 6-7 http://www.caiso.com/Documents/Presentation-MarketPerformancePlanningForum-Jun162022.pdf

Figure 3.24 WEIM greenhouse gas price and cleared quantity

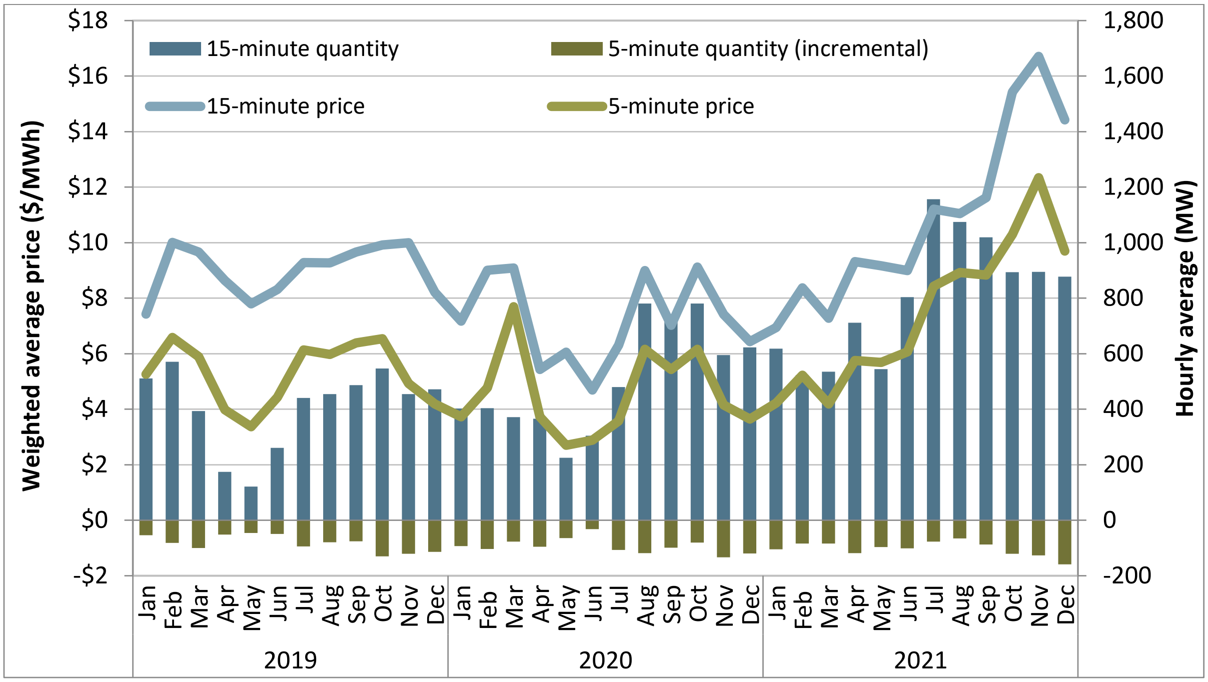


Figure 3.25 and Figure 3.26 illustrate the frequency of high prices for each market and quarter of the last three years, as well as the maximum price by quarter. The estimated cost impact ($/MWh) is calculated for each quarter based on the average quarterly greenhouse gas allowance price index and is included in the figures.[213] In Figure 3.25, we see a drastic increase in WEIM greenhouse gas compliance prices in the second half of 2021, where prices in the 15-minute market were over $10/MWh in 50 percent of intervals in the third quarter, and 70 percent in the fourth quarter. This is driven in large part by the increase in greenhouse gas allowance prices reflected in the higher cost impacts and discussed in Section 1.2.8. Similarly, prices were much higher in the 5-minute market as well, as seen in Figure 3.26.

After the secondary dispatch policy change in November 2018, which limited the capacity that could be deemed delivered, there were some price spikes that were not set by bids from emitting generators. Greenhouse gas supply can be exhausted, limiting the total transfer of energy imported to California through the WEIM and setting greenhouse gas prices that exceed the highest cleared bid. In 2020, the highest 15-minute price was $708/MWh and the highest 5-minute price was $970/MWh. This trend changed in 2021, when prices were higher on average but there were no extreme price spikes like in the previous year. The highest 15-minute and 5-minute prices in 2021 were $255/MWh and $267/MWh, respectively.

[213] This calculation is explained in more detail in footnote 91 in Section 1.2.8.

Figure 3.25 High 15-minute WEIM greenhouse gas prices

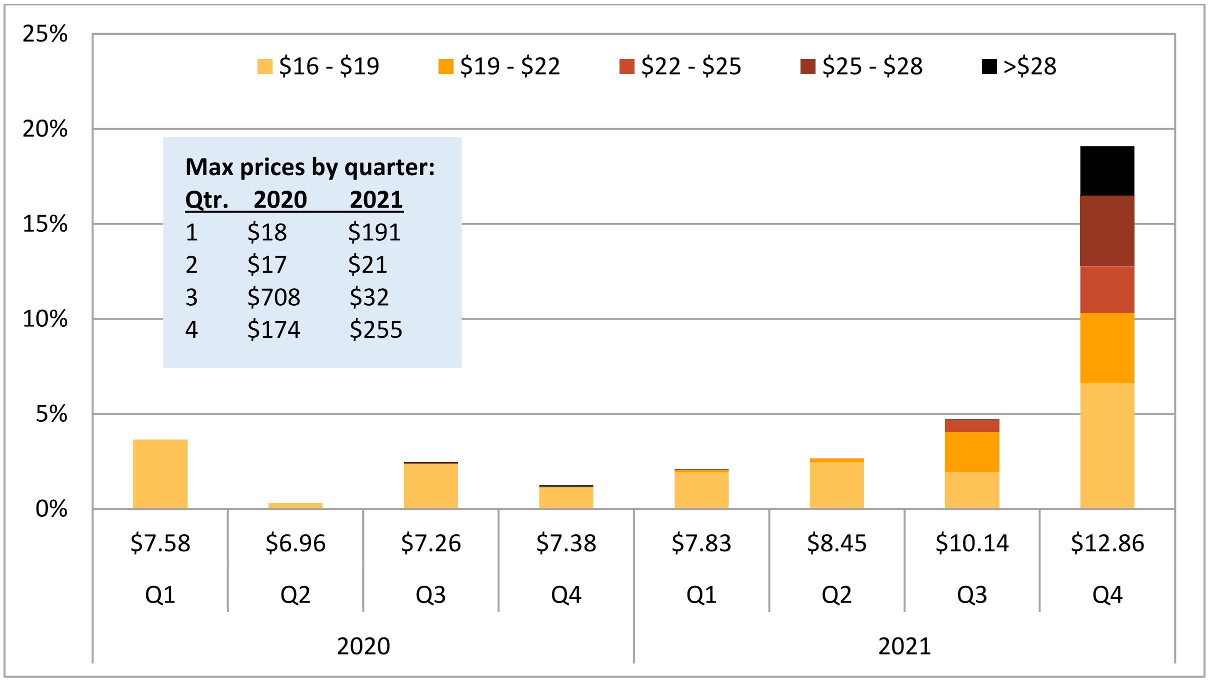
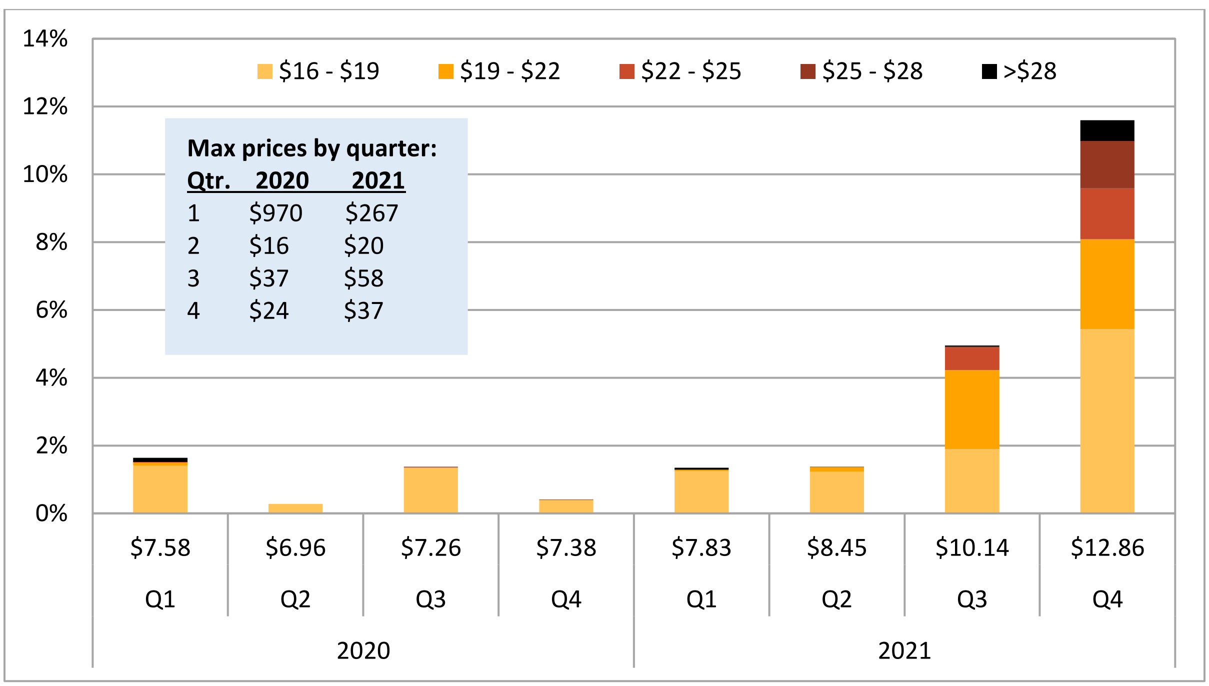


Figure 3.26 High 5-minute WEIM greenhouse gas prices

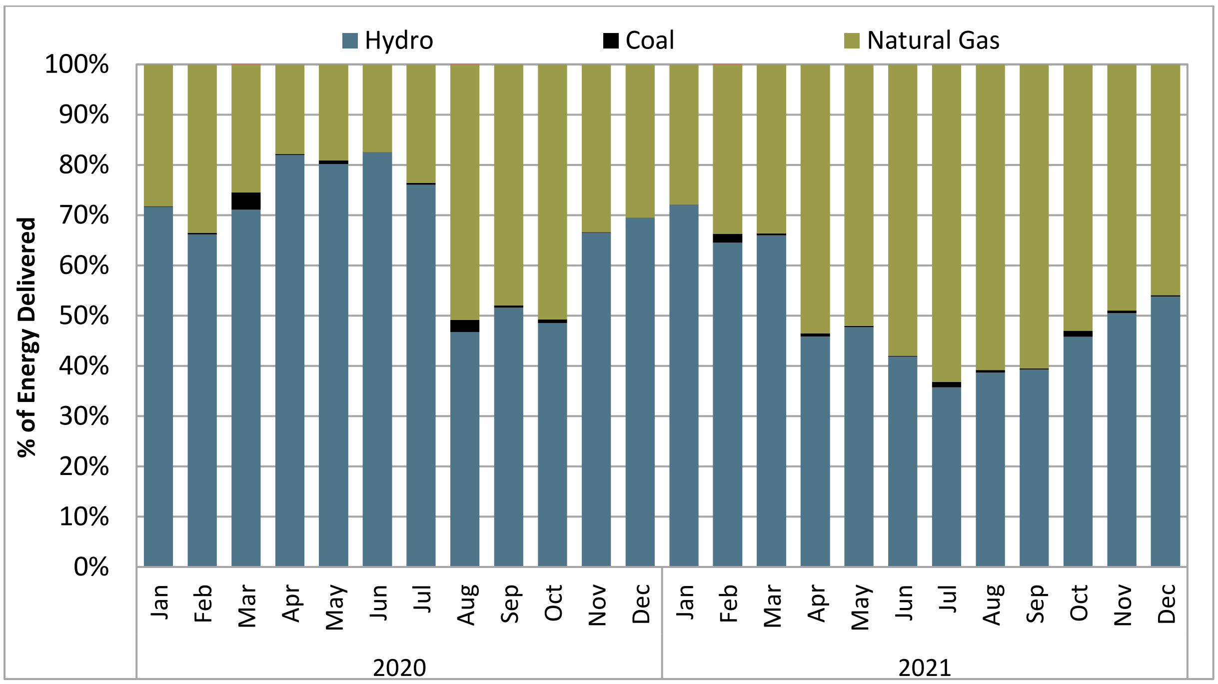


Energy delivered to California by fuel type and balancing area

Figure 3.27 shows hourly average greenhouse gas energy by fuel type. In 2021, about 50 percent of WEIM greenhouse gas compliance obligations were assigned to hydro resources, compared to about 67 percent in the previous year. The portion of energy delivered to California from natural gas resources was roughly 50 percent, an increase from 31 percent in 2020.

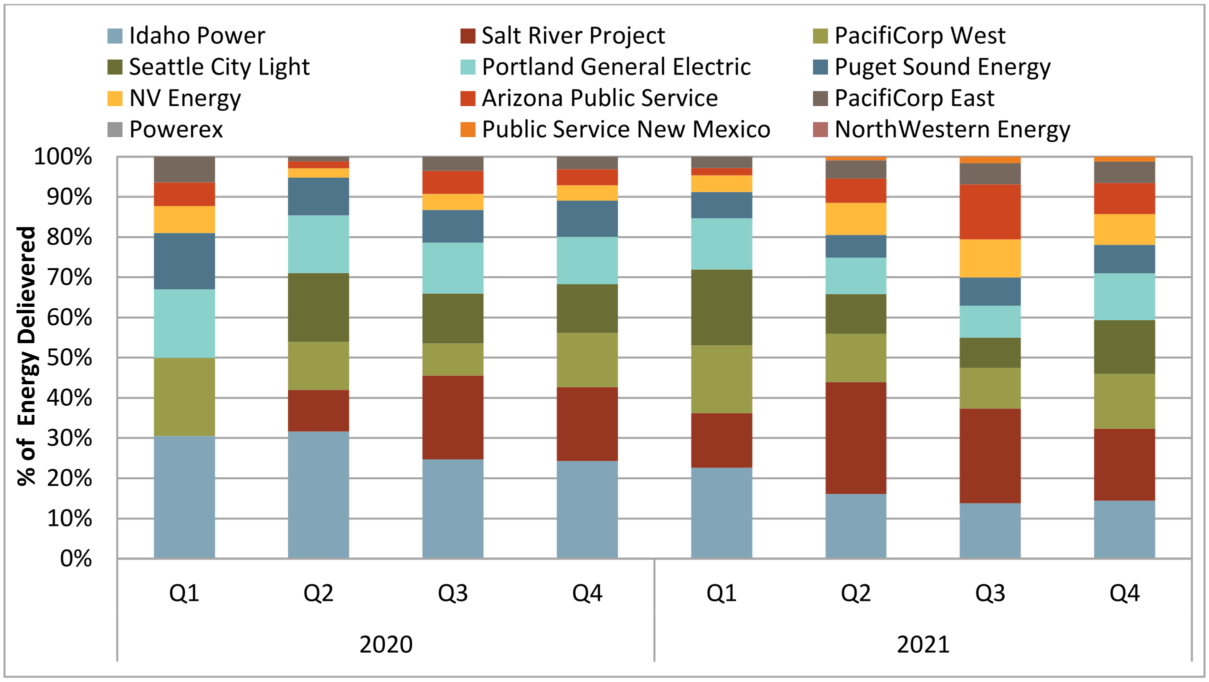
Figure 3.28 shows the percentage of total greenhouse gas energy cleared by area. In 2021, 60 percent of greenhouse gas energy came from entities in the Pacific Northwest with large fleets of hydroelectric resources, compared to about 75 percent in 2020. An increased percentage of delivered energy came from PacifiCorp East, NV Energy, Arizona Public Service, and particularly Salt River Project, which accounted for 20 percent of the total greenhouse gas energy deemed delivered.

Figure 3.27 Percentage of greenhouse gas energy delivered to California by fuel type[214]



214 In 2020 and 2021, there were a couple negligible instances of energy from oil delivered to California.

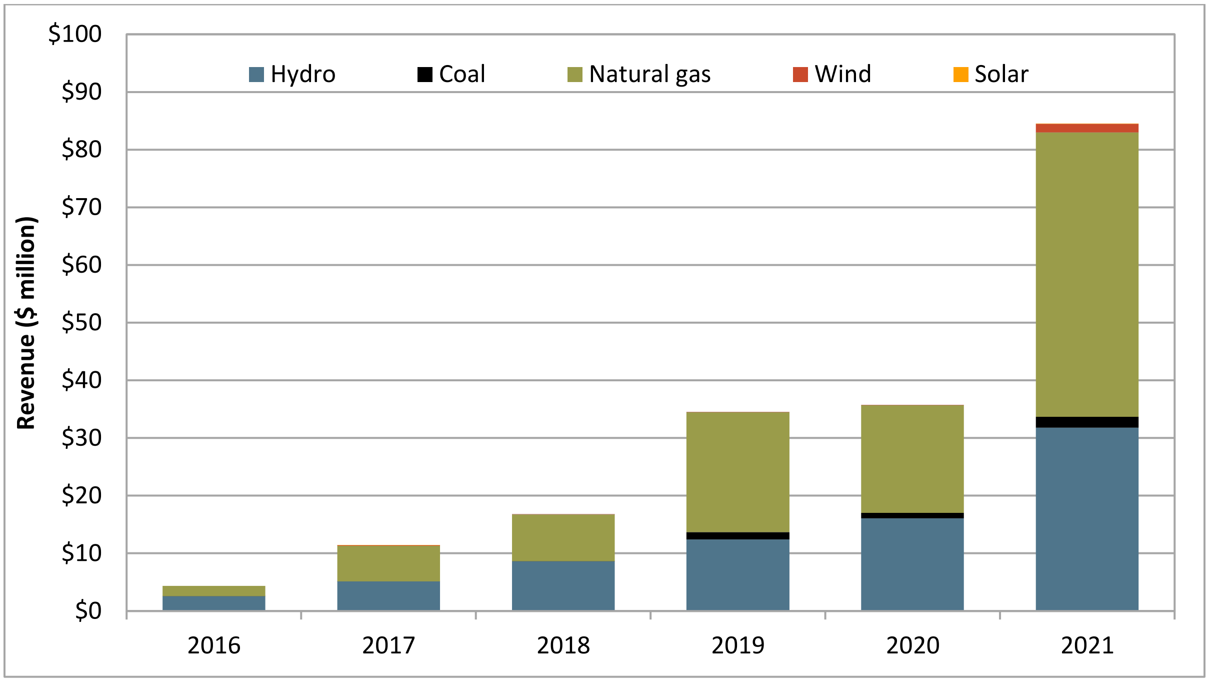
Figure 3.28 Percentage of greenhouse gas energy delivered to California by area



WEIM greenhouse gas revenues

Figure 3.29 shows revenues accruing to WEIM resources for energy delivered to California by fuel type. In 2021, revenues totaled roughly $84.6 million, which was over twice as much as it was the previous year. This drastic increase in revenues was driven by the higher prices of compliance obligations in 2021. In 2021, natural gas revenues comprised 58 percent of revenues, while hydroelectric revenues comprised 38 percent. Coal and wind revenues comprised about 2 percent of revenues each. It is important to note that resources can receive greenhouse gas revenues without being deemed as serving California load if they are scheduled in the 15-minute market but decrementally dispatched in the 5-minute market.

Figure 3.29 Annual greenhouse gas revenues



3.8 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 California 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.

Base schedules can create flows above limits on constraints internal to a balancing authority area. If base scheduled 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 California ISO, will have to pay to offset deficits caused by base schedule flows that exceed internal constraint limits.

The real-time congestion imbalance charges from internal transmission constraints in the 15-minute market were estimated and remained low in 2021, similar to last year. These estimates did not include congestion imbalances from the real-time dispatch, inter-balancing authority area transfer constraints, or unscheduled flows. With the exception of the California ISO, which settles deviations from day-ahead market schedules, this data estimates the extent to which congestion imbalance deficits are the result of base schedule flows exceeding 15-minute market transmission limits.

4 Convergence bidding

Convergence bidding is designed to align day-ahead and real-time prices by allowing financial arbitrage between the two markets. Throughout 2021, the volume of cleared virtual supply exceeded cleared virtual demand, as it has in all quarters since 2014.Convergence bidding was profitable on an annual basis.

- **Annual profits paid to convergence bidders totaled around $37.8 million**, a decrease from about $45 million in 2020, after accounting for about $21.9 million in bid cost recovery charges allocated to virtual bids. Virtual demand generated negative revenues of about $1.7 million for the year, while virtual supply generated about $61.3 million, before accounting for bid cost recovery charges.
- **Virtual supply exceeded virtual demand by an average of about 870 MW per hour**, compared to 560 MW in 2020. The percent of bid in virtual supply and demand clearing was around 34 percent, a slight increase from about 32 percent in 2020.
- **Financial entities and marketers continued to earn most profits from virtual bidding,** receiving about 85 percent and 10 percent of net revenues, respectively. Physical generators and load serving entities received about 4 percent of net virtual bidding revenues.
- **Financial participants held over 75 percent of cleared virtual positions throughout 2021**, continuing a multi-year trend. As with the previous years, financial participants bid more virtual supply than demand, which contributed to the increase in net virtual supply.

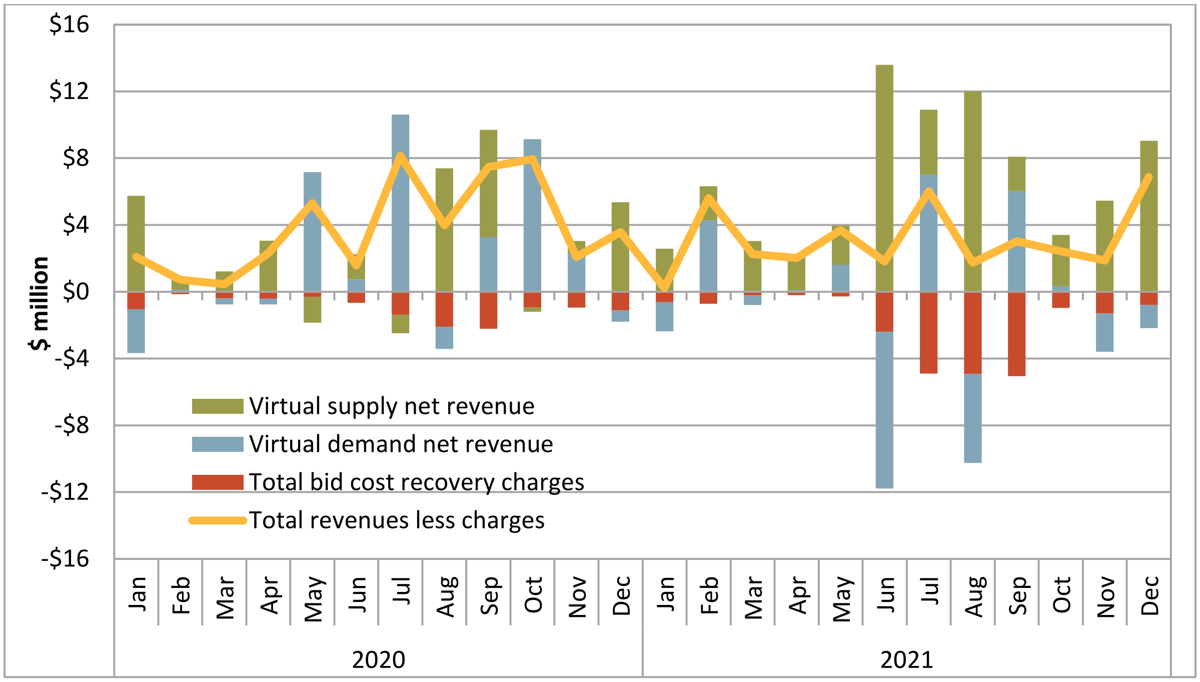
4.1.1 Convergence bidding revenues

Overall, participants engaged in convergence bidding were profitable in every month and quarter of 2021. Net revenues for convergence bidders, before accounting for bid cost recovery charges, were about $61.3 million. Net revenues for virtual supply and demand fell to about $37.8 million after the inclusion of about $21.9 million of virtual bidding bid cost recovery charges, primarily associated with virtual supply.[215]

Figure 4.1 shows total monthly net revenues for virtual supply (green bars), total net revenues for virtual demand (blue bars), the total amount paid for bid cost recovery charges (red bars), and the total payments for all convergence bidding inclusive of bid cost recovery charges (gold line).

215 For more information on how bid cost recovery charges are allocated please refer to: Department of Market Monitoring, *Q3 2017 Report on Market Issues and Performance*, December 8, 2017, pp. 40-41: http://www.caiso.com/Documents/2017ThirdQuarterReport-MarketIssuesandPerformance-December2017.pdf

Figure 4.1 Convergence bidding revenues and bid cost recovery charges



Net revenues and volumes by participant type

Table 4.1 and Table 4.2 compare the distribution of convergence bidding cleared volumes and net revenues among different groups of convergence bidding participants.[216]

Financial entities represented the largest segment of the virtual bidding market on a quarterly and annual basis as they have in recent years, with over 70 to 80 percent of both volume and settlement revenue. Marketers continue to have about 10 to 20 percent of both volume and settlement revenue. Generation owners and load serving entities represented a small segment of the virtual market in terms of both volumes and settlement revenue (sometimes negative), between 2 percent and 3 percent, respectively, throughout the year.

[216] DMM has defined financial entities as participants who do not own physical power and only participate in the convergence bidding and congestion revenue rights markets. Physical generation and load are represented by participants that primarily participate in the California ISO markets as physical generators and load serving entities, respectively. Marketers include participants on the interties and participants whose portfolios are not primarily focused on physical or financial participation in the California ISO market.

Table 4.1 Convergence bidding volumes and revenues by participant type – Q1 to Q4

Trading entities	Average hourly megawatts			Revenues\Losses ($ million)				Total Revenue after BCR
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply before BCR	Virtual bid cost recovery	Virtual supply after BCR	
2021 Q1								
Financial	953	1,494	2,447	$1.59	$7.06	-$1.01	$6.05	$7.65
Marketer	338	487	825	$0.35	$0.75	-$0.38	$0.37	$0.72
Physical load	0	27	27	$0.00	-$0.24	-$0.10	-$0.35	-$0.35
Physical generation	12	40	52	$0.00	$0.16	-$0.04	$0.12	$0.12
Total	**1,303**	**2,048**	**3,352**	**$1.94**	**$7.72**	**-$1.53**	**$6.19**	**$8.14**
2021 Q2								
Financial	1,536	1,938	3,474	-$3.84	$14.33	-$2.10	$12.23	$8.39
Marketer	423	487	910	-$3.63	$3.21	-$0.58	$2.63	-$1.00
Physical load	0	38	38	$0.00	$0.22	-$0.09	$0.13	$0.13
Physical generation	14	41	56	-$0.21	$0.33	-$0.11	$0.23	$0.01
Total	**1,974**	**2,505**	**4,478**	**-$7.69**	**$18.09**	**-$2.87**	**$15.22**	**$7.53**
2021 Q3								
Financial	1,191	2,117	3,308	$7.87	$12.18	-$10.10	$2.08	$9.95
Marketer	296	527	823	$0.15	$5.46	-$2.85	$2.61	$2.76
Physical load	0	26	26	$0.00	$0.10	-$0.71	-$0.61	-$0.61
Physical generation	27	84	111	-$0.63	$0.22	-$0.72	-$0.51	-$1.13
Total	**1,515**	**2,754**	**4,268**	**$7.39**	**$17.96**	**-$14.38**	**$3.57**	**$10.96**
2021 Q4								
Financial	1,008	1,736	2,744	-$2.25	$13.74	-$2.19	$11.55	$9.30
Marketer	311	499	811	-$0.95	$3.48	-$0.67	$2.81	$1.86
Physical load	0	18	18	$0.00	$0.13	-$0.12	$0.01	$0.01
Physical generation	14	47	62	-$0.14	$0.22	-$0.09	$0.13	-$0.01
Total	**1,334**	**2,301**	**3,634**	**-$3.33**	**$17.57**	**-$3.07**	**$14.50**	**$11.17**

Table 4.2 Convergence bidding volumes and revenues by participant type – 2021

Trading entities	Average hourly megawatts			Revenues\Losses ($ million)				Total Revenue after BCR
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply before BCR	Virtual bid cost recovery	Virtual supply after BCR	
Financial	1,172	1,821	2,993	$3.37	$47.31	-$15.40	$31.91	$35.29
Marketer	342	500	842	-$4.08	$12.90	-$4.48	$8.42	$4.34
Physical load	0	27	27	$0.00	$0.21	-$1.02	-$0.82	-$0.82
Physical generation	17	53	70	-$0.98	$0.93	-$0.96	-$0.03	-$1.01
Total	**1,532**	**2,402**	**3,933**	**-$1.69**	**$61.34**	**-$21.85**	**$39.48**	**$37.80**

5 Ancillary services

This chapter provides a summary of the ancillary service market in 2021. Key trends highlighted in this chapter include the following:

- **Ancillary service costs decreased to $165 million,** down from $199 million in 2020.
- **Operating reserve requirements decreased as regulation requirements increased, with adjustments for net load variability**. Regulation down requirements increased 30 percent to 684 MW and regulation up requirements increased 4 percent to 404 MW. Average combined requirements for spinning and non-spinning operating reserves decreased by 3 percent from the previous year to about 1,770 MW.
- **Provision of ancillary services from limited energy storage resources continued to increase, replacing procurement from imports.** Average hourly procurement of ancillary services served by battery resources has been steadily increasing the past three years, growing from 179 MW in 2019 to 400 MW in 2021.
- **The frequency of ancillary service scarcity intervals continued to decrease.** There were 55 intervals in the 15-minute market with ancillary service scarcity, compared to 129 in 2020 and almost 200 in 2019.
- **Thirty percent of resources failed** ancillary service performance audits and unannounced compliance tests for spinning and non-spinning reserves, compared to 30 percent in 2020 and 20 percent in 2019.

The California ISO 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 in both the day-ahead and real-time markets. A detailed description of the ancillary service market design is provided in DMM's 2010 annual report.[217]

5.1 Ancillary service costs

Costs for ancillary services totaled about $165 million in 2021, a decrease from $199 million in 2020, but an increase from $148 million in 2019.

The costs reported in this section account for rescinded ancillary service payments; penalties incurred when resources providing ancillary services do not fulfill the availability requirement associated with the awards. About 4.5 percent of payments were rescinded in 2021.

Figure 5.1 shows ancillary service costs both as percentage of wholesale energy costs and per megawatt-hour of load from 2019 to 2021. Following an increase of ancillary service costs in 2020, the

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

cost per megawatt-hour decreased to $0.78 from $0.95 in 2020. As a percent of energy costs, ancillary service costs decreased to 1.3 percent from 1.7 percent in 2019, and 2.2 percent in 2020.

Figure 5.2 shows the total cost of procuring ancillary service products by quarter, as well as the total ancillary service cost for each megawatt-hour of load served. Similar to 2020, ancillary service costs were highest in the third quarter, although costs in the third quarter of 2021 were substantially lower than the previous year. Payments decreased for operating reserves (both spin and non-spin) and regulation up. Payments for regulation down, however, increased by almost 50 percent.

Figure 5.1 Ancillary service cost as a percentage of wholesale energy costs (2019-2021)

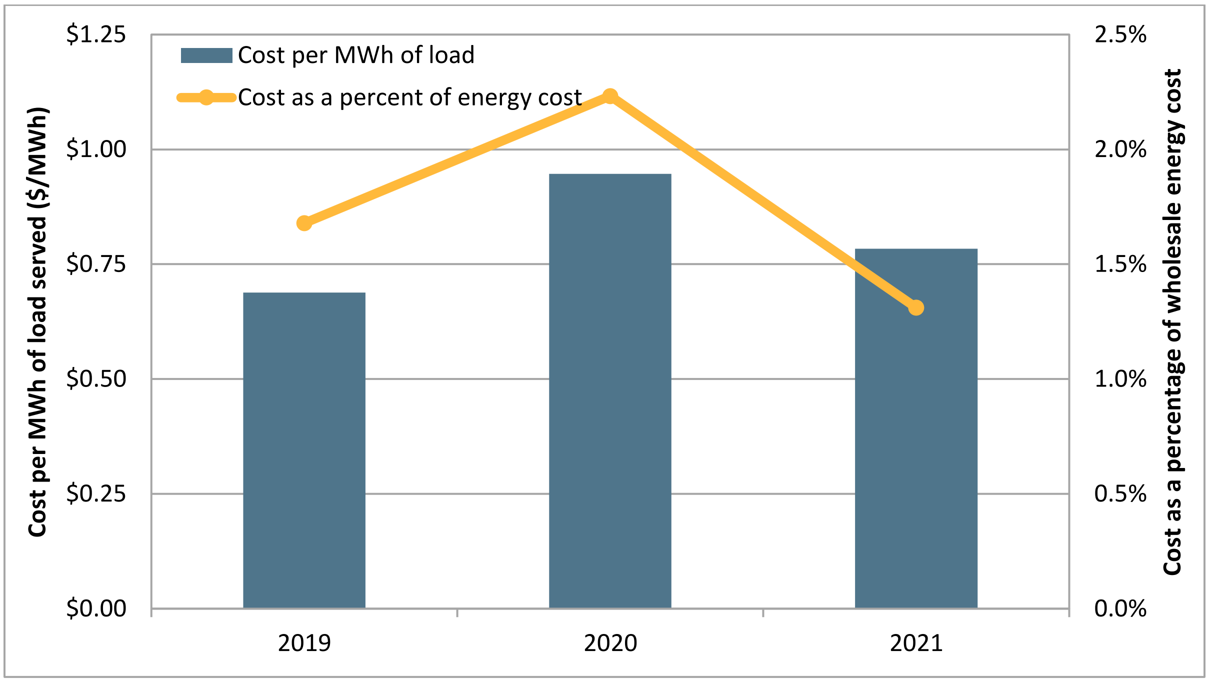
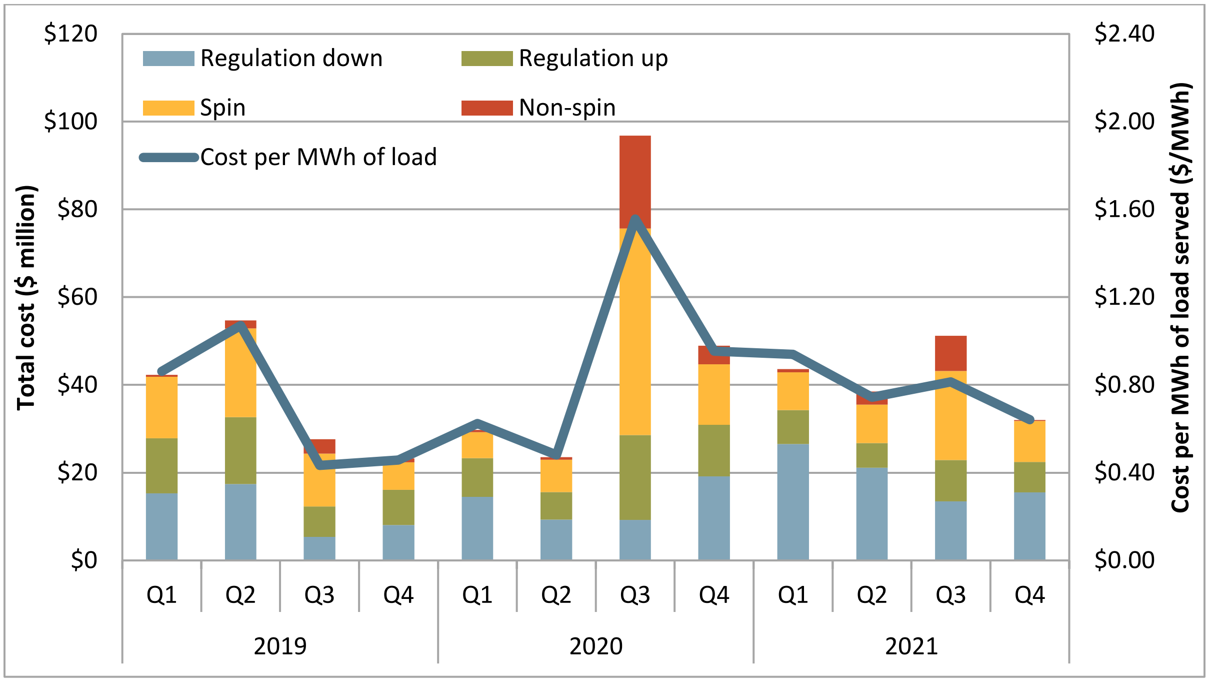


Figure 5.2 Total ancillary service cost by quarter and type



The value of self-provided ancillary services fell below 0.4 percent of the total cost of ancillary services. Scheduling coordinators are assigned a share of the ancillary service requirement based on their metered demand. The cost of procuring ancillary services is charged to demand using a system-wide user rate, based on the average cost of procuring each type of ancillary service. Scheduling coordinators may self-provide all or a portion of their obligation. Scheduling coordinators pay the remainder of their obligation, less their self-provided quantity. The value of self-provided ancillary services is the reduction in obligation costs, totaling less than $661 thousand in 2021. This value is a small fraction of total ancillary service costs, $165 million, and is lower than the value of self-provided ancillary services over the last four years, $2-$3 million.

5.2 Ancillary service requirements and procurement

The California ISO procures four ancillary services in the day-ahead and real-time markets: regulation up, regulation down, spinning reserves, and non-spinning reserves.[218] 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 CAISO attempts to procure all ancillary services in the day-ahead market to the extent possible.

The CAISO 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

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

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 CAISO), internal system, expanded South of Path 26, internal South of Path 26, expanded North of Path 26, and internal North of Path 26.

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.[219] 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.[220] The total operating reserve requirements are then typically split equally between spinning and non-spinning reserves.

Figure 5.3 includes quarterly average day-ahead operating reserve requirements since 2019. Operating reserve requirements in the day-ahead market averaged 1,770 MW in 2021, a 3 percent decrease from 2020.

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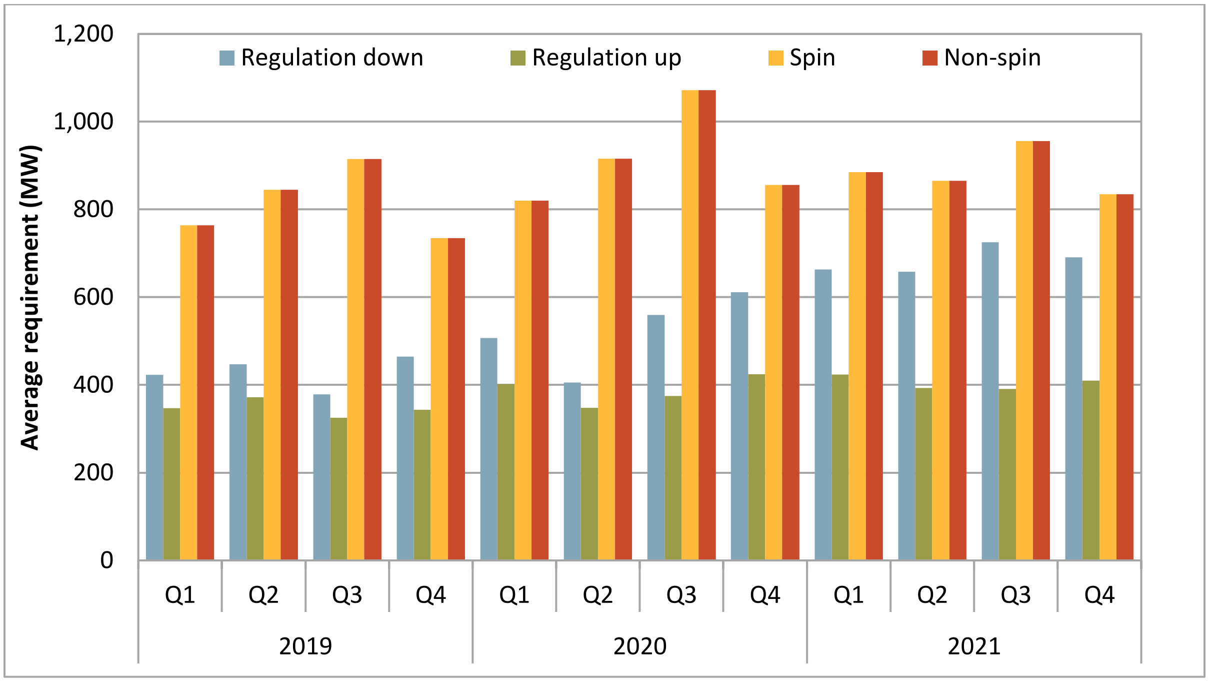
[219] On June 8, 2017, the North American Electric Reliability Corporation published a report that found a previously unknown reliability risk related to a frequency measurement error that can potentially cause a large loss of solar generation. Only solar forecasts from resources that have the potential for the inverter issue are considered.

[220] 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 CAISO balancing area. The Federal Energy Regulatory Commission approved a set of requirements in BAL-002-2 that required the California ISO to reevaluate the most severe single contingency. 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. 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

Figure 5.3 Quarterly average day-ahead ancillary service requirements



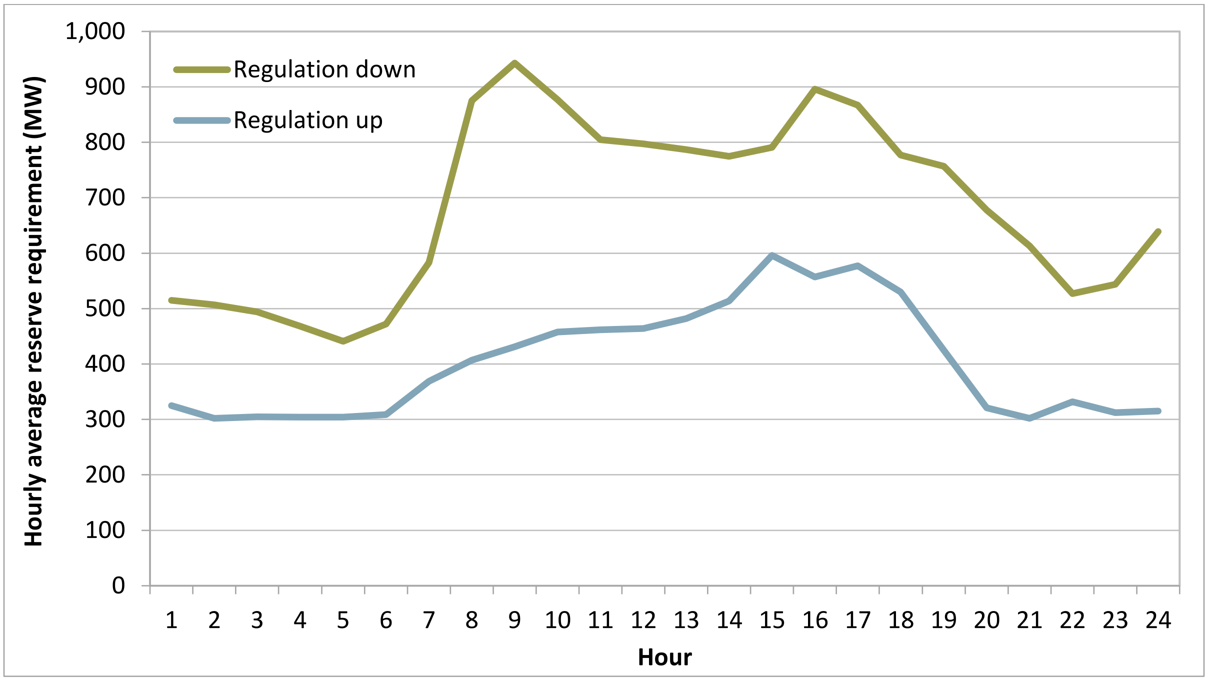
Regulation requirements

The California 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 California 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 2021, day-ahead requirements for both regulation up and regulation down increased, however regulation down requirements increased much more substantially. Regulation down requirements averaged 684 MW, a 30 percent increase from 2020. Regulation up requirements averaged 404 MW, a 4 percent increase from 2020.

Figure 5.4 summarizes the average hourly profile of the day-ahead regulation requirements in 2021. Requirements for regulation down were higher than requirements for regulation up. Regulation up requirements were highest during mid-day 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 when solar was ramping either up or down.

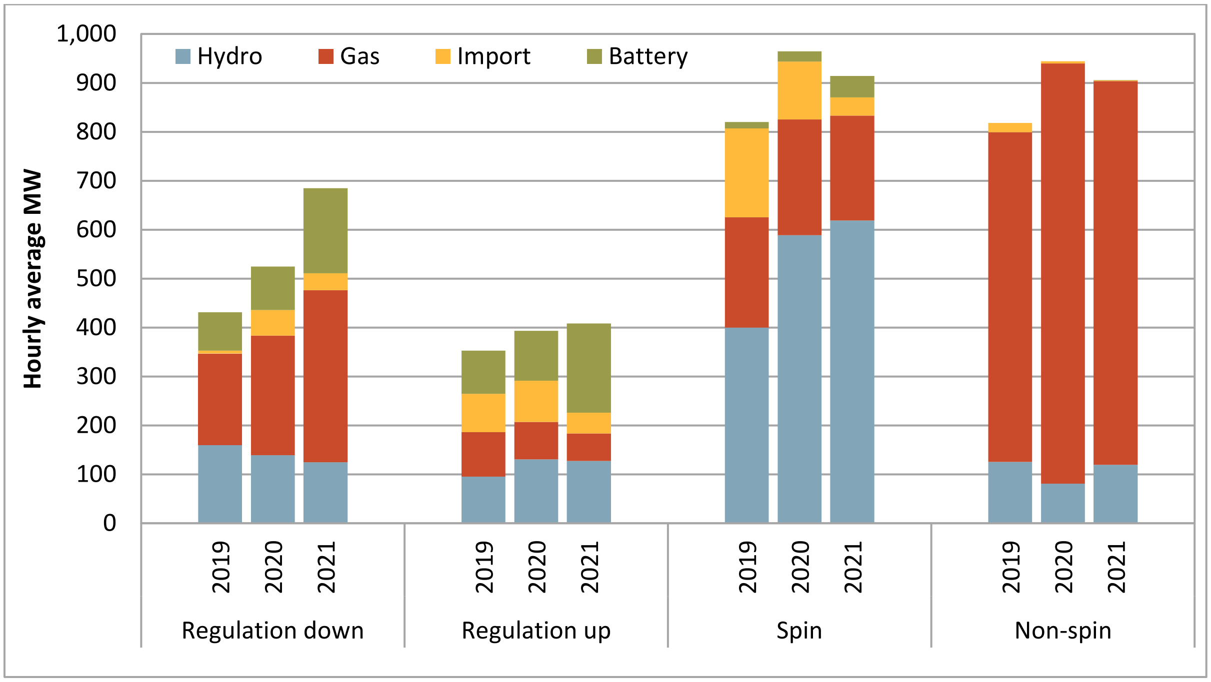
Figure 5.4 Hourly average day-ahead regulation requirements (2021)



Ancillary service procurement by fuel

Figure 5.5 shows the portion of ancillary services procured by fuel type from 2019 through 2021. Ancillary service requirements are met by both internal resources and imports (tie generation) which are indirectly limited by minimum requirements set for the procurement of ancillary services from within the CAISO 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 the California ISO resources.

Figure 5.5 Procurement by internal resources and imports



Total procurement of regulation down increased 30 percent in 2021, due to the increase in requirements. This increase was met by an increase in procurement from both gas resources and batteries. Although the requirement for regulation up remained similar to 2020, the composition changed due to a large increase in procurement from batteries.

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 served by battery resource has been steadily increasing the past three years, growing from 179 MW in 2019 to 400 MW in 2021. Compared to 2020, the supply of batteries increased for each of the four types of ancillary services.

As batteries have been increasing, the total hourly average of procurement served by imports has been decreasing. The decrease was more substantial this year, with a 9 percent decrease in 2020, and a 55 percent decrease in 2021. In 2021, imports supplied only 4 percent of ancillary services.

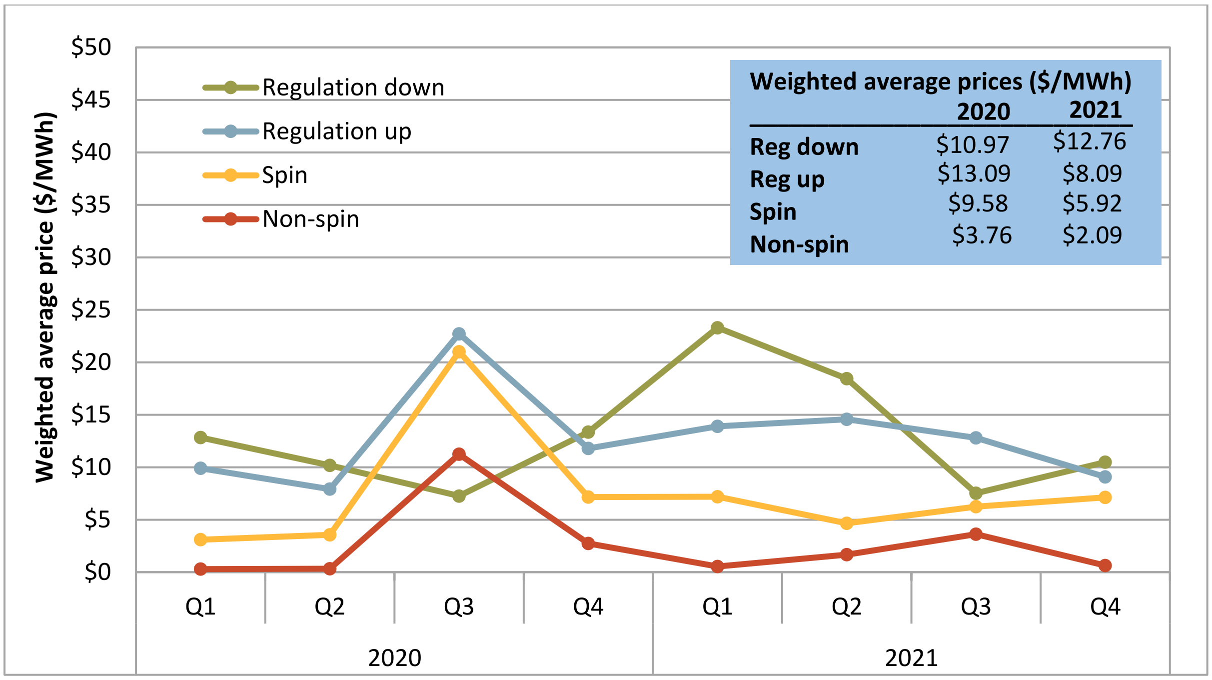
5.3 Ancillary service pricing

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 2020 and 2021, weighted by the quantity settled.[221]

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

As shown in Figure 5.6, weighted average day-ahead prices for regulation down increased, whereas operating reserves and regulation up decreased from 2020 to 2021. For operating reserves, this is consistent with the decrease in requirements. Following this year's increase in regulation requirements, weighted average day-ahead prices decreased for regulation up and increased for regulation down by 38 and 16 percent, respectively. Differences between the price changes of regulation up and regulation down services may be attributable to differences in procurement by fuel. In the past year, there was an increase in battery capacity that supplies regulation services. However, compared to regulation up, regulation down has a higher proportion of procurement from gas resources and a lower proportion of procurement from batteries.[222]

Figure 5.6 Day-ahead ancillary service market clearing prices

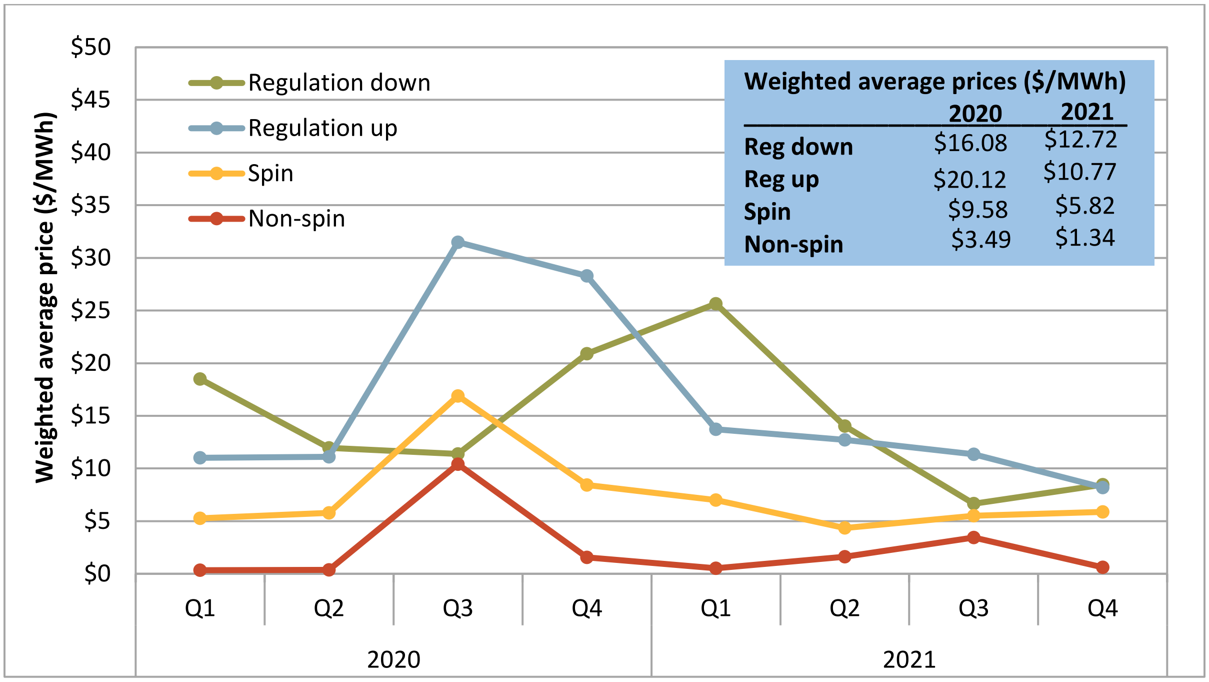


Weighted average prices ($/MWh)	2020	2021
Reg down	$10.97	$12.76
Reg up	$13.09	$8.09
Spin	$9.58	$5.92
Non-spin	$3.76	$2.09

Figure 5.7 shows that the weighted average prices for ancillary services decreased for both regulation and operating reserves in the real-time market. In general, regulation prices were higher in the real-time market than in the day-ahead market. However, ancillary costs are largely determined by day-ahead market prices since most ancillary services are procured in the day-ahead market, with only 6 percent of ancillary costs incurred in the real-time market.

[222] See Section 1.2.4 and Figure 1.23 for more information.

Figure 5.7 Real-time ancillary service market clearing prices



5.4 Special issues

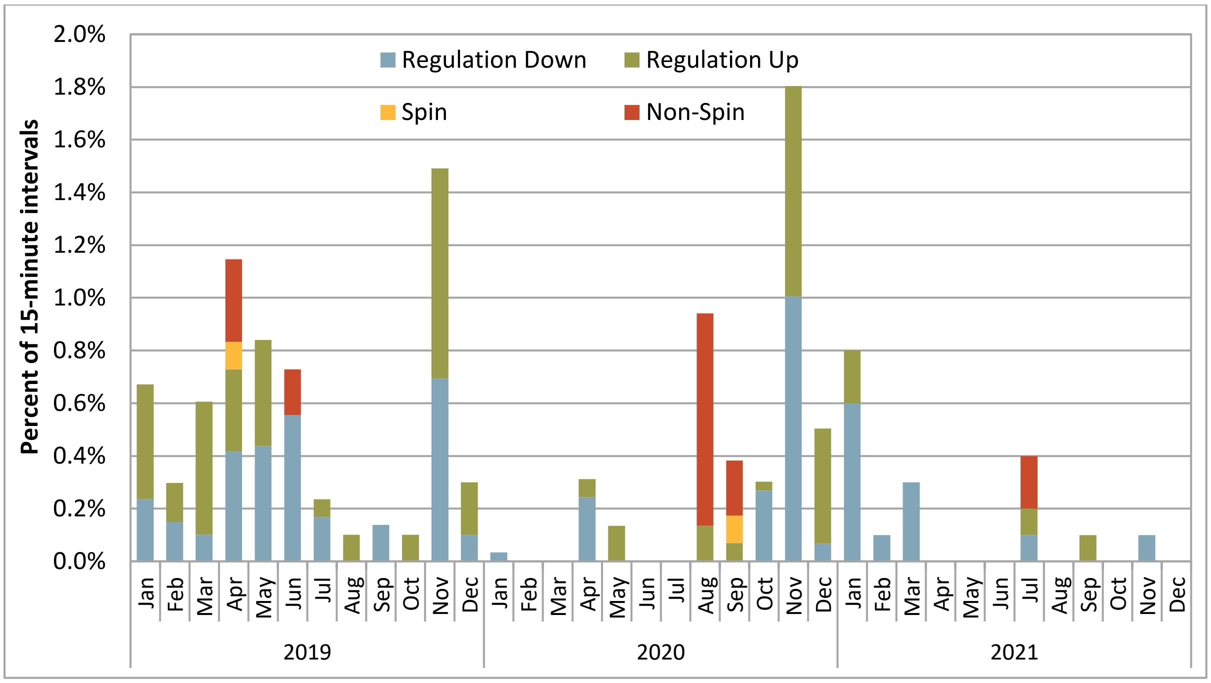
5.4.1 Ancillary service scarcity

Ancillary service scarcity pricing occurs when there is insufficient supply to meet reserve requirements. Under the ancillary service scarcity price mechanism, the California 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 2021. However, there were 55 valid scarcity intervals in the 15-minute market, which is lower than 2020 when there were almost 129 scarcity instances. The number of regulation scarcities decreased substantially, particularly in the fourth quarter. Scarcities in regulation are most common during periods of high variability in loads (spring and winter). From Figure 5.8, we see that the number of non-spin scarcities decreased as well, particularly in August and September, when the California ISO faced tighter conditions in 2020 versus 2021.

Most of the ancillary services scarcities in 2021 were small, with almost 75 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.[223] This type of scarcity can occur with battery resources that have been increasingly used to support ancillary services. By region, 58 percent of scarcity events occurred in the expanded North of Path 26 region, 24 percent in the expanded South of Path 26 region, and 18 percent in the expanded system 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.[224]

During 2021, the California ISO performed a total of 234 performance audits and unannounced compliance tests for resources with either spinning or non-spinning reserves, which was a slight

223 For a more detailed description of ancillary service scarcity, see: Department of Market Monitoring, *2019 Annual Report on Market Issues and Performance,* June 2020, p. 171: http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf

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

decrease from the 257 tests performed in 2020. The failure rate was almost 30 percent for unannounced tests, and about 8 percent for performance tests. In 2021, the CAISO implemented a change to allow successful non-spin tests to constitute as passing performances for spin tests as well. For resources registered as battery or other (hybrid, hydro), a successful spin test will also constitute a passing performance for non-spin.[225]

225 Ibid, p. 14.

6 Market competitiveness and mitigation

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

- **Overall prices in the California ISO 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.[226]

- **There were significantly fewer structurally uncompetitive hours** in the day-ahead energy market, which accounts for most of the California ISO total wholesale energy market**.** Both the significant increase in battery capacity and milder peak summer demand contributed to the decrease in non-competitive hours despite continual low hydroelectric availability.

- **The market for capacity needed to meet local resource adequacy requirements was structurally uncompetitive in all local areas.** In both 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 2021. The percent of non-competitive constraint intervals increased slightly in the day-ahead and real-time markets, relative to 2020.[227]

- **The performance of local market power mitigation on Western Energy Imbalance Market transfer constraints improved.** In both the 15-minute and 5-minute markets, the percent of congested constraint-intervals that were under-predicted decreased in 2021, compared to 2020.

- **The commitment costs and default energy bid enhancements (CCDEBE) was implemented on February 16, 2021.** This functionality allows market participants to submit reference level adjustment requests above bid caps in the market. Since its implementation, this additional flexibility was utilized during a limited number of days when there was gas price volatility.

- **Effective May 20, 2021, the California ISO started including maximum gas burn constraint as part of the local market power mitigation (LMPM)** process to automatically designate a constraint as competitive or not.[228]

- **Effective November 1, 2021, battery energy storage resources were also subject to mitigation** in the local market power mitigation process.

- **Energy subject to mitigation increased in both the day-ahead and real-time markets,** for both the California ISO and Western Energy Imbalance Market balancing areas. For the California ISO, the

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

[227] For a detailed description of DMM's framework to analyze overall accuracy of transmission competitiveness, see: Department of Market Monitoring, *2020 Annual Report on Market Issues and Performance*, August 2021: http://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf

[228] California ISO, *Business Requirements Specifications for Aliso Canyon Phase 5,* May 5, 2020: http://www.caiso.com/Documents/BusinessRequirementsSpecification-AlisoCanyonPhase5.pdf

increase was due, in part, to the increase in concentration of generation in the portfolios of net sellers and load in the portfolios of net buyers.

- **Most resources were subject to mitigation submitted competitive offer prices, so a low portion of bids were lowered as a result of the bid mitigation process;** day-ahead bids for an average of 295 MW were changed in 2021, compared to 331 MW in 2020.
- **Capacity with bids lowered by mitigation in the 15-minute market remained low**, averaging 150 MW per hour in the California ISO and 90 MW per hour in the Western Energy Imbalance Market. In the 5-minute market, capacity with bids lowered by mitigation averaged 180 MW per hour in the California ISO and 68 MW in the Western Energy Imbalance Market.
- **Local market power mitigation limited above-market costs for exceptional dispatches for energy** in 2021 by about $1.1 million.

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.[229] 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 to account for supply and demand:

- Day-ahead input bids for physical generating resources (adjusted for outages and de-rates).

229 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.

- Transmission losses are not explicitly added to demand. The day-ahead load forecast already factors in losses.
- Non-dispatchable pump load is used for additional demand. This reflects a change from prior reports; the end of the section provides more details on this change.
- Including self-scheduled exports as demand (combined with the day-ahead load forecast plus upward ancillary service requirements).
- Ancillary services bids are included in excess of energy bids to account for this additional supply available to meet ancillary service requirements in the day-ahead market.
- CPUC jurisdictional investor-owned utilities are excluded as potentially pivotal suppliers.
- Accounting for the maximum availability of non-pivotal imports offered relative to import transmission constraint limits.
- As in prior DMM analyses, virtual bids are excluded.

During 2021, DMM observed fewer hours with a residual supply index less than one compared to 2020, but these were still more frequent relative to some of the prior 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. For 2021, the residual supply index with the three largest suppliers removed (RSI_3) was less than one during 291 hours, and the index was less than one during 171 hours with the two largest suppliers removed (RSI_2). With the largest single supplier removed (RSI_1), there were 75 hours in 2021 with the index less than one.

Figure 6.2 shows the lowest 500 RSI_3 values for each year. Milder peak summer loads and significant additions in battery capacity compared to the previous year contributed to a decrease in potentially non-competitive hours despite continual low hydroelectric availability. The figure also shows similar structural competitiveness in 2021 to that of 2018. During 2021, with the three largest suppliers removed, the RSI_3 was less than 0.9 in 95 hours and less than 0.8 in 7 hours. At its lowest, the RSI_3 was around 0.76 in 2021, compared to around 0.67 in 2020, 0.87 in 2019, and 0.75 in 2018.

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

Year	RSI_1	RSI_2	RSI_3
2018	34	114	337
2019	2	50	166
2020	129	333	524
2021	84	189	316

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

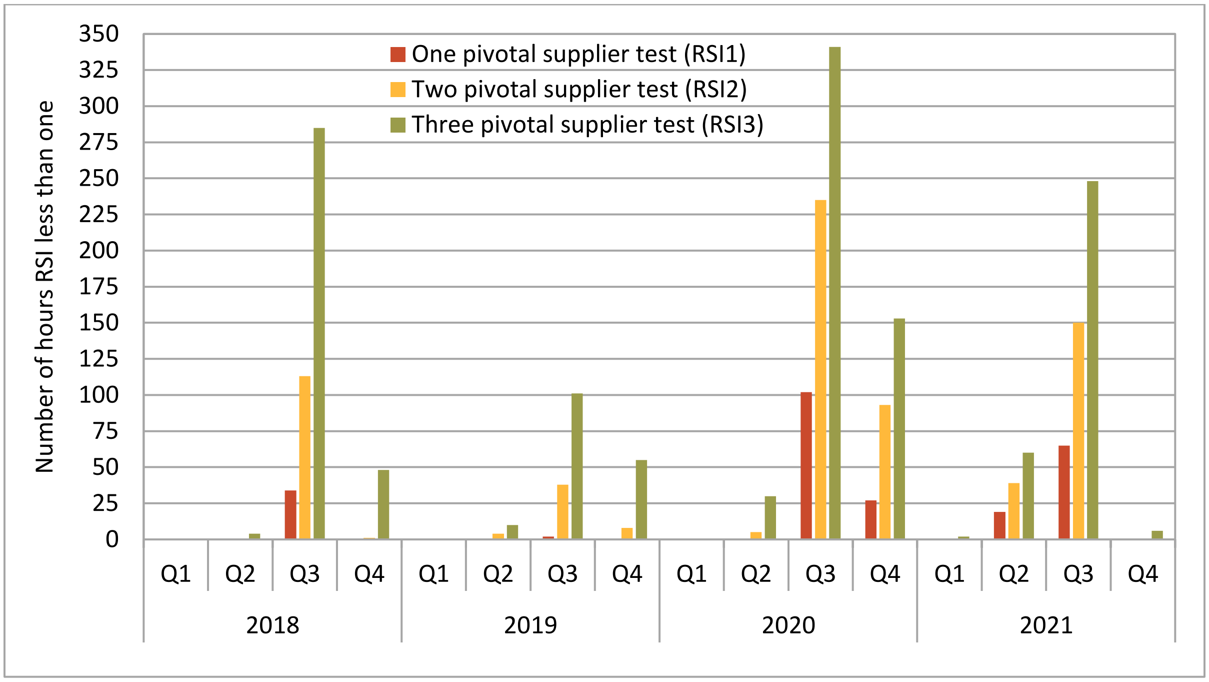
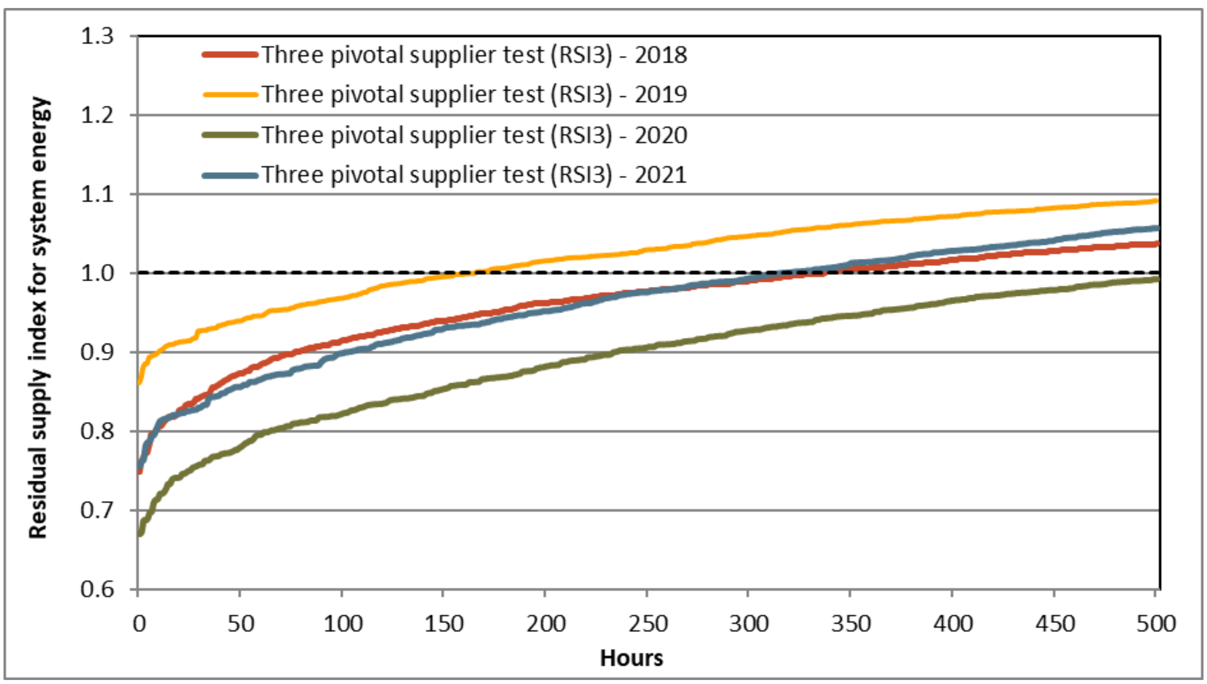
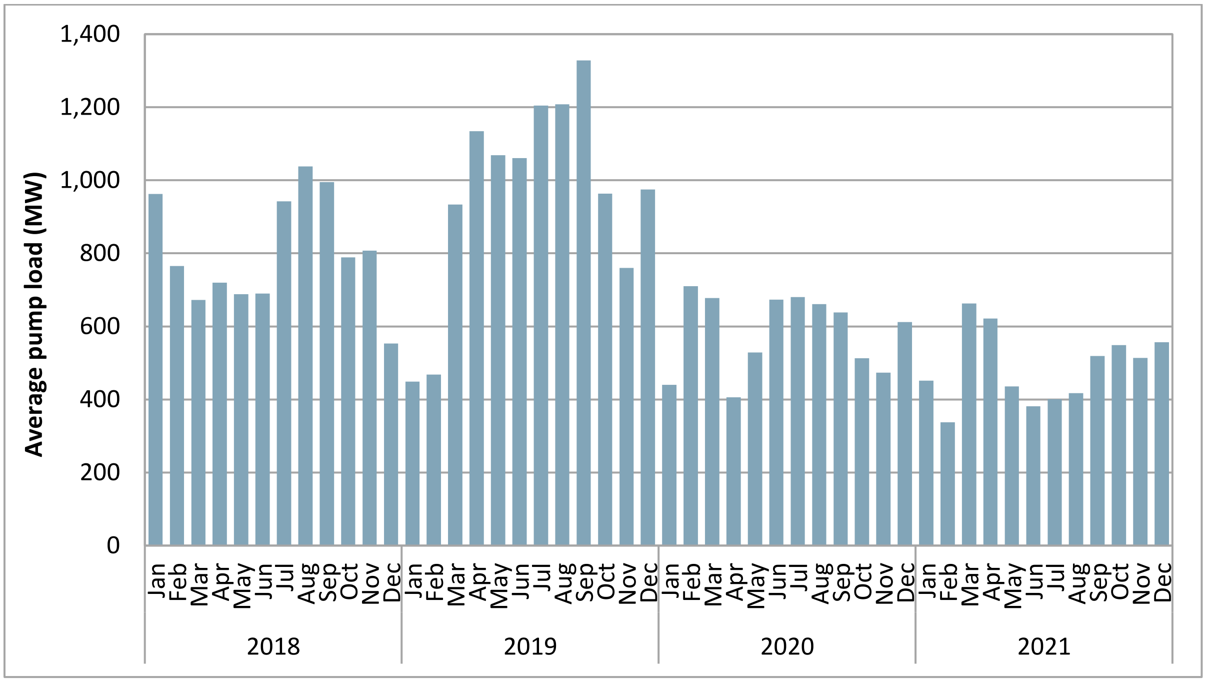


Figure 6.2 Residual supply index with largest three suppliers excluded (RSI_3) – lowest 500 hours



In this report, DMM refined the residual supply index calculation going back to 2018 to include non-dispatchable pump load. This is additional forecasted demand that is added on top of the CAISO load forecast to account for pump load (excluding dispatchable pumps) in the residual unit commitment process. To illustrate this change, Figure 6.3 shows the average forecast for non-dispatchable pump load by month. In 2021, this monthly average ranged between 330 and 670 MW. However, this can vary from year to year based on hydro conditions, with higher pump demand during periods with greater hydro generation, such as 2019. Including this demand in the analysis resulted in more potentially non-competitive hours. After accounting for this factor, hours with a RSI_3 of less than one increased from 291 to 316, for 2021.

Figure 6.3 Average day-ahead forecasts for non-dispatchable pump load



6.1.2 Local capacity requirements

In 2021, most of the local capacity areas were not structurally competitive because there was at least one supplier that was pivotal and controlled a significant portion of capacity needed to meet local requirements.

The California 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.[230]

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.

The California ISO performs annual studies to identify the minimum local resource capacity requirements in each local area to meet established reliability criteria. An updated criterion is used in the study to match the NERC transmission planning standards for resource adequacy year 2021.[231] As a result, the total local capacity requirement increased by around 2 percent between 2020 and 2021 with a considerable increase to the Greater Bay local capacity area requirement.

Key finding of this analysis include the following:

- The Greater Bay, Kern, North Coast/North Bay, Sierra, 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.
- In 2021, the Greater Bay local capacity requirement increased significantly which has resulted in the local capacity area becoming structurally uncompetitive under a single pivotal supplier test. In 2020, this local area was structurally uncompetitive under a two pivotal supplier test.
- In 2021, the LA Basin local area met its local capacity requirement with capacity scheduled by load serving entities and had no residual demand for local capacity from merchant generators. This change occurred due to suppliers of local capacity for the LA Basin area switching from net buyer to net seller between 2020 and 2021.

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 California ISO may need to procure capacity from the unit using the backstop procurement authority under the capacity procurement mechanism of the tariff.[232]

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[230] 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.

[231] California ISO, *2021 Local Capacity Technical Study*, May 1, 2020: http://www.caiso.com/Documents/Final2021LocalCapacityTechnicalReport.pdf

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

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	3,649	4,668	1.28	0.69	0.27	0.11	2
Kern	147	166	1.13	0.06	0.02	0.01	1
North Coast/North Bay	712	716	1.01	0.02	0.01	0.01	3
Sierra	420	489	1.16	0.61	0.39	0.27	2
Stockton	27	56	2.07	1.00	0.33	0.25	0
San Diego/Imperial Valley	1,201	1,680	1.40	0.90	0.40	0.13	2

In the day-ahead and real-time energy markets, the potential for local market power is mitigated through bid mitigation procedures. These procedures require that each congested transmission constraint be designated as either competitive or non-competitive. This designation is based on established procedures for applying a pivotal supplier test in assessing the competitiveness of constraints. Section 6.2.1 examines the frequency and impact of these automated bid mitigation procedures.

6.2 Local market power mitigation

This section provides an assessment of the frequency and impact of the automated local market power mitigation procedures in the California ISO (CAISO) and Western Energy Imbalance Market (WEIM) 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.

6.2.1 Frequency and impact of automated bid mitigation

In the CAISO and WEIM balancing areas, average incremental energy subject to mitigation has increased in 2021, relative to 2020. However, average incremental energy with bids lowered because of mitigation continues to be very low. For the CAISO 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. Effective November 1, 2021, the California ISO implemented the ESDER 4 initiative, which introduces local market power mitigation to battery energy storage resources.[233]

Background

The California ISO 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. Most recently, effective

[233] California ISO Market Notice*: ESDER Phase 4 Initiative: Deployment Effective for Trade Date 11/1/21,* October 29, 2021: http://www.caiso.com/Documents/ESDERPhase4Initiative-DeploymentEffectiveforTradeDate-11121.html

November 1, 2021, a new default energy bid option and local market power mitigation for battery energy storage resources was implemented.

The automated local market power mitigation (LMPM) procedures are triggered when congestion occurs on a constraint that is determined to be uncompetitive. When this occurs, bids are mitigated to the higher of the system market energy price, or a default energy bid designed to reflect a unit's marginal energy cost.

The impact of mitigated bids on market prices 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.[234]

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

Day-ahead market

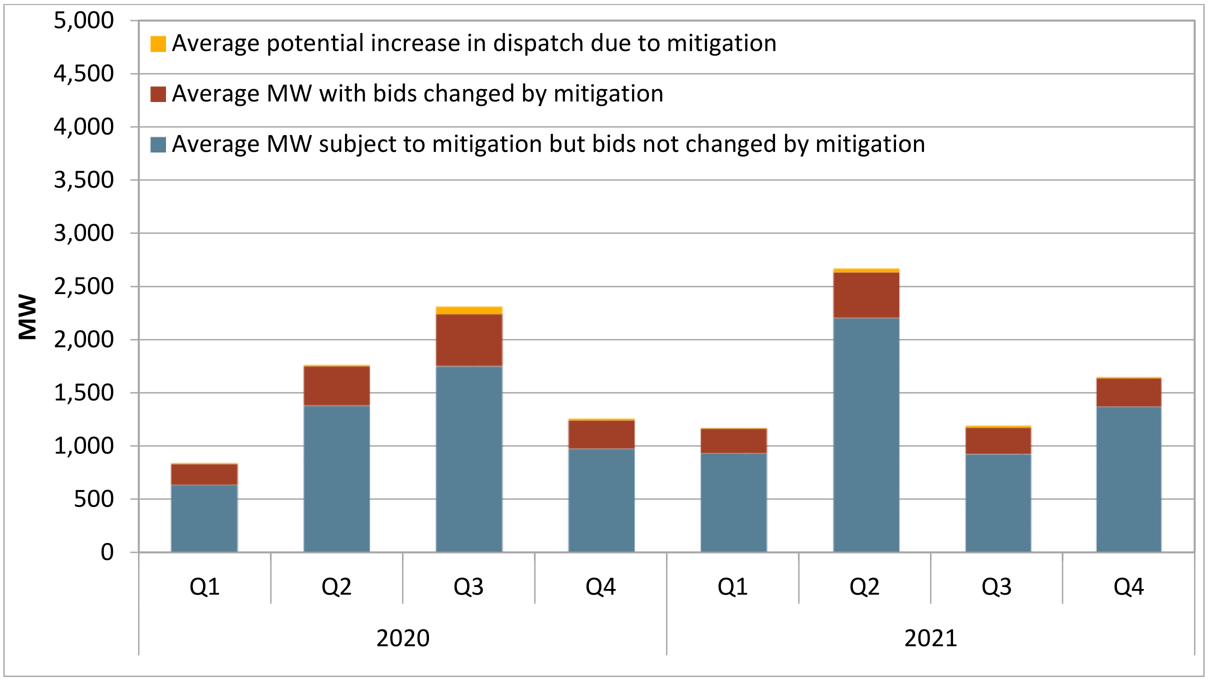
As shown in Figure 6.4, in 2021, the average incremental energy subject to mitigation increased slightly relative to 2020.

- Bids for an average of 1,354 MW per hour were subject to mitigation but not lowered in 2021, an increase from 1,183 MW in 2020. Out of 1,354 MW that is subject to mitigation, about 630 MW is from gas resources followed by 400 MW from hydro resources. As mentioned earlier, effective November 1, 2021, battery energy storage resources are also subject to mitigation. On average, about 74 MW per hour from battery resources was subject to mitigation but bids were not lowered.[235]
- Bids for an average of 295 MW per hour were changed in 2021, down from 331 MW in 2020. About 80 percent of this incremental energy that had bids lowered came from gas and hydro resources.
- Day-ahead dispatch instructions from bid mitigation increased by about 17 MW per hour in 2021, compared to 26 MW per hour in 2020.

[234] 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.

[235] For battery energy storage units, both charge and discharge bid curves are subject to mitigation if local market power mitigation measures are triggered.

Figure 6.4 Average incremental energy mitigated in day-ahead market



Real-time market

Figure 6.5 and Figure 6.6 highlight the frequency and volume of 15-minute and 5-minute market mitigation in the CAISO balancing area. As shown in these figures, average incremental energy subject to mitigation is consistently higher in the 5-minute than in the 15-minute market.

- In the 15-minute market, an average of 826 MW of incremental energy bids was subject to mitigation, which is an increase from 572 MW in 2020. Of this energy, about 674 MW were not lowered due to mitigation. The remaining 152 MW which had bids lowered came from hydro (108 MW) and gas resources (32 MW).
- In the 5-minute market, an average of 1,453 MW of bids was subject to mitigation, and only 182 MW were lowered.
- On average, the potential increase in 15-minute dispatch due to bid mitigation was similar in 2021 compared to 2020. On the other hand, potential increase in 5-minute dispatch from bid mitigation declined significantly to 19 MW per hour in 2021 compared to 38 MW per hour in 2020.

Figure 6.5 Average incremental energy mitigated in 15-minute real-time market (CAISO)

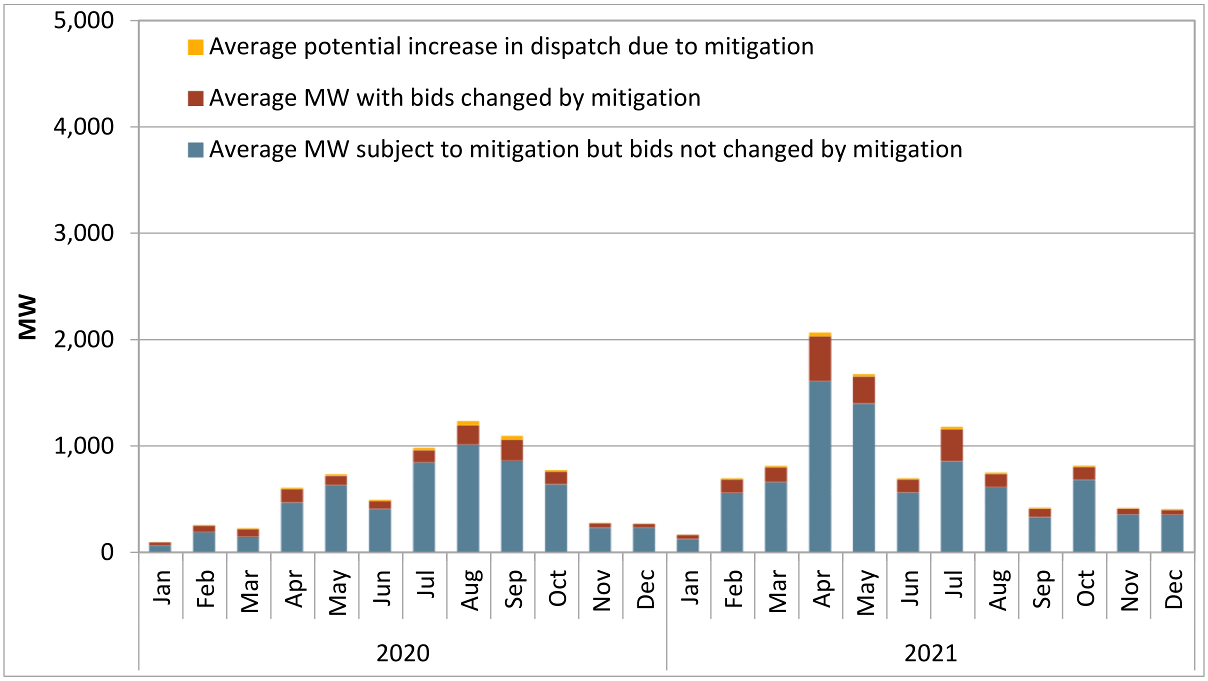


Figure 6.6 Average incremental energy mitigated in 5-minute real-time market (CAISO)

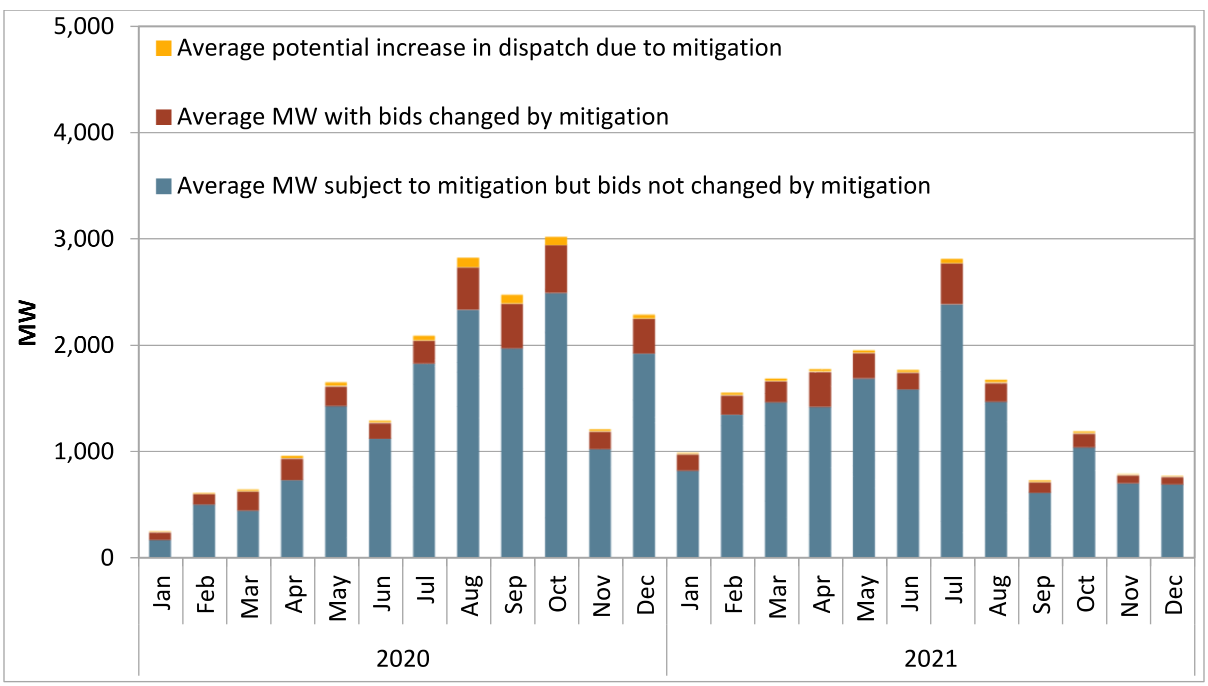


Figure 6.7 and Figure 6.8 highlight the frequency and volume of 15-minute and 5-minute market mitigation in all of the WEIM balancing areas outside the California ISO. Figures show that, except for the second quarter of 2021, mitigation rates were higher in 2021 when compared to 2020. Part of the increase can be attributed to four new balancing areas joining WEIM in 2021.

- As shown by blue bars in the figures, in the 15-minute market, bids for an average of 869 MW were subject to mitigation but not lowered in 2021 compared to 613 MW in 2020. In the 5-minute market, bids for about 800 MW were subject to mitigation but not lowered in 2021 compared to 512 MW in 2020.
- Red bars in the figures show that average incremental energy with bids lowered because of mitigation continues to be very low in 2021.
- Because of decreased bid mitigation in 2021, the average potential increase in dispatch also decreased in 15-minute and 5-minute markets.

Figure 6.7 Average incremental energy mitigated in 15-minute real-time market (WEIM)

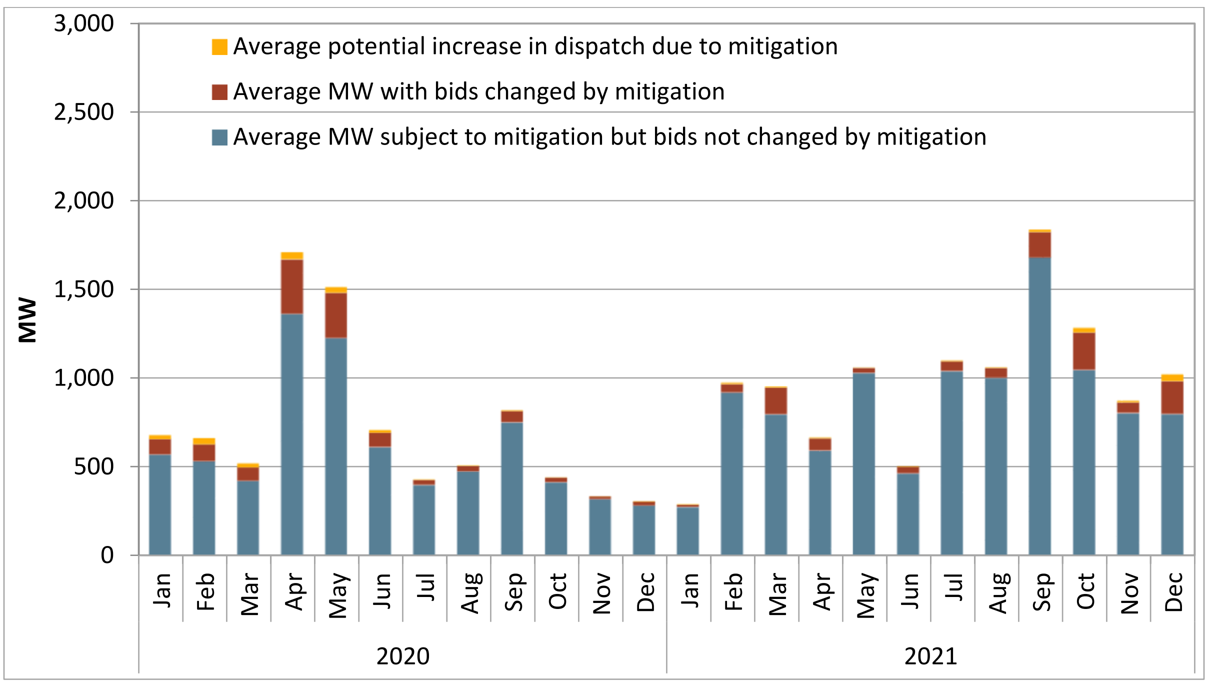
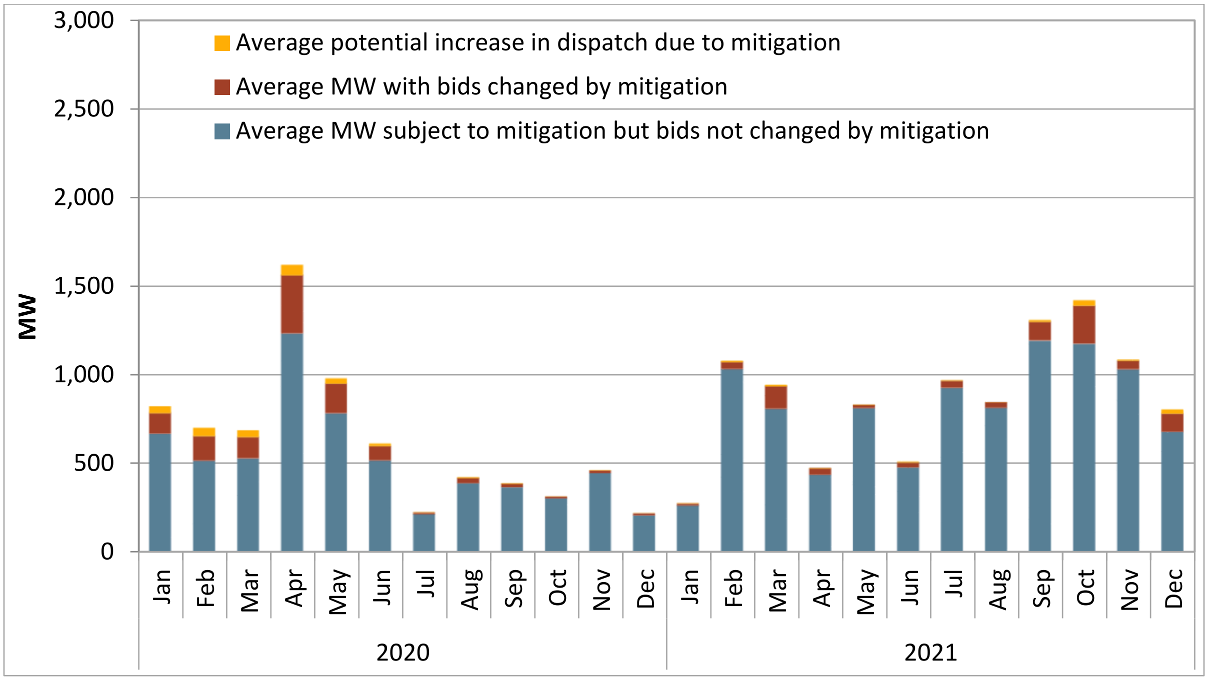


Figure 6.8 Average incremental energy mitigated in 5-minute real-time market (WEIM)



6.2.2 Mitigation of exceptional dispatches

Overview

Exceptional dispatches are instructions issued by grid operators when the market optimization is not able to address a particular reliability requirement or constraint.[236] Total energy from exceptional dispatches in 2021 remained about the same as the previous year. The above-market costs for exceptional dispatches, however, increased totaling $27 million in 2021 compared to $16 million in 2020. A majority of this cost was associated with exceptional dispatch commitments to minimum load rather than out-of-market costs for exceptional dispatch of incremental energy.

Commitment cost bids for units that are committed via exceptional dispatch are not subject to any additional mitigation beyond the commitment cost bid caps, which include 25 percent headroom above estimated start-up and minimum load costs. Exceptional dispatches for energy above minimum load are subject to mitigation if a grid operator indicates the dispatch is made for any of the following reasons:

- Address reliability requirements related to non-competitive transmission constraints;
- Ramp resources with ancillary services awards or residual unit commitment capacity to a dispatch level that ensures their availability in real time;

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

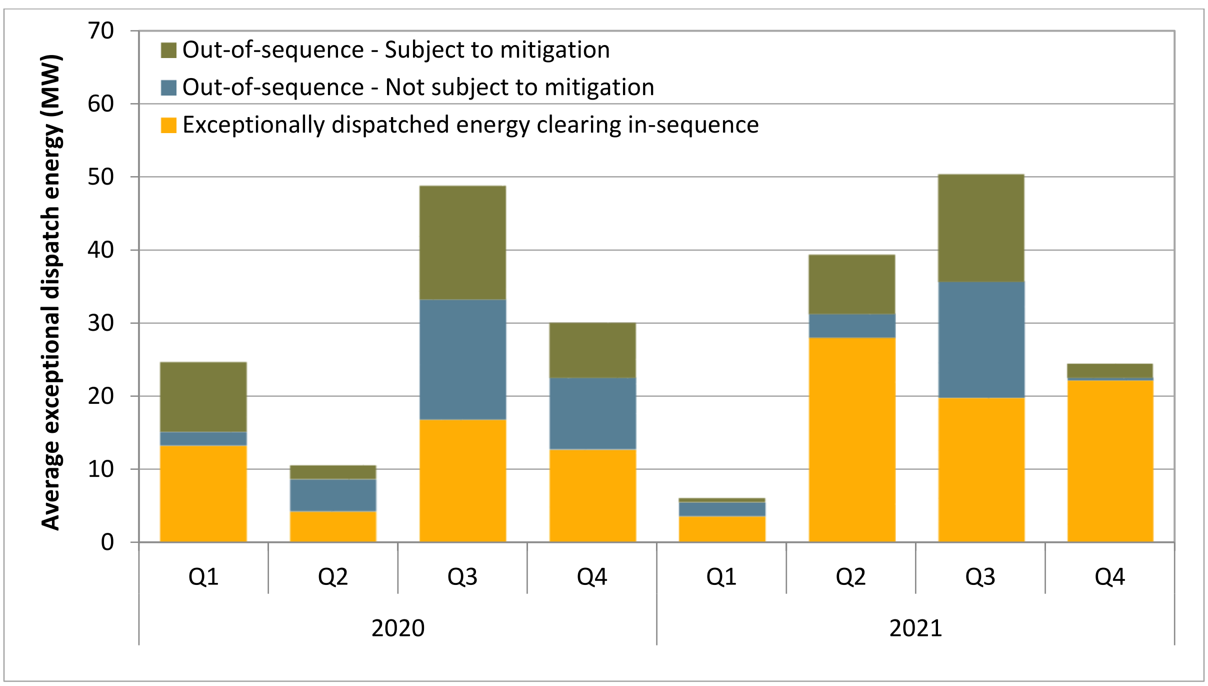
- Ramp resources to their minimum dispatch level in real time, allowing the resource to be more quickly ramped up if needed to manage congestion or meet another reliability requirement; or
- Address unit-specific environmental constraints not incorporated into the model or the market software that affect the dispatch of units in the Sacramento Delta, commonly known as *Delta Dispatch*.

In 2021, local market power mitigation played a large role in limiting above-market costs for exceptional dispatches for energy, reducing these costs by 1.1 million.

Volume and percent of exceptional dispatches subject to mitigation

As shown in Figure 6.9, the overall volume of exceptional dispatch energy above minimum load remained about the same in 2021 when compared to 2020. As 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 a third in 2021 compared to 2020. Out-of-sequence exceptional dispatches subject to mitigation decreased by about a quarter in 2021 compared to 2020.

Figure 6.9 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 this 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, this energy is out-of-sequence if the unit's default energy bid used in mitigation is above the market clearing price.

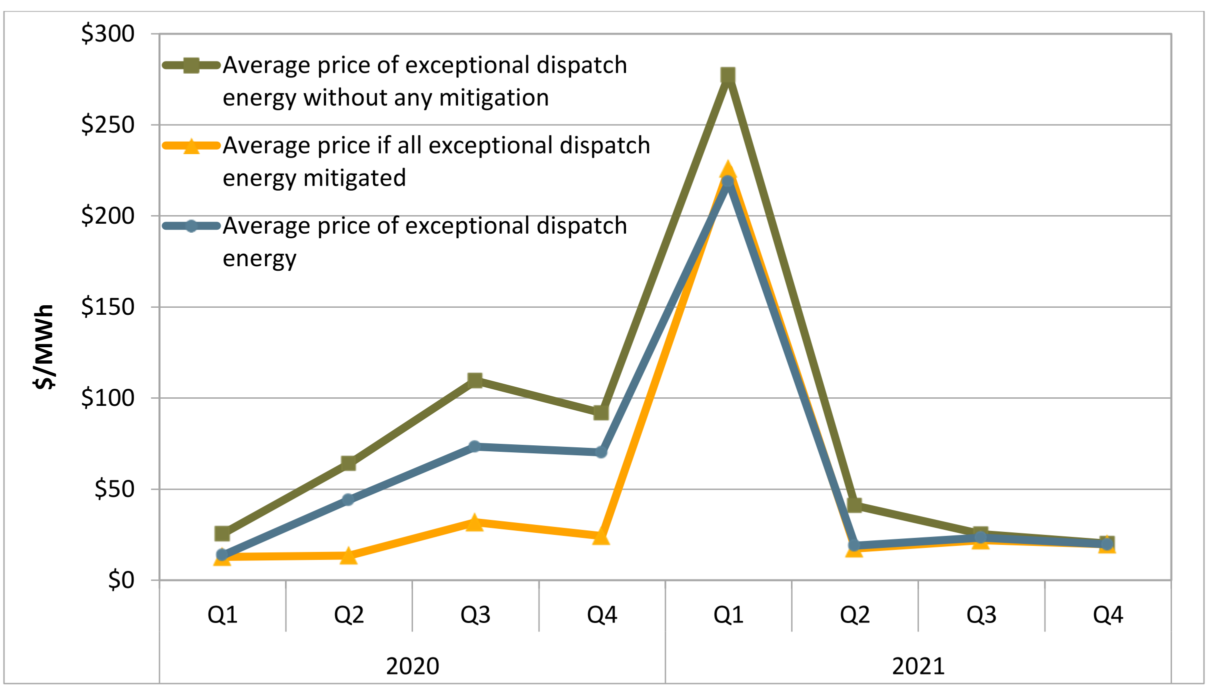
Using the value of out-of-sequence costs with the corresponding megawatt quantities of out-of-sequence exceptional dispatch energy, one can calculate the average price of out-of-sequence exceptional dispatch energy. This price is the amount per megawatt-hour by which out-of-sequence exceptional dispatch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

Figure 6.10 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 6.10 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 6.10 shows, this price difference decreased in 2021 compared to 2020. The greatest impact of mitigation occurred in the first quarter when natural gas prices were at their highest during the year.

The yellow line in Figure 6.10 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 typically is largest during the summer months but instead occurred in the first quarter instead of the third quarter of 2021, again due to the peak in natural gas prices.

The average price of out-of-sequence exceptional dispatch energy increased in 2021 to $70/MWh from $50/MWh in 2020. The increase in average prices for exceptional dispatch energy was driven by the higher average price in the first quarter of 2021 at $218/MWh. In all other quarters in 2021, average prices for exceptional dispatch energy declined year over year.

Figure 6.10 Average prices for out-of-sequence exceptional dispatch energy



6.3 Start-up and minimum load bids

This section analyzes commitment cost bid behavior for California ISO (CAISO) gas capacity – excluding use-limited resources – under the proxy cost option. For 2021, DMM estimates that about 65 percent of the CAISO's total bid cost recovery payments, approximately $98 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 reference proxy costs. About 95 percent of these payments are 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.[237] This option was modified 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 registered cost option was retained, but this option is restricted to use-limited resources eligible for opportunity costs with insufficient data for opportunity cost calculation. Participants with resources on the registered cost option continued to have the ability to bid up to 150 percent of the cap.[238] However, the registered costs continued to remain fixed for a period of 30 days.[239] These changes were implemented 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, opportunity cost adders were implemented to proxy start-up and proxy minimum load costs for use-limited resources that have limitations on numbers of starts, run hours, and energy output.[240] This initiative phased out the

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[237] FERC Order No. ER15-15-000 and ER15-15-001, *Order Accepting Proposed Tariff Revisions and Directing Informational Filing,* December 30, 2014: https://www.caiso.com/Documents/Dec302014_OrderAcceptingCommitmentCostEnhancementsTariffRevision_ER15-15-001.pdf

[238] 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 previously capped at 200 percent. 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. For additional details, see: California ISO policy initiative, *Commitment costs refinement 2012,* approved by FERC on October 29, 2013: http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/CommitmentCostsRefinement2012.aspx.

[239] California ISO, *Fifth Replacement Electronic Tariff, Section 30.4.1.1.6.1.1 Use-Limited Resource Criteria,* pp. 10-11: http://www.caiso.com/Documents/Section30-Bid-Self-ScheduleSubmission-CAISOMarkets-asof_Apr1-2019.pdf

[240] California ISO, *Commitment costs enhancements stakeholder process*: various phases:
Phase 1, approved by FERC December 30, 2014: California ISO - Commitment cost enhancements phase 1 (caiso.com)
Phase 2, approved by FERC November 1, 2016: California ISO - Commitment cost enhancements phase 2 (caiso.com)
Phase 3, approved by FERC April 1, 2019: California ISO - Commitment cost enhancements phase 3 (caiso.com)

registered cost option and limited the use of that option to resources that do not have sufficient data to calculate an opportunity cost adder.

Effective February 16, 2021, the California ISO implemented Commitment Cost and Default Energy Bid Enhancements Phase 1 (CCDEBE).[241] Under this market design, resources can submit automated and manual adjustments to commitment cost and default energy bid reference levels.

Figure 6.11 and Figure 6.12 highlight how proxy commitment costs were bid into the day-ahead and real-time markets in 2021, compared to 2020.[242,243]

As shown in Figure 6.11 about 38 percent of the capacity submitted start-up bids at or near the proxy cost cap in 2021, compared to 37 percent in 2020. About 31 percent of capacity submitted start-up bids at or below the proxy cost cap in the day-ahead market in 2021, compared to 32 percent in 2020. About 37 percent of the startable capacity submitted bids at or near the proxy cost cap in the real-time market in 2021, similar to 2020.

As shown in Figure 6.12, 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 2020 and 2021.

241 California ISO Market Notice, *Commitment Cost and Default Energy Bid Enhancements Phase 1: Deployment Effective for Trade Date 2/16/21*, February 14, 2021: http://www.caiso.com/Documents/CommitmentCost-DefaultEnergyBidEnhancementsPhase1-DeploymentEffective-TradeDate21621.html#search=market%20notice%202%2F16%2F21

242 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.

243 The analysis excludes days with CCDEBE automated and manual reference level adjustment requests. This is because automated requests are evaluated against resource-specific reasonable thresholds and manual requests are evaluated on a case-by-case basis with supporting documentation.

Figure 6.11 Day-ahead and real-time gas-fired capacity under the proxy cost option for start-up cost bids (percentage)

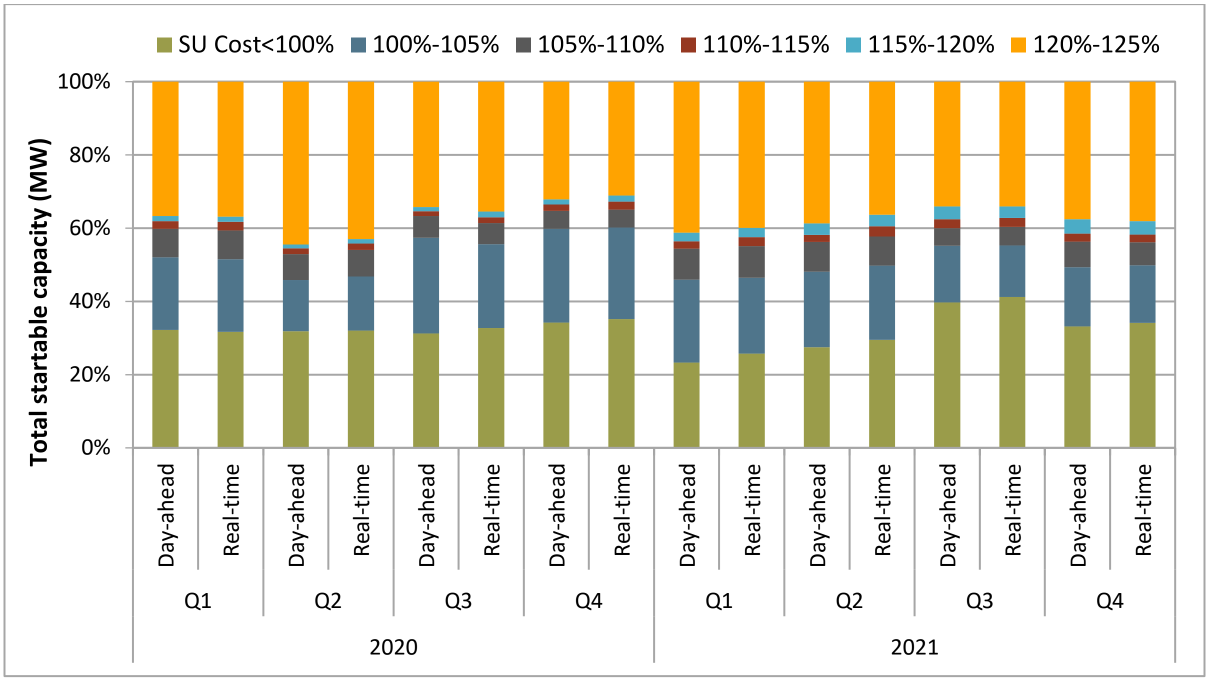
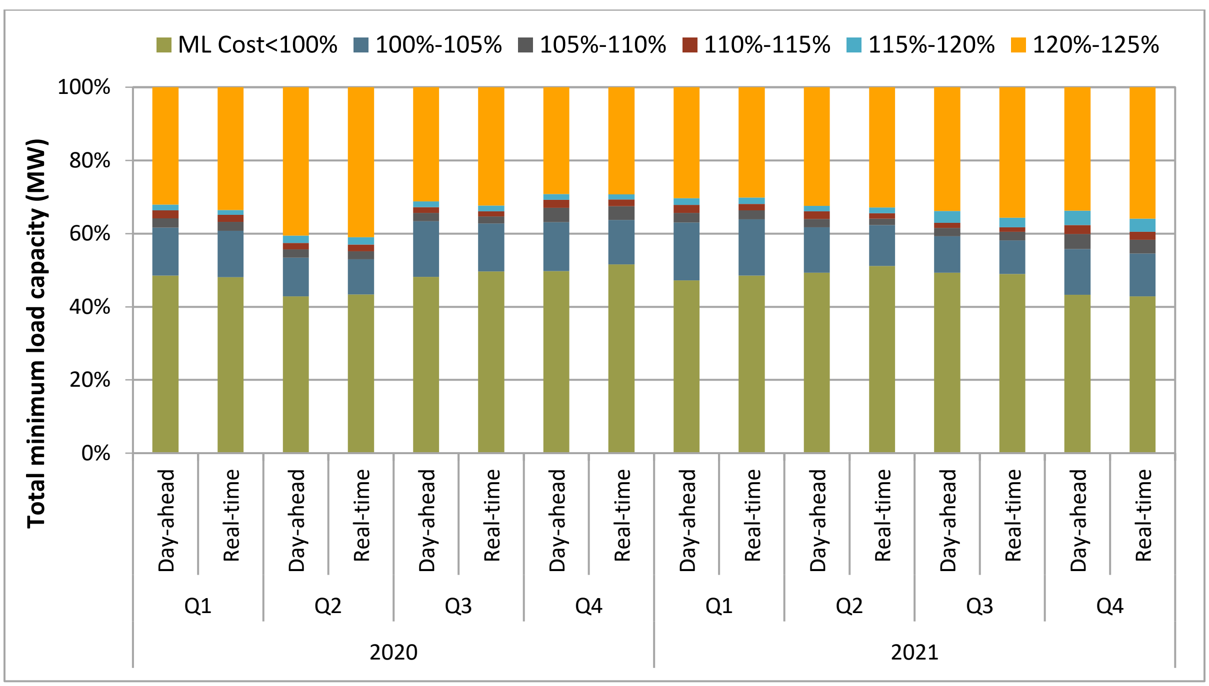


Figure 6.12 Day-ahead and real-time gas-fired capacity under the proxy cost option for minimum load cost bids (percentage)



Commitment Cost and Default Energy Bid Enhancements (CCDEBE)

For resources utilizing the proxy-cost option, start-up and minimum-load bids are capped at 125 percent of estimated costs. After the implementation of CCDEBE on February 16, 2021, resources can submit requests to adjust their commitment costs in order to submit a start-up or minimum-load bid above this cap.[244] This process can be automated or manual, depending on the resource's bid and reasonableness threshold. The reasonableness threshold is a new measure, which includes an additional multiplier meant to reflect variability in fuel or fuel-equivalent costs.[245] For requests below this reasonableness threshold, resources submit automated requests that automatically flow into the market and are subject to audit after the fact. For requests above this reasonableness threshold, resources submit manual requests and scheduling coordinators must provide evidence of the higher fuel or fuel-equivalent cost driving the commitment cost over the proxy-cost calculation.

In 2021, there were only a handful of manual and automated requests, all of them from gas resources. These requests were during a few different timeframes: February 16-18, June 14-19, and September 7-9. When the policy was first implemented there were a number of manual requests that were denied for a variety of reasons, such as requests incorporating Operational Flow Order (OFO) penalties, inability to determine the specific price requested, and inadequate supporting documentation.

6.4 Market-based rate authority in the Western Energy Imbalance Market

Western 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 WEIM. Once granted, each entity's authority to continue selling at market-based rates in the WEIM and other markets is reviewed by FERC on a triennial basis. Currently, all FERC jurisdictional WEIM participants have authority to sell in the Western 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 WEIM, as well as participants that have since undergone triennial review by FERC and retained this authority.

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[244] For additional DMM analysis, see: Department of Market Monitoring, *Q1 2021 Report on Market Issues and Performance,* June 9, 2021, pp. 90-93: http://www.caiso.com/Documents/2021-First-Quarter-Report-on-Market-Issues-and-Performance-Jun-9-2021.pdf

[245] California ISO*, Tariff Amendment to Enable Updates to Default Commitment Costs and Default Energy Bids*, filed with FERC on July 9, 2020, pp. 33-37: http://www.caiso.com/Documents/Jul9-2020-TariffAmendment-CommitmentCostsandDefaultEnergyBidEnhancementsCCDEBE-ER20-2360.pdf

7 Congestion

This chapter provides a review of congestion and the congestion revenue rights auction in 2021.[246] Findings from this chapter include the following:

- **Day-ahead market congestion decreased.** Both the frequency and the price impact of day-ahead congestion were lower in 2021 than in 2020. The primary constraints impacting price separation in the day-ahead market were the Quinto-Los Banos 230 kV line, a Miguel 500/230 kV transformer, and the Midway-Vincent #2 500 kV line. In 2021, day-ahead congestion revenues totaled about 5.2 percent of total day-ahead market energy costs, compared to about 6.0 percent in 2020.

- **Real-time market congestion decreased**. Both the 15-minute and 5-minute markets had patterns of congestion that followed seasonal trends in both solar production and load. The three primary constraints creating price separation in the real-time market were the Path 26 Control Point 1 nomogram, the Quinto-Los Banos 230 kV line, and the Gates-Midway 230 kV line.

- **The frequency and impact of transfer constraint congestion decreased**. Similar to prior years, the frequency of congestion was highest for load areas located in the Pacific Northwest, where it primarily decreased prices.

- **Intertie congestion decreased**. Congestion on interties across all markets (day-ahead, 15-minute, and 5-minute) reached about $164 million, down from $263 million in 2020. This decrease was largely driven by decreased congestion on the two major interties linking the CAISO with the Pacific Northwest: the Malin 500 and the Nevada/Oregon Border (NOB).

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 California ISO implemented two sets of changes to the congestion revenue rights auction process**. The first (Track 1A) reduced the number and pairs of nodes at which congestion revenue rights can be purchased in the auction. The second (Track 1B) 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. DMM continues to support both initiatives as incremental improvements that should help reduce the losses incurred by transmission ratepayers due to the CAISO auction of congestion revenue rights.

- **Payouts to congestion revenue rights sold in the California ISO auction exceeded auction revenues by $43 million in 2021, down from $71 million in 2020**. 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.

[246] For a detailed background of congestion, from how it is calculated to how it interacts with other market elements, see: Department of Market Monitoring, *2019 Annual Report on Market Issues and Performance*, June 2020, Section 8.1: http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf

- **Transmission ratepayers received about 71 cents in auction revenue per dollar paid out to these rights purchased in the auction in 2021.** Track 1B revenue deficiency offsets reduced payments to auctioned CRRs by about $81 million. Losses from auctioned congestion revenue rights totaled about 7 percent of total day-ahead congestion rent in 2021, compared to about 14 percent in 2020, 6 percent in 2019, and 21 percent in 2018.

- **DMM believes the current auction is unnecessary and could be eliminated**.[247,248] If the CAISO 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 also assesses the impact of congestion to the major load serving areas in the California ISO (Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric), as well as the Western Energy Imbalance Market.

Highlights of 2021 include:

- In the day-ahead market, the impact and frequency of congestion decreased in 2021, relative to 2020. This congestion increased average day-ahead prices in both the Pacific Gas and Electric and San Diego Gas & Electric areas and decreased average prices in the Southern California Edison area.

- In the 15-minute market, congestion followed seasonal trends in solar production and load. The top three constraints that had the greatest impact on price separation in the 15-minute market were the Path 26 Control Point 1 nomogram, the Quinto-Los Banos 230 kV line, and the Gates-Midway 230 kV line.

- In the WEIM, congestion decreased prices in the majority of areas. Internal congestion from a small number of constraints had significant impacts on prices everywhere. Transfer congestion primarily impacted prices in the Pacific Northwest.

7.1.1 Day-ahead congestion

Congestion rent and loss surplus

Total congestion rents and loss surpluses were higher in 2021 than 2020. At $613 million, total day-ahead congestion rents were about 5.2 percent of the day-ahead market energy costs, compared to 6 percent in 2020. Congestion rent and loss surplus variation increased in 2021, compared to previous

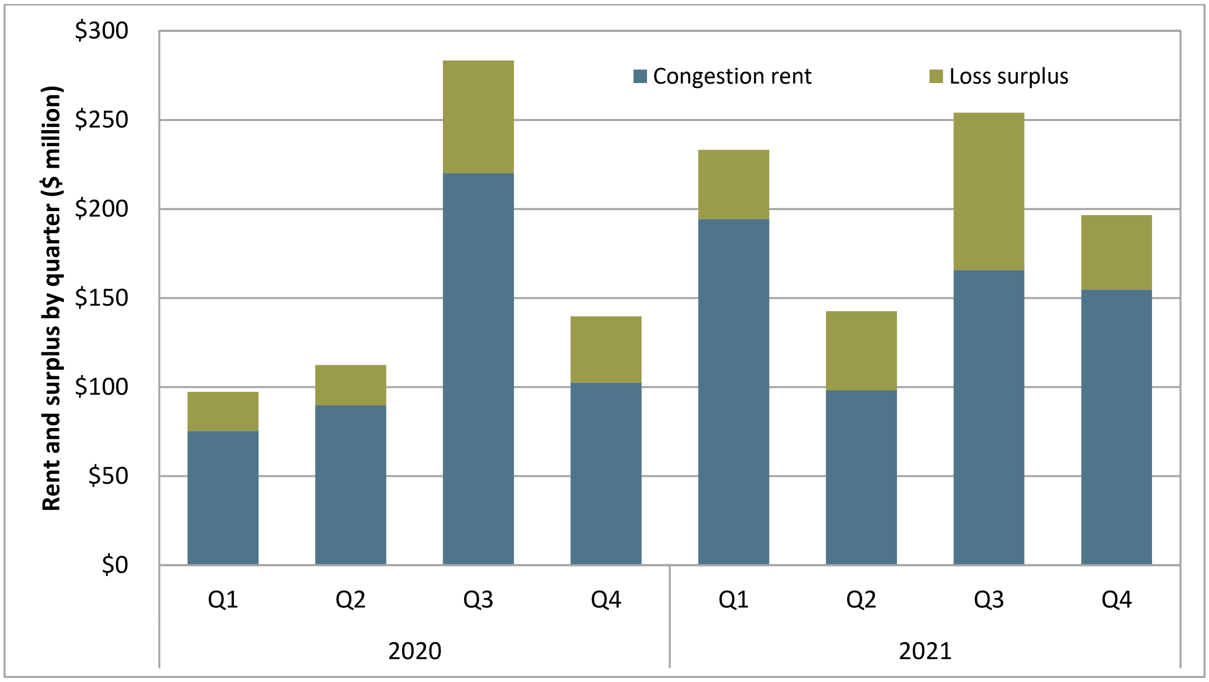
247 DMM whitepaper, *Problems in the performance and design of the congestion revenue rights auction,* November 27, 2017: http://www.caiso.com/Documents/DMMWhitePaper-Problems_Performance_Design_CongestionRevenueRightAuction-Nov27_2017.pdf

248 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

years. Congestion rents were highest in the first quarter while the loss surplus peaked in the third quarter.

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.[249]

Figure 7.1 Congestion rent and loss surplus by quarter (2020 – 2021)



Congestion impact in the day-ahead market from internal, flow-based constraints

The impact and frequency of day-ahead congestion decreased in 2021, relative to 2020. This congestion increased average day-ahead prices in both the San Diego Gas & Electric and Pacific Gas and Electric areas and decreased average prices in the Southern California Edison area.

- For San Diego Gas & Electric, congestion increased average prices above the system average by about $1.05/MWh (1.8 percent), compared to about $1.66/MWh (3.3 percent) in 2020.
- For Pacific Gas and Electric, congestion increased prices in the area by about $0.60/MWh (1.2 percent), compared to a decrease of $1.46/MWh (3.2 percent) in 2020.

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[249] For more information on marginal loss surplus allocation refer to the California ISO Business Practice Manual Change Management, *Settlements and Billing, CG CC 6947 IFM Marginal Losses Surplus Credit Allocation:* https://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing

- For Southern California Edison, congestion drove prices down by about $0.47/MWh (1.1 percent), compared to an increase of $0.94/MWh (1.2 percent) in 2020.

Figure 7.2 Overall impact of congestion on price separation in the day-ahead market

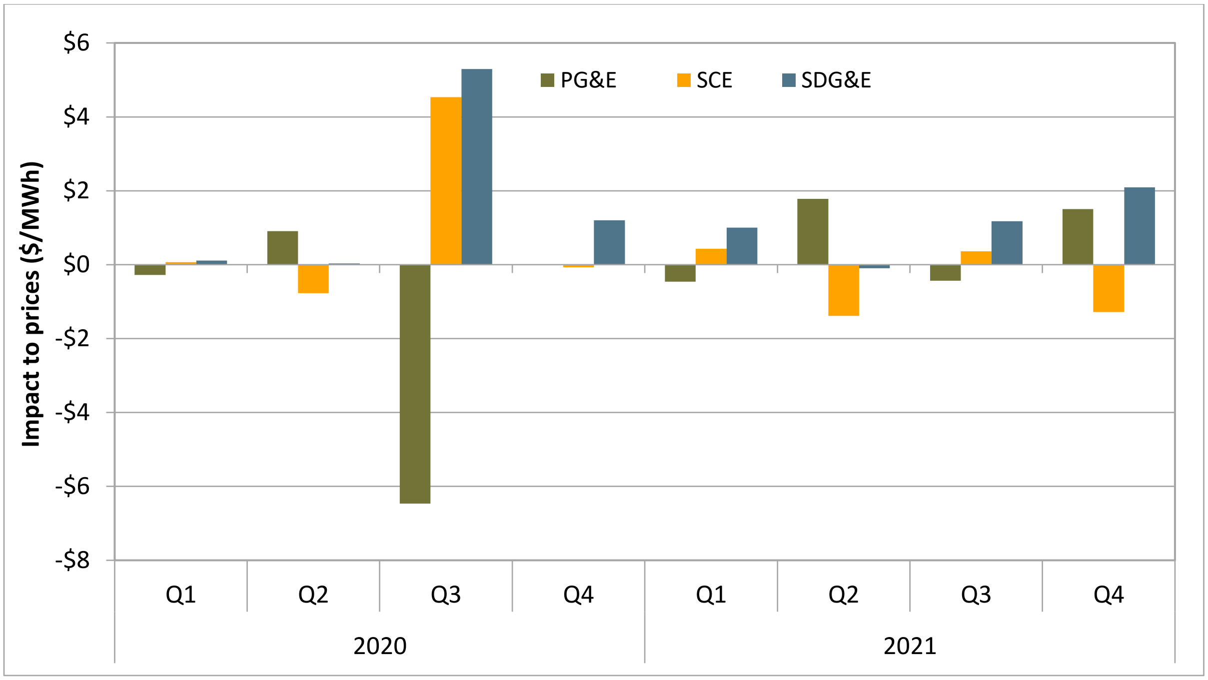


Figure 7.3 Percent of hours with congestion impacting prices by load area

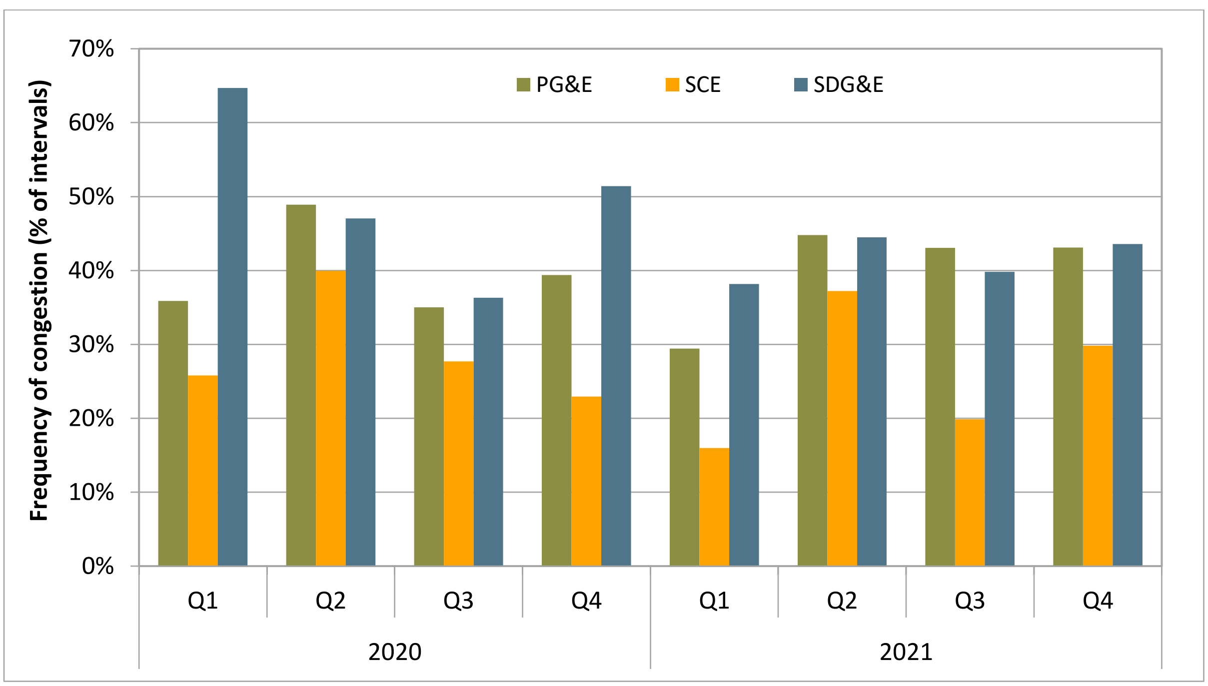


Table 7.1 shows the quarterly frequency and annualized impact of congestion from individual constraints on prices in each load aggregation area.[250] The three constraints that had the greatest impact on price separation over the year were the Quinto-Los Banos 230 kV line, a Miguel 500/230 kV transformer, and the Midway-Vincent #2 500 kV line.

Quinto-Los Banos 230 kV line

The Quinto-Los Banos 230 kV line (30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1) was frequently congested in the second and fourth quarter. Over the year, the constraint increased prices in the PG&E area and decreased prices in the SCE and SDG&E areas. This line bound primarily due to maintenance on the Tesla-Los Banos 500 kV line and limited the ability for renewable resources in the South to meet demand in the North.

Miguel 500/230 kV transformer nomogram

The Miguel 500/230 kV transformer nomogram (MIGUEL_BKs_MXFLW_NG) was often enforced in the fourth quarter. It had a significant impact on SDG&E prices, but little to no impact on prices in PG&E and SCE. The nomogram was used to mitigate flows on one of the 500/230 kV transformers at the Miguel substation while another at the substation was out of service.

Midway-Vincent #2 500 kV line

The Midway-Vincent #2 500 kV line (30060_MIDWAY_500_24156_VINCENT_500_BR_2_3) was congested throughout the year and limited north-to-south flows within the California ISO. This resulted in lower prices in the PG&E area and higher prices in SCE and SDG&E. This line was impacted by a variety of factors over the year, including maintenance on the Midway-Whirlwind 500 kV and system conditions that necessitated the temporary de-rating of the line.

[250] For a breakdown of each individual constraint's impact on prices during the respective quarter, see DMM quarterly reports: 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 (2021)

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	0.0%	10.2%	1.9%	11.0%	$0.35	0.65%	-$0.29	-0.56%	-$0.26	-0.49%
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	1.6%	15.3%	5.3%	5.4%	$0.14	0.26%	-$0.06	-0.11%	-$0.05	-0.09%
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	0.4%	5.7%	0.0%	3.7%	$0.09	0.17%	-$0.07	-0.13%	-$0.06	-0.12%
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	0.3%	7.1%	0.3%	3.7%	$0.09	0.16%	-$0.07	-0.13%	-$0.06	-0.12%
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _2	0.0%	4.0%	0.0%	0.3%	$0.07	0.14%	-$0.06	-0.12%	-$0.06	-0.10%
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	0.2%	3.9%	0.3%	1.7%	$0.06	0.11%	-$0.05	-0.09%	-$0.05	-0.08%
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1	0.0%	3.5%	0.0%	0.1%	$0.05	0.09%	-$0.04	-0.08%	-$0.04	-0.07%
	30790_PANOCHE _230_30900_GATES _230_BR_1 _1	0.3%	7.1%	0.3%	0.5%	$0.05	0.09%	-$0.04	-0.07%	-$0.04	-0.07%
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _3	0.2%	2.6%	0.0%	0.0%	$0.05	0.08%	-$0.04	-0.07%	-$0.03	-0.06%
	7440_MetcalfImport_Tes-Metcalf	0.0%	1.9%	0.0%	1.9%	$0.04	0.07%	-$0.03	-0.06%	-$0.03	-0.05%
	GATES-PNOCHE_RT_NG	0.0%	0.0%	0.0%	3.0%	$0.04	0.07%	-$0.01	-0.02%	-$0.01	-0.02%
	30885_MUSTANGS_230_30900_GATES _230_BR_1 _1	0.0%	0.0%	5.4%	0.3%	$0.03	0.06%	-$0.03	-0.05%	-$0.02	-0.05%
	RM_TM21_NG	2.3%	0.5%	1.0%	0.0%	$0.01	0.02%	$0.00	0.00%	-$0.01	-0.02%
	30055_GATES1 _500_30900_GATES _230_XF_12_P	0.0%	0.9%	2.0%	0.4%	$0.01	0.02%	-$0.01	-0.01%	-$0.01	-0.01%
	37585_TRCY PMP_230_30625_TESLA D _230_BR_2 _1	0.0%	0.4%	0.0%	0.0%	$0.01	0.01%	$0.00	-0.01%	$0.00	-0.01%
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	0.2%	0.5%	1.0%	0.2%	-$0.01	-0.02%	$0.01	0.02%	$0.01	0.02%
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	1.0%	2.7%	5.4%	0.9%	-$0.25	-0.46%	$0.16	0.31%	$0.16	0.29%
SCE	6410_CP1_NG	0.9%	0.0%	0.0%	0.0%	-$0.18	-0.33%	$0.16	0.31%	$0.16	0.30%
	OMS 8797800_D-VST1_OOS_CP3	4.4%	0.0%	0.0%	0.0%	$0.00	0.00%	$0.00	0.00%	-$0.01	-0.03%
	6410_CP10_NG	1.2%	0.0%	0.0%	0.2%	$0.02	0.03%	-$0.01	-0.03%	-$0.01	-0.02%
	6410_CP7_NG	3.4%	0.0%	0.0%	0.0%	$0.03	0.05%	-$0.02	-0.04%	-$0.02	-0.04%
SDG&E	MIGUEL_BKs_MXFLW_NG	1.1%	0.5%	0.0%	7.1%	-$0.04	-0.08%	$0.00	0.00%	$0.64	1.20%
	7820_TL 230S_OVERLOAD_NG	7.3%	13.0%	0.7%	11.4%	-$0.04	-0.07%	$0.00	0.00%	$0.39	0.73%
	7820_TL23040_IV_SPS_NG	0.0%	1.5%	5.0%	0.0%	-$0.01	-0.01%	$0.00	0.00%	$0.15	0.28%
	22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1	0.0%	0.0%	5.4%	1.3%	$0.00	0.00%	$0.00	0.00%	$0.07	0.14%
	22420_SILVERGT_69.0_22868_URBAN _69.0_BR_1 _1	0.0%	0.4%	0.0%	0.2%	$0.00	0.00%	$0.00	0.00%	$0.05	0.09%
	OMS 9964817_TL50003_NG	0.0%	1.1%	0.0%	0.0%	$0.00	-0.01%	$0.00	0.00%	$0.03	0.06%
	OMS 10827057_TL50003_NG	0.0%	0.0%	0.0%	0.5%	$0.00	-0.01%	$0.00	0.00%	$0.03	0.05%
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _P	0.0%	1.1%	0.0%	0.0%	$0.00	-0.01%	$0.00	0.00%	$0.03	0.05%
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	0.1%	1.6%	0.5%	0.8%	-$0.01	-0.03%	$0.01	0.02%	$0.02	0.05%
	22480_MIRAMAR _69.0_22756_SCRIPPS _69.0_BR_1 _1	0.0%	0.0%	0.0%	0.0%	$0.00	0.00%	$0.00	0.00%	$0.02	0.03%
	22886_SUNCREST_230_22885_SUNCREST_500_XF_2 _S	0.6%	0.0%	0.0%	0.0%	$0.00	0.00%	$0.00	0.00%	$0.01	0.02%
	22442_MELRSETP_69.0_22724_SANMRCOS_69.0_BR_1 _1	0.0%	0.0%	0.0%	0.0%	$0.00	0.00%	$0.00	0.00%	-$0.02	-0.03%
	OMS 8797939_D-SBLR_OOS_CP3	6.4%	0.0%	0.0%	0.0%	$0.01	0.01%	$0.00	0.00%	-$0.02	-0.03%
Other						$0.04	0.07%	$0.01	0.01%	$0.08	0.15%
Total						**$0.60**	**1.11%**	**-$0.47**	**-0.91%**	**$1.05**	**1.96%**

7.1.2 Real-time congestion

Congestion in the real-time market followed seasonal trends in solar production and load. Days when there is high load and low solar typically see congestion in the north-to-south direction, while low load and high solar days see congestion in the south-to-north direction. These congestion scenario impact prices across the CAISO and WEIM. Congestion in the 15-minute real-time market was similar to the 5-minute market, but had a lower impact on locational price differences. Below is an analysis of the frequency and effects of internal congestion in the 15-minute market.

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 CAISO and WEIM by quarter. Internal congestion resulted in a net increase to prices in the CAISO area and a net decrease for most areas in the WEIM.

On a quarterly basis, net price separation due to internal congestion was greatest in the first quarter. During this quarter, San Diego Gas & Electric experienced the largest price impact, with prices increasing by $6.35/MWh (13 percent). Price impacts in PacifiCorp West, Portland General Electric, Puget Sound Energy, Powerex, and Seattle City Light remained similar in each quarter, leading prices in these areas to decrease by an average of $0.72/MWh (3 percent) due to internal congestion over 2021.

Figure 7.4 Overall impact of internal congestion on price separation in the 15-minute market

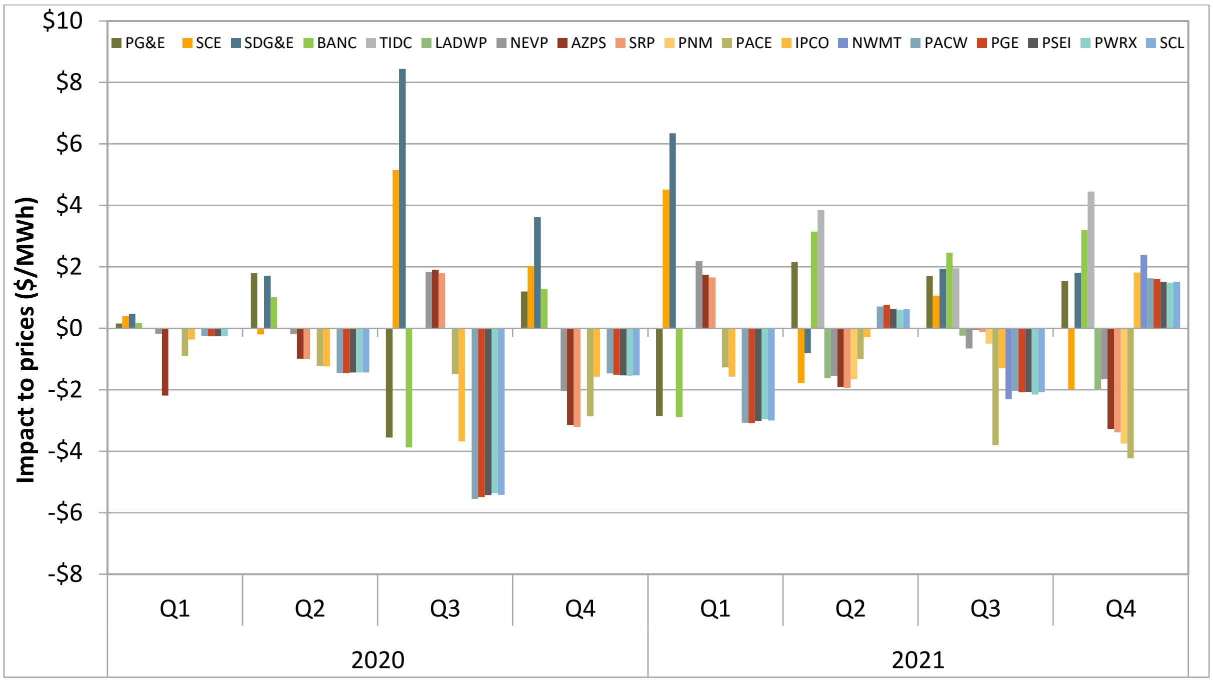


Table 7.2 shows the annualized impact of 15-minute market congestion from individual constraints on prices in each load area. The impact from transfer constraints are included at the bottom of the table and are discussed in greater depth in Section 7.1.3. This section focuses on individual flow-based constraints that are internal to balancing authority areas, rather than schedule-based constraints between areas. The three constraints that had the greatest impact on price separation in the 15-minute market were the Path 26 Control Point 1 nomogram, the Quinto-Los Banos 230 kV line, and the Gates-Midway 230 kV line.

Path 26 Control Point 1 nomogram

The Path 26 Control Point 1 nomogram (6410_CP1_NG) had the greatest impact on average 15-minute prices in 2021. This nomogram heavily impacted prices within the California ISO and Pacific Northwest. This nomogram is used to mitigate the Midway-Whirlwind line for the contingency of the Midway-Vincent #1 and #2 lines.

Quinto-Los Banos 230 kV line

The Quinto-Los Banos 230 kV line (30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1) impacted most WEIM areas. It had a significant impact on prices in the TIDC, where it accounted for almost half of the total internal congestion in the area. The line was congested due to the loss of the Tracy-Los Banos 500 kV line and the Tesla-Los Banos 500 kV line.

Table 7.2 Impact of internal constraint congestion on overall 15-minute prices during all hours

Constraint Location	Constraint	PG&E	SCE	SDG&E	BANC*	TIDC*	LADWP*	NEVP	AZPS	SRP	PNM*	PACE	IPCO	NWMT	PACW	PGE	PSEI	PWRX	SCL
IPCO	T342.MPSN	$0.06	-$0.05	-$0.08	$0.11	$0.09	-$0.18	-$0.20	-$0.11	-$0.11	-$0.19	-$0.33	$0.50	$0.04	$0.18	$0.18	$0.18	$0.17	$0.18
	T341.BORA	$0.01	-$0.01	-$0.01	$0.02	$0.01	-$0.03	$0.00	-$0.02	-$0.02	-$0.03	-$0.06	$0.05	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
	T501_xA	$0.06	$0.00	$0.00	$0.09	$0.08	-$0.07	-$0.06	-$0.03	-$0.04	-$0.08	-$0.19	-$0.11	$0.00	$0.08	$0.09	$0.08	$0.07	$0.07
NWMT	RIMROCK_PAR	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.20	$0.00	$0.38	$0.00	$0.00	$0.00	$0.00	$0.00
	FC-CH2	$0.00	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	-$0.07	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	FC-MK	$0.00	$0.02	$0.02	$0.00	$0.00	$0.00	$0.02	$0.00	$0.00	-$0.22	-$0.04	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00
PACE	EAST_WYO_EXP	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.08	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	WINDSTAR EXPORT TCOR	$0.00	$0.00	$0.00	$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	$0.00
	TOTAL_WYOMING_EXPORT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$1.06	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
PACW	ALVEY$_DIXONVIL_500	$0.01	$0.00	$0.00	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	DIXONVIL_MERIDIAN_500	$0.03	$0.02	$0.02	$0.04	$0.04	$0.01	$0.01	$0.01	$0.01	$0.01	-$0.02	-$0.04	-$0.05	-$0.04	-$0.07	-$0.06	-$0.06	-$0.06
PG&E	30763_Q0577SS _230_30765_LOSBANOS_230_BR_1 _1	$0.22	-$0.44	-$0.41	$0.84	$1.51	-$0.45	-$0.23	-$0.36	-$0.36	-$0.40	$0.00	$0.19	$0.20	$0.34	$0.34	$0.33	$0.32	$0.33
	ML_RM12	$0.20	$0.11	$0.10	$0.24	$0.25	$0.07	$0.01	$0.07	$0.07	$0.05	-$0.12	-$0.22	-$0.27	-$0.34	-$0.33	-$0.32	-$0.31	-$0.32
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.19	-$0.23	-$0.22	$0.31	$0.33	-$0.24	-$0.12	-$0.19	-$0.19	-$0.21	$0.00	$0.02	$0.04	$0.17	$0.17	$0.16	$0.16	$0.16
	30885_MUSTANGS_230_30900_GATES _230_BR_1 _1	$0.17	-$0.09	-$0.08	$0.12	$0.13	-$0.10	-$0.06	-$0.08	-$0.08	-$0.09	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30790_PANOCHE _230_30900_GATES _230_BR_1 _1	$0.15	-$0.17	-$0.16	$0.25	$0.29	-$0.16	-$0.06	-$0.14	-$0.14	-$0.15	$0.00	$0.00	$0.00	$0.12	$0.12	$0.12	$0.12	$0.12
	RM_TM21_NG	$0.15	$0.09	$0.08	$0.01	$0.01	$0.00	$0.03	$0.07	$0.07	$0.00	-$0.06	-$0.12	$0.00	-$0.17	-$0.17	-$0.17	-$0.17	-$0.17
	40687_MALIN _500_30005_ROUND MT_500_BR_1 _3	$0.12	$0.06	$0.05	$0.15	$0.14	$0.04	$0.00	$0.04	$0.04	$0.02	-$0.08	-$0.13	-$0.04	-$0.18	-$0.18	-$0.18	-$0.17	-$0.18
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _1	$0.07	-$0.08	-$0.08	$0.11	$0.11	-$0.11	-$0.04	-$0.07	-$0.07	-$0.08	$0.00	$0.03	$0.00	$0.06	$0.06	$0.06	$0.06	$0.06
	30879_HENTAP1 _230_30885_MUSTANGS_230_BR_1 _1	$0.06	-$0.02	-$0.01	$0.05	$0.05	-$0.01	$0.00	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1	$0.05	$0.00	$0.00	$0.13	$0.04	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.02	-$0.02	-$0.06	-$0.07	-$0.07	-$0.07	-$0.07
	30790_PANOCHE _230_30900_GATES _230_BR_2 _1	$0.04	-$0.06	-$0.06	$0.08	$0.10	-$0.05	-$0.01	-$0.05	-$0.05	-$0.05	$0.00	$0.00	$0.00	$0.03	$0.03	$0.02	$0.01	$0.02
	30056_GATES2 _500_30060_MIDWAY _500_BR_2 _3	$0.03	-$0.04	-$0.04	$0.05	$0.05	-$0.05	-$0.02	-$0.03	-$0.03	-$0.03	$0.00	$0.01	$0.00	$0.03	$0.03	$0.03	$0.03	$0.03
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _1	$0.03	-$0.04	-$0.03	$0.04	$0.04	-$0.03	-$0.02	-$0.03	-$0.03	-$0.03	$0.00	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02
	RM_TM12_NG	$0.03	$0.01	$0.01	$0.02	$0.03	$0.01	$0.00	$0.01	$0.01	$0.00	-$0.02	-$0.03	-$0.04	-$0.05	-$0.05	-$0.05	-$0.05	-$0.05
	ROUND_MOUNTAIN	$0.02	$0.01	$0.01	$0.03	$0.03	$0.01	$0.00	$0.01	$0.01	$0.00	-$0.01	-$0.03	-$0.04	-$0.04	-$0.04	-$0.04	-$0.04	-$0.04
	7440_MetcalfImport_Tes-Metcalf	$0.02	-$0.02	-$0.01	$0.02	$0.02	-$0.02	-$0.01	-$0.01	-$0.01	-$0.02	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.00	$0.01
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	$0.01	$0.01	$0.01	$0.01	$0.02	$0.00	$0.00	$0.01	$0.01	$0.00	-$0.01	-$0.02	-$0.02	-$0.02	-$0.03	-$0.02	-$0.02	-$0.02
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	$0.01	-$0.02	-$0.02	$0.01	$0.01	-$0.01	-$0.01	-$0.02	-$0.02	-$0.01	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
	GATES-PNOCHE_RT_NG	$0.01	-$0.04	-$0.04	$0.04	$0.06	-$0.02	-$0.01	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
	30750_MOSSLD _230_30797_LASAGUIL_230_BR_1 _1	$0.01	-$0.03	-$0.02	$0.01	$0.02	-$0.01	$0.00	-$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30050_LOSBANOS_500_30055_GATES1 _500_BR_1 _1	$0.01	-$0.01	-$0.01	$0.01	$0.01	-$0.01	$0.00	-$0.01	-$0.01	-$0.01	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
	6110_SOL10_NG	$0.01	$0.00	$0.00	$0.02	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _1	-$0.02	$0.01	$0.01	-$0.03	-$0.03	$0.02	$0.01	$0.01	$0.01	$0.01	$0.00	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _3	-$0.02	$0.01	$0.01	-$0.03	-$0.03	$0.02	$0.01	$0.01	$0.01	$0.02	$0.00	-$0.01	-$0.02	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	-$0.03	$0.03	$0.02	-$0.02	-$0.02	$0.02	$0.01	$0.02	$0.02	$0.02	$0.00	-$0.01	-$0.01	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02
	30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3	-$0.17	$0.15	$0.15	-$0.13	-$0.14	$0.07	$0.09	$0.13	$0.13	$0.07	$0.01	-$0.06	-$0.03	-$0.12	-$0.12	-$0.12	-$0.11	-$0.12
	30515_WARNERVL_230_30800_WILSON _230_BR_1 _1	$0.00	$0.00	$0.00	-$0.03	-$0.04	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30765_LOSBANOS_230_30790_PANOCHE _230_BR_2 _1	$0.00	-$0.03	-$0.02	$0.01	$0.02	$0.00	$0.00	-$0.02	-$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	32214_RIO OSO _115_32244_BRNSWKT2_115_BR_2 _1	$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	$0.00	$0.00	$0.00	$0.00	$0.00
	32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.07	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	7430_CP6_NG	$0.00	$0.00	$0.00	$0.42	$0.19	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SCE	6410_CP1_NG	-$1.02	$1.12	$1.12	-$0.11	-$0.11	$0.08	$0.62	$0.99	$0.98	$0.07	$0.05	-$0.28	-$0.05	-$0.68	-$0.67	-$0.65	-$0.64	-$0.65
	OMS_10629362_LUGO-RVISTA	-$0.01	$0.05	$0.05	-$0.02	-$0.02	-$0.04	-$0.03	-$0.01	-$0.01	-$0.02	-$0.02	-$0.02	-$0.02	-$0.01	-$0.02	-$0.02	-$0.02	-$0.02
	24385_WEST TS _500_24384_EAST TS _500_BR_1 _1	-$0.03	$0.03	$0.04	-$0.04	-$0.04	$0.00	$0.01	$0.02	$0.02	$0.02	$0.00	-$0.01	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02
	OMS 9076082 ELD-MHV_NG	$0.02	$0.02	$0.00	$0.00	$0.00	$0.00	-$0.04	-$0.04	-$0.04	$0.00	-$0.02	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.01	$0.01	$0.01	$0.01	$0.01	-$0.03	-$0.01	-$0.01	-$0.01	-$0.02	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	6410_CP6_NG	-$0.01	$0.01	$0.01	-$0.01	-$0.01	$0.01	$0.00	$0.00	$0.00	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 8797800_D-VST1_OOS_CP3	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.03	-$0.03	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Victorville_Los_Angeles	$0.00	-$0.01	$0.00	$0.00	-$0.01	-$0.02	$0.02	$0.02	$0.02	$0.02	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	6410_CP7_NG	$0.04	-$0.05	-$0.05	$0.00	$0.00	$0.00	-$0.03	-$0.04	-$0.04	$0.00	$0.00	$0.01	$0.00	$0.03	$0.03	$0.03	$0.03	$0.03
	24801_DEVERS _500_24804_DEVERS _230_XF_2 _P	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.02	-$0.02	-$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SDG&E	7820_TL 230S_OVERLOAD_NG	$0.00	$0.09	$1.18	$0.00	$0.00	$0.00	-$0.09	-$0.25	-$0.27	-$0.16	-$0.09	-$0.04	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	MIGUEL_BKs_MXFLW_NG	$0.00	$0.00	$0.56	$0.00	$0.00	$0.00	-$0.01	-$0.19	-$0.19	-$0.17	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 10214484 ML_BK80_NG	$0.00	$0.00	$0.08	$0.00	$0.00	$0.00	$0.00	-$0.02	-$0.02	-$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 10827054_TL50003_NG	$0.00	$0.01	$0.08	$0.00	$0.00	$0.00	-$0.01	-$0.02	-$0.02	-$0.02	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS_10721323_TL23055_NG	$0.00	$0.00	$0.05	$0.00	$0.00	$0.00	$0.00	-$0.02	-$0.02	-$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	92321_SYCA TP2_230_22832_SYCAMORE_230_BR_2 _1	$0.00	$0.00	$0.05	$0.00	$0.00	$0.00	$0.00	-$0.02	-$0.02	-$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	$0.00	$0.01	$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	24801_DEVERS _500_24804_DEVERS _230_XF_1 _P	$0.01	$0.00	$0.01	$0.01	$0.01	$0.00	-$0.01	-$0.03	-$0.04	-$0.03	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 8797659_SB-VSTA_OOS_CP6	$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.03	-$0.04	$0.00	-$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	OMS 8797939_D-SBLR_OOS_CP3	$0.02	-$0.02	$0.00	$0.01	$0.01	$0.00	-$0.02	-$0.14	-$0.14	$0.00	-$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	22716_SANLUSRY_230_22232_ENCINA _230_BR_1 _1	$0.01	$0.01	-$0.06	$0.00	$0.00	$0.00	$0.00	-$0.02	-$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	22716_SANLUSRY_230_24131_S.ONOFRE_230_BR_3 _1	$0.01	$0.01	-$0.11	$0.00	$0.00	$0.00	$0.00	-$0.03	-$0.03	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	22442_MELRSETP_69.0_22724_SANMRCOS_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	$0.00	$0.00	$0.00	$0.00
	OMS 8797559_EC-SB_OOS_CP3	$0.01	-$0.01	$0.00	$0.00	$0.00	$0.00	-$0.01	-$0.07	-$0.07	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Other	$0.07	$0.01	$0.24	-$1.24	$0.09	$0.00	-$0.14	-$0.11	-$0.16	-$0.10	-$0.06	$0.01	-$0.03	-$0.01	$0.01	-$0.02	-$0.04	-$0.02
	Internal Total	**$0.65**	**$0.43**	**$2.30**	**$1.60**	**$3.36**	**-$1.28**	**-$0.43**	**-$0.88**	**-$0.96**	**-$1.97**	**-$2.59**	**-$0.33**	**$0.01**	**-$0.68**	**-$0.69**	**-$0.72**	**-$0.75**	**-$0.73**
	Transfers				-$0.01	-$0.21	$0.47	$0.58	-$0.09	$0.14	$0.01	-$0.47	$0.24	$8.54	-$1.37	-$1.46	-$3.78	-$3.05	-$4.12
	Grand Total	**$0.65**	**$0.43**	**$2.30**	**$1.59**	**$3.15**	**-$0.81**	**$0.15**	**-$0.97**	**-$0.82**	**-$1.96**	**-$3.06**	**-$0.09**	**$8.55**	**-$2.05**	**-$2.15**	**-$4.50**	**-$3.80**	**-$4.85**

*Since joining the WEIM only

Gates-Midway 230 kV line

The Gates-Midway 230 kV line (30900_GATES_230_30970_MIDWAY_230_BR_1_1) impacted prices across most of the WEIM, but led to less price separation than the constraints above. This constraint was congested due to maintenance and contingency situations associated with the Gates-Midway 500 kV line.

7.1.3 Congestion on Western Energy Imbalance Market transfer constraints

Table 7.3 shows the frequency of transfer constraint congestion and average price impact in the 15-minute and 5-minute markets for 2021. The highest frequency occurred either into or away from the WEIM load areas located in the Pacific Northwest. Similar to previous years, transfer congestion reduced prices in those areas. Notably, the impact of transfer congestion changed from negative to positive and vice-versa between markets in a number of areas.

The results of this section are the same as those found in Section 3.2 of this report. Both sections analyze transfer constraint congestion in the WEIM; however, each focus on different aspects. Section 3.2 focuses on the impact of transfer constraint congestion on transfer capability. Thus, Section 3.2 discusses congestion frequency split by the direction of congestion into (import congestion) or out of (export congestion) the WEIM area. On the other hand, this section discusses the same data as an increase or decrease to prices. When congestion decreases prices in the WEIM 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 Average price impact and congestion frequency on WEIM transfer constraints (2021)

	15-minute market		5-minute market	
	Congestion Frequency	Price Impact ($/MWh)	Congestion Frequency	Price Impact ($/MWh)
BANC*	1%	-$0.27	1%	$0.15
Turlock Irrigation District	1%	-$0.50	1%	-$0.11
Arizona Public Service	2%	-$0.92	3%	$0.89
L.A. Dept. of Water and Power*	2%	-$0.30	2%	$0.26
NV Energy	2%	$0.63	3%	$2.00
Public Service Company of NM*	5%	-$0.77	5%	$0.01
PacifiCorp East	6%	-$0.73	6%	$0.40
Idaho Power	7%	-$0.40	7%	$0.24
Salt River Project	10%	$1.03	10%	$3.35
NorthWestern Energy*	30%	$4.41	26%	-$0.24
PacifiCorp West	34%	-$3.15	24%	-$1.37
Portland General Electric	36%	-$2.33	26%	-$0.77
Seattle City Light	42%	-$4.73	40%	-$2.96
Puget Sound Energy	43%	-$4.32	40%	-$1.90
Powerex	39%	-$5.05	54%	-$2.93

*Since joining the WEIM only

Transfer congestion in the 15-minute market

Figure 7.5 shows the frequency of congestion on transfer constraints by quarter for 2021 and 2020. Figure 7.6 shows the average impact to prices in the 15-minute market by quarter over the same period. Similar to previous years, the frequency of congestion was highest among the load areas located in the Pacific Northwest. The impact of transfer congestion on price separation varied over the year but trended in the same positive or negative directions each quarter. Transfer congestion in Northwestern Energy increased sharply in the fourth quarter due to an outage that severely limited NWMT's import and export capability.[251]

[251] This outage and its effects are discussed in greater detail in Department of Market Monitoring, *September 2021 Energy Imbalance Market Transition Period Report for NorthWestern Energy,* December 22, 2021; also filed with FERC under Docket No. ER15-2565: http://www.caiso.com/Documents/Dec-22-2021-DMM-EIM-Special-Report-for-NorthWestern-Energy-for-September-2021.pdf

Figure 7.5 WEIM transfer constraint congestion frequency in the 15-minute market (>$0.01/MWh)

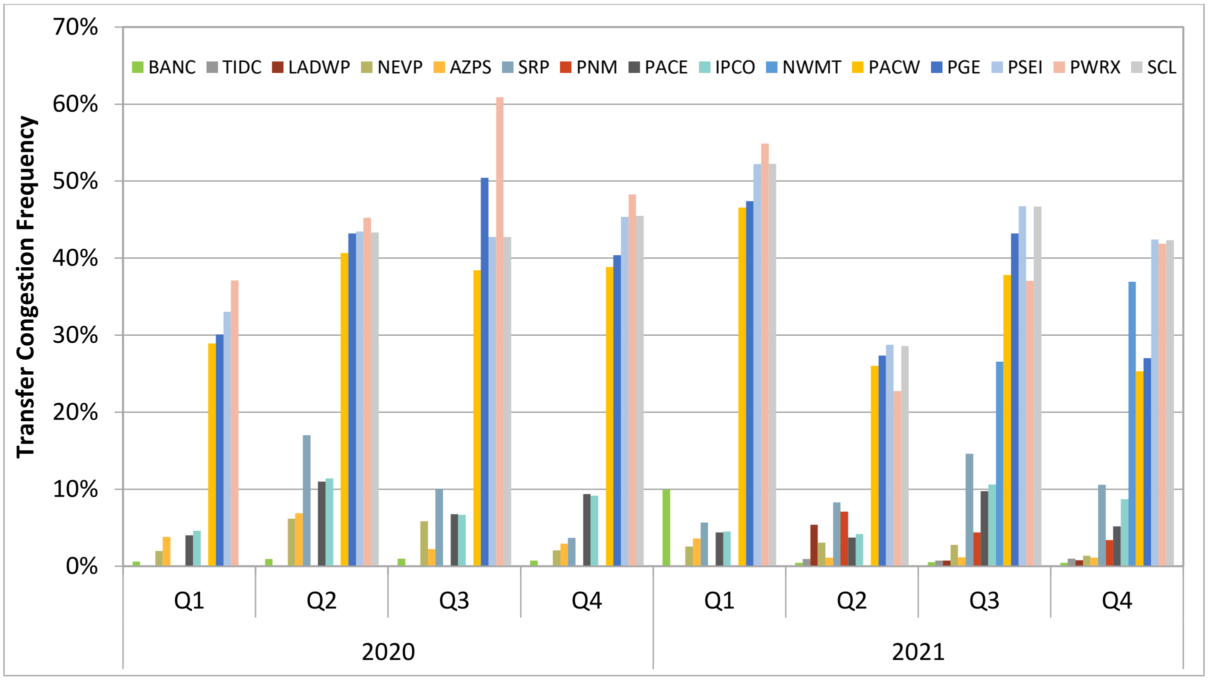
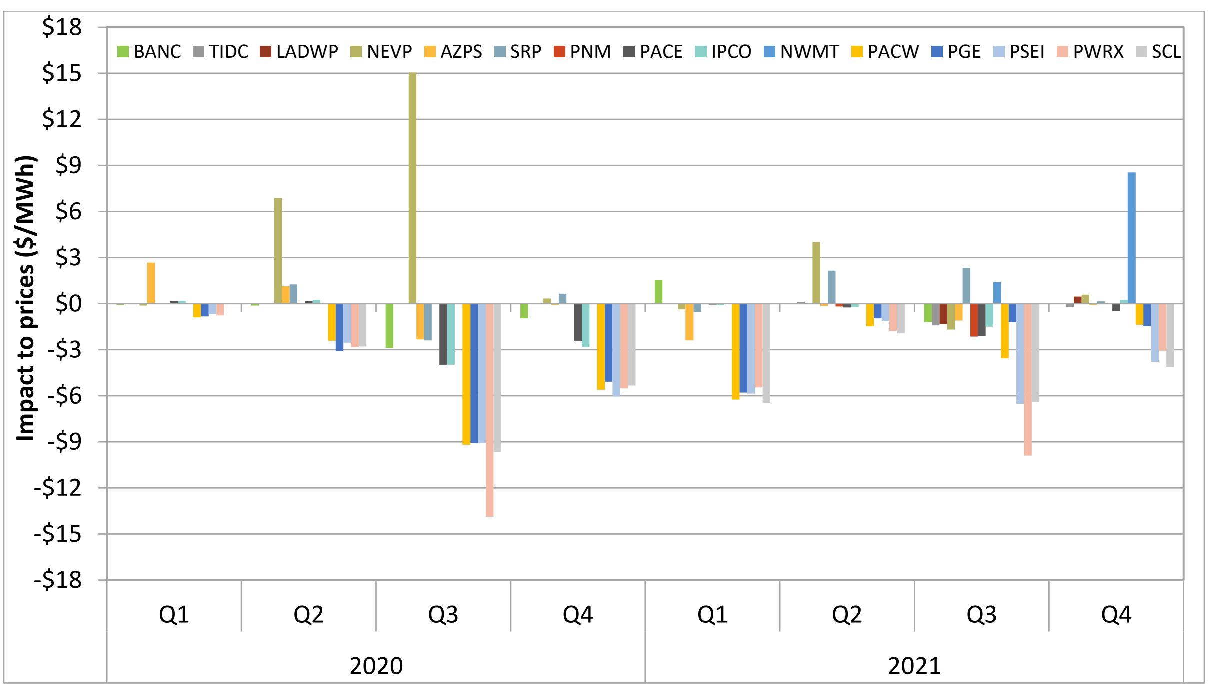


Figure 7.6 WEIM transfer constraint congestion average impact on prices in the 15-minute market



7.2 Congestion on interties

The frequency and financial impact of congestion on most interties connecting the CAISO with other balancing authority areas decreased relative to 2020, particularly on interties connecting the CAISO to the Pacific Northwest.

Congestion on interties between the CAISO and other balancing areas impact 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 CAISO 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 CAISO 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 markets. 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 CAISO side of the intertie and the lower price outside of the CAISO. This congestion charge also represents the amount paid to owners of congestion revenue rights that are sourced outside of the CAISO at points corresponding to these interties.

Figure 7.7 compares the percentage of hours that major interties were congested in the day-ahead market during the last three years. Figure 7.8 shows the total congestion charges on major interties between 2017 and 2021. Additionally, the figure includes the intertie congestion charges as a percentage of total day-ahead congestion rent during the same time period.

Trends in impact of congestion on interties

Congestion on interties across all markets (day-ahead, 15-minute, and 5-minute) reached about $164 million, down from $263 million in 2020. The decrease was largely driven by decreased congestion on the two major interties linking the CAISO with the Pacific Northwest: the Malin 500 and Nevada/Oregon Border (NOB). On these interties, total congestion charges fell $128 million from 2020 and returned to levels more similar to 2019. In the 15-minute and 5-minute markets, import congestion charges on interties decreased by $13 million and $10 million from 2020, respectively.

Table 7.4 Summary of import congestion (2019-2021)

Import region	Intertie	Day-ahead frequency of import congestion			Day-ahead average congestion charge ($/MW)			Total import congestion charges* (thousands)		
		2019	2020	2021	2019	2020	2021	2019	2020	2021
Northwest	Malin 500	21.5%	35.4%	23.0%	$12.76	$10.16	$13.41	$65,103	$140,802	$77,112
	NOB	7.6%	26.4%	11.0%	$8.40	$13.45	$13.96	$14,051	$95,249	$31,432
	COTPISO	1.1%	8.3%	0.5%	$25.60	$16.39	$12.59	$90	$518	$73
Southwest	Palo Verde	7.4%	2.5%	6.6%	$11.69	$12.10	$37.37	$21,716	$10,239	$25,178
	IPP Utah	11.4%	9.0%	5.8%	$7.92	$11.87	$17.25	$3,436	$2,757	$2,412
	IPP DC Mona			0.1%			$186.66			$2,320
	West Wing Mead	0.9%	0.1%	0.5%	$25.04	$12.66	$76.69	$779	$30	$1,278
	Mead	0.7%	0.8%	0.2%	$24.25	$26.61	$40.82	$1,673	$1,398	$749
	El Dorado			0.1%			$68.32		$115	$618
	IPP DC Adelanto	11.3%	0.1%	0.2%	$17.85	$23.56	$4.91	$39,645	$2,813	$396
	IPP DC Gonder	2.9%		0.4%	$666.53		$179.58	$2,847		$339
	Merchant			0.1%			$19.65	$22	$9	$150
	North Gila 500			0.2%			$25.46	$40	$21	$74
	IID - SDG&E	0.0%		0.0%	$938.17		$43.81	$197		$5
	Other							$1,946	$9,290	$21,629
Total								***$151,544***	***$263,243***	***$163,765***

* Total import congestion charges is the combined total from the day ahead, 15-minute, and 5-minute markets.

Figure 7.7 Percent of hours with day-ahead congestion on major interties (2019-2021)

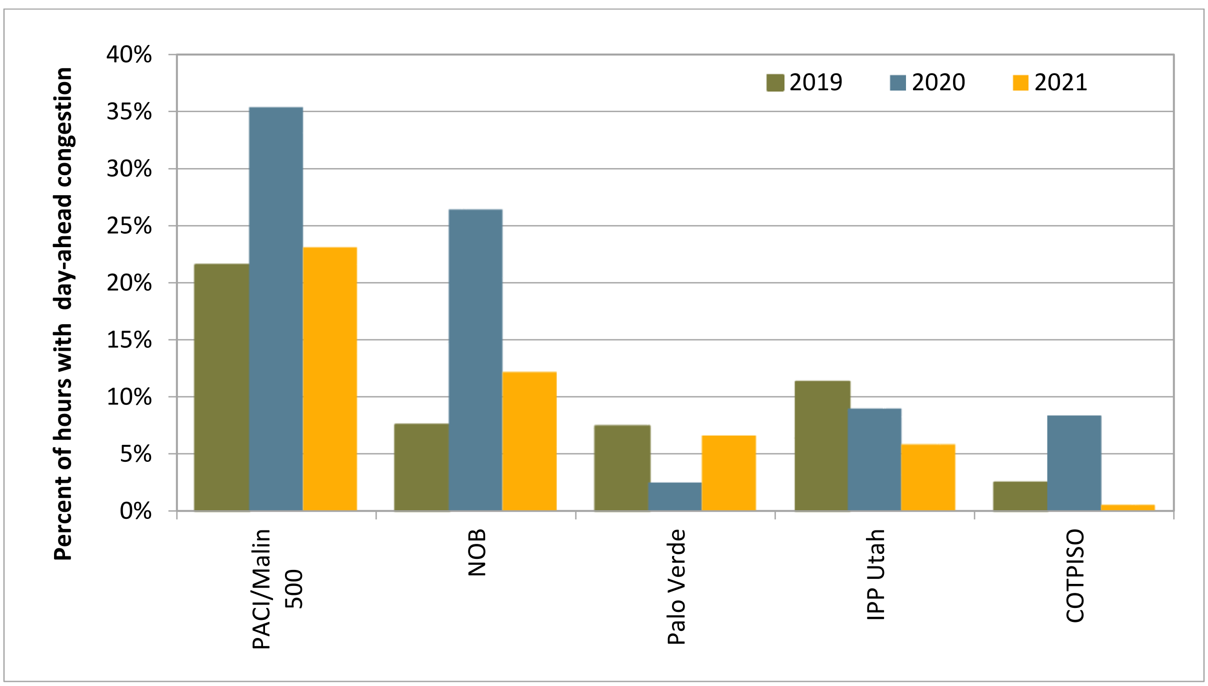
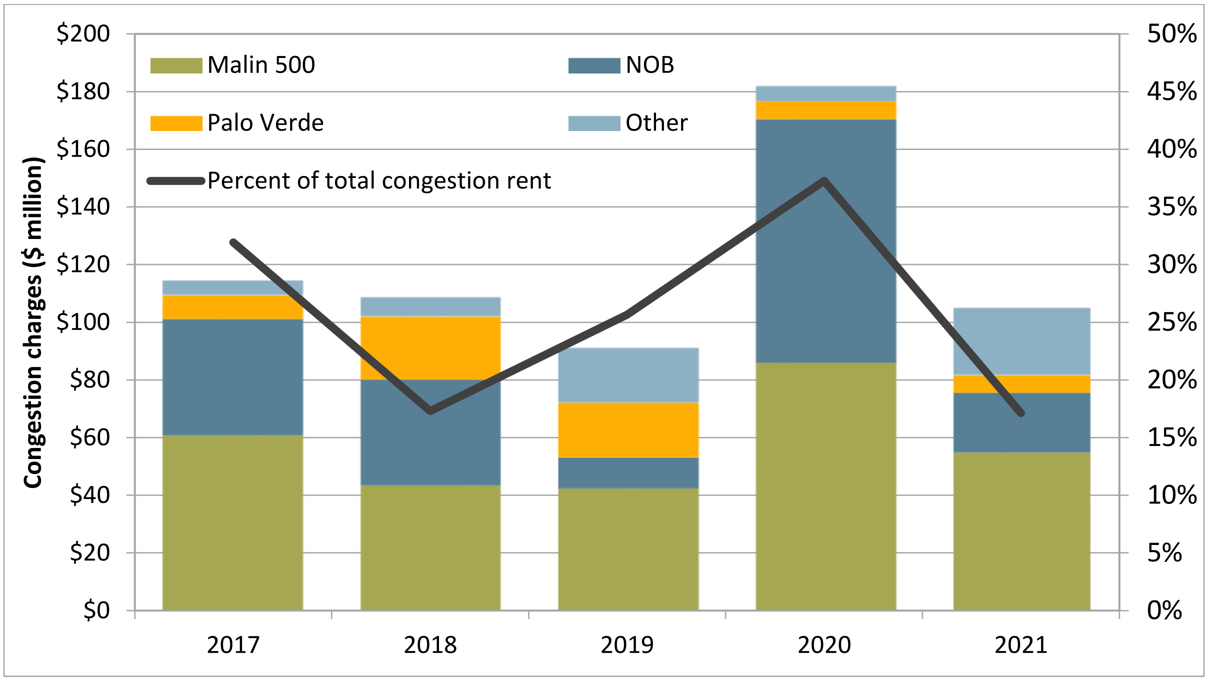


Figure 7.8 Day-ahead import congestion charges on major interties (2017-2021)



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 California 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.[252]
- Track 1A – Limiting allowable source and sink pairs to "delivery path" combinations.[253]

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252 California ISO, *Congestion Revenue Rights Auction Efficiency Track 1B Straw Proposal*, April 19, 2018: http://www.caiso.com/InitiativeDocuments/StrawProposal-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

253 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.[254]

In 2021, transmission ratepayer losses from congestion revenue right auctions totaled over $43 million. Transmission ratepayers received about 71 cents in auction revenue per dollar paid out to these rights purchased in the auction.

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 revenue 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.[255]

Ratepayers own the day-ahead transmission rights not held by merchant transmission or long-term rights holders. Allocating congestion revenue rights, also known as congestion rent, is a means of distributing the revenue from the sale of these rights 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 MW from node A to node B, and 10 MW from node B to node A. The participant's net holding of transmission rights is 0 MW, but the

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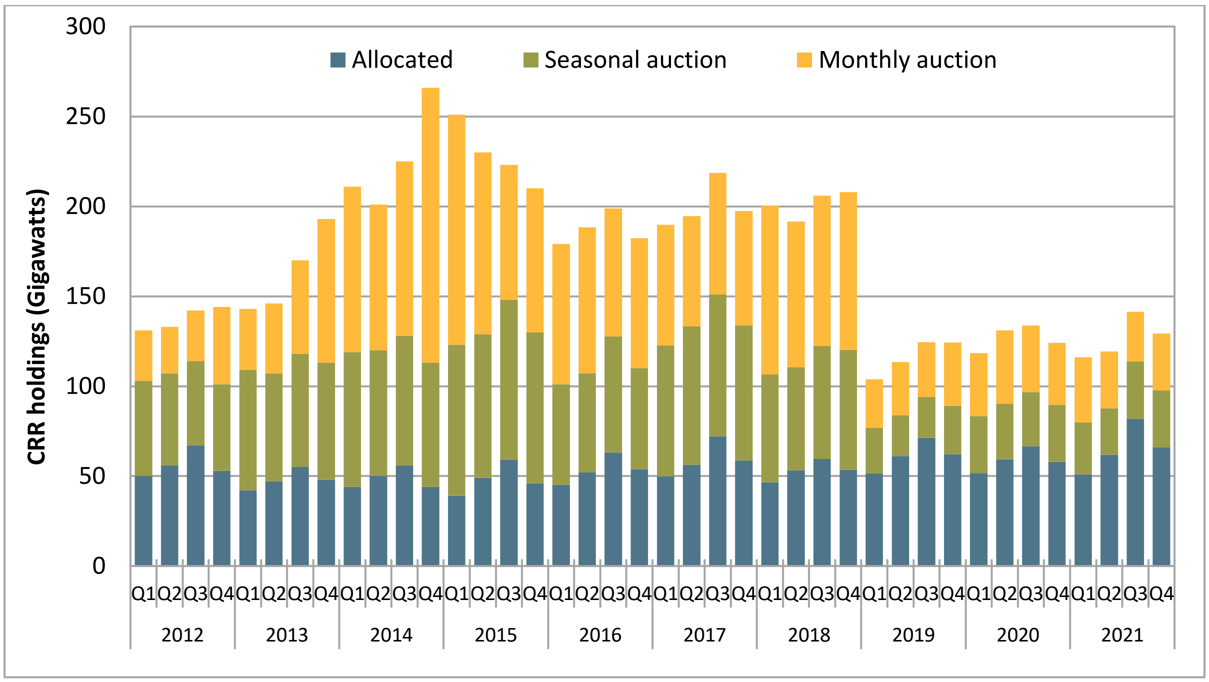
[254] California ISO, *Congestion Revenue Rights Auction Efficiency Track 1B Draft Final Proposal Second Addendum*, June 11, 2018: http://www.caiso.com/InitiativeDocuments/DraftFinalProposalSecondAddendum-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

[255] For a more detailed explanation of the congestion revenue right processes, see California ISO, *2015 Annual CRR Market Results Report*, Mar 9, 2015: http://www.caiso.com/Documents/2015AnnualCRRMarketResultsReport.pdf.

total megawatts of congestion revenue rights held is 20 MW. Total congestion revenue right megawatts do not give a complete view of the transmission rights held.

Figure 7.9 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 2021, the share of allocated congestion revenue rights was about 51 percent of the total megawatts held and auctioned rights shared were about 49 percent of the total. As shown in the figure, the change in the trend in 2019 was because of the Track 1A changes implemented, beginning in the 2019 auction, which limited allowable source and sink pairs to "delivery path" combinations.

Figure 7.9 Congestion revenue rights held by procurement type (2012 – 2021)[256]



[256] Allocated CRR holdings also include existing transmission rights (ETCs) and transmission ownership rights (TORs).

7.3.2 Congestion revenue right auction returns

The CRR auction returns compares the auction revenues that ratepayers receive for rights sold in the California ISO 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,[257] the California 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.[258]
- Track 1A – Limiting allowable source and sink pairs to "delivery path" combinations.[259]
- Track 1B – Limiting congestion revenue right payments to not exceed congestion rents actually collected from the underlying transmission constraints.[260]

DMM believes the current auction is unnecessary and could be eliminated.[261] If the California 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.

257 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.

258 California ISO, *Congestion Revenue Rights Auction Efficiency Track 1B Straw Proposal*, April 19, 2018: http://www.caiso.com/InitiativeDocuments/StrawProposal-CongestionRevenueRightsAuctionEfficiencyTrack1B.pdf

259 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

260 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

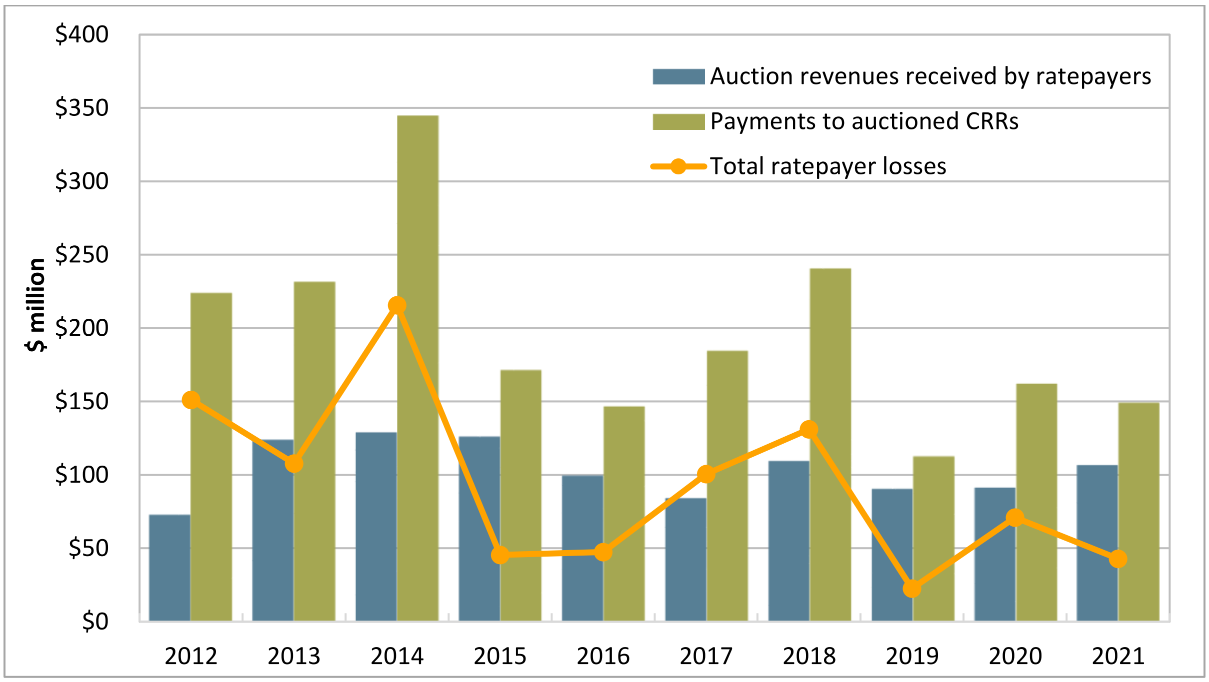
261 DMM whitepaper, *Problems in the performance and design of the congestion revenue rights auction,* November 27, 2017: http://www.caiso.com/Documents/DMMWhitePaper-Problems_Performance_Design_CongestionRevenueRightAuction-Nov27_2017.pdf

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 7.10 compares the following for each of the last several years:

- Auction revenues received by ratepayers from congestion revenue rights sold in auction (blue bars).[262]
- 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).

Figure 7.10 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 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.

262 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.

In 2021, ratepayer auctions losses were around $43 million, or about 7 percent of day-ahead market congestion rent. Ratepayers received an average of 71 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 $81 million.

In 2020, losses were around $71 million, or about 14 percent of day-ahead market congestion rent. Ratepayers received an average of 56 cents in auction revenue per dollar paid out. Track 1B revenue deficiency offsets reduced payments to auctioned rights by about $47 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 the CAISO 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 7.11 shows the estimated breakout of ratepayer auction losses by CAISO 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 CAISO 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 7.11 Estimated CRR auction loss breakout by CAISO and load serving entity

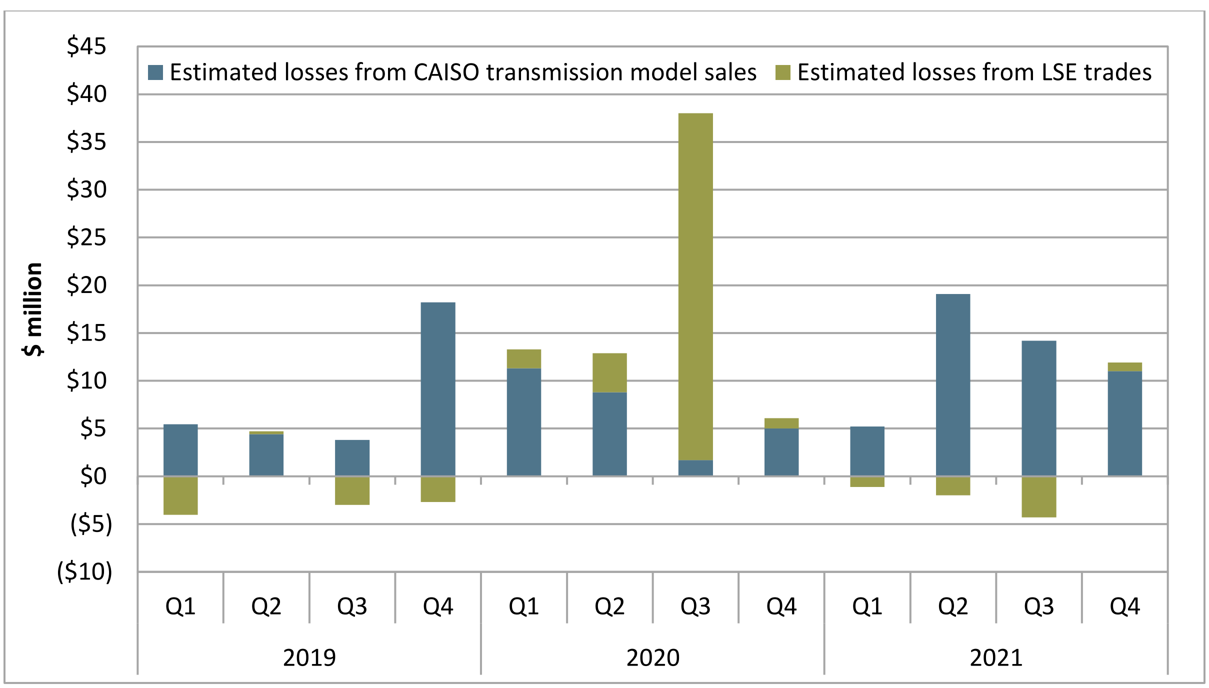


Figure 7.12 through Figure 7.14 compare the auction revenues paid for and payments received from congestion revenue rights traded in the auction by market participant type.[263] The difference between auction revenues and the payments to congestion revenue rights are the profits for the entities holding the auctioned rights. These profits are losses to ratepayers.

- Financial entities received net revenue of nearly $28 million in 2021, up from $24 million in 2020. Total revenue deficit offsets were about $46 million.
- Marketers received net revenues of nearly $6 million from auctioned rights in 2021 down significantly from $34 million in 2020. Total revenue deficit offsets were nearly $27 million.
- Physical generation entities received about $8 million in net revenue from auctioned rights in 2021 down from about $13 million in 2020. 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 2021 physical generators as a group continued to 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 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.

[263] 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 CAISO 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 CAISO markets. Balancing authority areas are participants that are balancing authority areas outside the CAISO. 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.

Figure 7.12 Auction revenues and payments (financial entities)

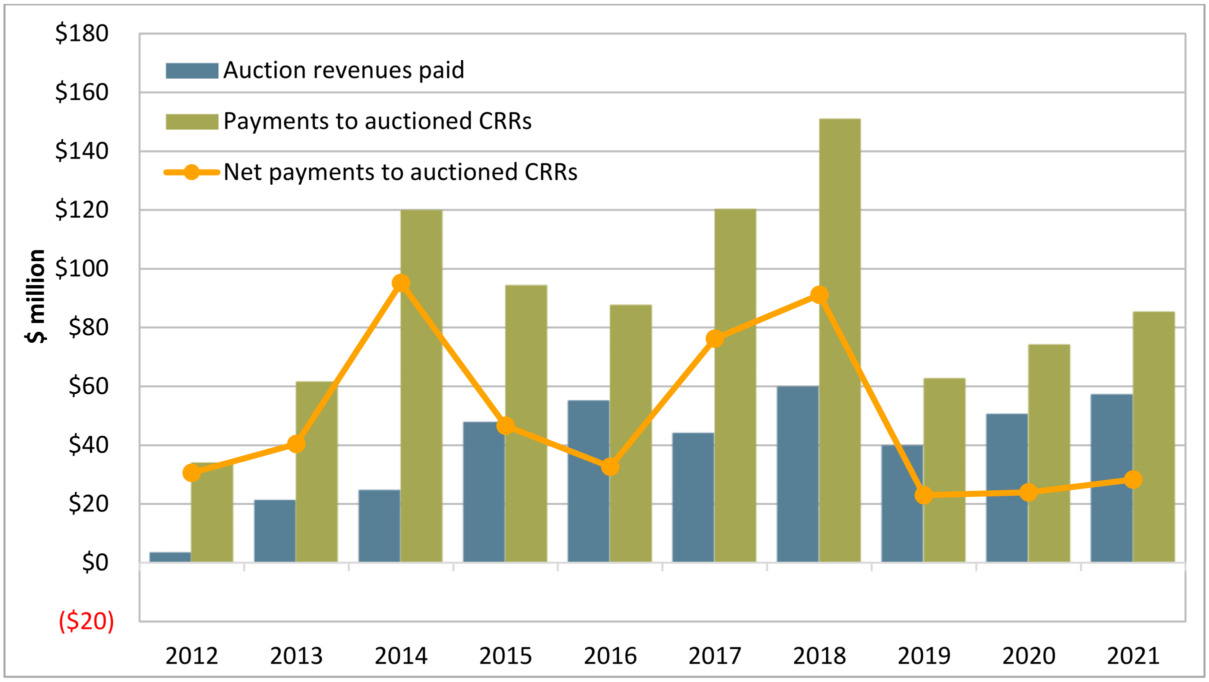


Figure 7.13 Auction revenues and payments (marketers)

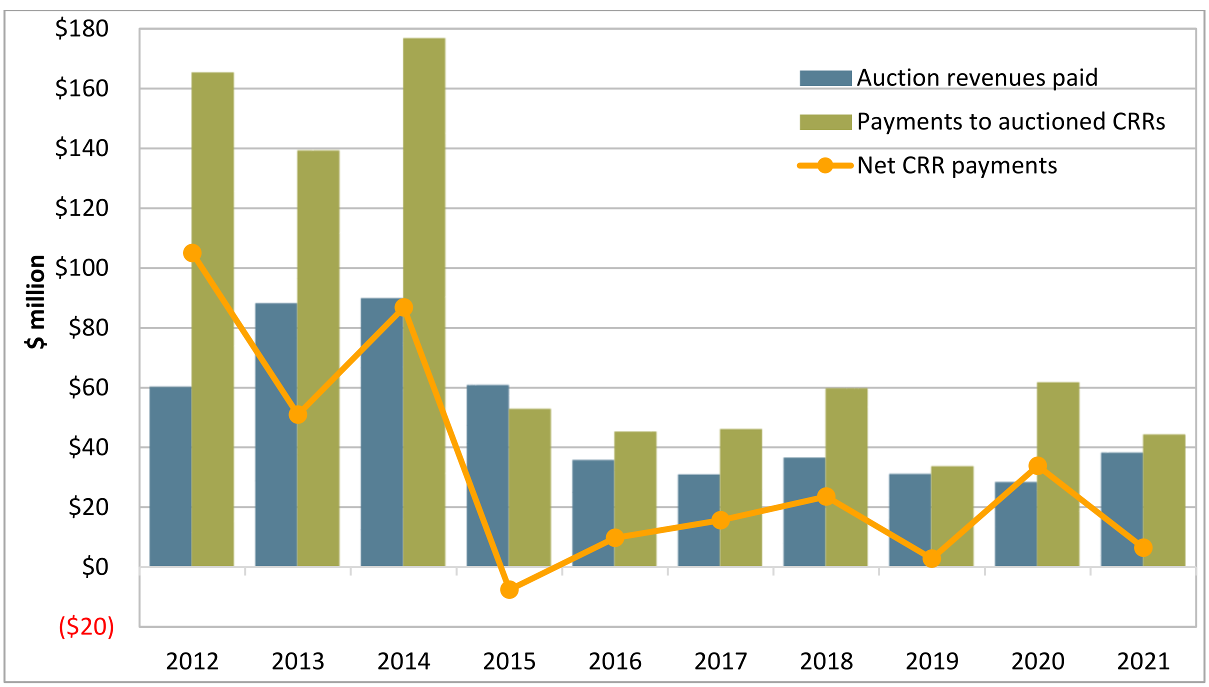
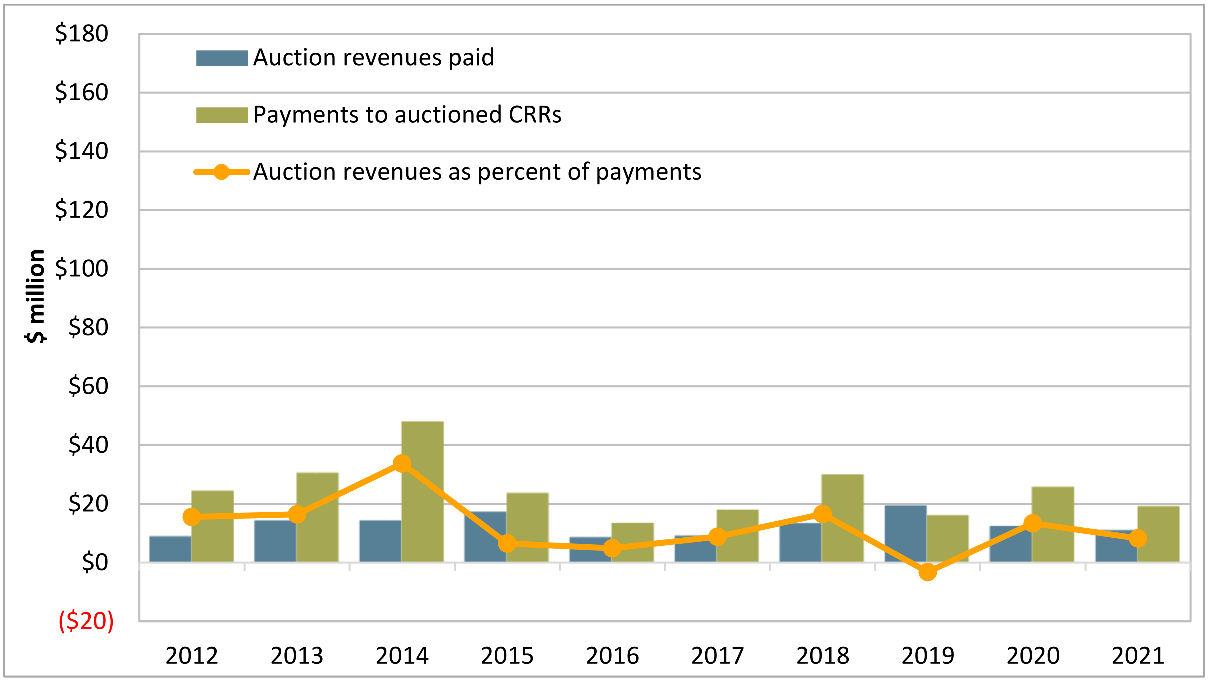


Figure 7.14 Auction revenues and payments (generators)



8 Market adjustments

Given the complexity of market models and systems, all ISOs allow operators to adjust the inputs and outputs of 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 California ISO and WEIM 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 California ISO has placed a priority on reducing market adjustments.

Findings from this chapter include the following:

- **Total energy resulting from all types of exceptional dispatch was similar to 2020** and continued to account for a relatively low portion of total system load at 0.5 percent in both 2020 and 2021. Exceptional dispatch energy above minimum load increased by approximately 6 percent in 2021 from 2020, while minimum load energy from unit commitments decreased by 11 percent.
- **Total above-market costs from exceptional dispatch increased by 73 percent to $27.4 million from $15.8 million in 2020.** The increase in natural gas prices explains much of the increase.
- **Out-of-market dispatches of both imports and emergency assistance decreased significantly, compared to 2020**. In 2021, the California ISO imported about 5,600 MWh of non-emergency assistance out-of-market dispatches on the ties, a substantial decrease from 46,000 MWh. No emergency assistance from neighboring balancing authority areas was manually dispatched in 2021.
- **California ISO operator residual unit commitment adjustments declined by 36 percent compared to 2020**. In the third quarter, the average adjustment was over 724 MW per hour compared to 1,158 MW in the same quarter in 2020. In 2021, these manual adjustments were primarily issued to address reliability concerns and load forecast errors.
- **High levels of real-time market load adjustments by the California ISO continued in the morning and evening solar ramping periods.** The maximum load adjustments in the morning ramp hovered around 1,500 MW in hour-ending 6 through 8 while the maximum evening ramp is greater than 2,000 MW in hour end 17 to 21.

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 California 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 2021, about the same as 2020.

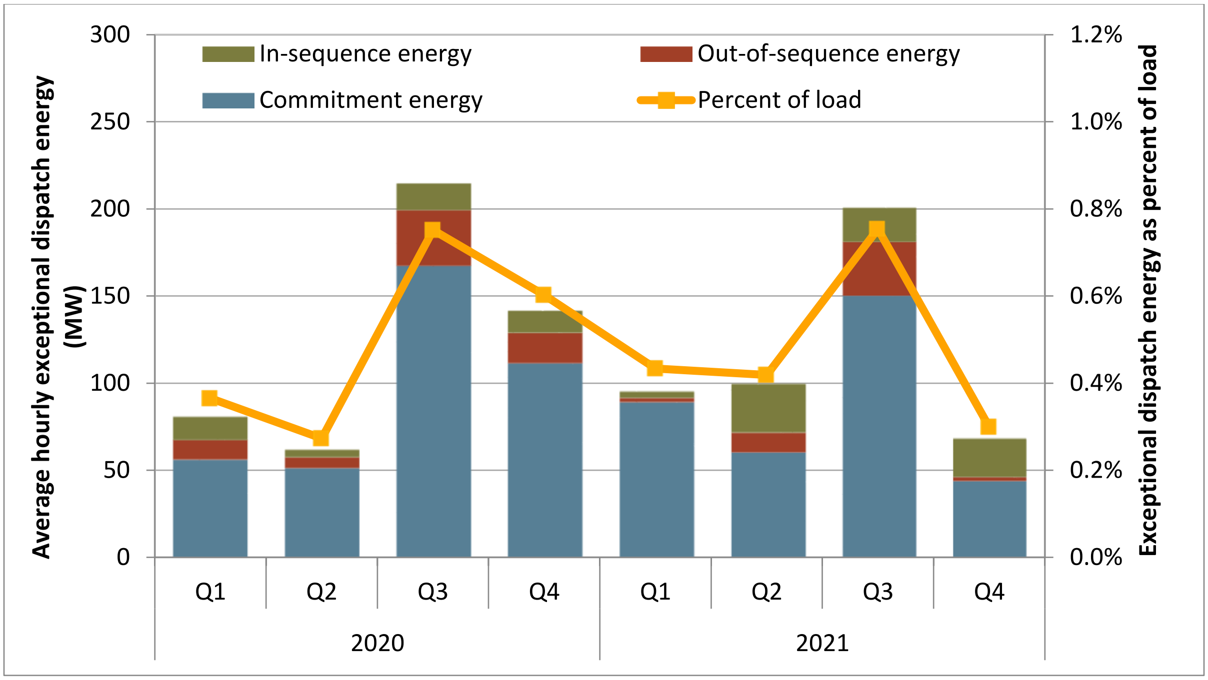
Exceptional dispatch energy above minimum load increased by approximately 6 percent in 2021 from 2020, while minimum load energy from unit commitments decreased by 11 percent. As shown in Figure 8.1, minimum load energy from units committed via exceptional dispatch accounted for 74 percent of all exceptional dispatch energy in 2021. About 10 percent of energy from exceptional dispatches was from out-of-sequence energy (to operate above minimum load), and the remaining 16 percent was from in-sequence energy.

The decrease in above minimum load energy from exceptional dispatches in 2021 is attributed to less minimum load energy exceptionally dispatched in fourth quarter than in the previous year. Additionally, the increase in above minimum load energy was due to an increase of in-sequence energy from unit testing exceptional dispatches in the second and fourth quarters. Out-of-sequence energy from exceptional dispatch decreased year over year.

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 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

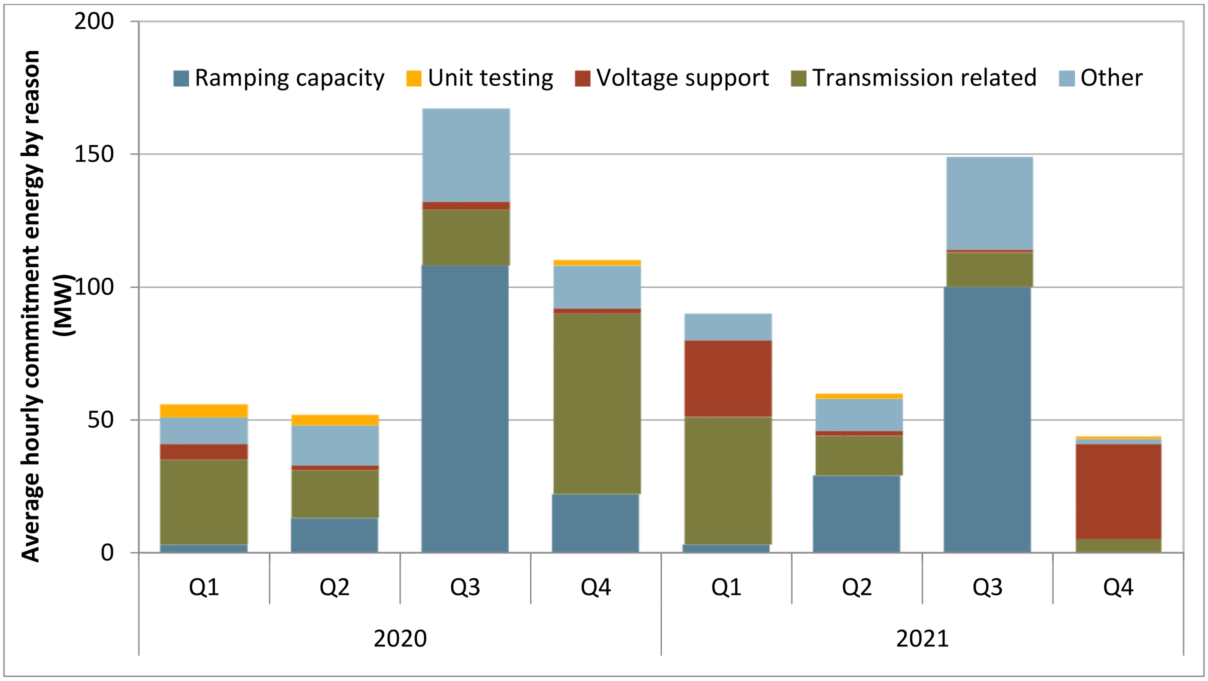


Exceptional dispatches for unit commitment

California 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 California 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 decreased slightly in 2021 compared to 2020, with most occurring in the first and third quarters of 2021. Exceptional dispatch unit commitments in the third quarter of 2021 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 first quarter, exceptional dispatch unit commitments were predominately issued for transmission related modeling limitations and to provide voltage support due to generation outages.

Figure 8.2 Average minimum load energy from exceptional dispatch unit commitments



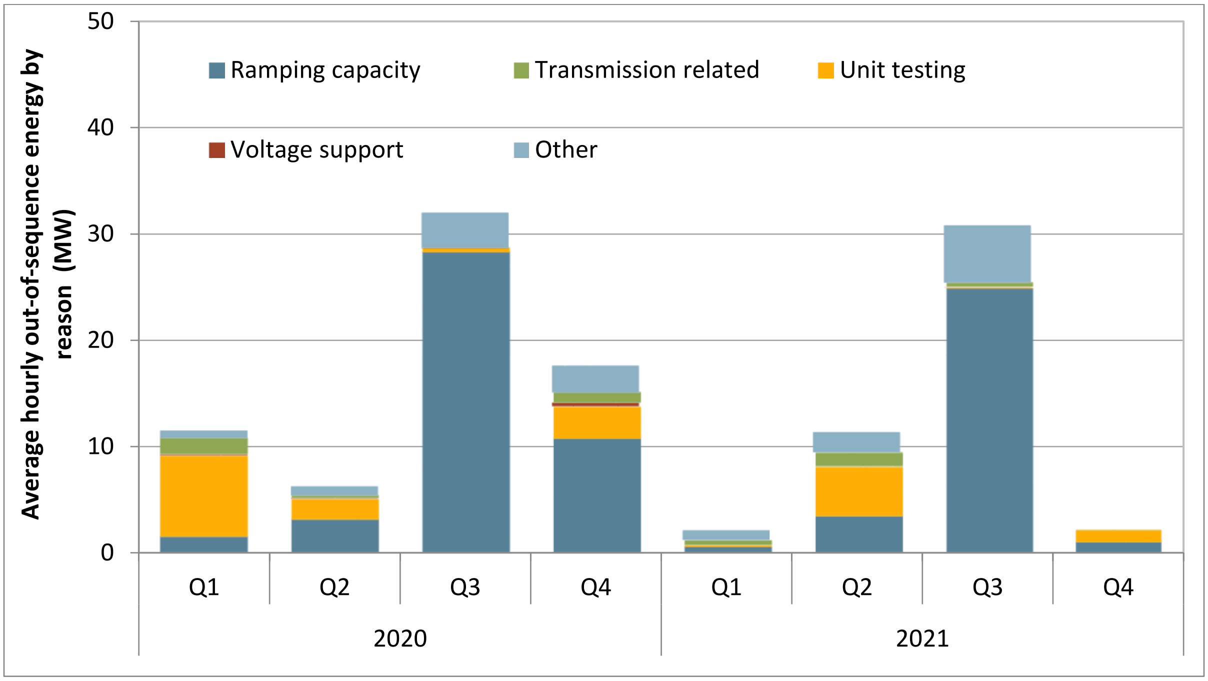
Exceptional dispatches for energy

Energy from real-time exceptional dispatches to ramp units above minimum load, or to ensure they do not operate below their regular market dispatch, increased by 6 percent in 2021. As illustrated in Figure 8.1, about 39 percent of this type of exceptional dispatch was out-of-sequence, meaning the bid price was greater than the locational market clearing price.[264] While the level of exceptional dispatch energy was similar to the previous years, the amount of exceptional dispatch for out-of-sequence energy decreased.

Figure 8.3 shows the change in out-of-sequence exceptional dispatch energy by quarter for 2020 and 2021. 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.

[264] 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

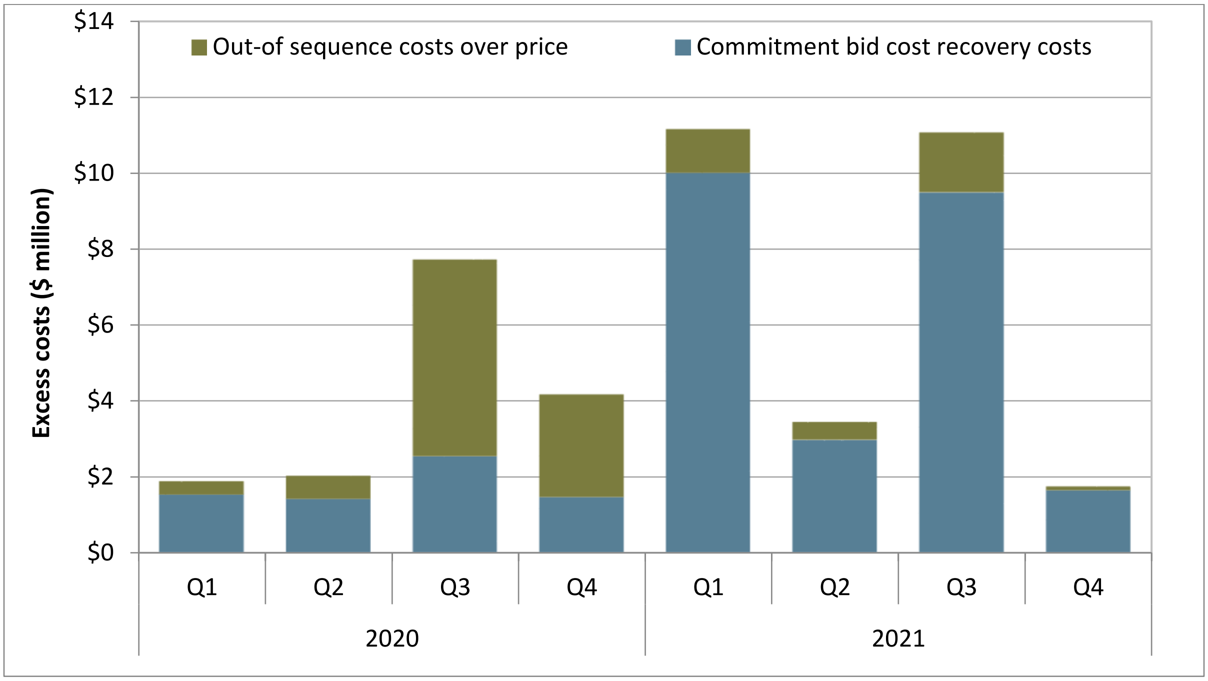
Exceptional dispatches can create two types of additional costs not recovered through the market clearing price of energy.

- 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 increased from $6.9 million to $24 million and out-of-sequence energy costs decreased from $8.8 million to $3.3 million in 2021.[265] Total above-market costs increased by 73 percent to about $27.4 million in 2021 from $15.8 million in 2020. As discussed above, the total amount of exceptional dispatch energy was similar to the previous year. However, the increase in total excess costs from exceptional dispatch can largely be attributed to higher natural gas prices in California—particularly in the first and third quarter.

[265] 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 California ISO operators when the market optimization is not able to address a particular reliability requirement or constraint. Energy dispatches issued by the California ISO operators are sometimes referred to as manual or out-of-market dispatches. During periods of extreme temperature and energy demand, the California ISO may call upon neighboring balancing authority areas to provide emergency assistance on the interties in the real-time markets.

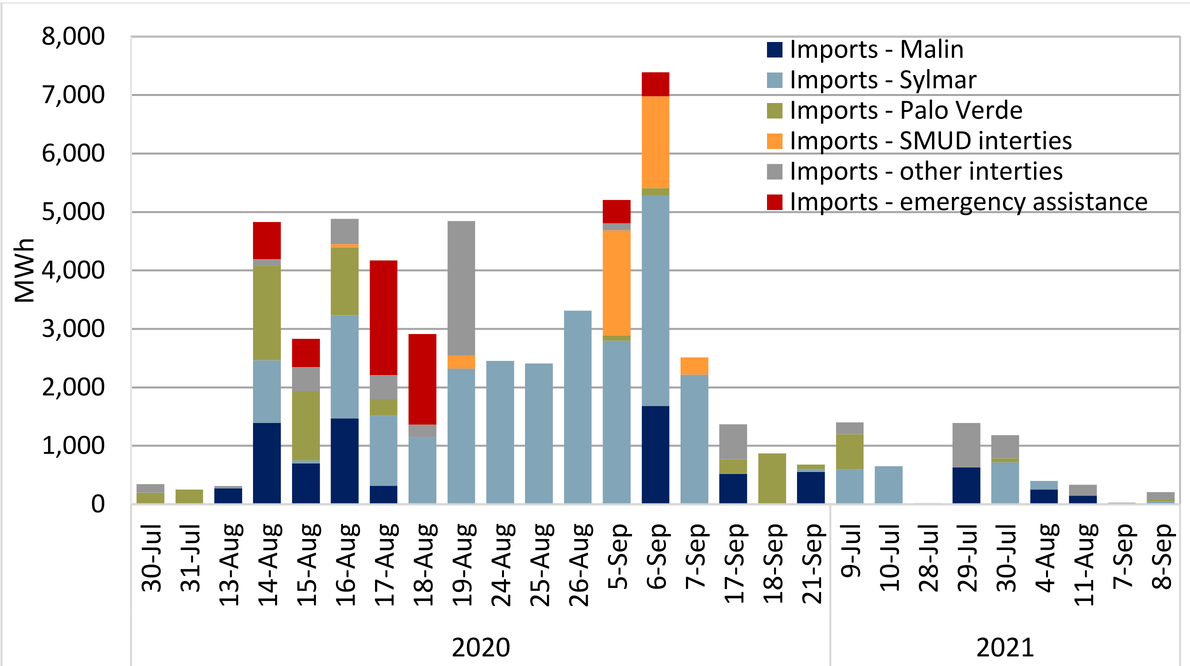
Figure 8.5 shows the total hourly megawatts from all manual dispatch and emergency assistance over the past two years. Imports coming from emergency assistance reflect energy imported from balancing authority areas with whom the California ISO has contractual agreements during emergency conditions. All other manual dispatches reflect energy from offers made by the California 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'.[266]

Out-of-market dispatches of both imports and emergency assistance decreased substantially from 2020 to 2021. In 2021, the CAISO imported about 5,600 MWh of non-emergency assistance out-of-market dispatches on the ties, a large decrease from about 46,000 MWh in 2020. Nearly 6,000 MWh of

266 For additional details on manual dispatch types and prices paid for out-of-market imports, see Department of Market Monitoring, *2019 Annual Report on Market Issues and* Performance, June 2020, pp. 206-207: http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf

emergency assistance was received from neighboring balancing authority areas in 2020, while there was no emergency assistance was imported in to the California ISO in 2021.

Figure 8.5 Manual dispatch and emergency assistance on CAISO interties (July-September)



Western Energy Imbalance Market

Western Energy Imbalance Market areas sometimes need to dispatch resources out-of-market for reliability, to manage transmission constraints, or for other reasons. In the market, manual dispatches are similar to exceptional dispatches in the California ISO. Manual dispatches within the WEIM are not issued by the CAISO and can only be issued by a WEIM entity for their respective balancing authority area. Manual dispatches may be issued for both participating and non-participating resources.

Like exceptional dispatches in the CAISO system, manual dispatches in the WEIM do not set prices, and the reasons for these manual dispatches are similar to those given for the CAISO exceptional dispatches. However, manual dispatches in the WEIM are not settled in the same manner as exceptional dispatches within the CAISO. Energy from these manual dispatches is settled on the market clearing price, similar to uninstructed energy. This eliminates the possibility of exercising market power either by setting prices or by being paid “as-bid” at above-market prices.

Figure 8.6 through Figure 8.8 summarize monthly manual dispatch activity of participating and non-participating resources for WEIM areas with incremental or decremental volume above 10 MW in any month. The volume of manual dispatches in WEIM areas can peak in the first few months that a new market participant is active in the market, such as Public Service Company of New Mexico balancing area in 2021.

Figure 8.6 WEIM manual dispatches – Arizona Public Service area

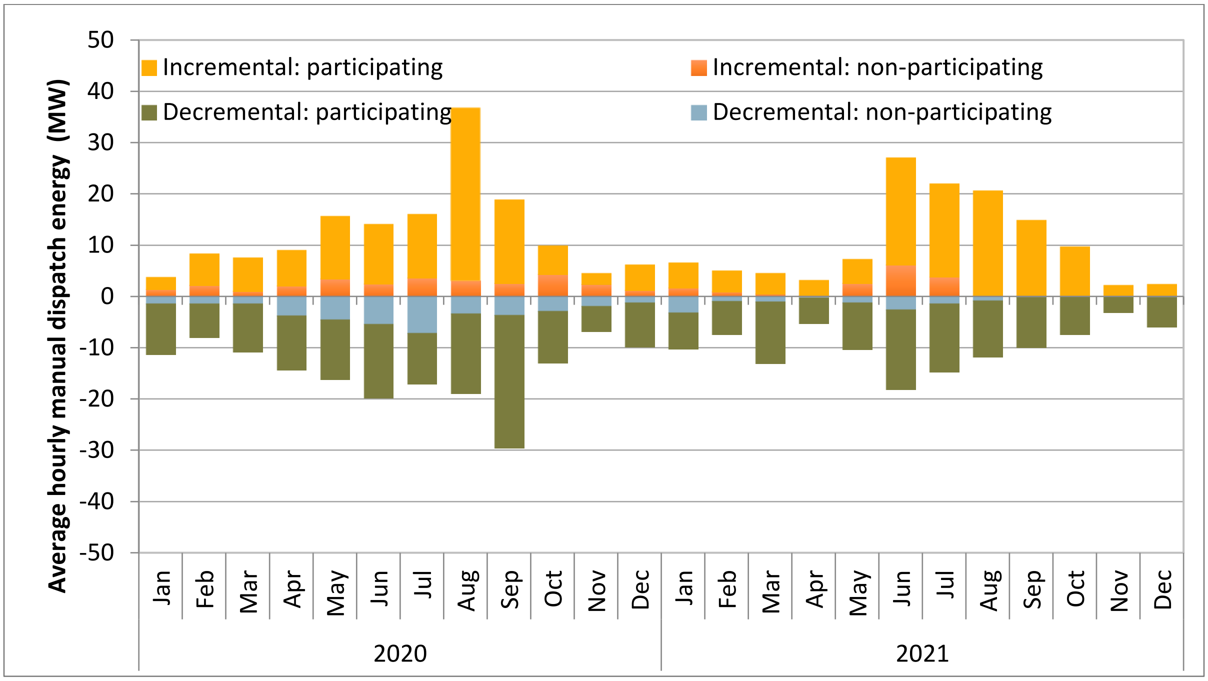


Figure 8.7 WEIM manual dispatches – Salt River Project area

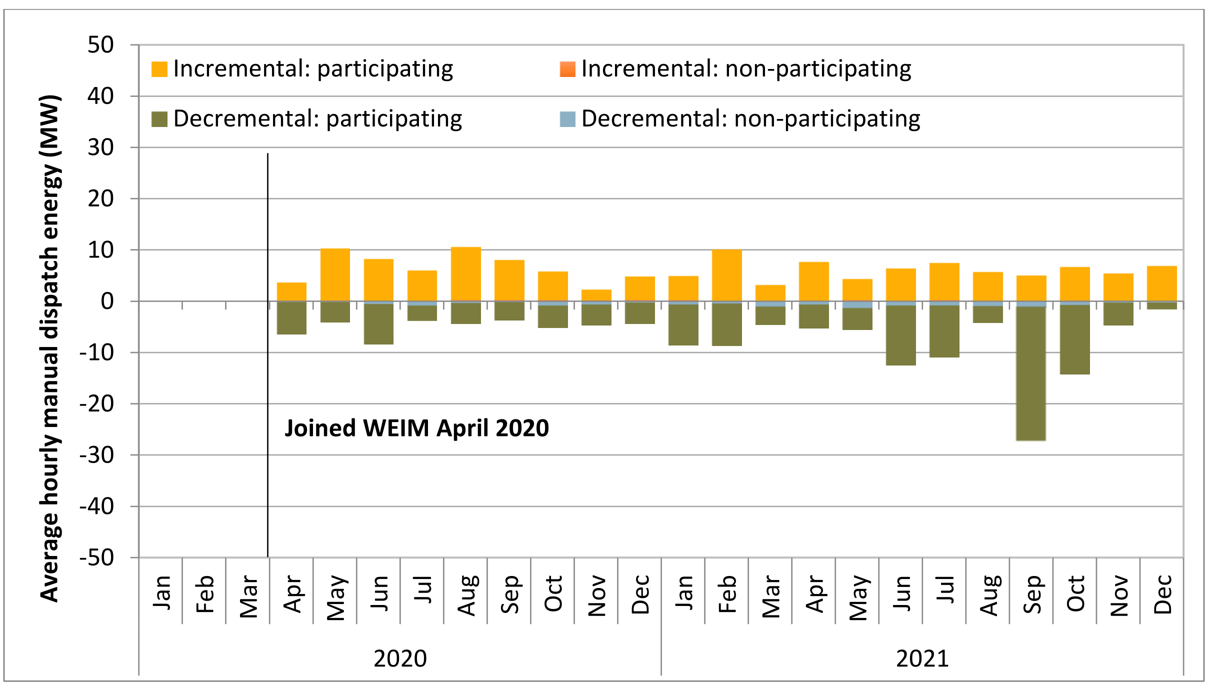
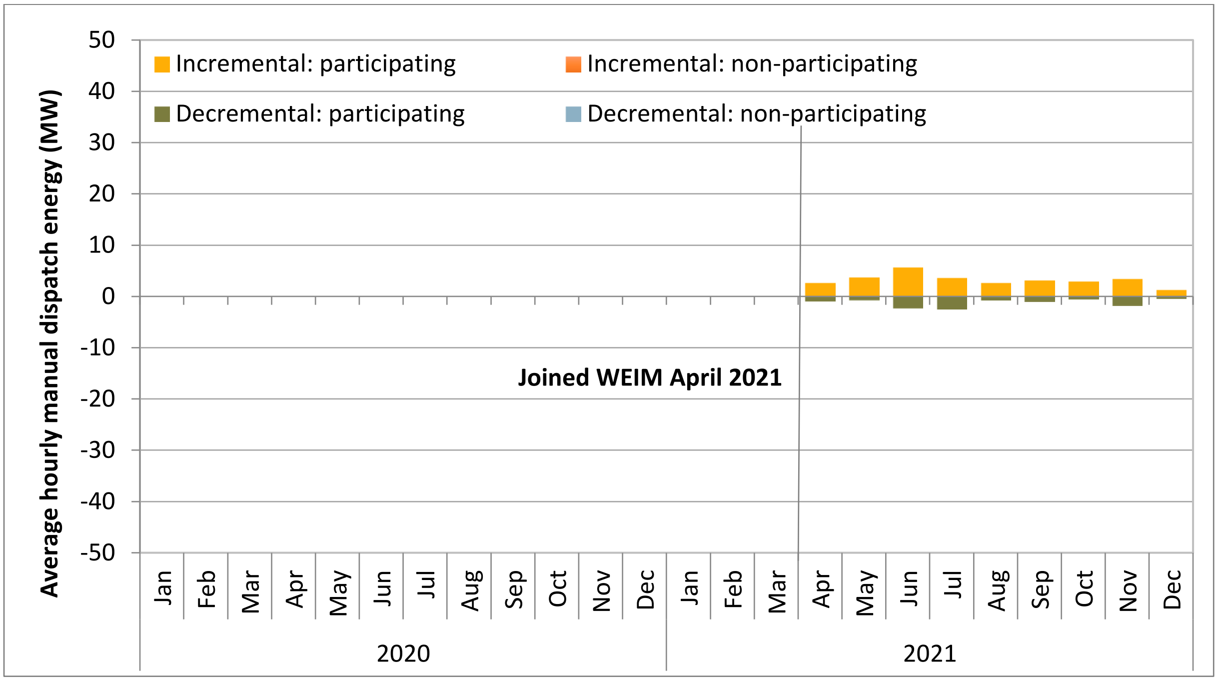


Figure 8.8 WEIM manual dispatches – Public Service Company of New Mexico area



8.3 Residual unit commitment adjustments

The quantity of residual unit commitment procured is determined by several automatically calculated components, as well as any manual adjustment that operators make to increase residual unit commitment requirements for reliability purposes. In 2021, these operator adjustments declined by 36 percent compared to 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 process is run immediately after the integrated forward market (IFM) is ran for 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 2020 and 2021.

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 2021, 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 increased from 555 MW in 2020 to 870 MW in 2021.

California 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 234 MW per hour to requirements, a decrease from about 372 MW per hour in 2020. The figure also shows that these adjustments were most frequent during the third quarter. Figure 8.11

shows the hourly distribution of these operator adjustments during the third quarter of 2021. The black line shows the average adjustment quantity in each hour and the red markers highlight outliers in each hour. The operators used this tool on 82 days in the third quarter out of total 130 days in 2021. Although the frequency of these adjustments increased, the magnitude decreased by 38 percent relative to the third quarter in 2020. 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 CAISO day-ahead load forecast. This difference decreased residual unit commitment requirements by 25 MW on a yearly average basis in 2021. This was a significant shift from 2020 during which this factor contributed to an average increase of 370 MW to residual unit commitment requirements.

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

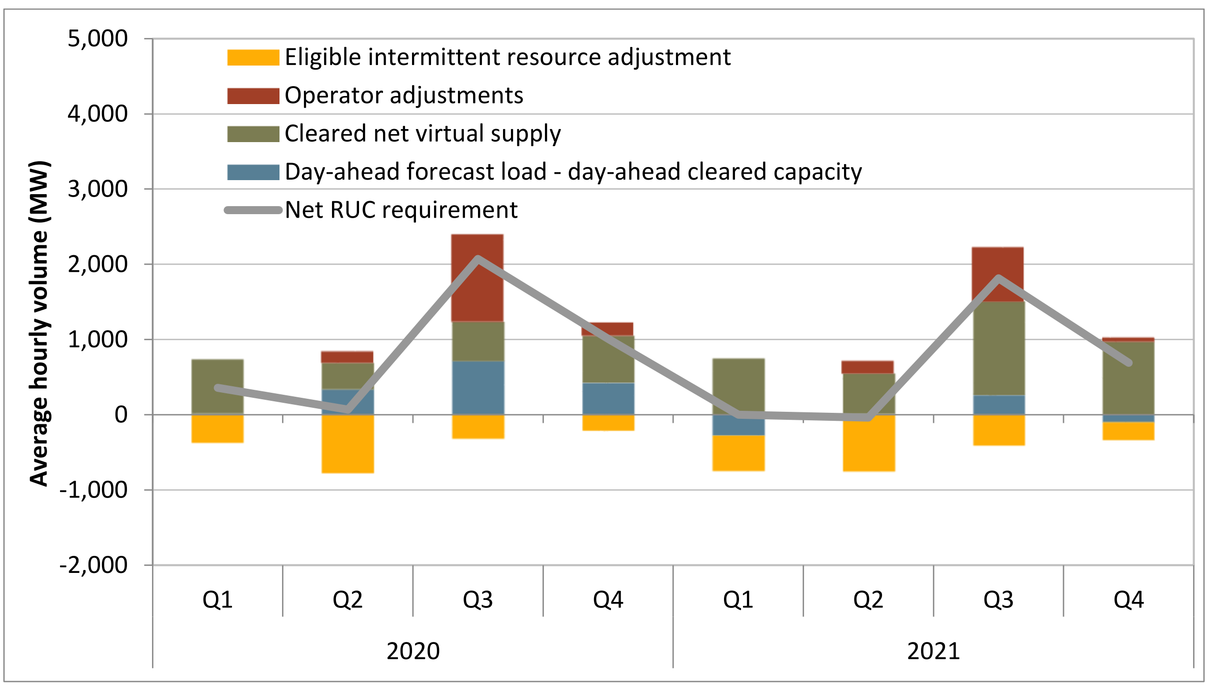


Figure 8.10 shows these same four determinants of the residual unit commitment requirements for 2021 for each operating hour of the day. As shown by the red bars in Figure 8.10, manual adjustments by grid operators tended to be greatest between the peak load hours ending 9 through 22. During the third quarter of 2021, operators increased the residual unit commitment requirement by about 1,158 MW on average for hours ending 9 through 23.

While 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 9 through 17 in 2021. Similar to 2020, 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 (2021)

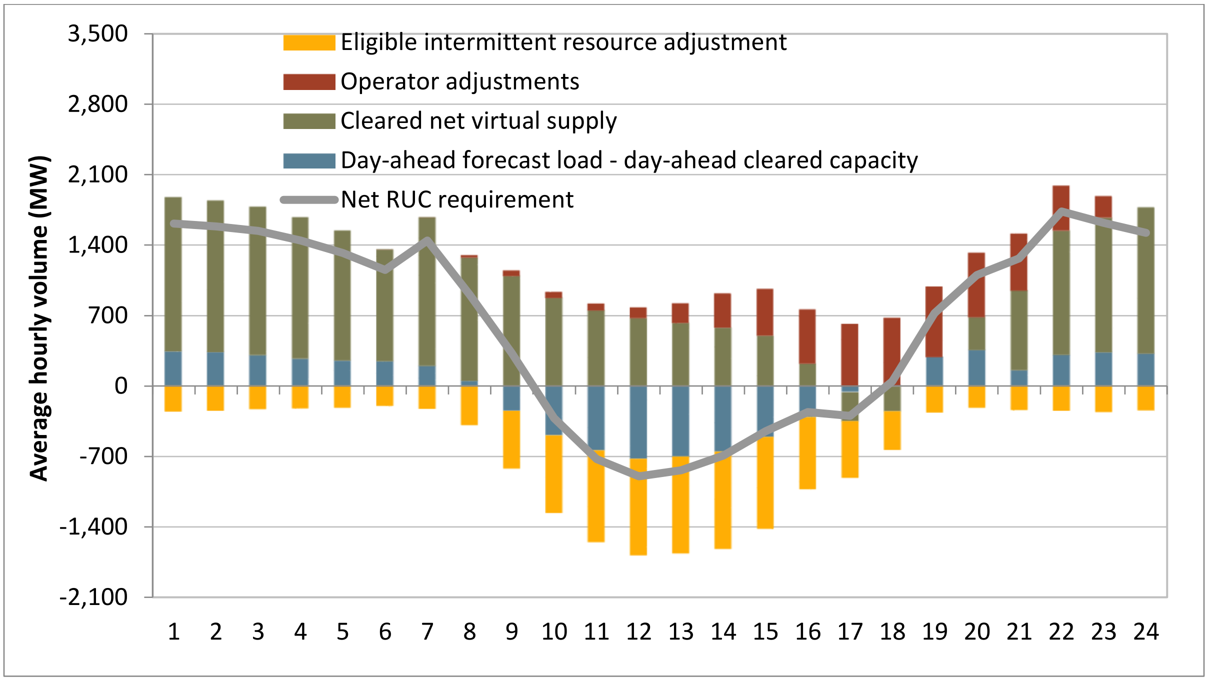
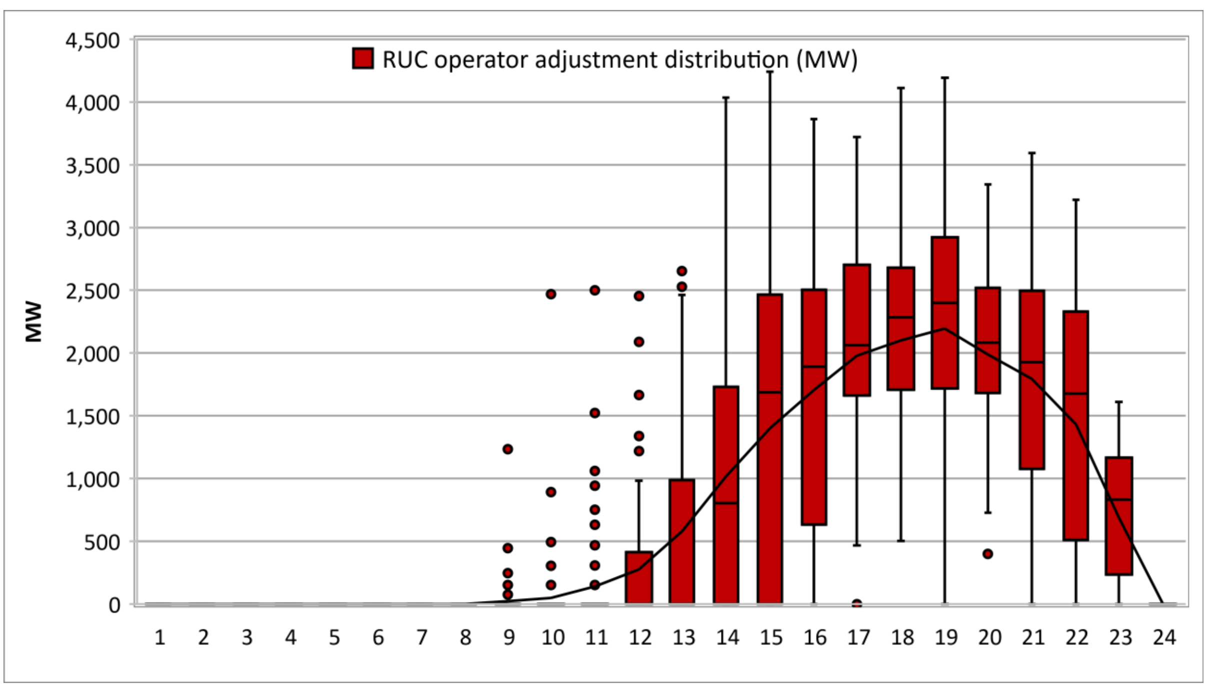


Figure 8.11 Hourly distribution of residual unit commitment operator adjustments (Jul – Sep)



8.4 Real-time imbalance conformance

Load forecast adjustments

Operators in the California ISO and Western 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 CAISO uses the term *imbalance conformance* to describe these adjustments. Load forecast adjustments can be used to account for potential modeling inconsistencies and inaccuracies.

In the CAISO, load adjustments are routinely used in the hour-ahead and 15-minute scheduling processes to increase the supply of ramping capacity within the CAISO during morning and evening hours when net loads increase sharply. Increasing the hour-ahead and 15-minute forecast can increase ramping capacity within the CAISO by increasing hourly imports and committing additional units. The California ISO performed a counterfactual analysis showing that load adjustments led to additional hour-ahead imports, WEIM transfers, and additional internal generation.[267]

Real-time market load adjustments by the California 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 California ISO hour-ahead and 15-minute markets. This trend continued in 2021, with average hourly load adjustments in the hour-ahead and 15-minute markets peaking at almost 1,250 MW, almost a three-fold increase from the 2016 peak of 460 MW.

Figure 8.12 shows the average hourly load adjustment profile for the hour-ahead and 5-minute markets for 2019 to 2021.[268] As in prior years, the general shape and direction of load adjustments were similar for hour-ahead and 15-minute adjustments. However, the 2021 morning adjustments dropped from the 2019 maximum level of about 550 MW to close to the prior year level of 380 MW. As shown in Figure 8.12, average hour-ahead load forecast adjustments in 2021 mirror the pattern of net loads over the course of the day, averaging nearly 370 MW over the entire day with a maximum of about 400 MW in the morning ramp hours and nearly 1,250 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 2021, the 5-minute market more closely resembles the shape of 2020 with little adjustment prior to early morning ramp and after the evening ramp. However, greater negative adjustments occurred just after the morning peak and were slightly less positive just prior to the 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 1,000 MW.

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[267] California ISO, Market Analysis and Forecasting, *WEIM Transfers, Hourly Interties and Load Conformance*, June 21, 2022. http://www.caiso.com/InitiativeDocuments/FinalAnalysisReport-WEIMTransfers-HourlyInterties-Load.pdf

[268] 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.

Figure 8.13 shows the distribution of the 15-minute market imbalance conformance into quartiles for the load adjustment profile for 2021. This box and whisker plot highlights the minimum, maximum and the median, as well as the mean (line). The maximum load adjustments in the morning ramp hover around 1,500 MW in hour-ending 6 through 8 while the maximum evening ramp is greater than 2,000 MW in hour-ending 17 to 21.

Figure 8.12 Average hourly load adjustment (2019 - 2021)

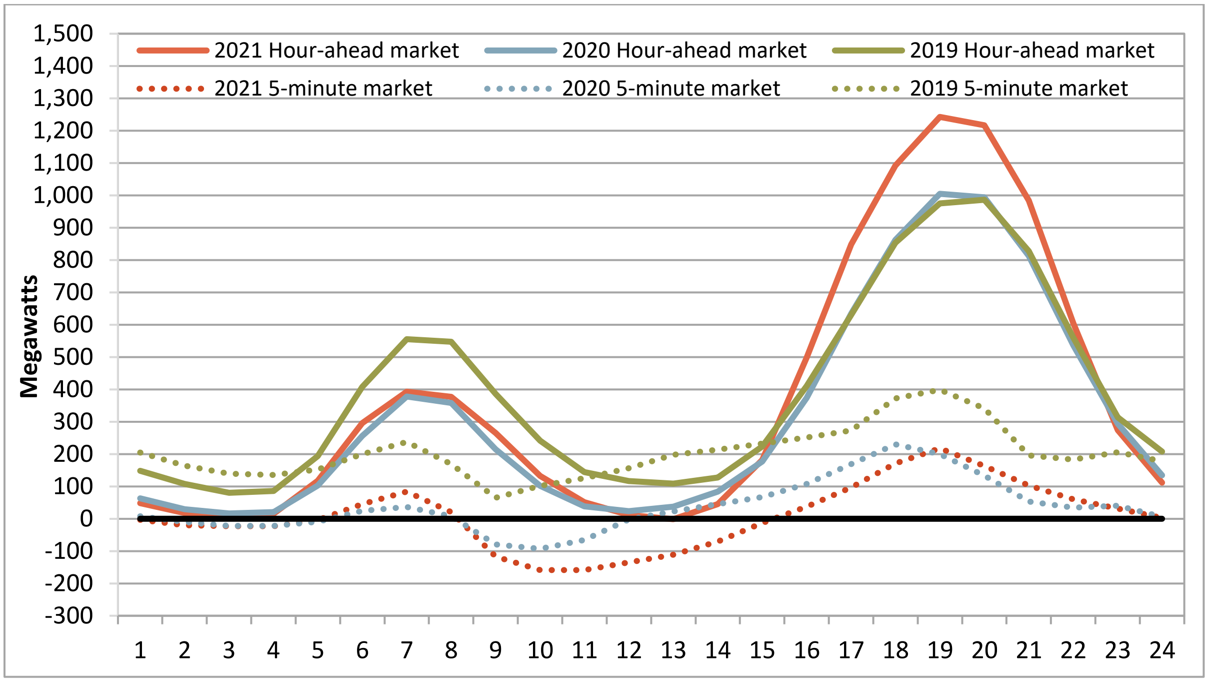
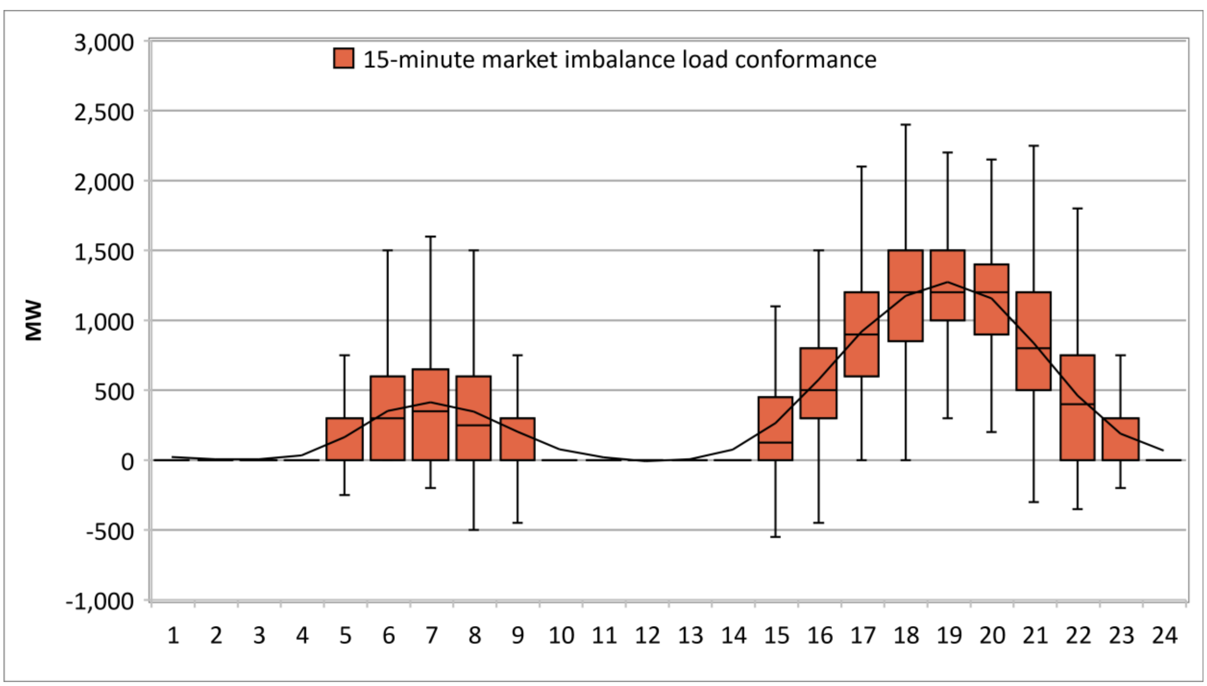


Figure 8.13 15-minute market hourly distribution of operator load adjustments (2021)



Adjustments are often associated with over- or under-forecasted load, changes in expected renewable generation, and morning or evening net load ramp periods. The CAISO also adjusts loads in the 15-minute and 5-minute real-time markets to account for potential modeling inconsistencies. Some of these inconsistencies are due to changing system and market conditions, such as changes in load and supply (e.g., exceptional dispatches), between the executions of different real-time markets.[269] Operators have listed multiple reasons for use of load adjustments including managing load and generation deviations, automatic time error correction, scheduled interchange variation, reliability events, and software issues.

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 CAISO 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 CAISO during the morning and evening ramping hours.

The impact of the hour-ahead load bias on real-time imports is reflected in Figure 8.14, which shows the incremental change in gross and net imports in the real-time market. The light green area in Figure 8.14 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.

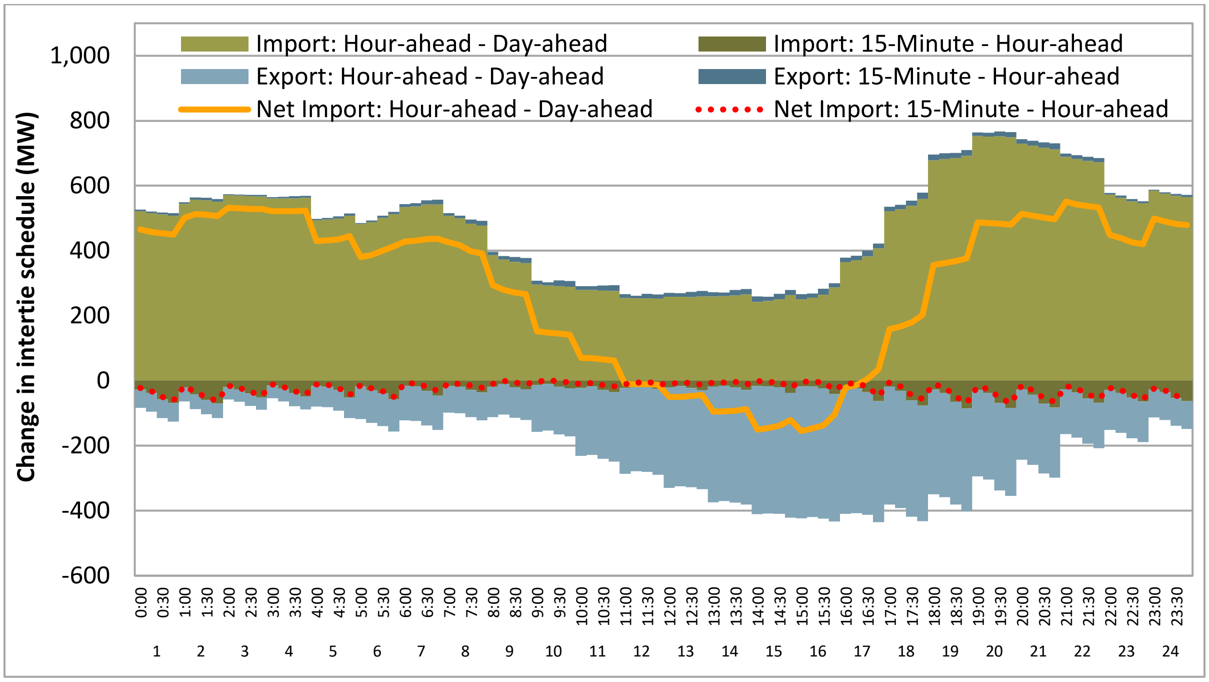
The yellow line in Figure 8.14 shows the change in net interchange, summing the effects of increased imports and exports. The red dotted line represents the change in net interchange between the 15-minute and hour-ahead markets and is the sum of incremental decreases in imports (dark green) and exports (dark blue). These are lower values relative to the changes observed between the day-ahead and the hour-ahead.

As shown in Figure 8.14, 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 2021, net interchange averaged about 390 MW, an increase from an average of 380 MW during these hours in 2020. Similar to 2020, the highest average net interchange was in hours ending 19 to 22, reaching a peak of 550 MW in hour ending 22.

As with the previous year, there was a noticeable increase in both imports and exports in 2021 between the hour-ahead and day-ahead markets during mid-day solar peak periods. Net imports fell between the day-ahead and hour-ahead markets in these hours, similar to prior years. This appears to be associated with re-bidding 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.

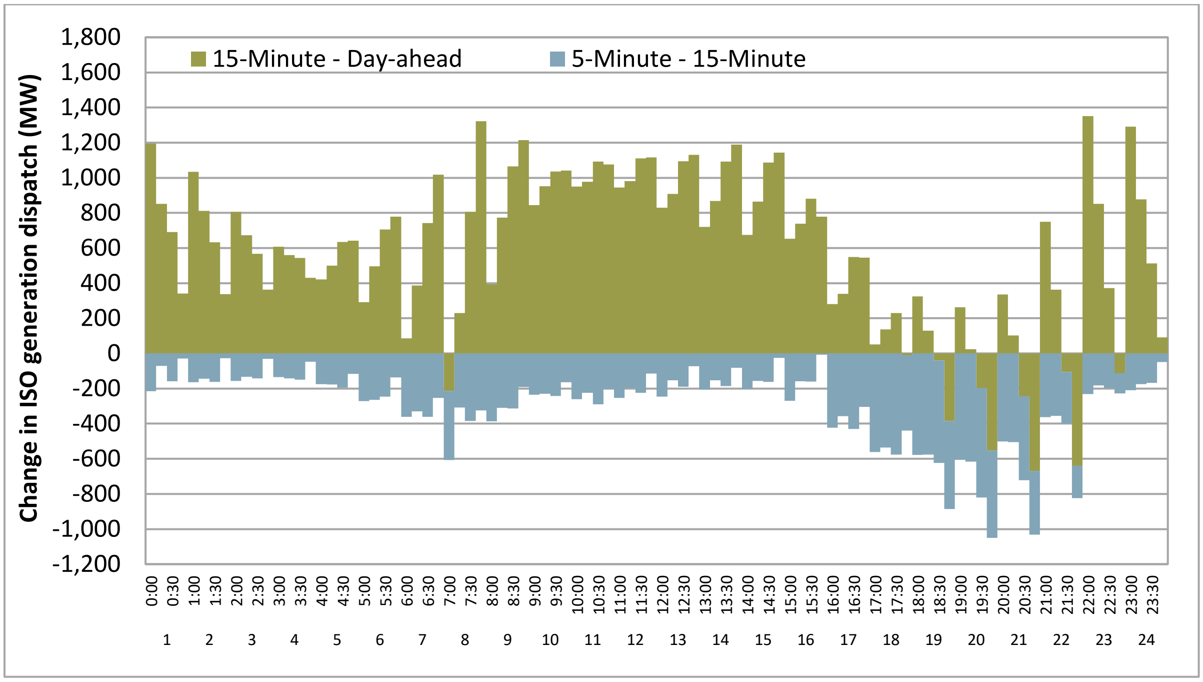
269 FERC Docket No. ER15-861-006; *153 FERC ¶ 61,305 Order on Compliance Filing*, December 17, 2015: http://www.caiso.com/Documents/Dec17_2015_OrderAcceptingComplianceFiling_AvailableBalancingCapacity_ER15-861-006.pdf

Figure 8.14 Net interchange dispatch volume



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 8.15 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 CAISO tends to offset the increases in energy imports in the hour-ahead market as shown in Figure 8.14.

Figure 8.15 Imbalance generation dispatch volume



Load adjustments in the Western Energy Imbalance Market

Western Energy Imbalance Market operators can also make load adjustments in their respective balancing areas.[270] The frequency of positive and negative load forecast adjustments for the 15-minute and 5-minute markets are shown in Figure 8.16 through Figure 8.19.

For much of the year, in the 15-minute market, positive and negative load adjustments were most frequent in NorthWestern Energy, Arizona Public Service, and Puget Sound Energy. 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.

[270] Average frequency of load adjustments for new WEIM market participants between March 25-31, 2021, are identified on the graphs as Q1. These are Turlock Irrigation District; BANC comprised of Modesto Irrigation District, the City of Redding, the City of Roseville; and the Western Area Power Administration – Sierra Nevada Region. NorthWestern Energy data for June 16-30, 2021, are identified as Q2 in the graphs. The Los Angeles Department of Water and Power and the Public Service Company of New Mexico joined on April 1, 2021 and are included starting with Q2 on the graphs.

Figure 8.16 Average frequency of positive and negative load adjustments: 2021 WEIM – North (15-minute market)

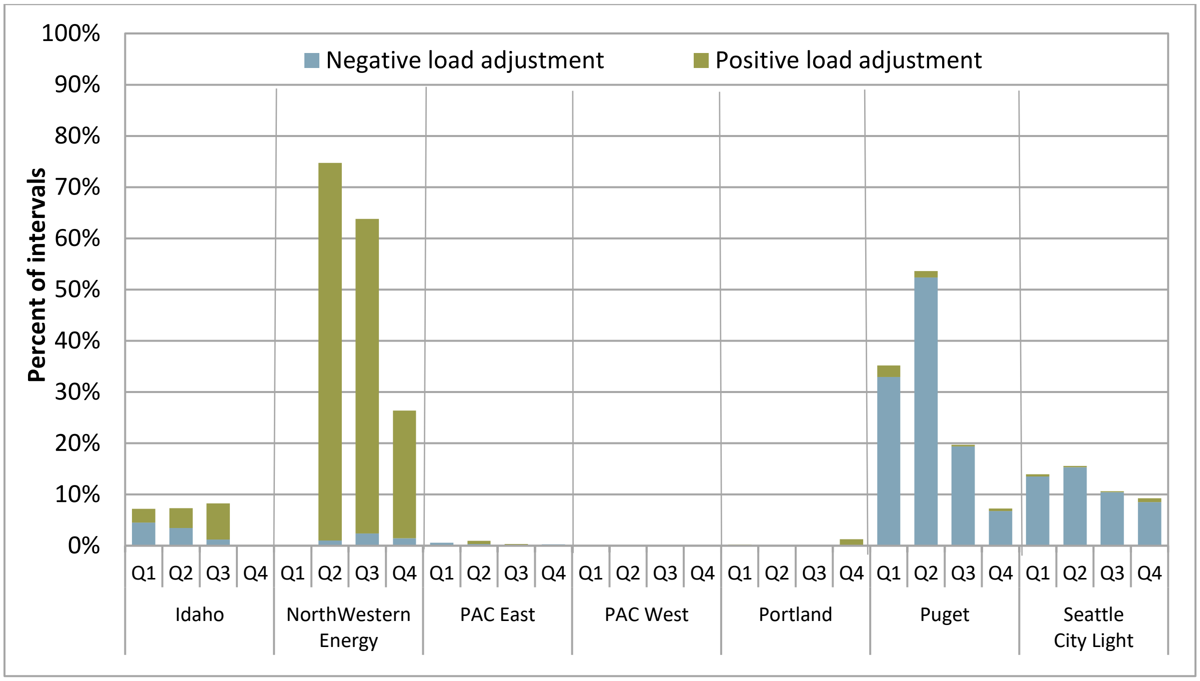


Figure 8.17 Average frequency of positive and negative load adjustments: 2021 WEIM East and within California (15-minute market)

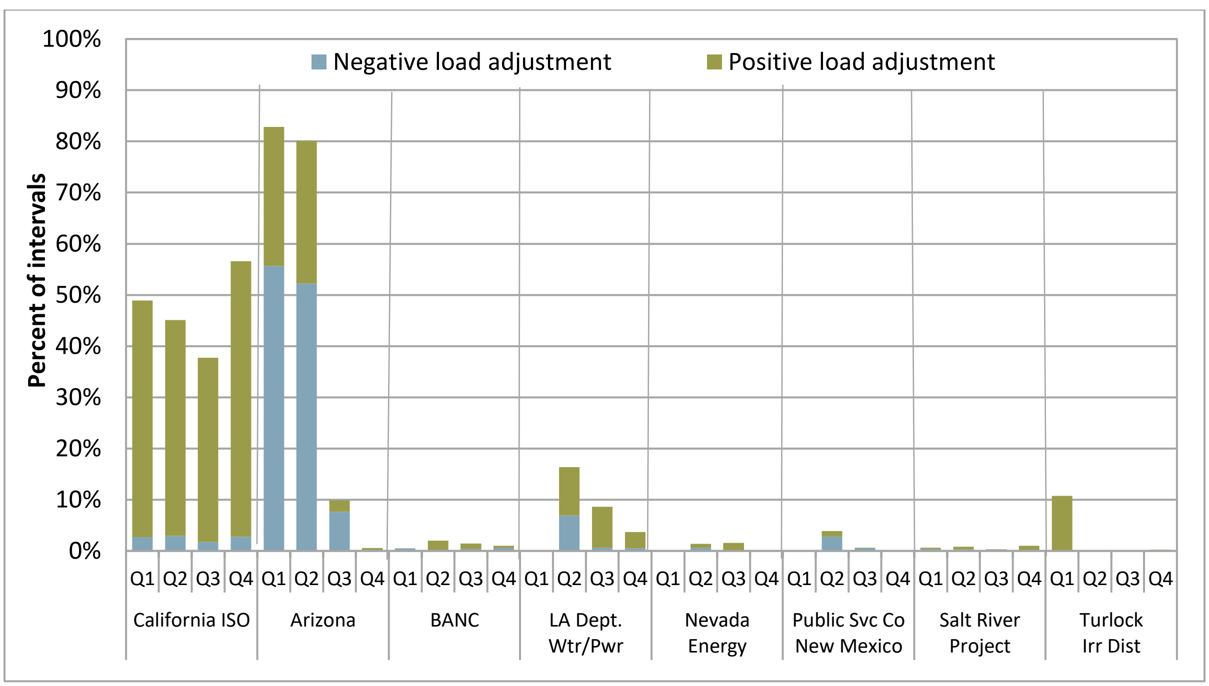


Figure 8.18 Average frequency of positive and negative load adjustments: 2021 WEIM – North (5-minute market)

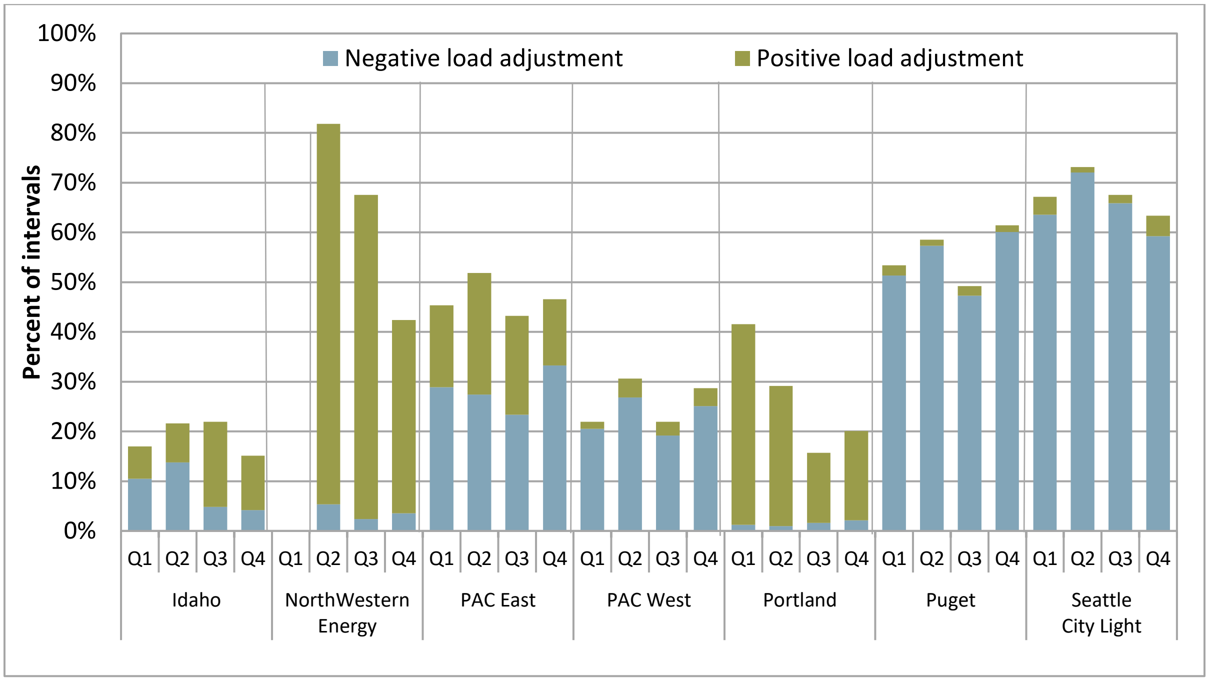
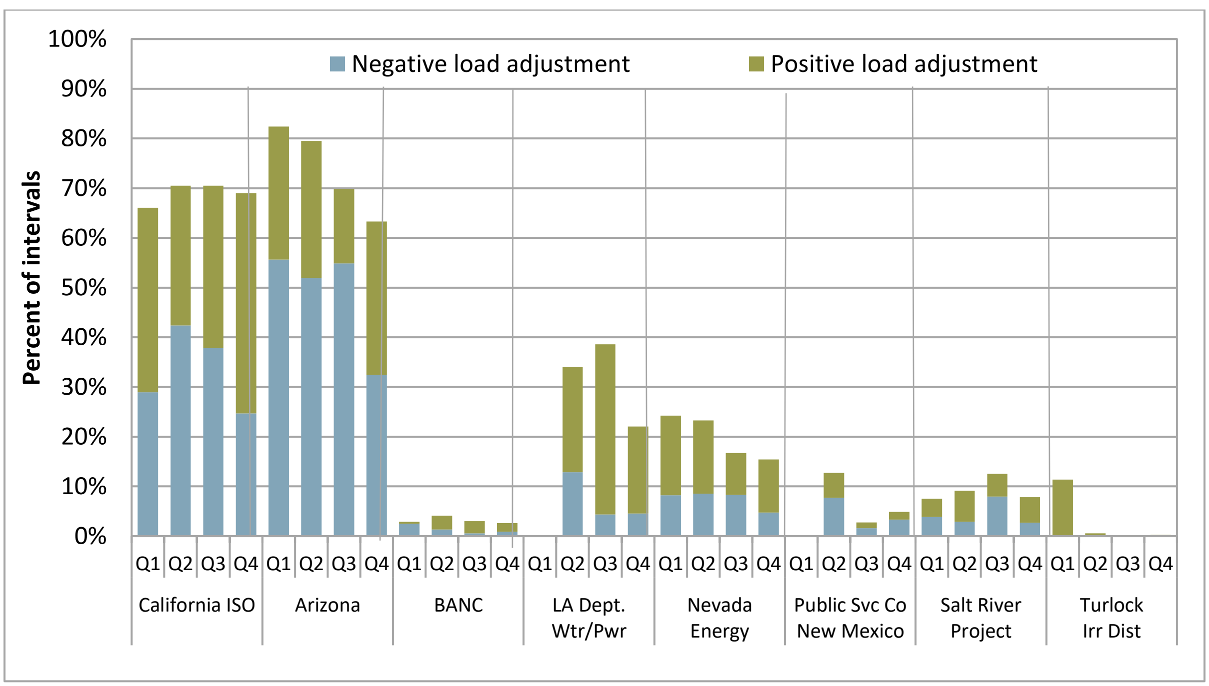


Figure 8.19 Average frequency of positive and negative load adjustments: 2021 WEIM East and within California (5-minute market)



8.5 Blocked instructions and dispatches

Instruction types and reasons

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.[271] 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 California ISO software has problems with dispatching pumped storage units as the model does not reflect all of its operational characteristics.

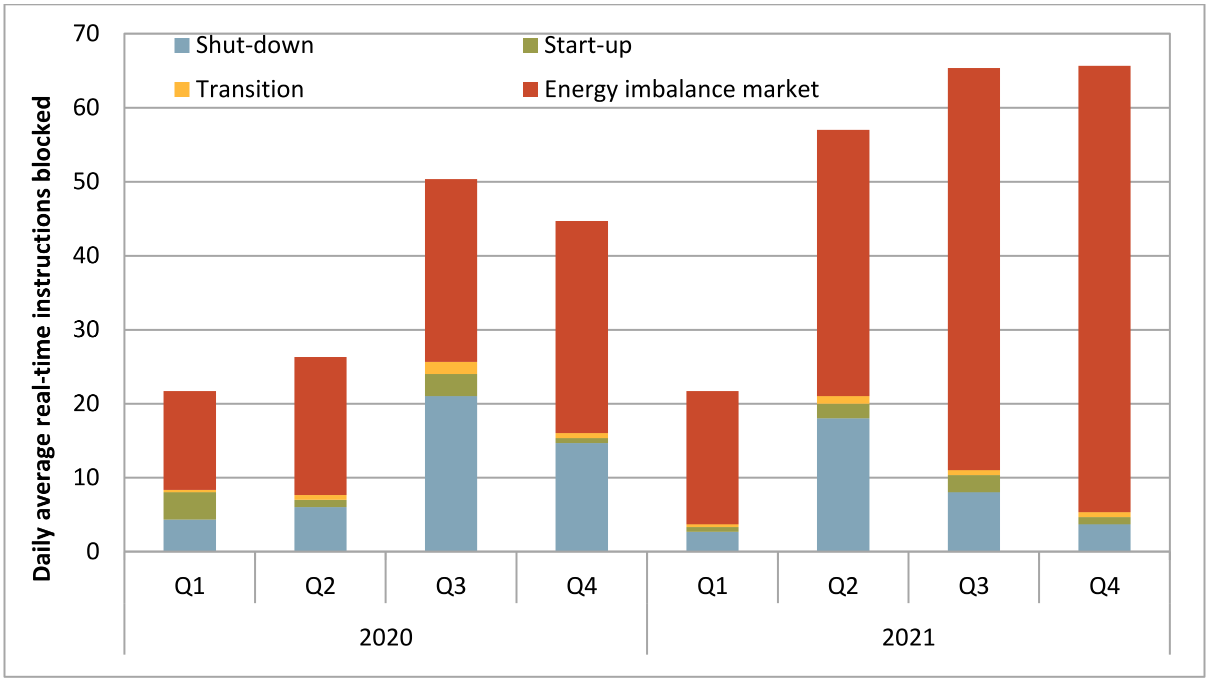
- **Information systems and processes.** In some cases, problems occur in the complex combination of information systems and processes needed to operate the real-time market on a timely and accurate basis. In such cases, operators may need to block commitment or dispatch instructions generated by the real-time market model.

Within the CAISO, blocked instructions decreased from a daily average of 14 in 2020 to 10 in 2021 (blue, green, and gold bars in the figure). Figure 8.20 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 79 percent in 2021, about the same as the previous year.

Blocked start-up instructions accounted for about 15 percent of blocked instructions within the CAISO in 2021, similar to the previous year. Blocked transition instructions to multi-stage generating units also remained about the same year-over-year at about 6 percent in 2021. The average number of instructions blocked by Western Energy Imbalance Market operators was 42 per day in 2021 and 22 in 2020 (red bars in Figure 8.20).

271 California ISO, *Market performance metric catalog 2020.* Blocked instruction information can be found in the later sections of the catalog report.
https://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=AF1E04BD-C7CE-4DCB-90D2-F2ED2EE8F6E9

Figure 8.20 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 California 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 California ISO began blocking dispatches in 2011 as both market participants and California 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.

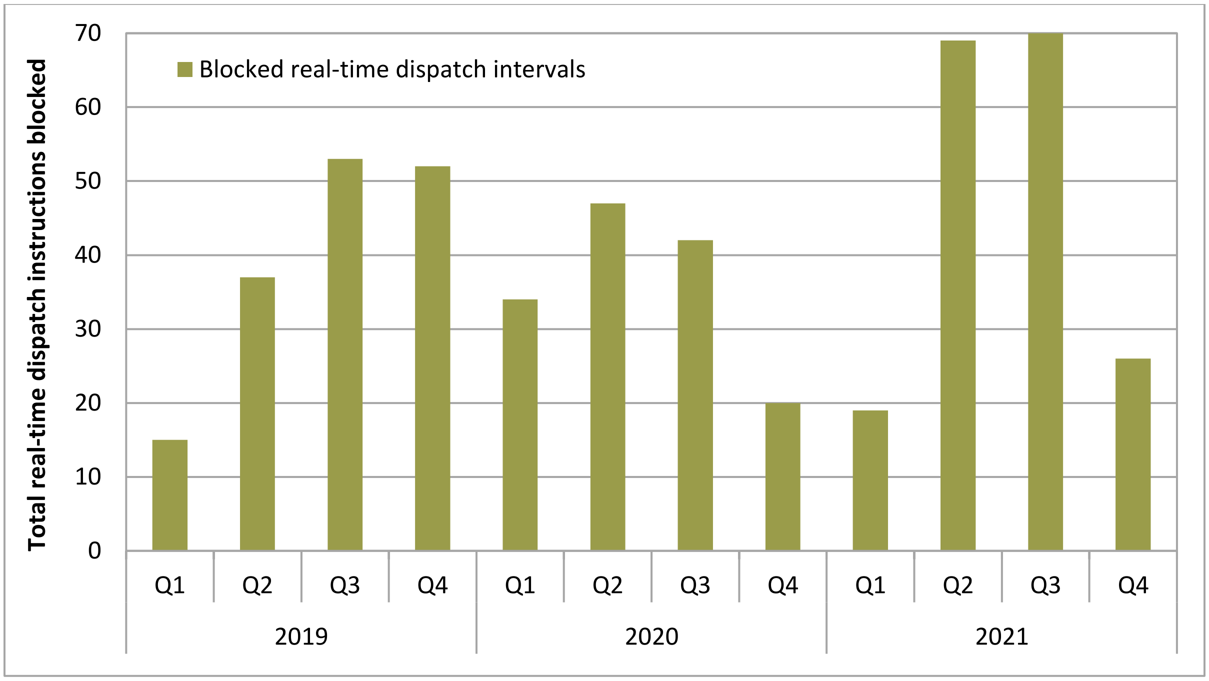
Operators can choose to block the entire market result to stop dispatches and prices resulting from a variety of factors including incorrect telemetry, intertie scheduling information, or load forecasting data. Furthermore, the market software is also capable of automatically blocking a solution when market results exceed threshold values.[272]

Figure 8.21 shows the frequency that operators blocked price results in the real-time dispatch from the first quarter 2019 through 2021. The total number of blocked intervals in 2021 increased about 29 percent from the previous year. The second quarter intervals occurred primarily in the month of April and were associated with Idaho Power and Pacific Corp East and West. Higher levels of blocked intervals

[272] For example, if the load were to drop by 50 percent in one interval, the software can automatically block results.

in the third and fourth quarter were mainly associated with Pacific Corp West in July and NorthWestern Energy in September and October of 2021.

Figure 8.21 Frequency of blocked real-time dispatch intervals



9 Resource adequacy

The purpose of the resource adequacy program is to ensure the California 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:

- **Investor-owned utilities procured most system resource adequacy capacity.** Investor-owned utilities accounted for about 60 percent of procurement, community choice aggregators contributed 23 percent, municipal utilities contributed 8 percent, and direct access services contributed 8 percent.
- **Use-limited resources comprised over half of resource adequacy capacity** and were thus exempt from CAISO bid insertion in all hours.
- **In the real-time market, less than 90 percent of system resource adequacy capacity was bid or self-scheduled during system emergency hours.** During Alert+ hours in 2021, 93 percent of system resource adequacy capacity was available in the day-ahead market after outages; 88 percent was offered in the day-ahead market; 92 percent was available after outages in the real-time market; and 87 percent was offered in the real-time market. This analysis caps offered bids at individual resource adequacy values.
- **Bids from CPUC jurisdictional import resource adequacy resources exceeded $0/MWh only during a few peak hours in 2021**. This is a result of CPUC Decision D.20-06-028, which requires non-resource-specific resource adequacy imports to self-schedule or bid at or below $0/MWh during availability assessment hours beginning in 2021. Procurement of import capacity also declined compared to previous years.
- **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 lower than the local area requirements.
- **Most charges and payments made through the resource adequacy availability incentive mechanism (RAAIM) are attributed to system and local resource adequacy resources.** In 2021, there was about $39 million in RAAIM charges and $30 million in incentive payments; most accrued in the second and third quarters.
- **Intra-monthly capacity procurement mechanism (CPM) designations cost about $9.8 million in 2021**. After extreme heat events throughout the west in June, the California ISO issued intra-monthly significant event designations in July, August, September, and October to ensure electricity reliability during the summer.

9.1 Background

The purpose of the resource adequacy program is to ensure the California ISO system has enough capacity to operate the grid reliably. In conjunction with the California ISO and the California Energy Commission (CEC), the California Public Utilities Commission (CPUC) and other local regulatory authorities (LRAs) establish 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 provide revenue to compensate the fixed costs of existing generators and the financing needed for new generator construction. The resource adequacy program includes California 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 make filings to the California ISO to demonstrate they have procured enough capacity to fulfill their obligations for all three types of resource adequacy. Once established in a supply plan, entities must make capacity available to the California ISO market according to rules that depend on requirement and resource type.

9.2 System resource adequacy

This section analyzes the availability and performance of system resource adequacy resources throughout the year, with a focus on tight system hours when the California ISO issued an alert, warning, or emergency notification to operate the grid safely and reliably.[273]

Regulatory requirements

The California 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 (PRM) which has historically been 15 percent.[274] Load serving entities then procure capacity to meet these requirements and file annual and monthly supply plans to the California 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.[275] For monthly supply plan showings, CPUC-jurisdictional entities

[273] Previous annual reports analyzed resource adequacy availability during the top 210 load hours of the year. This type of analysis will continue in quarterly reports that include a resource adequacy chapter.

[274] The planning reserve margin reflects operating reserve requirements and additional capacity that may be needed to cover forced outages and potential load forecast error.

[275] A showing is the list of resources and procured capacity that load serving entities and suppliers show to the CAISO in annual and monthly resource/supply plans.

must demonstrate they have procured 100 percent of their monthly system obligation. Table 9.1 shows recent CPUC decisions that affected the procurement, availability, or performance of resource adequacy resources in 2021:

Table 9.1 Recent CPUC decisions relevant to 2021 resource adequacy year

Decision	Title	Description
D.20-06-002	Decision on the Central Procurement of Resource Adequacy Program	Central Procurement Entities in the PG&E and SCE distribution service areas will procure Local RA capacity for LSE's three-year requirements starting in 2023. LSEs are responsible for fulfilling their requirements during the transition period. LSEs were responsible for 100% of their 2021 and 2022 requirements in 2020, and 100% of the 2022 requirement in 2021.
D.20-06-031	Decision Adopting Local Capacity Obligations for 2021, Adopting Flexible Capacity Obligations for 2021, and Refining the Resource Adequacy Program	Seasonal system penalty prices: penalty prices are shaped as $8.88/kW-month in the summer months (May-October) and $4.44/kW-month in non-summer months. Waiver for provider of last resort (POLR): POLRs can apply for a limited system and flexible RA obligation waiver if retail load is returned to the POLR with insufficient time to meet the RA requirement, or not transferred from the POLR to an LSE due to the actions of the LSE. Changes to Local RA requirement fulfillment in the PG&E Other LCAs: LSEs can fulfill their RA obligations in the disaggregated LCAs if they complete the local waiver process, and if their Year Ahead procurement of local RA capacity in the disaggregated LCAs meets the LSE's collective requirement for the disaggregated LCAs Revised Maximum Cumulative Capacity (MCC) buckets: MCC buckets are updated by setting a cap of 8.3% on the DR bucket, requiring non-DR use limited resources be available at least 40 hours in each summer month, spreading availability for resources in Categories 2-4 across an entire month, and requiring at least 56.1% of RA resources be available for all 24 hours during each day of the month.
D.20-06-028	Decision Adopting Resource Adequacy Import Requirements	Import RA requirements: non-resource-specific imports can count towards RA requirements if the contract is an energy contract with no economic curtailment provisions, the energy must self-schedule or bid into the CAISO day-ahead and real-time markets between -$150/MWh and $0/MWh during the availability assessment hours, and the energy must be delivered to LSE's in accordance with the contract and consistent with MCC buckets.
D.21-03-056	Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2021 and 2022	Emergency Load Reduction Program (ELRP): PG&E, SCE, and SDG&E were directed to each develop a 5-year ELRP pilot program in accordance with guidelines that define eligible capacity, availability requirements, event triggers, and compensation. Planning Reserve Margin (PRM): the effective PRM was raised to 17.5% from 15% starting in the summer of 2021. The 2.5% increase was assigned to the three IOUs and will be active until a new PRM is decided on through the RA reform proceeding.

Bid, schedule, and meter data processing for generic resource adequacy

For the following system and local resource adequacy analysis, day-ahead market bids include energy bids and non-overlapping ancillary service bids, while real-time market bids include energy bids only.[276] Day-ahead cleared schedules include total energy, spin reserves, non-spin reserves, and regulation up schedules, while real-time market cleared schedules include energy schedules only.[277] This analysis caps bids, schedules, and meter amounts at the resource adequacy capacity values of individual resources, unless otherwise indicated in the tables; this is to measure the availability of capacity that load serving entities secured during the planning timeframe. The analysis also caps bids and schedules according to individual resource outages and de-rates.[278]

Availability and performance during alert, warning, and emergency hours

The California ISO is a summer peaking balancing area with a generation mix that is becoming increasingly more intermittent. California's resource adequacy program recognizes that a portion of the state's generation is only available during limited hours. Load serving entities can meet a portion of their resource adequacy requirements with availability-limited generation. Reliability rules typically focus on making sure these resources are available when loads and net loads are highest. For example, the CPUC uses a maximum cumulative capacity bucket to require most resource adequacy capacity be available at least 200 hours across summer months.[279]

Although planning for the highest loads of the year is important for reliability, the California ISO grid can also experience stressed conditions in non-summer months. Even though there are relatively lower loads at that time, generation and transmission capacity is more likely to be on outage for maintenance, and winter conditions may threaten the supply of natural gas to California. The California ISO issues emergency notifications when operating reserves or transmission capacity limitations threaten the ability to operate the grid reliably, regardless of what time of the year it is.[280]

This section focuses on the availability and performance of resource adequacy resources during the hours throughout the year when the California ISO issued an emergency notification. Table 9.2 shows the California ISO Alert, Warning, and Emergency (AWE) notification descriptions and how hours with these notifications are included in the analysis of this section.

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276 Due to data issues, hourly real-time bid amounts reflect the maximum of average hourly bids in the hour-ahead, 15-minute, and 5-minute markets, adjusted for de-rates.

277 Due to data issues, hourly real-time cleared schedule amounts reflect the maximum of average hourly energy schedules in the hour-ahead, 15-minute, and 5-minute markets, adjusted for de-rates.

278 In addition, this analysis no longer filters out long-start resources that bid into the day-ahead but do not have a day-ahead or residual unit commitment schedule from real-time analysis.

279 200 hours comes 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 200 hours across summer months. CPUC decision D.20-06-031 changed this number from 210 hours in previous years.

280 These emergency notifications are documented in the California ISO "AWE Grid History Report – 1998 to Present" available at http://www.caiso.com/informed/Pages/Notifications/NoticeLog.aspx.

Table 9.2 Alert, Warning, and Emergency notification categories and analysis groups

Notification Category	Description	Analysis Category		
		Flex Alert	RMO+	Alert+
Flex Alerts	A call to consumers to voluntarily conserve energy when demand for power could outstrip supply. This generally occurs during heatwaves when elelctical demand is high. The California ISO can declare a Flex Alert whenever there is expected stress on the system.	X		
RMO (Restricted Maintenance Operations)	Requires generators and transmission operators to postpone any planned outages for routine equipment maintenance, ensuring all grid assets are available for use.		X	
Alerts	Issued by 3 p.m. the day before anticipated energy deficiency. The California ISO may require additional resources to avoid an emergency.		X	X
Warnings	Indicate that grid operators anticipate using operating reserves. Activates demand response programs (voluntary load reduction) to decrease overall demand.		X	X
Stage 1 Emergency	Declared by the California ISO if Contingency Reserve shortfalls exist or are forecast to occur. Strong need for conservation.		X	X
Stage 2 Emergency	Declared by the California ISO when all mitigating actions have been taken and the California ISO is no longer able to provide for its expected energy requirements. Requires California ISO intervention in the market, such as ordering power plants online.		X	X
Stage 3 Emergency	Declared by the California ISO when unable to meet minimum contingency reserve requirements, and load interruption is imminent or in progress. Notice issued to utilities of potential electricity interruptions through firm load shedding.		X	X
Transmission Emergency	Declared by the California ISO for any event threatening or limiting transmission grid capability, including line or transformer overloads or loss. A Transmission Emergency notice can be issued on a system-wide or regional basis.		X	X
1-Hour Probable Load Interruptions	Declared by the California ISO to encourage maximum conservation efforts for the time period. Utility Distribution Companies and Metered Subsystems await further orders from the California ISO. This notice is being issued in compliance with the Governor's Executive Order D-38-01.		X	X

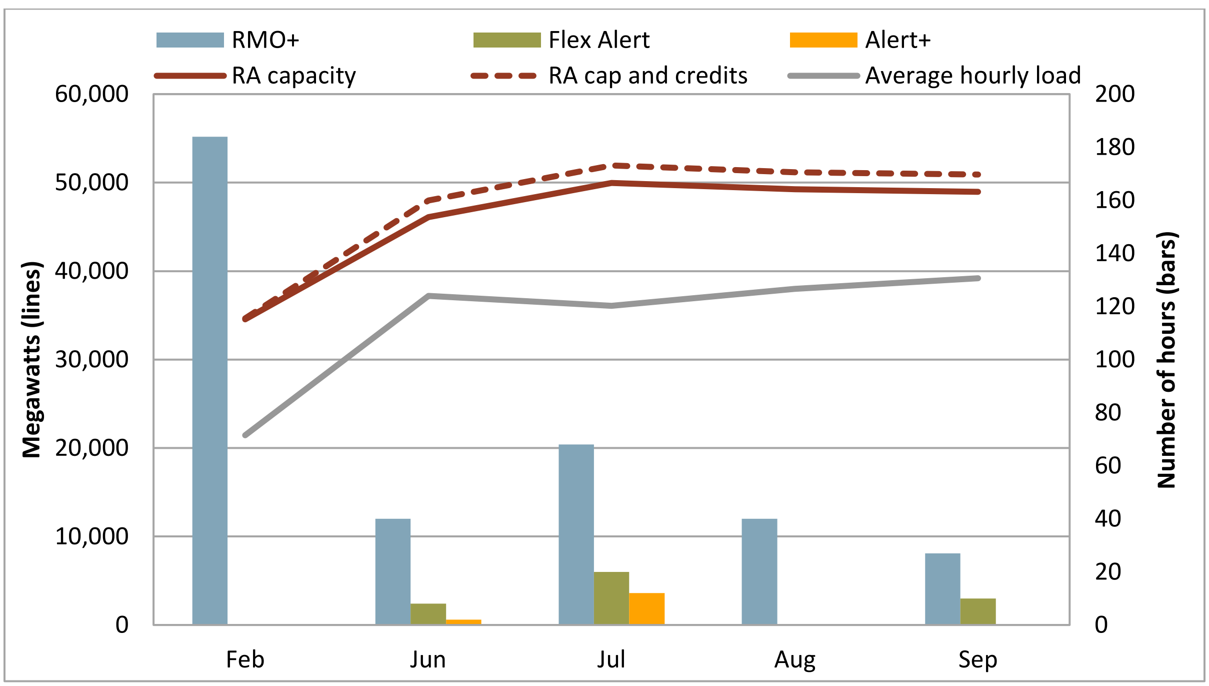
The following analysis groups emergency notification hours to show availability and performance during a variety of stressed system conditions. The last three columns in Table 9.2 show the system emergency analysis categories, which are necessary because the emergency notifications are not mutually exclusive and may not occur in a chronological fashion. Basing the analysis on the notification category alone may omit more severe system conditions, as well as limit the analysis to a small sample size where a single event may affect availability and performance. This is a bigger concern amid the more severe notifications that occur less often.

There are three analysis categories: *Flex Alert, RMO+, and Alert+.* The *Flex Alert* category includes hours throughout the year where the California ISO issued a Flex Alert notification, regardless of the issuance of more severe notifications. The choice to look at Flex Alert hours is due to the role they play in the

California ISO summer readiness program.[281] Flex Alerts typically include evening peak hours; however, they can also include hours that span over a few days. The *RMO+* category includes hours where the California ISO issued a notification at least as severe as a Restricted Maintenance Operations notification, which often last over multiple days, so this analysis includes many off-peak hours. Finally, the *Alert+* category includes hours where the California ISO issued a notification at least as severe as an alert notification; these hours mostly occur during the evening peak, although the analysis includes some hours during the middle of the day. Most of the analysis in this section focuses on the *Alert+* category.

Figure 9.1 provides an overview of resource adequacy capacity during system emergency notification hours in 2021. The green, blue, and yellow bars show the number of hours, by month, that are in the *RMO+, Flex Alert*, and *Alert+* categories, respectively. These categories are clustered bars, as opposed to stacked bars, because the hours are not mutually exclusive. The solid grey line shows average hourly load during these hours. The solid red line shows monthly average procured resource adequacy supply.[282] The dashed red line adds the additional capacity the CPUC credits towards load serving entity obligations, as well as legacy reliability must-run capacity.[283]

Figure 9.1 Average hourly resource adequacy capacity and load (2021 emergency notification hours)



281 California ISO, *2020 Summer readiness:* http://www.caiso.com/about/Pages/News/SummerReadiness.aspx

282 Monthly average load and procured resource adequacy capacity is weighted by the number of RMO+, Flex Alert, and Alert+ hours.

283 These credits include capacity from utility demand response programs with a PRM adder as well as liquidated damage credits.

Key findings of this analysis include:

- ***Hours with stressed system conditions were not constrained to the summer months in 2021.*** There were 359 total hours with RMO+ emergency notifications, 38 Flex Alert hours, and 14 Alert+ hours. About half of the RMO+ hours occurred in February when cold weather and record natural gas prices throughout the West caused the California ISO to issue an RMO for Southern California from Sunday February 13 to Saturday February 20.

- ***The most severe emergency notifications in 2021 occurred in June and July.*** There were 108 RMO+ hours, 28 Flex Alert hours, and 14 Alert+ hours in these months. The Alert+ hours include three hours on July 9 when the California ISO issued a Stage 2 Emergency due to the Bootleg Fire in southern Oregon, which threatened transmission lines and reduced import energy from the Pacific Northwest.

- ***Average resource adequacy capacity exceeded average load during the emergency notification hours in 2021***. Average hourly load was 34,380 MW during these hours, while average resource adequacy capacity was 47,336 MW. Omitting February increases these averages to 37,614 MW and 50,507 MW for load and capacity, respectively.

Table 9.3 shows capacity procurement, de-rates, availability, and performance of system resource adequacy resources during emergency notification hours from 2019 to 2021. Bids and self-schedules, cleared schedules, and meter amounts are capped by resource adequacy capacity at the resource level, unless otherwise indicated.

Table 9.3 Average total system resource adequacy capacity, availability, and performance by system emergency notification category

Year	Alert Category	Number of hours	Total RA capacity	Day-ahead market			Real-time market				Meter	Uncapped meter
				Capacity de-rate	Bids and self-schedules	Schedules	Capacity de-rate	Bids and self-schedules	Schedules	Uncapped schedules		
2019	RMO +	45	48,605	95%	87%	61%	94%	85%	61%	73%	59%	69%
	Flex Alert	6	47,605	94%	84%	67%	91%	80%	70%	77%	65%	71%
	Alert +	17	48,177	96%	87%	60%	95%	86%	61%	73%	58%	68%
2020	RMO +	390	47,723	94%	87%	61%	93%	86%	58%	68%	55%	64%
	Flex Alert	154	48,602	95%	87%	67%	93%	85%	63%	73%	61%	68%
	Alert +	97	45,404	95%	89%	72%	94%	88%	68%	79%	65%	73%
2021	RMO +	359	41,480	93%	88%	57%	92%	87%	52%	66%	50%	63%
	Flex Alert	38	48,878	94%	88%	81%	92%	87%	77%	87%	73%	81%
	Alert +	14	49,359	93%	85%	80%	92%	85%	77%	85%	73%	80%

Key findings of this analysis include:

- ***A small percentage of procured capacity was on outage during stressed hours from 2019 to 2021.*** The day-ahead and real-time markets could access between 91 and 96 percent of procured capacity during these hours. Gas-fired generators and hydro generators de-rated their capacity more than other fuel categories, although there was variability across the years and alert category groups.

- ***Resource availability, as measured by capped bids and self-schedules, was moderately high.*** On average, between 84 and 89 percent of procured capacity bid or self-scheduled into the day-ahead and real-time markets. The exception was the 2019 Flex Alert hours when only 80 percent of procured capacity bid or self-scheduled into the real-time market. This analysis category included six peak net load hours with very low availability from procured solar (49 percent) and wind (40 percent) capacity. Solar availability rises to 74 percent of procured capacity when the remaining capacity from partial resource adequacy resources is included.

- ***Accounting for the remaining capacity of partial resource adequacy resources increases performance when compared to procured capacity amounts.*** The table shows real-time cleared schedules and meter data not capped, or "uncapped," by individual resource adequacy values. Solar and wind resources drive this increase in performance since their production can surpass net qualifying capacity values, particularly during non-peak hours.
- ***Cleared schedules and meter amounts during RMO+ hours were significantly lower than Flex Alert and Alert+ hours in 2021.*** Day-ahead and real-time cleared schedules ranged between 52 and 57 percent of procured capacity in the day-ahead and real-time markets during RMO+ hours. These proportions were between 77 and 81 percent during Flex Alert and Alert+ hours. The RMO+ category included 184 hours during February when natural gas prices were historically high in the West. High marginal costs essentially priced a large amount of gas-fired resource adequacy units out of the market while other resource types supplied relatively low loads.

Load serving entities can contract with multiple types of resources to fulfill their resource adequacy obligations. Table 9.4 shows capacity procurement by resource type, capacity de-rates, availability, and performance of system resource adequacy resources during Alert+ hours in 2021.[284] Separate sub-totals (must-offer) are provided for the resources that the California ISO creates bids for if market participants do not submit a bid or self-schedule as well as the sub-totals for the resources the California ISO does not create bids for (other).

[284] Bids and self-schedules in the day-ahead and real-time markets are reported as the proportion of total resource adequacy capacity.

Table 9.4 Average system resource adequacy capacity, availability, and performance by fuel type (Alert+ hours)

Resource type	Total RA capacity	Day-ahead market			Real-time market				Meter	Uncapped meter
		Capacity de-rate	Bids and self-schedules	Schedules	Capacity de-rate	Bids and self-schedules	Schedules	Uncapped schedules		
Must-Offer:										
Gas-fired generators	19,230	87%	87%	79%	86%	86%	82%	85%	80%	82%
Other generators	1,407	93%	93%	93%	93%	93%	93%	96%	92%	96%
Subtotal	20,637	88%	88%	80%	86%	86%	83%	86%	81%	83%
Other:										
Imports	2,771	97%	96%	88%	99%	88%	69%	70%	56%	57%
Imports - MSS	336	100%	85%	85%	100%	85%	85%	85%	78%	78%
Use-limited gas units	8,407	98%	97%	91%	96%	96%	84%	87%	78%	79%
Hydro generators	5,855	94%	88%	88%	92%	87%	64%	71%	62%	68%
Nuclear generators	2,867	100%	99%	99%	100%	99%	99%	101%	99%	101%
Solar generators	4,697	99%	35%	35%	97%	43%	38%	53%	35%	48%
Wind generators	1,468	100%	82%	82%	99%	93%	95%	231%	90%	204%
Qualifying facilities	844	99%	94%	90%	98%	94%	90%	107%	87%	106%
Demand response	257	100%	68%	9%	99%	46%	18%	18%	9%	10%
Storage	866	99%	89%	66%	99%	92%	71%	76%	54%	58%
Other non-dispatchable	354	96%	94%	94%	95%	94%	92%	101%	91%	99%
Subtotal	28,722	97%	84%	80%	97%	84%	72%	85%	67%	78%
Total	**49,359**	**93%**	**85%**	**80%**	**92%**	**85%**	**77%**	**85%**	**73%**	**80%**

Key findings of this analysis include:

- ***Gas-fired generators accounted for about 55 percent of capacity procurement***. Gas-fired resources (gas-fired must-offer generators and use-limited gas units) supplied about 27,600 MW of resource adequacy capacity during the Alert+ hours of 2021.
- ***Resources that are not availability-limited accounted for just 41 percent of system capacity.*** About 21,000 MW of system capacity was subject to CAISO bid insertion 24x7.[285] Gas-fired generation in this category made up about 19,200 MW (39 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 CAISO bid insertion.*** These resources contributed about 8,400 MW of total capacity (17 percent). Hydro generators contributed 13 percent, imports (including metered subsystems) contributed 6 percent, solar resources contributed 9 percent, nuclear resources contributed 6 percent, wind resources contributed 3 percent, qualifying facility resources contributed 2 percent, storage contributed 2 percent, demand response contributed less than one percent, and other non-dispatchable resources contributed less than one percent of system capacity.
- ***Capacity available after reported outages and de-rates continued to be significant***. Average resource adequacy capacity was around 49,800 MW during the Alert+ hours in 2021, about 3,600 MW more than in 2020. The 2020 Alert+ hours included significantly more hours than 2021, as well

[285] When scheduling coordinators did not submit bids for these resources, the California ISO automatically generated them. Generation was excluded from the bidding requirement when an outage was reported to the California ISO.

as some lower load hours due to a transmission emergency in Northern California. After adjusting for outages and de-rates, the remaining capacity in the day-ahead market was about 93 percent of the overall resource adequacy capacity, which was about 2 percent lower than in 2020.

- ***Day-ahead market availability was moderately high for all resource types***. About 88 percent of must-offer and 84 percent of non-must-offer resources were available in the day-ahead market. Must-offer resources bid in about 100 percent of day-ahead de-rated capacity. Non-must-offer resources bid in about 86 percent of the day-ahead availability. These are typically variable and non-dispatchable energy resources. Additionally, all of the AWE+ hours occurred in evening peak hours when solar resources and other non-must-offer resources have limited availability.

- ***After accounting for outages and de-rates, most capacity was available in the real-time market***. About 86 percent of must-offer and 85 percent of non-must-offer capacity bid or self-scheduled in the real-time market. These totals are capped by individual resource adequacy values. Solar generators accounted for most of the de-rated capacity that did not bid into the real-time market because the Alert+ hours occurred during the net load peak. This increases to 65 percent of procured capacity if bids from the remaining capacity from partial resource adequacy resources are included.

- ***A higher percentage of procured must-offer resources cleared and were generating in the real-time market compared to non-must-offer resources.*** About 81 to 83 percent of procured must-offer capacity cleared the real-time market and metered, compared to 67 to 72 percent of non-must-offer capacity. These percentages are capped by individual resource adequacy values. The performance of must-offer and non-must-offer resources is more similar when accounting for the remaining capacity of partial resource adequacy resources in the uncapped schedules and meter. This is mainly due to the generation of wind resources above their NQC values.

Table 9.5 shows the availability and performance of resources aggregated by the type of load serving entity that contracted with them. This analysis uses supply plans to proportionally assign resource bid availability and performance to load serving entities based on corresponding contracted capacity.[286] Bid, schedules, and meter are 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. Capacity labeled as “not on a plan” represents resources that were not originally on a load serving entity’s supply plan. This could be substituted or a capacity procurement mechanism designation.

[286] Since a single resource can contract with multiple load serving entities, bidding behavior and performance metrics for individual resources were 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 are assigned to LSE 1 and 40 percent to LSE 2. Load serving entity assigned bids and performance are then aggregated up to the type of load the entity serves.

Table 9.5 Average system resource adequacy capacity and availability by load type (Alert+ hours)

Load Type	Total RA capacity	Day-ahead market			Real-time market				Meter	Uncapped meter
		Capacity de-rate	Bids and self-schedules	Schedules	Capacity de-rate	Bids and self-schedules	Schedules	Uncapped schedules		
CCA	11,180	96%	89%	81%	94%	89%	81%	93%	77%	87%
DA	3,769	94%	88%	82%	94%	88%	80%	90%	77%	85%
IOU	29,746	92%	84%	79%	91%	83%	74%	82%	71%	76%
Muni	3,871	96%	86%	83%	97%	87%	80%	90%	77%	85%
Not on a plan	791	86%	74%	67%	85%	79%	69%	79%	62%	68%
Total	**49,357**	**93%**	**85%**	**80%**	**92%**	**85%**	**77%**	**85%**	**73%**	**80%**

Key findings of this analysis include:

- ***Investor-owned utilities procured most of the system capacity.*** Investor-owned utilities accounted for about 30,000 MW (or 60 percent) of system resource adequacy procurement, community choice aggregators contributed 23 percent, municipal utilities contributed 8 percent, and direct access services contributed 8 percent.

- ***Capacity for all load types had similar availability in the day-ahead and real-time markets.*** Resources bid between 83 and 89 percent of procured capacity from the four load types in these markets. These bids are capped by individual resource adequacy values.

- ***Investor-owned utilities, municipal utilities, and community choice aggregators contracted with a majority of resources with availability limitations that are not subject to California ISO bid insertion.*** Investor-owned utilities procured 64 percent of their resource adequacy capacity from these resources, while municipal utilities procured 67 percent, community choice aggregators procured 55 percent, and direct access services procured 45 percent.

- ***Municipal utilities were the only load type that procured a significant amount of imports to meet system resource adequacy requirements.*** Municipal utilities procured 16 percent of their resource adequacy capacity from imports, while community choice aggregators procured 8 percent, direct access services procured 8 percent, and investor-owned utilities procured 4 percent. Omitting metered subsystem imports reduces this to 7 percent for municipal utilities.

- ***Load type capacity performance was similar, but slightly less investor-owned utility capacity cleared the real-time market and metered.*** Investor-owned utility capacity typically cleared and metered 6 to 11 percent less procured capacity compared to CCAs, DAs, and IOUs. This is primarily because IOUs procured the largest amount of gas resources. A lower percentage of these resources cleared the real-time market compared to the gas resources of other load types.

Table 9.6 shows the availability of resource adequacy capacity in the CAISO markets based on whether the capacity was exempt from charges under the resource adequacy availability incentive mechanism. This analysis uses settlements data to identify resources exempt from RAAIM charges if they were unavailable during the availability assessment hours.[287]

Table 9.6 Average system resource adequacy capacity and availability by RAAIM category (Alert+ hours)

RAAIM Category	Total resource adequacy capacity	Day-ahead market			Real-time market				Meter	Uncapped meter
		Capacity de-rate	Bids and self-schedules	Schedules	Capacity de-rate	Bids and self-schedules	Schedules	Uncapped schedules		
Non-RAAIM exempt	37,179	92%	91%	84%	91%	89%	80%	83%	76%	78%
RAAIM exempt	12,178	97%	69%	67%	96%	73%	68%	93%	65%	86%
Total	**49,357**	**93%**	**85%**	**80%**	**92%**	**85%**	**77%**	**85%**	**73%**	**80%**

Key findings of this analysis include:

- ***RAAIM exempt resources accounted for about 25 percent of overall resource adequacy capacity during the Alert+ hours of 2021.*** This was mostly solar, gas, and wind resources.
- ***Resources subject to RAAIM adjusted more for outages, but bid a higher percentage of available capacity in the markets***. This considers bids capped at individual resource adequacy values. About 91 percent of resource adequacy capacity subject to RAAIM was accessible to the real-time market on average. Hydro and gas resources comprised most of the de-rates in this category.
- ***RAAIM exempt resources bid and performed at a lower percentage in the markets***. RAAIM exempt capacity adjusted for outages less often, but bid only 69 to 73 percent of their capacity into the markets during emergency notification hours. This considers bids capped at individual resource adequacy values. Including the remaining capacity from partial resource adequacy resources, nearly 100 percent of the procured capacity from RAAIM exempt resources bid into the real-time market. This is due to wind resources that bid significantly above their NQC values. About 78 to 86 percent of total capacity from resource adequacy and partial resource adequacy resources cleared and metered in real-time.

287 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.

Resource adequacy imports

Load serving entities can use imports to meet system resource adequacy requirements. Imports can 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.[288]

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 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.

In June 2020, the CPUC issued a decision specifying that CPUC jurisdictional non-resource-specific import resource adequacy resources must bid into the CAISO markets at or below $0/MWh, at minimum in the availability assessment hours.[289] These rules became effective at the beginning of 2021. They appear to have influenced the bid-in quantity and bid-in prices. An overall decline in volumes began in late 2020 and continued throughout 2021 as well as into the first quarter of 2022. The $0/MWh or below bidding rule does not apply to non-CPUC jurisdictional imports. Bids greater than $0/MWh were submitted by CPUC-jurisdictional entities in only a few hours in 2021.

Figure 9.2 shows the average hourly volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market during peak hours.[290] The grey bars reflect import capacity that was either self-scheduled or bid near the price floor, while the remaining bars summarize the volume of price-sensitive resource adequacy import capacity in the day-ahead market.

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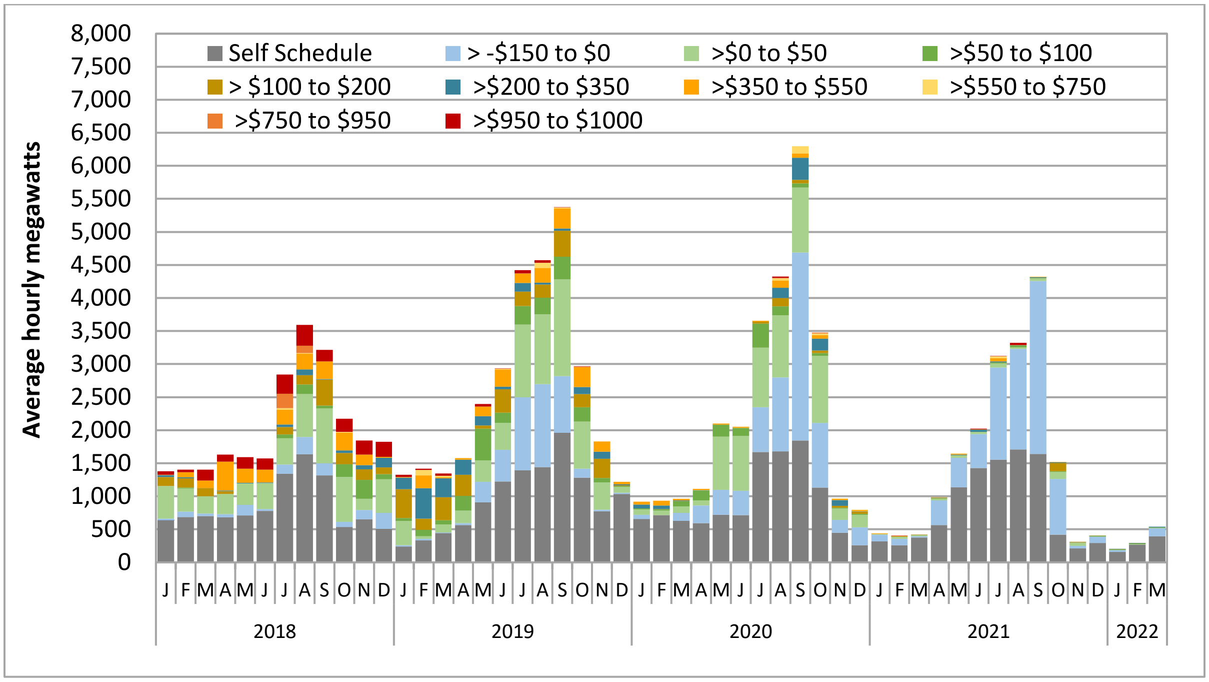
288 In 2021, Phase 1 (March 20) and Phase 2 (June 13) of the FERC Order No. 831 compliance tariff amendment were implemented. Phase 1 allows resource adequacy imports to bid over the soft offer cap of $1,000/MWh when the maximum import bid price (MIBP) is over $1,000/MWh or when the CAISO has accepted a cost-verified bid over $1,000/MWh. Phase 2 imposed bidding rules capping resource adequacy import bids over $1,000/MWh at the greater of MIBP or the highest cost-verified bid up to the hard offer cap of $2,000/MWh.

289 CPUC Docket No. R.17-09-020, *Decision Adopting Resource Adequacy Import Requirements (D.20-06-028)*, June 25, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K516/342516267.PDF

290 Peak hours in this analysis reflect non-weekend and non-holiday periods between hours ending 17 and 21.

Figure 9.2 Average hourly resource adequacy imports by price bin



9.3 Local resource adequacy

Analysis in this section focuses on the market availability and performance of resource adequacy resources in local capacity areas throughout the year. There is a focus on tight system condition hours when the California ISO issued an alert, warning, or emergency notification to operate the grid safely and reliably.[291] 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. The California ISO performs this study on an annual basis. It 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 California ISO). The California 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.

291 Previous annual reports analyzed resource adequacy availability during the top 210 load hours of the year. Analysis on these hours will continue in quarterly reports that include a resource adequacy chapter.

For CPUC-jurisdictional load serving entities, the CPUC re-allocates local requirements to load serving entities in each TAC 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 they have procured 100 percent of their local resource adequacy requirements for each month of the compliance year.[292] Load serving entities must also demonstrate they have met revised monthly local obligations 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.[293]

Bidding and scheduling obligations

Scheduling coordinators representing local resource adequacy capacity must make capacity 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 system resource adequacy.

Availability and performance during alert, warning, and emergency hours

Table 9.7 shows an analysis similar to the availability and performance analysis for system resource adequacy. This table compares the local area capacity requirements established by the California ISO to the procurement, availability, and performance of capacity in the day-ahead and real-time markets during the Alert+ hours of 2021.[294] Availability and performance numbers are shown as a percent of the local capacity requirement as opposed to procurement amounts.

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[292] Under the CPUC's Decision (D.) 19-02-022, local resource adequacy requirements are three-year forward requirements starting in the 2021 compliance year. CPUC-jurisdictional load serving entities are 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.

[293] For more information on competitiveness in local capacity areas, refer to Chapter 6.

[294] California ISO, *2020 Local Capacity Technical Study, Final Report and Study Results*, Local capacity area resource adequacy requirements obtained from the *2020 Local Capacity Technical Analysis*, May 1, 2019, p. 24, Table 3.1-1: http://www.caiso.com/Documents/Final2020LocalCapacityTechnicalReport.pdf.

Table 9.7 Average local resource adequacy capacity and availability (Alert+ hours)

Load capacity area	TAC Area	Total RA capacity	Local req.	Day-ahead market			Real-time market				Meter	Uncapped meter
				Capacity de-rate	Bids and self-schedules	Schedules	Capacity de-rate	Bids and self-schedules	Schedules	Uncapped schedules		
Greater Bay Area	PG&E	6,911	6,353	96%	95%	93%	96%	95%	93%	99%	91%	96%
Greater Fresno	PG&E	3,037	1,694	175%	154%	149%	171%	154%	97%	107%	91%	98%
Sierra	PG&E	1,694	1,821	84%	83%	83%	83%	82%	80%	89%	77%	84%
North Coast/North Bay	PG&E	833	842	90%	88%	88%	90%	89%	88%	92%	87%	91%
Stockton	PG&E	618	596	99%	92%	92%	96%	91%	84%	91%	79%	83%
Kern	PG&E	444	413	106%	90%	89%	106%	92%	90%	96%	88%	93%
Humboldt	PG&E	156	130	116%	115%	115%	109%	108%	98%	100%	95%	97%
LA Basin	SCE	8,812	6,127	138%	136%	117%	136%	133%	121%	127%	114%	119%
Big Creek/Ventura	SCE	4,415	2,296	156%	142%	117%	144%	131%	105%	109%	101%	105%
San Diego	SDG&E	4,116	3,888	103%	92%	85%	102%	93%	85%	96%	77%	85%
Total		**31,036**	**24,160**	**118%**	**112%**	**103%**	**116%**	**111%**	**99%**	**106%**	**94%**	**100%**

Key findings of this analysis include:

- ***Overall, total shown resource adequacy capacity exceeded requirements in local capacity areas.*** Load serving entities procured about 31,000 MW of capacity in local areas in 2021, compared to about 24,000 MW of required capacity. Even after controlling for outages, the overall capacity exceeded local requirements in the day-ahead (118 percent of requirements) and real-time (116 percent of requirements) markets.

- ***Procurement in some local capacity areas was lower than the local area requirement.*** Total resource adequacy capacity was below the local requirements in the Sierra and North Coast/North Bay local areas.[295]

- ***Gas-fired generators accounted for most local resource adequacy procurement.*** Gas-fired generators accounted for between 54 and 94 percent of procurement in the Greater Bay Area, Big Creek/Ventura, Humboldt, Kern, San Diego, LA Basin, and Stockton areas. Hydro capacity accounted for between 58 and 68 percent of procurement in the Greater Fresno and Sierra areas, while other must-offer resources accounted for 84 percent of procurement in the North Coast/North Bay local area.

- ***Significant amounts of capacity, beyond requirements, were available in the day-ahead market for several local capacity areas.*** Even when capped at individual resource adequacy values, local resources bid into the markets at 111 to 112 percent of local requirements. Capacity in the Greater Fresno, Humboldt, LA Basin, and Big Creek/Ventura bid between 108 and 154 percent of requirements. When this happens, this offsets lower availability rates from capacity in the Greater Bay Area, Sierra, North Coast/North Bay, Stockton, Kern, and San Diego.

- ***A high percentage of capacity, compared to local capacity requirements, cleared and metered during the Alert+ hours of 2021.*** Between 99 and 103 percent of local capacity cleared the

[295] Under the CPUC's Decision (D.) 20-06-031, starting 2021, LSEs can fulfill their RA obligations in the disaggregated PG&E Other LCAs if they complete the local waiver process, and if their Year Ahead procurement of local RA capacity in the disaggregated LCAs meets the LSE's collective requirement for the disaggregated LCAs.

day-ahead and real-time markets, while 94 percent of this capacity responded based on meter values. These percentages are capped at individual resource adequacy values.

For instances where available resource adequacy capacity does not meet the needs of a local area, the California ISO can designate additional capacity through the capacity procurement mechanism. Additional information regarding capacity procurement mechanism designations in 2021 is described in depth in Section 9.6.

Table 9.8 shows availability and performance of local resource adequacy resources in the California ISO markets aggregated by transmission access charge area and load type. The analysis uses supply plans to proportionally assign resource bids and performance to load serving entities based on corresponding contracted capacity. Bid availability and performance metrics were 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. Capacity labeled as "not on a plan" represents resources that were not originally on a load serving entity's supply plan – such as substitute or capacity that the California ISO designated through the capacity procurement mechanism.

Table 9.8 Average local resource adequacy capacity and availability by TAC area load type (Alert+ hours)

			Day-ahead market			Real-time market					
TAC Area	Load Type	Total RA capacity	Capacity de-rate	Bids and self-schedules	Schedules	Capacity de-rate	Bids and self-schedules	Schedules	Uncapped schedules	Meter	Uncapped meter
PG&E	CCA	4,024	94%	90%	88%	93%	90%	83%	87%	81%	84%
	DA	1,256	93%	90%	88%	92%	89%	85%	88%	83%	85%
	IOU	7,248	89%	86%	84%	89%	86%	75%	81%	72%	77%
	Muni	950	94%	82%	80%	94%	85%	78%	89%	77%	86%
	Not on plan	216	99%	97%	94%	95%	95%	81%	89%	77%	84%
	Subtotal	**13,694**	**92%**	**87%**	**86%**	**91%**	**87%**	**79%**	**84%**	**76%**	**81%**
SCE	CCA	1,885	96%	91%	54%	94%	88%	76%	83%	69%	74%
	DA	675	94%	92%	70%	93%	92%	81%	92%	77%	87%
	IOU	9,398	89%	87%	78%	85%	83%	73%	75%	71%	73%
	Muni	1,094	99%	84%	76%	98%	85%	72%	78%	65%	69%
	Not on plan	174	100%	100%	93%	99%	86%	76%	86%	74%	83%
	Subtotal	**13,226**	**91%**	**88%**	**74%**	**88%**	**84%**	**74%**	**78%**	**70%**	**73%**
SDG&E	CCA	568	94%	94%	94%	94%	94%	90%	91%	86%	88%
	DA	459	98%	95%	91%	95%	93%	84%	89%	82%	85%
	IOU	3,067	97%	84%	76%	97%	86%	78%	91%	69%	79%
	Muni	1	100%	100%	100%	100%	100%	0%	0%	0%	0%
	Not on plan	20	100%	95%	95%	100%	95%	65%	65%	30%	30%
	Subtotal	**4,115**	**97%**	**87%**	**80%**	**97%**	**88%**	**80%**	**90%**	**73%**	**81%**
	Total	**31,035**	**92%**	**87%**	**80%**	**90%**	**86%**	**77%**	**82%**	**73%**	**78%**

Key findings of this analysis include:

- ***Investor-owned utilities procured the most local resource adequacy capacity.*** Investor-owned utilities accounted for about 20,000 MW (or about 63 percent) of local resource adequacy procurement, community choice aggregators contributed 21 percent, direct access services contributed 8 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 29 percent of total resource adequacy capacity in the Pacific Gas and Electric area. This was mostly in the Greater Bay Area, Greater Fresno, and Sierra local capacity areas.
- ***Day-ahead capacity, after accounting for outages and de-rates, was high for all load types in each TAC area.*** Availability in the day-ahead market ranged from 89 percent to 100 percent of total resource adequacy capacity for each area and load type.
- ***Most resource adequacy capacity was available in the day-ahead and real-time markets for all load types in each TAC area.*** About 86 to 87 percent of the total local resource adequacy capacity bid into the day-ahead and real-time markets during the Alert+ hours. This is when bids are capped at individual resource adequacy values.

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 increased to manage changes in net load. The system typically needs this ramping capability in the downward direction in the morning when solar generation ramps up and replaces gas generation. In the evening, the system needs upward ramping capability as solar generation rapidly decreases while system loads are increasing. The greatest need for three-hour ramping capability occurs during evening hours.

The CPUC and the California ISO developed flexible resource adequacy requirements to address flexibility needs for changing system conditions. FERC approved the flexible resource adequacy framework in 2014 and it became effective in January 2015. This framework now serves as an additional tool to help maintain grid reliability.[296]

Requirements

The California ISO determines flexible capacity needs through the annual flexible capacity needs assessment study. This study identifies the minimum amount of flexible capacity that must be available to the California ISO to address ramping needs for the upcoming year. The California 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 CAISO balancing authority area.

The flexible resource adequacy framework provides capacity with the attributes required to manage the grid during extended periods of ramping needs. This framework calculates the monthly flexible requirement as the maximum contiguous three-hour net load ramp forecast plus a capacity factor.[297,298]

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296 For additional information, see: FERC Docket No. ER14-2574, *149 FERC ¶ 61,042, Order on Tariff Revisions,* October 16, 2014: http://www.caiso.com/Documents/Oct16_2014_OrderConditionallyAcceptingTariffRevisions-FRAC-MOO_ER14-2574.pdf

297 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.

298 Net load is total load less wind and solar production.

Because the grid commonly faces two pronounced upward net load ramps per day, flexible resource adequacy categories address both the maximum primary and secondary net load ramp.[299]

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. Load serving entities submit annual supply plans to the California 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 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. Below is a brief description of each category, its purpose, requirements, and must-offer obligations.

- **Category 1 (base flexibility):** Category 1 resources must be able 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 covers 100 percent of the secondary net load ramp and a portion of the primary net load ramp. Therefore, the forecasted maximum three-hour secondary ramp sets this category's requirement. There is no limit to the amount of Category 1 resources 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 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 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

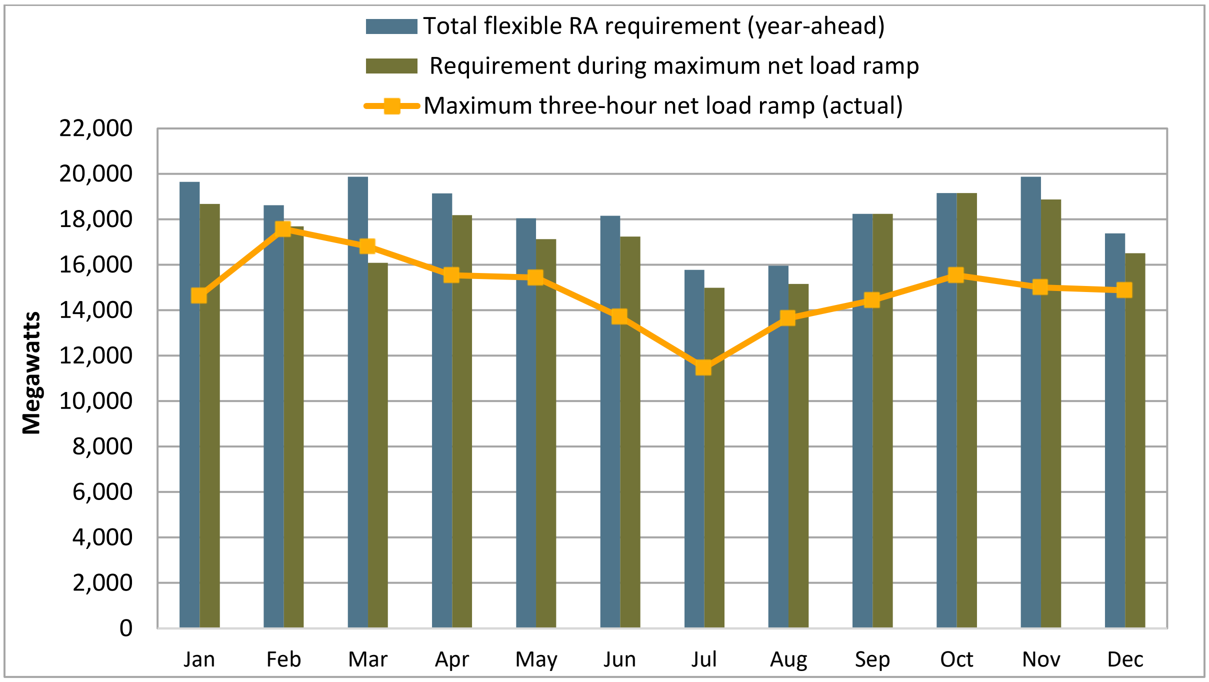
Figure 9.3 investigates how well flexible resource adequacy requirements addressed system load ramping needs in 2021 by comparing the requirements and the actual maximum three-hour net load

[299] The California 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.

ramp on a monthly basis.[300] 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 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.[301] Therefore, this analysis first identified the day and hours the maximum net load ramp occurred, and then averaged the flexible capacity requirements for the categories with must-offer obligations during those hours.

Figure 9.3 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 2021.*** This is 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 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 March.

The effectiveness of flexible requirements and must-offer rules in addressing supply during maximum load ramps is dependent on the ability to predict the size and timing of the maximum net load ramp.

300 Estimates of the net load ramp may vary slightly from the California ISO calculations because DMM uses 5-minute interval data and the California ISO uses one-minute interval data.

301 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.

This analysis suggests the 2021 requirements and must-offer hours were sufficient in reflecting actual ramping needs in the vast majority of cases.

Table 9.9 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 9.9 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	14,632	19,656	18,674	1/1/2021	14:00	Y	
Feb	17,571	18,626	17,696	2/28/2021	15:05	Y	
Mar	16,806	19,874	16,092	3/8/2021	15:00	N	Ramp start time occurred before Category 2 requirement.
Apr	15,546	19,143	18,186	4/3/2021	16:15	Y	
May	15,439	18,040	17,136	5/9/2021	16:45	Y	
Jun	13,712	18,158	17,249	6/6/2021	16:55	Y	
Jul	11,475	15,785	14,995	7/4/2021	16:55	Y	
Aug	13,653	15,961	15,160	8/22/2021	15:55	Y	
Sep	14,446	18,243	18,243	9/30/2021	14:55	Y	
Oct	15,538	19,153	19,153	10/14/2021	15:00	Y	
Nov	14,998	19,877	18,883	11/28/2021	14:00	Y	
Dec	14,873	17,382	16,511	12/11/2021	14:00	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 1,500 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 March.
- ***In March, the maximum net load ramp occurred at least partially outside of Category 2 and Category 3 must-offer hours.*** The maximum net load ramp began an hour before Category 2 and Category 3must-offer obligations.

Procurement

Table 9.10 shows what types of resources provided flexible resource adequacy and details the average monthly flexible capacity procurement in 2021 by fuel type. The flexible resource adequacy categories and must-offer rules are technology neutral, allowing a variety of resources to provide flexibility to the California ISO to meet ramping needs. While the CPUC and California 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 2021.

Table 9.10 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	11,339	60%	11	1%	0	0%
Use-limited gas units	5,243	28%	659	85%	51	14%
Use-limited hydro generators	1,761	9%	74	10%	0	0%
Other hydro generators	107	1%	4	1%	0	0%
Geothermal	172	1%	0	0%	0	0%
Energy Storage	364	2%	30	4%	320	86%
Total	**18,986**	**100%**	**778**	**100%**	**371**	**100%**

Key findings of this analysis include:

- ***Gas-fired resource accounted for most flexible resource adequacy capacity procurement.*** About 11,350 MW (or 53 percent) of total flexible capacity came from these resources. Almost all (99 percent) of the capacity supplied by gas-fired generators served as Category 1 resources in 2021.
- ***Use-limited gas units made up the second largest volume of flexible resource adequacy capacity.*** These generators made up 28 percent of Category 1 capacity and about 30 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 nine percent of Category 1 capacity.
- ***Load serving entities procured significantly more Category 3 flexible capacity in 2021 than they had previously.*** Load serving entities procured a monthly average of 371 MW of Category 3 capacity. Energy storage accounts for most of this capacity.

Table 9.11 shows flexible resource adequacy procurement by load serving entity type in 2021. The analysis uses supply plans to determine monthly LSE procurement and average it over the year by flexible resource adequacy category.

Table 9.11 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	4,308	23%	18	2%	65	18%
DA	1,555	8%	7	1%	5	1%
IOU	12,477	66%	711	92%	299	81%
Muni	645	3%	41	5%	2	1%
Total	**18,985**	**100%**	**777**	**100%**	**371**	**100%**

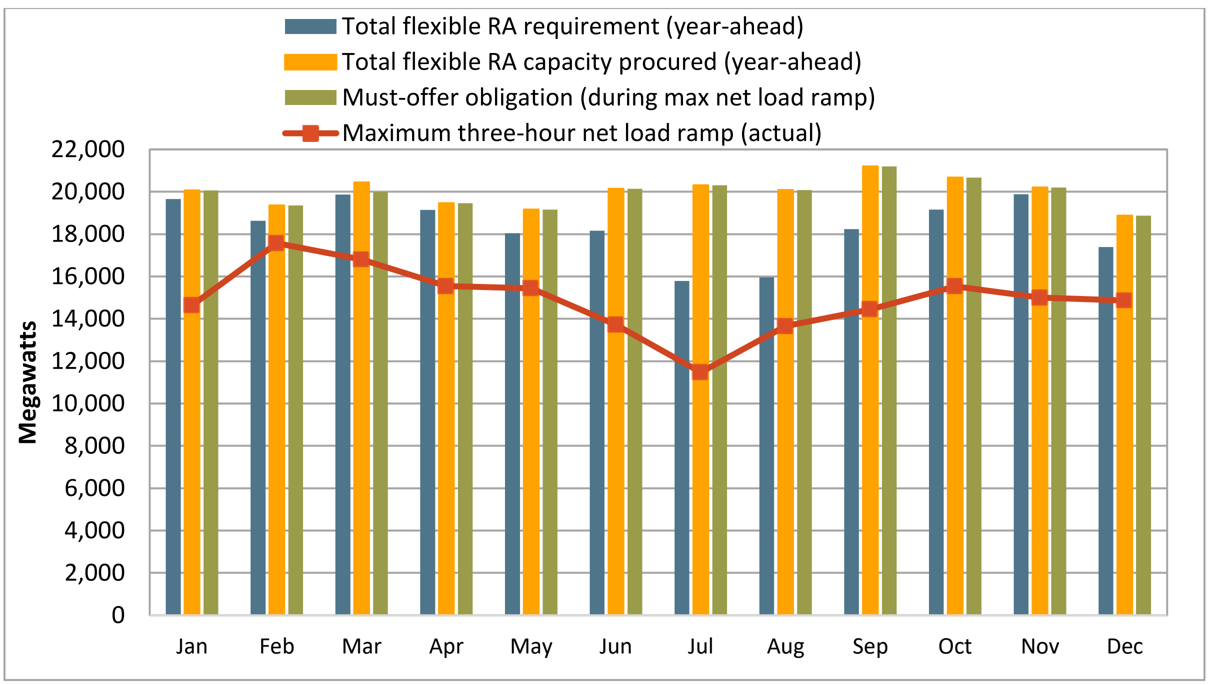
Key findings of this analysis include:

- ***Investor-owned utilities procured the highest proportion of each flexible resource adequacy category***. Investor-owned utilities procured 67 percent of total flexible capacity, community choice aggregators procured 22 percent, direct access services procured eight percent, and municipal utilities procured three percent. Investor-owned utilities procured at least 66 percent of the capacity of each category.

- ***All load types procured resources for multiple flexible resource adequacy category***. Investor-owned utilities, community choice aggregators, direct access services, and municipal utilities procured Category 1, 2, and 3 flexible resource adequacy resources. In previous years, 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 (18 percent) capacity.

Due in part to greater amounts of Category 1 capacity, total flexible resource adequacy procurement exceeded requirements for all months in 2021. Figure 9.4 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.[302] 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.

Figure 9.4 Flexible resource adequacy procurement during the maximum net load ramp



302 The must-offer obligation estimate used in this chart includes 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.

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 the same as total procurement in most months***. Must-offer obligations during maximum net load ramps (green bars) is the same as total procurement (gold bars) for all months except for March. For March, the must-offer obligation is about 450 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 2021.

Availability

Table 9.12 presents an assessment of the availability of flexible resource adequacy capacity in the day-ahead and real-time markets. 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. This analysis considers extra-long-start resource as available in the day-ahead market to the extent that the resource did not have outages limiting its ability to provide its full obligation. The analysis considers long-start and extra-long-start resources as available 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 2021. This analysis does not to replicate how the resource adequacy availability incentive mechanism measures availability.

Table 9.12 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	19,458	17,098	88%	13,901	11,824	85%
February	18,583	16,255	87%	13,000	10,783	83%
March	18,448	14,391	78%	13,381	10,854	81%
April	17,575	14,193	81%	13,533	11,409	84%
May	18,437	14,670	80%	12,910	11,283	87%
June	19,380	16,640	86%	14,869	12,412	83%
July	19,416	17,002	88%	15,569	12,513	80%
August	19,453	17,526	90%	14,941	12,609	84%
September	20,030	17,933	90%	14,620	12,053	82%
October	19,276	16,790	87%	14,021	11,449	82%
November	19,472	16,971	87%	13,831	11,539	83%
December	18,228	16,196	89%	13,737	11,590	84%
Total	**18,980**	**16,305**	**86%**	**14,026**	**11,693**	**83%**

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 2021***. Average availability in the day-ahead market was 86 percent and ranged from 78 percent to 90 percent. This is similar to 2020 when average availability in the day-ahead market was about 85 percent with a range from 77 percent to 90 percent. Average availability in the real-time market was 83 percent and ranged from 80 percent to 87 percent. This is slightly lower than 2020 when average real-time availability was 84 percent and ranged from 77 percent to 91 percent.
- ***The real-time average must-offer obligation is much lower than the day-ahead obligation***. Flexible capacity must-offer requirements were about 16,300 MW in the day-ahead market and only about 14,000 MW in the real-time market on average. This reflects several factors. First, resources may receive ancillary service awards in the day-ahead market covering all or part of their resource adequacy obligation. Second, long-start and extra-long-start resources do not have an obligation in the real-time market if they are not committed in the day-ahead market, residual unit commitment process, or the extra-long-start commitment process. In addition, day-ahead energy awards are excluded from the real-time availability requirement for the incentive mechanism calculation.

Table 9.13 includes the same data summarized in Table 9.12, but aggregates average flexible resource adequacy availability by the contracted resource load type. Supply plans were used to proportionally assign 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 9.13 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	4,294	3,486	81%	2,928	2,507	86%
DA	1,538	1,313	85%	1,116	960	86%
IOU	12,498	10,902	87%	9,379	7,726	82%
Muni	653	608	93%	604	502	83%
Total	**18,983**	**16,308**	**86%**	**14,028**	**11,695**	**83%**

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 85 percent availability, and those that contracted with investor-owned utilities and municipalities had 87 to 93 percent availability. In the real-time market, these resources were available between 82 and 86 percent of the time, depending on load type.

9.5 Incentive mechanism payments

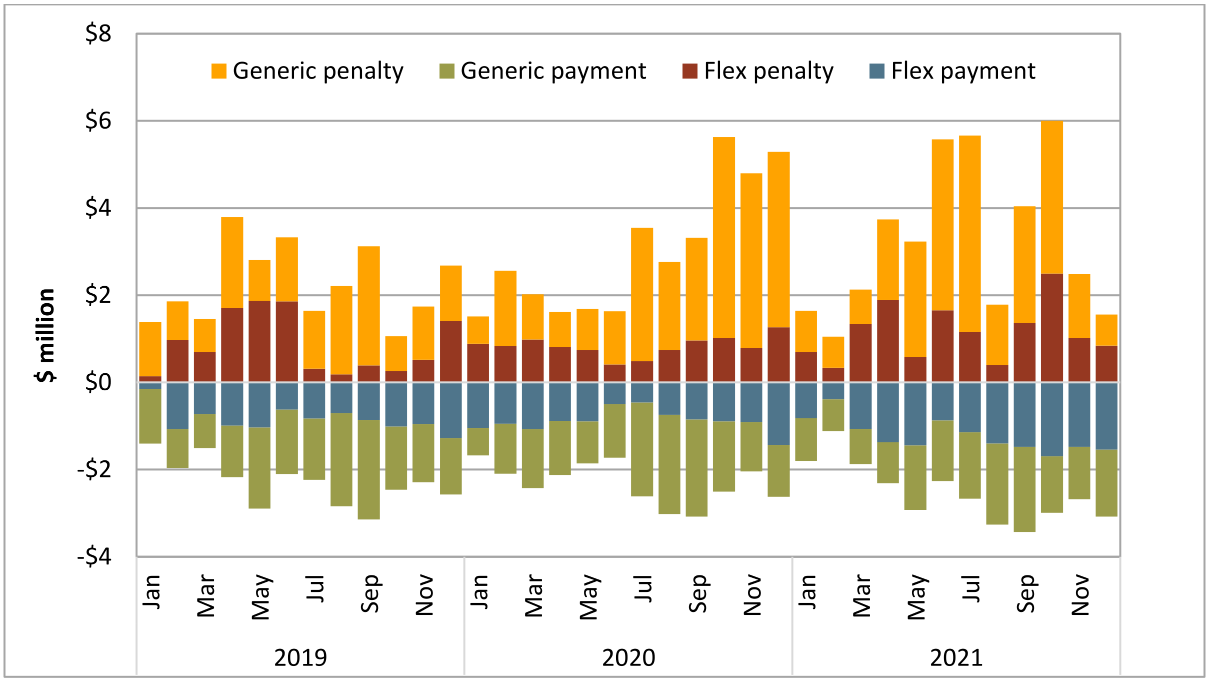
The purpose of the resource adequacy availability incentive mechanism (RAAIM) is to provide an incentive for resource adequacy resources to meet their bidding obligations and provide energy bids to the market. Resources that are designated as either system, local, or flexible resource adequacy capacity are subject to RAAIM. The monthly performances of these resources are measured by the availability of bids and self-schedules in the market during designated availability assessment hours. The 2021 availability assessment hours for *system and local resource adequacy resources* were hours ending 17 to 21 and *flexible resource adequacy resources* were assessed for hours ending 6 to 22 for base ramping resources. For both peak ramping and super-peak ramping resources, these were assessed for hours ending 15 to 19 in January, February, November, and December; hours ending 17 to 21 in March through August; and hours ending 16 to 20 in September and October.

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.[303]

[303] 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.

Figure 9.5 summarizes monthly RAAIM charges and payments to resource adequacy resources from January 2019 to December 2021. Financial sums are presented in relation to how money flows through the CAISO. RAAIM penalties that resources pay the CAISO are in the positive direction on the graph while RAAIM payments where the CAISO pays resources are in the negative direction. Charges and payments are presented for generic and flex resource adequacy resources.

Figure 9.5 Monthly RAAIM penalties and payments



Key findings from this analysis include:

- ***Generic resource adequacy resources account for most RAAIM charges and payments.*** In 2021, RAAIM charges were about $39 million and incentive payments were about $30 million. About 65 percent of penalties and 52 percent of payments were to generic resource adequacy resources.
- ***In 2021, most RAAIM charges occurred after the first quarter.*** RAAIM charges averaged almost $4 million per month from the second to fourth quarters, compared to less than $2 million per month in the first quarter.

9.6 Capacity procurement mechanism

Background

The capacity procurement mechanism (CPM) provides backstop procurement authority to ensure that the California ISO will have sufficient capacity available to maintain reliable grid operations. This mechanism facilitates pay-as-bid competitive solicitations for backstop capacity and establishes a price cap at which the CAISO can procure backstop capacity to meet resource adequacy requirements that are not met through load serving entity showings.

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 CAISO capacity procurement mechanism. Bids may range up to a soft offer cap set at $6.31/kW-month ($75.68/kW-year).

The CAISO 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 CAISO 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 a CAISO generated bid may choose to decline that designation within 24 hours of receiving notice.

The California 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 CAISO 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 CAISO 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 2021. 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 2021, and there have not been any since the program was implemented in 2016.

Intra-monthly designations

Table 9.14 shows the intra-monthly capacity procurement mechanism designations that occurred in 2021. The table shows the designated resources, 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 9.14 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
ARCOGN_2_UNITS	17	7/22/21	7/31/21	SIGEVT	$6.31	$0.03	SYS	Significant Event CPM Designation
BARRE_6_PEAKER	44	7/12/21	7/31/21	SIGEVT	$6.31	$0.19	SYS	Significant Event CPM Designation
BLKCRK_2_GMCBT1	133	7/9/21	7/31/21	SIGEVT	$6.31	$0.64	SYS	Significant Event CPM Designation
BUCKBL_2_PL1X3	51	7/9/21	7/31/21	SIGEVT	$6.31	$0.25	SYS	Significant Event CPM Designation
CALFTN_2_CFSBT1	60	9/1/21	9/30/21	SIGEVT	$6.31	$0.38	SYS	Significant Event CPM Designation
DRACKR_2_DSUBT1	63	9/1/21	9/30/21	SIGEVT	$6.31	$0.40	SYS	Significant Event CPM Designation
DRACKR_2_DSUBT3	81	8/2/21	8/31/21	SIGEVT	$6.31	$0.51	SYS	Significant Event CPM Designation
ELKHIL_2_PL1X3	30	8/1/21	8/31/21	SIGEVT	$6.30	$0.20	SYS	Significant Event CPM Designation
GARLND_2_GARBT1	45	9/1/21	9/30/21	SIGEVT	$6.31	$0.28	SYS	Significant Event CPM Designation
GATEWY_2_GESBT1	5	10/1/21	10/30/21	SIGEVT	$6.31	$0.03	SYS	Significant Event CPM Designation
HINSON_6_LBECH1	5	7/9/21	7/31/21	SIGEVT	$6.31	$0.02	SYS	Significant Event CPM Designation
HINSON_6_LBECH2	7	7/9/21	7/31/21	SIGEVT	$6.31	$0.03	SYS	Significant Event CPM Designation
HINSON_6_LBECH3	7	7/9/21	7/31/21	SIGEVT	$6.31	$0.03	SYS	Significant Event CPM Designation
HINSON_6_LBECH4	4	7/9/21	7/31/21	SIGEVT	$6.31	$0.02	SYS	Significant Event CPM Designation
INTKEP_2_UNITS	121	7/9/21	7/31/21	ED	$6.31	$0.59	SYS	Exceptional Dispatch CPM Capacity Need
JAWBNE_2_SRWWD2	2	10/1/21	10/30/21	SIGEVT	$6.31	$0.01	SYS	Significant Event CPM Designation
JOANEC_2_STABT1	20	7/12/21	7/31/21	SIGEVT	$6.31	$0.08	SYS	Significant Event CPM Designation
KRNCNY_6_UNIT	5	7/9/21	7/31/21	SIGEVT	$6.31	$0.02	SYS	Significant Event CPM Designation
KRNCNY_6_UNIT	3	8/1/21	8/8/21	SIGEVT	$6.31	$0.01	SYS	Significant Event CPM Designation
MNDALY_6_MCGRTH	43	7/9/21	8/8/21	ED	$6.31	$0.28	SYS	Exceptional Dispatch CPM Capacity Need
OMAR_2_UNIT 1	1	8/2/21	8/31/21	SIGEVT	$6.31	$0.00	SYS	Significant Event CPM Designation
OMAR_2_UNIT 1	1	9/1/21	9/30/21	SIGEVT	$6.31	$0.00	SYS	Significant Event CPM Designation
OMAR_2_UNIT 1	2	10/1/21	10/30/21	SIGEVT	$6.31	$0.01	SYS	Significant Event CPM Designation
OMAR_2_UNIT 2	2	8/2/21	8/31/21	SIGEVT	$6.31	$0.01	SYS	Significant Event CPM Designation
OMAR_2_UNIT 2	2	9/1/21	9/30/21	SIGEVT	$6.31	$0.01	SYS	Significant Event CPM Designation
OMAR_2_UNIT 2	2	10/1/21	10/30/21	SIGEVT	$6.31	$0.01	SYS	Significant Event CPM Designation
OMAR_2_UNIT 3	2	8/2/21	8/31/21	SIGEVT	$6.31	$0.01	SYS	Significant Event CPM Designation
OMAR_2_UNIT 3	2	9/1/21	9/30/21	SIGEVT	$6.31	$0.01	SYS	Significant Event CPM Designation
OMAR_2_UNIT 3	2	10/1/21	10/30/21	SIGEVT	$6.31	$0.01	SYS	Significant Event CPM Designation
OMAR_2_UNIT 4	2	8/2/21	8/31/21	SIGEVT	$6.31	$0.01	SYS	Significant Event CPM Designation
OMAR_2_UNIT 4	2	9/1/21	9/30/21	SIGEVT	$6.31	$0.01	SYS	Significant Event CPM Designation
OMAR_2_UNIT 4	2	10/1/21	10/30/21	SIGEVT	$6.31	$0.01	SYS	Significant Event CPM Designation
RUSCTY_2_UNITS	350	8/11/21	8/31/21	SIGEVT	$6.31	$1.55	SYS	Significant Event CPM Designation
RUSCTY_2_UNITS	251	9/1/21	9/10/21	SIGEVT	$6.31	$0.53	SYS	Significant Event CPM Designation
SBERDO_2_PSP3	15	7/9/21	7/31/21	SIGEVT	$6.31	$0.07	SYS	Significant Event CPM Designation
SBERDO_2_PSP4	45	7/9/21	7/31/21	SIGEVT	$6.31	$0.22	SYS	Significant Event CPM Designation
SCE1_MALIN500_I_F_262626	42	9/1/21	9/30/21	SIGEVT	$6.31	$0.27	SYS	Significant Event CPM Designation
SCE1_MALIN500_I_F_272727	25	9/1/21	9/30/21	SIGEVT	$6.31	$0.16	SYS	Significant Event CPM Designation
SCE1_MALIN500_I_F_282828	25	9/1/21	9/30/21	SIGEVT	$6.31	$0.16	SYS	Significant Event CPM Designation
SCE1_MALIN500_I_F_292929	25	9/1/21	9/30/21	SIGEVT	$6.31	$0.16	SYS	Significant Event CPM Designation
SCE1_MALIN500_I_F_303030	50	9/1/21	9/30/21	SIGEVT	$6.31	$0.32	SYS	Significant Event CPM Designation
SCE1_MALIN500_I_F_313131	50	9/1/21	9/30/21	SIGEVT	$6.31	$0.32	SYS	Significant Event CPM Designation
SCE1_MALIN500_I_F_414141	25	9/1/21	9/30/21	SIGEVT	$6.31	$0.16	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 1	3	8/2/21	8/31/21	SIGEVT	$6.31	$0.02	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 1	3	9/1/21	9/30/21	SIGEVT	$6.31	$0.02	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 1	3	10/1/21	10/30/21	SIGEVT	$6.31	$0.02	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 2	5	8/2/21	8/31/21	SIGEVT	$6.31	$0.03	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 2	3	9/1/21	9/30/21	SIGEVT	$6.31	$0.02	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 2	8	10/1/21	10/30/21	SIGEVT	$6.31	$0.05	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 3	70	7/10/21	8/9/21	ED	$6.31	$0.46	SYS	Exceptional Dispatch CPM Capacity Need
SYCAMR_2_UNIT 3	73	8/10/21	8/31/21	SIGEVT	$6.31	$0.34	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 3	4	9/1/21	9/9/21	SIGEVT	$6.31	$0.01	SYS	Significant Event CPM Designation
SYCAMR_2_UNIT 3	3	9/10/21	10/10/21	SIGEVT	$6.31	$0.02	SYS	Significant Event CPM Designation
VESTAL_2_WELLHD	38	7/9/21	7/31/21	SIGEVT	$6.31	$0.18	SYS	Significant Event CPM Designation
VISTRA_5_DALBT4	100	8/2/21	8/31/21	SIGEVT	$6.31	$0.63	SYS	Significant Event CPM Designation
Total	1,982					$9.83		

Key findings of this analysis include:

- ***About 1,980 MW of capacity was procured with an estimated cost of $9.8 million in 2021.*** In response to climate change and extreme heat events in the early part of the summer, the CPUC, CEC, and California ISO issued a joint statement on July 1, 2021, to secure additional energy resources and ensure electricity reliability during the summer.[304] The California ISO used its authority to issue a CPM Significant Event to procure additional capacity starting on July 9. In addition to the capacity procured for the significant event, the CAISO issued Exceptional Dispatch CPM designations to address a capacity deficiency that risked it not being able to meet load and reserve obligations. The California ISO procured about 230 MW of capacity at a total cost of about $1.3 million to address the exceptional dispatch system reliability need. Significant event CPM designations continued in August, September, and October to address the same concerns.

- ***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 CAISO 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.

9.7 Reliability must-run contracts

As of December 2021, capacity designated as reliability must-run (RMR) totaled about 469 MW. Total settlement for reliability must-run capacity was about $38 million in 2021, significantly up from $13 million and $11 million in 2020 and 2019, respectively. From 1998 through 2007, reliability must-run contracting played a significant role in the California ISO market, ensuring the reliable operation of the grid. In 2007, the CPUC's resource adequacy program was implemented and provided a cost-effective alternative to reliability must-run contracting by the California ISO.

Table 9.15 shows resources that are designated to be reliability must-run from 2016 through 2021. As shown in the table, in 2017, three new efficient gas units that represent almost 700 MW were designated to provide reliability must-run service beginning in 2018.[305] About 600 MW of this 700 MW of gas-fired generation was not re-designated for reliability must-run service in 2019. The need to designate the Metcalf Energy Center as a reliability must-run unit was eliminated by transmission upgrades completed in December 2018 and January 2019 and this resource returning as a resource adequacy unit in 2019. The remaining 100 MW of gas-fired generation was not re-designated for reliability must-run service in 2020. The two units, Yuba City Energy Center and Feather River Energy Center, returned as resource adequacy units in 2020.

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[304] Joint statement from CPUC and CEC to California ISO, *Joint Statement from the CPUC President Marybel Batjer, CEC Chair David Hochschild, and California ISO CEO Elliot Mainzer on decision to procure additional energy,* July 2, 2021: https://www.caiso.com/Documents/CapacityProcurementMechanismSignificantEvent-JointStatementandLetter.pdf.

[305] These included 593 MW of capacity from the combined cycle Metcalf Energy Center, and 94 MW of peaking capacity owned by Calpine.

Table 9.15 Designated reliability must-run resource capacity (2016 – 2021)

RMR Start date	RMR End date	RMR resource name	MW
5-Dec-2016	N/A	Oakland Station Unit 1	55.00
5-Dec-2016	31-Dec-2020	Oakland Station Unit 2	55.00
5-Dec-2016	N/A	Oakland Station Unit 3	55.00
1-Jan-2018	31-Dec-2018	Metcalf Energy Center	593.16
1-Jan-2018	31-Dec-2019	Feather River Energy Center	47.60
1-Jan-2018	31-Dec-2019	Yuba City Energy Center	47.60
1-May-2020	N/A	Channel Islands Power	27.50
1-Jun-2020	31-Dec-2020	E.F Oxnard	47.70
1-Jun-2020	N/A	Greenleaf II Cogen	49.20
1-Feb-2021	N/A	Midway Sunset Cogeneration Plant	248.00
1-May-2021	N/A	Kingsburg Cogen	34.50

In 2018, the California ISO designated one unit at the Ormond Beach Generating Station and Ellwood Energy Support Facility as reliability must-run units (aggregating 800 MW) extending the life of the units to the retirement dates originally considered in system planning. In 2019, the California ISO did not enter into reliability must-run contracts with these units and they were picked up in the resource adequacy program.

In 2020, three new units aggregating 124.4 MW of capacity, namely E.F. Oxnard, Greenleaf II, and Channel Islands Power, were designated for service as reliability must-run units. The contracts for these three units were filed at FERC in the May-June timeframe. About 47.7 MW of this capacity from E.F Oxnard returned as a resource adequacy unit in 2021.

In 2021, about 282.5 MW of additional capacity from Midway Sunset Cogeneration plant and Kingsbury Cogen have been designated as reliability must-run. In 2021, about 28.56 MW from Agnews Power Plant was approved for reliability must-run designation.[306] Ultimately, the California ISO did not enter into contract with this resource because it received a resource adequacy contract in 2022. On January 20, 2022, this resource notified of its intention to retire on January 1, 2023, and repower the site. Since this resource is required to meet local reliability needs in San Jose sub-area, the California ISO is recommending to designate it for reliability must-run services for year 2023.[307]

The California ISO completed a stakeholder initiative to clarify the reliability must-run designation type (local or system) when more than one reliability need exists.[308] The type of reliability need triggers cost allocation as well as the resource adequacy credits allocation of the reliability must-run contract. The final proposal considers "local" to be primary reliability need as it is consistent with both cost causation and resource adequacy credits allocation principles while also providing other incentives and benefits.

306 California ISO, *Potential reliability must-run designation – Agnews Power Plant,* presented by Catalin Micsa, May 18, 2021: http://www.caiso.com/Documents/PresentationPotentialReliabilityMustRunDesignationAgnewsPowerPlant-May182021.pdf

307 California ISO Market Notice, *Potential Reliability Must-Run Designation: Agnews Power Plant*, May 19, 2022: http://www.caiso.com/Documents/Potential-Reliability-Must-Run-Designation-Agnews-Power-Plant-Call-051922.html

308 California ISO initiative: *Clarifications to reliability must-run designation process:* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Clarifications-to-reliability-must-run-designation-process

10 Recommendations

As the California 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 California ISO, the California ISO Governing Board, FERC staff, state regulators, market participants, and other interested entities.[309] DMM participates in the CAISO stakeholder process and provides recommendations in written comments. DMM also provides recommendations in quarterly, annual, and other special reports, which are also posted on the CAISO 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 CAISO website.[310] A summary of key recommendations is provided in the executive summary of this report.

10.1 Western Energy Imbalance Market resource sufficiency tests

The resource sufficiency tests for both capacity and flexible ramping capacity are key elements of the Western Energy Imbalance Market design, which are intended to ensure that enough resources are available to meet reliability needs and prevent one balancing area from leaning on other WEIM areas.

The California ISO implemented a number of changes to the resource sufficiency evaluation in June 2022 as part of the resource sufficiency evaluation enhancements phase 1.[311] This phase includes changes to the capacity test that will exclude some capacity that is unavailable because of various operating limitations. It also includes the suspension of intertie and net load uncertainty in the capacity test, while the California ISO continues its efforts to develop a better approach for incorporating uncertainty into the requirement in phase 2. DMM supported both of these changes.[312]

Phase 2 of the initiative continues to explore other accuracy enhancements as well as failure consequences. DMM supports exploring broader changes to the resource sufficiency evaluation that would provide better incentives to deter balancing areas from leaning on the Western Energy Imbalance Market, while still allowing for efficient transfers of energy between different balancing areas through the WEIM. As part of this initiative, DMM is providing additional information and analysis about resource sufficiency evaluation performance, accuracy, and impacts in regular monthly reports.[313]

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

310 Department of Market Monitoring reports, presentations, and stakeholder comments can be found on the California ISO website: http://www.caiso.com/market/Pages/MarketMonitoring/Default.aspx

311 California ISO initiative: *WEIM resource sufficiency evaluation enhancements*: https://stakeholdercenter.caiso.com/StakeholderInitiatives/EIM-resource-sufficiency-evaluation-enhancements

312 Department of Market Monitoring, *Comments on EIM Resource Sufficiency Evaluation Enhancements Phase 1 Revised Draft Final Proposal*, January 11, 2022. http://www.caiso.com/Documents/DMM-Comments-EIM-Resource-Sufficiency-Evaluation-Enhancements-Phase-1-Revised-Draft-Final-Proposal-Jan-11-2022.pdf

313 Department of Market Monitoring, *2022 Western Energy Imbalance Market resource sufficiency evaluation reports:* http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=1571AD84-67B2-4641-BA7D-4499082910E5

As part of this ongoing initiative, DMM recommends the California ISO re-consider the uncertainty requirements used in the resource sufficiency tests, which is the same uncertainty used in the CAISO real-time market flexible ramping product.

The ISO's persistent use of load biasing in the hour-ahead and 15-minute markets and out-of-market dispatches show that the flexible ramping product is not providing CAISO operators with the ramping capacity they anticipate needing to protect against uncertainty. DMM believes careful consideration of measurement and transparent inclusion of uncertainty in the sufficiency tests will better accomplish the tests' goal of discouraging capacity leaning.

DMM continues to recommend that changes to the failed test consequences also be considered. Currently, when a WEIM area fails either the capacity test or flexible ramping test, WEIM 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 has recommended that both the California ISO and stakeholders consider other options, such as imposing a capacity charge or other financial charge.

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 California ISO start another stakeholder initiative to work on other important enhancements to the product's basic design.[314] Since 2016, DMM has recommended the following two key enhancements:[315]

- Increase the locational procurement of flexible ramping capacity to decrease the likelihood that the product is not deliverable (or *stranded*) because of transmission constraints. The CAISO implemented interim changes to address this issue in the 15-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 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 below.

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314 California ISO, Market and Infrastructure Development, *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

315 DMM highlighted these two recommendations in their 2018 annual report as well as in recent comments in the California ISO stakeholder process.
Department of Market Monitoring, *2018 Annual Report on Market Issues and Performance*, May 2019, pp. 269-270: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

Locational procurement

Analyses by DMM and the California ISO have shown that a significant portion of the current real-time flexible ramping product capacity procured is not deliverable because of transmission constraints.[316] Locational procurement that accounts for transmission constraints should result in deliverable reserves, which will significantly increase the efficiency of the CAISO market awards and dispatches. The California ISO plans to implement nodal procurement as part of the flexible ramping product refinements stakeholder initiative, which is currently expected to be implemented in the fall of 2022.[317]

Real-time product for uncertainty over longer time horizons

DMM continues to recommend that the California ISO develop an approach for extending the time horizon of the flexible ramping product to account for uncertainty over longer time horizons. The current product is designed to address uncertainty between both 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). The range of uncertainty increases over longer time horizons.[318]

The current flexible ramping product design both procures and prices ramping capability in the 15-minute market to account for uncertainty between the 15-minute and 5-minute markets. In the 5-minute market, the market software procures and prices the appropriate amount of ramping capability to account for the uncertainty in only 5-minute net load forecasts. As the CAISO incorporates growing quantities of distributed and variable energy resources, there will be 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 routinely enter large positive load adjustments (e.g., from 1,000 to 3,000 MW) 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. These manual actions include committing additional gas-fired units and then ramping these resources up in the peak ramping hours using exceptional dispatches. 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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316 California ISO Market Surveillance Committee Meeting, *Discussion on flexible ramping product*, presented by Lin Xu, Ph.D., September 8, 2017 pp. 16-17:
http://www.caiso.com/Documents/Discussion_FlexibleRampingProduct.pdf

Department of Market Monitoring, *Q3 Report on Market Issues and Performance*, December 5, 2019, pp. 84-86.
http://www.caiso.com/Documents/2019ThirdQuarterReportonMarketIssuesandPerformance.pdf

317 California ISO initiative: *Flexible ramping product refinements:*
https://stakeholdercenter.caiso.com/StakeholderInitiatives/Flexible-ramping-product-refinements

318 Illustrations of this concept as applied to the flexible ramping product are available in:
Department of Market Monitoring, *Enhancing the flexible ramping product to better address net load uncertainty,* presentation by Ryan Kurlinski at the WEIM 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 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 California ISO day-ahead market enhancements initiative, the CAISO is proposing a new imbalance reserve product that would be procured in the day-ahead market, based on the net load forecast. Without changes to the real-time flexible ramping product, capacity procured through the day-ahead imbalance reserve product may be inefficiently released and not replaced in the real-time market. Extending the real-time flexible ramping product horizons will help ensure that imbalance reserves procured in the day-ahead market are not released inefficiently.

10.3 Day-ahead market enhancements

In 2018, the California ISO initiated a process to develop a proposal for day-ahead market enhancements.[319] This initiative is intended to feed into a separate ongoing initiative to develop an extended (regional) day-ahead market that includes balancing areas participating in the real-time Western Energy Imbalance Market.

Day-ahead imbalance reserve product

A key element of the 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 the procurement of this product.

However, if the California 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 California 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 future net load forecasts.

DMM is not convinced that the imbalance reserve design would significantly increase overall efficiency of the CAISO markets in the absence of an extended (regional) day-ahead market. The imbalance reserve product has some complicated design issues that may be difficult to resolve in the near term.[320] DMM recommends that the California ISO focus its efforts on the aspects of day-ahead market enhancements that may be needed to complete a regional extended day-ahead market initiative. This

[319] California ISO Initiative, *Day-Ahead Market Enhancements:* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements

[320] Department of Market Monitoring, *Comments on Day-Ahead Market Enhancements: Third Revised Straw Proposal,* May 19, 2022: http://www.caiso.com/Documents/DMM-Comments-Day-Ahead-Market-Enhancements-3rd-Revised-Straw-Proposal-May-20-2022.pdf

would facilitate considering other potential day-ahead capacity procurement options that may be needed to complete a reliable and equitable extended day-ahead market.

10.4 Extended day-ahead energy market

In 2019, the California ISO initiated a process to develop a proposal for extending the day-ahead market to include other entities in the Western Energy Imbalance Market.[321] DMM supports the CAISO's efforts to extend the day-ahead market to other balancing areas across the west. This has the potential to provide significant efficiency benefits by facilitating trade between diverse areas and resource types.

This initiative is designed to build on market design changes made in the day-ahead market enhancements initiative. As noted above, DMM views the day-ahead imbalance reserve product proposed in the day-ahead market enhancements initiative as being a key element of an extended regional day-ahead market. DMM suggests that this design feature be considered in the context of an extended regional market, amongst other potential day-ahead capacity procurement options that may be needed to complete a reliable and equitable extended day-ahead market.

As explained in DMM's comments on the California ISO's April 2022 straw proposal, several areas of the proposed design warrant substantial development or clarification in order to produce a feasible design.[322] The California ISO needs to define clearly how the core elements of the extended day-ahead market design will work together during the critical hours each year when the potential exists for a supply shortfall in the extended day-ahead market footprint.

For example, the California ISO has verbally indicated that the extended day-ahead market design is intended to have all participating balancing areas that pass the day-ahead resource sufficiency evaluation share the consequences of any real-time supply shortfall in the extended day-ahead market footprint. DMM agrees that this high-level design would be ideal. However, other elements of the California ISO's April straw proposal suggest that this principle may not be applied in real-time under the current proposal.

10.5 Congestion revenue rights

Over the 10-year period from 2009 through 2018, payouts to non-load-serving entities purchasing congestion revenue rights in the California ISO auction exceeded the auction revenues by about $860 million. If the CAISO did not auction these congestion revenue rights, these congestion 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 $860 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 that do not serve any load or schedule any generation in the CAISO.

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321 California ISO, *Extending the Day-Ahead Market to EIM Entities Issue Paper*, October 10, 2019: http://www.caiso.com/Documents/IssuePaper-ExtendedDayAheadMarket.pdf

322 Department of Market Monitoring, *Comments on Extended Day-Ahead Market Straw Proposal,* June 17, 2022: http://www.caiso.com/Documents/DMM-Comments-Extended-Day-Ahead-Market-Straw-Proposal-June-17-2022.pdf

In response to the consistently large losses from sales of congestion revenue rights, the CAISO instituted significant changes to the auction starting in the 2019 settlement year.[323] The changes implemented in 2019 have reduced, but not eliminated, ratepayer auction losses.

- Ratepayer losses have averaged $45 million per year in the three years since the changes, compared to $114 million in the seven years before the changes.
- Ratepayers were paid an average of 68 cents per dollar paid out to auctioned congestion revenue rights, compared to about 48 cents per dollar before the changes.
- In the three years since, auction losses have averaged 9 percent of day-ahead congestion rent, down from 28 percent before the changes.

DMM continues to believe that the current auction is unnecessary and could be eliminated, with all congestion rents being returned to transmission ratepayers. If the CAISO 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.

Building on the existing reforms could further reduce ratepayer losses. Auction losses could be further reduced by reducing the amount of auctioned rights, either generally or from specific locations with significant underpricing. Reducing the amount of rights could be achieved by lowering auction constraint limits.

Some load serving entities have pointed out that ratepayer losses could also be reduced by raising (rather than lowering) constraint limits in the allocation process. This could reduce the amount of rights that could be sold in the auction without reducing rights allocated to load serving entities, as could occur if constraints were de-rated in the allocation and auction.

10.6 Pricing under tight supply conditions

In 2021, the California ISO implemented numerous changes that feature steps to allow prices to rise and increase compensation for imports during tight supply conditions. First, the FERC Order No. 831 compliance filing included 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 CAISO 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 California ISO developed and implemented the following changes on an expedited basis in order to improve pricing and compensation of needed supply under tight conditions:

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[323] Department of Market Monitoring, *2019 Annual Report on Market Issues and Performance,* June 2020, pp. 230-234: http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf

- 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 be paid below their offer price in any given hour during tight system conditions.
- When the CAISO arms load to serve as operating reserves (i.e., prepares to shed load in a controlled manner, if needed), and then releases generation that was serving as reserves into the energy supply stack, the CAISO 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 supports these changes and believes they will improve the functioning of the CAISO markets during tight system conditions.[324] 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 California ISO review and consider market performance, with these changes in effect, as it considers adding additional scarcity pricing provisions.

The California ISO is scheduled to consider changes to its scarcity pricing provisions under a broader price formation initiative beginning in 2022. DMM has 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.

10.7 Scarcity pricing and system-level market power

The CAISO has tariff provisions and automated procedures for mitigating local market power in congested areas within the balancing area. However, CAISO rules do not provide for mitigating potential market power at a system level, or across the entire CAISO balancing area. Despite the lack of any bid mitigation for system market power, the CAISO energy markets have been highly competitive at a system level since the early 2000s due to a number of factors. These include a high level of forward bilateral energy contracting by the CAISO load serving entities, relatively high supply margins, and access to imports from other balancing areas.

In recent years, however, a number of regulatory and structural market changes have occurred that have increased the potential for system-level market power in the CAISO balancing area and throughout the entire western region. In 2018, DMM recommended that the California ISO 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. As noted in DMM's 2020 annual report,

[324] Department of Market Monitoring, *Motion To Intervene and Comments (FERC 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

several of these recommendations are being addressed in different California ISO stakeholder initiatives and CPUC proceedings.[325]

System market power bid mitigation

In 2020, the California ISO developed system market power mitigation measures for the real-time market only. The proposed measures are triggered when the CAISO balancing area may be import constrained.[326,327] In early 2021, the California ISO deferred further work on approving and implementing a final proposal that could have been approved and implemented before summer of 2021.

DMM supports the California ISO efforts to design and implement system market power mitigation, and is generally supportive of the proposal being developed. Despite some limitations of the current proposal, DMM believes that it 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 California 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.

As part of an initiative that will include the consideration of changes to the CAISO scarcity pricing provisions, the California ISO is scheduled to resume the system market power mitigation proposal in late 2022. DMM cautioned, 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.[328] The CPUC took steps to address this issue in 2020 by requiring that non-resource-specific import resource adequacy resources, procured by CPUC-jurisdictional participants, must be self-scheduled or bid into the CAISO markets at or below $0/MWh during the peak net load hours of 4-9 p.m., starting in 2021.[329]

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325 Department of Market Monitoring, *2020 Annual Report on Market Issues and Performance*, August 2021, pp. 278 - 279: http://www.caiso.com/Documents/2020AnnualReportonMarketIssuesandPerformance.pdf

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

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

328 Department of Market Monitoring, *2018 Annual Report on Market Issues and Performance*, May 2019, p. 269: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf
Department of Market Monitoring, *Import Resource Adequacy*, September 10, 2018: http://www.caiso.com/Documents/ImportResourceAdequacySpecialReport-Sept102018.pdf

329 CPUC Docket No. R.17-09-020, *Decision adopting resource adequacy import requirements (D.20-06-028)*, June 5, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K516/342516267.PDF

DMM has suggested that the CAISO market rules could be modified so the resource adequacy imports would 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. The California ISO contends that subjecting resource adequacy imports to any type of bid mitigation would be "ineffective and inappropriate."[330]

DMM has also suggested that the California ISO consider options for increasing the supply and availability of energy from resource adequacy imports beyond the day-ahead market into real-time.

10.8 Export and wheeling schedules

The summer 2020 heat wave highlighted the need to review the California ISO policies and procedures for curtailing load versus curtailing exports and wheeling schedules. During the hours in August 2020 when the California ISO grid operators curtailed the CAISO balancing area load, operators did not curtail any exports or wheeling schedules. In the following days and weeks, the CAISO took several steps to modify its software and procedures so that some exports would be curtailed before curtailment of CAISO area load.

In addition, the CAISO 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.[331] This process resulted in tariff changes that provide for curtailment of some exports and wheeling schedules before curtailment of CAISO area load. These interim rules were initially approved by FERC for a one year period through 2022.

In 2021, the California ISO began the transmission service and market scheduling priorities initiative.[332] The first phase of this initiative extended the interim rules until 2024. Through the second phase of this initiative, the CAISO continues to 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 CAISO balancing authority area, while better aligning the CAISO market rules and practices with those of other balancing areas, independent system operators, and regional transmission organizations. Over the longer term, DMM continues to recommend that the California ISO develop an approach for transmission scheduling priority that is more similar to that of other independent system operators.

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. Currently, the California ISO does not have a process to account for the needs of the CAISO balancing area load at an existing firm use, or a way to determine the

[330] California ISO, *System Market Power Mitigation Straw Proposal*, December 11, 2019, pp. 30-32: http://www.caiso.com/InitiativeDocuments/StrawProposal-SystemMarketPowerMitigation.pdf

[331] California ISO Initiative, *Market enhancements for summer 2021 readiness:* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Market-enhancements-for-summer-2021-readiness

[332] California ISO Initiative, *Transmission service and market scheduling priorities:* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Transmission-service-and-market-scheduling-priorities

long-term availability of excess transmission that could be sold to other entities at priority equal to the CAISO load.

Based on DMM's understanding of the rules and practices in other balancing areas, making the California ISO rules consistent with that of other independent system operators and balancing areas would involve the following additional changes:

- Establish a process to determine excess available transmission capacity on the CAISO 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 the CAISO 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 California ISO's commitment to work with stakeholders in the ongoing transmission services and market scheduling priorities initiative to develop more comprehensive longer-term rules for transmission scheduling priorities by summer 2024.

10.9 WECC soft offer cap

During several days in August 2020 and summer 2021, numerous entities made bilateral spot market sales at prices over $1,000/MWh in the Western Electricity Coordinating Council (WECC) outside 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 FERC cost justification.

DMM submitted comments in these cost justification proceedings, noting, "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-ahead and real-time energy markets."[333] DMM recommended that the Commission develop and provide clear guidance and precedent on what constitutes valid cost justification through these proceedings.

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 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. In April 2022, FERC issued rulings on a portion of the cost justification filings submitted for sales in 2020. These rulings provided clarification on several aspects of its prior guidance.

- FERC approved numerous cost filings for hourly or multi-hourly sales at or below the weighted average price index for day-ahead 16-hour peak energy product in the Intercontinental Exchange.
- FERC ordered refunds for the incremental amount by which some sales prices exceeded these day-ahead price indices.

333 Department of Market Monitoring, *Comments on WECC Soft Offer Cap, Shell Energy North America (FERC Docket No. ER21-57)*, October 28, 2020. http://www.caiso.com/Documents/CommentsoftheDepartmentofMarketMonitoring-WECCSoftOfferCap-ShellEnergy-ER21-57-000-Oct282020.pdf

- FERC approved numerous bilateral sales that were based on price indices for nearby trading hubs, but did not allow sales made in the Pacific Northwest (e.g., Mid-C) to be justified by price indices for distant trading hubs in the Southwest (e.g., Palo Verde).

DMM believes that, on balance, this additional clarification is beneficial to the market. However, numerous other issues and details remain to be addressed in the context of other cost filings still pending before the Commission. DMM will continue to review 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.

10.10 Resource adequacy

California relies on the state's long-term bilateral procurement process and resource adequacy program to maintain adequate system capacity and help mitigate market power through forward energy contracting. 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 finalized two important changes to resource adequacy in 2020:

- Adopt a multi-year framework for local resource adequacy requirements and procurement by load serving entities.
- Develop a central buyer framework for meeting any local resource adequacy requirements not met by resource adequacy capacity procured by CPUC-jurisdictional load serving entities.

The CPUC has identified additional options for addressing these issues and is currently working with the California ISO and stakeholders on moving forward with more detailed market design options and decisions. These options include the following:

- Strengthen requirements for the use of imports to meet system-level resource adequacy requirements.
- Develop resource adequacy requirements and resource capacity ratings that ensure sufficient flexible capacity needed to integrate a high level of renewable resource capacity.
- Develop 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 under consideration by the CPUC as potentially effective steps in addressing the current gaps in the state's resource adequacy framework. DMM also recommends the California 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 has warned that existing CAISO 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 current CAISO resource adequacy rules, imports can routinely be 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.[334]

The CPUC has sought to address this concern 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 the CAISO markets at or below $0/MWh during peak net load hours of 4-9 p.m.[335] 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.[336]

In May 2021, the CPUC issued another decision deferring the 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.[337]

DMM supported development of a source-specific framework for resource adequacy imports that 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 California ISO and CPUC.

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 that are being relied upon to meet an increasing portion of resource adequacy requirements.[338] These resources include solar, imports, demand response, and battery capacity in peak net load hours. Each of these resource types have generally had limited availability during peak net load hours when the CAISO counts on resource adequacy capacity to be available the most.

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334 Department of Market Monitoring Special Report*: Import Resource Adequacy*, September 10, 2018, pp. 1-2: http://www.caiso.com/Documents/ImportResourceAdequacySpecialReport-Sept102018.pdf

335 CPUC Docket R.17-09-020, *Decision adopting resource adequacy import requirements (D.20-06-028)*, June 5, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K516/342516267.pdf

336 Department of Market Monitoring, *Comments on Proposed Decision Clarifying Resource Adequacy Import Rules,* CPUC Docket No. R.17--09--020, September 26, 2019: http://www.caiso.com/Documents/CommentsofDepartmentofMarketMonitoringonProposedDecisionClarifyingRAImportRules-R17-09-020-Sept262019.pdf

337 CPUC Docket R.19-11-009, *Decision adopting Local Capacity Obligations for 2022 – 2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program (D.21-06-029),* June 24, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.pdf

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

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 CAISO needed to curtail uninterruptible load for the first time in 20 years during two hours. Reports by both DMM and the California ISO found that a key factor contributing to these outages was that current rules for counting the resource adequacy capacity provided by different resources significantly overstate the actual available capacity of these resources during critical peak net load hours.[339]

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.[340] DMM supports the CPUC's decision that 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, as well as 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 the California ISO, will begin to develop new capacity counting methodologies for demand response resources with variable availability.[341]

The CPUC will also remove 6 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.[342] DMM supports these efforts, which could more accurately measure the capacity contribution of demand response resources.

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.[343] 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 adequacy program discussed above which could better capture the temporal contribution of different resource types towards meeting energy and capacity requirements.

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339 Department of Market Monitoring, *Report on system and market conditions, issues and performance: August and September 2020*, November 24, 2020, pp. 1-3: http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

340 CPUC Docket No. R.19-11-009, *Decision on Track 3B.2 Issues: Restructure of the Resource Adequacy Program (D.21-07-014),* July 15, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M393/K334/393334426.pdf

341 CPUC Docket No. R.19-11-009, *Decision adopting Local Capacity Obligations for 2022 – 2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program (D.21-06-029)*, June 24, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.pdf

342 Ibid.

343 CPUC Docket No. R.20-11-003, *Decision Directing PG&E, SCE, and SDG&E to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2021 and 2022 (D.21-03-056),* March 26, 2021: https://docs.cpuc.ca.gov/publisheddocs/published/g000/m373/k745/373745051.pdf

Resource adequacy performance incentives

The current California ISO mechanism for incentivizing the availability of resource adequacy capacity is the 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 CAISO CPM soft offer cap, which is currently $6.31/kW-month.[344]

As capacity becomes more limited and prices increase in the west, the difference between capacity payments and potential RAAIM penalties also increases. Additionally, starting in 2021, the CPUC's penalty costs for system resource adequacy showing deficiencies for summer month increased from $6.66/kW-month to $8.88/kW-month.[345] Starting in 2022, these penalties will become much higher for load serving entities with repeated deficiencies.[346]

DMM is concerned that if the California ISO 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. A supplier could also avoid current penalties by offering capacity into the CAISO market even though this capacity fails to perform when called upon.

During the 2020 and 2021 heat waves, resources that were scheduled to operate, but did not perform in real-time, generally faced little financial consequences. This resulted from the fact that during these heat waves, real-time energy market prices were often lower than day-ahead prices. The recent California ISO summer readiness enhancements may enhance real-time pricing during tight system conditions, and create stronger financial incentives for resources to deliver expected energy. However, DMM still has some concerns that if capacity payments are very high, there could also be limited incentives for resources receiving these payments to actually perform when needed by the CAISO.

DMM recommends that the California 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 CAISO. This type of mechanism could also better incentivize suppliers to sell highly available, and dependable, capacity up front.

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344 California ISO Tariff Section 40.9.6.1(c): http://www.caiso.com/Documents/Section40-ResourceAdequacyDemonstration-for-SchedulingCoordinatorsintheCaliforniaISOBalancingAuthorityArea-Jun1-2022.pdf

345 CPUC Docket No. R.19-11-009, *Decision Adopting Local Capacity Obligations for 2021 – 2023, Flexible Capacity Obligations for 2021, and Refining the Resource Adequacy Program (D.20-06-031),* June 24, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K083/342083913.PDF

346 CPUC Docket No. R.19-11-009, *Decision adopting Local Capacity Obligations for 2022 – 2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program (D.21-06-029),* 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 at least one *central procurement entity* authorized to procure the 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. DMM supports the CPUC decision to adopt a multi-year framework for local resource adequacy through a central buyer framework.[347] The adopted framework should help avoid unnecessary reliance on the California ISO's two backstop procurement mechanisms: the capacity procurement mechanism, and the reliability must-run contracts.

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.[348] 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. 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.

10.11 Demand response resources

In the last two years, the California ISO has increasingly relied on demand response to curtail load during peak summer hours. Demand response resources are currently used to meet about 3 to 4 percent of total system resource adequacy capacity requirements in the peak summer months. About 85 percent of this capacity is comprised of utility demand response programs that are credited towards reducing resource adequacy requirements. The remaining 15 percent of this capacity is from programs run by non-utility third parties.

DMM's analysis of how demand response resources participated and performed in the CAISO market on high load days in summer 2020 and 2021 shows that a large portion of demand response resource adequacy capacity was not available for dispatch, or performed significantly below dispatched levels during key peak net load hours.[349] This results from a combination of how demand response resources are counted toward resource adequacy requirements, as well as by the performance of some demand response programs after being dispatched.

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347 Department of Market Monitoring, *2018 Annual Report on Market Issues and Performance*, p. 268: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

348 CPUC Docket No. R.17-09-020, *Decision on Central Procurement of the Resource Adequacy Program (D.20-06-002)*, June 11, 2020: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M340/K671/340671902.PDF

349 Department of Market Monitoring, *Demand Response Issues and Performance 2021*, January 12, 2022: http://www.caiso.com/Documents/Demand-Response-Issues-Performance-Report-Jan-12-2022.pdf

Department of Market Monitoring, *2020 Annual Report on Market Issues and Performance,* August 2021, pp. 21-22: http://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf

Resource adequacy payments, or the value of reduced resource adequacy requirements, are the primary revenue sources for demand response resources. Even when demand response resources are frequently dispatched, the energy market revenues from actually performing (or charges for failing to perform) represent a relatively small portion of the overall compensation or value of these resources. This current market framework does not provide a strong financial incentive for most demand response resources to perform when needed most under critical system conditions.

In prior reports, DMM has highlighted some recommendations that the CAISO and CPUC could consider to enhance the availability and performance of demand response resources, especially before increasing reliance on demand response towards meeting resource adequacy requirements.[350] The California ISO, CPUC, and CEC are currently working on addressing some important issues pertaining to demand response. DMM's major recommendations include the following:

- ***Re-examine demand response counting methodologies.*** The California ISO, CPUC, and CEC are currently examining different counting methodologies for demand response, including methodologies which would better capture the variable nature of demand response availability.[351] Counting methodologies should better capture the capacity contribution of demand response resources with load reduction capabilities that vary across the day and may have limited output in general.
- ***Adopt the California ISO's recommendation to remove the planning reserve margin adder applied to demand response capacity counted towards system resource adequacy requirements under the CPUC jurisdiction.*** The CAISO has recommended that the CPUC discontinue applying a planning reserve margin adder to demand response capacity values.[352] Starting in 2022, the CPUC will remove 6 of the 15 percent planning reserve margin adder applied to demand response capacity credits, and the CEC will examine whether the remaining 9 percent of the adder should be retained.[353] The CAISO and DMM recommend that the CPUC consider removing the remaining 9 percent of the planning reserve margin adder, as this adder contributes to overestimating the actual resource adequacy value of utility demand response programs on high load days.

[350] Department of Market Monitoring, *Demand response, issues and performance*, February 25, 2021, pp. 3-4: http://www.caiso.com/Documents/ReportonDemandResponseIssuesandPerformance-Feb252021.pdf

Department of Market Monitoring, *2020 Annual Report on Market Issues and Performance*, August 2021, pp. 21-22: http://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf

[351] California Energy Commission, *CEC Docket Log for Docket 21-DR-01:* https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=21-DR-01

[352] CPUC Docket R.19-11-009, *California Independent System Operator Corporation Consolidated Comments on all Workshops and Proposals*, March 23, 2020, pp. 10-11: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M330/K052/330052136.pdf

[353] CPUC Docket No. R19-11-009, *Decision adopting Local Capacity Obligations for 2022 – 2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program (D.21-06-029)*, June 25, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.pdf

- ***Make demand response available on Saturdays.*** In 2021, the CPUC also approved rules that would require demand response programs counted towards resource adequacy to be available on Saturdays, which DMM supported as high load days in recent years have not been limited to weekdays.[354]

- ***Consider developing a performance-based penalty or incentive structure for resource adequacy resources***. A performance-based penalty or incentive mechanism could be particularly relevant for demand response resources because of the difficulty of determining, in advance, whether or not a new demand response resource—or an existing provider that is selling additional new capacity—is capable of delivering load curtailment in critical hours equal to the quantity of resource adequacy capacity that the resource has been paid to provide.

10.12 Energy storage resources

The amount of energy storage resources on the CAISO system has increased significantly in recent years. Battery energy storage capacity is projected to continue increasing in coming years and is being relied upon to play a key role in the integration of renewable resources. While battery resources are generally very fast responding and flexible, the availability of these resources depends on their state of charge levels. For example, battery resources providing resource adequacy sometimes do not have sufficient charge to provide resource adequacy values for four consecutive hours across peak net load periods. Consequently, DMM has played an active role in efforts to develop new market rules and software enhancements to facilitate use of energy storage resources.

DMM has suggested potential changes to CPUC and CAISO 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 CAISO's non-generator resource (NGR) model to local market power mitigation, and developing methods to better reflect costs of energy storage resources in market models.[355] Starting in November 2021, storage resources default energy bids were developed and these resources became subject to market power mitigation. DMM also recommended that the CAISO 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 CAISO consider enhancing processes for issuing exceptional dispatches to battery resources by issuing these dispatches as state of charge values instead of megawatt values.

DMM has previously recommended new bid cost recovery (BCR) rules for energy storage resources. New BCR rules are needed to mitigate inefficiencies and potential gaming opportunities that may result from differences between day-ahead and real-time state of charge. Recently observed market outcomes and the growing capacity of energy storage resources on the CAISO system continue to underscore the

[354] CPUC Docket No. R.19-11-009, *Decision Adopting Local Capacity Obligations for 2022-2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program, (D.21-06-029),* June 25, 2021, pp. 9-10: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.PDF

[355] Department of Market Monitoring, *2018 Annual Report on Market Issues and Performance*, May 2019, p. 24: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf

need to address BCR for energy storage resources. DMM continues to recommend that the CAISO develop these revised BCR rules as soon as practicable.

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 California 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.[356]

The CAISO and DMM have made significant progress in understanding the costs of batteries through both the ESDER 4 and energy storage enhancements stakeholder processes. This information has led to the development of a default energy bid for energy storage resources, as well as proposals to model different operational limitations of these resources, and a proposal to develop a new energy storage model that reflect costs and bids based on state of charge. DMM supports these efforts, as well as the CAISO's application of local market power mitigation procedures to energy storage resources.

The default energy bids for energy storage resources, developed in the ESDER 4 initiative, model three types of costs – energy costs, variable operations costs including cycling and cell degradation costs, and opportunity costs. The CAISO calculates a static default energy bid value over the day for each battery resource.[357]

DMM is supportive of this framework but has recommended several additional refinements.[358] DMM recommends that the CAISO 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;
- Reconsider the use of day-ahead local market power mitigation run prices as an input to the day-ahead storage default energy bid; and

[356] Department of Market Monitoring, *2019 Annual Report on Market Issues and Performance*, June 2020, pp. 306-307: http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf

[357] California ISO, *Energy Storage and Distributed Energy Resources – Storage Default Energy Bid – Final Proposal*, October 22, 2020: http://www.caiso.com/InitiativeDocuments/FinalProposal-EnergyStorage-DistributedEnergyResourcesPhase4-DefaultEnergyBid.pdf

[358] Department of Market Monitoring, *Comments on Energy Storage and Distributed Energy Resources – Storage Default Energy Bid Final Proposal*, November 12, 2020. http://www.caiso.com/Documents/DMMComments-EnergyStorageandDistributedEnergyResources-StorageDefaultEnergyBidFinalProposal-Nov122020.pdf

- 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.

DMM also supports the CAISO's proposal in the energy storage enhancements stakeholder initiative to develop a new energy storage model based on state of charge. This proposed model is likely to be a significant improvement in the ability of battery storage resources to accurately reflect costs applicable to a particular market interval.[359]

Resource adequacy battery capacity

Batteries are part of a more general category of energy-limited or availability-limited resources that 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. For example, DMM has 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.

A longer real-time look ahead horizon could help position storage resources to be able to meet demand in peak net load hours. Battery resources should also be incentivized to be charged for peak net load hours when the CAISO will rely on storage capacity the most. DMM recommends that the CAISO 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; and
- 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, when operators have issued exceptional dispatches to batteries with existing ancillary service awards, the

[359] Department of Market Monitoring, *Comments on Energy Storage Enhancements Revised Straw Proposal*, April 7, 2022. http://www.caiso.com/Documents/DMM-Comments-on-Energy-Storage-Enhancements-Revised-Straw-Proposal-Apr-7-2022.pdf

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 maintain better operating reserve awards and could help avoid unnecessary charging and discharging of storage resources.

The CAISO is considering such enhancements in the energy storage enhancements stakeholder initiative. DMM supports these proposed enhancements to the exceptional dispatch process for energy storage resources.

Bid cost recovery rules for energy storage resources

DMM recommends that the CAISO consider developing new bid cost recovery (BCR) rules for energy storage resources as soon as practicable. These new BCR rules are needed to mitigate potential gaming opportunities and improve the efficiency of market dispatch when day-ahead state of charge values deviate significantly from actual state of charge values in real-time.

In the day-ahead market, battery resources submit an initial state of charge value that the day-ahead market software assumes will be 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. Real-time market dispatches and regulation movements can further contribute to differences between day-ahead and real-time state of charge values. When these values diverge significantly, the real-time market may schedule a battery much differently than was predicted in the day-ahead market. In many of these cases, resources receive significant real-time bid cost recovery when they 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 4 stakeholder processes, DMM recommended the CAISO consider the implications of a day-ahead submitted state of charge as a new and unique intertemporal constraint between markets.[360] DMM recommended that the CAISO revisit this topic in future initiatives to address potential settlement implications. DMM has recently observed market outcomes that continue to support the need to revise bid cost recovery rules for energy storage resources.

[360] Department of Market Monitoring, *Stakeholder Comment on Energy Storage and Distributed Energy Resources (ESDER), Revised Draft Final Proposal*, February 2, 2016. http://www.caiso.com/InitiativeDocuments/DMMComments-EnergyStorageDistributedEnergyResources-RevisedDraftFinalProposal.pdf